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 24 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 632,604 members in the United States, and 2,954 members in Louisiana. 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 April 14, 2014.

Yolanda Andersen

Yolanda Andersen

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.

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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).

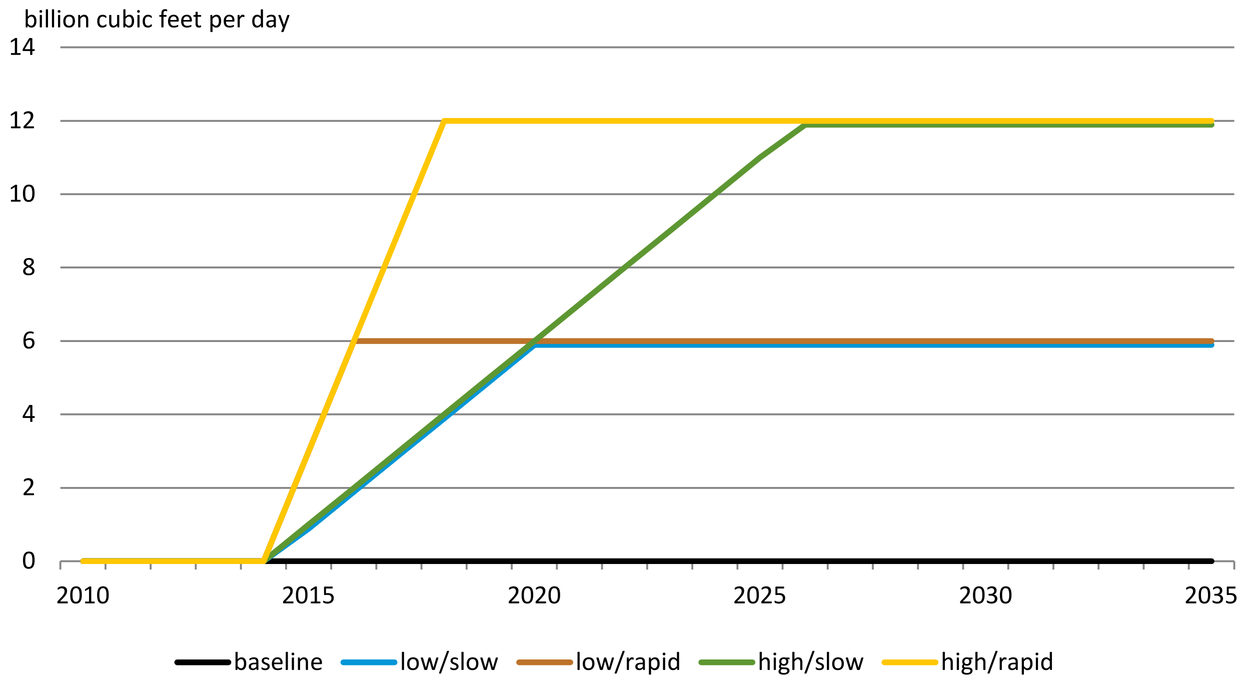
Total marketed natural gas production in 2011 was about 66 Bcf/d. The two ultimate levels of increased natural gas demand due to additional exports in the DOE/FE scenarios represent roughly 9 percent or 18 percent of current production.

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.

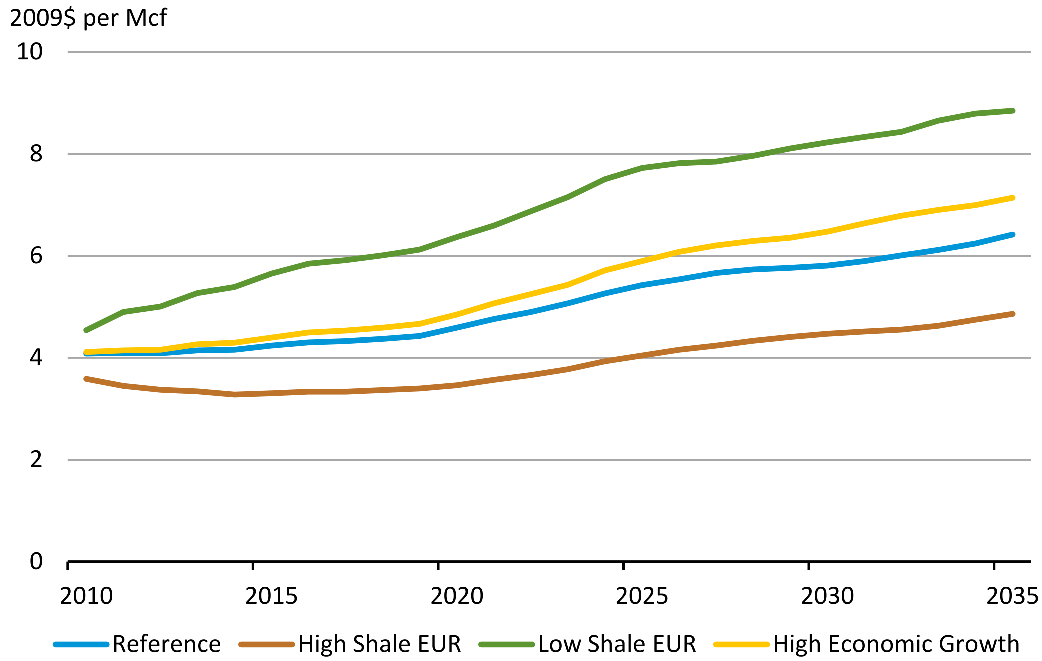
Natural gas prices

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

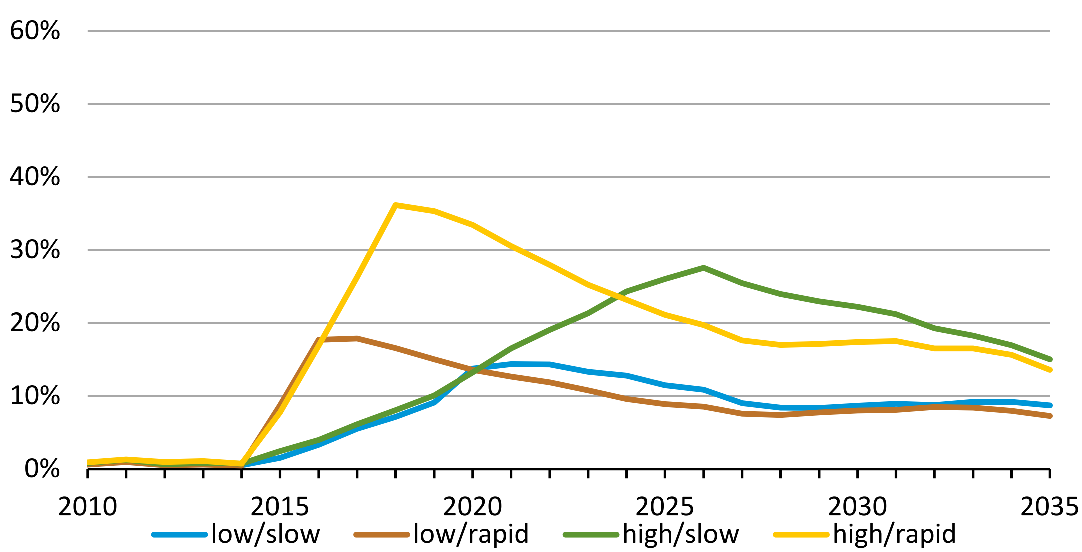
Increases in natural gas prices at the wellhead translate to similar absolute increases in delivered prices to customers under all export scenarios and baseline cases. However, delivered prices include transportation charges (for most customers) and distribution charges (especially for residential and 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

