DECLARATION OF YOLANDA ANDERSEN

I, Yolanda Andersen, declare as follows:

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

6. When an individual becomes a member of the Sierra Club, his or her current residential address is recorded in our membership database. The database entry reflecting the member's residential address is verified or updated as needed.
7. The Sierra Club currently has 583,913 members in the United States and 21,527 members in Texas. These members have a strong interest in protecting human health and the environment from the effects of natural gas extraction and export.

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

Yolanda Andersen

Yolanda Andersen

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

Before the

Committee on Energy and Natural Resources
United States Senate

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

November 8, 2011

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

DOE's Statutory Authority

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

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

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

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

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

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

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

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

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

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

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

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

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

Recent Developments in LNG Exports

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

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

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

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

Sabine Pass Liquefaction, LLC

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

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

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

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

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

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

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

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

- The public record supported the conclusion that the requested authorization will yield tangible benefits to the public whereas the allegations of negative impacts submitted by interveners opposing the application were not substantiated on the record. In particular,

> the interveners failed to offer any rebuttal studies of natural gas supply, demand and/or price analysis to support their claim the application was not consistent with the public interest.

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

Pending LNG Export Applications

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

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

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

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

Conclusion

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

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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OFFICE OF
ECOSYSTEMS,
TRIBAL AND PUBLIC
AFFAIRS

October 29, 2012

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

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

Dear Secretary Bose:

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

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

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

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

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

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

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

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

Sincerely,

Christine B. Reichgott

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

Enclosure

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

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

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

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

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

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

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

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

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

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

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

Environmental Consequences

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

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

Water Quality

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

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

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

Hydrostatic Test Water

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

Source Water Protection

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

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

Wetlands and Aquatic Habitats

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

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

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

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

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

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

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

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

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

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

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

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

Biological Resources, Habitat and Wildlife

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

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

Land Use Impacts

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

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

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

Invasive Species

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

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

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

Hazardous Materials/Hazardous Waste/Solid Waste

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

Seismic and Other Risks

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

Blasting Activities

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

National Historic Preservation Act

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

Environmental Justice and Impacted Communities

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Climate Change

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

Coordination with Tribal Governments

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

Indirect Impacts

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

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

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

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

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

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

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

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

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

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

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

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

November 15, 2012

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

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

Dear Secretary Bose:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely,

Jeffrey D. Lapp, Associate Director
Office of Environmental Programs

Document Content(s)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

OFFICE OF
ECOSYSTEMS,
TRIBAL AND PUBLIC
AFFAIRS

December 26, 2012

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

Re: SCOPING COMMENTS – The Oregon LNG Export Project and Washington Expansion Project. EPA Region 10 Project Number: 12-0055-FRC. *FERC Docket Nos. PF12-18-000 and PF12-20-000.*

Dear Secretary Bose:

The U.S. Environmental Protection Agency would like to provide detailed scoping comments in response to the Federal Energy Regulatory Commission's (FERC's) September 24, 2012 Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for the Oregon Liquefied Natural Gas (LNG) Export Project and Washington Expansion. These comments were prepared in accordance with our authorities pursuant to the National Environmental Policy Act (NEPA), Section 309 of the Clean Air Act, the Clean Water Act, and our responsibilities as a Cooperating Agency. We appreciate the opportunity for early involvement at this step of the NEPA process.

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

As described in the NOI, the Oregon LNG export project would consist of components new to and modified from the originally proposed import-only LNG terminal and pipeline (Docket Nos. CP09-6-000 and CP09-7-000) to allow Oregon LNG to export LNG. The export project would be capable of liquefying approximately 1.3 billion cubic feet per day (Bcf/d) of pretreated natural gas for the export of approximately 9 million metric tons per annum (MTPA) of LNG via LNG carriers.

Specifically, the Export Project would be comprised of liquefaction and export facilities at Warrenton, Oregon and approximately 39 miles of new pipeline. Liquefaction facilities would include:

- A natural gas pretreatment facility to remove sulfur compounds, water, mercury, and other impurities;
- Two liquefaction process trains, each capable of a liquefaction capacity of approximately 4.5 MTPA;
- Refrigerant storage;
- New flare system;

- New water intake on the Columbia River and water delivery pipeline from the intake to a new water treatment system.

Pipeline facilities would include:

- 39 miles of new pipeline commencing at milepost (MP) 47.5 of the pending proposed Oregon Pipeline; and
- A new compressor station at MP 80.8.

The connected Washington Expansion Project (WEP) would expand the capacity of Northwest Pipeline GP (Northwest) between Sumas and Woodland, Washington, by 750,000 dekatherms per day to provide natural gas to the proposed Oregon LNG terminal, and to markets in the state of Washington.

Pipeline facilities for the WEP would include:

- Approximately 140 miles of 36-inch-diameter pipeline loop along Northwest's existing Northwest Pipeline in 10 segments; and
- An additional 96,000 horsepower (hp) of compression at five existing compressor stations.

The enclosed scoping comments were prepared based on our review of the NOI referenced above and the draft Resource Report 1. Our comments reflect a broad range of issues that we believe to be significant and warrant treatment in the EIS.

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

Sincerely,

Christine B. Reichgott

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

Enclosure

U.S. Environmental Protection Agency
Detailed Scoping Comments to Address the Federal Energy Regulatory Commission's Notice of Intent to Prepare an Environmental Impact Statement for the Oregon LNG Export Project and Washington Expansion Project
FERC Docket Nos. PF12-18-000 and PF12-20-000

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

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

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

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

Water Quality
In order to adequately address water quality issues, the EPA recommends the EIS identify water bodies likely to be impacted by the project, the nature of the potential impacts, and the specific discharges and pollutants likely to impact those waters (addressing both Section 402 and 404 discharges and potential impairments to water quality standards). We also recommend the EIS disclose information regarding

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

relevant Total Maximum Daily Load allocations, the water bodies to which they apply, water quality standards and pollutants of concern.

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

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

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

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

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

Wetlands and Aquatic Habitats

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

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

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

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

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

Water Body Crossing

We appreciate the effort that the FERC and the proponent have made in the past to establish appropriate water body crossing procedures. We encourage the FERC to build upon these efforts through the use of risk screening tools that have been developed more recently. Specifically, we encourage the use of 1) a Project Screening Risk Matrix to evaluate the potential risks posed by the project to species or habitat, and to prioritize reviews; 2) a Project Information Checklist to evaluate whether all the necessary information is available to facilitate critical and thorough project evaluation; and 3) the River

Restoration Assessment Tool, which can promote consistent and comprehensive project planning and review. These tools are available at www.restorationreview.com.

Dredging

According to Resource Report 1, Oregon LNG expects that construction of the berth and turning basin will require an estimated 1,275,000 cubic yards of dredge material requiring removal. (Section 1.3.1). Oregon LNG has been actively working with agencies and stakeholders to identify an appropriate location for dredge material disposal. We understand that Oregon LNG priority sites have shifted to the USEPA Deepwater Site, the USEPA Shallow Water Site, the US Army Corps of Engineers (USACE) North Jetty S, and the USACE South Jetty Nearshore Site. We provide the following comments for FERC's consideration as Resource Report 10 and the DEIS are developed:

- Capacity at the USEPA Deep Water Site has been characterized by the proponent as "unlimited"[3]. The EPA agrees that capacity at the site is large, but it is not unlimited. The EPA has asked USACE to conduct an assessment of long term capacity as part of the Annual Use Plan for 2014.
- The USEPA Shallow Water Site is used to capacity every season, and accretion limits are very low. Because shoaling is an unacceptable outcome, disposals at this site would need to be monitored with USACE and the EPA.
- The South Jetty Nearshore Site (Oregon) was accepted by the Lower Columbia Solutions Group (LCSG) on a provisional basis in 2011. Future use of this site would need to be coordinated with the LCSG as well as the USACE. The crab fishing community has requested demonstrable proof over multiple seasons that crabs will not be affected by dredge material disposal activity.

The EPA supports and appreciates the long standing efforts of the proponents and FERC to identify alternative disposal site locations. We will continue to work with the proponent and FERC to identify disposal locations that meet established criteria under Section 103 of the Marine Protection, Research and Sanctuaries Act (MPRSA).

Air Quality

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

Fugitive Dust Emissions

Fugitive dust may contain small airborne particles that have the potential to adversely affect human health and the environment. The EPA defines fugitive dust as "particulate matter that is generated or emitted from open air operations (emissions that do not pass through a stack or a vent)". The most

[3] Attachment 10-1 Table of Dredge Material Disposal Sites

common forms of particulate matter (PM) are known as PM_{10} and $PM_{2.5}$ (particulate matter size less than 10 and 2.5 microns, respectively).

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

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

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

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

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

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

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

Invasive Species

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

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

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

Hazardous Materials/Hazardous Waste/Solid Waste

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

As an example, page 1-9 of Draft Resource Report 1 indicates that as a part of the gas conditioning process, sweetened gas will pass through multiple, consumable parallel carbon beds for the removal of any mercury in the gas. Because the carbon beds cannot be regenerated, it will be necessary to replace them after a design life of several years. We recommend the EIS address the expected mercury content of the expended carbon beds, and address disposal requirements consistent with 40 CFR 268.40.

We also note that the proposed pipeline route between MP 3 and MP 4 passes just upstream of the Astoria Marine Construction Company Site. This site and adjacent river sediments are contaminated with tributyltin and heavy metals from ship refurbishment operations from 1926 to present[4]. The Oregon Department of Environmental Quality (DEQ) will oversee the investigation and cleanup of contaminated soil, groundwater and sediments at the site under an agreement signed with the EPA. We recommend that FERC and the proponents collaborate closely with Oregon DEQ as the pipeline route is analyzed. Should additional construction BMPs be required at this location, those measures should be included in the EIS.

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

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

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

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

EO 12898 requires each Federal agency to identify and address disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations,

[4] http://www.deq.state.or.us/lq/cu/nwr/AstoriaMarine/AstoriaMarineConstructionCo.pdf

low-income populations, and Native American tribes.[5] The EPA also considers children, the disabled, the elderly, and those of limited English proficiency to be potential Environmental Justice communities due to their unique vulnerabilities.

According to the Council on Environmental Quality, when determining whether environmental effects are disproportionately high and adverse, agencies should consider the following factors: [6]

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

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

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

- Population Characteristics
- Community and Institutional Structures
- Political and Social Resources
- Community Resources.

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

Greenhouse Gas (GHG) Emissions
On February 18, 2010, the CEQ issued draft guidance to Federal Agencies on analyzing the effects of Greenhouse Gas (GHG) emissions and climate change when describing the environmental effects of a proposed agency action in accordance with NEPA[7].

CEQ's draft guidance defines GHG emissions in accordance with Section 19(i) of *E.O. 13514 Federal Leadership in Environment, Energy, and Economic Performance (October 5, 2009)* to include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbon (HFCs), perfluorcarbon (PFCs),

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[5] EO 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations. February 11, 1994.
[6] http://ceq.hss.doe.gov/nepa/regs/ej/justice.pdf
[7] See http://ceq.hss.doe.gov/current_developments/new_ceq_nepa_guidance.html

and sulfurhexafluoride (SF_6). Because CO_2 is the reference gas for climate change based on their potential to absorb heat in the atmosphere, measures of non-CO_2 GHGs should be reflected as CO_2-equivalent (CO_2-e) values.

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

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

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

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

Indirect Impacts
Per CEQ regulations at CFR 1508.8(b), the indirect effects analysis "may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems." The 2012 report from the Energy Information Administration[8] states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report also notes that about three-quarters of that increased production would be from shale resources. We recommend that FERC consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.

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

For the cumulative impacts assessment, we recommend focusing on resources of concern or resources that are "at risk" and /or are significantly impacted by the proposed project, before mitigation. For this project, the FERC should conduct a thorough assessment of the cumulative impacts to aquatic and biological resources, air quality, and commercial and recreational use of the Columbia River within the projects area of influence.

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

Please refer to CEQ's "Considering Cumulative Effects Under the National Environmental Policy Act"[9] and the EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents"[10] for assistance with identifying appropriate boundaries and identifying appropriate past, present, and reasonably foreseeable future projects to include in the analysis.

Mitigation and Monitoring
On February 18, 2010, CEQ issued draft guidance on the Appropriate Use of Mitigation and Monitoring. This guidance seeks to enable agencies to create successful mitigation planning and implementation procedures with robust public involvement and monitoring programs[11].

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[8] Energy Information Administration, Effects of Increased Natural Gas Exports on Domestic Energy Markets, 6 (January 2012) available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf
[9] http://ceq.hss.doe.gov/nepa/ccenepa/ccenepa.htm
[10] http://www.epa.gov/compliance/resources/policies/nepa/cumulative.pdf
[11] http://ceq.hss.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf

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

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

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

Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of April 2, 2013)

All Changes Since March 7, 2013 Update Are In Red

Company	Quantity [a]	FTA Applications [b] (Docket Number)	Non-FTA Applications [c] (Docket Number)
Sabine Pass Liquefaction, LLC	2.2 billion cubic feet per day (Bcf/d) [d]	Approved (10-85-LNG)	Approved (10-111-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC	1.4 Bcf/d [d]	Approved (10-160-LNG)	Under DOE Review (10-161-LNG)
Lake Charles Exports, LLC	2.0 Bcf/d [e]**	Approved (11-59-LNG)	Under DOE Review (11-59-LNG)
Carib Energy (USA) LLC	0.03 Bcf/d: FTA 0.01 Bcf/d: non-FTA [f]	Approved (11-71-LNG)	Under DOE Review (11-141-LNG)
Dominion Cove Point LNG, LP	1.0 Bcf/d [d]	Approved (11-115-LNG)	Under DOE Review (11-128-LNG)
Jordan Cove Energy Project, L.P.	1.2 Bcf/d: FTA 0.8 Bcf/d: non-FTA [g]	Approved (11-127-LNG)	Under DOE Review (12-32-LNG)
Cameron LNG, LLC	1.7 Bcf/d [d]	Approved (11-145-LNG)	Under DOE Review (11-162-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC [h]	1.4 Bcf/d [d]	Approved (12-06-LNG)	Under DOE Review (11-161-LNG)
Gulf Coast LNG Export, LLC [i]	2.8 Bcf/d[d]	Approved (12-05-LNG)	Under DOE Review (12-05-LNG)
Gulf LNG Liquefaction Company, LLC	1.5 Bcf/d[d]	Approved (12-47-LNG)	Under DOE Review (12-101-LNG)
LNG Development Company, LLC (d/b/a Oregon LNG)	1.25 Bcf/d[d]	Approved (12-48-LNG)	Under DOE Review (12-77-LNG)
SB Power Solutions Inc.	0.07 Bcf/d	Approved (12-50-LNG)	n/a
Southern LNG Company, L.L.C.	0.5 Bcf/d[d]	Approved (12-54-LNG)	Under DOE Review (12-100-LNG)
Excelerate Liquefaction Solutions I, LLC	1.38 Bcf/d[d]	Approved (12-61-LNG)	Under DOE Review (12-146-LNG)
Golden Pass Products LLC	2.6 Bcf/d[d]	Approved (12-88 -LNG)	Under DOE Review (12-156-LNG)
Cheniere Marketing, LLC	2.1 Bcf/d[d]	Approved (12-99-LNG)	Under DOE Review (12-97-LNG)
Main Pass Energy Hub, LLC	3.22 Bcf/d***	Approved (12-114-LNG)	n/a
CE FLNG, LLC	1.07 Bcf/d[d]	Approved (12-123-LNG)	Under DOE Review (12-123-LNG)
Waller LNG Services, LLC	0.16 Bcf/d	Approved (12-152-LNG)	n/a
Pangea LNG (North America) Holdings, LLC	1.09 Bcf/d[d]	Approved (12-174-LNG)	Under DOE Review (12-184-LNG)
Magnolia LNG, LLC	0.54 Bcf/d	Approved (12-183-LNG)	n/a

Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of April 2, 2013)

All Changes Since March 7, 2013 Update Are In Red

Company	Quantity [(a)]	FTA Applications [(b)] (Docket Number)	Non-FTA Applications [(c)] (Docket Number)
Trunkline LNG Export, LLC	2.0 Bcf/d**	Approved (13-04-LNG)	Under DOE Review (13-04-LNG)
Gasfin Development USA, LLC	0.2 Bcf/d	Approved (13-06-LNG)	n/a
Freeport-McMoRan Energy LLC	3.22 Bcf/d***	Pending Approval (13-26-LNG)	Under DOE Review (13-26-LNG)
Sabine Pass Liquefaction, LLC	0.28 Bcf/d[(d)]	Pending Approval (13-30-LNG)	Under DOE Review (13-30-LNG)
Sabine Pass Liquefaction, LLC	0.24 Bcf/d[(d)]	Pending Approval (13-42-LNG)	Under DOE Review (13-42-LNG)
Total of all Applications Received		**29.93 Bcf/d(**) (***)**	**28.54 Bcf/d**

** Lake Charles Exports, LLC (LCE) and Trunkline LNG Export, LLC (TLNG), the owner of the Lake Charles Terminal, have both filed an application to export up to 2.0 Bcf/d of LNG from the Lake Charles Terminal. The total quantity of combined exports requested between LCE and TLNG does not exceed 2.0 Bcf/d (i.e., both requests are not additive and only 2 Bcf/d is included in the bottom-line total of applications received).

*** Main Pass Energy Hub, LLC (MPEH) and Freeport McMoRan Energy LLC (FME), have both filed an application to export up to 3.22 Bcf/d of LNG from the Main Pass Energy Hub. (The existing Main Pass Energy Hub structures are owned by FME). The total quantity of combined FTA exports requested between MPEH and FME does not exceed 3.22 Bcf/d (i.e., both requests are not additive and only 3.22 Bcf/d is included in the bottom-line total of FTA applications received). FME's application includes exports of 3.22 Bcf/d to non-FTA countries and is included in the bottom line total of non-FTA applications received, while MPEH has not submitted an application to export LNG to non-FTA countries.

(a) Actual applications were in the equivalent annual quantities.

(b) FTA – Applications to export to free trade agreement (FTA) countries. The Natural Gas Act, as amended, has deemed FTA exports to be in the public interest and applications shall be authorized without modification or delay.

(c) Non-FTA applications require DOE to post a notice of application in the Federal Register for comments, protests and motions to intervene, and to evaluate the application to make a public interest consistency determination.

(d) Requested approval of this quantity in both the FTA and non-FTA export applications. Total facility is limited to this quantity (i.e., FTA and non-FTA volumes are not additive at a facility).

(e) Lake Charles Exports, LLC submitted one application seeking separate authorizations to export LNG to FTA countries and another authorization to export to Non-FTA countries. The proposed facility has a capacity of 2.0 Bcf/d, which is the volume requested in both the FTA and Non-FTA authorizations.

(f) Carib Energy (USA) LLC requested authority to export the equivalent of 11.53 Bcf per year of natural gas to FTA countries and 3.44 Bcf per year to non-FTA countries.

(g) Jordan Cove Energy Project, L.P. requested authority to export the equivalent of 1.2 Bcf/d of natural gas to FTA countries and 0.8 Bcf/d to non-FTA countries.

(h) DOE/FE received a new application (11-161-LNG) by FLEX to export an additional 1.4 Bcf/d of LNG from new trains to be located at the Freeport LNG Terminal, to non-FTA countries, and a separate application (12-06-LNG) to export this same 1.4 Bcf/d of LNG to FTA countries (received January 12, 2012). This 1.4 Bcf/d is in addition to the 1.4 Bcf/d FLEX requested in dockets (10-160-LNG and 10-161-LNG).

(i) An application was submitted by Gulf Coast on January 10, 2012, seeking one authorization to export LNG to any country not prohibited by U.S. law or policy. On September 11, 2012, Gulf Coast revised their application by seeking separate authorizations for LNG exports to FTA countries and Non-FTA countries.

(j) Total does not include 2.0 Bcf/d eia U.S. Energy Information Administration

NATURAL GAS

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Monthly Natural Gas Gross Production Report

Data Files **Methodology and Analysis** **Form and Instructions**

Monthly Natural Gas Gross Production Report with data for November 2012
Released: January 31, 2013
Next Release: February 28, 2013

The two graphs below show total U.S. and Lower 48 natural gas production on one and the individual State production on the other.

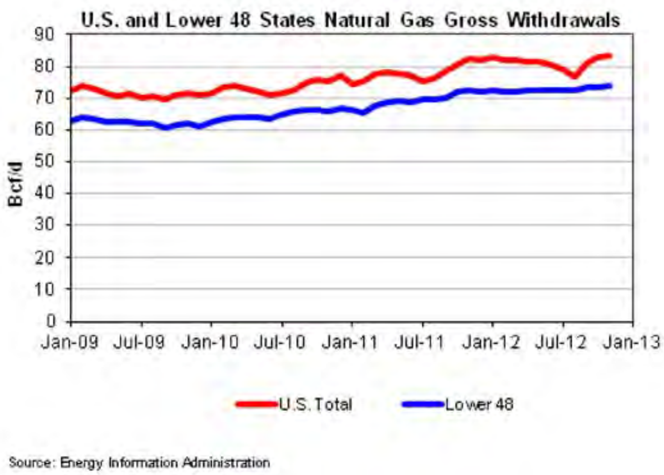


Figure Data

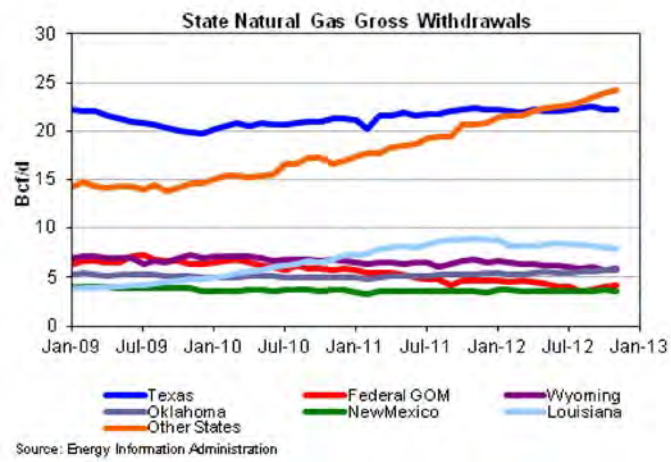


Figure Data

In November, Lower 48 States production rose 0.6 percent or 0.41 billion cubic feet per day (Bcf/d). Other States had the largest volume increase at 1.4 percent or 0.33 Bcf/d as some operators reported new wells coming online in the Marcellus shale play. Wyoming production grew 3.1 percent or 0.18 Bcf/d as two gas plants were back in full production. Gulf of Mexico also increased 3.5 percent or 0.14 Bcf/d partially because shut-in wells were put back online. Louisiana production decreased 2.6 percent or 0.21 Bcf/d as some operators reported shut-ins.

Gross Withdrawals of Natural Gas[1], November 2011 through November 2012
(Billion Cubic Feet per Day)

Area	Federal Offshore Gulf of Mexico		Louisiana		New Mexico		Oklahoma		Texas[2]	
Report Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month
Nov-11	4.61	-0.2	9.06	2.0	3.51	-1.1	5.36	0.4	22.38	0.8
Dec-11	4.63	0.4	8.91	-1.7	3.45	-1.7	5.37	0.2	22.24	-0.6
Jan-12	4.63	0.0	8.81	-1.1	3.67	6.4	5.37	0.0	22.16	-0.4
Feb-12	4.53	-2.2	8.26	-6.2	3.71	1.1	5.32	-0.9	22.02	-0.6
Mar-12	4.69	3.5	8.26	0.0	3.62	-2.4	5.31	-0.2	21.91	-0.5
Apr-12	4.54	-3.2	8.20	-0.7	3.57	-1.4	5.43	2.3	22.26	1.6
May-12	4.29	-5.5	8.32	1.5	3.59	0.6	5.53	1.8	22.15	-0.5
Jun-12	3.99	-7.0	8.49	2.0	3.52	-1.9	5.48	-0.9	22.04	-0.5
Jul-12	4.09	2.5	8.47	-0.2	3.61	2.6	5.50	0.4	22.18	0.6
Aug-12	3.64	-11.0	8.32	-1.8	3.59	-0.6	5.54	0.7	22.40	1.0
Sep-12	3.68	1.1	8.21	-1.3	3.58	-0.3	5.64	1.8	22.61	0.9
Oct-12	R 4.02	9.2	R 8.08	-1.6	R 3.69	3.1	R 5.68	0.7	R 22.27	-1.5
Nov-12	4.16	3.5	7.87	-2.6	3.64	-1.4	5.75	1.2	22.22	-0.2

Area	Wyoming		Other States[3]		Lower 48 States		Alaska State Data[4]		U.S. Total	
Report Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month
Nov-11	6.82	2.2	20.72	0.4	72.46	0.8	10.09	14.4	82.55	2.3
Dec-11	6.58	-3.5	20.90	0.9	72.08	-0.5	9.98	-1.1	82.06	-0.6
Jan-12	6.65	1.1	21.40	2.4	72.69	0.8	10.32	3.4	83.01	1.2

Jan-12	6.65	1.1	21.40	2.4	72.69	0.8	10.32	3.4	83.01	1.2
Feb-12	6.46	-2.9	21.65	1.2	71.95	-1.0	10.04	-2.7	81.99	-1.2
Mar-12	6.43	-0.5	21.64	0.0	71.86	-0.1	9.99	-0.5	81.85	-0.2
Apr-12	6.30	-2.0	22.02	1.8	72.32	0.6	9.18	-8.1	81.50	-0.4
May-12	6.19	-1.7	22.42	1.8	72.49	0.2	9.12	-0.7	81.61	0.1
Jun-12	6.17	-0.3	R 22.56	0.6	R 72.25	-0.3	8.43	-7.6	R 80.68	-1.1
Jul-12	6.10	-1.1	R 22.67	0.5	R 72.62	0.5	6.67	-20.9	R 79.29	-1.7
Aug-12	5.97	-2.1	R 23.08	1.8	R 72.54	-0.1	4.04	-39.4	R 76.58	-3.4
Sep-12	5.99	0.3	R 23.53	1.9	R 73.24	1.0	7.71	90.8	R 80.95	5.7
Oct-12	R 5.77	-3.7	R 23.96	1.8	R 73.47	0.3	9.39	21.8	R 82.86	2.4
Nov-12	5.95	3.1	24.29	1.4	73.88	0.6	9.66	2.9	83.54	0.8

Source: EIA-914 and EIA Natural Gas Annual

Note: Data presented in the table are monthly natural gas gross withdrawals estimated from data collected on the EIA-914 survey. In 2011, data are from the *EIA Natural Gas Annual*. Gross withdrawals are converted to marketed natural gas production which is reported on the EIA website in the Natural Gas Data Tables, and in the *Natural Gas Monthly* and *Natural Gas Annual* reports. Marketed production is calculated by subtracting gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations from gross withdrawals.

1 The EIA-914 estimates are based on the simple ratio method, explained in the *Methodology*.

2 Texas gross withdrawals data do not include CO_2 production associated with injection projects. Texas CO_2 Adjustment Article

3 2012-Forward monthly Other States total estimates are determined by applying the ratio of 2011 gross natural gas production published at http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm to the 2011 reported EIA-914 survey production.

4 Alaska data is from the State of Alaska, not the EIA-914. It's included here for completeness.

R=Revised data. It is EIA-914's revision policy to revise the prior month's data for any change when the latest month's data is released. Earlier months are only revised when a current estimate differs by the amount specified in the Revision Policy.

Notes: New Mexico EIA-914 gross withdrawals estimates now include CO_2 production in the same manner as it is reported by the State of New Mexico. All associated EIA-914 Data Files have been updated. Area estimates may not add to the lower 48 estimate due to independent rounding.

All estimates, except as footnoted, are based on the simple ratio estimate method, which is explained in the Methodology. Readers are encouraged to review these reports to better understand all aspects of the EIA-914 survey. The Data Files contain initial and revised production estimates for each month (revisions are based on company resubmissions and late reports) and response rates by month. Data and graphs showing comparisons between EIA-914 estimates and other sources can also be found here.

Using GPCM® to Model LNG Exports from the US Gulf Coast

Robert Brooks, Ph.D., President, RBAC, Inc.

March 2, 2012

As the gas industry rolled into the 21st century, natural gas production was beginning to decline and the outlook for production looked rather bleak. A small upsurge due to the advent of coal-bed methane development had begun to play out and it looked like the future lay in LNG imports. Billions of dollars were spent in designing and getting permitted dozens of new LNG import terminals. Ten new terminals and two offshore receiving stations were actually built. As it turned out, the companies that lagged behind and didn't actually build these expensive terminals were the winners, because the industry as a whole did not predict an upstream revolution which was quietly occurring at the same time. A breakthrough in horizontal drilling combined with hydro-fracturing and advanced 3D imaging finally made it possible to economically develop the enormous gas and oil resources long known to exist in vast shale formations throughout much of North America.

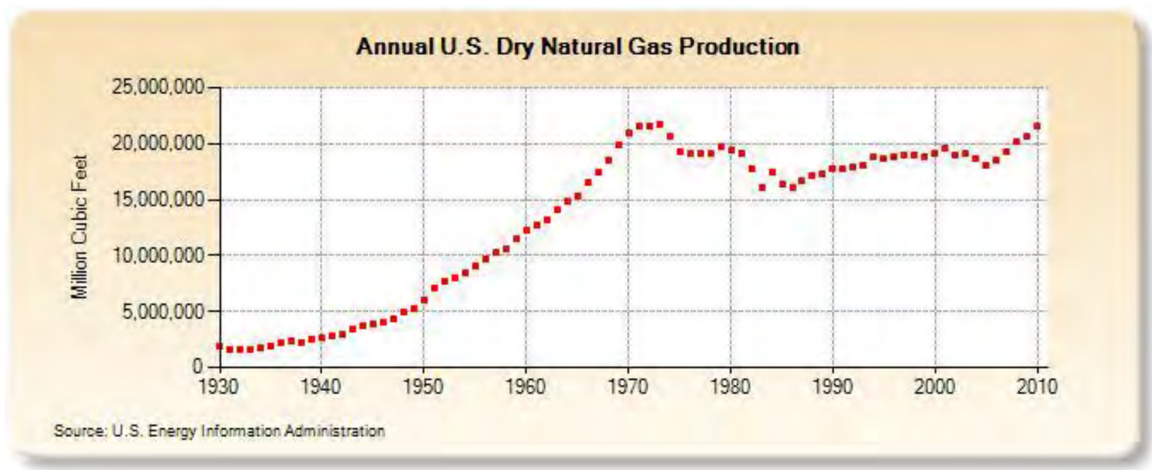


Figure 1: US Dry Natural Gas Production 1930-2010

A drilling boom began which completely turned the US production graph around. (See Figure 1.) All of a sudden there was more gas than could be easily absorbed in a recession-bound market. Natural gas prices began to erode, moving from the $6/mmbtu range to under $4/mmbtu (Figure 2), and the new challenge became "what are we going to do with all this gas?"

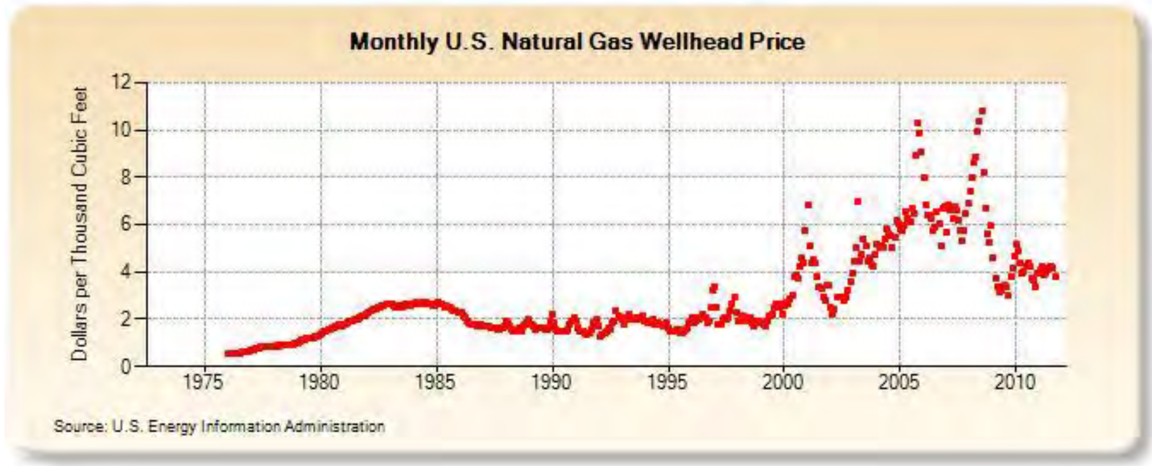


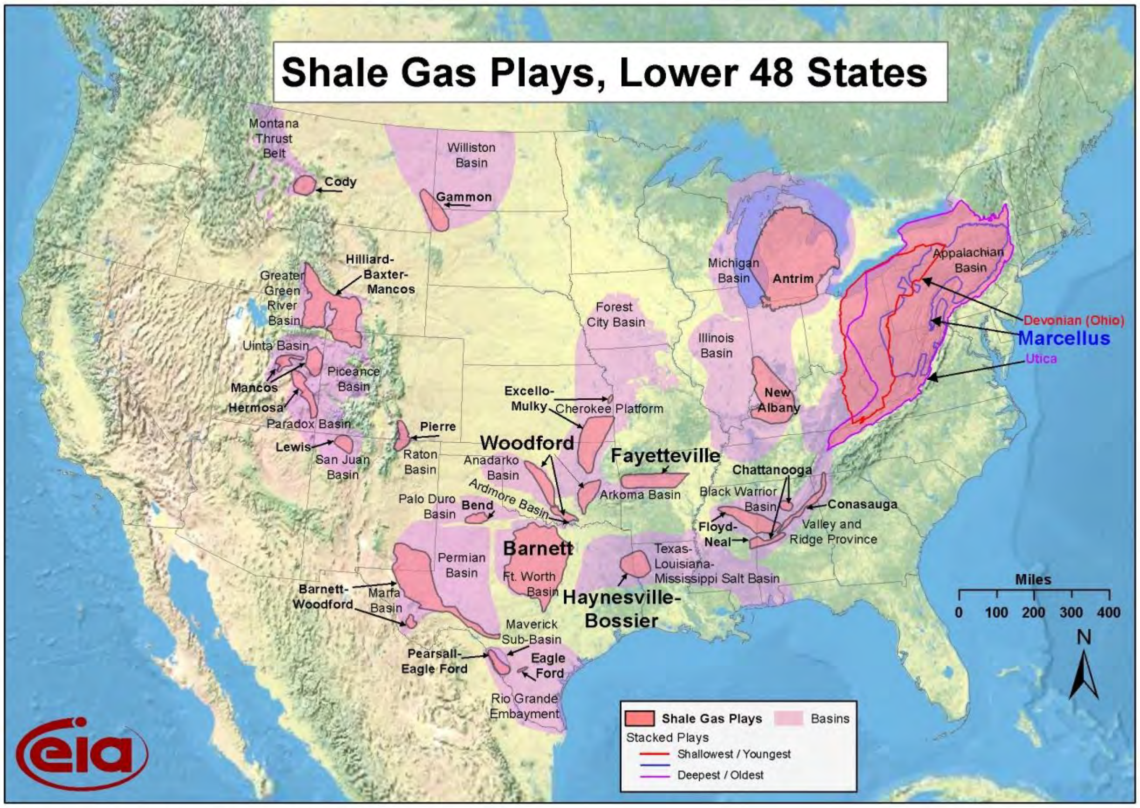
Figure 2: Monthly Natural Gas Wellhead Prices 1975-2010

Five answers have been put forward: redirect drilling from dry gas plays to plays having higher concentrations of more profitable natural gas liquids, replace coal with natural gas in electricity generation; build new fleets of natural gas powered trucks, buses, and cars; convert the gas into liquids for use in transportation; and, most recently, liquefy the gas and export it to other countries willing to pay much higher prices, notably Japan, China, Korea, and India.

As of year-end 2011 redirection to wetter gas plays has not solved the problem because the wetter gas plays have proven to be even more prolific gas producers than the dry gas plays drilled earlier. Replacing coal with gas in electricity production has been occurring but is a slow process which will take decades to unfold. Similarly, the natural gas vehicle market is growing, but from such a small base that it will take a very long time to have an impact on gas price, if ever. Gas-to-liquids is a mature technology, but is expensive, and its future in North America is still quite uncertain.

Up until very recently, the idea of liquefying excess North American natural gas and exporting it to overseas markets did not appear to be likely of success. That was before late 2011 when Cheniere Energy, owner of the Sabine Pass LNG terminal in Louisiana, announced the completion of agreements with UK-based BG Group and Spain's Gas Natural Fenosa to export LNG to Europe and Latin America and with GAIL (India) Limited for similar exports to India. Each of these agreements is for 3.5 million tons of LNG per year. In January 2012, Cheniere and Korea Gas Corporation (KOGAS) announced a similar agreement for another 3.5 million tons per year. 14 million tons per year of LNG would require almost 2 billion cubic feet per day (bcf/day) of production.

Much or most of the gas to be liquefied into LNG would be produced out of the nearby Haynesville-Bossier Shale play of northern Louisiana and east Texas. Following upon these deals, Cheniere announced plans to convert its planned Corpus Christi LNG import terminal into a second liquefaction and export terminal, this one located near the prolific Eagle Ford Shale wet gas play in South Texas.



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

Figure 3: Shale Gas Plays in the United States

Some concern has been expressed by end-users of natural gas that these export projects would increase natural gas prices in the United States. Cheniere estimated that exports of 2 bcf/day could raise gas prices by as much as 10%. DOE's Energy Information Administration was requested by Congress to make its own projection. DOE assumed a much more extreme range of exports between 6 and 12 bcf/day with two different ramp-up rates (1 bcf/day per year and 3 bcf/day per year). In their 6 bcf/day scenario with 2 year ramp-up, the so-called "low, rapid" scenario, EIA projected an average price increase at the Henry Hub in Southern Louisiana of $0.60 per million btu (mmbtu) over the period 2016-2035.

Using its WGM model with the assumption of a 6 bcf/day export volume, consultant Deloitte MarketPoint LLC projected an average increase of only $0.22 mmbtu at the Henry Hub in Southern Louisiana over the same time period as EIA. Deloitte attributed the tiny magnitude of this price impact to the ability of the North American gas market to quickly and efficiently adjust to the prospect of an export market.

Using the GPCM model RBAC has produced its own analysis to address this question. Starting with RBAC's GPCM 11Q3 Base Case released in October 2011, which assumed Gulf LNG exports of 0.7 bcf/day, we have created five new scenarios: 1) no LNG exports from the US lower-48 states, 2) 1 bcf/day, 3) 2 bcf/day, 4) 4 bcf/day, and 5) 6 bcf per day. Each of the

LNG scenarios took 3 years to ramp up to maximum by 2018 and continued at that level through 2035.

The following figures show the results from these scenarios and the impact of various volumes of LNG exports on prices at Henry Hub.

Figure 4 shows Henry Hub price forecasts for the five scenarios. Prices are expected to be in the sub-$4 range from 2012-2015 for all scenarios, varying from that point depending on the volume of LNG exports in each.

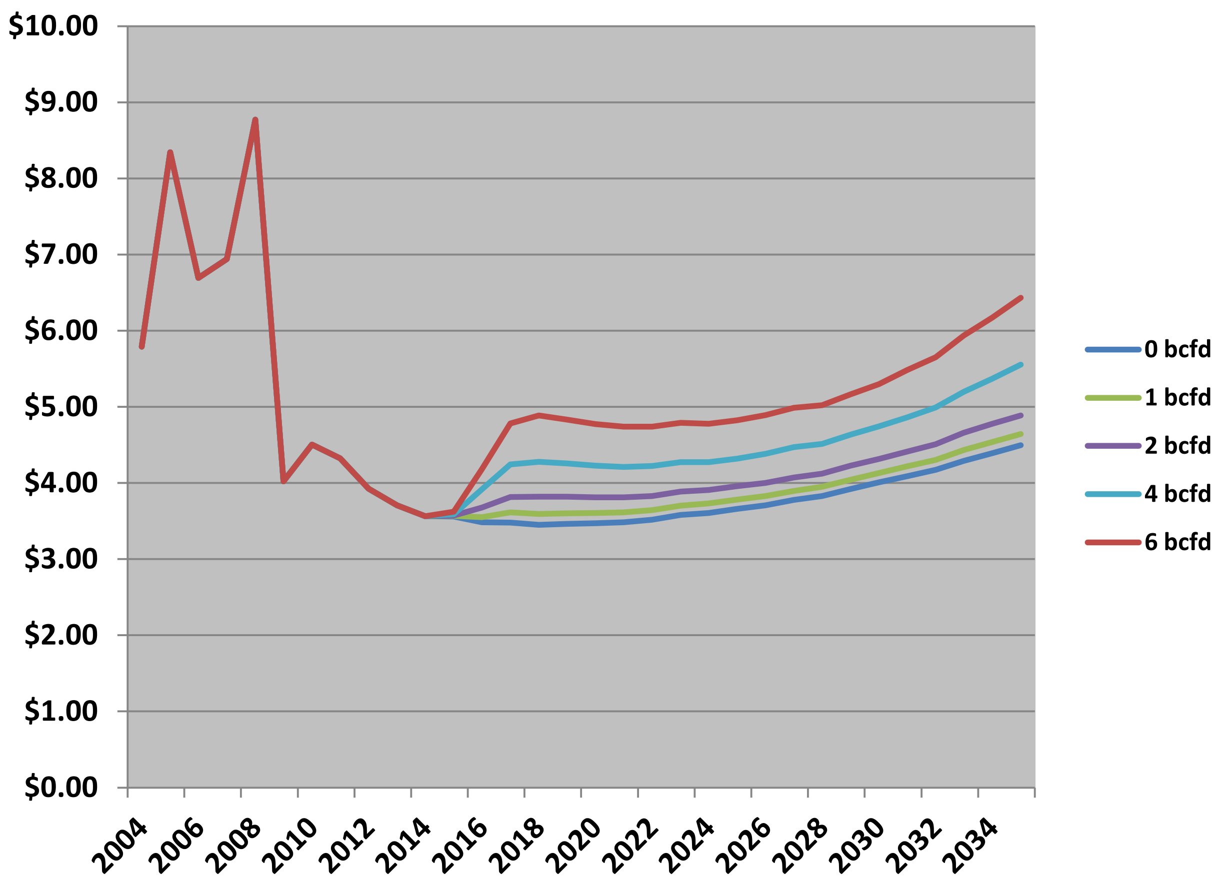


Figure 4: Annual Average Henry Hub Gas Price Forecast: 0, 1, 2, 4, and 6 bcf/day exports

Figure 5 shows the price difference between the no-LNG and the 1, 2, 4, and 6 bcf/day scenarios.

Figure 6 shows the average price impact over the 20 year 2016-2035 time period of each of the LNG export scenarios versus a zero-LNG export scenario.

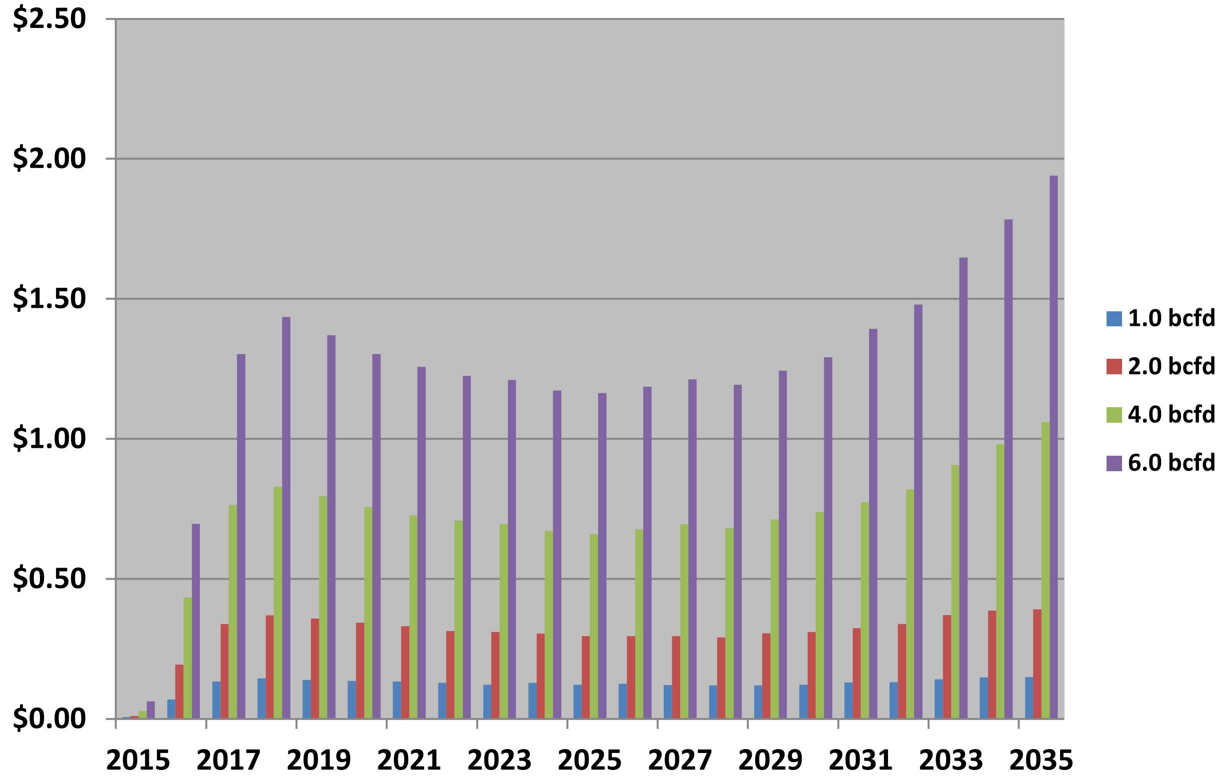


Figure 5: Price Impact at Henry Hub Due to Various Levels of Gulf Coast LNG Exports

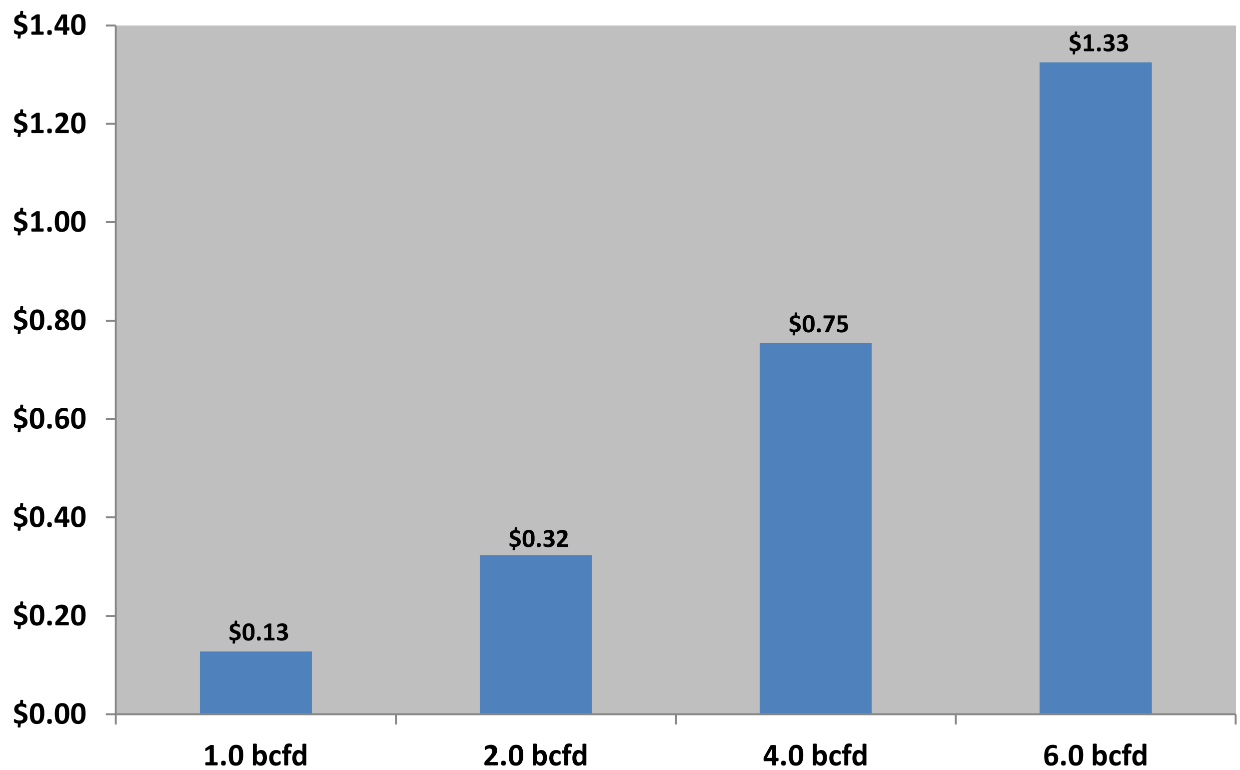


Figure 6: Average Price Impact at Henry Hub 2016-2035 of Different Gulf LNG Export Levels

The price impact of this level of LNG exports predicted using RBAC's GPCM model is about the same as Cheniere for the 2 bcf/day scenario ($0.32), but much greater for the more extreme 6 bcf/day scenario than that estimated by EIA ($0.60) or Deloitte ($0.22). It averages about $1.33 per mmbtu over the forecast horizon, a 30% increase at Henry Hub. RBAC's 6 bcf/day scenario does not forecast that the industry will respond with speed and efficiency with an insignificant gas-price increase as does the Deloitte model. The flexibility of the industry to respond to this large and sudden increase in demand comes at a price.

The following figure shows the effect of this extreme level of LNG exports and resulting higher prices on domestic gas deliveries.

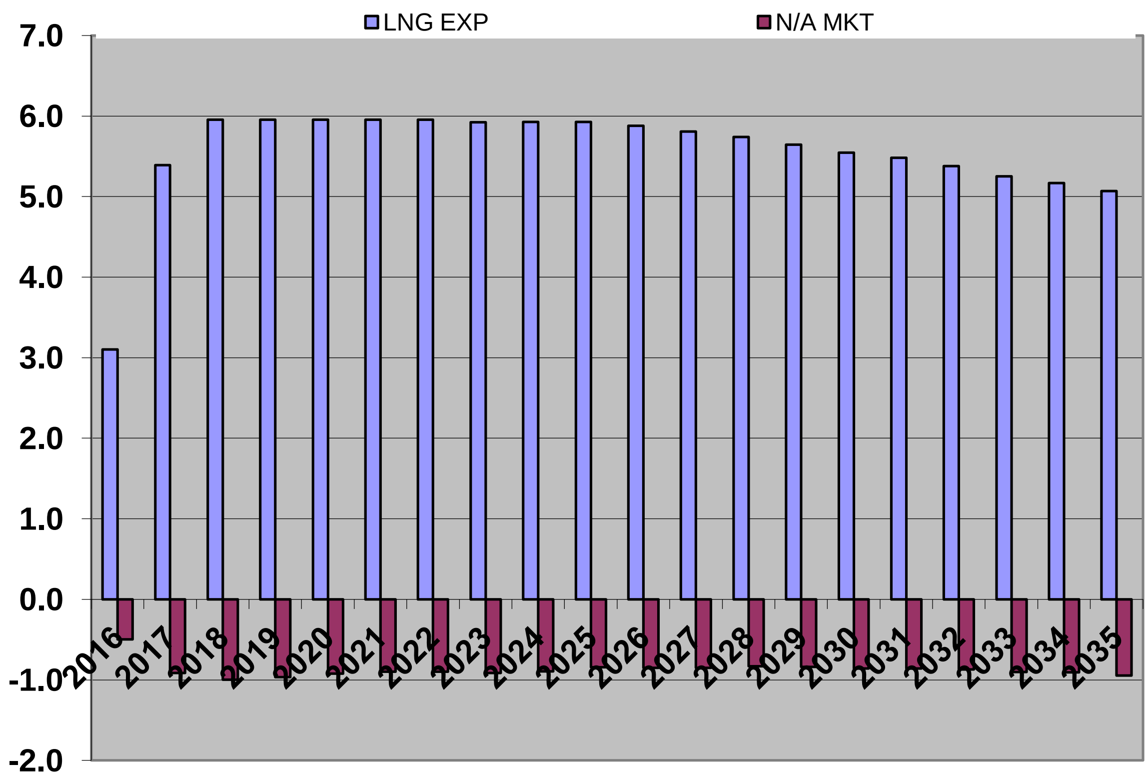


Figure 7: Impact of LNG Exports on Deliveries to the North American Market

First note that the scenario as designed ran into difficulty exporting 6 BCF/day after 2025. The amount available for export slowly fell to about 5 BCF/day by 2035. The 6 bcf/day scenario assumes 3 bcf/day from Louisiana and 3 bcf/day from Texas. In the longer run, it is more difficult to supply 3 bcf/day for LNG exports from Texas due to competition with Mexico. On average the LNG exports were about 5.5 BCF/day in this scenario.

The addition of 5.5 BCF/day LNG export demand raises prices enough to reduce deliveries to the domestic North American market by almost 0.8 BCF/day. Most of this reduction is felt by the industrial market, the most price sensitive sector in the US. Thus the net additional production required by the new LNG export market is about 4.7 BCF/day.

Perhaps one reason why EIA's price response is less than RBAC's is that EIA assumes an increase in production of only 3.8 bcf/day will be required to supply 6 bcf/day in exports. This surprising result comes about because EIA's result shows a 2.1 bcf/day decrease in gas available to consumers in the US. Their demand model is much more price-sensitive than RBAC's.

Figure 8 shows where the additional supply will originate in the 6 bcf/day RBAC scenario. About 10% of the required new supply comes from coal-bed methane and a small uptick in LNG imports. The latter is due to the fact that the Mexican market is dependent on imports from the US as well as LNG. With less pipeline gas available to Mexico from South Texas, more local gas must be produced and more LNG imported.

One surprise is that conventional sources will initially provide about 50% of the incremental supply needed for the net increase in demand with shale providing about 40%. However, as shale becomes the predominant source of production, it also takes over as the primary source of incremental supply for exports, reaching more than 60% by year 2035. This may be more a result of the fact that GPCM models physical gas flows. How gas is contracted could be quite different.

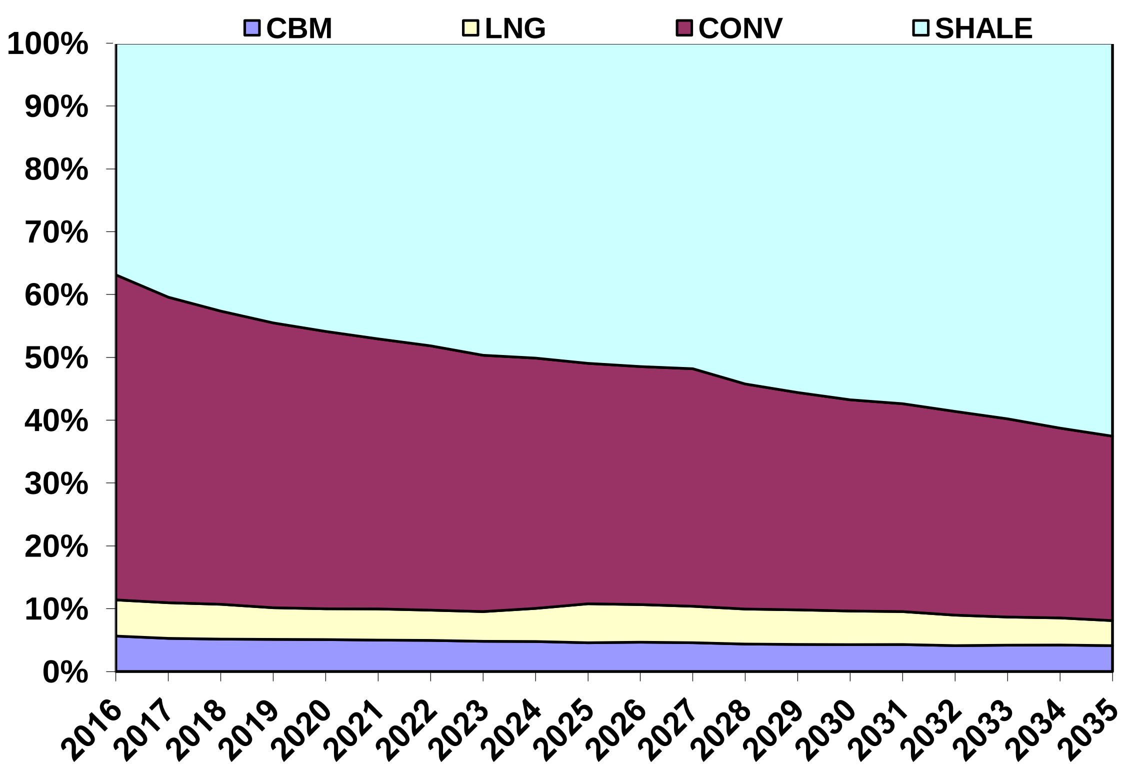


Figure 8: Share of New Supply Required in 6 bcf/day LNG Exports Scenario

Sensitivity of Results to Supply Assumptions

A sixth scenario was run to test the sensitivity of these results to the base case assumption of supply responsiveness to changes in demand. By raising price sensitivity of supply for prices higher than about $4/mmbtu, production capacity grows faster than in the original 6 bcf/day LNG exports scenario. By 2035 capacity is about 4 BCF/day (3%) higher for the same price.

Figure 9 shows the effect of this higher production sensitivity case on Henry Hub price.

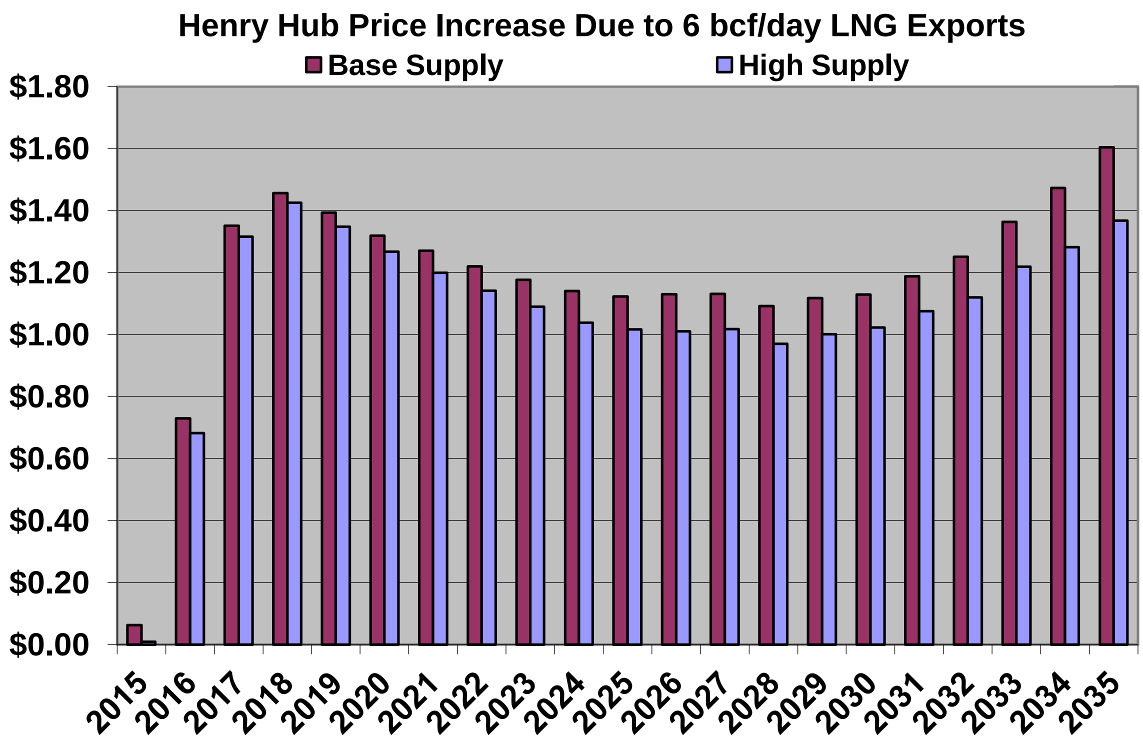


Figure 9: Sensitivity of Henry Hub Price Effect to Supply Capacity Growth

The price effect of LNG exports is reduced by about $0.05 in 2016 growing to almost $0.25 by 2035. The average price effect in the sensitivity case is $1.13, about $0.10 less than the original 6 bcf/day exports case. These results suggest that both EIA and Deloitte models may substantially underestimate the price effect of 6 bcf/day LNG exports of the magnitude reported in their studies. The adjustments which the industry makes to meet the challenge of this large new demand are not likely to be made so quickly and with so little impact on price.

Deloitte.

Deloitte MarketPoint.

Analysis of Economic Impact of LNG Exports from the United States

Contents

Executive summary

Deloitte MarketPoint LLC ("DMP") has been engaged by Excelerate Energy L.P. ("Excelerate") to provide an independent and objective assessment of the potential economic impacts of LNG exports from the United States. We analyzed the impact of exports from Excelerate's Lavaca Bay terminal, located along the Gulf coast of Texas, by itself and also in combination with varying levels of LNG exports from other locations.

A fundamental question regarding LNG exports is: Are there sufficient domestic natural gas supplies for both domestic consumption and LNG exports. That is, does the U.S. need the gas for its own consumption or does the U.S. possess sufficiently abundant gas resources to supply both domestic consumption and exports? A more difficult question is: How much will U.S. natural gas prices increase as a result of LNG exports? To understand the possible answers to these questions, one must consider the full gamut of natural gas supply and demand in the U.S. and the rest of the world and how they are dynamically connected.

In our view, simple comparisons of total available domestic resources to projected future consumption are insufficient to adequately analyze the economic impact of LNG exports. The real issue is not one of volume, but of price impact. In a free market economy, price is one of the best measures of scarcity, and if price is not significantly affected, then scarcity and shortage of supply typically do not occur. In this report, we demonstrate that the magnitude of domestic price increase that results from exports of natural gas in the form of LNG is projected to be quite small.

However, other projections, including those developed by the DOE's Energy Information Administration (EIA), estimate substantially larger price impacts from LNG exports than derived from our analysis. We shall compare different projections and provide our assessment as to why the projections differ. A key determinant to the estimated price impact is the supply response to increased demand including LNG exports. To a large degree, North American gas producers' ability to increase productive capacity in anticipation of LNG export volumes will determine the price impact. After all, there is widespread agreement of the vast size of the North American natural gas resource base among the various studies and yet estimated price impacts vary widely. If one assumes that producers will fail to keep pace with demand growth, including LNG exports, then the price impact of LNG exports, especially in early years of operations, will be far greater than if they anticipate demand and make supplies available as they are needed. Hence, a proper model of market supply-demand dynamics is required to more accurately project price impacts.

DMP applied its integrated North American and World Gas Model (WGM or Model) to analyze the price and quantity impacts of LNG exports on the U.S. gas market.[1] The WGM projects

[1] This report was prepared for Excelerate Energy L.P. ("Client") and should not be disclosed to, used or relied upon by any other person or entity. Deloitte Marketpoint LLC shall not be responsible for any loss sustained by any such use or reliance. Please note that the analysis set forth in this report is based on the application of economic logic and specific

monthly prices and quantities over a 30 year time horizon based on demonstrated economic theories. It includes disaggregated representations of North America, Europe, and other major global markets. The WGM solves for prices and quantities simultaneously across multiple markets and across multiple time points. Unlike many other models which compute prices and quantities assuming all parties work together to achieve a single global objective, WGM applies fundamental economic theories to represent self-interested decisions made by each market "agent" along each stage of the supply chain. It rigorously adheres to accepted microeconomic theory to solve for supply and demand using an "agent based" approach. More information about WGM is included in the Appendix.

Vital to this analysis, the WGM represents fundamental natural gas producer decisions regarding when and how much reserves to develop given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the impact of demand changes (e.g., LNG exports) because without it, the answer will likely greatly overestimate the price impact. Indeed, producers will anticipate the export volumes and make production decisions accordingly. LNG exporters might back up their multi-billion dollar projects with long-term supply contracts, but even if they do not, producers will anticipate future prices and demand growth in their production decisions. Missing this supply-demand dynamic is tantamount to assuming the market will be surprised and unprepared for the volume of exports and have to ration fixed supplies to meet the required volumes. Static models assume a fixed supply volume (i.e., productive capacity) during each time period and therefore are prone to over-estimate the price impact of a demand change. Typically, users have to override this assumption by manually adjusting supply to meet demand. If insufficient supply volumes are added to meet the incremental demand, prices could shoot up until enough supply volumes are added to eventually catch up with demand.

Instead of a static approach, the WGM uses sophisticated depletable resource modeling to represent producer decisions. The model uses a "rational expectations" approach, which assumes that today's drilling decisions affect tomorrow's price and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

It is well documented that shale gas production has grown tremendously over the past several years. According to the EIA, shale gas production climbed to over 35% of the total U.S. production in January of 2012[2]. By comparison, shale gas production was only about 5% of the total U.S. production in 2006, when improvements in shale gas production technologies (e.g., hydraulic fracturing combined with horizontal drilling) were starting to significantly reduce production costs. However, there is considerable debate as to how long this trend will continue and how much will be produced out of each shale gas basin. Rather than simply extrapolating past trends, WGM projects production based resource volumes and costs, future gas demand, particularly for power generation, and competition among various sources in each market area. It computes incremental sources to meet a change in demand and the resulting impact on price.

assumptions and the results are not intended to be predictions of events or future outcomes.

Notwithstanding the foregoing, Client may submit this report to the U.S. Department of Energy and the Federal Energy Regulatory Commission in support of Client's liquefied natural gas "(LNG") export application.

[2] Computed from the EIA's Natural Gas Weekly Update for week ending June 27, 2012.

Based on our existing model and assumptions, which we will call the "Reference Case", we developed five cases with different LNG export volumes to assess the impact of LNG exports. The five LNG export scenarios and their assumed export volumes by location are shown in Figure 1. Other Gulf in the figure refers to all other Gulf of Mexico terminals in Texas and Louisiana besides Lavaca Bay.

All cases are identical except for the assumed volume of LNG exports. The 1.33 Bcfd case assumed only exports from Lavaca Bay so that we could isolate the impact of the terminal. In the other LNG export cases, we assumed the Lavaca Bay terminal plus volumes from other locations so that the total exports volume equaled 3, 6, 9, and 12 Bcfd. The export volumes were assumed to be constant for twenty years from 2018 through 2037.

We represented LNG exports in the model as demands at various model locations generally corresponding to the locations of proposed export terminals (e.g., Gulf Texas, Gulf Louisiana, and Cove Point) that have applied for a DOE export license. The cases are not intended as forecasts of which export terminals will be built, but rather to test the potential impact given alternative levels of LNG exports. Furthermore, the export volumes are assumed to be constant over the entire 20 year period. Since our existing model already represented these import LNG terminals, we only had to represent exports by adding demands near each of the terminals. Comparing results of the five LNG export cases to the Reference Case, we projected how much the various levels of LNG exports could increase domestic prices and affect production and flows.

Given the model's assumptions and economic logic, the WGM projects prices and volumes for over 200 market hubs and represents every state in the United States. We can examine the impact at each location and also compute a volume-weighted average U.S. "citygate" price by weighting price impact by state using the state's demand. Impact on the U.S. prices increase along with the volume of exports.

As shown in Figure 2, the WGM's projected

Figure 1: LNG export scenarios

	Export Case				
Terminal	**1.33 Bcfd**	**3 Bcfd**	**6 Bcfd**	**9 Bcfd**	**12 Bcfd**
Lavaca Bay	1.33	1.33	1.33	1.33	1.33
Other Gulf		1.67	4.67	6.67	9.67
Cove Point (MD)				1.0	1.0
Total	1.33	3.0	6.0	9.0	12.0

Figure 2: Potential Impact of LNG export on U.S. prices (Average 2018-37)

Export Case	Average US Citygate	Henry Hub	New York
1.33 Bcfd	0.4%	0.4%	0.3%
3 Bcfd	1.0%	1.7%	0.9%
6 Bcfd	2.2%	4.0%	1.9%
9 Bcfd	3.2%	5.5%	3.2%
12 Bcfd	4.3%	7.7%	4.1%

impact on average U.S. citygate prices for the assumed years of operation (2018 to 2037) ranged from well under 1% in the 1.33 Bcfd (Lavaca Bay only) case to 4.3% in the 12 Bcfd case. However, the impacts vary significantly by location. Figure 2 shows the percentage change relative to the Reference Case to the projected average U.S. citygate price and at the Henry Hub and New York prices under various LNG export volumes.

As Figure 2 shows, the price impact is highly dependent on location. The impact on the price at Henry Hub, the world's most widely used benchmark for natural gas prices, is significantly higher than the national average. The reason is that the Henry Hub, located in Louisiana, is in close proximity to the prospective export terminals, which are primarily located in the U.S. Gulf of Mexico region. Since there are several cases analyzed, we will primarily describe results of the 6 Bcfd export case since it is the middle case. The impacts are roughly proportional to the export volumes. In the 6 Bcfd export case, the impact on the Henry Hub price is an increase of 4.0% over the Reference Case. Generally, the price impact in markets diminishes with distance away from export terminals as other supply basins besides those used to feed LNG exports are used to supply those markets. Distant market areas, such as New York and Chicago, experience only about half the price impact as at the Henry Hub. Focusing solely on the Henry Hub or regional prices around the export terminals will greatly overstate the total estimated impact on the U.S. consumers.

The results show that if exports can be anticipated, and clearly they can with the public application process and long lead time required to construct a LNG liquefaction plant, then producers, midstream players, and consumers can act to mitigate the price impact. Producers will bring more supplies online, flows will be adjusted, and consumers will react to price change resulting from LNG exports.

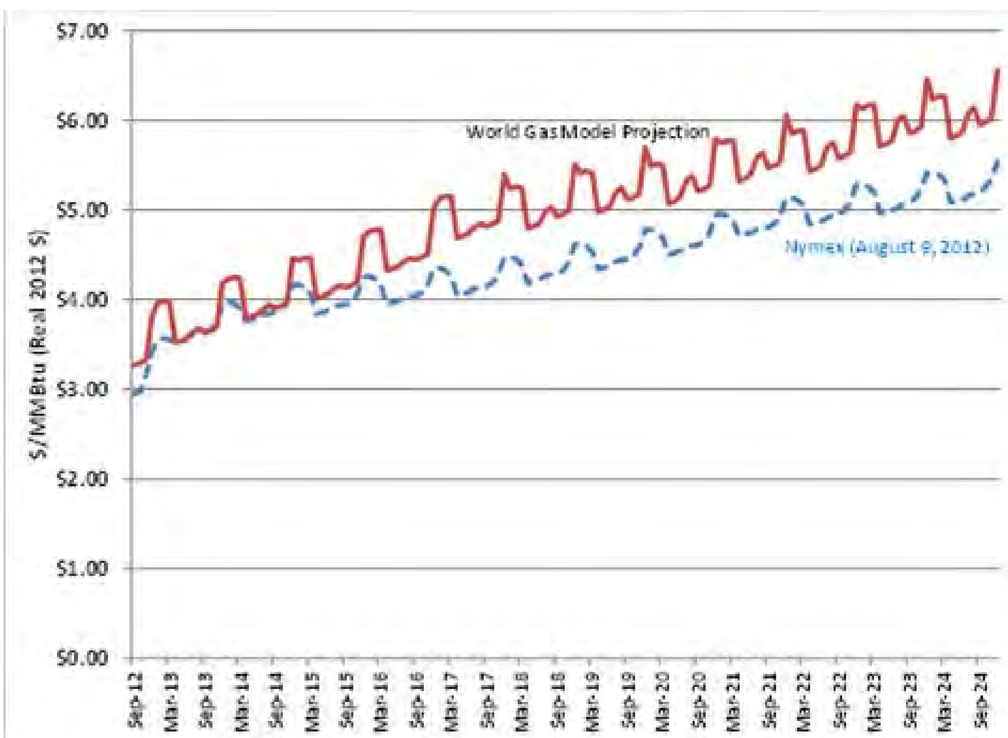
According to our projections, 12 Bcfd of LNG exports are projected to increase the average U.S. citygate gas price by 4.3% and Henry Hub price by 7.7% on average over a twenty year period (2018-37). This indicates that the projected level of exports is not likely to induce scarcity on domestic markets. The domestic resource base is expected to be large enough to absorb the incremental volumes required by LNG exports without a significant increase to future production costs. If the U.S. natural gas industry can make the supplies available by the time LNG export terminals are ready for operation, then the price impact will likely reflect the minimal change in production cost. As the industry has shown in the past several years, it is capable of responding to market signals and developing supplies as needed. Furthermore, the North American energy market is highly interconnected so any change in prices due to LNG exports from the U.S. will cause the entire market to re-equilibrate, including gas fuel burn for power generation and net imports from Canada and Mexico. Hence, the entire North American energy market would be expected to in effect work in tandem to mitigate the price impact of LNG exports from the U.S.

Overview of Deloitte MarketPoint Reference Case

The WGM Reference Case assumes a "business as usual" scenario including no LNG exports from the United States. U.S. gas demand growth rates for all sectors except for electricity were based on EIA's recently released Annual Energy Outlook (AEO) 2012 projection, which shows a significantly higher US gas demand than in the previous year's projection. Our gas demand for power generation is based on projections from DMP's electricity model, which is integrated with our WGM. (There is no intended advocacy or prediction of these events one way or the other. Rather, we use these assumptions as a frame of reference. The impact of LNG exports could easily be tested against other scenarios, but the overall conclusion would be rather similar.)

In the WGM Reference Case, natural gas prices are projected to rebound from current levels and continue to strengthen over the next two decades, although nominal prices do not return to the peak levels of the mid-to-late 2000s until after 2020. In real terms (i.e., constant 2012 dollars), benchmark U.S. Henry Hub spot prices are projected by the WGM to increase from currently depressed levels to $5.34 per MMBtu in 2020, before rising to $6.88 per MMBtu in

Figure 3: Projected Henry Hub prices from the WGM compared to Nymex futures prices



2030 in the Reference Case scenario.

The WGM Reference Case projection of Henry Hub prices is compared to the Nymex futures prices in Figure 3. (The Nymex prices, which are the dollars of the day, were deflated by 2.0%[3] per year to compare to our projections, which are in real 2012 dollars.) Our Henry Hub price projection is similar to the Nymex prices in the near-term but rises above it in the longer term. Bear in mind that our Reference Case by design assumes no LNG exports whereas there is possible there is some expectation of LNG exports from the U.S. built into the Nymex prices. Under similar assumptions, the difference between our price projection and Nymex likely would be even higher. Hence, our Reference Case would represent a fairly high price projection even without LNG exports.

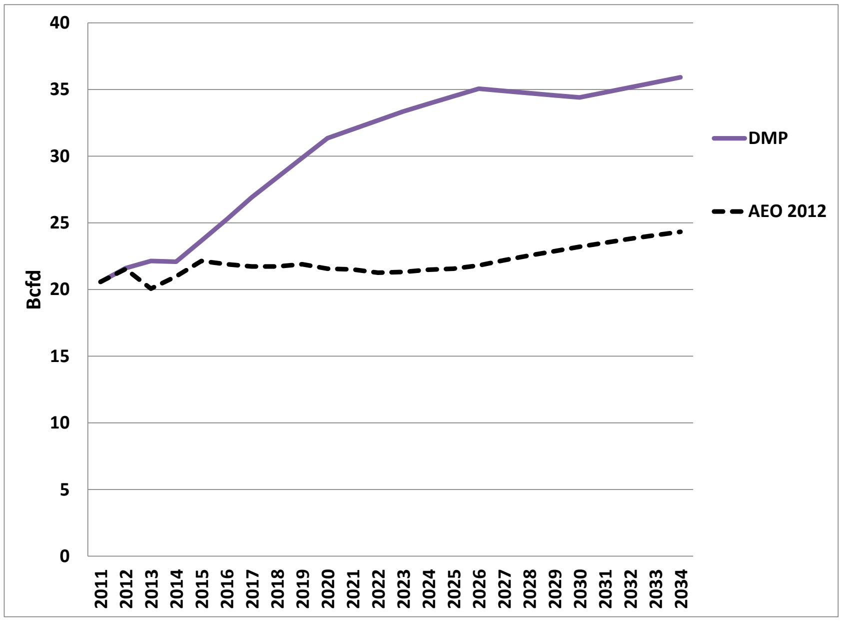
One possible reason why our price projection in the longer term is higher than market expectation, as reflected by the Nymex futures prices, is because of our projected rapid increase in gas demand for power generation. Based on our electricity model projections, we forecast natural gas consumption for electricity generation to drive North American natural gas demand higher during the next two decades.

As shown in Figure 4, the DMP projected gas demand for U.S. power generation gas is far greater than the demand predicted by EIA's AEO 2012, which forecasts fairly flat demand for power generation. In the U.S., the power sector, which accounts for nearly all of the projected future growth, is projected to increase by about 50% (approximately 11 Bcfd) over the next decade. Our integrated electricity model projects that natural gas will become the fuel of choice for power generation due to a variety of reasons, including: tightening application of existing environmental regulations for mercury, NOx, and SOx; expectations of ample domestic gas supply at competitive gas prices; coal plant retirements; and the need to back up intermittent renewable sources such as wind and solar to ensure reliability. Like the EIA's AEO 2012 forecast, our Reference Case projection does not assume any new carbon legislation.

Our electricity model, fully integrated with our gas (WGM) and coal models, contains a detailed representation of the North American electricity system including environmental emissions for key pollutants (CO2, SOx, NOx, and mercury). The integrated structure of these models is shown in Figure 5. The electricity model projects electric generation capacity addition, dispatch and fuel burn based on competition among different types of power generators given a number of factors, including plant capacities, fuel prices, heat rates, variable costs, and environmental emissions costs. The model integration of North American natural gas with the rest of the world and the North American electricity market captures the global linkages and also the inter-commodity linkages. Integrating gas and electricity is vitally important because U.S. natural gas demand growth is expected to be driven almost entirely by the electricity sector, which is predicted to grow at substantial rates.

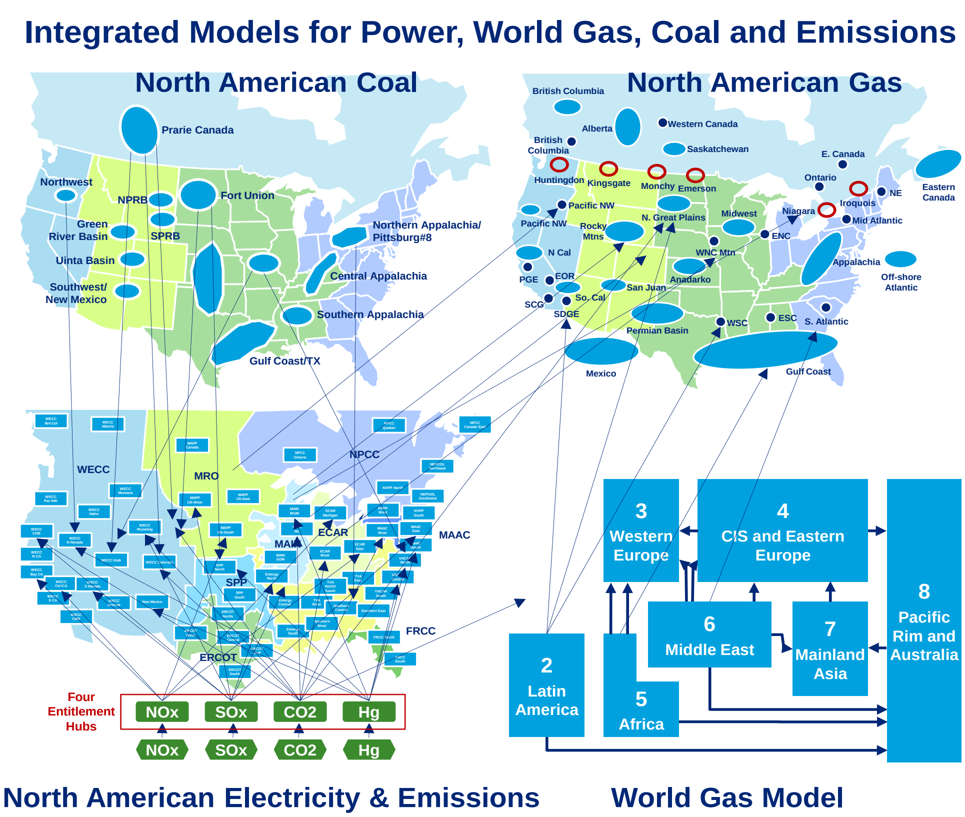
[3] Approximately the average consumer price index over the past 5 years according to the Bureau of Labor Statistics.

Figure 4: Comparison of projections of the U.S. gas demand for power generation



Furthermore, the electricity sector is projected to be far more responsive to natural gas price than any other sector. We model demand elasticity in the electricity sector directly rather than through elasticity estimates.

Figure 5: DMP North American Representation



Hence, the WGM projections include the impact of increased natural gas demand for electricity generation, which vies with LNG exports for domestic supplies. From the demand perspective, this is a conservative case in that the WGM would project a larger impact of LNG export than if we had assumed a lower US gas demand, which would likely make more supply available for LNG export and tend to lessen the price impact. Higher gas demand would tend to increase the projected prices impacts of LNG export. However, the real issue is not the absolute price of exported gas, but rather the price impact resulting from the LNG exports. The absolute price of natural gas will be determined by a number of supply and demand factors in addition to the volume of LNG exports.

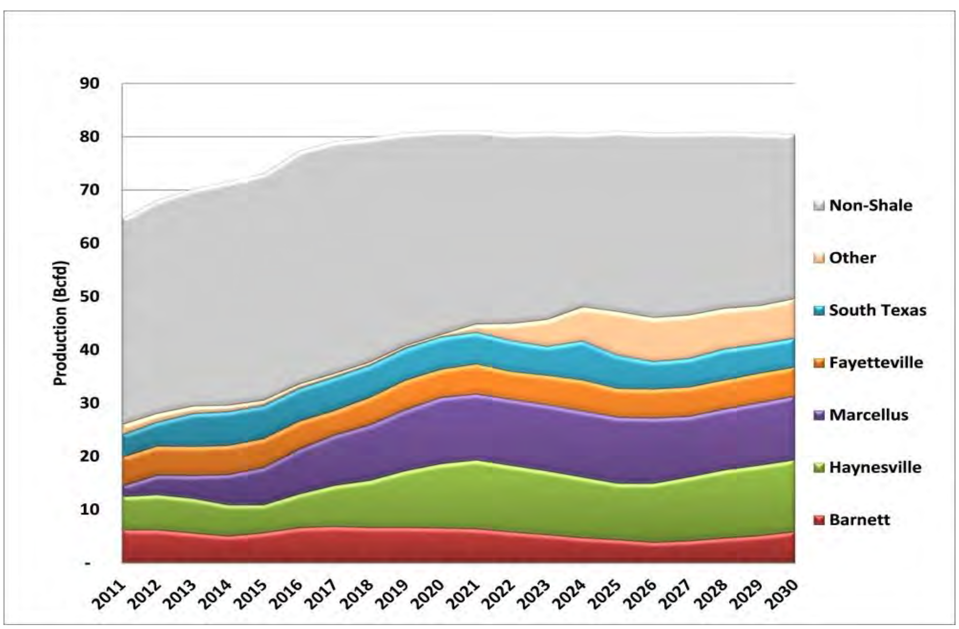
Buffering the price impact of LNG exports is the large domestic resource base, particularly shale gas which we project to be an increasingly important component of domestic supply. As shown in Figure 6, the Reference Case projects shale gas production, particularly in the Marcellus Shale in Appalachia and the Haynesville Shale in Texas and Louisiana, to grow and eventually become the largest component of domestic gas supply. Increasing U.S. shale gas output bolsters total domestic gas production, which grows from about 66 Bcfd in 2011 to almost 79 Bcfd in 2018 before tapering off.

The growth in production from a large domestic resource base is a crucial point and consistent with fundamental economics. Many upstream gas industry observers today believe that there is a very large quantity of gas available to be produced in the shale regions of North America at a more or less constant price. They believe, de facto, that natural gas supply is highly “elastic,” i.e., the supply curve is very flat.

A flattening supply curve is consistent with the resource pyramid diagram that the United States Geological Survey and others have postulated. At the top of the pyramid are high quality gas supplies which are low cost but also are fairly scarce. As you move down the pyramid, the costs increase but the supplies are more plentiful. This is another interpretation of our supply curve which has relatively small amounts of low cost supplies but as the cost increases, the supplies become more abundant.

Gas production in Canada is projected to decline over the next several years, reducing exports to the U.S. and continuing the recent slide in

Figure 6: U.S. gas production by type



production out of the Western Canadian Sedimentary Basin. However, Canadian production is projected to ramp up in the later part of this decade with increased production out of the Horn River and Montney shale gas plays in Western Canada. Further into the future, the Mackenzie Delta pipeline may begin making available supplies from Northern Canada. Increased Canadian production makes more gas available for export to the U.S.

Rather than basing our production projections solely on the physical decline rates of producing fields, the WGM considers economic displacement as new, lower cost supplies force their way into the market. The North American natural gas system is highly integrated so Canadian supplies can easily access U.S. markets when economic.

Increasing production from major shale gas plays, many of which are not located in traditional gas-producing areas, has already started to transform historical basis relationships (the difference in prices between two markets) and the trend is projected to continue during the next two decades. Varying rates of regional gas demand growth, the advent of new natural gas infrastructure, and evolving gas flows may also contribute to changes in regional basis, although to a lesser degree.

Most notably, gas prices in the Eastern U.S., historically the highest priced region in North America, could be dampened by incremental shale gas production within the region. Eastern bases to Henry Hub are projected to sink under the weight of surging gas production from the Marcellus Shale. Indeed, the flattening of Eastern bases is already becoming evident. The Marcellus Shale is projected to dominate the Mid-Atlantic natural gas market, including New York, New Jersey, and Pennsylvania, meeting most of the regional demand and pushing gas through to New England and even to South Atlantic markets. Gas production from Marcellus Shale will help shield the Mid-Atlantic region from supply and demand changes in the Gulf region. Pipelines built to transport gas supplies from distant producing regions — such as the Rockies and the Gulf Coast — to Northeastern U.S. gas markets may face stiff competition. The result could be displacement of volumes from the Gulf which would depress prices in the Gulf region. Combined with the growing shale production out of Haynesville and Eagle Ford, the Gulf region is projected to continue to have plentiful production and remain one of the lowest cost regions in North America.

Understanding the dynamic nature of the natural gas market is paramount to understanding the impact of LNG exports. If LNG is exported from any particular location, the entire North American natural gas system will potentially reorient production, affecting basis differentials and flows. Basis differentials are not fixed and invariant to LNG exports or any other supply and demand changes. On the contrary, LNG exports will likely alter basis differentials, which lead to redirection of gas flows to highest value markets from each source given available capacity.

Potential impact of LNG exports

Impact on natural gas prices

We analyzed five LNG export cases within this report: one case with Lavaca Bay only (1.33 Bcfd) and four other cases with varying levels of total U.S. LNG export volumes (3 Bcfd, 6 Bcfd, 9 Bcfd and 12 Bcfd exports). Each case was run with the DMP's Integrated North American Power and Gas Models in order to capture the dynamic interactions across commodities.

For ease of reporting, we will focus on the results with 6 Bcfd of LNG exports, our middle case, without any implication that it is more likely than any other case. Given the model's assumptions, the WGM projects 6 Bcfd of LNG exports will result in a weighted-average price impact of $0.15/MMBtu on the average U.S. citygate price from 2018 to 2037. The $0.15/MMBtu increase represents a 2.2% increase in the projected average U.S. citygate gas price of $6.96/MMBtu over this time period. The projected increase in Henry Hub gas price is $0.26/MMBtu during this period. It is important to note the variation in price impact by location. The impact at the Henry Hub will be much greater than the impact in other markets more distant from export terminals.

For all five export cases considered, the projected natural gas price impacts at the Henry Hub, New York, and average US citygate from 2018 through 2037 are shown in Figure 7.

To put the impact in perspective, Figure 8 shows the price impact of the midpoint 6 Bcfd case compared to projected Reference Case U.S. average citygate prices over a twenty year period. The height of the bars represents the projected price with LNG exports.

The small incremental price impact may not appear intuitive or expected to those familiar with market traded fluctuations in natural gas prices. For example, even a 1 Bcfd increase in demand due to sudden weather changes can cause near term traded gas prices to surge because in the short term, both supply and demand are highly inelastic (i.e., fixed quantities). However, in the long-term, producers can develop more reserves in anticipation of demand growth, e.g. due to LNG exports. Indeed, LNG export projects will likely be linked in the origination market to long-term supply contracts, as well as long-term contracts with LNG buyers. There will be ample notice and

Figure 7: Price impact by scenario for 2018-37 ($/MMBtu)

Export Case	Average US Citygate	Henry Hub	New York
1.33 Bcfd	$ 0.03	$ 0.03	$ 0.02
3 Bcfd	$ 0.07	$ 0.11	$ 0.06
6 Bcfd	$ 0.15	$ 0.26	$ 0.14
9 Bcfd	$ 0.22	$ 0.36	$ 0.23
12 Bcfd	$ 0.30	$ 0.50	$ 0.29

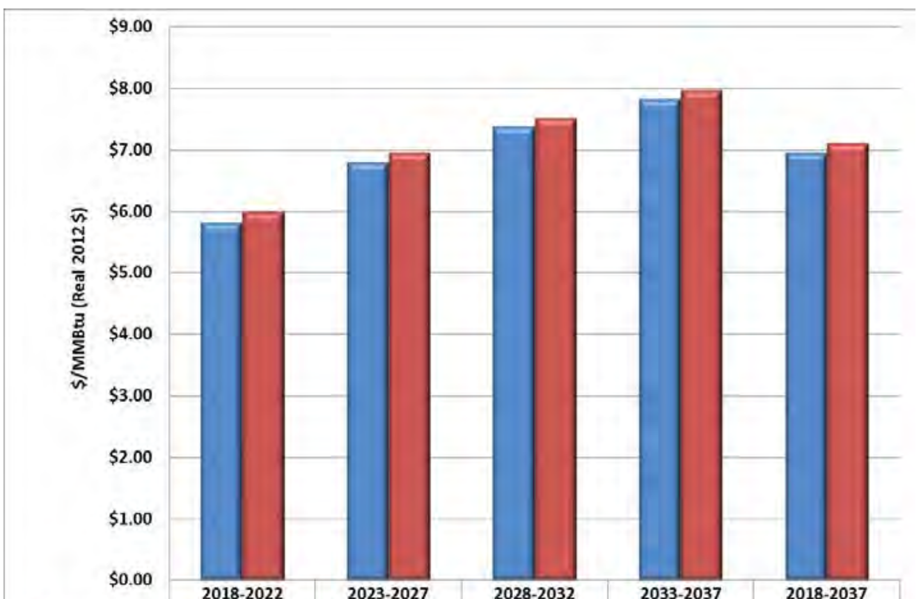
time in advance of the LNG exports for suppliers to be able to develop supplies so that they are available by the time export terminals come into operation. Therefore, under our long-term equilibrium modeling assumptions, long-term changes to demand may be anticipated and incorporated into supply decisions. The built-in market expectations allows for projected prices to come into equilibrium smoothly over time. Hence, our projected price impact primarily reflects the estimated change in the production cost of the marginal gas producing field with the assumed export volumes.

As previously stated, the model projected price impact varies by location as shown in Figure 9.

As previously described, the price impact diminishes with distance from export terminals. For all cases the impact is greatest at Henry Hub, situated near most export terminals. For the midpoint case of 6 Bcfd, the impact at the Houston Ship Channel is nearly as much as Henry Hub, at $0.26/MMBtu on average from 2018 to 2037. As distance from export terminals increases (i.e., distance to downstream markets such as Chicago, California and New York) the price impact is generally only about $0.12 to $0.14/MMBtu on average from 2018 to 2037.

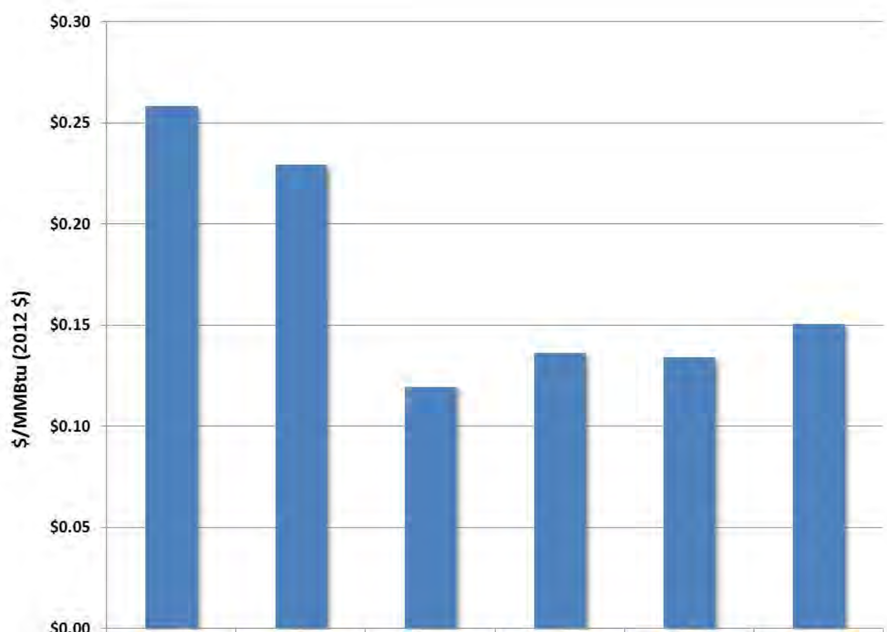
Similarly, Figures 8 and 9 corresponding to the other export cases (1.33, 3.0, 9.0 and 12.0 Bcfd) are shown in the Appendix.

Figure 8: Projected Impact of LNG exports on average U.S. Citygate gas prices (Real 2012 $)



	2018-2022	2023-2027	2028-2032	2033-2037	2018-2037
Reference Case	$5.83	$6.80	$7.38	$7.83	$6.96
6 Bcfd Case	$5.99	$6.96	$7.51	$7.97	$7.11

Figure 9: Price impact varies by location in 6 Bcfd export case (average 2018-37)



	Henry Hub	HSC	Chicago	New York	California	Average US
6 Bcfd Case	$0.26	$0.23	$0.12	$0.14	$0.13	$0.15

Impact on electricity prices

The projected impact on electricity prices is even smaller than the projected impact on gas prices. DMP's integrated power and gas model allows us to estimate incremental impact on electricity prices resulting from LNG export assumptions, as natural gas is also a fuel used for generating electricity. Since our integrated model represents the geographic linkages between the electricity and natural gas systems, we can compute the potential impact of LNG exports in local markets (local to LNG exports) where the impact would be the largest.

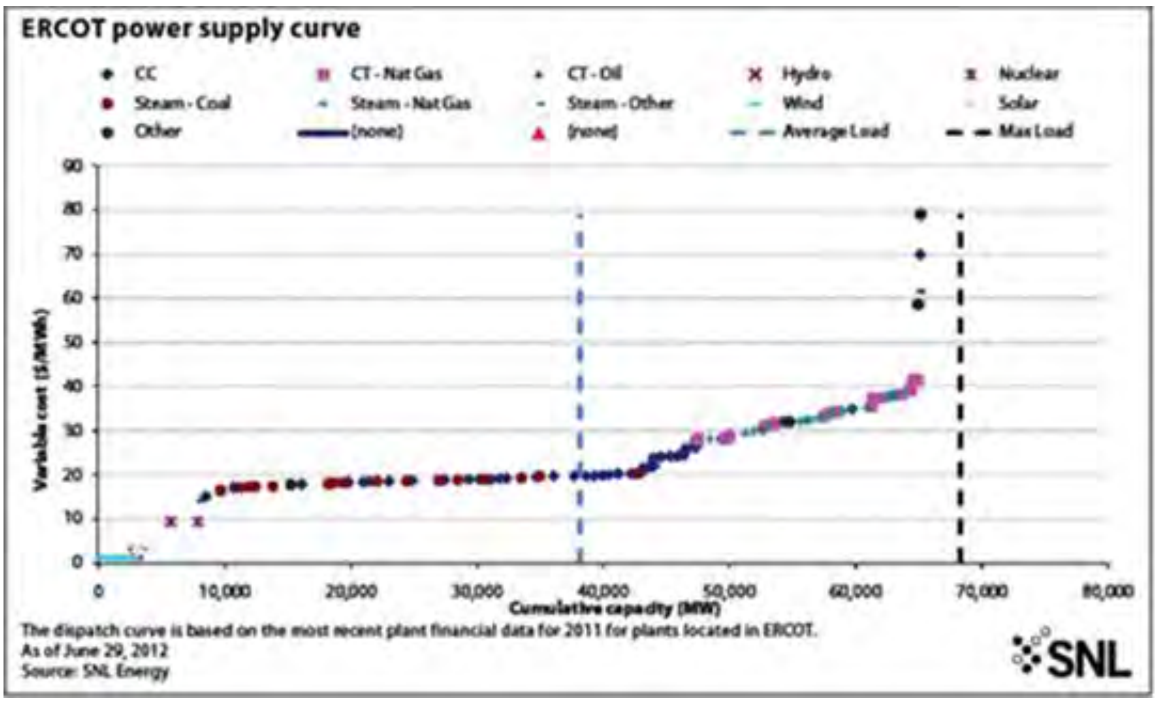
A similar comparison for electricity shows that the projected average (2018-2037) electricity prices increase by 0.8% in ERCOT (the Electric Reliability Council of Texas), under the 6 Bcfd export case. The impact on electricity prices is much less than the 4.0% Henry Hub gas price impact. For power markets in other regions, the electricity price impact is much lower, because the gas price impact is much lower.

A key reason why the price impact for electricity is less than that of gas is that electricity prices will only be directly affected by an increase in gas prices when gas-fired generation is the marginal source of power generation. That is, gas price only affects power price if it changes the marginal unit (i.e., the last unit in the generation stack needed to service the final amount of electricity load). When gas-fired generation is lower cost than the marginal source, then a small increase in gas price will only impact electricity price if it is sufficient to drive gas-fired generation to be the marginal source of generation. If gas-fired generation is already more expensive than the marginal source of generation, then an increase in gas price will not impact electricity price, since gas-fired generation is not being utilized because there is sufficient capacity from units with lower generation costs.

If gas-fired generation is the marginal source, then electricity price will increase with gas price, but only up to the point that some other source can displace it as marginal source. Every power region has numerous competing power generation plants burning different fuel types, which will mitigate the price impact of an increase in any one fuel type. Moreover, within DPM's integrated power and gas model, fuel switching among coal, nuclear, gas, hydro, wind and oil units is directly represented as part of the modeling.

Figure 10 shows the power supply curve for ERCOT. The curve plots the variable cost of generation and capacity by fuel type. Depending on where the demand curve intersects the supply curve, a generating unit with a particular fuel type will set the electricity price. During extremely low demand periods, hydro, nuclear or coal plants will likely set the price. An increase in gas price during these periods would not impact electricity price in this region because gas-fired plants are typically not utilized. Since the marginal source sets the price, a change in gas price under these conditions would not affect power prices.

Figure 10: Power supply curve for ERCOT region

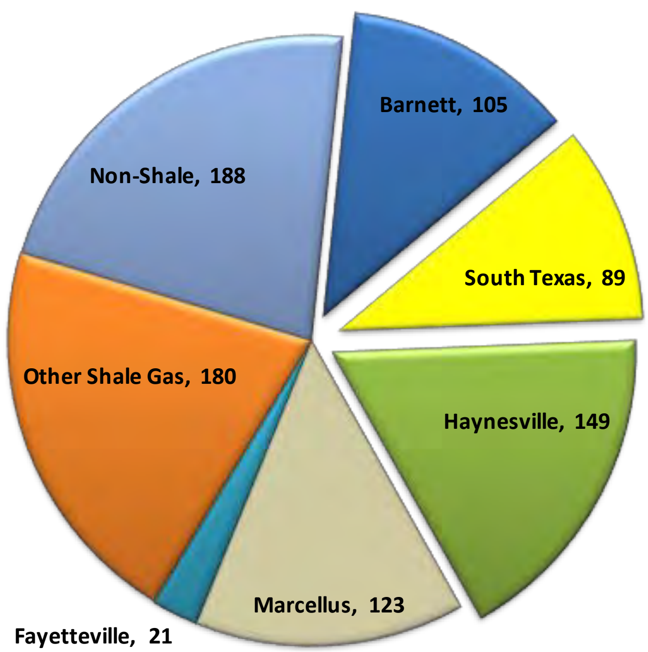


Incremental production impact in Texas from Lavaca Bay export

All of the gas used as feedstock for 1.33 Bcfd of LNG exports from Lavaca Bay is projected to come from Texas production. About one-third of the gas is incremental supplies from Texas production with the remaining two-thirds coming from Texas gas that would have otherwise been exported out of the state but instead is diverted to the terminal. The diverted volumes stimulate production in other supply basins outside Texas. Figure 11 shows the projected increase in production volume on average from 2018-2037.

The shale gas basins that are entirely or at least partially located in Texas are separated to highlight the impact on the State. One might expect South Texas, which includes Eagle Ford shales, to have a larger incremental impact. However, the region is rich in liquids and is projected to grow strongly even without boost from LNG exports. The incremental supplies indicate the marginal regions which would be stimulated with incremental demand.

Figure 11: Average incremental production with Lavaca Bay export, 2018-37 (MMcfd)

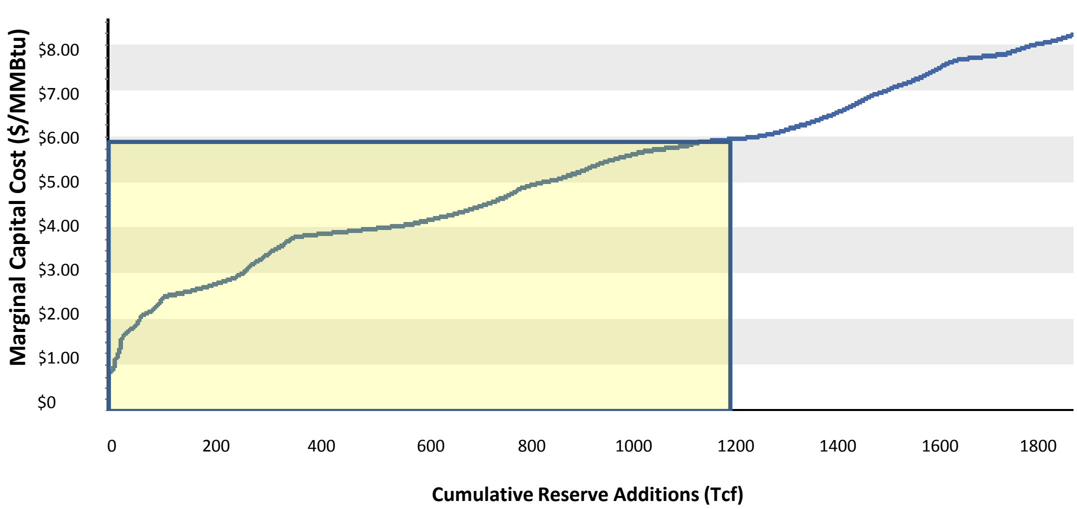


Large domestic supply buffers impact

Figure 12 shows the aggregate U.S. supply curve, including all types of gas formations. It plots the volumes of reserve additions available at different all-in marginal capital costs, including financing, return on equity, and taxes. The marginal capital cost is equivalent to the wellhead price necessary to induce a level of investment required to bring the estimated volumes on line. The model includes over one hundred different supply nodes representing the geographic and geologic diversity of domestic supply basins. The supply data is based on publically available documents and discussions with sources such as the United States Geological Survey, National Petroleum Council, Potential Gas Committee, and the DOE's Energy Information Administration.

The area of the supply curve that matters most for the next couple decades is the section below \$6/MMBtu of capital cost because wellhead prices are projected to fall under this level during most of the time horizon considered. These are the volumes that are projected to get produced over the next couple decades. The Reference Case estimates about 1,200 Tcf available at wellhead prices below \$6/MMBtu in current dollars. To put the LNG export volumes into perspective, it will accelerate depletion of the domestic resource base, estimated to include about 1,200 Tcf at prices below \$6/MMBtu in all-in capital cost, by 2.2 Tcf per year (equivalent to 6 Bcfd). Alternatively, the 2.2 Tcf represents an increase in demand of about 8% to the projected demand of 26 Tcf by the time exports are assumed to commence in 2016. The point is not to downplay the export volume, but to show the big picture. The magnitude of total LNG exports is substantial on its own, but not very significant relative to the entire U.S. resource base or total U.S. demand.

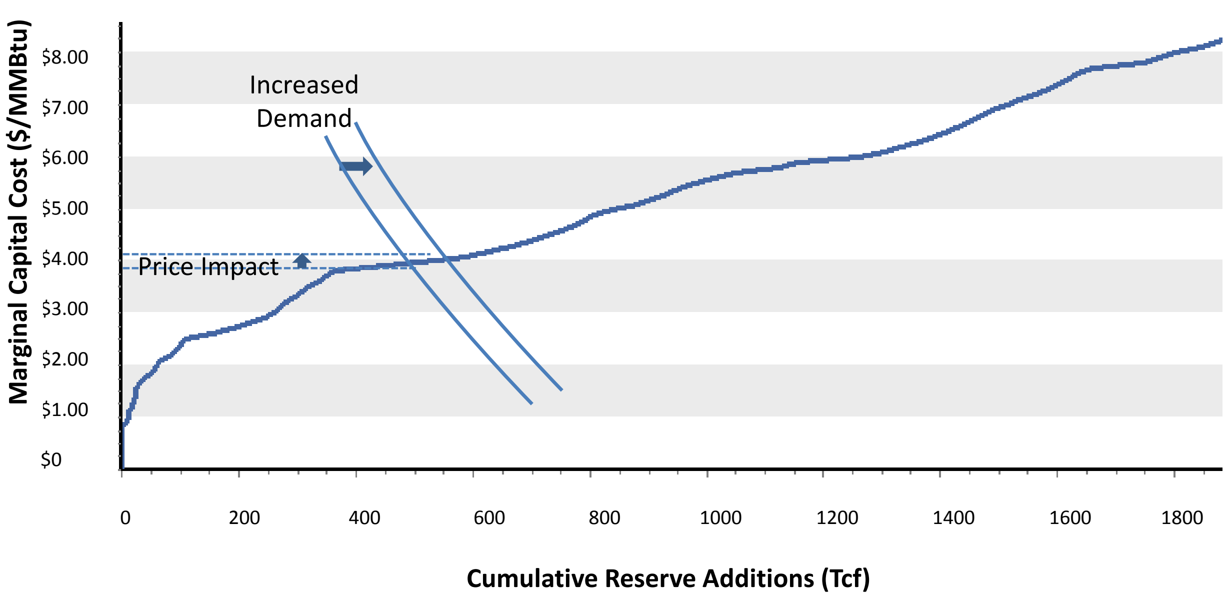
Figure 12: Aggregate U.S. natural gas supply curve (2012 \$)



With regards to the potential impact of LNG exports, the absolute price is not the driving factor but rather the shape of the aggregate supply curve which determines the price impact. Figure 13 depicts how demand increase affects price. Incremental demand pushes out the demand curve, causing it to intersect the supply curve at a higher point. Since the supply curve is fairly flat in the area of demand, the price impact is fairly small. The massive shale gas resources have flattened the U.S. supply curve. It is the shape of the aggregate supply curve that really matters. Hence, leftward and rightward movements in the demand curve (where such leftward and rightward movements would be volumes of LNG export) cut through the supply curve at pretty much the same price. Flat, elastic supply means that the price of domestic natural gas is increasingly and continually determined by supply issues (e.g., production cost). Given that there is a significant quantity of domestic gas available at modest production costs, the export of 6 Bcfd of LNG would not increase the price of domestic gas very much because it would not increase the production cost of domestic gas very much.

The projected sources of incremental volumes used to meet the assumed export volumes come from multiple sources, including domestic resources (both shale gas and non-shale gas), import volumes, and demand elasticity. Figure 14 shows the sources of incremental volumes in the 6 Bcfd LNG export case on average from 2018 to 2037, the assumed years of LNG exports. (The source fractions are similar for other LNG export cases so we only show the 6 Bcfd case.) The bulk of the incremental volumes come from shale gas production. Including non-shale gas production, the domestic production contributes 63% of the total incremental volume. Net pipeline imports, comprised mostly of imports from Canada, contribute another 18%. Higher U.S. prices induce greater Canadian production, primarily from Horn River and Montney shale gas resources, making gas available for export to the U.S. The net exports to Mexico declines slightly as higher cost of U.S. supplies will likely prompt more Mexican production and would reduce the need for U.S. exports to Mexico. Higher gas prices are also projected to trigger demand elasticity so less gas is consumed, representing about 19% of the incremental volume. Most of the reduction in gas consumption comes from the power sector as higher gas prices incentivize greater utilization of generators burning other types of fuels.

Figure 13: Impact of higher demand on price (illustrative)

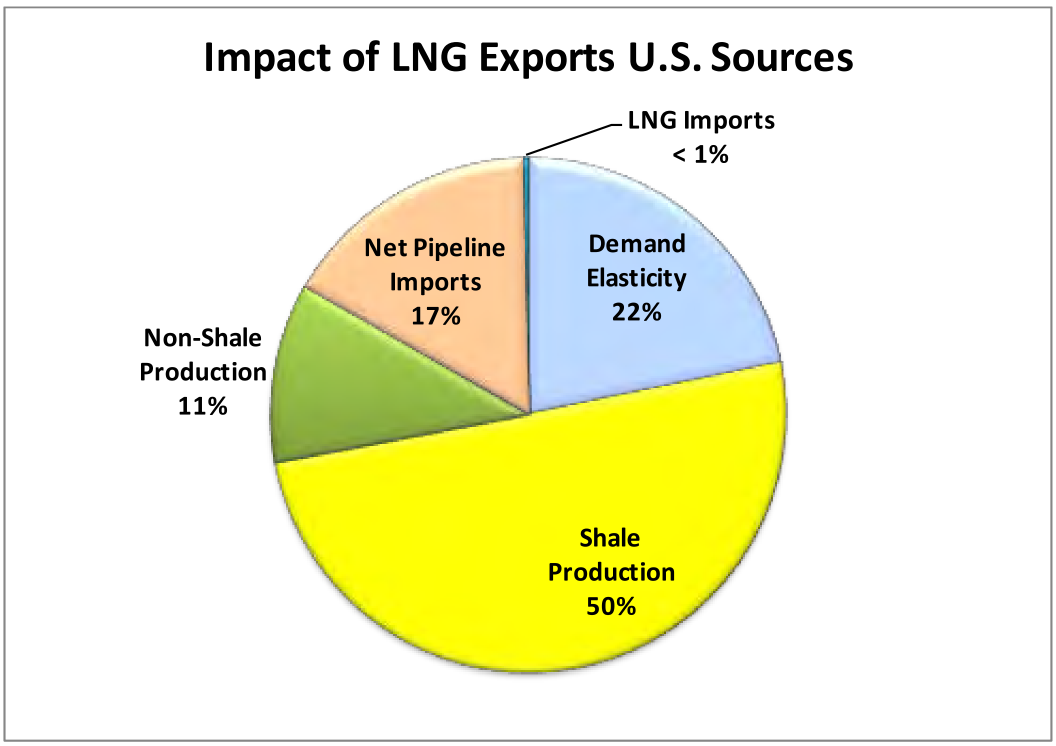


Finally, there is an insignificant increment, less than 1%, coming from LNG imports. Having both LNG imports and exports is not necessarily contradictory since there is variation in price by terminal (e.g., Everett terminal near Boston will likely see higher prices than will Gulf terminals) and by time (e.g., LNG cargos will seek to arbitrage seasonal price).

These results underscore the fact that the North American natural gas market is highly integrated and the entire market works to mitigate price impacts of demand changes.

During moderate or moderately high demand periods, coal or gas could be the marginal fuel type. If it is gas on the margin, price can rise only up to the cost of the next marginal fuel type (e.g., coal plant). If gas remains on margin, then it will be a simple calculation to see electricity price impact. At the projected Henry Hub gas price impact of \$0.26/MMBtu, a typical gas plant with a heat rate of 8,000 would cost an additional \$2.08/MWh (=\$0.26/MMBtu x 8000 Btu/MWh x 1 MMBtu/1000 Btu). We believe that is the most that the gas price increase could elevate electricity price. Power load fluctuates greatly during a day, typically peaking during mid-afternoon and falling during the night. That implies that the marginal fuel type will also vary and gas will be at the margin only part of the time.

Figure 14: Projected sources of incremental volume in the 6 Bcfd Export Case (Average 2018-37)



Comparison of results to other studies

A number of studies, including others submitted to the DOE in association with LNG export applications, have estimated impacts of LNG exports from the U.S. The EIA also performed a study[4] at the request of the DOE. The various studies used different models and assumptions, but a comparison of their results might shed some light on the key factors and range of possible outcomes.

Figure 15 compares projections of estimated Henry Hub price impact from 2015 to 2035 with 6 Bcfd of LNG exports. The price impact ranges from 4% to 11%, with this study being on the low end and the ICF International being on the high end. The first observation is that, although the percentage differences are large on a relative basis, the range of estimated impacts is not so large. These studies consistently show that the price impact will not be that large relative to the change in demand. Bear in mind that 6 Bcfd is a fairly large incremental demand. In fact, it exceeds the combined gas demands in New York (3.3 Bcfd) and Pennsylvania (2.4 Bcfd) in 2011. These studies indicate that adding a sizeable incremental gas load on the U.S. energy system might result in a gas price increase of 11% or less.

Although we have limited data relating to specific assumptions and detailed output from the other studies, we can infer why the impacts differ so much. By most accounts, the resource base in the United States is plentiful, perhaps sufficient to last some 100 years at current production levels. All of the studies listed, including our own, had estimated natural gas resource volumes, including proved reserves and undiscovered gas of all types, of over 2,000 Tcf. Why then would the LNG export impacts vary as much as they do?

An important distinction between our analysis and the other studies is the representation of market dynamics, particularly for supply response to demand changes. That is, how do the studies represent how producers will respond to demand changes? The World Gas Model has a dynamic supply representation in which producers are assumed to anticipate demand and price changes. Producers do more than just respond to price that they see, but

Figure 15: Comparison of projected price impact from 2015-35 at the Henry Hub with 6 Bcfd of LNG exports

Study	Price without Exports ($/MMBtu)	Price with Exports ($/MMBtu)	Average Price Increase (%)
EIA	$ 5.28	$ 5.78	9%
Navigant (2010)	$ 4.75	$ 5.10	7%
Navigant (2012)	$ 5.67	$ 6.01	6%
ICF International	$ 5.81	$ 6.45	11%
Deloitte MarketPoint	$ 6.11	$ 6.37	4%

Source: Brookings Institute for all estimates besides Deloitte MarketPoint's

[4] "Effect of Increased Natural Gas Exports on Domestic Energy Markets," Howard Gruenspecht, EIA, January 2012.

rather anticipate events. Accordingly, prices will rise to induce producers to develop supplies in time to meet future demand.

Other models, primarily based on linear programming (LP)[5] or similar approaches, use static representation of supply in that supply does not anticipate price or demand growth. These static supply models require the user to input estimates of productive capacities in each future time period. The Brookings Institution completed a study assessing the impact of LNG exports and analyzing different economic approaches.[6] . As the Brookings study states:

"… static supply model, which, unlike dynamic supply models, does not fully take account of the effect that higher prices have on spurring additional production."

Since the supply volumes available in each time period is an input into LP models, the user must input how supply will respond to demand. In the case of LNG exports, the user must input how much supplies will increase and how quickly given the export volumes. Hence, the price impact is largely determined by how the user changes these inputs.

The purpose of this discussion is not to assert which approach is best, but rather to understand the differences so that the projections can be understood in their proper context. Assuming little or no price anticipation will tend to elevate the projected price impact while assuming price anticipation will tend to mitigate the projected price impact. Depending on the issue being analyzed, one approach may be more appropriate than the other. In the case of LNG export terminals, our belief is that the assumption of dynamic supply demand balance is appropriate. Given the long lead time, expected to be at least five years, required to permit, site, and construct an LNG export terminal, producers will have both ample time and plenty of notice to prepare for the export volumes. It would be a different matter if exports were to begin with little advanced notice.

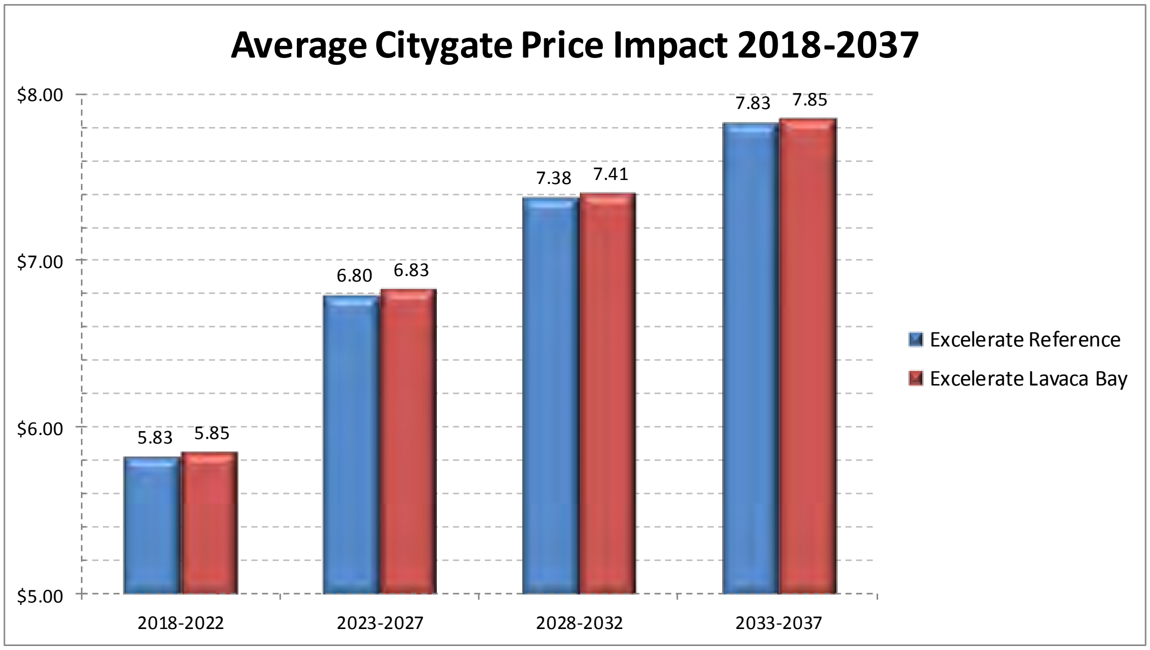
The importance of timing is evident in EIA's projections. The projected price impact is highly dependent on how quickly export volumes are assumed to ramp up. Furthermore, in all cases, the impacts are the greatest in the early years of exports. The impacts dissipate over time as supplies are assumed to eventually catch up with the demand growth.

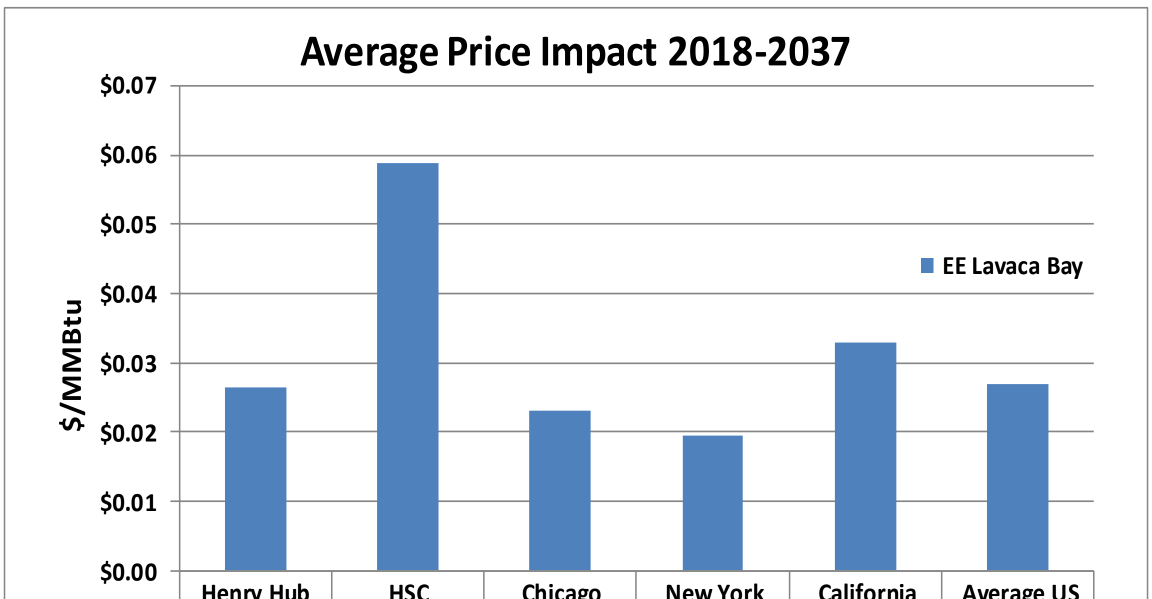
Natural gas producers are highly sophisticated companies with analytical teams monitoring and forecasting market conditions. Producers, well aware of the potential LNG export projects, are looking forward to the opportunity to supply these projects.

[5] Linear programming ("LP") is a mathematical technique for solving a global objective function subject to a series of linear constraints

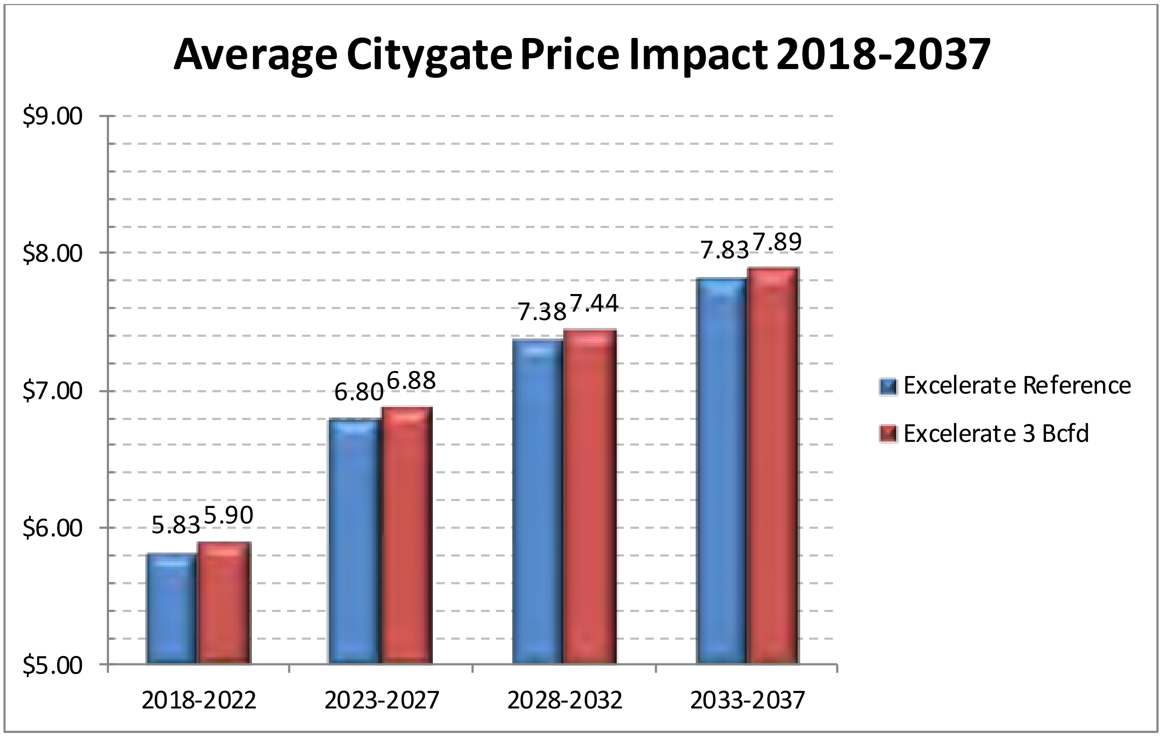
[6] "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas," Brookings Institution (2012).

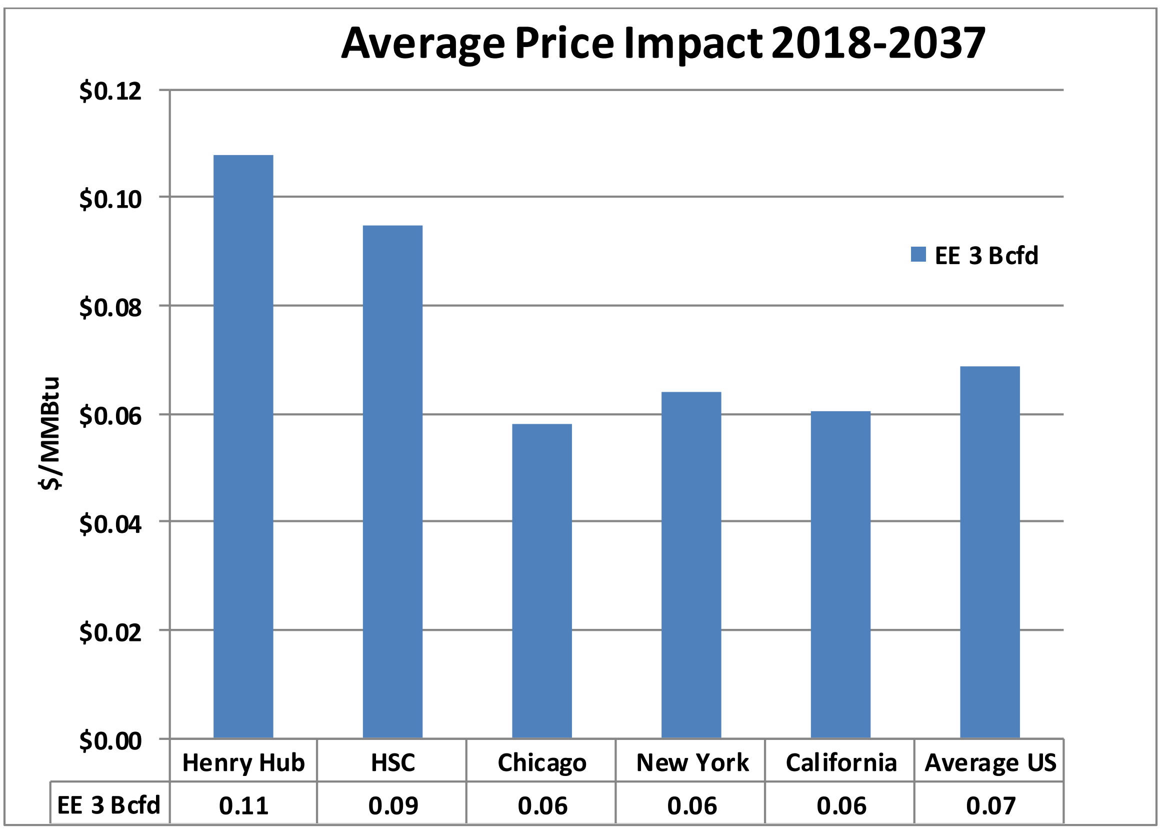
Appendix A: Price Impact Charts for other Export Cases

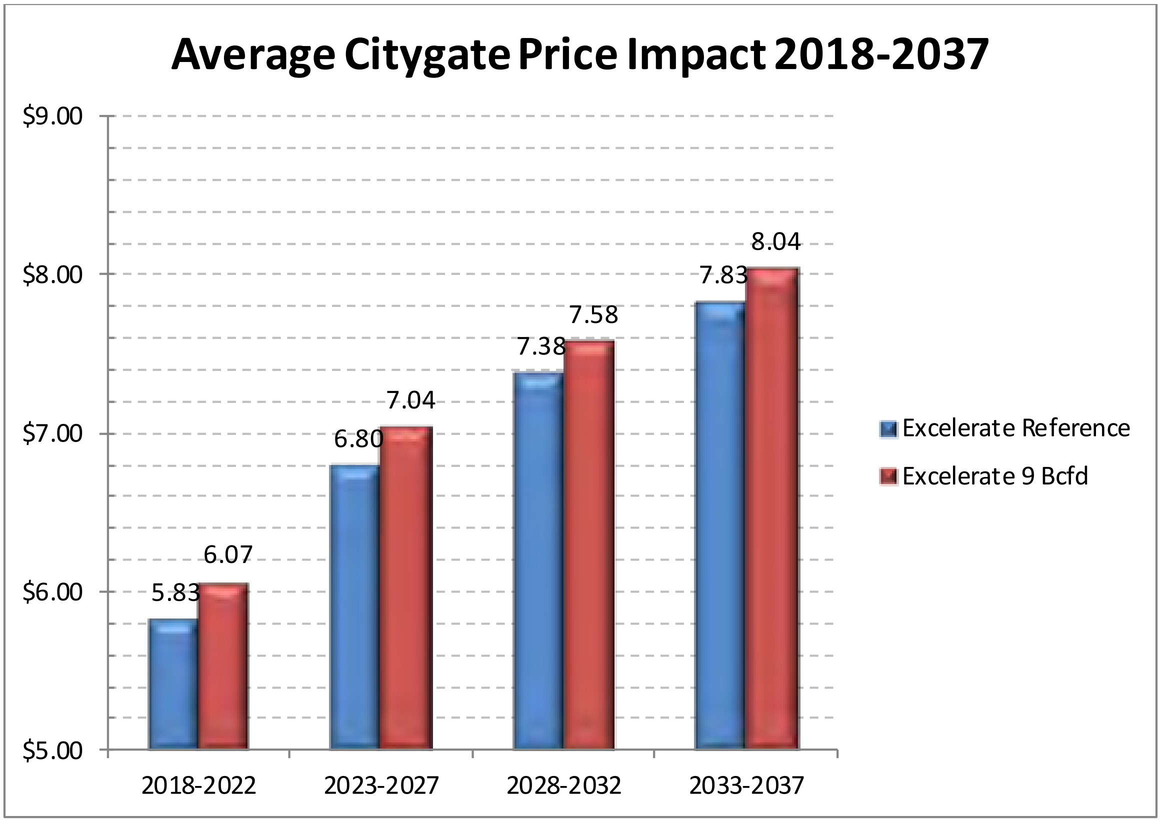


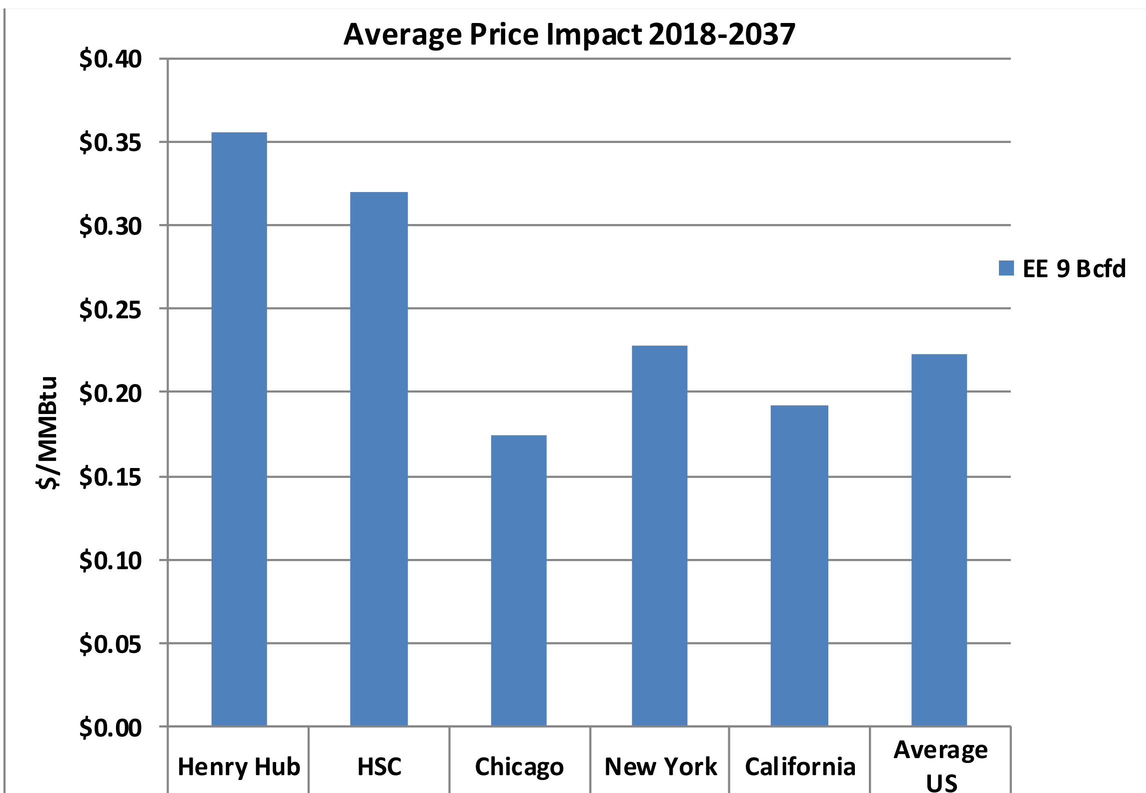


	Henry Hub	HSC	Chicago	New York	California	Average US
EE Lavaca Bay	0.03	0.06	0.02	0.02	0.03	0.03

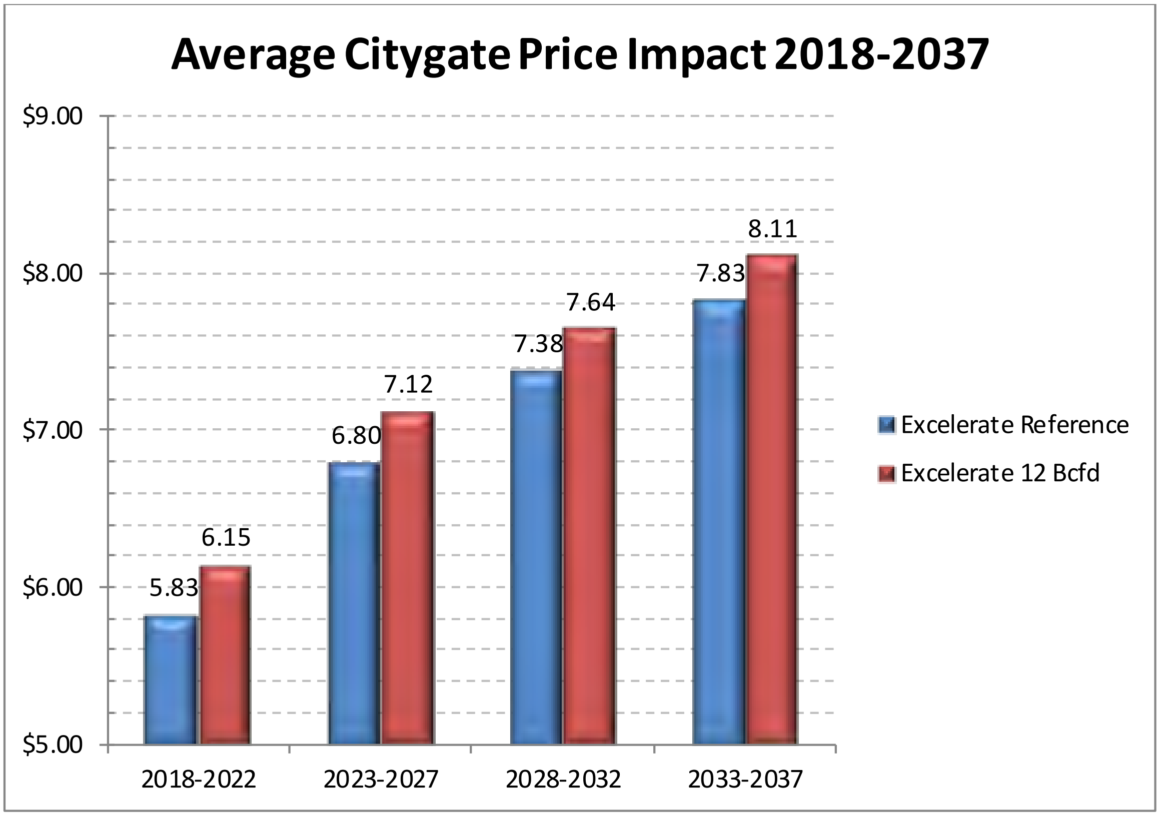

Average Citygate Price Impact 2018-2037
$9.00
$8.00
$7.00
$6.00
$5.00
5.83
5.90
6.80
6.88
7.38
7.44
7.83
7.89
2018-2022
2023-2027
2028-2032
2033-2037
Excelerate Reference
Excelerate 3 Bcfd

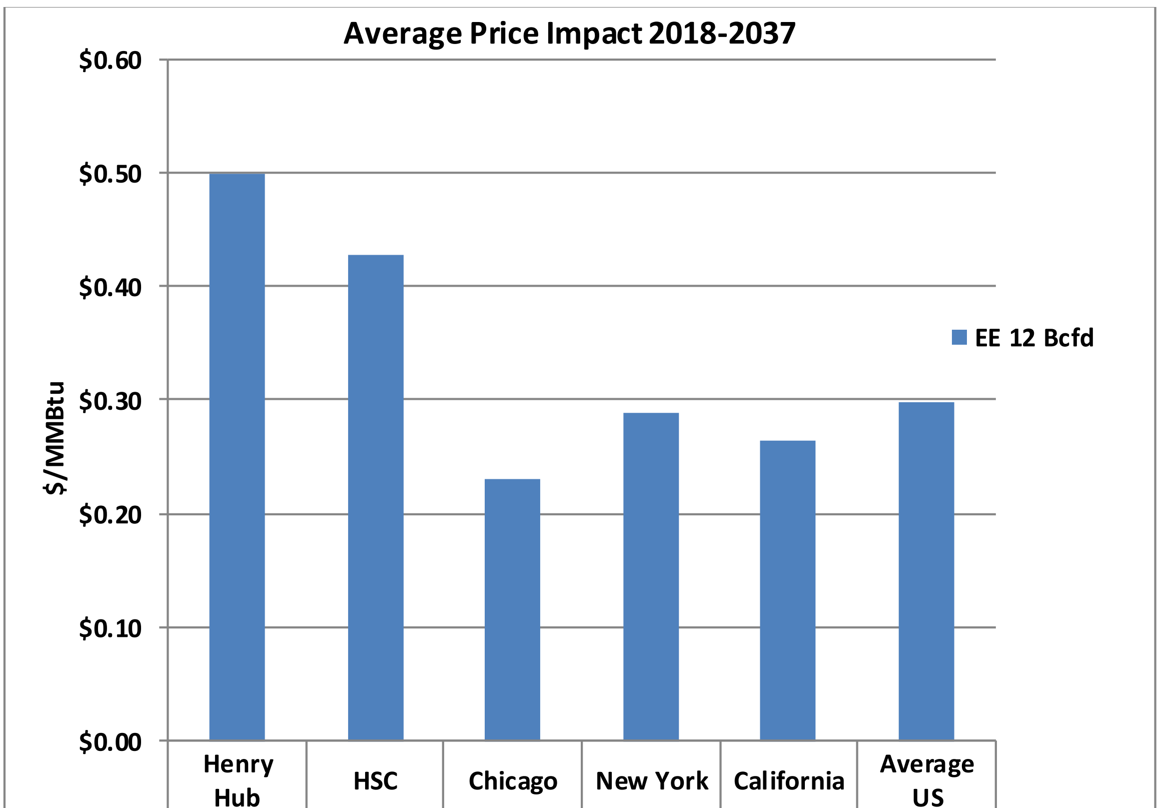

Average Price Impact 2018-2037
$/MMBtu
$0.12
$0.10
$0.08
$0.06
$0.04
$0.02
$0.00
EE 3 Bcfd
Henry Hub
HSC
Chicago
New York
California
Average US
EE 3 Bcfd
0.11
0.09
0.06
0.06
0.06
0.07





	Henry Hub	HSC	Chicago	New York	California	Average US
EE 9 Bcfd	0.36	0.32	0.17	0.23	0.19	0.22





	Henry Hub	HSC	Chicago	New York	California	Average US
EE 12 Bcfd	0.50	0.43	0.23	0.29	0.26	0.30

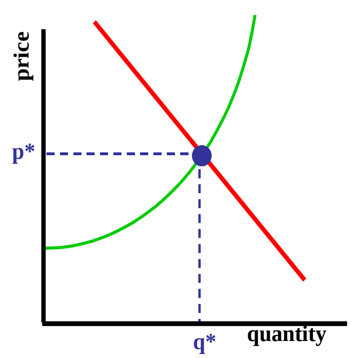
Appendix B: DMP's World Gas Model and data

To help understand the complexities and dynamics of global natural gas markets, DMP uses its World Gas Model ("WGM") developed in our proprietary MarketBuilder software. The WGM, based on sound economic theories and detailed representations of global gas demand, supply basins, and infrastructure, projects market clearing prices and quantities over a long time horizon on a monthly basis. The projections are based on market fundamentals rather than historical trends or statistical extrapolations.