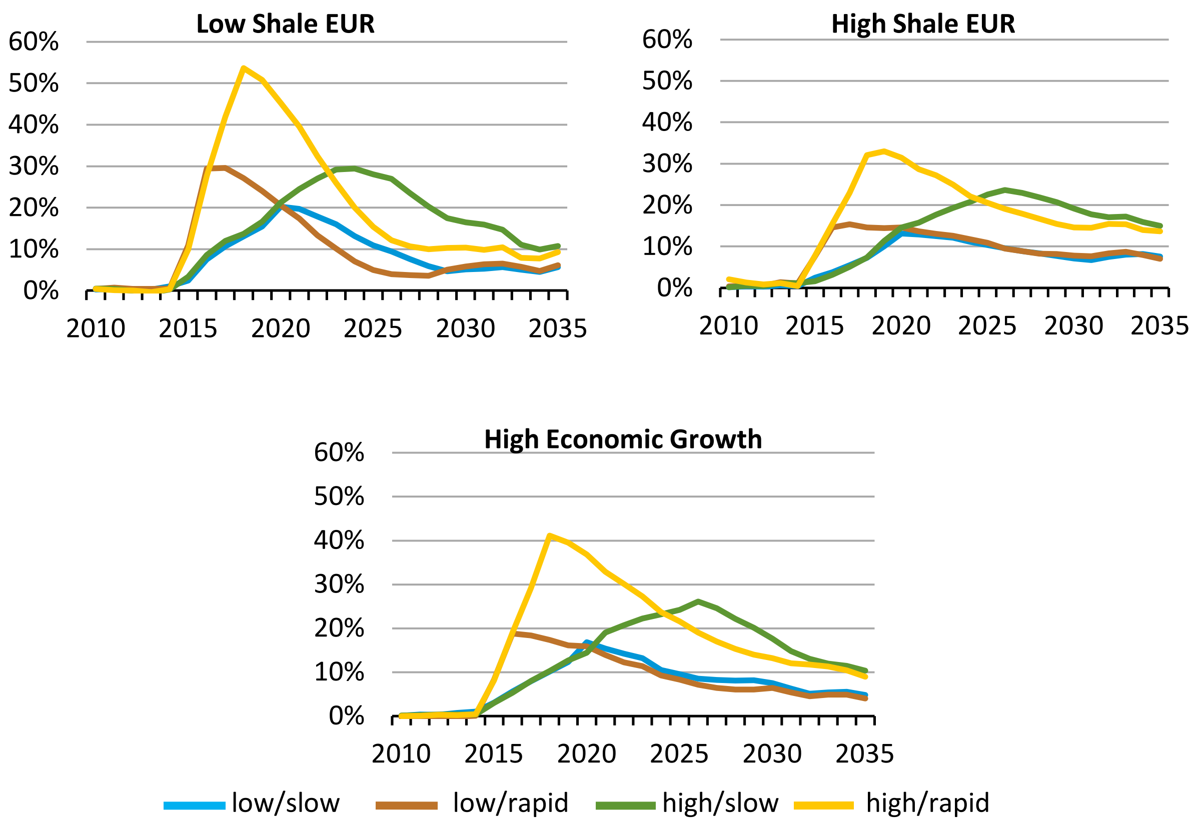


Source: U.S. Energy Information Administration, National Energy Modeling System

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

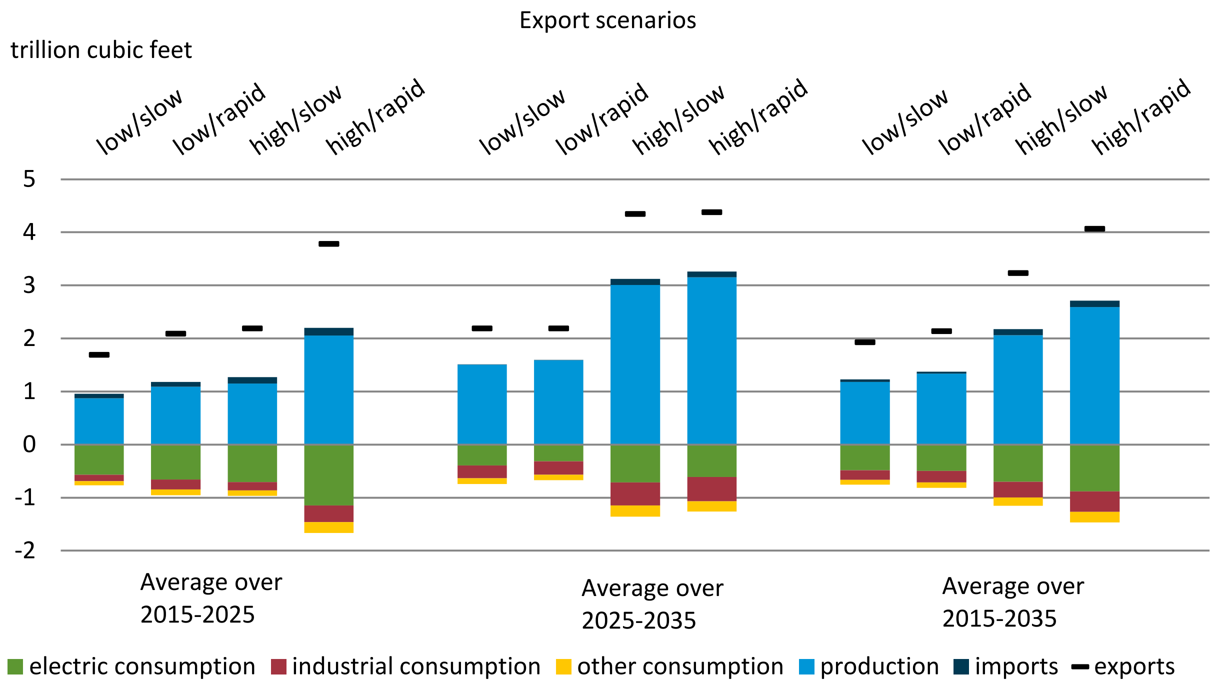
In the AEO2011 Reference case, total domestic natural gas production grows from 22.4 trillion cubic feet (Tcf) in 2015 to 26.3 Tcf in 2035, averaging 24.2 Tcf for the 2015-2035 period. U.S. net imports of natural gas decline from 11 percent of total supply in 2015 to 1 percent in 2035, with lower net 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.

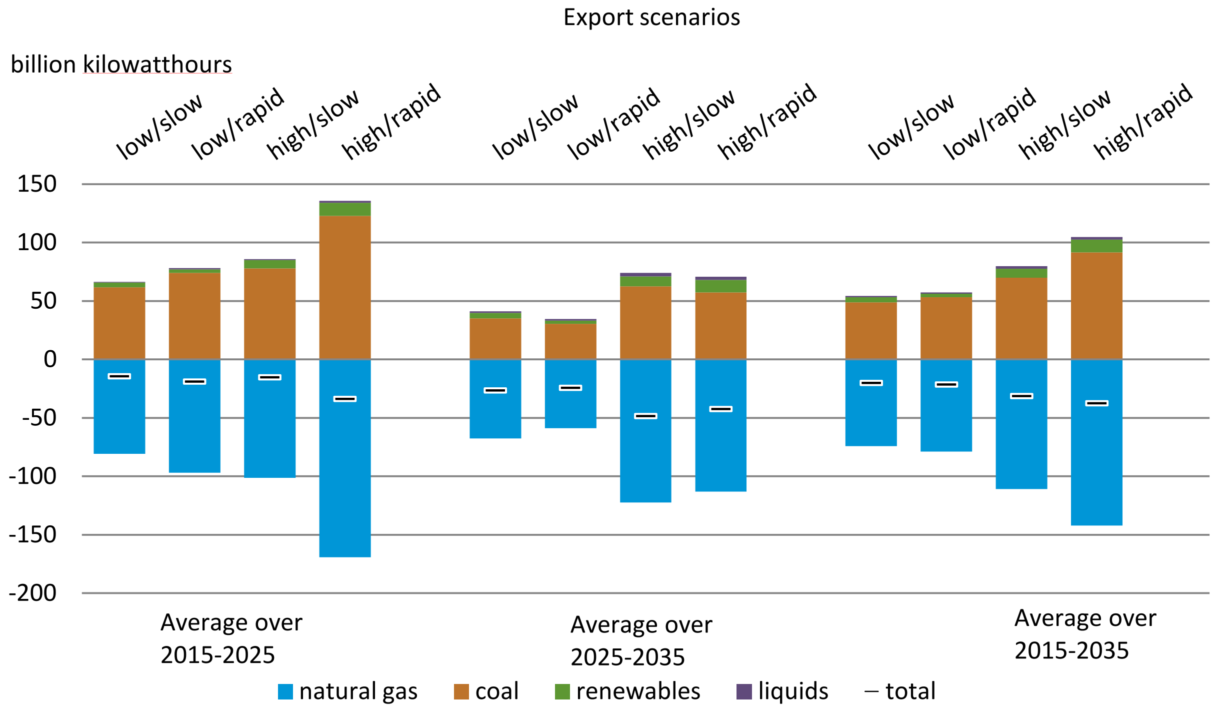
In addition, small increases in renewable generation contribute to reduced natural gas-fired generation. Relatively speaking, the role of renewables is greater in a higher-gas-price environment (i.e., the Low Shale EUR case), when they can more successfully compete with coal, and in a higher-generation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

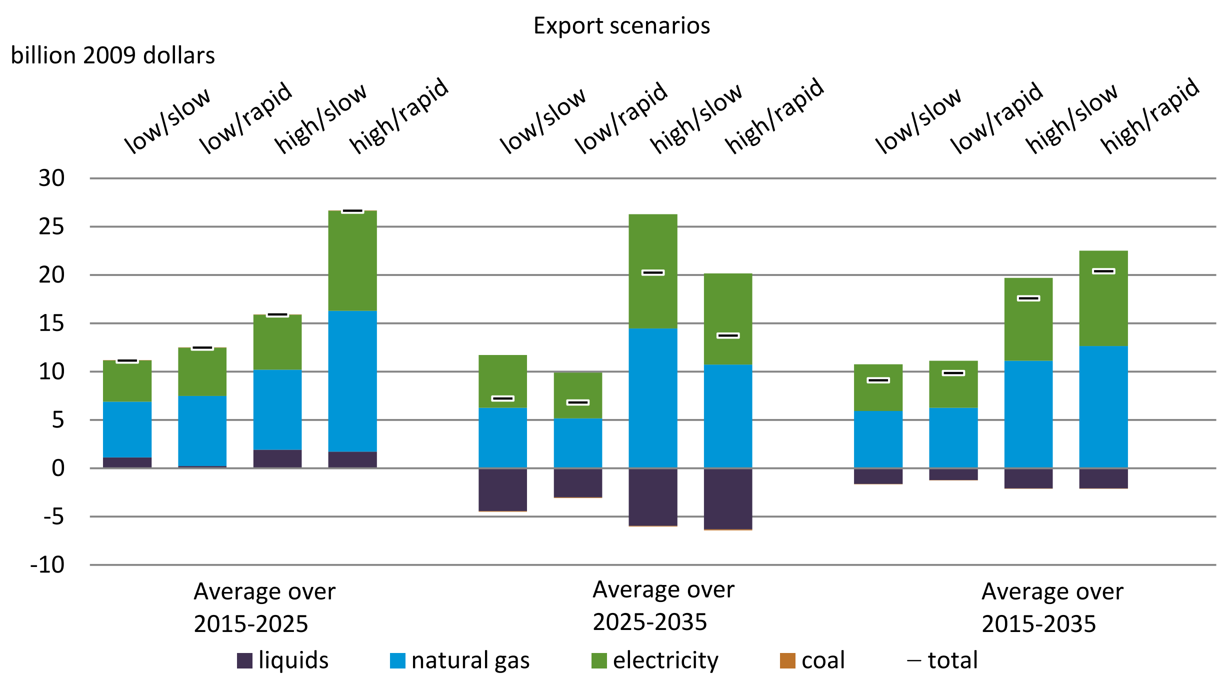
If exports to Canada and Mexico were allowed to vary under these additional export scenarios, they would likely respond similarly to domestic consumption and decrease in response to higher natural gas prices.

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).

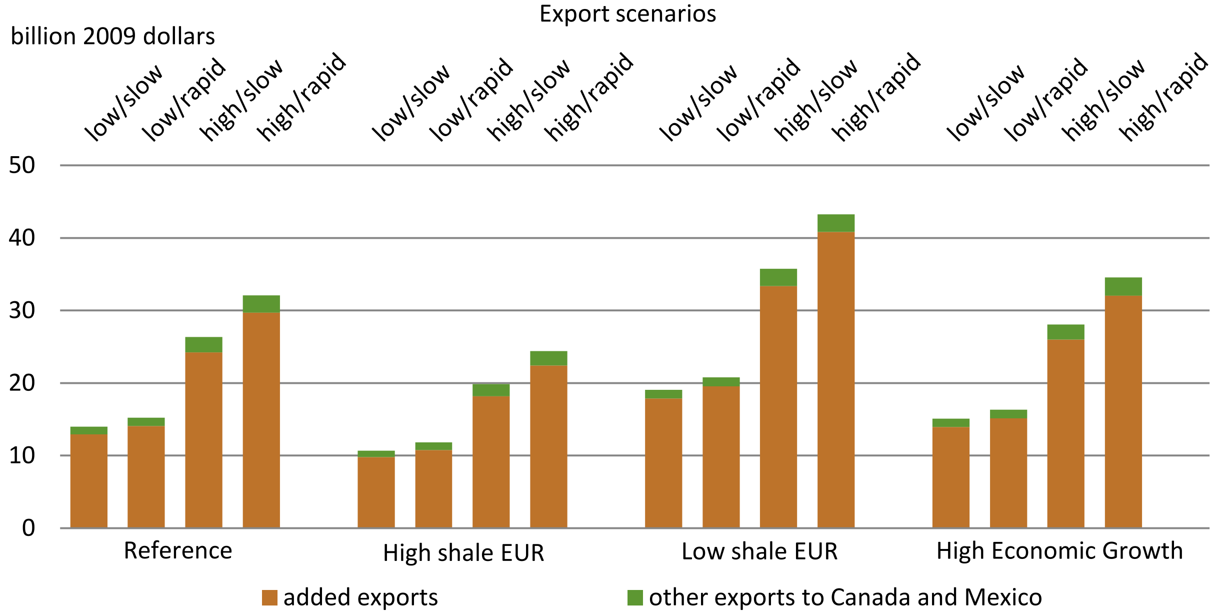
Similar to natural gas, higher electricity prices due to the increased exports reduce end-use consumption making the percentage change in end-use electricity expenditures less than the percentage change in delivered electricity prices; additionally, the percentage increase in end-use electricity expenditures 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.

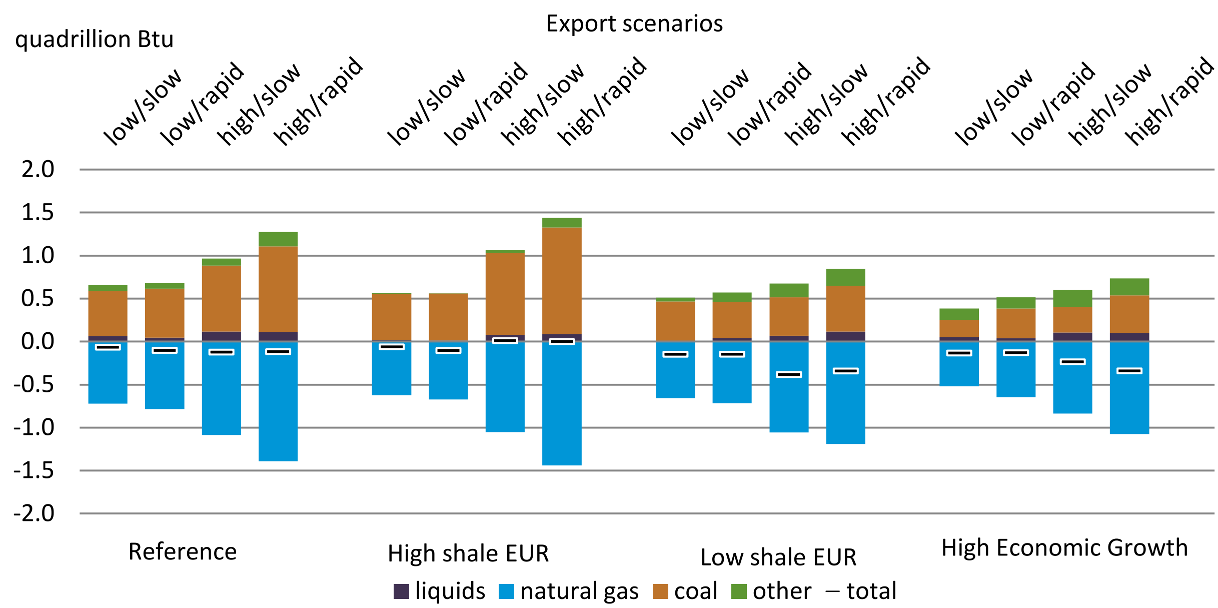
Total energy use and energy-related carbon dioxide emissions

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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ECONOMIC CONSULTING

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U.S. Department of Energy
1000 Independence Avenue, SW
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

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Macroeconomic Impacts of LNG Exports from the United States

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

Contents

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List of Acronyms

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

NewEra 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 NewEra

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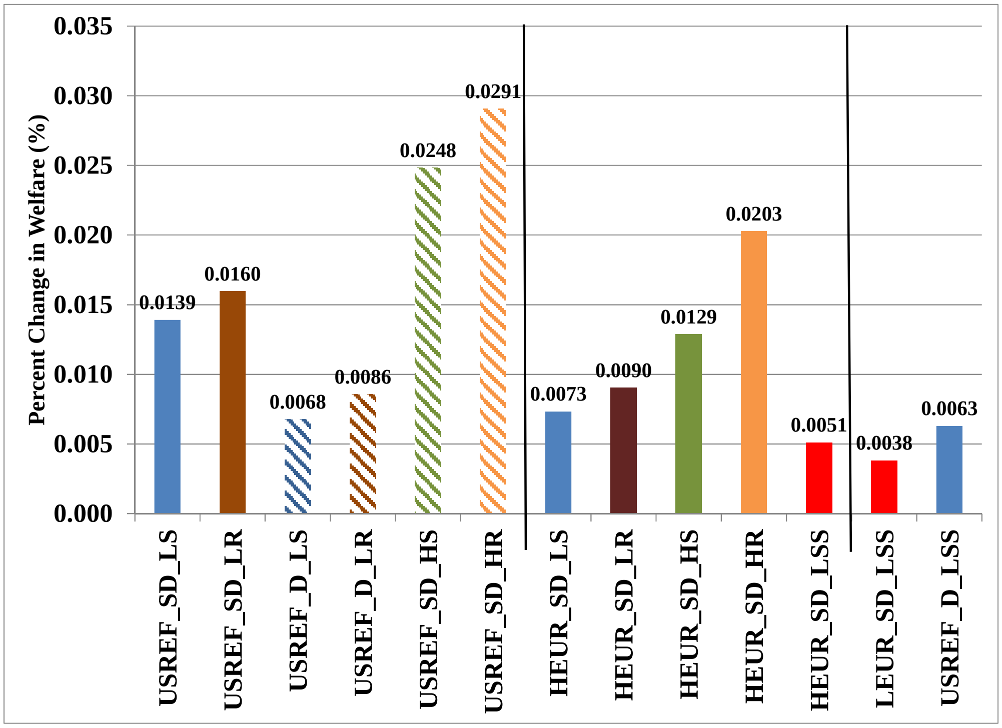
4 NERA did not run the EIA High Growth case because the results would be similar to the REF case.

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

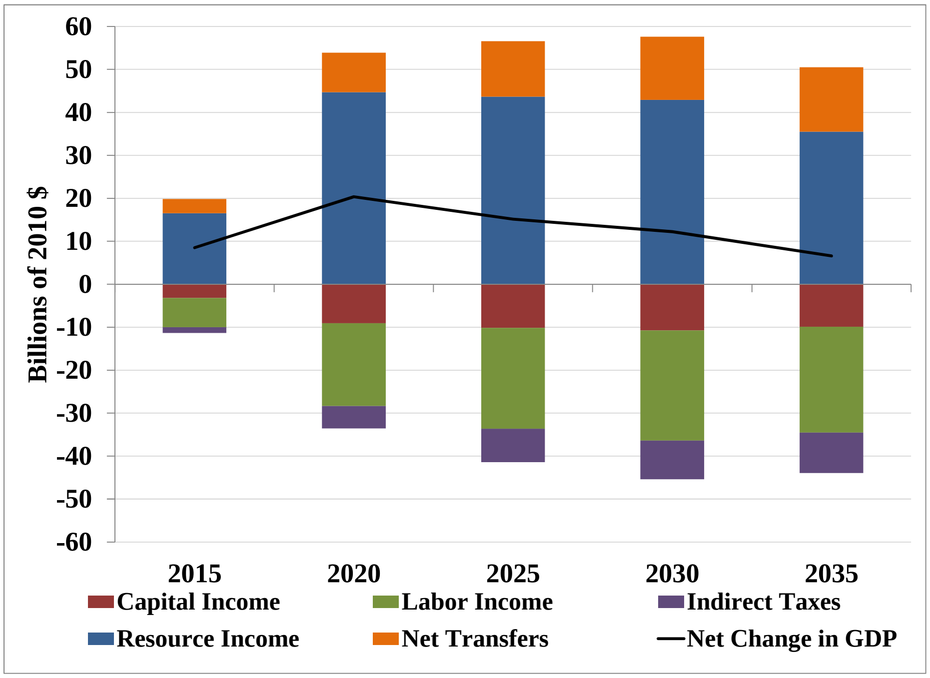
At the same time that LNG exports create higher income in total in the U.S., they shift the composition of income so that both wage income and income from capital investment are reduced. Our measure of total income is GDP measured from the income side, that is, by adding up income from labor, capital 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

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.