WGM represents fundamental producer decisions regarding the timing and quantity of reserves to develop given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the market value of gas supply in remote parts of the world. The WGM uses sophisticated depletable resource logic in which today's drilling decisions affect tomorrow's price and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

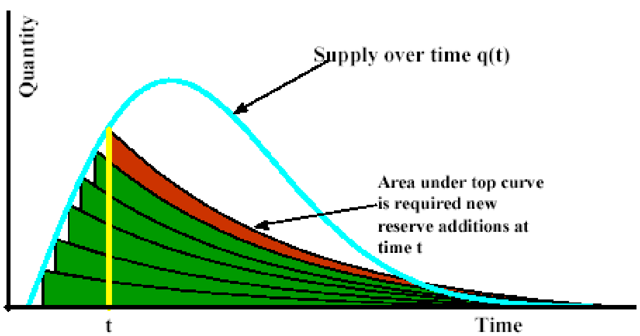
WGM simulates how regional interactions among supply, transportation, and demand interact to determine market clearing prices, flowing volumes, reserve additions, and pipeline entry and exit through 2046. The WGM divides the world into major geographic regions that are connected by marine freight. Within each major region are very detailed representations of many market elements: production, liquefaction, transportation, market hubs, regasification and demand by country or sub area. All known significant existing and prospective trade routes, LNG liquefaction plants, LNG regasification plants and LNG terminals are represented. Competition with oil and coal is modeled in each region. The capability to model the related markets for emission credits and how these may impact LNG markets is included. The model includes detailed representation of LNG liquefaction, shipping, and regasification; pipelines; supply basins; and demand by sector. Each regional diagram describes how market elements interact internally and with other regions.

Agent based economic methodology. MarketBuilder rigorously adheres to accepted microeconomic theory to solve for supply and demand using an "agent based" approach. To understand the benefits of the agent based approach, suppose you have a market comprised of 1000 agents, i.e., producers, pipelines, refineries, ships, distributors, and consumers. If your model of that market is to be correct, how many optimization problems must there be in your model of that 1000 agent market? The answer is clear—there must be 1000 distinct, independent optimization problems. Every individual agent must be represented as simultaneously solving and pursuing his or her own maximization problem, vying for market share and trying to maximize his or her own individual profits. Market prices

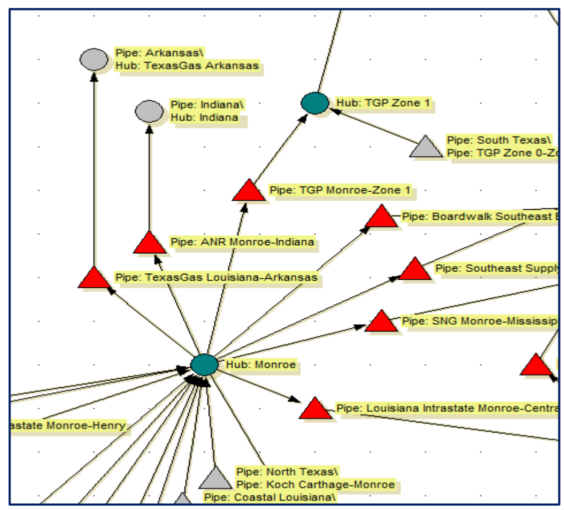


arise from the competition among these 1000 disparate, profit-seeking agents. This is the essence of microeconomic theory and competitive markets — people vying in markets for profits — and MarketBuilder rigorously approaches the problem from this perspective. In contrast, LP models postulate a single optimization problem no matter how many agents there are in the market; they only allow one, overall, global optimization problem. With LP, all 1000 agents are assumed to be manipulated by a "central authority" who forces them to act in lockstep to minimize the worldwide cost of production, shipment, and consumption of oil, i.e., to minimize the total cost of gas added up over the entire world.

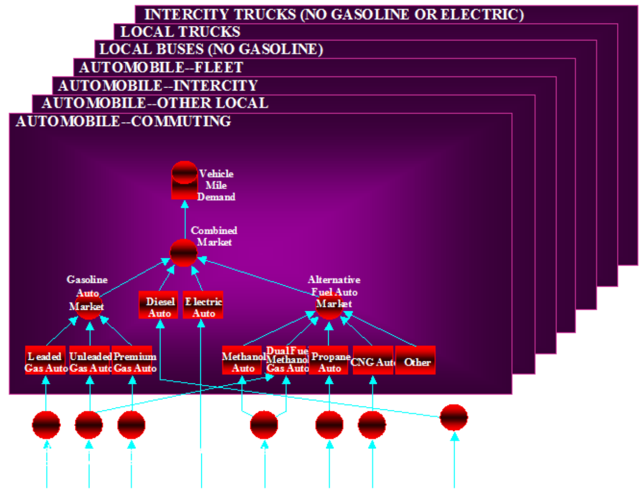
Supply methodology and data. Working with data from agencies such as the United States Geological Survey (USGS), Energy Information Administration (EIA), and International Energy Agency (IEA), we have compiled a full and credible database of global supplies. In particular, we relied on USGS' world oil and gas supply data including proved reserves, conventional undiscovered resources, growth of reserves in existing fields, continuous and unconventional deposits, deep water potential, and exotic sources. Derived from detailed probabilistic analysis of the world oil and gas resource base (575 plays in the US alone), the USGS data lies at the heart of DMP' reference case resource database. Only the USGS does a worldwide, "bottom up" resource assessment. Customers can easily substitute their own proprietary view where they believe they have better information. MarketBuilder allows the use of sophisticated depletable resource modeling to represent production of primary oil and gas (an extended Hotelling model). The DMP Hotelling depletable resource model uses a "rational expectations" approach, which assumes that today's drilling affects tomorrow's price and tomorrow's price affects today's drilling. Thus MarketBuilder combines a resource model that approaches resource development the same way real producers do given the available data.



Transportation data. DMP maintains a global pipeline and transportation database. DMP and our clients regularly revise and update the transportation data including capacity, tariffs, embedded cost, discounting behavior, dates of entry of prospective new pipelines, and costs of those new pipelines.



Non-linear demand methodology. MarketBuilder allows the use of multi-variate nonlinear representations of demand by sector, without limit on the number of demand sectors. DMP is skilled at performing regression analyses on historical data to evaluate the effect of price, weather, GNP, etc. on demand. Using our methodology, DMP systematically models the impact of price change on demand (demand price feedback) to provide realistic results.



Independent Statistics & Analysis
U.S. Energy Information Administration

Effect of Increased Natural Gas Exports on Domestic Energy Markets

as requested by the Office of Fossil Energy

January 2012

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

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Preface

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

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

Contents

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Introduction

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

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

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

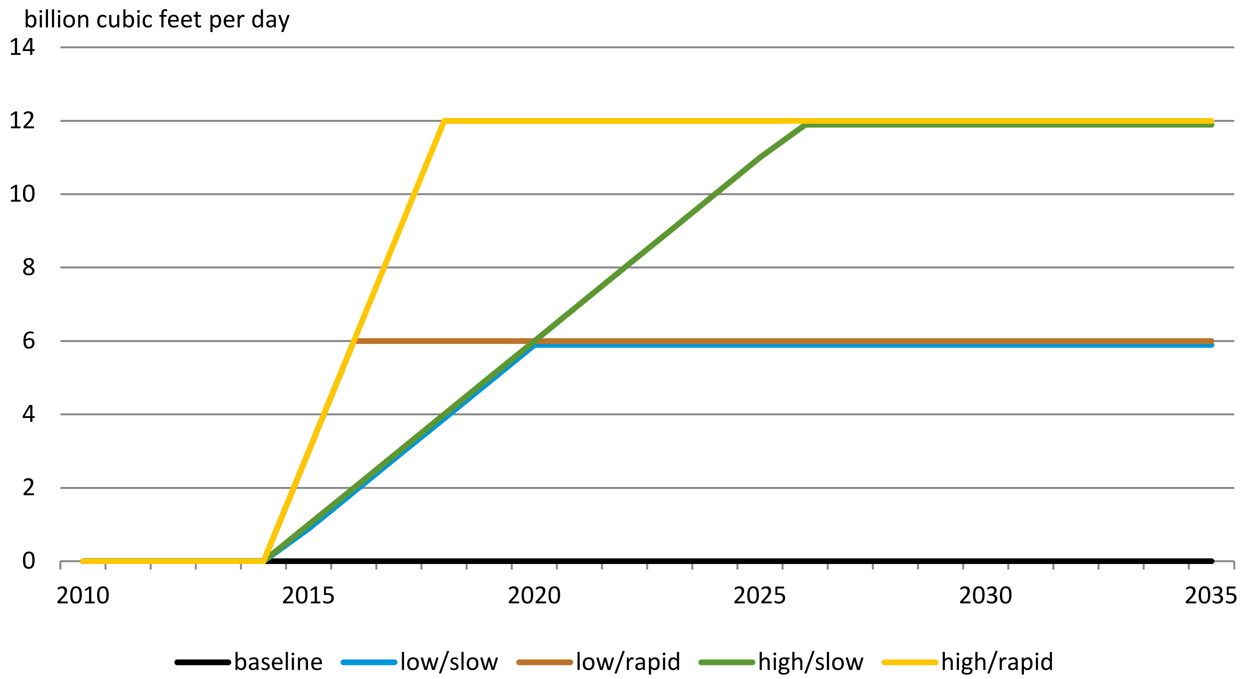
Total marketed natural gas production in 2011 was about 66 Bcf/d. The two ultimate levels of increased natural gas demand due to additional exports in the DOE/FE scenarios represent roughly 9 percent or 18 percent of current production.

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

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

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

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



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

Analysis approach

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

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

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

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

Caveats regarding interpretation of the analysis results

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

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

Representation of natural gas markets

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Summary of Results

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

Impacts overview

- **Increased natural gas exports lead to increased natural gas prices.** Larger export levels lead to larger domestic price increases, while rapid increases in export levels lead to large initial price increases that moderate somewhat in a few years. Slower increases in export levels lead to more gradual price increases but eventually produce higher average prices during the decade between 2025 and 2035.

- **Natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production.** Increased natural gas production satisfies about 60 to 70 percent of the increase in natural gas exports, with a minor additional contribution from increased imports from Canada. Across most cases, about three-quarters of this increased production is from shale sources.

- **The remaining portion is supplied by natural gas that would have been consumed domestically if not for the higher prices.** The electric power sector accounts for the majority of the decrease in delivered natural gas. Due to higher prices, the electric power sector primarily shifts to coal-fired generation, and secondarily to renewable sources, though there is some decrease in total generation due to the higher price of natural gas. There is also a small reduction in natural gas use in all sectors from efficiency improvements and conservation.

- **Even while consuming less, on average, consumers will see an increase in their natural gas and electricity expenditures.** On average, from 2015 to 2035, natural gas bills paid by end-use consumers in the residential, commercial, and industrial sectors combined increase 3 to 9 percent over a comparable baseline case with no exports, depending on the export scenario and case, while increases in electricity bills paid by end-use customers range from 1 to 3 percent. In the rapid growth cases, the increase is notably greater in the early years relative to the later years. The slower export growth cases tend to show natural gas bills increasing more towards the end of the projection period.

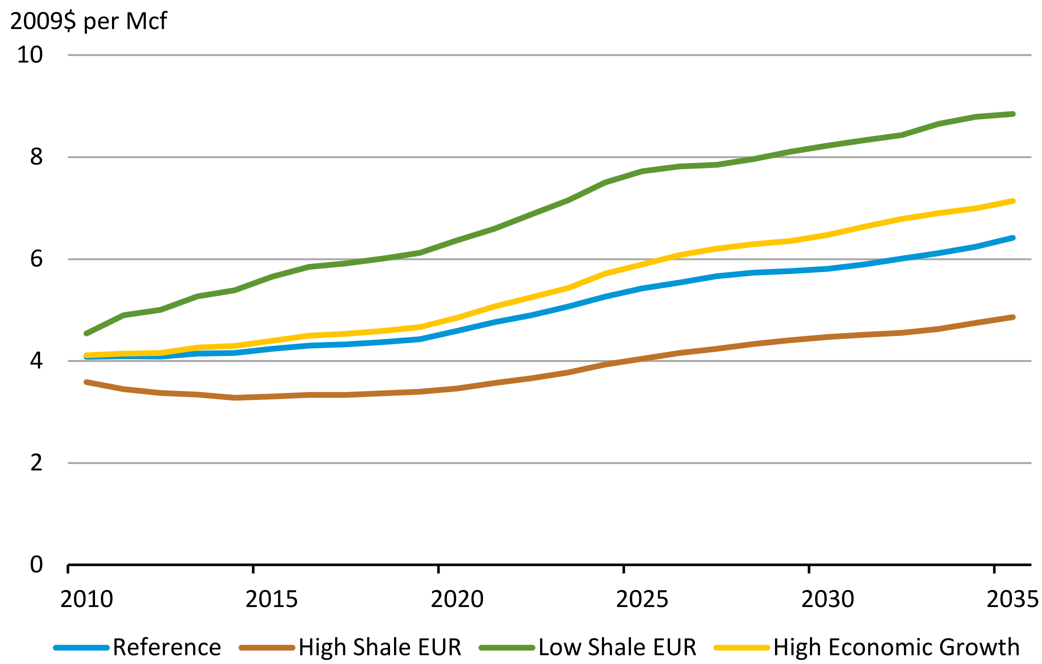
Natural gas prices

Wellhead natural gas prices in the baseline cases (no additional exports)

EIA projects that U.S. natural gas prices are projected to rise over the long run, even before considering the possibility of additional exports (Figure 2). The projected price increase varies considerably, depending on the assumptions one makes about future gas supplies and economic growth. Under the Reference case, domestic wellhead prices rise by about 57 percent between 2010 and 2035. But different assumptions produce different results. Under the more optimistic resource assumptions of the High Shale EUR case, prices actually fall at first and rise by only 36 percent by 2035. In contrast, under the more pessimistic resource assumptions of the Low Shale EUR case, prices nearly double by 2035.

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

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



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

Export scenarios—relationship between wellhead and delivered natural gas prices

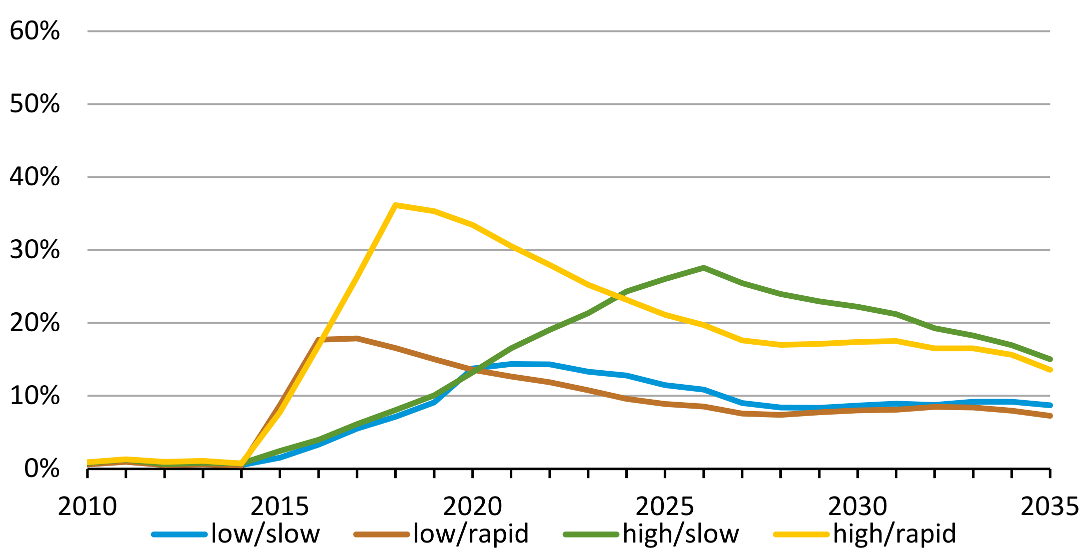
Increases in natural gas prices at the wellhead translate to similar absolute increases in delivered prices to customers under all export scenarios and baseline cases. However, delivered prices include transportation charges (for most customers) and distribution charges (especially for residential and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

Export scenarios – wellhead price changes under the Reference case.

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

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

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

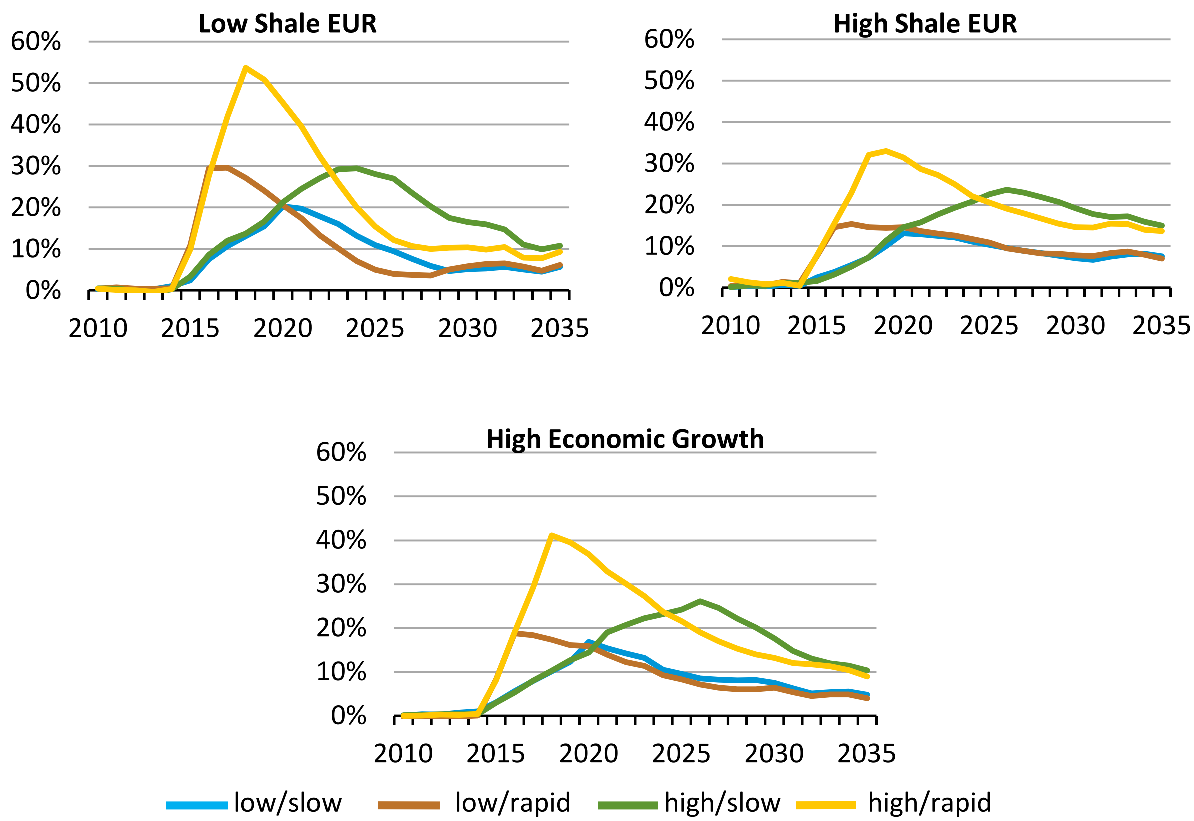


Source: U.S. Energy Information Administration, National Energy Modeling System

Export scenarios—wellhead price changes under alternative baseline cases

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

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



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

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

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

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

Natural gas supply and consumption

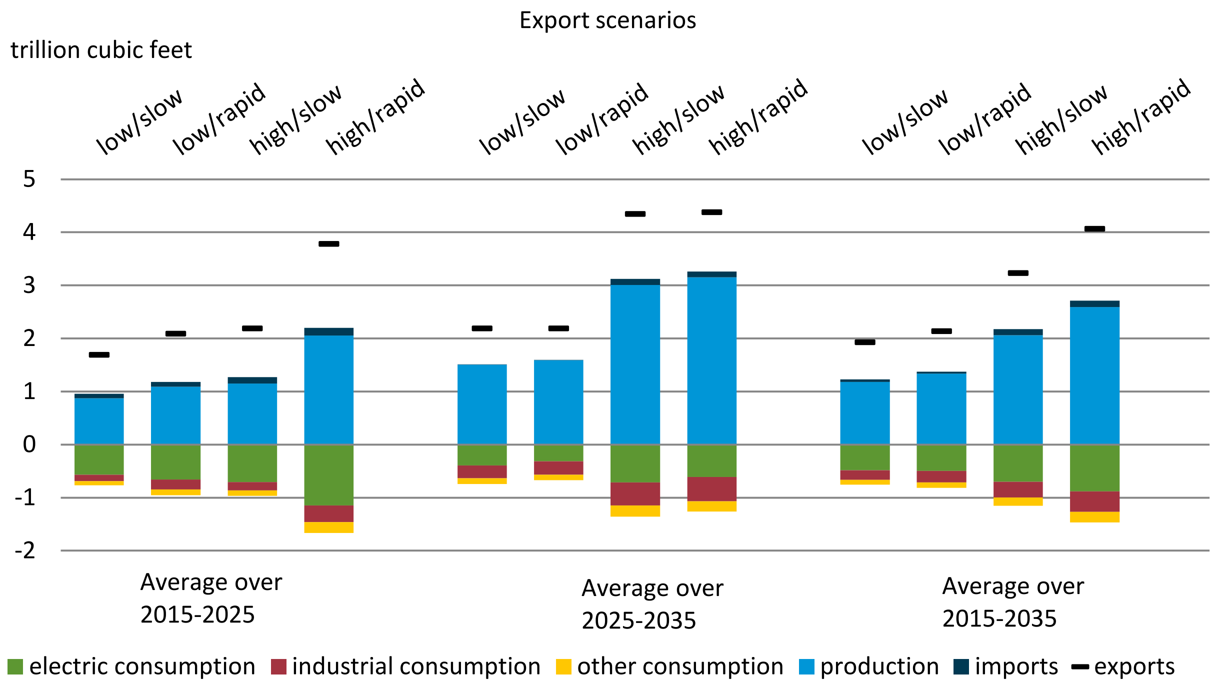
In the AEO2011 Reference case, total domestic natural gas production grows from 22.4 trillion cubic feet (Tcf) in 2015 to 26.3 Tcf in 2035, averaging 24.2 Tcf for the 2015-2035 period.   U.S. net imports of natural gas decline from 11 percent of total supply in 2015 to 1 percent in 2035, with lower net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

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

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

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

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



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

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

Supply

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

Consumption by sector

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

Electric power generation

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

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

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

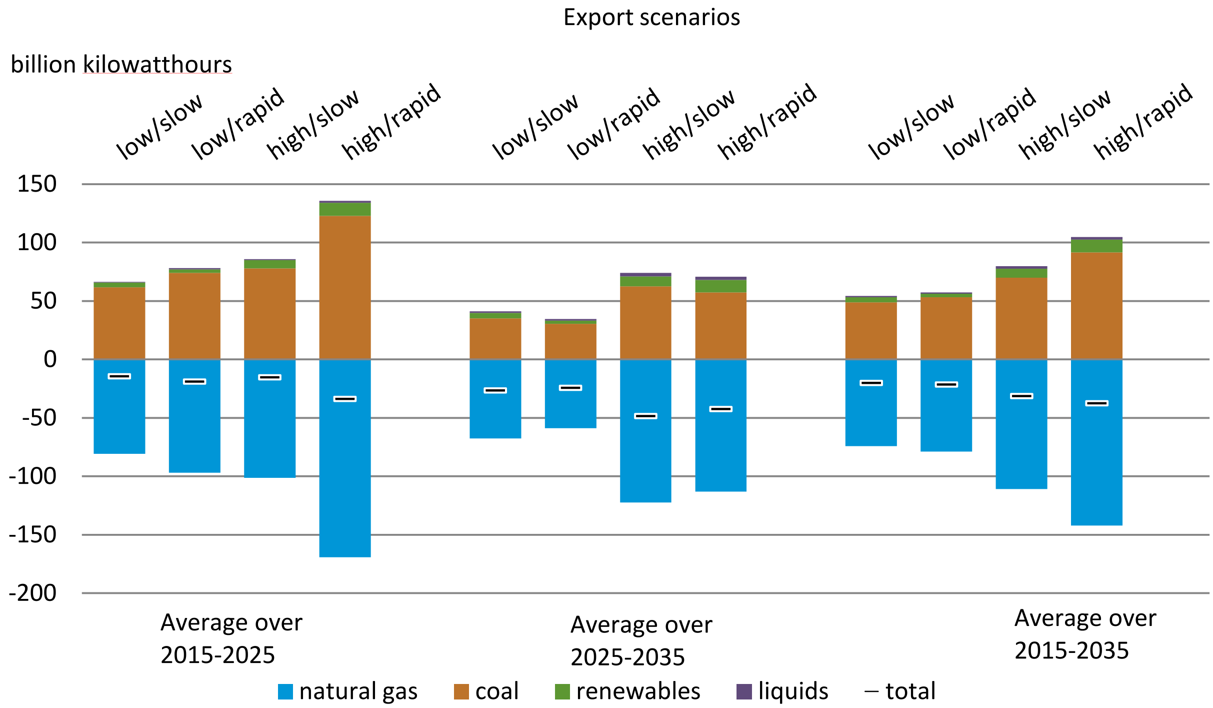
In addition, small increases in renewable generation contribute to reduced natural gas-fired generation. Relatively speaking, the role of renewables is greater in a higher-gas-price environment (i.e., the Low Shale EUR case), when they can more successfully compete with coal, and in a higher-generation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

Industrial sector

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

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

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



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

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

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

Other sectors

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

Exports to Canada and Mexico

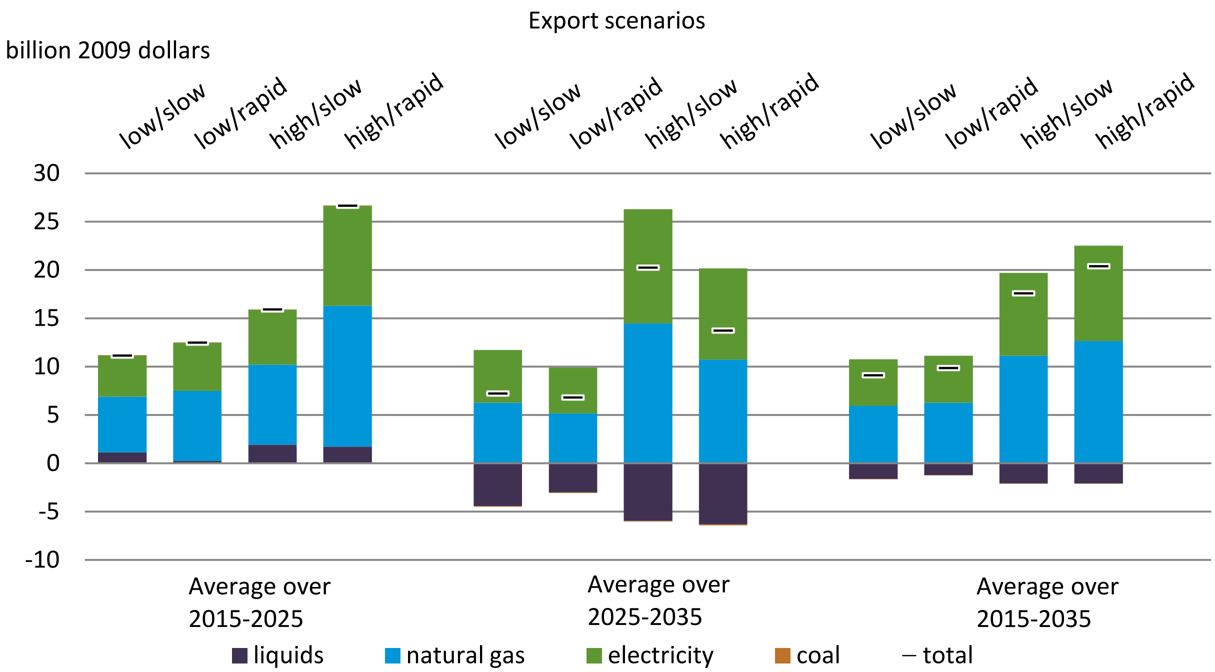
If exports to Canada and Mexico were allowed to vary under these additional export scenarios, they would likely respond similarly to domestic consumption and decrease in response to higher natural gas prices.

End-use energy expenditures

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

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

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



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

Natural gas expenditures

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

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

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

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

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

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

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

Electricity expenditures

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

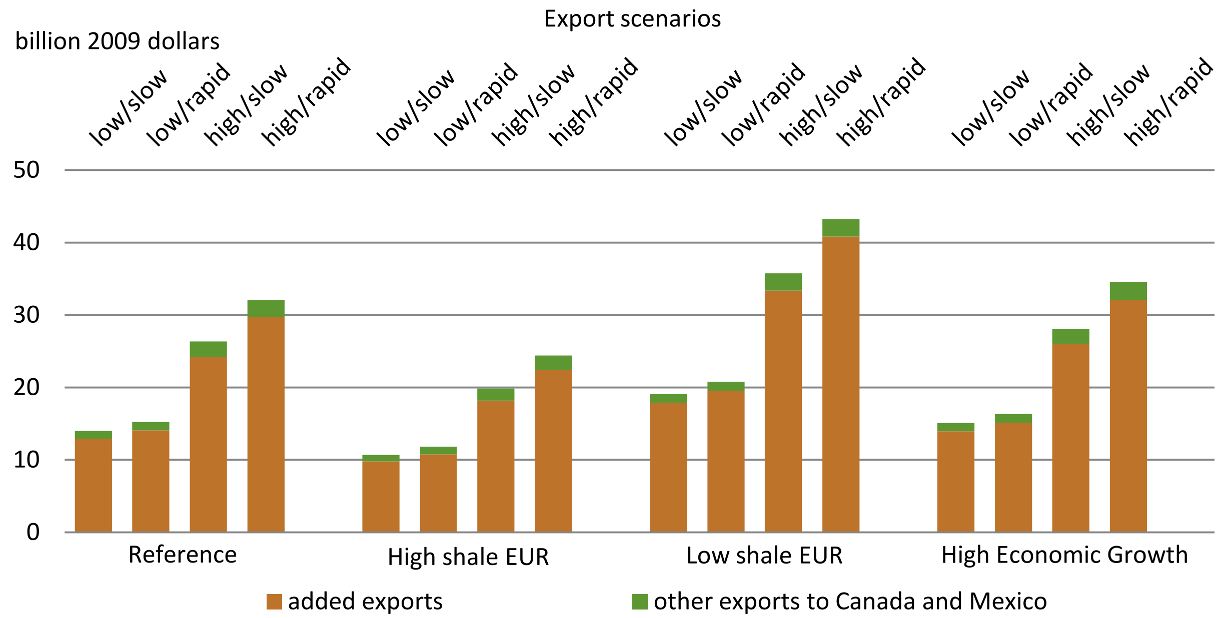
Similar to natural gas, higher electricity prices due to the increased exports reduce end-use consumption making the percentage change in end-use electricity expenditures less than the percentage change in delivered electricity prices; additionally, the percentage increase in end-use electricity expenditures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

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

Natural gas producer revenues

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

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



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

Impacts beyond the natural gas industry

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

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

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

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

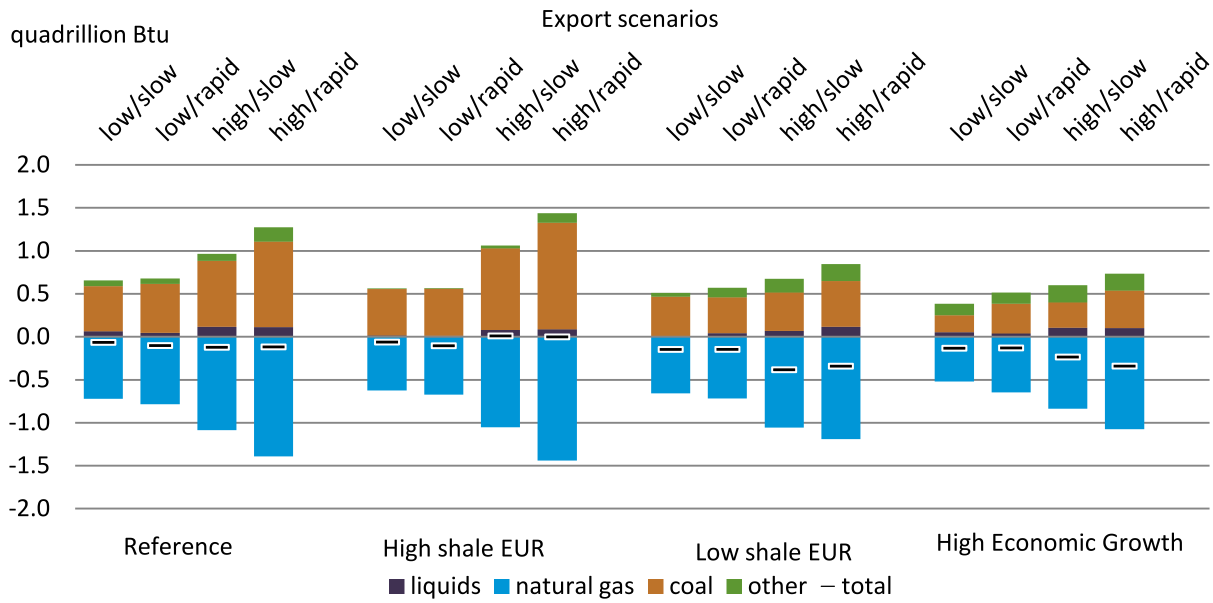
Total energy use and energy-related carbon dioxide emissions

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

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

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

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



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

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

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

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

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

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

Appendix A. Request Letter

Department of Energy
Washington, DC 20585
August 15, 2011

MEMORANDUM

TO: HOWARD K. GRUENSPECHT
ACTING ADMINISTRATOR
ENERGY INFORMATION ADMINISTRATION

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

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

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

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

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

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

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

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

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

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

RECOMMENDATION: That you approve this request.

APPROVE:______________ DISAPPROVE: ________________ DATE: _______

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

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

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

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

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

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

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

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

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

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

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

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

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

(A) set the matter for hearing;

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

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

(D) issue or deny the appropriate order accordingly.

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

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

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

(ii) condition an order on -

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

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

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

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

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

(f) Military installations

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

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

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

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

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

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

-SOURCE-

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

-REFTEXT-

REFERENCES IN TEXT

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

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

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

-MISC1-

AMENDMENTS

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

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

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

-TRANS-

TRANSFER OF FUNCTIONS

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

DELEGATION OF FUNCTIONS

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

-EXEC-

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

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

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

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

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

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

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

Sec. 2. [Deleted.]

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

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

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

-FOOTNOTE-

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

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

-End-

Appendix B. Summary Tables

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

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

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

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

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

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

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

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

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

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

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

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

FOOTNOTES

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

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

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

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

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

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

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

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Washington, DC 20585

December 3, 2012

Attn: Deputy Assistant Secretary Christopher Smith

Dear Mr. Smith

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

Sincerely,

W. David Montgomery
Senior Vice President

Enclosure

document8

Macroeconomic Impacts of LNG Exports from the United States

NERA

Economic Consulting

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

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List of Acronyms

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

Scenario Naming Convention

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

Generic Naming Convention:

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

U.S. Cases:

USREF	US Reference case
HEUR	High Shale EUR
LEUR	Low Shale EUR

International Cases:

INTREF	International Reference case
D	International Demand Shock
SD	International Supply/Demand Shock

U.S. LNG Export Cases

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

Quota Rent Cases:

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

N$_{ew}$Era Baselines:

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

Scenarios Analyzed by N$_{ew}$Era

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

EXECUTIVE SUMMARY

Approach

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

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

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

Key Findings

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

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

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

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

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

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

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

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

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

I. SUMMARY

A. What NERA Was Asked to Do

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

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

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

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

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

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

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

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

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

Figure 1: Feasible Scenarios Analyzed in the Macroeconomic Model

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

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

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

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

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

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

B. Key Assumptions

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

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

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

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

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

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

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

C. Key Results

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

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

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

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

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

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

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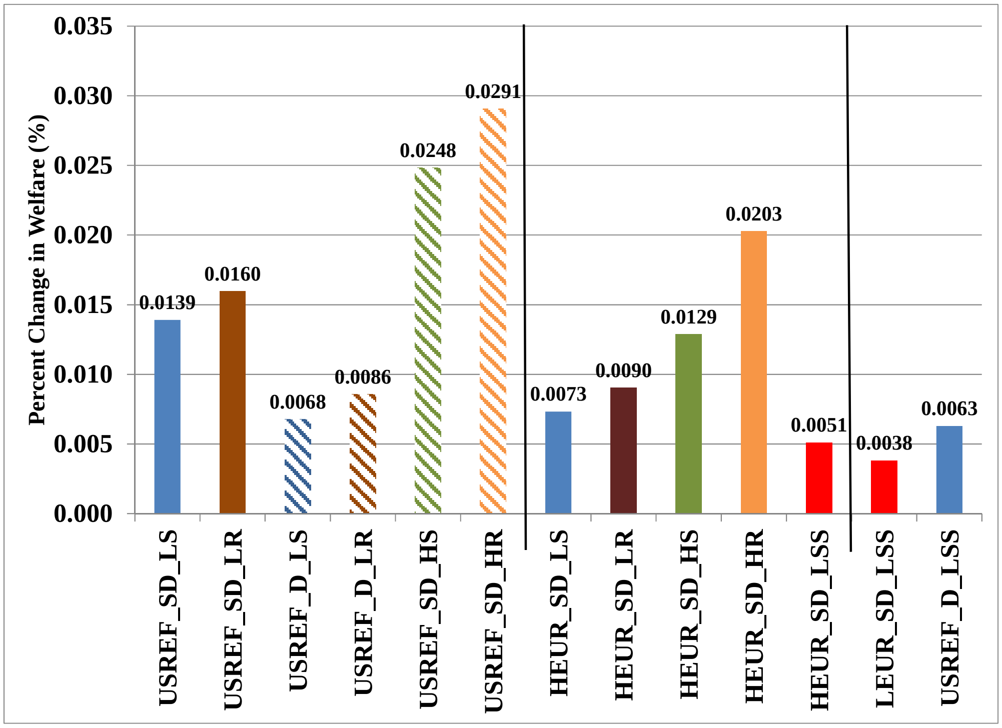
4 NERA did not run the EIA High Growth case because the results would be similar to the REF case.

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

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

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



3. Sources of Income Would Shift

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

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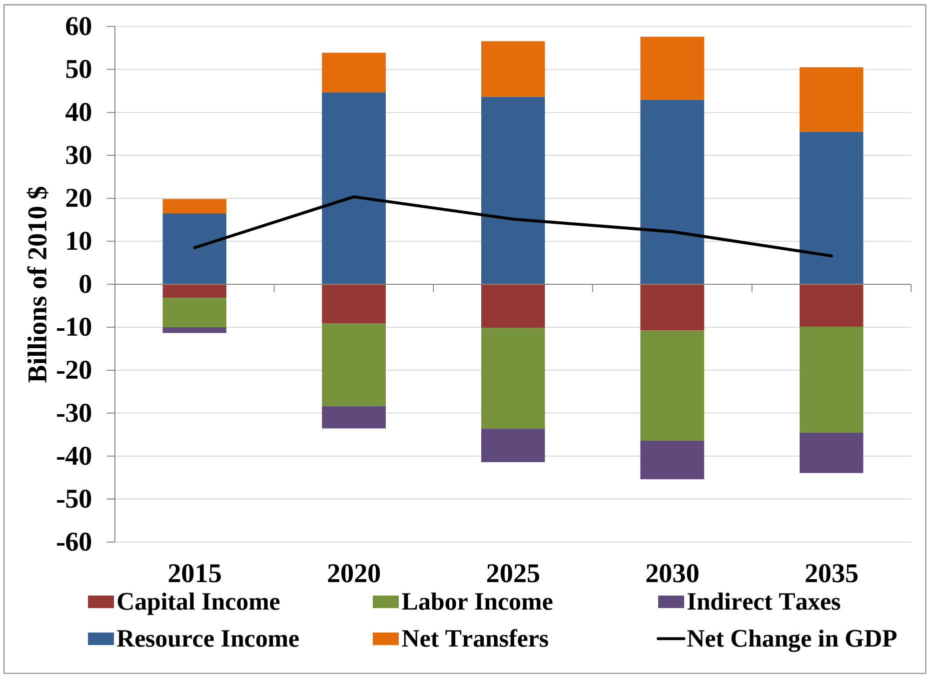
[6] Welfare is calculated as a single number that represents in present value terms the amount that households are made better (worse) off over the entire time horizon from 2015 to 2035.

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

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

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



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

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

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

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

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

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

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

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

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

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

Figure 5: NERA Export Volumes (Tcf)

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

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

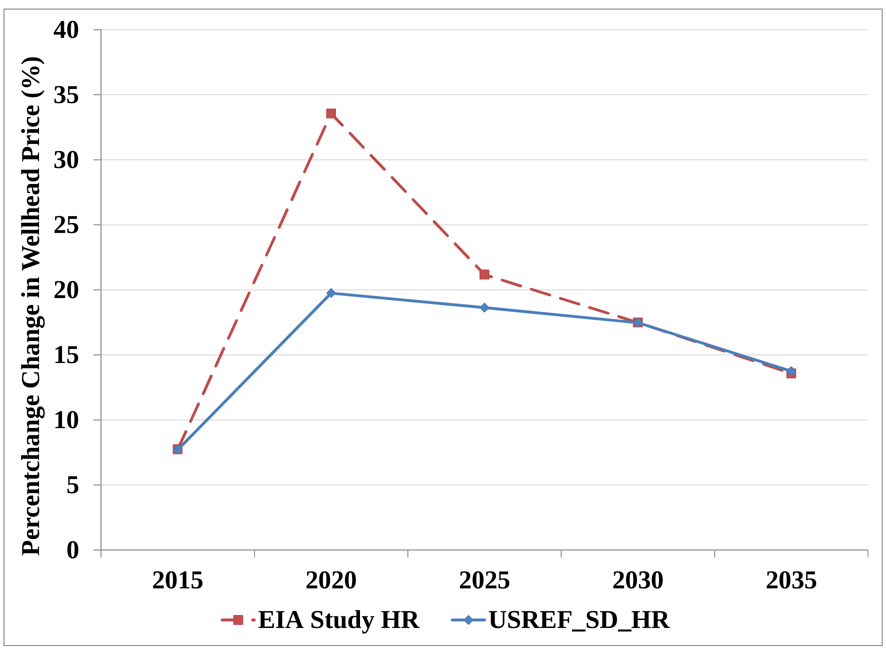
To match the characterization of U.S. supply and demand for natural gas in EIA's NEMS model, NERA calibrated its macroeconomic model so that for the same level of LNG exports as assumed in the EIA Study, the NERA model reproduced the prices projected by EIA. Thus natural gas price responses were similar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

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

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

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

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



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

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

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

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

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

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

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

II. INTRODUCTION

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

A. Statement of the Problem

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

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

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

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

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

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

B. Scope of NERA and EIA Study

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

1. EIA Study

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

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

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

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

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

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

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

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

1. The AEO 2011 Reference case;

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

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

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

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

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

2. NERA Study

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

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

C. Organization of the Report

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

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

A. Natural Gas Market Description

1. Worldwide

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

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

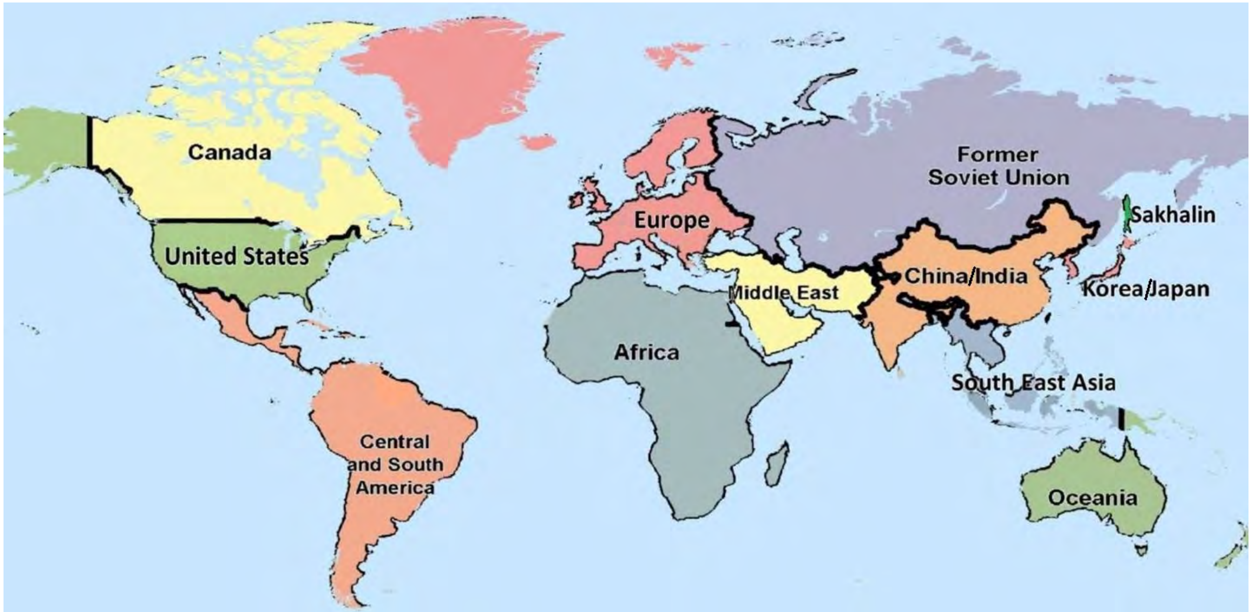
Figure 8: Global Natural Gas Demand and Production (Tcf)

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

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

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

Figure 9: Regional Groupings for the Global Natural Gas Model



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

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

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

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

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

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

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

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

2. LNG Trade Patterns

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

Figure 10: 2010 LNG Trade (Tcf)

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

Source: "The LNG Industry 2010," GIIGNL.

3. Basis Differentials

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

B. NERA's Global Natural Gas Model

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

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

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

C. N$_{ew}$ERA Macroeconomic Model

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

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

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

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

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

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

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

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

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

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

IV. DESCRIPTION OF SCENARIOS

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

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

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

1. World Outlooks

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

Figure 11: International Scenarios

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

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

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

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

b. Uncertainties about Global Natural Gas Demand and Supply

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

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

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

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

2. U.S. Scenarios Address Three Factors

a. Decisions about the Upper Limit on Exports

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

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

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

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

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

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

B. Matrix of U.S. Scenarios

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Figure 12: Matrix of U.S. Scenarios

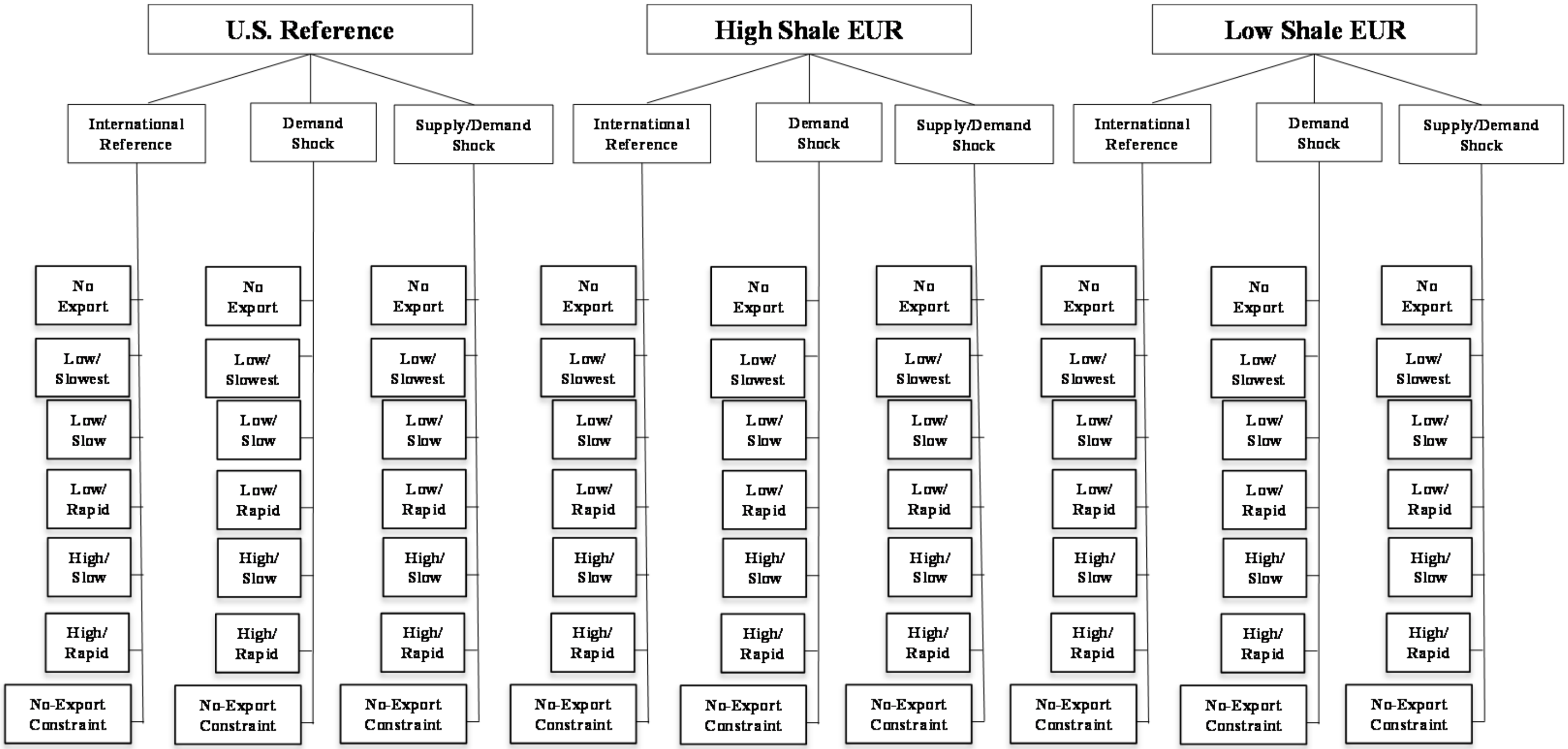
U.S. Supply	LNG Export Capacity	U.S. Supply	LNG Export Capacity	U.S. Supply	LNG Export Capacity
Reference	Low/Slow	High EUR	Low/Slow	Low EUR	Low/Slow
Reference	Low/Rapid	High EUR	Low/Rapid	Low EUR	Low/Rapid
Reference	High/Slow	High EUR	High/Slow	Low EUR	High/Slow
Reference	High/Rapid	High EUR	High/Rapid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

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

C. Matrix of Worldwide Natural Gas Scenarios

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

Figure 13: Tree of All 63 Scenarios



V. GLOBAL NATURAL GAS MODEL RESULTS

A. NERA Worldwide Supply and Demand Baseline

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

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

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

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

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

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

Figure 14: Baseline Natural Gas Production (Tcf)

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

Figure 15: Baseline Natural Gas Demand (Tcf)

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

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

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

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

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

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

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

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

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

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

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

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

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

Figure 19: Baseline LNG Exports (Tcf)

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

Figure 20: Baseline LNG Imports (Tcf)

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

B. Behavior of Market Participants

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

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

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

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

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

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

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

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

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

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

C. Available LNG Liquefaction and Shipping Capacity

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

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

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

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

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

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

- The difference in delivered costs between an exporting region and the U.S.;
- The magnitude of the demand shock or increased demand; and
- The magnitude of the supply shock or reduction in world supply.

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

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

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

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

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

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

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

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

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

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

1. Findings for the U.S. Reference Scenario

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5. LNG Exports: Relationship between Price and Volume

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

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

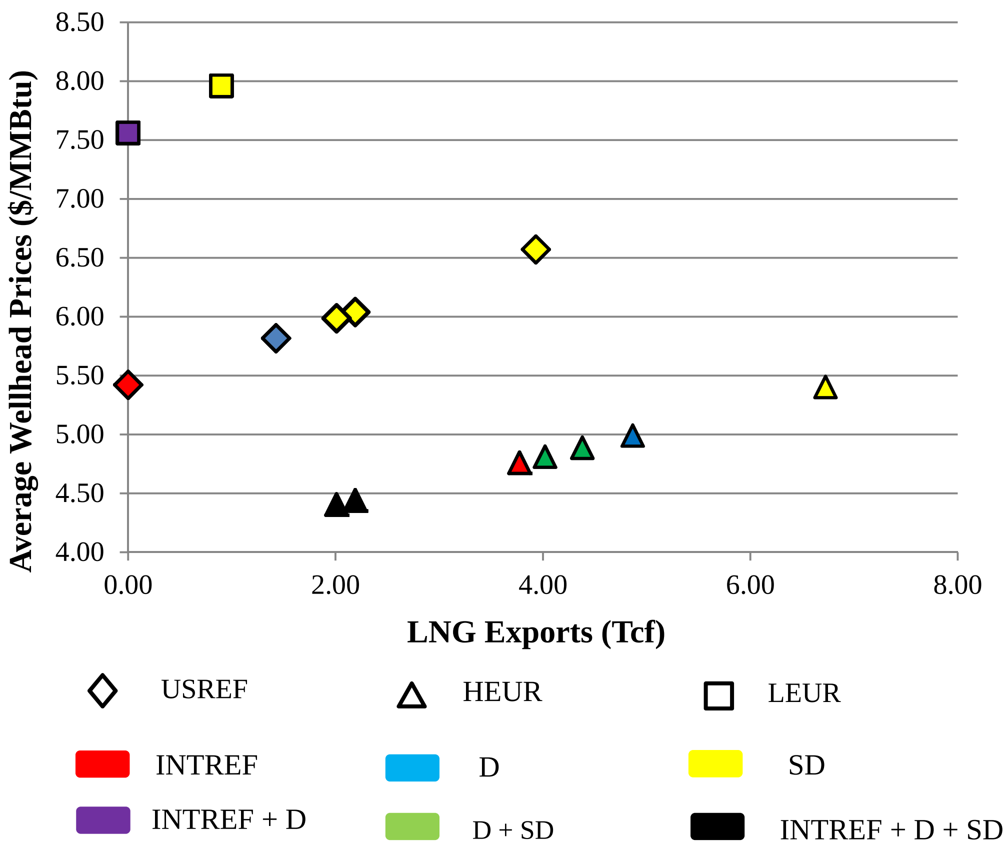
- Shapes are used to differentiate among the different U.S. scenarios: U.S. Reference (diamond), High Shale EUR (triangle), and Low Shale EUR (square); and
- Colors are used to differentiate among the International cases: International Reference (red), Demand Shock (blue), and Supply/Demand Shock (yellow).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

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

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

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

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



BCF/day = 2.74 * Tcf/Year

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

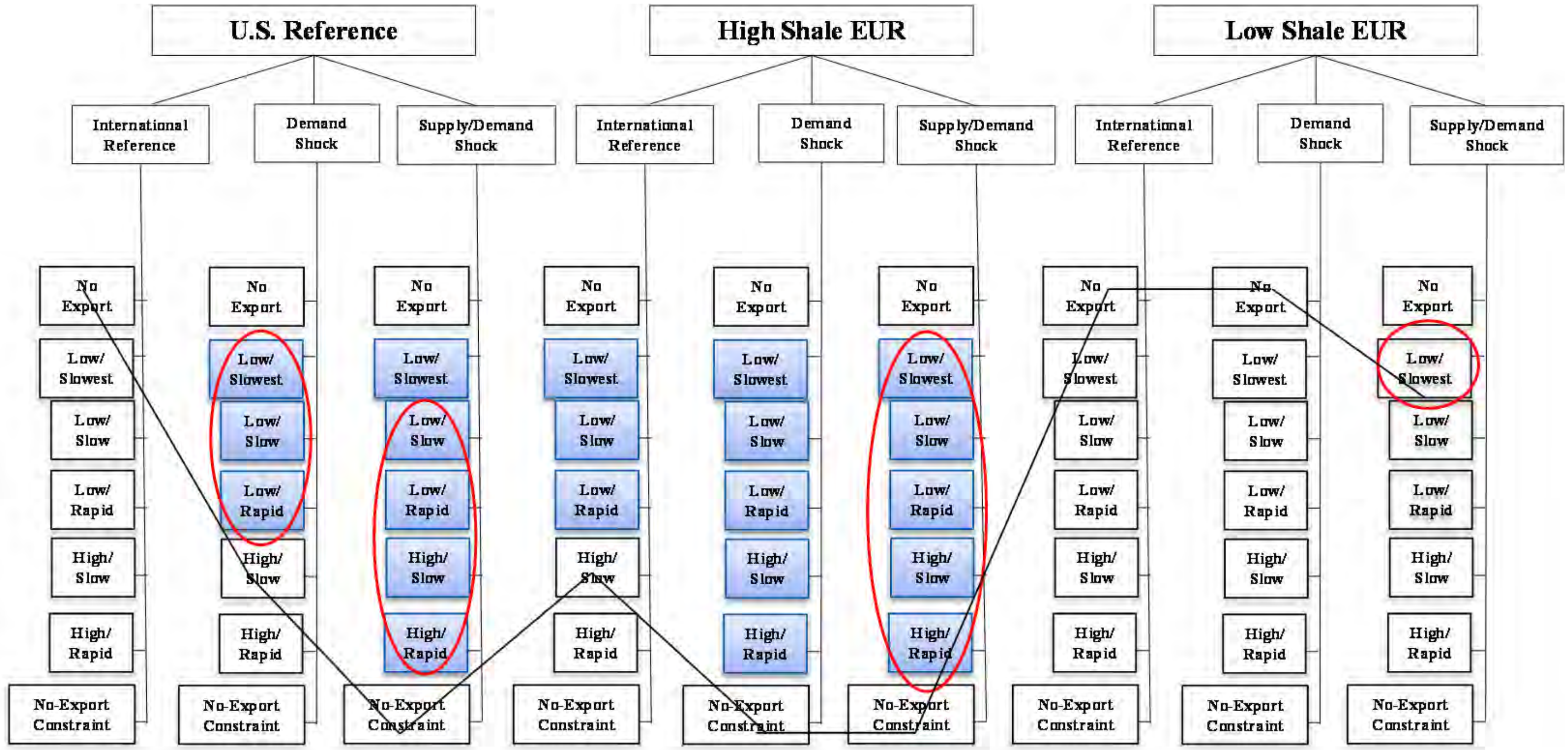
The supply curve traced out by the scenarios that include U.S. Reference case (represented by diamonds) are higher than in the High EUR cases because domestic gas is less plentiful. When only a Demand shock exists, the LNG export capacity limits are non-binding so the level of exports (the lone blue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

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

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

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

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



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

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

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

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

VI. U.S. ECONOMIC IMPACTS FROM NEWERA

A. Organization of the Findings

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

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

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

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

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

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

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

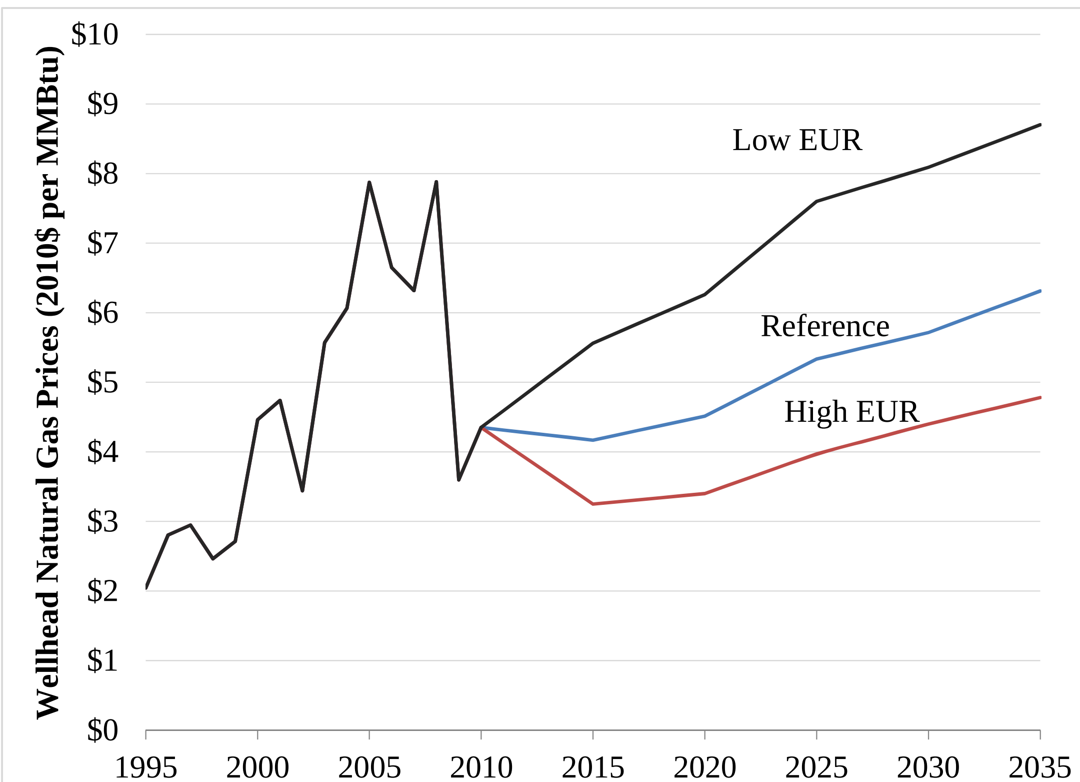
[17] NERA also ran 3 cases in which the LNG export capacity was assumed to be unlimited.

B. Natural Gas Market Impacts

1. Price, Production, and Demand

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

Figure 27: Historical and Projected Wellhead Natural Gas Price Paths



Source: Energy Information Agency (EIA)

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

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

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

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

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

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18 See Appendix D for comparison of natural gas prices.

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

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

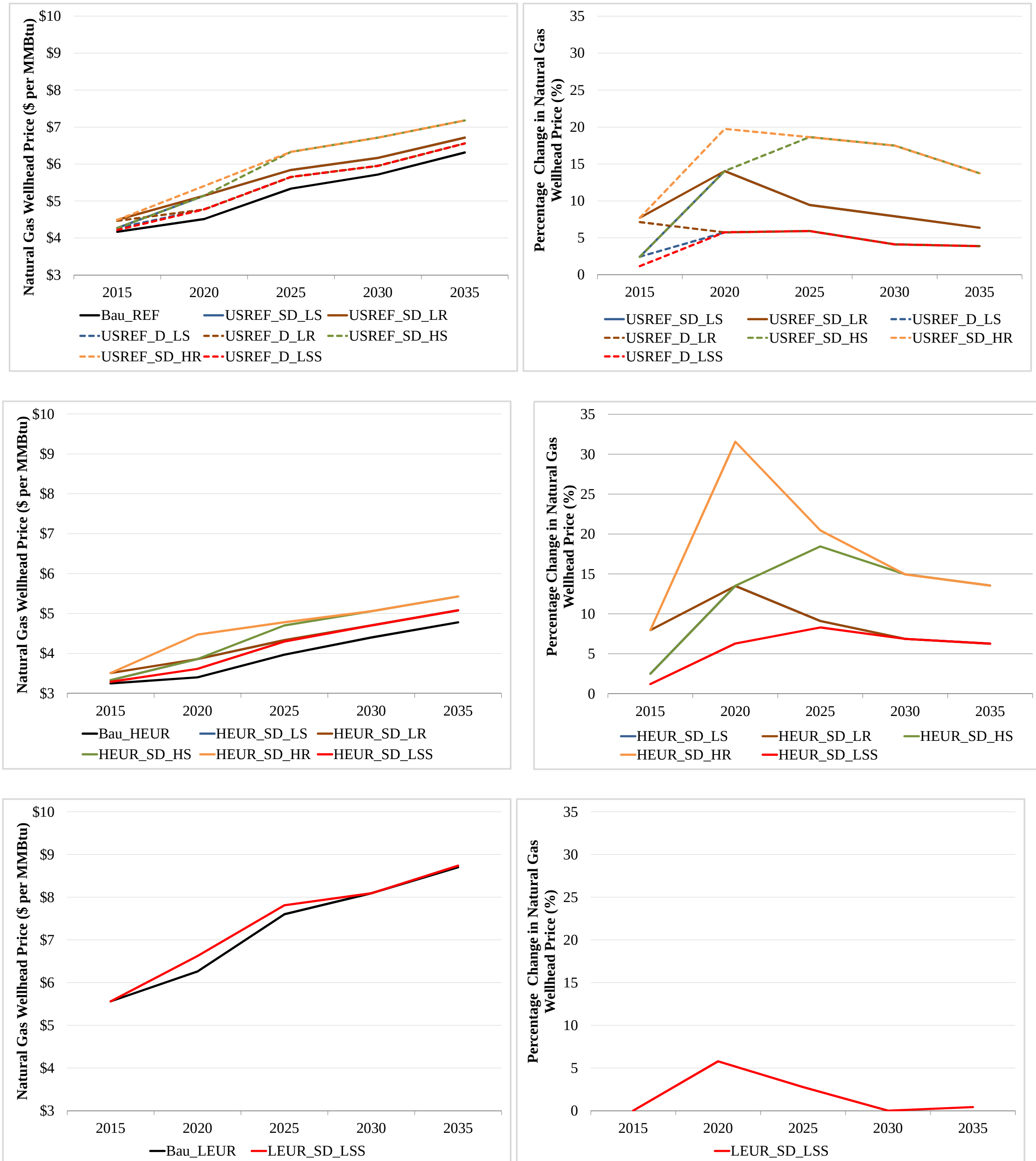


Figure 29: Change in Natural Gas Price Relative to the Corresponding Baseline of Zero LNG Exports (2010$/Mcf)

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

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

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

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

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

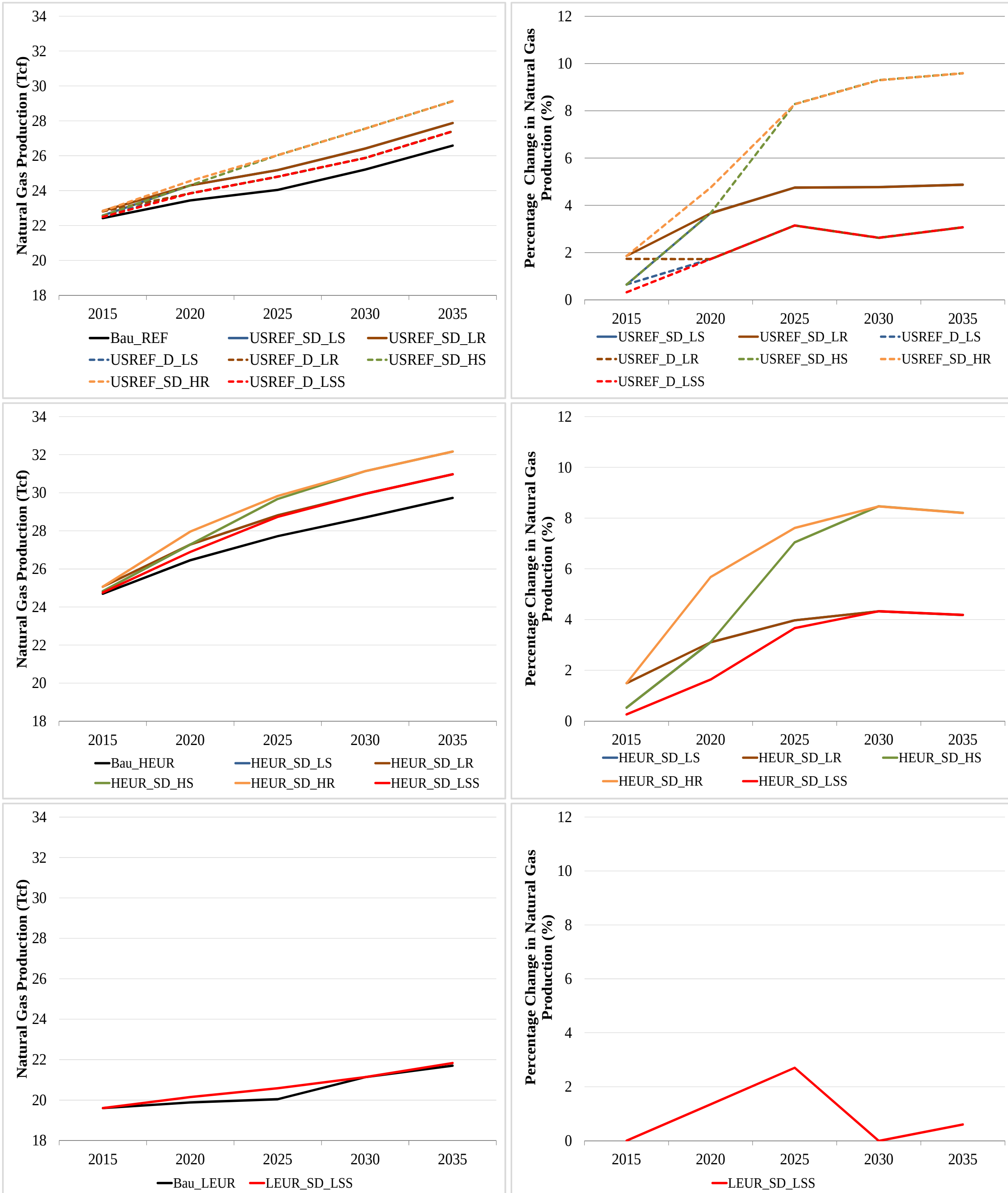


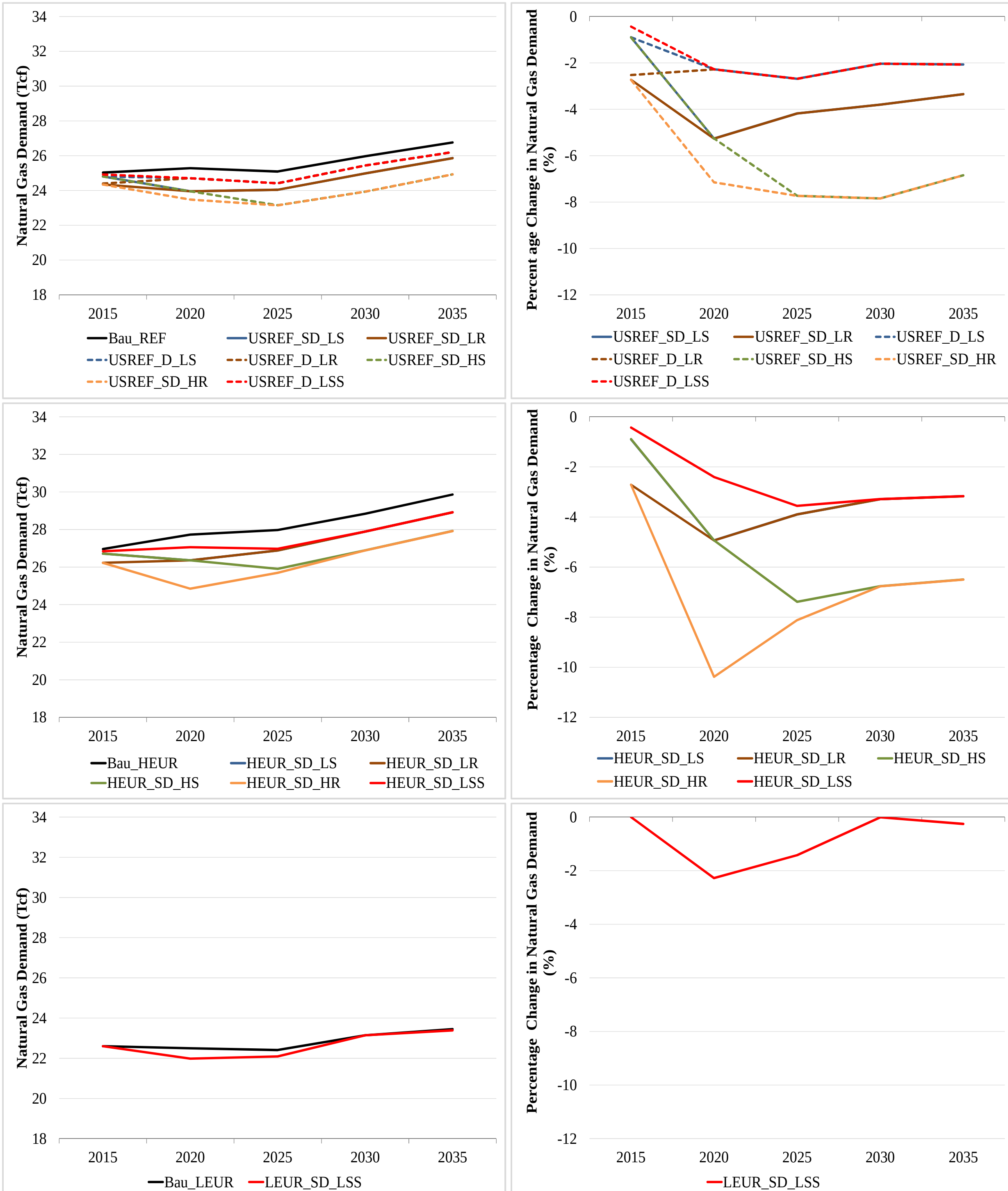
Figure 31: Change in Natural Gas Production Relative to the Corresponding Baseline (Tcf)

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

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

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

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



C. Macroeconomic Impacts

1. Welfare

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

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

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

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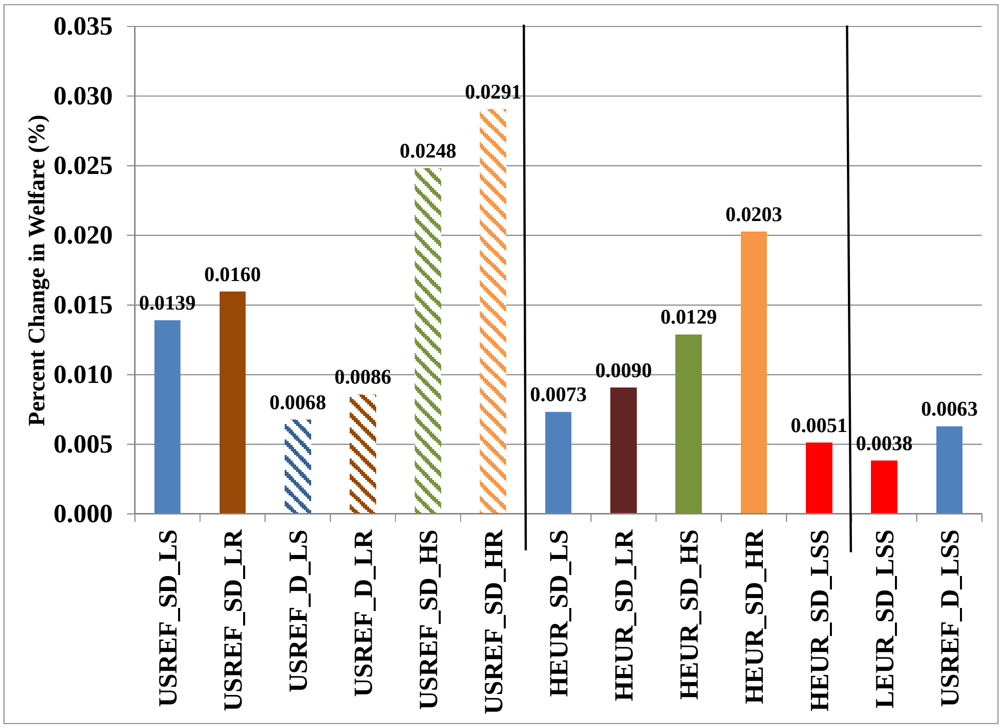
21 *Intermediate Microeconomics: A Modern Approach*, Hal Varian, 7th Edition (December 2005), W.W. Norton & Company, pp. 255-256. "Another way to measure the impact of a price change in monetary terms is to ask how much money would have to be taken away from the consumer *before* the price change to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

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

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



2. GDP

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

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

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

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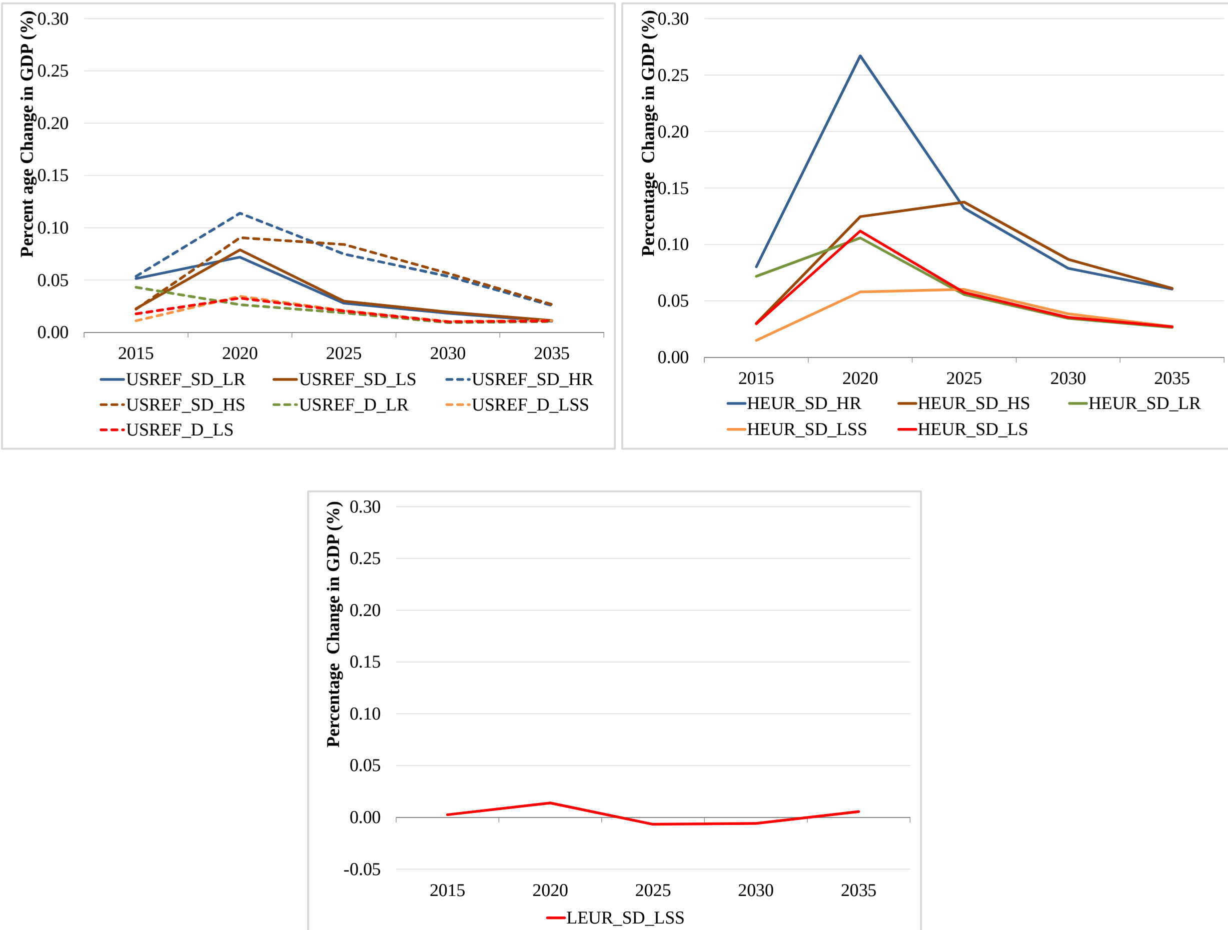
23 Welfare is calculated as a single number that represents in present value terms the amount that households are made better (worse) off over the entire time horizon from 2015 to 2035.

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

Figure 34: Percentage Change in GDP for NERA Core Scenarios

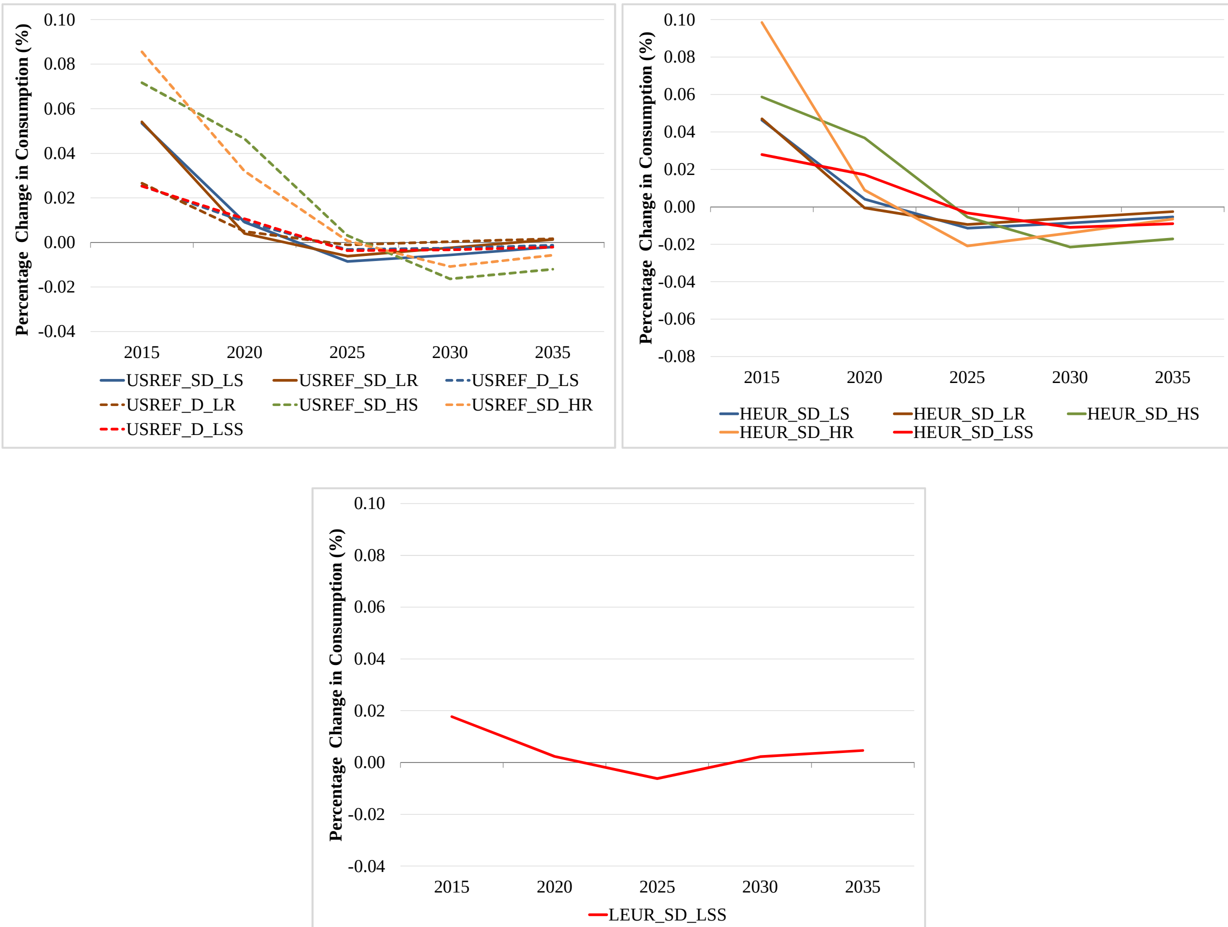


3. Aggregate Consumption

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

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

Figure 35: Percentage Change in Consumption for NERA Core Scenarios



4. Aggregate Investment

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

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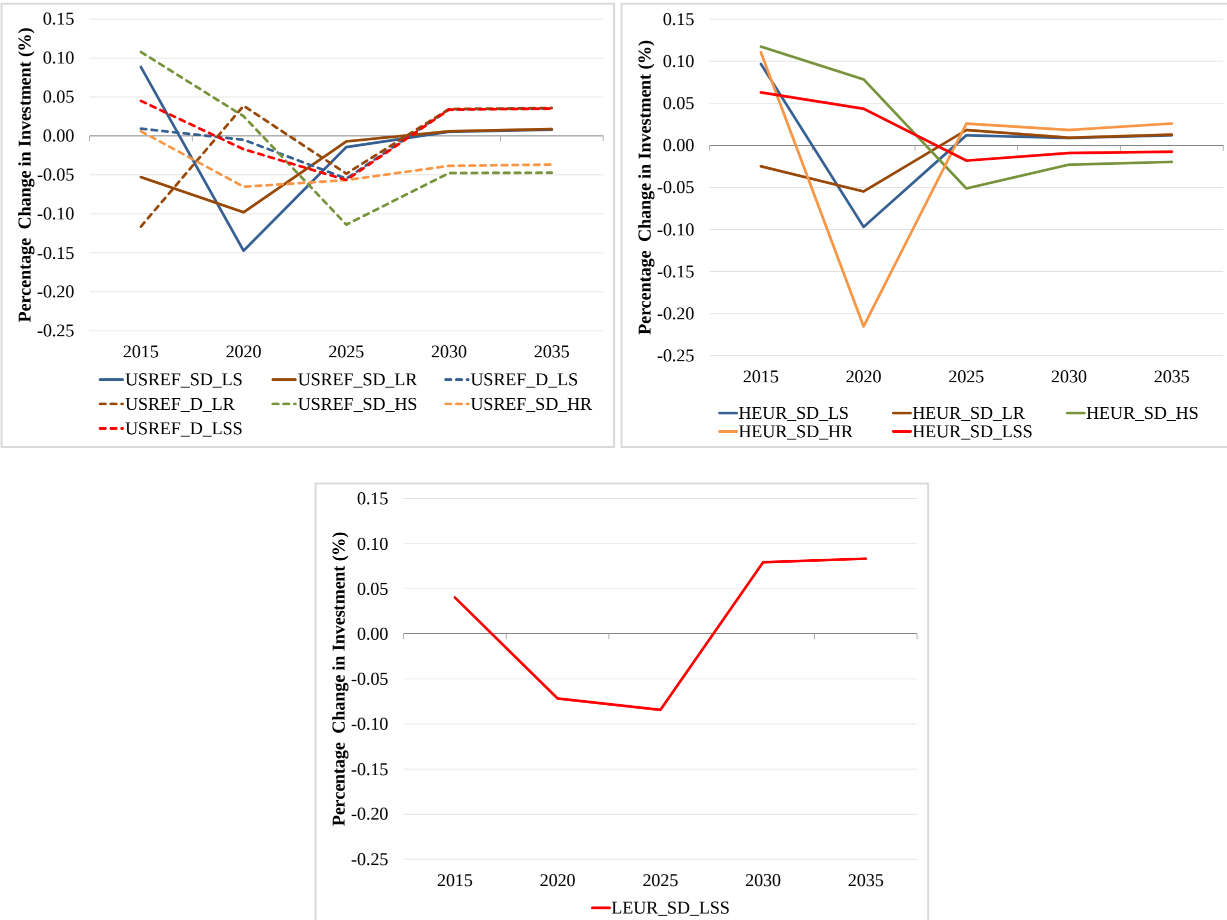
[24] Each model year represents a span of five years, thus the investment in 2015 represents an average annual investment between 2015 and 2019.

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

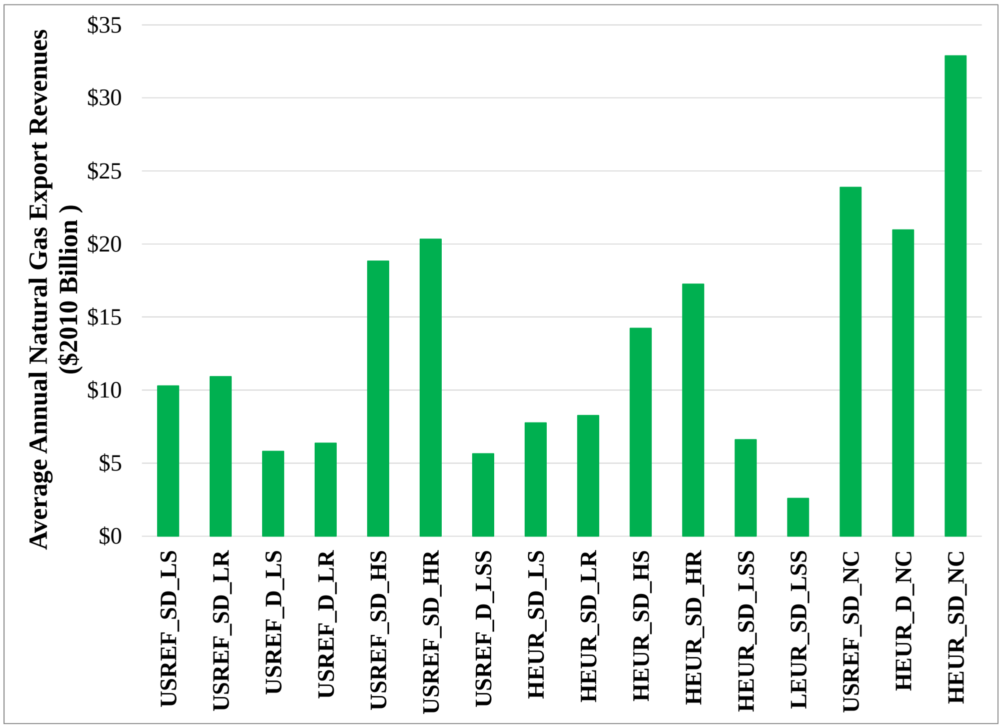
Figure 36: Percentage Change in Investment for NERA Core Scenarios



5. Natural Gas Export Revenues

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

Figure 37: Average Annual Increase in Natural Gas Export Revenues

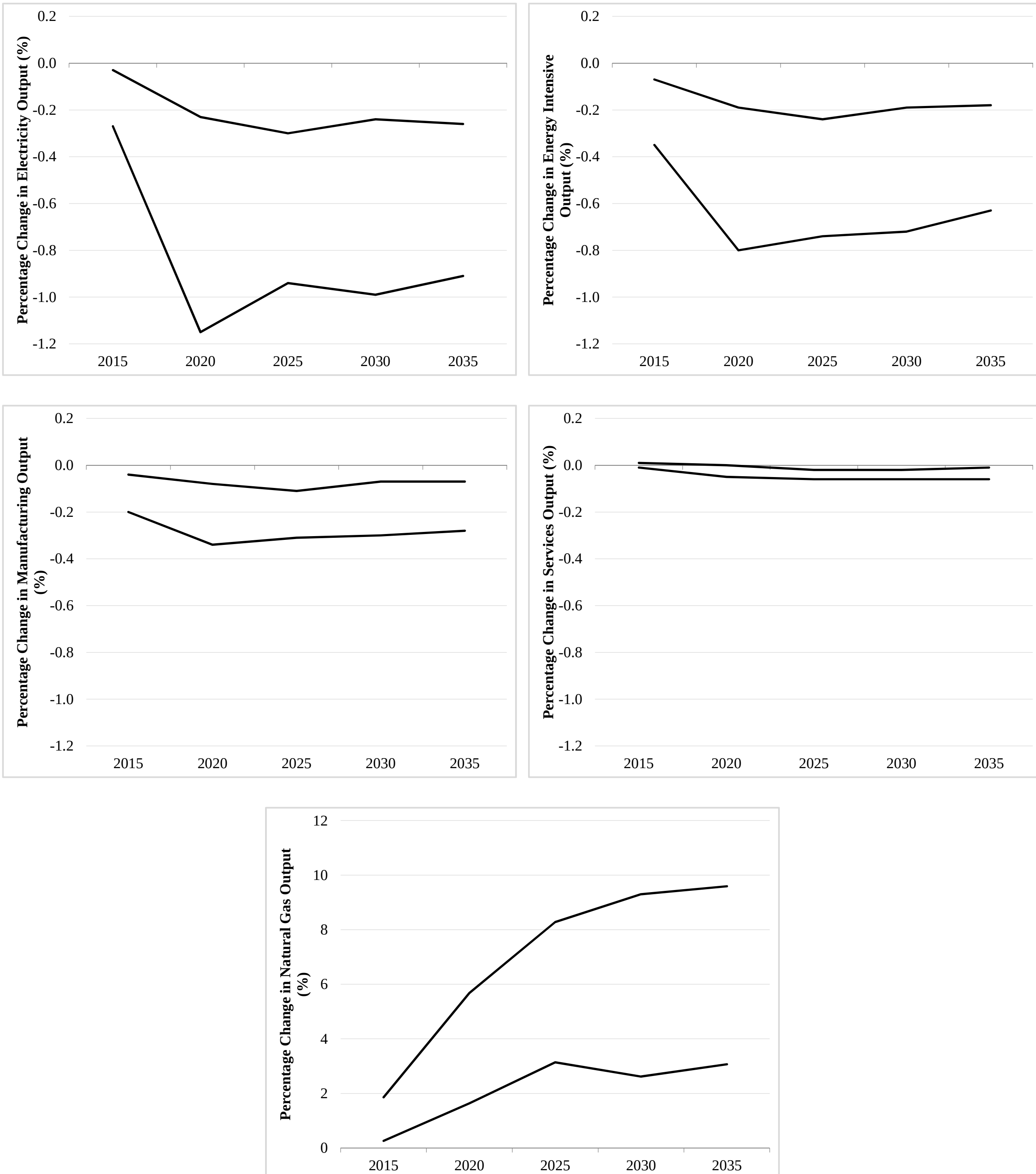


6. Range of Sectoral Output Changes for Some Key Economic Sectors

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

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

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

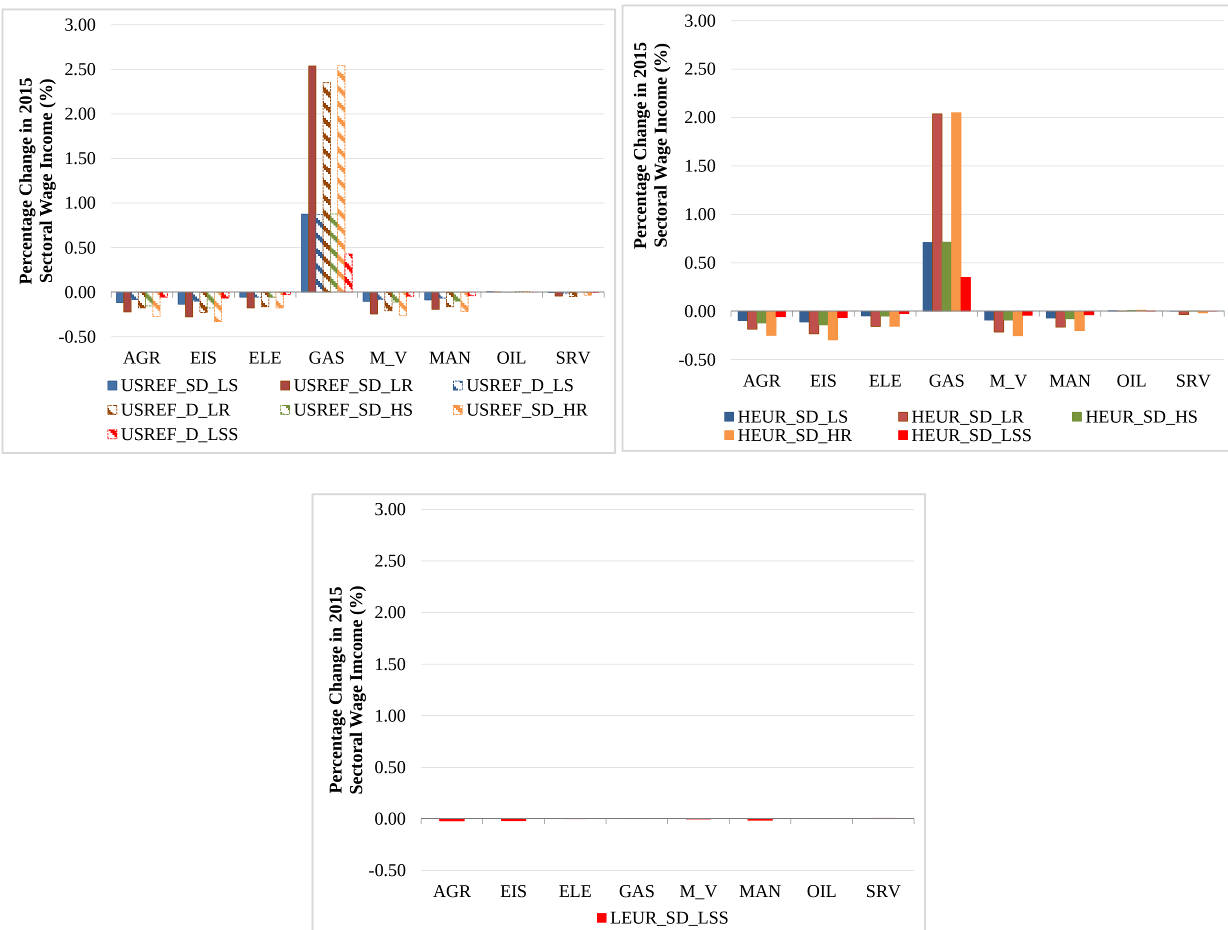


7. Wage Income and Other Components of Household Income

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

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

Figure 39: Percentage Change in 2015 Sectoral Wage Income



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

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

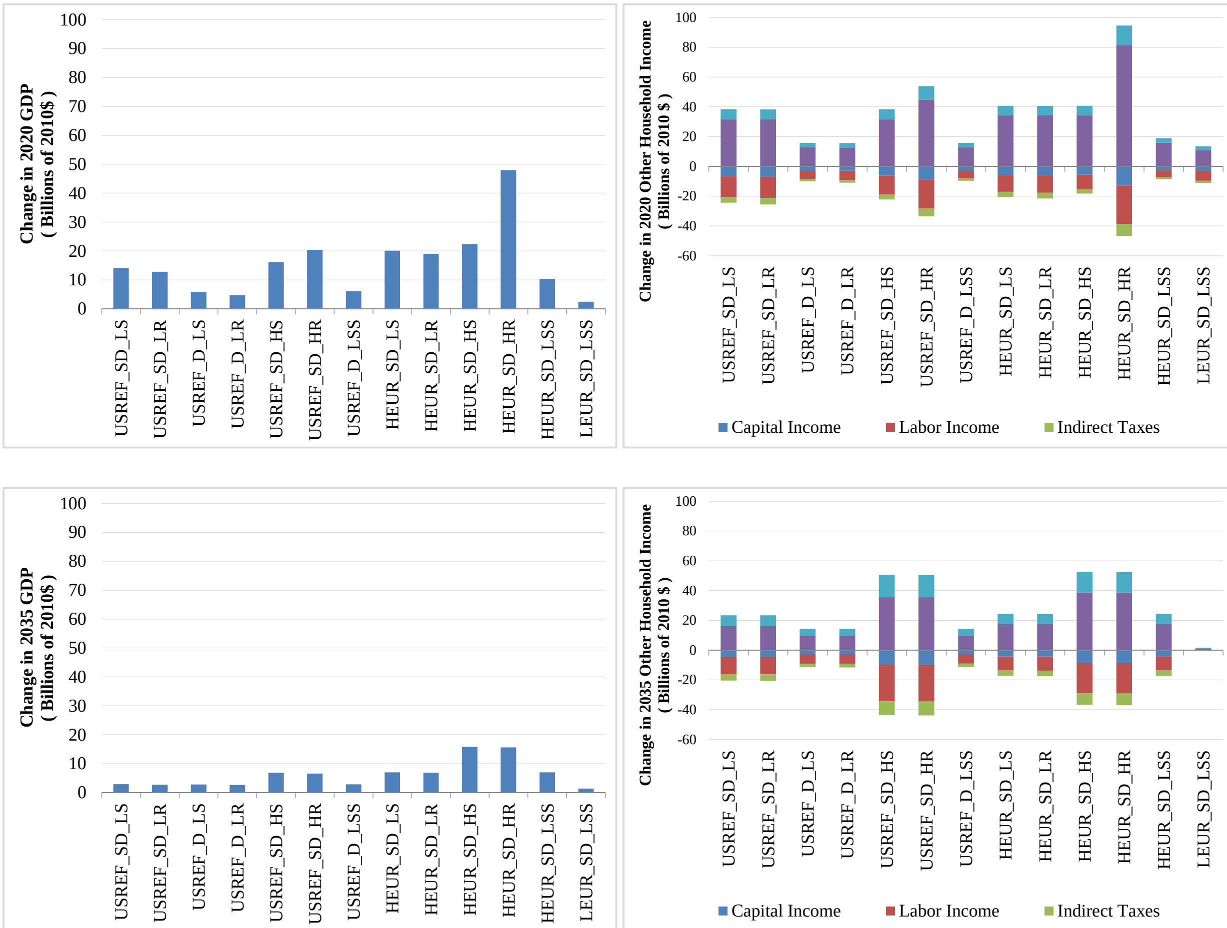


Figure 40 shows a snapshot of changes in GDP and household income components in 2020 and 2035. GDP impacts in 2020 provide the largest increase, while 2035 impacts provide a picture of the long run changes. Capital income, wage income, and indirect tax revenues drop in all scenarios, while resource income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

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

D. Impacts on Energy-Intensive Sectors

1. Output and Wage Income

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

1) Paper and pulp manufacturing (NAICS 322);
2) Chemical manufacturing (NAICS 326);
3) Glass manufacturing (NAICS 3272);
4) Cement manufacturing (NAICS 3273); and
5) Primary metal manufacturing (NAICS 331) that includes iron, steel and aluminum.[27]

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

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

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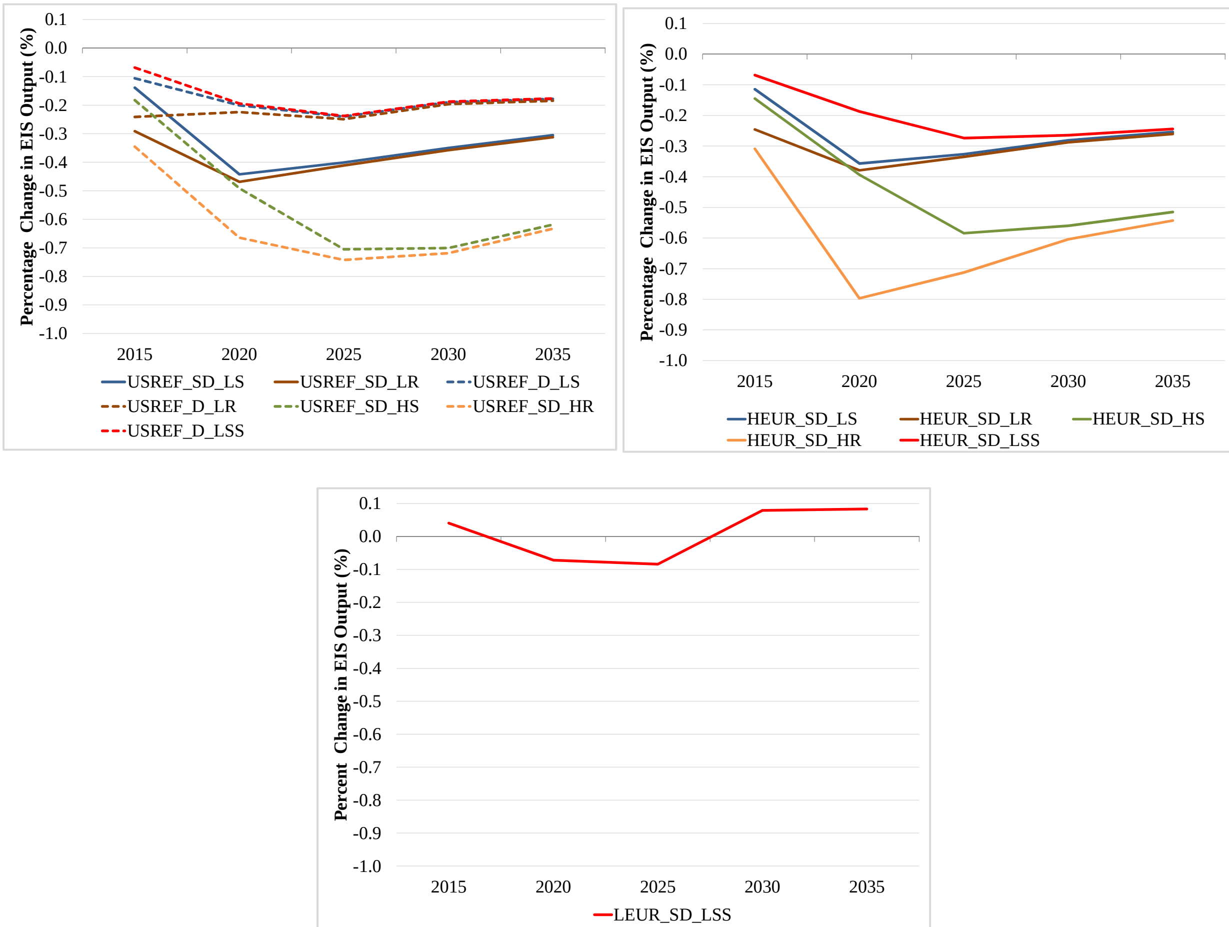
[26] IMPLAN dataset provides inter-industry production and financial transactions for all states of the U.S. (www.implan.com).

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

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

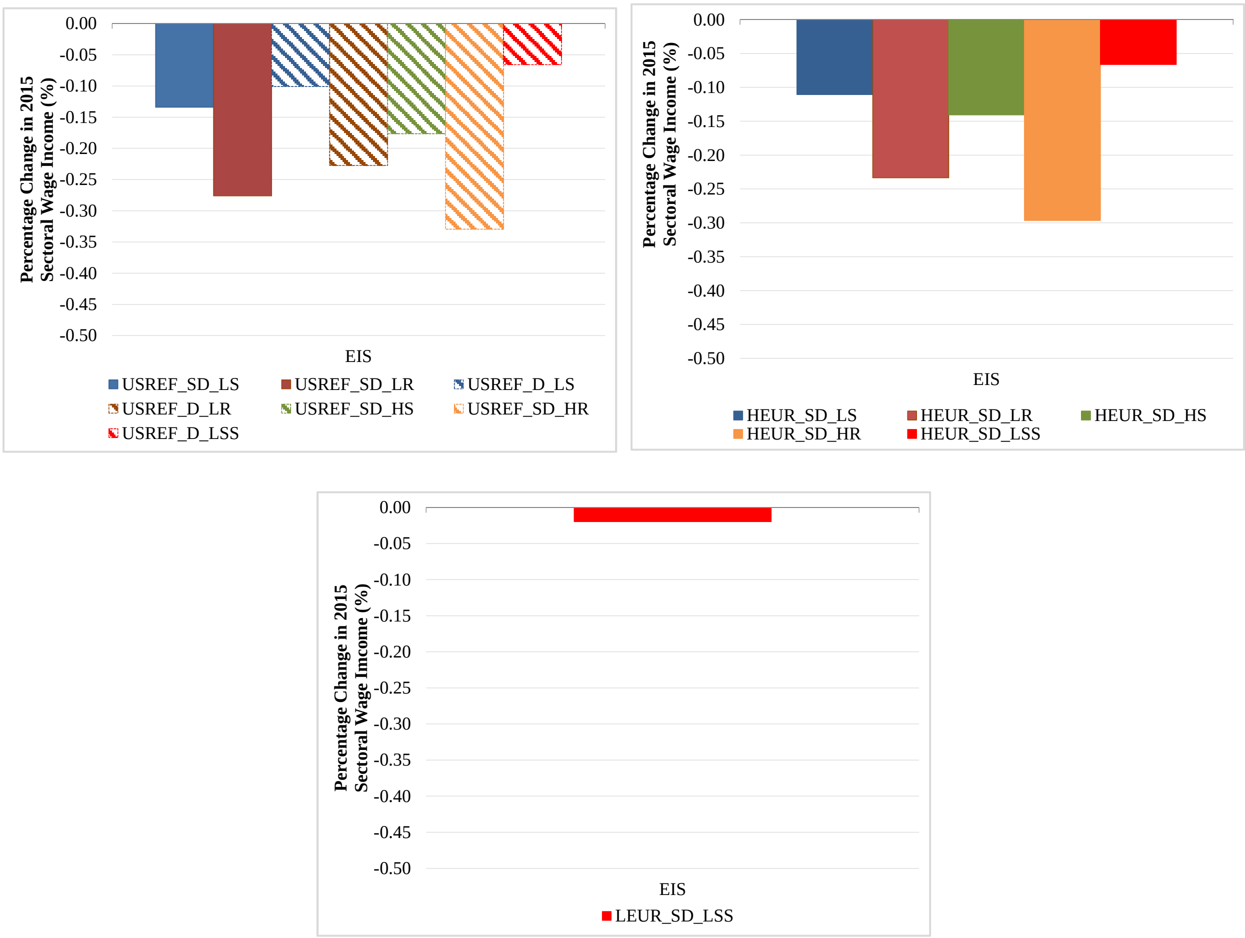
Figure 41: Percentage Change in EIS Output for NERA Core Scenarios



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

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

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



2. Rate of Change

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

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

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

To identify where higher natural gas prices might cause severe impacts such as plant closings (due to an inability to compete with overseas suppliers not experiencing similar natural gas price increases), it is necessary to look at much smaller slices of U.S. manufacturing. Fortunately, this was done in a study by an Interagency Task Force in 2007 that analyzed the impacts of proposed climate legislation, the Waxman-Markey bill (H.R.2454), on energy-intensive, trade-exposed industries ("EITE") using data from the 2007 Economic Census.[30] The cap-and-trade program in the Waxman-Markey bill would have caused increases in energy costs and impacts on EITE even broader than would the allowing of LNG exports because the Waxman-Markey bill applied to all fuels and increased the costs of fuels used for about 70% of electricity generation. Thus, the Task Force's data and conclusions are directly relevant.

The Interagency Report defined an industry's energy intensity as "its energy expenditures as a share of the value of its domestic production."[31] The measure of energy intensity used in the Interagency Report included all sources of energy, including electricity, coal, fuel oil, and natural gas. Thus, natural gas intensity will be even less than energy intensity.

The Interagency Report further defined an energy-intensive, trade-exposed industry (those that were "presumptively eligible" for emission allowance allocations under the Waxman-Markey bill) as ones where the industry's "energy intensity or its greenhouse gas intensity is at least 5 percent, and its trade intensity is at least 15 percent."[32]

The Interagency Report found:

> *According to the preliminary assessment of the nearly 500 six-digit manufacturing industries, 44 would be deemed "presumptively eligible" for allowance rebates under H.R. 2454 ["presumptive eligibility" screened out industries that did not have a significant exposure to foreign competition]. Of these, 12 are in the chemicals sector, 4 are in the paper sector, 13 are in the nonmetallic minerals sector (e.g., cement and glass manufacturers), and 8 are in the primary metals sector (e.g., aluminum and steel manufacturers). Many of these sectors are at or near the beginning of the value chain, and provide the basic materials needed for manufacturing advanced technologies. In addition to these 44 industries, the processing subsectors of a few mineral industries are also likely to be deemed "presumptively eligible." In total, in 2007, the "presumptively eligible" industries accounted for 12 percent of total manufacturing output and*

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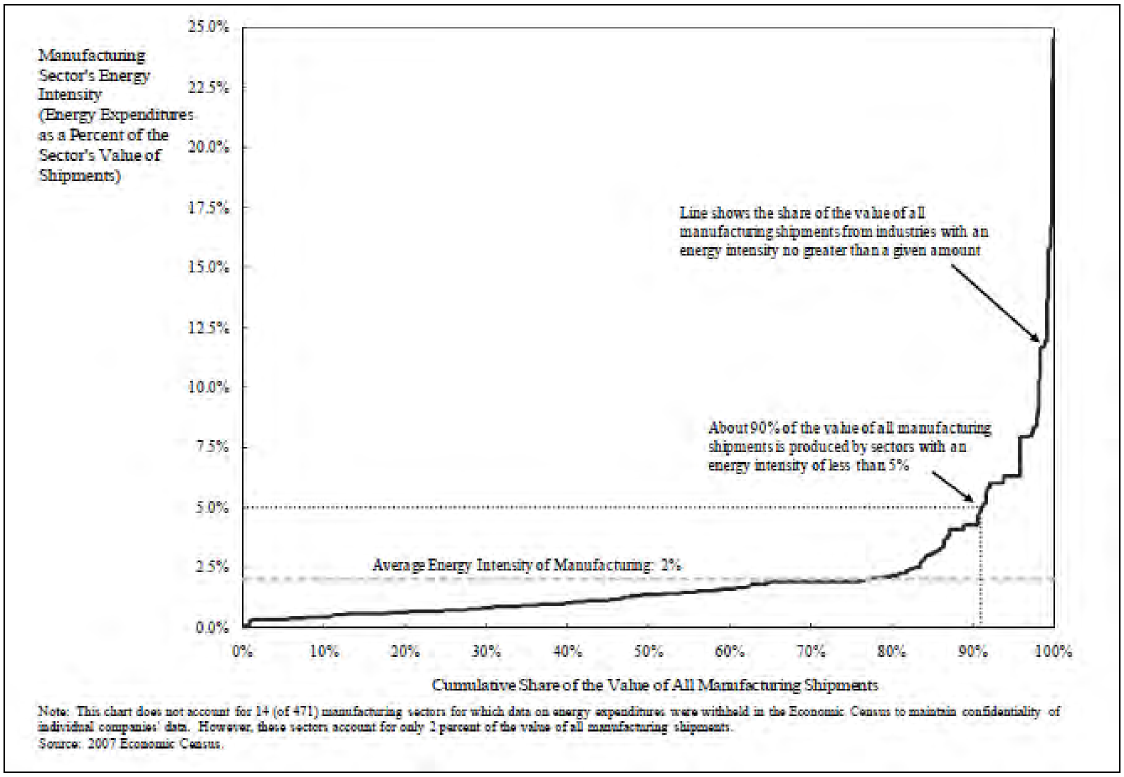
30 "The Effects of H.R.2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," An Interagency Report Responding to a Request from Senators Bayh, Specter, Stabenow, McCaskill, and Brown December 2, 2009.

31 "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 8.

32 "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 8.

employed about 780,000 workers, or about 6 percent of manufacturing employment and half a percent of total U.S. non-farm employment. [Figure 1 shows that] most industrial sectors have energy intensities of less than 5 percent, and will therefore have minimal direct exposure to a climate policy's economic impacts.[33]

Figure 43: Interagency Report (Figure 1)



Source: "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 7.

If we were to use the same criterion for EITE for natural gas, it would imply that an energy-intensive industry was one that would have expenditures on natural gas at the projected industrial price for natural gas greater than 5% of its value of output.

4. Vulnerable Industries are not High Value-Added Industries

A high value-added industry is one in which wage income and profits are a large share of revenues, implying that purchases of other material inputs and energy are a relatively small share. This implies that in a high value-added industry, increases in natural gas prices would have a relatively small impact on overall costs of production. Exactly that pattern is seen in Figure 44, which shows that the industries with the highest energy intensity are low margin

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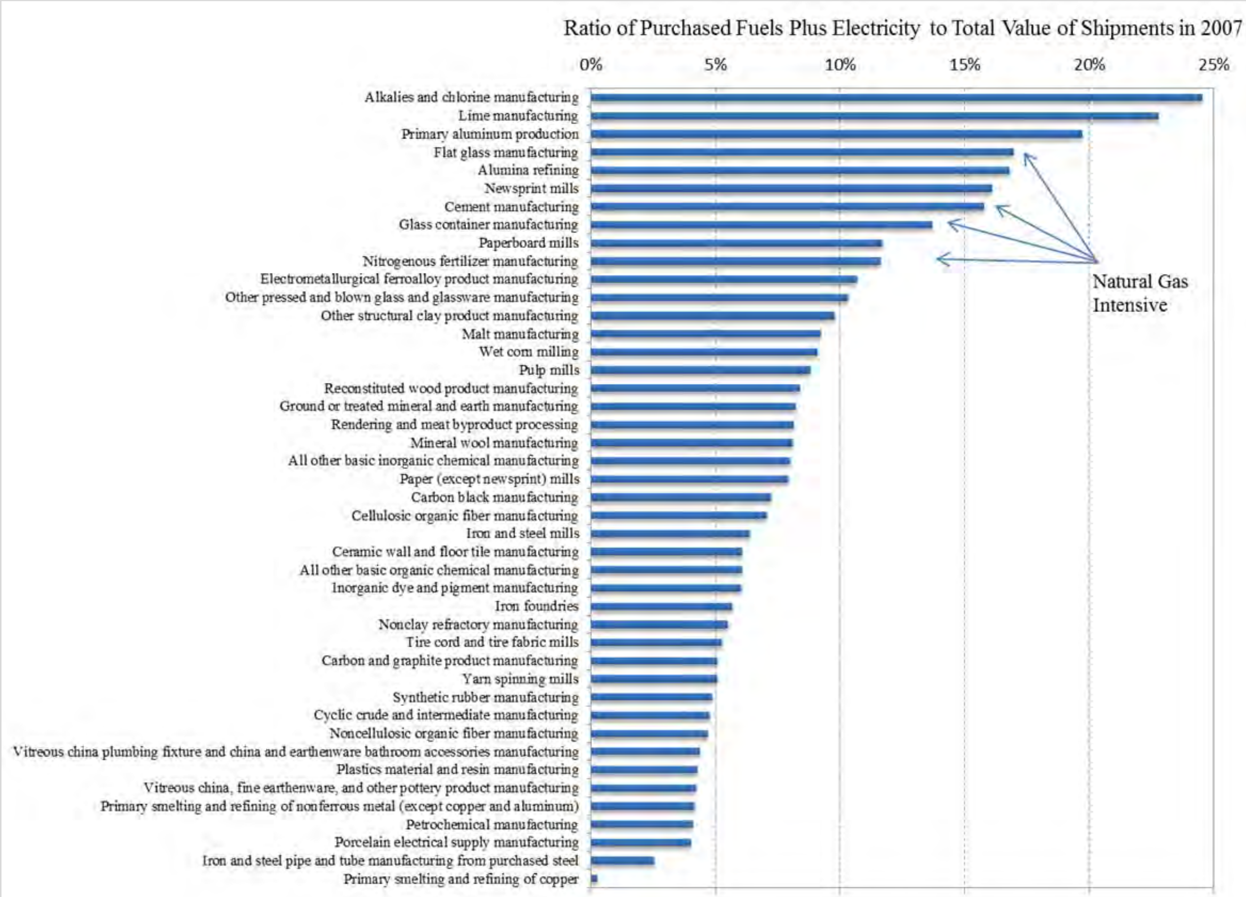
[33] "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 9.

industries that use high heats for refining, smelting, or beneficiation processes, or else they are bulk chemical processes with low value-to-weight ratios and large amounts of natural gas used as a feedstock.

Figure 44: Energy Intensity of Industries "Presumptively Eligible" for Assistance under Waxman-Markey



Source: Based on information from Census.gov. Energy intensity is measured as the value of purchased fuels plus electricity divided by the total value of shipments.

For manufacturing as a whole in 2007,[34] the ratio of value added to the total value of shipments was 78%. In the nitrogenous fertilizer industry, as an example of a natural gas-intensive, trade-exposed industry, the ratio of value added to value of shipments was only 44%. It is also a small industry with a total of 3,920 employees nationwide in 2007.[35] The ratio of value added to value of shipments for the industries that would be classified as EITE under the Waxman-Markey criteria was approximately 41%.[36] Thus there is little evidence that trade-exposed industries that

34 The date of the most recent Economic Census that provides these detailed data is the year 2007.

35 http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk.

36 Excludes two six-digit NAICS codes for which data was withheld to protect confidentiality, 331411 and 331419. Source: http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk.

would experience the largest cost increases due to higher natural gas prices are high value-added industries.

The Interagency Study similarly observed:

> *On the whole, energy expenditures equal only 2 percent of the value of U.S. manufacturing's output (see Figure 1) and three-quarters of all manufacturing output is from industries with energy expenditures below 2 percent of the value of their output. Thus, the vast majority of U.S. industry will be relatively unaffected by a greenhouse gas cap-and-trade program.*[37]

The same conclusion should apply to the effects of price increases attributable to LNG exports.

5. Impacts on Energy-Intensive Industries at the Plant or 5- to 6-Digit NAICS Level

The issue of EITE industries was investigated exhaustively during Congressional deliberations on climate legislation in the last Congress. In particular, H.R.2454 (the Waxman-Markey bill) set out specific criteria for classification as EITE. A broad consensus developed among analysts that at the 2 to 4-digit level of NAICS classification there were no industries that fit those criteria for EITE, and that only at the 5- to 6-digit level would there be severe impacts on any specific industry.[38] The phrase "deep but narrow" was frequently used to characterize the nature of competitive impacts. Some examples of industries that did fit the criteria for EITE were 311251 (nitrogenous fertilizer) within the 31 (2-digit chemicals) industry and 331111 (iron and steel mills) within the 3311 (4-digit iron and steel) industry. Analysis in this report strongly suggests that competitive impacts of higher natural gas prices attributable to LNG exports will be very narrow, but it was not possible to model impacts on each of the potentially affected sectors.

E. Sensitivities

1. Lost Values from Quota Rents

When scarcity is created there is value associated with supplying an additional unit. In economic terms, a quantity restriction to create this scarcity is called a quota. By enacting a quota, one creates a price difference between the world supply price (netback price) and the domestic price. This generates economic rent referred to as the "quota rent." Mathematically, a quota rent is the quota amount times the difference between the world net back price and the domestic price. A quota rent provides an additional source of revenue to the seller.

The quota levels for the13 scenarios analyzed and discussed in this study correspond to the export volumes assumed in the EIA Study. We assume that the quota rents are held by foreign

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[37] "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 7.

[38] Richard Morgenstern, *et al.*, RFF Workshop Report.

parties. That is, the rents do not recycle back into the U.S. economy. In this section, we look at how the welfare results would change if the quota rents were recycled back to the U.S.

Figure 45 shows the quota price in 2010 dollars per Mcf for all 13 scenarios determined in the GNGM. The quota price is the marginal price of the quota, or the quota rents divided by the level of exports. The quota price is zero for scenarios that have a non-binding quota constraint. That is, export volumes are less than the quota levels. All of the scenarios under the High EUR and Low EUR cases have binding quota constraints leading to a positive quota price. The quota price is highest in the scenarios in which the domestic natural gas price is the lowest (*i.e.*, the low scenarios for the High EUR outlook). The largest quota price results in the High EUR case with the Low/Slowest export expansion scenario (HEUR_SD_LSS). For this scenario, the quota price is around $3/Mcf.

Figure 45: Quota Price (2010$/Mcf)

Scenario	Quota Price (2010$/Mcf)				
	2015	2020	2025	2030	2035
USREF_SD_LS	1.24	0.52	1.11	1.2	1.62
USREF_SD_LR	1.09	0.52	1.11	1.2	1.62
USREF_D_LS	-	-	-	-	-
USREF_D_LR	-	-	-	-	-
USREF_SD_HS	1.24	0.52	-	0.08	0.67
USREF_SD_HR	0.74	-	-	0.08	0.67
USREF_D_LSS	0.46	-	-	-	-
HEUR_SD_LS	2.23	1.88	2.71	2.69	3.28
HEUR_SD_LR	1.8	1.88	2.71	2.69	3.28
HEUR_SD_HS	2.23	1.88	1.73	1.73	2.47
HEUR_SD_HR	1.8	0.52	1.53	1.73	2.47
HEUR_SD_LSS	2.34	2.63	2.81	2.69	3.28
LEUR_SD_LSS	-	-	-	-	-

Figure 46: Quota Rents (Billions of 2010$)

Scenario	Quota Rents* (Billions of 2010$)				
	2015	2020	2025	2030	2035
USREF_SD_LS	0.41	1.02	2.19	2.37	3.19
USREF_SD_LR	1.08	1.02	2.19	2.37	3.19
USREF_D_LS	-	-	-	-	-
USREF_D_LR	-	-	-	-	-
USREF_SD_HS	0.41	1.02	-	0.32	2.64
USREF_SD_HR	0.73	-	-	0.32	2.64
USREF_D_LSS	0.07	-	-	-	-
HEUR_SD_LS	0.74	3.71	5.34	5.30	6.46
HEUR_SD_LR	1.78	3.71	5.34	5.30	6.46
HEUR_SD_HS	0.74	3.71	6.26	6.82	9.74
HEUR_SD_HR	1.78	2.05	6.03	6.82	9.74
HEUR_SD_LSS	0.38	2.60	5.08	5.30	6.46
LEUR_SD_LSS	-	-	-	-	-

** The quota rents are based on net export volumes.*

The quota rents on the other hand, depend on the price and quantity. Even though the price is the highest under the low export scenarios, as seen in Figure 45, quota rents are the largest for the high export expansion scenarios. Under the high quota rent scenario, HEUR_SD_HR, the average annual quota rents range from $1.8 billion to $9.7 billion. Over the model horizon, 2015 through 2035, maximum total quota rents amount to about $130 billion (Figure 47). This is an important source of additional income that would have potential benefits to the U.S. economy. However, in the event that U.S. companies are unable to capture these rents, this source of additional income would not accrue to the U.S. economy.

Figure 47: Total Lost Values

Scenario	Total Lost Value from 2015-2035 (Billions of 2010$)	Average Annual Lost Value (Billions of 2010$)
USREF_SD_LS	$45.92	$1.84
USREF_SD_LR	$49.25	$1.97
USREF_D_LS	$0.00	$0.00
USREF_D_LR	$0.00	$0.00
USREF_SD_HS	$21.97	$0.88
USREF_SD_HR	$18.45	$0.74
USREF_D_LSS	$0.37	$0.01
HEUR_SD_LS	$107.78	$4.31
HEUR_SD_LR	$112.98	$4.52
HEUR_SD_HS	$136.32	$5.45
HEUR_SD_HR	$132.10	$5.28
HEUR_SD_LSS	$99.16	$3.97
LEUR_SD_LSS	$0.00	$0.00

2. A Larger Share of Quota Rents Increases U.S. Net Benefits

To understand how the macroeconomic impacts (or U.S. net benefits) would change if the quota rents were retained by U.S. companies, we performed sensitivities on two different scenarios – one with high quota price, HEUR_SD_LSS, and the other with high quota rents, HEUR_SD_HR. The sensitivities put an upper bound on the potential range of improvement in the net benefits to the U.S. consumers.

In the sensitivity runs, we assume that quota rents are returned to the U.S. consumers as a lump-sum wealth transfer from foreign entities.

Figure 48 shows the range of welfare changes for the sensitivities of the two scenarios. Under both scenarios, the welfare improves because the quota rents provide additional income to the household in the form of a wealth transfer. Consumers have more to spend on goods and services leading to higher welfare. The welfare in the Low/Slowest scenario improves by more than threefold, while under the High/Rapid scenario the improvement in welfare increases by twofold. The ability to extract quota rents unequivocally benefits U.S. consumers.

Figure 48: Change in Welfare with Different Quota Rents[39]

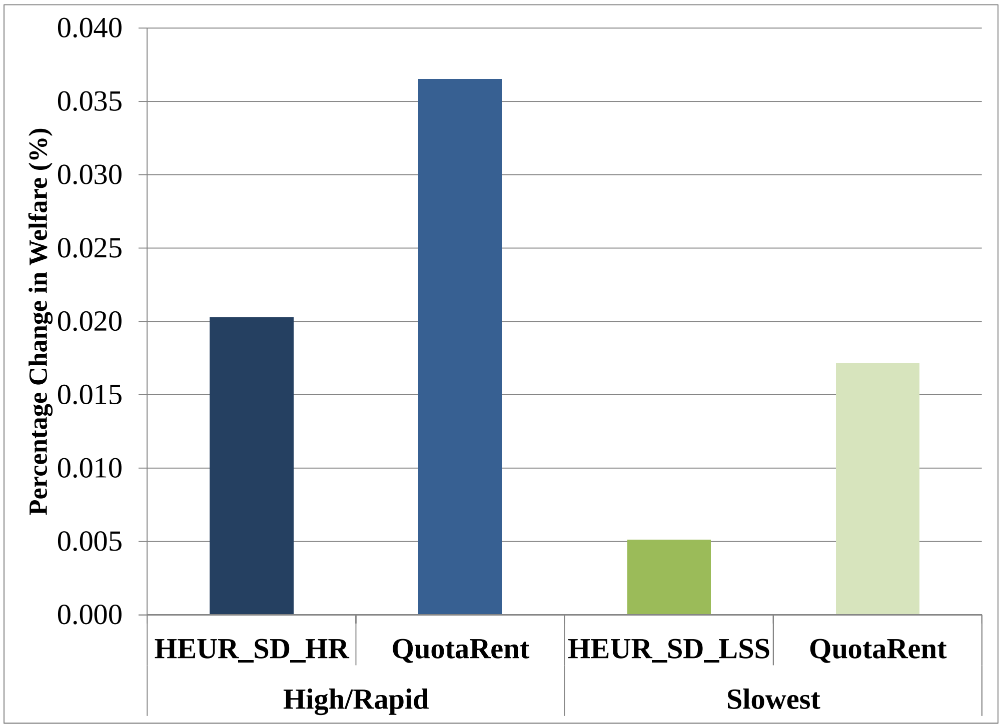
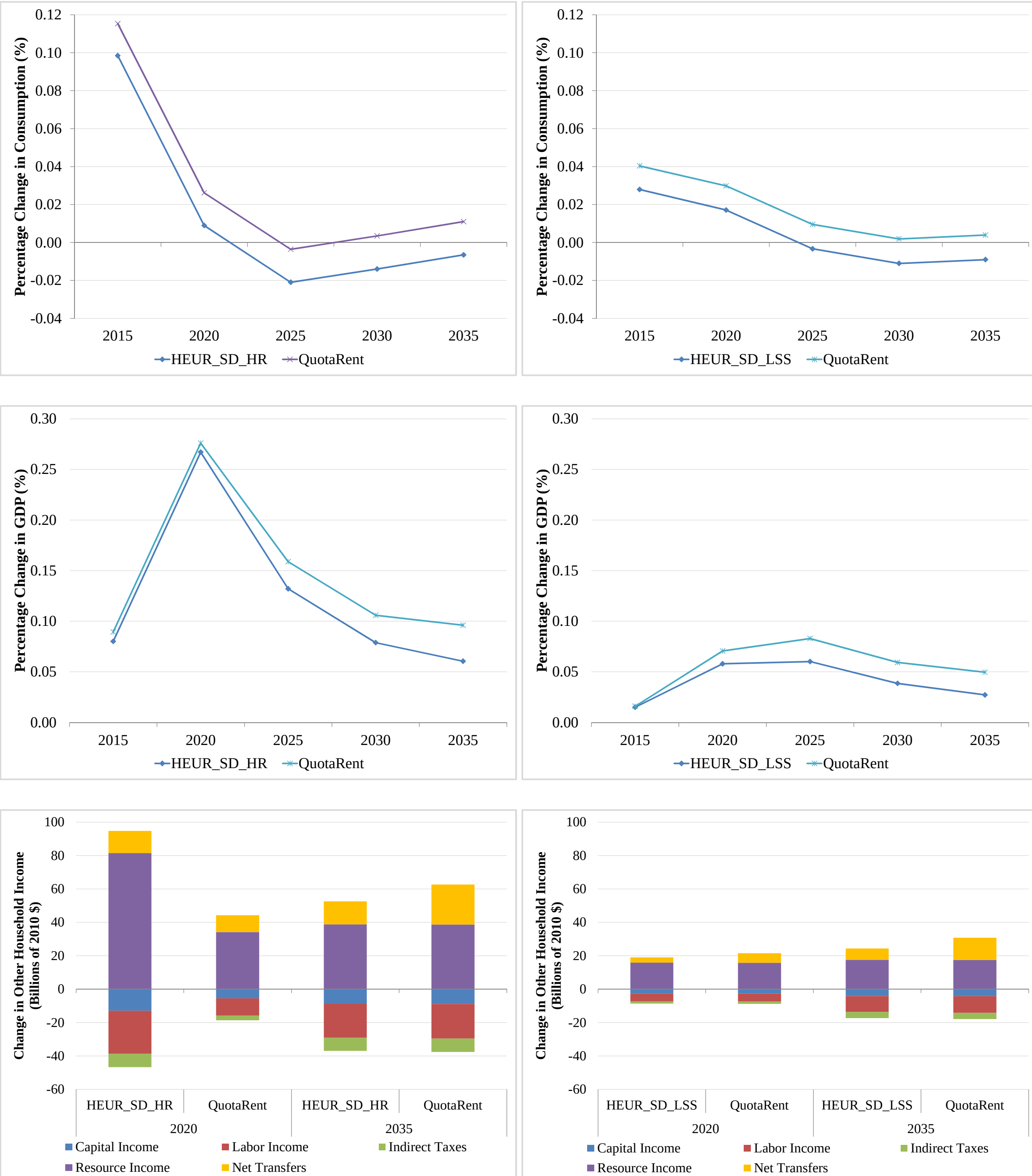


Figure 49 shows the change in impacts on aggregate consumption, GDP, and other household income for different quota rent sensitivities. The additional income from quota rents makes consumers wealthier, leading to increased expenditures on goods and services. This increase in economic activity leads to higher aggregate consumption and GDP. The impacts are highest when allowing for maximum quota rent transfer. The pattern of impacts is the same across the High/Rapid and Low/Slowest scenarios - the only difference is in the magnitude of the effect. The change under the Low/Slowest scenario is relatively smaller because of the smaller amount of transfers compared to the High/Rapid scenario. The consumption change under the maximum quota rent transfer scenario in 2015 is 50% higher than the scenario with no quota rent transfer. In this optimistic scenario, consumption changes are always positive throughout the model horizon for both scenarios. The charts below also highlight changes in other household incomes that add to GDP. While all other income source changes remain the same, only the net transfers change. As quota rents increase so does the change in net transfers leading to higher real income. As a result, higher quota rents lead to more imports, more consumption, higher GDP, and ultimately greater well-being of U.S. consumers.