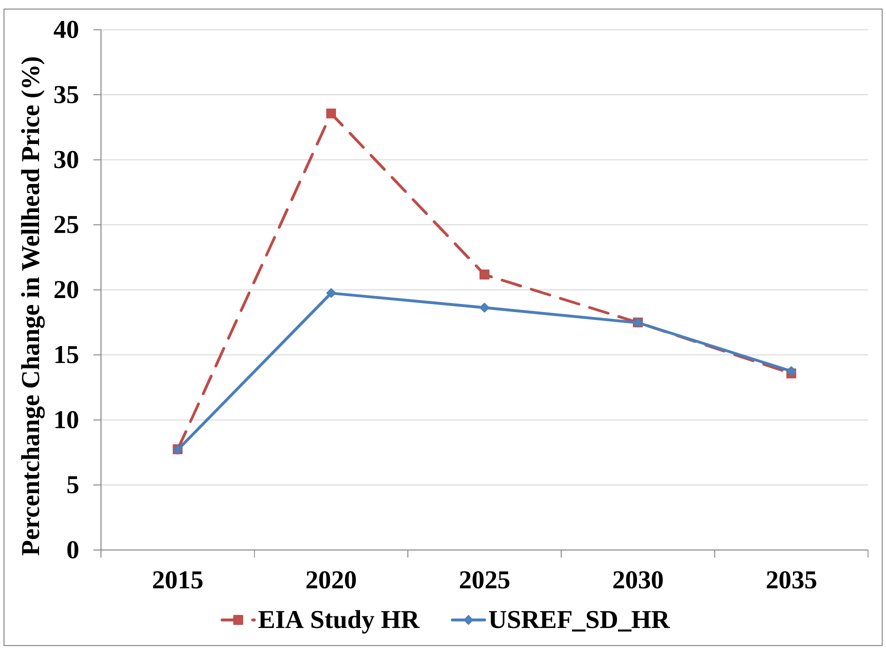
To match the characterization of U.S. supply and demand for natural gas in EIA's NEMS model, NERA calibrated its macroeconomic model so that for the same level of LNG exports as assumed in the EIA Study, the NERA model reproduced the prices projected by EIA. Thus natural gas price responses were similar 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.

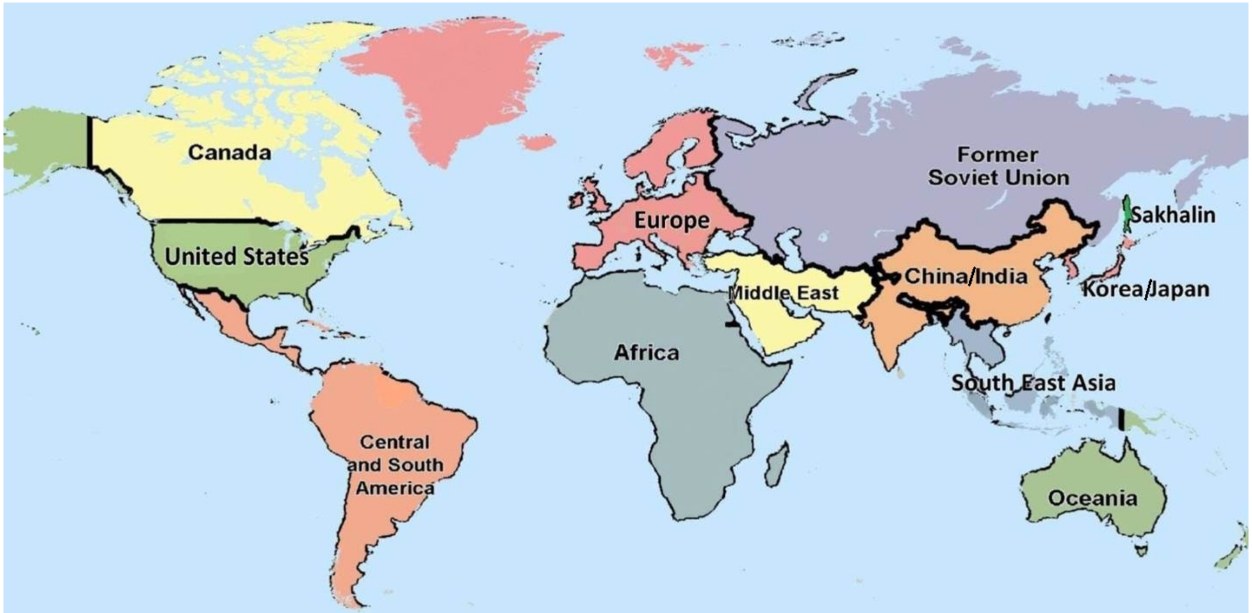
Figure 8: Global Natural Gas Demand and Production (Tcf)

	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

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[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 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 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.

U.S. wellhead natural gas prices are not precisely the same in the GNGM 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.

The 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 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

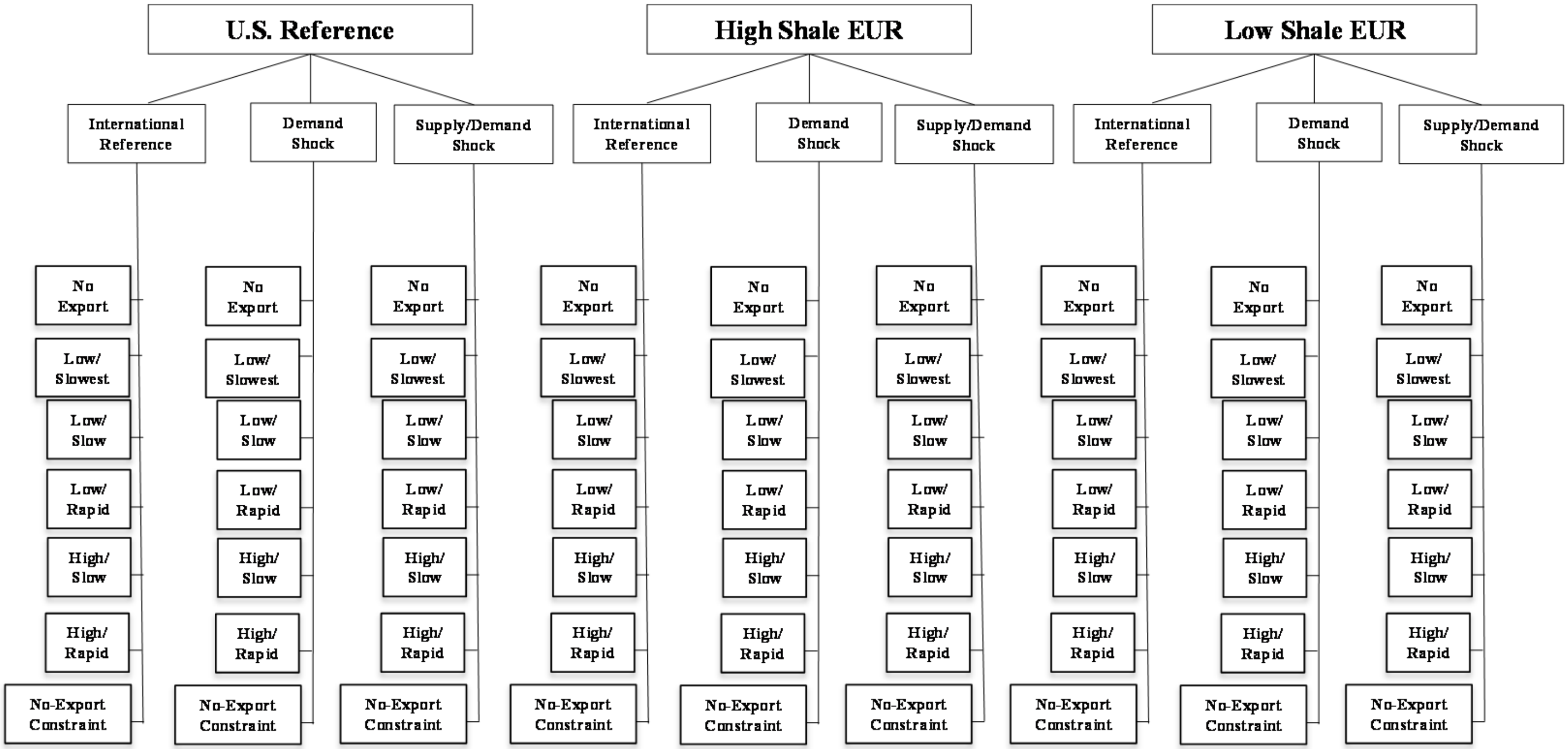
U.S. Supply	LNG Export Capacity	U.S. Supply	LNG Export Capacity	U.S. Supply	LNG Export Capacity
Reference	Low/Slow	High EUR	Low/Slow	Low EUR	Low/Slow
Reference	Low/Rapid	High EUR	Low/Rapid	Low EUR	Low/Rapid
Reference	High/Slow	High EUR	High/Slow	Low EUR	High/Slow
Reference	High/Rapid	High EUR	High/Rapid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

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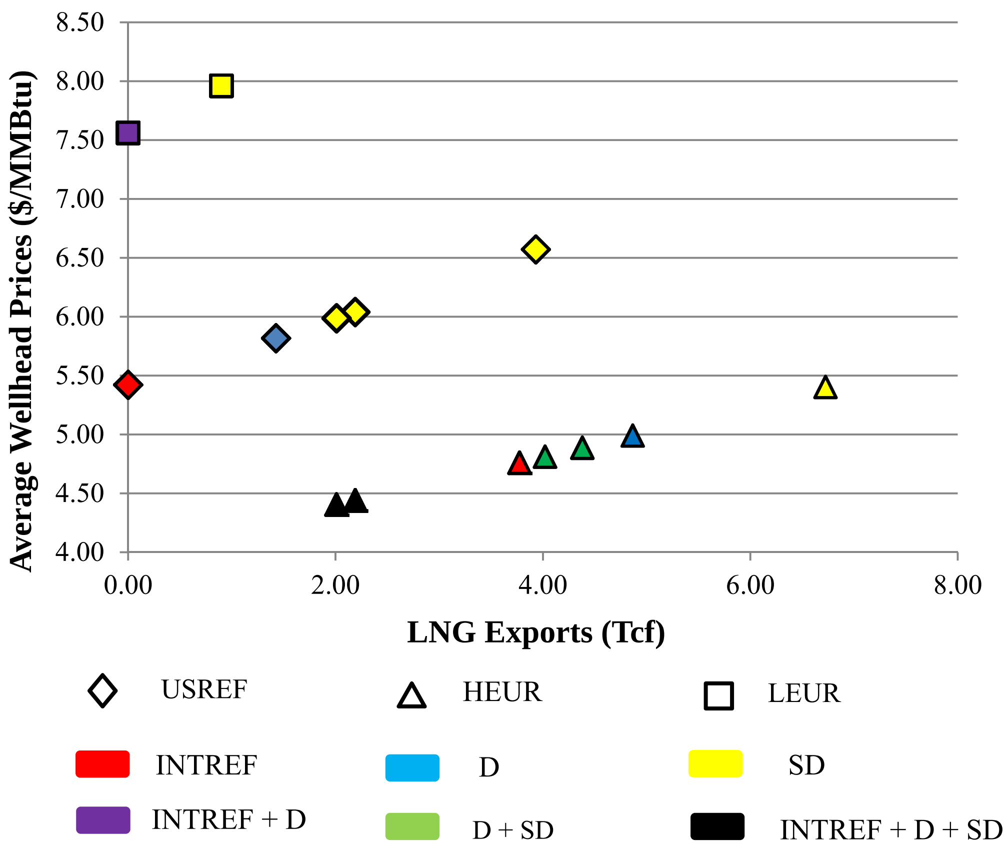
[16] In order to keep the discussion of macroeconomic impacts as concise as possible, this report does not discuss in detail all the scenarios that were run.

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.

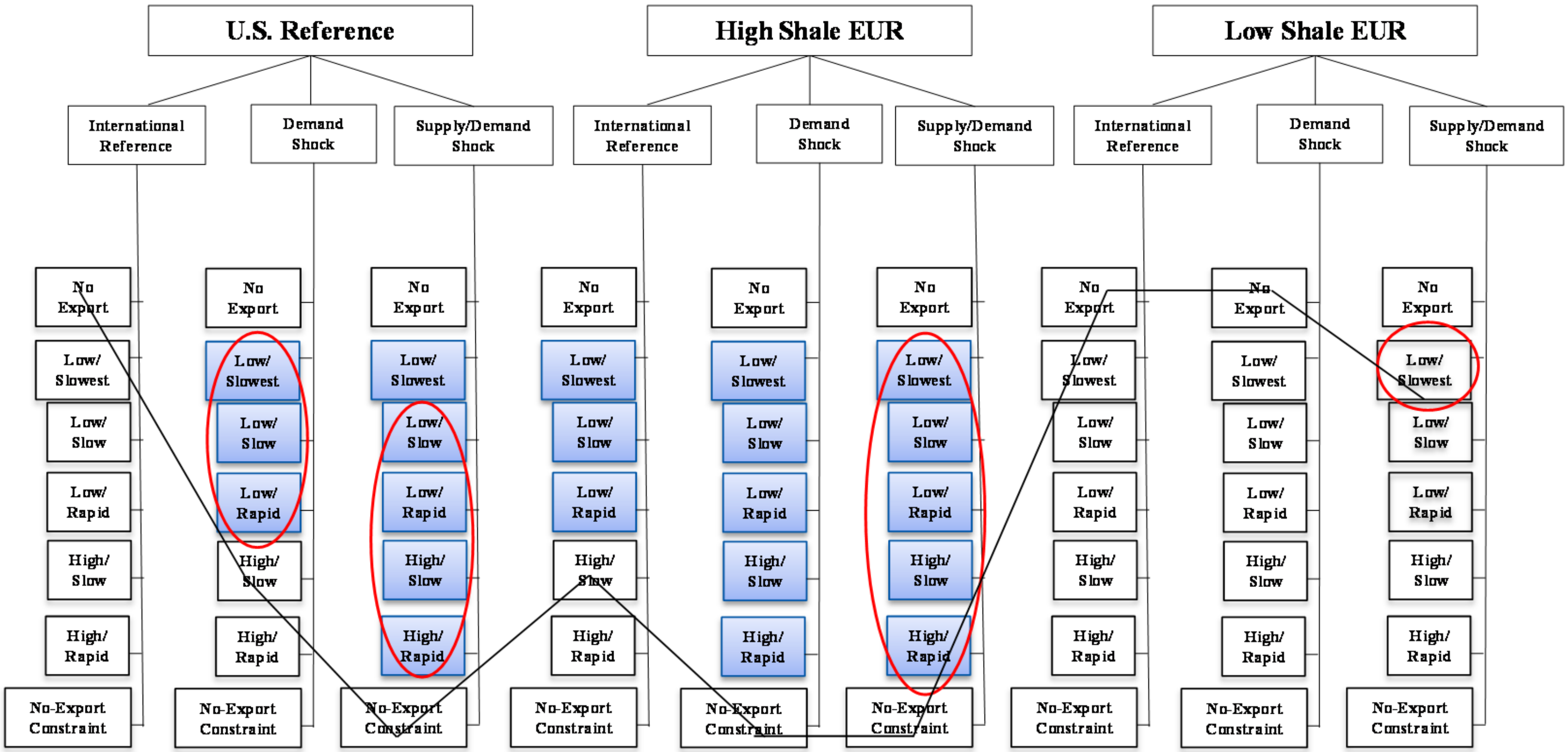
The supply curve traced out by the scenarios that include U.S. Reference case (represented by diamonds) are higher than in the High EUR cases because domestic gas is less plentiful. When only a Demand shock exists, the LNG export capacity limits are non-binding so the level of exports (the lone blue 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 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 N_{ew}ERA model does not differentiate various international outlooks. For N_{ew}ERA, the critical issue is the level of U.S. LNG exports and U.S. natural gas production. Of the 13 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.

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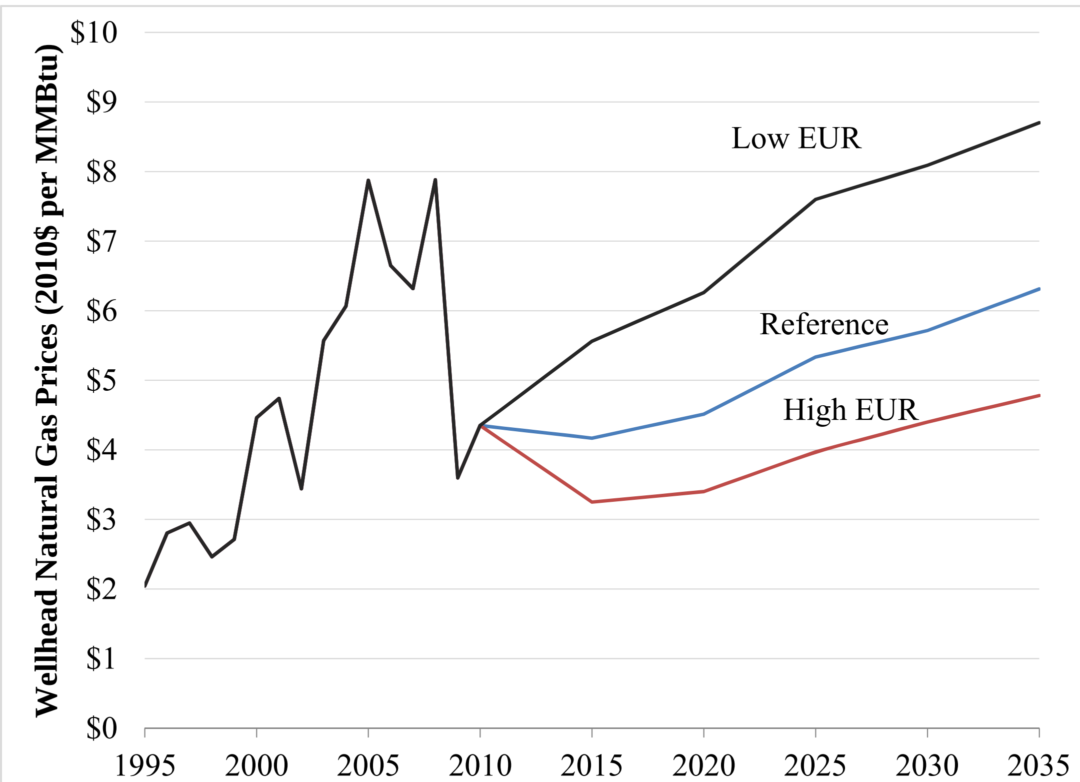
[17] NERA also ran 3 cases in which the LNG export capacity was assumed to be unlimited.