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

Figure 49: Macroeconomic Impacts for the High EUR – High/Rapid and Low/Slowest Scenario Sensitivities



VII. CONCLUSIONS

NERA developed a Global Natural Gas Model ("GNGM") and a general equilibrium model of the U.S. economy ("N_{ew}ERA Model") to evaluate feasible levels of LNG exports and their impacts on the U.S. economy. These two models allowed us to determine feasible export levels, characterize the international gas market conditions, and evaluate overall macroeconomic effects. Given the wide range in export expansion outcomes, it is not surprising to find great variation in the macroeconomic impacts and natural gas market changes. Nevertheless, several observations may be distilled from the patterns that emerged.

A. LNG Exports Are Only Feasible under Scenarios with High International Demand and/or Low U.S. Costs of Production

Under status quo conditions in the world and the U.S. (U.S. Reference and International Reference cases) there is no feasible level of exports possible from the U.S. Under the low natural price case (High Shale EUR), LNG exports from the U.S. are feasible. However, under a low shale gas outlook (Low Shale EUR), international demand has to increase along with a tightening of international supply for the U.S. to be an LNG exporter.

B. U.S. Natural Gas Prices Do Not Rise to World Prices

LNG exports will not drive the price of domestic natural gas to levels observed in countries that are willing to pay oil parity-based prices for LNG imports. U.S. exports will drive prices down in regions where U.S. supplies are competitive so that even export prices will come down at the same time that U.S. prices will rise.

Moreover, basis differentials due to transportation costs from the U.S. to high-priced regions of the world will still exist, and U.S. prices will never get closer to those prices than the cost of liquefaction plus the cost of transportation to and regasification in the final destination. Thus even in the scenarios with no binding export levels, the wellhead price in the U.S. is below the import price in Japan, where the U.S. sends some of its exports.

The largest change in international natural gas prices in 2015 and 2025 is about $0.33/MMBtu and $1/MMBtu, respectively. These increases occur only in highly stressed conditions or when global markets are willing to take the full quantities of export volumes at prices above marginal production cost in the U.S. plus liquefaction, transportation, and regasification costs incurred to get the LNG to market.

C. Consumer Well-being Improves in All Scenarios

The macroeconomic analysis shows that there are consistent net economic benefits across all the scenarios examined and that the benefits generally become larger as the amount of exports increases. These benefits are measured most accurately in a comprehensive measure of economic welfare of U.S. households that takes into account changes in their income from all sources and the cost of goods and services they buy. This measure gives a single indicator of relative overall well-being of the U.S. population, and it consistently ranks all the scenarios with

LNG exports above the scenario with No-Exports. Welfare improvement is highest under the high export volume scenarios because U.S. consumers benefit from an increase in wealth transfer and export revenues.

D. There Are Net Benefits to the U.S.

A related measure that shows how economic impacts are distributed over time is GDP. Like welfare, GDP also increases as a result of LNG exports. The most dramatic changes are in the short term, when investment in liquefaction capacity adds to export revenues and tolling charges to grow GDP. Under the Reference case, GDP increases could range from $5 billion to $20 billion. Under the High Shale case, GDP in 2020 could increase by $10 billion to $47 billion. Under the Low Shale case, GDP in 2020 could increase by $4.4 billion. Every scenario shows improvement in GDP over the No-Exports cases although in the long run the impact on GDP is relatively smaller than in the short run.

Although the patterns are not perfectly consistent across all scenarios, the increase in investment for liquefaction facilities and increased natural gas drilling and production provides, in general, near-term stimulus to the economy. At the same time, higher energy costs do create a small drag on economic output in the U.S. so that total worker compensation declines.

E. There Is a Shift in Resource Income between Economic Sectors

The U.S. has experienced many changes in trade patterns as a result of changing patterns of comparative advantage in global trade. Each of these has had winners and losers. Grain exports raised the income of farmers and transferred income from U.S. consumers to farmers, steel imports lowered the income of U.S. steel companies and lowered costs of steel for U.S. manufacturing, etc.

The U.S. economy will experience some shifts in output by industrial sectors as a result of LNG exports. Compared to the No-Exports case, incomes of natural gas producers will be greater, labor compensation in the natural gas sector will increase while other industrial sector output and labor compensation decreases. The natural gas sector could experience an increase in production by 0.4 Tcf to 1.5 Tcf by 2020 and 0.3 Tcf to 2.6 Tcf by 2035 to support LNG exports. The LNG exports could lead to an average annual increase in natural export revenues of $10 billion to $30 billion. Impacts on sectoral output vary. Manufacturing sector output decreases by less than 0.4% while EIS and electric sector output impacts could be about 1% in 2020 when the natural gas price is the highest. Changes in industry output and labor compensation are very small. Even energy-intensive sectors experience changes of 1% or less in output and labor compensation during the period when U.S. natural gas prices are projected to rise more rapidly than in a No-Exports case.

Harm is likely to be confined to narrow segments of the industry, and vulnerable industries are not high value-added industries. The electricity sector, energy-intensive sector, and natural gas-dependent goods and services producers will all be impacted by price rises. Conversely, natural gas suppliers will benefit. Labor wages will likewise decrease or increase, respectively, depending on the sector of the economy. The overall impact on the economy depends on the tradeoff between these sectors.

In terms of natural gas-dependent production, producers switch to cheaper fuels or use natural gas more efficiently as natural gas prices rise and production overall is reduced. Reductions in tax revenues are directly related to changes in sectoral output. Industrial output declines the most in scenarios that have the highest increase in natural gas and fuel costs.

The costs and benefits of natural gas price increases are shifted in two ways. Costs and benefits experienced by industries do not remain with the companies paying the higher energy bills or receiving higher revenues. Part of the cost of higher energy bills will be shifted forward onto consumers, in the form of higher prices for goods being produced. The percentage of costs shifted forward depends on two main factors: first, how demand for those goods responds to increases in price, and second, whether there are competitors who experience smaller cost increases. The remainder of the cost of higher energy bills is shifted backwards onto suppliers of inputs to those industries, to their workers, and to owners of the companies. As each supplier in the chain experiences lower revenue, its losses are also shifted back onto workers and owners.

Gains from trade are shifted in the same way. Another part of the increased income of natural gas producers comes from foreign sources. This added revenue from overseas goes immediately to natural gas producers and exporters but does not come from U.S. consumers. Therefore, it is a net benefit to the U.S. economy and is also shifted back to the workers and owners of businesses involved directly and indirectly in natural gas production and exports.

In the end, all the costs and benefits of any change in trade patterns or prices are shifted back to labor and capital income and to the value of resources in the ground, including natural gas resources. One of the primary reasons for development of computable general equilibrium models like N$_{ew}$ERA is to allow analysts to estimate how impacts are shifted back to the different sources of income and their ultimate effects on the economy at large. In conclusion, the range of aggregate macroeconomic results from this study suggests that LNG export has net benefits to the U.S. economy.

APPENDIX A - TABLES OF ASSUMPTIONS AND NON-PROPRIETARY INPUT DATA FOR GLOBAL NATURAL GAS MODEL

A. Region Assignment

Figure 50: Global Natural Gas Model Region Assignments

Region	Countries
Africa	Algeria, Angola, Egypt, Equatorial Guinea, Ghana, Libya, Morocco, Mozambique, Nigeria, Tunisia
Canada	Canada
China/India	China, Hong Kong, India
Central and South America	Andes, Argentina, Bolivia, Brazil, Central America and Caribbean, Chile, Dominican Republic, Mexico, Peru, Southern Cone, Trinidad & Tobago, Uruguay, Venezuela
Europe	Albania, Austria, Belgium, Croatia, Denmark, Estonia, France, Germany, Greece, Ireland, Italy, Netherlands, North Sea, Norway, Poland, Portugal, Romania, Spain, Sweden, Switzerland, Ukraine, United Kingdom
Former Soviet Union	Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan
Korea/Japan	South Korea, Japan
Middle East	Abu Dhabi, Cyprus, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, Turkey, United Arab Emirates, Yemen
Oceania	Australia, New Zealand, Papua New Guinea
Sakhalin	Sakhalin Island
Southeast Asia	Brunei, Indonesia, Malaysia, Myanmar, Singapore, Taiwan, Thailand
U.S.	Puerto Rico, United States

B. EIA IEO 2011 Natural Gas Production and Consumption

Figure 51: EIA IEO 2011 Natural Gas Production (Tcf)

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

Figure 52: EIA IEO 2011 Natural Gas Consumption (Tcf)

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

C. Pricing Mechanisms in Each Region

1. Korea/Japan

Korea/Japan was assumed to continue to rely upon LNG to meet its natural gas demand. LNG was assumed to continue to be supplied under long-term contracts with index pricing tied to crude oil prices. It was assumed that with time, supplier competition would result in some softening in the LNG pricing relative to crude.[40] This Reference case assumes some growth in Korea/Japan demand but does not incorporate significant shifts away from nuclear energy to natural gas-fired generation.

2. China/India

LNG pricing for China/India is also assumed to be linked to crude oil prices but at a discount to Korea/Japan. The discount was intended to reflect that China/India, although short of natural gas supplies, have other sources of natural gas that LNG complements. As a result, we assumed that China/India would have some additional market leverage in negotiating contracting terms.

3. Europe

Europe receives natural gas from a variety of sources. The prices of some supplies are indexed to petroleum prices. Other sources are priced based upon regional gas-on-gas competition. In our analysis, we assumed that European natural gas prices would reflect a middle point with prices not tied directly either to petroleum or to local natural gas competition. We assumed that European prices would remain above the pricing levels forecast for North America but not as high as in Asia. Europe was also assumed to remain dependent upon imported supplies of natural gas to meet its moderately growing demand.

4. United States

The United States was assumed to follow the forecast for supply and demand and pricing as presented in the EIA's AEO 2011 Reference case.

5. Canada

The analysis assumed that Canada is part of an integrated North American natural gas market. As a consequence, Canadian pricing is linked to U.S. prices, and Canadian prices relate by a basis differential to U.S. prices. We assumed that Canadian production was sufficient to meet Canadian demand plus exports to the United States as forecast in the EIA AEO 2011. We did not allow for Canadian exports of LNG in the Reference case. Also, we held exports to the United States constant across different scenarios so as to be able to eliminate the secondary impacts of changing imports on the economic impacts of U.S. LNG on the U.S. economy.

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[40] This is consistent with the IEO WEO 2011, which forecasts the LNG to Crude index will decline from 82% to 63% between now and 2035.

6. Africa, Oceania, and Southeast Asia

These three regions were assumed to produce natural gas from remote locations. The analysis assumed that these natural gas supplies could be produced economically today at a price between $1 and $2/MMBtu. The EIA's IEO 2011 was used as the basis for forecasting production volumes.

7. Middle East

Qatar is assumed to be the low-cost producer of LNG in the world. It is assumed that although Qatar has vast natural gas resources, it decides to continue to limit its annual LNG exports to 4.6 Tcf during the forecast horizon.

8. Former Soviet Union

The FSU was assumed to grow its natural gas supply at rates that far exceed its domestic demand. The resulting excess supplies were assumed to be exported mostly to Europe and, to a lesser degree, to China/India.

9. Central and South America

Central and South America was assumed to produce sufficient natural gas to meet its growing demand in every year during the forecast horizon. The region also has the potential for LNG exports that the model considered in determining worldwide LNG flows.

Figure 53: Projected Wellhead Prices ($/MMBtu)

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

Source: U.S. wellhead prices are from EIA AEO 2012 Early Release.

Figure 54: Projected City Gate Prices ($/MMBtu)

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

D. Cost to Move Natural Gas via Pipelines

Figure 55: Cost to Move Natural Gas through Intra- or Inter-Regional Pipelines ($/MMBtu)

From	To	Cost
Africa	Africa	$1.00
Africa	Europe	$1.00
Canada	Canada	$1.20
Canada	U.S.	$1.20
China/India	China/India	$1.50
FSU	FSU	$1.00
FSU	Europe	$1.00
FSU	China-India	$1.00
U.S.	U.S.	$1.00
U.S.	Canada	$1.00
C&S America	C&S America	$2.50
Middle East	Middle East	$2.83
Oceania	Oceania	$1.50
Korea/Japan	Korea/Japan	$0.50
Europe	Europe	$1.00
Sakhalin	Sakhalin	$0.50
Southeast Asia	Southeast Asia	$1.00

E. LNG Infrastructures and Associated Costs

1. Liquefaction

The world liquefaction plants data is based upon the International Group of LNG Importers' ("GIIGNL") 2010 LNG Industry report. The dataset includes 48 existing liquefaction facilities worldwide, totaling 13.58 Tcf of export capacity. The future liquefaction facility dataset, based upon *LNG Journal* (October 2011),[41] includes 32 LNG export projects and totals 10.59 Tcf of planned export capacity. This dataset covers worldwide liquefaction projects from 2011 to 2017. Beyond 2017, each region's liquefaction capacity is assumed to grow at the average annual growth rate of its natural gas supply.[42]

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41 LNG Journal, Oct 2011. Available at: http://lngjournal.com/lng/.

42 Rates are adopted from IEO 2011.

The liquefaction cost per MMBtu can be broken down into three components:

1. An operation and maintenance cost of $0.16;
2. A capital cost that depends on the location of the facility; and
3. A fuel use cost that varies with natural gas prices over time.

To derive the capital cost per MMBtu, we obtained a set of investment costs per million metric tons per annum ("MMTPA") by region (Figure 56).[43] The U.S.'s investment cost per MMTPA is competitive because most domestic projects convert existing idle regasification facilities to liquefaction facilities. This implies a 30% to 40% cost savings relative to greenfield projects. Offshore LNG export projects are more costly, raising the investment costs per unit of capacity in Southeast Asia and Oceania.

Figure 56: Liquefaction Plants Investment Cost by Region ($millions/ MMTPA Capacity)

	$Millions/MMTPA	Capital Cost ($/MMBtu produced)
Africa	$1,031	$3.05
Canada	$1,145	$3.39
C&S America	$802	$2.37
Europe	$802	$2.37
FSU	$802	$2.37
Middle East	$859	$2.54
Oceania	$1,317	$3.90
Sakhalin	$802	$2.37
Southeast Asia	$1,145	$3.39
U.S.	$544	$1.61

The total investment cost is then annualized assuming an average plant life of 25 years and a discount rate of 10%. The capital cost per MMBtu of LNG produced is obtained after applying a 72% capacity utilization factor to the capital cost per MMBtu of LNG capacity. Figure 57 shows the liquefaction fixed cost component in $/MMBtu LNG produced.

$$\text{Equivalent Annual Cost} = \frac{\text{Asset Price} \times \text{Discount Rate}}{1-(1+\text{Discount Rate})^{-\text{Number of Periods}}}$$

[43] From Paul Nicholson, a Marsh & McLennan company colleague (NERA is a subsidiary of Marsh & McClennan).

In the liquefaction process, 9% of the LNG is burned off. This fuel use cost is priced at the wellhead and included in the total liquefaction costs.

Figure 57: Liquefaction Costs per MMBtu by Region, 2010-2035

	2010	2015	2020	2025	2030	2035
Africa	$3.37	$3.38	$3.40	$3.42	$3.44	$3.46
Canada	$3.85	$3.88	$3.93	$4.02	$4.06	$4.15
C & S America	$2.71	$2.73	$2.75	$2.77	$2.79	$2.82
Europe	$3.35	$3.43	$3.50	$3.61	$3.65	$3.72
FSU	$2.65	$2.65	$2.67	$2.68	$2.70	$2.71
Middle East	$2.81	$2.82	$2.84	$2.85	$2.87	$2.88
Oceania	$4.22	$4.23	$4.25	$4.27	$4.29	$4.31
Sakhalin	$2.65	$2.65	$2.67	$2.68	$2.70	$2.71
Southeast Asia	$3.73	$3.74	$3.76	$3.79	$3.81	$3.84
U.S.	$2.13	$2.14	$2.18	$2.25	$2.28	$2.34

2. Regasification

The world regasification plants data is based upon the GIIGNL's annual LNG Industry report, 2010. The dataset includes 84 existing regasification facilities worldwide, totaling to a 28.41 Tcf annual import capacity. Korea and Japan together own 12.58 Tcf or 44% of today's world regasification capacities. The GNGM future regasification facility database includes data collected from multiple sources: the GLE Investment Database September 2011, LNG journal Oct 2011, and GIIGNL's 2010 LNG Industry report. It includes 46 LNG import projects, totaling to 12.12 Tcf of planned import capacity, and covers regasification projects from 2011 to 2020 worldwide. Beyond 2020, each region's regasification capacity is assumed to grow at the average annual growth rate of its natural gas demand.[44]

LNG regasification cost can also be broken down into three components: an operation and maintenance cost of $0.20/MMBtu, a fixed capital cost of $0.46/MMBtu, and a fuel use cost that varies with natural gas demand prices by region and time. The capital cost assumes a 40% capacity utilization factor, and the fuel use component assumes a 1.5% LNG loss in regasification. LNG regasification cost in GNGM is shown in Figure 58.

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[44] Rates adopted from IEO 2011.

Figure 58: Regasification Costs per MMBtu by Region 2010-2035

	2010	2015	2020	2025	2030	2035
C&S America	$0.73	$0.73	$0.73	$0.74	$0.74	$0.75
Canada	$0.73	$0.74	$0.75	$0.76	$0.77	$0.78
China/India	$0.87	$0.88	$0.88	$0.88	$0.89	$0.89
Europe	$0.81	$0.83	$0.84	$0.86	$0.86	$0.87
FSU	$0.74	$0.75	$0.75	$0.76	$0.77	$0.78
Korea/Japan	$0.89	$0.90	$0.90	$0.91	$0.91	$0.91
Middle East	$0.72	$0.72	$0.73	$0.73	$0.73	$0.73
Southeast Asia	$0.71	$0.71	$0.71	$0.72	$0.72	$0.72
U.S.	$0.73	$0.73	$0.74	$0.75	$0.76	$0.77

3. Shipping Cost

GNGM assumes that the shipping capacity constraint is non-binding. There are sufficient LNG carriers to service any potential future route in addition to existing routes.

Shipping cost consists of a tanker cost and a LNG boil-off cost, both of which are a function of the distance between the export and import regions. An extra Panama Canal toll of 13 cents roundtrip is applied to gulf-Asia Pacific shipments.[45] Tanker costs are based on a $65,000 rent per day and average tanker speed of 19.4 knots. Fuel use costs assume a 0.15% per day boil off rate and an average tanker capacity of 149,000 cubic meters of LNG. LNG boil-off cost is valued at city gate prices in importing regions. Shipping distances for existing routes are based upon the GIIGNL's 2010 LNG Industry report while distances for potential routes are calculated with the Sea Rates online widget.[46]

45 $0.13 roundtrip toll calculated based upon a 148,500 cubic meter tanker using approved 2011 rates published at http://www.pancanal.com/eng/maritime/tolls.html.

46 http://www.searates.com/reference/portdistance/.

Figure 59: 2010 Shipping Rates ($/MMBtu)

	Canada	China/ India	C&S America	Europe	Korea/ Japan	Oceania	SE Asia	U.S.
Africa		$1.76	$1.44	$0.46	$2.60		$1.70	$2.60
Canada		$1.51	$1.53		$1.23		$1.55	
China/ India								$2.81
C&S America	$1.53	$2.22	$1.26	$1.39	$2.73			$1.54
Europe								$1.27
FSU			$2.15			$2.39	$2.44	$1.17
Korea/ Japan								$2.54
Middle East		$0.96	$2.36	$1.30	$1.61		$1.15	$2.16
Oceania		$0.74	$2.38		$0.90		$0.63	$2.41
Sakhalin		$0.48			$0.26		$0.84	$2.50
Southeast Asia		$0.52			$0.66		$0.32	$2.63
U.S.		$2.81	$1.53	$1.27	$2.54		$2.61	

The Gulf Coast has a comparative disadvantage in accessing the Asia pacific market due to the long shipping distances and Panama Canal tolls.

4. LNG Pipeline Costs

A pair of pipeline transport costs is also included in LNG delivery process to account for the fact that pipelines are necessary to transport gas from wellheads to liquefaction facilities in supply regions and from regasification facilities to city gates in demand regions.

Figure 60: Costs to Move Natural Gas from Wellheads to Liquefaction Plants through Pipelines ($/MMBtu)

Region	Cost
Africa	$1.00
Canada	$0.70
China/India	$1.50
C&S America	$0.50
Europe	$1.00
FSU	$1.00
Korea/Japan	$1.00
Middle East	$1.42
Oceania	$0.50
Sakhalin	$0.50
Southeast Asia	$1.00
U.S.	$1.00

Figure 61: Costs to Move Natural Gas from Regasification Plants to City Gates through Pipelines ($/MMBtu)

Region	Cost
Africa	$1.00
Canada	$0.50
China/India	$1.50
C&S America	$0.50
Europe	$1.00
FSU	$1.00
Korea/Japan	$0.50
Middle East	$1.42
Oceania	$0.50
Sakhalin	$0.50
Southeast Asia	$1.00
U.S.	$1.00

5. Total LNG Costs

Costs involved in exporting LNG from the Gulf Coast to demand regions are aggregated in Figure 62. The largest cost components are liquefaction and shipping.

Figure 62: Total LNG Transport Cost, 2015 ($/MMBtu)

	China/India	Europe	Korea/Japan
Regas to city gate pipeline cost	$1.50	$1.00	$0.50
Regas cost	$0.88	$0.83	$0.90
Shipping cost	$2.87	$1.33	$2.60
Liquefaction cost	$2.14	$2.14	$2.14
Wellhead to liquefaction pipeline cost	$1.00	$1.00	$1.00
Total LNG transport cost	$8.39	$6.30	$7.14

F. Elasticity

1. Supply Elasticity

All regions are assumed to have a short-run supply elasticity of 0.2 in 2010 and a long-run elasticity of 0.4 in 2035. Elasticities in the intermediate years are interpolated with a straight line method. There are two exceptions to this rule.

The U.S. supply elasticity is computed based upon the price and production fluctuations under different scenarios in the EIA Study. The median elasticity in 2015 and 2035 is recorded and elasticities for the other years are extrapolated with a straight line method.

After numerous test runs, we found that African supply elasticity is appropriately set at 0.1 for all years. Supply elasticity in GNGM is:

Figure 63: Regional Supply Elasticity

	2010	2015	2020	2025	2030	2035
Africa	0.10	0.10	0.10	0.10	0.10	0.10
U.S.	0.17	0.24	0.33	0.46	0.65	0.90
All other regions	0.20	0.23	0.26	0.30	0.35	0.40

2. Demand Elasticity

All regions are assumed to have a short run demand elasticity of -0.10 in 2010 and a long run demand elasticity of -0.20 in 2035 except the U.S. The U.S. demand elasticity is derived based on average delivered price and consumption fluctuations reported in the EIA Study.

Figure 64: Regional Demand Elasticity

	2010	2015	2020	2025	2030	2035
U.S.	-0.33	-0.36	-0.39	-0.42	-0.46	-0.50
All other regions	-0.10	-0.11	-0.13	-0.15	-0.17	-0.20

G. Adders from Model Calibration[47]

Figure 65: Pipeline Cost Adders ($/MMBtu)

Exporters	Importers	2010	2015	2020	2025	2030	2035
Africa	Europe	$7.43	$8.23	$8.88	$9.83	$10.03	$10.62
Canada	Canada	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
Canada	U.S.	$0.30	$0.12				
FSU	China/India	$8.71	$8.93	$8.58	$8.30	$8.03	$7.31
FSU	Europe	$4.88	$5.47	$5.83	$6.46	$6.32	$6.52
Sakhalin	Sakhalin	$2.04	$2.04	$2.04	$2.04	$2.04	$2.04

47 Appendix B provides details on the generation of cost adders in GNGM.

Figure 66: LNG Cost Adders Applied to Shipping Routes ($/MMBtu)

Exporter	Importer	2010	2015	2020	2025	2030	2035
Africa	China/India	$3.59	$3.97	$3.89	$3.89	$3.93	$3.57
Africa	Europe	$1.73	$2.50	$3.11	$4.01	$4.18	$4.73
Africa	Korea/Japan	$5.09	$5.60	$5.54	$5.59	$5.70	$5.33
Canada	China/India	$5.91	$2.16	$1.71	$0.90	$0.72	-
Canada	Korea/Japan	$8.54	$4.93	$4.52	$3.77	$3.67	$2.44
C&S America	China/India	$4.06	$4.41	$4.29	$4.25	$4.24	$3.85
C&S America	Europe	$1.73	$2.43	$2.97	$3.78	$3.90	$4.36
C&S America	Korea/Japan	$5.89	$6.37	$6.28	$6.30	$6.37	$5.96
Sakhalin	China/India	$6.64	$7.09	$7.07	$7.16	$7.29	$7.01
Sakhalin	Korea/Japan	$9.19	$9.79	$9.81	$9.96	$10.17	$9.89
Middle East	China/India	$5.05	$5.49	$5.47	$5.55	$5.67	$5.40
Middle East	Europe	$1.55	$2.32	$2.96	$3.88	$4.11	$4.70
Middle East	Korea/Japan	$6.74	$7.31	$7.32	$7.46	$7.65	$7.37
U.S.	China/India	$1.51	$1.86	$1.60	$0.92	$0.80	$0.08
U.S.	Europe	-	$0.61	$1.02	$1.21	$1.21	$1.35
U.S.	Korea/Japan	$4.13	$4.62	$4.40	$3.78	$3.74	$3.00
Oceania	China/India	$4.26	$4.66	$4.58	$4.59	$4.64	$4.29
Oceania	Korea/Japan	$6.44	$6.99	$6.94	$7.01	$7.14	$6.77
Southeast Asia	China/India	$4.21	$4.59	$4.48	$4.46	$4.47	$4.08
Southeast Asia	Korea/Japan	$6.42	$6.94	$6.86	$6.91	$7.00	$6.58

H. Scenario Specifications

Figure 67: Domestic Scenario Conditions

	2010	2015	2020	2025	2030	2035
Reference Case						
Production (Tcf)	21.10	22.40	23.40	24.00	25.10	26.40
Wellhead price ($/MMBtu)	$3.72	$3.83	$4.28	$5.10	$5.48	$6.36
Pipeline imports from Canada (Tcf)	2.33	2.33	1.4	0.74	0.64	0.04
High EUR						
Production (Tcf)	21.21	24.68	26.37	27.52	28.61	30.19
Wellhead price ($/MMBtu)	$3.23	$2.90	$3.15	$3.72	$4.14	$4.80
Pipeline imports from Canada (Tcf)	2.18	2.01	0.87	0.01	-0.18	-0.68
Low EUR						
Production (Tcf)	20.93	19.61	19.88	20.06	21.13	21.67
Wellhead price ($/MMBtu)	$4.54	$5.65	$6.37	$7.72	$8.23	$8.85
Pipeline imports from Canada (Tcf)	2.45	2.66	2.06	1.96	1.93	1.66

Figure 68: Incremental Worldwide Natural Gas Demand under Two International Scenarios (in Tcf of Natural Gas Equivalents)

	2010	2015	2020	2025	2030	2035
Demand Shock						
Japan converts nuclear to gas	2.41	3.18	3.41	3.56	3.86	4.19
Supply& Demand Shock						
Japan and Korea convert nuclear to gas and limited international supply expansion	3.82	5.00	5.59	5.88	6.37	6.86

Sources: EIA IEO 2011 Nuclear energy consumption, reference case.

Figure 69: Scenario Export Capacity (Tcf)

	2010	2015	2020	2025	2030	2035
No Export	0	0	0	0	0	0
Low Slow	0	0.37	2.19	2.19	2.19	2.19
High Slow	0	0.37	2.19	4.02	4.38	4.38
Low Rapid	0	1.10	2.19	2.19	2.19	2.19
High Rapid	0	1.10	4.38	4.38	4.38	4.38
Low/Slowest	0	0.18	1.10	2.01	2.19	2.19
No Constraint	∞	∞	∞	∞	∞	∞

Source: EIA Study.

APPENDIX B – DESCRIPTION OF MODELS

A. Global Natural Gas Model

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

1. Model Calibration

The model is calibrated to match the EIA's IEO and AEO 2011 Reference Case natural gas production, consumption, wellhead, and delivered price forecasts, after adjusting the AEO and IEO production and consumption forecasts so that:

- World supply equaled world demand
- U.S. imports from Canada equaled total U.S. imports as defined by the AEO Reference case, less U.S. LNG imports as defined by the AEO Reference case
- Middle East LNG exports were capped at 4.64 Tcf, which meant that for the Middle East
  - Production ≤ Demand + Min(Liquefaction capacity, LNG export cap)
- FSU pipeline capacity satisfied the expression
  - Production ≤ Demand + pipeline export capacity
- Regasification capacity satisfied the expression for LNG importing regions:
  - Production ≤ Supply + Regasification Capacity
- Sufficient liquefaction capacity exists in LNG exporting regions
  - Production ≤ Demand + liquefaction capacity + pipeline export capacity

The GNGM assumes that the world natural gas market is composed of a perfectly competitive group of countries with a dominant supplier that limits exports. Therefore, if we simply added the competitive transportation costs to transport gas among regions, the model would not find the market values and would be unable to match the EIA's forecasts because the world natural gas market is not perfectly competitive and at its current scale includes important risks and transaction costs. For example, the city gate prices in the Korea/Japan region represent not only the cost of delivering LNG to this region but also this region's willingness to pay a premium above the market price to ensure a stable supply of imports.

Therefore to calibrate the GNGM to the EIA's price and volume forecasts, we had to introduce cost adders that represented the real world cost differentials, including these transaction costs. To derive these cost adders, we developed a least-squares algorithm that solved for these adders. The least-squares algorithm minimized the sum of the inter-region pipeline and LNG shipping cost adders subject to matching the EIA natural gas production, consumption, wellhead, and city gate prices for each region (see Appendix A for the resulting cost adders).

These pipeline and LNG shipping cost adders were added to the original pipeline and LNG shipping costs, respectively, to develop adjusted pipeline and LNG shipping costs. The GNGM made use of these adjusted transportation costs in all the model runs.

These adders can be interpreted in several ways consistent with their function in the GNGM:

- As transaction costs that could disappear as the world market became larger and more liquid, in the process shifting downward the demand curve for assured supplies in the regions where such a premium now exists
- As a leftover from long term contracts and therefore a rent to producers that will disappear as contracts expire and are renegotiated
- As a rent taken by natural gas utilities and traders within the consuming regions, that would either continue to be taken within importing countries or competed away if there were more potential suppliers

Under all of these interpretations, the amount of the adder would not be available to U.S. exporters, nor would it be translated into potentially higher netback prices to the U.S.

2. Input Data Assumptions for the Model Baseline

a. GNGM Regions

The GNGM regional mapping scheme is largely adapted from the EIA IEO regional definitions with modifications to address the LNG-intensive regions.

- OECD Regions: the OECD region of Americas maps to GNGM regions U.S., Canada and Central and South America; OECD Europe maps to GNGM Europe; OECD Asia maps to GNGM Korea-Japan and Oceania.

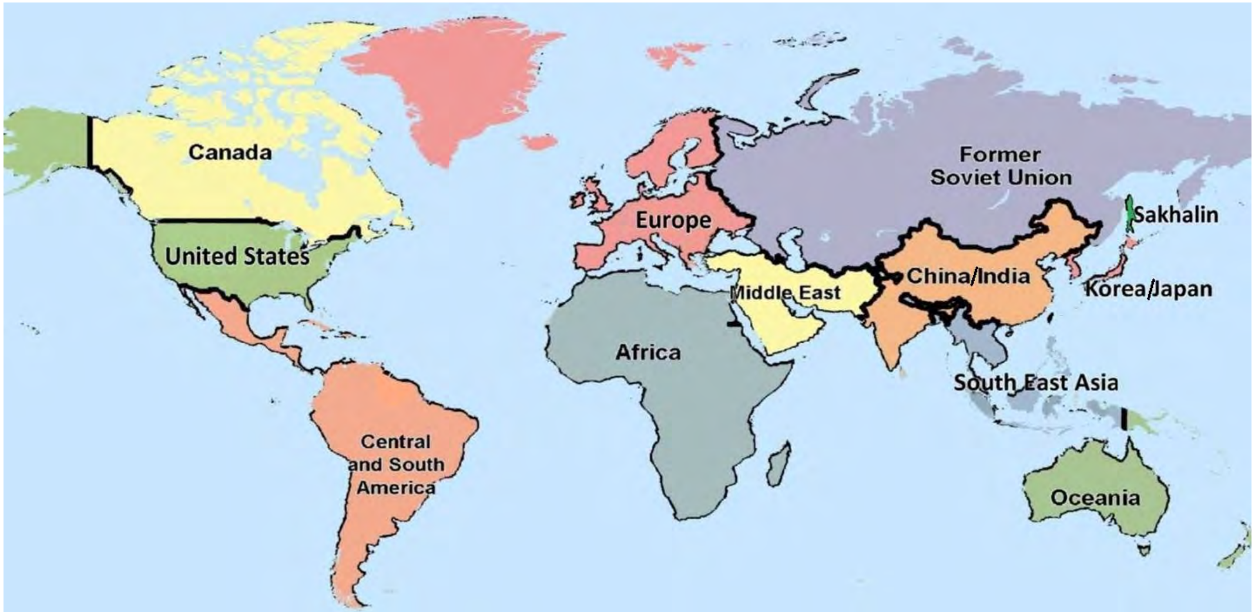
- Non-OECD Regions: the non-OECD regions of Eurasia and Europe map to GNGM regions Former Soviet Union and Sakhalin; Non-OECD Asia maps to China-India and Southeast Asia; Middle East maps to GNGM Middle East; Africa to GNGM Africa; Non-OECD Central and South America maps to GNGM Central and South America.

- Sakhalin is a Russian island just north of Japan. All Russian or FSU LNG exports in 2010 were produced in Sakhalin.[48] This island is characterized as a pure supply region with zero demand and adopted as a separate GNGM region from the rest of the FSU for its proximity to the demand regions. Its LNG production in 2010 is set equal to the

[48] "The LNG Industry 2010," GIIGNL. Available at: www.giignl.org/fr/home-page/publications.

FSU's LNG exports in 2010 and grows at a rate of 1.1% per annum for the subsequent years.[49]

Figure 70: Map of the Twelve Regions in the GNGM



b. Time Horizon

GNGM reads in forecast data from each year and outputs the optimized gas trade flows. The model's input data currently covers years 2010 through 2035, but can be readily extended given data availability. For this analysis, we solved the model in five-year time steps starting with 2010.

c. Projected World Natural Gas Production and Consumption

The model's international natural gas consumption and production projections are based upon the IEO 2011 reference case. GNGM assumes four different future U.S. natural gas markets: the AEO 2011 reference case is adopted as the baseline and three other U.S. futures are obtained with the following modifications.

- High Shale EUR: U.S. natural gas production and wellhead prices are replaced by AEO 2011 High Shale EUR projections. All other regions are held constant.
- Low Shale EUR: U.S. natural gas production and wellhead prices are replaced by AEO 2011 Low Shale EUR projections. All other regions are held constant.
- High Economic Growth: U.S. natural gas consumption is replaced by AEO 2011 High Economic Growth projections. All other regions are held constant.

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[49] The 1.1% per annum rate corresponds to IEO 2011 projected Russian natural gas production average annual growth rate for 2008 through 2035.

d. Gas Production and Consumption Prices

NERA has developed a set of world natural gas price projections based upon a number of data sources. The approach focuses on the wellhead price forecasts for net export regions and city gate price forecasts for net import regions. In naturally gas-abundant regions like the Middle East and Africa, the wellhead price is assumed to equal the natural gas extraction cost or lifting cost. City gate prices are estimated by adding a transportation cost to the wellhead prices.

In the major demand markets, natural gas prices are determined on an oil-parity basis using crude oil price forecasts from IEA's WEO 2011. The resultant prices are highly consistent with the relevant historical pipeline import prices[50] and LNG spot market prices as well as various oil and natural gas indices (*i.e.*, JCC, WTI, Henry Hub, AECO Hub indices, and UK National Balancing Point). U.S. wellhead and average city gate prices are adopted from AEO 2011. Canadian wellhead and city gate prices are projected to be $0.35 less than the U.S. prices in the reference case. A region-by-region price forecast description is presented in Section II.

e. Natural Gas Transport Options

Pipelines

GNGM assumes that all intra-regional pipeline capacity constraints are non-binding. Each region is able to transport its indigenously-produced natural gas freely within itself at an appropriate cost.

Four inter-regional pipeline routes are acknowledged in GNGM. The Africa-to-Europe route, including the Greenstream Pipeline, Trans-Mediterranean Pipeline, and Maghreb–Europe Gas Pipeline, is assigned a total capacity of 1.9 Tcf/year (connecting Northern Africa to Spain, Portugal, and Italy). The Turkmenistan–China Gas Pipeline, connecting FSU to China/India, has a maximum discharge of 1.41 Tcf/year. The FSU-Europe pipeline route has a total capacity of 8.3 Tcf/year in 2010 and grows to 10.8 Tcf/year in 2025. Lastly, the U.S.-Canada pipeline route is open and assumed to have unlimited capacity.

LNG Routes

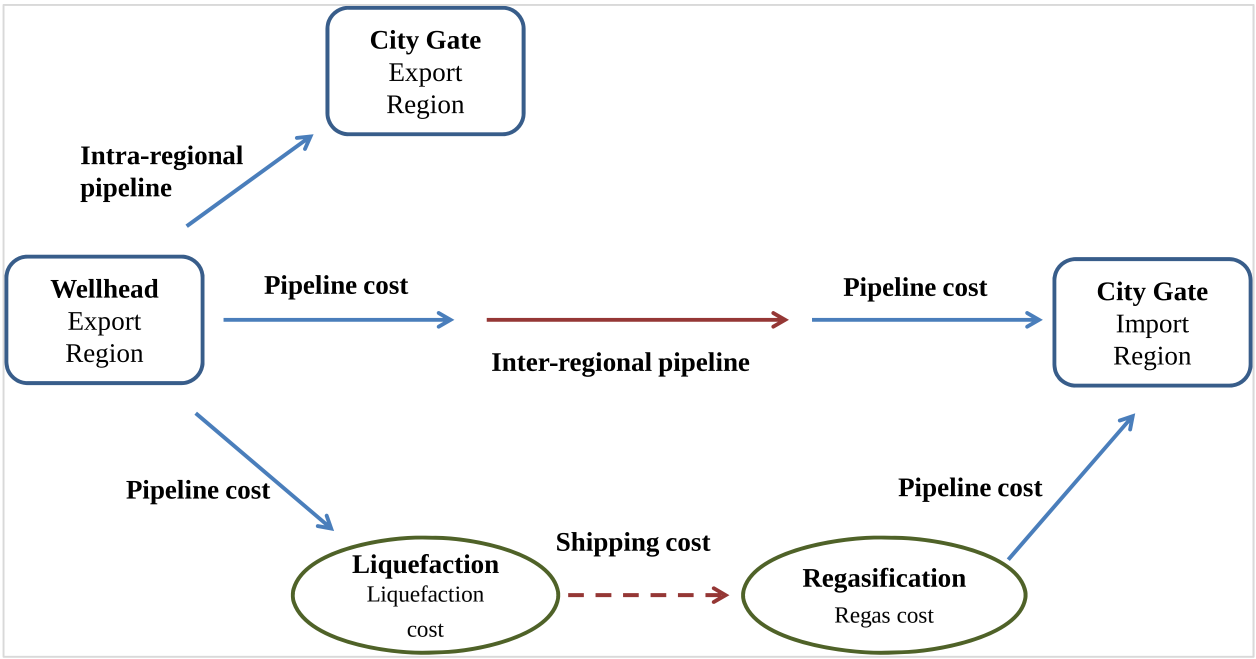
GNGM sets two constraints on LNG transportation. Each export region is subjected to a liquefaction capacity constraint and each import region to a regasification capacity constraint. There are five components in transporting LNG (Figure 71), and capacity constraints on the wellhead to liquefaction pipeline, LNG tankers, and regasification to city gate pipeline are assumed to be non-binding.

LNG transportation costs are generally four to seven times higher than the pipeline alternative since, to satisfy natural gas demand with LNG, shipments incur five segments of costs: 1) pipeline shipping cost to move gas from the wellhead to the liquefaction facility, 2) liquefaction

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

cost, 3) shipping cost between the liquefaction to regasification facilities, 4) regasification cost and 5) the pipeline shipping cost to move gas from the regasification facility to the city gate terminal in the demand region. A detailed cost breakdown for each leg of this process is presented in Appendix A.

Figure 71: Natural Gas Transport Options



f. Fuel Supply Curves

The supply of natural gas in each region is represented by a CES supply curve (see Equation 1). The supply curve provides a relationship between the supply of gas (Q) and the wellhead price of gas (P). The elasticity of the supply curves dictates how the price of natural gas changes with changes in production.

Equation 1: CES Supply Curve

$$\mathbf{Q(t) / Q_{0,t} = (P(t) / P_{0,t})^{\text{elasticity of supply}}}$$

Each supply curve is calibrated to the benchmark data points ($Q_{0.t}$, $P_{0.t}$) for each year t, where the benchmark data points represent those of the EIA’s adjusted forecasts.[51] $Q_{0.t}$ represents the EIA’s adjusted forecasted quantity of natural gas production for year t, and $P_{0.t}$ represents the EIA’s forecasted wellhead price of gas for year t. The elasticity of supply for all regions is included in Figure 63.

[51] See Section IV.B for a discussion of how the EIA’s forecasts are adjusted before the GNGM model is calibrated. Note, only quantities are adjusted.

g. Fuel Demand Curves

The demand curve for natural gas has a similar functional form as the supply curve. As with the supply curves, the demand curve in each region is represented by a CES function (see Equation 2). The demand curve provides a relationship between the demand for gas (Q) and the city gate price of gas (P). The demand curves dictate how the price of natural gas changes with changes in demand in each region.

Equation 2: CES Demand Curve

$$Q(t) / Q_{0,t} = (P(t) / P_{0,t})^{\text{elasticity of demand}}$$

Each demand curve is calibrated to the benchmark data points ($Q_{0.t}$, $P_{0.t}$) for each year t, where the benchmark data points represent those of the EIA's adjusted forecasts. $Q_{0.t}$ represents the EIA's adjusted forecasted demand for natural gas for year t and $P_{0.t}$ represents the EIA's forecasted city gate price of gas for year t. The elasticity of demand for all regions except the U.S. is based on the elasticities used in MIT's Emissions Prediction and Policy Analysis ("EPPA") model.[52] For the U.S., the demand elasticity was estimated by using the percentage changes in natural gas demand and city gate prices between the EIA's AEO 2011 Reference scenario and the different shale gas scenarios.

3. Model Formulation

The GNGM is formulated as a non-linear program. The following text describes at a high level the GNGM's non-linear objective function and linear constraints.

Maximize: Consumer Surplus + Producer Surplus – Transportation Costs

Subject to:

$$Supply(s) = \sum_d PipeGas(s,d) + LNG(s,d)$$

$$Demand(d) = \sum_s PipeGas(s,d) + LNG(s,d)$$

$$\sum_d LNG(s,d) \leq LiquefactionCapacity(s)$$

$$\sum_s LNG(s,d) \leq RegasificationCapacity(d)$$

52 "The MIT Emissions Prediction and Policy Analysis ("EPPA") Model: Version 4," Sergey Paltsev, John M. Reilly, Henry D. Jacoby, Richard S. Eckaus, James McFarland, Marcus Sarofim, Malcolm Asadoorian and Mustafa Babiker, August 2004.

$$PipeGas(s,d) \leq PipelineCapacity(s,d)$$

$$PipeGas('Canada','USA') = BaselinePipeGas('Canada','USA')$$

Scenario Constraints

* Quota Constraint

$$\sum_{d} LNG('USA',d) \leq Quota$$

* Supply Shock

$$\sum_{d} LNG('Oceania',\mathrm{d}) + LNG('Africa',d) + LNG('SouthEastAsia',d) \leq MaxExports$$

Consumer Surplus = $\int CityGatePrice(d)\ x\ (\frac{Demand(d)}{Demand0(d)})^{(\frac{1}{ElasOfDemand(d)})}$

Producer Surplus= $\int WellheadPrice(s)\ x\ (\frac{Supply(s)}{Supply0(s)})^{(\frac{1}{ElasOfSupply(s)})}$

Transportation Costs =

$$\sum_{s,d} ShipCost(s,d)\ x\ LNG(s,d) + \sum_{s,d} PipeLineCost(s,d)\ x\ PipeGas(s,d) + \sum_{s,d} RegasCost(d)\ x\ LNG(s,d) + \sum_{s,d} LiquefactionCost(s)\ x\ LNG(s,d)$$

where,

LiquefactionCost(s) = Cost to liquefy natural gas in region s + transport the gas from the wellhead to the liquefaction facility within region s.

RegasCost(d) = Cost to re-gasify natural gas in region d + transport the gas from the regasification facility to the city gate within region d.

PipelineCost(s,d) = Cost to transport natural gas along a pipeline from supply region s to demand region d.

ShipCost(s,d) = Cost to ship natural gas from supply region s to demand region d.

Quota = Maximum allowable amount of U.S. LNG exports. This varies by time period and scenario.

The supply curves capture the technological issues (penetration rate, availability and cost) for natural gas in each region. The demand curves for natural gas capture the change in utility from consuming natural gas.

The main constraints are applied to all cases while scenario constraints are case specific. The demand shocks are modeled by changing the baseline level of natural gas demand ($\text{Demand}_0(d)$).

B. N$_{ew}$ERA Model

1. Overview of the N$_{ew}$ERA Macroeconomic Model

The N$_{ew}$ERA macro model is a forward-looking, dynamic, computable general equilibrium model of the United States. The model simulates all economic interactions in the U.S. economy, including those among industry, households, and the government. The economic interactions are based on the IMPLAN[53] 2008 database for a benchmark year, which includes regional detail on economic interactions among 440 different economic sectors. The macroeconomic and energy forecasts that are used to project the benchmark year going forward are calibrated to the most recent AEO produced by the Energy Information Administration (EIA). Because the model is calibrated to an internally-consistent energy forecast, the use of the model is particularly well-suited to analyze economic and energy policies and environmental regulations.

2. Model Data (IMPLAN and EIA)

The economic data is taken from the IMPLAN 2008 database which includes balanced Social Accounting Matrices for all states in 2008. These inter-industry matrices provide a snapshot of the economy. Since the IMPLAN database contains only economic values, we benchmark energy supply, demand, trade, and prices to EIA historical statistics to capture the physical energy flows. The integration of the EIA energy quantities and prices into the IMPLAN economic database results in a balanced energy-economy dataset.

Future economic growth is calibrated to macroeconomic (GDP), energy supply, energy demand, and energy price forecasts from the EIA’s AEO 2011. Labor productivity, labor growth, and population forecasts from the Census Bureau are used to project labor endowments along the baseline and ultimately employment by industry.

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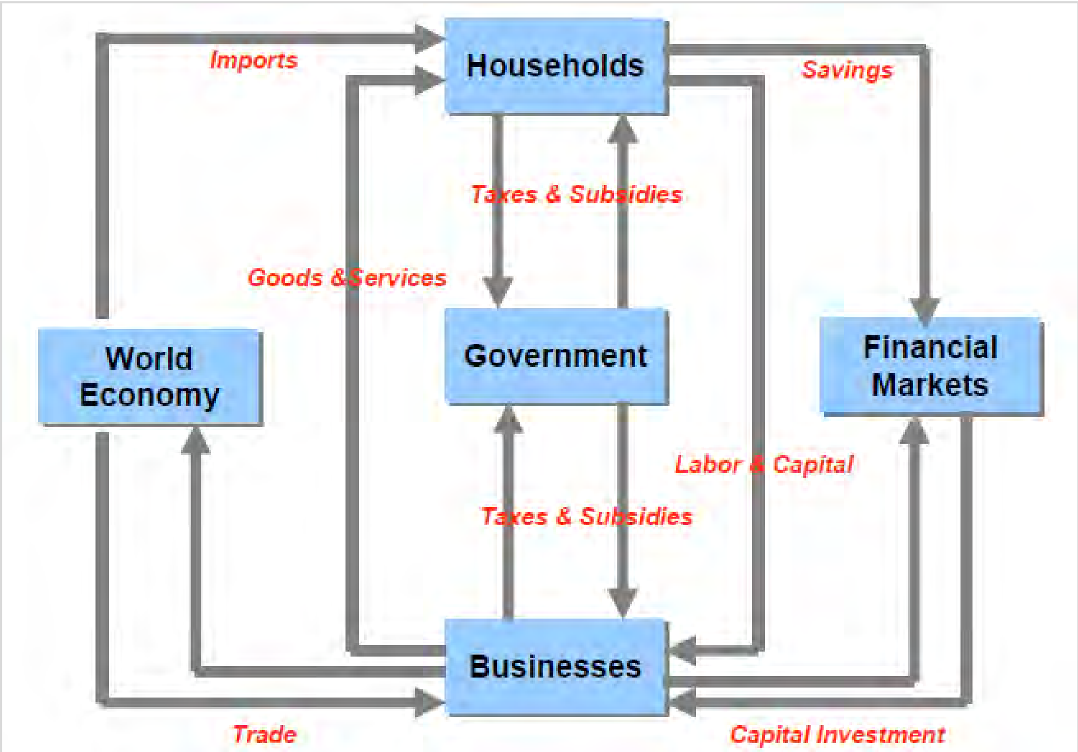
53 IMPLAN produces unique set of national structural matrices. The structural matrices form the bais for the inter-industry flows which we use to characterize the production, household, and government transactions, see www.implan.com.

3. Brief Discussion of Model Structure

The theoretical construct behind the N$_{ew}$ERA model is based on the circular flow of goods, services, and payments in the economy (every economic transaction has a buyer and a seller whereby goods/service go from a seller to a buyer and payment goes from the seller to the buyer). As shown in Figure 72, the model includes households, businesses, government, financial markets, and the rest of the world economy as they interact economically in the global economy. Households provide labor and capital to businesses, taxes to the government, and savings to financial markets, while also consuming goods and services and receiving government subsidies. Businesses produce goods and services, pay taxes to the government and use labor and capital. Businesses are both consumers and producers of capital for investment in the rest of the economy. Within the circular flow, equilibrium is found whereby goods and services consumed is equal to those produced and investments are optimized for the long term. Thus, supply is equal to demand in all markets.

The model assumes a perfect foresight, zero profit condition in production of goods and services, no changes in monetary policy, and full employment within the U.S. economy.

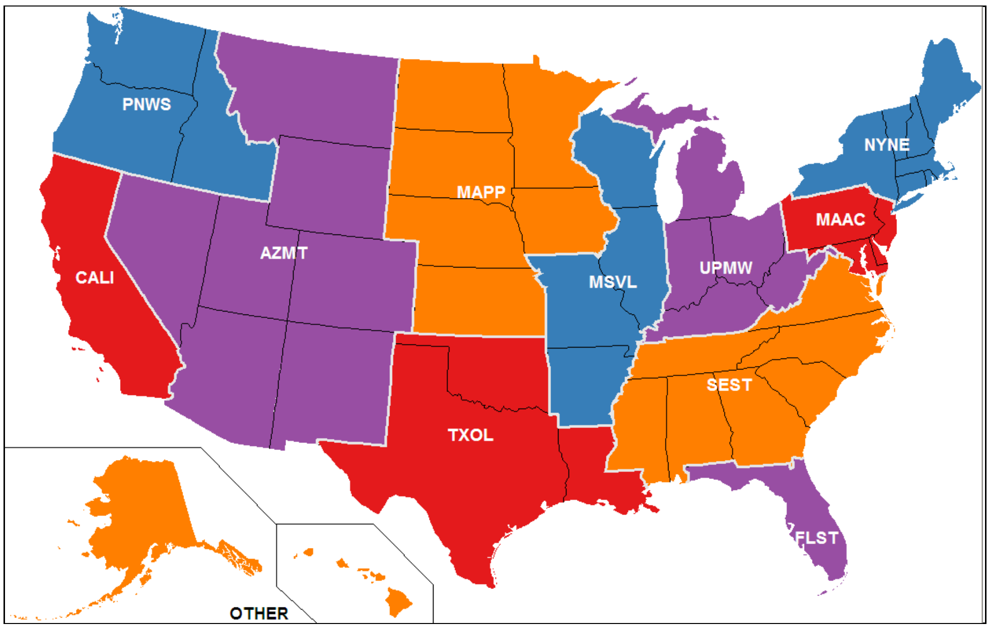
Figure 72: Circular Flow of Income



a. Regional Aggregation

The N_{ew}ERA macro model includes 11 regions: NYNE-New York and New England; MAAC-Mid-Atlantic Coast; UPMW-Upper Mid-West; SEST-South East; FLST-Florida; MSVL-Mississippi Valley; MAPP-Mid America; TXOL-Texas, Oklahoma, and Louisiana; AZMT-Arizona and Mountain states; CALI-California; and PNWS-Pacific Northwest.54 The aggregate model regions are built up from the 50 U.S. states' and the District of Columbia's economic data. The model is flexible enough to create other regional specifications, depending upon the need of the project. The 11 N_{ew}ERA regions and the States within each N_{ew}ERA region are shown in the following figure. For this Study we aggregate the 11 N_{ew}ERA regions into a single U.S. region.

Figure 73: N_{ew}ERA Macroeconomic Regions



b. Sectoral Aggregation

The N_{ew}ERA model includes 12 sectors: five energy (coal, natural gas, crude oil, electricity, and refined petroleum products) and seven non-energy sectors (services, manufacturing, energy-intensive, agriculture, commercial transportation excluding trucking, trucking, and motor vehicles). These sectors are aggregated up from the 440 IMPLAN sectors to 28 sectors, defined as the AEO sector in Figure 74. These 28 sectors' economic and energy data are consistent with IMPLAN and EIA, respectively. For this study, we further aggregate these 28 production sectors into 12 sectors. The mapping of the sectors is show below in Figure 72. The model has the flexibility to represent sectors at any level of aggregation.

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[54] Hawaii and Alaska are included in the PNWS region.

Figure 74: N$_{ew}$ERA Sectoral Representation

	NewERA	AEO	
Final Demand	C	C	Household consumption
	G	G	Government consumption
	I	I	Investment demand
Energy Sectors	COL	COL	Coal
	GAS	GAS	Natural gas
	OIL	OIL	Refined Petroleum Products
	CRU	CRU	Crude oil
	ELE	ELE	Electricity
Non-Energy Sectors	AGR	AGR	Agriculture
	TRN	TRN	Transportation
	TRK	TRK	Trucking
	M_V	M_V	Motor vehicle
	SRV	SRV	Services
	SRV	DWE	Dwellings
	EIS	PAP	Paper and Pulp
	EIS	CHM	Chemicals
	EIS	GLS	Glass Industry
	EIS	CMT	Cement Industry
	EIS	I_S	Primary Metals
	EIS	ALU	Alumina and Aluminum
	MAN	CNS	Construction
	MAN	MIN	Mining
	MAN	FOO	Food, Beverage and Tobacco Products
	MAN	FAB	Fabricated Metal Products
	MAN	MAC	Machinery
	MAN	CMP	Computer and Electronic Products
	MAN	TRQ	Transportation Equipment
	MAN	ELQ	Electrical Equip., Appliances, and Components
	MAN	WOO	Wood and furniture
	MAN	PLA	Plastics
	MAN	OMA	Other Manufacturing sectors

c. Production and Consumption Characterization

Behavior of households, industries, investment, and government is characterized by nested constant elasticity of substitution production or utility functions. Under such a CES structure, inputs substitute against each other in a nested form. The ease of substitutability is determined by the value of the elasticity of substitution between the inputs. The higher the value of the substitution elasticity between the inputs, the greater the possibility of tradeoffs.

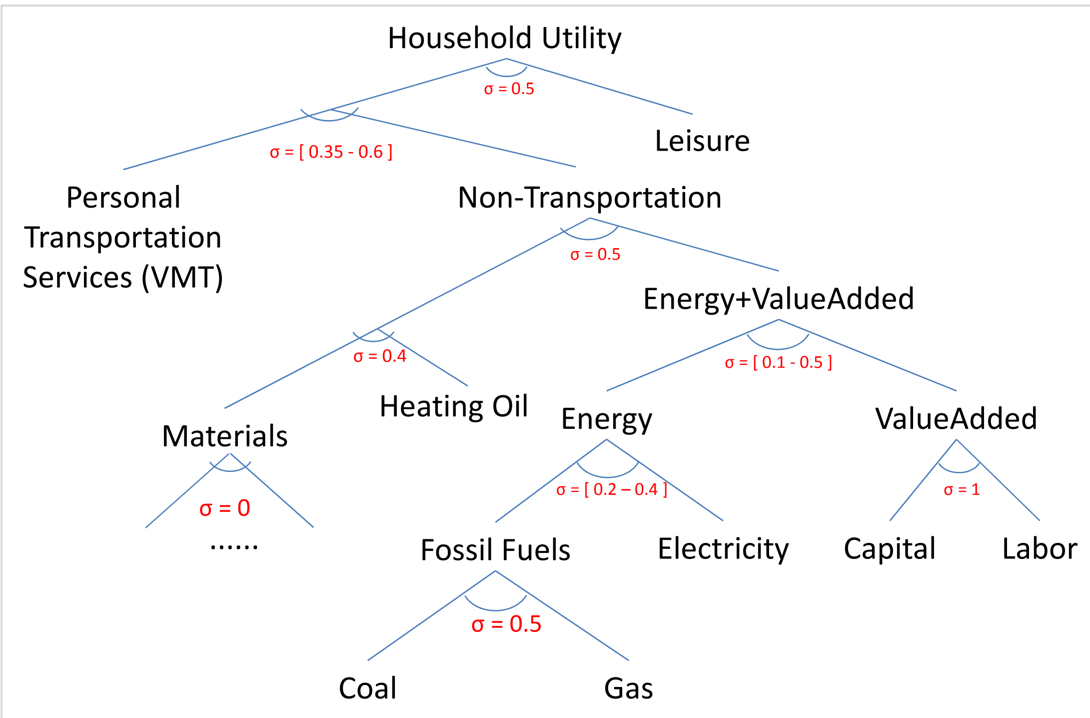
The CES nesting structure defines how inputs to a production activity compete with each other. In the generic production structure, intermediate inputs are aggregated in fixed proportion with a composite of energy and value-added inputs. The energy input aggregates fossil and non-fossil energy sources, and the value-added input combines capital and labor. Sectors with distinctive production characteristics are represented with structures different from the generic form. For alternative transportation fuels, such as ethanol and bio-diesel, inputs are demanded in fixed proportion. The characterization of nonrenewable resource supply adds a fixed resource that is calibrated to a declining resource base over time, so that it implies decreasing returns to scale.

This also implies rising marginal costs of production over time for exhaustible resources. The detailed nesting structure of the households and production sectors, with assumed elasticity of substitution parameters, are shown in figures below.

i. Households

Consumers are represented by a single representative household. The representative household derives utility from both consumption of goods and services, transportation services, and leisure. The utility is represented by a nested CES utility function. The elasticity of substitution parameters between goods are shown in Figure 75.

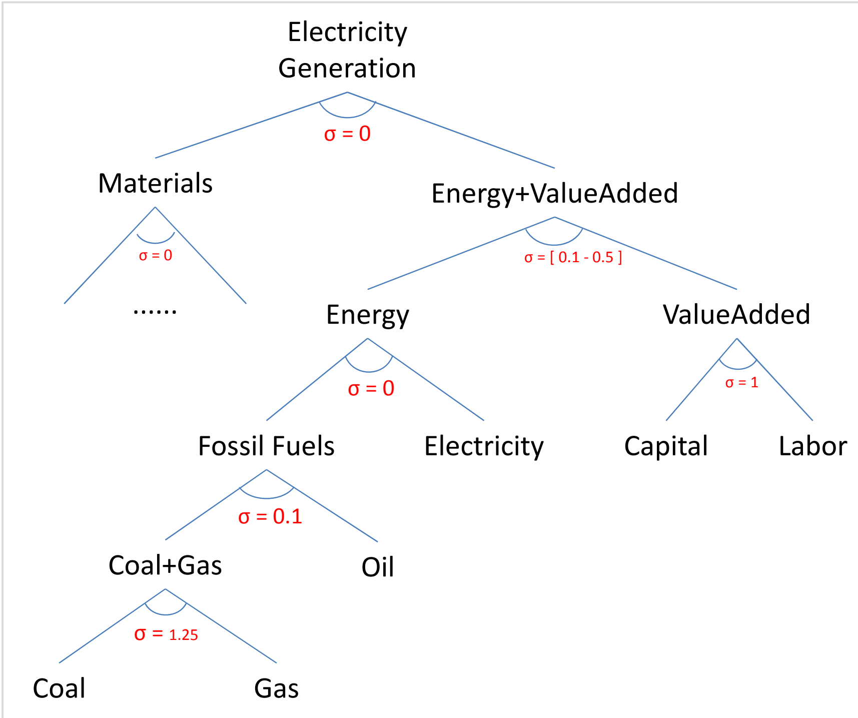
Figure 75: N$_{ew}$ERA Household Representation



ii. Electric Sector

We assume a simple representation of the electric sector. The electric sector models natural gas, coal, and oil-fired generation. The representation of the production is shown below.

Figure 76: N_{ew}ERA Electricity Sector Representation



iii. Other Sectors

The trucking and commercial transportation sector production structure is shown in Figure 77. The trucking sector uses diesel as transportation fuel. This sector has limited ability to substitute other fossil fuels. The other industrial sectors (agriculture, manufacturing, energy-intensive, motor vehicles) and the services sector production structure, with assumed elasticity of substitution, are shown in Figure 78.

Figure 77: N$_{ew}$ERA Trucking and Commercial Transportation Sector Representation

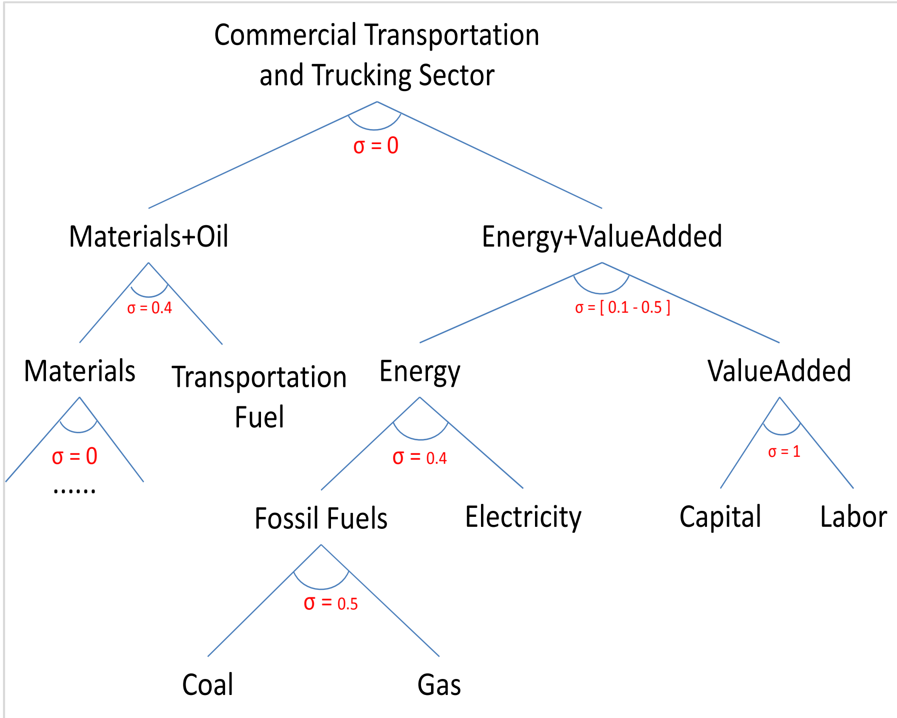
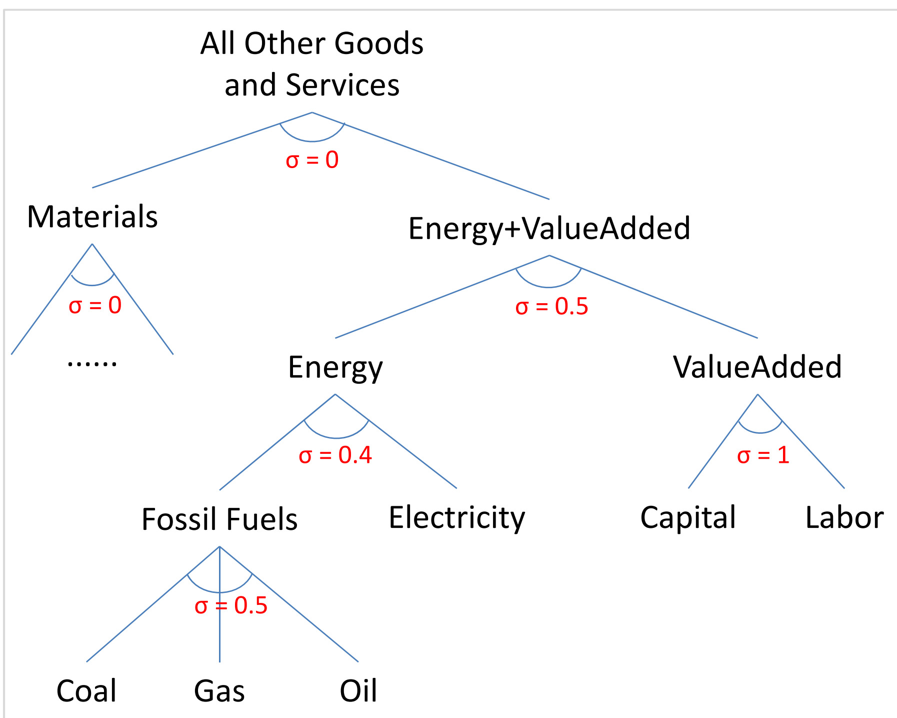


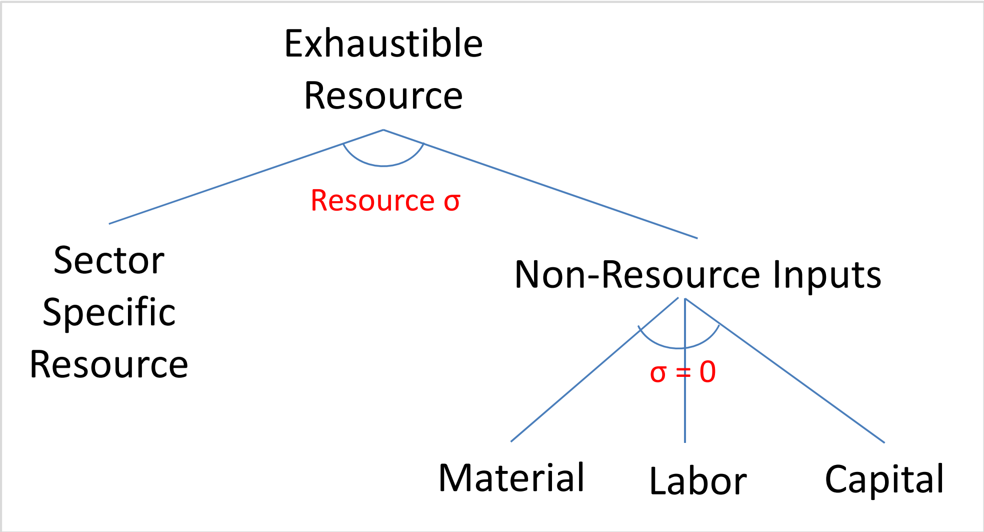
Figure 78: N$_{ew}$ERA Other Production Sector Representation



iv. Exhaustible Resource Sector

The simplest characterization of non-renewable resource supply adds a fixed resource that is calibrated to decline over time, so that the decreasing returns to scale implied for the non-resource inputs lead to rising marginal costs of production over time. The top level elasticity of substitution parameter is calibrated to be consistent with resource supply elasticity. We assume natural gas resource supply elasticity to be 0.25 in the short run (2010) and 1.5 in the long run (2050). Similarly, crude oil supply elasticity is assumed to be 0.3 in 2010 and 1.0 in 2050. Coal supply elasticity is assumed to be 0.4 in 2010 and 1.5 in 2050. The production structure of natural gas, crude oil, and coal is shown below.

Figure 79: N$_{ew}$ERA Resource Sector Representation



d. Trade Structure

All goods and services, except crude oil, are treated as Armington goods, which assumes that domestic and foreign goods are differentiated and thus, are imperfect substitutes. The level of imports depends upon the elasticity of substitution between the imported and domestic goods. The Armington elasticity among imported goods is assumed to be twice as large as the elasticity between domestic and aggregate imported goods, characterizing greater substitutability among imported goods.

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

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

e. Investment Dynamics

Periods in the model are linked by capital and investment dynamics. Capital turnover in the model is represented by the standard process that capital at time t+1 equals capital at time t plus investment at time t minus depreciation. The model optimizes consumption and savings decisions in each period, taking account of changes in the economy over the entire model horizon with perfect foresight. The consumers forego consumption to save for current and future investment.

f. Model Assumptions

The underlying assumptions of labor growth and initial capital stock drive the economy over time in the model.

The model assumes full employment in the labor market. This assumption means total labor demand in a policy scenario would be the same as the baseline labor projection. The baseline labor projections are based on population growth and labor productivity forecasts over time. Hence, the labor projection can be thought to be a forecast of efficient labor units. The model assumes that labor is fungible across sectors. That is, labor can move freely out of a production sector into another sector without any adjustment costs or loss of productivity. Capital, on the other hand, is vintaged in the model. We assume two types of capital stock to portray the current technology and more advanced technologies that develop over time. A non-malleable capital (the clay) is used in fixed proportion in the existing production activity. The clay portion of the capital decays over time as new capital replaces it. A malleable capital (the putty) is used in new production activity. The putty capital in the new production activity can substitute against other inputs. The replacement of the clay capital depends upon the extent of use of new capital. This gradual capital turnover of the fixed capital stock and costs associated with it is represented by the putty-clay formulation.

Energy intensities are calibrated to the EIA projections. The differentiated energy intensities across regions result in different responses in energy supply and demand as energy price changes.

The N_{ew}ERA macroeconomic model includes a simple tax representation. The model includes only two types of input taxes: marginal tax rates on capital and labor. The tax rates are based on the NBER TAXSIM model. Other indirect taxes such as excise and sales are included in the output values and not explicitly modeled.

The N_{ew}ERA macro model is solved through 2050, starting from 2010 in five-year time intervals.

g. Some Key Model Features

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

In addition, we assume that natural gas is a homogenous good, similar to crude oil price. Hence, if there was a no-export constraint on LNG exports, domestic natural gas price will converge with the world net-back price.

Consumption of electricity as a transportation fuel could also affect the natural gas market. The N_{ew}ERA model is able to simulate impacts on the supply and disposition of transportation fuels (petroleum-based, biofuels, and electricity), along with responses to the personal driving behavior of the consumer. The personal driving or personal transportation services in the model is represented by Vehicle Miles Traveled (“VMT”), which takes vehicles’ capital, transportation fuels, and other driving expenditures as inputs. The model chooses among changes in consumption of transportation fuels, changes in vehicle fuel efficiency, and changes in the overall level of travel in response to changes in the transportation fuel prices.

h. Advantages of the Macro Model Framework

The N_{ew}ERA model incorporates EIA energy quantities and energy prices into the IMPLAN Social Accounting Matrices. This in-house developed approach results in a balanced energy-economy dataset that has internally consistent energy benchmark data, as well as IMPLAN consistent economic values.

The macro model incorporates all production sectors and final demanders of the economy and is linked through terms of trade. The effects of policies are transmitted throughout the economy as all sectors and agents in the economy respond until the economy reaches equilibrium. The ability of the model to track these effects and substitution possibilities across sectors and regions makes it a unique tool for analyzing policies, such as those involving energy and environmental regulations. These general equilibrium substitution effects, however, are not fully captured in a partial equilibrium framework or within an input-output modeling framework. The smooth production and consumption functions employed in this general equilibrium model enable gradual substitution of inputs in response to relative price changes, thus, avoiding all or nothing solutions.

Business investment decisions are informed by future policies and outlook. The forward looking characteristic of the model enables businesses and consumers to determine the optimal savings and investment while anticipating future policies with perfect foresight. The alternative approach on savings and investment decisions is to assume agents in the model are myopic, thus, have no expectations for the future. Though both approaches are equally unrealistic to a certain extent, the latter approach can lead the model to produce inconsistent or incorrect impacts from an announced future policy.

The CGE modeling tool such as the N_{ew}ERA macro model can analyze scenarios or policies that call for large shocks outside historical observation. Econometric models are unsuitable for policies that impose large impacts because these models' production and consumption functions remain invariant under the policy. In addition, econometric models assume that the future path depends on the past experience and therefore fail to capture how the economy might respond under a different and new environment. For example, an econometric model cannot represent changes in fuel efficiency in response to increases in energy prices. However, the N_{ew}ERA macro model can consistently capture future policy changes that envisage having large effects.

The N_{ew}ERA macro model is also a unique tool that can iterate over sequential policies to generate consistent equilibrium solutions starting from an internally consistent equilibrium baseline forecast (such as the AEO reference case). This ability of the model is particularly helpful to decompose macroeconomic effects of individual policies. For example, if one desires to perform economic analysis of a policy that includes multiple regulations, the N_{ew}ERA modeling framework can be used as a tool to layer in one regulation at a time to determine the incremental effects of each policy.

i. Model Outputs

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

APPENDIX C – TABLES AND MODEL RESULTS

In this section, we present the numerical results from both the Global Natural Gas Model and the U.S. macroeconomic model ("N$_{ew}$ERA") for all the scenarios that were run as part of the study.

A. Global Natural Gas Model

We evaluated a total of 63 cases with all possible combinations of the following:

- Three domestic outlooks: Reference ("USREF"), High Shale EUR ("HEUR"), Low Shale EUR ("LEUR"),
- Three international outlooks: Reference ("INTREF"), Demand Shock ("D"), Supply/Demand Shock ("SD"), and
- Seven quota schedules: No-Export Capacity ("NX"), Low/Slowest ("LSS"), Low/Slow ('LS"), Low/Rapid ("LR"), High/Slow ("HS"), High/Rapid ("HR"), No-Export Constraint ("NC").

Out of the 45 cases where a quota is enforced, 21 are feasible (*i.e.*, projected U.S. LNG exports are at a level comparable to the quota allotted for each year), as shown in Figure 80. Detailed results for each case are shown in Figure 81 through Figure 143.

The U.S. Reference, International Reference, and the No-Export Capacity cases (Figure 81) are the ultimate baselines to which all other GNGM cases are compared. It assumes no U.S. and Canadian export capacities. After allowing for North American exports in the baseline scenario (Figure 87), our model determines that the U.S. does not export LNG, despite unlimited liquefaction capacities. Running the International Reference outlook with all three domestic outlooks, GNGM found that the U.S. is only able to export under the High Shale EUR scenario (Figure 87, Figure 108, and Figure 129). The projected level of exports is short of the high quotas specified by the EIA, even in the High Shale EUR case. We have thus developed two international shocks that favor U.S. LNG export.

The No-Export Constraint series shows the optimal amounts of U.S. exports under each domestic and international outlook as determined in GNGM. Since GNGM assumes a perfectly-competitive natural gas market, all quota rents are zero if the No-Export Constraint is in effect. A positive rent is collected, however, when the country supplies less than its perfectly-competitive volumes – Figure 105 is one example. When the number of export licenses available is greater than the optimal export level as determined by the natural gas market, the remaining licenses are unutilized and export rent drops to zero (Figure 93). The quota rent per MMBtu reaches the maximum under the High Shale EUR, Supply/Demand Shock, Low/Slowest quota scenario, where the conditions for U.S. exports are most favorable. However, the quota is highly restrictive (Figure 117). A high marginal price on an additional unit of export quota is thus generated.

Figure 80: Scenario Tree with Feasible Cases Highlighted

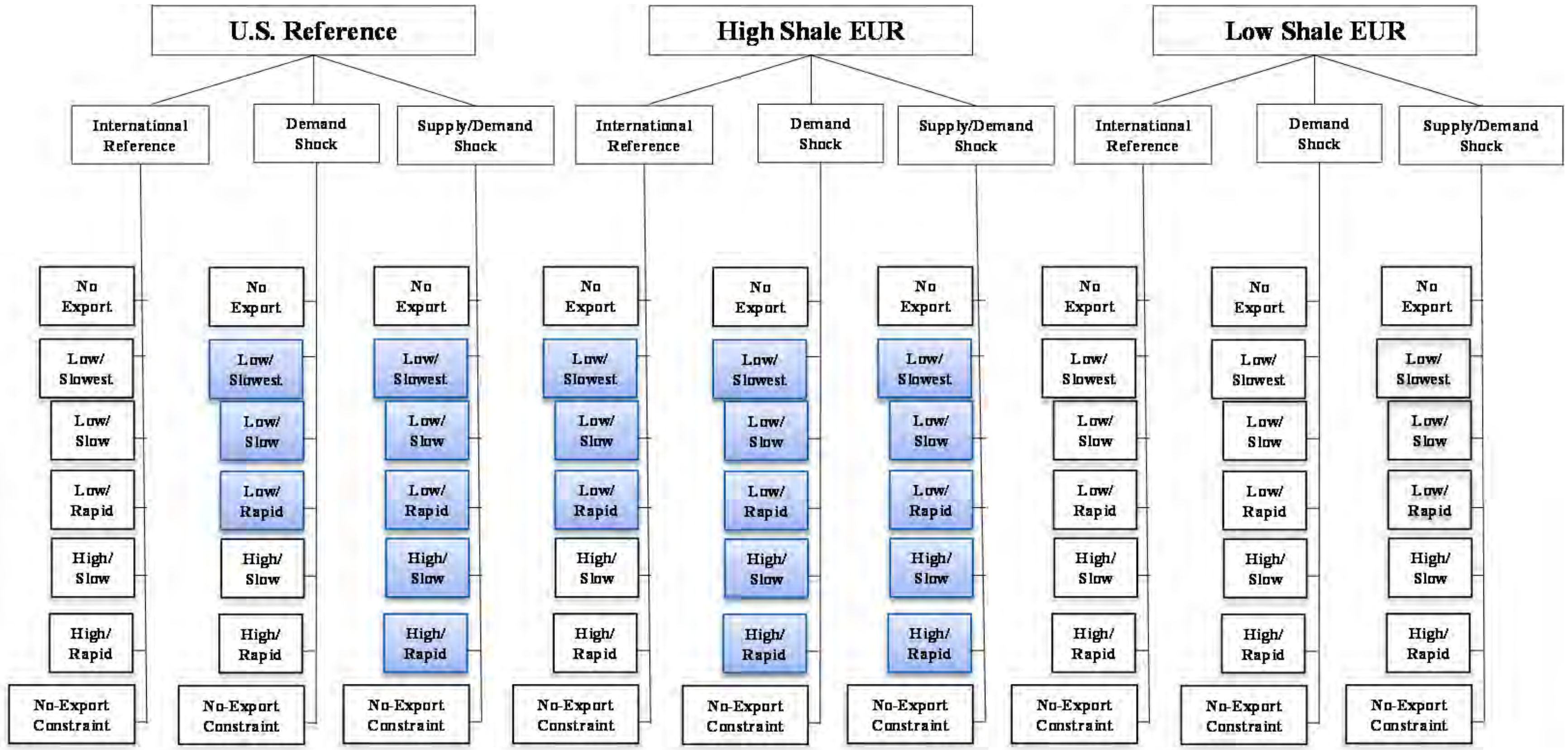


Figure 81: Detailed Results from Global Natural Gas Model, USREF_INTREF_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.09	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.10	22.39	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.23**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent (2010$/Mcf)	**-**	**$0.07**	**-**	**-**	**-**	**-**

Figure 82: Detailed Results from Global Natural Gas Model, USREF_INTREF_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$//Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$//Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 83: Detailed Results from Global Natural Gas Model, USREF_INTREF_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$//Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$//Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$//Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 84: Detailed Results from Global Natural Gas Model, USREF_INTREF_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$//Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 85: Detailed Results from Global Natural Gas Model, USREF_INTREF_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 86: Detailed Results from Global Natural Gas Model, USREF_INTREF_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 87: Detailed Results from Global Natural Gas Model, USREF_INTREF_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.10	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 88: Detailed Results from Global Natural Gas Model, USREF_D_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.09	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.39	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.23**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.85**	**$5.11**	**$6.23**	**$6.48**	**$7.18**
Quota Rent (2010$/Mcf)	**-**	**$0.62**	**$0.53**	**$0.81**	**$0.68**	**$0.77**

Figure 89: Detailed Results from Global Natural Gas Model, USREF_D_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.16**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.98	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.18	0.96	1.30	1.19	1.37
China/India	-	0.06	0.26	0.40	0.38	0.41
Europe	-	0.07	0.25	0.47	0.39	0.50
Korea/Japan	-	0.06	0.45	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.16**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.46	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.29**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.75**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**$0.46**	**-**	**-**	**-**	**-**

Figure 90: Detailed Results from Global Natural Gas Model, USREF_D_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.87	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	0.96	1.30	1.19	1.37
China/India	-	0.11	0.26	0.40	0.38	0.41
Europe	-	0.15	0.24	0.47	0.39	0.50
Korea/Japan	-	0.11	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.54	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**$0.35**	**-**	**-**	**-**	**-**

Figure 91: Detailed Results from Global Natural Gas Model, USREF_D_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.50	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.02	0.96	1.30	1.19	1.37
China/India	-	0.22	0.26	0.40	0.38	0.41
Europe	-	0.55	0.24	0.47	0.39	0.50
Korea/Japan	-	0.25	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.82	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 92: Detailed Results from Global Natural Gas Model, USREF_D_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.87	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	0.96	1.30	1.19	1.37
China/India	-	0.11	0.26	0.40	0.38	0.41
Europe	-	0.15	0.24	0.47	0.39	0.50
Korea/Japan	-	0.11	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.54	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**$0.35**	**-**	**-**	**-**	**-**

Figure 93: Detailed Results from Global Natural Gas Model, USREF_D_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.50	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.02	0.96	1.30	1.19	1.37
China/India	-	0.22	0.26	0.40	0.38	0.41
Europe	-	0.55	0.25	0.47	0.39	0.50
Korea/Japan	-	0.25	0.45	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.10	22.82	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 94: Detailed Results from Global Natural Gas Model, USREF_D_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.50	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.02	0.96	1.30	1.19	1.37
China/India	-	0.22	0.26	0.40	0.38	0.41
Europe	-	0.55	0.24	0.47	0.39	0.50
Korea/Japan	-	0.25	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.10	22.82	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 95: Detailed Results from Global Natural Gas Model, USREF_SD_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.09	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.39	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.23**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$5.83**	**$9.20**	**$10.04**	**$8.63**	**$9.33**
Quota Rent (2010$/Mcf)	**-**	**$1.60**	**$4.62**	**$4.61**	**$2.83**	**$2.92**

Figure 96: Detailed Results from Global Natural Gas Model, USREF_SD_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.16**	**25.83**	**26.21**	**27.25**	**27.97**
Domestic Demand	23.86	24.98	24.73	24.20	25.06	25.78
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	0.06	0.24	0.51	0.55	0.46
Europe	-	0.06	0.24	0.48	0.14	0.37
Korea/Japan	-	0.06	0.62	1.02	1.50	1.36
Total Supply (Tcf)	**23.86**	**25.16**	**25.83**	**26.21**	**27.25**	**27.97**
Domestic Production	21.1	22.46	23.93	25.11	26.45	27.87
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.29**	**$4.91**	**$5.99**	**$6.30**	**$6.82**
Netback Price (2010$/Mcf)	**-**	**$5.65**	**$6.29**	**$7.22**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$1.36**	**$1.38**	**$1.23**	**$1.20**	**$1.62**

Figure 97: Detailed Results from Global Natural Gas Model, USREF_SD_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Demand	23.86	24.87	24.19	24.13	25.06	25.78
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	0.11	0.33	0.54	0.55	0.46
Europe	-	0.13	0.35	0.51	0.14	0.37
Korea/Japan	-	0.13	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**25.24**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Production	21.1	22.54	24.48	25.22	26.45	27.87
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$5.25**	**$6.04**	**$6.30**	**$6.82**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$1.24**	**$0.52**	**$1.11**	**$1.20**	**$1.62**

Figure 98: Detailed Results from Global Natural Gas Model, USREF_SD_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.56**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Demand	23.86	24.46	24.19	24.13	25.06	25.78
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	0.26	0.33	0.54	0.55	0.46
Europe	-	0.43	0.35	0.51	0.14	0.37
Korea/Japan	-	0.40	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**25.56**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Production	21.1	22.86	24.48	25.22	26.45	27.87
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.61**	**$5.25**	**$6.04**	**$6.30**	**$6.82**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$0.74**	**$0.52**	**$1.11**	**$1.20**	**$1.62**

Figure 99: Detailed Results from Global Natural Gas Model, USREF_SD_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**26.38**	**27.32**	**28.65**	**29.50**
Domestic Demand	23.86	24.87	24.19	23.39	24.27	25.12
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	2.19	3.93	4.38	4.38
China/India	-	0.11	0.33	0.83	0.93	0.75
Europe	-	0.13	0.35	0.77	0.27	0.59
Korea/Japan	-	0.13	1.51	2.34	3.17	3.03
Total Supply (Tcf)	**23.86**	**25.24**	**26.38**	**27.32**	**28.65**	**29.50**
Domestic Production	21.1	22.54	24.48	26.22	27.85	29.40
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$5.25**	**$6.57**	**$6.82**	**$7.24**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$6.57**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$1.24**	**$0.52**	**-**	**$0.08**	**$0.67**

Figure 100: Detailed Results from Global Natural Gas Model, USREF_SD_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.56**	**26.75**	**27.32**	**28.65**	**29.50**
Domestic Demand	23.86	24.46	23.83	23.39	24.27	25.12
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.10	2.92	3.93	4.38	4.38
China/India	-	0.26	0.46	0.83	0.93	0.75
Europe	-	0.43	0.74	0.77	0.27	0.59
Korea/Japan	-	0.40	1.72	2.34	3.17	3.03
Total Supply (Tcf)	**23.86**	**25.56**	**26.75**	**27.32**	**28.65**	**29.50**
Domestic Production	21.10	22.86	24.85	26.22	27.85	29.40
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.61**	**$5.49**	**$6.57**	**$6.82**	**$7.24**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$5.49**	**$6.57**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$0.74**	**-**	**-**	**$0.08**	**$0.67**

Figure 101: Detailed Results from Global Natural Gas Model, USREF_SD_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.02**	**26.75**	**27.32**	**28.76**	**30.47**
Domestic Demand	23.86	23.85	23.83	23.39	24.21	24.73
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	2.17	2.92	3.93	4.54	5.75
China/India	-	0.39	0.39	0.83	0.97	1.04
Europe	-	0.99	0.41	0.77	0.29	0.74
Korea/Japan	-	0.80	2.12	2.34	3.28	3.97
Total Supply (Tcf)	**23.86**	**26.02**	**26.75**	**27.32**	**28.76**	**30.47**
Domestic Production	21.10	23.32	24.85	26.22	27.96	30.37
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$5.02**	**$5.49**	**$6.57**	**$6.86**	**$7.50**
Netback Price (2010$/Mcf)	**-**	**$5.02**	**$5.49**	**$6.57**	**$6.86**	**$7.50**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 102: Detailed Results from Global Natural Gas Model, HEUR_INTREF_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Demand	23.86	26.98	27.66	27.82	28.60	29.71
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Production	21.1	24.60	26.29	27.45	28.62	30.33
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.27**	**$3.43**	**$4.03**	**$4.47**	**$4.88**
Netback Price (2010$/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent (2010$/Mcf)	**-**	**$1.03**	**$1.02**	**$1.21**	**$0.91**	**$0.92**

Figure 103: Detailed Results from Global Natural Gas Model, HEUR_INTREF_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Demand	23.86	26.88	27.13	26.98	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	-	0.11	0.65	0.74	0.69
Europe	-	0.18	0.99	1.02	1.30	1.35
Korea/Japan	-	-	0.00	0.34	0.14	0.15
Total Supply (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Production	21.1	24.68	26.86	28.62	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.49	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.01	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.31**	**$3.66**	**$4.41**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.24**	**$4.23**	**$4.94**	**$5.00**	**$5.48**
Quota Rent (2010$/Mcf)	**-**	**$0.93**	**$0.57**	**$0.53**	**$0.18**	**$0.32**

Figure 104: Detailed Results from Global Natural Gas Model, HEUR_INTREF_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.78	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	-	0.38	0.70	0.74	0.69
Europe	-	0.37	1.71	1.12	1.30	1.35
Korea/Japan	-	-	0.10	0.37	0.14	0.15
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	24.77	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.41	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.09	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.21**	**$4.13**	**$4.92**	**$5.00**	**$5.48**
Quota Rent (2010$/Mcf)	**-**	**$0.85**	**$0.24**	**$0.48**	**$0.18**	**$0.32**

Figure 105: Detailed Results from Global Natural Gas Model, HEUR_INTREF_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.37	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	-	0.38	0.70	0.74	0.69
Europe	-	1.10	1.71	1.12	1.30	1.35
Korea/Japan	-	-	0.10	0.37	0.14	0.15
Total Supply (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.10	25.09	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.41	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.09	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.08**	**$4.13**	**$4.92**	**$5.00**	**$5.48**
Quota Rent (2010$/Mcf)	**-**	**$0.53**	**$0.24**	**$0.48**	**$0.18**	**$0.32**

Figure 106: Detailed Results from Global Natural Gas Model, HEUR_INTREF_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**30.04**	**30.56**	**32.75**
Domestic Demand	23.86	26.78	26.61	26.26	27.60	28.69
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	3.77	2.78	3.38
China/India	-	-	0.38	1.06	0.89	1.01
Europe	-	0.37	1.71	1.99	1.73	2.22
Korea/Japan	-	-	0.10	0.72	0.16	0.16
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**30.04**	**30.56**	**32.75**
Domestic Production	21.1	24.77	27.43	29.67	30.40	32.69
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.41	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.09	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.76**	**$4.91**	**$5.31**
Netback Price (2010$/Mcf)	**-**	**$4.21**	**$4.13**	**$4.76**	**$4.91**	**$5.31**
Quota Rent (2010$/Mcf)	**-**	**$0.85**	**$0.24**	**-**	**-**	**-**

Figure 107: Detailed Results from Global Natural Gas Model, HEUR_INTREF_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Demand	23.86	26.37	26.24	26.26	27.60	28.69
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.97	3.77	2.78	3.38
China/India	-	-	0.72	1.06	0.89	1.01
Europe	-	1.10	1.96	1.99	1.73	2.22
Korea/Japan	-	-	0.28	0.72	0.16	0.16
Total Supply (Tcf)	**23.86**	**27.47**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Production	21.1	25.09	27.84	29.67	30.40	32.69
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.35	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.15	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Netback Price (2010$/Mcf)	**-**	**$4.08**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Quota Rent (2010$/Mcf)	**-**	**$0.53**	**-**	**-**	**-**	**-**

Figure 108: Detailed Results from Global Natural Gas Model, HEUR_INTREF_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.98**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Demand	23.86	25.76	26.24	26.26	27.60	28.69
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	2.23	2.97	3.77	2.78	3.38
China/India	-	0.08	0.71	1.06	0.89	1.01
Europe	-	2.14	1.99	1.99	1.73	2.22
Korea/Japan	-	0.00	0.27	0.72	0.16	0.16
Total Supply (Tcf)	**23.86**	**27.98**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Production	21.10	25.60	27.84	29.67	30.40	32.69
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.35	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.15	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.86**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Netback Price (2010$/Mcf)	**-**	**$3.86**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 109: Detailed Results from Global Natural Gas Model, HEUR_D_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Demand	23.86	26.98	27.66	27.82	28.60	29.71
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Production	21.1	24.60	26.29	27.45	28.62	30.33
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.00	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.27**	**$3.43**	**$4.03**	**$4.47**	**$4.88**
Netback Price (2010$/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent (2010$/Mcf)	**-**	**$1.58**	**$1.67**	**$2.20**	**$2.01**	**$2.30**

Figure 110: Detailed Results from Global Natural Gas Model, HEUR_D_LSS

	EIA Ref	NERA Projections				
	2010	**2015**	**2020**	**2025**	**2030**	**2035**
Total Demand (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Demand	23.86	26.88	27.13	26.98	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	0.06	0.28	0.59	0.68	0.63
Europe	-	0.07	0.28	0.75	0.72	0.84
Korea/Japan	-	0.06	0.54	0.67	0.79	0.72
Total Supply (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Production	21.1	24.68	26.86	28.62	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.31**	**$3.66**	**$4.41**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.75**	**$4.80**	**$5.55**	**$5.61**	**$6.31**
Quota Rent (2010$/Mcf)	**-**	**$1.44**	**$1.15**	**$1.15**	**$0.80**	**$1.15**

Figure 111: Detailed Results from Global Natural Gas Model, HEUR_D_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.78	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	0.11	0.47	0.64	0.68	0.63
Europe	-	0.15	0.63	0.81	0.72	0.84
Korea/Japan	-	0.11	1.10	0.73	0.79	0.72
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	24.77	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.60**	**$5.51**	**$5.61**	**$6.31**
Quota Rent (2010$/Mcf)	**-**	**$1.35**	**$0.71**	**$1.07**	**$0.80**	**$1.15**

Figure 112: Detailed Results from Global Natural Gas Model, HEUR_D_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.37	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	0.23	0.47	0.64	0.68	0.63
Europe	-	0.61	0.63	0.81	0.72	0.84
Korea/Japan	-	0.26	1.10	0.73	0.79	0.72
Total Supply (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	25.09	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.56**	**$4.60**	**$5.51**	**$5.61**	**$6.31**
Quota Rent (2010$/Mcf)	**-**	**$1.01**	**$0.71**	**$1.07**	**$0.80**	**$1.15**

Figure 113: Detailed Results from Global Natural Gas Model, HEUR_D_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Demand	23.86	26.78	26.61	26.16	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	4.02	4.38	4.38
China/India	-	0.11	0.47	1.08	1.28	1.18
Europe	-	0.15	0.63	1.54	1.61	1.67
Korea/Japan	-	0.11	1.10	1.41	1.49	1.52
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Production	21.1	24.77	27.43	29.81	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.01	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.35	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.81**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.60**	**$5.08**	**$5.24**	**$5.77**
Quota Rent (2010$/Mcf)	**-**	**$1.35**	**$0.71**	**$0.27**	**$0.07**	**$0.33**

Figure 114: Detailed Results from Global Natural Gas Model, HEUR_D_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**29.73**	**30.40**	**31.61**	**33.46**
Domestic Demand	23.86	26.37	25.79	26.02	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	3.94	4.38	4.38	4.38
China/India	-	0.23	0.71	1.13	1.28	1.18
Europe	-	0.61	1.57	1.69	1.61	1.67
Korea/Japan	-	0.26	1.66	1.56	1.49	1.52
Total Supply (Tcf)	**23.86**	**27.47**	**29.73**	**30.40**	**31.61**	**33.46**
Domestic Production	21.1	25.09	28.36	30.03	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.00	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$4.30**	**$4.89**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$4.56**	**$4.30**	**$5.04**	**$5.24**	**$5.77**
Quota Rent (2010$/Mcf)	**-**	**$1.01**	**-**	**$0.15**	**$0.07**	**$0.33**

Figure 115: Detailed Results from Global Natural Gas Model, HEUR_D_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**28.47**	**29.73**	**30.69**	**31.75**	**34.35**
Domestic Demand	23.86	25.18	25.79	25.83	26.98	28.06
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	3.30	3.94	4.87	4.59	5.61
China/India	-	0.43	0.70	1.20	1.33	1.52
Europe	-	2.30	1.79	1.88	1.71	2.19
Korea/Japan	-	0.58	1.45	1.79	1.55	1.90
Total Supply (Tcf)	**23.86**	**28.47**	**29.73**	**30.69**	**31.75**	**34.35**
Domestic Production	21.10	26.09	28.36	30.32	31.59	34.29
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.50	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.18**	**$4.30**	**$4.99**	**$5.21**	**$5.60**
Netback Price (2010$/Mcf)	**-**	**$4.18**	**$4.30**	**$4.99**	**$5.21**	**$5.60**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 116: Detailed Results from Global Natural Gas Model, HEUR_SD_NX

	EIA Ref	NERA Projections				
	2010	**2015**	**2020**	**2025**	**2030**	**2035**
Total Demand (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Demand	23.86	26.98	27.66	27.82	28.60	29.71
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Production	21.1	24.60	26.29	27.45	28.62	30.33
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.27**	**$3.43**	**$4.03**	**$4.47**	**$4.88**
Netback Price (2010$/Mcf)	**-**	**$5.83**	**$9.20**	**$10.04**	**$8.63**	**$9.33**
Quota Rent (2010$/Mcf)	**-**	**$2.56**	**$5.77**	**$6.01**	**$4.16**	**$4.45**

Figure 117: Detailed Results from Global Natural Gas Model, HEUR_SD_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Demand	23.86	26.88	27.13	26.98	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	0.06	0.23	0.51	0.55	0.46
Europe	-	0.06	0.24	0.48	0.14	0.37
Korea/Japan	-	0.06	0.63	1.02	1.50	1.36
Total Supply (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Production	21.10	24.68	26.86	28.62	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.31**	**$3.66**	**$4.41**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$5.65**	**$6.29**	**$7.22**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$2.34**	**$2.63**	**$2.81**	**$2.69**	**$3.28**

Figure 118: Detailed Results from Global Natural Gas Model, HEUR_SD_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.78	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	0.11	0.33	0.54	0.55	0.46
Europe	-	0.13	0.35	0.51	0.14	0.37
Korea/Japan	-	0.13	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	24.77	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$2.23**	**$1.88**	**$2.71**	**$2.69**	**$3.28**

Figure 119: Detailed Results from Global Natural Gas Model, HEUR_SD_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.37	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	0.26	0.33	0.54	0.55	0.46
Europe	-	0.43	0.35	0.51	0.14	0.37
Korea/Japan	-	0.40	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	25.09	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$1.80**	**$1.88**	**$2.71**	**$2.69**	**$3.28**

Figure 120: Detailed Results from Global Natural Gas Model, HEUR_SD_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Demand	23.86	26.78	26.61	26.16	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	4.02	4.38	4.38
China/India	-	0.11	0.33	0.84	0.93	0.75
Europe	-	0.13	0.35	0.78	0.27	0.59
Korea/Japan	-	0.13	1.51	2.39	3.17	3.03
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Production	21.1	24.77	27.43	29.81	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.81**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$6.54**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$2.23**	**$1.88**	**$1.73**	**$1.73**	**$2.47**

Figure 121: Detailed Results from Global Natural Gas Model, HEUR_SD_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**29.97**	**30.40**	**31.61**	**33.46**
Domestic Demand	23.86	26.37	25.59	26.02	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	4.38	4.38	4.38	4.38
China/India	-	0.26	0.55	0.91	0.93	0.75
Europe	-	0.43	0.65	0.83	0.27	0.59
Korea/Japan	-	0.40	3.18	2.63	3.17	3.03
Total Supply (Tcf)	**23.86**	**27.47**	**29.97**	**30.40**	**31.61**	**33.46**
Domestic Production	21.1	25.09	28.60	30.03	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$4.41**	**$4.89**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$4.93**	**$6.41**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$1.80**	**$0.52**	**$1.53**	**$1.73**	**$2.47**

Figure 122: Detailed Results from Global Natural Gas Model, HEUR_SD_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**28.91**	**30.54**	**31.84**	**33.29**	**36.38**
Domestic Demand	23.86	24.68	25.10	25.11	26.22	27.31
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	4.23	5.44	6.72	6.89	8.39
China/India	-	0.51	0.69	1.60	1.75	2.00
Europe	-	2.23	1.04	1.09	0.57	1.18
Korea/Japan	-	1.49	3.71	4.03	4.57	5.21
Total Supply (Tcf)	**23.86**	**28.91**	**30.54**	**31.84**	**33.29**	**36.38**
Domestic Production	21.10	26.53	29.17	31.47	33.13	36.32
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.00	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.47**	**$4.68**	**$5.40**	**$5.61**	**$5.97**
Netback Price (2010$/Mcf)	**-**	**$4.47**	**$4.68**	**$5.40**	**$5.61**	**$5.97**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 123: Detailed Results from Global Natural Gas Model, LEUR_INTREF_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 124: Detailed Results from Global Natural Gas Model, LEUR_INTREF_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 125: Detailed Results from Global Natural Gas Model, LEUR_INTREF_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 126: Detailed Results from Global Natural Gas Model, LEUR_INTREF_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 127: Detailed Results from Global Natural Gas Model, LEUR_INTREF_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 128: Detailed Results from Global Natural Gas Model, LEUR_INTREF_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 129: Detailed Results from Global Natural Gas Model, LEUR_INTREF_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 130: Detailed Results from Global Natural Gas Model, LEUR_D_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 131: Detailed Results from Global Natural Gas Model, LEUR_D_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 132: Detailed Results from Global Natural Gas Model, LEUR_D_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 133: Detailed Results from Global Natural Gas Model, LEUR_D_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 134: Detailed Results from Global Natural Gas Model, LEUR_D_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 135: Detailed Results from Global Natural Gas Model, LEUR_D_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 136: Detailed Results from Global Natural Gas Model, LEUR_D_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 137: Detailed Results from Global Natural Gas Model, LEUR_SD_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$5.83**	**$9.20**	**$10.04**	**$8.63**	**$9.33**
Quota Rent ($2010/Mcf)	**-**	**-**	**$2.70**	**$2.47**	**$0.66**	**$0.63**

Figure 138: Detailed Results from Global Natural Gas Model, LEUR_SD_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 139: Detailed Results from Global Natural Gas Model, LEUR_SD_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 140: Detailed Results from Global Natural Gas Model, LEUR_SD_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 141: Detailed Results from Global Natural Gas Model, LEUR_SD_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 142: Detailed Results from Global Natural Gas Model, LEUR_SD_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 143: Detailed Results from Global Natural Gas Model, LEUR_SD_NC

	EIA Ref	NERA Projections				
	2010	**2015**	**2020**	**2025**	**2030**	**2035**
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

B. N$_{ew}$ERA Model Results

The following figures (Figure 144 through Figure 164) contain detailed macroeconomic outputs for all modeled baselines, scenarios, and sensitivities. For each figure, the “Level Values” section depicts the numerical results from the scenario or baseline, and the “Percentage Change” section shows the percentage change in the Level Values for a given scenario relative to its baseline case. Figure 144 through Figure 162 contain detailed results for the scenarios. Figure 163 through Figure 164 contain results for the sensitivity tests. All tables use the following acronyms defined in the following list:

AGR – agriculture sector
COL – coal sector
CRU – crude oil sector
EIS – energy-intensive sector
ELE – electricity sector
GAS – natural gas sector
M_V – motor vehicle manufacturing sector
MAN – other manufacturing sector
OIL – refining sector
SRV – commercial sector
TRK – commercial trucking sector
TRN – other commercial transportation sector
C – household sector
G – government sector

Figure 144: Detailed Results for U.S. Reference Baseline Case

Reference Baseline Case (USREF)								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,883	$17,862	$20,277	$22,880	$25,756
	Consumption		Billion 2010$	$12,404	$13,969	$15,972	$18,153	$20,521
	Investment		Billion 2010$	$2,467	$2,791	$3,161	$3,517	$3,977
Natural Gas	Wellhead Price		2010$ per Mcf	$4.29	$4.65	$5.49	$5.89	$6.50
	Production		Tcf	22.42	23.44	24.04	25.21	26.58
	Exports		Tcf	-	-	-	-	-
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	25.03	25.28	25.09	25.97	26.76
	Sectoral Demand	AGR	Tcf	0.16	0.16	0.16	0.16	0.17
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.35	3.27	3.16	3.08
		ELE	Tcf	6.94	6.82	6.65	7.35	7.93
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.18	0.18
		MAN	Tcf	4.23	4.32	4.34	4.41	4.54
		OIL	Tcf	1.32	1.41	1.36	1.40	1.38
		SRV	Tcf	2.44	2.53	2.58	2.67	2.79
		TRK	Tcf	0.47	0.48	0.49	0.53	0.56
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.80	4.84	4.84	4.84	4.82
		G	Tcf	0.93	0.96	0.99	1.02	1.06
	Export Revenues [1]		Billion 2010$	$0.00	$0.00	$0.00	$0.00	$0.00
Percentage Change								
Macro	Gross Domestic Product		%					
	Gross Capital Income		%					
	Gross Labor Income		%					
	Gross Resource Income		%					
	Consumption		%					
	Investment		%					
Natural Gas	Wellhead Price		%					
	Production		%					
	Pipeline Imports		%					
	Total Demand		%					
	Sectoral Demand	AGR	%					
		COL	%					
		CRU	%					
		EIS	%					
		ELE	%					
		GAS	%					
		M_V	%					
		MAN	%					
		OIL	%					
		SRV	%					
		TRK	%					
		TRN	%					
		C	%					
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 145: Detailed Results for High Shale EUR Baseline Case

High Shale EUR Baseline Case (HEUR)								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,960	$17,964	$20,411	$23,002	$25,902
	Consumption		Billion 2010$	$12,429	$13,999	$16,013	$18,184	$20,565
	Investment		Billion 2010$	$2,483	$2,811	$3,177	$3,532	$3,995
Natural Gas	Wellhead Price		2010$ per Mcf	$3.35	$3.50	$4.09	$4.53	$4.92
	Production		Tcf	24.69	26.46	27.72	28.70	29.73
	Exports		Tcf	-	-	-	-	-
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.96	27.73	27.97	28.84	29.86
	Sectoral Demand	AGR	Tcf	0.16	0.16	0.16	0.17	0.17
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.47	3.58	3.55	3.48	3.39
		ELE	Tcf	8.27	8.38	8.35	8.90	9.69
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.20	0.19	0.19	0.20
		MAN	Tcf	4.44	4.64	4.75	4.87	5.01
		OIL	Tcf	1.32	1.40	1.37	1.44	1.40
		SRV	Tcf	2.53	2.65	2.75	2.85	2.97
		TRK	Tcf	0.48	0.51	0.55	0.60	0.65
		TRN	Tcf	0.23	0.24	0.26	0.28	0.30
		C	Tcf	4.89	4.96	5.00	4.99	4.95
		G	Tcf	0.97	1.01	1.05	1.09	1.13
	Export Revenues 1		Billion 2010$	$0.00	$0.00	$0.00	$0.00	$0.00
Percentage Change								
Macro	Gross Domestic Product		%					
	Gross Capital Income		%					
	Gross Labor Income		%					
	Gross Resource Income		%					
	Consumption		%					
	Investment		%					
Natural Gas	Wellhead Price		%					
	Production		%					
	Pipeline Imports		%					
	Total Demand		%					
	Sectoral Demand	AGR	%					
		COL	%					
		CRU	%					
		EIS	%					
		ELE	%					
		GAS	%					
		M_V	%					
		MAN	%					
		OIL	%					
		SRV	%					
		TRK	%					
		TRN	%					
		C	%					
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 146: Detailed Results for Low Shale EUR Baseline Case

Low Shale EUR Baseline Case (LEUR)								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,790	$17,716	$20,061	$22,693	$25,567
	Consumption		Billion 2010$	$12,379	$13,920	$15,862	$18,093	$20,476
	Investment		Billion 2010$	$2,442	$2,759	$3,138	$3,493	$3,953
Natural Gas	Wellhead Price		2010$ per Mcf	$5.73	$6.45	$7.83	$8.33	$8.96
	Production		Tcf	19.60	19.88	20.04	21.13	21.70
	Exports		Tcf	-	-	-	-	-
	Pipeline Imports		Tcf	3.00	2.61	2.37	2.01	1.75
	Total Demand		Tcf	22.60	22.50	22.41	23.14	23.45
	Sectoral Demand	AGR	Tcf	0.16	0.16	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.18	3.15	3.02	2.86	2.76
		ELE	Tcf	5.23	5.00	5.16	5.91	6.12
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.16	0.16
		MAN	Tcf	3.99	3.99	3.92	3.95	4.00
		OIL	Tcf	1.32	1.41	1.39	1.36	1.39
		SRV	Tcf	2.32	2.37	2.38	2.45	2.55
		TRK	Tcf	0.45	0.46	0.47	0.49	0.51
		TRN	Tcf	0.21	0.21	0.22	0.23	0.24
		C	Tcf	4.68	4.68	4.64	4.63	4.59
		G	Tcf	0.89	0.90	0.91	0.94	0.97
	Export Revenues 1		Billion 2010$	$0.00	$0.00	$0.00	$0.00	$0.00
Percentage Change								
Macro	Gross Domestic Product		%					
	Gross Capital Income		%					
	Gross Labor Income		%					
	Gross Resource Income		%					
	Consumption		%					
	Investment		%					
Natural Gas	Wellhead Price		%					
	Production		%					
	Pipeline Imports		%					
	Total Demand		%					
	Sectoral Demand	AGR	%					
		COL	%					
		CRU	%					
		EIS	%					
		ELE	%					
		GAS	%					
		M_V	%					
		MAN	%					
		OIL	%					
		SRV	%					
		TRK	%					
		TRN	%					
		C	%					
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 147: Detailed Results for USREF_D_LSS

Scenario: USREF_D_LSS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,884	$17,868	$20,281	$22,883	$25,759
	Consumption		Billion 2010$	$12,408	$13,971	$15,972	$18,152	$20,520
	Investment		Billion 2010$	$2,468	$2,790	$3,160	$3,518	$3,978
Natural Gas	Wellhead Price		2010$ per Mcf	$4.34	$4.92	$5.82	$6.13	$6.75
	Production		Tcf	22.49	23.84	24.80	25.87	27.40
	Exports		Tcf	0.18	0.98	1.43	1.19	1.37
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.92	24.71	24.41	25.44	26.20
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.30	3.24	3.16	3.09	3.00
		ELE	Tcf	6.91	6.65	6.45	7.18	7.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.17	0.18
		MAN	Tcf	4.21	4.20	4.20	4.31	4.43
		OIL	Tcf	1.31	1.37	1.32	1.37	1.35
		SRV	Tcf	2.43	2.48	2.53	2.63	2.74
		TRK	Tcf	0.47	0.47	0.49	0.52	0.55
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.79	4.77	4.76	4.77	4.75
		G	Tcf	0.93	0.95	0.96	1.00	1.04
	Export Revenues [1]		Billion 2010$	$0.72	$4.47	$7.72	$6.76	$8.58
Percentage Change								
Macro	Gross Domestic Product		%	0.01	0.03	0.02	0.01	0.01
	Gross Capital Income		%	(0.01)	(0.07)	(0.08)	(0.06)	(0.05)
	Gross Labor Income		%	(0.01)	(0.05)	(0.07)	(0.05)	(0.04)
	Gross Resource Income		%	2.37	8.70	7.64	4.95	4.62
	Consumption		%	0.03	0.01	(0.00)	(0.00)	(0.00)
	Investment		%	0.05	(0.02)	(0.06)	0.03	0.04
Natural Gas	Wellhead Price		%	1.17	5.75	5.93	4.12	3.88
	Production		%	0.32	1.73	3.15	2.63	3.07
	Pipeline Imports		%					
	Total Demand		%	(0.43)	(2.28)	(2.68)	(2.03)	(2.07)
	Sectoral Demand	AGR	%	(0.66)	(3.11)	(3.44)	(2.51)	(2.46)
		COL	%					
		CRU	%					
		EIS	%	(0.65)	(3.07)	(3.41)	(2.50)	(2.45)
		ELE	%	(0.43)	(2.46)	(3.00)	(2.34)	(2.43)
		GAS	%					
		M_V	%	(0.42)	(2.23)	(2.70)	(2.06)	(2.10)
		MAN	%	(0.58)	(2.83)	(3.18)	(2.33)	(2.30)
		OIL	%	(0.59)	(2.89)	(3.21)	(2.34)	(2.30)
		SRV	%	(0.28)	(1.61)	(2.02)	(1.56)	(1.61)
		TRK	%	(0.17)	(1.03)	(1.45)	(1.16)	(1.26)
		TRN	%	(0.18)	(1.06)	(1.49)	(1.20)	(1.29)
		C	%	(0.23)	(1.38)	(1.76)	(1.36)	(1.42)

1 Export revenues are based on LNG exports net of liquefaction loss.

Figure 148: Detailed Results for USREF_D_LS

Scenario: USREF_D_LS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,886	$17,867	$20,281	$22,883	$25,759
	Consumption		Billion 2010$	$12,408	$13,970	$15,972	$18,152	$20,520
	Investment		Billion 2010$	$2,467	$2,791	$3,160	$3,518	$3,978
Natural Gas	Wellhead Price		2010$ per Mcf	$4.40	$4.92	$5.82	$6.13	$6.75
	Production		Tcf	22.56	23.84	24.80	25.87	27.40
	Exports		Tcf	0.37	0.98	1.43	1.19	1.37
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.81	24.71	24.41	25.44	26.20
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.28	3.24	3.16	3.09	3.00
		ELE	Tcf	6.88	6.65	6.45	7.18	7.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.17	0.18
		MAN	Tcf	4.18	4.20	4.20	4.31	4.43
		OIL	Tcf	1.30	1.37	1.32	1.37	1.35
		SRV	Tcf	2.42	2.48	2.53	2.63	2.74
		TRK	Tcf	0.47	0.47	0.49	0.52	0.55
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.77	4.77	4.76	4.77	4.75
		G	Tcf	0.92	0.95	0.96	1.00	1.04
	Export Revenues [1]		Billion 2010$	$1.51	$4.47	$7.72	$6.76	$8.58
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.03	0.02	0.01	0.01
	Gross Capital Income		%	(0.03)	(0.07)	(0.08)	(0.06)	(0.05)
	Gross Labor Income		%	(0.02)	(0.05)	(0.07)	(0.05)	(0.04)
	Gross Resource Income		%	5.00	8.68	7.64	4.95	4.62
	Consumption		%	0.03	0.01	(0.00)	(0.00)	(0.00)
	Investment		%	0.01	(0.00)	(0.05)	0.03	0.04
Natural Gas	Wellhead Price		%	2.44	5.75	5.93	4.12	3.88
	Production		%	0.65	1.72	3.15	2.63	3.07
	Pipeline Imports		%					
	Total Demand		%	(0.90)	(2.28)	(2.69)	(2.03)	(2.07)
	Sectoral Demand	AGR	%	(1.34)	(3.12)	(3.44)	(2.51)	(2.46)
		COL	%					
		CRU	%					
		EIS	%	(1.31)	(3.07)	(3.41)	(2.50)	(2.45)
		ELE	%	(0.91)	(2.46)	(3.00)	(2.34)	(2.43)
		GAS	%					
		M_V	%	(0.85)	(2.23)	(2.70)	(2.06)	(2.10)
		MAN	%	(1.19)	(2.83)	(3.18)	(2.33)	(2.30)
		OIL	%	(1.21)	(2.89)	(3.21)	(2.34)	(2.30)
		SRV	%	(0.59)	(1.61)	(2.02)	(1.56)	(1.61)
		TRK	%	(0.35)	(1.03)	(1.45)	(1.17)	(1.26)
		TRN	%	(0.36)	(1.07)	(1.49)	(1.20)	(1.29)
		C	%	(0.50)	(1.38)	(1.76)	(1.36)	(1.42)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 149: Detailed Results for USREF_D_LR

Scenario: USREF_D_LR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,890	$17,866	$20,280	$22,882	$25,758
	Consumption		Billion 2010$	$12,408	$13,970	$15,972	$18,153	$20,521
	Investment		Billion 2010$	$2,464	$2,792	$3,160	$3,518	$3,978
Natural Gas	Wellhead Price		2010$ per Mcf	$4.60	$4.92	$5.82	$6.13	$6.75
	Production		Tcf	22.81	23.84	24.80	25.87	27.40
	Exports		Tcf	1.02	0.98	1.43	1.19	1.37
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.40	24.71	24.41	25.44	26.20
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.21	3.24	3.16	3.09	3.00
		ELE	Tcf	6.77	6.65	6.45	7.18	7.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.18	0.17	0.17	0.18
		MAN	Tcf	4.09	4.20	4.20	4.31	4.43
		OIL	Tcf	1.27	1.37	1.32	1.37	1.35
		SRV	Tcf	2.40	2.48	2.53	2.63	2.74
		TRK	Tcf	0.47	0.47	0.49	0.52	0.55
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.73	4.77	4.76	4.77	4.75
		G	Tcf	0.91	0.95	0.96	1.00	1.04
	Export Revenues [1]		Billion 2010$	$4.35	$4.47	$7.72	$6.76	$8.58
Percentage Change								
Macro	Gross Domestic Product		%	0.04	0.03	0.02	0.01	0.01
	Gross Capital Income		%	(0.09)	(0.08)	(0.09)	(0.06)	(0.05)
	Gross Labor Income		%	(0.07)	(0.06)	(0.07)	(0.05)	(0.04)
	Gross Resource Income		%	14.69	8.61	7.62	4.94	4.62
	Consumption		%	0.03	0.00	(0.00)	0.00	0.00
	Investment		%	(0.12)	0.04	(0.05)	0.03	0.04
Natural Gas	Wellhead Price		%	7.13	5.74	5.93	4.12	3.88
	Production		%	1.73	1.72	3.14	2.62	3.07
	Pipeline Imports		%					
	Total Demand		%	(2.52)	(2.28)	(2.69)	(2.03)	(2.07)
	Sectoral Demand	AGR	%	(3.72)	(3.13)	(3.45)	(2.52)	(2.46)
		COL	%					
		CRU	%					
		EIS	%	(3.62)	(3.09)	(3.42)	(2.51)	(2.46)
		ELE	%	(2.57)	(2.46)	(3.00)	(2.34)	(2.43)
		GAS	%					
		M_V	%	(2.37)	(2.24)	(2.70)	(2.07)	(2.10)
		MAN	%	(3.30)	(2.83)	(3.18)	(2.34)	(2.31)
		OIL	%	(3.42)	(2.89)	(3.21)	(2.34)	(2.30)
		SRV	%	(1.70)	(1.61)	(2.02)	(1.56)	(1.61)
		TRK	%	(0.99)	(1.04)	(1.45)	(1.17)	(1.26)
		TRN	%	(1.01)	(1.08)	(1.49)	(1.20)	(1.30)
		C	%	(1.46)	(1.38)	(1.76)	(1.35)	(1.42)

[1] Export revenues are based on LNG exports net of liquefaction loss.

Figure 150: Detailed Results for USREF_SD_LS

Scenario: USREF_SD_LS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,886	$17,876	$20,283	$22,885	$25,759
	Consumption		Billion 2010$	$12,411	$13,970	$15,971	$18,152	$20,520
	Investment		Billion 2010$	$2,469	$2,787	$3,161	$3,517	$3,977
Natural Gas	Wellhead Price		2010$ per Mcf	$4.40	$5.30	$6.01	$6.35	$6.92
	Production		Tcf	22.56	24.30	25.18	26.41	27.88
	Exports		Tcf	0.37	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.81	23.95	24.04	24.98	25.86
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.28	3.11	3.10	3.02	2.95
		ELE	Tcf	6.88	6.43	6.34	7.03	7.62
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.17	0.16	0.17	0.18
		MAN	Tcf	4.18	4.04	4.12	4.22	4.37
		OIL	Tcf	1.30	1.32	1.29	1.34	1.33
		SRV	Tcf	2.42	2.43	2.50	2.59	2.71
		TRK	Tcf	0.47	0.47	0.48	0.51	0.55
		TRN	Tcf	0.22	0.22	0.22	0.24	0.25
		C	Tcf	4.78	4.68	4.71	4.72	4.71
		G	Tcf	0.92	0.92	0.95	0.99	1.03
	Export Revenues [1]		Billion 2010$	$1.51	$10.76	$12.21	$12.90	$14.04
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.08	0.03	0.02	0.01
	Gross Capital Income		%	(0.02)	(0.17)	(0.14)	(0.11)	(0.09)
	Gross Labor Income		%	(0.02)	(0.13)	(0.11)	(0.09)	(0.08)
	Gross Resource Income		%	4.97	21.48	12.23	9.64	7.64
	Consumption		%	0.05	0.01	(0.01)	(0.01)	(0.00)
	Investment		%	0.09	(0.15)	(0.01)	0.01	0.01
Natural Gas	Wellhead Price		%	2.44	14.04	9.45	7.92	6.37
	Production		%	0.65	3.67	4.75	4.77	4.87
	Pipeline Imports		%					
	Total Demand		%	(0.90)	(5.26)	(4.18)	(3.80)	(3.35)
	Sectoral Demand	AGR	%	(1.37)	(7.14)	(5.35)	(4.68)	(3.97)
		COL	%					
		CRU	%					
		EIS	%	(1.35)	(7.03)	(5.31)	(4.65)	(3.96)
		ELE	%	(0.90)	(5.67)	(4.66)	(4.36)	(3.91)
		GAS	%					
		M_V	%	(0.88)	(5.15)	(4.19)	(3.86)	(3.40)
		MAN	%	(1.21)	(6.51)	(4.92)	(4.35)	(3.73)
		OIL	%	(1.21)	(6.64)	(4.98)	(4.36)	(3.71)
		SRV	%	(0.59)	(3.76)	(3.16)	(2.92)	(2.61)
		TRK	%	(0.35)	(2.42)	(2.27)	(2.19)	(2.05)
		TRN	%	(0.38)	(2.49)	(2.34)	(2.26)	(2.10)
		C	%	(0.47)	(3.24)	(2.76)	(2.55)	(2.30)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 151: Detailed Results for USREF_SD_LR

Scenario: USREF_SD_LR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,891	$17,874	$20,282	$22,885	$25,758
	Consumption		Billion 2010$	$12,411	$13,970	$15,971	$18,152	$20,521
	Investment		Billion 2010$	$2,465	$2,788	$3,161	$3,517	$3,977
Natural Gas	Wellhead Price		2010$ per Mcf	$4.62	$5.30	$6.01	$6.35	$6.92
	Production		Tcf	22.83	24.30	25.18	26.41	27.88
	Exports		Tcf	1.10	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.35	23.95	24.04	24.98	25.86
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.19	3.11	3.10	3.02	2.95
		ELE	Tcf	6.75	6.43	6.34	7.03	7.62
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.17	0.18
		MAN	Tcf	4.08	4.04	4.12	4.22	4.37
		OIL	Tcf	1.27	1.32	1.29	1.34	1.33
		SRV	Tcf	2.39	2.43	2.50	2.59	2.71
		TRK	Tcf	0.46	0.47	0.48	0.51	0.55
		TRN	Tcf	0.22	0.22	0.22	0.24	0.25
		C	Tcf	4.72	4.68	4.71	4.72	4.71
		G	Tcf	0.91	0.92	0.95	0.99	1.03
	Export Revenues [1]		Billion 2010$	$4.72	$10.76	$12.21	$12.90	$14.04
Percentage Change								
Macro	Gross Domestic Product		%	0.05	0.07	0.03	0.02	0.01
	Gross Capital Income		%	(0.09)	(0.18)	(0.14)	(0.12)	(0.09)
	Gross Labor Income		%	(0.08)	(0.14)	(0.11)	(0.09)	(0.08)
	Gross Resource Income		%	15.94	21.40	12.22	9.63	7.64
	Consumption		%	0.05	0.00	(0.01)	(0.00)	0.00
	Investment		%	(0.05)	(0.10)	(0.01)	0.01	0.01
Natural Gas	Wellhead Price		%	7.73	14.03	9.44	7.92	6.37
	Production		%	1.86	3.67	4.75	4.77	4.87
	Pipeline Imports		%					
	Total Demand		%	(2.73)	(5.26)	(4.18)	(3.80)	(3.35)
	Sectoral Demand	AGR	%	(4.04)	(7.15)	(5.36)	(4.68)	(3.98)
		COL	%					
		CRU	%					
		EIS	%	(3.94)	(7.05)	(5.32)	(4.66)	(3.97)
		ELE	%	(2.77)	(5.67)	(4.66)	(4.36)	(3.91)
		GAS	%					
		M_V	%	(2.58)	(5.15)	(4.20)	(3.86)	(3.40)
		MAN	%	(3.59)	(6.50)	(4.93)	(4.36)	(3.73)
		OIL	%	(3.69)	(6.64)	(4.98)	(4.36)	(3.71)
		SRV	%	(1.83)	(3.77)	(3.16)	(2.92)	(2.61)
		TRK	%	(1.07)	(2.43)	(2.27)	(2.20)	(2.05)
		TRN	%	(1.10)	(2.50)	(2.34)	(2.26)	(2.11)
		C	%	(1.55)	(3.25)	(2.76)	(2.55)	(2.29)

[1] Export revenues are based on LNG exports net of liquefaction loss.