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

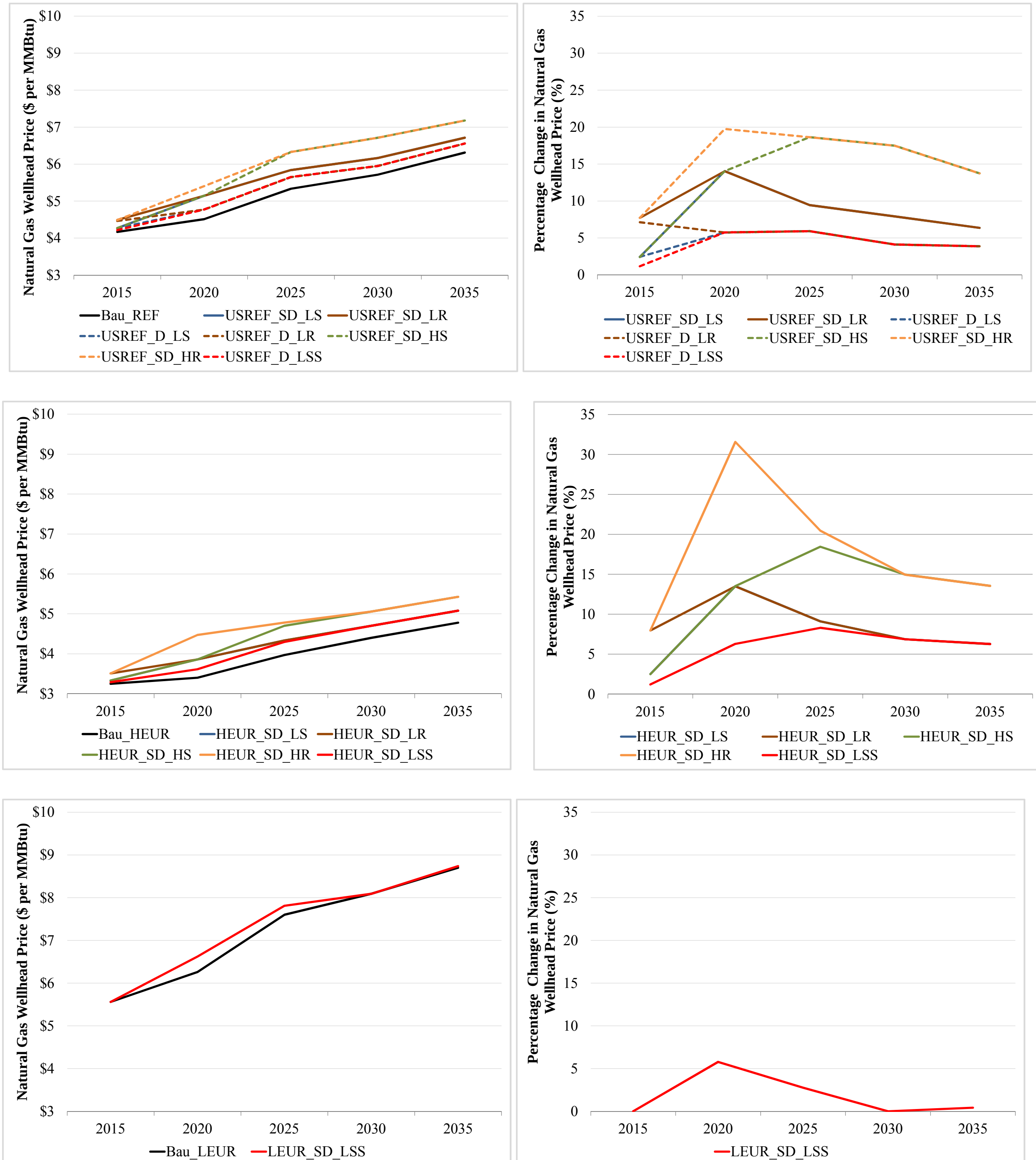


Figure 29: Change in Natural Gas Price Relative to the Corresponding Baseline of Zero LNG Exports (2010$/Mcf)

	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

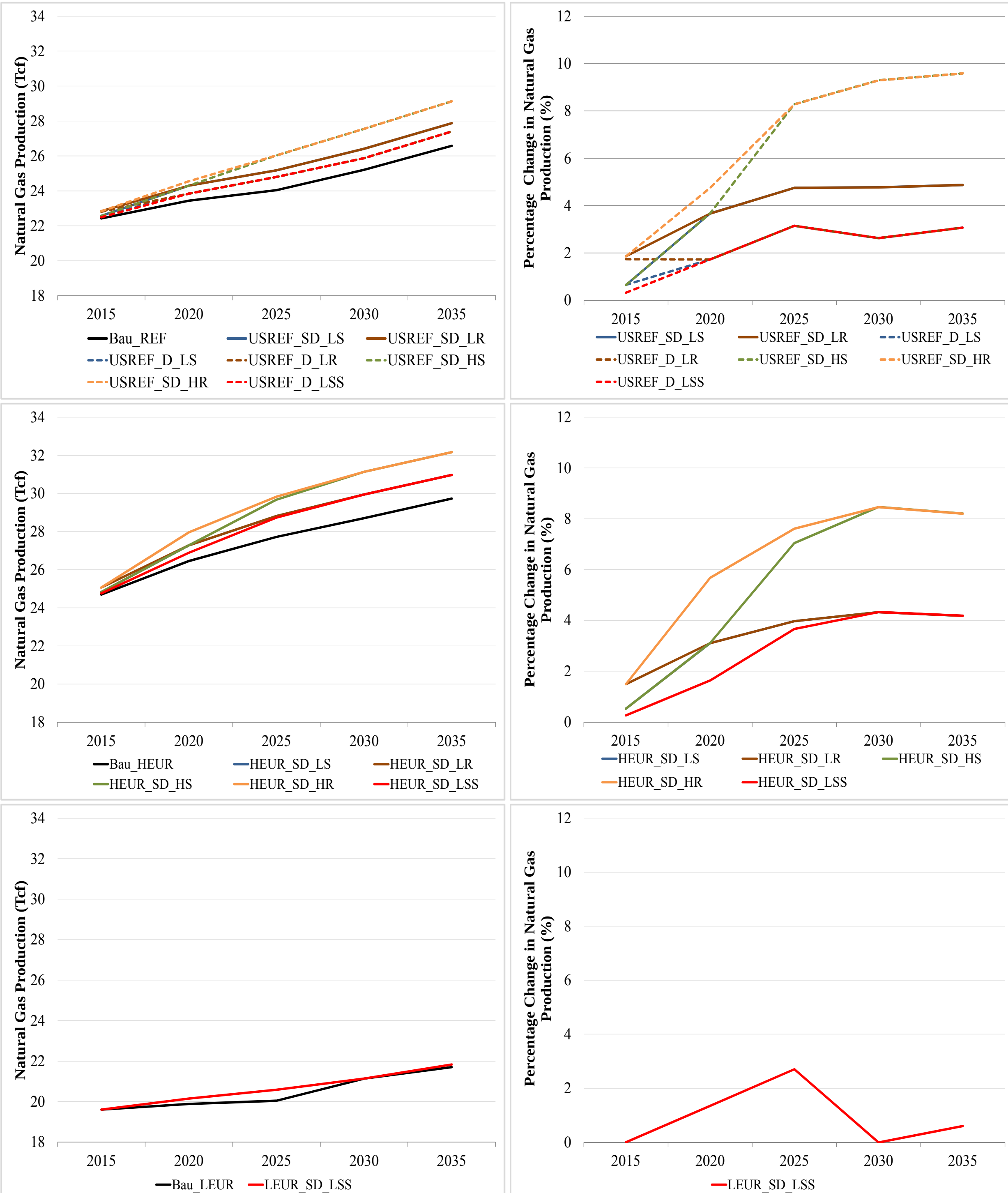


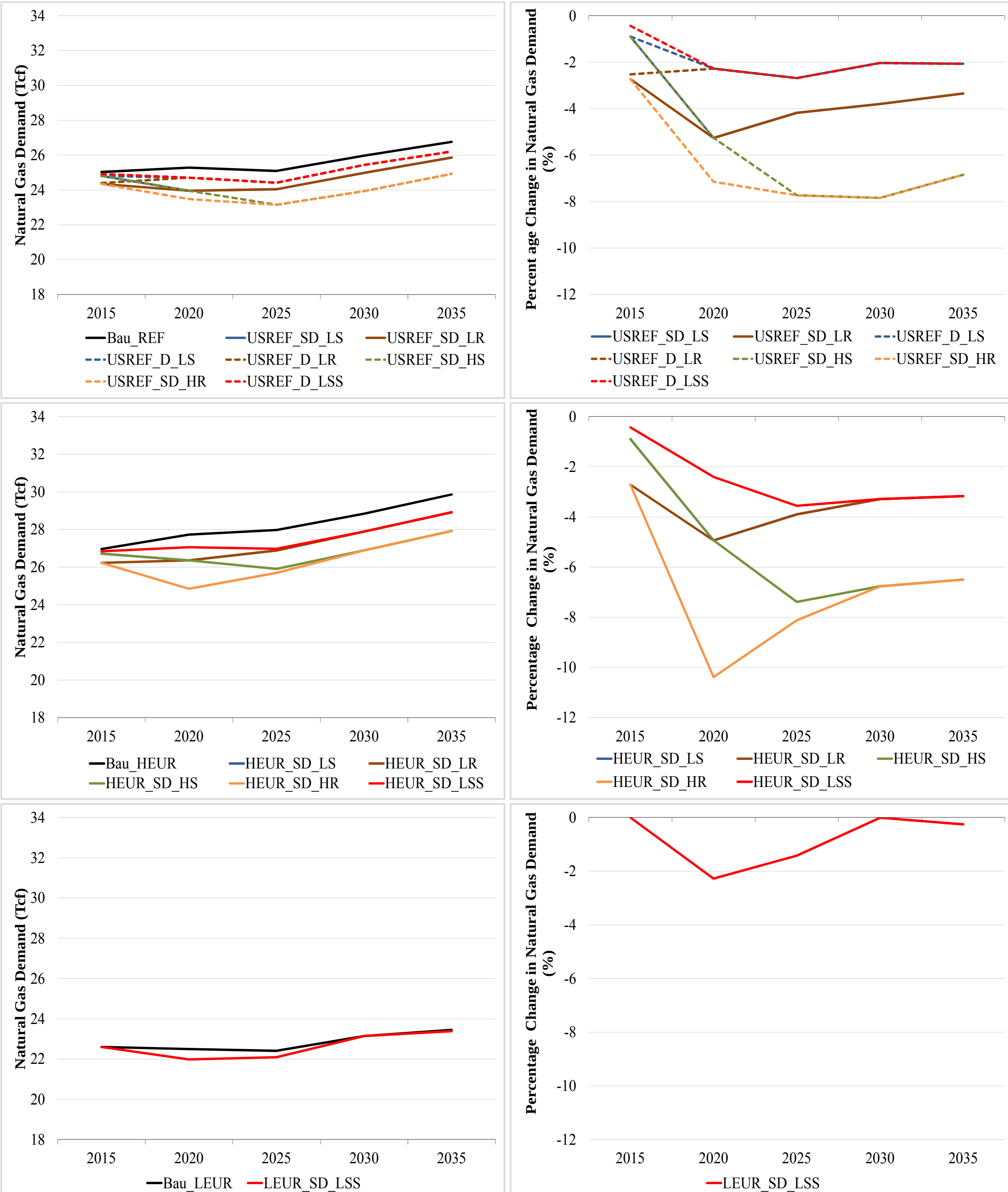
Figure 31: Change in Natural Gas Production Relative to the Corresponding Baseline (Tcf)