Figure 152: Detailed Results for USREF_SD_HS

Scenario: USREF_SD_HS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,886	$17,878	$20,294	$22,893	$25,763
	Consumption		Billion 2010$	$12,413	$13,976	$15,973	$18,150	$20,518
	Investment		Billion 2010$	$2,469	$2,792	$3,158	$3,515	$3,975
Natural Gas	Wellhead Price		2010$ per Mcf	$4.40	$5.30	$6.52	$6.92	$7.40
	Production		Tcf	22.56	24.30	26.03	27.55	29.13
	Exports		Tcf	0.37	2.19	3.93	4.38	4.38
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.80	23.95	23.15	23.93	24.93
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.28	3.11	2.95	2.86	2.83
		ELE	Tcf	6.88	6.44	6.08	6.69	7.30
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.17	0.16	0.16	0.17
		MAN	Tcf	4.18	4.04	3.94	4.01	4.19
		OIL	Tcf	1.30	1.32	1.24	1.28	1.28
		SRV	Tcf	2.42	2.43	2.43	2.51	2.64
		TRK	Tcf	0.47	0.47	0.47	0.50	0.53
		TRN	Tcf	0.22	0.22	0.22	0.23	0.25
		C	Tcf	4.78	4.68	4.59	4.58	4.59
		G	Tcf	0.92	0.92	0.92	0.95	1.00
	Export Revenues [1]		Billion 2010$	$1.51	$10.76	$23.75	$28.08	$30.03
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.09	0.08	0.06	0.03
	Gross Capital Income		%	(0.02)	(0.16)	(0.24)	(0.24)	(0.20)
	Gross Labor Income		%	(0.02)	(0.12)	(0.19)	(0.19)	(0.16)
	Gross Resource Income		%	4.89	21.45	24.76	21.89	16.93
	Consumption		%	0.07	0.05	0.00	(0.02)	(0.01)
	Investment		%	0.11	0.03	(0.11)	(0.05)	(0.05)
Natural Gas	Wellhead Price		%	2.42	14.04	18.65	17.49	13.75
	Production		%	0.65	3.67	8.28	9.30	9.59
	Pipeline Imports		%					
	Total Demand		%	(0.90)	(5.26)	(7.73)	(7.84)	(6.84)
	Sectoral Demand	AGR	%	(1.41)	(7.17)	(9.83)	(9.58)	(8.08)
		COL	%					
		CRU	%					
		EIS	%	(1.39)	(7.08)	(9.73)	(9.52)	(8.05)
		ELE	%	(0.89)	(5.66)	(8.61)	(8.97)	(7.97)
		GAS	%					
		M_V	%	(0.89)	(5.17)	(7.76)	(7.94)	(6.95)
		MAN	%	(1.22)	(6.52)	(9.09)	(8.95)	(7.60)
		OIL	%	(1.21)	(6.64)	(9.17)	(8.97)	(7.56)
		SRV	%	(0.58)	(3.75)	(5.91)	(6.09)	(5.38)
		TRK	%	(0.36)	(2.42)	(4.26)	(4.61)	(4.25)
		TRN	%	(0.40)	(2.50)	(4.37)	(4.72)	(4.36)
		C	%	(0.45)	(3.21)	(5.18)	(5.36)	(4.76)

1 Export revenues are based on LNG exports net of liquefaction loss.

Figure 153: Detailed Results for USREF_SD_HR

Scenario: USREF_SD_HR								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,891	$17,882	$20,292	$22,893	$25,762
	Consumption		Billion 2010$	$12,415	$13,974	$15,972	$18,151	$20,519
	Investment		Billion 2010$	$2,467	$2,789	$3,160	$3,516	$3,975
Natural Gas	Wellhead Price		2010$ per Mcf	$4.62	$5.57	$6.52	$6.91	$7.40
	Production		Tcf	22.83	24.55	26.03	27.55	29.13
	Exports		Tcf	1.10	2.92	3.93	4.38	4.38
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.35	23.48	23.15	23.93	24.93
	Sectoral Demand	AGR	Tcf	0.15	0.14	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.19	3.03	2.95	2.86	2.83
		ELE	Tcf	6.75	6.30	6.08	6.69	7.30
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.16	0.17
		MAN	Tcf	4.08	3.94	3.94	4.01	4.19
		OIL	Tcf	1.27	1.29	1.24	1.28	1.28
		SRV	Tcf	2.39	2.40	2.43	2.51	2.64
		TRK	Tcf	0.46	0.46	0.47	0.50	0.53
		TRN	Tcf	0.22	0.22	0.22	0.23	0.25
		C	Tcf	4.73	4.63	4.59	4.58	4.59
		G	Tcf	0.91	0.91	0.92	0.95	1.00
	Export Revenues [1]		Billion 2010$	$4.71	$15.07	$23.75	$28.08	$30.03
Percentage Change								
Macro	Gross Domestic Product		%	0.05	0.11	0.07	0.05	0.03
	Gross Capital Income		%	(0.09)	(0.24)	(0.25)	(0.24)	(0.20)
	Gross Labor Income		%	(0.07)	(0.19)	(0.20)	(0.19)	(0.16)
	Gross Resource Income		%	15.86	30.34	24.68	21.87	16.92
	Consumption		%	0.09	0.03	0.00	(0.01)	(0.01)
	Investment		%	0.01	(0.07)	(0.06)	(0.04)	(0.04)
Natural Gas	Wellhead Price		%	7.71	19.75	18.64	17.48	13.75
	Production		%	1.86	4.75	8.28	9.29	9.59
	Pipeline Imports		%					
	Total Demand		%	(2.73)	(7.15)	(7.73)	(7.84)	(6.84)
	Sectoral Demand	AGR	%	(4.09)	(9.69)	(9.85)	(9.59)	(8.09)
		COL	%					
		CRU	%					
		EIS	%	(3.99)	(9.55)	(9.76)	(9.53)	(8.06)
		ELE	%	(2.76)	(7.69)	(8.61)	(8.97)	(7.97)
		GAS	%					
		M_V	%	(2.60)	(7.00)	(7.76)	(7.95)	(6.95)
		MAN	%	(3.61)	(8.81)	(9.09)	(8.95)	(7.60)
		OIL	%	(3.69)	(8.99)	(9.18)	(8.97)	(7.56)
		SRV	%	(1.82)	(5.15)	(5.91)	(6.09)	(5.38)
		TRK	%	(1.08)	(3.34)	(4.27)	(4.61)	(4.26)
		TRN	%	(1.13)	(3.44)	(4.39)	(4.73)	(4.37)
		C	%	(1.52)	(4.43)	(5.18)	(5.35)	(4.76)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 154: Detailed Results for USREF_SD_NC

Scenario: USREF_SD_NC								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,900	$17,880	$20,292	$22,896	$25,773
	Consumption		Billion 2010$	$12,415	$13,973	$15,973	$18,153	$20,520
	Investment		Billion 2010$	$2,461	$2,791	$3,161	$3,520	$3,980
Natural Gas	Wellhead Price		2010$ per Mcf	$5.01	$5.57	$6.52	$6.96	$7.73
	Production		Tcf	23.19	24.55	26.03	27.63	29.90
	Exports		Tcf	2.17	2.92	3.93	4.54	5.75
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	23.64	23.47	23.15	23.85	24.33
	Sectoral Demand	AGR	Tcf	0.14	0.14	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.06	3.03	2.95	2.85	2.75
		ELE	Tcf	6.55	6.30	6.08	6.67	7.09
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.16	0.17
		MAN	Tcf	3.93	3.94	3.94	4.00	4.08
		OIL	Tcf	1.22	1.29	1.24	1.27	1.25
		SRV	Tcf	2.34	2.40	2.43	2.50	2.59
		TRK	Tcf	0.46	0.46	0.47	0.50	0.53
		TRN	Tcf	0.21	0.22	0.22	0.23	0.24
		C	Tcf	4.64	4.63	4.59	4.57	4.51
		G	Tcf	0.89	0.91	0.92	0.95	0.98
	Export Revenues [1]		Billion 2010$	$10.08	$15.06	$23.75	$29.29	$41.23
Percentage Change								
Macro	Gross Domestic Product		%	0.11	0.10	0.07	0.07	0.07
	Gross Capital Income		%	(0.20)	(0.25)	(0.25)	(0.24)	(0.24)
	Gross Labor Income		%	(0.17)	(0.19)	(0.20)	(0.19)	(0.20)
	Gross Resource Income		%	34.72	30.19	24.65	22.89	23.81
	Consumption		%	0.09	0.03	0.01	0.00	(0.00)
	Investment		%	(0.21)	0.02	(0.01)	0.10	0.09
Natural Gas	Wellhead Price		%	16.69	19.72	18.63	18.26	18.97
	Production		%	3.46	4.74	8.27	9.62	12.48
	Pipeline Imports		%					
	Total Demand		%	0.00	0.00	0.00	(0.00)	0.00
	Sectoral Demand	AGR	%	(5.57)	(7.15)	(7.74)	(8.14)	(9.09)
		COL	%	(8.17)	(9.71)	(9.86)	(9.96)	(10.69)
		CRU	%					
		EIS	%					
		ELE	%	(7.97)	(9.59)	(9.78)	(9.91)	(10.65)
		GAS	%	(5.64)	(7.69)	(8.61)	(9.31)	(10.56)
		M_V	%					
		MAN	%	(5.24)	(7.00)	(7.76)	(8.24)	(9.19)
		OIL	%	(7.25)	(8.81)	(9.09)	(9.29)	(10.06)
		SRV	%	(7.48)	(8.99)	(9.18)	(9.31)	(10.04)
		TRK	%	(3.78)	(5.15)	(5.91)	(6.33)	(7.19)
		TRN	%	(2.22)	(3.35)	(4.27)	(4.79)	(5.69)
		C	%	(2.28)	(3.47)	(4.40)	(4.92)	(5.83)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 155: Detailed Results for HEUR_D_NC

Scenario: HEUR_D_NC								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$16,000	$18,002	$20,442	$23,023	$25,929
	Consumption		Billion 2010$	$12,441	$14,000	$16,012	$18,184	$20,565
	Investment		Billion 2010$	$2,475	$2,812	$3,176	$3,537	$4,001
Natural Gas	Wellhead Price		2010$ per Mcf	$4.31	$4.46	$5.04	$5.25	$5.82
	Production		Tcf	25.66	27.83	30.04	31.24	32.82
	Exports		Tcf	3.30	3.94	4.87	4.59	5.61
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	24.63	25.16	25.42	26.79	27.35
	Sectoral Demand	AGR	Tcf	0.14	0.14	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.04	3.13	3.14	3.18	3.05
		ELE	Tcf	7.54	7.54	7.50	8.17	8.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.18	0.17	0.18	0.18
		MAN	Tcf	3.93	4.10	4.23	4.47	4.53
		OIL	Tcf	1.16	1.23	1.22	1.32	1.27
		SRV	Tcf	2.39	2.48	2.57	2.70	2.78
		TRK	Tcf	0.47	0.49	0.52	0.57	0.62
		TRN	Tcf	0.22	0.23	0.24	0.27	0.29
		C	Tcf	4.65	4.70	4.71	4.77	4.68
		G	Tcf	0.90	0.94	0.97	1.02	1.05
	Export Revenues [1]		Billion 2010$	$13.18	$16.30	$22.77	$22.33	$30.25
Percentage Change								
Macro	Gross Domestic Product		%	0.25	0.21	0.15	0.09	0.10
	Gross Capital Income		%	(0.31)	(0.32)	(0.29)	(0.20)	(0.21)
	Gross Labor Income		%	(0.24)	(0.23)	(0.22)	(0.15)	(0.16)
	Gross Resource Income		%	63.40	45.34	33.90	21.40	24.37
	Consumption		%	0.10	0.01	(0.01)	0.00	0.00
	Investment		%	(0.31)	0.06	(0.03)	0.14	0.15
Natural Gas	Wellhead Price		%	28.73	27.46	23.37	15.80	18.15
	Production		%	3.93	5.19	8.38	8.85	10.41
	Pipeline Imports		%					
	Total Demand		%	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
	Sectoral Demand	AGR	%	(8.64)	(9.26)	(9.10)	(7.11)	(8.42)
		COL	%	(12.74)	(12.66)	(11.72)	(8.79)	(10.02)
		CRU	%					
		EIS	%					
		ELE	%	(12.44)	(12.52)	(11.63)	(8.77)	(9.99)
		GAS	%	(8.80)	(9.99)	(10.17)	(8.15)	(9.86)
		M_V	%					
		MAN	%	(8.20)	(9.14)	(9.19)	(7.25)	(8.53)
		OIL	%	(11.47)	(11.61)	(10.89)	(8.22)	(9.45)
		SRV	%	(11.88)	(11.91)	(11.04)	(8.26)	(9.48)
		TRK	%	(5.65)	(6.35)	(6.61)	(5.27)	(6.32)
		TRN	%	(3.18)	(3.96)	(4.57)	(3.88)	(4.78)
		C	%	(3.24)	(4.10)	(4.70)	(4.00)	(4.91)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 156: Detailed Results for HEUR_SD_LSS

Scenario: HEUR_SD_LSS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,963	$17,974	$20,423	$23,011	$25,909
	Consumption		Billion 2010$	$12,433	$14,001	$16,013	$18,182	$20,563
	Investment		Billion 2010$	$2,484	$2,812	$3,176	$3,531	$3,995
Natural Gas	Wellhead Price		2010$ per Mcf	$3.39	$3.72	$4.43	$4.84	$5.23
	Production		Tcf	24.76	26.89	28.73	29.95	30.97
	Exports		Tcf	0.18	1.10	2.01	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.84	27.06	26.98	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.45	3.46	3.39	3.34	3.26
		ELE	Tcf	8.23	8.16	8.02	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.18	0.18	0.19
		MAN	Tcf	4.41	4.49	4.55	4.68	4.83
		OIL	Tcf	1.31	1.36	1.31	1.38	1.35
		SRV	Tcf	2.53	2.61	2.68	2.78	2.90
		TRK	Tcf	0.48	0.51	0.54	0.59	0.64
		TRN	Tcf	0.22	0.24	0.25	0.27	0.30
		C	Tcf	4.88	4.90	4.89	4.89	4.85
		G	Tcf	0.96	0.99	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$0.57	$3.80	$8.25	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.06	0.06	0.04	0.03
	Gross Capital Income		%	(0.01)	(0.06)	(0.10)	(0.09)	(0.08)
	Gross Labor Income		%	(0.01)	(0.04)	(0.07)	(0.07)	(0.06)
	Gross Resource Income		%	2.58	10.21	11.75	9.10	8.13
	Consumption		%	0.03	0.02	(0.00)	(0.01)	(0.01)
	Investment		%	0.06	0.04	(0.02)	(0.01)	(0.01)
Natural Gas	Wellhead Price		%	1.20	6.29	8.29	6.87	6.27
	Production		%	0.26	1.64	3.66	4.33	4.18
	Pipeline Imports		%					
	Total Demand		%	(0.43)	(2.41)	(3.56)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(0.68)	(3.35)	(4.61)	(4.07)	(3.79)
		COL	%					
		CRU	%					
		EIS	%	(0.67)	(3.30)	(4.57)	(4.05)	(3.77)
		ELE	%	(0.43)	(2.61)	(4.00)	(3.78)	(3.73)
		GAS	%					
		M_V	%	(0.43)	(2.40)	(3.60)	(3.35)	(3.22)
		MAN	%	(0.60)	(3.07)	(4.29)	(3.81)	(3.57)
		OIL	%	(0.60)	(3.14)	(4.36)	(3.84)	(3.58)
		SRV	%	(0.26)	(1.59)	(2.53)	(2.41)	(2.34)
		TRK	%	(0.15)	(0.98)	(1.73)	(1.76)	(1.76)
		TRN	%	(0.17)	(1.01)	(1.77)	(1.80)	(1.80)
		C	%	(0.20)	(1.32)	(2.15)	(2.08)	(2.02)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 157: Detailed Results for HEUR_SD_LS

Scenario: HEUR_SD_LS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,965	$17,984	$20,422	$23,011	$25,909
	Consumption		Billion 2010$	$12,435	$14,000	$16,012	$18,182	$20,564
	Investment		Billion 2010$	$2,485	$2,808	$3,177	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.43	$3.98	$4.46	$4.84	$5.23
	Production		Tcf	24.82	27.28	28.82	29.95	30.97
	Exports		Tcf	0.37	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.72	26.36	26.88	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.42	3.34	3.38	3.34	3.26
		ELE	Tcf	8.20	7.93	7.99	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.18	0.18	0.19
		MAN	Tcf	4.38	4.35	4.53	4.68	4.83
		OIL	Tcf	1.30	1.31	1.30	1.38	1.35
		SRV	Tcf	2.52	2.56	2.67	2.78	2.90
		TRK	Tcf	0.48	0.50	0.54	0.59	0.64
		TRN	Tcf	0.22	0.23	0.25	0.27	0.30
		C	Tcf	4.87	4.82	4.88	4.89	4.85
		G	Tcf	0.96	0.97	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$1.18	$8.07	$9.06	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.03	0.11	0.06	0.04	0.03
	Gross Capital Income		%	(0.02)	(0.15)	(0.12)	(0.09)	(0.08)
	Gross Labor Income		%	(0.01)	(0.11)	(0.09)	(0.07)	(0.06)
	Gross Resource Income		%	5.44	22.13	12.88	9.08	8.12
	Consumption		%	0.05	0.00	(0.01)	(0.01)	(0.01)
	Investment		%	0.10	(0.10)	0.01	0.01	0.01
Natural Gas	Wellhead Price		%	2.52	13.51	9.11	6.86	6.27
	Production		%	0.53	3.11	3.97	4.33	4.18
	Pipeline Imports		%					
	Total Demand		%	(0.89)	(4.93)	(3.89)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(1.38)	(6.79)	(5.05)	(4.08)	(3.79)
		COL	%					
		CRU	%					
		EIS	%	(1.35)	(6.70)	(5.02)	(4.06)	(3.78)
		ELE	%	(0.90)	(5.34)	(4.37)	(3.79)	(3.73)
		GAS	%					
		M_V	%	(0.88)	(4.88)	(3.94)	(3.35)	(3.22)
		MAN	%	(1.23)	(6.25)	(4.69)	(3.82)	(3.57)
		OIL	%	(1.24)	(6.41)	(4.77)	(3.84)	(3.58)
		SRV	%	(0.55)	(3.31)	(2.77)	(2.41)	(2.34)
		TRK	%	(0.32)	(2.05)	(1.90)	(1.76)	(1.76)
		TRN	%	(0.33)	(2.09)	(1.96)	(1.81)	(1.81)
		C	%	(0.43)	(2.78)	(2.37)	(2.08)	(2.02)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 158: Detailed Results for HEUR_SD_LR

Scenario: HEUR_SD_LR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,972	$17,983	$20,422	$23,010	$25,909
	Consumption		Billion 2010$	$12,435	$13,999	$16,012	$18,182	$20,564
	Investment		Billion 2010$	$2,482	$2,809	$3,178	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.61	$3.97	$4.46	$4.84	$5.23
	Production		Tcf	25.06	27.28	28.82	29.94	30.97
	Exports		Tcf	1.10	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.23	26.36	26.88	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.34	3.37	3.34	3.26
		ELE	Tcf	8.04	7.93	7.99	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.19	0.18	0.18	0.19
		MAN	Tcf	4.27	4.35	4.53	4.68	4.83
		OIL	Tcf	1.27	1.31	1.30	1.38	1.35
		SRV	Tcf	2.49	2.56	2.67	2.78	2.90
		TRK	Tcf	0.48	0.50	0.54	0.59	0.64
		TRN	Tcf	0.22	0.23	0.25	0.27	0.30
		C	Tcf	4.82	4.82	4.88	4.89	4.85
		G	Tcf	0.95	0.97	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$3.69	$8.07	$9.06	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.07	0.11	0.06	0.03	0.03
	Gross Capital Income		%	(0.09)	(0.16)	(0.12)	(0.09)	(0.08)
	Gross Labor Income		%	(0.07)	(0.11)	(0.09)	(0.07)	(0.06)
	Gross Resource Income		%	17.33	22.05	12.86	9.07	8.11
	Consumption		%	0.05	(0.00)	(0.01)	(0.01)	(0.00)
	Investment		%	(0.02)	(0.05)	0.02	0.01	0.01
Natural Gas	Wellhead Price		%	7.97	13.49	9.11	6.86	6.27
	Production		%	1.49	3.10	3.97	4.32	4.18
	Pipeline Imports		%					
	Total Demand		%	(2.71)	(4.94)	(3.90)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(4.08)	(6.80)	(5.06)	(4.08)	(3.80)
		COL	%					
		CRU	%					
		EIS	%	(3.98)	(6.71)	(5.03)	(4.07)	(3.79)
		ELE	%	(2.76)	(5.35)	(4.37)	(3.78)	(3.73)
		GAS	%					
		M_V	%	(2.60)	(4.88)	(3.94)	(3.36)	(3.22)
		MAN	%	(3.67)	(6.25)	(4.69)	(3.82)	(3.58)
		OIL	%	(3.78)	(6.41)	(4.76)	(3.84)	(3.58)
		SRV	%	(1.71)	(3.32)	(2.78)	(2.41)	(2.34)
		TRK	%	(0.96)	(2.05)	(1.90)	(1.76)	(1.76)
		TRN	%	(0.98)	(2.11)	(1.96)	(1.81)	(1.81)
		C	%	(1.42)	(2.78)	(2.36)	(2.07)	(2.02)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 159: Detailed Results for HEUR_SD_HS

Scenario: HEUR_SD_HS								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,965	$17,986	$20,439	$23,022	$25,918
	Consumption		Billion 2010$	$12,437	$14,004	$16,013	$18,180	$20,561
	Investment		Billion 2010$	$2,486	$2,813	$3,175	$3,531	$3,994
Natural Gas	Wellhead Price		2010$ per Mcf	$3.43	$3.98	$4.84	$5.21	$5.59
	Production		Tcf	24.82	27.28	29.67	31.13	32.17
	Exports		Tcf	0.37	2.19	4.02	4.38	4.38
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.72	26.36	25.90	26.89	27.92
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.15	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.42	3.34	3.22	3.20	3.13
		ELE	Tcf	8.20	7.93	7.66	8.21	8.95
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.17	0.18	0.18
		MAN	Tcf	4.38	4.35	4.33	4.49	4.64
		OIL	Tcf	1.30	1.31	1.24	1.32	1.30
		SRV	Tcf	2.52	2.56	2.60	2.70	2.82
		TRK	Tcf	0.48	0.50	0.53	0.58	0.63
		TRN	Tcf	0.22	0.23	0.25	0.27	0.29
		C	Tcf	4.87	4.82	4.77	4.78	4.75
		G	Tcf	0.96	0.97	0.99	1.03	1.07
	Export Revenues [1]		Billion 2010$	$1.18	$8.07	$18.05	$21.15	$22.70
Percentage Change								
Macro	Gross Domestic Product		%	0.03	0.12	0.14	0.09	0.06
	Gross Capital Income		%	(0.02)	(0.14)	(0.21)	(0.19)	(0.17)
	Gross Labor Income		%	(0.01)	(0.10)	(0.16)	(0.14)	(0.13)
	Gross Resource Income		%	5.38	22.12	26.64	20.29	17.95
	Consumption		%	0.06	0.04	(0.01)	(0.02)	(0.02)
	Investment		%	0.12	0.08	(0.05)	(0.02)	(0.02)
Natural Gas	Wellhead Price		%	2.51	13.51	18.45	14.96	13.55
	Production		%	0.52	3.11	7.05	8.47	8.21
	Pipeline Imports		%					
	Total Demand		%	(0.89)	(4.93)	(7.39)	(6.76)	(6.50)
	Sectoral Demand	AGR	%	(1.40)	(6.82)	(9.52)	(8.33)	(7.73)
		COL	%					
		CRU	%					
		EIS	%	(1.38)	(6.74)	(9.44)	(8.29)	(7.70)
		ELE	%	(0.89)	(5.33)	(8.28)	(7.76)	(7.62)
		GAS	%					
		M_V	%	(0.88)	(4.90)	(7.47)	(6.88)	(6.60)
		MAN	%	(1.24)	(6.26)	(8.87)	(7.82)	(7.31)
		OIL	%	(1.24)	(6.41)	(9.00)	(7.86)	(7.32)
		SRV	%	(0.55)	(3.30)	(5.33)	(5.01)	(4.85)
		TRK	%	(0.32)	(2.04)	(3.66)	(3.68)	(3.66)
		TRN	%	(0.35)	(2.11)	(3.75)	(3.77)	(3.75)
		C	%	(0.41)	(2.75)	(4.55)	(4.34)	(4.20)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 160: Detailed Results for HEUR_SD_HR

Scenario: HEUR_SD_HR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,973	$18,012	$20,438	$23,021	$25,918
	Consumption		Billion 2010$	$12,442	$14,000	$16,010	$18,181	$20,564
	Investment		Billion 2010$	$2,486	$2,805	$3,178	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.61	$4.61	$4.93	$5.21	$5.59
	Production		Tcf	25.06	27.96	29.83	31.13	32.17
	Exports		Tcf	1.10	4.38	4.38	4.38	4.38
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.23	24.85	25.70	26.89	27.92
	Sectoral Demand	AGR	Tcf	0.15	0.14	0.15	0.15	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.08	3.18	3.19	3.13
		ELE	Tcf	8.04	7.44	7.59	8.21	8.95
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.18	0.18
		MAN	Tcf	4.27	4.03	4.29	4.49	4.64
		OIL	Tcf	1.27	1.21	1.23	1.32	1.30
		SRV	Tcf	2.49	2.46	2.59	2.70	2.82
		TRK	Tcf	0.48	0.49	0.53	0.57	0.63
		TRN	Tcf	0.22	0.23	0.24	0.27	0.29
		C	Tcf	4.82	4.66	4.74	4.78	4.75
		G	Tcf	0.95	0.93	0.98	1.03	1.07
	Export Revenues [1]		Billion 2010$	$3.69	$18.71	$20.00	$21.15	$22.70
Percentage Change								
Macro	Gross Domestic Product		%	0.08	0.27	0.13	0.08	0.06
	Gross Capital Income		%	(0.07)	(0.34)	(0.26)	(0.20)	(0.17)
	Gross Labor Income		%	(0.06)	(0.25)	(0.19)	(0.15)	(0.13)
	Gross Resource Income		%	17.27	52.53	29.53	20.22	17.92
	Consumption		%	0.10	0.01	(0.02)	(0.01)	(0.01)
	Investment		%	0.11	(0.22)	0.03	0.02	0.03
Natural Gas	Wellhead Price		%	7.96	31.57	20.46	14.95	13.54
	Production		%	1.49	5.68	7.61	8.46	8.20
	Pipeline Imports		%					
	Total Demand		%	(2.71)	(10.38)	(8.12)	(6.77)	(6.50)
	Sectoral Demand	AGR	%	(4.14)	(14.12)	(10.46)	(8.36)	(7.75)
		COL	%					
		CRU	%					
		EIS	%	(4.05)	(13.92)	(10.39)	(8.32)	(7.73)
		ELE	%	(2.75)	(11.20)	(9.08)	(7.76)	(7.62)
		GAS	%					
		M_V	%	(2.64)	(10.24)	(8.20)	(6.90)	(6.60)
		MAN	%	(3.71)	(13.02)	(9.71)	(7.83)	(7.31)
		OIL	%	(3.77)	(13.34)	(9.87)	(7.86)	(7.32)
		SRV	%	(1.70)	(7.15)	(5.87)	(5.01)	(4.85)
		TRK	%	(0.97)	(4.47)	(4.05)	(3.69)	(3.66)
		TRN	%	(1.01)	(4.57)	(4.18)	(3.79)	(3.76)
		C	%	(1.36)	(6.06)	(5.03)	(4.33)	(4.19)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 161: Detailed Results for HEUR_SD_NC

Scenario: HEUR_SD_NC								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$16,017	$18,025	$20,462	$23,039	$25,948
	Consumption		Billion 2010$	$12,447	$14,002	$16,012	$18,184	$20,565
	Investment		Billion 2010$	$2,473	$2,812	$3,177	$3,538	$4,002
Natural Gas	Wellhead Price		2010$ per Mcf	$4.68	$4.98	$5.55	$5.71	$6.41
	Production		Tcf	25.87	28.24	30.81	32.43	34.24
	Exports		Tcf	4.23	5.44	6.72	6.89	8.39
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	23.91	24.07	24.34	25.67	25.99
	Sectoral Demand	AGR	Tcf	0.13	0.13	0.14	0.14	0.14
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	2.91	2.95	2.97	3.02	2.87
		ELE	Tcf	7.32	7.19	7.15	7.78	8.23
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.17	0.17
		MAN	Tcf	3.77	3.88	4.02	4.25	4.28
		OIL	Tcf	1.11	1.17	1.15	1.25	1.20
		SRV	Tcf	2.34	2.41	2.49	2.61	2.67
		TRK	Tcf	0.46	0.48	0.51	0.56	0.60
		TRN	Tcf	0.22	0.22	0.24	0.26	0.28
		C	Tcf	4.58	4.57	4.59	4.64	4.53
		G	Tcf	0.88	0.90	0.94	0.99	1.01
	Export Revenues [1]		Billion 2010$	$18.35	$25.13	$34.58	$36.49	$49.83
Percentage Change								
Macro	Gross Domestic Product		%	0.35	0.34	0.25	0.16	0.18
	Gross Capital Income		%	(0.42)	(0.47)	(0.42)	(0.32)	(0.33)
	Gross Labor Income		%	(0.33)	(0.34)	(0.32)	(0.25)	(0.26)
	Gross Resource Income		%	88.35	70.57	52.78	36.18	41.62
	Consumption		%	0.14	0.02	(0.01)	0.00	0.00
	Investment		%	(0.41)	0.04	0.01	0.18	0.18
Natural Gas	Wellhead Price		%	39.81	42.27	35.75	26.06	30.14
	Production		%	4.78	6.75	11.16	12.97	15.18
	Pipeline Imports		%					
	Total Demand		%	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
	Sectoral Demand	AGR	%	(11.32)	(13.18)	(12.97)	(10.98)	(12.98)
		COL	%	(16.58)	(17.87)	(16.58)	(13.50)	(15.34)
		CRU	%					
		EIS	%					
		ELE	%	(16.19)	(17.66)	(16.46)	(13.45)	(15.30)
		GAS	%	(11.50)	(14.17)	(14.43)	(12.54)	(15.11)
		M_V	%					
		MAN	%	(10.73)	(13.00)	(13.07)	(11.18)	(13.14)
		OIL	%	(14.93)	(16.41)	(15.42)	(12.64)	(14.50)
		SRV	%	(15.45)	(16.82)	(15.63)	(12.69)	(14.54)
		TRK	%	(7.51)	(9.21)	(9.55)	(8.24)	(9.89)
		TRN	%	(4.25)	(5.81)	(6.66)	(6.10)	(7.55)
		C	%	(4.35)	(6.01)	(6.86)	(6.29)	(7.74)

1 Export revenues are based on LNG exports net of liquefaction loss.

Figure 162: Detailed Results for LEUR_SD_LSS

Scenario: LEUR_SD_LSS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,791	$17,719	$20,060	$22,691	$25,568
	Consumption		Billion 2010$	$12,382	$13,920	$15,861	$18,093	$20,477
	Investment		Billion 2010$	$2,443	$2,757	$3,135	$3,495	$3,956
Natural Gas	Wellhead Price		2010$ per Mcf	$5.73	$6.82	$8.04	$8.33	$9.00
	Production		Tcf	19.60	20.15	20.58	21.13	21.83
	Exports		Tcf	-	0.78	0.86	-	0.19
	Pipeline Imports		Tcf	3.00	2.61	2.37	2.01	1.75
	Total Demand		Tcf	22.60	21.98	22.09	23.14	23.39
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.18	3.05	2.96	2.86	2.75
		ELE	Tcf	5.23	4.88	5.08	5.91	6.10
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.16	0.15	0.16	0.16
		MAN	Tcf	3.99	3.88	3.86	3.95	3.99
		OIL	Tcf	1.32	1.37	1.37	1.36	1.38
		SRV	Tcf	2.32	2.33	2.35	2.45	2.54
		TRK	Tcf	0.45	0.45	0.47	0.49	0.51
		TRN	Tcf	0.21	0.21	0.22	0.23	0.24
		C	Tcf	4.68	4.61	4.59	4.63	4.58
		G	Tcf	0.88	0.89	0.90	0.94	0.97
	Export Revenues [1]		Billion 2010$	$0.00	$4.93	$6.41	$0.00	$1.58
Percentage Change								
Macro	Gross Domestic Product		%	0.00	0.01	(0.01)	(0.01)	0.01
	Gross Capital Income		%	0.00	(0.08)	(0.06)	(0.01)	(0.00)
	Gross Labor Income		%	0.00	(0.06)	(0.05)	(0.00)	(0.00)
	Gross Resource Income		%	(0.02)	7.82	3.12	(0.06)	0.43
	Consumption		%	0.02	0.00	(0.01)	0.00	0.00
	Investment		%	0.04	(0.07)	(0.08)	0.08	0.08
Natural Gas	Wellhead Price		%	(0.00)	5.78	2.75	(0.00)	0.42
	Production		%	(0.00)	1.35	2.70	(0.01)	0.60
	Pipeline Imports		%					
	Total Demand		%	(0.00)	(2.28)	(1.42)	(0.01)	(0.25)
	Sectoral Demand	AGR	%	(0.02)	(3.06)	(1.78)	(0.03)	(0.30)
		COL	%					
		CRU	%					
		EIS	%	(0.02)	(3.01)	(1.76)	(0.04)	(0.31)
		ELE	%	0.01	(2.46)	(1.56)	(0.00)	(0.29)
		GAS	%					
		M_V	%	(0.00)	(2.19)	(1.44)	(0.01)	(0.25)
		MAN	%	(0.02)	(2.76)	(1.64)	(0.00)	(0.27)
		OIL	%	0.00	(2.81)	(1.62)	(0.00)	(0.28)
		SRV	%	0.00	(1.70)	(1.14)	(0.01)	(0.21)
		TRK	%	(0.00)	(1.11)	(0.89)	(0.01)	(0.17)
		TRN	%	(0.01)	(1.14)	(0.91)	(0.02)	(0.19)
		C	%	0.02	(1.50)	(1.04)	0.00	(0.19)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 163: Detailed Results for HEUR_SD_LSS_QR

Scenario: HEUR_SD_LSS_QR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,963	$17,976	$20,428	$23,016	$25,915
	Consumption		Billion 2010$	$12,434	$14,003	$16,015	$18,184	$20,566
	Investment		Billion 2010$	$2,484	$2,812	$3,176	$3,531	$3,995
Natural Gas	Wellhead Price		2010$ per Mcf	$3.39	$3.72	$4.43	$4.84	$5.23
	Production		Tcf	24.76	26.89	28.73	29.94	30.97
	Exports		Tcf	0.18	1.10	2.01	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.84	27.06	26.97	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.45	3.46	3.39	3.34	3.26
		ELE	Tcf	8.23	8.16	8.02	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.18	0.18	0.19
		MAN	Tcf	4.41	4.49	4.55	4.68	4.83
		OIL	Tcf	1.31	1.36	1.31	1.38	1.35
		SRV	Tcf	2.53	2.61	2.68	2.78	2.90
		TRK	Tcf	0.48	0.51	0.54	0.59	0.64
		TRN	Tcf	0.22	0.24	0.25	0.27	0.30
		C	Tcf	4.88	4.90	4.89	4.89	4.85
		G	Tcf	0.96	0.99	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$0.57	$3.80	$8.25	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.07	0.08	0.06	0.05
	Gross Capital Income		%	(0.01)	(0.07)	(0.10)	(0.09)	(0.08)
	Gross Labor Income		%	(0.01)	(0.05)	(0.07)	(0.07)	(0.07)
	Gross Resource Income		%	2.51	10.16	11.70	9.06	8.09
	Consumption		%	0.04	0.03	0.01	0.00	0.00
	Investment		%	0.06	0.04	(0.02)	(0.01)	(0.01)
Natural Gas	Wellhead Price		%	1.19	6.27	8.28	6.86	6.26
	Production		%	0.26	1.63	3.66	4.32	4.18
	Pipeline Imports		%					
	Total Demand		%	(0.43)	(2.41)	(3.56)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(0.70)	(3.37)	(4.64)	(4.09)	(3.82)
		COL	%					
		CRU	%					
		EIS	%	(0.70)	(3.34)	(4.61)	(4.08)	(3.81)
		ELE	%	(0.43)	(2.60)	(3.99)	(3.78)	(3.73)
		GAS	%					
		M_V	%	(0.45)	(2.42)	(3.63)	(3.38)	(3.25)
		MAN	%	(0.61)	(3.09)	(4.31)	(3.83)	(3.59)
		OIL	%	(0.60)	(3.14)	(4.36)	(3.84)	(3.58)
		SRV	%	(0.26)	(1.59)	(2.53)	(2.41)	(2.34)
		TRK	%	(0.16)	(0.99)	(1.74)	(1.77)	(1.77)
		TRN	%	(0.19)	(1.03)	(1.79)	(1.82)	(1.82)
		C	%	(0.19)	(1.31)	(2.14)	(2.06)	(2.01)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 164: Detailed Results for HEUR_SD_HR_QR

Scenario: HEUR_SD_HR_QR								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,974	$18,013	$20,443	$23,027	$25,927
	Consumption		Billion 2010$	$12,444	$14,003	$16,013	$18,184	$20,567
	Investment		Billion 2010$	$2,486	$2,804	$3,178	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.61	$4.61	$4.93	$5.21	$5.59
	Production		Tcf	25.06	27.96	29.83	31.13	32.17
	Exports		Tcf	1.10	4.38	4.38	4.38	4.38
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.22	24.85	25.70	26.89	27.92
	Sectoral Demand	AGR	Tcf	0.15	0.14	0.15	0.15	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.08	3.18	3.19	3.13
		ELE	Tcf	8.04	7.44	7.59	8.21	8.95
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.18	0.18
		MAN	Tcf	4.27	4.03	4.29	4.48	4.64
		OIL	Tcf	1.27	1.21	1.23	1.32	1.30
		SRV	Tcf	2.49	2.46	2.59	2.70	2.82
		TRK	Tcf	0.48	0.49	0.53	0.57	0.63
		TRN	Tcf	0.22	0.23	0.24	0.27	0.29
		C	Tcf	4.82	4.66	4.75	4.78	4.75
		G	Tcf	0.95	0.93	0.98	1.03	1.07
	Export Revenues [1]		Billion 2010$	$3.68	$18.70	$20.00	$21.15	$22.70
Percentage Change								
Macro	Gross Domestic Product		%	0.09	0.28	0.16	0.11	0.10
	Gross Capital Income		%	(0.07)	(0.34)	(0.26)	(0.20)	(0.18)
	Gross Labor Income		%	(0.06)	(0.25)	(0.19)	(0.15)	(0.14)
	Gross Resource Income		%	17.17	52.44	29.47	20.17	17.87
	Consumption		%	0.12	0.03	(0.00)	0.00	0.01
	Investment		%	0.11	(0.22)	0.02	0.01	0.02
Natural Gas	Wellhead Price		%	7.94	31.55	20.45	14.94	13.53
	Production		%	1.49	5.68	7.61	8.45	8.20
	Pipeline Imports		%					
	Total Demand		%	(2.72)	(10.38)	(8.12)	(6.77)	(6.50)
	Sectoral Demand	AGR	%	(4.17)	(14.15)	(10.50)	(8.40)	(7.79)
		COL	%					
		CRU	%					
		EIS	%	(4.09)	(13.96)	(10.43)	(8.37)	(7.77)
		ELE	%	(2.74)	(11.19)	(9.08)	(7.76)	(7.61)
		GAS	%					
		M_V	%	(2.68)	(10.27)	(8.23)	(6.94)	(6.64)
		MAN	%	(3.73)	(13.03)	(9.73)	(7.85)	(7.33)
		OIL	%	(3.77)	(13.33)	(9.87)	(7.86)	(7.32)
		SRV	%	(1.69)	(7.15)	(5.87)	(5.01)	(4.85)
		TRK	%	(0.98)	(4.48)	(4.06)	(3.70)	(3.68)
		TRN	%	(1.04)	(4.59)	(4.19)	(3.81)	(3.78)
		C	%	(1.34)	(6.04)	(5.01)	(4.31)	(4.17)
1	Export revenues are based on LNG exports net of liquefaction loss.							

APPENDIX D - COMPARISON WITH EIA STUDY

NERA's modeling of shifts in natural gas price, production, and demand are built off an attempt to replicate EIA's price path. This was an important step to ensure that the NERA model output was consistent with the EIA's model. Of particular importance was the ability to replicate EIA's natural gas prices as closely as possible since it is a key driver of macroeconomic impacts. In this process, we ran the exact export scenarios reflected in the EIA Study. We ran Low/Slow, Low/High, High/Slow, and High/Rapid export expansion scenarios for the Reference, High Shale, and Low Shale outlooks. In total we ran 16 EIA consistent scenarios to compare model results. NERA Reference shale gas case scenarios are referenced as NERA_REF_LS, NERA_REF_LR, NERA_REF_HS, and NERA_REF_HR. Similarly, the High Shale and Low Shale case outlook for the NERA Study is referenced as NERA_HEUR_LS, NERA_HEUR_LR, NERA_HEUR_HS, NERA_HEUR_HR, NERA_LEUR_LS, NERA_LEUR_LR, NERA_LEUR_HS, NERA_LEUR_HR, respectively. The corresponding EIA scenarios are referenced as EIA_REF_LS, EIA_REF_LR, EIA_REF_HS, EIA_REF_HR, EIA_HEUR_LS, EIA_HEUR_LR, EIA_HEUR_HS, EIA_HEUR_HR, EIA_LEUR_LS, EIA_LEUR_LR, NERA_LEUR_HS, and NERA_LEUR_HR.

The natural gas supply curve in the NERA model was calibrated to EIA's natural gas supply curve in order to produce a response similar to the EIA High/Rapid scenario for the respective baselines. While the results of this price calibration scenario were nearly duplicated, other macroeconomic scenarios exhibited some differences between the NERA and EIA model runs. These variances are due primarily to differences in the model structure and modeling characteristics such as sectoral price elasticity of demand, supply elasticity, and other behavioral model parameters.

For changes in natural gas prices, the most apparent difference between the EIA and NERA model runs is seen in the High/Slow scenario. This is true for the Reference, High EUR and Low EUR baselines as seen in Figure 165, Figure 166, and Figure 167.These differences arise because we first estimate the implied price elasticity of natural gas supply to replicate the High/Rapid case and then adopt that elasticity for the other scenario runs.

Figure 165: Reference Case Natural Gas Price Percentage Changes

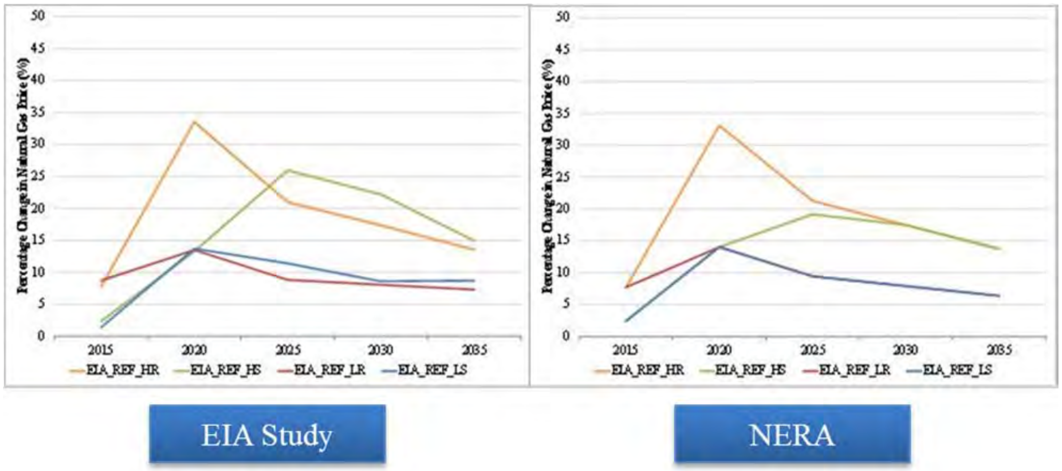


Figure 166: High EUR Natural Gas Price Percentage Changes

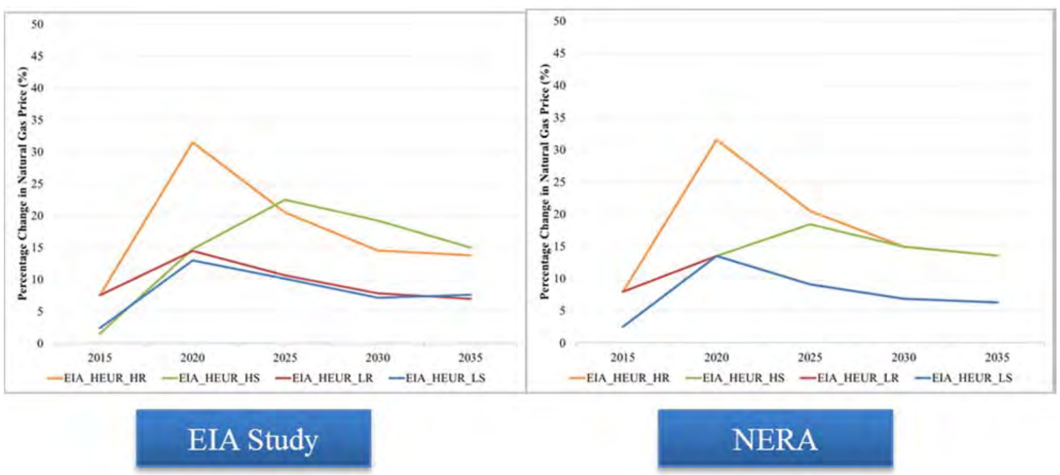
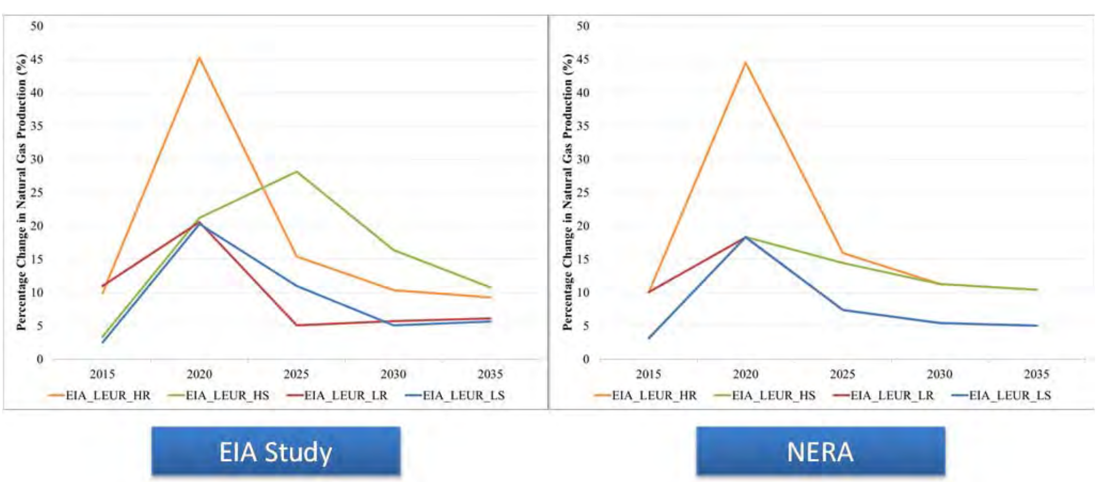


Figure 167: Low EUR Natural Gas Price Percentage Changes



The prices seen in the EIA High/Slow scenario in each baseline case deviate primarily in 2025, but also in 2030, in the range of 5% to 10% higher than the price change seen in the NERA High/Slow scenario. The low/slow scenario also shows small, but noticeable, differentials between the EIA and NERA model runs, particularly with the Reference and Low EUR baselines in 2025. Other than these differences, the general paths of price development in the NERA model runs tend to closely follow those estimated in the EIA study.

Changes in levels of natural gas demand and production show greater differences between the EIA and NERA runs than those seen in price. As briefly mentioned above, and elaborated on to a greater extent below, much of these variances result from the different elasticities used in the models and the overall model structures. The similar paths, but different magnitudes, of demand and production changes compared to the closely matched price changes reveal implied elasticities as a major source of variance. Figure 169 shows the implied supply elasticities for each case in 2015, 2025, and 2035.

The EIA Study assumed four different export scenarios for three different natural gas resources estimates (Reference, High Shale EUR, and Low Shale EUR). The scenarios for each baseline provide sufficient information about natural gas prices and supply quantities to be able to examine the natural gas supply curves. The supply curves are characterized by prices, quantities and the curvature. The current study makes all effort to simulate the EIA's supply curves despite the differences in the model construct. Figure 168 shows the EIA Study and NERA study supply curves for years 2020 and 2035 for the three natural gas resource outlooks.

Examining the curves suggests that the short-run supply curves (2020) are more inelastic than the long-run (2035) supply curves in both studies. The flattening of the supply curves is due to the fact that production and resource constraints are less binding over time. Under the High EUR case, 30 to 34 Tcf of natural gas can be supplied within a price range of $5 to $6/Mcf in the long run. However, under the Low EUR case, less natural gas can be supplied at a much higher price.

The EIA Study supply curves are shown as solid lines and the NERA supply curves are shown as dotted lines. Although the long-run supply curves are fairly close to one another, the short-run NERA supply curves are more inelastic. Given the supply curves, for a given change in quantity supplied, natural gas production in NERA model is relatively more price responsive in 2020 than in the EIA Study. The differences in the underlying assumption of the implied supply elasticities in 2020 drive this shape of the supply curve.

Figure 168: Natural Gas Supply Curves

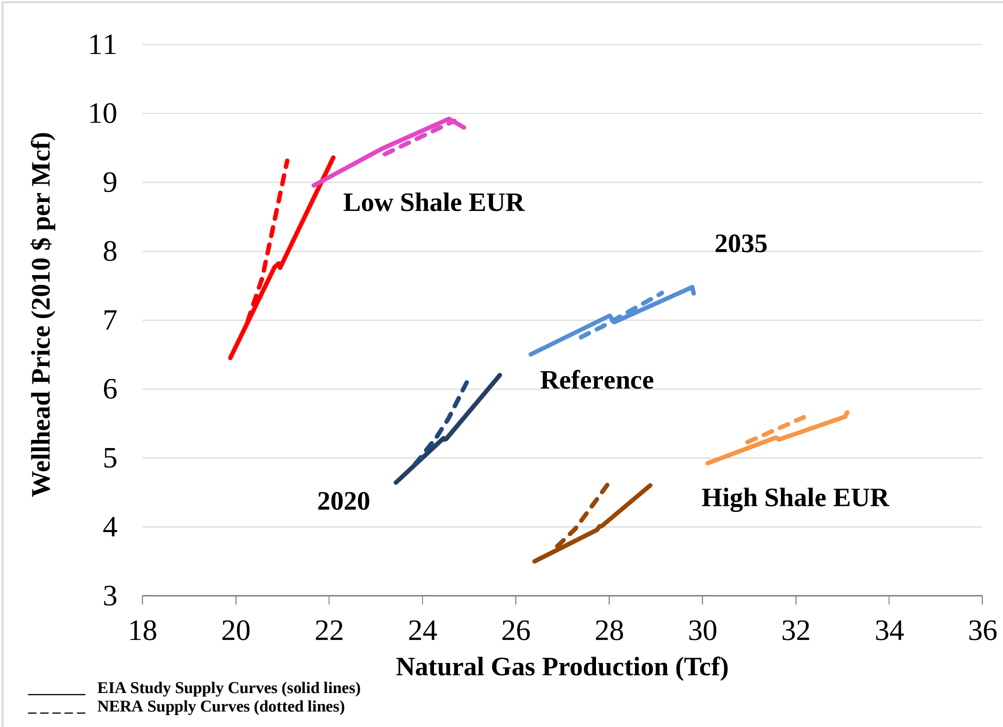
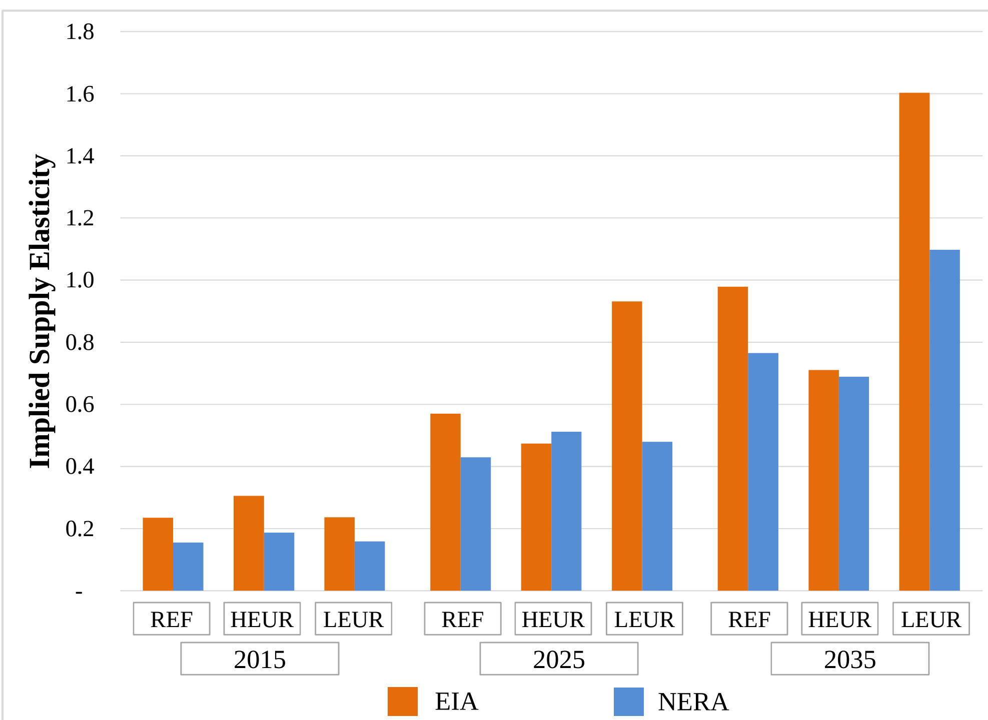


Figure 169: Implied Elasticities of Supply for Cases



Overall, the changes in natural gas demand are dampened in the EIA Study relative to the changes seen in the NERA model results, as seen in Figure 170, Figure 171, and Figure 172. The biggest differences appear to be found in the two rapid scenarios, High/Rapid and Low/Rapid. For each of the baseline cases, the rapid scenarios in the EIA Study show a significantly smaller magnitude of change in demand than they do in the comparable NERA model runs. Similar to the changes in price seen earlier, these differences are most pronounced in 2025 and 2030.

Figure 170: Reference Case Natural Gas Demand Percentage Changes

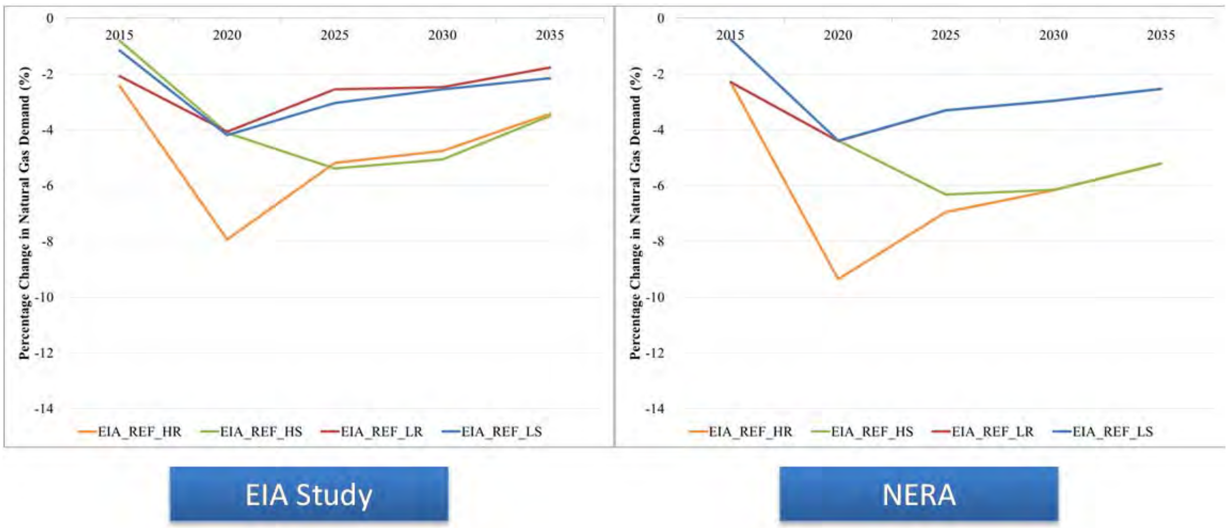


Figure 171: High EUR Natural Gas Demand Percentage Changes

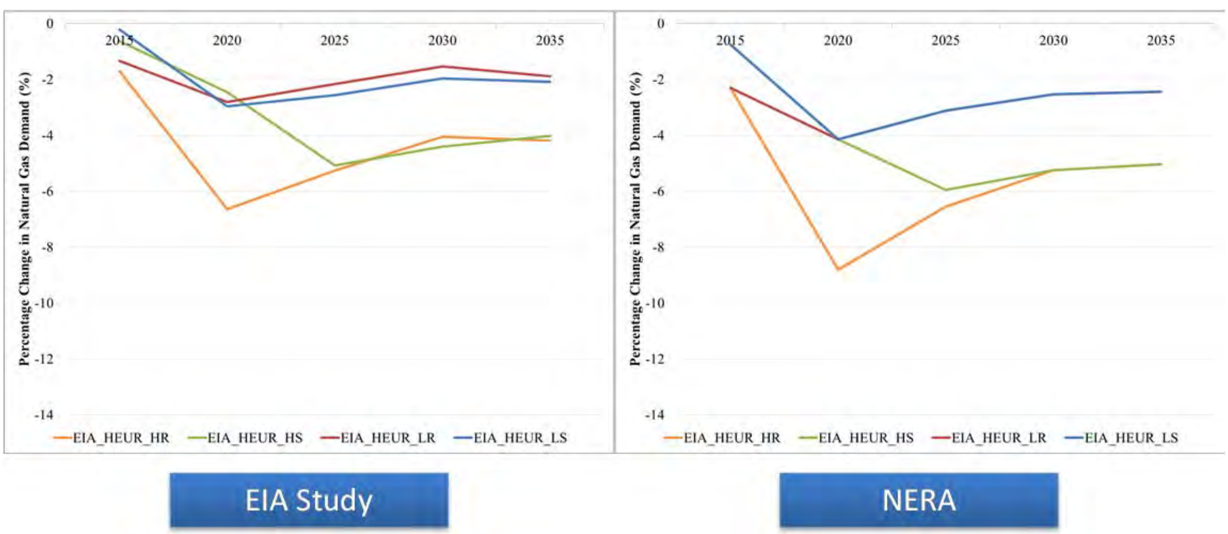
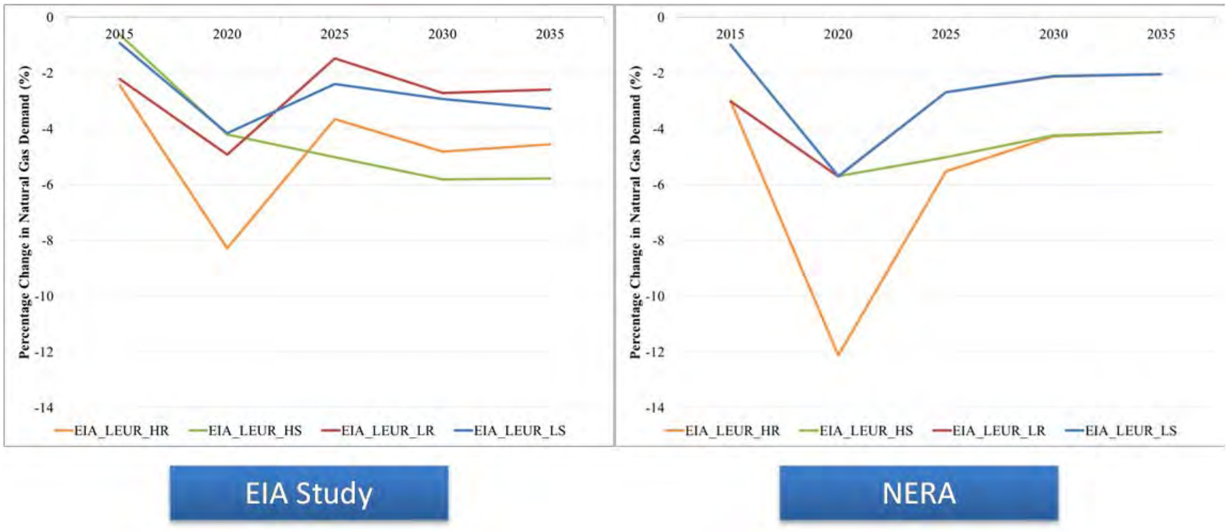


Figure 172: Low EUR Natural Gas Demand Percentage Changes



The results of the Low EUR baseline seen in Figure 172 show the most variance between the EIA and NERA results. In addition to the previously mentioned observation of overall lower magnitude changes in the EIA numbers relative to the NERA numbers and the largest differences being seen in 2025 and 2030, the paths of demand change in the two slow scenarios (High/Slow and Low/Slow) vary in later model years. In the EIA Study the changes in the High/Slow and Low/Slow scenarios get larger from 2025 to 2035 while in the NERA model the changes get smaller towards the end of the model horizon.

Differences between the changes in natural gas production seen in the EIA Study and the NERA modeling results are similar to those seen in demand changes, but in the opposite direction. In this metric, the EIA results show greater magnitudes of change than the NERA results, as can be seen in Figure 173, Figure 174, and Figure 175. This difference can be as large as 3% to 4%, as seen in the 2030 and 2035 years of the Reference Case high scenarios (High/Rapid and High/Slow).

Figure 173: Reference Case Natural Gas Production Percentage Changes

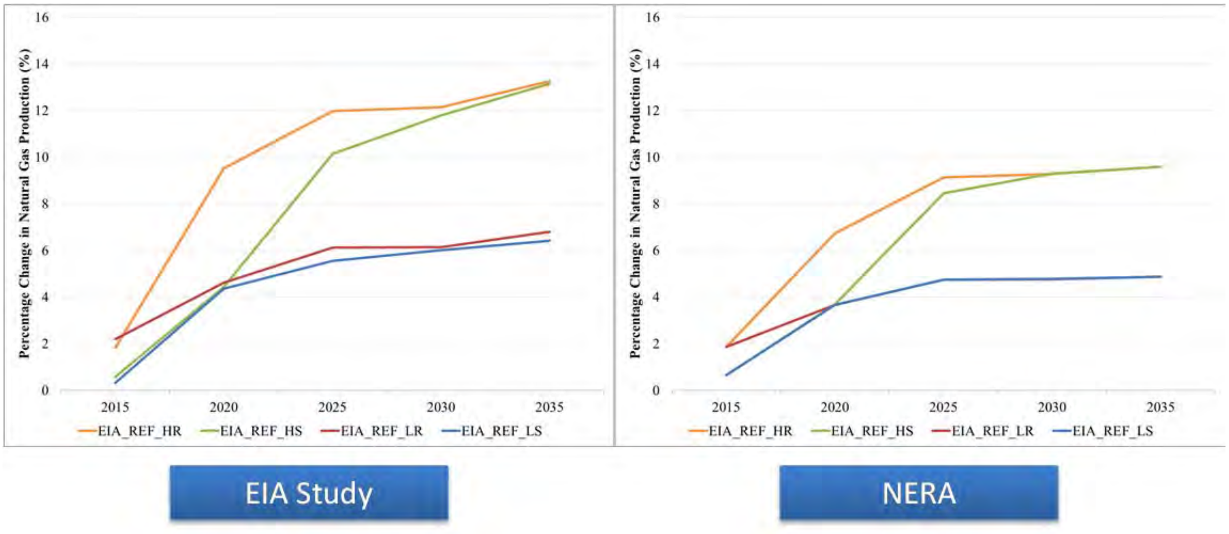


Figure 174: High EUR Natural Gas Production Percentage Changes

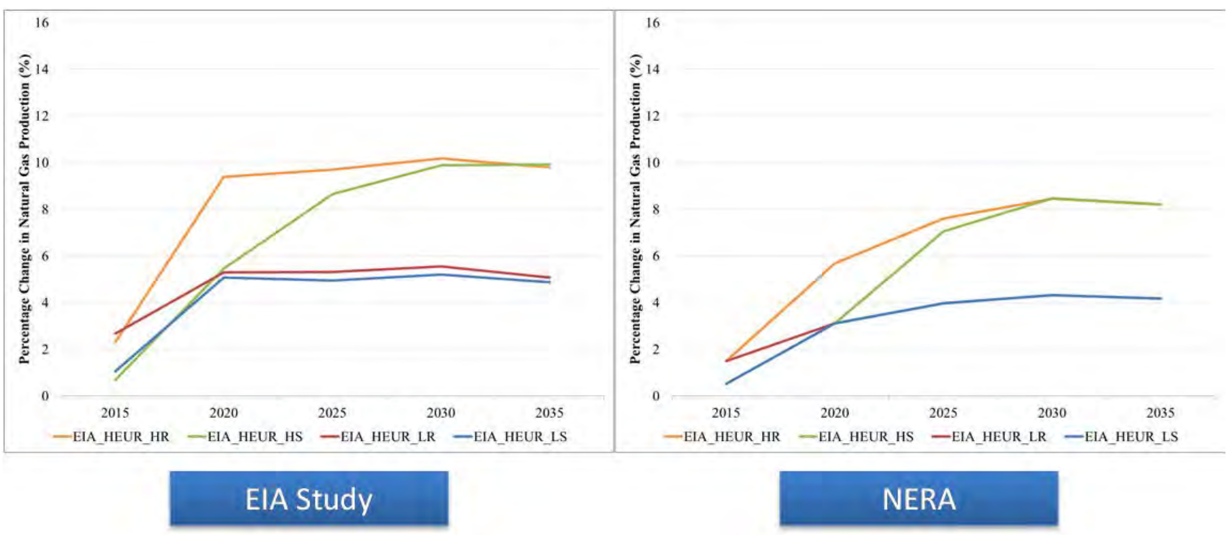
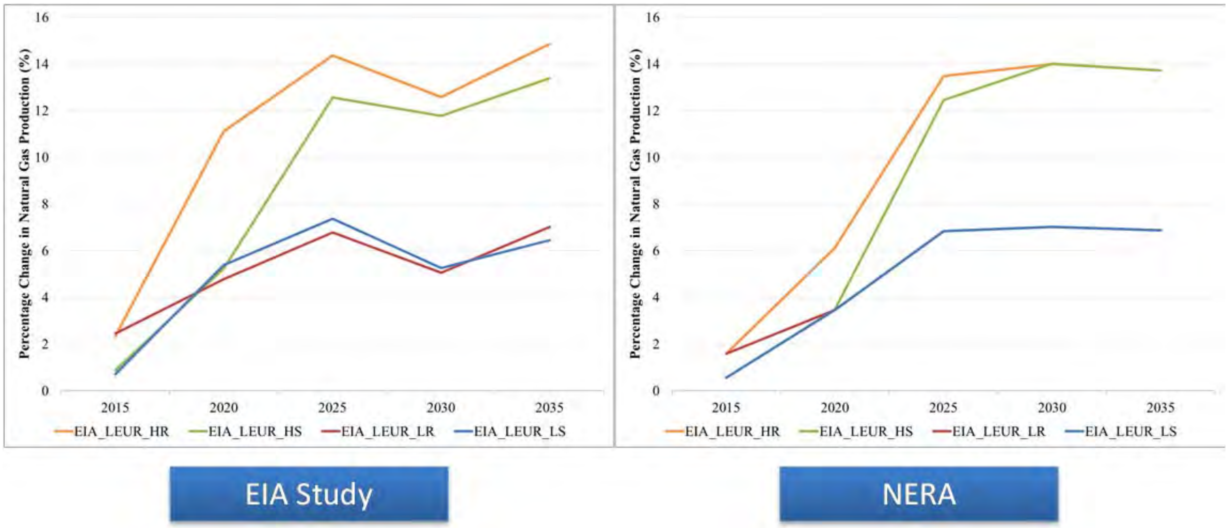


Figure 175: Low EUR Natural Gas Production Percentage Changes



Apart from the overall difference in levels of change seen between the two sets of model results, the general paths and patterns remain fairly similar because they are primarily driven by the level values and the pace of export expansion. The largest differences tend to occur in 2025 and 2030, similar to what is observed in the previous results, but the production changes also show some more variation in 2020.

Comparing changes in natural gas demand at a sectoral level reveal additional similarities and differences between the EIA Study model runs and the NERA model runs. As seen in Figure 176, Figure 177, and Figure 178, while overall levels of natural gas consumption are relatively consistent between the EIA Study and the NERA results, the sectoral components exhibit notable divergences. In particular, the NERA results show much greater demand response in the industrial sector while at the same time much less demand response in the electricity sector. These differences appear to be consistent across all baseline cases. The main reason for the variations in the electricity sector comes from the different way that the sector is modeled. EIA's NEMS model has a detailed bottom-up representation of the electricity sector, while the electricity sector in the NERA model is a nested CES function with limited technologies. This means that NEMS allows for switching from natural gas-based generation to other technology types easily, while the possibility of switching out of natural gas is more limited and controlled in the NERA model.

Figure 176: Reference Case Average Change in Natural Gas Consumed by Sector

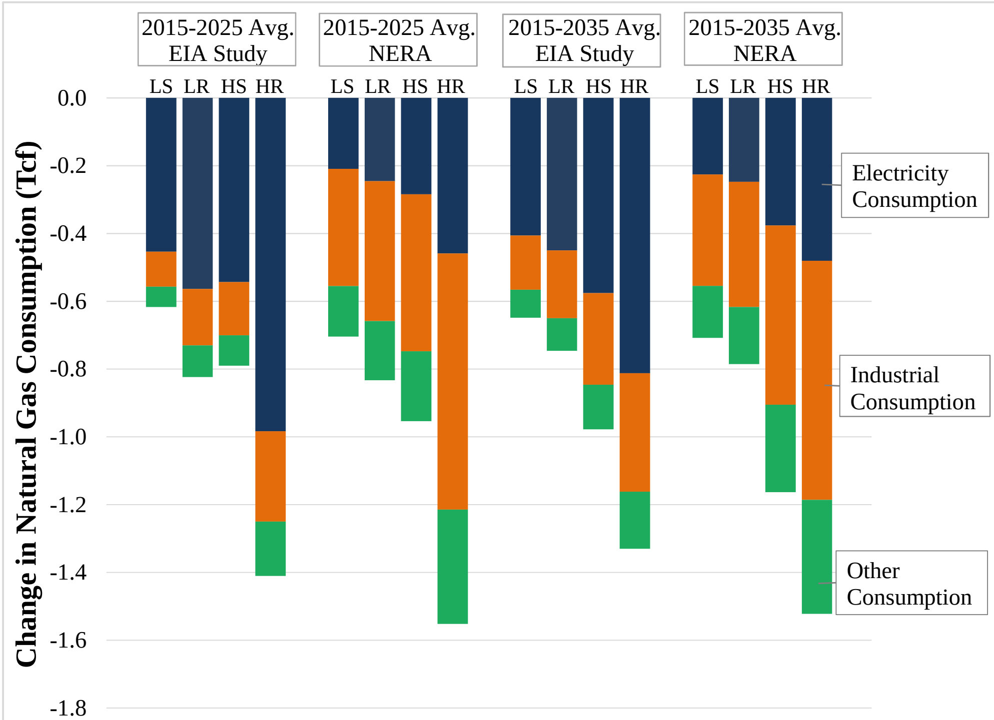


Figure 177: High EUR Average Change in Natural Gas Consumed by Sector

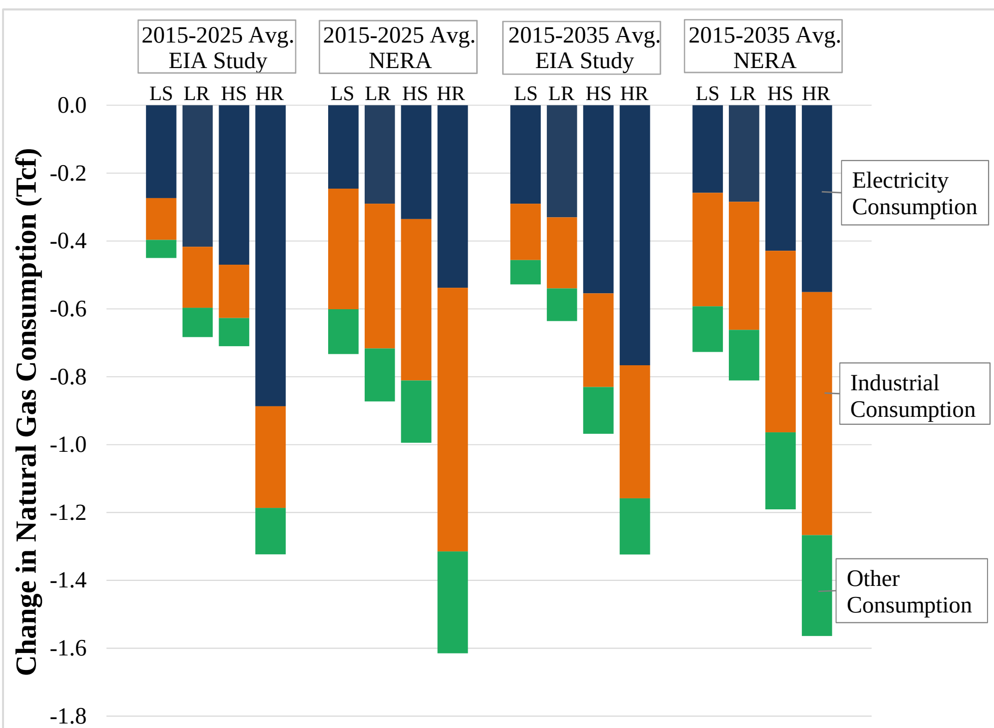
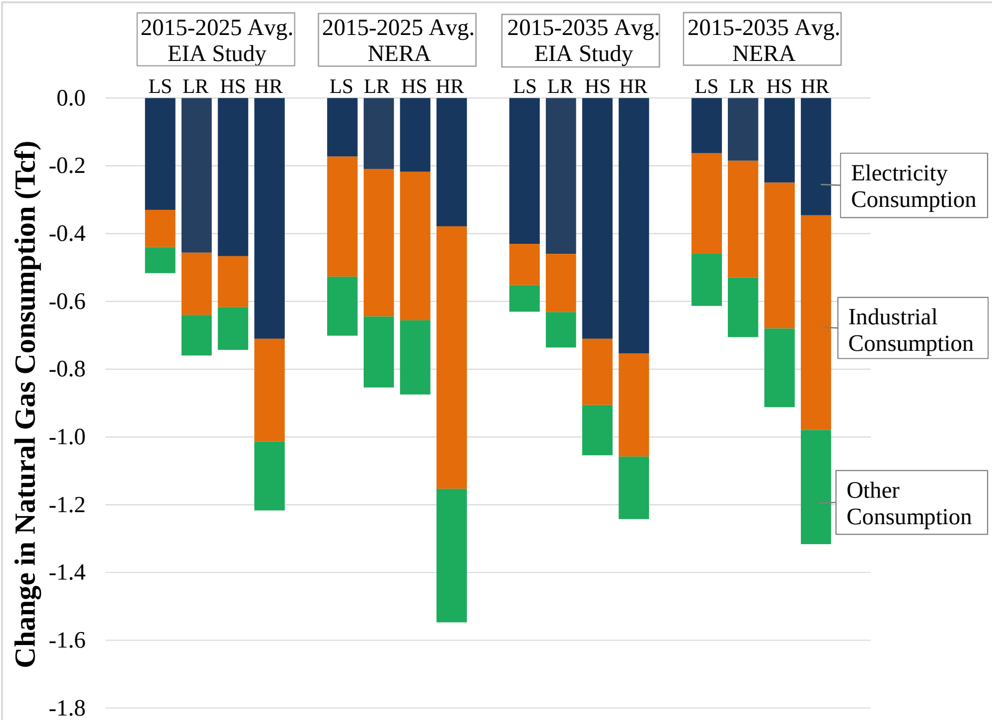


Figure 178: Low EUR Case Average Change in Natural Gas Consumed by Sector



APPENDIX E - FACTORS THAT WE DID NOT INCLUDE IN THE ANALYSIS

There are a number of issues that this study did not address directly. To avoid the misinterpretation of these results or the drawing of unwarranted implications, this section provides brief comments on each.

A. How Will Overbuilding of Export Capacity Affect the Market

This study assumes that the amount of capacity built will match market demand and that the pricing of liquefaction services will be based on long-run marginal costs. Should developers overbuild capacity, there could be pressure on take-or-pay contracts and potentially the margins earned for liquefaction services could be driven below the amount required to cover debt service and expected profits, just as has been the case with petroleum refining margins during periods of slack capacity.

B. Engineering or Infrastructure Limits on How Fast U.S. Liquefaction Capacity Could Be Built

Many of the scenarios investigated in this report assume rates of expansion of liquefaction facilities in the U.S. (and worldwide) that some industry sources believe will strain the capacity of engineering and construction providers. This could drive up the cost of building liquefaction facilities and constrain the rate of expansion to levels lower than those projected in the different scenarios investigated in this report, even if the U.S. resource and global market conditions were as assumed in those scenarios. This possibility requires analysis of the capabilities of the relevant global industries to support rapid construction that could be addressed in later studies.

C. Where Production or Export Terminals Will Be Located

There are proposals for export facilities in the Mid-Atlantic, Pacific Northwest and Canada, all of which could change basis differentials and potentially the location of additional natural gas production, with corresponding implications for regional impacts. To analyze alternative locations of export facilities it would be necessary to repeat both the EIA and the NERA analyses with additional scenarios incorporating demand for natural gas export in different regions.

D. Regional Economic Impacts

Since the EIA assumed that all of the demand for domestic production associated with LNG exports was located in the Gulf region, it was not possible in this study to examine regional impacts on either natural gas prices or economic activity. The Gulf Coast is not necessarily a representative choice given the range of locations now in different applications, so that any attempt to estimate regional impacts would be misleading without more regional specificity in the location of exports.

E. Effects on Different Socioeconomic Groups

Changes in energy prices are often divided into "effects on producers" and "effects on consumers." Although convenient to indicate that there are winners and losers from any market or policy change, this terminology gives limited insight into how the gains and losses are distributed in the economy. The ultimate incidence of all price changes is on individuals and households, for private businesses are all owned ultimately by people. Price changes affect not only the cost of goods and services purchased by households, but also their income from work and investments, transfers from government, and the taxes they pay. More relevant indicators of the distribution of gains and losses include real disposable income by income category, real consumption expenditures by income category, and possibly other measures of distribution by socioeconomic group or geography. This study addresses only the net economic effects of natural gas price changes and improved export revenues, not their distribution.

F. Implications of Foreign Direct Investment in Facilities or Gas Production

In this report it is assumed that all of the investment in liquefaction facilities and in increased natural gas drilling and extraction come from domestic sources. Macroeconomic effects could be different if these facilities and activities were financed by foreign direct investment ("FDI") that was additional to baseline capital flows into the U.S. FDI would largely affect the timing of macroeconomic effects, but quantifying these differences would require consideration of additional scenarios in which the business model was varied.

APPENDIX F – COMPLETE STATEMENT OF WORK

Task Title: Macroeconomic Analysis of LNG Exports

INTRODUCTION:

U.S. shale gas production has increased significantly due to novel hydraulic fracturing and horizontal drilling techniques that have reduced production costs. In the *Annual Energy Outlook 2011* prepared by the Department of Energy's Energy Information Administration, domestic natural gas production grows from 21.0 trillion cubic feet (Tcf) in 2009 to 26.3 Tcf in 2035, while shale gas production grows to 12.2 Tcf in 2035, when it is projected to make up 47 percent of total U.S. production. With this increased volume of domestic natural gas supply available, several companies have applied to the DOE/FE under section 3 of the Natural Gas Act ("NGA")[55] for authorization to export domestic natural gas as LNG to international markets where prices are currently higher. DOE/FE must determine whether applications to export domestically produced LNG to non-free trade agreement ("FTA") countries are consistent with the public interest[56].

To assist with the review of current and potential future applications to DOE/FE to export domestically produced LNG, DOE/FE has requested a natural gas export case study be performed by EIA. The EIA study will provide an independent case study analysis of the impact of increased domestic natural gas demand, as exports, under different incremental demand scenarios using the *AEO 2011* National Energy Modeling System ("NEMS") model. While useful to provide the range of marginal full-cost domestic natural gas production in different scenarios, the EIA NEMS case study will not address the macroeconomic impact of natural gas exports on the U.S. economy. A macroeconomic study that evaluates the impact of LNG exports is needed to more fully examine the impact of LNG exports on the U.S. economy.

PURPOSE:

The purpose of this task is to evaluate the macroeconomic impact of LNG exports using a general equilibrium macroeconomic model of the U.S. economy with an emphasis on the energy sector and natural gas in particular. The general equilibrium model should be developed to incorporate the EIA case study output from NEMS into the natural gas production module in order to calibrate supply cost curves in the macroeconomic model. A macroeconomic case study will be performed to evaluate the impact that LNG exports could have on multiple economic factors, but primarily on U.S. Gross Domestic Product, employment, and real income.

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[55] The authority to regulate the imports and exports of natural gas, including liquefied natural gas, under section 3 of the NGA (15 U.S.C. §717b) has been delegated to the Assistant Secretary for FE in Redelegation Order No. 00-002.04E issued on April 29, 2011.

[56] Under NGA section 3(c), the import and export of natural gas, including LNG, from and to a nation with which there is in effect a FTA requiring national treatment for trade in natural gas and the import of LNG from other international sources are deemed to be consistent with the public interest and must be granted without modification or delay. Exports of LNG to non FTA countries have not been deemed in the public interest and require a DOE/FE review.

The cases to be run will reflect LNG export volumes increasing by one billion cubic feet per day (Bcf/d) annually until reaching six Bcf/d from a reference case aligned with the *AEO 2011* reference case, a high natural gas resource case, and a low natural gas resource case. Additional cases will be run to evaluate the impact of LNG export volumes that increase much slower and much faster than in the reference case.

Some have commented that U.S. domestic natural gas prices could become disconnected with marginal domestic natural gas production cost and be influenced by higher international market prices. An analysis will be performed to assess whether there is an additional price increase, a "tipping point" price increase, above which exports of LNG have negative impacts on the U.S. economy for several of the cases. The "tipping point" price increase in this analysis could be above the marginal full production cost.

A qualitative report will be prepared that discusses how natural gas prices are formed in the United States and the potential impact that higher international prices could have on the U.S. market. This analysis will include an assessment of whether there are scenarios in which the domestic market could become unlinked to marginal production cost and instead become linked to higher international petroleum-based prices, and whether this could be a short-term or long-term impact, or both.

Initially, a preliminary assessment of the macroeconomic impact of the cases will be prepared and discussed with DOE. This will provide an opportunity for any adjustments to the ultimate cases that will be prepared. Finally, a report will be prepared that discusses the results of the macroeconomic study including topics identified in the Statement of Work.

STATEMENT OF WORK:

The types of analysis and discussions to be conducted include, but are not limited to:

1. U.S. Scenario Analysis (all 16 EIA cases) – Perform a case study on the impacts of a range of LNG export volumes on domestic full production costs under various export volume scenarios. A macroeconomic model will be aligned with the *AEO 2011 Reference Case* and other cases from the DOE/FE-requested EIA case study in different scenarios. Modify a general equilibrium model to calibrate supply cost curves in the macroeconomic model for consistency with EIA NEMS model. The following cases will be run with 5-year intervals through 2035:
    a. **Reference LNG Export Case –** using the macroeconomic model aligned with the *AEO 2011 Reference Case*, show export-related increases in LNG demand equal to the four export scenarios in the EIA study.
    b. Run sensitivity cases related to alternative shale gas resources and recovery economics. These include:
        i. **Low Shale Resource LNG Export Case** - align the macroeconomic model to the *AEO 2011 Low Shale EUR Case*, reflect LNG export volumes over time equal to the four export scenarios in the EIA study.

ii. **High Shale Resource LNG Export Case** – align the macroeconomic model to the *AEO 2011 High Shale EUR Case*, reflect LNG export volumes over time equal to the four export scenarios in the EIA study.

iii. **High Economic Growth LNG Export Case** - align the macroeconomic model to the *AEO 2011 High Economic Growth Case;* reflect LNG export volumes over time equal to the four export scenarios in the EIA study.

c. Run additional sensitivity cases – **Slow Increase in LNG Exports Case** - using the macroeconomic model aligned with the *AEO 2011 Reference Case*, increase LNG exports increase at a slower pace, growing at 0.5 Bcf/d beginning in 2015, until reaching 6 Bcf/d.

2. Preliminary Analysis – Prepare a preliminary analysis of the above cases and provide an initial summary of whether those cases have a positive or negative impact on GDP. After providing that information, discuss the results and determine whether the cases identified are still valid, if some cases should be eliminated, or others added.
3. Worldwide Scenario Analysis – Develop four global LNG market scenarios that define a range of international supply, demand, and market pricing into which U.S. LNG could be exported, as defined below. Using these scenarios, identify potential international demand for U.S. LNG exports, recognizing delivered LNG prices from the United States versus other global sources.
   a. Base case which is calibrated to EIA *International Energy Outlook 2011* for all natural gas
   b. Increased global LNG demand
   c. A restricted global LNG supply scenario in which only liquefaction facilities, of which there is already substantial construction, are completed
   d. Combination of higher international LNG demand and lower international LNG supply
4. Prepare a sensitivity analysis to examine how the ownership of the exported LNG and/or the liquefaction facility affects the U.S. economy.
5. Macroeconomic Report – Prepare a report that discusses the results of the different cases run with the key focus on the macroeconomic impacts of LNG exports. Combine global analysis and U.S. analysis to create new export scenarios that could be supported by the world market (as opposed to the EIA study in which LNG exports were exogenous to the model). Identify and quantify the benefits and drawbacks of LNG exports. Using a macroeconomic model, evaluate the comprehensive impact of all factors on:
   a. U.S. GDP
   b. Employment
   c. Household real income

   The Report will also include a discussion on:

   a. The observations on key cases run

    b. Balance of trade impact
    c. Expected impact on tax receipts from increased production of natural gas and exports
    d. The impact of LNG exports on energy intensive sectors for the scenarios developed
    e. Ownership sensitivity analysis
    f. Benefits
        - Jobs creation for the nation, not just a region
        - Potential increases in Federal revenues
        - Export earnings and balance of trade
    g. Drawbacks
        - Increased natural gas prices
        - Potential for, and impact of, loss of jobs in energy intensive industries
    h. GDP Macroeconomic impact
        - Authoritative analysis on GDP of above factors
    i. Other relevant analysis and information developed in consultation with DOE/FE
6. The price impacts of natural gas exports will be discussed in a qualitative report that includes how natural gas prices are formed in the United States and the potential impact that higher international prices could have on the U.S. market. This report could be stand-alone or part of the overall macroeconomic study. It will include, at a minimum, a discussion of:
    a. Current market mechanism that establishes U.S. domestic benchmark prices (e.g., Henry Hub)
    b. Potential market mechanism for linkage of domestic markets with higher international markets
    c. The potential linkage of natural gas with petroleum in international markets
7. Assess whether there is some volume of LNG exports, or price increase, above which the United States loses the opportunity for domestic value added industry development from use of low-cost domestic natural gas resources. The discussion will include:
    a. Identification of energy-intensive, trade-exposed industries potentially affected and characterization of their energy costs, employment and value added compared to all manufacturing
    b. Potential impacts on U.S. production of selected natural gas based bulk chemicals
8. After releasing the study results, at the request of DOE, prepare up to three responses to questions raised about the study in an LNG export proceeding or other public release of the study in which these questions or issues are raised

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Office of Natural Gas Regulatory Activities
Office of Fossil Energy
Forrestal Building, Room 3E-042
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Dear Secretary Chu:

Thank you and the Department of Energy's Office of Fossil Energy ("DOE/FE") for accepting these comments on NERA Economic Consulting's study (the "NERA Study," or "the Study") on the macroeconomic impacts of liquefied natural gas ("LNG") export on the U.S. economy. We submit these comments on behalf of the Sierra Club, including its Atlantic (New York), Colorado, Kansas, Michigan, Pennsylvania, Ohio, Oregon, Texas, Virginia, West Virginia, and Wyoming Chapters; and on behalf of Catskill Citizens for Safe Energy, the Center for Biological Diversity, Center for Coalfield Justice, Clean Air Council, Clean Ocean Action, Columbia Riverkeeper, Damascus Citizens for Sustainability, Delaware Riverkeeper Network, Earthworks' Oil and Gas Accountability Project, Food and Water Watch, Lower Susquehanna Riverkeeper, Shenandoah Riverkeeper, and Upper Green River Alliance, and on behalf of our millions of members and supporters.[1]

DOE/FE is required to determine whether gas exports are "consistent with the public interest." 15 U.S.C. § 717b(a). Although the NERA Study purports to demonstrate that LNG export is in the economic interest (if not the public interest) of the United States, it does not do so. In fact the study, prepared by a consultant with deep ties to fossil fuel interests, actually shows that LNG export would weaken the United States economy as a whole, while transferring wealth from the poor and middle class to a small group of wealthy corporations that own natural gas resources. This wealth transfer comes along with significant

[1] We have submitted these comments electronically. Hard copies of this document and CDs of all exhibits were also hand-delivered to TVA for filing, as requested by John Anderson at DOE/E today.

structural economic costs caused by increased gas production, which destabilizes regional economies and leaves behind a legacy of environmental damage.

Indeed, an independent analysis, attached to these comments and incorporated to them, demonstrates that NERA's own study shows that LNG export will harm essentially every other sector of the U.S. economy, driving down wages and potentially reducing employment by hundreds of thousands of jobs annually. While LNG exporters will certainly benefit, the nation will not.

An extensive economic literature demonstrates that nations that depend on exporting raw materials, rather than finished goods and intellectual capital, are worse off – a condition sometimes referred to as the "resource curse." The same curse often applies at the smaller scale of the towns and counties in which extraction occurs; those communities are often left with hollowed-out economies, damaged infrastructure, and environmental contamination once a resource boom passes. These dangers apply here with considerable force, but NERA did not even acknowledge, much less analyze them. Indeed, the basic economic model NERA used (which has not been shared with the public) is not suited for this analysis.

Moreover, NERA has entirely failed to account for, or even to acknowledge, the real economic costs which *environmental* harms impose. Intensifying gas production for export will also intensify the air and water pollution problems, public health threats, and ecological disruption associated with gas production – effects which DOE's own experts have cautioned are inadequately managed. The air pollution that gas production for export would generate would alone impose hundreds of millions or potentially billions of dollars of costs, and would greatly erode or even cancel the benefits of recent federal gas pollution standards. Yet, NERA omits this entire negative side of the ledger.

The NERA study, in short, is fundamentally flawed. DOE would be acting arbitrarily and capriciously if it relied upon that report to decide upon export licenses, because NERA misstates or entirely fails to consider critical aspects of this vital public interest question. *See* 5 U.S.C. § 706(2)(A); *see also Motor Vehicle Mftrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*¸ 463 U.S. 29, 43 (1983).

I. Introduction: The Magnitude of the LNG Export Issue and DOE/FE's Obligation to Protect the Public Interest

Recognizing the importance of the natural gas market to the national interest, Congress has vested DOE/FE with the power to license gas exports and imports. This direct regulatory control underlines the gravity of DOE/FE's responsibility. Gas exports, if they occur, will fundamentally affect the nation's environmental and economic future. DOE/FE has a strict Congressional charge to ensure that these exports only go forward if they are "consistent with the public interest." 15 U.S.C. § 717b(a).[2]

This inquiry has never before been so pointed because it has never before been possible for the United States even to consider exporting a large quantity of natural gas as LNG. Becoming a major supplier of LNG to the world market will increase gas production (and, hence, hydro-fracturing or "fracking"), and will also increase gas and energy prices.

These effects have the potential to be very large. DOE/FE is currently considering licenses to export 24.8 billion cubic feet per day ("bcf/d") of natural gas as LNG to nations with which the United States has not signed a free trade agreement ("nFTA" nations). It has already authorized 31.41 bcf/d of export to free-trade-agreement ("FTA") nations because it believes it lacks discretion to deny such FTA applications – though such FTA licenses are of somewhat less moment because most major gas importers are nFTA nations.[3] These are very large volumes of gas. In 2011, the United States produced just under 23,000 bcf of gas over the year.[4] The 24.8 bcf/d of nFTA exports are equivalent to 9,052 bcf/y, or about 39% of total U.S. production. Exporting such a large volume would have major effects on the U.S. economy and the environment, as production both increases and shifts away from domestic uses. While NERA assumes that lower volumes will ultimately be exported, the amounts involved are still large: The 4,380/y bcf case it uses as a high bar sees about 19% of current

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[2] We note that the concerns raised below apply with equal force to exports from both onshore and offshore facilities.

[3] The Act separately provides that DOE/FE must approve exports to nations that have signed a free trade agreement requiring national treatment for trade in natural gas "without modification or delay." 15 U.S.C.§ 717b(c). This provision was intended to speed *imports* of natural gas from Canada. Congress never understood it to allow automatic licenses for export. *See generally*, C. Segall, *Look Before the LNG Leap*, Sierra Club White Paper (2012) at 40-41 (discussing the congressional history of this provision), attached as Ex. 1. That DOE/FE has nonetheless issued export licenses under it, without raising the issue for Congressional correction, is itself an arbitrary and dangerous decision, inconsistent with Congressional intent.

[4] EIA, Natural Gas Monthly December 2012, Table 1 (volume reported is dry gas), attached as Ex. 2.

U.S. production sent abroad; the 1,370 bcf/y "low" case is still 5% of current production.[5]

Although the effects of export would, of course, likely be smaller with smaller volumes of export, applications for 9,052 bcf/y are before DOE/FE, and it would be arbitrary not to consider the cumulative impacts of the full volume of export which DOE/FE is now weighing. But even exporting smaller volumes of gas would necessarily alter the domestic economy and environment in significant ways. The Energy Information Administration ("EIA") has concluded that about two-thirds of gas for export would be drawn from new production, while the remaining third would be diverted from domestic uses, such as power production and manufacturing.[6] On the order of 93% of the new production would come from unconventional gas sources, and so would require fracking to extract the gas.[7]

DOE/FE's earlier public interest investigations of LNG imports did not so directly implicate such shifts in daily domestic life. As a result, DOE/FE's past, largely laissez-faire approach to gas import questions does not translate to gas export. DOE/FE has recognized as much, writing, in response to Congressional inquiries, that the public interest inquiry is to be applied with a careful look across a wide range of factors, informed by reliable data. DOE/FE Deputy Assistant Secretary Christopher Smith has testified that "[a] wide range of criteria are considered as part of DOE's public interest review process, including . . . U.S. energy security . . . [i]mpact on the U.S. economy . . . [e]nvironmental considerations . . . [and] [o]ther issues raised by commenters and/or interveners deemed relevant to the proceeding."[8]

Such care is manifestly appropriate here, and is legally required. As well as charging DOE with "assur[ing] the public a reliable supply of gas at reasonable prices," *United Gas Pipe Line Co v. McCombs*, 442 U.S. 529 (1979), he Natural Gas Act also grants DOE/FE "authority to consider conservation, environmental, and antitrust questions." *NAACP v. Federal Power Comm'n*, 425 U.S. 662, 670 n.4 (1976) (citing 15 U.S.C. § 717b as an example of a public interest provision); *see*

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[5] *See* NERA Study at 10 (Figure 5).

[6] EIA, Effects of Increased Natural Gas Exports on Domestic Energy Markets (Jan. 2012) at 6, 10--11, attached as Ex. 3.

[7] *See id.*

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

also id. at 670 n.6 (explaining that the public interest includes environmental considerations). In interpreting an analogous public interest provision applicable to hydroelectric power, the Court has explained that the public interest determination "can be made only after an exploration of all issues relevant to the 'public interest,' including future power demand and supply, alternate sources of power, the public interest in preserving reaches of wild rivers and wilderness areas, the preservation of anadromous fish for commercial and recreational purposes, and the protection of wildlife." *Udall v. Fed. Power Comm'n*, 387 U.S. 428, 450 (1967) (interpreting § 7(b) of the Federal Water Power Act of 1920, as amended by the Federal Power Act, 49 Stat. 842, 16 U.S.C. § 800(b)). Other courts have applied *Udall*'s holding to the Natural Gas Act. See, e.g., *N. Natural Gas Co. v. Fed. Power Comm'n*, 399 F.2d 953, 973 (D.C. Cir. 1968) (interpreting section 7 of the Natural Gas Act).

Despite these clear legal requirements, DOE/FE has thus far failed actually to conduct a careful and reasoned analysis of LNG export. Such an analysis would offer a thorough description of LNG exports' implications for the economy on both a macro-scale and on the scale on which people actually live. It would consider the effects of increasing dependence on resource exports on communities in the gas fields, on domestic industry, on the environment, and on U.S. energy policy. It would also offer counterfactuals, considering whether or not the nation would be better off without LNG export, or with lower volumes of export than are now proposed.

The NERA Study does none of these things. Instead, it reduces its analysis ultimately to a consideration solely of U.S. GDP, concluding that because GDP rises with export in its model, even though real wages and incomes fall, export must benefit the country. This conclusion is unsupported, and fails even to weigh the real effects of exports on the nation's life. The NERA Study's many flaws, in particular, prevent that document from serving as a meaningful contribution to DOE/FE's decisionmaking. Rather than relying upon it, DOE/FE should prepare a new study, with full public participation, investigating the many fundamental economic issues which NERA entirely fails to consider.[9]

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[9] Of course, economic issues are not the only matters germane to the public interest analysis. Environmental factors are also vital, and not only because environmental damage necessarily imposes economic costs (a point which we discuss in detail below). They are also relevant in their own right, as the Supreme Court has held and DOE/FE itself has repeatedly acknowledged.

Because DOE/FE must consider environmental impacts in addition to economic considerations, it must gather considerable additional information before deciding whether LNG exports are in the

II. The NERA Study Fails to Account for LNG Export's Significant Negative Impacts on the U.S. Economy

The NERA Study's fundamental flaw is that it mistakes an increase in U.S. GDP, which, even if real, would be captured largely by a narrow set of moneyed interests, for the public interest. It simplistically sums the gains from export that a few accrue with the losses of the many to conclude that Americans benefit overall. A fair look at NERA's own results, and the extensive literature on how resource extraction affects countries and communities, demonstrates that this facile equivalence is simply false.

NERA's flawed approach is perhaps best summed up by its own figures. The figure below, drawn directly from NERA's report[10] for one export scenario, shows a net change in GDP (the black line on the figure) occurring only because NERA expects the natural gas "resource income" which exporters and producers reap to rise somewhat more than labor and capital income fall in response to exports. Even if that is so, the groups that benefit are not the same as those that suffer. Many Americans would experience some portion of the approximately $45 billion in declining wages that NERA forecasts in a single year, and many would suffer the pollution and community disruption that comes with gas production for export. Only a few would reap the revenues. In essence, LNG export transfers billions from the middle class to gas companies.

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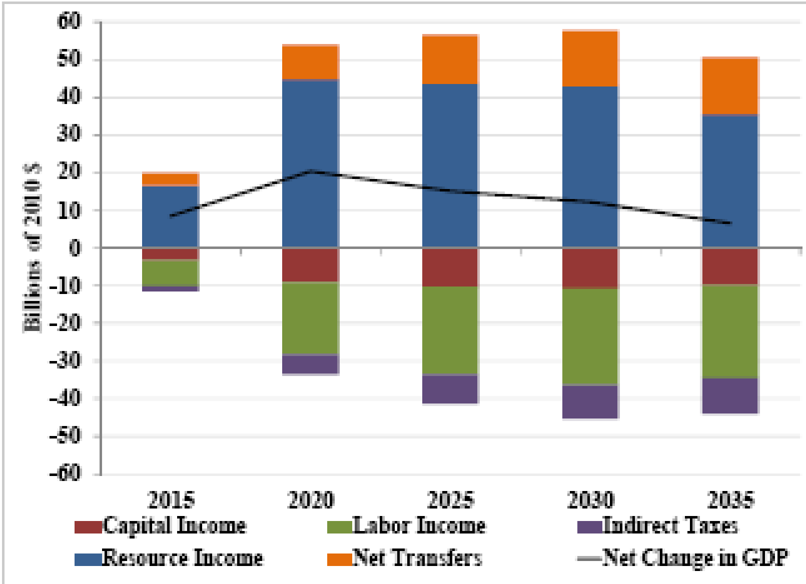
public interest. It can and must do so by complying with NEPA, which requires federal agencies to consider and disclose the "environmental impacts" of proposed agency actions. 42 U.S.C. § 4332(C)(i). NEPA requires preparation of an "environmental impact statement" (EIS) where, as is the case with LNG export proposals, the proposed major federal action would "significantly affect[] the quality of the human environment." 42 U.S.C. § 4332(C). DOE/FE regulations similarly provide that "[a]pprovals or disapprovals of authorizations to import or export natural gas . . . involving major operational changes (such as a major increase in the quantity of liquefied natural gas imported or exported)" will "normally require [an] EIS." 10 C.F.R. Part 1021, Appendix D, D9. DOE must assess these impacts cumulatively across all terminals and export proposals.

A full programmatic EIS is required here, and must consider, among many other points, both the immediate environmental consequences of constructing and operating LNG export facilities and the consequences of the increased gas production necessary to supply them.

[10] NERA Study at 8 (Figure 3).



The costs suffered by the rest of the country to procure a GDP increase that even NERA acknowledges is "very small"[11] are very large – and grow larger as the volume of export increases. They include falling wages and employment, a lasting legacy of community disruption, and likely long-term damage to the national economy's resilience and diversity. They also, as we discuss later in these comments, come with environmental damage, which imposes both economic and ecological costs.

A. The NERA Study Itself Demonstrates that LNG Exports Will Cause Economic Harm and That NERA Does Not Reliably Support Its Claims of Benefits

Sierra Club asked Synapse Energy Economics to conduct a thorough independent review of the NERA Study. Synapse's review is attached to these comments[12] and incorporated in full by reference. Synapse concluded, consistent with other comments in the record, that the NERA study is not reliable and does not demonstrate that LNG exports are in the national economic interest, much less in the public interest generally.[13]

Critical points in that analysis include:

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[11] *Id*. at 8.
[12] See attached, as Ex. 5.
[13] *See also, e.g.,* the Comments of Jannette Barth, Wallace Tyner, David Bellman, and Carlton Buford, in this docket.

LNG Exports Cause The Other Components of GDP To Fall

Just as NERA's own figures suggest, LNG export raises GDP almost entirely because LNG exporters can sell their product at a high price, and capture those revenues. Yet, because LNG export raises gas prices and diverts investment from other sectors, NERA's own results show that the other components of GDP either stay level or *decline* in response to export. In essence, the rest of the economy shrinks as exports expand, leaving a less diversified, and smaller, economy for those who do not profit directly from exports.

LNG Exports Cause Job Losses, According to NERA's Own Methodology

NERA avoided providing employment figures in this report, but the methodology that NERA has used in other studies for that purpose shows major job losses. The declining labor income NERA predicts translates into job losses of between 36,000 to 270,000 "job-equivalents"[14] *per year*; the greater the pace and magnitude of exports, the greater the job losses.

Most Americans Will *Only* Experience the Costs of Export

NERA acknowledges that "[h]ouseholds with income solely from wages" will not benefit from LNG export.[15] But that group contains *most* Americans. Only about half of all Americans own any stock, and only a few, generally wealthy, people own a significant amount. That means very few Americans will benefit at all from enriching LNG and gas companies. For most people, LNG exports simply mean declining wages and employment.

A Significant Amount of LNG and Natural Gas Revenues May Leave America

NERA assumes that LNG export revenues all rest in domestic companies. In fact, many of the companies which now propose to run export terminals are foreign-owned, in whole or in part (including one entity which is owned by the government of Qatar, which would be one of America's competitors in the LNG market), and some are not publicly-held. The complex ownership structure of these companies raises the real possibility that

[14] A "job-equivalent' is the salary of a worker earning the average salary.

[15] NERA Study at 8.

revenues will leave the United States and so may escape domestic taxation and securities markets.[16]

Increasing Exports of Raw Materials Is Associated with Economic Damage
Nations which emphasize raw material export often suffer from significant harm, as export impedes manufacturing and other economic mainstays. This "resource curse" has caused the decline of middle class industrial jobs in other nations, and is also associated with higher levels of corruption and other governance problems. Because the NERA Report relies on stale data that underestimates gas demand, it may underestimate the scope of these potential problems.

NERA Fails Even to Acknowledge the Economic Implications of Environmental Harm from Export
LNG export would significantly increase fracking and other environmental and public health threats. Increased environmental and health damage imposes substantial economic costs. Yet NERA does not acknowledge, much less analyze, these costs.

The Synapse analysis, in short, shows that NERA has entirely missed the point of its own report. Export will cause many wage-earners to lose their jobs or suffer decreased wage income as a result of increases in gas prices. Even employees whose jobs are not directly affected will suffer decreased "real wage growth" as gas prices and household gas expenditures increase relative to nominal wages.[17] All consumers of natural gas—residential, commercial, industrial, and electricity generating users—will suffer higher gas bills despite reducing their gas consumption.[18] While NERA trumpets GDP increases driven by increasing export revenues, its report really shows those increasing export dollars are coming out of the pockets of the American middle class.[19]

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[16] A detailed analysis of the ownership of LNG export companies is attached as Ex 6.
[17] NERA Report at 9.
[18] EIA Export study, at 11, 15. These increases are very large in absolute terms. At a minimum, in the EIA's low/slow scenario, gas and electricity bills increase by $9 billion per year, and this increase grows to $20 billion per year in other scenarios. *Id.* at 14.
[19] The very wealthy do not need more money. An extensive body of economic and philosophical literature demonstrates that the marginal utility of money declines with income—an extra $100 matters less the more money a person has. *See, e.g.*, Matthew D. Adler, *Risk Equity: A New Proposal*, 32 Harv. Envtl. L. Rev. 1 (2008), attached as Ex 7.

The more economic activity that is dedicated to gas production for LNG export, the less focus will there be on building a diversified and strong economic base in this country. Likewise, as LNG export wealth flows to a lucky few, income inequality will grow.

The public interest analysis must account for these effects. Indeed, the Obama Administration has repeatedly emphasized the need to avoid regressive policies that transfer wealth from the middle classes to the wealthy.[20] As the President has explained that "Our economic success has never come from the top down; it comes from the middle out. It comes from the bottom up."[21] Similarly, the President has warned against short-sighted management of wealth. As he explained in the 2009 State of the Union address, the nation erred when "too often short-term gains were prized over long-term prosperity, where we failed to look beyond the next payment, the next quarter, or the next election."[22] DOE/FE must not allow a "surplus [to] bec[o]me an excuse to transfer wealth to the wealthy instead of an opportunity to invest in our future."[23]

B. The NERA Study Underestimates Economic Harm to Manufacturing and Other Sectors That Will Offset the Purported Economic Benefits of Export

The Synapse report explains in detail that, as a result of several flawed assumptions and oversimplifications, the NERA study understates economic harms to manufacturing and other sectors that will result from LNG export. These errors may, in fact, be great enough, on their own, to actually depress total GDP, contrary to NERA's conclusions, as another macroeconomic study in the record, by Purdue economist Dr. Wallace Tyner, explains.[24] Certainly, little in the NERA study inspires any confidence:

First, NERA's use of outdated forecasts of domestic demand for natural gas caused it to significantly understate both price impacts and harm to gas-

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[20] *See, e.g.*, State of the Union Address (January 24, 2012), available at http://www.whitehouse.gov/the-press-office/2012/01/24/remarks-president-state-union-address

[21] Remarks by the President at the Daimler Detroit Diesel Plant, Redford, MI (Dec. 10, 2012), attached as Ex 8 and available at http://www.whitehouse.gov/the-press-office/2012/12/10/remarks-president-daimler-detroit-diesel-plant-redford-mi

[22] State of the Union Address (Feb. 24, 2009), attached as Ex 9 available at http://www.whitehouse.gov/the_press_office/Remarks-of-President-Barack-Obama-Address-to-Joint-Session-of-Congress

[23] *Id.*

[24] *See* Comments of Dr. Wallace Tyner in this docket.

dependent sectors of the U.S. economy. Second, NERA failed to model exports' impact on each economic sector potentially impacted by price increases, and thus impacts to individual industries are obscured. Third, NERA failed to assess impacts to several industries likely to be affected by export. Finally, NERA failed to account for LNG transaction costs that are likely to increase export volumes and exacerbate the price impacts of export. Unless these flaws are corrected, any LNG export decision based on the NERA study will "entirely fail[] to consider . . . important aspect[s]" of the export problem, and will thus be arbitrary and capricious. *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*¸ 463 U.S. 29, 43 (1983).

First, as Synapse explains in detail, the NERA Study inexplicably failed to use the EIA's most recent natural gas demand forecasts, even though NERA has used the more recent data in other reports. NERA used EIA's Annual Energy Outlook (AEO) 2011, even though AEO 2012 was finalized in June 2012, months before the NERA study was completed.[25] Indeed, an October 2012 report entitled *Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector* used the more recent data, showing that it would not have been infeasible for NERA to use it in its December 2012 export study. Moreover, an early release of AEO 2013 was published just days after NERA's report was finalized. NERA nonetheless failed to use the 2013 data – or even the 2012 data – in its analysis.

NERA's failure to use the most recent data significantly altered the outcome of its analysis. Between AEO 2011 and AEO 2012, projections of domestic consumption of natural gas rose above previously predicted levels. Accordingly, NERA's use of the older 2011 data resulted in an underestimate of domestic demand for gas. Using the more recently, higher predictions of demand would decrease the amount of natural gas available for export, thus increasing domestic prices and in turn increasing economic impacts that flow from price increases, including lost income to wage earners and increased costs to household and business consumers of natural gas for heating and electricity.[26]

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[25] See Synapse Report at 17.

[26] Synapse Report at 8. Contrasted against its willingness to use higher demand figures to generate inflated cost estimates for EPA rules controlling toxic mercury emissions, NERA's failure to use the same demand figures here underscores the appearance of bias discussed in detail in part IV, below. For DOE to rely on a study that contains such flaws would "raise questions as to whether the agency is fulfilling its statutory mandates impartially and competently." *Humane Soc'y v. Locke*, 626 F.3d 1040, 1049 (9th Cir. 2010).

Second, by its own admission NERA failed to model exports' impact on each economic sector potentially impacted by price increases, obscuring impacts to individual industries.[27] NERA fails to explain why sector-specific modeling could not be accomplished, stating simply that "it was not possible to model impacts of each of the potentially affected sectors."[28] As Congressman Markey points out in his letter to DOE, however, sector-specific modeling *was* recently conducted in an interagency report designed to assess the economic impacts of the Waxman-Markey cap-and-trade bill, demonstrating that such analysis is both feasible and useful.[29] Without sector-by-sector modeling that uses the most recent data available, impacts to individual economic sectors remain unknown, and those harmed by exports are consequently unable to fully understand and comment on these impacts. The failure to fully describe impacts sector-by-sector, using the most current data available, thus obscures exports' true costs and constrains public participation in export decisions.

Third, NERA failed to fully assess economic impacts to all industries likely to be affected by price increases. NERA states that energy-intensive, trade-exposed industries likely to be affected by price increases are "not high value-added industries," but it does not grapple with the contention – offered by Congressman Markey and by Dow Chemical – that impacts to the manufacturing sector propagate through the economy because they dampen production throughout the value chain.[30] DOE must address this shortcoming in NERA's analysis in order to make an informed decision whether to subject American industry to such far-reaching effects.

Finally, NERA fails to accurately account for transaction costs of LNG exports and thus fails to accurately predict the behavior of market participants. When properly accounted for, these costs tend to increase exports to levels exceeding those predicted by NERA, thus intensifying the impact of export on U.S. gas prices. NERA first potentially overstates the transportation costs associated with export of U.S. gas by assuming that all U.S. gas will be exported from the

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[27] NERA Study at 70.
[28] *Id*.
[29] Letter from Rep. Edward J. Markey to Hon. Steven Chu (Dec. 14, 2012), *available at* http://democrats.naturalresources.house.gov/sites/democrats.naturalresources.house.gov/files/documents/2012-12-14_Chu_NERA.pdf, at 5, attached as Ex 10. Senator Wyden has also written to express similar concerns. *See* Letter from Senator Ron Wyden to Hon. Steven Chu (Jan. 10, 2013), attached as Ex 11.
[30] *Id*. at 6.

Gulf Coast.[31] Exports from the Gulf Coast to Asia have high transportation costs, raising prices paid by the importer and thus making exports less economically attractive. Several export terminals are proposed for the West Coast, however, and these terminals will be able to transport gas to Asia with fewer transportation costs. Accordingly, completion of these terminals may lead to higher volumes of exports than NERA predicts.

In addition, NERA ignores the possibility that long-term contracts at export terminals will lock in exports regardless of subsequent domestic price increases. Under the "take or pay" liquefaction services arrangements that many LNG export terminals will likely adopt, would-be exporters will be required to pay a fee to reserve terminal capacity, regardless of whether that capacity is actually used to liquefy and export gas.[32] This arrangement may cause exporters to continue to export U.S. gas even if prices increase, because the required liquefaction services charges will discourage them from switching to alternative energy sources. As a result, exports may continue to occur – and prices may continue to rise – even where NERA predicts that exports will cease.[33] Such price increases would exacerbate harms to residential and commercial gas consumers, as well as wage earners in manufacturing and other energy-intensive sectors.

In short, NERA not only wrongly attempts to offset harm to the base of the American economy with benefits to a few gas corporations to reach its sunny conclusions, it also very likely understates the real magnitude of the harm.

C. LNG Exports Will Harm Communities Across the Country

Harms associated with LNG export are not limited to other industrial sectors. A closer look at the real consequences of increasing dependence on export and gas production underlines NERA's core error of mistaking gas company profits for the public interest. Indeed, the real costs extend beyond the national-level declines in middle class welfare and industry. The "resource curse" which LNG export portends for the nation as a whole is echoed by the stories of similarly "cursed" regions across the country that are dependent upon resource extraction as an economic driver. In those regions, the same patterns recur: Weak growth or decline in other industries, population losses, soaring infrastructure costs, and

[31] NERA Study at 88-89, 210.

[32] *See Sabine Pass* DOE Order No. 2961, at 4 (May 20, 2011); Cheniere Energy April 2011 Marketing Materials, *available at* http://tinyurl.com/cqpp2h8 (last visited Jan. 13, 2013), at 14.

[33] *See* NERA Study at 37-46.

all the other consequences of being at the receiving end of an extractive apparatus that channels the wealth of a resource boom from an entire landscape into just a few pockets.[34]

Of course, many communities are already suffering these costs as the shale gas boom sweeps the nation. But the question now is whether to double-down on that economic strategy. Export will intensify the demand for gas, and accelerate the shift towards extraction-based economies around the country, with all the costs that attach to that choice. NERA entirely fails to consider these impacts, but they are central to the public interest question before DOE/FE, and it would be arbitrary and capricious to ignore them in the way that NERA has done. DOE/FE must weigh them in its analysis.

i. Resource Extraction Is Associated with Economic Damage

"Resource curse" effects are well documented in the economic literature. One of the most comprehensive surveys, by Professors Freudenburg and Wilson, of economic studies of "mining" communities (including oil and gas communities) concludes that the long-term economic outcomes are "consistently and significantly negative."[35] That research surveys a broad body of international and national work to conclude that strikingly few studies report long-term positive consequences for mining-dependent communities. One of the many papers recorded in that comprehensive survey concludes that census data from across the country showed that "mining-dependent counties had lower incomes and more persons in poverty than did the nonmining counties."[36]

These results occur because resource extraction dependent economies are fragile economies. Increasing dependence on raw material markets diverts investment from more durable industries, less influenced by resource availability and changing market costs. The inherent boom and bust cycle of such activities also stresses the infrastructure and social fabrics of regions focused on resource

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[34] Other workers have raised further important questions, which DOE/FE must consider, about the shale gas boom's implications for the domestic economy and environment, as well as for U.S. energy security. *See, e.g.*, Food and Water Watch, *U.S. Energy Insecurity: Why Fracking for Oil and Natural Gas is a False Solution* (2012), available at http://documents.foodandwaterwatch.org/doc/USEnergyInsecurity.pdf, and attached as Ex 12.
[35] W.R. Freudenburg & L.J. Wilson, *Mining the Data: Analyzing the Economic Implications of Mining for Nonmetropolitan Regions*, 72 Sociological Inquiry 549 (2002) at 549, attached as Ex 13.
[36] *Id.* at 552.

extraction to the exclusion of more sustainable growth. As Freudenburg & Wilson explain:

> [T]here is a potentially telling contrast in two types of studies that have gauged the reaction of local leaders. In regions that are expected increased mining or just beginning to experience a "boom," it is typical to find … "euphoria." Unfortunately, in regions that have actually experienced natural resource extraction, local leaders have been found to view their economic prospects less in terms of jubilation than of desperation.[37]

Indeed, the Rural Sociological Society's Task Force on Rural Poverty "ultimately identified resource extraction not as an antidote to poverty but as something more like a cause or correlate."[38]

A study of the long-term prospects of western U.S counties which focused on resource extraction rather than more durable economic growth strategies documents this trend. That 2009 study by Headwaters Economics looked at the performance of "energy-focusing" regions compared to comparable counties over the decades since 1970.[39] It concludes that "counties that have focused on energy development are underperforming economically compared to peer counties that have little or no energy development."[40]

These differences are stark. The economic data Headwaters gathered shows that energy-focused counties have careened through periods of intense booms and lasting busts which have impaired the resilience and long-term growth of their economies.[41] Although growth spiked during boom periods, it cratered when energy production faltered, creating economies "characterized by fast acceleration and fast deceleration."[42] This stutter-step depresses long-term growth. In energy-focusing counties from 1990 to 2005, for instance, the average rate of personal income growth was 0.6% lower than in more diversified counties, and the employment growth rate was 0.5% lower.[43]

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[37] *Id.* at 553.
[38] *Id.*
[39] Headwaters Economics, *Fossil Fuel Extraction as a County Economic Development Strategy: Are Energy-Focusing Counties Benefiting?* (revised. July 2009), attached as Ex 14.
[40] *Id.* at 2.
[41] *See id.* at 8-10.
[42] *Id.* at 10.
[43] *Id.*

These slow growth rates are symptomatic of deep structural differences. As Headwaters explains, the energy-focusing counties did not diversify their economies; indeed, they were nearly three times less diversified than their peer counties, meaning that they hosted far fewer different industries than their peers.[44] As a result, when growth occurred, it occurred only in a few sectors, leaving those counties vulnerable to contractions in energy use and to energy price spikes.[45]

Narrowly focusing on energy jobs also rendered these counties less broadly prosperous. A wage gap of over $30,000 annually opened between energy workers and workers in other fields in these counties between 1990 and 2006.[46] This "is not a healthy sign" because it means that "more people, including teachers, nurses, and farm workers, will be left behind if renewed energy development increases the general cost of living, especially the cost of housing."[47] The energy-focusing counties show this divergence between haves and have-nots: their income distributions show a larger proportion of relatively poorer families and a few very wealthy ones, indicating that energy wealth does not flow readily into the larger economy.[48]

The energy-focusing counties also had systematically lower levels of education, and lower levels of retirement and investment dollars than their peers.[49] By focusing on energy, rather than providing a broad range of services, they were less able than their peers to attract a broad economic base that could attract new investors and educated workers.

The upshot is that, on almost every measure, energy production did not prove to be a successful development strategy. Only one of the 30 energy-focused counties Headwaters studied ranked among the top 30 economic performers in the western United States in 2009, and more than half were losing population.[50] As Headwaters summarized its conclusions:

> EF ["Energy-focusing"] counties are today less well positioned to compete economically. EF counties are less diverse economically, which makes them

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[44] *Id.* at 17.
[45] *See id.* at 17-18.
[46] *Id.* at 19.
[47] *Id.*
[48] *Id.* at 20.
[49] *Id.* at 20-21.
[50] *Id.* at 2.

> less resilient but also means they are less successful at competing for new jobs and income in growing service sectors where most of the West's economic growth has taken place in recent decades. EF counties are also characterized by a greater gap between high and low income households, and between the earnings of mine and energy workers and all other workers. And EF counties are less well educated and attract less investment and retirement income, both important areas for future competitiveness.[51]

The experience of one of these counties, Sublette County, Wyoming, is particularly telling in this regard. A 2009 report prepared for the Sublette County Commissioners[52] describes experiences consistent with those analyzed by Freudenburg & Wilson and by Headwaters.

The Sublette study shows that a gas boom accompanied by thousands of wells, has caused real economic stress in the country, even as it enriched some residents. It determined that the 34% population increase in the county, which far outstripped historical trends, and accompanying demands on infrastructure and social services, were seriously disrupting the regional economy.[53]

The study records a region struggling under the impacts of a boom. The population of the country increased by over 3,000 people in under a decade, and is expected to grow by another 3,000.[54] This huge influx of energy-related employees is badly stressing regional social and physical infrastructure. The regional governments have already spent over $60 million on capital upgrades to improve roads and sewers which are crumbling under the strain, but remain at least $160 million in the hole relative to projects which they need to undertake to accommodate their new residents.[55] One town will need to spend the equivalent of ten years of annual revenue for just one necessary sewer project and "[s]imilar scenarios exist for all jurisdictions within Sublette County."[56] Municipalities across the country are unable to afford upgrades necessary to maintain their systems.[57]

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[51] *Id.* at 22.
[52] Ecosystem Research Group, *Sublette County Socioeconomic Impact Study Phase II- Final Report* (Sept. 28, 2009), attached as Ex 15
[53] *See id* at ES-3 – ES-5.
[54] *Id.*at 10-15.
[55] *Id.* at 55.
[56] *Id.*
[57] *Id.* at 115-116.

Meanwhile, just as Headwaters reported for the West generally, energy extraction is driving up economic inequality and making it more difficult to sustain other county residents. Housing prices in Sublette County increased by over $21,000 *annually*,[58] far ahead of income growth. Indeed, the gap between the qualifying income to buy an average Sublette County home and the median wage was over $17,000 in 2007.[59] The report concludes that "[i]f this trend continues fewer and fewer families will be able to afford an average home."[60] Only employees in the gas sector could afford such purchases; "all other employment sectors had average annual incomes significantly below that required to buy a house."[61]

Consistent with the increase in housing costs, the cost of living increased throughout the county, with energy job wages far outpacing those in all other sectors meaning that "[w]orkers in sectors with lower average wages may find it difficult to keep up."[62]

The boom has also come with social disruption. Traffic has vastly increased and accidents have more than doubled, with over a quarter of them resulting in injury.[63] Over $87 million in road projects are necessary to manage this increased traffic.[64] Crime has also jumped: there were only 2 violent offenses (such as rape and murder) in 2000, before the boom but there were 17 in 2007.[65] Juvenile arrests rose by 92% and DUI cases have spiked sharply upwards, increasing by 57% from 2000 to 2007.[66]

All these disruptions and tens of millions in spending come to support a boom that will not last. The report records that the oil and gas companies operating in the counties expect to see employment drop from thousands of workers to only several hundred within the next decades.[67] Once the wave passes, Sublette County will be left with lingering infrastructure costs, a less diversified economy, and the pollution from thousands of wells and associated equipment. That path

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[58] *Id.*at 90.
[59] *Id.* at 92.
[60] *Id.*
[61] *Id.*
[62] *Id.*at 87.
[63] *Id.*at 102.
[64] *Id.* at 107.
[65] *Id.*
[66] *Id.* at 110-11.
[67] *Id*. at 81.

leads, as the Headwaters report shows, towards a less resilient, less prosperous, future.

ii. The Shale Gas Boom is Causing Similar Problems, and LNG Export Will Worsen Them

The shale gas production boom which LNG export would exacerbate is very likely to follow this familiar pattern of short-term gain for a few, accompanied by long-term economic suffering for many more residents of resource production regions. Although the boom is still in a relatively early phase, available analysis already suggests that the same problems will recur. Export-linked production will intensify the pace and severity of the boom, causing further economic dislocation.

One recent study by Amanda Weinstein and Professor Mark Partridge of Ohio State University, for instance, documents patterns that mimic those seen in the Headwaters and Sublette studies, and in the Freudenburg and Wilson review paper.[68] Using Bureau of Economics Analysis statistics, the study directly compared employment and income in counties in Pennsylvania with significant Marcellus drilling and without significant drilling, and before after the boom started. As Table 1, below, shows, counties in both areas *lost* jobs even as drilling accelerated during the economic recession of 2008, and that the drilling counties lost jobs more quickly. Income increased more quickly in those counties at the same time in a pattern that tracks the results from the western United States studies discussed above: Drilling activities brings more wealth into an area, but that wealth is concentrated in the extraction sector, even as job losses occur in other sectors

Table 1: Comparing Pennsylvania Counties, With and Without Drilling, Over Time[69]

	Employment Growth Rate 2001-2005	**Employment Growth Rate 2005-2009**	**Income Growth Rate 2001-2005**	**Income Growth Rate 2005-2009**
Drilling	1.4%	-0.6%	12.8%	18.2%

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[68] Amanda Weinstein and Mark D. Partridge, *The Economic Value of Shale Natural Gas in Ohio*, OHIO STATE UNIVERSITY, Swank Program in Rural-Urban Policy Summary and Report (December 2010) ("Ohio Study"), attached as Ex 16.

[69] Adapted from Table 1 of the *Ohio Study* at 15.

Counties				
Non-Drilling Counties	5.3%	-0.4%	12.6%	13.6%

These shifts in the job market are accompanied by the same set of infrastructure costs and harms to other industries that are familiar from the western case studies.[70] Tourism, a particularly lucrative industry in the northeastern regions where the Marcellus Shale boom is expanding, is likely to be particularly hard hit. Gas production harms tourism by clogging roads, impacting infrastructure, diminishing the scenic value of rural areas, and through other means. These threats to the tourism industry are particularly concerning for many parts of the Marcellus region, including New York's Southern Tier, where tourism is a major source of income and employment. In the Southern Tier, according to one recent study, the tourism industry directly accounts for $66 million in direct labor income, and 4.7% of all jobs, and supports 6.7% of the region's employment.[71]

And, once again, job losses seem likely to follow the boom, as the initial production phase ends. As the Ohio Study explains, "impact studies do not produce continuous employment numbers. If an impact study says there are 200,000 jobs, this does not mean 200,000 workers are continuously employed on a permanent basis. . . . [W]hile the public is likely more interested in continuous ongoing employment effects, impact studies are producing total numbers of supported jobs that occur in a more piecemeal fashion."[72] This failing is particularly relevant here, because the manufacturing and other jobs LNG exports and export-related production will eliminate are typically permanent positions,[73] whereas the gas production jobs induced production will create typically do not provide sustainable, well-paying local employment. This is in part because the industry's employment patterns are uneven: one study found that, in Pennsylvania, "*the drilling phase accounted for over 98% of the natural gas*

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[70] Infrastructure costs include, for example, costs to roads, water, and hospitals. *See, e.g.*, CJ Randall, *Hammer Down: A Guide to Protecting Local Roads Impacted by Shale Gas Drilling* (Dec. 2010), attached as Ex 17; Susan Riha & Brian G. Rahm, *Framework for Assessing Water Resource Impacts from Shale Gas Drilling* (Dec. 2010), attached as Ex 18; Associated Press, *Gas Field Workers Cited in Pa. Hospital's Losses*, Pressconnects.com (Dec. 24, 2012), attached as Ex 19.
[71] Andrew Rumbach, *Natural Gas Drilling in the Marcellus Shale: Potential Impacts on the Tourism Economy of the Southern Tier* (2011), attached as Ex 20.
[72] Ohio Study at 11.
[73] NERA report at 62.

industry workforce engaged at the drilling site," and that complementary Wyoming data showed a similar drop-off.[74]

Drilling jobs, in short, correspond to the boom and bust cycle inherent to resource extraction industries.[75] The remaining, small, percentage of production-phase and office jobs are far more predictable, but must be filled with reasonably experienced workers.[76] Although job training at the local level can help residents compete, the initial employment burst is usually made up for people from out of the region moving in and out of job sites; indeed, "[t]he gas industry consistently battles one of the highest employee turnover problems of any industrial sector."[77]

A set of studies from Cornell University's Department of City and Regional Planning confirm this pattern of a short burst of economic activity followed by general economic decline. Those researchers spent more than a year studying the economic impacts of the gas boom on Pennsylvania and New York. Their core conclusion is that boom-bust cycle inherent in gas extraction makes employment benefits tenuous, and may leave some regions hurting if they are unable to convert the temporary boom into permanent growth. As the researchers put it:

> The extraction of non-renewable natural resources such as natural gas is characterized by a "boom-bust" cycle in which a rapid increase in economic activity is followed by a rapid decrease. The rapid increase occurs when drilling crews and other gas-related businesses move into a region to extract the resource. During this period, the local population grows and jobs in construction, retail and services increase, though because the natural gas extraction industry is capital rather than labor intensive, drilling activity itself will produce relatively few jobs for locals. Costs to communities also rise significantly, for everything from road maintenance and public safety to schools. When drilling ceases because the commercially recoverable resource is depleted, there is an economic "bust" – population and jobs depart the region, and fewer people are left to support the boomtown infrastructure.[78]

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[74] *See* Jeffrey Jacquet, *Workforce Development Challenges in the Natural Gas Industry*, at 4 (Feb. 2011) (emphasis in original), attached as Ex 21.

[75] *Id.*

[76] *Id.* at 4-5, 12-14.

[77] *Id.* at 13.

[78] Susan Cristopherson, CaRDI Reports, *The Economic Consequences of Marcellus Shale Gas Extraction: Key Issues* (Sept. 2011) at 4, attached as Ex 22.

This boom and bust cycle is exacerbated by the purportedly vast resources of the Marcellus play, because regional impacts will persist long after local benefits have dissipated, as the authors explain, and may be destructive if communities are not able to plan for, and capture, the benefits of industrialization:

> [B]ecause the Marcellus Play is large and geologically complex, the play as a whole is likely to have natural gas drilling and production over an extended period of time. While individual counties and municipalities within the region experience short-term booms and busts, the region as a whole will be industrialized to support drilling activity, and the storage and transportation of natural gas, for years to come. Counties where drilling-related revenues were never realized or could have ended may still be impacted by this <u>regional</u> industrialization: truck traffic, gas storage facilities, compressor plants, and pipelines. The cumulative effect of these seemingly contradictory impacts – a series of localized short-term boom-bust cycles coupled with regional long-term industrialization of life and landscape – needs to be taken into account when anticipating what shale gas extraction will do communities, their revenues, and the regional labor market, as well as to the environment.[79]

Some people will prosper and some will not during the resultant disruption and, warn the Cornell researchers, the long-term effects may well not be positive, based upon years of research on the development of regions dependent on resource extraction:

> [T]he experience of many economies based on extractive industries warns us that short-term gains frequently fail to translate into lasting, community-wide economic development. *Most alarmingly, a growing body of credible research evidence in recent decades shows that resource dependent communities can and often do end up worse than they would have been without exploiting their extractive reserve.* When the economic waters recede, the flotsam left behind can look more like the aftermath of a flood than of a rising tide.

Id. at 6 (emphasis supplied).

[79] *Id.* (emphasis in original).

A later, peer-reviewed and formally published version of this work, builds upon these lessons.[80] Collecting research from around the country, including the Sublette County experience discussed above, it canvasses the infrastructure stresses,[81] social dislocations and population shifts,[82] and environmental costs of resource extraction,[83] to conclude that expanding the shale gas boom may well harm many communities, explaining that "rural regions whose economies are dependent on natural resource extraction frequently have poor long-term development outcomes."[84]

In fact, the researchers conclude that in some cases communities "may wind up worse off" than they were before the boom started.[85] They explain that the boom-related cost of living and materials expense increases may well crowd out other industries, such as the fragile dairy industry now operating in many northeastern shale plays.[86] Gas boom regions may even wind up shrinking. Counties in New York and Pennsylvania with significant natural gas drilling between 1994 and 2009 have lost more population than peers without drilling activity.[87]

After the boom recedes, the weakened local economy struggles to provide for the infrastructure that was required to support the boom:

> During the boom period, the county's physical infrastructure was planned and installed to accommodate an expanding population. The nature of infrastructure such as roads, sewer and water facilities, and schools is that once it is built, it generates ongoing maintenance costs (as well as debt service costs) even if consumption of the facilities declines…. The departure of [boom time] workers and higher income, mobile professionals [will leave] the burden of paying for such costs to remaining smaller, lower-income, population.[88]

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[80] S. Christopherson & N. Rightor, *How shale gas extraction affects drilling localities: Lessons for regional and city policy makers*, 2 Journal of Town & City Management 1 (2012), attached as Ex 23.
[81] *Id.* at 11-12.
[82] *Id.* at 10-11.
[83] *Id.* at 12-13.
[84] *Id.* at 15.
[85] *Id.*
[86] *Id.*
[87] *Id.*
[88] *Id.* at 16.

In short, resource booms may bring wealth to a few companies, and, transiently, to some regions, but the long-term consequences are negative.[89] After the boom passes, those who remain behind must live with a lasting negative legacy. If LNG exports drive regional economies towards an even more intense boom, the bust, when it comes, will be all the worse.

D. Conclusions on Industrial Costs and Community Impacts

At bottom, LNG export means intensifying an economic strategy that has failed nations and communities over and over again. It would mark a path towards increasing economic inequality, a weaker social fabric in communities across the country, and a weaker middle class. Even during the boom, infrastructure costs and social disruption impose major burdens on extraction regions. DOE/FE must consider all these costs. But NERA sets all those costs at naught because the raw revenues from LNG export are so large for those that capture them. DOE/FE's task, though, is to look to the *public* interest, not the interest of a narrow segment of industry. It would be arbitrary and capricious to approve of exports on the basis of the NERA Report, which so entirely under-values the very considerations which must be at the heart of DOE/FE's analysis.

III. NERA Fails to Account for the Economic Implications of Environmental Harm Caused by LNG Export; DOE/FE Must Do So.

Just as NERA ignores or improperly downplays the serious negative consequences of developing a resource-extraction based economy for export, it also entirely fails to acknowledge that LNG exports impose substantial environmental costs. These costs range from the immediate costs of treating waste from fracking to the public health costs of air and water pollution from the gas production sector to the increased risk of global climate change inherent in deepening our dependence on fossil fuels. Indeed, air pollution emissions alone likely impose costs in the hundreds of millions of dollars, at a minimum, and would erode recent pollution control efforts.

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[89] Indeed, there is significant evidence that many studies touting high benefits from gas extraction suffer from systematic procedural flaws which render them unreliable. *See* T. Kinnaman, *The economic impact of shale gas extraction: A review of existing studies*, 70 Ecological Economics 1243 (2011). Dr. Kinnaman concludes that a careful review of actual data on shale gas reserves in Pennsylvania, Arkansas, and Texas shows that "shale drilling and extraction activities decreased per capita incomes" rather than benefitting residents of gas fields in those areas, attached as Ex 24.

The existence of these impacts, and their importance, should be familiar to DOE/FE, based upon the work of DOE's own Secretary of Energy Advisory Board Subcommittee on Shale Gas Production.[90] In response to Presidential and Secretarial directives, the Subcommittee met for months to assess measures to be taken to reduce the environmental impact of shale gas production. It concluded that "if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country… there is real risk of serious environmental consequences."[91] Action is especially necessary because the gas production industry currently enjoys exemptions to many federal environmental statutes, and as such, gas producers have greater ability act in ways that impose external costs on the public.[92] The Subcommittee recommended building a "strong foundation of regulation and enforcement" to improve shale gas production practices, and set forth twenty regulatory recommendations addressing air and water pollution and other threats from current production practices.[93] The Subcommittee was alarmed that progress on these recommendations was less than it had hoped, and urged "concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production."[94]

The vast majority of the Subcommittee's recommendations, which were made in 2011, remain unfulfilled, meaning that the risk of "excessive environmental impacts" remains pressing, as the Subcommittee put it. The LNG exports DOE/FE is now considering would intensify these risks by intensifying shale gas production around the country. The environmental costs of that decision are very real. They are measured in the costs of treatment plants and landfills, of emergency room visits and asthma attacks, of lost property values and rising seas. They will be felt as acutely as the wage and income losses export will cause, and must be accounted for in any proper economic analysis. Indeed, the very existence of these impacts, and the continued absence of the "strong foundation" of regulation recommended by the expert Subcommittee

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[90] Secretary of Energy Advisory Board Shale Gas Production Subcommittee, *Second 90-Day Report* (Nov. 18, 2011), attached as Ex 25.

[91] *Id.* at 10.

[92] For example, gas production is exempt from various provisions of the Safe drinking Water Act, 42 U.S.C. § 300h(d)(1)(B), certain hazardous air pollution regulations under the Clean Air Act, 42 U.S.C. § 7412(n)(4)(B) , stormwater provisions of the Clean Water Act, 33 U.S.C. § 1362(24), and the Comprehensive Environmental Response, Compensation, and Liability Act 42 U.S.C. § 9601(10)(I), (14), (33).

[93] *See SEAB Second 90-Day Report* at 10, 16-18.

[94] *Id.* at 10.

demonstrates that LNG exports counsels strongly against moving forward with export.

Yet, NERA ignores these impacts completely. Because its report fails to even acknowledge this critically important negative side of the ledger, the study is ultimately incomplete and unreliable.

A. Induced Production Can and Must be Analyzed as Part of This Accounting

Before turning to some of the many environmental costs imposed by LNG export, it is important to emphasize that DOE/FE can, in fact, account for them. These costs fall into two classes: The environmental impacts associated with LNG export infrastructure itself (such as the emissions from liquefaction facilities, increased traffic of LNG tankers, and the network of pipelines and compressors needed to support them); and the environmental impacts of the major increase in natural gas production to supply gas for export. There is no real dispute, even within DOE/FE, that the first set of impacts can be estimated. But DOE/FE has previously questioned whether it can analyze the second set of impacts. In fact, DOE's own models allow it to do so.

As the NERA Study acknowledges, LNG exports will increase U.S. gas production.[95] Indeed, these production increases provide at least a portion of the purported benefits of export that the Study touts.[96] If DOE/FE intends to advance induced production as part of the justification for exports, then induced production is plainly a reasonably foreseeable effect of exports that must be analyzed under NEPA. DOE/FE must consider the considerable impacts on air, land, water, and human health from induced production.[97]

These impacts can be calculated. EIA and DOE have precise tools enabling them to estimate how U.S. production will change in response to LNG exports. These tools enable DOE/FE to predict how and when production will increase in individual gas plays. EIA's core analytical tool is the National Energy Modeling System ("NEMS"). NEMS was used to produce the EIA exports study that

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[95] NERA Study at 51-52 & fig. 30.
[96] *See, e.g.*, *id.* at 9 fig.4; 62 fig.39.
[97] Sierra Club has described these impacts in numerous comments on individual export proposals. *E.g.*, Sierra Club Mot. Intervene, Protest, and Comments, *In the Matter of Southern LNG Company*, DOE/FE Dkt. No. 12-100-LNG (Dec. 17, 2012), attached as Ex 26.

preceded the NERA study. NEMS models the economy's energy use through a series of interlocking modules that represent different energy sectors on geographic levels.[98] Notably, the "Natural Gas Transmission and Distribution" module already models the relationship between U.S. and Canadian gas production, consumption, and trade, specifically projecting U.S. production, Canadian production, imports from Canada, etc.[99] For each region, the module links supply and demand annually, taking transmission costs into account, in order to project how demand will be met by the transmission system.[100] Importantly, the Transmission Module is *already* designed to model LNG imports and exports, and contains an extensive modeling apparatus allowing it to do so on the basis of production in the U.S., Canada, and Mexico.[101] At present, the Module focuses largely on LNG imports, reflecting U.S. trends up to this point, but it also already links the Supply Module to the existing Alaskan *export* terminal and projects exports from that site and their impacts on production.[102]

Similarly, the "Oil and Gas Supply" module models individual regions and describes how production responds to demand across the country. Specifically, the Supply Module is built on detailed state-by-state reports of gas production curves across the country.[103] As EIA explains, "production type curves have been used to estimate the technical production from known fields" as the basis for a sophisticated "play-level model that projects the crude oil and natural gas supply from the lower 48."[104] The module distinguishes coalbed methane, shale gas, and tight gas from other resources, allowing for specific predictions distinguishing unconventional gas supplies from conventional supplies.[105] The module further projects the number of wells drilled each year, and their likely production – which are important figures for estimating environmental impacts.[106] In short, the supply module "includes a comprehensive assessment method for

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[98] Energy Information Administration ("EIA"), *The National Energy Modeling System: An Overview*, 1-2 (2009), attached as Ex 27, available at http://www.eia.gov/oiaf/aeo/overview/pdf/0581(2009).pdf.
[99] *Id.* at 59.
[100] EIA, *Model Documentation: Natural Gas Transmission and Distribution Module of the National Energy Modeling System*, 15-16 (2012), attached Ex 28, *available at* http://www.eia.gov/FTPROOT/modeldoc/m062(2011).pdf.
[101] *See id.* at 22-32.
[102] *See id.* at 30-31.
[103] EIA, *Documentation of the Oil and Gas Supply Module*, 2-2 (2011), attached as Ex 29, *available at* http://www.eia.gov/FTPROOT/modeldoc/m063(2011).pdf.
[104] *Id.* at 2-3.
[105] *Id.* at 2-7.
[106] *See id.* at 2-25 to 2-26.

determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision."[107] Thus, for each play in the lower 48 states, the EIA is able to predict future production based on existing data. The model is also equipped to evaluate policy changes that might impact production; according to EIA, "the model design provides the flexibility to evaluate alternative or new taxes, environmental, or other policy changes in a consistent and comprehensive manner."[108]

EIA is not alone in its ability to predict localized effects of LNG exports. A study and model developed by Deloitte Marketpoint claims the ability to make localized predictions about production impacts, and numerous other LNG export terminal proponents have relied on this study in applications to FERC and DOE.[109] According to Deloitte, its "North American Gas Model" and "World Gas Model" allow it to predict how gas production, infrastructure construction, and storage will respond to changing demand conditions, including those resulting from LNG export. According to Deloitte, the model connects to a database that contains "field size and depth distributions for every play," allowing the company to model dynamics between these plays and demand centers. "The end result," Deloitte maintains, "is that valuing storage investments, identifying maximally effectual storage field operation, positioning, optimizing cycle times, demand following modeling, pipeline sizing and location, and analyzing the impacts of LNG has become easier and generally more accurate."[110]
But even if not all impacts can be precisely estimated and monetized, DOE/FE cannot avoid acknowledging them. Where uncertainty exists, DOE/FE could still meaningfully analyze the environmental impacts of induced drilling by estimating impacts from all permitted exports in the aggregate, based on industry-wide data regarding the impacts of gas drilling.

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[107] *Id.* at 2-3.

[108] *Id.*

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

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

Thus, there is no technical barrier to modeling where exports will induce production going forward, or to beginning to monetize and disclose the costs they will impose. Indeed, EIA used such models for its export study, which forecast production and price impacts, and which DOE/FE already relies upon. DOE/FE cannot assert that it is unable to count the significant environmental and economic costs associated with increased gas production for export. It must do disclose and consider these costs.

B. Gas Production for Export Will Come With Significant Environmental Costs

The environmental toll of increased unconventional gas production is very great, especially without full implementation of the Shale Gas Subcommittee report. We do not intend here to fully count these costs: That is DOE/FE's charge, under both NEPA and the Natural Gas Act. The discussion in these comments merely indicates some of the many costs which DOE/FE must consider, and which NERA failed to disclose.

In this regard, we draw DOE/FE's attention to a recent report by researchers at Environment America, which attempts to monetize many costs from fracking activities, ranging from direct pollution costs to infrastructure costs to lost property values.[111] We incorporate that report by reference. DOE/FE should fully account for all the costs enumerated therein.

It is true that some uncertainty necessarily attaches to environmental costs like the ones we discuss below. But, as the Ninth Circuit Court of Appeals explained in *Center for Biological Diversity v. NHTSA*, some uncertainty in estimation methodologies does not support declining to quantitatively value benefits associated with reducing climate change pollution at all.[112] Where, as here, "the record shows that there is a range of values [for these benefits], the value of carbon emissions reduction is certainly not zero."[113] Therefore, the agency is obligated to consider such a value, or range of values.[114] Since LNG export plainly imposes these significant environmental costs, DOE/FE should calculate and disclose them (accompanied by an explanation of any limitations or

[111] *See* T. Dutzik *et al.*, *The Costs of Fracking* (2012), attached as Ex 30.
[112] *See Center for Biological Diversity*, 538 F.3d 1172, 1200 (9th Cir. 2008) (citing Office of Management and Budget Circular A-4 as providing that "agencies are to monetize costs and benefits whenever possible.").
[113] *See id.*
[114] *See id.* at 1203.

uncertainties in each methodology, as necessary). It may not, however, simply ignore them.

i. Air Pollution and Climate Costs

Oil and gas production, transmission, and distribution sources are among the very largest sources of methane and volatile organic compounds in the country, and also emit large amounts of hazardous air pollutants ("HAPs") and nitrogen oxide, among other pollutants.[115] Although EPA has recently issued pollution standards that control some pollutants from new sources, the majority of the industry remains unregulated. Increasing gas production will necessarily increase air pollution from the industry. Indeed, gas export would produce enough air pollution to diminish – if not to entirely offset – the benefits of EPA's recent standards.

LNG exports would also increase air pollution costs in other ways. They would, for instance, likely increase the use of coal-fired electricity, which imposes significant public health costs. They would also deepen our economic dependence on fossil fuels, which are exacerbating global climate change. DOE/FE must account for all of these costs.

Direct Emissions Costs

The potential air pollution increase from LNG exports is very large. 9,052 bcf per year of gas are proposed for export, and NERA considered scenarios of between 4,380 bcf and 1,370 bcf of exports per year by 2035. The EIA's induced production models indicate that 63% of this gas (or more) will come from new production.[116] Although the range of estimates for gas leaked from productions systems varies, if even a small amount of this newly produced gas escapes to the atmosphere the pollution consequences are major.

EPA's current greenhouse gas inventory implies that about 2.4% of gross gas production leaks to the atmosphere in one way or another, a leak rate that makes

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[115] *See generally* U.S. EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution* : *Background Supplemental Technical Support Document for the Final New Source Performance Standards* (2012) (discussing these and other pollutants), attached as Ex 31; U.S. EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards* (2011) (hereinafter "2011 TSD"), attached as Ex 32.
[116] EIA Study at 10.

oil and gas production the single largest source of industrial methane emissions in the country, and among the very largest sources of greenhouse gases of any kind.[117] More recent work by National Oceanic and Atmospheric Administration ("NOAA") scientists suggest, based on direct measurement at gas fields, that this leak rate may be between 4.8% and 9%, at least in some fields.[118] These leak rates, and EPA conversion factors between the typical volumes of methane, VOC, and HAP in natural gas,[119] make it possible to calculate the potential impact of increasing gas production in the way that LNG export would require. We note that fugitive emissions include additional pollutants not discussed here, such as radioactive radon.[120]

The table below shows our calculations of expected pollution from fugitive emissions of methane, VOCs, and HAP based on these conversion factors, at varying leak rates (starting at 1% of production and going to 9%).[121] We acknowledge, of course, that these calculations are necessarily only a first cut at the problem. The point, here, is not to generate the final analysis (which DOE/FE must conduct) but to demonstrate that the problem is a serious one.

Export Volume in	Methane (tons)	VOC (tons)	HAP (tons)

[117] Alvarez *et al.*, *Greater focus needed on methane leakage from natural gas infrastructure*, Proceedings of the National Academy of Science (Apr. 2012) at 1, attached as Ex 33; *see also* EPA, *U.S. Greenhouse Gas Emissions and Sinks 1990-2010* (Apr. 15, 2012) at Table ES-2, attached as Ex 34.

[118] *See* G. Petron *et al.*, *Hydrocarbon emissions characterization in the Colorado Front Range – A pilot study*, Journal of Geophysical Research (2012), attached as Ex 35; J. Tollefson, *Methane leaks erode green credentials of natural gas*, Nature (2013), attached as Ex 36.

[119] *See* EPA, 2011 TSD at Table 4.2. EPA calculated average composition factors for gas from well completions. These estimates, which are based on a range of national data are robust, but necessarily imprecise for particular fields and points along the line from wellhead to LNG terminal. Nonetheless, they provide a beginning point for quantitative work. EPA's conversions are: 0.0208 tons of methane per mcf of gas; 0.1459 lb VOC per lb methane; and 0.0106 lb HAP per lb methane.

[120] *See* Marvin Resnikoff, *Radon in Natural Gas from Marcellus Shale* (Jan. 10, 2012), attached as Ex 37**.** Insofar as LNG exports induce greater gas production nationwide, and exports predominantly draw on wells in the Gulf (as NERA assumes), then exports will presumably increase the share of gas used in households in the Northeast that is provided by Marcellus shale wells, and thereby aggravate the radon exposure issues highlighted by Resnikoff.

[121] These figures were calculated by multiplying the volume of gas to be exported (in bcf) by 1,000,000 to convert to mcf, and then by 63% to generate new production volumes. The new production volumes of gas were, in turn, multiplied by the relevant EPA conversion factors to generate tonnages of the relevant pollutants. These results are approximations: Although we reported the arithmetic results of this calculation, of course only the first few significant figures of each value should be the focus.

2035 (bcf)			
1% Leak Rate			
9,052 bcf	1,186,174	173,062.8	12,573.45
4,380 bcf	573,955.2	83,740.06	6,083.925
1,370 bcf	179,524.8	26,192.67	1,902.963
2.4% Leak Rate			
9,052 bcf	2,846,818	415,350.7	30,176.27
4,380 bcf	1,377,492	200,976.2	14,601.42
1,370 bcf	430,859.5	62,862.4	45,67.111
4.8% Leak Rate			
9,052 bcf	5,693,636	830,701.4	60,352.54
4,380 bcf	2,754,985	401,952.3	29,202.84
1,370 bcf	861,719	125,724.8	9,134.222
9% Leak Rate			
9,052 bcf	10,675,567	1,557,565	113,161
4,380 bcf	5,165,597	753,660.6	54,755.33
1,370 bcf	1,615,723	235,734	17,126.67

The *total* emissions reductions associated with EPA's new source performance standards for oil and gas production are, according to EPA, about 1.0 million tons of methane, 190,000 tons of VOC, and 12,000 tons of HAP. As the table demonstrates, the additional air pollution which would leak from the oil and gas system substantially erodes those figures, even at the lowest volume of LNG export and the lowest leak rate of 1% -- which is well below the 2.4% leak rate which EPA now estimates. It would generate over 179,000 tons of methane, over 26,000 tons of VOC, and over 1,902 tons of HAP. More realistic leak rates make the picture even worse: At the EPA's estimated 2.4% leak rate, the figures for the lowest export volume are over 430,000 tons of methane, over 62,000 tons of VOC, and over 45,000 tons of HAP.

Put differently, even if LNG export is almost 9 times less than the current volume proposed for license before DOE/FE, and even if the natural gas system leak rate is less than half that which EPA now estimates, LNG export will still produce enough air pollution to erode the benefits of EPA's air standards by on the order of 20%. If export volumes increase, or if the leak rate is higher, the surplus emissions swamp the air standards completely. At a 4.8% leak rate and the mid-range 4,380 bcf export figure, LNG export would produce almost three times as many methane emissions – 2.7 million tons -- as the EPA air standards control.

In short, ramping up production for export comes with major air pollution increases. This additional pollution would impose real public health and environmental burdens.

Methane emissions, for instance, are linked to ozone pollution and to global climate change. The climate change risks associated with methane are monetizable using the Social Cost of Carbon framework developed by a federal working group led by EPA.[122] These costs vary based on assumptions of the discount rate at which to value future avoided harm from emissions reductions, and also likely vary by gas (methane, for instance, is a more potent climate forcer than carbon dioxide). Nonetheless, in its recent air pollution control rules, EPA estimated monetized climate emissions benefits from methane reductions simply by multiplying the reductions by the social cost of carbon dioxide (at a 3% discount rate) and the global warming potential of methane (which converts the radiative forcing of other greenhouse gases to their carbon dioxide equivalents).[123]

The global warming potential of methane, on a 100-year basis,[124] is at least 25,[125] and the social cost of carbon at a 3% discount rate is $25/ton (in 2008 dollars).[126] Thus, the social cost of the roughly 179,000 tons of methane emissions produced even by the lowest volume of export at the lowest leak rate is (25)(25)(179,000) or $111,875,000 *per year*. The same volume of export at 2.4% leak rate imposes methane costs of approximately $274 million per year. Again, higher volumes of export, and higher leak rates are associated with even higher costs.

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[122] EPA, *The Social Cost of Carbon*, available at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, attached as Ex 38.

[123] EPA, *Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry* (2012) at 4-32 – 4-33, attached as Ex 39. EPA acknowledges that its method is still provisional, but it does provide at least a sense of the real economic costs of methane emissions.

[124] Methane acts more quickly than carbon dioxide to warm the climate, and also oxidizes rapidly. As such, many argue that a shorter time period (20 years or less) is appropriate to calculate its global warming potential. We have conservatively used a 100 years here. The true cost of methane emissions is thus likely higher.

[125] Intergovermental Panel on Climate Change, *Direct Global Warming Potentials* (2007), available at http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html, attached as Ex 39.

[126] 2012 RIA at 4-33.

Our calculation is notably conservative: It uses a global-warming potential that is lower than that reported in more recent literature,[127] and a higher discount rate for climate damages than may be appropriate. Yet even this conservative calculation identifies hundreds of millions of dollars in damages from methane associated with export. More recent global warming potentials (which exceed 70) or more appropriate discount rates (which arguably should be zero or negative), would readily push these costs into the billions of dollars annually.

Other large costs arise from the VOC emissions from production. VOCs are often themselves health hazards, and interact with other gases in the atmosphere to produce ozone.[128] Ozone is a potent public health threat associated with thousands of asthma attacks annually, among other harm to public health. Ground-level ozone has significant and well-documented negative impacts on public health and welfare, and gas production is already strongly linked to ozone formation. One recent study, for instance, showed that over half of the ozone precursors in the atmosphere near Denver arise from gas operations.[129] Other studies show that ozone can increase by several parts per billion immediately downwind of individual oil and gas production facilities.[130] The cumulative impact of dozens or hundreds of such individual facilities can greatly degrade air quality – so much so that the study's author concludes that gas facilities may make it difficult for production regions to come into compliance with public health air quality standards if not controlled.[131]

Some studies have documented how reductions in ground-level ozone would benefit public health and welfare, and so also demonstrate how increases in ozone levels will harm the public. Using a global value of a statistical life (VSL) of $1 million (substantially lower than the value used by EPA, currently $7.4 million (in 2006 dollars)[132]), West *et al.* calculate a monetized benefit from avoided mortality due to methane reductions of $240 per metric ton (range of

[127] We use the IPCC's methane 100-year global warming potential of 25, *see supra* n.125. A more recent study puts this figure at approximately 34, while acknowledging that it could be significantly higher. Drew T. Shindell, *et al.*, *Improved Attribution of Climate Forcing Emissions*, 326 Science No. 5953, page 717 fig. 2 (Oct. 30 2009), attached as Ex 40.

[128] Methane is also an ozone precursor, albeit a somewhat less potent one

[129] J.B. Gilman *et al.*, *Source signature of volatile organic compounds from oil and natural gas operations in northeastern Colorado*, Env. Sci. & Technology (2013), attached as Ex 41.

[130] E.P. Olaguer, *The potential near-source ozone impacts of upstream oil and gas industry emissions*, Journal of the Air & Waste Management Assoc. (2012), attached as Ex 42.

[131] *Id.* at 976.

[132] http://yosemite.epa.gov/ee/epa/eed.nsf/pages/MortalityRiskValuation.html, attached as Ex 43.

$140 - $450 per metric ton).[133] Because VOCs are more potent ozone precursors than methane,[134] the monetary benefits of VOC reduction for avoided mortality are certainly greater on a tonnage basis. Further, as well as direct mortality and morbidity impacts, ozone can significantly reduce the productivity of individual workers, even at low levels. One recent study shows that even a 10 ppb increase in ozone concentrations can decrease the productivity of field workers by several percentage points – a difference that translates into something on the order of $700 million in annual productivity costs.[135]

Ground-level ozone also significantly reduces yields of a wide variety of crops. A recent study finds that in 2000, ozone damage reduced global yields 3.9-15% for wheat, 8.5-14% for soybeans, and 2.2-5.5% for corn, with total costs for these three crops of $11 billion to $18 billion and costs within the US alone over $3 billion (all in year 2000 dollars).[136] Due to the growth in the emissions of ozone precursors in coming years, these crop losses are likely to increase. In 2030, ozone is predicted to reduce global yields 4-26% for wheat, 9.5-19% for soybeans, and 2.5-8.7% for corn, with total costs for these three crops (2000 dollars) of $12 billion to $35 billion.[137] Another recent study included damage to rice (3-4% reduction in yield for year 2000) and finds even higher total costs for year 2000 ($14 billion to $26 billion).[138] Many other crops are damaged by ozone, so these estimates only capture a portion of the economic damage to crops from ground-level ozone. Ozone precursors from export-linked production would add to these costs.

The HAPs from gas production for export also impose significant public health costs. HAPs, by definition, are toxic and also may be carcinogenic. High levels of carcinogens, including benzene compounds, are associated with gas production sites. Unsurprisingly, recent risk assessments from Colorado

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133 West *et al.* at 3991.

134 Methane, technically, *is* a VOC; it is often referred to separately, however, and we do so here.

135 J. Graff Zivin & M. Neidell, *Pollution and Worker Productivity*, 102 American Economic Review 3652 at 3671 (2012), attached as Ex 44.

136 Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 1. Year 2000 crop production losses and economic damage," *Atmos. Env.*, 45, 2284-2296, attached as Ex 45.

137 Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 2. Year 2030 potential crop production losses and economic damage under two scenarios of O_3 pollution," *Atmos. Env.*, 45, 2297-2309, attached as Ex 46.

138 Van Dingenen, R, F.J. Dentener, F. Raes, M.C. Krol, L. Emberson, and J. Cofala, (2009) "The global impact of ozone on agricultural crop yields under current and future air quality legislation," *Atmos. Env.*, 43, 604-618, attached as Ex 47.

document elevated health risks for residents living near gas wells.[139] Indeed, levels of benzene and other toxics near wells in rural Colorado were "higher than levels measured at 27 out of 37 EPA air toxics monitoring sites … including urban sites" in major industrial areas."[140] These pollution levels are even more concerning than these high concentrations would suggest because several of the toxics emitted by gas operations are endocrine disruptors, which are compounds known to harm human health by acting on the endocrine system even at very low doses; some such compounds may, in fact, be especially dangerous specifically at the low, chronic, doses one would expect near gas operations.[141]

Other air pollutants add to all of these public health burdens. Particulate matter from flares and dusty roads, diesel fumes from thousands of truck trips, NO_x emissions from compressors and other onsite engines, and so on all add to the stew of pollution over gas fields. LNG export will increase all of these emissions in proportion to the scale of export.

Further, these emissions would not be spread uniformly around the country. Instead, they would be concentrated in and around gas fields. Those fields, like the Barnett field in Dallas Fort-Worth, or the Marcellus Shale near eastern cities, often are not far from (or are even directly within) major population centers. Residents of those cities will receive concentrated doses of air pollution, as will residents of the fields themselves. They thus will suffer public health harms from particularly concentrated pollution.

Costs from Increased Use of Coal

The EIA estimates that gas price increases associated with LNG export will favor continued and increased use of coal power, on the margin.[142] Another recent study, prepared by the Joint Institute for Strategic Energy Analysis (JISEA), also modeled power sector futures resulting from increasing U.S. reliance on natural gas.[143] That study found that, under baseline assumptions for future electricity

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[139] L. McKenzie *et al.*, *Human health risk assessment of air emissions from development of unconventional natural gas resources*, Science of the Total Environment (2012), attached as Ex 48.
[140] *Id.* at 5.
[141] *See* L. Vandenberg *et al.*, *Hormones and Endocrine-Disrupting Chemicals: Low-Dose Effects and Nonmonotonic Dose Responses*, Endocrine Disruption Review (2012), attached as Ex 49.
[142] EIA Study at 17-18.
[143] Jeffrey Logan et al., Joint Inst. for Strategic Analysis, Natural Gas and the Transformation of the U.S. Energy Sector (2012) ("JISEA report"), available at http://www.nrel.gov/docs/fy13osti/55538.pdf, attached as Ex 50.

demand and policy measures, "natural gas and coal swap positions compared to their historical levels," with wind energy growing at a rate that represents "a significant reduction from deployment in recent years;" as a result, CO_2 emissions "do not begin to transition to a trajectory that many scientists believe is necessary to avoid dangerous impacts from climate change."[144]

The costs of the increased CO_2 emissions triggered by LNG export are along significant, and DOE/FE must disclose and weigh them. DOE/FE suggests that they are on the order of 200-1500 million metric tons of CO_2.[145] Again, depending on the social cost of carbon figure used, these increased emissions may impose hundreds of millions or billions in additional costs.

And costs extend beyond climate disruption. Coal combustion is a particularly acute public health threat. It is among the largest sources of all forms of air pollution in the country, including toxic mercury emissions and emissions particulate matter, which is linked to asthma and to heart attacks. To the extent that LNG export prolongs or intensifies the use of coal power, the public health costs of that additional coal use are attributable to export, and must be accounted for.

Likewise, EPA, in calculating compliance costs for several of its clean air rules, has assumed that some portion of these costs will be addressed by switching from coal to natural gas. If these switches still occur, but LNG exports have raised natural gas prices, the compliance costs of necessary public health measures will be higher than they otherwise would be.

Costs from Further Investment in Fossil Fuels

LNG exports will also deepen our national investment in fossil fuels, even though those fuels are causing destructive climate change. The costs of increased climate risks must be factored into the export calculation.

Specifically, a recent study by the International Energy Agency predicts that international trade in LNG and other measures to increase global availability of natural gas will lead many countries to use natural gas in place of wind, solar, or other renewables, displacing these more environmentally beneficial energy sources instead of displacing other fossil fuels, and that these countries may also

[144] *Id.* at 98.
[145] EIA Study at 19.

increase their overall energy consumption beyond the level that would occur with exports.[146] In the United States alone, the IEA expects the gas boom to result in a 10% reduction in renewables relative to a baseline world without increased gas use and trade.[147] The IEA goes on to conclude that high levels of gas production and trade will produce "only a small net shift" in global greenhouse gas emissions, with atmospheric CO_2 levels stabilizing at over 650 ppm and global warming in excess of 3.5 degrees Celsius, "well above the widely accepted 2°C target."[148]

Such temperature increases would be catastrophic. Yet, an LNG export strategy commits the United States, and the world, to further fossil fuel combustion, increasing the risk of hundreds of billions of economic costs imposed by severe climate change.

Summing up air pollution impacts

Across all of these harms, the public health damage associated just with air pollution from increased production to support export very likely runs into the hundreds of millions, if not billions, of dollars. DOE/FE must account for these costs as it weighs the economic merits of expanding gas production, and gas pollution, for export.

ii. Water Pollution Costs

The hundreds or thousands of wells required to support export will require millions of gallons of water to frack and will produce millions of gallons of wastewater. The extraction process will likewise increase the risk of contamination from surface spills and casing failures, as well as from the fracking process itself. All of these contamination and treatment risks impose economic costs which DOE must take into account.

Water Withdrawal Costs

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[146] International Energy Agency, *Golden Rules for a Golden Age of Gas*, Ch. 2 p. 91 (2012), available at
http://www.iea.org/publications/freepublications/publication/WEO2012_GoldenRulesReport.pdf, attached as Ex 51.
[147] *Id.* at 80.
[148] *Id.*

Fracking requires large quantities of water. The precise amount of water varies by the shale formation being fracked. The amount of water varies by well and by formation. For example, estimates of water needed to frack a Marcellus Shale wells range from 4.2 to over 7.2 million gallons.[149] In the Gulf States' shale formations (Barnett, Haynesville, Bossier, and Eagle Ford), fracking a single well requires from 1 to over 13 million gallons of water, with averages between 4 and 8 million gallons.[150] Fresh water constitutes 80% to 90% of the total water used to frack a well even where operators recycle "flowback" water from the fracking of previous wells for use in drilling the current one.[151] Many wells are fractured multiple times over their productive life.

DOE/FE can and must predict the number of wells that will be needed to provide the volume of gas exported. We provide an unrealistically conservative (i.e., industry-friendly) estimate here to illustrate the magnitude of the problem, although DOE/FE can and must engage in a more sophisticated analysis of the issue. As noted above, EIA predicts that at least 63% percent of the gas exported will come from additional production, and that roughly 72% of this production will come from shale gas sources, with an additional 23% coming from other unconventional gas reserves. The USGS has estimated that even in the most productive formations, average expected ultimate recoveries for unconventional shale gas wells are less than 3 bcf, and that most formations provided drastically

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[149] TNC, Pennsylvania Energy Impacts Assessment, Report 1: Marcellus Shale Natural Gas and Wind 10, 18 (2010), attached as Ex 52. *Accord* N.Y. Dep't of Envtl. Conservation, Revised Draft Supplemental General Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, 5-5 (2011) ("NY RDSGEIS") at 6-10, available at http://www.dec.ny.gov/energy/75370.html ("Between July 2008 and February 2011, average water usage for high-volume hydraulic fracturing within the Susquehanna River Basin in Pennsylvania was 4.2 million gallons per well, based on data for 553 wells."). Other estimates suggest that as much as 7.2 million gallons of frack fluid may be used in a 4000 foot well bore. NRDC, *et al.*, *Comment on NY RDSGEIS on the Oil, Gas and Solution Mining Regulatory Program* (Jan. 11, 2012) (Attachment 2, Report of Tom Myers, at 10), attached as Ex 53 ("Comment on NY RDSGEIS").

[150] Jean-Philippe Nicot, *et al.*, *Draft Report – Current and Projected Water Use in the Texas Mining and Oil and Gas Industry*, 52-54 (Feb. 2011) (water use from 1 to over 13 million gallons), attached as Ex 54; Jean-Philippe Nicot, *et al.*, *Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report* 11-14 (Sept. 2012) (updated data presented as averages), attached as Ex. 55. DOE's Shale Gas Subcommittee generally states that nationwide, fracking an individual well requires between 1 and 5 million gallons of water. DOE, Shale Gas Production Subcommittee First 90-Day Report (2012), at 19, attached as Ex 56.

[151] NY RDSGEIS at 6-13, *accord* Nicot 2012, *supra* n.150, at 54.

lower average expected ultimate recoveries.[152] As noted above, the average horizontal fracked well requires roughly 4 million gallons of water, at least 80% of which (3.2 million gallons) is new fresh water.[153]

Combining these figures and assuming high average recovery, low/average water per frack jobs, only a single frack per well, and maximal use of recycled water, we see the following volumes of water. These figures are only for *shale* gas production, because we have water use figures for such wells; additional unconventional production, of the sort that the EIA predicts, would increase water use.

Volume of exports (bcf/y)	Induced Shale Gas Production (bcf/y)[a]	Equivalent Number of Shale Wells Needed Per Year[b]	New Fresh Water Required (millions of gallons per year)[c]
9,052	4,105	1,368	4,378
4,308	1,954	651	2,038
1,370	621	207	662

[a.] Volume of export * 0.63 * 0.72
[b.] Volume of production / 3.
[c.] Number of wells * 3.2

Of course, we reiterate that this forecast methodology is crude and that the inputs we use are unrealistically conservative, but at the very least, this illustrates the minimum scale of the problem. This calculation ignores the production curves for gas wells and the fact that although wells produce over a number of years, all of the water (under the assumption of one frack job per well) is consumed up front; the table naively averages water requirements out over the duration of exports. Additionally, this only considers water withdrawals associated with the shale gas production EIA predicts: EIA predicts that other forms of production (primarily other unconventional production) will also

[152] USGS, *Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United* States, USGS Open-File Report 212-1118 (2012), attached as Ex 57**.** Although some oil and gas producers have publicly stated higher expected ultimate recoveries, DOE/FE must begin with the data-backed assessment of its expert and impartial sister agency.
[153] Taking the most industry friendly of each of these values is particularly unrealistic because the values are not independent. For example, higher-producing wells are likely to be wells with a longer fracked lateral, which are in turn wells that use higher volumes of water. Using the high range of the average expected ultimate recovery but the low range of the average water requirement therefore represents a combination unlikely to occur in reality.

increase alongside the above increases in shale gas production, and this other production will also require significant water withdrawals. In its public interest analysis, DOE/FE must engage in a more considered evaluation of the water consumption exports will require, and the costs (environmental and economic) thereof.

These water withdrawals would drastically impact aquatic ecosystems and human communities. Their effects are larger than their raw volumes because withdrawals would be concentrated in particular watersheds and regions. Reductions in instream flow negatively affect aquatic species by changing flow depth and velocity, raising water temperature, changing oxygen content, and altering streambed morphology.[154] Even when flow reductions are not themselves problematic, the intake structures can harm aquatic organisms.[155] Where water is withdrawn from aquifers, rather than surface sources, withdrawal may cause permanent depletion of the source. This risk is even more prevalent with withdrawals for fracking than it is for other withdrawal, because fracking is a consumptive use. Fluid injected during the fracking process is (barring accident) deposited below freshwater aquifers and into sealed formations.[156] Thus, the water withdrawn from the aquifer will be used in a way that provides no opportunity to percolate back down to the aquifer and recharge it.

The impacts of withdrawing this water – especially in arid regions of the west – are large, and can greatly change the demand upon local water systems. The Environment America report notes that fracking is expected to comprise 40% of water consumption in one county in the Eagle Ford shale region of Texas, for example.[157] As fracking expands, and operators seek to secure water rights to divert water from other uses, these withdrawal costs will also rise.

Groundwater Contamination

Gas extraction activities pose a substantial risk of groundwater contamination. Contaminants include chemicals added to the fracturing fluid and naturally

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[154] *Id.* at 6-3 to 6-4; *see also* Maya Weltman-Fahs, Jason M. Taylor, *Hydraulic Fracturing and Brook Trout Habitat in the Marcellus Shale Region: Potential Impacts and Research Needs*, 38 Fisheries 4, 6-7 (Jan. 2013), attached as Ex 58.
[155] *Id.* at 6-4.
[156] *Id.* at 6-5; First 90-Day Report at 19 ("[I]n some regions and localities there are significant concerns about consumptive water use for shale gas development.").
[157] *The Cost of Fracking* at 26.

occurring chemicals that are mobilized from deeper formations to groundwater via the fracking process. Contamination may occur through several methods, including where the well casing fails or where the fractures created through drilling intersect an existing, poorly sealed well. Although information on groundwater contamination is incomplete, the available research indicates that contamination has already occurred on multiple occasions.

Once groundwater is contaminated, the clean-up costs are enormous. The Environment America report, for instance, documents costs of over $109,000 for methane removal for just 14 households with contaminated groundwater.[158] EPA has estimated treatment costs for some forms of groundwater remediation at between $150,000 to $350,000 per acre.[159] Such costs can continue for years, with water replacement costs adding additional hundreds of thousands in costs.[160] Indeed, a recent National Research Council report observed that for many forms of subsurface and groundwater hazardous chemical contamination, "significant limitations with currently available remedial technologies" make it unlikely that contaminated aquifers can be fully remediated "in a time frame of 50-100 years."[161]

There are several vectors by which gas production can contaminate groundwater supplies. Perhaps the most common or significant are inadequacies in the casing of the vertical well bore.[162] The well bore inevitably passes through geological strata containing groundwater, and therefore provides a conduit by which chemicals injected into the well or traveling from the target formation to the surface may reach groundwater. The well casing isolates the groundwater from intermediate strata and the target formation. This casing must be strong enough to withstand the pressures of the fracturing process—the very purpose of which is to shatter rock. Multiple layers of steel casing must be used, each pressure tested before use, then centered within the well bore. Each layer of casing must be cemented, with careful testing to ensure the integrity of the cementing.[163]

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[158] *Id.* at 13.
[159] *Id.* at 14.
[160] *Id.*
[161] National Research Council, *Prepublication Copy- Alternatives for Managing the Nation's Complex Contaminated Groundwater Sites*, ES-5 (2012), executive summary attached as Ex 59, full report available at http://www.nap.edu/catalog.php?record_id=14668#toc.
[162] DOE, Shale Gas Production Subcommittee First 90-Day Report at 20.
[163] Natural Resources Defense Council, Earthjustice, and Sierra Club, Comments [to EPA] on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels 3, (June 29, 2011), at 5-9, attached as Ex 60.

Separate from casing failure, contamination may occur when the zone of fractured rock intersects an abandoned and poorly-sealed well or natural conduit in the rock.[164] One recent study concluded, on the basis of geologic modeling, that frack fluid may migrate from the hydraulic fracture zone to freshwater aquifers in less than ten years.[165]

Available empirical data indicates that fracking has resulting in groundwater contamination in at least five documented instances. One study "documented the higher concentration of methane originating in shale gas deposits . . . into wells surrounding a producing shale production site in northern Pennsylvania."[166] By tracking certain isotopes of methane, this study – which the DOE Subcommittee referred to as "a recent, credible, peer-reviewed study" determined that the methane originated in the shale deposit, rather than from a shallower source.[167] Two other reports "have documented or suggested the movement of fracking fluid from the target formation to water wells linked to fracking in wells."[168] "Thyne (2008)[[169]] had found bromide in wells 100s of feet above the fracked zone. The EPA (1987)[[170]] documented fracking fluid moving into a 416-foot deep water well in West Virginia; the gas well was less than 1000 feet horizontally from the water well, but the report does not indicate the gas-bearing formation."[171]

More recently, EPA has investigated groundwater contamination in Pavillion, Wyoming and Dimock, Pennsylvania. In the Pavillion investigation, EPA's draft

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[164] Comment on NY RDSGEIS, attachment 3, Report of Tom Myers, at 12-15.

[165] Tom Myers, *Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers* (Apr. 17, 2012), attached Ex 61.

[166] DOE, Shale Gas Production Subcommittee First 90-Day Report at 20 (citing Stephen G. Osborn, Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson, *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, Proceedings of the National Academy of Science, 108, 8172-8176, (2011), attached as Ex 62).

[167] *Id.*

[168] Comment on NY RDSGEIS, attachment 3, Report of Tom Myers, at 13.

[169] Dr. Myers relied on Geoffrey Thyne, *Review of Phase II Hydrogeologic Study* (2008), prepared for Garfield County, Colorado, *available at* http://cogcc.state.co.us/Library/Presentations/Glenwood_Spgs_HearingJuly_2009/(1_A)_ReviewofPhase-II-HydrogeologicStudy.pdf.

[170] Environmental Protection Agency, *Report to Congress, Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, vol. 1 (1987), *available at* nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=20012D4P.txt, attached as Ex 63.

[171] Comment on NY RDSGEIS, attachment 3, Report of Tom Myers, at 13.

report concludes that "when considered together with other lines of evidence, the data indicates likely impact to ground water that can be explained by hydraulic fracturing."[172] EPA tested water from wells extending to various depths within the range of local groundwater. At the deeper tested wells, EPA discovered inorganics (potassium, chloride), synthetic organic (isopropanol, glycols, and tert-butyl alcohol), and organics (BTEX, gasoline and diesel range organics) at levels higher than expected.[173] At shallower levels, EPA detected "high concentrations of benzene, xylenes, gasoline range organics, diesel range organics, and total purgeable hydrocarbons."[174] EPA determined that surface pits previously used for storage of drilling wastes and produced/flowback waters were a likely source of contamination for the shallower waters, and that fracturing likely explained the deeper contamination.[175] The U.S. Geological Survey, in cooperation with the Wyoming Department of Environmental Quality, also provided data regarding chemicals found in wells surrounding Pavillion.[176] Although the USGS did not provide analysis regarding the likely source of the contaminants found, an independent expert who reviewed the USGS and EPA data at the request of Sierra Club and other environmental groups concluded that the USGS data supports EPA's findings.[177]

EPA also identified elevated levels of hazardous substances in home water supplies near Dimock, Pennsylvania.[178] EPA's initial assessment concluded that

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[172] EPA, Draft Investigation of Ground Water Contamination near Pavillion, Wyoming, at xiii (2011), available at http://www.epa.gov/region8/superfund/wy/pavillion/EPA_ReportOnPavillion_Dec-8-2011.pdf, attached as Ex 64. EPA has not yet released a final version of this report, instead recently extending the public comment period to September 30, 2013. 78 Fed. Reg. 2396 (Jan. 11, 2013).

[173] *Id.* at xii.

[174] *Id.* at xi.

[175] *Id.* at xi, xiii.

[176] USGS, *Groundwater-Quality and Quality-Control Data for two Monitoring Wells near Pavillion, Wyoming, April and May 2012*, USGS Data Series 718 p.25 (2012), attached as Ex 65.

[177] Tom Myers, *Assessment of Groundwater Sampling Results Completed by the U.S. Geological Survey* (Sept. 30, 2012), attached as Ex 66. Another independent expert, Rob Jackson of Duke University, has stated that the USGS and EPA data is "suggestive" of fracking as the source of contamination. Jeff Tollefson, *Is Fracking Behind Contamination in Wyoming Groundwater?*, Nature (Oct. 4, 2012), attached as Ex 67. *See also* Tom Meyers, *Review of DRAFT: Investigation of Ground Water Contamination near Pavillion Wyoming* (April 30, 2012) (concluding that EPA's initial study was well-supported), attached as Ex 68.

[178] EPA Region III, Action Memorandum - Request for Funding for a Removal Action at the Dimock Residential Groundwater Site (Jan. 19, 2012), available at http://www.epaosc.org/sites/7555/files/Dimock%20Action%20Memo%2001-19-12.PDF, attached

"a number of home wells in the Dimock area contain hazardous substances, some of which are not naturally found in the environment," including arsenic, barium, bis(2(ethylhexyl)phthalate, glycol compounds, manganese, phenol, and sodium.[179] Arsenic, barium, and manganese were present in five home wells "at levels that could present a health concern."[180] Many of these chemicals, including arsenic, barium, and manganese, are hazardous substances as defined under CERCLA section 101(14). *See* 42 U.S.C. § 9604(a); 40 C.F.R. § 302.4. EPA's assessment was based in part on "Pennsylvania Department of Environmental Protection (PADEP) and Cabot Oil and Gas Corporation (Cabot) sampling information, consultation with an EPA toxicologist, the Agency for Toxic Substances and Disease Registry (ATSDR) Record of Activity (AROA), issued, 12/28/11, and [a] recent EPA well survey effort."[181] The PADEP information provided reason to believe that drilling activities in the area led to contamination of these water supplies. Drilling in the area began in 2008, and was conducted using the hazardous substances that have since been discovered in well water. Shortly thereafter methane contamination was detected in private well water. The drilling also caused several surface spills. Although EPA ultimately concluded that the five homes with potentially unsafe levels of hazardous substances had water treatment systems sufficient to mitigate the threat, [182] the Dimock example indicates the potential for gas development to contaminate groundwater.

The serious groundwater contamination problems experienced at the Pavillion and Dimock sites demonstrate a possibility of contamination, and attendant human health risks. Such risks are not uncommon in gas field sites, and will be intensified by production for export. DOE/FE must account for these risks, as well, in its economic evaluation.

Surface Water Contamination

Of course the same chemicals that can contaminate groundwater can also contaminate surface water, either through spills or communication with groundwater, or simply through dumping or improper treatment. Even the extensive road and pipeline networks created by gas extraction come with a risk

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as Ex 69; EPA, *EPA Completes Drinking Water Sampling in Dimock, Pa.* (Jul. 25, 2012), attached as Ex 70.

[179] *Id.* at 1, 3-4.

[180] *EPA Completes Drinking Water Sampling in Dimock, Pa.*, *supra* n.178

[181] *Id.* at 1.

[182] *EPA Completes Drinking Water Sampling in Dimock, Pa.*, *supra* n.178

of significant stormwater and sediment run-off which can contaminate surface waters. Gas field operations themselves, with their significant waste production and spill potential exacerbate these risks.

The Environment America report, for instance, documents fish kills caused by pipeline ruptures in the Marcellus Shale region, which impose costs on Pennsylvania's multi-billion dollar recreational fishing industry.[183] Such risks will be intensified by extraction for export.

Summing up water pollution costs

Water pollution is expensive to treat and can impose enormous burdens on public health and ecosystem function. Even a single instance of contamination can lead to hundreds of thousands of dollars in treatment costs, and many such incidents are not only possible, but likely, with an expansion of gas production for export. DOE/FE must account for these risks.

iii. Waste Management Costs

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

On site, drilling mud, drill cuttings, flowback and produced water are often stored in pits. Open pits can have harmful air emissions, can leach into shallow groundwater, and can fail and result in surface discharges. Many of these harms can be minimized by the use of seal tanks in a "closed loop" system.[184] Presently, only New Mexico mandates the use of closed loop waste management systems, and pits remain in use elsewhere.

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[183] *The Cost of Fracking* at 20.
[184] *See, e.g.*, NY RDSGEIS, at 1-12.

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

Underground injection wells present risks of groundwater contamination similar to those identified above for fracking itself. Gas production wastes are not categorized as hazardous under the Safe Drinking Water Act, 42 U.S.C. § 300f *et seq*., and may be disposed of in Class II injection wells. Class II wells are brine wells, and the standards and safeguards in place for these wells were not designed with the contaminants found in fracking wastes in mind.[185]

Additionally, underground injection of fracking wastes appears to have induced earthquakes in several regions. For example, underground injection of fracking waste in Ohio has been correlated with earthquakes as high as 4.0 on the Richter scale.[186] Underground injection may cause earthquakes by causing movement on existing fault lines: "Once fluid enters a preexisting fault, it can pressurize the rocks enough to move; the more stress placed on the rock formation, the more powerful the earthquake."[187] Underground injection is more likely than fracking to trigger large earthquakes via this mechanism "because more fluid is usually being pumped underground at a site for longer periods."[188] In light of the apparent induced seismicity, Ohio has put a moratorium on injection in the affected region. Similar associations between earthquakes and injection have occurred in Arkansas, Texas, Oklahoma and the United Kingdom.[189] In light of these effects, Ohio and Arkansas have placed moratoriums on injection in the

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[185] *See* NRDC et al., *Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy* (Sept. 8, 2010), attached as Ex 71.
[186] Columbia University, Lamont-Doherty Earth Observatory, Ohio Quakes Probably Triggered by Waste Disposal Well, Say Seismologists (Jan. 6, 2012), available at http://www.ldeo.columbia.edu/news-events/seismologists-link-ohio-earthquakes-waste-disposal-wells, attached as Ex 72.
[187] *Id.*
[188] *Id.*
[189] *Id.*; *see also* Alexis Flynn, Study Ties Fracking to Quakes in England, Wall Street Journal (Nov. 3, 2011), *available at* http://online.wsj.com/article/SB10001424052970203804204577013771109580352.html.

affected areas.[190] The recently released abstract of a forthcoming United States Geological Survey study affirms the connection between disposal wells and earthquakes.[191]

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

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

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[190] Lamont-Doherty Earth Observatory; Arkansas Oil and Gas Commission, Class II Commercial Disposal Well or Class II Disposal Well Moratorium (Aug. 2, 2011), *available at* http://www.aogc.state.ar.us/Hearing%20Orders/2011/July/180A-2-2011-07.pdf.

[191] Ellsworth, W. L., et al., Are Seismicity Rate Changes in the Midcontinent Natural or Manmade?, Seismological Society of America, (April 2012), available at http://www2.seismosoc.org/FMPro?-db=Abstract_Submission_12&-recid=224&-format=%2Fmeetings%2F2012%2Fabstracts%2Fsessionabstractdetail.html&-lay=MtgList&-find, attached as Ex 73.

> expensive treatment for disinfection of drinking water. This transfer of costs to the public should not be permitted.[192]

Similarly, municipal treatment works typically to not treat for radioactivity, whereas produced water can have high levels of naturally occurring radioactive materials. In one examination of three samples of produced water, radioactivity (measured as gross alpha radiation) were found ranging from 18,000 pCi / L to 123,000 pCi/L, whereas the safe drinking water standard is 15 pCi/L.[193]

A recent NRDC expert report describes these options in detail, and we direct DOE/FE's attention to it.[194] The report demonstrates that all waste treatment options have significant risks, and require substantial investments to manage properly. Fracking for export, again, has the potential to significantly increase these waste management costs. Such costs will largely fall on communities in the gas fields, which may be ill-equipped to bear them.

Summing Up Waste Management Costs

More drilling means significantly greater waste management problems, and more waste management costs.[195] It is not surprising DOE's own Shale Gas Subcommittee urged significant new regulatory work on waste management rules and research. Thus far, though, these problems have not been addressed systematically. LNG export will exacerbate them, imposing further costs on communities across the country.

iv. Costs Arising from Damage to Property and Landscapes

Expanding gas production alters entire landscapes, fundamentally compromising ecosystem services and reducing property values. Land use disturbance associated with gas development impacts plants and animals

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[192] Comment on NY RDSGEIS, attachment 3, Report of Glen Miller, at 13.
[193] *Id.* at 4.
[194] R. Hammer *et al.*, *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewater* (2012), attached as Ex 74.
[195] Indeed, the waste from existing fracking operations are already on the verge of overwhelming disposal infrastructure. *See, e.g.*, Bob Downing, Akron Beacon-Journal, *Pennsylvania Drilling Wastes Might Overwhelm Ohio Injection Wells* (Jan. 23, 2012), available at http://www.ohio.com/news/local/pennsylvania-drilling-wastes-might-overwhelm-ohio-injection-wells-1.367102, attached as Ex 75.

through direct habitat loss, where land is cleared for gas uses, and indirect habitat loss, where land adjacent to direct losses loses some of its important characteristics. These costs, too, must figure in the export economic analysis.

The presence of gas production equipment can markedly reduce property values, both through direct resource damage and through perceived increases in risk. A recent Resources for the Future study, for instance, canvasses empirical data from Pennsylvania to show that concerns (rather than any demonstrated damage) over groundwater contamination reduced property values for ground-water dependent homes by as much as 24%.[196] A study from Texas saw decreases in value of between 3-14% for homes near wells, and a Colorado study saw decreases of up to 22% for homes near wells.[197] Notably, the Resources for the Future study concluded that the property value declines it measured completely offset any increased value from expected lease payments.[198] And these decreases are only those associated with ordinary operation of gas activities. Actual contamination will, of course, reduce property values still more. Thus, as gas extraction spreads across the landscape, many properties may actually lose value, even as some owners secure royalty payments.

Other threats to property values come through risks to home financing. Gas extraction is a major industrial activity inconsistent with essentially all home mortgage policies.[199] Accordingly, signing a gas lease without the consent of the lender may cause an immediate mortgage default, leading to foreclosure.[200] And most lenders will refuse such consent, and will refuse to grant new mortgages allowing gas development.[201] The result is that that expansion of gas drilling, including extraction for export, may significantly limit the ability of many people to extract value from their homes.

In addition to these immediate threats to property values, gas production also threatens ecosystems and the services they provide. Land is lost through development of well pads, roads, pipeline corridors, corridors for seismic testing, and other infrastructure. The Nature Conservancy (TNC) estimated that in

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[196] L. Muehlenbachs *et al.*, *Shale Gas Development and Property Values Differences across Drinking Water Sources*, Resources for the Future Discussion Paper (2012), attached as Ex 76.
[197] *The Costs of Fracking* at 30.
[198] Muehlenbachs *et al.* at 29-30.
[199] E. Radow, *Homeowners and Gas Drilling Leases: Boom or Bust?*, New York State Bar Association Journal (Dec. 2011), attached as Ex 77.
[200] *Id.* at 20.
[201] *Id.* at 21.

Pennsylvania, "[w]ell pads occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad."[202] New York's Department of Environmental Conservation reached similar estimates.[203] After initial drilling is completed the well pad is partially restored, but 1 to 3 acres of the well pad will remain disturbed through the life of the wells, estimated to be 20 to 40 years.[204] Associated infrastructure such as roads and corridors will likewise remain disturbed. Because these disturbances involve clearing and grading of the land, directly disturbed land is no longer suitable as habitat.[205]

Indirect losses occur on land that is not directly disturbed, but where habitat characteristics are affected by direct disturbances. "Adjacent lands can also be impacted, even if they are not directly cleared. This is most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on "interior" forest conditions."[206] "Research has shown measureable impacts often extend at least 330 feet (100 meters) into forest adjacent to an edge."[207]

These effects are profound. Although impacts could be reduced with proper planning,[208] more development makes mitigation more difficult. Indeed, the Pennsylvania Department of Conservation and Natural Resources, for instance, recently concluded that "zero" remaining acres of the state forests are suitable for leasing with surface disturbing activities, or the forests will be significantly degraded.[209]

The lost ecosystem services from wild land and clean rivers and wetlands are valuable. Such services can be monetized in various ways, including through surveys of citizens' "willingness to pay" for them, which generally show that people view ecosystem services as major economic assets. Work in

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[202] TNC, Pennsylvania Energy Impacts Assessment, Report 1: Marcellus Shale Natural Gas and Wind 10, 1.
[203] NY RDSGEIS at 5-5.
[204] Id. at 6-13.
[205] *Id.* at 6-68.
[206] Pennsylvania Energy Impacts Assessment at 10.
[207] NY RDSGEIS at 6-75.
[208] *See id.*
[209] Penn. Dep't of Conservation and Natural Resources, *Impacts of Leasing Additional State Forest for Natural Gas Development* (2011), attached as Ex 78.

Pennsylvania, for instance, showed that undisturbed forests were worth at least $294 per acre to residents.[210] Thus, increased production for export effectively costs Pennsylvanians at least this much per acre of forest disrupted. Similarly, in the gas fields of western Pennsylvania, households are willing to pay up to $51 per household to improve water quality in a single stream.[211] Water degradation can properly be said to impose these costs in return. Direct recreational spending also provides an index of the costs to society of landscape disruption; for instance, if export-linked production risks disrupting Pennsylvania's over $1.4 billion in spending by anglers and $1.8 billion in spending by hunters,[212] these costs, too, must be taxed against export projects.

Summing Up Land-Related Costs

Just as with direct pollution costs, the costs of landscape disruption may well be in the hundreds of millions of dollars in harm to property values and ecosystem services. NERA ignores these costs, as well, but DOE/FE must account for them.

C. Conclusions on Environmental Costs

Our discussion of environmental costs only scratches the surface. It is clear that these costs are in the billions of dollars annually, and range from burdens on regional infrastructure to long-lasting ecosystem service disruptions. These costs are just as real as reduced income to labor, and just as pressing for policymakers. DOE/FE is required to consider them under its public interest mandate. NERA's conclusions that export would produce economic benefits are completely unfounded because they neglect these costs entirely.

IV. DOE/FE's Use of the NERA Study is Procedurally Flawed and Raises a Serious and Inappropriate Appearance of Bias

DOE/FE reliance on the NERA study would be inappropriate not just for the many substantive reasons discussed above but because the study process has been procedurally flawed from the outset in ways that limit public participation and raise serious questions of bias. NERA has significant ties to the fossil fuel industry, including to parties which would benefit financially from LNG export,

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[210] ECONorthwest, *An Economic Review of the Environmental Assessment of the MARC I Hub Line Project* at 25 (July 2011), attached as Ex 79.
[211] *Id.* at 24.
[212] *Id.* at 29.

and the consultant who authored the report is known for his hostility to government regulation of the energy sector. NERA was selected through a secret contracting process and developed its results with a proprietary model which has not been released to the public. NERA's ideological commitments, financial conflicts, and closed process all raise, at a minimum, the appearance of serious bias and conflicts of interest. DOE/FE cannot properly rely upon a study that is tainted in this way.

NERA has spent years attacking environmental regulations on behalf of the American Petroleum Institute and the coal industry, among others. The LNG export report's author, NERA senior vice president W. David Montgomery, has strongly opposed regulatory and legislative efforts to control climate change, raise fuel efficiency, and improve air quality. These ideological commitments, and business relationships, all raise serious questions about NERA's role in this process.

NERA was founded in 1961 by conservative economists and has maintained this ideological anti-regulation bent.[213] Indeed, co-founder Irwin Stelzer is now a senior fellow at the right-wing Hudson Institute, which advocates against environmental regulations and supports climate skeptics.[214] Following that lead, NERA itself has been a consistent voice against environmental safeguards. In recent years, NERA staff have repeatedly opposed environmental efforts on behalf of industry groups. NERA staff have:

- Written, on behalf of the American Petroleum Institute, against the tightened ozone smog standards recommended by EPA's science advisors.[215]
- On behalf of the American Coalition for Clean Coal Energy, generated inflated cost estimates for EPA rules controlling toxic mercury emissions, asthma-inducing SO_2, and other pollutants.[216]
- Testified against EPA's efforts to control mercury emissions.[217]

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[213] http://www.nera.com/7250.htm.

[214] *See* http://www.hudson.org/learn/index.cfm?fuseaction=staff_bio&eid=StelIrwi.

[215] NERA, *Summary and Critique of the Benefits Estimates in the RIA for the Ozone NAAQS Reconsideration* (2011), available at: http://www.nera.com/nera-files/PUB_Smith_OzoneNAAQS_0711.pdf.

[216] NERA, *Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector* (2012), available at: http://www.nera.com/nera-files/PUB_ACCCE_1012.pdf.

[217] Testimony of Anne E. Smith before the House Subcommittee on Energy and Power (Feb. 8, 2012), available at: http://www.nera.com/nera-files/PUB_Smith_Testimony_ECC_0212.pdf.

- Testified against new soot standards designed to protect the public from the respiratory problems and heart disease.[218]
- Prepared a report, on behalf of the Utility Water Group, opposing standards designed to reduce fish kills and protect aquatic ecosystems from cooling water withdrawals.[219]

Dr. Montgomery, a NERA Senior Vice President, shares the basic ideological commitments of his firm. He has repeatedly spoken against President Obama's green jobs agenda and the Department of Energy's efforts to promote renewable energy. He has also consistently opposed legislative efforts to reduce domestic carbon pollution, including the Kyoto Protocols. Dr. Montgomery has also been a fellow at the far-right Marshall Institute, an industry-funded group which devotes much of its resources to attacking climate science.[220] In recent years Dr. Montgomery has:

- Testified against capping U.S. carbon pollution emissions.[221]
- Testified repeatedly against EPA's public health air rules, arguing that they have high costs and should be reconsidered.[222]
- Testified against DOE's programs supporting green energy investment, arguing that "the entire concept of using stimulus money to create a Green Economy is unsound."[223]
- Testified opposing the Federal Green Jobs Agenda.[224]

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[218] Testimony of Anne E. Smith before the House Subcommittee on Energy and Power (June 28, 2012), available at: http://www.nera.com/nera-files/PUB_Smith_EPA_0612.pdf.

[219] NERA, *Comments on EPA's Notice of Data Availability for § 316(b) Stated Preference Survey* (July 2012), available at: http://www.nera.com/nera-files/PUB_UWAG_0712_final.pdf.

[220] *See http://www.marshall.org/experts.php?id=103.*

[221] Testimony of W. David Montgomery before the House Committee on Science, Space and Technology (March 31, 2011), available at: http://science.house.gov/sites/republicans.science.house.gov/files/documents/hearings/Montgomery%203_31_11%20v2.pdf.

[222] *See* Testimony of W. David Montgomery before the Senate Committee on Environment and Public Works (Feb. 15, 2011), available at: http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=5abed004-c3d2-4f28-a721-734ad78cdd99; and Testimony of W. David Montgomery Senate Committee on Environment and Public Works (Mar. 17, 2011), available at: http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=227a0fdb-905d-47b1-ac1d-b5dad9c6a605.

[223] Testimony of W. David Montgomery before the House Committee on Oversight and Government Spending (Nov. 2, 2011), available at: http://democrats.oversight.house.gov/images/stories/Montgomery_testimony.pdf

- Opposed raising fuel efficiency standards as "the worst strategy you could think of."[225]

Dr. Montgomery and NERA, in short, share intellectual commitments that have made them preferred advocates of business interests seeking to oppose President Obama's public health and environmental efforts, as well as DOE's own efforts to increase the use of cleaner energy in this country. Many of those same interests have much to gain from LNG exports. The members and funders of the American Petroleum Institute, a NERA client, will naturally benefit from increased gas production. Likewise, coal interests, which are also frequent NERA clients, stand to benefit if LNG export leads to an increase in U.S. coal use, as the EIA has predicted. NERA does not acknowledge, much less address, these and similar conflicts in the LNG study. Nor does DOE/FE.

This failure of disclosure has infected the process as a whole. To our knowledge, DOE/FE issued no public solicitation of bids for the LNG export analysis, nor offered the public any chance, until now, to comment upon the contractors it selected. Nor have either DOE/FE or NERA provided the underlying NewERA model which NERA used to produce its results. Obviously, it is difficult to fully evaluate the study without access to the modeling files and underlying assumptions which NERA used. Other commenters[226] have made clear that it is good contracting practice to provide such materials as a matter of course. It is certainly appropriate to do so here, where DOE/FE must transparently justify its decisions after a full public process, as required by the Natural Gas Act and the Administrative Procedure Act. DOE/FE's failure to provide these critical disclosures undermines the public's ability to critically assess and analyze the study.

DOE/FE also has not disclosed how it has funded the NERA study, nor how DOE/FE influenced the study's conclusions. The magnitude of DOE/FE's involvement and investment here is of critical importance because DOE/FE claims that it has taken no position on the study or its conclusions and will dispassionately weigh public comments. Yet, if DOE/FE staff have funded the

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[224] Testimony of W. David Montgomery before the House Committee on Energy and Commerce (June 19, 2012), available at: http://energycommerce.house.gov/sites/republicans.energycommerce.house.gov/files/Hearings/OI/20120619/HHRG-112-IF02-WState-DMontgomery-20120619.pdf.
[225] Heritage Foundation, *Fuel Economy Standards: Do they Work? Do they Kill?* (2002), available at: http://www.heritage.org/research/reports/2002/03/fuel-economy-standards.
[226] *See* the Comments of Dr. Jannette Barth in this docket, for instance.

study, and, more importantly, shared in its development, there is a serious question whether DOE/FE will be able to fairly weight the finished product on its own merits. Staff clearly had some such involvement: Dr. Montgomery writes on the first page of the document that he is providing a “clean” copy, implying that past DOE/FE comments have been incorporated and addressed. The scope and nature of this involvement, however, remains unclear. DOE/FE must make its involvement transparent if it is set itself up as a neutral arbiter of the merits of NERA’s work.

If DOE does not share this information in time for it inform public comment, it will have prevented the public from participating in a pressing policy debate. The courts have repeatedly held that such a denial is an irreparable injury, so preventing such an injury is plainly a compelling need. *See, e.g.*, *Electronic Privacy Info. Ctr. v. Dep’t of Justice*, 416 F. Supp. 2d 30, 41-42 (D.D.C. 2006); *Washington Post v. Dep’t of Homeland Security*, 459 F. Supp. 2d 61, 74-75 (D.D.C. 2006); *Electronic Frontier Found. v. Office of the Director*, 2007 WL 4208311, *6 (N.D. Cal. 2007); *EFF v. Office of the Director*, 542 F. Supp. 2d 1181,1186 (N.D. Cal. 2008).

DOE/FE must not take the arbitrary and capricious step of relying upon the questionable results of a study infected with the appearance (and perhaps the reality) of bias. Nor may it finally adopt or seriously weigh the conclusions of the study if it shuts out of the process in the way that it has done.

V. Conclusion

NERA is able to conclude that LNG export is in the nation’s economic interest only because it wrongly believes that transferring billions of dollars from the nation’s middle class to a small group of gas export companies benefits the country as a whole. It does not: As we have demonstrated in these comments, the likely consequences of a major shift towards LNG export will be a weakened domestic economy, “resource-cursed” communities, and lasting environmental damage.

Even if one were to accept NERA’s indefensible attempt to balance national suffering against the private economic prosperity of a few, its conclusions are not maintainable. NERA projects at most a net GDP increase of at most $ 20 billion in a single year when it does this sum, subtracting labor income from LNG export revenues; the net benefit is often much less – on the order of a few billion dollars.[227] We have identified billions of dollars in pollution costs, infrastructure damage, and property value losses that NERA has not accounted for. Indeed, the cost just of increased methane emissions from LNG export is at least in the hundreds of millions annually. These costs almost certainly offset the nominal benefits which NERA claims to have identified. Certainly, NERA cannot claim otherwise, since it has not even considered them.

The Natural Gas Act charges DOE/FE with the weighty responsibility of protecting the public interest. Licensing LNG export would not serve that interest, and the NERA study certainly does not provide a basis to think otherwise. DOE/FE must not approve export licenses in reliance upon that flawed study, prepared by a contractor with at least the appearance of serious conflicts of interest. Instead, DOE/FE should begin an open, public process intended to fully identify and accurately account for the many economic and environmental impacts of LNG export.

Sincerely,

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[227] NERA Study at 8.

February 25, 2013

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Dear Secretary Chu:

We thank you and the Department of Energy's Office of Fossil Energy ("DOE/FE") for accepting these comments in reply to the initial comments submitted regarding on NERA Economic Consulting's study (the "NERA Study") of the macroeconomic impacts of liquefied natural gas ("LNG") export on the U.S. economy. We submit these reply comments on behalf the Sierra Club, including its Colorado, Kansas, Michigan, Oregon, Pennsylvania, Texas, and Wyoming Chapters; and on behalf of Catskill Citizens for Safe Energy, Center for Biological Diversity, Clean Air Council, Columbia Riverkeeper, Delaware Riverkeeper, Lower Susquehanna Riverkeeper, Shenandoah Riverkeeper, and Upper Green River Alliance.[1]

Having reviewed the initial comments other individuals and organizations submitted on the NERA Study, we stand by and reiterate the concerns raised in the Sierra Club's initial comment. The NERA Study concludes that LNG exports' primary effect will be to transfer wealth from the majority of Americans to the small minority of wealthy corporations that will own natural gas resources or LNG export infrastructure. The purported "net benefit" of this transfer, in NERA's view, is an increase in GDP that even NERA acknowledges is slight. Thus, taken at face value, the NERA Study shows that exports will be *contrary* to the public interest, by any reasonable interpretation of the term.

[1] We have submitted these comments and exhibits electronically, a procedure confirmed as acceptable by Larine Moore at DOE/FE today.

DOE/FE must not, however, take the NERA Study on its own terms. Even on the narrow issue of net GDP impacts, the NERA Study's conclusion is contradicted by the only other available comprehensive model of LNG exports' impacts, conducted recently by Purdue University economists Kemal Sarica and Wallace E. Tyner.[2] This independent study provides credible evidence undermining the NERA Study's sole finding of a public benefit. More broadly, the NERA Study's focus on net GDP impacts is too narrow in scope, and the NERA Study contains numerous errors, as we explained in our initial filing. The Natural Gas Act public interest inquiry must consider numerous issues ignored by NERA, including the way that increased gas production necessary to supply exports will cause harmful environmental impacts and disrupt communities where gas production occurs. These effects have economic aspects that could have been, but were not, included in the macroeconomic study. On a more technical level, NERA understates the potential volume of exports and domestic gas price increases. These price increases will merely transfer wealth from ordinary Americans and domestic businesses to the relatively few owners of natural gas companies and to foreign investors. Consideration of these additional impacts reinforces the Purdue Study's conclusion that the likely net effect of LNG exports will be a *decrease* in United States GDP, rather than the slight increase NERA predicts.

Nor may DOE/FE sidestep its public interest review obligations on the basis of free trade arguments advanced by other commenters. DOE/FE has a statutory obligation to consider the public interest; trade concerns, if they are considered at all, must be evaluated within this context and balanced against other aspects of the public interest. Moreover, export proponents have not shown that denying export applications would be inconsistent with the U.S.'s obligations under the General Agreement on Tariffs and Trade (GATT) or with underlying free trade principles. GATT recognizes countries' authority to restrict trade when necessary to protect human health or the environment or to conserve exhaustible natural resources. DOE/FE cannot conclude that free trade concerns weigh in favor of exports without exploring the extent to which these provisions apply here.

Finally, we reiterate our concerns regarding DOE/FE's process, both with the NERA Study itself and with respect to export authorization more generally. We previously explained the reasons why NERA's objectivity is suspect, and

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[2] *See* Kemal Sarica & Wallace E. Tyner, *Economic and Environmental Impacts of Increased US Exports of Natural Gas* (Purdue Univ., Working Paper, 2013) (available from the authors) [hereinafter Purdue Study].

DOE/FE still has not provided important information regarding the process by which NERA was selected or work was assigned. Nor has DOE/FE provided the details of NERA's NewERA model or other information necessary to allow external validation of the NERA Study's assessment. As to DOE/FE's own process, DOE/FE has provided inadequate information regarding how it will evaluate the public interest in individual applications, or the steps DOE/FE will take to monitor the impacts of exports if and when exports to non-free trade agreement countries are authorized. Failing to provide this information during the period for public comment on the NERA Study frustrates the purposes of FOIA, the Natural Gas Act, and general principles of administrative law, because withholding of this information limits the public's ability to assess and comment on the relevant documents.

In summary, LNG exports will have many effects that are not considered by the NERA report but are contrary to the public interest. The record contains abundant information demonstrating that these impacts will be significant, as we explain in further detail below.[3] DOE/FE cannot move forward without considering them.

I. DOE/FE Cannot Approve Applications without Considering The Environment, Employment/Job Losses, and Other Aspects of The Public Interest Not Examined by The NERA Study

Several commenters request that, now that the NERA Study is complete, DOE/FE immediately approve pending export applications without additional process.[4] DOE/FE must reject these requests. As DOE/FE has acknowledged elsewhere and as Sierra Club has explained in other filings, the scope of the public interest inquiry extends beyond the macroeconomic factors discussed by the NERA

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[3] The Center for Liquefied Natural Gas asserts that DOE has already decided that there is no evidence about exports being contrary to the public interest. Comment of Center for Liquefied Natural Gas at 4. This is obviously incorrect. The Center for Liquefied Natural Gas quotes two-year old DOE/FE statements, in an order conditionally authorizing exports from Sabine Pass LNG, where DOE/FE explained that in the record before it in that case at that time, there was insufficient evidence to indicate that the exports proposed there would be contrary to the public interest. DOE/FE is now facing a vastly different factual record and an order of magnitude more proposed exports. As such, these statements have no bearing here.

[4] *See, e.g.*, Comment of Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC.

Study.[5] Among other things, DOE/FE must consider proposed exports' impacts on the environment, employment, and communities in which production will occur.

A. Environmental Impacts

Exports will induce additional gas production. EIA and most other commenters predict that between 60 and 70% of the volume of gas exported will be sourced from production that would not have otherwise occurred; EIA's best estimate is that 63% of exported gas will be from induced production.[6] DOE/FE must reject the American Petroleum Institute's nonsensical argument that DOE/FE may ignore the effects of this production "because natural gas development using hydraulic fracturing is occurring and will continue to occur across the country regardless of whether a single additional export authorization is ever granted."[7] We agree that *some* production increases are likely to occur regardless of whether exports are approved, but this is irrelevant to DOE/FE's obligation to consider the effects of the *additional* or marginal increase in production that will result from exports. Indeed, American Petroleum Institute itself argues that exports will increase production.[8] American Petroleum Institute offers no explanation as to why it believes DOE should consider production increases in the context of jobs but not in the context of environmental impacts.

As Sierra Club's initial comment explained, the additional production that exports will induce will have significant environmental impacts.[9] These impacts will be particularly severe if that production is conducted in accordance with current industry practice and lax regulatory frameworks. The Secretary of Energy Advisory Board (SEAB)'s subcommittee on shale gas identified a number of gaps in existing regulations and industry practice, and few, if any, of these gaps have been filled.[10]

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[5] *Accord* Comment of the American Public Gas Association at 7, Comment of Dow Chemical Company at 2.
[6] EIA Study at 10.
[7] Comment of American Petroleum Institute at 22-23.
[8] *Id.* at 5.
[9] Comment of Sierra Club at 29-52.
[10] Comment of Sierra Club at Ex. 56 (DOE, Shale Gas Production Subcommittee First 90-Day Report (2012)).

The environmental impacts of gas production, and of the failure to regulate it, must be factored into assessment of exports' net and distributional impacts. In terms of net impacts, the economic cost of environmental harm, such as the cost of increased air emissions, erodes (if not entirely erases) the net benefit NERA purports to find. Although DOE/FE cannot limit its consideration of environmental impacts to those that are easily monetizable, DOE/FE must, at a minimum, apply available tools to estimate the economic impacts of environmental harms. For example, under the USREF_SD_LR scenario, NERA predicts 2.19 tcf/y of exports in 2035, with a $2 billion GDP increase relative to the baseline.[11] Using EIA estimates of the share of exports that will result from induced production (63%) and EPA's current estimate of the leak rate for gas production (2.4%), the Sierra Club estimated that 2.19 tcf/y of exports will release an additional 689,000 tons of methane into the atmosphere each year.[12] Using a conservative global warming potential for methane of 25 and EPA's social cost of carbon price of $25/ton, the social cost of the production-side methane emissions alone will be $430,625,000,[13] displacing more than 20% of the GDP increase NERA predicts under this scenario. Liquefaction and processing of natural gas further adds to greenhouse gas emissions. Other environmental impacts also impose monetizable costs, which must be added to any calculation of net impacts and thus further erase the claimed benefit. Moreover, as we explain below, the Purdue Study indicates that NERA has overstated the likely GDP benefit, such that even if environmental costs are excluded from consideration, the net GDP impact of exports would be negative. If those studies are correct, acknowledging environmental impacts makes a bad deal even worse.

Environmental impacts also aggravate the distributional inequity predicted by the NERA study. Environmental costs are borne by the public at large. Providing a market for increased gas production therefore effectively transfers wealth from the public, which suffers environmental harm as a result of increased production, to the production companies, which realize profits from this production. This effective wealth transfer must be considered in addition to the purely monetary wealth transfer identified by NERA.

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[11] *Compare* NERA Study at 179 *with* Comment of Sierra Club, Ex. 56 at 186.

[12] *See* Comment of Sierra Club at 31-32 for methodology.

[13] *I.e.,* (25)(25)($689,000). For more background on these estimates, *see* Comment of Sierra Club at 33-34.

In light of gas production's environmental impacts, even some export proponents have argued that the environmental impacts of gas production must be reduced before exports occur. Notably, a report by Michael Levi of the Brookings Institution concludes that the benefits of gas exports outweigh the risks and costs *if* "proper steps are taken to protect the environment."[14] Levi concludes that "environmental risks arising from natural gas production would . . . rise due to new production for exports," and that safe management of these risks would not happen without further action.[15] Levi recommended that, for a start, the environmental practices recommended by the SEAB should be required prior to exports.[16] In this proceeding, the Bipartisan Policy Center explicitly endorses Levi's argument, arguing that exports will be in the public interest only if environmental impacts are addressed.[17] Numerous other commenters, however, cite Levi's study for the purported conclusion that exports will be in the public interest without acknowledging Levi's qualification that environmental impacts must be addressed first.[18] Sierra Club disagrees with Levi's conclusion that exports will be in the public interest provided that gas production is more carefully regulated. At a minimum, however, DOE/FE must reject any implication that Levi's report indicates that exports would further the public interest even if production occurs under the status quo.

Moreover, although regulations that limit gas production's environmental impacts may increase the cost of production and thus gas prices, such price increases have a markedly different impact on the public interest than price increases caused by demand for exports. What the public "buys" when it experiences a price increase attributable to environmental regulation is increased environmental protection that would otherwise have been caused by production of the gas being used. Regulation also avoids emergency cleanup, public health care, and emergency costs resulting from environmental harm related to drilling, ultimately saving public tax dollars. In contrast, when prices increase because of exports, the public doesn't receive anything in exchange for paying increased prices. Indeed, whereas higher prices resulting from less environmentally destructive practices lessen the environmental impacts borne by the public,

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[14] Michael Levi, *A Strategy For U.S. Natural Gas Exports*, at 6 (June 2012), available at http://www.hamiltonproject.org/files/downloads_and_links/06_exports_levi.pdf and attached here as exhibit 1.

[15] *Id.*

[16] *Id.* at 21.

[17] Comment of Bipartisan Policy Center at 2.

[18] *See, e.g.*, Comment of American Petroleum Institute at 15.

higher prices resulting from competition with exports increase the environmental harm the public suffers, by stimulating increases in overall production and consumption and thus increases in environmental impacts such as emissions of greenhouse gases and traditional air pollutants. Similarly, when the public pays for price increases in response to purely domestic demand growth, the public "buys" the benefits of a strong manufacturing industry, but when prices increase because of export, the public receives no analogous benefit.

Thus, DOE/FE must consider the environmental impacts of exports, including the effects of induced gas production and of liquefaction, in its assessment of the public interest. DOE/FE must consider the alternative of withholding approval of export authorizations until additional regulation—such as that recommended by the SEAB—is in place to ameliorate these impacts.[19] Even under such an alternative, however, DOE/FE would need to consider the effects of remaining environmental impacts, which, though diminished, would still weigh against the public interest.

B. Employment and Job Losses

LNG export proponents and opponents generally agree that exports will have significant effects on domestic employment and that employment effects are a key component of the public interest, but that the NERA Study did not directly consider this issue.

There is an apparent consensus among informed observers that if exports are approved, there will be additional jobs in the fields of gas production and terminal construction, but that the resulting increase in gas prices will eliminate

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[19] Contrary to American Petroleum Institute's contention, DOE/FE plainly has authority to deny export applications on the basis of environmental impacts. Comment of American Petroleum Institute at 23. American Petroleum Institute rests on *Department of Transportation v. Public Citizen,* 541 U.S. 751 (2004). *Public Citizen* held that "where an agency has *no ability* to prevent a certain effect due to its limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant 'cause' of the effect," and that the effect could be excluded from NEPA analysis. *Id.* at 770 (emphasis added). There, where the agency had "no discretion to prevent the entry of Mexican trucks, its [environmental assessment] did not need to consider the environmental effects arising from the entry." *Id.* Here, DOE/FE unquestionably has the authority and duty to consider environmental impacts in its public interest analysis, the authority to deny export authorization on the basis of environmental impacts, and thereby to prevent the environmental harms associated with induced production. Accordingly, *Public Citizen* does not support American Petroleum Institute's argument.

jobs in other industries, such as manufacturing, that are highly energy dependent. The NERA Study acknowledges both of these effects.[20] NERA did not, however, provide a sufficient analysis of their absolute or relative magnitudes. As the Synapse Report provided by Sierra Club explained, because of the NewERA model's assumption of full employment, "the potential economic impact that is of the greatest interest to many policymakers, namely the effects of increased LNG exports on jobs, cannot be meaningfully studied with NERA's model."[21] Numerous export proponents also criticize the NERA Study's assumption of full employment.[22] Accordingly, DOE/FE cannot approve the pending export applications without conducting a study capable of examining the job creation or destruction impacts of LNG exports.

If DOE/FE were to make a decision on the available evidence, DOE/FE would have to conclude that LNG exports will cause a severe net *decrease* in domestic jobs. As Sierra Club explained in its initial comment, although the NERA Study did not directly assess job impacts, it attempted to predict impacts on aggregate labor income, and these predictions can be used to evaluate gain or loss in "job equivalents."[23] Considering the increase in labor income in sectors benefited by exports (gas production and terminal construction) and the decrease in labor income in other sectors, NERA predicted a loss of labor income equivalent to 36,000 to 270,000 jobs per year.[24] This is the only economy-wide discussion of job impacts in the record, and it provides a strong indication that exports would be contrary to the public interest.

Although many export applicants have provided studies purporting to show job growth, none of these studies attempts to account for decrease in employment in the industries that will be negatively affected by increased gas prices. For example, in its initial comments, Golden Pass Products disputes the NERA Study's conclusion that "'higher energy costs do create a small drag on economic output in the U.S. so that total worker compensation declines.'"[25] Golden Pass Products' basis for disputing this conclusion is the contention that its own export proposal would generate "tens of thousands of direct and indirect jobs across the U.S." as a result of construction and operation of the needed export facility and

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[20] NERA Study at 60-61, 65.
[21] Comment of Sierra Club at Ex. 5, 15.
[22] *See, e.g.*, Comments of Cameron LNG at 12, Cheniere Energy at 5, ExxonMobil at 2.
[23] Comment of Sierra Club at 8, Ex. 5, 4-5.
[24] *Id*.
[25] Comment of Golden Pass Products at 3 (quoting NERA Study at 77).

production of the gas required for export.[26] But Golden Pass Products and the economic study it relies on are completely silent as to the countervailing effects of jobs lost in other industries as a result of increased gas prices. Accordingly, the study Golden Pass Products submitted provides no basis for DOE/FE to conclude that exports will result in net job growth. As Sierra Club has explained in the individual dockets for other pending export applications, all of the studies applicants have submitted regarding employment impacts suffer this defect.[27]

Finally, DOE/FE must reject the various assertions that jobs in terminal and liquefaction facility construction provide a substitute for lost manufacturing jobs.[28] It is possible that, from the perspective of an individual employee, the two may be comparable on a short term basis,[29] but it is extraordinarily unlikely that the number of facility construction jobs created will equal the number of manufacturing jobs lost. This is especially true over the 20-year lifetime of the export authorizations requested, because facility construction jobs are by nature temporary and will span only the beginning few years of the exports.

The NERA Study's failure to consider job impacts is a glaring gap in the public interest analysis, and DOE/FE must address this gap before approving any of the pending export applications. The best evidence in the existing record regarding net job impacts, however, is Sierra Club's application of NERA's own "job equivalent" methodology to the NERA Study's labor income forecasts, and this evidence strongly indicates that the volumes of exports considered by the NERA study will cost between 36,000 and 270,000 jobs annually.

C. Resource Extraction Hurts, Rather than Benefits, The Communities in which It Occurs

On a macroeconomic level, exports will increase output of the gas production industry while reducing output of many manufacturing and other energy intensive industries. Similarly, in terms of aggregate employment figures, exports will create some jobs in gas extraction but eliminate jobs in other industries. It is therefore understandable for the NERA Study and many

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[26] *Id.* at 4.
[27] The job creation arguments submitted by export applicants suffer numerous additional flaws, as Sierra Club has explained in the individual dockets.
[28] *See, e.g.*, Comment of American Petroleum Institute at 5-6.
[29] Of course, even a shift between comparable jobs could have a net adverse effect on the public interest, due to the social and economic costs of displacing workers.

commenters to approach the public interest analysis by examining whether the benefits realized by increased gas production outweigh the costs felt by other industries, whether these costs and benefits are measured in industry profits or jobs supported.

On a community level, however, it would be inappropriate for DOE/FE to conduct a simplistic comparison of the "benefits" of increased production and the harms of reduced energy intensive industry. Empirical evidence indicates that in the long term, resource extraction hurts, rather than helps, the communities in which it occurs.[30] Many individuals living in communities currently experiencing America's shale gas boom submitted initial comments on the NERA Study testifying to the degradation their communities have experienced as a result of shale gas extraction. DOE/FE must ensure that the infrastructure costs, population declines, and other symptoms of the "resource curse" that often affects these communities are accounted for in whatever framework DOE/FE ultimately uses to assess the public interest. The NERA Study is not up to this task.

II. Price Impacts

Turning to questions the NERA Study purports to answer, the effects of LNG exports on domestic gas prices are a key aspect of the Natural Gas Act's public interest inquiry. Sierra Club previously explained that the NERA Study understates the potential magnitude of these increases, and comments from other entities support Sierra Club's argument on this point. Industry commenters further support the conclusion that exports, if approved, are likely to ramp up quickly, risking domestic price spikes.

A. LNG Exports Will Raise Domestic Gas Prices Without Providing Corresponding Social or Environmental Benefits

As a threshold issue, all available evidence indicates that exports will increase gas prices. DOE/FE therefore must reject assertions by some export proponents, such as the American Exploration and Production Council, that the demand created by exports is necessary to avoid a decline in production that would lead

[30] Comment of Sierra Club at 13-25.

to even greater price increases.[31] No study or modeling submitted by export applicants supports this argument. Instead, every model and forecast that compares future worlds with and without U.S. LNG exports concludes that U.S. gas prices will be higher with exports, and that prices will increase as export volumes increase. Indeed, even the American Exploration and Production Council apparently endorses the NERA Study's price forecasts—which predict that exports will increase prices relative to a baseline future without exports—on the page prior to the group's assertion that exports will lower prices.

B. The NERA Study Overstates Potential Market Limits on Exports, and Thus Underestimates The Potential Ceiling on Domestic Price Increases

The NERA Study concludes price increases will be self-limiting because exports will only make economic sense when regasified U.S. LNG can be had in receiving markets for less than the cost of alternative supplies. In other words, the spread between prices in the U.S. and receiving markets must be greater than the cost of liquefying, transporting, and re-gasifying LNG. Thus, the NERA Study concludes that there will be a market ceiling on the extent to which exports can cause domestic gas prices to rise: exports should drive U.S. prices above the highest price in a receiving market minus the price of transporting gas to that market. The NERA Study explains that at present, the highest priced markets are Japan and Korea, and that the total costs to deliver gas to Asian markets are $6.89/MMBtu to China and India and $6.64/MMBtu to Korea and Japan.[32]

For reasons Sierra Club previously explained, the NERA Study's projected ceiling on domestic prices is too low. First, NERA overstates transportation costs. The NERA Study assumes that all U.S. export terminals will be in the Gulf Coast, and estimates transportation costs accordingly. Two facilities, however, have been proposed for the West Coast. One of these, proposed by Jordan Cove Energy Project, filed comments explaining that its transportation costs to Japan were significantly lower than those assumed by the NERA Study. Although Jordan Cove Energy Project would face higher facility construction and thus liquefaction costs than Gulf Coast facilities, Jordan Cove asserts that, in aggregate, its total processing and transportation costs will be $0.44/MMBtu

[31] Comment of American Exploration and Production Council at 2.

[32] NERA Study at 90, Figure 62 (figures here exclude the "Regas to city gate pipeline cost").

lower than the estimates used by NERA.[33] Accordingly, insofar as the cost of processing and transporting LNG sets the ceiling on price increases resulting from exports, that ceiling could be $0.44/MMBtu higher than the NERA Study estimates. $0.44/MMBtu represents roughly 5 to 10% of NERA's predicted 2035 wellhead gas prices, meaning NERA may have significantly underestimated the price range within which exports will occur.[34]

Another factor that causes the NERA Study to underestimate the potential volume of exports, and thus the magnitude of price increases, is the failure to acknowledge the effects of "take or pay" contracts. Under these contracts, importers agree to pay a fee to reserve terminal capacity regardless of whether that capacity is actually used to liquefy and export gas. These contracts are generally for the full term of the export authorization, *i.e.*, 20 years. Various foreign commenters state that they have already entered these long-term contracts with export applicants.[35] Accordingly, these importers have already sunk a portion of the cost of liquefaction, and could minimize or disregard this cost when deciding whether to import gas once facilities enter operation.

C. Exports Will Likely Increase Domestic Gas Price Volatility

Numerous commenters have argued that exports will decrease gas price volatility, but the available evidence indicates that, if anything, exports may lead to an increase in volatility as a surge in exports ramps up quickly.

There is reason to think that exports will *increase* domestic gas price volatility in the short term. Both EIA and the NERA Study found the highest increases in domestic gas prices in scenarios in which exports were phased in rapidly. Numerous export proponents have argued that it is imperative that the U.S. move quickly to establish exports before other sources of gas come online.[36] These other competitive sources of gas could be expanded LNG export operations from other countries such as Australia or Canada, development of additional international pipeline capacity, or development of unconventional gas reserves in countries that would otherwise seek to import US LNG. In light of these statements about the need and intention to proceed quickly, it is quite

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[33] Comment of Jordan Cove Energy Project at 2.
[34] NERA Study at 50.
[35] Comment of Japan Gas Assoc. (explaining that Japanese firms already have a take-or-pay agreement with Freeport LNG and are close to concluding a similar agreement with Dominion).
[36] Comment of Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC.

possible that exports will ramp up as quickly as DOE/FE allows. If this happens, demand may increase more rapidly than production, leading to periods of increased scarcity and price spikes, as the EIA predicts.[37]

On the other hand, there is little evidence, if any, that exports will meaningfully reduce volatility. Export applicants have argued that increasing stable gas demand resulting from exports will induce domestic production and provide for a broader, less volatile market.[38] The Institute for 21st Century Energy, for example, argues that gas prices were particularly volatile when Congress limited consumption of gas by industrial and electricity generating users, and that volatility was reduced once these sectors began consuming gas.[39] Even if exports do not occur, however, these sectors will present exactly the type of demand growth that exports would provide. Gas prices are already expected to rise due to increasing consumption in the industrial and electricity sectors, and allowing exports would drive prices up further. Accordingly, to the extent that exports might marginally reduce volatility, they would do so by resulting in higher, if slightly more stable, gas prices.

Fundamentally, even if exports reduce volatility, this effect is almost certain to be less important than overall increases in price. Any reduction in volatility will be the result of raising prices to eliminate troughs. On the available record, DOE/FE cannot conclude that any such effect will meaningfully benefit the public interest.

D. Use of Updated Annual Energy Outlook Demand and Supply Forecasts

As Sierra Club and many others noted in the initial comments, the NERA Study used outdated predictions of domestic natural gas demand, relying on the EIA's 2011 Annual Energy Outlook instead of the 2012 data available at the time NERA undertook the study or the early release 2013 forecast. Greater baseline demand generally entails greater price increases for any given level of exports. Other commenters counter that, although more recent Annual Energy Outlooks forecast higher domestic demand, they also forecast baseline higher domestic production, which would generally tend to lower the price increase caused by any given volume of exports.

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[37] *Accord*, Comment of Dow Chemical Corp. at 5, 16.
[38] *See, e.g.*, Comment of Center for Liquefied Natural Gas, 15.
[39] Comment of Institute for 21st Century Energy, 2-3.

In light of the significant changes between the 2011 and 2013 Annual Energy Outlooks, DOE/FE should revisit the price impacts analysis. We recognize that new data and forecasts will regularly be released, such that there are limits to DOE/FE's ability to always use the *most* current information. In light of the importance of this issue and the availability of newer data during the period in which the NERA Study was conducted, however, NERA's decision to rely on the 2011 Annual Energy Outlook is unreasonable.

E. Conclusion Regarding Price Impacts

As we explain above and in prior comments, LNG exports will increase domestic gas prices, and the price increases rise with export volumes. The NERA Study overestimates the costs of moving gas to foreign markets and disregards the long-term nature of export agreements, leading NERA to understate potential export volumes. NERA therefore underestimates potential domestic gas price increases. The following section discusses the effects increased prices will have on the domestic economy.

III. Macroeconomic Impacts

The NERA Study's conclusions regarding macroeconomic impacts are stark: exports will decrease household incomes for the majority of Americans, effectively transferring wealth from low and middle class families to gas production companies and owners of liquefaction infrastructure. These deleterious effects are corroborated by the Purdue Study, which found similar impacts. Notwithstanding these distributional effects, the NERA Study concluded that exports would be a net benefit to the U.S. because the benefits realized by gas companies would create a slight overall increase in GDP. This conclusion is undermined by the Purdue Study, which concludes that exports will cause a net decrease in GDP.

As explained in Sierra Club's initial comment, the distributional effects of LNG exports are resoundingly contrary to the public interest; there are multiple reasons to doubt the NERA Study's conclusion regarding aggregate GDP impacts; and even if NERA were correct about effects on the overall GDP, an increase in GDP does not itself demonstrate furtherance of the public interest. These arguments are generally supported by the initial comments submitted by other parties.

A. Exports Will Transfer Wealth from Middle and Low Income Families to Gas Production and Exporting Companies

The NERA Study concluded that Americans who do not own stock in companies involved in gas production or LNG export—*i.e.*, the overwhelming majority of Americans—will be made worse off by exports. None of the initial comments on the NERA Study call this conclusion into question. This regressive redistribution of wealth is highly detrimental to the public interest.

In an apparent attempt to minimize the impact of this effect, the NERA Study argues that the benefits realized by gas production companies are realized by "consumers" generally, because "[c]onsumers own all production processes and industries by virtue of owning stock in them."[40] As Sierra Club explained, however, only about half of American families own any stock at all, and only a small subset of stock owners own stocks in the gas production companies that will benefit from exports.[41]

Moreover, many of the economic benefits of exports will not accrue to U.S. residents. Sierra Club's initial comment demonstrated extensive foreign investment in U.S. liquefaction capacity.[42] Japan's Osaka Gas and Chubu Electric utilities provide additional evidence on this point, expressing their belief that foreign investors (presumably including these companies) will make significant additional investments in U.S. liquefaction facilities.[43] A result of these investments will be that, contrary to the NERA Study's assumptions, a share of the profits realized by liquefaction operators will accrue to foreign investors.[44] Moreover, while Sierra Club's initial comment only discussed foreign ownership in the context of liquefaction and terminal facilities, other commenters demonstrate that foreign entities are also investing directly in natural gas production. India's GMR Energy Limited notes that Indian companies have already taken stakes in production of Marcellus and Eagle Ford Shales.[45] Foreign investment rebuts the NERA Study's assumption that profits from gas production will accrue solely to U.S. consumers.

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[40] NERA Study at 55 n.22.
[41] Comment of Sierra Club at Ex. 5, 9-10.
[42] *Id.*
[43] Comment of Chubu Electric Power Co.
[44] *See* Comment of Sierra Club at Ex. 5, 9.
[45] Comment of GMR Energy Limited.

B. The NERA Study Understates Exports' Effects on Domestic Industry and Is Overly Optimistic about Changes in Gross Domestic Product

Contrary to the NERA Study's conclusions, it is unlikely that LNG exports will increase GDP.

Although the NERA Study concludes that LNG exports will slightly increase GDP, this conclusion is contradicted by the recent independent Purdue Study.[46] Purdue's Prof. Tyner submitted a summary of this study as an initial comment, and Sierra Club discussed this work previously. The Purdue Study concludes that aggregate effects on GDP will be negative, although the two studies agree that in absolute terms, effects will be small. The Purdue Study explains that its results differ from the NERA Study's because the former predicts larger price increases as a result of exports, and thus larger declines in energy intensive sectors.[47] The Purdue Study is built on publicly available models and was conducted by independent researchers, making it every bit as credible as the NERA Study. Accordingly, DOE/FE cannot simply credit the NERA Study's conclusion that exports will provide a slight increase in GDP as a basis for concluding that exports are in the public interest.

Furthermore, both the NERA and Purdue Studies ignore many effects that will lower overall GDP. The Purdue Study acknowledges this omission, explaining that both its analysis and the analysis used in the NERA Study understate the impacts on energy intensive industries such as manufacturing, because these domestic industries' success depends not just on their energy costs, but also on the relative difference between what domestic industry must pay for gas and energy and what foreign competitors pay. Because LNG exports will likely simultaneously raise domestic energy costs while lowering foreign costs, exports will inhibit domestic industry's ability to compete in a global marketplace. Nor does either analysis account for the environmental harms, "resource curse" effects, or other issues described in part I, above.

We also reiterate our concerns—shared by Congressman Markey, Dow Chemical, and other commenters—about the NERA Study's modeling (or lack thereof) of effects on other industries.[48] Sector-specific modeling of exports'

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[46] *See supra* n.2.

[47] Purdue Study, *supra* n.2, at 4.

[48] Comment of Sierra Club, Ex. 5, 5-6.

impacts can be reasonably obtained, but the NERA Study does not provide this analysis. The NERA Study asserts that adversely affected industries are not "high value-added," but does not support this assertion by modeling the systemic impacts of impacts to these industries. The NERA Study further assumes that industries in which energy expenditures constitute less than 5% of total costs will not be significantly adversely affected by exports,[49] but it appears that other industries may likely be affected.

In light of these concerns, this is another area in which DOE/FE should seek to ground its public interest analysis in empirical work, including case studies. As Alcoa suggests in its comments, Australia's recent experience with LNG export can provide a useful starting point for analysis. Alcoa states that domestic gas prices in Western Australia, which currently exports LNG, are at least double U.S. prices, despite extensive Australian natural gas resources.[50] We encourage DOE/FE to investigate the Australian experience with LNG export for calibration of, or in addition to, use of economic models and forecasting, before deciding whether to approve LNG export proposals.

IV. Trade

Numerous commenters invoke the United States' obligations under the General Agreement on Tariffs and Trade (GATT), as well as an underlying commitment to free trade principles, as grounds for approving LNG exports. DOE/FE's statutory obligation is to determine whether exports are in the public interest, and trade considerations, assuming they apply at all, are merely one factor DOE/FE can consider in this analysis. Insofar as trade issues are pertinent, we note that commenters have overstated the extent to which denying export applications would conflict with trade policy. Even if there is a conflict, however, free trade arguments at most factor into, and do not displace, the public interest inquiry required by the Natural Gas Act.

The GATT preserves the United States' authority to restrict LNG exports in these circumstances. Specifically, the GATT states:

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[49] *See, e.g.*, NERA Study at 68.
[50] Comment of Alcoa, 2, 4

> [N]othing in this Agreement shall be construed to prevent the adoption or enforcement . . . of measures: . . . (b) necessary to protect human, animal or plant life or health; [or] . . . (g) relating to the conservation of exhaustible natural resources if such measures are made effective in conjunction with restrictions on domestic production or consumption.[51]

As explained above and in prior comments, exports will cause significant harm to human health and the environment. Under the Natural Gas Act, DOE/FE can and should deny export applications on this ground. In light of GATT's explicit recognition of signatories' power to restrict exports in these circumstances, DOE/FE must reject the assertion that denying export authorizations would violate the United States' GATT obligations.

Even if denying applications could potentially brush against free trade principles, this would be at most just one factor to consider in the public interest analysis. Congress has commanded DOE/FE to evaluate proposals for exports to countries lacking a bilateral free trade agreement on a case by case basis. If DOE/FE were to categorically determine that all exports to WTO nations were consistent with the public interest DOE/FE would, among other errors, disregard the Congressional command to engage in case-by-case inquiry and thereby fail to give effect to the terms of the governing statute. Under the existing statutory framework DOE/FE can, at most, attempt to assess on a case-by-case basis whether the benefits of adherence to free trade principles in that particular case, together with other factors furthering the public interest, outweigh the effects that will be contrary to the public interest.

V. DOE/FE Process

Finally, we have a number of concerns regarding the process by which DOE/FE has addressed the question of whether to authorize LNG exports, as well as the process DOE/FE will use going forward.

As the above concerns amply demonstrate, in making its public interest determinations regarding individual export proposals, DOE/FE must confront a

[51] General Agreement on Tariffs and Trade, Oct. 30, 1947, 61 Stat. A-11, 55 U.N.T.S. 194 at Art. XX.

wide range of issues addressed inadequately, if at all, by the NERA Study. We join with other commenters, including Dow Chemical Corporation, in requesting that DOE/FE explicitly articulate the framework it will use in making these determinations. Development of this framework would most sensibly take place in the context of a separate rulemaking.

Similarly, we remind DOE/FE that it must consider the cumulative environmental, economic, and other impacts of LNG exports; DOE/FE cannot consider individual applications in isolation. Regarding environmental impacts, the best way to consider these impacts is through preparation of a programmatic environmental impact statement (EIS), pursuant to the National Environmental Policy Act, 42 U.S.C § 4332(c). Whether conducted under the auspices of a programmatic EIS or otherwise, DOE/FE cannot approve any individual application until it has considered the cumulative impacts of all foreseeable applications. Although export proponents have argued that only a subset of proposed export projects are likely to be constructed, DOE/FE may not decline to consider the impacts of all pending proposals on that basis. Moreover, DOE/FE must recognize that the mere existence of a proposal or authorization of exports has immediate effects on energy markets and dependent industries, as other players adjust their expectations regarding the potential for exports. DOE/FE must acknowledge that authorization of a proposal has important effects even if that authorization is not put to use.

DOE/FE should also articulate the standards it will use in retaining jurisdiction over exports after they are approved. In the Sabine Pass proceeding, DOE/FE stated that it would continue to exercise jurisdiction over the approved exports, and would revisit the authorization if subsequent events demonstrated that exports had become contrary to the public interest.[52] If DOE/FE wrongly concludes that exports are in the public interest now, DOE/FE should nonetheless provide examples of the types and severity of circumstances that would cause DOE/FE to revisit this determination and revoke approval.[53]

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[52] DOE/FE Order No. 2961 at 31-33.

[53] DOE/FE's ongoing supervisory authority is not a substitute for making a proper initial public interest evaluation. DOE/FE must reject the Center for Liquefied Natural Gas's apparent suggestion that DOE/FE approve the pending applications now without attempting to predict their consequences, with the plan of taking action once adverse impacts manifest themselves. Comment of Center for Liquefied Natural Gas, 6. The Center for Liquefied Natural Gas asserts that "The role of the regulator is . . . not to be a predictor of future events," and that DOE should not "predict future events," presumably meaning price increases and effects on the American

Finally, we reiterate our concerns about the lack of transparency regarding DOE/FE's selection of NERA, as well as the quality of the NERA Study itself. As Sierra Club previously explained, NERA in general, and study author Dr. Montgomery in particular, have a history of activities that raises serious questions about their objectivity. These questions are made even more pertinent by the dearth of information regarding DOE/FE's solicitation and selection of NERA and the modeling and data used by NERA in generating this study, including information regarding the underlying NewERA model. DOE/FE has refused to make this information available for review during the public comment period.[54] For a study of this importance, however, DOE should have provided this information in order to support full public participation and rigorous peer review, and to inspire public trust in the study's conclusions.

VI. Conclusion

Exports will cause severe environmental harms, eliminate more jobs than they create, disrupt communities with the boom/bust cycle of resource production, redistribute wealth from the lower and middle classes to wealthy owners of gas production companies, and have broad effects on the output of various sectors of the American economy. The NERA Study disregards nearly all of these considerations in concluding that exports will be a "net benefit" to the United States. DOE/FE's review of the public interest cannot be so constrained. Initial comments on the NERA Study submitted by other parties only reinforce the arguments advanced in Sierra Club's initial comment.

On the record before it, DOE/FE cannot conclude that any of the pending export applications would be in the public interest. DOE/FE must begin a transparent process that will acknowledge and evaluate all of the proposed LNG exports' impacts on the public interest.

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economy, "during the authorization proceeding for projects with lifespans in excess of twenty (20) years each." *Id.* The Center for Liquefied Natural Gas's assertion that regulators should not predict impacts in the domains they regulate, including the impacts of that regulation, severely misunderstands the role of a regulator. Common sense and general principles of administrative law are that when such predictions are available, the agency must seek them out and use them to inform its actions.

[54] Sierra Club, *Freedom of Information Act Request Re: LNG Export Studies* (Jan. 22, 2013), attached as exhibit 2; DOE Interim Response to HQ-2013-00423-F (Jan. 24, 2013), attached as exhibit 3; Sierra Club, *Freedom of Information Appeal, re: HQ-2013-00423-F* (Feb. 22, 2013), attached as exhibit 4.

Sincerely,

/s/ Nathan Matthews

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To: LNGStudy
Subject: 2012 LNG Export Study
Date: Monday, January 14, 2013 11:25:34 AM
Attachments: Comparison of Analysis of Natural Gas Export Impacts w exec sum Jan rev.pdf

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Comments attached.

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

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Executive Summary

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

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

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

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

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

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

NERA Economic Consulting study

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

The NERA analysis focused on export levels of 6 and 12 BCF per day, but there were many other scenarios and sensitivity analyses. In general, the welfare or net income increases estimated in the NERA scenarios were very small, generally ranging from 0.01 to 0.025 percent over the reference case. There were considerable losses in capital and wage income in sectors affected by the higher natural gas prices, and income gains to natural gas resource owners through export earnings and wealth transfers to resource owners. By 2030 the total net increase in GDP amounted to about $10 billion 2010$, which could be perceived as being quite small in a $15 trillion economy [3]. Wage income falls in agriculture, energy intensive sectors, and the electricity sector. The percentage declines in wages in these sectors were generally much greater than the percentage increases in net national income. Natural gas price increases did not exceed 20 percent in any of the simulations. The NewERA energy-economy model takes inputs from the EIA NEMS natural gas projections [2] and from a global natural gas model.

Purdue MARKAL-Macro Analysis

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

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

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

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

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

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

Comparison

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

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

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

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

Conclusions

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

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

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

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Regulatory Impact Analysis

Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry

U.S. Environmental Protection Agency
Office of Air and Radiation
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July 2011

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1 EXECUTIVE SUMMARY

1.1 Background

The U.S. Environmental Protection Agency (EPA) reviewed the New Source Performance Standards (NSPS) for volatile organic compound and sulfur dioxide emissions from Natural Gas Processing Plants. As a result of these NSPS, this proposal amends the Crude Oil and Natural Gas Production source category currently listed under section 111 of the Clean Air Act to include Natural Gas Transmission and Distribution, amends the existing NSPS for volatile organic compounds (VOCs) from Natural Gas Processing Plants, and proposes NSPS for stationary sources in the source categories that are not covered by the existing NSPS. In addition, this proposal addresses the residual risk and technology review conducted for two source categories in the Oil and Natural Gas sector regulated by separate National Emission Standards for Hazardous Air Pollutants (NESHAP). It also proposes standards for emission sources not currently addressed, as well as amendments to improve aspects of these NESHAP related to applicability and implementation. Finally, it addresses provisions in these NESHAP related to emissions during periods of startup, shutdown, and malfunction.

As part of the regulatory process, EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed $100 million. EPA estimates the proposed NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. Because the NESHAP amendments are being proposed in the same rulemaking package (i.e., same Preamble), we have chosen to present the economic impact analysis for the proposed NESHAP amendments within the same document as the NSPS RIA.

This RIA includes an economic impact analysis and an analysis of human health and climate impacts anticipated from the proposed NSPS and NESHAP amendments. We also estimate potential impacts of the proposed NSPS on the national energy economy using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using a 7 percent discount rate. This analysis assumes an analysis year of 2015.

Several proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One emissions control option, reduced emissions well completions, also recovers saleable hydrocarbon condensates which would otherwise be lost to the environment. The revenues derived from additional natural gas and condensate recovery are expected to offset the engineering costs of implementing the NSPS in the proposed option. In the economic impact and energy economy analyses for the NSPS, we present results for three regulatory options that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

1.2 NSPS Results

For the proposed NSPS, the key results of the RIA follow and are summarized in Table 1-1:

- **Benefits Analysis:** The proposed NSPS is anticipated to prevent significant new emissions, including 37,000 tons of hazardous air pollutants (HAPs), 540,000 tons of VOCs, and 3.4 million tons of methane. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The methane emissions reductions associated with the proposed NSPS are likely to result in significant climate co-benefits. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of carbon dioxide (CO_2), 510 tons of nitrogen oxides NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital cost of the proposed NSPS will be $740 million. The total annualized engineering costs of the proposed NSPS will be $740 million. When estimated revenues from additional natural gas and condensate recovery are included, the annualized engineering costs of the proposed NSPS are estimated at $-45 million, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf) and condensate price of $70/barrel. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA. The estimated engineering compliance costs that include the product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For example, $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million, given EPA estimates that 180 billion cubic feet of natural gas

will be recovered by implementing the proposed NSPS option. All estimates are in 2008 dollars.

- **Energy System Impacts:** Using the NEMS, when additional natural gas recovery is included, the analysis of energy system impacts for the proposed NSPS shows that domestic natural gas production is likely to increase slightly (about 20 billion cubic feet or 0.1 percent) and average natural gas prices to decrease slightly (about $0.04/Mcf or 0.9 percent at the wellhead for onshore production in the lower 48 states). Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.02/barrel or less than 0.1 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NSPS, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at 230 full-time-equivalent employees. The annual labor requirement to comply with proposed NSPS is estimated at about 2,400 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

Table 1-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Oil and Natural Gas NSPS Regulatory Options in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane[5]	3.4 million tons of methane[5]	3.4 million tons of methane[5]
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

1.3 NESHAP Amendments Results

For the proposed NESHAP amendments, the key results of the RIA follow and are summarized in Table 1-2:

- **Benefits Analysis:** The proposed NESHAP amendments are anticipated to reduce a significant amount of existing emissions, including 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane. Results from the residual risk assessment indicate that for existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with benzene as the primary cancer risk driver. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and PM, we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, and climate effects as well as additional natural gas recovery. The specific control technologies for the proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital costs of the proposed NESHAP amendments to be $52 million. Total annualized engineering costs of the proposed NESHAP amendments are estimated to be $16 million. All estimates are in 2008 dollars.
- **Energy System Impacts:** We did not estimate the energy economy impacts of the proposed NESHAP amendments as the expected costs of the rule are not likely to have estimable impacts on the national energy economy.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NESHAP amendments, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NESHAP Amendments is estimated at 120 full-time-equivalent employees. The annual labor requirement to comply with proposed NESHAP Amendments is estimated at about 102 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

- **Break-Even Analysis:** A break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas, ozone benefits valued at $240 to $1,000 per ton of VOC emissions reduced, and climate co-benefits valued at $110 to $1,400 per short ton of methane reduced. All estimates are in 2008 dollars.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs 9,200 tons of VOCs[4] 4,900 tons of methane[4] Health effects of HAP exposure Health effects of $PM_{2.5}$ and ozone exposure[4] Visibility impairment[4] Vegetation effects[4] Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, PM2.5 and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

1.4 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents statutory and executive order analyses. Section 6 presents a comparison of benefits and costs. Section 7 presents energy system impact, employment impact, and small business impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes the following five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS and NESHAP amendments propose controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210—Pipeline Transportation of Natural Gas. While other NAICS (213112—Support Activities for Oil and Gas Operations, 221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the proposed NSPS and NESHAP amendments.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2009, the Energy Information Administration (EIA) estimates that about 526,000 producing oil wells and 493,000 producing natural gas wells operated in the United States. Domestic dry natural gas production was 20.5 trillion cubic feet (tcf) in 2009, the highest production level since 1970. The leading five natural gas producing states are Texas, Alaska, Wyoming, Oklahoma, and New Mexico. Domestic crude oil production in 2009 was 1,938 million barrels (bbl). The leading five crude oil producing states are Texas, Alaska, California, Oklahoma, and New Mexico.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the proposed NSPS and NESHAP Amendments. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analysis in this RIA. The Industry Profile relies heavily on background material from the U.S. EPA's "Economic Analysis of Air

Pollution Regulations: Oil and Natural Gas Production" (1996) and the U.S. EPA's "Sector Notebook Project: Profile of the Oil and Gas Extraction Industry" (2000).

2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and natural gas and reservoir characteristics are likely to be different from that of any other reservoir.

2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another classification measure of crude oil and other hydrocarbons is by API gravity. API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with API gravity of 20^{o} or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase of the petroleum industry may be referred to as live crudes. Live crudes contain entrained or dissolved gases which may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.

2.2.2 Natural Gas

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists in a gaseous phase or in solution with crude oil or other hydrocarbon liquids in natural underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H_2S), CO_2, mercaptans, and entrained solids.

Natural gas may be classified as wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas streams that contain threshold concentrations of H_2S are classified as sour gases. Those with threshold concentrations of CO_2 are classified as acid gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening. The most common sweetening method is amine treating. Sour gas contains a H_2S concentration of greater than 0.25 grain per 100 standard cubic feet, along with the presence of CO_2. Concentrations of H_2S and CO_2, along with organic sulfur compounds, vary widely among sour gases. A majority total onshore natural gas production and nearly all of offshore natural gas production is classified as sweet.

2.2.3 Condensates

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40^{o} or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 Other Recovered Hydrocarbons

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 Produced Water

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 Exploration and Drilling

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either abandonment if no hydrocarbons are found or to well completion if hydrocarbons are found in sufficient quantities.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper sections of drill pipe are added. A mix of fluids called drilling mud is released down into the drill pipe then up the walls of the well bore, which removes drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out ("blowing out"). The well bore is cased in with telescoping steel piping during drilling to avoid its collapse and to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore so that more oil or natural gas can move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as "fracking") has been performed since the 1940s (U.S. DOE, 2009). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant is a mix of sand and other materials that is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During **primary extraction,** pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). Lacking enough pressure for the resource to surface, gas or water is injected into the well to increase the well pressure and force the resource out (**secondary** or **improved oil recovery).** Finally, **in tertiary extraction** or **enhanced recovery,** gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock or sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2009). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional natural gas resource types relevant for this proposal include:

- **Shale Natural Gas:** Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2009).

- **Tight Sands Natural Gas:** Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2009).

- **Coalbed Methane:** Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).

2.3.3 Natural Gas Processing

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of sufficient quality to pass through transportation systems and used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems.

The most significant impurity is H_2S, which may or may not be contained in natural gas. H_2S is toxic (and potentially fatal at certain concentrations) to humans and is corrosive for pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration. The glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 Natural Gas Transmission and Distribution

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.

2.4.1 Domestic Proved Reserves

Table 2-1 shows crude oil and natural gas proved reserves, inferred reserves, and undiscovered and total technically recoverable resources as of 2007. According to EIA[1], these concepts are defined as:

- **Proved reserves:** estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

- **Inferred reserves:** the estimate of total volume recovery from known crude oil or natural gas reservoirs or aggregation of such reservoirs is expected to increase during the time between discovery and permanent abandonment.

- **Technically recoverable:** resources that are producible using current technology without reference to the economic viability of production.

The sum of proved reserves, inferred reserves, and undiscovered technically recoverable resources equal the total technically recoverable resources. As seen in Table 2-1, as of 2007, proved domestic crude oil reserves accounted for about 12 percent of the totally technically recoverable crude oil resources.

[1] U.S. Department of Energy, Energy Information Administration, Glossary of Terms <http://www.eia.doe.gov/glossary/index.cfm?id=P> Accessed 12/21/2010.

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2007

Region	Proved Reserves	Inferred Reserves	Undiscovered Technically Recoverable Resources	Total Technically Recoverable Resources
Crude Oil and Lease Condensate (billion bbl)				
48 States Onshore	14.2	48.3	25.3	87.8
48 States Offshore	4.4	10.3	47.2	61.9
Alaska	4.2	2.1	42.0	48.3
Total U.S.	22.8	60.7	114.5	198.0
Dry Natural Gas (tcf)				
Conventionally Reservoired Fields	194.0	671.3	760.4	1625.7
48 States Onshore Non-Associated Gas	149.0	595.9	144.1	889.0
48 States Offshore Non-Associated Gas	12.4	50.7	233.0	296.0
Associated-Dissolved Gas	20.7		117.2	137.9
Alaska	11.9	24.8	266.1	302.8
Shale Gas and Coalbed Methane	43.7	385	64.2	493.0
Total U.S.	237.7	1056.3	824.6	2118.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Inferred reserves for associated-dissolved natural gas are included in "Undiscovered Technically Recoverable Resources." Totals may not sum due to independent rounding.

Proved natural gas reserves accounted for about 11 percent of the totally technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and offshore areas.

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2008. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. While crude oil and natural gas are nonrenewable resources, the table shows that proved ultimate recovery rises over time as new discoveries become economically accessible. Reserves growth and decline is also partly a function of exploration activities, which are correlated with oil and natural gas prices. For example, when oil prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to develop unconventional sources.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1977-2008

	Crude Oil and Lease Condensate (million bbl)			Dry Natural Gas (bcf)		
Year	Cumulative Production	Proved Reserves	Proved Ultimate Recovery	Cumulative Production	Proved Reserves	Proved Ultimate Recovery
1990	158,175	27,556	185,731	744,546	169,346	913,892
1991	160,882	25,926	186,808	762,244	167,062	929,306
1992	163,507	24,971	188,478	780,084	165,015	945,099
1993	166,006	24,149	190,155	798,179	162,415	960,594
1994	168,438	23,604	192,042	817,000	163,837	980,837
1995	170,832	23,548	194,380	835,599	165,146	1,000,745
1996	173,198	23,324	196,522	854,453	166,474	1,020,927
1997	175,553	23,887	199,440	873,355	167,223	1,040,578
1998	177,835	22,370	200,205	892,379	164,041	1,056,420
1999	179,981	23,168	203,149	911,211	167,406	1,078,617
2000	182,112	23,517	205,629	930,393	177,427	1,107,820
2001	184,230	23,844	208,074	950,009	183,460	1,133,469
2002	186,327	24,023	210,350	968,937	186,946	1,155,883
2003	188,400	23,106	211,506	988,036	189,044	1,177,080
2004	190,383	22,592	212,975	1,006,564	192,513	1,199,077
2005	192,273	23,019	215,292	1,024,638	204,385	1,229,023
2006	194,135	22,131	216,266	1,043,114	211,085	1,254,199
2007	196,079	22,812	218,891	1,062,203	237,726	1,299,929
2008	197,987	20,554	218,541	1,082,489	244,656	1,327,145

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

However, annual production as a percentage of proved reserves has declined over time for both crude oil and natural gas, from above 10 percent in the early 1990s to 8 to 9 percent from 2006 to 2008 for crude oil and from above 11 percent during the 1990s to about 8 percent from 2008 to 2008 for natural gas.

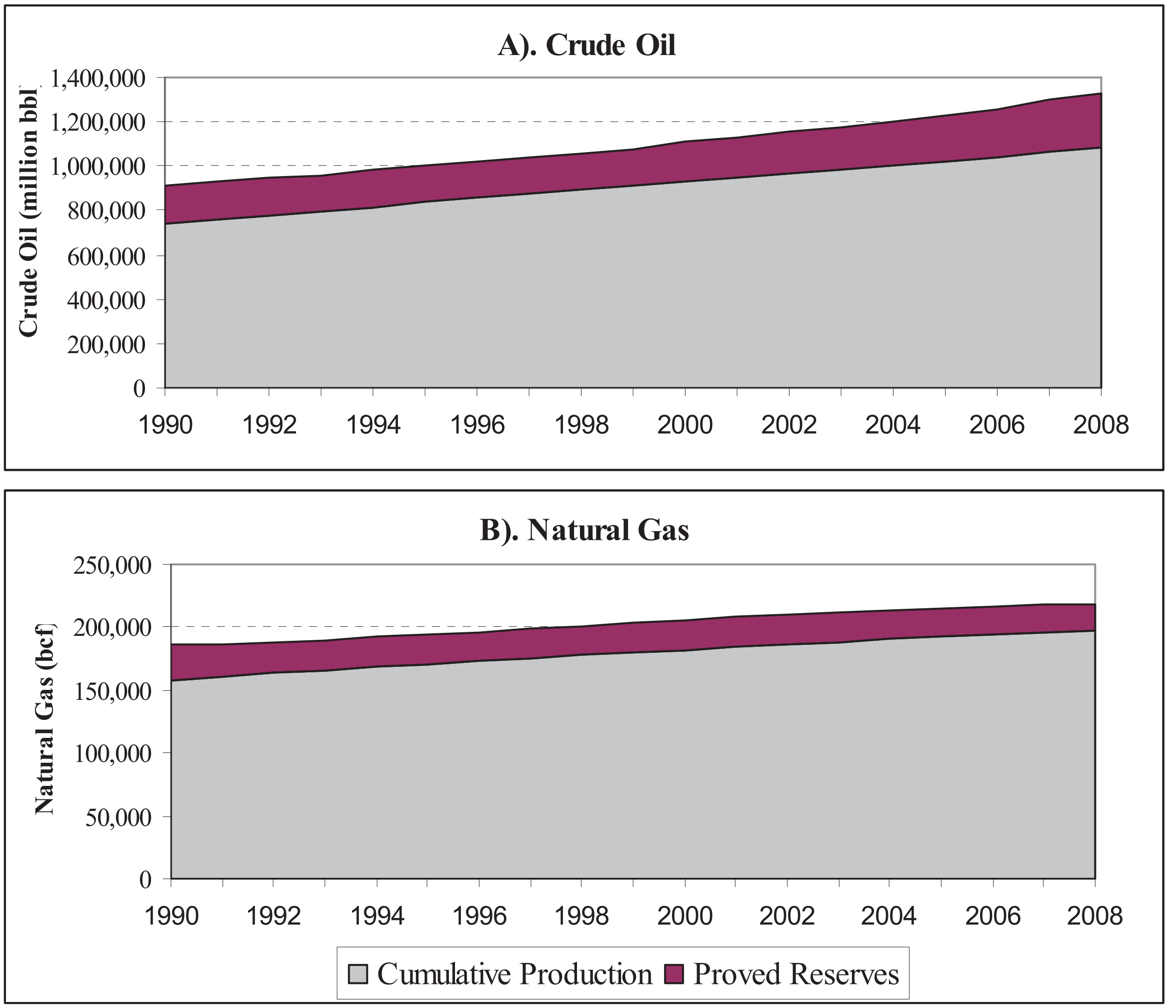

Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2008. Four areas currently account for 77 percent of the U.S. total proved reserves of crude oil, led by Texas and followed by U.S. Federal Offshore, Alaska, and California. The top five states (Texas, Wyoming, Colorado, Oklahoma, and New Mexico) account for about 69 percent of the U.S. total proved reserves of natural gas.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2008

State/Region	Crude Oil (million bbls)	Dry Natural Gas (bcf)	Crude Oil (percent of total)	Dry Natural Gas (percent of total)
Alaska	3,507	7,699	18.3	3.1
Alabama	38	3,290	0.2	1.3
Arkansas	30	5,626	0.2	2.3
California	2,705	2,406	14.1	1.0
Colorado	288	23,302	1.5	9.5
Florida	3	1	0.0	0.0
Illinois	54	0	0.3	0.0
Indiana	15	0	0.1	0.0
Kansas	243	3,557	1.3	1.5
Kentucky	17	2,714	0.1	1.1
Louisiana	388	11,573	2.0	4.7
Michigan	48	3,174	0.3	1.3
Mississippi	249	1,030	1.3	0.4
Montana	321	1,000	1.7	0.4
Nebraska	8	0	0.0	0.0
New Mexico	654	16,285	3.4	6.7
New York	0	389	0.0	0.2
North Dakota	573	541	3.0	0.2
Ohio	38	985	0.2	0.4
Oklahoma	581	20,845	3.0	8.5
Pennsylvania	14	3,577	0.1	1.5
Texas	4,555	77,546	23.8	31.7
Utah	286	6,643	1.5	2.7
Virginia	0	2,378	0.0	1.0
West Virginia	23	5,136	0.1	2.1
Wyoming	556	31,143	2.9	12.7
Miscellaneous States	24	270	0.1	0.1
U.S. Federal Offshore	3,903	13,546	20.4	5.5
Total Proved Reserves	**19,121**	**244,656**	100.0	100.0

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Totals may not sum due to independent rounding.

2.4.2 Domestic Production

Domestic oil production is currently in a state of decline that began in 1970. Table 2-4 shows U.S. production in 2009 at 1938 million bbl per year, the highest level since 2004. However, annual domestic production of crude oil has dropped by almost 750 million bbl since 1990.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price

Year	Total Production (million bbl)	Producing Wells (1000s)	Avg. Well Productivity (bbl/well)	U.S. Average First Purchase Price/Barrel (2005 dollars)
1990	2,685	602	4,460	27.74
1991	2,707	614	4,409	22.12
1992	2,625	594	4,419	20.89
1993	2,499	584	4,279	18.22
1994	2,431	582	4,178	16.51
1995	2,394	574	4,171	17.93
1996	2,366	574	4,122	22.22
1997	2,355	573	4,110	20.38
1998	2,282	562	4,060	12.71
1999	2,147	546	3,932	17.93
2000	2,131	534	3,990	30.14
2001	2,118	530	3,995	24.09
2002	2,097	529	3,964	24.44
2003	2,073	513	4,042	29.29
2004	1,983	510	3,889	38.00
2005	1,890	498	3,795	50.28
2006	1,862	497	3,747	57.81
2007	1,848	500	3,697	62.63
2008	1,812	526	3,445	86.69
2009	1,938	526	3,685	51.37*

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased. * 2009 Oil price is preliminary

Average well productivity has also decreased since 1990 (Table 2-4 and Figure 2-2). These production and productivity decreases are in spite of the fact that average first purchase prices have shown a generally increasing trend. The exception to this general trend occurred in 2008 and 2009 when the real price increased up to 86 dollars per barrel and production in 2009 increased to almost 2 million bbl of oil.

Annual production of natural gas from natural gas wells has increased nearly 3000 bcf from the 1990 to 2009 (Table 2-5). Natural gas extracted from crude oil wells (associated natural gas) has remained more or less constant for the last twenty years. Coalbed methane has become a significant component of overall gas withdrawals in recent years.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2009

	Natural Gas Gross Withdrawals (bcf)					Natural Gas Well Productivity	
Year	Natural Gas Wells	Crude Oil Wells	Coalbed Methane Wells	Total	Dry Gas Production*	Producing Wells (no.)	Avg. Productivity per Well (MMcf)
1990	16,054	5,469	NA	21,523	17,810	269,100	59.657
1991	16,018	5,732	NA	21,750	17,698	276,337	57.964
1992	16,165	5,967	NA	22,132	17,840	275,414	58.693
1993	16,691	6,035	NA	22,726	18,095	282,152	59.157
1994	17,351	6,230	NA	23,581	18,821	291,773	59.468
1995	17,282	6,462	NA	23,744	18,599	298,541	57.888
1996	17,737	6,376	NA	24,114	18,854	301,811	58.770
1997	17,844	6,369	NA	24,213	18,902	310,971	57.382
1998	17,729	6,380	NA	24,108	19,024	316,929	55.938
1999	17,590	6,233	NA	23,823	18,832	302,421	58.165
2000	17,726	6,448	NA	24,174	19,182	341,678	51.879
2001	18,129	6,371	NA	24,501	19,616	373,304	48.565
2002	17,795	6,146	NA	23,941	18,928	387,772	45.890
2003	17,882	6,237	NA	24,119	19,099	393,327	45.463
2004	17,885	6,084	NA	23,970	18,591	406,147	44.036
2005	17,472	5,985	NA	23,457	18,051	425,887	41.025
2006	17,996	5,539	NA	23,535	18,504	440,516	40.851
2007	17,065	5,818	1,780	24,664	19,266	452,945	37.676
2008	18,011	5,845	1,898	25,754	20,286	478,562	37.636
2009	18,881	5,186	2,110	26,177	20,955	495,697	38.089

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**
*Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

The number of wells producing natural gas wells has nearly doubled between 1990 and 2009 (Figure 2-2). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies.

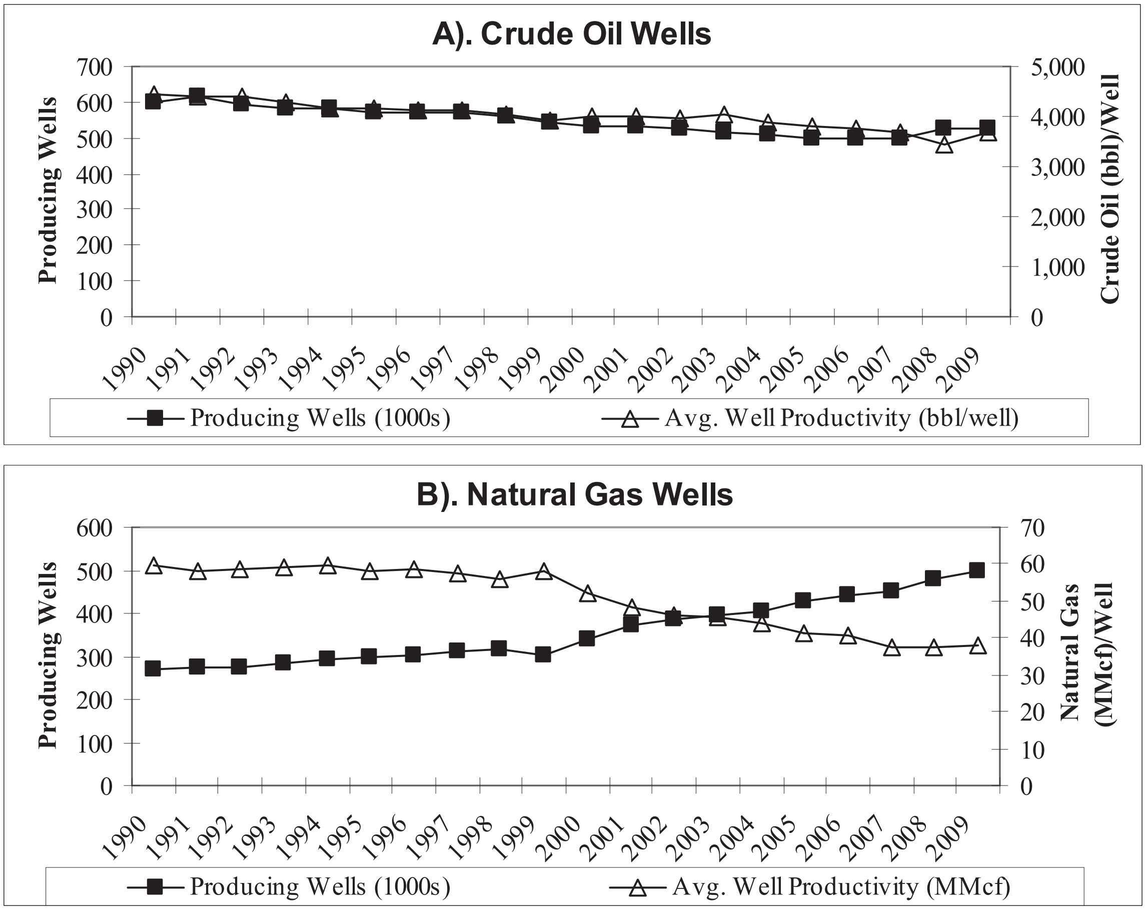

Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2009, crude oil well drilling showed significant increases, although the 1992-2001 period showed relatively low levels of crude drilling activity compared to periods before and after (Table 2-6). The drop in 2009 showed a departure from this trend, likely due to the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2009 period. Like crude oil drilling, 2009 saw a relatively low level of natural gas drillings. The success rate of wells (producing wells versus dry wells) has also increased gradually over time from 75 percent in 1990, to 86 percent in 2000, to 90 percent in 2009 (Table 2-6). The increasing success rate reflects improvements in exploration technology, as well as technological improvements in well drilling and completion. Similarly, well average depth has also increased by during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2009

	Wells Drilled					
Year	Crude Oil	Natural Gas	Dry Holes	Total	Successful Wells (percent)	Average Depth (ft)
1990	12,800	11,227	8,237	32,264	75	4,841
1991	12,542	9,768	7,476	29,786	75	4,872
1992	9,379	8,149	5,857	23,385	75	5,138
1993	8,828	9,829	6,093	24,750	75	5,407
1994	7,334	9,358	5,092	21,784	77	5,736
1995	8,230	8,081	4,813	21,124	77	5,560
1996	8,819	9,015	4,890	22,724	79	5,573
1997	11,189	11,494	5,874	28,557	79	5,664
1998	7,659	11,613	4,763	24,035	80	5,722
1999	4,759	11,979	3,554	20,292	83	5,070
2000	8,089	16,986	4,134	29,209	86	4,942
2001	8,880	22,033	4,564	35,477	87	5,077
2002	6,762	17,297	3,728	27,787	87	5,223
2003	8,104	20,685	3,970	32,759	88	5,418
2004	8,764	24,112	4,053	36,929	89	5,534
2005E	10,696	28,500	4,656	43,852	89	5,486
2006E	13,289	32,878	5,183	51,350	90	5,537
2007E	13,564	33,132	5,121	51,817	90	5,959
2008E	17,370	34,118	5,726	57,214	90	6,202
2009E	13,175	19,153	3,537	35,865	90	6,108

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Values for 2005-2009 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging. Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of flowback water from hydraulic fracturing activities (ANL 2009).

Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

State	Crude Oil (1000 bbl)	Total Gas (bcf)	Produced Water (1000 bbl)	Total Oil and Natural Gas (1000 bbls oil equivalent)	Barrels Produced Water per Barrel Oil Equivalent
Alabama	5,028	285	119,004	55,758	2.13
Alaska	263,595	3,498	801,336	886,239	0.90
Arizona	43	1	68	221	0.31
Arkansas	6,103	272	166,011	54,519	3.05
California	244,000	312	2,552,194	299,536	8.52
Colorado	2,375	1,288	383,846	231,639	1.66
Florida	2,078	2	50,296	2,434	20.66
Illinois	3,202	no data	136,872	3,202	42.75
Indiana	1,727	4	40,200	2,439	16.48
Kansas	36,612	371	1,244,329	102,650	12.12
Kentucky	3,572	95	24,607	20,482	1.20
Louisiana	52,495	1,382	1,149,643	298,491	3.85
Michigan	5,180	168	114,580	35,084	3.27
Mississippi	20,027	97	330,730	37,293	8.87
Missouri	80	no data	1,613	80	20.16
Montana	34,749	95	182,266	51,659	3.53
Nebraska	2,335	1	49,312	2,513	19.62
Nevada	408	0	6,785	408	16.63
New Mexico	59,138	1,526	665,685	330,766	2.01
New York	378	55	649	10,168	0.06
North Dakota	44,543	71	134,991	57,181	2.36
Ohio	5,422	86	6,940	20,730	0.33
Oklahoma	60,760	1,643	2,195,180	353,214	6.21
Pennsylvania	1,537	172	3,912	32,153	0.12
South Dakota	1,665	12	4,186	3,801	1.10
Tennessee	350	1	2,263	528	4.29
Texas	342,087	6,878	7,376,913	1,566,371	4.71
Utah	19,520	385	148,579	88,050	1.69
Virginia	19	112	1,562	19,955	0.08
West Virginia	679	225	8,337	40,729	0.20
Wyoming	54,052	2,253	2,355,671	455,086	5.18
State Total	***1,273,759***	***21,290***	***20,258,560***	***5,063,379***	***4.00***
Federal Offshore	467,180	2,787	587,353	963,266	0.61
Tribal Lands	9,513	297	149,261	62,379	2.39
Federal Total	***476,693***	***3,084***	***736,614***	***1,025,645***	***0.72***
U.S. Total	**1,750,452**	**24,374**	**20,995,174**	**6,089,024**	**3.45**

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low rates of water production compared to more Midwestern states, such Illinois, Missouri, Indiana, and Kansas.

Figure 2-3 shows the distribution of produced water management practices in 2007.

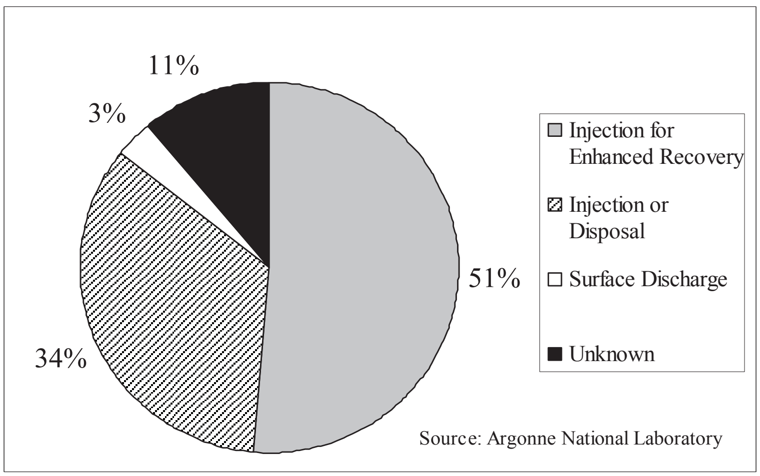

Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. Another third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) is discharged into surface water when it meets water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage has decreased during the 1990-2008 period (Table 2-8), appearing to follow the downward supply trend shown in Table 2-4. While exhibiting some variation, pipeline mileage transporting refined products remained relatively constant.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 1990-2008

	Oil Pipelines			Natural Gas Pipelines			
Year	Crude Lines	Product Lines	Total	Distribution Mains	Transmission Pipelines	Gathering Lines	Total
1990	118,805	89,947	208,752	945,964	291,990	32,420	1,270,374
1991	115,860	87,968	203,828	890,876	293,862	32,713	1,217,451
1992	110,651	85,894	196,545	891,984	291,468	32,629	1,216,081
1993	107,246	86,734	193,980	951,750	293,263	32,056	1,277,069
1994	103,277	87,073	190,350	1,002,669	301,545	31,316	1,335,530
1995	97,029	84,883	181,912	1,003,798	296,947	30,931	1,331,676
1996	92,610	84,925	177,535	992,860	292,186	29,617	1,314,663
1997	91,523	88,350	179,873	1,002,942	294,370	34,463	1,331,775
1998	87,663	90,985	178,648	1,040,765	302,714	29,165	1,372,644
1999	86,369	91,094	177,463	1,035,946	296,114	32,276	1,364,336
2000	85,480	91,516	176,996	1,050,802	298,957	27,561	1,377,320
2001	52,386	85,214	154,877	1,101,485	290,456	21,614	1,413,555
2002	52,854	80,551	149,619	1,136,479	303,541	22,559	1,462,579
2003	50,149	75,565	139,901	1,107,559	301,827	22,758	1,432,144
2004	50,749	76,258	142,200	1,156,863	303,216	24,734	1,484,813
2005	46,234	71,310	131,348	1,160,311	300,663	23,399	1,484,373
2006	47,617	81,103	140,861	1,182,884	300,458	20,420	1,503,762
2007	46,658	85,666	147,235	1,202,135	301,171	19,702	1,523,008
2008	50,214	84,914	146,822	1,204,162	303,331	20,318	1,527,811

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, available at http://ops.dot.gov/stats.htm as of Apr. 28, 2010. Totals may not sum due to independent rounding.

Table 2-8 splits natural gas pipelines into three types: distribution mains, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites to deliver directly to gas processing plants or compression stations that connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants to distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers. Table 2-8 shows gathering lines decreasing from 1990 from above 30,000 miles from 1990 to 1995 to around 20,000 miles in 2007 and 2008. Transmission pipelines added about 10,000 miles during this period, from about 292,000 in 1990 to about 303,000 miles in 2008. The most significant growth among all types of pipeline was in distribution, which increased about 260,000 miles during the 1990 to 2008 period, driving an increase in total natural gas pipeline mileage (Figure 2-1). The growth in distribution is likely driven by expanding production as well as expanding gas markets in growing U.S. towns and cities.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2009 are shown in Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008 when consumption dropped as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2009.

Table 2-9 Crude Oil Consumption by Sector, 1990-2009

		Percent of Total				
Year	Total (million bbl)	Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	6,201	4.4	2.9	25.3	64.1	3.3
1991	6,101	4.4	2.8	25.2	64.4	3.1
1992	6,234	4.4	2.6	26.5	63.9	2.5
1993	6,291	4.5	2.4	25.7	64.5	2.9
1994	6,467	4.3	2.3	26.3	64.4	2.6
1995	6,469	4.2	2.2	25.9	65.8	1.9
1996	6,701	4.4	2.2	26.3	65.1	2.0
1997	6,796	4.2	2.0	26.6	65.0	2.2
1998	6,905	3.8	1.9	25.6	65.7	3.0
1999	7,125	4.2	1.9	25.8	65.4	2.7
2000	7,211	4.4	2.1	24.9	66.0	2.6
2001	7,172	4.3	2.1	24.9	65.8	2.9
2002	7,213	4.1	1.9	25.0	66.8	2.2
2003	7,312	4.2	2.1	24.5	66.5	2.7
2004	7,588	4.0	2.0	25.2	66.2	2.6
2005	7,593	3.9	1.9	24.5	67.1	2.6
2006	7,551	3.3	1.7	25.1	68.5	1.4
2007	7,548	3.4	1.6	24.4	69.1	1.4
2008	7,136	3.7	1.8	23.2	70.3	1.1
2009*	6,820	3.8	1.8	22.5	71.1	0.9

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary.

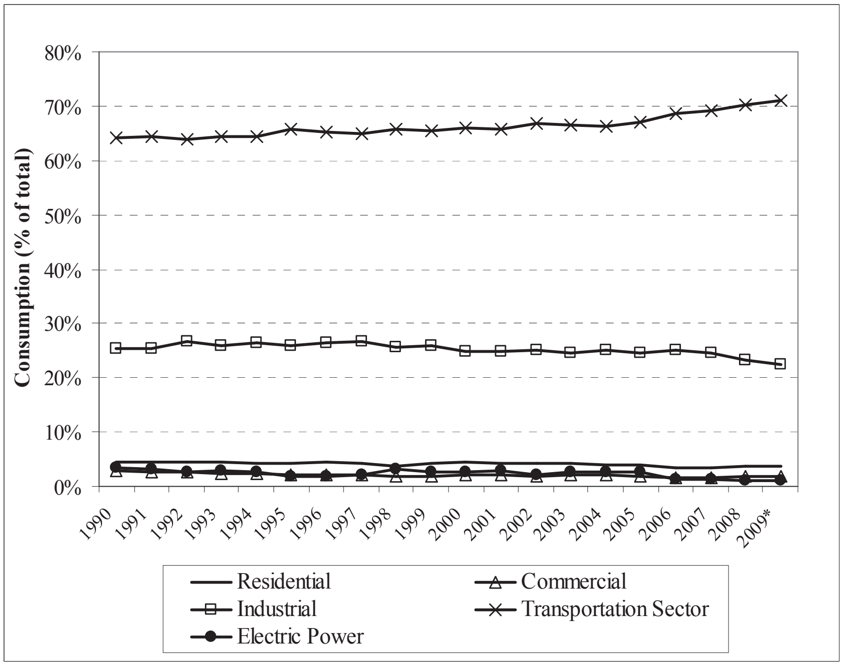

Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009

Natural gas consumption has increased over the last twenty years. From 1990 to 2009, total U.S. consumption increased by an average of about 1 percent per year (Table 2-10 and Figure 2-5). Over the same period, industrial consumption of natural gas declined, whereas electric power generation increased its consumption quite dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential, commercial, and transportation sectors maintained their consumption levels at more or less constant levels during this time period.

Table 2-10 Natural Gas Consumption by Sector, 1990-2009

Year	Total (bcf)	Percent of Total				
		Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	19,174	22.9	13.7	43.1	3.4	16.9
1991	19,562	23.3	13.9	42.7	3.1	17.0
1992	20,228	23.2	13.9	43.0	2.9	17.0
1993	20,790	23.8	13.8	42.7	3.0	16.7
1994	21,247	22.8	13.6	42.0	3.2	18.4
1995	22,207	21.8	13.6	42.3	3.2	19.1
1996	22,609	23.2	14.0	42.8	3.2	16.8
1997	22,737	21.9	14.1	42.7	3.3	17.9
1998	22,246	20.3	13.5	42.7	2.9	20.6
1999	22,405	21.1	13.6	40.9	2.9	21.5
2000	23,333	21.4	13.6	39.8	2.8	22.3
2001	22,239	21.5	13.6	38.1	2.9	24.0
2002	23,007	21.2	13.7	37.5	3.0	24.7
2003	22,277	22.8	14.3	37.1	2.7	23.1
2004	22,389	21.7	14.0	37.3	2.6	24.4
2005	22,011	21.9	13.6	35.0	2.8	26.7
2006	21,685	20.1	13.1	35.3	2.8	28.7
2007	23,097	20.4	13.0	34.1	2.8	29.6
2008	23,227	21.0	13.5	33.9	2.9	28.7
2009*	22,834	20.8	13.6	32.4	2.9	30.2

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary. Totals may not sum due to independent rounding.