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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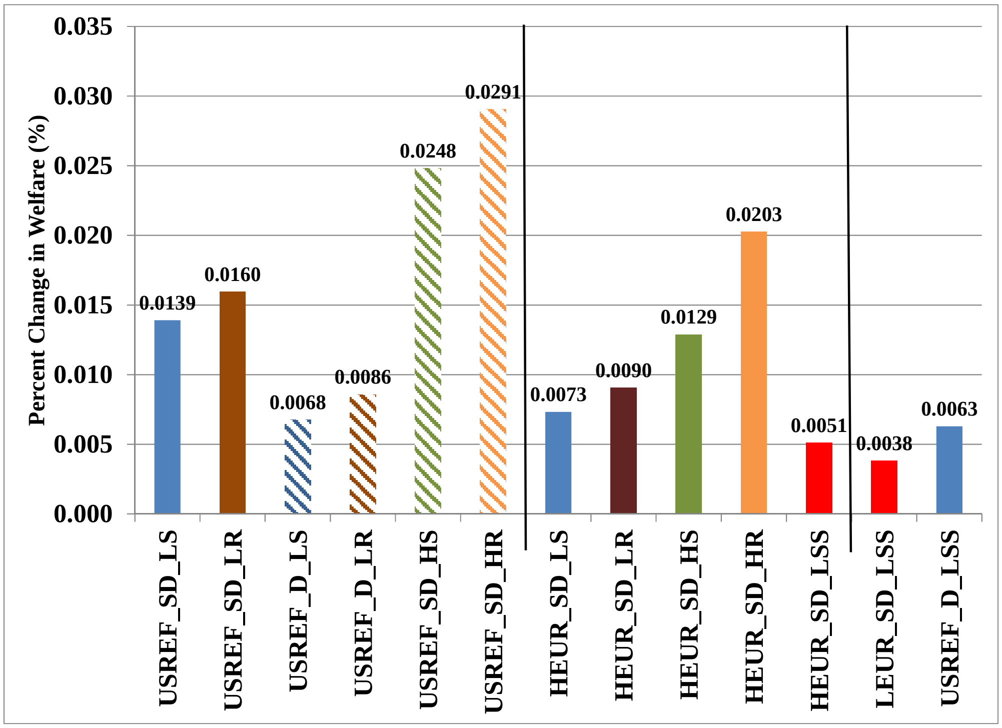
[21] *Intermediate Microeconomics: A Modern Approach*, Hal Varian, 7th Edition (December 2005), W.W. Norton & Company, pp. 255-256. "Another way to measure the impact of a price change in monetary terms is to ask how much money would have to be taken away from the consumer *before* the price change to 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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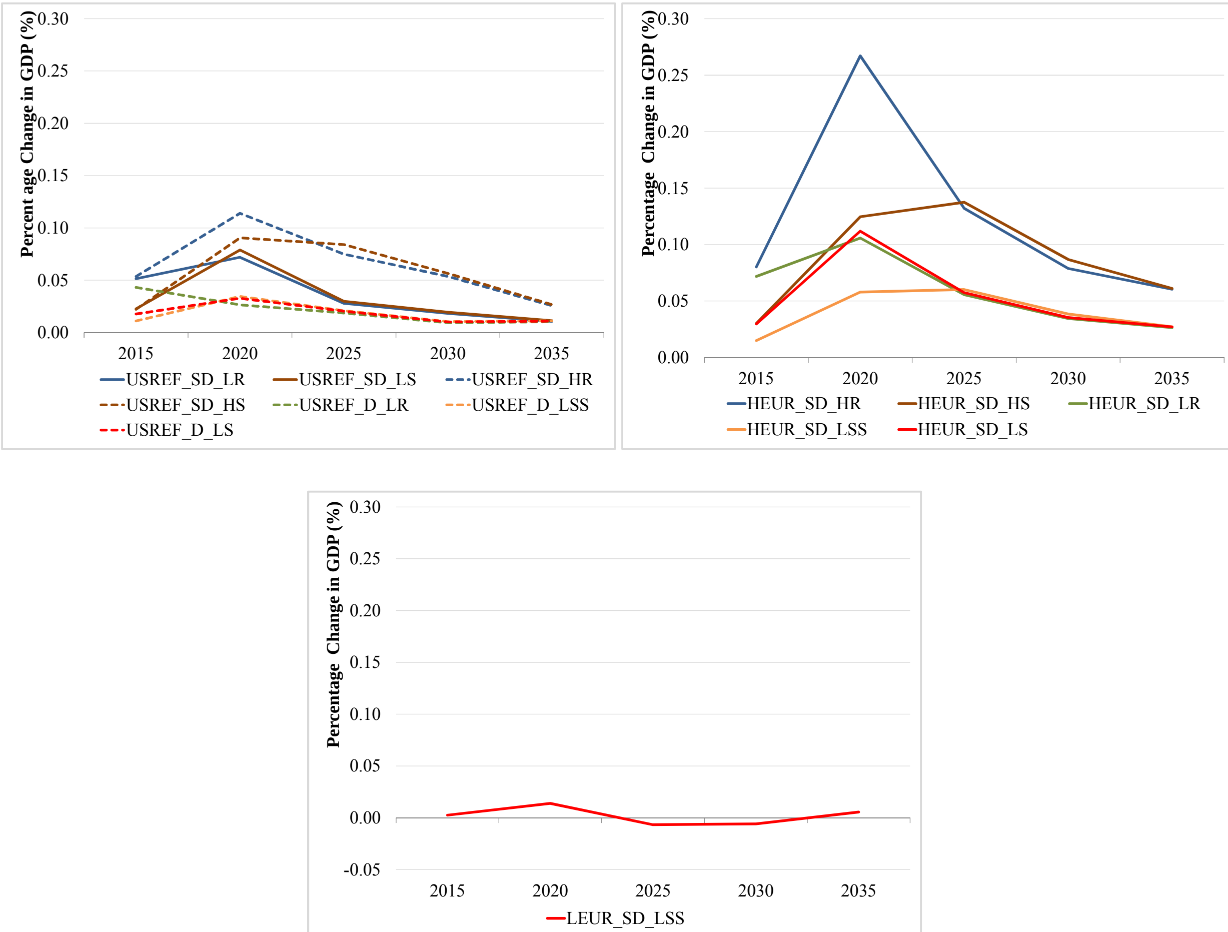
23 Welfare is calculated as a single number that represents in present value terms the amount that households are made better (worse) off over the entire time horizon from 2015 to 2035.