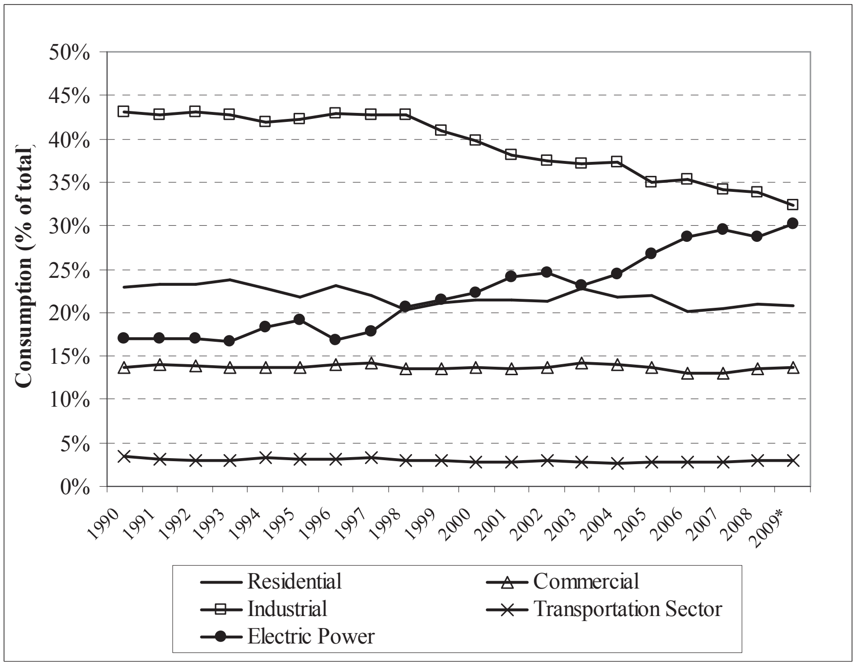

Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009

2.4.4 International Trade

Imports of crude oil and refined petroleum products have increased over the last twenty years, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S (Table 2-11). Crude oil imports have increased by about 2 percent per year on average, whereas petroleum products have increased by 1 percent on average per year.

Table 2-11 Total Crude Oil and Petroleum Products Imports (Million Bbl), 1990-2009

Year	Crude Oil	Petroleum Products	Total Petroleum
1990	2,151	775	2,926
1991	2,111	673	2,784
1992	2,226	661	2,887
1993	2,477	669	3,146
1994	2,578	706	3,284
1995	2,639	586	3,225
1996	2,748	721	3,469
1997	3,002	707	3,709
1998	3,178	731	3,908
1999	3,187	774	3,961
2000	3,320	874	4,194
2001	3,405	928	4,333
2002	3,336	872	4,209
2003	3,528	949	4,477
2004	3,692	1,119	4,811
2005	3,696	1,310	5,006
2006	3,693	1,310	5,003
2007	3,661	1,255	4,916
2008	3,581	1,146	4,727
2009	3,307	973	4,280

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** * 2009 Imports are preliminary.

Natural gas imports also increased steadily from 1990 to 2007 in volume and percentage terms (Table 2-12). The years 2007 and 2008 saw imported natural gas constituting a lower percentage of domestic natural gas consumption. In 2009, the U.S exported 700 bcf natural gas to Canada, 338 bcf to Mexico via pipeline, and 33 bcf to Japan in LNG-form. In 2009, the U.S. primarily imported natural gas from Canada (3268 bcf, 87 percent) via pipeline, although a growing percentage of natural gas imports are in LNG-form shipped from countries such as Trinidad and Tobago and Egypt. Until recent years, industry analysts forecast that LNG imports would continue to grow as a percentage of U.S consumption. However, it is possible that increasingly accessible domestic unconventional gas resources, such as shale gas and coalbed methane, might reduce the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2009

Year	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.5
1991	1,773	129	1,644	8.4
1992	2,138	216	1,921	9.5
1993	2,350	140	2,210	10.6
1994	2,624	162	2,462	11.6
1995	2,841	154	2,687	12.1
1996	2,937	153	2,784	12.3
1997	2,994	157	2,837	12.5
1998	3,152	159	2,993	13.5
1999	3,586	163	3,422	15.3
2000	3,782	244	3,538	15.2
2001	3,977	373	3,604	16.2
2002	4,015	516	3,499	15.2
2003	3,944	680	3,264	14.7
2004	4,259	854	3,404	15.2
2005	4,341	729	3,612	16.4
2006	4,186	724	3,462	16.0
2007	4,608	822	3,785	16.4
2008	3,984	1,006	2,979	12.8
2009*	3,748	1,071	2,677	11.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 Imports are preliminary.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the 2011 Annual Energy Outlook produced by EIA, the most current forecast information available from EIA. As will be discussed in detail in Section 3, to analyze the impacts of the proposed NSPS on the national energy economy, we use the National Energy Modeling System (NEMS) that was used to produce the 2011 Annual Energy Outlook.

Table 2-13 and Figure 2-6 present forecasts of successful wells drilled in the U.S. from 2010 to 2035. Crude oil well forecasts for the lower 48 states show a rise from 2010 to a peak in 2019, which is followed by a gradual decline until the terminal year in the forecast, totaling a 28 percent decline for the forecast period. The forecast of successful offshore crude oil wells shows a variable but generally increasing trend.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

	Lower 48 U.S. States					Offshore		Totals	
Year	Crude Oil	Conventional Natural Gas	Tight Sands	Devonian Shale	Coalbed Methane	Crude Oil	Natural gas	Crude Oil	Natural Gas
2010	12,082	7,302	2,393	4,196	2,426	74	56	12,155	16,373
2011	10,271	7,267	2,441	5,007	1,593	81	73	10,352	16,380
2012	10,456	7,228	2,440	5,852	1,438	80	71	10,536	17,028
2013	10,724	7,407	2,650	6,758	1,564	79	68	10,802	18,447
2014	10,844	7,378	2,659	6,831	1,509	85	87	10,929	18,463
2015	10,941	7,607	2,772	7,022	1,609	84	87	11,025	19,096
2016	11,015	7,789	2,817	7,104	1,633	94	89	11,108	19,431
2017	11,160	7,767	2,829	7,089	1,631	104	100	11,264	19,416
2018	11,210	7,862	2,870	7,128	1,658	112	101	11,323	19,619
2019	11,268	8,022	2,943	7,210	1,722	104	103	11,373	20,000
2020	10,845	8,136	3,140	7,415	2,228	89	81	10,934	21,000
2021	10,849	8,545	3,286	7,621	2,324	91	84	10,940	21,860
2022	10,717	8,871	3,384	7,950	2,361	90	77	10,807	22,642
2023	10,680	9,282	3,558	8,117	2,499	92	96	10,772	23,551
2024	10,371	9,838	3,774	8,379	2,626	87	77	10,458	24,694
2025	10,364	10,200	3,952	8,703	2,623	93	84	10,457	25,562
2026	10,313	10,509	4,057	9,020	2,705	104	103	10,417	26,394
2027	10,103	10,821	4,440	9,430	2,862	99	80	10,202	27,633
2028	9,944	10,995	4,424	9,957	3,185	128	111	10,072	28,672
2029	9,766	10,992	4,429	10,138	3,185	121	127	9,887	28,870
2030	9,570	11,161	4,512	10,539	3,240	127	103	9,697	29,556
2031	9,590	11,427	4,672	10,743	3,314	124	109	9,714	30,265
2032	9,456	11,750	4,930	11,015	3,449	143	95	9,599	31,239
2033	9,445	12,075	5,196	11,339	3,656	116	107	9,562	32,372
2034	9,278	12,457	5,347	11,642	3,669	128	92	9,406	33,206
2035	8,743	13,003	5,705	12,062	3,905	109	108	8,852	34,782

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.**

Meanwhile, Table 2-13 and Figure 2-6 show increases for all types of natural gas drilling in the lower 48 states. Drilling in shale reservoirs is expected to rise most dramatically, about 190 percent during the forecast period, while drilling in coalbed methane and tight sands reservoirs increase significantly, 61 percent and 138 percent, respectively. Despite the growth in drilling in unconventional reservoirs, EIA forecasts successful conventional natural gas wells to increase about 78 percent during this period. Offshore natural gas wells are also expected to increase during the next 25 years, but not to the degree of onshore drilling.

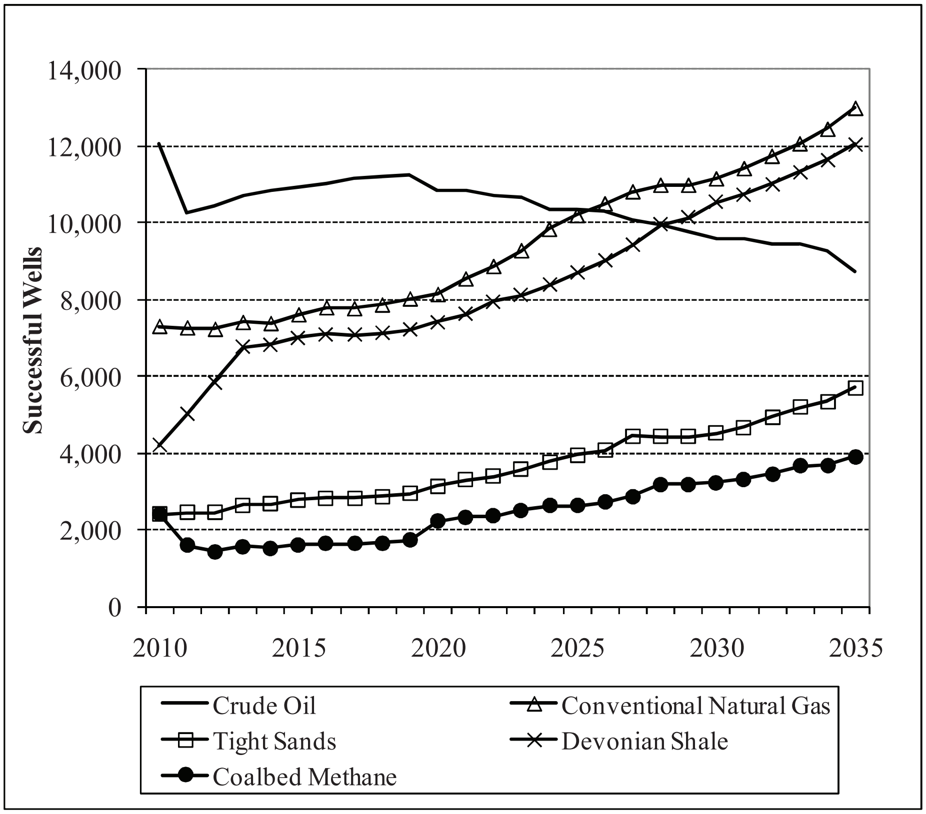

Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and prices. Domestic crude oil production increases slightly during the forecast period, with much of the growth coming from onshore production in the lower 48 states. Alaskan oil production is forecast to decline from 2010 to a low of 99 million barrels in 2030, but rising above that level for the final five years of the forecast. Net imports of crude oil are forecast to decline slightly during the forecast period. Figure 2-7 depicts these trends graphically. All told, EIA forecasts total crude oil to decrease about 3 percent from 2010 to 2035.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2010-2035

	Domestic Production (million bbls)							
Year	Total Domestic	Lower 48 Onshore	Lower 48 Offshore	Alaska	Lower 48 End of Year Reserves	Net Imports	Total Crude Supply (million bbls)	Lower 48 Average Wellhead Price (2009 dollars per bbl)
2010	2,011	1,136	653	223	17,634	3,346	5,361	78.6
2011	1,993	1,212	566	215	17,955	3,331	5,352	84.0
2012	1,962	1,233	529	200	18,026	3,276	5,239	86.2
2013	2,037	1,251	592	194	18,694	3,259	5,296	88.6
2014	2,102	1,267	648	188	19,327	3,199	5,301	92.0
2015	2,122	1,283	660	179	19,690	3,177	5,299	95.0
2016	2,175	1,299	705	171	20,243	3,127	5,302	98.1
2017	2,218	1,320	735	163	20,720	3,075	5,293	101.0
2018	2,228	1,323	750	154	21,129	3,050	5,277	103.7
2019	2,235	1,343	746	147	21,449	3,029	5,264	105.9
2020	2,219	1,358	709	153	21,573	3,031	5,250	107.4
2021	2,216	1,373	680	163	21,730	3,049	5,265	108.8
2022	2,223	1,395	659	169	21,895	3,006	5,229	110.3
2023	2,201	1,418	622	161	21,921	2,994	5,196	112.0
2024	2,170	1,427	588	155	21,871	2,996	5,166	113.6
2025	2,146	1,431	566	149	21,883	3,010	5,155	115.2
2026	2,123	1,425	561	136	21,936	3,024	5,147	116.6
2027	2,114	1,415	573	125	22,032	3,018	5,131	117.8
2028	2,128	1,403	610	116	22,256	2,999	5,127	118.8
2029	2,120	1,399	614	107	22,301	2,988	5,108	119.3
2030	2,122	1,398	625	99	22,308	2,994	5,116	119.5
2031	2,145	1,391	641	114	22,392	2,977	5,122	119.6
2032	2,191	1,380	675	136	22,610	2,939	5,130	118.8
2033	2,208	1,365	691	152	22,637	2,935	5,143	119.1
2034	2,212	1,351	714	147	22,776	2,955	5,167	119.2
2035	2,170	1,330	698	142	22,651	3,007	5,177	119.5

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2010 to 2035, an increase of 28 percent overall. This increment is larger than the forecast increase in production from the lower 48 states during this period, 8 percent, showing reserves are forecast to grow more rapidly than production. Table 2-14 also shows average wellhead prices increasing a total of 52 percent from 2010 to 2035, from $78.6 per barrel to $119.5 per barrel in 2008 dollar terms.

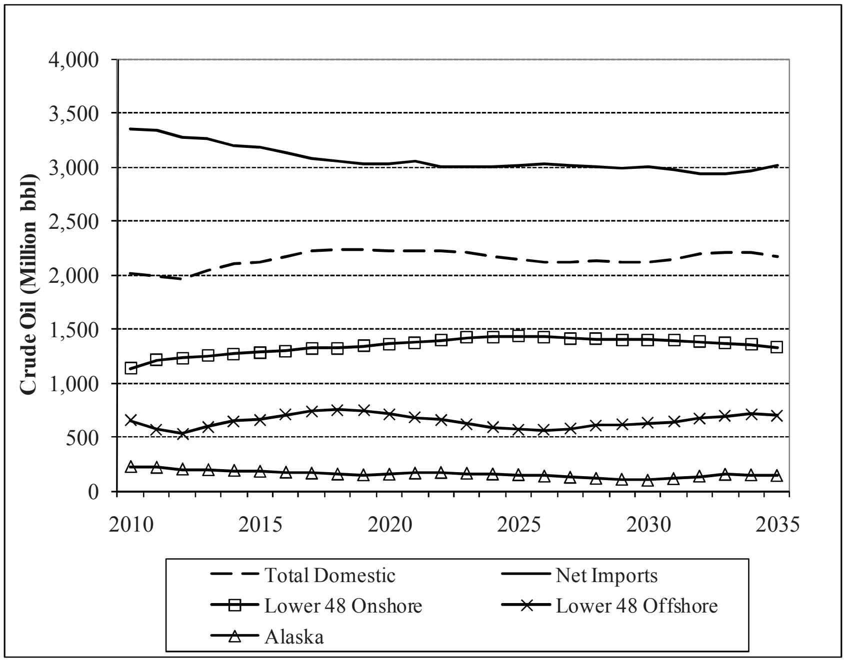

Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035

Table 2-15 shows domestic natural gas production is forecast to increase about 24 percent from 2010 to 2035. Contrasted against the much higher growth in natural gas wells drilled as shown in Table 2-13, per well productivity is expected to continue its declining trend. Meanwhile, imports of natural gas via pipeline are expected to decline during the forecast period almost completely, from 2.33 tcf in 2010 to 0.04 in 2035 tcf. Imported LNG also decreases from 0.41 tcf in 2010 to 0.14 tcf in 2035. Total supply, then, increases about 10 percent, from 24.08 tcf in 2010 to 26.57 tcf in 2035.

Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price

	Production		Net Imports				
Year	Dry Gas Production	Supplemental Natural Gas	Net Imports (Pipeline)	Net Imports (LNG)	Total Supply	Lower 48 End of Year Dry Reserves	Average Lower 48 Wellhead Price (2009 dollars per Mcf)
2010	21.28	0.07	2.33	0.41	24.08	263.9	4.08
2011	21.05	0.06	2.31	0.44	23.87	266.3	4.09
2012	21.27	0.06	2.17	0.47	23.98	269.1	4.09
2013	21.74	0.06	2.22	0.50	24.52	272.5	4.15
2014	22.03	0.06	2.26	0.45	24.80	276.6	4.16
2015	22.43	0.06	2.32	0.36	25.18	279.4	4.24
2016	22.47	0.06	2.26	0.36	25.16	282.4	4.30
2017	22.66	0.06	2.14	0.41	25.28	286.0	4.33
2018	22.92	0.06	2.00	0.43	25.40	289.2	4.37
2019	23.20	0.06	1.75	0.47	25.48	292.1	4.43
2020	23.43	0.06	1.40	0.50	25.40	293.6	4.59
2021	23.53	0.06	1.08	0.52	25.19	295.1	4.76
2022	23.70	0.06	0.89	0.49	25.14	296.7	4.90
2023	23.85	0.06	0.79	0.45	25.15	297.9	5.08
2024	23.86	0.06	0.77	0.39	25.08	298.4	5.27
2025	23.99	0.06	0.74	0.34	25.12	299.5	5.43
2026	24.06	0.06	0.71	0.27	25.10	300.8	5.54
2027	24.30	0.06	0.69	0.22	25.27	302.1	5.67
2028	24.59	0.06	0.67	0.14	25.47	304.4	5.74
2029	24.85	0.06	0.63	0.14	25.69	306.6	5.78
2030	25.11	0.06	0.63	0.14	25.94	308.5	5.82
2031	25.35	0.06	0.57	0.14	26.13	310.1	5.90
2032	25.57	0.06	0.50	0.14	26.27	311.4	6.01
2033	25.77	0.06	0.38	0.14	26.36	312.6	6.12
2034	26.01	0.06	0.23	0.14	26.44	313.4	6.24
2035	26.33	0.06	0.04	0.14	26.57	314.0	6.42

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past two decades, particularly in recent years. Cost per well has increased by an annual average of about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure 2-8).

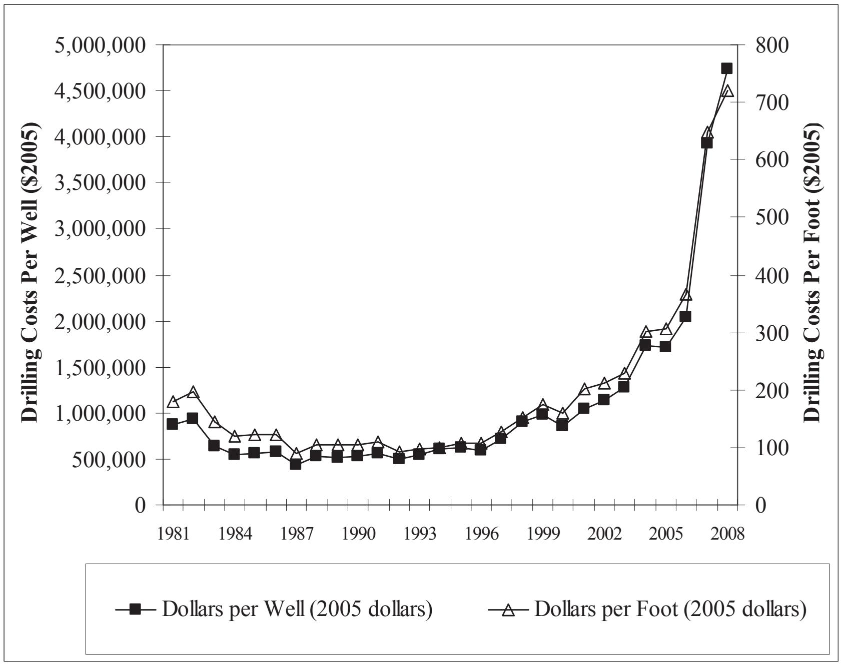

Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by EIA add an additional level of detail to drilling costs, in that finding costs incorporate the costs more broadly associated with adding proved reserves of crude oil and natural gas. These costs include exploration and development costs, as well as costs associated with the purchase or leasing of real property. EIA publishes finding costs as running three-year averages, in order to better compare these costs, which occur over several years, with annual average lifting costs. Figure 2-9 shows average domestic onshore and offshore and foreign finding costs for the sample of U.S. firms in EIA's Financial Reporting System (FRS) database from 1981 to 2008. The costs are reported in 2008 dollars on a barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore and offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

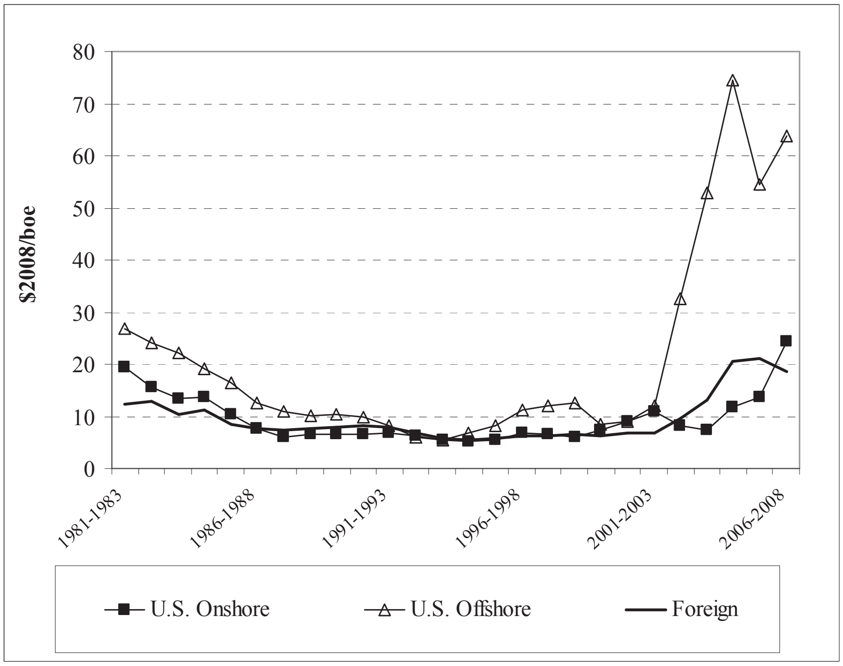

Figure 2-9 Finding Costs for FRS Companies, 1981-2008

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore and offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-8 and finding costs in Figure 2-9 present similar trends overall.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, EIA reports average lifting costs for FRS firms in 2008 dollars on a barrel of oil equivalent basis. Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-10 depicts direct lifting cost trends from 1981 to 2008 for domestic and foreign production.

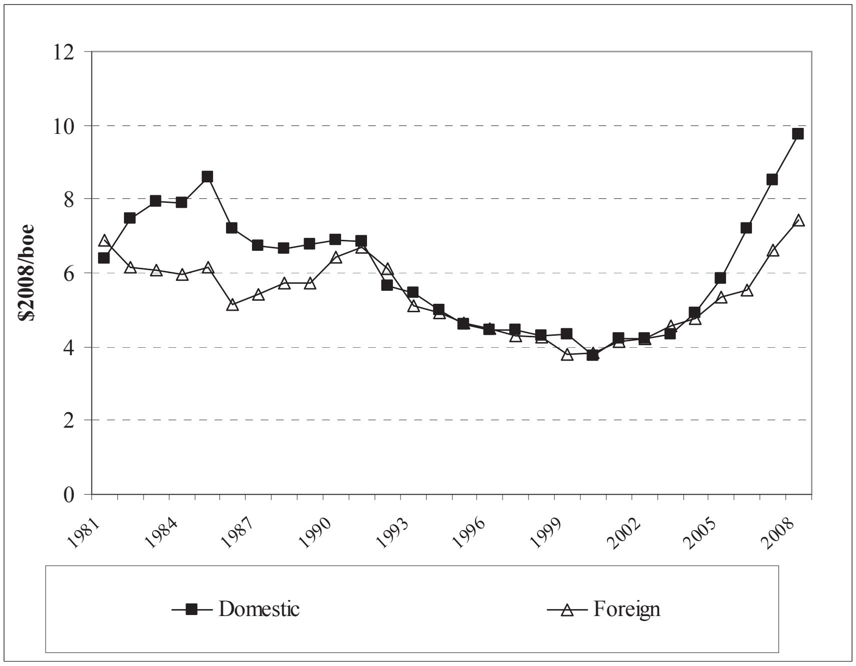

Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than $2 per barrels of oil equivalent from 1981 to 1985, then declined almost $5 per barrel of oil equivalent from 1985 until 2000. From 2000 to 2008, domestic lifting costs increased sharply, about $6 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs from 1981 to 1991, as foreign lifting costs were lower than domestic costs during this period. Foreign and domestic lifting costs followed a similar track until they again diverged in 2004, with domestic lifting again becoming more expensive. Combined with finding costs, the total finding and lifting costs rose significantly in from 2000 to 2008.

2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[2], contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in

[2] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-11 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s.

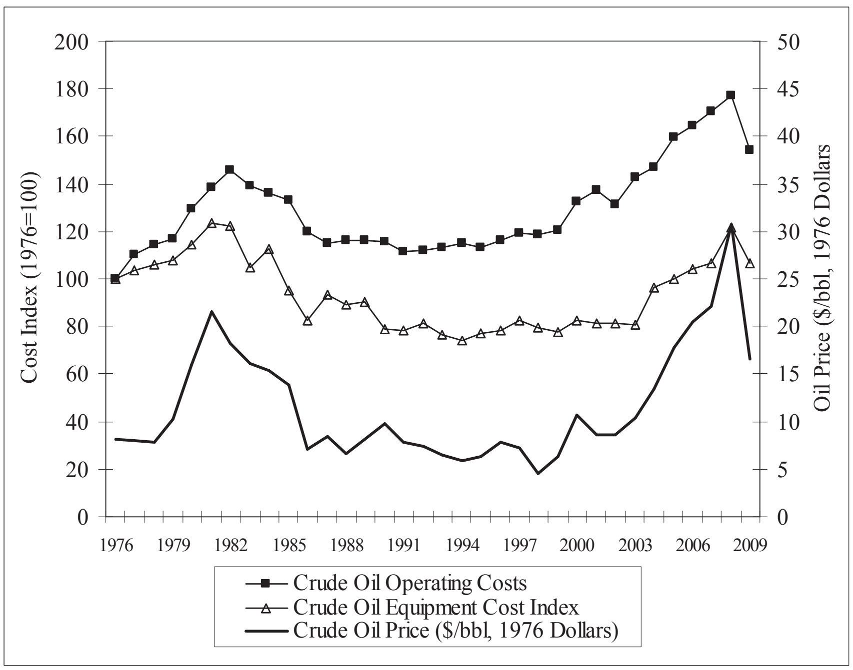

Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009

Oil costs and prices again generally rose between 2000 to present, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

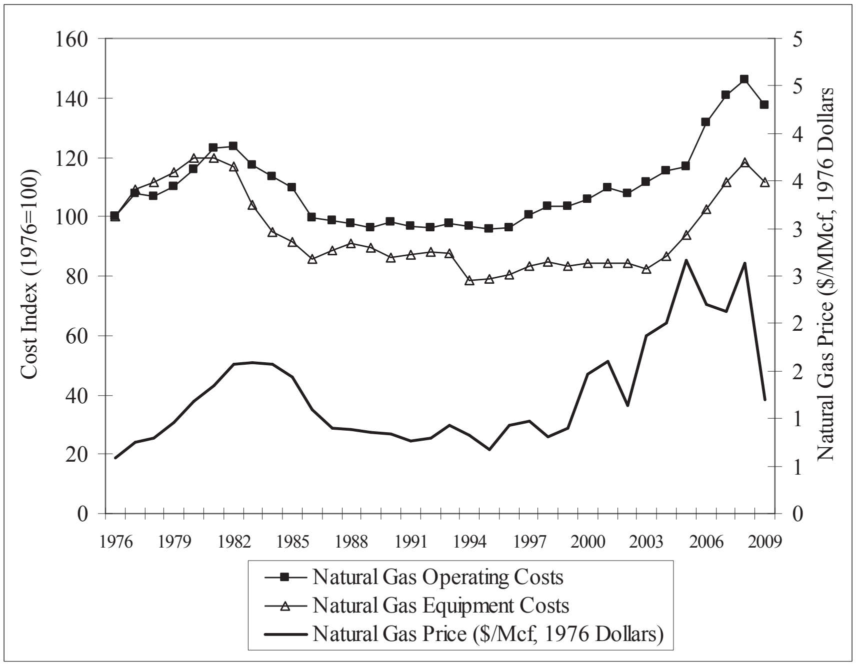

Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Figure 2-12 depicts natural gas operating and equipment costs indices, as well as natural gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs track the price of natural gas over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late 1970s, but generally decreased from about 1980 until the mid 1990s. The 2009 index values for natural gas operating and equipment costs are 137 and 112, respectively.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract, process, and transport extracted streams recovered from the raw crude oil and natural gas resources. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies that are involved in each of the five industry segments: drilling and exploration, production, transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 68 percent of domestic crude oil production of our oil, 85 percent of domestic natural gas, and drill almost 90 percent of the wells in the U.S (IPAA, 2009). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected

As of 2007, there were 6,563 firms within the 211111 and 211112 NAICS codes, of which 6427 (98 percent) were considered small businesses (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for 59 percent of employment and generate about 80 percent of estimated receipts listed under the NAICS.

Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

NAICS	NAICS Description	SBA Size Standard	Small Firms	Large Firms	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	98	41	139
213111	Drilling Oil and Gas Wells	500	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	61*	65*	126
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	24,683
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	500	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	20,796,681

Note: *The counts of small and large firms in NAICS 486210 is based upon firms with less than $7.5 million in receipts, rather than the $7 million required by the SBA Size Standard. We used this value because U.S. Census reports firm counts for firms with receipts less than $7.5 million. **Employment and receipts could not be split between small and large businesses because of non-disclosure requirements faced by the U.S. Census Bureau.
Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007."
<http://www.census.gov/econ/susb/>

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 66 percent and 69 percent of employment and estimated receipts, respectively. Because there are relatively few firms within NAICS 486210, the Census Bureau cannot release breakdowns of firms by size in sufficient detail to perform similar calculation.

2.6.3 *Trends in National Employment and Wages*

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2009. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 313,703 in 1999, but rebounding to a 2008 peak of 511,805. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.

Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-09

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Ops. (213112)	Pipeline Trans. of Crude Oil (486110)	Pipeline Trans. of Natural Gas (486210)	Total
1990	182,848	8,260	52,365	109,497	11,112	47,533	411,615
1991	177,803	8,443	46,466	116,170	11,822	48,643	409,347
1992	169,615	8,819	39,900	99,924	11,656	46,226	376,140
1993	159,219	7,799	42,485	102,840	11,264	43,351	366,958
1994	150,598	7,373	44,014	105,304	10,342	41,931	359,562
1995	142,971	6,845	43,114	104,178	9,703	40,486	347,297
1996	139,016	6,654	46,150	107,889	9,231	37,519	346,459
1997	137,667	6,644	55,248	117,460	9,097	35,698	361,814
1998	133,137	6,379	53,943	122,942	8,494	33,861	358,756
1999	124,296	5,474	41,868	101,694	7,761	32,610	313,703
2000	117,175	5,091	52,207	108,087	7,657	32,374	322,591
2001	119,099	4,500	62,012	123,420	7,818	33,620	30,469
2002	116,559	4,565	48,596	120,536	7,447	31,556	329,259
2003	115,636	4,691	51,526	120,992	7,278	29,684	329,807
2004	117,060	4,285	57,332	128,185	7,073	27,340	341,275
2005	121,535	4,283	66,691	145,725	6,945	27,341	372,520
2006	130,188	4,670	79,818	171,127	7,202	27,685	420,690
2007	141,239	4,842	84,525	197,100	7,975	27,431	463,112
2008	154,898	5,183	92,640	223,635	8,369	27,080	511,805
2009	155,150	5,538	67,756	193,589	8,753	26,753	457,539

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

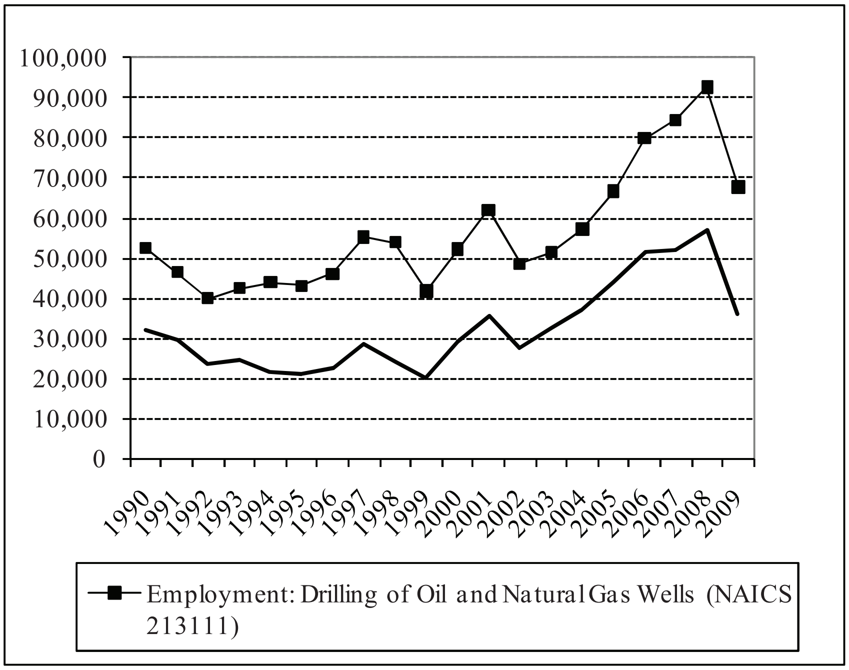

Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009

Figure 2-13 compares employment in Drilling of Oil and Natural Gas Wells (NAICS 213111) with the total number of oil and natural gas wells drilled from 1990 to 2009. The figure depicts a strong positive correlation between employment in the sector with drilling activity. This correlation also holds throughout the period covered by the data.

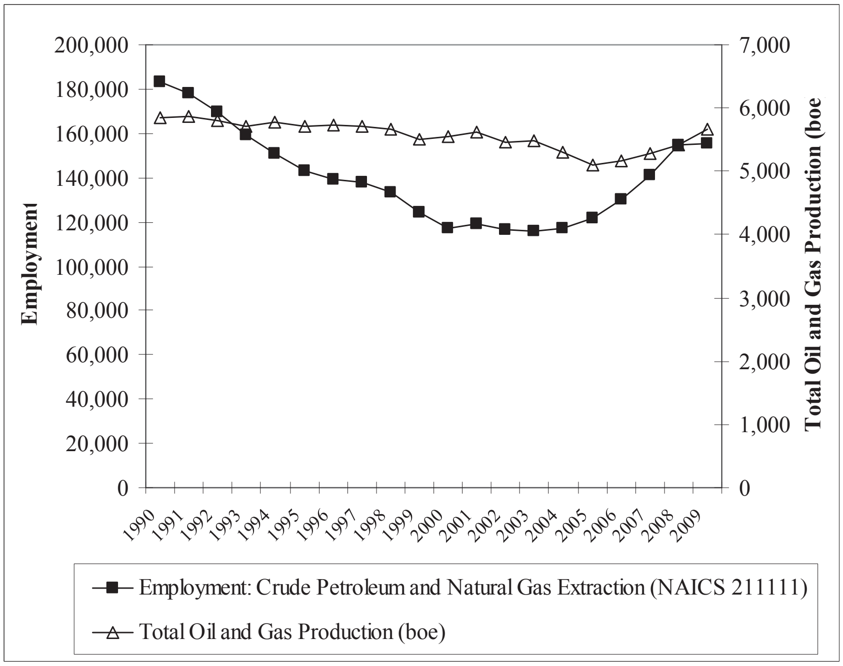

Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009

Figure 2-14 compares employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) with total domestic oil and natural gas production from 1990 to 2009 in barrels of oil equivalent terms. While until 2003, employment in this sector and total production declined gradually, employment levels declined more rapidly. However, from 2004 to 2009 employment in Extraction recovered, rising to levels similar to the early 1990s.

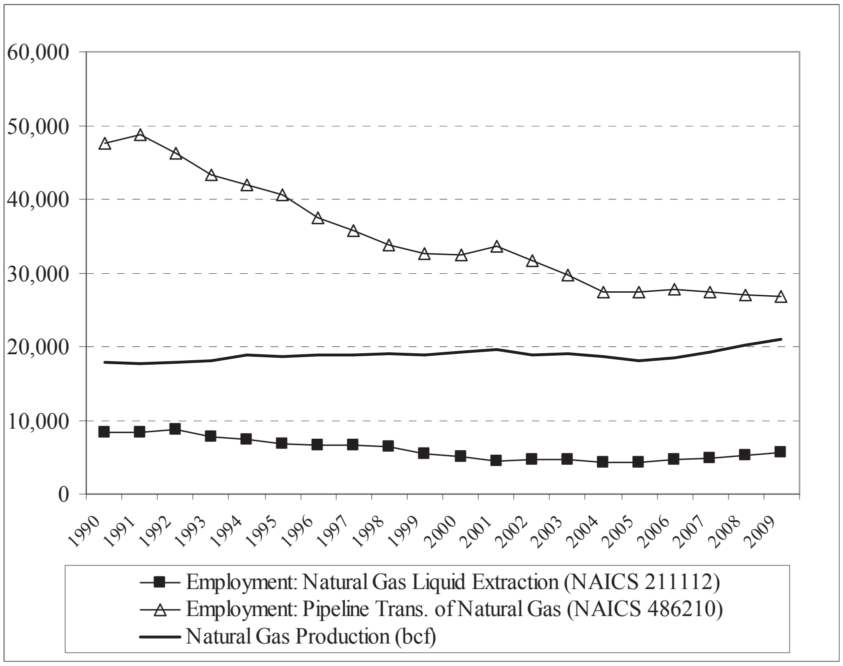

Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009

Figure 2-15 depicts employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009. While total natural gas production has risen slightly over this time period, employment in natural gas pipeline transportation has steadily declined to almost half of its 1991 peak. Employment in natural gas liquid extraction declined from 1992 to a low in 2005, then rebounded slightly from 2006 to 2009. Overall, however, these trends depict these sectors becoming decreasingly labor intensive, unlike the trends depicted in Figure 2-13 and Figure 2-14.

From 1990 to 2009, average wages for the oil and natural gas industry have increased. Table 2-18 and Figure 2-16 show real wages (in 2008 dollars) from 1990 to 2009 for the NAICS codes associated with the oil and natural gas industry.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 (2008 dollars)

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Operations (213112)	Pipeline Transportation of Crude Oil (486110)	Pipeline Transportation of Natural Gas (486210)	Total
1990	71,143	66,751	42,215	45,862	68,044	61,568	59,460
1991	72,430	66,722	43,462	47,261	68,900	65,040	60,901
1992	76,406	68,846	43,510	48,912	74,233	67,120	64,226
1993	77,479	68,915	45,302	50,228	72,929	67,522	64,618
1994	79,176	70,875	44,577	50,158	76,136	68,516	64,941
1995	81,433	67,628	46,243	50,854	78,930	71,965	66,446
1996	84,211	68,896	48,872	52,824	76,841	76,378	68,391
1997	89,876	79,450	52,180	55,600	78,435	82,775	71,813
1998	93,227	89,948	53,051	57,578	79,089	84,176	73,722
1999	98,395	89,451	54,533	59,814	82,564	94,471	79,078
2000	109,744	112,091	60,862	60,594	81,097	130,630	86,818
2001	111,101	111,192	61,833	61,362	83,374	122,386	85,333
2002	109,957	103,653	62,196	59,927	87,500	91,550	82,233
2003	110,593	112,650	61,022	61,282	87,388	91,502	82,557
2004	121,117	118,311	63,021	62,471	93,585	93,684	86,526
2005	127,243	127,716	70,772	67,225	92,074	90,279	90,292
2006	138,150	133,433	74,023	70,266	91,708	98,691	94,925
2007	135,510	132,731	82,010	71,979	96,020	105,441	96,216
2008	144,542	125,126	81,961	74,021	101,772	99,215	99,106
2009	133,575	123,922	80,902	70,277	100,063	100,449	96,298

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

Employees in the NAICS 211 codes enjoy the highest average wages in the industry, while employees in the NAICS 213111 code have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation, with a rapid climb from 1990 to 2000, more than doubling in real terms. However, since 2000 wages have declined in the pipeline transportation sector, while wages have risen in the other NAICS.

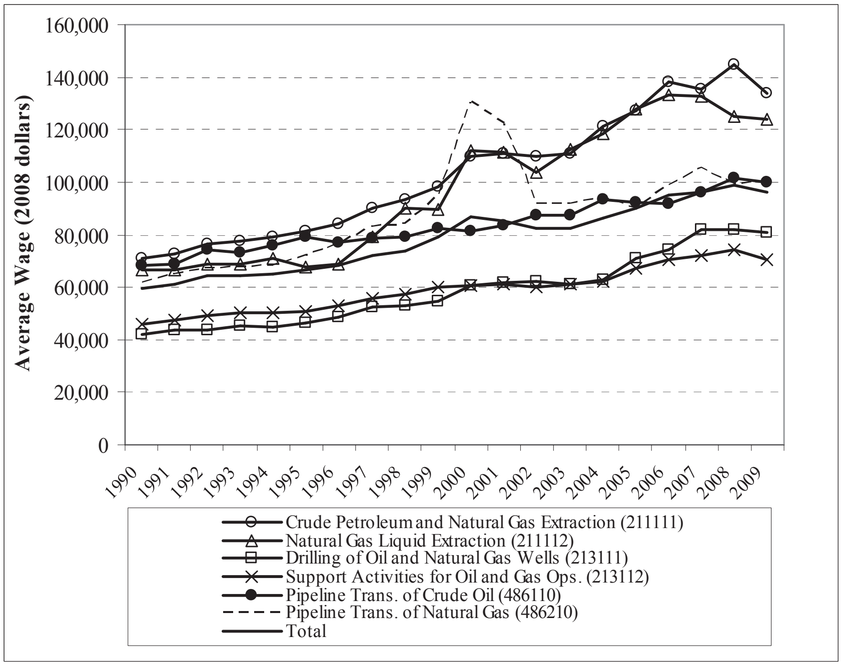

Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasing performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the wellhead from the sale of oil and natural gas or the provision of oil and gas production-related engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated. Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 Firm-level Information

The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for top 150 public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, now the top 150. In 2010, only 137 companies are listed[3]. Table 2-19 lists selected statistics for

[3] Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.

the top 20 companies in 2010. The results presented in the table reflect relatively lower production and financial figures as a result of the economic recession of this period.

Total earnings for the top 137 companies fell from 2008 to 2009 from $71 billion to $27 billion, reflecting the weak economy. Revenues for these companies also fell 35 percent during this period. 69 percent of the firms posted net losses in 2009, compared to 46 percent one year earlier (*Oil and Gas Journal*, September 6, 2010).

The total worldwide liquids production for the 137 firms declined 0.5 percent to 2.8 billion bbl, while total worldwide gas production increased about 3 percent to a total of 16.5 tcf (*Oil and Gas Journal*, September 6, 2010). Meanwhile, the 137 firms on the OGJ list increased both oil and natural gas production and reserves from 2008 to 2009. Domestic production of liquids increased about 7 percent to 1.1 billion bbl, and natural gas production increased to 10.1 tcf. For context, the OGJ150 domestic crude production represents about 57 percent of total domestic production (1.9 billion bbl, according to EIA). The OGJ150 natural gas production represents about 54 percent of total domestic production (18.8 tcf, according to EIA).

The OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used a recent list of U.S. gas processing facilities (*Oil and Gas Journal*, June 7, 2010) and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a processing capacity of 73,767 million cubic feet per day and throughout of 45,472 million cubic feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration, as large firms own multiple facilities, which also tend to be relatively large facilities (Table 2-20). While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total throughput) own 264 or 46 percent of the facilities. That larger companies tend to own larger facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent of actual throughput.

Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2010

						Worldwide Production		U.S. Production		
Rank by Total Assets	Company	Employees	Total Assets ($ millions)	Total Rev. ($ millions)	Net Inc. ($ millions)	Liquids (Million bbl)	Natural Gas (Bcf)	Liquids (Million bbl)	Natural Gas (Bcf)	Net Wells Drilled
1	ExxonMobil Corp.	102,700	233,323	310,586	19,280	725	2,383	112	566	466
2	Chevron Corp.	64,000	164,621	171,636	10,563	674	1,821	177	511	594
3	ConocoPhillips	30,000	152,588	152,840	4,858	341	1,906	153	850	692
4	Anadarko Petroleum Corp.	4,300	50,123	9,000	-103	88	817	63	817	630
5	Marathon Oil Corp.	28,855	47,052	54,139	1,463	90	351	23	146	115
6	Occidental Petroleum Corp.	10,100	44,229	15,531	2,915	179	338	99	232	260
7	XTO Energy Inc.	3,129	36,255	9,064	2,019	32	855	32	855	1,059
8	Chesapeake Energy Corp.	8,200	29,914	7,702	-5,805	12	835	12	835	1,003
9	Devon Energy Corp.	5,400	29,686	8,015	-2,479	72	966	43	743	521
10	Hess Corp.	13,300	29,465	29,569	740	107	270	26	39	48
11	Apache Corp.	3,452	28,186	8,615	-284	106	642	35	243	124
12	El Paso Corp.	4,991	22,505	4,631	-539	6	219	6	215	134
13	EOG Resources Inc.	2,100	18,119	14,787	547	29	617	26	422	652
14	Murphy Oil Corp.	8,369	12,756	18,918	838	48	68	6	20	3
15	Noble Energy Inc.	1,630	11,807	2,313	-131	29	285	17	145	540
16	Williams Cos. Inc.	4,801	9,682	2,219	400	0	3,435	0	3,435	488
17	Questar Corp.	2,468	8,898	3,054	393	4	169	4	169	194
18	Pioneer Nat. Resources Co.	1,888	8,867	1,712	-52	19	157	17	148	67
19	Plains Expl. & Prod. Co.	808	7,735	1,187	136	18	78	18	78	53
20	Petrohawk Energy Corp.	469	6,662	41,084	-1,025	2	174	2	174	162

Source: *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.
Notes: The source for employment figures is the American Business Directory.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

Rank	Company	Processing Plants (No.)	Natural Gas Capacity (MMcf/day)	Natural Gas Throughput (MMcf/day)
1	BP PLC	19	13,378	11,420
2	DCP Midstream Inc.	64	9,292	5,586
3	Enterprise Products Operating LP—	23	10,883	5,347
4	Targa Resources	16	4,501	2,565
5	Enbridge Energy Partners LP—	19	3,646	2,444
6	Williams Cos.	10	4,826	2,347
7	Martin Midstream Partners	16	3,384	2,092
8	Chevron Corp.	23	1,492	1,041
9	Devon Gas Services LP	6	1,038	846
10	ExxonMobil Corp.	6	1,238	766
11	Occidental Petroleum Corp	7	776	750
12	Kinder Morgan Energy Partners	9	1,318	743
13	Enogex Products Corp.	8	863	666
14	Hess Corp.	3	1,060	613
15	Norcen Explorer	1	600	500
16	Copano Energy	1	700	495
17	Anadarko	18	816	489
18	Oneok Field Services	10	1,751	472
19	Shell	4	801	446
20	DTE Energy	1	800	400
	TOTAL FOR TOP 20	264	63,163	40,028
	TOTAL FOR ALL COMPANIES	579	73,767	45,472

Source: *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 136 companies in 2010 (*Oil and Gas Journal*, November 1, 2010). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2009. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of pipeline companies and the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional market.

The top 20 companies maintain about 63 percent of the total pipeline mileage and transport about 54 percent of the volume of the industry (Table 2-21). Operating revenues of the top 20 companies equaled $11.5 billion, representing 60 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 64 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2009

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Op. Rev. (thousand $)	Net Income
1	Natural Gas Pipeline Co of America	9,312	1,966,774	1,131,548	348,177
2	Dominion Transmission Inc.	3,452	609,193	831,773	212,365
3	Columbia Gas Transmission LLC	9,794	1,249,188	796,437	200,447
4	Panhandle Eastern Pipe Line Co. LP	5,894	675,616	377,563	196,825
5	Transcontinental Gas Pipe Line Co. LLC	9,362	2,453,295	1,158,665	192,830
6	Texas Eastern Transmission LP	9,314	1,667,593	870,812	179,781
7	Northern Natural Gas Co.	15,028	922,745	690,863	171,427
8	Florida Gas Transmission Co. LLC	4,852	821,297	520,641	164,792
9	Tennessee Gas Pipeline Co.	14,113	1,704,976	820,273	147,378
10	Southern Natural Gas Co.	7,563	867,901	510,500	137,460
11	El Paso Natural Gas Co.	10,235	1,493,213	592,503	126,000
12	Gas Transmission Northwest Corp.	1,356	809,206	216,526	122,850
13	Rockies Express Pipeline LLC	1,682	721,840	555,288	117,243
14	CenterPoint Energy Gas Transmission Co.	6,162	1,292,931	513,315	116,979
15	Colorado Interstate Gas Co.	4,200	839,184	384,517	108,483
16	Kern River Gas Transmission Co.	1,680	789,858	371,951	103,430
17	Trunkline LNG Co. LLC	—	—	134,150	101,920
18	Northwest Pipeline GP	3,895	817,832	434,379	99,340
19	Texas Gas Transmission LLC	5,881	1,006,906	361,406	91,575
20	Algonquin Gas Transmission LLC	1,128	388,366	237,291	82,472
	TOTAL FOR TOP 20	124,903	21,097,914	11,510,401	3,021,774
	TOTAL FOR ALL COMPANIES	198,381	38,793,532	18,934,674	4,724,456

Source: *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the U.S. major energy producing companies. This information is used in annual report to Congress, as well as is released to the public in aggregate form. While the companies that report information to FRS each year changes, EIA makes an effort to retain sufficient consistency such that trends can be evaluated.

For 2008, there are 27 companies in the FRS[4] that accounted for 41 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 77 percent of U.S. refining capacity, and 0.2 percent of U.S. electricity net generation (U.S. EIA, 2010). Table 2-22 shows a series of financial trends in 2008 dollars selected and aggregated from FRS firms' financial statements. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising as well. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, although 2008 saw a decline from previous periods, as oil and natural gas prices declined significantly during the latter half of 2008.

Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

Year	Operating Revenues	Operating Expenses	Operating Income	Interest Expense	Other Income*	Income Taxes	Net Income
1990	766.9	706.4	60.5	16.8	13.6	24.8	32.5
1991	673.4	635.7	37.7	14.4	13.4	15.4	21.3
1992	670.2	637.2	33.0	12.7	-5.6	12.2	2.5
1993	621.4	586.6	34.8	11.0	10.3	12.7	21.5
1994	606.5	565.6	40.9	10.8	6.8	14.4	22.5
1995	640.8	597.5	43.3	11.1	12.9	17.0	28.1
1996	706.8	643.3	63.6	9.1	13.4	26.1	41.8
1997	673.6	613.8	59.9	8.2	13.4	23.9	41.2
1998	614.2	594.1	20.1	9.2	11.0	6.0	15.9
1999	722.9	682.6	40.3	10.9	12.7	13.6	28.6
2000	1,114.3	1,011.8	102.5	12.9	18.4	42.9	65.1
2001	961.8	880.3	81.5	10.8	7.6	33.1	45.2
2002	823.0	776.9	46.2	12.7	7.9	17.2	24.3
2003	966.9	872.9	94.0	10.1	19.5	37.2	66.2
2004	1,188.5	1,051.1	137.4	12.4	20.1	54.2	90.9
2005	1,447.3	1,263.8	183.5	11.6	34.6	77.1	129.3
2006	1,459.0	1,255.0	204.0	12.4	41.2	94.8	138.0
2007	1,475.0	1,297.7	177.3	11.1	47.5	86.3	127.4
2008	1,818.1	1,654.0	164.1	11.4	32.6	98.5	86.9

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). * Other Income includes other revenue and expense (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

[4] Alenco, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., WRB Refining LLC, and XTO Energy, Inc.

Table 2-23 shows in percentage terms the estimated return on investments for a variety of business lines, in 1998, 2003, and 2008, for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production has remained the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent for the three years evaluated. Returns to foreign oil and natural gas production rose above domestic production in 2008. Electric power generation and sales emerged in 2008 as a highly profitable line of business for the FRS companies.

Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, and 2008 (percent)

Line of Business	1998	2003	2008
Petroleum	10.8	13.4	12.0
U.S. Petroleum	10	13.7	8.2
Oil and Natural Gas Production	12.5	16.5	10.7
Refining/Marketing	6.6	9.3	2.6
Pipelines	6.7	11.5	2.4
Foreign Petroleum	11.9	13.0	17.8
Oil and Natural Gas Production	12.5	14.2	16.3
Refining/Marketing	10.6	8.0	26.3
Downstream Natural Gas*	-	8.8	5.1
Electric Power*	-	5.2	181.4
Other Energy	7.1	2.8	-2.1
Non-energy	10.9	2.4	-5.3

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). Note: Return on investment measured as contribution to net income/net investment in place. * The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state, and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2008 for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes deductions for the U.S. Federal Investment Tax Credit ($198 million in 2008) and the effect of the Alternative Minimum Tax ($34 million in 2008). Income taxes paid to state and local authorizes were $3,060 million in 2008, about 13 percent of the total paid to U.S. authorities.

Table 2-24 Income and Production Taxes, 1990-2008 (Million 2008 Dollars)

Year	U.S. Federal, State, and Local Taxes Paid or Accrued	Total Current	Total Deferred	Total Income Tax Expense	Other Non-Income Production Taxes Paid
1990	9,568	25,056	-230	24,826	4,341
1991	6,672	18,437	-3,027	15,410	3,467
1992	4,994	16,345	-4,116	12,229	3,097
1993	3,901	13,983	-1,302	12,681	2,910
1994	3,348	13,556	887	14,443	2,513
1995	6,817	17,474	-510	16,965	2,476
1996	8,376	22,493	3,626	26,119	2,922
1997	7,643	20,764	3,141	23,904	2,743
1998	1,199	7,375	-1,401	5,974	1,552
1999	2,626	13,410	140	13,550	2,147
2000	14,308	36,187	6,674	42,861	3,254
2001	10,773	28,745	4,351	33,097	3,042
2002	814	17,108	46	17,154	2,617
2003	9,274	30,349	6,879	37,228	3,636
2004	19,661	50,185	4,024	54,209	3,990
2005	29,993	72,595	4,529	77,125	5,331
2006	29,469	85,607	9,226	94,834	5,932
2007	28,332	84,119	2,188	86,306	7,501
2008	23,199	95,590	2,866	98,456	12,507

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The difference between total current taxes and U.S. federal, state, and local taxes in includes taxes and royalties paid to foreign countries. As can be seen in Table 2-24, foreign taxes paid far exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other production-related taxes.

2.7 References

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3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This section includes three sets of discussions for both the proposed NSPS and NESHAP amendments:

- Emission Sources and Points
- Emissions Control Options
- Engineering Cost Analysis

3.2 Emissions Points, Controls, and Engineering Costs Analysis

This section discusses the emissions points and pollution control options for the proposed NSPS and NESHAP amendments. This discussion of emissions points and control options is meant to assist the reader of the RIA in better understanding the economic impact analysis. However, we provide reference to the detailed technical memoranda prepared by the Office of Air Quality Planning and Standards (OAQPS) for the reader interested in a greater level of detail. This section also presents the engineering cost analysis, which provides a cost basis for the energy system, welfare, employment, and small business analyses.

Before going into detail on emissions points and pollution controls, it is useful to provide estimates of overall emissions from the crude oil and natural industry to provide context for estimated reductions as a result of the regulatory options evaluated. To estimate VOC emissions from the oil and gas sector, we modified the emissions estimate for the crude oil and natural gas sector in the 2008 National Emissions Inventory (NEI). During this review, EPA identified VOC emissions from natural gas sources which are likely relatively under-represented in the NEI, natural gas well completions primarily. Crude oil and natural gas sector VOC emissions estimated in the 2008 NEI total approximately 1.76 million tons. Of these emissions, the NEI identifies about 21 thousand tons emitted from natural gas well completion processes. We substituted the estimates of VOC emissions from natural gas well completions estimated as part of the engineering analysis (510,000 tons, which is discussed in more detail in the next section), bringing the total estimated VOC emissions from the crude oil and natural gas sector to about 2.24 million tons VOC.

The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e to approximately 330 $MMtCO_2$-e.

3.2.1 Emission Points and Pollution Controls assessed in the RIA

3.2.1.1 NSPS Emission Points and Pollution Controls

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of possible emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant chapters within the Technical Support Document (TSD) which is published in the Docket. The chapters are also referenced below. EPA is soliciting public comment and data relevant to several emissions-related issues related to the proposed NSPS. The comments we receive during the public comment period will help inform the rule development process as we work toward promulgating a final action.

Centrifugal and reciprocating compressors (TSD Chapter 6)**:** There are many locations throughout the oil and gas sector where compression of natural gas is required to move the gas along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines, or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses and pumps the natural gas through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compression does not require the use of any of the natural gas from the pipeline, but it does require a source of electricity. Reciprocating spark ignition engines are also used to power many compressors, referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline.

Both centrifugal and reciprocating compressors are sources of VOC emissions, and EPA evaluated compressors for coverage under the NSPS. Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. The seals in some compressors use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated, and the gas is commonly vented to the atmosphere. These are commonly called "wet" seals. An alternative to a wet seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Fugitive VOC is emitted from dry seals around the compressor shaft. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency.

Reciprocating compressors in the natural gas industry leak natural gas during normal operation. The highest volume of gas loss is associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the gas compressed to high pressure in the compressor cylinder from leaking, while allowing the rod to move freely. Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce VOC emissions.

Equipment leaks (TSD Chapter 8)**:** Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps, and other components within an oil and gas production, processing, and transmission facility, equipment leaks of volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components. These types of equipment also exist at production sites and gas transmission/compressor stations. While the number of components at individual transmission/compressor stations is relatively smaller than at processing plants, collectively there are many components that can result in significant emissions. Therefore, EPA evaluated NSPS for equipment leaks for facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant or refinery.

Pneumatic controllers (TSD Chapter 5): Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations, the pneumatic controllers used in the oil and gas sector make use of the available high-pressure natural gas to regulate temperature, pressure, liquid level, and flow rate across all areas of the industry. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. Not all pneumatic controllers are gas driven. These "non-gas driven" pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non gas-driven controllers are typically used. Gas-driven pneumatic controllers are typically characterized as "high-bleed" or "low-bleed", where a high-bleed device releases at least 6 cubic feet of gas per hour. EPA evaluated the impact of requiring low-bleed controllers.

Storage vessels (TSD Chapter 7): Crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process equipment used to separate, treat, and store crude oil, condensate, natural gas, and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells. Emissions from storage vessels are a result of working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emission will occur in the storage stage. The two ways of controlling tanks with significant emissions would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks or to route the emissions from the tanks to a control device.

Well completions (TSD Chapter 4): In the oil and natural gas sector, well completions contain multi-phase processes with various sources of emissions. One specific emission source during completion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production.

Hydraulic fracturing is one completion step for improving gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with proppant (generally sand) that “props open” the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high velocity necessary to lift excess proppant to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand, and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Thus, we estimate completions involving hydraulic fracturing vent substantially more natural gas, approximately 230 times more, than completions not involving hydraulic fracturing. Specifically, we estimate that uncontrolled well completion emissions for a hydraulically fractured well are about 23 tons of VOC, where emissions for a conventional gas well completion are around 0.1 ton VOC. Our data indicate that hydraulically fractured wells have higher emissions but we believe some wells that are not hydraulically fractured may have higher emissions than our data show, or in some cases, hydraulically fractured wells could have lower emissions that our data show.

Reduced emission completions, which are sometimes referred to as "green completions" or "flareless completions," use equipment at the well site to capture and treat gas so it can be directed into the sales line and avoid emissions from venting. Equipment required to conduct a reduced emissions completion may include tankage, special gas-liquid-sand separator traps, and gas dehydration. Equipment costs associated with reduced emission completions will vary from well to well. Based on information provided to the EPA Natural Gas STAR program, 90 percent of gas potentially vented during a completion can be recovered during a reduced emission completion.

3.2.1.2 NESHAP Emission Points and Pollution Controls

A series of emissions controls will be required under the proposed NESHAP Amendments. This section provides a basic description of potential sources of emissions and the controls intended for each to facilitate the reader's understanding of the economic impacts and subsequent benefits analysis section. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant technical memos which are published in the Docket. The memos are also referenced below.

Glycol dehydrators[5]: Once natural gas has been separated from any liquid materials or products (e.g., crude oil, condensate, or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant

[5] Memorandum. Brown, Heather, EC/R Incorporated, to Bruce Moore and Greg Nizich, EPA/OAQPS/SPPD/FIG. Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options. July 17,2011.

dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions. Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol separator (GCG separator or flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent. The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device.

The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator, or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser’s emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

Storage vessels: Please see the discussion of storage vessels in the NSPS section above.

3.2.2 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make in order to comply with the proposed

NSPS and NESHAP amendments. A detailed discussion of the methodology used to estimate cost impacts is presented in series of memos published in the Docket as part of the TSD.

3.2.2.1 NSPS Sources

Table 3-1 shows the emissions sources, points, and controls analyzed in three NSPS regulatory options, which we term Option 1, Option 2, and Option 3. Option 2 was selected for proposal. The proposed Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly drilled natural gas wells that are hydraulically fractured. Option 2 also requires a subset of wells that are worked over, or recompleted, using hydraulic fracturing to implement RECs. The proposed Option 2 requires emissions reductions from reciprocating compressors at gathering and boosting stations, processing plants, transmission compressor stations, and underground storage facilities. The proposed Option 2 also requires emissions reductions from centrifugal compressors, processing plants, and transmission compressor stations. Finally, the proposed Option 2 requires emissions reductions from pneumatic controllers at oil and gas production facilities and natural gas transmission and storage and reductions from high throughput storage vessels.

Table 3-1 Emissions Sources, Points, and Controls Included in NSPS Options

Emissions Sources and Points	Emissions Control	Option 1	Option 2 (proposed)	Option 3
Well Completions of Post-NSPS Wells				
Hydraulically Fractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC	Combustion	**X**	**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Well Recompletions				
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC		**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Equipment Leaks				
Well Pads	NSPS Subpart VV			**X**
Gathering and Boosting Stations	NSPS Subpart VV			**X**
Processing Plants	NSPS Subpart VVa		**X**	**X**
Transmission Compressor Stations	NSPS Subpart VV			**X**
Reciprocating Compressors				
Well Pads	Annual Monitoring/ Maintenance (AMM)			
Gathering/Boosting Stations	AMM	**X**	**X**	**X**
Processing Plants	AMM	**X**	**X**	**X**
Transmission Compressor Stations	AMM	**X**	**X**	**X**
Underground Storage Facilities	AMM	**X**	**X**	**X**
Centrifugal Compressors				
Processing Plants	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Transmission Compressor Stations	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Pneumatic Controllers -				
Oil and Gas Production	Low Bleed/Route to Process	**X**	**X**	**X**
Natural Gas Transmission and Storage	Low Bleed/Route to Process	**X**	**X**	**X**
Storage Vessels				
High Throughput	95% control	**X**	**X**	**X**
Low Throughput	95% control			

The distinction between Option 1 and the proposed Option 2 is the inclusion of completion combustion and REC requirements for recompletions at existing wells and an equipment leak standard for natural gas processing plants in Option 2. Option 2 requires the implementation of completion combustion and REC for existing wells as well as wells completed after the implementation date of the proposed NSPS. Option 1 applies the requirement only to new wells, not existing wells. The main distinction between proposed Option 2 and Option 3 is the inclusion of a suite of equipment leak standards. These equipment leak standards would apply at well pads, gathering and boosting stations, and transmission compressor stations. Option 1 differs from Option 3 in that it does not include the combustion and REC requirements at existing wells or the full suite of equipment leak standards.

Table 3-2 summarizes the unit level capital and annualized costs for the evaluated NSPS emissions sources and points. The detailed description of costs estimates is provided in the series of technical memos included in the TSD in the document, as referenced in Section 3.2.1 of this RIA. The table also includes the projected number of affected units. Four issues are important to note on Table 3-2: the approach to annualizing costs, the projection of affected units in the baseline; that capital and annualized costs are equated for RECs; and additional natural gas and hydrocarbon condensates that would otherwise be emitted to the environment are recovered from several control options evaluated in the NSPS review.

First, engineering capital costs were annualized using a 7 percent interest rate. However, different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used:

- Reduced emissions completions and combustion devices: 1 year (more discussion of the selection of a one-year lifetime follows in this section momentarily)
- Reciprocating compressors: 3 years
- Centrifugal compressors and pneumatic controllers: 10 years
- Storage vessels: 15 years
- Equipment leaks: 5 to 10 years, depending on specific control

To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. An alternative approach would be to establish an overall, representative project time horizon and annualize costs after consideration of control options that would need to be replaced periodically within the given time horizon. For example, a 15 year project would require replacing reciprocating compressor-related controls five times, but only require a single installation of controls on storage vessels. This approach, however, is equivalent to the approach selected; that is to sum the annualized costs across options, without establishing a representative project time horizon.

Second, the projected number of affected units is the number of units that our analysis shows would be affected in 2015, the analysis year. The projected number of affected units accounts for estimates of the adoption of controls in absence of Federal regulation. While the procedures used to estimate adoption in absence of Federal regulation are presented in detail within the TSD, because REC requirements provide a significant component of the estimated emissions reductions and engineering compliance costs, it is worthwhile to go into some detail on the projected number of RECs within the RIA. We use EIA projections consistent with the Annual Energy Outlook 2011 to estimate the number of natural gas well completions with hydraulic fracturing in 2015, assuming that successful wells drilled in coal bed methane, shale, and tight sands used hydraulic fracturing. Based on this assumption, we estimate that 11,403 wells were successfully completed and used hydraulic fracturing. To approximate the number of wells that would not be required to perform RECs because of the absence of sufficient infrastructure, we draw upon the distinction in EIA analysis between exploratory and developmental wells. We assume exploratory wells do not have sufficient access to infrastructure to perform a REC and are exempt from the REC requirement. These 446 wells are removed from the REC estimate and are assumed to combust emissions using pit flares.

The number of hydraulically fractured recompletions of existing wells was approximated using assumptions found in Subpart W's TSD[6] and applied to well count data found in the proprietary HPDI® database. The underlying assumption is that wells found in coal bed

[6] U.S. Environmental Protection Agency (U.S. EPA). 2010. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC.

methane, shale, and tight sand formations require re-fracture, on average, every 10 years. In other words, 10 percent of the total wells classified as being performed with hydraulic fracturing would perform a recompletion in any given year. Natural gas well recompletions performed without hydraulic fracturing were based only on 2008 well data from HPDI®.

The number of completions and recompletions already controlling emissions in absence of a Federal regulation was estimated based on existing State regulations that require applicable control measures for completions and workovers in specific geographic locations. Based on this criterion, 15 percent of natural gas completions with hydraulic fracturing and 15 percent of existing natural gas workovers with hydraulic fracturing are estimated to be controlled by either flare or REC in absence of Federal regulations. Completions and recompletions without hydraulic fracturing were assumed as having no controls in absence of a Federal regulation. Following these procedures leads to an estimate of 9,313 completions of new wells and 12,050 recompletions of existing wells that will require either a REC under the proposed NSPS in 2015.

It should be noted that natural gas prices are stochastic and, historically, there have been periods where prices have increased or decreased rapidly. These price changes would be expected to affect adoption of emission reduction technologies in absence of regulation, particularly control measures such as RECs that capture emission significantly over short periods of time.

Third, for well completion requirements, annualized costs are set equal to capital costs. We chose to equate the capital and annualized cost because the completion requirements (combustion and RECs) are essentially one-shot events; the emissions controls are applied over the course of a well completion, which will typically range over a few days to a couple of weeks. After this relatively short period of time, there is no continuing control requirement, unless the well is again completed at a later date, sometimes years later. We reasoned that the absence of a continuing requirement makes it appropriate to equate capital and annualized costs.

Fourth, for annualized cost, we present two figures, the annualized costs with revenues from additional natural gas and condensate recovery and annualized costs without additional revenues this product recovery. Several emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. RECs also capture saleable condensates that would otherwise be lost to the environment. The engineering analysis assumes a REC will capture 34 barrels of condensate per REC and that the value of this condensate is $70/barrel.

The assumed price for natural gas is within the range of variation of wellhead prices for the 2010-11 period. The $4/Mcf is below the 2015 EIA-forecasted wellhead price, $4.22/Mcf in 2008 dollars. The $4/Mcf payment rate does not reflect any taxes or tax credits that might apply to producers implementing the control technologies. As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars.

As will be seen in subsequent analysis, the estimate of revenues from additional product recovery is critical to the economic impact analysis. However, before discussing this assumption in more depth, it is important to further develop the engineering estimates to contextualize the discussion and to provide insight into why, if it is profitable to capture natural gas emissions that are otherwise vented, producers may not already be doing so.

Table 3-3 presents the estimated nationwide compliance costs, emissions reductions, and VOC reduction cost-effectiveness broken down by emissions sources and points for those sources and points evaluated in the NSPS analysis. The reporting and recordkeeping costs for the proposed NSPS Option 2 are estimated at $18,805,398 and are included in Table 3-3. Because of time constraints, we were unable to estimate reporting and recordkeeping costs customized for Options 1 and 3; for these options, we use the same $18,805,398 for reporting and recordkeeping costs for these options.

As can be seen from Table 3-3 controls associated with well completions and recompletions of hydraulically fractured wells provide the largest potential for emissions reductions from evaluated emissions sources and points, as well as present the most significant compliance costs if revenue from additional natural gas recovery is not included. Emissions reductions from conventional natural gas wells and crude oil wells are clearly not as significant as the potential from hydraulically fractured wells, as was discussed in Section 3.2.1.1.

Several evaluated emissions sources and points are estimated to have net financial savings when including the revenue from additional natural gas recovery. These sources form the core of the three NSPS options evaluated in this RIA. Table 3-4 presents the estimated engineering costs, emissions reductions, and VOC reduction cost-effectiveness for the three NSPS options evaluated in the RIA. The resulting total national annualized cost impact of the proposed NSPS rule (Option 2) is estimated at $740 million per year without considering revenues from additional natural gas recovery. Annual costs for the proposed NSPS are estimated at -$45 million when revenue from additional natural gas recovery is included. All figures are in 2008 dollars.

Table 3-2 Summary of Capital and Annualized Costs per Unit for NSPS Emissions Points

Sources/Emissions Point	Projected No. of Affected Units	Capital Costs (2008$)	Per Unit Annualized Cost (2008$)	
			Without Revenues from Additional Product Recovery	With Revenues from Additional Product Recovery
Well Completions				
Hydraulically Fractured Gas Wells that Meet Criteria for REC	9,313	$33,237	$33,237	-$2,173
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	446	$3,523	$3,523	$3,523
Conventional Gas Wells	7,694	$3,523	$3,523	$3,523
Oil Wells	12,193	$3,523	$3,523	$3,523
Well Recompletions				
Hydraulically Fractured Gas Wells (existing wells)	12,050	$33,237	$33,237	-$2,173
Conventional Gas Wells	42,342	$3,523	$3,523	$3,523
Oil Wells	39,375	$3,523	$3,523	$3,523
Equipment Leaks				
Well Pads	4,774	$68,970	$23,413	$21,871
Gathering and Boosting Stations	275	$239,494	$57,063	$51,174
Processing Plants	29	$7,522	$45,160	$33,884
Transmission Compressor Stations	107	$96,542	$25,350	$25,350
Reciprocating Compressors				
Well Pads	6,000	$6,480	$3,701	$3,664
Gathering/Boosting Stations	210	$5,346	$2,456	$870
Processing Plants	209	$4,050	$2,090	-$2,227
Transmission Compressor Stations	20	$5,346	$2,456	$2,456
Underground Storage Facilities	4	$7,290	$3,349	$3,349
Centrifugal Compressors				
Processing Plants	16	$75,000	$10,678	-$123,730
Transmission Compressor Stations	14	$75,000	$10,678	-$77,622
Pneumatic Controllers -				
Oil and Gas Production	13,632	$165	$23	-$1,519
Natural Gas Trans. and Storage	67	$165	$23	$23
Storage Vessels				
High Throughput	304	$65,243	$14,528	$13,946
Low Throughput	17,086	$65,243	$14,528	$13,946

Table 3-3 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

		Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	**Emissions Control**	**Without Addl. Revenues**	**With Addl. Revenues**	**VOC**	**Methane**	**HAP**	**Without Addl. Revenues**	**With Addl. Revenues**
Well Completions (New Wells)								
Hydraulically Fractured Gas Wells	REC	$309,553,517	-$20,235,748	204,134	1,399,139	14,831	$1,516	-$99
Hydraulically Fractured Gas Wells	Combustion	$1,571,188	$1,571,188	9,801	67,178	712	$160	$160
Conventional Gas Wells	Combustion	$27,104,761	$27,104,761	857	5,875	62	$31,619	$31,619
Oil Wells	Combustion	$42,954,036	$42,954,036	83	88	0	$520,580	$520,580
Well Recompletions (Existing Wells)								
Hydraulically Fractured Gas Wells (existing wells)	REC	$400,508,928	-$26,181,572	264,115	1,810,245	19,189	$1,516	-$99
Conventional Gas Wells	Combustion	$149,164,257	$149,164,257	316	2,165	23	$472,227	$472,227
Oil Wells	Combustion	$138,711,979	$138,711,979	44	47	0	$3,134,431	$3,134,431
Equipment Leaks								
Well Pads	NSPS Subpart VV	$111,773,662	$104,412,154	10,646	38,287	401	$10,499	$9,808
Gathering and Boosting Stations	NSPS Subpart VV	$15,692,325	$14,072,850	2,340	8,415	88	$6,705	$6,013
Processing Plants	NSPS Subpart VVa	$1,309,650	$982,648	392	1,411	15	$3,343	$2,508
Transmission Compressor Stations	NSPS Subpart VV	$2,712,450	$2,712,450	261	9,427	8	$10,389	$10,389
Reciprocating Compressors								
Well Pads	Annual Monitoring/ Maintenance (AMM)	$22,204,209	$21,984,763	263	947	10	$84,379	$83,545
Gathering/Boosting Stations	AMM	$515,764	$182,597	400	1,437	15	$1,291	$457
Processing Plants	AMM	$436,806	-$465,354	1,082	3,892	41	$404	-$430
Transmission Compressor Stations	AMM	$47,892	$47,892	12	423	0	$4,093	$4,093
Underground Storage Facilities	AMM	$13,396	$13,396	2	87	0	$5,542	$5,542

Table 3-3 (continued) Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

		Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	**Emissions Control**	**Without Addl. Revenues**	**With Addl. Revenues**	**VOC**	**Methane**	**HAP**	**Without Addl. Revenues**	**With Addl. Revenues**
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	$170,853	-$1,979,687	288	3,183	10	$593	-$6,874
Transmission Compressor Stations	Dry Seals/Route to Process or Control	$149,496	-$1,086,704	43	1,546	1	$3,495	-$25,405
Pneumatic Controllers -								
Oil and Gas Production	Low Bleed/Route to Process	$320,071	-$20,699,918	25,210	90,685	952	$13	-$821
Natural Gas Trans. and Storage	Low Bleed/Route to Process	$1,539	$1,539	6	212	0	$262	$262
Storage Vessels								
High Throughput	95% control	$4,411,587	$4,234,856	29,654	6,490	876	$149	$143
Low Throughput	95% control	$248,225,012	$238,280,976	6,838	1,497	202	$36,298	$34,844

Table 3-4 Estimated Engineering Compliance Costs, NSPS (2008$)

	Option 1	Option 2 (Proposed)	Option 3
Capital Costs	$337,803,930	$738,530,998	$1,143,984,622
Annualized Costs			
Without Revenues from Additional Natural Gas Product Recovery	$336,163,858	$737,982,436	$868,160,873
With Revenues from Additional Natural Gas Product Recovery	-$19,496,449	-$44,695,374	$76,502,080
VOC Reductions (tons per year)	270,695	535,201	548,449
Methane Reduction (tons per year)	1,574,498	3,386,154	3,442,283
HAP Reductions (tons per year)	17,442	36,645	37,142
VOC Reduction Cost-Effectiveness ($/ton without additional product revenues)	$1,241.86	$1,378.89	$1,582.94
VOC Reduction Cost-Effectiveness ($/ton with additional product revenues)	-$72.02	-$83.51	$139.49

Note: the VOC reduction cost-effectiveness estimate assumes there is no benefit to reducing methane and HAP, which is not the case. We however present the per ton costs of reducing the single pollutant for illustrative purposes. As product prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional product recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars. The cost estimates for each regulatory option also include reporting and recordkeeping costs of $18,805,398.

As mentioned earlier, the single difference between Option 1 and the proposed Option 2 is the inclusion of RECs for recompletions of existing wells in Option 2. The implication of this inclusion in Option 2 is clear in Table 3-4, as the estimated engineering compliance costs without additional product revenue more than double and VOC emissions reductions also more than double. Meanwhile, the addition of equipment leaks standards in Option 3 increases engineering costs more than $400 million dollars in 2008 dollars, but only marginally increase estimates of emissions reductions of VOCs, methane, and HAPS.

As the price assumption is very influential on estimated impacts, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering costs estimate of the proposed NSPS. Figure 3-1 plots the annualized costs after revenues from natural gas product recovery have been incorporated (in millions of 2008 dollars) as a function of the assumed price of natural gas paid to producers at the wellhead for the recovered natural gas (represented by the sloped, dotted line). The vertical solid lines in the figure represent the natural gas price assumed in the RIA ($4.00/Mcf) for 2015 and the 2015 forecast by EIA in the 2011 Annual Energy Outlook ($4.22/Mcf) in 2008 dollars.

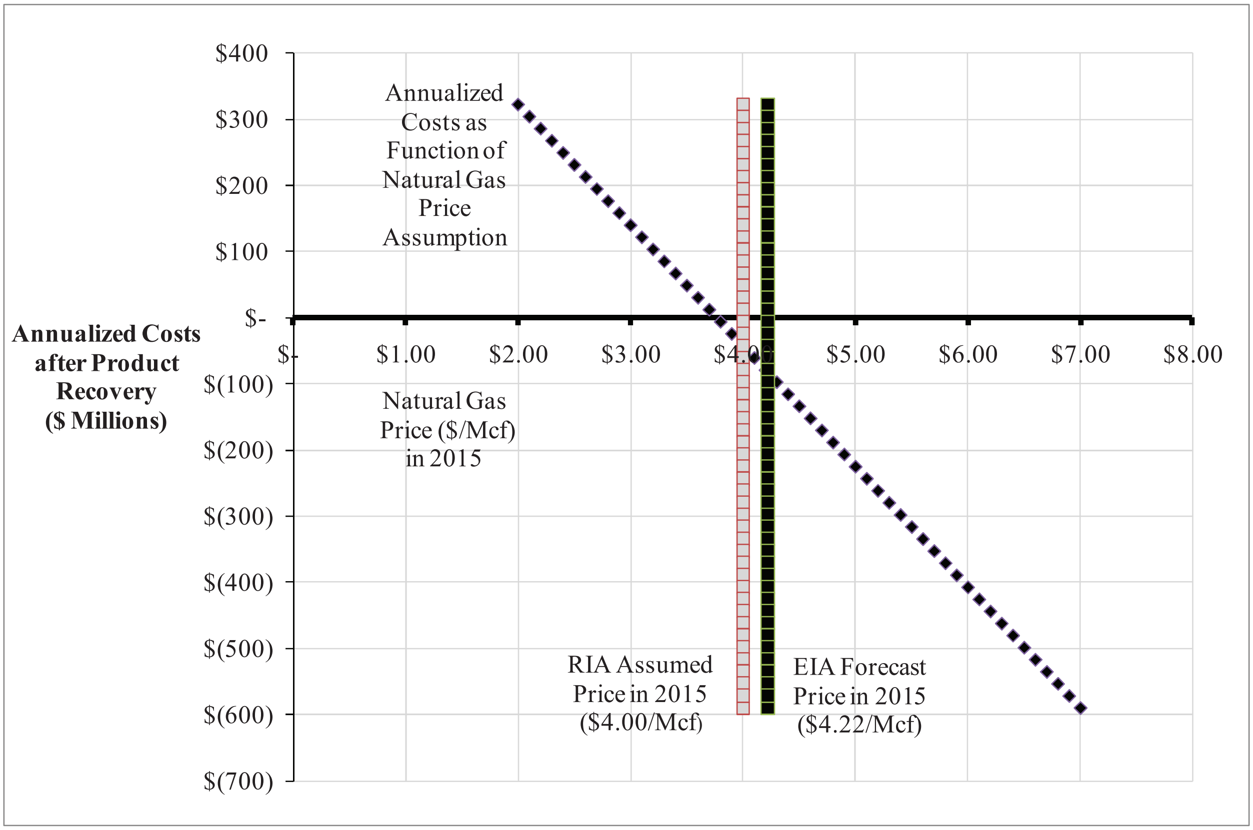

Figure 3-1 Sensitivity Analysis of Proposed NSPS Annualized Costs after Revenues from Additional Product Recovery are Included

As shown in Table 3-4, at the assumed $4/Mcf, the annualized costs are estimated at -$45 million. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook, the annualized costs are estimated at about -$90 million, which would approximately double the estimate of net cost savings of the proposed NSPS. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the proposed NSPS breaks-even is around $3.77/Mcf. As mentioned earlier, a $1/Mcf change in the wellhead natural gas price leads to about a $180 million change in the annualized engineering costs of the proposed NSPS. Consequently, annualized engineering costs estimates would increase to about $140 million under a $3/Mcf price or decrease to about -$230 million under a $5/Mcf price.

It is additionally helpful to put the quantity of natural gas and condensate potentially recovered in the context of domestic production levels. To do so, it is necessary to make two adjustments. First, not all emissions reductions can be directed into production streams to be ultimately consumed by final consumers. Several controls require combustion of the natural gas rather than capture and direction into product streams. After adjusting estimates of national emissions reductions in Table 3-3 for these combustion-type controls, Options 1, 2, and 3 are estimated to capture about 83, 183, and 185 bcf of natural gas and 317,000, 726,000, and 726,000 barrels of condensate, respectively. For control options that are expected to recover natural gas products. Estimates of unit-level and nation-level product recovery are presented in Section 3 of the RIA. Note that completion-related requirements for new and existing wells generate all the condensate recovery for all NSPS regulatory options. For natural gas recovery, RECs contribute 77 bcf (92 percent) for Option 1, 176 bcf (97 percent) for Option 2, and 176 bcf (95 percent) for Option 3.

Table 3-5 Estimates of Control Unit-level and National Level Natural Gas and Condensate Recovery, NSPS Options, 2015

Source/ Emissions Points	Emissions Control	NSPS Option	Projected No. of Affected Units	Unit-level Product Recovery		Total Product Recovery	
				Natural Gas Savings (Mcf/unit)	Condensate (bbl/unit)	Natural Gas Savings (Mcf)	Condensate (bbl)
Well Completions							
Hydraulically Fractured Gas Wells	REC	1, 2, 3	9,313	8,258	34	76,905,813	316,657
Hydraulically Fractured Gas Wells	Combustion	1, 2, 3	446	0	0	0	0
Hydraulically Fractured Gas Wells (existing wells)	REC	2, 3	12,050	8,258	34	99,502,875	409,700
Equipment Leaks							
Well Pads	NSPS Subpart VV	3	4,774	386	0	1,840,377	0
Gathering and Boosting Stations	NSPS Subpart VV	3	275	1,472	0	404,869	0
Processing Plants	NSPS Subpart VVa	2, 3	29	2,819	0	81,750	0
Reciprocating Compressors							
Gathering/Boosting Stations	AMM	1, 2, 3	210	397	0	83,370	0
Processing Plants	AMM	1, 2, 3	375	1,079	0	404,677	0
Trans. Compressor Stations	AMM	1, 2, 3	199	1,122	0	223,374	0
Underground Storage Facilities	AMM	1, 2, 3	9	1,130	0	9,609	0
Centrifugal Compressors							
Processing Plants	Dry Seals/Route to Process or Ctrl	1, 2, 3	16	11,527	0	184,435	0
Trans. Compressor Stations	Dry Seals/Route to Process or Ctrl	1, 2, 3	14	5,716	0	80,018	0
Pneumatic Controllers -							
Oil and Gas Production	Low Bleed/Route to Process	1, 2, 3	13,632	386	0	5,254,997	0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	1, 2, 3	67	0	0	0	0
Processing Plants	Instrument Air	1, 2, 3	15	871.0	0	13,064	0
Storage Vessels							
High Throughput	95% control	1, 2, 3	304	146	0	44,189	0
Option 1 Total (Mcf)						**83,203,546**	**316,657**
Option 2 Total (Mcf)						**182,788,172**	**726,357**
Option 3 Total (Mcf)						**185,033,417**	**726,357**

A second adjustment to the natural gas quantities is necessary to account for nonhydrocarbon gases removed and gas that reinjected to repressurize wells, vented or flared, or consumed in production processes. Generally, wellhead production is metered at or near the wellhead and payments to producers are based on these metered values. In most cases, the natural gas is minimally processed at the meter and still contains impurities or co-products that must be processed out of the natural gas at processing plants. This means that the engineering cost estimates of revenues from additional natural gas recovery arising from controls implemented at the wellhead include payment for the impurities, such as the VOC and HAP content of the unprocessed natural gas. According to EIA, in 2009 the gross withdrawal of natural gas totaled 26,013 bcf, but 20,580 bcf was ultimately considered dry production (these figures exclude EIA estimates of flared and vented natural gas). Using these numbers, we apply a factor of 0.79 (20,580 bcf divided by 26,013 bcf) to the adjusted sums in the previous paragraph to estimate the volume of gas that is captured by controls that may ultimately by consumed by final consumers.

After making these adjustments, we estimate that Option 1 will potentially recover approximately 66 bcf, proposed Option 2 will potentially recover about 145 bcf, and Option 3 will potentially recover 146 bcf of natural gas that will ultimately be consumed by natural gas consumers.[7] EIA forecasts that the domestic dry natural gas production in 2015 will be 20,080 bcf. Consequently, Option 1, proposed Option 2, and Option 3 may recover production representing about 0.29 percent, 0.64 percent and 0.65 percent of domestic dry natural gas production predicted in 2015, respectively. These estimates, however, do not account for adjustments producers might make, once compliance costs and potential revenues from additional natural gas recovery factor into economic decisionmaking. Also, as discussed in the previous paragraph, these estimates do not include the nonhydrocarbon gases removed, natural gas reinjected to repressurize wells, and natural gas consumed in production processes, and therefore will be lower than the estimates of the gross natural gas captured by implementing controls.

[7] To convert U.S. short tons of methane to a cubic foot measure, we use the conversion factor of 48.04 Mcf per U.S. short ton.

Clearly, this discussion raises the question as to why, if emissions can be reduced profitably using environmental controls, more producers are not adopting the controls in their own economic self-interest. This question is made clear when examining simple estimates of the rate of return to installing emissions controls that, using the engineering compliance costs estimates, the estimates of natural gas product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula: product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula:

$$\text{rate of return} = \left(\frac{\text{estimated revenues}}{\text{estimated costs}} - 1 \right) \times 100 .$$

Table 3-6 Simple Rate of Return Estimate for NSPS Control Options

Emission Point	Control Option	Rate of Return
New Completions of Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Re-completions of Existing Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Reciprocating Compressors (Processing Plants)	Replace Packing Every 3 Years of Operation	208.3%
Centrifugal Compressors (Processing Plants)	Convert to Dry Seals	1158.7%
Centrifugal Compressors (Transmission Compressor Stations)	Convert to Dry Seals	726.9%
Pneumatic Controllers (Oil and Gas Production)	Low Bleed	6467.3%
Overall Proposed NSPS	**Low Bleed**	**6.1%**

Note: The table presents only control options where estimated revenues from natural gas product recovery exceeds estimated annualized engineering costs

Recall from Table 2-23 in the Industry Profile, that EIA estimates an industry-level rate of return on investments for various segments of the oil and natural gas industry. While the numbers varies greatly over time because of industry and economic factors, EIA estimates a 10.7 percent rate of return on investments for oil and natural gas production in 2008. While this amount is higher than the 6.5 percent rate estimated for RECs, it is significantly lower than the rate of returns estimated for other controls anticipated to have net savings.

Assuming financially rational producers, standard economic theory suggests that all oil and natural gas firms would incorporate all cost-effective improvements, which they are aware of, without government intervention. The cost analysis of this draft RIA nevertheless is based on the observation that emission reductions that appear to be profitable in our analysis have not been generally adopted. One possible explanation may be the difference between the average profit margin garnered by productive capital and the environmental capital where the primary motivation for installing environmental capital would be to mitigate the emission of pollutants and confer social benefits as discussed in Chapter 4.

Another explanation for why there appear to be negative cost control technologies that are not generally adopted is imperfect information. If emissions from the oil and natural gas sector are not well understood, firms may underestimate the potential financial returns to capturing emissions. Quantifying emissions is difficult and has been done in relatively few studies. Recently, however, advances in infrared imagery have made it possible to affordably visualize, if not quantify, methane emissions from any source using a handheld camera. This infrared camera has increased awareness within industry and among environmental groups and the public at large about the large number of emissions sources and possible scale of emissions from oil and natural gas production activities. Since, as discussed in the TSD chapter referenced above, 15 percent of new natural gas well completions with hydraulic fracturing and 15 percent of existing natural gas well recompletions with hydraulic fracturing are estimated to be controlled by either flare or REC in the baseline, it is unlikely that a lack of information will be a significant reason for these emission points to not be addressed in the absence of Federal regulation in 2015. However, for other emission points, a lack of information, or the cost associated with doing a feasibility study of potential emission capture technologies, may continue to prevent firms from adopting these improvements in the absence of regulation.

Another explanation is the cost associated with irreversibility associated with implementing these environmental controls are not reflected in the engineering cost estimates above. Due to the high volatility of natural gas prices, it is important to recognize the value of flexibility taken away from firms when requiring them to install and use a particular emissions capture technology. If a firm has not adopted the technology on its own, then a regulation mandating its use means the firm loses the option to postpone investment in the technology in order to pursue alternative investments today, and the option to suspend use of the technology if it becomes unprofitable in the future. Therefore, the full cost of the regulation to the firm is the engineering cost and the lost option value minus the revenues from the sale of the additional recovered product. In the absence of quantitative estimates of this option value for each emission point affected by the NSPS and NESHAP improvements, the costs presented in this RIA may underestimate the full costs faced by the affected firms. With these caveats in mind, EPA believes it is analytically appropriate to analyze costs and economic impacts costs presented in Table 3-2 and Table 3-3 using the additional product recovery and associated revenues.

3.2.2.2 NESHAP Sources

As discussed in Section 3.2.1.2, EPA examined three emissions points as part of its analysis for the proposed NESHAP amendments. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not direct significant quantities of natural gas that would otherwise be flared or vented into the production stream. Table 3-7 shows the projected number of controls required, estimated unit-level capital and annualized costs, and estimated total annualized costs. The table also shows estimated emissions reductions for HAPs, VOCs, and methane, as well as a cost-effectiveness estimate for HAP reduction, based upon engineering (not social) costs.

Table 3-7 Summary of Estimated Capital and Annual Costs, Emissions Reductions, and HAP Reduction Cost-Effectiveness for Proposed NESHAP Amendments

Source/Emissions Point	Projected No. of Controls Required	Capital Costs/ Unit (2008$)	Annualized Cost/Unit (2008$)	Total Annualized Cost (2008$)	Emission Reductions (tons per year) HAP	VOC	Methane	HAP Reduction Cost-Effectiveness (2008$/ton)
Production - Small Glycol Dehydrators	115	65,793	30,409	3,497,001	548	893	324	6,377
Transmission - Small Glycol Dehydrators	19	19,537	19,000	361,000	243	475	172	1,483
Storage Vessels	674	65,243	14,528	9,791,872	589	7,812	4,364	16,618
Reporting and Recordkeeping	---	196	2,933	2,369,755	---	---	---	---
Total	**808**			**16,019,871**	**1,381**	**9,243**	**4,859**	**10,576**

Note: Totals may not sum due to independent rounding.

Under the Proposed NESHAP Amendments, about 800 controls will be required, costing a total of $16.0 million (Table 3-7). We include reporting and recordkeeping costs as a unique line item showing these costs for the entire set of proposed amendments. These controls will reduce HAP emissions by about 1,400 tons, VOC emissions by about 9,200 tons, and methane by about 4,859 tons. The cost-per-ton to reduce HAP emissions is estimated at about $11,000 per ton. All figures are in 2008 dollars.

3.3 References

Oil and Gas Journal. “Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow.” November 1, 2010.

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4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The proposed Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. While we expect that these avoided emissions will result in improvements in air quality and reduce health effects associated with exposure to HAPs, ozone, and fine particulate matter ($PM_{2.5}$), we have determined that quantification of those health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no health benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. For the proposed NSPS, the HAP and climate benefits can be considered "co-benefits", and for the proposed NESHAP amendments, the ozone and $PM_{2.5}$ health benefits and climate benefits can be considered "co-benefits". These co-benefits occur because the control technologies used to reduce VOC emissions also reduce emissions of HAPs and methane.

The proposed NSPS is anticipated to prevent 37,000 tons of HAPs, 540,000 tons of VOCs, and 3.4 million tons of methane from new sources, while the proposed NESHAP amendments is anticipated reduce 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane from existing sources. The specific control technologies for the proposed NSPS is also anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 2,800 tons of CO, 7.6 tons of PM, and 1,000 tons of THC, and proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC. Both rules would have additional emission changes associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons for the proposed NSPS and 93 thousand metric tons for the proposed NESHAP. As described in the subsequent sections, these pollutants are associated with substantial health effects, welfare effects, and climate effects. With the data available, we are not able to provide a credible benefits estimates for any of these pollutants for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information, and the highly localized nature of air quality responses associated with HAP and VOC reductions. In addition, we do not yet have interagency agreed upon valuation estimates for greenhouse gases other than CO_2 that could be used to value the climate co-benefits associated with avoiding methane emissions. Instead, we provide a qualitative assessment of the benefits and co-benefits as well as a break-even analysis in Chapter 6 of this RIA. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis, we feel the results are illustrative, particularly in the context of previous benefit per ton estimates.

4.2 Direct Emission Reductions from the Oil and Natural Gas Rules

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for VOCs and HAPs including wells, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

In implementing these rules, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the NAAQS. Due to the high degree of variability in the responsiveness of ozone and $PM_{2.5}$ formation to VOC emission reductions, we are unable to determine how these rules might affect attainment status without air quality modeling data.[8] Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However,

[8] The responsiveness of ozone and $PM_{2.5}$ formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this RIA.

some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

By contrast, the emission reductions for this rule are from a specific class of well-characterized sources. In general, EPA is more confident in the magnitude and location of the emission reductions for these rules. It is important to note that emission reductions anticipated from these rules do not result in emission increases elsewhere (other than potential energy disbenefits). Emission reductions achieved under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining the NAAQS. EPA remains forward looking towards the next iteration of the 5-year review cycle for the NAAQS, and as a result does not issue updated RIAs for existing NAAQS that retroactively update the baseline for NAAQS implementation. For more information on the relationship between the NAAQS and rules such as analyzed here, please see Section 1.2.4 of the SO_2 NAAQS RIA (U.S. EPA, 2010d). Table 4-1 shows the direct emission reductions anticipated for these rules by option. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. Reducing VOC emissions would reduce precursors to secondary formation of $PM_{2.5}$ and ozone, which reduces exposure to these pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane are primarily at a global scale, but methane is also a precursor to ozone, a short-lived climate forcer that exhibits spatial and temporal variability.

Table 4-1 Direct Emission Reductions Associated with Options for the Oil and Natural Gas NSPS and NESHAP amendments in 2015 (short tons per year)

Pollutant	NESHAP Amendments	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3
HAPs	1,381	17,442	36,645	37,142
VOCs	9,243	270,695	535,201	548,449
Methane	4,859	1,574,498	3,386,154	3,442,283

4.3 Secondary Impacts Analysis for Oil and Gas Rules

The control techniques to avert leaks and vents of VOCs and HAPs are associated with several types of secondary impacts, which may partially offset the direct benefits of this rule. In this RIA, we refer to the secondary impacts associated with the specific control techniques as "producer-side" impacts.[9] For example, by combusting VOCs and HAPs, combustion increases emissions of carbon monoxide, NOx, particulate matter and other pollutants. In addition to "producer-side" impacts, these control techniques would also allow additional natural gas recovery, which would contribute to additional combustion of the recovered natural gas and ultimately a shift in the national fuel mix. We refer to the secondary impacts associated with the combustion of the recovered natural gas as "consumer-side" secondary impacts. We provide a conceptual diagram of both categories of secondary impacts in Figure 4-1.

[9] In previous RIAs, we have also referred to these impacts as energy disbenefits.

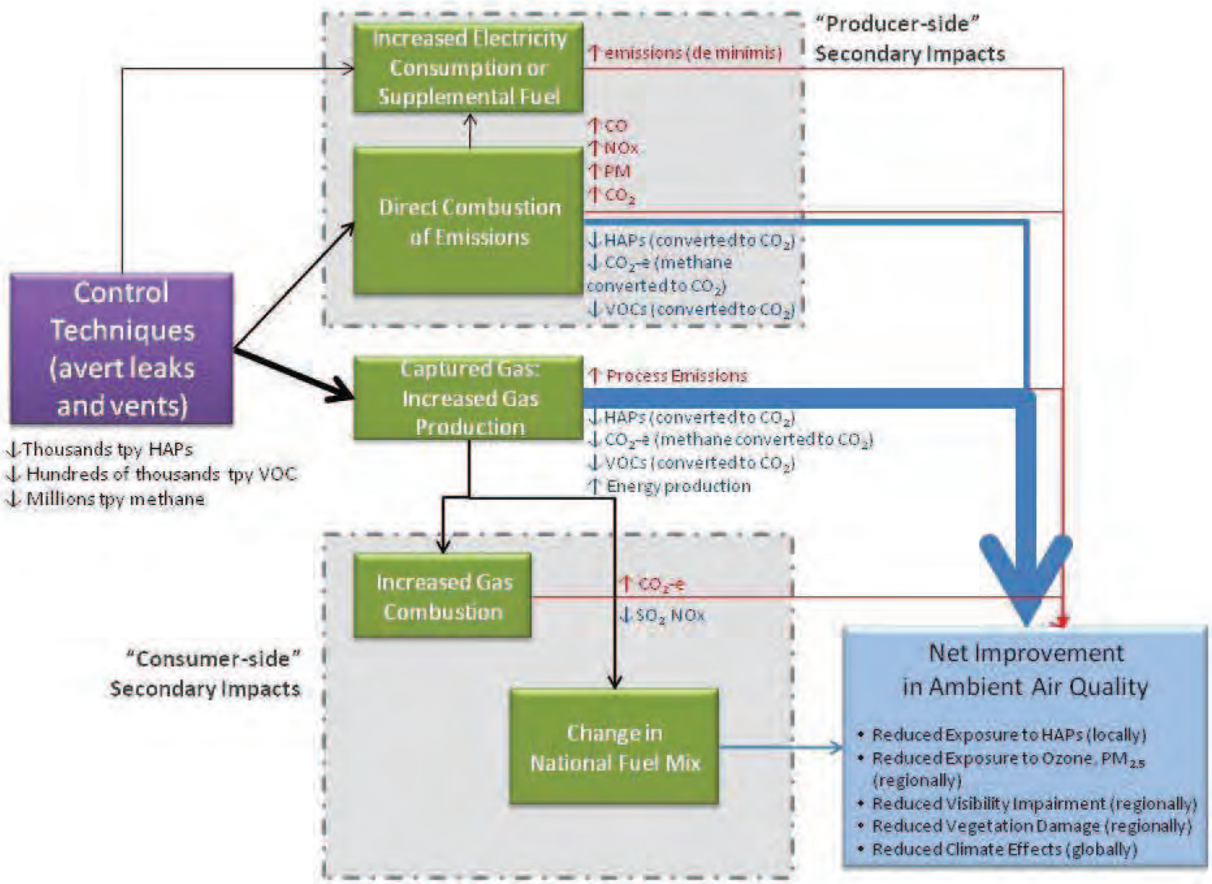

Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments

Table 4-2 shows the estimated secondary impacts for the selected option for the "producer-side" impacts. Relative to the direct emission reductions anticipated from these rules, the magnitude of these secondary air pollutant impacts is small. Because the geographic distribution of these emissions from the oil and gas sector is not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009), we are unable to monetize the $PM_{2.5}$ disbenefits associated with the producer-side secondary impacts. In addition, it is not appropriate to monetize the disbenefits associated with the increased CO_2 emissions without monetizing the averted methane emissions because the overall global warming potential (GWP) is actually lower. Through the combustion process, methane emissions are converted to CO_2 emissions, which have 21 times less global warming potential compared to methane (IPCC, 2007).[10]

Table 4-2 Secondary Air Pollutant Impacts Associated with Control Techniques by Emissions Category ("Producer-Side") (tons per year)

Emissions Category	CO_2	NOx	PM	CO	THC
Completions of New Wells (NSPS)	587,991	302	5	1,644	622
Recompletions of Existing Wells (NSPS)	398,341	205	-	1,114	422
Pneumatic Controllers (NSPS)	22	1.0	2.6	-	-
Storage Vessels (NSPS)	856	0.5	0.0	2.4	0.9
Total NSPS	**987,210**	**508**	**7.6**	**2,760**	**1,045**
Total NESHAP (Storage Vessels)	**5,543**	**2.9**	**0.1**	**16**	**6**

For the "consumer-side" impacts associated with the NSPS, we modeled the impact of the regulatory options on the national fuel mix and associated CO_2-equivalent emissions (Table 4-3).[11] We provide the modeled results of the "consumer-side" CO_2-equivalent emissions in Table 7-12Error! Reference source not found.

The modeled results indicate that through a slight shift in the national fuel mix, the CO_2-equivalent emissions across the energy sector would increase by 1.6 million metric tons for the proposed NSPS option in 2015. This is in addition to the other secondary impacts and directly avoided emissions, for a total 62 million metric tons of CO_2-equivalent emissions averted as shown in Table 4-4. Due to time limitations under the court-ordered schedule, we did not estimate the other emissions (e.g., NOx, PM, SOx) associated with the additional national gas consumption or the change in the national fuel mix.

[10] This issue is discussed in more detail in Section 4.7 of this RIA.
[11] A full discussion of the energy modeling is available in Section 7 of this RIA.

Table 4-3 Modeled Changes in Energy-related CO_2-equivalent Emissions by Fuel Type for the Proposed Oil and Gas NSPS in 2015 (million metric tons) ("Consumer-Side")[1]

Fuel Type	NSPS Option 1 (million metric tons change in CO_2-e)	NSPS Option 2 (million metric tons change in CO_2-e) (Proposed)	NSPS Option 3 (million metric tons change in CO_2-e)
Petroleum	-0.51	-0.14	-0.18
Natural Gas	2.63	1.35	1.03
Coal	-3.04	0.36	0.42
Other	0.00	0.00	0.00
Total modeled Change in CO_2-e Emissions	**-0.92**	**1.57**	**1.27**

[1] These estimates reflect the modeled change in CO_2-e emissions using NEMS shown in Table 7-12. Totals may not sum due to independent rounding.

Table 4-4 Total Change in CO_2-equivalent Emissions including Secondary Impacts for the Proposed Oil and Gas NSPS in 2015 (million metric tons)

Emissions Source	**NSPS Option 1**	**NSPS Option 2 (Proposed)**	**NSPS Option 3**	**NESHAP Amendments**
Averted CO_2-e Emissions from New Sources[1]	-30.00	-64.51	-65.58	-0.09
Additional CO_2-e Emissions from Combustion and Supplemental Energy (Producer-side)[2]	0.90	0.90	0.90	0.01
Total Modeled Change in Energy-related CO_2-e Emissions (Consumer-side)[3]	-0.92	1.57	1.27	--
Total Change in CO_2-e Emissions after Adjustment for Secondary Impacts	**-30.02**	**-62.04**	**-63.41**	**-0.09**

[1] This estimate reflects the GWP of the avoided methane emissions from new sources shown in Table 4-1 and has been converted from short tons to metric tons.

[2] This estimate represents the secondary producer-side impacts associated with additional CO_2 emissions from combustion and from additional electricity requirements shown in Table 4-2 and has been converted from short tons to metric tons. We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

[3]This estimate reflects the modeled change in the energy–related consumer-side impacts shown in Table 4-3.

Totals may not sum due to independent rounding.

Based on these analyses, the net impact of both the direct and secondary impacts of these rules would be an improvement in ambient air quality, which would reduce exposure to various harmful pollutants, improve visibility impairment, reduce vegetation damage, and reduce potency of greenhouse gas emissions. Table 4-5 provides a summary of the direct and secondary emissions changes for each option.

Table 4-5 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed option as a surrogate for the impacts of the other options. Totals may not sum due to independent rounding.

4.4 Hazardous Air Pollutant (HAP) Benefits

Even though emissions of air toxics from all sources in the U.S. declined by approximately 42 percent since 1990, the 2005 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2011d).[12] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, U.S. EPA conducts the NATA.[13] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

[12] The 2005 NATA is available on the Internet at http://www.epa.gov/ttn/atw/nata2005/.

[13] The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2005 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2011) 2005 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2005/

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient and exposure concentrations of air toxics across the United States

3) Estimating population exposures across the United States

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2005 NATA, EPA estimates that about 5 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 50 in a million. Nationwide, the key pollutants that contribute most to the overall cancer risks are formaldehyde and benzene.[14,15] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile and background sources contribute almost equal portions of the remaining cancer risk.

Noncancer health effects can result from chronic,[16] subchronic,[17] or acute[18] inhalation exposures to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2005 NATA, about three-fourths of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2005 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

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[14] Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2005 NATA risk estimates can be found at http://www.epa.gov/ttn/atw/nata1999/riskbg.html#Z2.

[15] Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at http://www.epa.gov/ttn/atw/nata/roy/page16.html.

[16] Chronic exposure is defined in the glossary of the Integrated Risk Information (IRIS) database (http://www.epa.gov/iris) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10% of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[17] Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10% of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

[18] Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

Figure 4-2 and Figure 4-3 depict the estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions are more than double acrolein emissions on a national basis, according to EPA's 2005 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, suggesting that acrolein could be potentially more toxic than acetaldehyde.[19] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

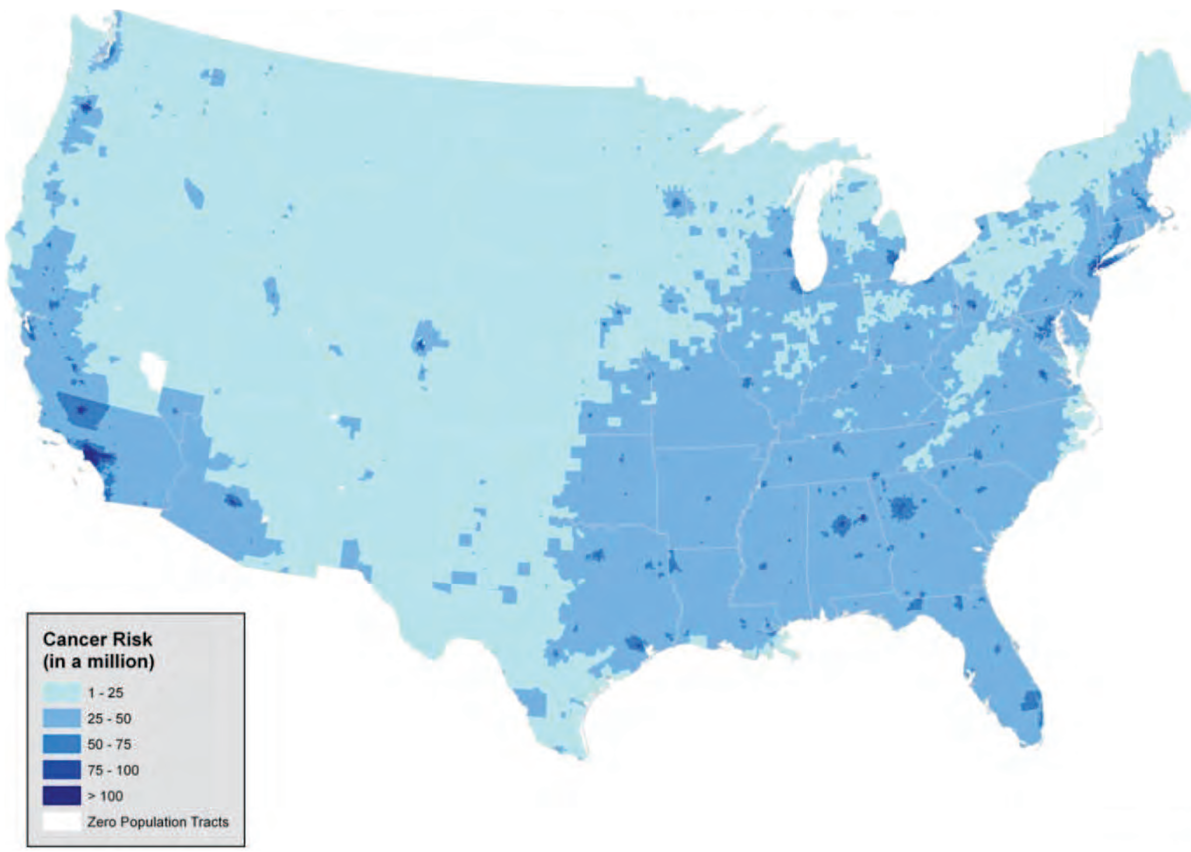

Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA)

[19] Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at http://cfpub.epa.gov/ncea/iris/compare.cfm.

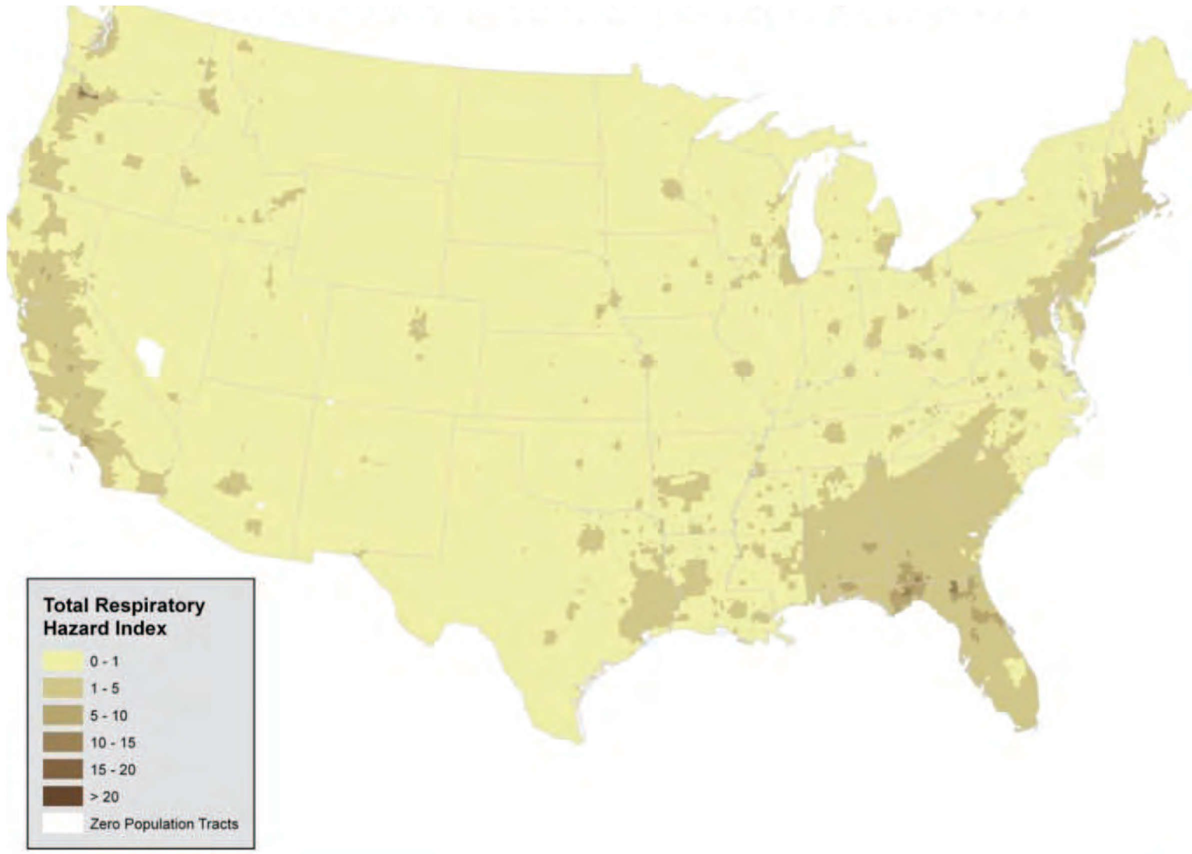

Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA)

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of these rules.. In a few previous analyses of the benefits of reductions in HAPs, EPA has quantified the benefits of potential reductions in the incidences of cancer and non-cancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) developed through risk assessment procedures.[20] These URFs are designed to be conservative, and as such, are more likely to represent the high end of the distribution of risk rather than a best or most likely estimate of risk. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the

[20]The unit risk factor is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one $\mu g/m^3$ of a pollutant.

benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAPs.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAPs. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al., 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAPs, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAPs in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAPs anticipated to be reduced by these rules and we summarize the results of the residual risk assessment for the Risk and Technology Review (RTR). EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAPs are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAPs make up a large percentage the total

HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011a). In the subsequent sections, we describe the health effects associated with the main HAPs of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. These rules combined are anticipated to avoid or reduce 58,000 tons of HAPs per year. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

EPA conducted a residual risk assessment for the NESHAP rule (U.S. EPA, 2011c). The results for oil and gas production indicate that maximum lifetime individual cancer risks could be 30 in-a-million for existing sources before and after controls with a cancer incidence of 0.02 before and after controls. For existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with a cancer incidence that decreases from 0.001 before controls to 0.0002 after controls. Benzene is the primary cancer risk driver. The results also indicate that significant noncancer impacts from existing sources are unlikely, especially after controls. EPA did not conduct a risk assessment for new sources affected by the NSPS. However, it is important to note that the magnitude of the HAP emissions avoided by new sources with the NSPS are more than an order of magnitude higher than the HAP emissions reduced from existing sources with the NESHAP.

4.4.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[21,22,23] EPA states in its IRIS database that data indicate a causal

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[21] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[22] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

[23] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[24,25] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[26,27] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[28,29] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[30,31,32,33] EPA's IRIS program has not yet evaluated these new data.

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[24] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[25] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[26] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[27] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[28] Rothman, N., G.L. Li, M. Dosemeci, W.E. Bechtold, G.E. Marti, Y.Z. Wang, M. Linet, L.Q. Xi, W. Lu, M.T. Smith, N. Titenko-Holland, L.P. Zhang, W. Blot, S.N. Yin, and R.B. Hayes (1996) Hematotoxicity among Chinese workers heavily exposed to benzene. Am. J. Ind. Med. 29: 236-246.

[29] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene (Noncancer Effects). Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[30] Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003). HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.

[31] Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, et al. (2002). Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42: 275-285.

[32] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., et al. (2004). Hematotoxically in Workers Exposed to Low Levels of Benzene. Science 306: 1774-1776.

[33] Turtletaub, K.W. and Mani, C. (2003). Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No.113.

4.4.2 Toluene[34]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.4.3 Carbonyl sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate

[34] All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene (CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <http://www.epa.gov/iris/subst/0118.htm>.

the eyes and skin in humans.[35] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.[36]

4.4.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral cavities in male and female rats exposed to ethylbenzene via the oral route.[37,38] The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).[39,40] The NTP (1999) carried out a chronic inhalation

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[35] Hazardous Substances Data Bank (HSDB), online database). US National Library of Medicine, Toxicology Data Network, available online at http://toxnet.nlm.nih.gov/. Carbonyl health effects summary available at http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1.

[36] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0617.htm.

[37] Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. Am J Ind Med 7:415-446.

[38] Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. Annals NY Acad Sci 837:15-52.

[39] International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.4.5 Mixed xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.[41] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[42] Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.[43] EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.4.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central

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[40] National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

[41] U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0270.htm.

[42] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

[43] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.[44]

4.4.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by these rules, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.[45]

4.5 VOCs

4.5.1 VOCs as a PM2.5 precursor

This rulemaking would reduce emissions of VOCs, which are a precursor to $PM_{2.5.}$ Most VOCs emitted are oxidized to carbon dioxide (CO_2) rather than to PM, but a portion of VOC emission contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce $PM_{2.5}$ formation, human exposure to $PM_{2.5}$, and the incidence of $PM_{2.5}$-related health effects. However, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory it is unlikely this sector has a large contribution to

[44] U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

[45] U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 μg/m^3.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of $PM_{2.5}$ formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient $PM_{2.5}$ levels without air quality modeling.

4.5.2 $PM_{2.5}$ health effects and valuation

Reducing VOC emissions would reduce $PM_{2.5}$ formation, human exposure, and the incidence of $PM_{2.5}$-related health effects. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA (2010c)). These health effects include premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, hospital admissions, and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and ER visits, work loss days, restricted activity days, and respiratory symptoms. Although EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

EPA assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, EPA estimates PM-related mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). Using the estimates in Fann, Fulcher, and Hubbell (2009), the monetized benefit-per-ton of reducing VOC emissions in nine urban areas of the U.S. ranges from $560 in Seattle, WA to $5,700 in San Joaquin, CA, with a national average of $2,400. These estimates assume a 50 percent reduction in VOCs, the Laden et al. (2006) mortality function (based on the Harvard Six City Study, a large cohort epidemiology study in the Eastern U.S.), an analysis year of 2015, and a 3 percent discount rate.

Based on the methodology from Fann, Fulcher, and Hubbell (2009), we converted their estimates to 2008$ and applied EPA's current VSL estimate.[46] After these adjustments, the range of values increases to $680 to $7,000 per ton of VOC reduced for Laden et al. (2006). Using alternate assumptions regarding the relationship between $PM_{2.5}$ exposure and premature mortality from empirical studies and supplied by experts (Pope et al., 2002; Laden et al., 2006; Roman et al., 2008), additional benefit-per-ton estimates are available from this dataset, as shown in Table 4-6. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) because they are both well-designed and peer reviewed studies, and EPA provides the benefit estimates derived from expert opinions in Roman et al. (2008) as a characterization of uncertainty. In addition to the range of benefits based on epidemiology studies, this study also provided a range of benefits associated with reducing emissions in eight specific urban areas. The range of VOC benefits that reflects the adjustments as well as the range of epidemiology studies and the range of the urban areas is $280 to $7,000 per ton of VOC reduced.

While these ranges of benefit-per-ton estimates provide useful context for the break-even analysis, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship

[46] For more information regarding EPA's current VSL estimate, please see Section 5.4.4.1 of the RIA for the proposed Federal Transport Rule (U.S. EPA, 2010a). EPA continues to work to update its guidance on valuing mortality risk reductions.

between VOC emissions and $PM_{2.5}$, these factors lead us to conclude that the available VOC benefit per ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

Table 4-6 Monetized Benefits-per-Ton Estimates for VOCs (2008$)

Area	Pope et al.	Laden et al.	Expert A	Expert B	Expert C	Expert D	Expert E	Expert F	Expert G	Expert H	Expert I	Expert J	Expert K	Expert L
Atlanta	$620	$1,500	$1,600	$1,200	$1,200	$860	$2,000	$1,100	$730	$920	$1,200	$980	$250	$940
Chicago	$1,500	$3,800	$4,000	$3,100	$3,000	$2,200	$4,900	$2,800	$1,800	$2,300	$3,000	$2,500	$600	$2,400
Dallas	$300	$740	$780	$610	$590	$420	$960	$540	$360	$450	$590	$480	$120	$460
Denver	$720	$1,800	$1,800	$1,400	$1,400	$1,000	$2,300	$1,300	$850	$1,100	$1,400	$1,100	$280	$850
NYC/ Philadelphia	$2,100	$5,200	$5,500	$4,300	$4,200	$3,000	$6,900	$3,900	$2,500	$3,200	$4,200	$3,400	$830	$3,100
Phoenix	$1,000	$2,500	$2,600	$2,000	$2,000	$1,400	$3,300	$1,800	$1,200	$1,500	$2,000	$1,600	$400	$1,500
Salt Lake	$1,300	$3,100	$3,300	$2,600	$2,500	$1,800	$4,100	$2,300	$1,500	$1,900	$2,500	$2,100	$530	$2,000
San Joaquin	$2,900	$7,000	$7,400	$5,800	$5,600	$4,000	$9,100	$5,200	$3,400	$4,300	$5,600	$4,600	$1,300	$4,400
Seattle	$280	$680	$720	$530	$550	$390	$890	$500	$330	$420	$550	$450	$110	$330
National average	**$1,200**	**$3,000**	**$3,200**	**$2,400**	**$2,400**	**$1,700**	**$3,900**	**$2,200**	**$1,400**	**$1,800**	**$2,400**	**$1,900**	**$490**	**$1,800**

* These estimates assume a 50 percent reduction in VOC emissions, an analysis year of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been updated from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and EPA's current VSL estimate. Using a discount rate of 7 percent, the benefit-per-ton estimates would be approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase the benefit-per-ton estimates by approximately 4 percent to 52 percent. Assuming a 25 percent reduction in VOC emissions would decrease the benefit-per-ton estimates by 5 percent to 52 percent. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) and provides the benefits estimates derived from the expert functions from Roman et al. (2008) as a characterization of uncertainty.

4.5.3 Organic PM welfare effects

According to the residual risk assessment for this sector (U.S. EPA, 2011a), persistent and bioaccumulative HAP reported as emissions from oil and gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes the polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The recently completed Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database on contaminant transport and PM depositional effects on sensitive ecosystems in the Western U.S. (Landers et al., 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and contaminants accumulate in proximity to individual agriculture and industry sources, which is counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

4.5.4 Visibility Effects

Reducing secondary formation of $PM_{2.5}$ would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2010c; U.S. EPA, 2011a) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

4.6 VOCs as an Ozone Precursor

This rulemaking would reduce emissions of VOCs, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NOx), combine in the presence of sunlight. In urban areas, compounds representing all classes of VOCs and CO are important compounds for ozone formation, but biogenic VOCs emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2006a). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a benefit-per-ton estimate. Third, the impact of reducing VOC emissions is spatially heterogeneous depending on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOCs. Rural areas and downwind suburban areas are often NOx-limited, which means that ozone concentrations are most effectively reduced by lowering NOx emissions, rather than lowering emissions of VOCs. Between these areas, ozone is relatively insensitive to marginal changes in both NOx and VOC.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of ozone formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient ozone concentrations without air quality modeling.

4.6.1 Ozone health effects and valuation

Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Epidemiological researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2006c). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. Although EPA has not quantified these effects in benefits analyses previously, the scientific literature is suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOCs from industrial boilers resulted in $3.6 to $15 million of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).[47] This implies a benefit-per-ton for ozone reductions of $240 to $1,000 per ton of VOCs reduced. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those

[47] While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NOx emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

estimates to provide useful estimates of the monetized benefits of these rules, even as a bounding exercise.

4.6.2 Ozone vegetation effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2006a). Sensitivity to ozone is highly variable across species, with over 65 plan species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

4.6.3 Ozone climate effects

Ozone is a well-known short-lived climate forcing (SLCF) greenhouse gas (GHG) (U.S. EPA, 2006a). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). A recent United Nations Environment Programme (UNEP) study reports that the threefold increase in ground level ozone during the past 100 years makes it the third most important contributor to human contributed climate change behind CO_2 and methane. This discernable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles. This study provides the most comprehensive analysis to date of the benefits of measures to reduce SLCF gases including methane, ozone, and black carbon assessing the health, climate, and agricultural benefits of a suite of mitigation technologies. The report concludes that the climate is changing now, and these changes have the potential to "trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss" (UNEP 2011). While reducing long-lived GHGs such as CO_2 is necessary to protect against long-term climate change, reducing SLCF gases including ozone is beneficial and will slow the rate of climate change within the first half of this century (UNEP 2011).

4.7 Methane (CH_4)

4.7.1 Methane as an ozone precursor

This rulemaking would reduce emissions of methane, a long-lived GHG and also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2006a). Unlike NOx and VOCs, which affect ozone concentrations regionally and at hourly time scales, methane emission reductions require several decades for the ozone response to be fully realized, given methane's relatively long atmospheric lifetime (HTAP, 2010). Studies have shown that reducing methane can reduce global background ozone concentrations over several decades, which would benefit both urban and rural areas (West et al., 2006). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. The health, welfare, and climate effects associated with ozone are described in the preceding sections. Without air quality modeling, we are unable to estimate the effect that reducing methane will have on ozone concentrations at particular locations.

4.7.2 Methane climate effects and valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that once emitted into the atmosphere absorbs terrestrial infrared radiation which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (2007), in 2004 the cumulative changes in methane concentrations since preindustrial times contributed about 14 percent to global warming due to anthropogenic GHG sources, making methane the second leading long-lived climate forcer after CO_2 globally. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

Processes in the oil and gas category emit significant amounts of methane. The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 (MMtCO_2-e). In 2009, total methane emissions from the oil and gas industry represented nearly 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2-equivalent (CO_2-e) emissions in the U.S., with natural gas systems being the single largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2011b, Table ES-2). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 MMtCO_2-e. The total methane emissions from Petroleum and Natural Gas Systems based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus Shale, is approximately 330 MMtCO_2-e.

This rulemaking proposes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The regulatory alternative proposed for this rule is expected to reduce methane emissions annually by about 3.4 million short tons or approximately 65 million metric tons CO_2-e. These reductions represent about 26 percent of the GHG emissions for this sector reported in the 1990-2009 U.S. GHG Inventory (251.55 MMTCO_2-e). This annual CO_2-e reduction becomes about 62 million metric tons when the secondary impacts associated with increased combustion and supplemental energy use on the producer side and CO_2-e emissions from changes in consumption patterns previously discussed are considered. However, it is important to note the emissions reductions are based upon predicted activities in 2015; EPA did not forecast sector-level emissions to 2015 for this rulemaking. The climate co-benefit from these reductions are equivalent of taking approximately 11 million typical passenger cars off the road or eliminating electricity use from about 7 million typical homes each year.[48]

EPA estimates the social benefits of regulatory actions that have a small or "marginal" impact on cumulative global CO_2 emissions using the "social cost of carbon" (SCC). The SCC is an estimate of the net present value of the flow of monetized damages from a one metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by one ton). The SCC includes (but is not limited to) climate damages due to changes in net agricultural productivity, human health, property damages from flood risk, and ecosystem services due to climate change. The SCC estimates currently used by the Agency were developed through an interagency process that included EPA and other executive branch entities, and concluded in February 2010. The Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 for the final joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards provides a complete discussion of the methods used to develop the SCC estimates (Interagency Working Group on Social Cost of Carbon, 2010).

To estimate global social benefits of reduced CO_2 emissions, the interagency group selected four SCC values for use in regulatory analyses: \$6, \$25, \$40, and \$76 per metric ton of CO_2 emissions in 2015, in 2008 dollars. The first three values are based on the average SCC estimated using three integrated assessment models (IAMs), at discount rates of 5.0, 3.0, and 2.5 percent, respectively. When valuing the impacts of climate change, IAMs couple economic and climate systems into a single model to capture important interactions between the components. SCCs estimated using different discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the distribution of SCC estimates from all three models at a 3.0 percent discount rate. It is included to represent higher-than-expected damages from temperature change further out in the tails of the SCC distribution.

[48] US Environmental Protection Agency. Greenhouse Gas Equivalency Calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html accessed 07/19/11.

Although there are relatively few region- or country-specific estimates of SCC in the literature, the results from one model suggest the ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7-10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent. On the basis of this evidence, values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. It is recognized that these values are approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time. (Interagency Working Group on Social Cost of Carbon, 2010).

The interagency group noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. The limited amount of research linking climate impacts to economic damages makes estimating damages from climate change even more difficult. The interagency group hopes that over time researchers and modelers will work to fill these gaps and that the SCC estimates used for regulatory analysis by the Federal government will continue to evolve with improvements in modeling. Additional details on these limitations are discussed in the SCC TSD.

A significant limitation of the aforementioned interagency process particularly relevant to this rulemaking is that the social costs of non-CO_2 GHG emissions were not estimated. Specifically, the interagency group did not directly estimate the social cost of non-CO_2 GHGs using the three models. Moreover, the group determined that it would not transform the CO_2 estimates into estimates for non-CO_2 GHGs using global warming potentials (GWPs), which measure the ability of different gases to trap heat in the atmosphere (i.e., radiative forcing per unit of mass) over a particular timeframe relative to CO_2. One potential method for approximating the value of marginal non-CO_2 GHG emission reductions is to convert the reductions to CO_2-equivalents which may then be valued using the SCC. Conversion to CO_2-e is typically done using the GWPs for the non-CO_2 gas. The GWP is an aggregate measure that approximates the additional energy trapped in the atmosphere over a given timeframe from a perturbation of a non-CO_2 gas relative to CO_2. The time horizon most commonly used is 100 years. One potential problem with utilizing temporally aggregated statistics, such as the GWPs, is that the additional radiative forcing from the GHG perturbation is not constant over time and any differences in temporal dynamics between gases will be lost. This is a potentially confounding issue given that the social cost of GHGs is based on a discounted stream of damages that are non-linear in temperature. For example, methane has an expected adjusted atmospheric lifetime of about 12 years and associated GWP of 21 (IPCC Second Assessment Report (SAR) 100-year GWP estimate). Gases with a shorter lifetime, such as methane, have impacts that occur primarily in the near term and thus are not discounted as heavily as those caused by the longer-lived gases, while the GWP treats additional forcing the same independent of when it occurs in time. Furthermore, the baseline temperature change is lower in the near term and therefore the additional warming from relatively short lived gases will have a lower marginal impact relative to longer lived gases that have an impact further out in the future when baseline warming is higher. The GWP also relies on an arbitrary time horizon and constant concentration scenario. Both of which are inconsistent with the assumptions used by the SCC interagency workgroup. Finally, impacts other than temperature change also vary across gases in ways that are not captured by GWP. For instance, CO_2 emissions, unlike methane will result in CO_2 passive fertilization to plants.

In light of these limitations, and the significant contributions of non-CO_2 emissions to climate change, further analysis is required to link non-CO_2 emissions to economic impacts and to develop social cost estimates for methane specifically. Such work would feed into efforts to develop a monetized value of reductions in methane greenhouse gas emissions in assessing the co-benefits of this rulemaking. As part of ongoing work to further improve the SCC estimates, the interagency group hopes to develop methods to value greenhouse gases other than CO_2, such as methane, by the time SCC estimates for CO_2 emissions are revised.

The EPA recognizes that the methane reductions proposed in this rule will provide significant economic climate co-benefits to society. However, EPA finds itself in the position of having no interagency accepted monetary values to place on these co-benefits. The 'GWP approach' of converting methane to CO_2-e using the GWP of methane, as previously described, is one approximation method for estimating the monetized value of the methane reductions anticipated from this rule. This calculation uses the GWP of the non-CO_2 gas to estimate CO_2 equivalents and then multiplies these CO_2 equivalent emission reductions by the SCC to generate monetized estimates of the co-benefits. If one makes these calculations for the proposed Option 2 (including expected methane emission reductions from the NESHAP amendments and NSPS and considers secondary impacts) of the oil and gas rule, the 2015 co-benefits vary by discount rate and range from about $373 million to over $4.7 billion; the SCC at the 3 percent discount rate ($25 per metric ton) results in an estimate of $1.6 billion in 2015. These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $480 at the 3 percent discount rate

As previously stated, these co-benefit estimates are not the same as would be derived using a directly computed social cost of methane (using the integrated assessment models employed to develop the SCC estimates) for a variety of reasons including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases. Methane is a precursor to ozone and ozone is a short-lived climate forcer as previously discussed. This use of the SAR GWP to approximate benefits may underestimate the direct radiative forcing benefits of reduced ozone levels, and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent NCEE working paper suggests that this quick 'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases (Marten and Newbold, 2011). This conclusion is reached using the 100 year GWP for methane of 25 as put forth in the IPCC Fourth Assessment Report as opposed to the lower value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the IPCC Fourth Assessment Report suggested a GWP of 25, EPA has used GWP of 21 consistent with the IPCC SAR to estimate the methane climate co-benefits for this oil and gas proposal. The use of the SAR GWP values allows comparability of data collected in this proposed rule to the national GHG inventory that EPA compiles annually to meet U.S. commitments to the United Nations Framework Convention on Climate Change (UNFCCC). To comply with international reporting standards under the UNFCCC, official emission estimates are to be reported by the U.S. and other countries using SAR GWP values. The UNFCCC reporting guidelines for national inventories were updated in 2002 but continue to require the use of GWPs from the SAR. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available. The SAR GWP value for methane is also currently used to establish GHG reporting requirements as mandated by the GHG Reporting Rule (2010e) and is used by the EPA to determine Title V and Prevention of Significant Deterioration GHG permitting requirements as modified by the GHG Tailoring Rule (2010f).

EPA also undertook a literature search for estimates of the marginal social cost of methane. A range of marginal social cost of methane benefit estimates are available in published literature (Fankhauser (1994), Kandlikar (1995), Hammitt et al. (1996), Tol et al. (2003), Tol, et al. (2006), Hope (2005) and Hope and Newberry (2006). Most of these estimates are based upon modeling assumptions that are dated and inconsistent with the current SCC estimates. Some of these studies focused on marginal methane reductions in the 1990s and early 2000s and report estimates for only the single year of interest specific to the study. The assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the IAMs. Without additional analysis, the methane climate benefit estimates available in the current literature are not acceptable to use to value the methane reductions proposed in this rulemaking.

Due to the uncertainties involved with 'GWP approach' estimates presented and estimates available in the literature, EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the 'GWP approach' climate co-benefit estimates as an interim method to produce lower-bound estimates until the interagency group develops values for non-CO_2 GHGs. EPA requests comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate co-benefits of methane reductions. In particular, EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined in the preamble for the rule. These comments will be considered in developing the final rule for this rulemaking.

4.8 References

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5 STATUTORY AND EXECUTIVE ORDER REVIEWS

5.1 Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 5-1 shows the results of the cost and benefits analysis for these proposed rules.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS and NESHAP Amendments in 2015 (millions of 2008$)[1]

	Proposed NSPS	Proposed NESHAP Amendments	Proposed NSPS and NESHAP Amendments Combined
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$45 million	$16 million	-$29 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	37,000 tons of HAPs	1,400 tons of HAPs	38,000 tons of HAPs
	540,000 tons of VOCs	9,200 tons of VOCs	540,000 tons of VOCs
	3.4 million tons of methane	4,900 tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

5.2 Paperwork Reduction Act

The information collection requirements in this proposed action have been submitted for approval to OMB under the PRA, 44 U.S.C. 3501, et seq. The ICR document prepared by the EPA has been assigned EPA ICR Numbers 1716.07 (40 CFR part 60, subpart OOOO), 1788.10 (40 CFR part 63, subpart HH), 1789.07 (40 CFR part 63, subpart HHH), and 1086.10 (40 CFR part 60, subparts KKK and subpart LLL).

The information to be collected for the proposed NSPS and the proposed NESHAP amendments are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

These proposed rules would require maintenance inspections of the control devices, but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

For sources subject to the proposed NSPS, the burden represents labor hours and costs associated from annual reporting and recordkeeping for each affected facility. The estimated burden is based on the annual expected number of affected operators for the first three years following the effective date of the standards. The burden is estimated to be 560,000 labor hours at a cost of around$18 million per year. This includes the labor and cost estimates previously estimated for sources subject to 40 CFR part 60, subpart KKK and subpart LLL (which is being incorporated into 40 CFR part 60, subpart OOOO). The average hours and cost per regulated entity, which is assumed to be on a per operator basis except for natural gas processing plants (which are estimated on a per facility basis) subject to the NSPS for oil and natural gas production and natural gas transmissions and distribution facilities would be 110 hours per response and $3,693 per response based on an average of 1,459 operators responding per year and 16 responses per year. The majority of responses are expected to be notifications of construction. One annual report is required that may include all affected facilities owned per each operator. Burden by for the proposed NSPS was based on EPA ICR Number 1716.07.

The estimated recordkeeping and reporting burden after the effective date of the proposed amendments is estimated for all affected major and area sources subject to the oil and natural gas production NESHAP (40 CFR 63, subpart HH) to be approximately 63,000 labor hours per year at a cost of $2.1 million per year. For the natural gas transmission and storage NESHAP, the recordkeeping and reporting burden is estimated to be 2,500 labor hours per year at a cost of $86,800 per year. This estimate includes the cost of reporting, including reading instructions, and information gathering. Recordkeeping cost estimates include reading instructions, planning activities, and conducting compliance monitoring. The average hours and cost per regulated entity subject to the oil and natural gas production NESHAP would be 72 hours per year and $2,500 per year based on an average of 846 facilities per year and three responses per facility. For the natural gas transmission and storage NESHAP, the average hours and cost per regulated entity would be 50 hours per year and $1,600 per year based on an average of 53 facilities per year and three responses per facility. Burden is defined at 5 CFR 1320.3(b). Burden for the oil and natural gas production NESHAP is estimated under EPA ICR Number 1788.10. Burden for the natural gas transmission and storage NESHAP is estimated under EPA ICR Number 1789.07.

5.3 Regulatory Flexibility Act

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) a small business whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

5.3.1 Proposed NSPS

After considering the economic impact of the Proposed NSPS on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities (SISNOSE). EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. Based upon the analysis in Section 7.4 in this RIA, EPA recognizes that a subset of small firms is likely to be significantly impacted by the proposed NSPS. However, the number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that the firm-level compliance cost estimates used in the small business impacts analysis are likely over-estimates of the compliance costs faced by firms under the Proposed NSPS; these estimates do not include the revenues that producers are expected receive from the additional natural gas recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from well completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated, if not fully offset. Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by the selection of highly cost-effective controls and specifying monitoring requirements that are the minimum to insure compliance.

5.3.2 Proposed NESHAP Amendments

After considering the economic impact of the Proposed NESHAP Amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Based upon the analysis in Section 7.4 in this RIA, we estimate that 62 of the 118 firms (53 percent) that own potentially affected facilities are small entities. EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent. Four of these 10 firms are likely to have impacts greater than 3 percent. While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211. Although this final rule will not impact a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

5.4 Unfunded Mandates Reform Act

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments nor does it impose obligations upon them.

5.5 Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this proposed rule.

5.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. The EPA has concluded that this proposed rule will not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

5.7 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This proposed rule is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is economically significant as defined in Executive Order 12866. However, EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. EPA’s risk assessments (included in the docket for this proposed rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

5.8 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211, (66 FR 28,355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines “significant energy actions” as “any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: 1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or 2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action."

The proposed rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The proposed NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001).

The proposed NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NSPS is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001). The basis for the determination is as follows.

We use the NEMS to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the U.S. DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

Proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the proposed NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the proposed NSPS.

The analysis of energy impacts for the proposed NSPS that includes the additional product recovery shows that domestic natural gas production is estimated to increase (20 billion cubic feet or 0.1 percent) and natural gas prices to decrease ($0.04/Mcf or 0.9 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. Domestic crude oil production is not estimated to change, while crude oil prices are estimated to decrease slightly ($0.02/barrel or less than 0.1 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. All prices are in 2008 dollars.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

5.9 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law No. 104-113 (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the requirements of the NTTAA apply to this action. We are proposing to revise 40 CFR part 63, subparts HH and HHH to allow ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (Part 10, Instruments and Apparatus) to be used in lieu of EPA Methods 3B, 6 and 16A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990. Also, we are proposing to revise 40 CFR part 63, subpart HHH, to allow ASTM D6420-99(2004), "Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry" to be used in lieu of EPA Method 18. For a detailed discussion of this VCS, and its appropriateness as a substitute for Method 18, see the final oil and natural gas production NESHAP (Area Sources) (72 FR 36, January 3, 2007).

As a result, the EPA is proposing ASTM D6420-99 for use in 40 CFR part 63, subpart HHH. The EPA also proposes to allow Method 18 as an option in addition to ASTM D6420-99(2004). This would allow the continued use of GC configurations other than GC/MS.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

5.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on Environmental Justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic, and economic groups within the populations living near the facilities where these source categories are located. The methods used to conduct demographic analyses for this rule are described in section VII.D of the preamble for this rule. The development of demographic analyses to inform the consideration of EJ issues in EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this proposed rulemaking as examples of how such analyses might be developed to inform such consideration, and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

For the demographic analyses, we focused on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examined the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source category-specific technical reports in the docket for both source categories covered in this proposal.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health.

Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. The EPA has determined that although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

6 COMPARISON OF BENEFITS AND COSTS

Because we are unable to estimate the monetary value of the emissions reductions from the proposed rule, we have chosen to rely upon a break-even analysis to estimate what the monetary value benefits would need to attain in order to equal the costs estimated to be imposed by the rule. A break-even analysis answers the question, “What would the benefits need to be for the benefits to exceed the costs.” While a break-even approach is not equivalent to a benefits analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the context of previously modeled benefits.

The total cost of the proposed NSPS in the analysis year of 2015 when the additional natural gas and condensate recovery is included in the analysis is estimated at -$45 million for domestic producers and consumers. EPA anticipates that this rule would prevent 540,000 tons of VOC, 3.4 million tons of methane, and 37,000 tons of HAPs in 2015 from new sources. In 2015, EPA estimates the costs for the NESHAP amendments floor option to be $16 million.[49] EPA anticipates that this rule would reduce 9,200 tons of VOC, 4,900 tons of methane, and 1,400 tons of HAPs in 2015 from existing sources. For the NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, and ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

For the proposed NSPS, the revenue from additional natural gas recovery already exceeds the costs, which renders a break-even analysis unnecessary. However, as discussed in Section 3.2.2., estimates of the annualized engineering costs that include revenues from natural gas product recovery depend heavily upon assumptions about the price of natural gas and hydrocarbon condensates in analysis year 2015. Therefore, we have also conducted a break-even analysis for the price of natural gas. For the NSPS, a break-even analysis suggests that the price

[49] See Section 3 of this RIA for more information regarding the cost estimates for the NESHAP.

of natural gas would need to be at least $3.77 per Mcf in 2015 for the revenue from product recovery to exceed the annualized costs. EIA forecasts that the price of natural gas would be $4.26 per Mcf in 2015. In addition to the revenue from product recovery, the NSPS would avert emissions of VOCs, HAPs, and methane, which all have value that could be incorporated into the break-even analysis. Figure 6-1 illustrates one method of analyzing the break-even point with alternate natural gas prices and VOC benefits. If, as an illustrative example, the price of natural gas was only $3.00 per Mcf, VOCs would need to be valued at $260 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

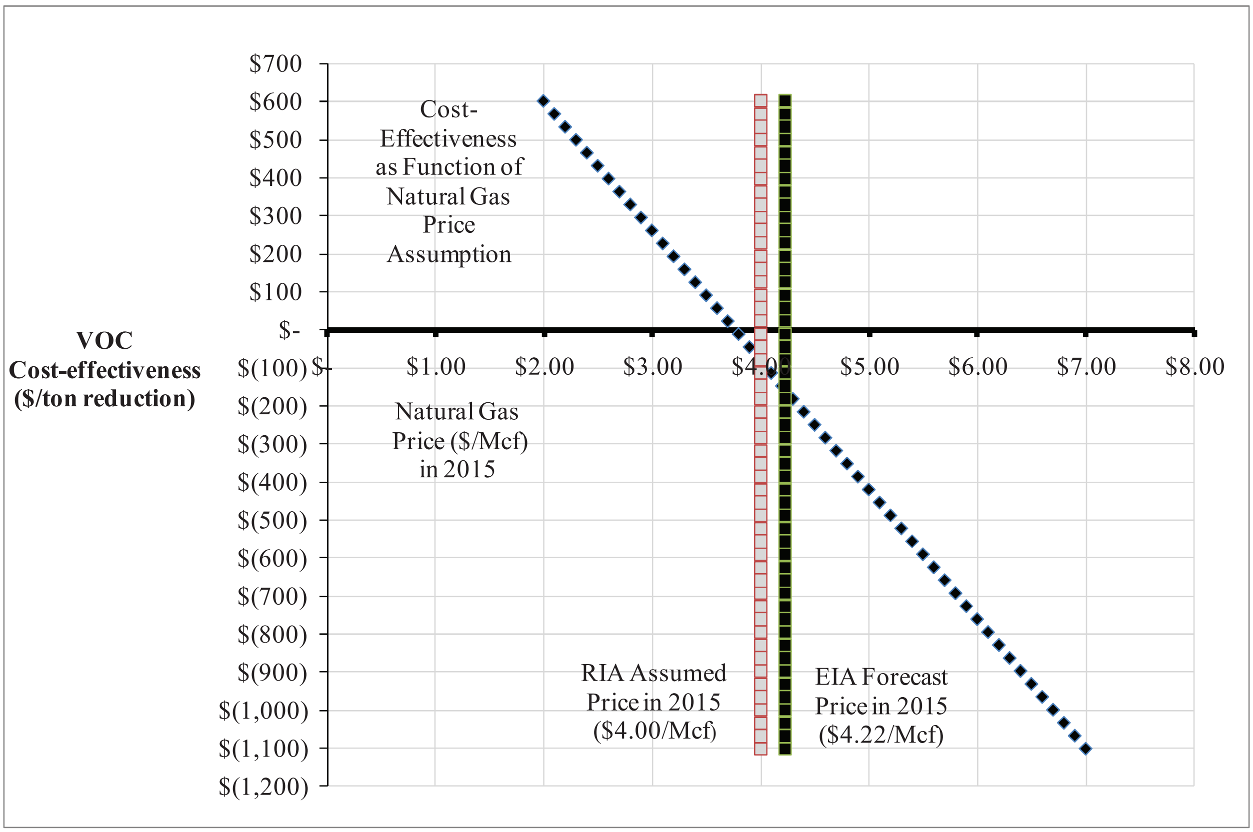

Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS

With the data available, we are not able to provide a credible benefit-per-ton estimate for any of the pollutant reductions for these rules to compare to the break-even estimates. Based on the methodology from Fann, Fulcher, and Hubbell (2009), average $PM_{2.5}$ health-related benefits of VOC emissions are valued at \$280 to \$7,000 per ton across a range of eight urban areas.[50] In addition, ozone benefits have been previously valued at \$240 to \$1,000 per ton of VOC reduced. Using the GWP approach, the climate co-benefits range from approximately \$110 to \$1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of \$760 at the 3 percent discount rate.

These break-even benefit-per-ton estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even estimate is actually lower than the estimates provided above because the other pollutants each have non-zero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOCs contribute to both ozone and $PM_{2.5}$ formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

As previously described, the revenue from additional natural gas recovery already exceeds the costs of the NSPS, but even if the price of natural gas was only \$3.00 per Mcf, it is likely that the VOC benefits would exceed the costs, As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the average modeled benefits, there is a reasonable chance that the benefits of these rules would exceed the costs, especially if we were able to monetize all of the benefits associated with ozone formation, visibility, HAPs, and methane.

Table 6-1 and Table 6-2 present the summary of the benefits, costs, and net benefits for the NSPS and NESHAP amendment options, respectively. Table 6-3 provides a summary of the direct and secondary emissions changes for each option.

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[50] See Section 4.5 of this RIA for more information regarding $PM_{2.5}$ benefits and Section 4.6 for more information regarding ozone benefits.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane	3.4 million tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP amendments in 2015 (millions of 2008\$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	\$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs 9,200 tons of VOCs[4] 4,900 tons of methane[4] Health effects of HAP exposure Health effects of $PM_{2.5}$ and ozone exposure[4] Visibility impairment[4] Vegetation effects[4] Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The cost estimates are assumed to be equivalent to the engineering cost estimates. The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

Table 6-3 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

7.1 Introduction

This section includes three sets of analyses for both the NSPS and NESHAP amendments:

- Energy System Impacts
- Employment Impacts
- Small Business Impacts Analysis

7.2 Energy System Impacts Analysis of Proposed NSPS

We use the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the U.S. energy system. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas. We evaluate whether and to what extent the increased production costs imposed by the NSPS might alter the mix of fuels consumed at a national level. With this information we estimate how the changed fuel mix affects national level CO_2-equivalent greenhouse gas emissions from energy sources. We additionally combine these estimates of changes in CO_2-equivalent greenhouse gas emissions from energy sources and emissions co-reductions of methane from the engineering analysis with NEMS analysis to estimate the net change in CO_2-equivalent greenhouse gas emissions from energy-related sources, but this analysis is reserved for the secondary environmental impacts analysis within Section 4.

A brief conceptual discussion about our energy system impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain at the producer level. For example, the analysis for the proposed NSPS shows that about 97 percent of the natural gas captured by emissions controls suggested by the rule is captured by performing RECs on new and existing wells that are completed after being hydraulically fractured. The assumed $4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers are paid based upon this metered production. Depending on the situation, the gas captured by RECs is sent through a temporary or permanent meter. Payments for the gas are typically made within 30 days.

To preview the energy systems modeling using NEMS, results show that after economic adjustments to the new regulations are made by producers, the captured natural gas represents both increased output (a slight increment in aggregate production) and increased efficiency (producing slightly more for less). However, because of differing objectives for the regulatory analysis we treat the associated savings differently in the engineering cost analysis (as an explicit output) and in NEMS (as an efficiency gain).

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

7.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy. NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. DOE first developed NEMS in the 1980s, and the model has been undergone frequent updates and expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at <http://www.eia.doe.gov/oiaf/aeo/overview/index.html>.

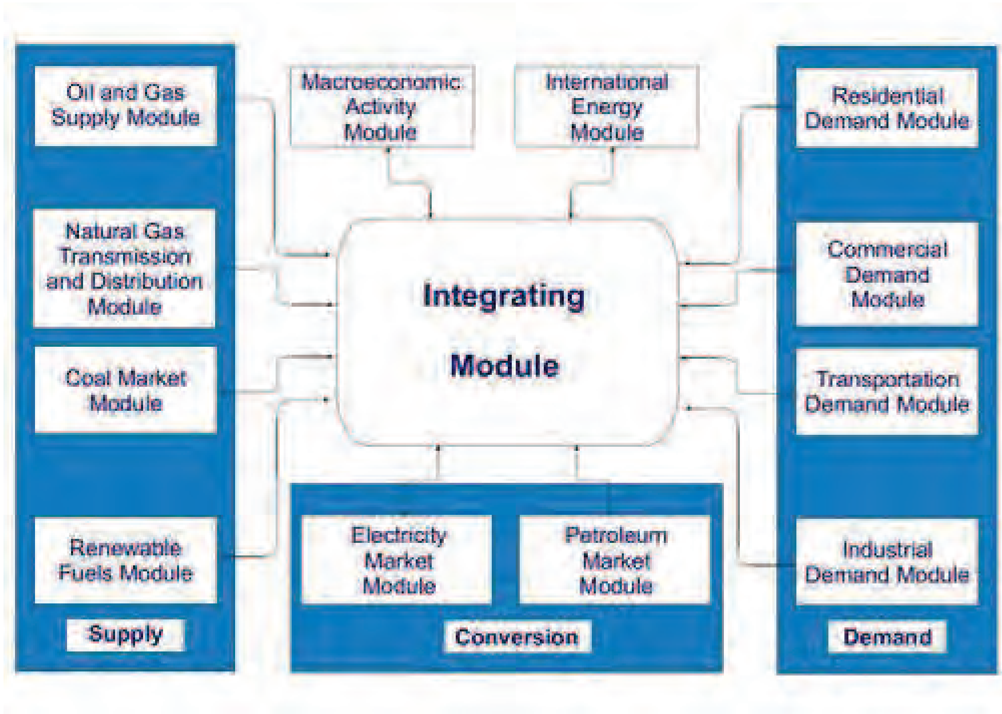

Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration)

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel et al. 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next model after establishing an updated provisional solution.

NEMS provides what EIA refers to as "mid-term" projections to the year 2035. However, as this RIA is concerned with estimating regulatory impacts in the first year of full implementation, our analysis focuses upon estimated impacts in the year 2015, with regulatory costs first imposed in 2011. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2011.[51] The RIA baseline is consistent with that of the Annual Energy Outlook 2011 which is used extensively in Section 2 in the Industry Profile.

[51] Assumptions for the 2011 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/index.cfm>.

7.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the NSPS, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore, Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2010). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern finding and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the Oil and Natural Gas NSPS. We are able to target additional expenditures for environmental controls expected to be required by the NSPS on new exploratory and developmental oil and gas production activities, as well as add additional costs to existing projects. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the NSPS regulatory options. However, we are unable to explicitly model the additional production of condensates expected to be recovered by reduced emissions completions, although we incorporate expected revenues from the condensate recovery in the economic evaluation of new drilling projects.

While the oil production simulated by the OGSM is sent to the refining module (the Petroleum Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and “negotiates” supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas transmitted through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

7.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Additional NSPS costs associated with reduced emission completions and future recompletions for new wells are added to drilling, completion, and stimulation costs, as these are, in effect, associated with activities that occur within a single time period, although they may be repeated periodically, as in the case of recompletions. Costs required for reduced emissions recompletions on existing wells are added to stimulation expenses for existing wells exclusively. Other costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The one-shot and continuing O&M expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells, natural gas wells, both oil and natural gas wells, or a subset of either. We base the per well cost estimates on the engineering costs including revenues from additional product recovery. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

One concern in basing the regulatory costs inputs into NEMS on the net cost of the compliance activity (estimated annualized cost of compliance minus estimated revenue from product recovery) is that potential barriers to obtaining capital may not be adequately incorporated in the model. However, in general, potential barriers to obtaining additional capital should be reflected in the annualized cost via these barriers increasing the cost of capital. With this in mind, assuming the estimates of capital costs and product recovery are valid, the NEMS results will reflect barriers to obtaining the retired capital. A caveat to this is that the estimated unit-level capital costs of controls which are newly required at a national-level as a result of the proposed regulation—RECs, for example—may not incorporate potential additional transitional costs as the supply of control equipment adjusts to new demand.

Table 7-1 shows the incremental O&M expenses that accrue to new drilling projects as a result of producers having to comply with the relevant NSPS option. We estimate those costs as a function of new wells expected to be drilled in a representative year. To arrive at estimates of the per well costs, we first identify which emissions reductions will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells. Based on the baseline projections of successful completions in 2015, we used 19,097 new natural gas wells and 12,193 new oil wells as the basis of these calculations. We then divide the estimated compliance costs for the given emissions point (from Table 3-3) by the appropriate number of expected new wells in the year of analysis. The result yields an approximation of a per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Like the engineering analysis, we assume that hydraulically fractured well completions and recompletions will be required of wells drilled into tight sand, shale gas, and coalbed methane formations. While costs for well recompletions reflect the cost of a single recompletion, the engineering cost analysis assumed that one in ten new wells drilled after the implementation of the promulgation and implementation of the NSPS are completed using hydraulic fracturing will receive a recompletion in any given year using hydraulic fracturing. Meanwhile, within NEMS, wells are assumed to be stimulated every five years. We assume these more frequent stimulations are less intensive than stimulation using hydraulic fracturing but add costs such that the recompletions costs reflect the same assumptions as the engineering analysis. In entering compliance costs into NEMS, we also account for reduced emissions completions, completion combustion, and recompletions performed in absence of the regulation, using the same assumptions as the engineering costs analysis (Table 7-2).

Table 7-1 Summary of Additional Annualized O&M Costs (on a Per New Well Basis) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Well Costs (2008$) Option 1	Option 2 (Proposed)	Option 3	Wells Applied To in NEMS
Equipment Leaks					
Well Pads	Subpart VV	Not in Option	Not in Option	$3,552	Oil and Gas
Gathering and Boosting Stations	Subpart VV	Not in Option	Not in Option	$806	Gas
Processing Plants	Subpart VVa	Not in Option	$56	$56	None
Transmission Compressor Stations	Subpart VV	Not in Option	Not in Option	$320	Gas
Reciprocating Compressors					
Well Pads	Annual Monitoring/ Maintenance	Not in Option	Not in Option	Not in Option	None
Gathering/Boosting Stations	AMM	$17	$17	$17	Gas
Processing Plants	AMM	$12	$12	$12	Gas
Transmission Compressor Stations	AMM	$19	$19	$19	Gas
Underground Storage Facilities	AMM	$1	$1	$1	Gas
Centrifugal Compressors					
Processing Plants	Dry Seals/Route to Process or Control	-$113	-$113	-$113	Gas
Transmission Compressor Stations	Dry Seals/Route to Process or Control	-$62	-$62	-$62	Gas
Pneumatic Controllers -					
Oil and Gas Production	Low Bleed/Route to Process	-$698	-$698	-$698	Oil and Gas
Natural Gas Transmission and Storage	Low Bleed/Route to Process	$0.10	$0.10	$0.10	Gas
Storage Vessels					
High Throughput	95% control	$143	$143	$143	Oil and Gas
Low Throughput	95% control	Not in Option	Not in Option	Not in Option	None

Table 7-2 Summary of Additional Per Completion/Recompletion Costs (2008$) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Completion/Recompletion Costs (2008$) Option 1	Option 2 (proposed)	Option 3	Wells Applied To in NEMS
Well Completions					
Hydraulically Fractured Gas Wells	REC	-$1,275	-$1,275	-$1,275	New Tight Sand/ Shale Gas/CBM
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Well Recompletions					
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	-$1,535	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Hydraulically Fractured Gas Wells (existing wells)	REC	Not in Option	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None

7.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A significant benefit of controlling VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right an increment consistent with the technically achievable emissions transferred into the production stream as a result of the proposed NSPS.

For all control options, with the exception of recompletions on existing wells, we enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per well basis for new wells. Because each NSPS Option is composed of a different suite of emissions controls, the per-well natural gas recovery value for new wells is different across wells. For Option 1, we estimate that natural gas recovery is 5,739 Mcf per well. For Option 2 and Option 3, we estimate that natural gas recovery is 5,743 Mcf per well. We make a simplifying assumption that natural gas recovery accruing to new wells accrues to new wells in shale gas, tight sands, and CBM fields. We make these assumptions because new wells in these fields are more likely to satisfy criteria such that RECs are required, which contributed that large majority of potential natural gas recovery. Note that these per well natural gas recovery is lower than the per well estimate when RECs are implemented. The estimate is lower because we account for emissions that are combusted, RECs that are implemented absent Federal regulation, as well as the likelihood that natural gas is used during processing and transmission or reinjected.

We treat the potential natural gas recovery associated with recompletions of existing wells (in proposed Option 2 and Option 3) differently in that we estimated the natural gas recovery by natural gas resource type and NSPS Option based on a combination of the engineering analysis and production patterns from the 2011 Annual Energy Outlook. We estimate that additional natural gas product recovered by recompleting existing wells in proposed Option 2 and Option 3 to be 78.7 bcf, with 38.4 bcf accruing to shale gas, 31.4 bcf accruing to tight sands, and 8.9 bcf accruing to CBM, respectively. This quantity is distributed within the NGTDM to reflect regional production by resource type.

7.2.2.3 Fixing Canadian Drilling Costs to Baseline Path

Domestic drilling costs serve as a proxy for Canadian drilling costs in the Canadian oil and natural gas sub-model within the NGTDM. This implies that, without additional modification, additional costs imposed by a U.S. regulation will also impact drilling decisions in Canada. Changes in international oil and gas trade are important in the analysis, as a large majority of natural gas imported into the U.S. originates in Canada. To avoid this problem, we fixed Canadian drilling costs using U.S. drilling costs from the baseline scenario. This solution enables a more accurate analysis of U.S.-Canada energy trade, as increased drilling costs in the U.S. as a result of environmental regulation serve to increase Canada's comparative advantage.

7.2.3 Energy System Impacts

As mentioned earlier, we estimate impacts to drilling activity, reserves, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas, as well as whether and to what extent the NSPS might alter the mix of fuels consumed at a national level. In each of these estimates, we present estimates for the baseline year of 2015 and results for the three NSPS options. For context, we provide estimates of production activities in 2011.

7.2.3.1 Impacts on Drilling Activities

Because the potential costs of the NSPS options are concentrated in production activities, we first report estimates of impacts on crude oil and natural gas drilling activities and production and price changes at the wellhead. Table 7-3 presents estimates of successful wells drilled in the U.S. in 2015, the analysis year, for the three NSPS options and in the baseline.

Table 7-3 Successful Oil and Gas Wells Drilled, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Successful Wells Drilled					
Natural Gas	16,373	19,097	19,191	18,935	18,872
Crude Oil	10,352	11,025	11,025	11,025	11,028
Total	**26,725**	**30,122**	**30,216**	**29,960**	**29,900**
% Change in Successful Wells Drilled from Baseline					
Natural Gas			0.49%	-0.85%	-1.18%
Crude Oil			0.00%	0.00%	0.03%
Total			**0.31%**	**-0.54%**	**-0.74%**

We estimate that the number of successful natural gas wells drilled increases slightly for Option 1, while the number of successful crude oil wells drilled does not change. In Options 2, where costs of the natural gas processing plants equipment leaks standard and REC requirements for existing wells apply, natural gas wells drilling is forecast to decrease less than 1 percent, while crude oil drilling does not change. For Option 3, where the addition of an additional equipment leak standards add to the incremental costs, natural gas well drilling is estimated to decrease about 1.2%. The number of successful crude oil wells drilled under Option 3 increases very slightly. While it may seem counter-intuitive that the number of successful crude wells increased as costs increase, it is important to note that crude oil and natural gas drilling compete with each other for factors of production, such as labor and material. The environmental compliance costs of the NSPS options predominantly affect natural gas drilling. As natural gas drilling declines, for example, as a result of increased compliance costs, crude oil drilling may increase because of the increased availability of labor and material, as well as the likelihood that crude oil can substitute for natural gas to some extent.

Table 7-4 presents the forecast of successful wells by well type, for onshore drilling in the lower 48 states. The results show that conventional well drilling is unaffected by the regulatory options, as reduced emission completion and completion combustion requirements are directed not toward wells in conventional reserves but toward wells that are hydraulically fractured, the wells in so-called unconventional reserves. The impacts on drilling tight sands, shale gas, and coalbed methane vary by option.

Table 7-4 Successful Wells Drilled by Well Type (Onshore, Lower 48 States), NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Successful Wells Drilled					
Conventional Gas Wells	7,267	7,607	7,607	7,607	7,607
Tight Sands	2,441	2,772	2,791	2,816	2,780
Shale Gas	5,007	7,022	7,074	6,763	6,771
Coalbed Methane	1,593	1,609	1,632	1,662	1,627
Total	**16,308**	**19,010**	**19,104**	**18,849**	**18,785**
% Change in Successful Wells Drilled from Baseline					
Conventional Gas Wells			0.00%	0.00%	0.00%
Tight Sands			0.70%	1.60%	0.29%
Shale Gas			0.74%	-3.68%	-3.57%
Coalbed Methane			1.44%	3.28%	1.09%
Total			**0.50%**	**-0.85%**	**-1.18%**

Well drilling in tight sands is estimated to increase slightly from the baseline under all three options, 0.70 percent, 1.60 percent, and 0.29% for Options 1, 2, and 3, respectively. Wells in CBM reserves are also estimated to increase from the baseline under all three options, or 1.44 percent, 3.28 percent, and 1.09 percent for Options 1, 2, and 3, respectively. However, drilling in shale gas is forecast to decline from the baseline under Options 2 and 3, by 3.68 percent and 3.57 percent, respectively.

7.2.3.2 Impacts on Production, Prices, and Consumption

Table 7-5 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS options, as of 2015. Domestic crude oil production is not forecast to change under any of the three regulatory options, again because impacts on crude oil drilling of the NSPS are expected to be negligible.

Table 7-5 Annual Domestic Natural Gas and Crude Oil Production, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Domestic Production					
Natural Gas (trillion cubic feet)	21.05	22.43	22.47	22.45	22.44
Crude Oil (million barrels/day)	5.46	5.81	5.81	5.81	5.81
% Change in Domestic Production from Baseline					
Natural Gas			0.18%	0.09%	0.04%
Crude Oil			0.00%	0.00%	0.00%

Natural gas production, on the other hand, increases under all three regulatory options for the NSPS from the baseline. A main driver for these increases is the additional natural gas recovery engendered by the control requirements. Another driver for the increases under Option 1 is the increase in natural gas well drilling. While we showed earlier that natural gas drilling is estimated to decline under Options 2 and 3, the increased natural gas recovery is sufficient to offset the production loss from relatively fewer producing wells.

For the proposed option, the NEMS analysis shown in Table 7-5 estimates a 20 bcf increase in domestic natural gas production. This amount is less than the amount estimated in the engineering analysis to be captured by emissions controls implemented as a result of the proposed NSPS (approximately 180 bcf). This difference is because NEMS models the adjustment of energy markets to the now relatively more efficient natural gas production sector. At the new natural gas supply and demand equilibrium in 2015, the modeling estimates 20 bcf more gas is produced at a relatively lower wellhead price (which will be presented momentarily). However, at the new equilibrium, producers implementing emissions controls still capture and sell approximately 180 bcf of natural gas. For example, as shown in Table 7-4, about 11,200 new unconventional natural gas wells are completed under the proposed NSPS; using assumptions from the engineering cost analysis about RECs required under State regulations and exploratory wells exempted from REC requirements, about 9,000 NSPS-required RECs would be performed on new natural gas well completions, according to the NEMS analysis. This recovered natural gas substitutes for natural gas that would be produced from the ground absent the rule. In effect, then, about 160 bcf of natural gas that would have been extracted and emitted into the atmosphere is left in the formation for future extraction.

As we showed for natural gas drilling, Table 7-6 shows natural gas production from onshore wells in the lower 48 states by type of well, predicted for 2015, the analysis year. Production from conventional natural gas wells and CBM wells are estimated to increase under all NSPS regulatory options. Production from shale gas reserves is estimated to decrease under Options 2 and 3, however, from the baseline projection. Production from tight sands is forecast to decline slightly under Option 1.

Table 7-6 Natural Gas Production by Well Type (Onshore, Lower 48 States), NSPS Options

	2011	Future NSPS Scenario, 2015 Baseline	Option 1	Option 2 (Proposed)	Option 3
Natural Gas Production by Well Type (trillion cubic feet)					
Conventional Gas Wells	4.06	3.74	3.75	3.76	3.76
Tight Sands	5.96	5.89	5.87	6.00	6.00
Shale Gas	5.21	7.20	7.26	7.06	7.06
Coalbed Methane	1.72	1.67	1.69	1.72	1.71
Total	**16.95**	**18.51**	**18.57**	**18.54**	**18.53**
% Change in Natural Gas Production by Well Type from Baseline					
Conventional Gas Wells			0.32%	0.42%	0.48%
Tight Sands			-0.43%	1.82%	1.72%
Shale Gas			0.73%	-1.97%	-1.93%
Coalbed Methane			1.07%	2.86%	2.60%
Total			0.31%	0.16%	0.13%

Note: Totals may not sum due to independent rounding.

Overall, of the regulatory options, the proposed Option 2 is estimated to have the highest natural gas production from onshore wells in the lower 48 states, showing a 1.2% increase over the baseline projection.

Table 7-7 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states, estimated for 2015, the year of analysis. All NSPS options show a decrease in wellhead natural gas and crude oil prices. The decrease in wellhead natural gas price form the baseline is attributable largely to the increased productivity of natural gas wells as a result of capturing a portion of completion emissions (in Options 1, 2, and 3) and in capturing recompletion emissions (in Options 2 and 3).

Table 7-7 Lower 48 Average Natural Gas and Crude Oil Wellhead Price, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Lower 48 Average Wellhead Price					
Natural Gas (2008$ per Mcf)	4.07	4.22	4.18	4.18	4.19
Crude Oil (2008$ per barrel)	83.65	94.60	94.59	94.58	94.58
% Change in Lower 48 Average Wellhead Price from Baseline					
Natural Gas			-0.94%	-0.94%	-0.71%
Crude Oil			-0.01%	-0.02%	-0.02%

Table 7-8 presents estimates of the price of natural gas to final consumers in 2008 dollars per million BTU. The production price decreases estimated across NSPS are largely passed on to consumers but distributed unequally across consuming sectors. Electric power sector consumers of natural gas are estimated to receive the largest price decrease while the transportation and residential sectors are forecast to receive the smallest price decreases.

Table 7-8 Delivered Natural Gas Prices by Sector (2008$ per million BTU), 2015, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Delivered Prices (2008$ per million BTU)					
Residential	10.52	10.35	10.32	10.32	10.33
Commercial	9.26	8.56	8.52	8.53	8.54
Industrial	4.97	5.08	5.05	5.05	5.06
Electric Power	4.81	4.77	4.73	4.74	4.75
Transportation	12.30	12.24	12.20	12.22	12.22
Average	**6.76**	**6.59**	**6.55**	**6.57**	**6.57**
% Change in Delivered Prices from Baseline					
Residential			**-0.29%**	**-0.29%**	**-0.19%**
Commercial			**-0.47%**	**-0.35%**	**-0.23%**
Industrial			**-0.59%**	**-0.59%**	**-0.39%**
Electric Power			**-0.84%**	**-0.63%**	**-0.42%**
Transportation			**-0.33%**	**-0.16%**	**-0.16%**
Average			**-0.60%**	**-0.41%**	**-0.30%**

Final consumption of natural gas is also estimated to increase in 2015 from the baseline under all NSPS options, as is shown on Table 7-9. Like delivered price, the consumption shifts are distributed differently across sectors.

Table 7-9 Natural Gas Consumption by Sector, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Consumption (trillion cubic feet)					
Residential	4.76	4.81	4.81	4.81	4.81
Commercial	3.22	3.38	3.38	3.38	3.38
Industrial	6.95	8.05	8.06	8.06	8.06
Electric Power	7.00	6.98	7.00	6.98	6.97
Transportation	0.03	0.04	0.04	0.04	0.04
Pipeline Fuel	0.64	0.65	0.65	0.66	0.66
Lease and Plant Fuel	1.27	1.20	1.21	1.21	1.21
Total	**23.86**	**25.11**	**25.15**	**25.14**	**25.13**
% Change in Consumption from Baseline					
Residential			0.00%	0.00%	0.00%
Commercial			0.00%	0.00%	0.00%
Industrial			0.12%	0.12%	0.12%
Electric Power			0.29%	0.00%	-0.14%
Transportation			0.00%	0.00%	0.00%
Pipeline Fuel			0.00%	1.54%	1.54%
Lease and Plant Fuel			0.83%	0.83%	0.83%
Total			**0.16%**	**0.12%**	**0.08%**

Note: Totals may not sum due to independent rounding.

7.2.3.3 Impacts on Imports and National Fuel Mix

The NEMS modeling shows that impacts from all NSPS options are not sufficiently large to affect the trade balance of natural gas. As shown in Table 7-10, estimates of crude oil and natural gas imports do not vary from the baseline in 2015 for each regulatory option.

Table 7-10 Net Imports of Natural Gas and Crude Oil, NSPS Options

	2011	Future NSPS Scenario, 2015 Baseline	Option 1	Option 2 (Proposed)	Option 3
Net Imports					
Natural Gas (trillion cubic feet)	2.75	2.69	2.69	2.69	2.69
Crude Oil (million barrels/day)	9.13	8.70	8.70	8.70	8.70
% Change in Net Imports					
Natural Gas			0.00%	0.00%	0.00%
Crude Oil			0.00%	0.00%	0.00%

Table 7-11 evaluates estimates of energy consumption by energy type at the national level for 2015, the year of analysis. All three NSPS options are estimated to have small effects at the national level. For Option 1, we estimate an increase in 0.02 quadrillion BTU in 2015, a 0.02 percent increase. The percent contribution of natural gas and biomass is projected to increase, while the percent contribution of liquid fuels and coal is expected to decrease under Option 1. Meanwhile, under the proposed Options 2, total energy consumption is also forecast to rise 0.02 quadrillion BTU, with increase coming from natural gas primarily, with an additional small increase in coal consumption. Under Option 3, total energy consumption is forecast to rise 0.01 quadrillion BTU, or 0.01%, with a slight decrease in liquid fuel consumption from the baseline, but increases in natural gas and coal consumption.

Table 7-11 Total Energy Consumption by Energy Type (Quadrillion BTU), NSPS Options

	2011	Future NSPS Scenario, 2015 Baseline	Option 1	Option 2 (Proposed)	Option 3
Consumption (quadrillion BTU)					
Liquid Fuels	37.41	39.10	39.09	39.10	39.09
Natural gas	24.49	25.77	25.82	25.79	25.79
Coal	20.42	19.73	19.71	19.74	19.74
Nuclear Power	8.40	8.77	8.77	8.77	8.77
Hydropower	2.58	2.92	2.92	2.92	2.92
Biomass	2.98	3.27	3.28	3.27	3.27
Other Renewable Energy	1.72	2.14	2.14	2.14	2.14
Other	0.30	0.31	0.31	0.31	0.31
Total	**98.29**	**102.02**	**102.04**	**102.04**	**102.03**
% Change in Consumption from Baseline					
Liquid Fuels			-0.03%	0.00%	-0.03%
Natural Gas			0.19%	0.08%	0.08%
Coal			-0.10%	0.05%	0.05%
Nuclear Power			0.00%	0.00%	0.00%
Hydropower			0.00%	0.00%	0.00%
Biomass			0.31%	0.00%	0.00%
Other Renewable Energy			0.00%	0.00%	0.00%
Other			0.00%	0.00%	0.00%
Total			**0.02%**	**0.02%**	**0.01%**

Note: Totals may not sum due to independent rounding.

With the national profile of energy consumption estimated to change slightly under the regulatory options in 2015, the year of analysis, it is important to examine whether aggregate energy-related CO_2-equivalent greenhouse gas (GHG) emissions also shift. A more detailed discussion of changes in CO_2-equivalent GHG emissions from a baseline is presented within the benefits analysis in Section 4. Here, we present a single NEMS-based table showing estimated changes in energy-related “consumer-side” GHG emissions. We use the terms “consumer-side” emissions to distinguish emissions from the consumption of fuel from emissions specifically associated with the extraction, processing, and transportation of fuels in the oil and natural gas sector under examination in this RIA. We term the emissions associated with extraction, processing, and transportation of fuels “producer-side” emissions.

Table 7-12 Modeled Change in Energy-related "Consumer-Side" CO_2-equivalent GHG Emissions

	2011	Future NSPS Scenario, 2015 Baseline	Option 1	Option 2 (Proposed)	Option 3
Energy-related CO_2-equivalent GHG Emissions (million metric tons CO_2-equivalent)					
Petroleum	2,359.59	2,433.60	2,433.12	2,433.49	2,433.45
Natural Gas	1,283.78	1,352.20	1,354.47	1,353.19	1,352.87
Coal	1,946.02	1,882.08	1,879.84	1,883.24	1,883.30
Other	11.99	11.99	11.99	11.99	11.99
Total	**5,601.39**	**5,679.87**	**5,679.42**	**5,681.91**	**5,681.61**
% Change in Energy-related CO_2-equivalent GHG Emissions from Baseline					
Petroleum			-0.02%	0.00%	-0.01%
Natural Gas			0.17%	0.07%	0.05%
Coal			-0.12%	0.06%	0.06%
Other			0.00%	0.00%	0.00%
Total			**-0.01%**	**0.04%**	**0.03%**

Note: Excludes “producer-side” emissions and emissions reductions estimated to result from NSPS alternatives. Totals may not sum due to independent rounding.

As is shown in Table 7-12, NSPS Option 1 is predicted to slightly decrease aggregate consumer-side energy-related CO_2-equivalent GHG emissions, by about 0.01 percent, while the mix of emissions shifts slightly away from coal and petroleum toward natural gas. Proposed Options 2 and 3 are estimated to increase consumer-side aggregate energy-related CO_2-equivalent GHG emissions by about 0.04 and 0.03 percent, respectively, mainly because consumer-side emissions from natural gas and coal combustion increase slightly.

7.3 Employment Impact Analysis

While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate of sustained high unemployment. Executive Order 13563, states, “Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation” (emphasis added). Therefore, we seek to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the proposed regulations using labor requirements for the installation, operation, and maintenance of control requirements, as well as reporting and recordkeeping requirements. Unlike several recent RIAs, however, we do not provide employment impacts estimates based on the study by Morgenstern et al. (2002); we discuss this decision after presenting estimates of the labor requirements associated with reporting and recordkeeping and the installation, operation, and maintenance of control requirements.

7.3.1 Employment Impacts from Pollution Control Requirements

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing regulations to make our air safer to breathe. When a new regulation is promulgated, a response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. Revenue and employment in the environmental technology industry have grown steadily between 2000 and 2008, reaching an industry total of approximately $300 billion in revenues and 1.7 million employees in 2008.[52] While these revenues and employment figures represent gains for the environmental technologies industry, they are costs to the regulated industries required to install the equipment. Moreover, it is not clear the 1.7 million employees in 2008 represent new employment as opposed to workers being shifted from the production of goods and services to environmental compliance activities.

Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment – much like they hire workers to produce more output. Morgenstern et al. (2002) examined how regulated industries respond to regulation. The authors found that, on average for the industries they studied, employment increases in regulated firms. Of course, these firms may also reassign existing employees to perform these activities.

[52] In 2008, the industry totaled approximately $315 billion in revenues and 1.9 million employees including indirect employment effects, pollution abatement equipment production employed approximately 4.2 million workers in 2008. These indirect employment effects are based on a multiplier for indirect employment = 2.24 (1982 value from Nestor and Pasurka - approximate middle of range of multipliers 1977-1991). Environmental Business International (EBI), Inc., San Diego, CA. Environmental Business Journal, monthly (copyright). http://www.ebiusa.com/ EBI data taken from the Department of Commerce International Trade Administration Environmental Industries Fact Sheet from April 2010: http://web.ita.doc.gov/ete/eteinfo.nsf/068f3801d047f26e85256883006ffa54/4878b7e2fc08ac6d85256883006c452c?OpenDocument

Environmental regulations support employment in many basic industries. In addition to the increase in employment in the environmental protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment. Bezdek et al. (2008) found that investments in environmental protection industries create jobs and displace jobs, but the net effect on employment is positive.

The focus of this part of the analysis is on labor requirements related to the compliance actions of the affected entities within the affected sector. We do not estimate any potential changes in labor outside of the oil and natural gas sector. This analysis estimates the employment impacts due to the installation, operation, and maintenance of control equipment, as well as employment associated with new reporting and recordkeeping requirements.

It is important to highlight that unlike the typical case where to reduce a bad output (i.e., emissions) a firm often has to reduce production of the good output, many of the emission controls required by the proposed NSPS will simultaneously increase production of the good output and reduce production of bad outputs. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. New labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because U.S. EPA does not currently have this information. The employment analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in this RIA includes estimates of the labor requirements associated with implementing the proposed regulations. Each of these labor changes may either be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual, annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

In other employment analyses U.S. EPA distinguished between employment changes within the regulated industry and those changes outside the regulated industry (e.g. a contractor from outside the regulated facility is employed to install a control device). For this regulation however, the structure of the industry makes this difficult. The mix of in-house versus contracting services used by firms is very case-specific in the oil and natural gas industry. For example, sometimes the owner of the well, processing plant, or transmission pipelines uses in–house employees extensively in daily operations, while in other cases the owner relies on outside contractors for many of these services. For this reason, we make no distinction in the quantitative estimates between labor changes within and outside of the regulated sector.

The results of this employment estimate are presented in Table 7-13 for the proposed NSPS and in Table 7-14 for the proposed NESHAP amendments. The tables breaks down the installation, operation, and maintenance estimates by type of pollution control evaluated in the RIA and present both the estimated hours required and the conversion of this estimate to FTE. For both the proposed NSPS and NESHAP amendments, reporting and recordkeeping requirements were estimated for the entire rules rather than by anticipated control requirements; the reporting and recordkeeping estimates are consistent with estimates EPA submitted as part of its Information Collection Request (ICR).

The up-front labor requirement is estimated at 230 FTEs for the proposed NSPS and about 120 FTEs for the proposed NESHAP amendments. These up-front FTE labor requirements can be viewed as short-term labor requirements required for affected entities to comply with the new regulation. Ongoing requirements are estimated at about 2,400 FTEs for the proposed NSPS and about 102 FTEs for the proposed NESHAP amendments. These ongoing FTE labor requirements can be viewed as sustained labor requirements required for affected entities to continuously comply with the new regulation

Two main categories contain the majority of the labor requirements for the proposed rules: implementing reduced emissions completions (RECs) and reporting and recordkeeping requirements for the proposed NSPS. Also, note that pneumatic controllers have no up-front or continuing labor requirements. While the controls do require labor for installation, operation, and maintenance, the required labor is less than that of the controllers that would be used absent the regulation. In this instance, we assume the incremental labor requirements are zero.

Implementing RECs are estimated to require about 2,230 FTE, over 90 percent of the total continuing labor requirements for the proposed NSPS.[53] We denote REC-related requirements as continuing, or annual, as the REC requirements will in fact recur annually, albeit at different wells each year. The REC requirements are associated with certain new well completions or existing well recompletions, which while individual completions occur over a short period of time (days to a few weeks), new wells and other existing wells are completed or recompleted annually. Because of these reasons, we assume the REC-related labor requirements are annual.

7.3.2 Employment Impacts Primarily on the Regulated Industry

In previous RIAs, we transferred parameters from a study by Morgenstern et al. (2002) to estimate employment effects of new regulations. (See, for example, the Regulatory Impact Analysis for the recently finalized Industrial Boilers and CISWI rulemakings, promulgated on February 21, 2011). The fundamental insight of Morgenstern, et al. is that environmental regulations can be understood as requiring regulated firms to add a new output (environmental quality) to their product mixes. Although legally compelled to satisfy this new demand, regulated firms have to finance this additional production with the proceeds of sales of their other (market) products. Satisfying this new demand requires additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms in their production processes.

Morgenstern et al. concluded that increased abatement expenditures in these industries generally do not cause a significant change in employment. Using plant-level Census

[53] As shown on earlier in this section, we project that the number of successful natural gas wells drilled in 2015 will decline slightly from the baseline projection. Therefore, there may be small employment losses in drilling-related employment that partly offset gains in employment from compliance-related activities.

information between the years 1979 and 1991, Morgenstern et al. estimate the size of each effect for four polluting and regulated industries (petroleum refining, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million (1987$) spending on pollution abatement results in a (statistically insignificant) net increase of 1.55 (+/- 2.24) jobs. As a result, the authors conclude that increases in pollution abatement expenditures do not necessarily cause economically significant employment changes.

For this version of RIA for the proposed NSPS and NESHAP amendments, however, we chose not to quantitatively estimate employment impacts using Morgenstern et al. because of reasons specific to the oil and natural gas industry and proposed rules. We believe the transfer of parameter estimates from the Morgenstern et al. study to the proposed NSPS and NESHAP amendments is beyond the range of the study for two reasons.

Table 7-13 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NSPS Option in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit Up- Front Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total Up- Front Labor Estimate (hours)	Total Annual Labor Estimate (hours)	Up-Front Full-Time Equivalent	Annual Full-Time Equivalent
Well Completions								
Hydraulically Fractured Gas Wells	Reduced Emissions Completion (REC)	9,313	0	218	0	2,025,869	0.0	974.0
Hydraulically Fractured Gas Wells	Combustion	446	0	22	0	9,626	0.0	4.6
Well Recompletions								
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC	12,050	0	218	0	2,621,126	0.0	1,260.2
Equipment Leaks								
Processing Plants	NSPS Subpart VVA	29	587	887	17,023	25,723	8.2	12.4
Reciprocating Compressors								
Gathering/Boosting Stations	AMM	210	1	1	210	210	0.1	0.1
Processing Plants	AMM	375	1	1	375	375	0.2	0.2
Transmission Compressor Stations	AMM	199	1	1	199	199	0.1	0.1
Underground Storage Facilities	AMM	9	1	1	9	9	0.0	0.0
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	16	355	0	5,680	0	2.7	0.0
Transmission Compressor Stations	Dry Seals/Route to Process or Control	14	355	0	4,970	0	2.4	0.0
Pneumatic Controllers								
Oil and Gas Production	Low Bleed/Route to Process	13,632	0	0	0	0	0.0	0.0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	67	0	0	0	0	0.0	0.0
Storage Vessels								
High Throughput	95% control	304	271	190	82,279	57,582	39.6	27.7
Reporting and Recordkeeping for Complete NSPS		---	---	---	360,443	201,342	173.3	96.8
TOTAL		**---**	**---**	**---**	**471,187**	**4,942,060**	**226.5**	**2,376.0**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-14 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NESHAP Amendments in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time Full-Time Equivalent	Annual Full-Time Equivalent
Small Glycol Dehydrators								
Production	Combustion devices, recovery devices, process modifications	115	27	285	3,108	32,821	1.5	15.8
Transmission	Combustion devices, recovery devices, process modifications	19	27	285	513	5,423	0.2	2.6
Storage Vessels								
Production	Combustion devices, recovery devices	674	311	198	209,753	133,231	100.8	64.1
Reporting and Recordkeeping for Complete NESHAP Amendments		---	---	---	36,462	39,923	17.5	19.2
TOTAL		**---**	**--**	**---**	**249,836**	**211,398**	**120.1**	**101.6**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

First, the possibility that the revenues producers are estimated to receive from additional natural gas recovery as a result of the proposed NSPS might offset the costs of complying with the rule presents challenges to estimating employment effects (see Section 3.2.2.1 of the RIA for a detailed discussion of the natural gas recovery). The Morgenstern et al. paper, for example, is intended to analyze the impact of environmental compliance expenditures on industry employment levels, and it may not be appropriate to draw on their demand and net effects when compliance costs are expected to be negative.

Second, the proposed regulations primarily affect the natural gas production, processing, and transmission segments of the industry. While the natural gas processing segment of the oil and natural gas industry is similar to petroleum refining, which is examined in Morgenstern et al., the production side of the oil and natural gas (drilling and extraction, primarily) and natural gas pipeline transmission are not similar to petroleum refining. Because of the likelihood of negative compliance costs for the proposed NSPS and the segments of the oil and natural gas industry affected by the proposals are not examined by Morgenstern et al., we decided not to use the parameters estimated by Morgenstern et al. to estimate within-industry employment effects for the proposed oil and natural gas NESHAP amendments and NSPS.

That said, the likelihood of additional natural gas recovery is an important component of the market response to the rule, as it is expected that this additional natural gas recovery will reduce the price of natural gas. Because of the estimated fall in prices in the natural gas sector due to the proposed NSPS, prices in other sectors that consume natural gas are likely drop slightly due to the decrease in energy prices. This small production increase and price decrease may have a slight stimulative effect on employment in industries that consume natural gas.

7.4 Small Business Impacts Analysis

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

After considering the economic impact of the proposed rules on small entities for both the NESHAP and NSPS, the screening analysis indicates that these proposed rules will not have a significant economic impact on a substantial number of small entities (or "SISNOSE"). The supporting analyses for these determinations are presented in this section of the RIA.

As discussed in previous sections of the economic impact analysis, under the proposed NSPS, some affected producers are likely to be able to recover natural gas that would otherwise be vented to the atmosphere, as well as recover saleable condensates that would otherwise be emitted. EPA estimates that the revenues from this additional natural gas product recovery will offset the costs of implementing control options implemented as a result of the Proposed NSPS. Because the total costs of the rule are likely to be more than offset by the revenues producers gain from increased natural gas recovery, we expect there will be no SISNOSE arising from the proposed NSPS. However, not all components of the proposed NSPS are estimated to have cost savings. Therefore, we analyze potential impacts to better understand the potential distribution of impacts across industry segments and firms. We feel taking this approach strengthens the determination that there will be no SISNOSE. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not recover significant quantities of natural gas products.

7.4.1 Small Business National Overview

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The U.S. Census Bureau's Statistics of U.S. Businesses (SUSB) provides national information on the distribution of economic variables by industry and enterprise size. The Census Bureau and the Office of Advocacy of the Small Business Administration (SBA) supported and developed these files for use in a broad range of economic analyses.[54] Statistics include the total number of establishments, and receipts for all entities in an industry; however, many of these entities may not necessarily be covered by the final rule. SUSB also provides statistics by enterprise employment and receipt size (Table 7-15 and Table 7-16).

[54]See http://www.census.gov/csd/susb/ and http://www.sba.gov/advocacy/ for additional details.

The Census Bureau's definitions used in the SUSB are as follows:

- *Establishment*: A single physical location where business is conducted or where services or industrial operations are performed.
- *Firm:* A firm is a business organization consisting of one or more domestic establishments in the same state and industry that were specified under common ownership or control. The firm and the establishment are the same for single-establishment firms. For each multi-establishment firm, establishments in the same industry within a state will be counted as one firm- the firm employment and annual payroll are summed from the associated establishments.
- *Receipts*: Receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.
- *Enterprise*: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the sum of employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008) apply to an establishment's "ultimate parent company," we assumed in this analysis that the "firm" definition above is consistent with the concept of ultimate parent company that is typically used for SBREFA screening analyses, and the terms are used interchangeably.

Table 7-15 Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

			Owned by Firms with:					
NAICS	NAICS Description	SBA Size Standard (effective Nov. 5, 2010)	< 20 Employees	20-99 Employees	100-499 Employees	Total < 500 Employees	> 500 Employees	Total Firms
Number of Firms by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	5,759	455	115	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	77	9	12	98	41	139
213111	Drilling Oil and Gas Wells	500	1,580	333	97	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	63	12	9	84	42	126
Total Employment by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	21,170	16,583	17,869	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	372	305	1,198	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	5,972	13,787	16,893	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	241	382	1,479	2,102	22,581	24,683
Estimated Receipts by Firm Size ($1000)								
211111	Crude Petroleum and Natural Gas Extraction	500	12,488,688	15,025,443	17,451,805	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	209,640	217,982	1,736,706	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	1,101,481	2,460,301	3,735,652	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	332,177	518,341	1,448,020	2,298,538	18,498,143	20,796,681

Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

Table 7-16 Distribution of Small and Large Firms by Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

			Percent of Firms		
NAICS	NAICS Description	Total Firms	Small Businesses	Large Businesses	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	6,424	98.5%	1.5%	100.0%
211112	Natural Gas Liquid Extraction	139	70.5%	29.5%	100.0%
213111	Drilling Oil and Gas Wells	2,059	97.6%	2.4%	100.0%
486210	Pipeline Transportation of Natural Gas	126	48.4%	51.6%	100.0%
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	133,286	41.7%	58.3%	100.0%
211112	Natural Gas Liquid Extraction	8,523	22.0%	78.0%	100.0%
213111	Drilling Oil and Gas Wells	106,426	34.4%	65.6%	100.0%
486210	Pipeline Transportation of Natural Gas	24,683	N/A*	N/A*	N/A*
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	194,107,252	23.2%	76.8%	100.0%
211112	Natural Gas Liquid Extraction	39,977,741	5.4%	94.6%	100.0%
213111	Drilling Oil and Gas Wells	23,848,238	30.6%	69.4%	100.0%
486210	Pipeline Transportation of Natural Gas	20,796,681	N/A*	N/A*	N/A*

Note: Employment and receipts could not be broken down between small and large businesses because of non-disclosure requirements.

Source: SBA

While the SBA and Census Bureau statistics provide informative broad contextual information on the distribution of enterprises by receipts and number of employees, it is also useful to additionally contrast small and large enterprises (where large enterprises are defined as those that are not small, according to SBA criteria) in the oil and natural gas industry. The summary statistics presented in previous tables indicate that there are a large number of relatively small firms and a small number of large firms. Given the majority of expected impacts of the proposed rules arises from well completion-related requirements, which impacts production activities, exclusively, some explanation of this particular market structure is warranted as it pertains to production and small entities. An important question to answer is whether there are particular roles that small entities serve in the production segment of the oil and natural gas industry that may be disproportionately affected by the proposed rules.

The first important broad distinction among firms is whether they are independent or integrated. Independent firms concentrate on exploration and production (E&P) activities, while integrated firms are vertically integrated and often have operations in E&P, processing, refining, transportation, and retail. To our awareness, there are no small integrated firms. Independent firms may own and operate wells or provide E&P-related services to the oil and gas industry. Since we are focused on evaluating potential impacts to small firms owning and operating new and existing hydraulically fractured wells, we should narrow down on this sector.

In our understanding, there is no single industry niche for small entities in the production segment of the industry since small operators have different business strategies and that small entities can own different types of wells. The organization of firms in oil and natural gas industry also varies greatly from firm to firm. Additionally, oil and natural gas resources vary widely geographically and can vary significantly within a single field.

Among many important roles, independent small operators historically pioneered exploration in new areas, as well as developed new technologies. By taking on these relatively large risks, these small entrepreneurs (wildcatters) have been critical sources of industrial innovation and opened up critical new energy supplies for the U.S. (HIS Global Insight). In recent decades, as the oil and gas industry has concentrated via mergers, many of these smaller firms have been absorbed into large firms.

Another critical role, which provides an interesting contrast to small firms pioneering new territory, is that smaller independents maintain and operate a large proportion of the Nation’s low producing wells, which are also known as marginal or stripper wells (Duda et al. 2005). While marginal wells represent about 80 percent of the population of producing wells, they produce about 15 percent of domestic production, according to EIA (Table 7-17).

Table 7-17 Distribution of Crude Oil and Natural Gas Wells by Productivity Level, 2009

Type of Wells	Wells (no.)	Wells (%)	Production (MMbbl for oil and Bcf gas)	Production (%)
Crude Oil				
Stripper Wells (<15 boe per year)	310,552	85%	311	19%
Other Wells (>=15 boe per year)	52,907	15%	1,331	81%
Total Crude Oil Wells	**363,459**	**100%**	**1,642**	**100%**
Natural Gas				
Natural Gas Stripper Wells (<15 boe per year)	338,056	73%	2,912	12%
Other Natural Gas Wells (>=15 boe per year)	123,332	27%	21,048	88%
Total Natural Gas Wells	**461,388**	**100%**	**23,959**	**100%**

Source: U.S. Energy Information Administration, **Distribution of Wells by Production Rate Bracket.** <http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html> Accessed 7/10/11.

Note: Natural gas production converted to barrels oil equivalent (boe) uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet natural gas.

Many of these wells were likely drilled and initially operated by major firms (although the data are not available to quantify the percentage of wells initially drilled by small versus large producers). Well productivity levels typically follow a steep decline curve; high production in earlier years but sustained low production for decades. Because of relatively low overhead of maintaining and operating few relatively co-located wells, some small operators with a particular business strategy purchase low producing wells from the majors, who concentrate on new opportunities. As small operators have provided important technical innovation in exploration, small operators have also been sources of innovation in extending the productivity and lifespan of existing wells (Duda et al. 2005).

7.4.2 Small Entity Economic Impact Measures

The proposed Oil and Natural Gas NSPS and NESHAP amendments will affect the owners of the facilities that will incur compliance costs to control their regulated emissions. The owners, either firms or individuals, are the entities that will bear the financial impacts associated with these additional operating costs. The proposed rule has the potential to impact all firms owning affected facilities, both large and small.

The analysis provides EPA with an estimate of the magnitude of impacts the proposed NSPS and NESHAP amendments may have on the ultimate domestic parent companies that own facilities EPA expects might be impacted by the rules. The analysis focuses on small firms because they may have more difficulty complying with a new regulation or affording the costs associated with meeting the new standard. This section presents the data sources used in the screening analysis, the methodology we applied to develop estimates of impacts, the results of the analysis, and conclusions drawn from the results.

The small business impacts analysis for the NSPS and NESHAP amendments relies upon a series of firm-level sales tests (represented as cost-to-revenue ratios) for firms that are likely to be associated with NAICS codes listed in Table 7-15. For both the NSPS and NESHAP amendments, we obtained firm-level employment, revenues, and production levels using various sources, including the American Business Directory, the *Oil and Gas Journal*, corporate websites, and publically-available financial reports. Using these data, we estimated firm-level compliance cost impacts and calculated cost-to-revenue ratios to identify small firms that might be significantly impacts by the rules. The approaches taken for the NSPS and NESHAP amendments differed; more detail on approaches for each set of proposed rules is presented in the following sections.

For the sales test, we divided the estimates of annualized establishment compliance costs by estimates of firm revenue. This is known as the cost-to-revenue ratio, or the "sales test." The "sales test" is the impact methodology EPA employs in analyzing small entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is often used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Revenues as typically published are correct figures and are more reliably reported when compared to profit data. The use of a "sales test" for estimating small business impacts for a rulemaking such as this one is consistent with guidance offered by EPA on compliance with SBREFA[55] and is consistent with guidance published by the U.S. SBA's Office of Advocacy that suggests that cost as a percentage

[55] The SBREFA compliance guidance to EPA rulewriters regarding the types of small business analysis that should be considered can be found at <http://www.epa.gov/sbrefa/documents/rfaguidance11-00-06.pdf>

of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (U.S. SBA, 2010).[568]

7.4.3 Small Entity Economic Impact Analysis, Proposed NSPS

7.4.3.1 Overview of Sample Data and Methods

The proposed NSPS covers emissions points within various stages of the oil and natural gas production process. We expect that firms within multiple NAICS codes will be affected, namely the NAICS categories presented in Table 7-15. Because of the diversity of the firms potentially affected, we decided to analyze three distinct groups of firms within the oil and natural gas industry, while accounting for overlap across the groups. We analyze firms that are involved in oil and natural gas extraction that are likely to drill and operate wells, while a subset are integrated firms involved in multiple segments of production, as well as retailing products. We also analyze firms that primarily operate natural gas processing plants. A third set of firms we analyzed contains firms that primarily operate natural gas compression and pipeline transmission.

To identify firms involved in the drilling and primary production of oil and natural gas, we relied upon the annual *Oil and Gas Journal* 150 Survey (OGJ 150) as described in the Industry Profile in Section 2. While the OGJ 150 lists public firms, we believe the list is reasonably representative of the larger population of public and private firms operating in this segment of the industry. While the proportion of small firm in the OGJ 150 is smaller than the proportion evaluated by the Census SUSB, the OGJ 150 provides detailed information on the production activities and financial returns of the firms within the list, which are critical ingredients to the small business impacts analysis. We drew upon the OGJ 150 lists published for the years 2008 and 2009 (*Oil and Gas Journal*, September 21, 2009 and *Oil and Gas Journal*, September 6, 2010). The year 2009 saw relatively low levels of drilling activities because of the economic recession, while 2008 saw a relatively high level of drilling activity because of high fuel prices. Combined, we believe these two years of data are representative.

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[56]U.S. SBA, Office of Advocacy. A Guide for Government Agencies, How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272, June 2010.

To identify firms that process natural gas, the OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used the most recent list of U.S. gas processing facilities[57] and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. To identify firms that compress and transport natural gas via pipelines, we examined the periodic OGJ survey on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies.[58] For these firms, we also used the American Business Directory and corporate websites to best identify the ultimate owner of the facilities or companies.

After combining the information for exploration and production firms, natural gas processing firms, and natural gas pipeline transmission firms in order to identify overlaps across the list, the approach yielded a sample of 274 firms that would potentially be affected by the proposed NSPS in 2015 assuming their 2015 production activities were similar to those in 2008 and 2009. We estimate that 129 (47 percent) of these firms are small according to SBA criteria. We estimate 121 firms (44 percent) are not small firms according to SBA criteria. We are unable to classify the remaining 24 firms (9 percent) because of a lack of required information on employee counts or revenue estimates.

Table 7-18 shows the estimated revenues for 250 firms for which we have sufficient data that would be potentially affected by the proposed NSPS based upon their activities in 2008 and 2009. We segmented the sample into four groups, production and integrated firms, processing firms, pipeline firms, and pipelines/processing firms. For the firms in the pipelines/processing group, we were unable to determine the firms' primary line of business, so we opted to group together as a fourth group.

[57] Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.
[58] Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

Table 7-18 Estimated Revenues for Firms in Sample, by Firm Type and Size

		Estimated Revenues (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	79	18,554.5	234.9	76.3	0.1	1,116.9
Large	49	1,347,463.0	27,499.2	1,788.3	12.9	310,586.0
Subtotal	128	1,366,017.4	10,672.0	344.6	0.1	310,586.0
Pipeline						
Small	11	694.5	63.1	4.6	0.5	367.0
Large	36	166,290.2	4,619.2	212.9	7.1	112,493.0
Subtotal	47	166,984.6	3,552.9	108.0	0.5	112,493.0
Processing						
Small	39	4,972.1	127.5	26.9	1.9	1,459.1
Large	23	177,632.1	8,881.6	2,349.4	10.4	90,000.0
Subtotal	62	182,604.2	3,095.0	41.3	1.9	90,000.0
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Subtotal	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Total						
Small	**129**	**24,221.1**	**187.8**	**34.9**	**0.1**	**1,459.1**
Large	**121**	**1,866,513.7**	**15,817.9**	**1,672.1**	**7.1**	**310,586.0**
Total	**250**	**1,890,734.8**	**7,654.8**	**163.9**	**0.1**	**310,586.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants. *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010. American Business Directory was used to determine number of employees.

As shown in Table 7-18, there is a wide variety of revenue levels across firm size, as well as across industry segments. The estimated revenues within the sample are concentrated on integrated firms and firms engaged in production activities (the E&P firms mentioned earlier).

The oil and natural gas industry is capital-intensive. To provide more context on the potential impacts of new regulatory requirements, Table 7-19 presents descriptive statistics for small and large integrated and production firms from the sample of firms (121 of the 128 integrated and production firms listed in the *Oil and Gas Journal*; capital and exploration expenditures for 7 firms were not reported in the *Oil and Gas Journal*).

Table 7-19 Descriptive Statistics of Capital and Exploration Expenditures, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

		Capital and Exploration Expenditures (millions, 2008 dollars)				
Firm Size	Number	Total	Average	Median	Minimum	Maximum
Small	76	13,478.8	177.4	67.1	0.1	2,401.9
Large	45	126,749.3	2,816.7	918.1	10.3	22,518.7
Total	**121**	**140,228.2**	**1,158.9**	**192.8**	**0.1**	**22,518.7**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

The average 2008 and 2009 total capital and exploration expenditures for the sample of 121 firms were $140 billion in 2008 dollars). About 10 percent of this total was spent by small firms. Average capital and explorations expenditures for small firms are about 6 percent of large firms; median expenditures of small firms are about 7 percent of large firms' expenditures. For small firms, capital and exploration expenditures are high relative to revenue, which appears to hold true more generally for independent E&P firms compared to integrated major firms. This would seem to indicate the capital-intensive nature of E&P activities. As expected, this would drive up ratios comparing estimated engineering costs to revenues and capital and exploration expenditures.

Table 7-20 breaks down the estimated number of natural gas and crude oil wells drilled by the 121 firms in the sample for which the *Oil and Gas Journal* information reported well-drilling estimates. Note the fractions on the minimum and maximum statistics; the fractions reported are due to our assumptions to estimate oil and natural gas wells drilled from the total wells drilled reported by the *Oil and Gas Journal*. The OGJ150 lists new wells drilled by firm in 2008 and 2009, but the drilling counts are not specific to crude oil or natural gas wells. We apportion the wells drilled to natural gas and crude oil wells using the distribution of well drilling in 2009 (63 percent natural gas and 37 percent oil).

Table 7-20 Descriptive Statistics of Estimated Wells Drilled, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

			Estimated Average Wells Natural Gas and Crude Oil Wells Drilled (2008 and 2009)				
Well Type	Firm Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Natural Gas							
	Small	76	2,288.3	30.1	6.0	0.2	259.3
	Large	45	9,445.1	209.9	149.1	0.6	868.3
	Subtotal	121	11,733.4	97.0	28.3	0.2	868.3
Crude Oil							
	Small	76	1,317.1	17.3	3.5	0.1	149.2
	Large	45	5,436.3	120.8	85.8	0.4	499.7
	Subtotal	121	6,753.4	55.8	16.3	0.1	499.7
Total							
	Small	**76**	**3,605.4**	**47.4**	**9.5**	**0.0**	**408.5**
	Large	**45**	**14,881.4**	**330.7**	**234.9**	**0.0**	**1,368.0**
	Total	**121**	**18,486.8**	**152.8**	**44.6**	**0.0**	**1,368.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

This table highlights the fact that many firms drill relatively few wells; the median for small firms is 6 natural gas wells compared to 149 for large firms. Later in this section, we examine whether this distribution has implications for the engineering costs estimates, as well as the estimates of expected natural product recovery from controls such as RECs.

Unlike the analysis that follows for the analysis of impacts on small business from the NESHAP amendments, we have no specific data on potentially affected facilities under the NSPS. The NSPS will apply to new and modified sources, for which data are not fully available in advance, particularly in the case of new and modified sources such as well completions and recompletions which are spatially diffuse and potentially large in number.

The engineering cost analysis estimated compliance costs in a top-down fashion, projecting the number of new sources at an annual level and multiplying these estimates by model unit-level costs to estimate national impacts. To estimate per-firm compliance costs in this analysis, we followed a procedure similar to that of entering estimate compliance costs in NEMS on a per well basis. We first use the OGJ150-based list to estimate engineering compliance costs for integrated and production companies that may operate facilities in more than one segment of the oil and natural gas industry. We then estimate the compliance costs per crude oil and natural gas well by totaling all compliance costs estimates in the engineering cost estimates for the proposed NSPS and dividing that cost by the total number of crude oil and natural gas wells forecast as of 2015, the year of analysis. These compliance costs include the expected revenue from natural gas and condensate recovery that result from implementation of some proposed controls.

This estimation procedure yielded an estimate of crude well compliance costs of $162 per drilled well and natural gas well compliance costs of $38,719 without considering estimated revenues from product recovery and -$2,455 per drilled well with estimated revenues from product recovery included. Note that the divergence of estimated per well costs between crude oil and natural gas wells is because the proposed NSPS requirements are primary directed toward natural gas wells. Also note that the per well cost savings estimate for natural gas wells is different than the estimated cost of implementing a REC; this difference is because this estimate is picking up savings from other control options. We then estimate a single-year, firm-level compliance cost for this subset of firms by multiplying the per well cost estimates with the well count estimates.

The OGJ reports plant processing capacity in terms of MMcf/day. In the energy system impacts analysis, the NEMS model estimates a 6.5 percent increase (from 21.05 tcf in 2011 to 22.43 tcf in 2015) in domestic natural gas production from 2011 to 2015, the analysis year. On this, basis, we estimate that natural gas processing capacity for all plants in the OGJ list will increase 1.3 percent per year. This annual increment is equivalent to an increase in national gas processing capacity of 350 bcf per year. We assume that the engineering compliance costs estimates associated with processing are distributed according to the proportion of the increased national processing capacity contributed by each processing plant. These costs are estimated at $6.9 million without estimated revenues from product recovery and $2.3 million with estimated revenues from product recovery, respectively, in 2008 dollars, or about $20/MMcf without revenues and $7/MMcf with revenues.

The OGJ report on pipeline companies has the advantage that it reports expenditures on plant additions. We assume that the firm-level proposed compression and transmission-related NSPS compliance costs are proportional to the expenditures on plant additions and that these additions reflect a representative year or this analysis. We estimate the annual compression and transmission-related NSPS compliance costs at $5.5 million without estimated revenues from product recovery and $3.7 million with estimated revenues from product recovery, respectively, in 2008 dollars.

7.4.3.2 Small Entity Impact Analysis, Proposed NSPS, Results

Summing estimated annualized engineering compliance costs across industry segment and individual firms in our sample, we estimate firms in the OGJ-based sample will face about $480 million in 2008 dollars, about 65 percent of the estimated annualized costs of the Proposed NSPS without including revenues from additional product recovery ($740 million). When including revenues from additional product recovery, the estimated compliance costs for the firms in the sample is about -$23 million, compared to engineering cost estimate of -$45 million.

Table 7-21 presents the distribution of estimated proposed NSPS compliance costs across firm size for the firms within our sample. Evident from this table, about 98 percent of the estimated engineering compliance costs accrue to the integrated and production segment of the industry, again explain by the fact that completion-related requirements contribute the bulk of the estimated engineering compliance costs (as well as estimated emissions reductions). About 17 percent of the total estimated engineering compliance costs (and about 18 percent of the costs accruing the integrated and production segment) are focused on small firms.

Table 7-21 Distribution of Estimated Proposed NSPS Compliance Costs Without Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs Without Estimated Revenues from Natural Gas Product Recovery (2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	82,293,903	1,041,695	221,467	3,210	10,054,401
Large	49	387,489,928	7,907,958	5,730,634	15,238	33,677,388
Subtotal	128	469,783,831	3,670,186	969,519	3,210	33,677,388
Pipeline						
Small	11	3,386	308	111	18	1,144
Large	36	1,486,929	41,304	3,821	37	900,696
Subtotal	47	1,490,314	31,709	2,263	18	900,696
Processing						
Small	39	476,165	12,209	1,882	188	276,343
Large	23	859,507	37,370	8,132	38	423,645
Subtotal	62	1,335,672	21,543	2,730	38	423,645
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	5,431,510	417,808	147,925	2,003	2,630,236
Subtotal	13	5,431,510	417,808	147,925	2,003	2,630,236
Total						
Small	**129**	**82,773,454**	**641,655**	**49,386**	**18**	**10,054,401**
Large	**121**	**395,267,874**	**3,266,677**	**57,220**	**37**	**33,677,388**
Total	**250**	**478,041,328**	**1,912,165**	**55,888**	**18**	**33,677,388**

These distributions are similar when the revenues from expected natural gas recovery are included (Table 7-22). About 21 percent of the total savings from the proposed NSPS is expected to accrue to small firms (about 19 percent of the savings to the integrated and production segment accrue to small firms). Note also in Table 7-22 that the pipeline and processing segments (and the pipeline/processing firms) are not expected to experience net cost savings (negative costs) from the proposed NSPS.

Table 7-22 Distribution of Estimated Proposed NSPS Compliance Costs With Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs With Estimated Revenues from Natural Gas Product Recovery (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	-5,065,551	-64,121	-13,729	-620,880	8,699
Large	49	-22,197,126	-453,003	-318,551	-2,072,384	423,760
Subtotal	128	-27,262,676	-212,990	-43,479	-2,072,384	423,760
Pipeline						
Small	11	2,303	209	76	12	779
Large	36	1,011,572	28,099	2,599	25	612,753
Subtotal	47	1,013,876	21,572	1,539	12	612,753
Processing						
Small	39	160,248	4,109	634	63	93,000
Large	23	289,258	12,576	2,737	13	142,573
Subtotal	62	449,506	7,250	919	13	142,573
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	3,060,373	235,413	86,301	716	1,746,730
Subtotal	13	3,060,373	235,413	86,301	716	1,746,730
Total						
Small	**129**	**-4,902,999**	**-38,008**	**-2,520**	**-620,880**	**93,000**
Large	**121**	**-17,835,922**	**-147,404**	**634**	**-2,072,384**	**1,746,730**
Total	**250**	**-22,738,922**	**-90,956**	**22**	**-2,072,384**	**1,746,730**

Table 7-23 Summary of Sales Test Ratios, Without Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio Without Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	2.18%	0.49%	0.01%	50.83%
Large	49	0.41%	0.28%	<0.01%	2.83%
Subtotal	128	1.50%	0.39%	<0.01%	50.83%
Pipeline					
Small	11	<0.01%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.06%
Subtotal	47	0.01%	<0.01%	<0.01%	0.06%
Processing					
Small	39	0.05%	0.01%	<0.01%	0.33%
Large	23	0.02%	0.01%	<0.01%	0.15%
Subtotal	62	0.04%	0.01%	<0.01%	0.33%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**1.34%**	**0.15%**	**<0.01%**	**50.83%**
Large	**121**	**0.17%**	**0.01%**	**<0.01%**	**2.83%**
Total	**250**	**0.78%**	**0.03%**	**<0.01%**	**50.83%**

The mean cost-sales ratio for all businesses when estimated product recovery is excluded from the analysis of the sample data is 0.78 percent, with a median ratio of 0.03 percent, a minimum of less than 0.01 percent, and a maximum of over 50 percent (Table 7-23). For small firms in the sample, the mean and median cost-sales ratios are 1.34 percent and 0.15 percent, respectively, with a minimum of less than 0.01 percent and a maximum of over 50 percent (Table 7-23). Each of these statistics indicates that, when considered in the aggregate, impacts are relatively higher on small firms than large firms when the estimated revenue from additional natural gas product recovery is excluded. However, as the next table shows, the reverse is true when these revenues are included.

Table 7-24 Summary of Sales Test Ratios, With Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio With Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	-0.13%	-0.03%	-2.96%	<0.00%
Large	49	-0.02%	-0.02%	-0.17%	0.06%
Subtotal	128	-0.09%	-0.02%	-2.96%	0.06%
Pipeline					
Small	11	<0.00%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.04%
Subtotal	47	0.01%	<0.01%	<0.01%	0.04%
Processing					
Small	39	0.01%	<0.01%	<0.01%	0.05%
Large	23	<0.00%	<0.01%	<0.01%	0.05%
Subtotal	62	0.01%	<0.01%	<0.01%	0.05%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**-0.08%**	**-0.01%**	**-2.96%**	**0.05%**
Large	**121**	**-0.01%**	**<0.01%**	**-0.17%**	**0.06%**
Total	**250**	**-0.04%**	**<0.01%**	**-2.96%**	**0.06%**

The mean cost-sales ratio for all businesses when estimated product recovery is included is in the sample is -0.04 percent, with a median ratio of less than 0.01 percent, a minimum of -2.96 percent, and a maximum of 0.06 percent (Table 7-24). For small firms in the sample, the mean and median cost-sales ratios are -0.08 percent and -0.01 percent, respectively, with a minimum of -2.96 percent and a maximum of 0.05 percent (Table 7-24). Each of these statistics indicates that, when considered in the aggregate, impacts are small on small business when the estimated revenue from additional natural gas product recovery are included, the reverse of the conclusion found when these revenues are excluded.

Meanwhile, Table 7-25 presents the distribution of estimated cost-sales ratios for the small firms in our sample with and without including estimates of the expected natural gas product recover from implementing controls. When revenues estimates are included, all 129 firms (100 percent) have estimated cost-sales ratios less than 1 percent. While less than 1 percent, the highest cost-sales ratios for small firms in the sample experiencing impacts are largely driven by costs accruing to processing and pipeline firms. That said, the incremental costs imposed on firms that process natural gas or transport natural gas via pipelines are not estimated to create significant impacts on a cost-sales ratio basis at the firm-level.

Table 7-25 Impact Levels of Proposed NSPS on Small Firms as a Percent of Small Firms in Sample, With and Without Revenues from Additional Natural Gas Product Recovery

	Without Estimated Revenues from Natural Gas Product Recovery		With Estimated Revenues from Natural Gas Product Recovery	
Impact Level	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected
C/S Ratio less than 1%	109	84.5%	129	100.00%
C/S Ratio 1-3%	11	8.5%	0	0.00%
CS Ratio greater than 3%	9	7.0%	0	0.00%

When the estimated revenues from product recovery are not included in the analysis, 11 firms (about 9 percent) are estimated to have sales test ratios between 1 and 3 percent. Nine firms (about 7 percent) are estimated to have sales test ratios greater than 3 percent. These results noted, the exclusion of product recovery is somewhat artificial. While the mean engineering compliance costs and revenues estimates are valid, drawing on the means ignores the distribution around the mean estimates, which risks masking effects. Because of this risk, the following section offers a qualitative discussion of small entities with regard to obtaining REC services, the validity of the cost and performance of RECs for small firms, as well as offers a discussion about whether older equipment, which may be disproportionately owned and operated be smaller producers, would be affected by the proposed NSPS.

7.4.3.3 Small Entity Impact Analysis, Proposed NSPS, Additional Qualitative Discussion

3.5.3.3.1 Small Entities and Reduced Emissions Completions

Because REC requirements of the proposed NSPS are expected to contribute the large majority of engineering compliance costs, it is important to examine these requirements more closely in the context small entities. Important issues to resolve are the scale of REC costs within a drilling project, how the payment system for recovered natural gas functions, whether small entities pursue particular “niche” strategies that may influence the costs or performance in a way that makes the estimates costs and revenues invalid.

According to the most recent natural gas well cost data from EIA, the average cost of drilling and completing a producing natural gas well in 2007 was about $4.8 million (adjusted to 2008 dollars). This average includes lower cost wells that may be relatively shallow or are not hydraulically fractured. Hydraulically fractured wells in deep formations may cost up to $10 million. RECs contracted from a service provider are estimated to cost $33,200 (in 2008 dollars) or roughly 0.3%-0.7% of the typical cost of a drilling and completing a natural gas well. As this range does not include revenues expected from natural gas and hydrocarbon condensate recovery expected to offset REC implementation costs, REC costs likely represent a small increment of the overall burden of a drilling project.

To implement an REC, a service provider, which may itself be a small entity, is typically contracted to bring a set of equipment to the well pad temporarily to capture the stream that would otherwise be vented to the atmosphere. Typically, service providers are engaged in a long term drilling program in a particular basin covering multiple wells on multiple well pads. For gas captured and sold to the gathering system, Lease Automatic Custody Transfer (LACT) meters are normally read daily automatically, and sales transactions are typically settled at the end of the month. Invoices from service providers are generally delivered in 30-day increments during the well development time period, as well as at the end of the working contract for that well pad. The conclusion from the information, based on the available information, in most cases, the owner/operator incurs the REC cost within the same 30 day period that the owner/operator receives revenue as a result of the REC.

We assume small firms are performing RECs in CO and WY, as in many instances RECs are required under state regulation. In addition to State regulations, some companies are implementing RECs voluntarily such as through participation in the EPA Natural Gas STAR Program and the focus of recent press reports.

As described in more detail below, many small independent E&P companies often do not conduct any of the actual field work. These firms will typically contract the drilling, completion, testing, well design, environmental assessment, and maintenance. Therefore, we believe it is likely that small independent E&P firms will contract for RECs from service providers if required to perform RECs. An important reminder is that performing a REC is a straightforward and inexpensive extension of drilling, completion, and testing activities.

To the extent that very small firms may specialize in operating relatively few low-producing stripper wells, it is important to ask whether low-producing wells are likely candidates for re-fracturing/re-completion and, if so, whether the expected costs and revenues would be valid. These marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion. To the extent the marginal wells may be good candidates for re-fracturing/completion, the REC costs are valid estimates. The average REC cost is valid for RECs performed on any well, regardless of the operator size. The reason for this is that the REC service is contracted out to specialty service providers who charge daily rates for the REC equipment and workers. The cost is not related to any well characteristic.

Large operators may receive a discount for offering larger contracts which help a service provider guarantee that REC equipment will be utilized. However, we should note that the existence of a potential discount for larger contracts is based on a strong assumption; we do not have evidence to support this assumption. Since contracting REC equipment is analogous to contracting for drilling equipment, completion equipment, etc., the premium would likely be in the same range as other equipment contracted by small operators. Since the REC cost is a small portion of the overall well drilling and completion cost, the effect of any bulk discount disparity between large and small operators will be small, if in fact it does exist.

Although small operators may own the majority of marginal and stripper wells, they will make decisions based on economics just as any sized company would. For developing a new well, any sized company will expect a return on their investment meaning the potential for sufficient gas, condensate, and/or oil production to pay back their investment and generate a return that exceeds alternative investment opportunities. Therefore, small or large operators that are performing hydraulic fracture completions will experience the same distribution of REC performance. For refracturing an existing well, the well must be a good candidate to respond to the re-fracture/completion with a production increase that merits the investment in the re-fracture/completion.

Plugging and abandoning wells is complex and costly, so sustaining the productivity of wells is important for maximizing the exploitation of proven domestic resources. However, many marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion, which means they are likely unaffected by the proposed NSPS.

3.5.3.3.2 Age of Equipment and Proposed Regulations

Given a large fraction of domestic oil and natural gas production is produced from older and generally low productivity wells, it is important to examine whether the proposed requirements might present impediments to owners and operators of older equipment. The NSPS is a standard that applies to new or modified sources. Because of this, NSPS requirements target new or modified affected facilities or equipment, such as processing plants and compressors. While the requirements may apply to modifications of existing facilities, it is important to discuss well completion-related requirements aside from other requirements in the NSPS distinctly.

Excluding well completion requirements from the cost estimates, the non-completion NSPS requirements (related to equipment leaks at processing plants, reciprocating and centrifugal compressors, pneumatic controllers, and storage vessels) are estimated to require $27 million in annualized engineering costs. EPA also estimates that the annualized costs of these requirements will be mostly if not fully offset by revenues expected from natural gas recovery. EPA does not expect these requirements to disproportionately affect producers with older equipment. Meanwhile, the REC and emissions combustion requirements in the proposed NSPS relate to well completion activities at new hydraulically fractured natural gas wells and existing wells which are recompleted after being fractured or re-fractured. These requirements constitute the bulk of the expected engineering compliance expenditures (about $710 million in annualized costs) and expected revenues from natural gas product recovery (about $760 million in revenues, annually).

While age of the well and equipment may be an important factor for small and large producers in determining whether it is economical to fracture or re-fracture an existing well, this equipment is unlikely to be subject to the NSPS. To comply with completion-related requirements, producers are likely to rely heavily on portable and temporary completion equipment brought to the wellpad over a short period of time (a few days to a few weeks) to capture and combust emissions that are otherwise vented. The equipment at the wellhead—newly installed in the case of new well completions or already in place and operating in the case of existing wells—is not likely to be subject to the NSPS requirement.

7.4.3.4 Small Entity Impact Analysis, Proposed NSPS, Screening Analysis Conclusion

The number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to reduced emissions completion activities occur without a significant time lag between implementing the control and obtaining the recovered product unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

7.4.4 Small Entity Economic Impact Analysis, Proposed NESHAP Amendments

The proposed NESHAP amendments will affect facilities operating three types of equipment: glycol dehydrators at production facilities, glycol dehydrators at transmission and compression facilities, and storage vessels. We identified likely affected facilities in the National Emissions Inventory (NEI) and estimated the number of newly required controls of each type that would be required by the NESHAP amendments for each facility. We then used available data sources to best identify the ultimate owner of the equipment that would likely require new controls and linked facility-level compliance cost estimates to firm-level employment and revenue data. These data were then used to calculate an estimated compliance costs to revenues ratio to identify small businesses that might be significantly impacted by the NESHAP.

While we were able to identify the owners all but 14 facilities likely to be affected, we could not obtain employment and revenue levels for all of these firms. Overall, we expect about 447 facilities to be affected, and these facilities are owned by an estimated 160 firms. We were unable to obtain financial information on 42 (26 percent) of these firms due to inadequate data. In some instances, firms are private, and financial data is not available. In other instance, firms may no longer exist, since NEI data are not updated continuously. From the ownership information and compliance cost estimates from the engineering analysis, we estimated total compliance cost per firm.

Of the 118 firms for which we have financial information, we identified 62 small firms and 56 large firms that would be affected by the NESHAP amendments. Annual compliance costs for small firms are estimated at $3.0 million (18 percent of the total compliance costs), and annual compliance costs for large firms are estimated at $10.7 million (67 percent of the total compliance costs). The facilities for which we were unable to identify the ultimate owners, employment, and revenue levels would have an estimated annual compliance cost of $2.3 million (15 percent of the total). All figures are in 2008 dollars.

The average estimated annualized compliance cost for the 62 small firms identified in the dataset is $48,000, while the mean annual revenue figure for the same firms is over $120 million, or less than 1 percent for a average sales-test ratio for all 62 firms (Table 7-26). The median sale-test ratio for these firms is smaller at 0.14 percent. Large firms are likely to see an average of $190,000 in annual compliance costs, whereas average revenue for these firms exceeds $30 billion since this set of firms includes many of the very large, integrated energy firms. For large firms, the average sales-test ratio is about 0.01 percent, and the median sales-test ratio is less than 0.01 percent (Table 7-26).

Table 7-26 Summary of Sales Test Ratios for Firms Affected by Proposed NESHAP Amendments

Firm Size	No. of Known Affected Firms	% of Total Known Affected Firms	Mean C/S Ratio	Median C/S Ratio	Min. C/S Ratio	Max. C/S Ratio
Small	62	53%	0.62%	0.14%	< 0.01%	6.2%
Large	56	47%	0.01%	< 0.01%	< 0.01%	0.4%
All	118	100%	0.34%	0.02%	< 0.01%	6.2%

Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent (Table 7-27). Four of these 10 firms are likely to have impacts greater than 3 percent (Table 7-27) While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211 (Table 7-27).

Table 7-27 Affected Small Firms as a Percent of Small Firms Nationwide, Proposed NESHAP amendments

Firm Size	Number of Small Firms Affected Nationwide	% of Small Firms Affected Nationwide	Affected Firms as a % of National Firms (6,427)
C/S Ratio less than 1%	52	83.9%	0.81%
C/S Ratio 1-3%	6	9.7%	0.09%
CS Ratio greater than 3%	4	6.5%	0.06%

Screening Analysis Conclusion: While there are significant impacts on small business, the analysis shows that a substantial number of small firms are not impacted. Based upon the analysis in this section, we presume there is no SISNOSE arising from the proposed NESHAP amendments.

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ORIGINAL ARTICLE

Long-Term Ozone Exposure and Mortality

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ABSTRACT

BACKGROUND

Although many studies have linked elevations in tropospheric ozone to adverse health outcomes, the effect of long-term exposure to ozone on air pollution–related mortality remains uncertain. We examined the potential contribution of exposure to ozone to the risk of death from cardiopulmonary causes and specifically to death from respiratory causes.

METHODS

Data from the study cohort of the American Cancer Society Cancer Prevention Study II were correlated with air-pollution data from 96 metropolitan statistical areas in the United States. Data were analyzed from 448,850 subjects, with 118,777 deaths in an 18-year follow-up period. Data on daily maximum ozone concentrations were obtained from April 1 to September 30 for the years 1977 through 2000. Data on concentrations of fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) were obtained for the years 1999 and 2000. Associations between ozone concentrations and the risk of death were evaluated with the use of standard and multilevel Cox regression models.

RESULTS

In single-pollutant models, increased concentrations of either $PM_{2.5}$ or ozone were significantly associated with an increased risk of death from cardiopulmonary causes. In two-pollutant models, $PM_{2.5}$ was associated with the risk of death from cardiovascular causes, whereas ozone was associated with the risk of death from respiratory causes. The estimated relative risk of death from respiratory causes that was associated with an increment in ozone concentration of 10 ppb was 1.040 (95% confidence interval, 1.010 to 1.067). The association of ozone with the risk of death from respiratory causes was insensitive to adjustment for confounders and to the type of statistical model used.

CONCLUSIONS

In this large study, we were not able to detect an effect of ozone on the risk of death from cardiovascular causes when the concentration of $PM_{2.5}$ was taken into account. We did, however, demonstrate a significant increase in the risk of death from respiratory causes in association with an increase in ozone concentration.

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STUDIES CONDUCTED OVER THE PAST 15 years have provided substantial evidence that long-term exposure to air pollution is a risk factor for cardiopulmonary disease and death.[1-5] Recent reviews of this literature suggest that fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) has a primary role in these adverse health effects.[6,7] The particulate-matter component of air pollution includes complex mixtures of metals, black carbon, sulfates, nitrates, and other direct and indirect byproducts of incomplete combustion and high-temperature industrial processes.

Ozone is a single, well-defined pollutant, yet the effect of exposure to ozone on air pollution–related mortality remains inconclusive. Several studies have evaluated this issue, but they have been short-term studies,[8-10] have failed to show a statistically significant effect,[1,3] or have been based on limited mortality data.[11] Recent reviews by the Environmental Protection Agency (EPA)[12] and the National Research Council[13] have questioned the overall consistency of the available data correlating exposure to ozone and mortality. Similar conclusions about the evidence base for the long-term effects of ozone on mortality were drawn by a panel of experts in the United Kingdom.[14]

Nonetheless, previous studies have suggested that a measurable effect of ozone may exist, particularly with respect to the risk of death from cardiopulmonary causes. In one of the larger studies, ozone was significantly associated with death from cardiopulmonary causes[15] but not with death from ischemic heart disease. However, the estimated effect of ozone on the risk of death from cardiopulmonary causes in this study was attenuated when $PM_{2.5}$ was added to the analysis in copollutant models. On the basis of suggested effects of ozone on the risk of death from cardiopulmonary causes (which includes death from respiratory causes) but an absence of evidence for effects of ozone on the risk of death from ischemic heart disease, we hypothesized that ozone might have a primary effect on the risk of death from respiratory causes.

METHODS

HEALTH, MORTALITY, AND CONFOUNDING DATA

Our study used data from the American Cancer Society Cancer Prevention Study II (CPS II) cohort.[16] The CPS II cohort consists of more than 1.2 million participants who were enrolled by American Cancer Society volunteers between September 1982 and February 1983 in all 50 states, the District of Columbia, and Puerto Rico. Enrollment was restricted to persons who were at least 30 years of age living in households with at least one person 45 years of age or older. After providing written informed consent, the participants completed a confidential questionnaire that included questions on demographic characteristics, smoking history, alcohol use, diet, and education.[17] Deaths were ascertained until August 1988 by personal inquiries of family members by the volunteers and thereafter by linkage with the National Death Index. Through 1995, death certificates were obtained and coded for cause of death. Beginning in 1996, codes for cause of death were provided by the National Death Index.[18]

The study population for our analysis included only those participants in CPS II who resided in U.S. metropolitan statistical areas within the 48 contiguous states or the District of Columbia (according to their address at the time of enrollment) and for whom data were available from at least one pollution monitor within their metropolitan area. The study was approved by the Ottawa Hospital Research Ethics Board, Canada.

Data on "ecologic" risk factors at the level of the metropolitan area representing social variables (educational level, percentage of homes with air conditioning, percentage of the population who were nonwhite), economic variables (household income, unemployment, income disparity), access to medical care (number of physicians and hospital beds per capita), and meteorologic variables were obtained from the 1980 U.S. Census and other secondary sources (see the Supplementary Appendix, available with the full text of this article at NEJM.org). These ecologic risk factors, as well as the individual risk factors collected in the CPS II questionnaire, were assessed as potential confounders of the effects of ozone.[3,5,19,20]

ESTIMATES OF EXPOSURE TO AIR POLLUTION

Ozone data were obtained from 1977 (5 years before the identification of the CPS II cohort) through 2000 for all air-pollution monitors in the study metropolitan areas from the EPA's Aerometric Information Retrieval System. Ozone data at each monitoring site were collected on an hourly basis, and the daily maximum value for the site was determined. All available daily maximum values for the monitoring site were averaged over each quarter year. The quarterly average values were reported for each monitor only when at least 75% of daily observations for that quarter were available.

The averages of the second (April through June) and third (July through September) quarters were calculated for each monitor if both quarterly averages were available. The period from April through September was selected because ozone concentrations tend to be elevated during the warmer seasons and because fewer data were available for the cooler seasons.

The average of the second and third quarterly averages for each year was then computed for all the monitors within each metropolitan area to form a single annual time series of air-pollution measurements for each metropolitan area for the period from 1977 to 2000. In addition, a summary measure of long-term exposure to ambient warm-season ozone was defined as the average of annual time-series measurements during the entire period from 1977 to 2000. Individual measures of exposure to ozone were then defined by assigning the average for the metropolitan area to each cohort member residing in that area.

Data on exposure to $PM_{2.5}$ were also obtained from the Aerometric Information Retrieval System database for the 2-year period from 1999 to 2000 (data on $PM_{2.5}$ were not available before 1999 for most metropolitan areas).[5] The average concentrations of $PM_{2.5}$ were included in our analyses to distinguish the effect of particulates from that of ozone on outcomes.

STATISTICAL ANALYSIS

Standard and multilevel random-effects Cox proportional-hazard models were used to assess the risk of death in relation to exposures to pollution. The subjects were matched according to age (in years), sex, and race. A total of 20 variables with 44 terms were used to control for individual characteristics that might confound or modify the association between air pollution and death. These variables, which were considered to be of potential importance on the basis of previous studies, included individual risk factors for which data had been collected in the CPS II questionnaire. Seven ecologic covariates obtained from the 1980 U.S. Census (median household income, the proportion of persons living in households with an income below 125% of the poverty line, the percentage of persons over the age of 16 years who were unemployed, the percentage of adults with less than a high-school [12th-grade] education, the percentage of homes with air conditioning, the Gini coefficient of income inequality [ranging from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income[20]], and the percentage of persons who were white) were also included. These variables were included at two levels: as the average for the metropolitan statistical area and as the difference between the average for the ZIP Code of residence and the average for the metropolitan statistical area. Additional sensitivity analyses were undertaken for ecologic variables that were available for only a subgroup of the 96 metropolitan statistical areas (see the Supplementary Appendix). Models were estimated for either ozone or $PM_{2.5}$. In addition, models with both $PM_{2.5}$ and ozone were estimated.

In additional analyses, our basic Cox models were modified by incorporating an adjustment for community-level random effects, which allowed us to take into account residual variation in mortality among communities.[21] The baseline hazard function was modulated by a community-specific random variable representing the residual risk of death for subjects in that community after individual and ecologic risk factors had been controlled for (see the Supplementary Appendix).

A formal analysis was conducted to assess whether a threshold existed for the association between exposure to ozone and the risk of death (see the Supplementary Appendix). A standard threshold model was postulated in which there was no association between exposure to ozone and the risk of death below a specified threshold concentration and a linear association (on the logarithmic scale of the proportional-hazards model) above the threshold.

The question of whether specific time windows were associated with the health effects was investigated by subdividing the follow-up interval into four periods (1982 to 1988, 1989 to 1992, 1993 to 1996, and 1997 to 2000). Exposures were matched for each of these periods and also tested for a 10-year average on the basis of the 5-year follow-up period and the 5 years before the follow-up period (see the Supplementary Appendix).

RESULTS

The analytic cohort included 448,850 subjects residing in 96 metropolitan statistical areas (Fig. 1).

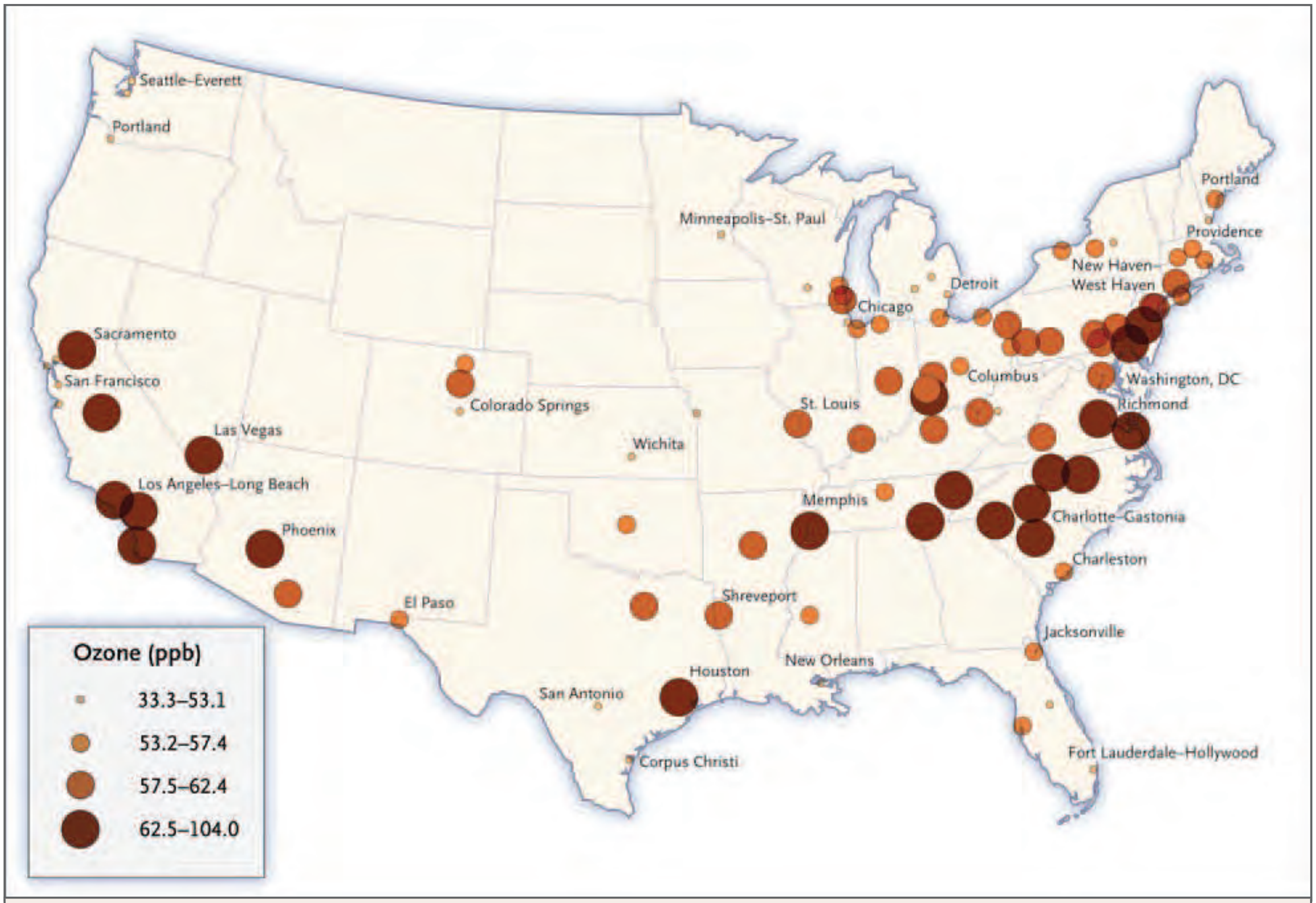

Figure 1. Ozone Concentrations in the 96 Metropolitan Statistical Areas in Which Members of the American Cancer Society Cohort Resided in 1982.

The average exposures were estimated from 1 to 57 monitoring sites within each metropolitan area from April 1 to September 30 for the years 1977 through 2000.

In 1980, the populations of these 96 areas ranged from 94,436 to 8,295,900. Data were available on the concentration of ambient ozone from all 96 areas and on the concentration of $PM_{2.5}$ from 86 areas. The average number of air-pollution monitors per metropolitan area was 11 (range, 1 to 57), and more than 80% of the areas had 6 or more monitors.

The average ozone concentration for each metropolitan area during the interval from 1977 to 2000 ranged from 33.3 ppb to 104.0 ppb (Fig. 1). The highest regional concentrations were in Southern California and the lowest in the Pacific Northwest and parts of the Great Plains. Moderately elevated concentrations were present in many areas of the East, Midwest, South, and Southwest.

The baseline characteristics of the study population, overall and as a function of exposure to ozone, are presented in Table 1. The mean age of the cohort was 56.6 years, 43.4% were men, 93.7% were white, 22.4% were current smokers, and 30.5% were former smokers. On the basis of estimates from 1980 Census data, 62.3% of homes had air conditioning at the time of initial data collection.

During the 18-year follow-up period (from initial CPS II data collection in 1982 through the end of follow-up in 2000), there were 118,777 deaths in the study cohort (Table 2). Of these, 58,775 were from cardiopulmonary causes, including 48,884 from cardiovascular causes (of which 27,642 were due to ischemic heart disease) and 9891 from respiratory causes.

In the single-pollutant models, exposure to ozone was not associated with the overall risk of death (relative risk, 1.001; 95% confidence interval [CI], 0.996 to 1.007) (Table 3). However, it was significantly correlated with an increase in the risk of death from cardiopulmonary causes. A

10-ppb increment in exposure to ozone elevated the relative risk of death from the following causes: cardiopulmonary causes (relative risk, 1.014; 95% CI, 1.007 to 1.022), cardiovascular causes (relative risk, 1.011; 95% CI, 1.003 to 1.023), ischemic heart disease (relative risk, 1.015; 95% CI, 1.003 to 1.026), and respiratory causes (relative risk, 1.029; 95% CI, 1.010 to 1.048).

Inclusion of the concentration of $PM_{2.5}$ measured in 1999 and 2000 as a copollutant (Table 3) attenuated the association with exposure to ozone for all the end points except death from respiratory causes, for which a significant correlation persisted (relative risk, 1.040; 95% CI, 1.013 to 1.067). The concentrations of ozone and $PM_{2.5}$ were positively correlated (r=0.64 at the subject level and r=0.56 at the metropolitan-area level), resulting in unstable risk estimates for both pollutants. The concentration of $PM_{2.5}$ remained significantly associated with death from cardio-

Table 1. Baseline Characteristics of the Study Population in the Entire Cohort and According to Exposure to Ozone.*

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
No. of MSAs	96	24	24	24	24
No. of MSAs with data on $PM_{2.5}$	86	21	20	23	22
Concentration of $PM_{2.5}$ ($\mu g/m^3$)		11.9±2.5	13.1±2.9	14.7±2.1	15.4±3.2
Individual risk factors					
Age (yr)	56.6±10.5	56.7±10.4	56.4±10.7	56.3±10.4	56.9±10.5
Male sex (%)	43.4	43.5	43.1	43.5	43.2
White race (%)	93.7	94.3	95.1	93.9	91.8
Education (%)					
Less than high school	12.1	11.5	13.6	12.1	11.6
High school	30.6	30.2	33.6	32.1	27.4
Beyond high school	57.3	58.3	52.8	55.8	61.0
Smoking status					
Current smokers					
Percentage of subjects	22.4	22.0	23.5	22.2	21.9
No. of cigarettes/day	22.0±12.4	22.0±12.3	22.0±12.5	22.2±12.5	21.9±12.4
Duration of smoking (yr)	33.5±11.0	33.4±10.8	33.4±11.1	33.4±11.0	33.9±11.2
Started smoking <18 yr of age (%)	9.6	9.3	10.5	9.4	9.3
Started smoking ≥18 yr of age (%)	13.2	13.3	13.4	13.3	13.0
Former smokers					
Percentage of subjects	30.5	31.2	30.8	29.5	30.4
No. of cigarettes/day	21.6±14.7	21.6±14.6	22.2±15.1	21.6±14.6	21.3±14.6
Duration of smoking (yr)	22.2±12.6	22.1±12.5	22.6±12.6	22.0±12.5	22.4±12.7
Started smoking <18 yr of age (%)	11.9	11.8	12.7	11.5	11.8
Started smoking ≥18 yr of age (%)	18.5	19.3	17.9	17.9	18.5
Exposure to smoking (hr/day)	3.3±4.4	3.2±4.4	3.4±4.5	3.4±4.5	3.1±4.4
Pipe or cigar smoker only (%)	4.1	4.0	4.2	4.3	3.8
Marital status (%)					
Married	83.5	84.2	83.0	83.7	83.1
Single	3.6	3.4	4.0	3.8	3.2
Separated, divorced, or widowed	12.9	12.4	13.0	12.5	13.7

Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Body-mass index†	25.1±4.1	25.1±4.1	25.3±4.2	25.1±4.1	24.8±4.0
Level of occupational exposure to particulate matter (%)‡					
0	50.7	50.9	50.0	50.8	51.0
1	13.3	13.4	13.1	13.3	13.3
2	11.4	11.5	10.8	11.4	11.9
3	4.6	4.7	4.8	4.6	4.5
4	6.1	6.2	6.2	6.1	6.0
5	4.2	4.2	4.3	4.1	4.1
6	1.1	1.0	9.5	1.4	8.4
Not able to ascertain	8.6	8.2	1.2	8.4	0.9
Self-reported exposure to dust or fumes (%)	19.5	19.5	19.8	19.7	19.1
Level of dietary-fat consumption (%)§					
0	14.5	13.7	14.9	14.1	15.3
1	15.9	15.8	16.5	15.6	15.9
2	17.4	17.6	17.7	17.2	17.1
3	21.2	21.8	21.1	21.3	20.8
4	30.9	31.1	29.8	31.9	30.9
Level of dietary-fiber consumption (%)¶					
0	16.6	16.0	17.5	16.7	16.6
1	19.9	19.4	20.5	20.1	19.7
2	18.8	18.6	19.2	19.1	18.5
3	22.8	23.0	22.4	22.8	22.7
4	21.9	23.0	20.4	21.3	22.5
Alcohol consumption (%)					
Beer					
Drinks beer	22.9	24.3	23.2	22.9	21.4
Does not drink beer	9.7	9.5	9.3	9.5	10.2
No data	67.4	66.2	67.5	67.6	68.4
Liquor					
Drinks liquor	28.0	30.4	27.9	25.4	27.9
Does not drink liquor	8.8	8.4	8.5	10.1	9.2
No data	63.2	61.2	63.6	65.5	62.9
Wine					
Drinks wine	23.5	25.4	22.5	21.1	24.3
Does not drink wine	8.9	8.7	8.8	9.3	9.1
No data	67.6	65.9	68.7	69.6	66.6

Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Ecologic risk factors‖					
Nonwhite race (%)	11.6±16.8	10.5±16.4	9.3±15.5	10.2±16.0	15.9±18.3
Home with air conditioning (%)	62.3±27.0	55.4±31.2	59.4±24.0	65.3±24.8	69.1±24.3
High-school education or greater (%)	51.7±8.2	53.5±7.9	52.4±7.5	50.8±7.2	50.0±9.5
Unemployment rate (%)	11.7±3.1	12.1±3.4	11.3±2.6	11.3±2.9	11.8±3.4
Gini coefficient of income inequality**	0.37±0.04	0.37±0.05	0.37±0.04	0.37±0.04	0.38±0.04
Proportion of population with income <125% of poverty line	0.12±0.08	0.11±0.08	0.12±0.08	0.11±0.07	0.13±0.09
Annual household income (thousands of dollars)††	20.7±6.6	21.9±7.1	19.8±6.0	21.2±6.7	19.7±6.3

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Plus–minus values are means ±SD. Because of rounding, percentages may not total 100. All baseline characteristics included in the survival model are listed (age, sex, and race were included as stratification factors). The model also includes squared terms for the number of cigarettes smoked per day and the number of years of smoking for both current and former smokers and a squared term for body-mass index.

† The body-mass index is the weight in kilograms divided by the square of the height in meters.

‡ Occupational exposure to particulate matter increases with increasing index number. The index was calculated by assigning a relative level of exposure to $PM_{2.5}$ associated with a cohort member's job and industry. These assignments were performed by industrial hygienists on the basis of their knowledge of typical exposure patterns for each occupation and specific job.[22]

§ Dietary-fat consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fat consumption according to five ordered categories.[20]

¶ Dietary-fiber consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fiber consumption according to five ordered categories.[23]

‖ For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. Some values for ecologic variables and individual variables differ, although they appear to measure the same risk factor. For example, for the entire cohort, the percentage of whites as listed under individual variables is 93.7, whereas the percentage of nonwhites as listed under ecologic variables is 11.6±16.8. This apparent contradiction is explained by the fact that the former is an exact figure based on the individual reports of the study participants in the CPS II questionnaire, whereas the latter is a mean (±SD) for the population based on Census estimates for each metropolitan statistical area.

** The Gini coefficient is a statistical dispersion measure used to calculate income inequality. The coefficient ranges from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income.[20] A coefficient of 0.37 indicates that on average there is a measurable inequality in the distribution of income among the different income groups within the MSAs.

†† Average household incomes for the cohort and for each quartile of ozone concentration were calculated from the median household income for the metropolitan statistical area.

pulmonary causes, cardiovascular causes, and ischemic heart disease when ozone was included in the model. The association of ozone concentrations with death from respiratory causes remained significant after adjustment for $PM_{2.5}$.

Risk estimates for ozone-related death from respiratory causes were insensitive to the use of a random-effects survival model allowing for spatial clustering within the metropolitan area and state of residence (Table 1S in the Supplementary Appendix). The association between increased ozone concentrations and increased risk of death from respiratory causes was also insensitive to adjustment for several ecologic variables considered individually (Table 2S in the Supplementary Appendix).

Subgroup analyses showed that environmental temperature and region of the country, but not sex, age at enrollment, body-mass index, education, or concentration of $PM_{2.5}$, significantly modified the effects of ozone on the risk of death from respiratory causes (Table 4).

Figure 2 illustrates the shape of the relation between exposure to ozone and death from re-

Table 2. Number of Deaths in the Entire Cohort and According to Exposure to Ozone.

Cause of Death	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
		number of deaths			
Any cause	118,777	32,957	25,642	27,782	32,396
Cardiopulmonary	58,775	16,328	12,621	13,544	16,282
Cardiovascular	48,884	13,605	10,657	11,280	13,342
Ischemic heart disease	27,642	7,714	6,384	6,276	7,268
Respiratory	9,891	2,723	1,964	2,264	2,940

Table 3. Relative Risk of Death Attributable to a 10-ppb Change in the Ambient Ozone Concentration.*

Cause of Death	Single-Pollutant Model†			Two-Pollutant Model‡	
	Ozone (96 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)
	relative risk (95% CI)				
Any cause	1.001 (0.996–1.007)	1.001 (0.996–1.007)	1.048 (1.024–1.071)	0.989 (0.981–0.996)	1.080 (1.048–1.113)
Cardiopulmonary	1.014 (1.007–1.022)	1.016 (1.008–1.024)	1.129 (1.094–1.071)	0.992 (0.982–1.003)	1.153 (1.104–1.204)
Respiratory	1.029 (1.010–1.048)	1.027 (1.007–1.046)	1.031 (0.955–1.113)	1.040 (1.013–1.067)	0.927 (0.836–1.029)
Cardiovascular	1.011 (1.003–1.023)	1.014 (1.005–1.023)	1.150 (1.111–1.191)	0.983 (0.971–0.994)	1.206 (1.150–1.264)
Ischemic heart disease	1.015 (1.003–1.026)	1.017 (1.006–1.029)	1.211 (1.156–1.268)	0.973 (0.958–0.988)	1.306 (1.226–1.390)

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone concentrations were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000; changes in the concentration of $PM_{2.5}$ of 10 μg per cubic meter were recorded for members of the cohort in 1999 and 2000. These models are adjusted for all the individual and ecologic risk factors listed in Table 1. For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. The risk of death was stratified according to age (in years), sex, and race.

† The single-pollutant models were based on 96 metropolitan statistical areas for which information on ozone was available and 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

‡ The two-pollutant models were based on 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

spiratory causes. There was limited evidence that a threshold model specification improved model fit as compared with a nonthreshold linear model (P=0.06) (Table 3S in the Supplementary Appendix).

Because air-pollution data from 1977 to 2000 were averaged, exposure values for persons who died during this period are based partly on data that were obtained after death had occurred. Further investigation by dividing this interval into specific time windows of exposure revealed no significant difference between the effects of earlier and later time windows within the period of follow-up. Allowing for a 10-year period of exposure to ozone (5 years of follow-up and 5 years before the follow-up period) did not appreciably alter the risk estimates (Table 4S in the Supplementary Appendix). Thus, when exposure values were matched more closely to the follow-up period and when exposure values were based on data obtained before the deaths, there was little change in the results.

DISCUSSION

Our principal finding is that ozone and $PM_{2.5}$ contributed independently to increased annual mortality rates in this large, U.S. cohort study in analyses that controlled for many individual and ecologic risk factors. In two-pollutant models that included ozone and $PM_{2.5}$, ozone was significantly associated only with death from respiratory causes.

For every 10-ppb increase in exposure to ozone, we observed an increase in the risk of death from respiratory causes of about 2.9% in single-pollutant models and 4% in two-pollutant models. Although this increase may appear moderate, the risk of dying from a respiratory cause is more than three times as great in the metropolitan areas with the highest ozone concentrations as in those with the lowest ozone concentrations. The effects of ozone on the risk of death from respiratory causes were insensitive to adjustment for individual, neighborhood, and metropolitan-area confounders or to differences in multilevel-model specifications.

There is biologic plausibility for a respiratory effect of ozone. In laboratory studies, ozone can increase airway inflammation[24] and can worsen pulmonary function and gas exchange.[25] In addition, exposure to elevated concentrations of tropospheric ozone has been associated with numerous adverse health effects, including the induction[26] and exacerbation[27,28] of asthma, pulmonary dysfunction,[29,30] and hospitalization for respiratory causes.[31]

Despite these observations, previous studies linking long-term exposure to ozone with death have been inconclusive. One cohort study conducted in the Midwest and eastern United States reported an inverse but nonsignificant association between ozone concentrations and mortality.[1] Subsequent reanalyses of this study replicated these findings but also suggested a positive association with exposure to ozone during warm seasons.[3] A study of approximately 6000 nonsmoking Seventh-Day Adventists living in Southern California showed elevated risks among men after long-term exposure to ozone,[11] but this finding was based on limited mortality data.

Previous studies using the CPS II cohort have also produced mixed results for ozone. An earlier examination based on a large sample of more than 500,000 people from 117 metropolitan areas and 8 years of follow-up indicated nonsignificant results for the relation between ozone and death from any cause and a significant inverse association between ozone and death from lung cancer. A positive association between death from cardiopulmonary causes and summertime exposure to ozone was observed in single-pollutant

Table 4. Relative Risk of Death from Respiratory Causes Attributable to a 10-ppb Change in the Ambient Ozone Concentration, Stratified According to Selected Risk Factors.*

Stratification Variable	% of Subjects in Stratum	Relative Risk (95% CI)	P Value of Effect Modification
Sex			0.11
Male	43	1.01 (0.99–1.04)	
Female	57	1.04 (1.03–1.07)	
Age at enrollment (yr)			0.74
<50	26	1.00 (0.90–1.11)	
50–65	54	1.03 (1.01–1.06)	
>65	20	1.02 (1.00–1.05)	
Education			0.48
High school or less	43	1.02 (1.00–1.05)	
Beyond high school	57	1.03 (1.01–1.06)	
Body-mass index†			0.96
<25.0	53	1.03 (1.01–1.06)	
25.0–29.9	36	1.03 (0.99–1.06)	
≥30.0	11	1.03 (0.96–1.10)	
$PM_{2.5}$ ($\mu g/m^3$)‡			0.38
<14.3	44	1.05 (1.01–1.09)	
>14.3	56	1.03 (1.00–1.05)	
Region§			0.05
Northeast	24.8	0.99 (0.92–1.07)	
Industrial Midwest	29.7	1.00 (0.91–1.09)	
Southeast	21.0	1.12 (1.05–1.19)	
Upper Midwest	5.2	1.14 (0.68–1.90)	
Northwest	7.7	1.06 (1.00–1.13)	
Southwest	3.9	1.21 (1.04–1.40)	
Southern California	7.8	1.01 (0.96–1.07)	
External temperature (°C)‡¶			0.01
<23.3	24	0.96 (0.90–1.01)	
>23.3 to <25.4	29	0.97 (0.87–1.08)	
>25.4 to <28.7	22	1.04 (0.92–1.16)	
>28.7	25	1.05 (1.03–1.08)	

* $PM_{2.5}$ denotes fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone exposures for the cohort were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000, with adjustment for individual risk factors, and with baseline hazard function stratified according to age (single-year groupings), sex, and race. These analyses are based on the single-pollutant model for ozone shown in Table 3. Because of rounding, percentages may not total 100.

† The body-mass index is the weight in kilograms divided by the square of the height in meters.

‡ Stratum cutoff is based on the median of the distribution at the metropolitan-area level, not at the subject level.

§ Definitions of regions are those used by the Environmental Protection Agency.[3]

¶ External temperature is calculated as the average daily maximum temperature recorded between April and September from 1977 to 2000.

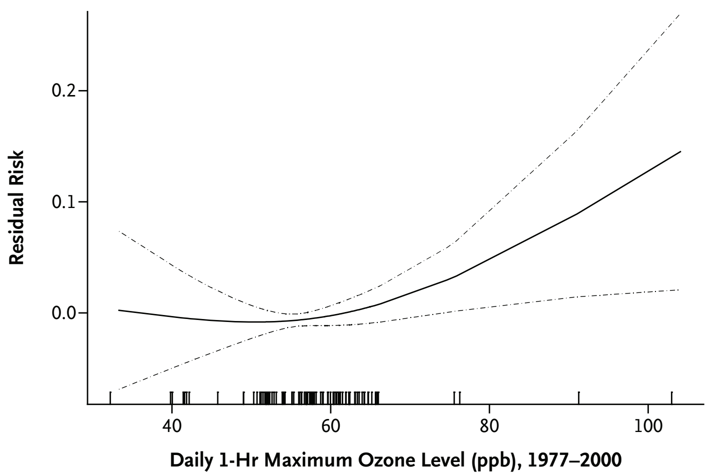

Figure 2. Exposure–Response Curve for the Relation between Exposure to Ozone and the Risk of Death from Respiratory Causes.

The curve is based on a natural spline with 2 df estimated from the residual relative risk of death within a metropolitan statistical area (MSA) according to a random-effects survival model. The dashed lines indicate the 95% confidence interval of fit, and the hash marks indicate the ozone levels of each of the 96 MSAs.

models, but the association with ozone was nonsignificant in two-pollutant models.[3] Further analyses based on 16 years of follow-up in 134 cities produced similarly elevated but nonsignificant associations that were suggestive of effects of summertime (July to September) exposure to ozone on death from cardiopulmonary causes.[5]

The increase in deaths from respiratory causes with increasing exposure to ozone may represent a combination of short-term effects of ozone on susceptible subjects who have influenza or pneumonia and long-term effects on the respiratory system caused by airway inflammation,[24] with subsequent loss of lung function in childhood,[32] young adulthood,[33,34] and possibly later life.[35] If exposure to ozone accelerates the natural loss of adult lung function with age, those exposed to higher concentrations of ozone would be at greater risk of dying from a respiratory-related syndrome.

In our two-pollutant models, the adjusted estimates of relative risk for the effect of ozone on the risk of death from cardiovascular causes were significantly less than 1.0, seemingly suggesting a protective effect. Such a beneficial influence of ozone, however, is unlikely from a biologic standpoint. The association of ozone with cardiovascular end points was sensitive to adjustment for exposure to $PM_{2.5}$, making it difficult to determine precisely the independent contributions of these copollutants to the risk of death. There was notable collinearity between the concentrations of ozone and $PM_{2.5}$.

Furthermore, measurement at central monitors probably represents population exposure to $PM_{2.5}$ more accurately than it represents exposure to ozone. Ozone concentration tends to vary spatially within cities more than does $PM_{2.5}$ concentration, because of scavenging of ozone by nitrogen oxide near roadways.[36] In the presence of a high density of local traffic, the measurement error is probably higher for exposure to ozone than for exposure to $PM_{2.5}$. The effects of ozone could therefore be confounded by the presence of $PM_{2.5}$ because of collinearity between the measurements of the two pollutants and the higher precision of measurements of $PM_{2.5}$.[37]

Measurements of $PM_{2.5}$ were available only for the end of the study follow-up period (1999 and 2000). Widespread collection of these data began only after the EPA adopted regulatory limits on such particulates in 1997. Since particulate air pollution has probably decreased in most metropolitan areas during the follow-up interval of our study, it is likely that we have underestimated the effect of $PM_{2.5}$ in our analysis.

A limitation of our study is that we were not able to account for the geographic mobility of the population during the follow-up period. We had information on home addresses for the CPS II cohort only at the time of initial enrollment in 1982 and 1983. Census data indicate that during the interval between 1982 and 2000, approximately 2 to 3% of the population moved from one state to another annually (with the highest rates in an age group younger than that of our study population).[38] However, any bias due to a failure to account for geographic mobility is likely to have attenuated, rather than exaggerated, the effects of ozone on mortality.

In summary, we investigated the effect of tropospheric ozone on the risk of death from any cause and cause-specific death in a large cohort, using data from 96 metropolitan statistical areas across the United States and controlling for the effect of particulate air pollutants. We were unable to detect a significant effect of exposure to ozone on the risk of death from cardiovascular causes when particulates were taken into account, but we did demonstrate a significant effect of exposure to ozone on the risk of death from respiratory causes.

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This article is dedicated to the memory of our coauthor and friend, Dr. Jeanne Calle, who died unexpectedly on February 17, 2009.

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United States Environmental Protection Agency

Ground-level Ozone
Health Effects

Ozone in the air we breathe can harm our health—typically on hot, sunny days when ozone can reach unhealthy levels. Even relatively low levels of ozone can cause health effects. People with lung disease, children, older adults, and people who are active outdoors may be particularly sensitive to ozone.

Children are at greatest risk from exposure to ozone because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Children are also more likely than adults to have asthma.

Breathing ozone can trigger a variety of health problems including chest pain, coughing, throat irritation, and congestion. It can worsen bronchitis, emphysema, and asthma. Ground level ozone also can reduce lung function and inflame the linings of the lungs. Repeated exposure may permanently scar lung tissue.

Ozone can:

- Make it more difficult to breathe deeply and vigorously.
- Cause shortness of breath and pain when taking a deep breath.
- Cause coughing and sore or scratchy throat.
- Inflame and damage the airways.
- Aggravate lung diseases such as asthma, emphysema, and chronic bronchitis.
- Increase the frequency of asthma attacks.
- Make the lungs more susceptible to infection.
- Continue to damage the lungs even when the symptoms have disappeared.

These effects may lead to increased school absences, medication use, visits to doctors and emergency rooms, and hospital admissions. Research also indicates that ozone exposure may increase the risk of premature death from heart or lung disease.

Ozone is particularly likely to reach unhealthy levels on hot sunny days in urban environments. It is a major part of urban smog. Ozone can also be transported long distances by wind. For this reason, even rural areas can experience high ozone levels. And, in some cases, ozone can occur throughout the year in some southern and mountain regions. Learn more about the formation and transport of ground level ozone.

The AIRNow Web site provides daily air quality reports for many areas. These reports use the Air Quality Index (or AQI) to tell you how clean or polluted the air is. EnviroFlash, a free service, can alert you via email when your local air quality is a concern. Sign up at www.enviroflash.info.

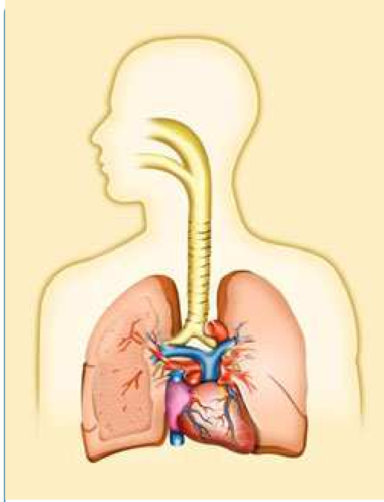
If you're a health care provider, visit AIRNow's Health Care Provider page for educational materials and trainings.

For more information on how EPA works to reduce ground level ozone, visit the Ozone Standards page.

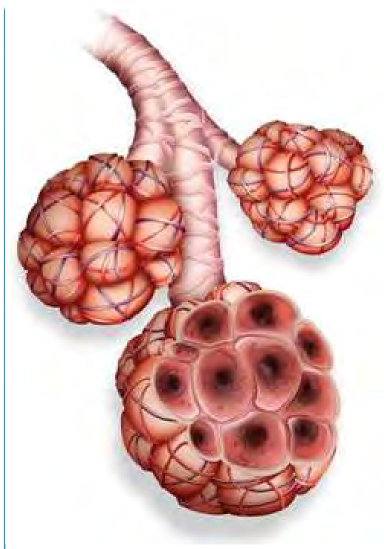
For more information on ground level ozone, health and the environment, visit:

- Ozone and Your Health (PDF) (2 pp, 2.5 MB) This short, colorful pamphlet tells who is at risk from exposure to ozone, what health effects are caused by ozone, and simple measures that can be taken to reduce health risk.
- Ozone: Good Up High, Bad Nearby (PDF) (2 pp, 1.3 MB) Ozone acts as a protective layer high above the earth, but it can be harmful to breathe. This publication provides basic information about ground level and high-altitude ozone.
- EPA's Air Quality Guide for Ozone Provides detailed information about what the Air Quality Index means. Helps determine ways to protect your family's health when ozone levels reach the unhealthy range, and ways you can help reduce ozone air pollution.
- Ozone and Your Patients' Health Training for Health Care Providers Designed for family practice doctors, pediatricians, nurse practitioners,

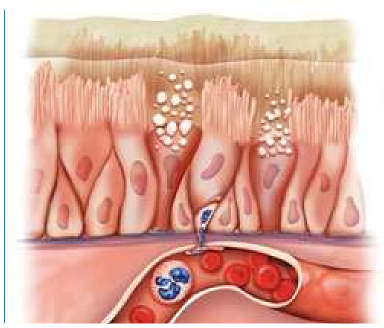
What are the effects of ozone?



Effects on the Airways. Ozone is a powerful oxidant that can irritate the air ways causing coughing, a burning sensation, wheezing and shortness of breath and it can aggravate asthma and other lung diseases.



Alveoli filled with trapped air. Ozone can cause the muscles in the airways to constrict, trapping air in the alveoli. This leads to wheezing and shortness of breath. In people with asthma it can result in asthma attacks.



asthma educators, and other medical professionals who counsel patients about asthma and respiratory symptoms.
- AIRNow Health Providers Information Provides information on how to help patients protect their health by reducing their exposure to air pollution.
- EPA's Asthma Web Site EPA's Communities in Action Asthma Initiative is a coordinated effort to reduce the burden of asthma and includes programs to address indoor and outdoor environments that cause, trigger or exacerbate asthma symptoms.
- Smog - Who Does it Hurt? (PDF) (10 pp, 819 KB) This 8-page booklet provides more detailed information than "Ozone and Your Health" about ozone health effects and how to avoid them.
- Summertime Safety: Keeping Kids Safe from Sun and Smog (PDF) (2 pp, 314 KB) This document discusses summer health hazards that pertain particularly to children and includes information about EPA's Air Quality Index and UV Index tools.

Airway Inflammation. With airway inflammation, there is an influx of white blood cells, increased mucous production, and fluid accumulation and retention. This causes the death and shedding of cells that line the airways and has been compared to the skin inflammation caused by sunburn.

Ozone and Your Patients' Health Training for Health Care Providers

Last updated on Thursday, November 01, 2012

Nitrogen Dioxide

Health

Current scientific evidence links short-term NO_2 exposures, ranging from 30 minutes to 24 hours, with adverse respiratory effects including airway inflammation in healthy people and increased respiratory symptoms in people with asthma.

Also, studies show a connection between breathing elevated short-term NO_2 concentrations, and increased visits to emergency departments and hospital admissions for respiratory issues, especially asthma.

NO_2 concentrations in vehicles and near roadways are appreciably higher than those measured at monitors in the current network. In fact, in-vehicle concentrations can be 2-3 times higher than measured at nearby area-wide monitors. Near-roadway (within about 50 meters) concentrations of NO_2 have been measured to be approximately 30 to 100% higher than concentrations away from roadways.

Individuals who spend time on or near major roadways can experience short-term NO_2 exposures considerably higher than measured by the current network. Approximately 16% of U.S housing units are located within 300 ft of a major highway, railroad, or airport (approximately 48 million people). This population likely includes a higher proportion of non-white and economically-disadvantaged people.

NO_2 exposure concentrations near roadways are of particular concern for susceptible individuals, including people with asthma asthmatics, children, and the elderly

The sum of nitric oxide (NO) and NO_2 is commonly called nitrogen oxides or NOx. Other oxides of nitrogen including nitrous acid and nitric acid are part of the nitrogen oxide family. While EPA's National Ambient Air Quality Standard (NAAQS) covers this entire family, NO_2 is the component of greatest interest and the indicator for the larger group of nitrogen oxides.

NOx react with ammonia, moisture, and other compounds to form small particles. These small particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death.

Ozone is formed when NOx and volatile organic compounds react in the presence of heat and sunlight. Children, the elderly, people with lung diseases such as asthma, and people who work or exercise outside are at risk for adverse effects from ozone. These include reduction in lung function and increased respiratory symptoms as well as respiratory-related emergency department visits, hospital admissions, and possibly premature deaths.

Emissions that lead to the formation of NO_2 generally also lead to the formation of other NOx. Emissions control measures leading to reductions in NO_2 can generally be expected to reduce population exposures to all gaseous NOx. This may have the important co-benefit of reducing the formation of ozone and fine particles both of which pose significant public health threats.

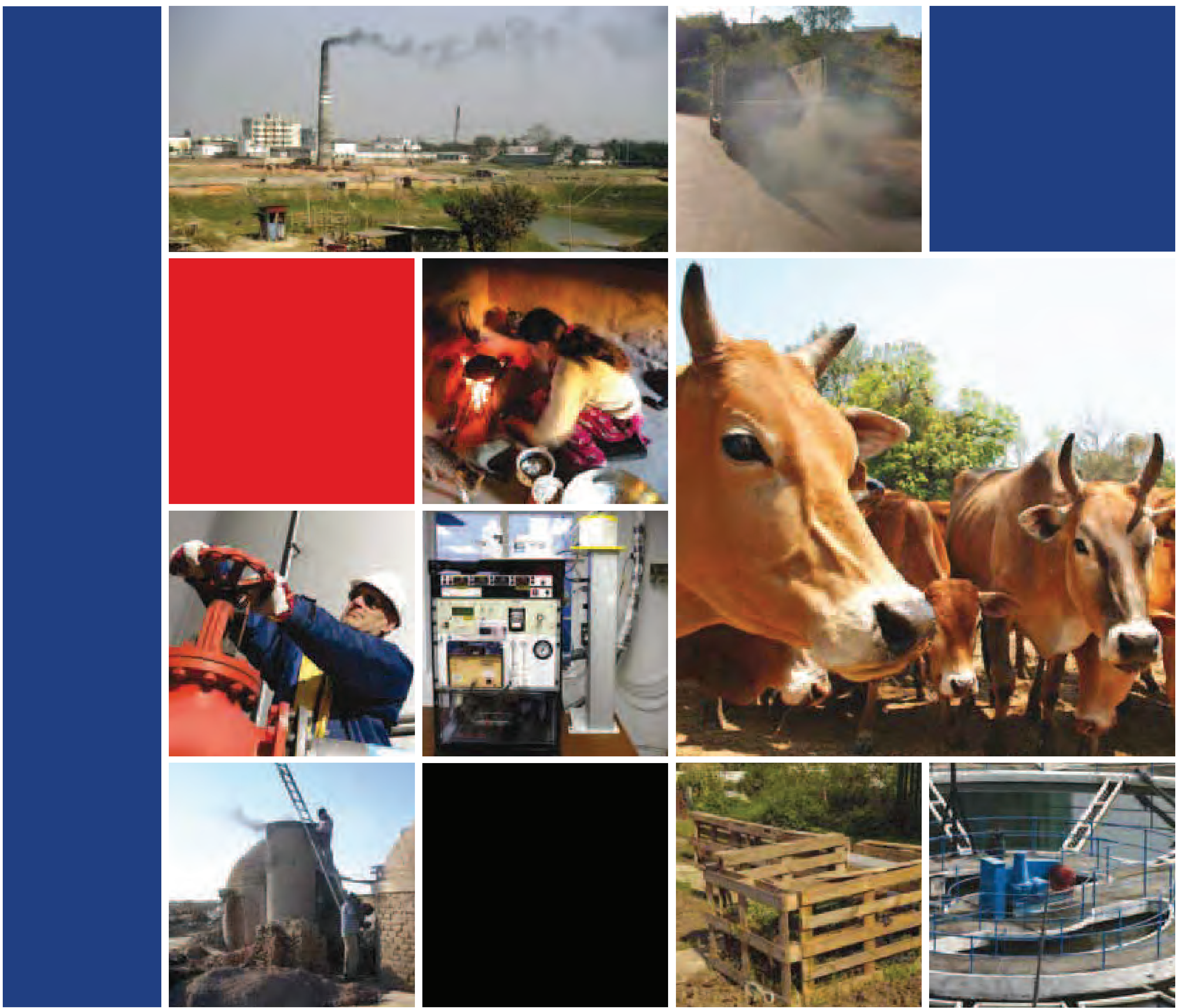
Last updated on Thursday, March 22, 2012

UNEP

World Meteorological Organization

Integrated Assessment of Black Carbon and Tropospheric Ozone

Summary for Decision Makers



A complete elaboration of the topics covered in this summary can be found in the Integrated Assessment of Black Carbon and Tropospheric Ozone report and in the fully referenced underlying research, analyses and reports.

For details of UNEP's regional and sub-regional areas referred to throughout this document see http://geodata.grid.unep.ch/extras/geosubregions.php.

UNEP/GC/26/INF/20

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We regret any errors or omissions that may have been unwittingly made.

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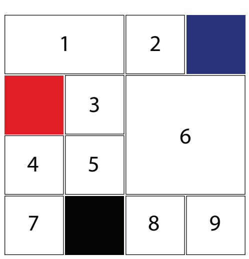

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Integrated Assessment of Black Carbon and Tropospheric Ozone

Summary for Decision Makers

Table of Contents

Main Messages

Scientific evidence and new analyses demonstrate that control of black carbon particles and tropospheric ozone through rapid implementation of proven emission reduction measures would have immediate and multiple benefits for human well-being.

Black carbon exists as particles in the atmosphere and is a major component of soot, it has significant human health and climate impacts. At ground level, ozone is an air pollutant harmful to human health and ecosystems, and throughout the troposphere, or lower atmosphere, is also a significant greenhouse gas. Ozone is not directly emitted, but is produced from emissions of precursors of which methane and carbon monoxide are of particular interest here.

THE CHALLENGE

1. **The climate is changing now, warming at the highest rate in polar and high-altitude regions.** Climate change, even in the near term, has the potential to trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss. The world has warmed by about 0.8˚C from pre-industrial levels, as reported by the

Credit: Kevin Hicks

Traditional brick kilns in South Asia are a major source of black carbon. Improved kiln design in this region is significantly reducing emissions.

Intergovernmental Panel on Climate Change (IPCC). The Parties to the United Nations Framework Convention on Climate Change (UNFCCC) have agreed that warming should not exceed 2˚C above pre-industrial levels.

2. **Black carbon and ozone in the lower atmosphere are harmful air pollutants that have substantial regional and global climate impacts.** They disturb tropical rainfall and regional circulation patterns such as the Asian monsoon, affecting the livelihoods of millions of people.

3. **Black carbon's darkening of snow and ice surfaces increases their absorption of sunlight, which, along with atmospheric heating, exacerbates melting of snow and ice around the world, including in the Arctic, the Himalayas and other glaciated and snow-covered regions.** This affects the water cycle and increases risks of flooding.

4. **Black carbon, a component of particulate matter, and ozone both lead to adverse impacts on human health leading to premature deaths worldwide. Ozone is also the most important air pollutant responsible for reducing crop yields, and thus affects food security.**

REDUCING EMISSIONS

5. **Reducing black carbon and tropospheric ozone now will slow the rate of climate change within the first half of this century. Climate benefits from reduced ozone are achieved by reducing emissions of some of its precursors, especially methane which is also a powerful greenhouse gas.** These short-lived climate forcers – methane, black carbon and ozone – are fundamentally different from longer-lived greenhouse gases, remaining in the atmosphere for only a relatively short time. Deep and immediate carbon dioxide reductions are required to protect long-term climate, as this cannot be achieved by addressing short-lived climate forcers.

6. **A small number of emission reduction measures targeting black carbon and ozone precursors could immediately begin to protect climate, public health, water and food security, and ecosystems.** Measures include the recovery of methane from coal, oil and gas extraction and transport, methane capture in waste management, use of clean-burning stoves for residential cooking, diesel particulate filters for vehicles and the banning of field burning of agricultural waste. Widespread implementation is achievable with existing technology but would require significant strategic investment and institutional arrangements.

7. **The identified measures complement but do not replace anticipated carbon dioxide reduction measures.** Major carbon dioxide reduction strategies mainly target the energy and large industrial sectors and therefore would not necessarily result in significant reductions in emissions of black carbon or the ozone precursors methane and carbon monoxide. Significant reduction of the short-lived climate forcers requires a specific strategy, as many are emitted from a large number of small sources.

BENEFITS OF EMISSION REDUCTIONS

8. **Full implementation of the identified measures would reduce future global warming by 0.5˚C (within a range of 0.2–0.7˚C, Figure 1).** If the measures were to be implemented by 2030, they could halve the potential increase in global temperature projected for 2050 compared to the Assessment's reference scenario based on current policies and energy and fuel projections. The rate of regional temperature increase would also be reduced.

9. **Both near-term and long-term strategies are essential to protect climate.** Reductions in near-term warming can be achieved by control of the short-lived climate forcers whereas carbon dioxide emission reductions, beginning now, are required to limit long-term climate change. Implementing both reduction strategies is needed to improve the chances of keeping the Earth's global mean temperature increase to within the UNFCCC 2˚C target.

10. **Full implementation of the identified measures would have substantial benefits in the Arctic, the Himalayas and other glaciated and snow-covered regions.** This could reduce warming in the Arctic in the next 30 years by about two-thirds compared to the projections of the Assessment's reference scenario. This substantially decreases the risk of changes in weather patterns and amplification of global warming resulting from changes in the Arctic. Regional benefits of the black carbon measures, such as their effects on snow- and ice-covered regions or regional rainfall patterns, are largely independent of their impact on global mean warming.

11. **Full implementation of the identified measures could avoid 2.4 million premature deaths (within a range of 0.7–4.6 million) and the loss of 52 million tonnes (within a range of 30–140 million tonnes), 1–4 per cent, of the global production of maize, rice, soybean and wheat each year (Figure 1).** The most substantial benefits will be felt immediately in or close to the regions where action is taken to reduce emissions, with the greatest health and crop benefits expected in Asia.

RESPONSES

12. The identified measures are all currently in use in different regions around the world to achieve a variety of environment and development objectives. **Much wider and more rapid implementation is required to achieve the full benefits identified in this Assessment.**

13. **Achieving widespread implementation of the identified measures would be most effective if it were country- and region-specific, and could be supported by the considerable existing body of knowledge and experience.** Accounting for near-term climate co-benefits could leverage additional action and funding on a wider international scale which would facilitate more rapid implementation of the measures. Many measures achieve cost savings over time. However, initial capital investment could be problematic in some countries, necessitating additional support and investment.

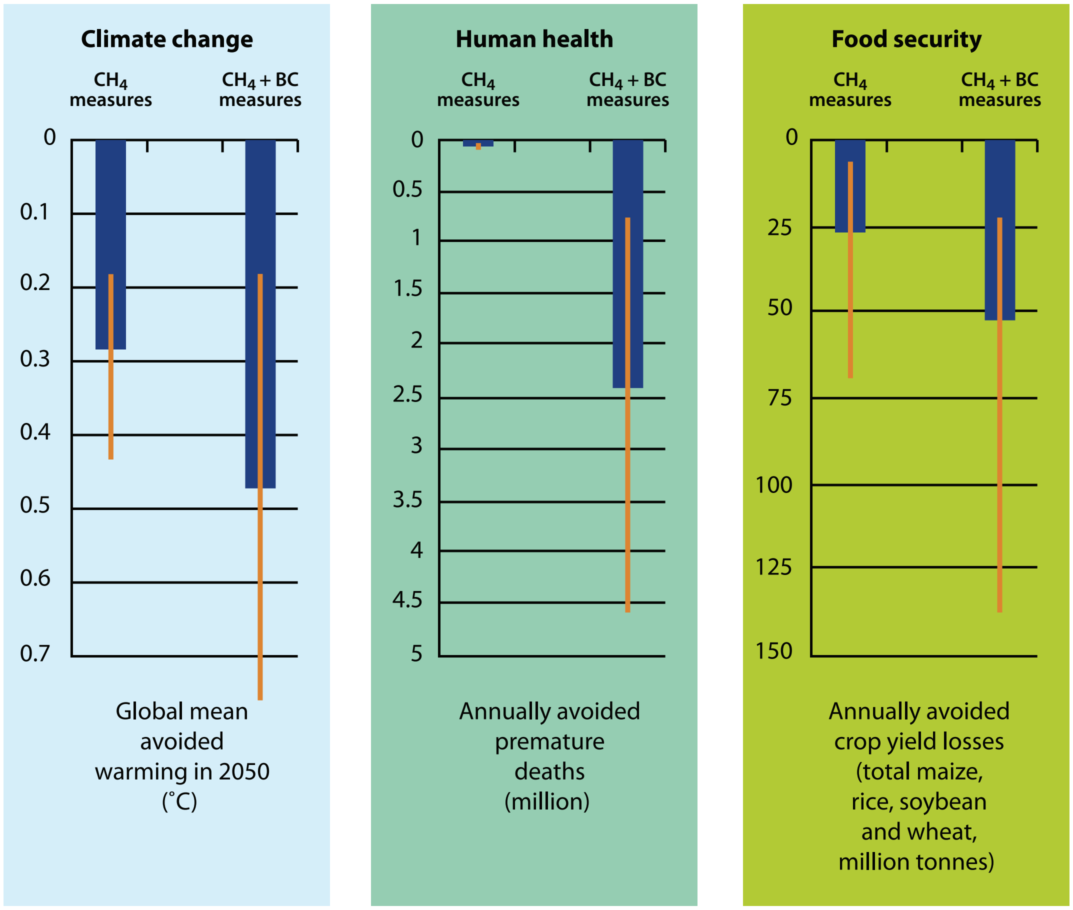


Figure 1. Global benefits from full implementation of the identified measures in 2030 compared to the reference scenario. The climate change benefit is estimated for a given year (2050) and human health and crop benefits are for 2030 and beyond.

14. **At national and sub-national scales many of the identified measures could be implemented under existing policies designed to address air quality and development concerns. Improved cooperation within and between regions would enhance widespread implementation and address transboundary climate and air quality issues.** International policy and financing instruments to address the co-benefits of reducing emissions of short-lived climate forcers need development and strengthening. Supporting and extending existing relevant regional arrangements may provide an opportunity for more effective cooperation, implementation and assessment as well as additional monitoring and research.

15. **The Assessment concludes that there is confidence that immediate and multiple benefits will be realized upon implementation of the identified measures.** The degree of confidence varies according to pollutant, impact and region. For example, there is higher confidence in the effect of methane measures on global temperatures than in the effect of black carbon measures, especially where these relate to the burning of biomass. There is also high confidence that benefits will be realized for human health from reducing particles, including black carbon, and to crop yields from reducing tropospheric ozone concentrations. Given the scientific complexity of the issues, further research is required to optimize near-term strategies in different regions and to evaluate the cost-benefit ratio for individual measures.

Introduction

Black carbon (BC, Box 1) and tropospheric ozone (O_3, Box 2) are harmful air pollutants that also contribute to climate change. In recent years, scientific understanding of how BC and O_3 affect climate and public health has significantly improved. This has catalysed a demand for information and action from governments, civil society and other stakeholders. The United Nations (UN) has been requested to urgently provide science-based advice on action to reduce the impacts of these pollutants[1].

The United Nations Environment Programme (UNEP), in consultation with partners, initiated an assessment designed to provide an interface between knowledge and action, science and policy, and to provide a scientifically credible basis for informed decision-making. The result is a comprehensive analysis of drivers of emissions, trends in concentrations, and impacts on climate, human health and ecosystems of BC, tropospheric O_3 and its precursors. BC, tropospheric O_3 and methane (CH_4) are often referred to as short-lived climate forcers (SLCFs) as they have a short lifetime in the atmosphere (days to about a decade) relative to carbon dioxide (CO_2).

The Assessment is an integrated analysis of multiple co-emitted pollutants reflecting the fact that these pollutants are not emitted in isolation (Boxes 1 and 2). The Assessment determined that under current policies, emissions of BC and O_3 precursors are expected globally either to increase or to remain roughly constant unless further mitigation action is taken.

The Integrated Assessment of Black Carbon and Tropospheric Ozone convened more than 50 authors to assess the state of science and existing policy options for addressing these pollutants. The Assessment team examined policy responses, developed an outlook to 2070 illustrating the benefits of political decisions made today and the risks to climate, human health and crop yields over the next decades if action is delayed. Placing a premium on robust science and analysis, the Assessment was driven by four main policy-relevant questions:

- Which measures are likely to provide significant combined climate and air-quality benefits?
- How much can implementation of the identified measures reduce the rate of global mean temperature increase by mid-century?
- What are the multiple climate, health and crop-yield benefits that would be achieved by implementing the measures?
- By what mechanisms could the measures be rapidly implemented?

In order to answer these questions, the Assessment team determined that new analyses were needed. The Assessment therefore relies on published literature as much as possible and on new simulations by two independent climate-chemistry-aerosol models: one developed and run by the NASA-Goddard Institute for Space Studies (GISS) and the other developed by the Max Planck Institute in Hamburg, Germany (ECHAM), and run at the Joint Research Centre of the European Commission in Ispra, Italy. The specific measures and emission estimates for use in developing this Assessment were selected using the International Institute for Applied Systems Analysis Greenhouse Gas and Air Pollution Interactions and Synergies (IIASA GAINS) model. For a more detailed description of the modelling see Chapter 1.

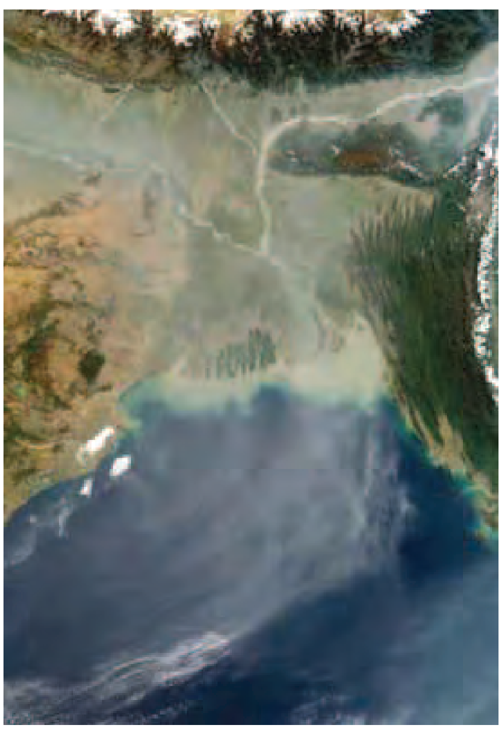
[1] The Anchorage Declaration of 24 April 2009, adopted by the Indigenous People's Global Summit on Climate Change; the Tromsø Declaration of 29 April 2009, adopted by the Sixth Ministerial Meeting of the Arctic Council and the 8th Session of the Permanent Forum on Indigenous Issues under the United Nations Economic and Social Council (May 2009) called on UNEP to conduct a fast track assessment of short-term drivers of climate change, specifically BC, with a view to initiating the negotiation of an international agreement to reduce emissions of BC. A need to take rapid action to address significant climate forcing agents other than CO_2, such as BC, was reflected in the 2009 declaration of the G8 leaders (Responsible Leadership for a Sustainable Future, L'Aquila, Italy, 2009).

Box 1: What is black carbon?

Black carbon (BC) exists as particles in the atmosphere and is a major component of soot. BC is not a greenhouse gas. Instead it warms the atmosphere by intercepting sunlight and absorbing it. BC and other particles are emitted from many common sources, such as cars and trucks, residential stoves, forest fires and some industrial facilities. BC particles have a strong warming effect in the atmosphere, darken snow when it is deposited, and influence cloud formation. Other particles may have a cooling effect in the atmosphere and all particles influence clouds. In addition to having an impact on climate, anthropogenic particles are also known to have a negative impact on human health.

Black carbon results from the incomplete combustion of fossil fuels, wood and other biomass. Complete combustion would turn all carbon in the fuel into carbon dioxide (CO_2). In practice, combustion is never complete and CO_2, carbon monoxide (CO), volatile organic compounds (VOCs), organic carbon (OC) particles and BC particles are all formed. There is a close relationship between emissions of BC (a warming agent) and OC (a cooling agent). They are always co-emitted, but in different proportions for different sources. Similarly, mitigation measures will have varying effects on the BC/OC mix.

The black in BC refers to the fact that these particles absorb visible light. This absorption leads to a disturbance of the planetary radiation balance and eventually to warming. The contribution to warming of 1 gramme of BC seen over a period of 100 years has been estimated to be anything from 100 to 2 000 times higher than that of 1 gramme of CO_2. An important aspect of BC particles is that their lifetime in the atmosphere is short, days to weeks, and so emission reductions have an immediate benefit for climate and health.



Haze with high particulate matter concentrations containing BC and OC, such as this over the Bay of Bengal, is widespread in many regions.

High emitting vehicles are a significant source of black carbon and other pollutants in many countries.

No retrofit system **Uncontrolled Diesel Exhaust** (Level 1)	Retrofitted with **Diesel Oxidation Catalyst (DOC)** (Level 1)	Retrofitted with **Partial Filter** (Level 2)	Retrofitted with **Diesel Particulate Filter (DPF)** (Level 3)
Old technlogy Little black carbon removal Little ultrafine PM removal Does not remove lube oil ash	Old technlogy Little black carbon removal Little ultrafine PM removal Does not remove lube oil ash	Little black carbon removal Little ultrafine PM removal Does not remove lube oil ash	New Technology Used on all new trucks since 2007 >85% black carbon removal >85% ultrafine removal >85% lube oil ash removal

Credit: Luisa Molina

Some of the largest emission reductions are obtained using diesel particle filters on high emitting vehicles. The exhibits above are actual particulate matter (PM) collection samples from an engine testing laboratory (International Council of Clean Transportation (ICCT)).

Box 2: What is tropospheric ozone?

Ozone (O_3) is a reactive gas that exists in two layers of the atmosphere: the stratosphere (the upper layer) and the troposphere (ground level to ~10–15 km). In the stratosphere, O_3 is considered to be beneficial as it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, at ground level, it is an air pollutant harmful to human health and ecosystems, and it is a major component of urban smog. In the troposphere, O_3 is also a significant greenhouse gas. The threefold increase of the O_3 concentration in the northern hemisphere during the past 100 years has made it the third most important contributor to the human enhancement of the global greenhouse effect, after CO_2 and CH_4.

In the troposphere, O_3 is formed by the action of sunlight on O_3 precursors that have natural and anthropogenic sources. These precursors are CH_4, nitrogen oxides (NO_X), VOCs and CO. It is important to understand that reductions in both CH_4 and CO emissions have the potential to substantially reduce O_3 concentrations and reduce global warming. In contrast, reducing VOCs would clearly be beneficial but has a small impact on the global scale, while reducing NO_X has multiple additional effects that result in its net impact on climate being minimal.

Credit: Luisa Molina

Credit: Warren Gretz/DOE/NREL

Tropospheric ozone is a major constituent of urban smog, left Tokyo, Japan; right Denver, Colorado, USA

Limiting Near-Term Climate Changes and Improving Air Quality

Identifying effective response measures

The Assessment identified those measures most likely to provide combined benefits, taking into account the fact that BC and O_3 precursors are co-emitted with different gases and particles, some of which cause warming and some of which, such as organic carbon (OC) and sulphur dioxide (SO_2) lead to cooling. The selection criterion was that the measure had to be likely to reduce global climate change and also provide air quality benefits, so-called win-win measures. Those measures that provided a benefit for air quality but increased warming were not included in the selected measures. For example, measures that primarily reduce emissions of SO_2 were not included.

The identified measures (Table 1) were chosen from a subset of about 2 000 separate measures that can be applied to sources in IIASA's GAINS model. The selection was based on the net influence on warming, estimated using the metric Global Warming Potential (GWP), of all of the gases and particles that are affected by the measure. The selection gives a useful indication of the potential for realizing a win for climate. All emission reduction measures were assumed to benefit air quality by reducing particulate matter and/or O_3 concentrations.

This selection process identified a relatively small set of measures which nevertheless provide about 90 per cent of the climate benefit compared to the implementation of all 2 000 measures in GAINS. The final analysis of the benefits for temperature, human health and crop yields considered the emissions of all substances resulting from the full implementation of the identified measures through the two global composition-climate models GISS and ECHAM (see Chapter 4). One hundred per cent implementation of the measures globally was used to illustrate the existing potential to reduce climate and air quality impacts, but this does not make any assumptions regarding the feasibility of full implementation everywhere. A discussion of the challenges involved in widespread implementation of the measures follows after the potential benefit has been demonstrated.

Achieving large emission reductions

The packages of policy measures in Table 1 were compared to a reference scenario (Table 2). Figure 2 shows the effect of the packages of policy measures and the reference scenario relative to 2005 emissions.

There is tremendous regional variability in how emissions are projected to change by the year 2030 under the reference scenario. Emissions of CH_4 – a major O_3 precursor and a potent greenhouse gas – are expected to increase in the future (Figure 2). This increase will occur despite current and planned regulations, in large part due to anticipated economic growth and the increase in fossil fuel production projected to accompany it. In contrast, global emissions of BC and accompanying co-emitted pollutants are expected to remain relatively constant through to 2030. Regionally, reductions in BC emissions are expected due to tighter standards on road transport and more efficient combustion replacing use of biofuels in the residential and commercial sectors,

Table 1. Measures that improve climate change mitigation and air quality and have a large emission reduction potential

Measure[1]	Sector
CH_4 measures	
Extended pre-mine degasification and recovery and oxidation of CH_4 from ventilation air from coal mines	Extraction and transport of fossil fuel
Extended recovery and utilization, rather than venting, of associated gas and improved control of unintended fugitive emissions from the production of oil and natural gas	Extraction and transport of fossil fuel
Reduced gas leakage from long-distance transmission pipelines	Extraction and transport of fossil fuel
Separation and treatment of biodegradable municipal waste through recycling, composting and anaerobic digestion as well as landfill gas collection with combustion/utilization	Waste management
Upgrading primary wastewater treatment to secondary/tertiary treatment with gas recovery and overflow control	Waste management
Control of CH_4 emissions from livestock, mainly through farm-scale anaerobic digestion of manure from cattle and pigs	Agriculture
Intermittent aeration of continuously flooded rice paddies	Agriculture
BC measures (affecting BC and other co-emitted compounds)	
Diesel particle filters for road and off-road vehicles	Transport
Elimination of high-emitting vehicles in road and off-road transport	Transport
Replacing coal by coal briquettes in cooking and heating stoves	Residential
Pellet stoves and boilers, using fuel made from recycled wood waste or sawdust, to replace current wood-burning technologies in the residential sector in industrialized countries	Residential
Introduction of clean-burning biomass stoves for cooking and heating in developing countries[2, 3]	Residential
Substitution of clean-burning cookstoves using modern fuels for traditional biomass cookstoves in developing countries[2, 3]	Residential
Replacing traditional brick kilns with vertical shaft kilns and Hoffman kilns	Industry
Replacing traditional coke ovens with modern recovery ovens, including the improvement of end-of-pipe abatement measures in developing countries	Industry
Ban of open field burning of agricultural waste[2]	Agriculture

1 There are measures other than those identified in the table that could be implemented. For example, electric cars would have a similar impact to diesel particulate filters but these have not yet been widely introduced; forest fire controls could also be important but are not included due to the difficulty in establishing the proportion of fires that are anthropogenic.
2 Motivated in part by its effect on health and regional climate, including areas of ice and snow.
3 For cookstoves, given their importance for BC emissions, two alternative measures are included.

although these are offset to some extent by increased activity and economic growth. The regional BC emission trends, therefore, vary significantly, with emissions expected to decrease in North America and Europe, Latin America and the Caribbean, and in Northeast Asia, Southeast Asia and the Pacific, and to increase in Africa and South, West and Central Asia.

The full implementation of the selected measures by 2030 leads to significant reductions of SLCF emissions relative to current emissions or to the 2030 emissions in the reference scenario (Figure 2). It also reduces a high proportion of the emissions relative to the maximum reduction from the implementation of all 2 000 or so measures in the GAINS model. The measures designed to reduce BC also have a considerable impact on OC, total fine particulate matter ($PM_{2.5}$) and CO emissions, removing more than half the total anthropogenic emissions. The largest BC emission reductions are obtained through measures controlling incomplete combustion of biomass and diesel particle filters.

The major sources of CO_2 are different from those emitting most BC, OC, CH_4 and CO. Even in the few cases where there is overlap, such as diesel vehicles, the particle filters that reduce BC, OC and CO have minimal effect on CO_2. The measures to reduce CO_2 over the next 20 years (Table 2) therefore hardly affect the emissions of BC, OC or CO. The influence of the CH_4 and BC measures is thus the same regardless of whether the CO_2 measures are imposed or not.

Reducing near-term global warming

The Earth is projected to continue the rapid warming of the past several decades and, without additional mitigation efforts, under the reference scenario global mean temperatures are projected to rise about a further 1.3°C (with a range of 0.8–2.0°C) by the middle of this century, bringing the total warming from pre-industrial levels to about 2.2°C (Figure 3). The Assessment shows that the measures targeted to reduce emissions of BC and CH_4 could greatly reduce global mean warming rates over the next few decades (Figure 3). Figure 1 shows that over half of the reduced global mean warming is achieved by the CH_4 measures and the remainder by BC measures. The greater confidence in the effect of CH_4 measures on warming is reflected in the narrower range of estimates.

When all measures are fully implemented, warming during the 2030s relative to the present day is only half as much as if no measures had been implemented. In contrast, even a fairly aggressive strategy to reduce CO_2 emissions under the CO_2 measures scenario does little to mitigate warming over the next 20–30 years. In fact, sulphate particles, reflecting particles that offset some of the committed warming for the short time they are in the atmosphere, are derived from SO_2 that is co-emitted with CO_2 in some of the highest-emitting activities, including coal burning in large-scale combustion such as in power plants. Hence, CO_2 measures alone may temporarily enhance near-term warming as sulphates are reduced (Figure 3;

Table 2. Policy packages used in the Assessment

Scenario	Description[1]
Reference	Based on energy and fuel projections of the International Energy Agency (IEA) *World Energy Outlook 2009* and incorporating all presently agreed policies affecting emissions
CH_4 measures	Reference scenario plus the CH_4 measures
BC measures	Reference scenario plus the BC measures (the BC measures affect many pollutants, especially BC, OC, and CO)
CH_4 + BC measures	Reference scenario plus the CH_4 and BC measures
CO_2 measures	Emissions modelled using the assumptions of the IEA *World Energy Outlook 2009* 450 Scenario[2] and the IIASA GAINS database. Includes CO_2 measures only. The CO_2 measures affect other emissions, especially SO_2[3]
CO_2 + CH_4 + BC measures	CO_2 measures plus CH_4 and BC measures

1 In all scenarios, trends in all pollutant emissions are included through 2030, after which only trends in CO_2 are included.
2 The 450 Scenario is designed to keep total forcing due to long-lived greenhouse gases (including CH_4 in this case) at a level equivalent to 450 ppm CO_2 by the end of the century.
3 Emissions of SO_2 are reduced by 35–40 per cent by implementing CO_2 measures. A further reduction in sulphur emissions would be beneficial to health but would increase global warming. This is because sulphate particles cool the Earth by reflecting sunlight back to space.

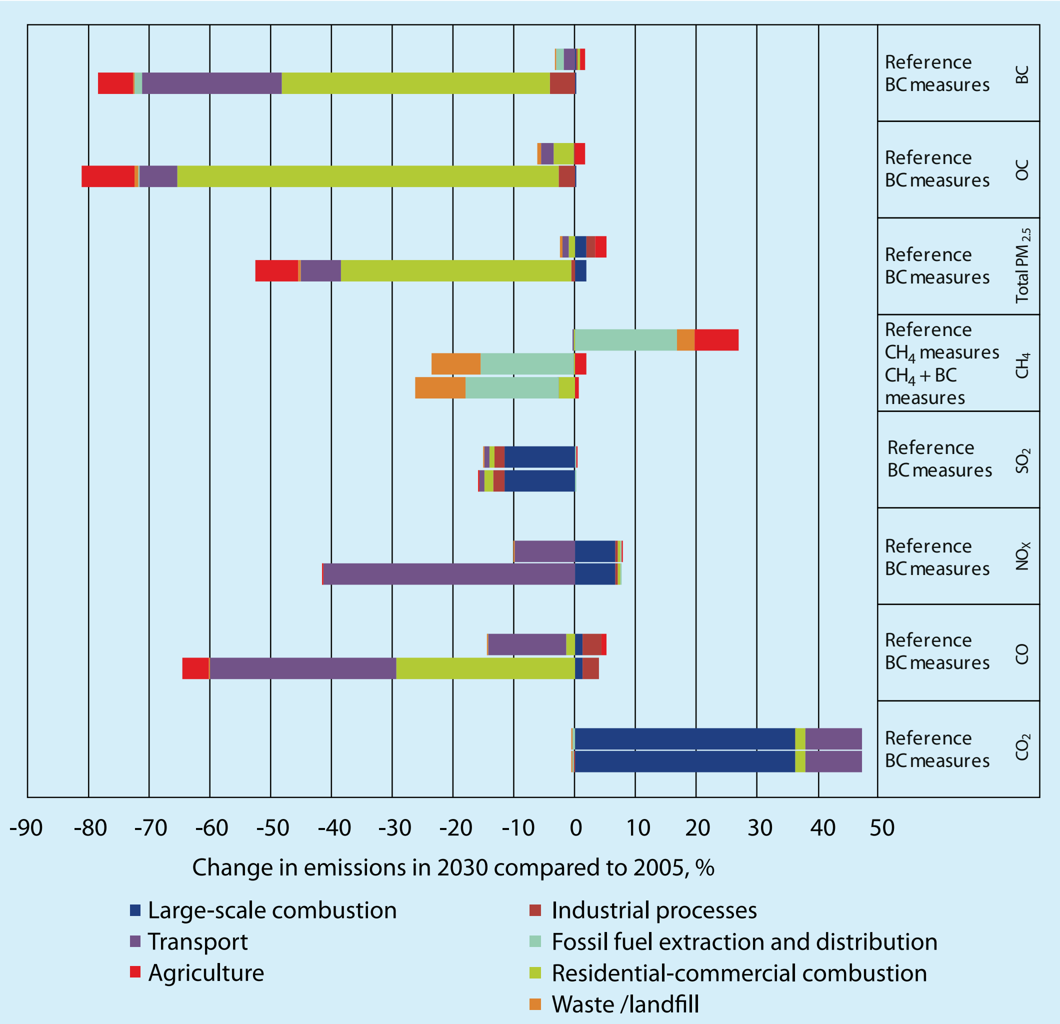


Figure 2. Percentage change in anthropogenic emissions of the indicated pollutants in 2030 relative to 2005 for the reference, CH_4, BC and CH_4 + BC measures scenarios. The CH_4 measures have minimal effect on emissions of anything other than CH_4. The identified BC measures reduce a large proportion of total BC, OC and CO emissions. SO_2 and CO_2 emissions are hardly affected by the identified CH_4 and BC measures, while NO_X and other $PM_{2.5}$ emissions are affected by the BC measures.

temperatures in the CO_2 measures scenario are slightly higher than those in the reference scenario during the period 2020–2040).

The CO_2 measures clearly lead to long-term benefits, with a dramatically lower warming rate in 2070 than under the scenario with only near-term CH_4 + BC measures. Owing to the long residence time of CO_2 in the atmosphere, these long-term benefits will only be achieved if CO_2 emission reductions are brought in quickly. In essence, the near-term CH_4 and BC measures examined in this Assessment are effectively decoupled from the CO_2 measures both in that they target different source sectors and in that their impacts on climate change take place over different timescales.

Near-term warming may occur in sensitive regions and could cause essentially irreversible changes, such as loss of Arctic land-ice, release of CH_4 or CO_2 from Arctic permafrost and species loss. Indeed, the projected warming in the reference scenario is greater in the Arctic than globally. Reducing the near-term rate of warming hence decreases the risk of irreversible transitions that could influence the global climate system for centuries.

Staying within critical temperature thresholds

Adoption of the near-term emission control measures described in this Assessment, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative to pre-industrial levels (Figure 3). With the CO_2 measures alone, warming exceeds 2˚C before 2050. Even with both the CO_2 measures and CH_4 measures envisioned under the same IEA 450 Scenario, warming exceeds 2˚C in the 2060s (see Chapter 5). However, the combination of CO_2, CH_4, and BC measures holds the temperature increase below 2˚C until around 2070. While CO_2 emission reductions even larger than those in the CO_2 measures scenario would of course mitigate more warming, actual CO_2 emissions over the past decade have consistently exceeded the most pessimistic emission scenarios of the IPCC. Thus, it seems unlikely that reductions more stringent than those in the CO_2 measures scenario will take place during the next 20 years.

Examining the more stringent UNFCCC 1.5˚C threshold, the CO_2 measures scenario exceeds this by 2030, whereas the near-term measures proposed in the Assessment delay that exceedance until after 2040. Again, while substantially deeper early reductions in CO_2 emissions than those in the CO_2 measures scenario could also delay the crossing of the 1.5˚C temperature threshold, such reductions would undoubtedly be even more difficult to achieve. However, adoption of the Assessment's near-term measures (CH_4 + BC) along with the CO_2 reductions would provide

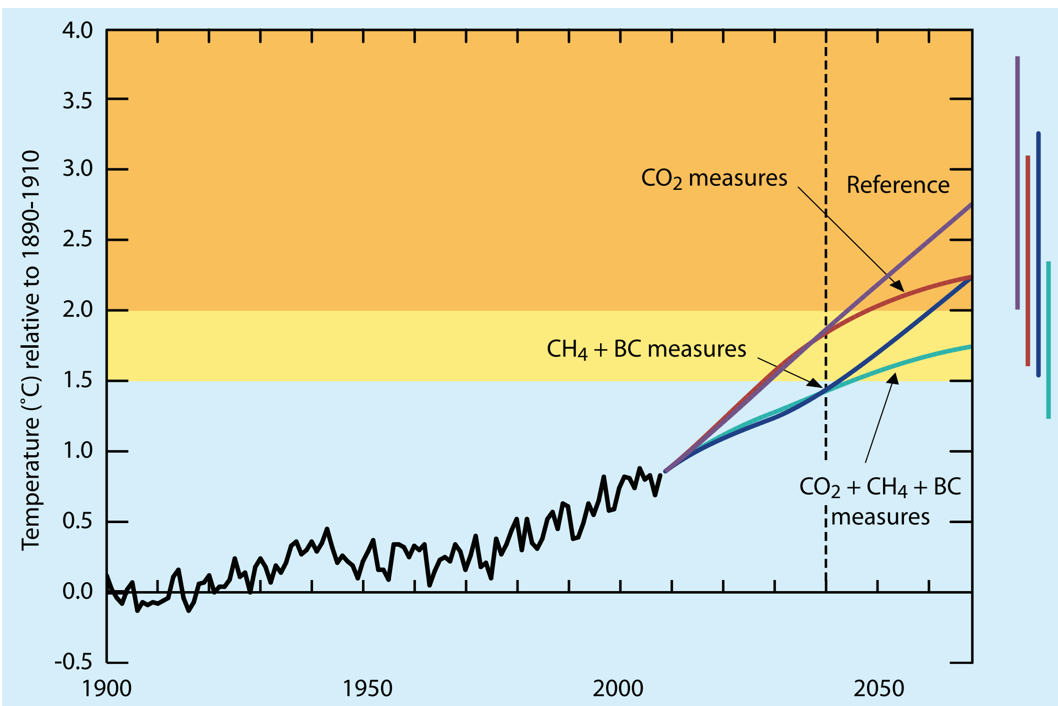


Figure 3. Observed deviation of temperature to 2009 and projections under various scenarios. Immediate implementation of the identified BC and CH_4 measures, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative to pre-industrial levels. The bulk of the benefits of CH_4 and BC measure are realized by 2040 (dashed line).

Explanatory notes: Actual mean temperature observations through 2009, and projected under various scenarios thereafter, are shown relative to the 1890–1910 mean temperature. Estimated ranges for 2070 are shown in the bars on the right. A portion of the uncertainty is common to all scenarios, so that overlapping ranges do not mean there is no difference, for example, if climate sensitivity is large, it is large regardless of the scenario, so temperatures in all scenarios would be towards the high-end of their ranges.

a substantial chance of keeping the Earth's temperature increase below 1.5°C for the next 30 years.

Benefits of early implementation

There would clearly be much less warming during 2020–2060 were the measures implemented earlier rather than later (Figure 4). Hence there is a substantial near-term climate benefit in accelerating implementation of the identified measures even if some of these might eventually be adopted owing to general air-quality and development concerns. Clearly the earlier implementation will also have significant additional human health and crop-yield benefits.

Accelerated adoption of the identified measures has only a modest effect on long-term climate change in comparison with waiting 20 years, however (Figure 4). This reinforces the conclusion that reducing emissions of O_3 precursors and BC can have substantial benefits in the near term, but that mitigating long-term climate change depends on reducing emissions of long-lived greenhouse gases such as CO_2.

Regional climate benefits

While global mean temperatures provide some indication of climate impacts, temperature changes can vary dramatically from place to place even in response to relatively uniform forcing from long-lived greenhouse gases. Figure 5 shows that warming is projected to increase for all regions with some variation under the reference scenario, while the Assessment's measures provide the benefit of reduced warming in all regions.

Climate change also encompasses more than just temperature changes. Precipitation, melting rates of snow and ice, wind patterns, and clouds are all affected, and these in turn have an impact on human well-being by influencing factors such as water availability, agriculture and land use.

Both O_3 and BC, as well as other particles, can influence many of the processes that lead to the formation of clouds and precipitation. They alter surface temperatures, affecting evaporation. By absorbing sunlight in the atmosphere, O_3 and especially BC can affect cloud formation, rainfall and weather patterns. They can change wind patterns by affecting the regional temperature contrasts that drive the winds, influencing where rain and snow fall. While some aspects of these effects are local, they can also affect temperature, cloudiness, and precipitation far away from the emission sources. The regional changes in all these aspects of climate will be significant, but are currently not well quantified.

Tropical rainfall patterns and the Asian monsoon

Several detailed studies of the Asian monsoon suggest that regional forcing by absorbing particles substantially alters precipitation patterns (as explained in the previous section). The fact that both O_3 and particle changes are predominantly in the northern hemisphere means that they cause temperature gradients between the two hemispheres that influence rainfall patterns throughout the tropics. Implementation of the measures analysed in this Assessment would substantially decrease the regional atmospheric heating by particles (Figure 6), and are hence very likely to reduce regional shifts in precipitation. As the reductions of atmospheric forcing are greatest over the Indian sub-continent and other parts of Asia, the emission reductions may have a substantial effect on the Asian monsoon, mitigating disruption of traditional rainfall patterns. However, results from global climate models are not yet robust for the magnitude or timing of monsoon shifts resulting from either greenhouse gas increases or changes in absorbing particles. Nonetheless, results from climate models provide examples of the type of change that might be expected. Shifts in the timing and strength of precipitation can have significant impacts on human well-being because of changes in water

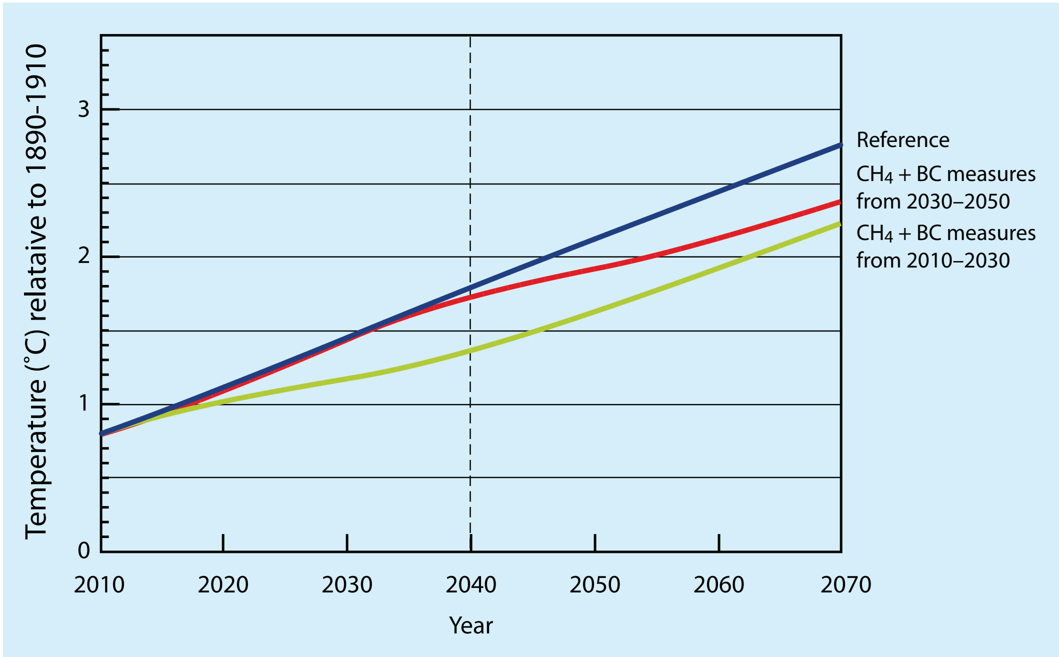


Figure 4. Projected global mean temperature changes for the reference scenario and for the CH_4 and BC measures scenario with emission reductions starting immediately or delayed by 20 years.

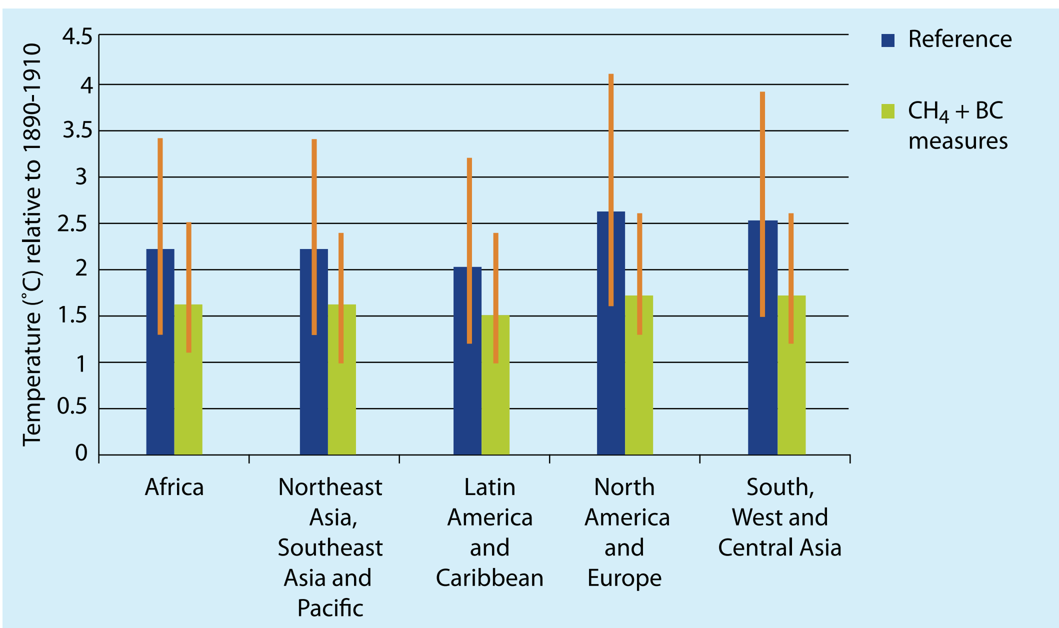


Figure 5. Comparison of regional mean warming over land (˚C) showing the change in 2070 compared with 2005 for the reference scenario (Table 2) and the CH_4 + BC measures scenario. The lines on each bar show the range of estimates.

supply and agricultural productivity, drought and flooding. The results shown in Figure 6 suggest that implementation of the BC measures could also lead to a considerable reduction in the disruption of traditional rainfall patterns in Africa.

Decreased warming in polar and other glaciated regions

Implementation of the measures would substantially slow, but not halt, the current rapid pace of temperature rise and other changes already occurring at the poles and high-altitude glaciated regions, and the reduced warming in these regions would likely be greater than that seen globally. The large benefits occur in part because the snow/ice darkening effect of BC is substantially greater than the cooling effect of reflective particles co-emitted with BC, leading to greater warming impacts in these areas than in areas without snow and ice cover.

Studies in the Arctic indicate that it is highly sensitive both to local pollutant emissions and those transported from sources close to the Arctic, as well as to the climate impact of pollutants in the mid-latitudes of the northern hemisphere. Much of the need for implementation lies within Europe and North America. The identified measures could reduce warming in the Arctic by about 0.7˚C (with a range of 0.2–1.3˚C) in 2040. This is nearly two-thirds of the estimated 1.1˚C (with a range of 0.7–1.7˚C) warming projected for the Arctic under the reference scenario, and should substantially decrease the risk of global impacts from changes in this sensitive region, such as sea ice loss, which affects global albedo, and permafrost melt. Although not identified as a measure for use in this Assessment, the control of boreal forest fires may also be important in reducing impacts in the Arctic.

The Antarctic is a far less studied region in terms of SLCF impacts. However, there are studies demonstrating BC deposition even in central portions of the continent, and reductions in O_3 and CH_4 should slow warming in places like the Antarctic Peninsula, currently the spot on the globe showing the most rapid temperature rise of all.

The Himalayas and the Tibetan Plateau are regions where BC is likely to have serious impacts. In the high valleys of the Himalayas, for example, BC levels can be as high as in

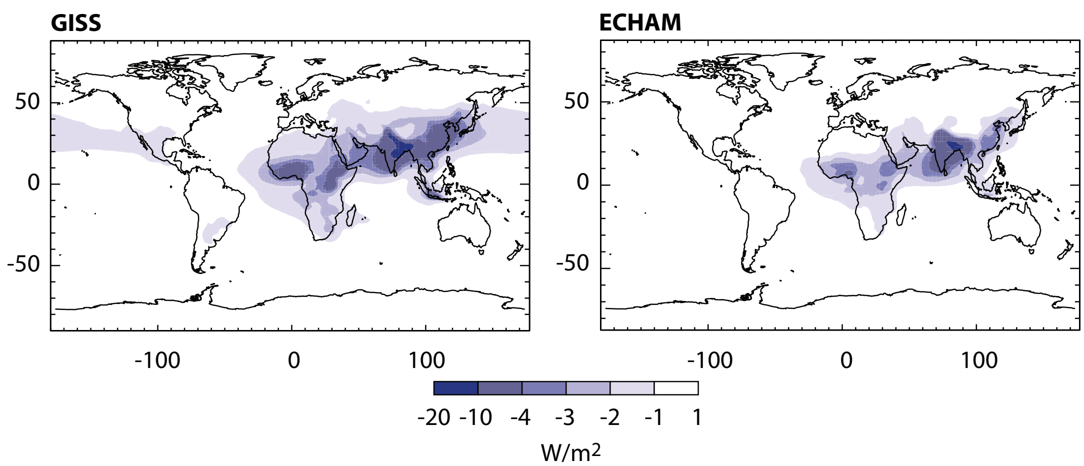


Figure 6. Change in atmospheric energy absorption (Watts per square metre, W/m^2 as annual mean), an important factor driving tropical rainfall and the monsoons resulting from implementation of BC measures. The changes in absorption of energy by the atmosphere are linked with changes in regional circulation and precipitation patterns, leading to increased precipitation in some regions and decreases in others. BC solar absorption increases the energy input to the atmosphere by as much as 5–15 per cent, with the BC measures removing the bulk of that heating. Results are shown for two independent models to highlight the similarity in the projections of where large regional decreases would occur.

a mid-sized city. Reducing emissions from local sources and those carried by long-range transport should lower glacial melt in these regions, decreasing the risk of impacts such as catastrophic glacial lake outbursts.

Benefits of the measures for human health

Fine particulate matter (measured as $PM_{2.5}$, which includes BC) and ground-level O_3 damage human health. $PM_{2.5}$ causes premature deaths primarily from heart disease and lung cancer, and O_3 exposure causes deaths primarily from respiratory illness. The health benefit estimates in the Assessment are limited to changes in these specific causes of death and include uncertainty in the estimation methods. However, these pollutants also contribute significantly to other health impacts including acute and chronic bronchitis and other respiratory illness, non-fatal heart attacks, low birth weight and results in increased emergency room visits and hospital admissions, as well as loss of work and school days.

Under the reference scenario, that is, without implementation of the identified measures, changes in concentrations of $PM_{2.5}$ and O_3 in 2030, relative to 2005, would have substantial effects globally on premature deaths related to air pollution. By region, premature deaths from outdoor pollution are projected to change in line with emissions. The latter are expected to decrease significantly over North America and Europe due to implementation of the existing and expected legislation. Over Africa and Latin America and the Caribbean, the number of premature deaths from these pollutants is expected to show modest changes under the reference scenario (Figure 7). Over Northeast Asia, Southeast Asia and Pacific, premature deaths are projected to decrease substantially due to reductions in $PM_{2.5}$ in some areas. However, in South, West and Central Asia, premature deaths are projected to rise significantly due to growth in emissions.

In contrast to the reference scenario, full implementation of the measures identified in the Assessment would substantially improve air quality and reduce premature deaths globally due to significant reductions in indoor and outdoor air pollution. The reductions in $PM_{2.5}$ concentrations resulting from the BC measures would, by 2030, avoid an estimated 0.7–4.6 million annual premature deaths due to outdoor air pollution (Figure 1).

Regionally, implementation of the identified measures would lead to greatly improved air quality and fewer premature deaths, especially in Asia (Figure 7). In fact, more than 80 per cent of the health benefits of implementing all measures occur in Asia. The benefits are large enough for all the worsening trends in human health due to outdoor air pollution to be reversed and turned into improvements, relative to 2005. In Africa, the benefit is substantial, although not as great as in Asia.

Benefits of the measures for crop yields

Ozone is toxic to plants. A vast body of literature describes experiments and observations showing the substantial effects of O_3 on visible leaf health, growth and productivity for a large number of crops, trees and other plants. Ozone also affects vegetation composition and diversity. Globally, the full implementation of CH_4 measures results in significant reductions in O_3 concentrations leading to avoided yield losses of about 25 million tonnes of four staple crops each year. The implementation of the BC measures would account for about a further 25 million tonnes of avoided yield losses in comparison with the reference scenario (Figure 1). This is due to significant reductions in emissions of the precursors CO, VOCs and NO_X that reduce O_3 concentrations.

The regional picture shows considerable differences. Under the reference scenario, O_3 concentrations over Northeast, Southeast

Asia and Pacific are projected to increase, resulting in additional crop yield losses (Figures 7 and 8). In South, West and Central Asia, both health and agricultural damage are projected to rise (Figure 8). Damage to agriculture is projected to decrease strongly over North America and Europe while changing minimally over Africa and Latin America and the Caribbean. For the whole Asian region maize yields show a decrease of 1–15 per cent, while yields decrease by less than 5 per cent for wheat and rice. These yield losses translate into nearly 40 million tonnes for all crops for the whole Asian region, reflecting the substantial cultivated area exposed to elevated O_3 concentrations in India – in particular the Indo-Gangetic Plain region. Rice production is also affected, particularly in Asia where elevated O_3 concentrations are likely to continue to increase to 2030. Yield loss values for rice are uncertain, however, due to a lack of experimental evidence on concentration-response functions. In contrast, the European and North American regional analyses suggest that all crops will see an improvement in yields under the reference scenario between 2005 and 2030. Even greater improvements would be seen upon implementation of the measures.

The identified measures lead to greatly reduced O_3 concentrations, with substantial benefits to crop yields, especially in Asia (Figure 8). The benefits of the measures are large enough to reverse all the worsening trends seen in agricultural yields and turn them into improvements, relative to 2005, with the exception of crop yields in Northeast and Southeast Asia and Pacific. Even in that case, the benefits of full implementation are quite large, with the measures reducing by 60 per cent the crop losses envisaged in the reference scenario.

It should be stressed that the Assessment's analyses include only the direct effect of changes in atmospheric composition on health and agriculture through changes in exposure to pollutants. As such, they do not include the benefits that avoided climate change would have on human health and agriculture due to factors such as reduced disruption of precipitation patterns, dimming, and reduced frequency of heat waves. Furthermore, even the direct influence on yields are based on estimates for only four staple crops, and impacts on leafy crops, productive grasslands and food quality were not included, so that the calculated values are likely to be an

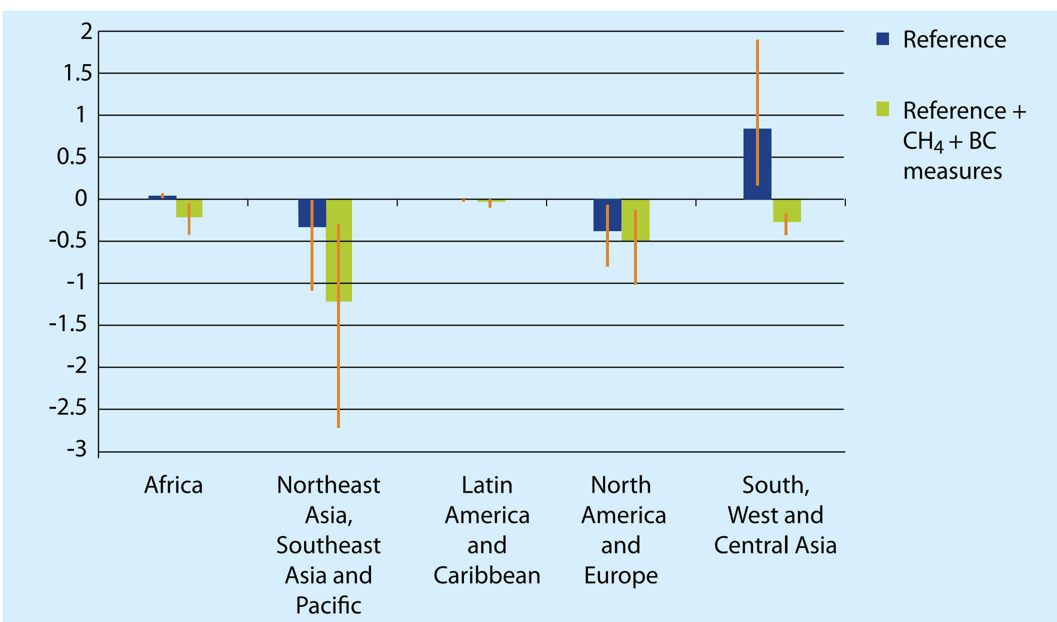


Figure 7. Comparison of premature mortality (millions of premature deaths annually) by region, showing the change in 2030 in comparison with 2005 for the reference scenario emission trends and the reference plus CH_4 + BC measures. The lines on each bar show the range of estimates.

The measures identified in the Assessment include replacement of traditional cookstoves, such as that shown here, with clean burning stoves which would substantially improve air quality and reduce premature deaths due to indoor and outdoor air pollution.

underestimate of the total impact. In addition, extrapolation of results from a number of experimental studies to assess O_3 impacts on ecosystems strongly suggests that reductions in O_3 could lead to substantial increases in the net primary productivity. This could have a substantial impact on carbon sequestration, providing additional climate benefits.

Relative importance and scientific confidence in the measures

Methane measures have a large impact on global and regional warming, which is achieved by reducing the greenhouse gases CH_4 and O_3. The climate mitigation impacts of the CH_4 measures are also the most certain because there is a high degree of confidence in the warming effects of this greenhouse gas. The reduced methane and hence O_3 concentrations also lead to significant benefits for crop yields.

The BC measures identified here reduce concentrations of BC, OC and O_3 (largely through reductions in emissions of CO). The warming effect of BC and O_3 and the compensating cooling effect of OC, introduces large uncertainty in the net effect of some BC measures on global warming (Figure 1). Uncertainty in the impact of BC measures is also larger than that for CH_4 because BC and OC can influence clouds that have multiple effects on climate that are not fully understood. This uncertainly in global impacts is particularly large for the

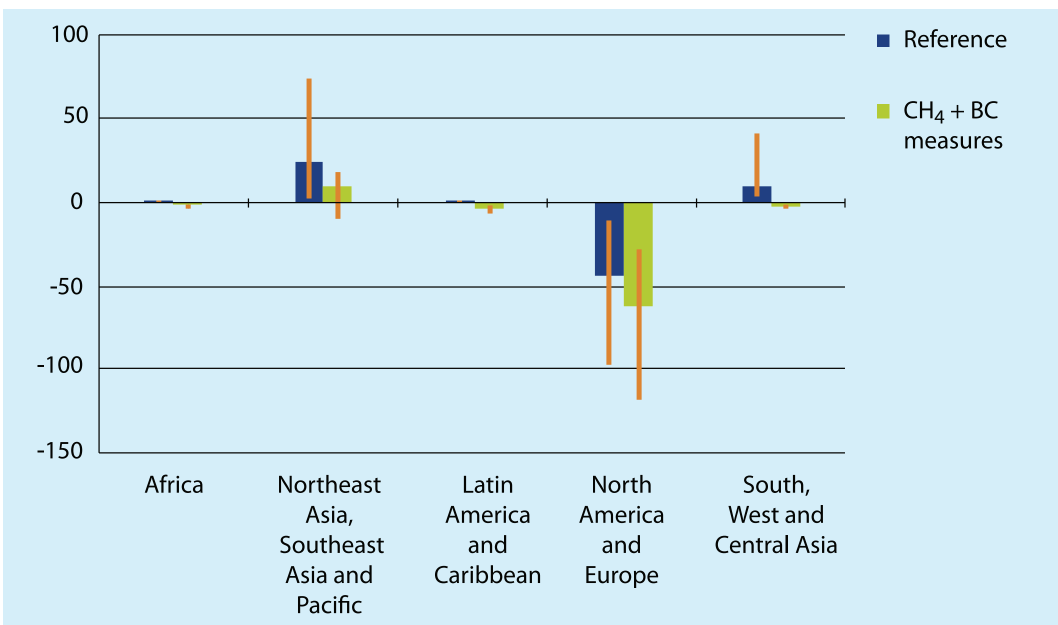
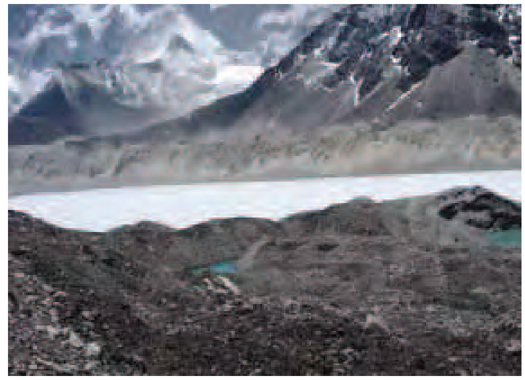


Figure 8. Comparison of crop yield losses (million tonnes annually of four key crops – wheat, rice, maize and soy combined) by region, showing the change in 2030 compared with 2005 for the reference emission trends and the reference with CH_4 + BC measures. The lines on each bar show the range of estimates.

Credit: Veerabhadran Ramanathan

Widespread haze over the Himalayas where BC concentrations can be as high as in mid-sized cities.



Credit: Govind Joshi

Reducing emissions should lower glacial melt and decrease the risk of outbursts from glacial lakes.

measures concerning biomass cookstoves and open burning of biomass. Hence with respect to global warming, there is much higher confidence for measures that mitigate diesel emissions than biomass burning because the proportion of co-emitted cooling OC particles is much lower for diesel.

On the other hand, there is higher confidence that BC measures have large impacts on human health through reducing concentrations of inhalable particles, on crop yields through reduced O_3, and on climate phenomena such as tropical rainfall, monsoons and snow-ice melt. These regional impacts are largely independent of the measures' impact on global warming. In fact, regionally, biomass cookstoves and open biomass burning can have much larger effects than fossil fuels. This is because BC directly increases atmospheric heating by absorbing sunlight, which, according to numerous published studies, affects the monsoon and tropical rainfall, and this is largely separate from the effect of co-emitted OC. The same conclusion applies with respect to the impact of BC measures on snow and ice. BC, because it is dark, significantly increases absorption of sunlight by snow and ice when it is deposited on these bright surfaces. OC that is deposited along with BC has very little effect on sunlight reflected by snow and ice since these surfaces are already very white. Hence knowledge of these regional impacts is, in some cases, more robust than the global impacts, and with respect to reducing regional impacts, all of the BC measures are likely to be significant. Confidence is also high that a large proportion of the health and crop benefits would be realized in Asia.

Mechanisms for rapid implementation

In December 2010 the Parties to the UNFCCC agreed that warming should not exceed 2˚C above pre-industrial levels during this century. This Assessment shows that measures to reduce SLCFs, implemented in combination with CO_2 control measures, would increase the chances of staying below the 2˚C target. The measures would also slow the rate of near-term temperature rise and also lead to significant improvements in health, decreased disruption of regional precipitation patterns and water supply, and in improved food security. The impacts of the measures on temperature change are felt over large geographical areas, while the air quality impacts are more localized near the regions where changes in emissions take place. Therefore, areas that control their emissions will receive the greatest human health and food supply benefits; additionally many of the climate benefits will be felt close to the region taking action.

The benefits would be realized in the near term, thereby providing additional incentives to overcome financial and institutional hurdles to the adoption of these measures. Countries in all regions have successfully implemented the identified measures to some degree for multiple environment and development objectives. These experiences

Credit: Brian Yap

Field burning of agricultural waste is a common way to dispose of crop residue in many regions.

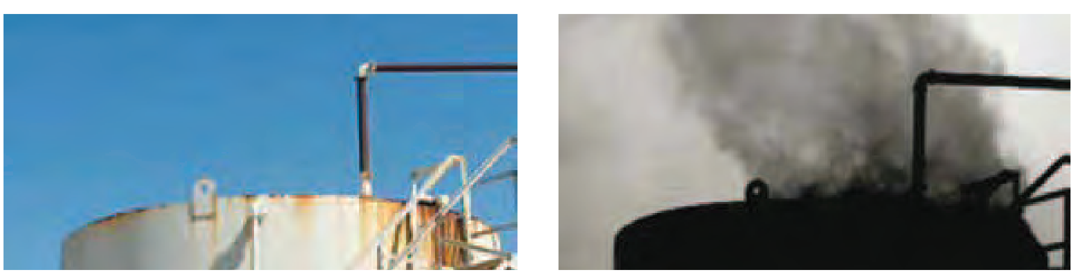
provide a considerable body of knowledge and potential models for others that wish to take action.

In most countries, mechanisms are already in place, albeit at different levels of maturity, to address public concern regarding air pollution problems. Mechanisms to tackle anthropogenic greenhouse gases are less well deployed, and systems to maximize the co-benefits from reducing air pollution and measures to address climate change are virtually non-existent. Coordination across institutions to address climate, air pollution, energy and development policy is particularly important to enhance achievement of all these goals simultaneously.

Many BC control measures require implementation by multiple actors on diffuse emission sources including diesel vehicles, field burning, cookstoves and residential heating. Although air quality and emission standards exist for particulate matter in some regions, they may or may not reduce BC, and implementation remains a challenge. Relevance, benefits and costs of different measures vary from region to region. Many of the measures entail cost savings but require substantial upfront investments. Accounting for air quality, climate and development co-benefits will be key to scaling up implementation.

Methane is one of the six greenhouse gases governed by the Kyoto Protocol, but there are no explicit targets for it. Many CH_4 measures are cost-effective and its recovery is, in many cases, economically profitable. There have been many Clean Development Mechanism (CDM) projects in key CH_4 emitting sectors in the past, though few such projects have been launched in recent years because of lack of financing.

Case studies from both developed and developing countries (Box 3) show that there are technical solutions available to deliver all of the measures (see Chapter 5). Given appropriate policy mechanisms the measures can be implemented, but to achieve the benefits at the scale described much wider implementation is required.



Credit: US EPA

To the naked eye, no emissions from an oil storage tank are visible (left), but with the aid of an infrared camera, escaping CH_4 is evident (right).

Box 3: Case studies of implementation of measures

CH_4 measures

Landfill biogas energy

Landfill CH_4 emissions contribute 10 per cent of the total greenhouse gas emissions in Mexico. Bioenergia de Nuevo Léon S.A. de C.V. (BENLESA) is using landfill biogas as fuel. Currently, the plant has an installed capacity of 12.7 megawatts. Since its opening in September 2003, it has avoided the release of more than 81 000 tonnes of CH_4, equivalent to the reduction in emissions of 1.7 million tonnes of CO_2, generating 409 megawatt hours of electricity. A partnership between government and a private company turned a liability into an asset by converting landfill gas (LFG) into electricity to help drive the public transit system by day and light city streets by night. LFG projects can also be found in Armenia, Brazil, China, India, South Africa, and other countries.

Recovery and flaring from oil and natural gas production

Oil drilling often brings natural gas, mostly CH_4, to the surface along with the oil, which is often vented to the atmosphere to maintain safe pressure in the well. To reduce these emissions, associated gas may be flared and converted to CO_2, or recovered, thus eliminating most of its warming potential and removing its ability to form ozone (O_3). In India, Oil India Limited (OIL), a national oil company, is undertaking a project to recover the gas, which is presently flared, from the Kumchai oil field, and send it to a gas processing plant for eventual transport and use in the natural gas grid. Initiatives in Angola, Indonesia and other countries are flaring and recovering associated gas yielding large reductions in CH_4 emissions and new sources of fuel for local markets.

Livestock manure management

In Brazil, a large CDM project in the state of Mina Gerais seeks to improve waste management systems to reduce the amount of CH_4 and other greenhouse gas emissions associated with animal effluent. The core of the project is to replace open-air lagoons with ambient temperature anaerobic digesters to capture and combust the resulting biogas. Over the course of a 10-year period (2004–2014) the project plans to reduce CH_4 and other greenhouse gas emissions by a total of 50 580 tonnes of CO_2 equivalent. A CDM project in Hyderabad, India, will use the poultry litter CH_4 to generate electricity which will power the plant and supply surplus electricity to the Andhra Pradesh state grid.

Credit: Raphaël V/flickr

Farm scale anaerobic digestion of manure from cattle is one of the key CH_4 measures

Box 3: Case studies of implementation of measures *(continued)*

BC measures

Diesel particle filters

In Santiago, municipal authorities, responding to public concern on air pollution, adopted a new emissions standard for urban buses, requiring installation of diesel particle filters (DPFs). Currently about one-third of the fleet is equipped with filters; it is expected that the entire fleet will be retrofitted by 2018. New York City adopted regulations in 2000 and 2003 requiring use of DPFs in city buses and off-road construction equipment working on city projects. London fitted DPFs to the city's bus fleet over several years beginning in 2003. Low emission zones in London and other cities create incentives for diesel vehicle owners to retrofit with particle filters, allowing them to drive within the city limits. Implementation in developing regions will require greater availability of low sulphur diesel, which is an essential prerequisite for using DPFs.

Improved brick kilns

Small-scale traditional brick kilns are a significant source of air pollution in many developing countries; there are an estimated 20 000 in Mexico alone, emitting large quantities of particulates. An improved kiln design piloted in Ciudad Juárez, near the border with the United States of America, improved efficiency by 50 per cent and decreased particulate pollution by 80 per cent. In the Bac Ninh province of Viet Nam, a project initiated with the aim of reducing ambient air pollution levels and deposition on surrounding rice fields piloted the use of a simple limestone scrubbing emissions control device and demonstrated how a combination of regulation, economic tools, monitoring and technology transfer can significantly improve air quality.

Credit: Alba Corral Avitia

Credit: Robert Marquez

A traditional brick kiln (left) and an improved (right) operating in Mexico.

Potential international regulatory responses

International responses would facilitate rapid and widespread implementation of the measures. Since a large portion of the impacts of SLCFs on climate, health, food security and ecosystems is regional or local in nature, regional approaches incorporating national actions could prove promising for their cost-effective reduction. This approach is still in its very early stage in most regions of the world. For example, the Convention on Long-Range Transboundary Air Pollution (CLRTAP) recently agreed to address BC in the revision of the Gothenburg Protocol in 2011 and to consider the impacts of CH_4 as an O_3 precursor in the longer term.

Other regional agreements (Box 4) are fairly new, and predominantly concentrate on scientific cooperation and capacity building. These arrangements might serve as a platform from which to address the emerging challenges related to air pollution from BC and tropospheric O_3 and provide potential vehicles for finance, technology transfer and capacity development. Sharing good practices

Box 4: Examples of regional atmospheric pollution agreements

The Convention on Long-Range Transboundary Air Pollution (CLRTAP) is a mature policy framework covering Europe, Central Asia and North America. Similar regional agreements have emerged in the last decades in other parts of the world. The Malé Declaration on Control and Prevention of Air Pollution and its Likely Transboundary Effects for South Asia was agreed in 1998 and addresses air quality including tropospheric O_3 and particulate matter. The Association of Southeast Asian Nations (ASEAN) Haze Protocol is a legally binding agreement addresses particulate pollution from forest fires in Southeast Asia. In Africa there are a number of framework agreements between countries in southern Africa (Lusaka Agreement), in East Africa (Nairobi Agreement); and West and Central Africa (Abidjan Agreement). In Latin America and the Caribbean a ministerial level intergovernmental network on air pollution has been formed and there is a draft framework agreement and ongoing collaboration on atmospheric issues under UNEP's leadership.

on an international scale, as is occurring within the Arctic Council, in a coordinated way could provide a helpful way forward.

This Assessment did not assess the cost-effectiveness of different identified measures or policy options under different national circumstances. Doing so would help to inform national air quality and climate policy makers, and support implementation on a wider scale. Further study and analyses of the local application of BC and tropospheric O_3 reduction technologies, costs and regulatory approaches could contribute to advancing adoption of effective action at multiple levels. This work would be best done based on local knowledge. Likewise further evaluation of the regional and global benefits of implementing specific measures by region would help to better target policy efforts. In support of these efforts, additional modelling and monitoring and measurement activities are needed to fill remaining knowledge gaps.

Opportunities for international financing and cooperation

The largest benefits would be delivered in regions where it is unlikely that significant national funds would be allocated to these issues due to other pressing development needs. International financing and technology support would catalyse and accelerate the adoption of the identified measures at sub-national, national and regional levels, especially in developing countries. Financing would be most effective if specifically targeted towards pollution abatement actions that maximize air quality and climate benefits.

Funds and activities to address CH_4 (such as the Global Methane Initiative; and the Global Methane Fund or Prototype Methane Financing Facility) and cookstoves (the Global Alliance for Clean Cookstoves) exist or are under consideration and may serve as models for other sectors. Expanded action will depend on donor recognition of the opportunity represented by SLCF reductions as a highly effective means to address near-term climate change both globally and especially in sensitive regions of the world.

Black carbon and tropospheric O_3 may also be considered as part of other environment, development and energy initiatives such as bilateral assistance, the UN Development Assistance Framework, the World Bank Energy Strategy, the Poverty and Environment Initiative of UNEP and the United Nations Development Programme (UNDP), interagency cooperation initiatives in the UN system such as the Environment Management Group and UN Energy, the UN Foundation, and the consideration by the UN Conference on Sustainable Development (Rio+20) of the institutional framework for sustainable development. These, and others, could take advantage of the opportunities identified in the Assessment to achieve their objectives.

Credit: John Ogren, NOAA

Aerosol measurement instruments

Credit: Christian Lagerek

Concluding Remarks

The Assessment establishes the climate co-benefits of air-quality measures that address black carbon and tropospheric ozone and its precursors, especially CH_4 and CO. The measures identified to address these short-lived climate forcers have been successfully tried around the world and have been shown to deliver significant and immediate development and environmental benefits in the local areas and regions where they are implemented.

Costs and benefits of the identified measures are region specific, and implementation often faces financial, regulatory and institutional barriers. However, widespread implementation of the identified measures can be effectively leveraged by recognizing that near-term strategies can slow the rate of global and regional warming, improving our chances of keeping global temperature increase below bounds that significantly lower the probability of major disruptive climate events. Such leverage should spur multilateral initiatives that focus on local priorities and contribute to the global common good.

It is nevertheless stressed that this Assessment does not in any way suggest postponing immediate and aggressive global action on anthropogenic greenhouse gases; in fact it requires such action on CO_2. This Assessment concludes that the chance of success with such longer-term measures can be greatly enhanced by simultaneously addressing short-lived climate forcers.

The benefits identified in this Assessment can be realised with a concerted effort globally to reduce the concentrations of black carbon and tropospheric ozone. A strategy to achieve this, when developed and implemented, will lead to considerable benefits for human well-being.

Glossary

Aerosol	A collection of airborne solid or liquid particles (excluding pure water), with a typical size between 0.01 and 10 micrometers (μm) and residing in the atmosphere for at least several hours. Aerosols may be of either natural or anthropogenic origin. Aerosols may influence climate in two ways: directly through scattering or absorbing radiation, and indirectly through acting as condensation nuclei for cloud formation or modifying the optical properties and lifetime of clouds.
Biofuels	Biofuels are non-fossil fuels. They are energy carriers that store the energy derived from organic materials (biomass), including plant materials and animal waste.
Biomass	In the context of energy, the term biomass is often used to refer to organic materials, such as wood and agricultural wastes, which can be burned to produce energy or converted into a gas and used for fuel.
Black carbon	Operationally defined aerosol species based on measurement of light absorption and chemical reactivity and/or thermal stability. Black carbon is formed through the incomplete combustion of fossil fuels, biofuel, and biomass, and is emitted in both anthropogenic and naturally occurring soot. It consists of pure carbon in several linked forms. Black carbon warms the Earth by absorbing heat in the atmosphere and by reducing albedo, the ability to reflect sunlight, when deposited on snow and ice.
Carbon sequestration	The uptake and storage of carbon. Trees and plants, for example, absorb carbon dioxide, release the oxygen and store the carbon.
Fugitive emissions	Substances (gas, liquid, solid) that escape to the air from a process or a product without going through a smokestack; for example, emissions of methane escaping from coal, oil, and gas extraction not caught by a capture system.
Global warming potential (GWP)	The global warming potential of a gas or particle refers to an estimate of the total contribution to global warming over a particular time that results from the emission of one unit of that gas or particle relative to one unit of the reference gas, carbon dioxide, which is assigned a value of one.
High-emitting vehicles	Poorly tuned or defective vehicles (including malfunctioning emission control system), with emissions of air pollutants (including particulate matter) many times greater than the average.
Hoffman kiln	Hoffmann kilns are the most common kiln used in production of bricks. A Hoffmann kiln consists of a main fire passage surrounded on each side by several small rooms which contain pallets of bricks. Each room is connected to the next room by a passageway carrying hot gases from the fire. This design makes for a very efficient use of heat and fuel.
Incomplete combustion	A reaction or process which entails only partial burning of a fuel. Combustion is almost always incomplete and this may be due to a lack of oxygen or low temperature, preventing the complete chemical reaction.
Oxidation	The chemical reaction of a substance with oxygen or a reaction in which the atoms in an element lose electrons and its valence is correspondingly increased.

Ozone	Ozone, the triatomic form of oxygen (O_3), is a gaseous atmospheric constituent. In the troposphere, it is created both naturally and by photochemical reactions involving gases resulting from human activities (it is a primary component of photochemical smog). In high concentrations, tropospheric ozone can be harmful to a wide range of living organisms. Tropospheric ozone acts as a greenhouse gas. In the stratosphere, ozone is created by the interaction between solar ultraviolet radiation and molecular oxygen. Stratospheric ozone provides a shield from ultraviolet B (UVB) radiation.
Ozone precursor	Chemical compounds, such as carbon monoxide (CO), methane (CH_4), non-methane volatile organic compounds (NMVOC), and nitrogen oxides (NO_X), which in the presence of solar radiation react with other chemical compounds to form ozone in the troposphere.
Particulate matter	Very small pieces of solid or liquid matter such as particles of soot, dust, or other aerosols.
Pre-industrial	Prior to widespread industrialisation and the resultant changes in the environment. Typically taken as the period before 1750.
Radiation	Energy transfer in the form of electromagnetic waves or particles that release energy when absorbed by an object.
Radiative forcing	Radiative forcing is a measure of the change in the energy balance of the Earth-atmosphere system with space. It is defined as the change in the net, downward minus upward, irradiance (expressed in Watts per square metre) at the tropopause due to a change in an external driver of climate change, such as, for example, a change in the concentration of carbon dioxide or the output of the Sun.
Smog	Classically a combination of smoke and fog in which products of combustion, such as hydrocarbons, particulate matter and oxides of sulphur and nitrogen, occur in concentrations that are harmful to human beings and other organisms. More commonly, it occurs as photochemical smog, produced when sunlight acts on nitrogen oxides and hydrocarbons to produce tropospheric ozone.
Stratosphere	Region of the atmosphere between the troposphere and mesosphere, having a lower boundary of approximately 8 km at the poles to 15 km at the equator and an upper boundary of approximately 50 km. Depending upon latitude and season, the temperature in the lower stratosphere can increase, be isothermal, or even decrease with altitude, but the temperature in the upper stratosphere generally increases with height due to absorption of solar radiation by ozone.
Trans-boundary movement	Movement from an area under the national jurisdiction of one State to or through an area under the national jurisdiction of another State or to or through an area not under the national jurisdiction of any State.
Transport (atmospheric)	The movement of chemical species through the atmosphere as a result of large-scale atmospheric motions.
Troposphere	The lowest part of the atmosphere from the surface to about 10 km in altitude in mid-latitudes (ranging from 9 km in high latitudes to 16 km in the tropics on average) where clouds and "weather" phenomena occur. In the troposphere temperatures generally decrease with height.

Acronyms and Abbreviations

ASEAN	Association of Southeast Asian Nations
BC	black carbon
BENLESA	Latin America Bioenergia de Nuevo Léon S.A. de C.V.
CDM	Clean Development Mechanism
CH_4	methane
CLRTAP	Convention on Long-Range Transboundary Air Pollution
CO	carbon monoxide
CO_2	carbon dioxide
DPF	diesel particle filter
ECHAM	Climate-chemistry-aerosol model developed by the Max Planck Institute in Hamburg, Germany
G8	Group of Eight: Canada, France, Germany, Italy, Japan, Russian Federation, United Kingdom, United States
GAINS	Greenhouse Gas and Air Pollution Interactions and Synergies
GISS	Goddard Institute for Space Studies
GWP	global warming potential
IEA	International Energy Agency
IIASA	International Institute for Applied System Analysis
IPCC	Intergovernmental Panel on Climate Change
LFG	landfill gas
NASA	National Aeronautics and Space Administration
NO_x	nitrogen oxides
O_3	ozone
OC	organic carbon
OIL	Oil India Limited
PM	particulate matter ($PM_{2.5}$ has a diameter of 2.5µm or less)
ppm	parts per million
SLCF	short-lived climate forcer
SO_2	sulphur dioxide
UN	United Nations
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
UV	ultraviolet
VOC	volatile organic compound
WMO	World Meteorological Organization

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About the Assessment:

Growing scientific evidence of significant impacts of black carbon and tropospheric ozone on human well-being and the climatic system has catalysed a demand for information and action from governments, civil society and other main stakeholders. The United Nations, in consultation with partner expert institutions and stakeholder representatives, organized an integrated assessment of black carbon and tropospheric ozone, and its precursors, to provide decision makers with a comprehensive assessment of the problem and policy options needed to address it.

An assessment team of more than 50 experts was established, supported by the United Nations Environment Programme, World Meteorological Organization and Stockholm Environment Institute. The Assessment was governed by the Chair and four Vice-Chairs, representing Asia and the Pacific, Europe, Latin America and the Caribbean and North America regions. A High-level Consultative Group, comprising high-profile government advisors, respected scientists, representatives of international organizations and civil society, provided strategic advice on the assessment process and preparation of the *Summary for Decision Makers*.

The draft of the underlying Assessment and its *Summary for Decision Makers* were extensively reviewed and revised based on comments from internal and external review experts. Reputable experts served as review editors to ensure that all substantive expert review comments were afforded appropriate consideration by the authors. The text of the *Summary for Decision Makers* was accepted by the Assessment Chair, Vice-Chairs and the High-level Consultative Group members.

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This document summarizes findings and conclusions of the assessment report: Integrated Assessment of Black Carbon and Tropospheric Ozone. The assessment looks into all aspects of anthropogenic emissions of black carbon and tropospheric ozone precursors, such as methane. It analyses the trends in emissions of these substances and the drivers of these emissions; summarizes the science of atmospheric processes where these substances are involved; discusses related impacts on the climatic system, human health, crops in vulnerable regions and ecosystems; and societal responses to the environmental changes caused by those impacts. The Assessment examines a large number of potential measures to reduce harmful emissions, identifying a small set of specific measures that would likely produce the greatest benefits, and which could be implemented with currently available technology. An outlook up to 2070 is developed illustrating the benefits of those emission mitigation policies and measures for human well-being and climate. The Assessment concludes that rapid mitigation of anthropogenic black carbon and tropospheric ozone emissions would complement carbon dioxide reduction measures and would have immediate benefits for human well-being.

The Summary for Decision Makers was prepared by a writing team with inputs from the members of the High-level Consultative Group and with support from UNEP and WMO. It is intended to serve decision makers at all levels as a guide for assessment, planning and management for the future.

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Carbon Monoxide
Health

CO can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues. At extremely high levels, CO can cause death.

Exposure to CO can reduce the oxygen-carrying capacity of the blood. People with several types of heart disease already have a reduced capacity for pumping oxygenated blood to the heart, which can cause them to experience myocardial ischemia (reduced oxygen to the heart), often accompanied by chest pain (angina), when exercising or under increased stress. For these people, short-term CO exposure further affects their body's already compromised ability to respond to the increased oxygen demands of exercise or exertion.

Last updated on Thursday, August 09, 2012

United States Environmental Protection Agency

April 2011

Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009

Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

All material taken from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009*, U.S. Environmental Protection Agency, Office of Atmospheric Programs, EPA 430-R-11-005, April 2011. You may electronically download the full inventory report from U.S. EPA's Global Climate Change web page at: **www.epa.gov/climatechange/emissions/usinventory.html.**

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the *Montreal Protocol*, using comparable methodologies…"[3] The United States views the Inventory as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2009. To ensure that the U.S. emission inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) *Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997), the IPCC *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (IPCC 2000), and the IPCC *Good Practice Guidance for Land Use, Land-Use Change, and Forestry* (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). The structure of the inventory report is consistent

[1] The term "anthropogenic", in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

Box ES-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in the inventory report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The inventory report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

ES.1. Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the *Montreal Protocol* on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[7] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2005, concentrations of these greenhouse gases have increased globally by 36, 148, and 18 percent, respectively (IPCC 2007).

[4] See < http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

[7] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the inventory report for informational purposes.

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the *Montreal Protocol*. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[8] The IPCC developed the global warming potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[9, 10] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[11] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2009 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the inventory report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of the inventory report. The GWP values used in the inventory report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in the Inventory Report

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)

* The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

[8] Albedo is a measure of the earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

[9] Carbon comprises 12/44[ths] of carbon dioxide by weight.

[10] One teragram is equal to 10^{12} grams or one million metric tons.

[11] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

ES.2. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2009, total U.S. greenhouse gas emissions were 6,633.2 Tg or million metric tons CO_2 Eq. While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO_2 Eq.). This decrease was primarily due to (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly. Since 1990, U.S. emissions have increased at an average annual rate of 0.4 percent.

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990.

Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2009.

Figure ES-1

U.S. Greenhouse Gas Emissions by Gas

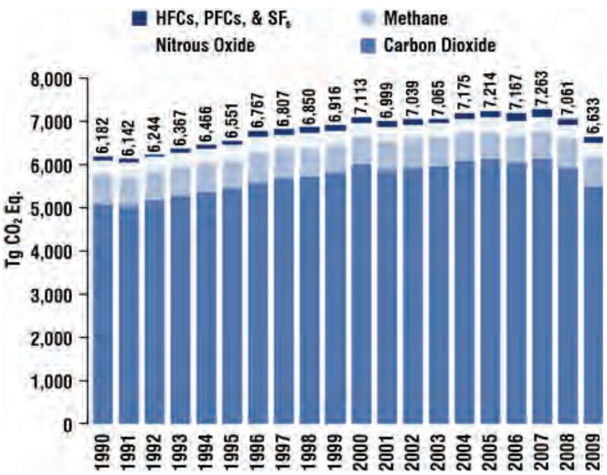


Figure ES-2

Annual Percent Change in U.S. Greenhouse Gas Emissions

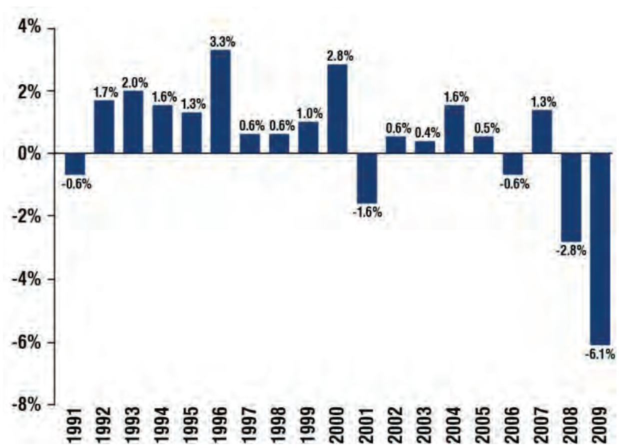


Figure ES-3

Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

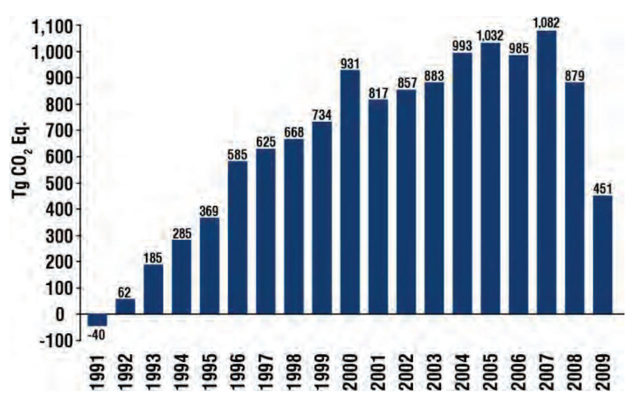


Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg or million metric tons CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**5,099.7**	**5,975.0**	**6,113.8**	**6,021.1**	**6,120.0**	**5,921.4**	**5,505.2**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
Land Use, Land-Use Change, and Forestry (Sink) [a]	*(861.5)*	*(576.6)*	*(1,056.5)*	*(1,064.3)*	*(1,060.9)*	*(1,040.5)*	*(1,015.1)*
Biomass – Wood [b]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels [c]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass – Ethanol [b]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**674.9**	**659.9**	**631.4**	**672.1**	**664.6**	**676.7**	**686.3**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining Forest Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg or million metric tons CO_2 Eq.) (continued)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**315.2**	**341.0**	**322.9**	**326.4**	**325.1**	**310.8**	**295.6**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining Forest Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[d]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

\+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

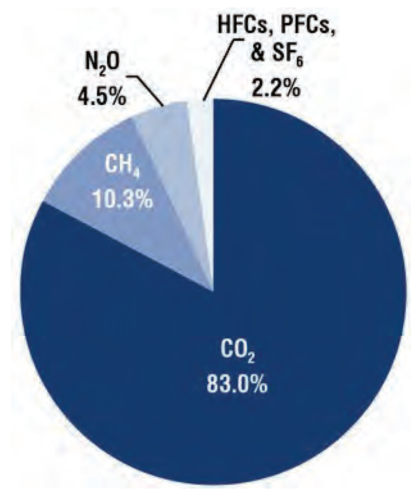
Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2009. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.0 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. Methane emissions, which have increased by 1.7 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management and mobile source fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted as a byproduct of primary aluminum production and from semiconductor manufacturing, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Overall, from 1990 to 2009, total emissions of CO_2 and CH_4 increased by 405.5 Tg CO_2 Eq. (8.0 percent) and 11.4 Tg CO_2 Eq. (1.7 percent), respectively. Conversely, N_2O emissions decreased by 19.6 Tg CO_2 Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 54.1 Tg CO_2 Eq. (58.8 percent). From 1990 to 2009, HFCs increased by 88.8 Tg CO_2 Eq. (240.41 percent), PFCs decreased by 15.1 Tg CO_2 Eq. (73.0 percent), and SF_6 decreased by 19.5 Tg CO_2 Eq. (56.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.3 percent of total emissions in 2009. The following sections describe each gas' contribution to total U.S. greenhouse gas emissions in more detail.

Figure ES-4

2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)



Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 36 percent (IPCC 2007), principally due to the combustion of fossil fuels. Within the United States, fossil fuel combustion accounted for 94.6 percent of CO_2 emissions in 2009. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[12] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

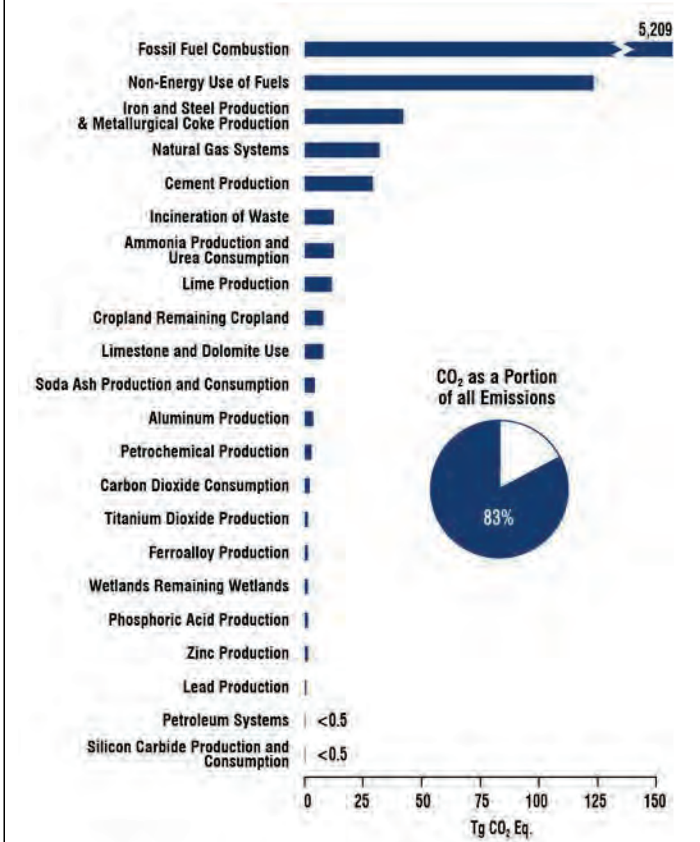
As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2009. The fundamental factors influencing this trend include: (1) a generally growing domestic economy over the last 20 years, and (2) overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2009, CO_2 emissions from fossil fuel combustion increased from 4,738.4 Tg CO_2 Eq. to 5,209.0 Tg CO_2 Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO_2 Eq. (6.4 percent), the largest decrease in any year over the twenty-year period.

[12] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* <http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-5

2009 Sources of CO_2 Emissions



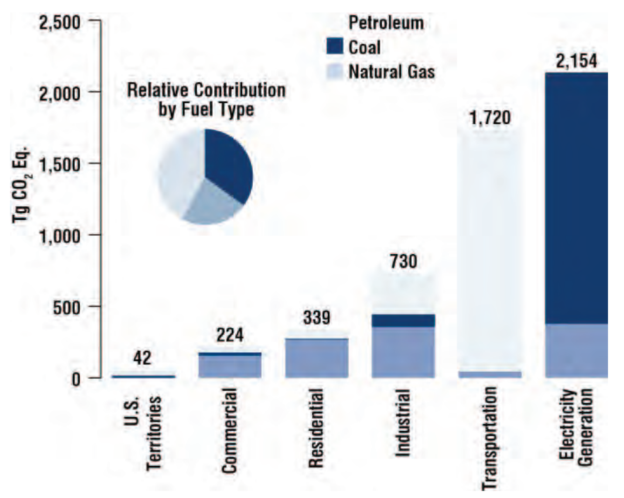
The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. Carbon dioxide emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or "end-use" sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Figure ES-6

2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type



Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

Figure ES-7

2009 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

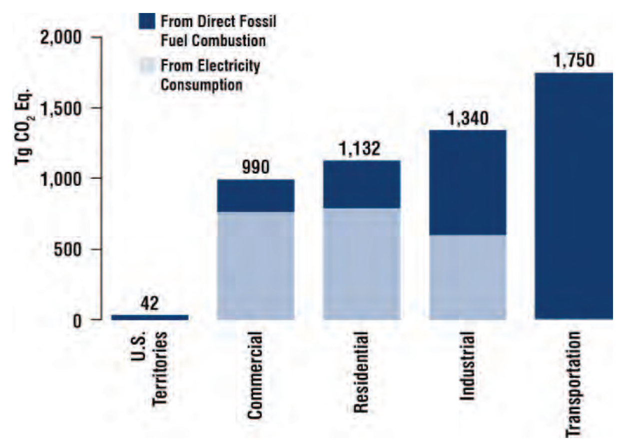


Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	**1,533.2**	**1,640.8**	**1,560.0**	**1,560.2**	**1,572.0**	**1,517.7**	**1,333.7**
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	**931.4**	**1,133.1**	**1,214.7**	**1,152.4**	**1,198.5**	**1,182.2**	**1,123.8**
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	**757.0**	**972.1**	**1,027.2**	**1,007.6**	**1,041.1**	**1,031.6**	**985.7**
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories [a]	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**

[a] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in the inventory report.
Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 33 percent of CO_2 emissions from fossil fuel combustion in 2009.[13] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-

[13] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 35 percent of U.S. emissions from fossil fuel combustion in 2009.

duty vehicles and jet fuel in aircraft. From 1990 to 2009, transportation emissions rose by 16 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2009. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2009. Both sectors relied heavily on electricity for meeting energy demands, with 70 and 77 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 25 percent since 1990, due to increasing electricity consumption for lighting, heating, air conditioning, and operating appliances.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 41 percent of the CO_2 from fossil fuel combustion in 2009. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 95 percent of all coal consumed for energy in the United States in 2009. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- Carbon dioxide emissions from non-energy use of fossil fuels have increased 4.7 Tg CO_2 Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq. in 2009, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.

- Carbon dioxide emissions from iron and steel production and metallurgical coke production decreased by 24.1 Tg CO_2 Eq. (36.6 percent) from 2008 to 2009, continuing a trend of decreasing emissions from 1990 through 2009 of 57.9 percent (57.7 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.

- In 2009, CO_2 emissions from cement production decreased by 11.5 Tg CO_2 Eq. (28.4 percent) from 2008. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the last three years. Overall, from 1990 to 2009, emissions from cement production decreased by 12.8 percent, a decrease of 4.3 Tg CO_2 Eq.

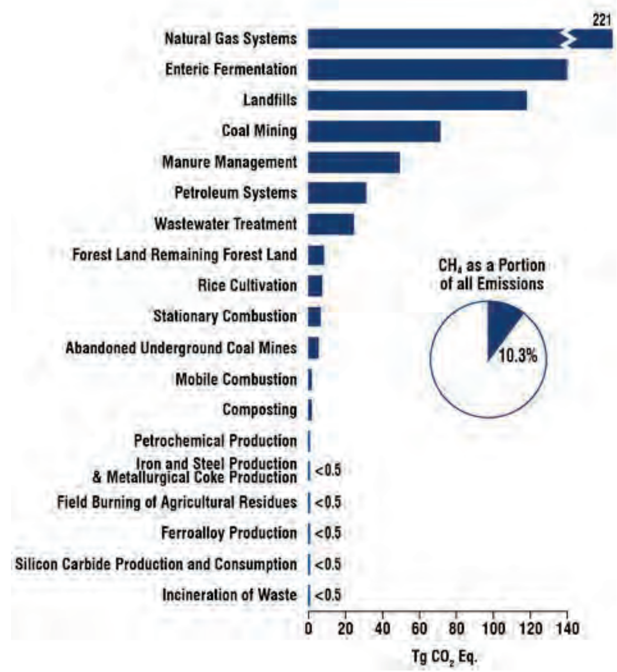
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 153.5 Tg CO_2 Eq. (17.8 percent) from 1990 through 2009. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 148 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8

2009 Sources of CH_4 Emissions



Some significant trends in U.S. emissions of CH_4 include the following:

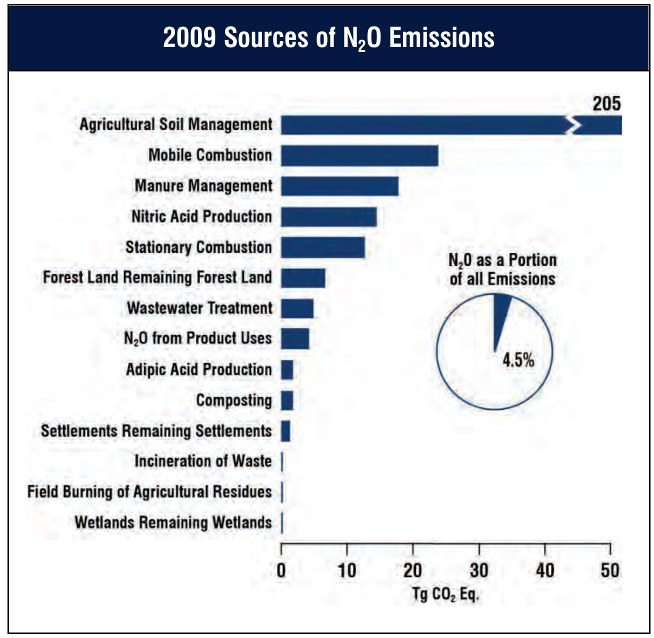
- In 2009, CH_4 emissions from coal mining were 71.0 Tg CO_2 Eq., a 3.9 Tg CO_2 Eq. (5.8 percent) increase over 2008 emission levels. The overall decline of 13.0 Tg CO_2 Eq. (15.5 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2009 with 221.2 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 31.4 Tg CO_2 Eq. (16.6 percent) since 1990. Methane emissions from this source increased 4 percent from 2008 to 2009 due to an increase in production and production wells.
- Enteric Fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2009, enteric fermentation CH_4 emissions were 139.8 Tg CO_2 Eq. (20 percent of total CH_4 emissions), which represents an increase of 7.7 Tg CO_2 Eq. (5.8 percent) since 1990.
- Methane emissions from manure management increased by 55.9 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 49.5 Tg CO_2 Eq. in 2009. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 17 percent of total CH_4 emissions (117.5 Tg CO_2 Eq.) in 2009. From 1990 to 2009, CH_4 emissions from landfills decreased by 29.9 Tg CO_2 Eq. (20 percent), with small increases occurring in some interim years. This downward trend in overall

emissions is the result of increases in the amount of landfill gas collected and combusted,[14] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

Nitrous Oxide Emissions

Nitrous oxide is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 18 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, manure management, nitric acid production and stationary fuel combustion, (see Figure ES-9).

Figure ES-9



Some significant trends in U.S. emissions of N_2O include the following:

- In 2009, N_2O emissions from mobile combustion were 23.9 Tg CO_2 Eq. (approximately 8.1 percent of U.S. N_2O emissions). From 1990 to 2009, N_2O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.

- Nitrous oxide emissions from adipic acid production were 1.9 Tg CO_2 Eq. in 2009, and have decreased significantly since 1996 from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990, and emissions from adipic acid production have remained consistently lower than pre-1996 levels since 1998.

- Agricultural soils accounted for approximately 69.2 percent of N_2O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990.

[14] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

HFC, PFC, and SF_6 Emissions

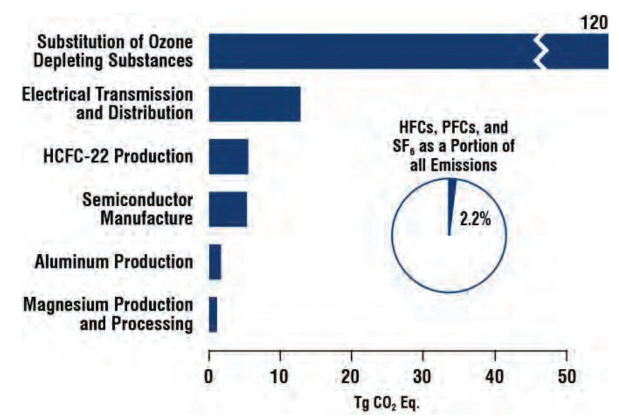
HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the *Montreal Protocol* and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the stratospheric ozone layer, and are therefore acceptable alternatives under the *Montreal Protocol*.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10

2009 Sources of HFCs, PFCs, and SF_6 Emissions



Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ODS (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-outs required under the *Montreal Protocol* come into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.

- HFC emissions from the production of HCFC-22 decreased by 85.2 percent (31.0 Tg CO_2 Eq.) from 1990 through 2009, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.

- Sulfur hexafluoride emissions from electric power transmission and distribution systems decreased by 54.8 percent (15.6 Tg CO_2 Eq.) from 1990 to 2009, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.

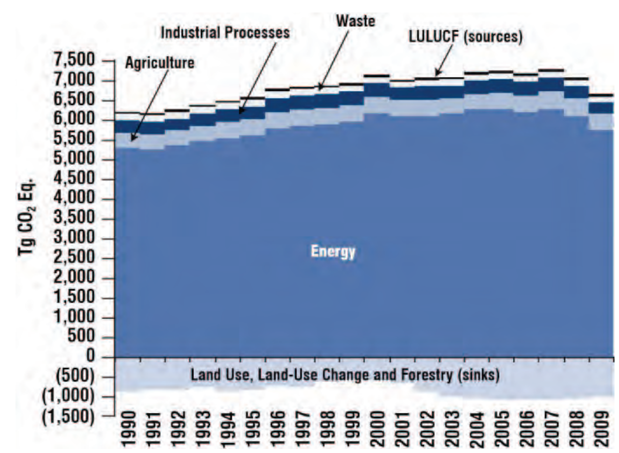
- PFC emissions from aluminum production decreased by 91.5 percent (17.0 Tg CO_2 Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

ES.3. Overview of Sector Emissions and Trends

In accordance with the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO_2 Eq. (9 percent), and 35.7 Tg CO_2 Eq. (9 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO_2 Eq. (10 percent), 24.7 Tg CO_2 Eq. (14 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 143.5 Tg CO_2 Eq. (17 percent).

Figure ES-11

U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use Sectors.

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	1990	2000	2005	2006	2007	2008	2009
Energy	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8	348.8	334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Agriculture	383.6	410.6	418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0	36.3	28.6	49.8	47.5	33.2	25.0
Waste	175.2	143.9	144.9	144.4	144.1	149.0	150.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Sinks)[a]	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

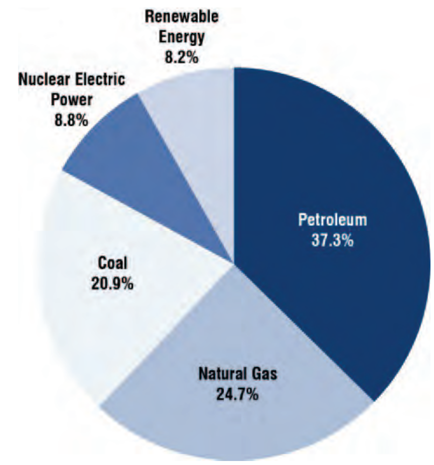
[a] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.
Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (49 percent and 13 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87 percent of total U.S. greenhouse gas emissions in 2009.

Figure ES-12

2009 U.S. Energy Consumption by Energy Source



Industrial Processes

The Industrial Processes chapter contains byproduct or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4 percent of U.S. greenhouse gas emissions in 2009.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a byproduct of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2009.

Agriculture

The Agriculture chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. Methane emissions from enteric fermentation and manure management represented 20 percent and 7 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2009.

Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2009, accounting for 69 percent. In 2009, emission sources accounted for in the Agriculture chapter were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 85 percent of total 2009 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5.5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18 percent of total U.S. CO_2 emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. The application of crushed limestone and dolomite to managed land (i.e., liming of agricultural soils) and urea fertilization resulted in CO_2 emissions of 7.8 Tg CO_2 Eq. in 2009, an increase of 11 percent relative to 1990. The application of synthetic fertilizers to forest and settlement soils in 2009 resulted in direct N_2O emissions of 1.9 Tg CO_2 Eq. Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils increased by 55 percent since 1990. Forest fires resulted in CH_4 emissions of 7.8 Tg CO_2 Eq., and in N_2O emissions of 6.4 Tg CO_2 Eq. in 2009. Carbon dioxide and N_2O emissions from peatlands totaled 1.1 Tg CO_2 Eq. and less than 0.01 Tg CO_2 Eq. in 2009, respectively.

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for just over 78 percent of this chapter's emissions, and 17 percent of total U.S. CH_4 emissions.[15] Additionally, wastewater treatment accounts for 20 percent of Waste emissions, 4 percent of U.S. CH_4 emissions, and 2 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.7 Tg CO_2 Eq. and 1.8 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 2.3 percent of total U.S. greenhouse gas emissions in 2009.

ES.4. Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2009.

[15] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the inventory report.

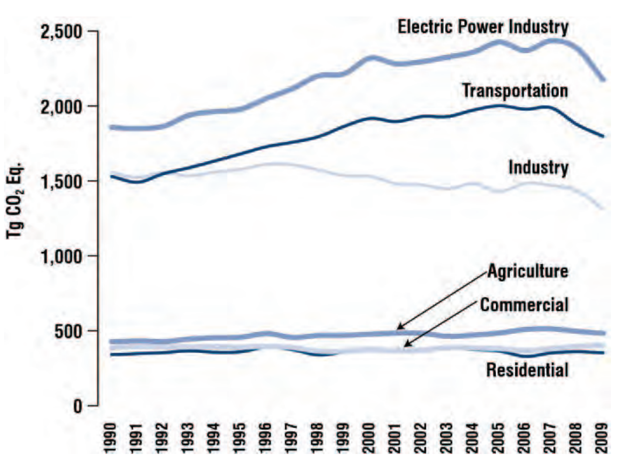
Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	1990	2000	2005	2006	2007	2008	2009
Electric Power Industry	1,868.9	2,337.6	2,444.6	2,388.2	2,454.0	2,400.7	2,193.0
Transportation	1,545.2	1,932.3	2,017.4	1,994.4	2,003.8	1,890.7	1,812.4
Industry	1,564.4	1,544.0	1,441.9	1,497.3	1,483.0	1,446.9	1,322.7
Agriculture	429.0	485.1	493.2	516.7	520.7	503.9	490.0
Commercial	395.5	381.4	387.2	375.2	389.6	403.5	409.5
Residential	345.1	386.2	371.0	335.8	358.9	367.1	360.1
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Land Use, Land-Use Change, and Forestry (Sinks)	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. See Table 2-12 of the inventory report for more detailed data.

Figure ES-13

Emissions Allocated to Economic Sectors



Note: Does not include U.S. Territories.

Using this categorization, emissions from electricity generation accounted for the largest portion (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2009. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 20 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial sector accounted for 6 percent of emissions while the residential sector accounted for 5 percent of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

Carbon dioxide was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[16] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

Table ES-8: U.S. Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (Tg or million metric tons CO_2 Eq.)

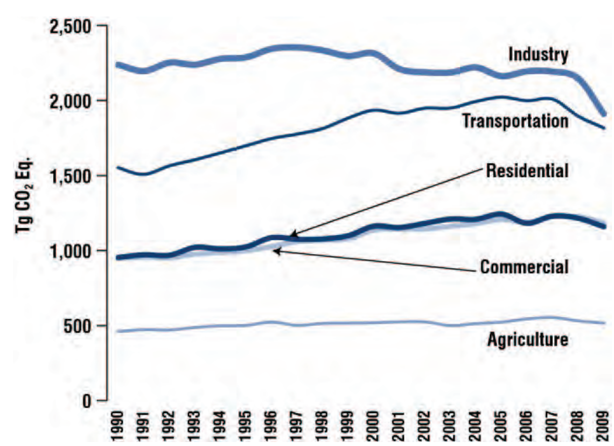
Implied Sectors	1990	2000	2005	2006	2007	2008	2009
Industry	2,238.3	2,314.4	2,162.5	2,194.6	2,192.9	2,146.5	1,910.9
Transportation	1,548.3	1,935.8	2,022.2	1,999.0	2,008.9	1,895.5	1,816.9
Commercial	947.7	1,135.8	1,205.1	1,188.5	1,225.3	1,224.5	1,184.9
Residential	953.8	1,162.2	1,242.9	1,181.5	1,229.6	1,215.1	1,158.9
Agriculture	460.0	518.4	522.7	544.1	553.2	531.1	516.0
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Land Use, Land-Use Change, and Forestry (Sinks)	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

See Table 2-14 of the inventory report for more detailed data.

When emissions from electricity are distributed among these sectors, industrial activities account for the largest share of U.S. greenhouse gas emissions (29 percent) in 2009. Transportation is the second largest contributor to total U.S. emissions (28 percent). The commercial and residential sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2009. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2009.

Figure ES-14

U.S. Emissions with Electricity Distributed to Economic Sectors



Note: Does not include U.S. Territories.

16 Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

Box ES-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.4 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

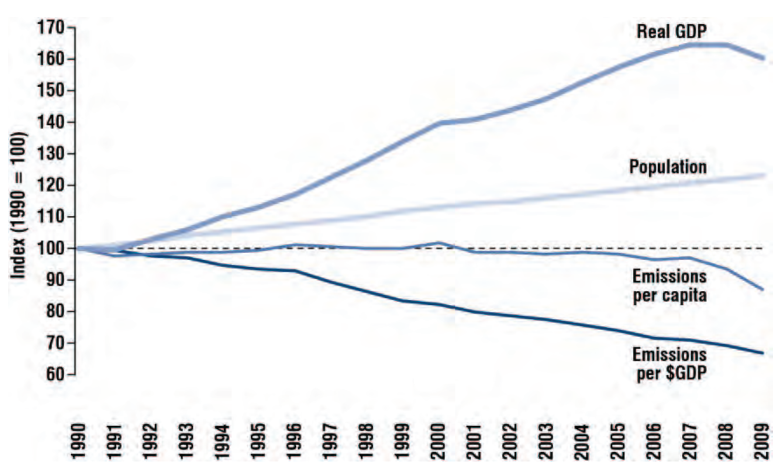
Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	1990	2000	2005	2006	2007	2008	2009	Growth Rate[a]
GDP [b]	100	140	157	162	165	165	160	2.5%
Electricity Consumption [c]	100	127	134	135	138	138	132	1.5%
Fossil Fuel Consumption [c]	100	117	119	117	119	116	108	0.5%
Energy Consumption [c]	100	116	118	118	120	118	112	0.6%
Population [d]	100	113	118	120	121	122	123	1.1%
Greenhouse Gas Emissions [e]	100	115	117	116	117	114	107	0.4%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy content-weighted values (EIA 2010b)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure ES-15

U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product



Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in the inventory report.

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[17] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[18] which are regulated under the Clean Air Act. Table ES-10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table ES-10: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,707**	**19,116**	**15,900**	**15,039**	**14,380**	**13,547**	**11,468**
Mobile Fossil Fuel Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	**130,038**	**92,243**	**70,809**	**67,238**	**63,625**	**60,039**	**51,452**
Mobile Fossil Fuel Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	**20,930**	**15,227**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**
Mobile Fossil Fuel Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel Combustion	912	1,077	716	918	1,120	1,321	424
Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**14,830**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**
Stationary Fossil Fuel Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

NA (Not Available)
Note: Totals may not sum due to independent rounding.
Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.

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17 See <http://unfccc.int/resource/docs/cop8/08.pdf>.

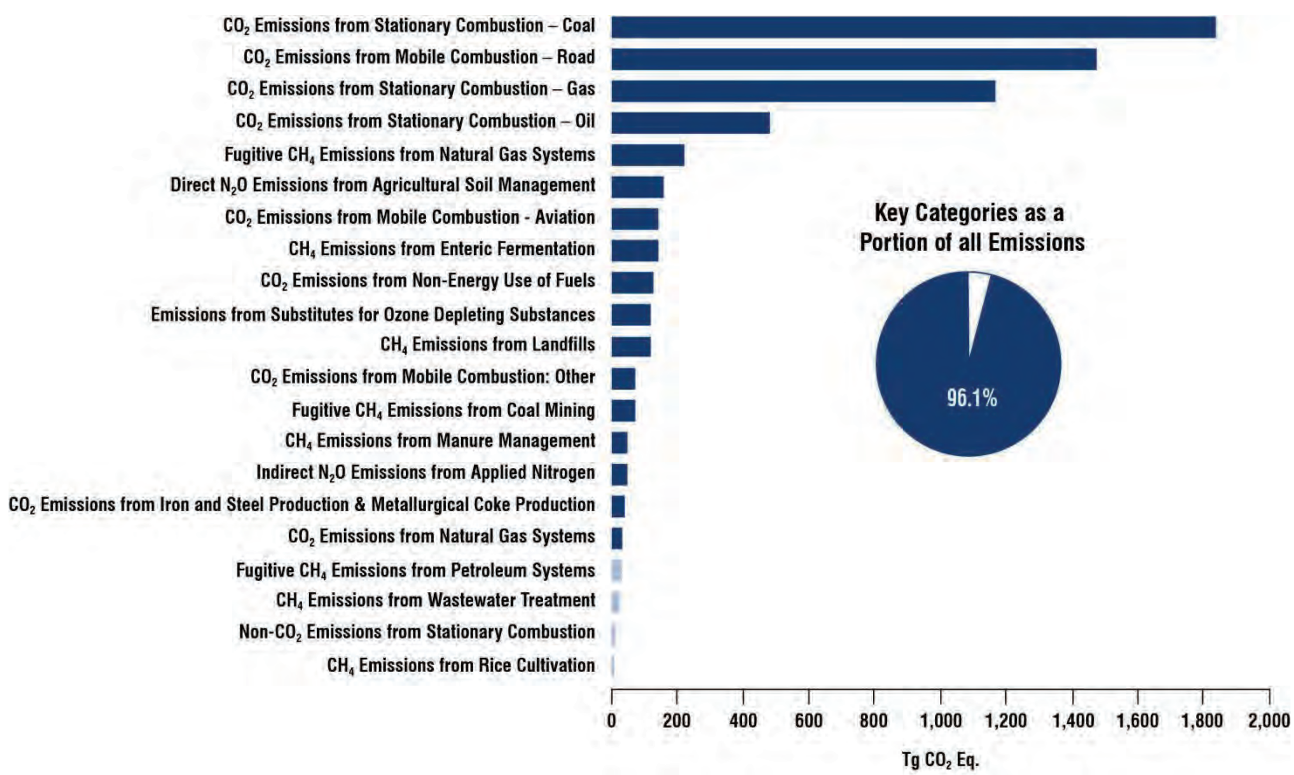
18 NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Key Categories

The *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[19] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16

2009 Key Categories



Note: For a complete discussion of the key category analysis, see Annex 1 of the inventory report. Darker bars indicate a Tier 1 level assessment key category. Lighter bars indicate a Tier 2 level assessment key category.

Figure ES-16 presents 2009 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

[19] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>.

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the inventory report. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

Box ES-3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the inventory report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, "Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods" when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors." In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2009) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

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United States
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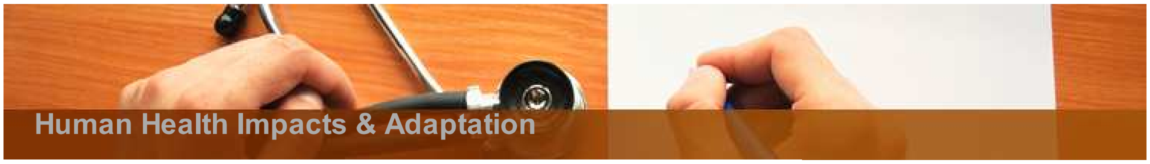
Climate Change
Human Health Impacts & Adaptation

climatechange/impacts-adaptation/health.html#adapt



[Climate Impacts on Human Health] [Adaptation Examples in Human Health]

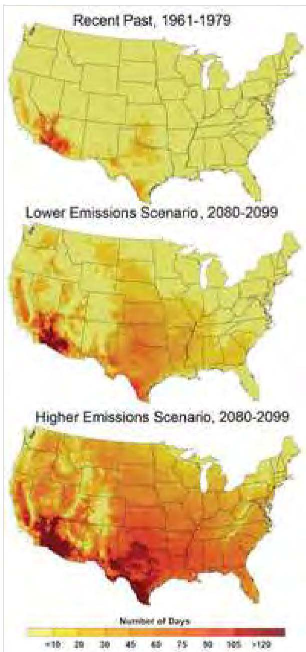
Weather and climate play a significant role in people's health. Changes in climate affect the average weather conditions that we are

ON THIS PAGE

accustomed to. Warmer average temperatures will likely lead to hotter days and more frequent and longer heat waves. This could increase the number of heat-related illnesses and deaths. Increases in the frequency or severity of extreme weather events such as storms could increase the risk of dangerous flooding, high winds, and other direct threats to people and property. Warmer temperatures could increase the concentrations of unhealthy air and water pollutants. Changes in temperature, precipitation patterns, and extreme events could enhance the spread of some diseases.


Sun setting over a city on a hot day.
Source: EPA (2010)

The impacts of climate change on health will depend on many factors. These factors include the effectiveness of a community's public health and safety systems to address or prepare for the risk and the behavior, age, gender, and economic status of individuals affected. Impacts will likely vary by region, the sensitivity of populations, the extent and length of exposure to climate change impacts, and society's ability to adapt to change.



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The number of 100-degree days per year is projected to increase.
Source: USGCRP (2009)

Although the United States has well-developed public health systems (compared with those of many developing countries), climate change will still likely affect many Americans. In addition, the impacts of climate change on public health around the globe could have important consequences for the United States. For example, more frequent and intense storms may require more disaster relief and declines in agriculture may increase food shortages.

Impacts from Heat Waves

Heat waves can lead to heat stroke and dehydration, and are the most common cause of weather-related deaths.[1] [2] Excessive heat is more likely to impact populations in northern latitudes where people are less prepared to cope with excessive temperatures. Young children, older adults, people with medical conditions, and the poor are more vulnerable than others to heat-related illness. The share of the U.S. population composed of adults over age 65 is currently 12%, but is projected to grow to 21% by 2050, leading to a larger vulnerable population.[1]

Climate change will likely lead to more frequent, more severe, and longer heat waves in the summer (see 100-degree-days figure), as well as less severe cold spells in the winter. A recent assessment of the science suggests that increases in heat-related deaths due to climate change would outweigh decreases in deaths from cold-snaps.[1]

Urban areas are typically warmer than their rural surroundings. Climate change could lead to even warmer temperatures in cities. This would increase the demand for electricity in the summer to run air conditioning, which in turn would increase air pollution and greenhouse gas emissions from power plants. The impacts of future heat waves could be especially severe in

Key Points

- A warmer climate is expected to both increase the risk of heat-related illnesses and death and worsen conditions for air quality.
- Climate change will likely increase the frequency and strength of extreme events (such as floods, droughts, and storms) that threaten human safety and health.
- Climate changes may allow some diseases to spread more easily.

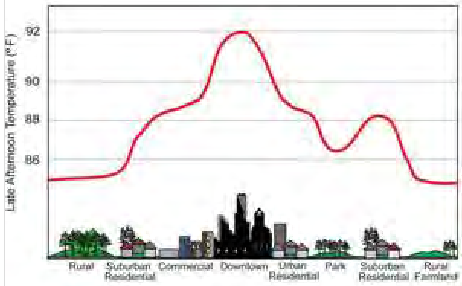
Related Links

EPA:

- Climate Change Indicators in the United States
- Heat Island Effect
- Excessive Heat Events Guidebook
- Global Change Research Program
- Climate Change and Children's Health
- Climate Change and Health Effects on Older Adults
- *Assessment of the Impacts of Global Change on Regional U.S. Air Quality: A Synthesis of Climate Change Impacts on Ground-Level Ozone*
- *Our Nation's Air: Status and Trends Through 2008*

Other:

- CDC Climate Change and Public Health
- USGCRP *Synthesis Assessment Product 4.6: Analyses of the Effects of Global Change on Human Health and Welfare and Human Systems*
- IPCC Fourth Assessment Report, Working Group II EXIT Disclaimer
- USGCRP, Global Climate Change Impacts in the United States: Human Health
- NRC America's Climate Choices: Adapting to the Impacts of Climate Change EXIT Disclaimer
- National Institute of Environmental Health Sciences: *A Human Health Perspective on Climate Change* (PDF)
- World Health Organization, *Climate Change and Human Health: Risks and Responses* EXIT Disclaimer



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The "urban heat island" refers to the fact that the local temperature in urban areas is a few degrees higher than the surrounding area. Source: USGCRP (2009)

large metropolitan areas. For example, in Los Angeles, annual heat-related deaths are projected to increase two- to seven-fold by the end of the 21st century, depending on the future growth of greenhouse gas emissions. [1] Heat waves are also often accompanied by periods of stagnant air, leading to increases in air pollution and the associated health effects

Impacts from Extreme Weather Events

The frequency and intensity of extreme precipitation events is projected to increase in some locations, as is the severity (wind speeds and rain) of tropical storms. [1] These extreme weather events could cause injuries and, in some cases, death. As with heat waves, the people most at risk include young children, older adults, people with medical conditions, and the poor. Extreme events can also indirectly threaten human health in a number of ways. For example, extreme events can:

- Reduce the availability of fresh food and water. [2]
- Interrupt communication, utility, and health care services. [2]
- Contribute to carbon monoxide poisoning from portable electric generators used during and after storms. [2]
- Increase stomach and intestinal illness among evacuees. [1]
- Contribute to mental health impacts such as depression and post-traumatic stress disorder (PTSD). [1]

Flooded streets in New Orleans after Hurricane Katrina in 2005. Source: FEMA (2005)

Climate Change Affects Human Health and Welfare

In 2008, the U.S. Global Change Research Program produced a report that analyzed the impacts of global climate change on human health and welfare. The report finds that:

- Many of the expected health effects are likely to fall mostly on the poor, the very old, the very young, the disabled, and the uninsured.
- Climate change will likely result in regional differences in U.S. impacts, due not only to a regional pattern of changes in climate but also to regional variations in the distribution of sensitive populations and the ability of communities to adapt to climate changes.
- Adaptation should begin now, starting with public health infrastructure. Individuals, communities, and government agencies can take steps to moderate the impacts of climate change on human health. (To learn more, see the Health Adaptation section)

Impacts from Reduced Air Quality

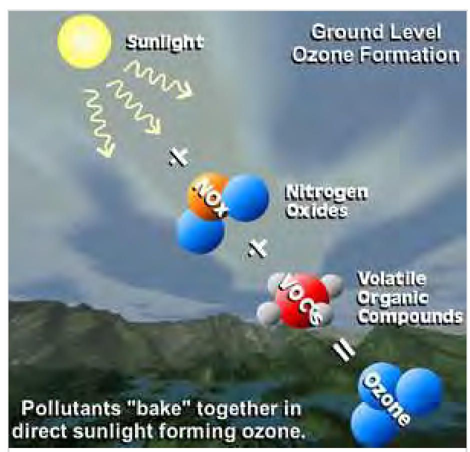
Despite significant improvements in U.S. air quality since the 1970s, as of 2008 more than 126 million Americans lived in counties that did not meet national air quality standards. [3]

Increases in Ozone

Scientists project that warmer temperatures from climate change will increase the frequency of days with unhealthy levels of ground-level ozone, a harmful air pollutant, and a component in smog. [2] [3]

- Ground-level ozone can damage lung tissue and can reduce lung function and inflame airways. This can increase respiratory symptoms and aggravate asthma or other lung diseases. It is especially harmful to children, older adults, outdoor workers, and those with asthma and other chronic lung diseases. [4]
- Ozone exposure also has been associated with increased susceptibility to respiratory infections, medication use, doctor visits, and emergency department visits and hospital admissions for individuals with lung disease. Some studies suggest that ozone may increase the risk of premature mortality, and possibly even the development of asthma. [1] [2] [3] [5]
- Ground-level ozone is formed when certain air pollutants, such as carbon monoxide, oxides of nitrogen (also called NO_X), and volatile organic compounds, are exposed to each other in sunlight. Ground-level ozone is one of the pollutants in smog. [2] [3]
- Because warm, stagnant air tends to increase the formation of ozone, climate change is likely to increase levels of ground-level ozone in already-polluted areas of the United States and increase the number of days with poor air quality. [1] If emissions of air pollutants remain fixed at today's levels until 2050, warming from climate change alone could increase the number of Red Ozone Alert Days (when the air is unhealthy for everyone) by 68% in the 50 largest eastern U.S. cities. [1] (See Box below "EPA Report on Air Quality and Climate Change.")

Smog in Los Angeles decreases visibility and can be harmful to human health. Source: California Air Resources Board (2011)



Ozone chemistry. Source: NASA (2012)

Changes in Fine Particulate Matter

Particulate matter is the term for a category of extremely small particles and liquid droplets suspended in the atmosphere. Fine particles include particles smaller than 2.5 micrometers (about one ten-thousandth of an inch). These particles may be emitted directly or may be formed in the atmosphere from chemical reactions of gases such as sulfur dioxide, nitrogen dioxide, and volatile organic compounds.

- Inhaling fine particles can lead to a broad range of adverse health effects, including premature mortality, aggravation of cardiovascular and respiratory disease, development of chronic lung disease, exacerbation of asthma, and decreased lung function growth in children. [6]
- Sources of fine particle pollution include power plants, gasoline and diesel engines, wood combustion, high-temperature industrial processes such as smelters and steel mills, and forest fires. [6]

Due to the variety of sources and components of fine particulate matter, scientists do not yet know whether climate change will increase or decrease particulate matter concentrations across the United States. [7] [8] A lot of particulate matter is cleaned from the air by rainfall, so increases in precipitation could have a beneficial effect. At the same time, other climate-related changes in stagnant air episodes, wind patterns, emissions from vegetation and the chemistry of atmospheric pollutants will likely affect particulate matter levels. [2] Climate change will also affect particulates through changes in wildfires, which are expected to become more frequent and intense in a warmer climate. [7]

Changes in Allergens

Climate change may affect allergies and respiratory health. [4] The spring pollen season is already occurring earlier in the United States due to climate change. The length of the season may also have increased. In addition, climate change may facilitate the spread of ragweed, an invasive plant with very allergenic pollen. Tests on ragweed show that increasing carbon dioxide concentrations and temperatures would increase the amount and timing of ragweed pollen production. [1] [2] [9]

Impacts from Climate-Sensitive Diseases

Changes in climate may enhance the spread of some diseases. [1] Disease-causing agents, called pathogens, can be transmitted through food, water, and animals such as deer, birds, mice, and insects. Climate change could affect all of these transmitters.

Food-borne Diseases

- Higher air temperatures can increase cases of salmonella and other bacteria-related food poisoning because bacteria grow more rapidly in warm environments. These diseases can cause gastrointestinal distress and, in severe cases, death. [1]
- Flooding and heavy rainfall can cause overflows from sewage treatment plants into fresh water sources. Overflows could contaminate certain food crops with pathogen-containing feces. [1]

Water-borne Diseases

- Heavy rainfall or flooding can increase water-borne parasites such as *Cryptosporidium* and *Giardia* that are sometimes found in drinking water. [1] These parasites can cause gastrointestinal distress and in severe cases, death.
- Heavy rainfall events cause stormwater runoff that may contaminate water bodies used for recreation (such as lakes and beaches) with other bacteria. [9] The most common illness contracted from contamination at beaches is gastroenteritis, an inflammation of the stomach and the intestines that can cause symptoms such as vomiting, headaches, and fever. Other minor illnesses include ear, eye, nose, and throat infections. [2]

EPA Report on Air Quality and Climate Change

Improving America's air quality is one of EPA's top priorities. EPA's Global Change Research Program is investigating the potential consequences of climate change on U.S. air quality. A recent interim assessment finds that:

- Climate change could increase surface-level ozone concentrations in areas w here pollution levels are already high.
- Climate change could make U.S. air quality management more difficult.
- Policy makers should consider the potential impacts of climate change on air quality w hen making air quality management decisions.

Animal-borne Diseases

- The geographic range of ticks that carry Lyme disease is limited by temperature. As air temperatures rise, the range of these ticks is likely to continue to expand northward. [9] Typical symptoms of Lyme disease include fever, headache, fatigue, and a characteristic skin rash.
- In 2002, a new strain of West Nile virus, which can cause serious, life-altering disease, emerged in the United States. Higher temperatures are favorable to the survival of this new strain. [1]

Mosquitoes favor w arm, w et climates and can spread diseases such as West Nile virus.

The spread of climate-sensitive diseases will depend on both climate and non-climate factors. The United States has public health infrastructure and programs to monitor, manage, and prevent the spread of many diseases. The risks for climate-sensitive diseases can be much higher in poorer countries that have less capacity to prevent and treat illness. [9] For more information, please visit the International Impacts & Adaptation page.

Other Heath Linkages

Other linkages exist between climate change and human health. For example, changes in temperature and precipitation, as well as droughts and floods, will likely affect agricultural yields and production. In some regions of the world, these impacts may compromise food security and threaten human health through malnutrition, the spread of infectious diseases, and food poisoning. The worst of these effects are projected to occur in developing countries, among vulnerable populations. [9] Declines in human health in other countries might affect the United States through trade, migration and immigration and have implications for national security. [1] [2]

Although the impacts of climate change have the potential to affect human health in the United States and around the world, there is a lot we can do to prepare for and adapt to these changes. Learn about how we can adapt to climate impacts on health.

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WCMS
Last updated on Thursday, June 14, 2012

Sulfur Dioxide
Health

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for asthmatics at elevated ventilation rates (e.g., while exercising or playing.)

Studies also show a connection between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

EPA's National Ambient Air Quality Standard for SO_2 is designed to protect against exposure to the entire group of sulfur oxides (SOx). SO_2 is the component of greatest concern and is used as the indicator for the larger group of gaseous sulfur oxides (SOx). Other gaseous sulfur oxides (e.g. SO3) are found in the atmosphere at concentrations much lower than SO_2.

Emissions that lead to high concentrations of SO_2 generally also lead to the formation of other SOx. Control measures that reduce SO_2 can generally be expected to reduce people's exposures to all gaseous SOx. This may have the important co-benefit of reducing the formation of fine sulfate particles, which pose significant public health threats.

SOx can react with other compounds in the atmosphere to form small particles. These particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death. EPA's NAAQS for particulate matter (PM) are designed to provide protection against these health effects.

Last updated on Thursday, July 12, 2012

United States Environmental Protection Agency

Particulate Matter (PM)

Health

The size of particles is directly linked to their potential for causing health problems. Small particles less than10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream.

Exposure to such particles can affect both your lungs and your heart. Small particles of concern include "inhalable coarse particles" (such as those found near roadways and dusty industries), which are larger than 2.5 micrometers and smaller than 10 micrometers in diameter; and "fine particles" (such as those found in smoke and haze), which are 2.5 micrometers in diameter and smaller.

The Clean Air Act requires EPA to set air quality standards to protect both public health and the public welfare (e.g. visibility, crops and vegetation). Particle pollution affects both.

Health Effects

Particle pollution - especially fine particles - contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- premature death in people with heart or lung disease,
- nonfatal heart attacks,
- irregular heartbeat,
- aggravated asthma,
- decreased lung function, and
- increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

People with heart or lung diseases, children and older adults are the most likely to be affected by particle pollution exposure. However, even if you are healthy, you may experience temporary symptoms from exposure to elevated levels of particle pollution. For more information about asthma, visit www.epa.gov/asthma.

Environmental Effects

Visibility impairment
Fine particles ($PM_{2.5}$) are the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas. For more information about visibility, visit www.epa.gov/visibility.

Environmental damage
Particles can be carried over long distances by wind and then settle on ground or water. The effects of this settling include: making lakes and streams acidic; changing the nutrient balance in coastal waters and large river basins; depleting the nutrients in soil; damaging sensitive forests and farm crops; and affecting the diversity of ecosystems. More information about the effects of particle pollution and acid rain.

Aesthetic damage
Particle pollution can stain and damage stone and other materials, including culturally important objects such as statues and monuments. More information about the effects of particle pollution and acid rain.

You w ill need Adobe Acrobat Reader to view the Adobe PDF files on this page. See EPA's PDF page for more information about getting and using the free Acrobat Reader.

For more information on particle pollution, health and the environment, visit:

Particle Pollution and Your Health (PDF) (2pp, 320k): Learn who is at risk from exposure to particle pollution, what health effects you may experience as a result of particle exposure, and simple measures you can take to reduce your risk.

How Smoke From Fires Can Affect Your Health: It's important to limit your exposure to smoke -- especially if you may be susceptible. This publication provides steps you can take to protect your health.

Integrated Science Assessment for Particulate Matter (December 2009): This comprehensive assessment of scientific data about the health and environmental effects of particulate matter is an important part of EPA's review of its particle pollution standards.

Last updated on Friday, June 15, 2012

EPA United States Environmental Protection Agency

Visibility

Basic Information

How far can you see?

Every year there are over 280 million visitors to our nation's most treasured parks and wilderness areas. Unfortunately, many visitors aren't able to see the spectacular vistas they expect. During much of the year a veil of white or brown haze hangs in the air blurring the view. Most of this haze is not natural. It is air pollution, carried by the wind often many hundreds of miles from where it originated.

In our nation's scenic areas, the visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from 140 miles to 35-90 miles.

What is haze?

Haze is caused when sunlight encounters tiny pollution particles in the air. Some light is absorbed by particles. Other light is scattered away before it reaches an observer. More pollutants mean more absorption and scattering of light, which reduce the clarity and color of what we see. Some types of particles such as sulfates, scatter more light, particularly during humid conditions.

Where does haze-forming pollution come from?

Air pollutants come from a variety of natural and manmade sources. Natural sources can include windblown dust, and soot from wildfires. Manmade sources can include motor vehicles, electric utility and industrial fuel burning, and manufacturing operations. Particulate matter pollution is the major cause of reduced visibility (haze) in parts of the United States, including many of our national parks. Find out more about particulate pollution.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are carried many miles from the source of the pollutants.

What else can these pollutants do to you and the environment?

Some of the pollutants which form haze have also been linked to serious health problems and environmental damage. Exposure to very small particles in the air have been linked with increased respiratory illness, decreased lung function, and even premature death. In addition, particles such as nitrates and sulfates contribute to acid rain formation which makes lakes, rivers, and streams unsuitable for many fish, and erodes buildings, historical monuments, and paint on cars.

How can I learn more about visibility?

How Air Pollution Affects the View (PDF) (2 pp, 793 KB) - EPA brochure describing the health and environmental effects of haze.

Introduction to Visibility (PDF) (79 pp., 3.3 MB) - Report by William Malm, National Park Service and Colorodo State Institute for Research on the Atmosphere

What other Federal agencies address visibility?

- National Park Service EXIT Disclaimer
- U.S. Forest Service EXIT Disclaimer
- U.S. Fish and Wildlife Service EXIT Disclaimer

Last updated on Thursday, May 31, 2012