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

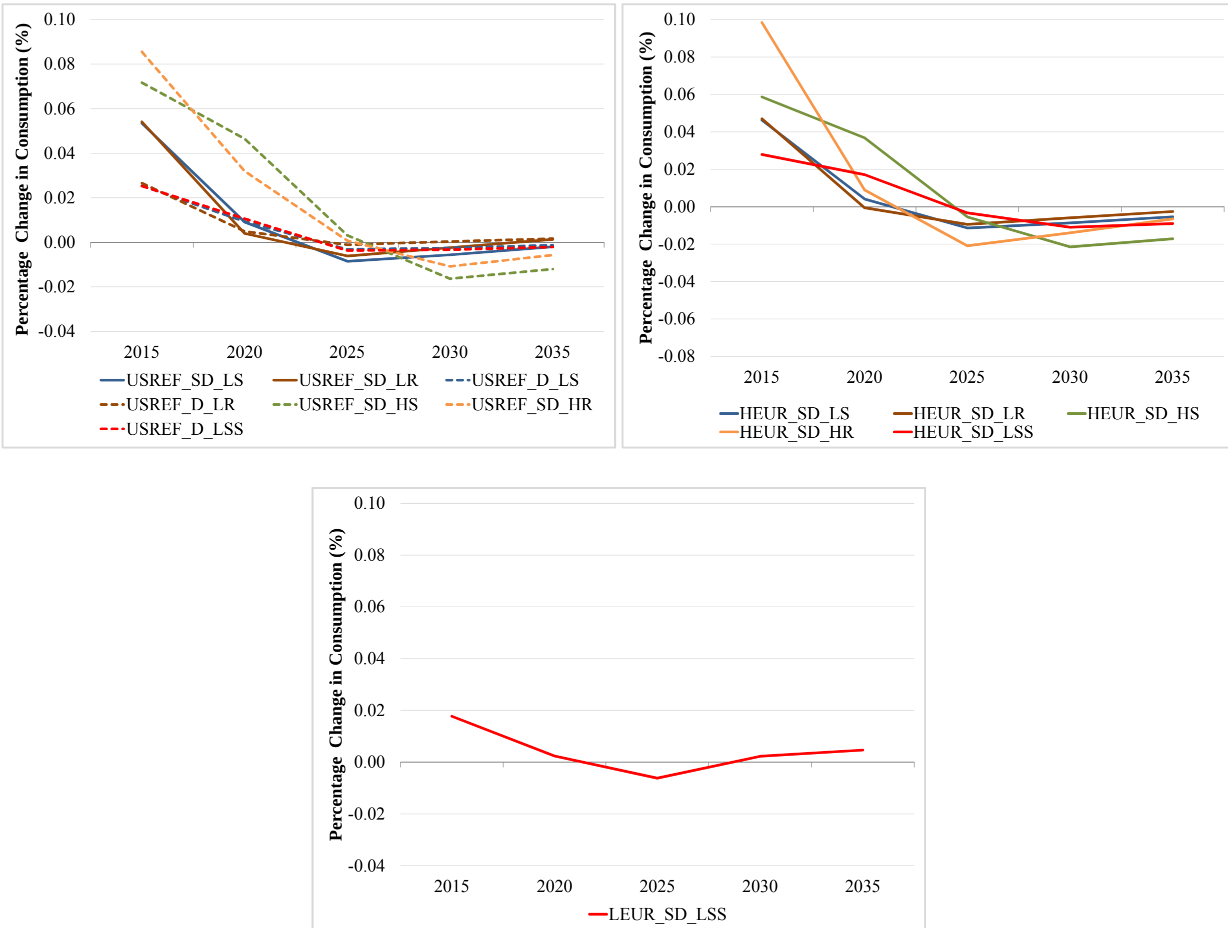


3. Aggregate Consumption

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



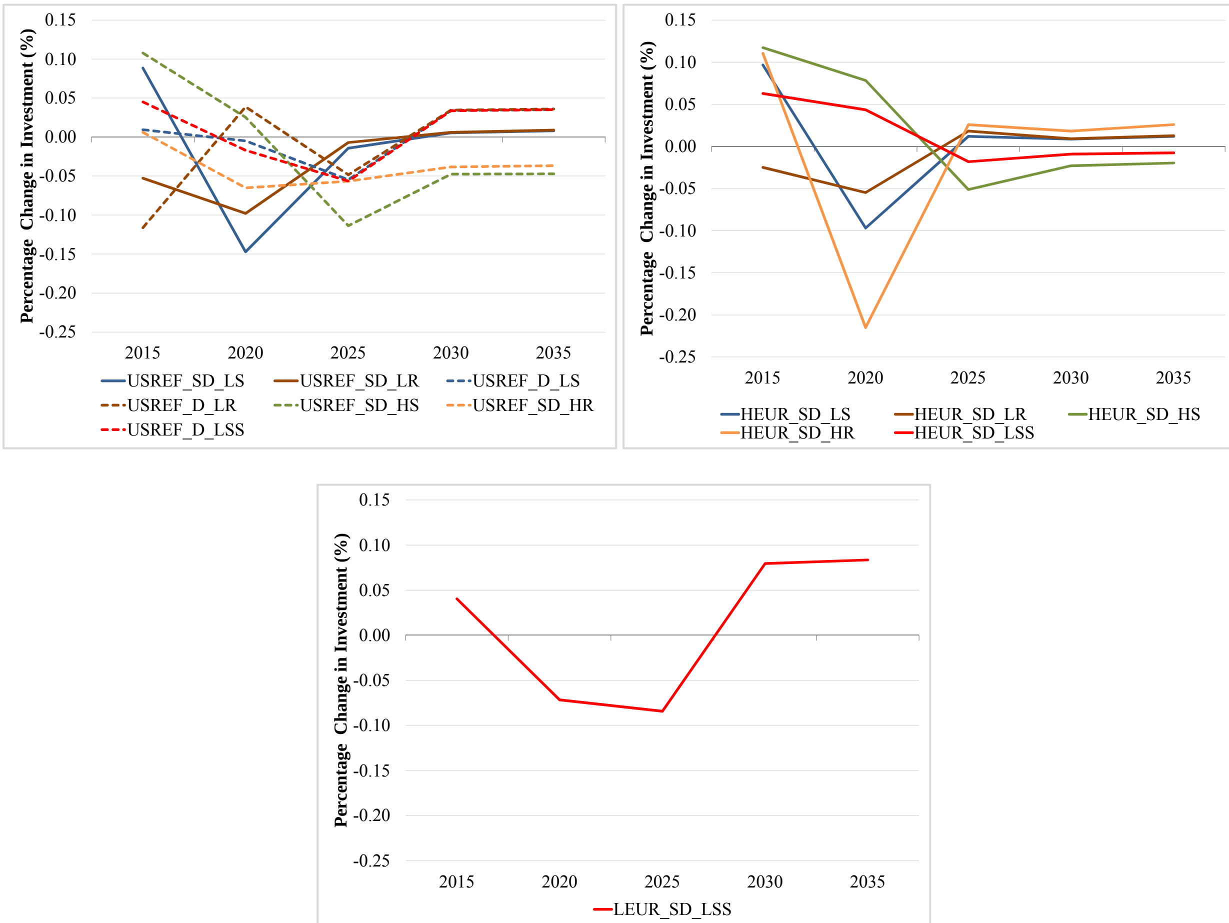
4. Aggregate Investment

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

[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%.

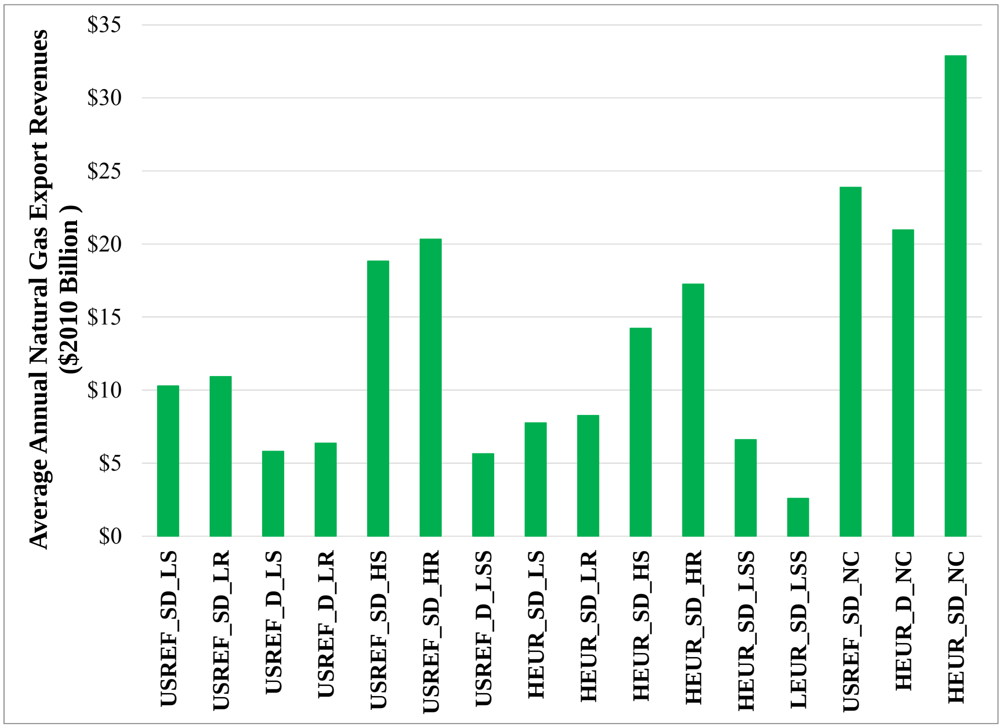
Figure 36: Percentage Change in Investment for NERA Core Scenarios



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

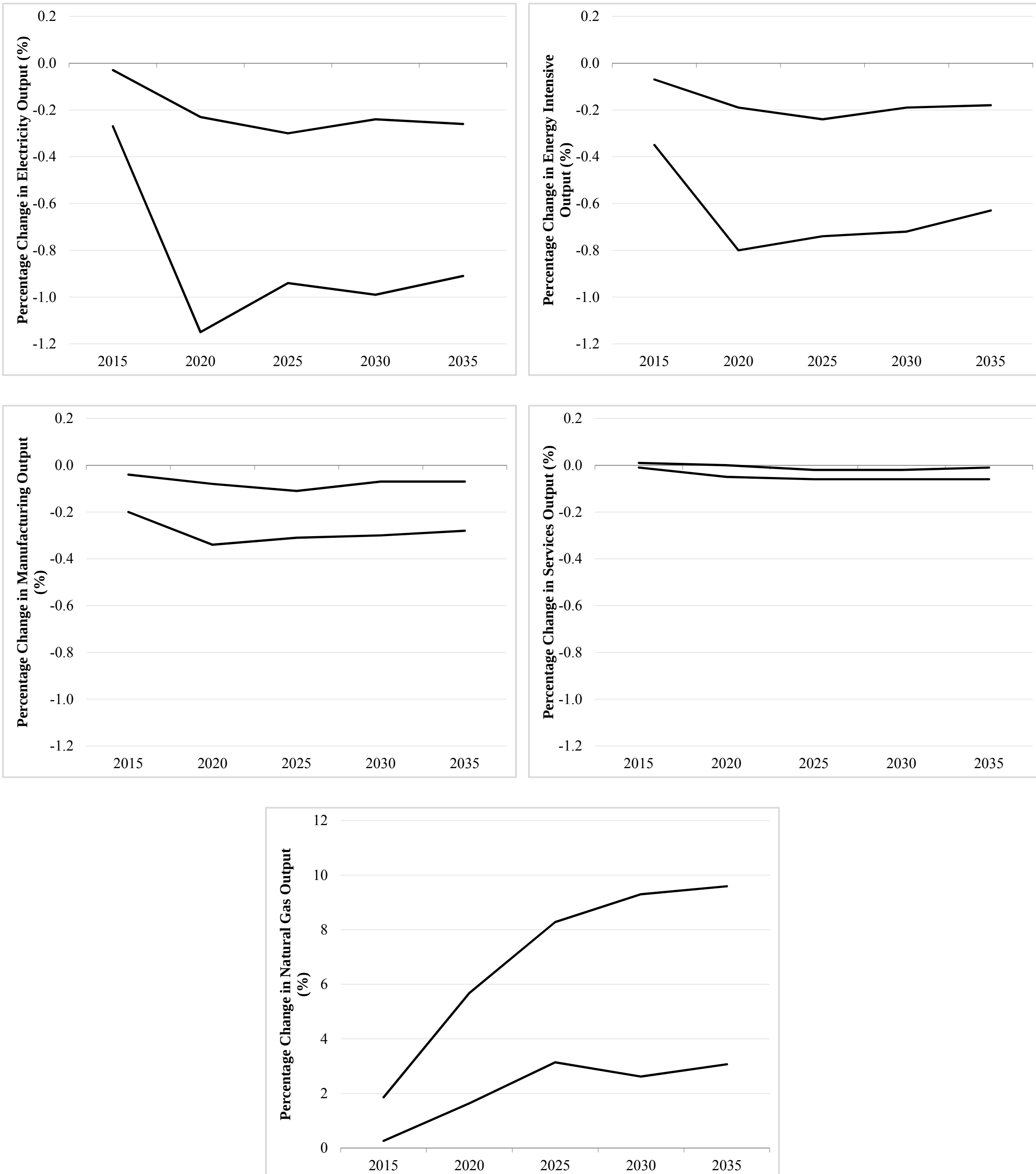


6. Range of Sectoral Output Changes for Some Key Economic Sectors

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

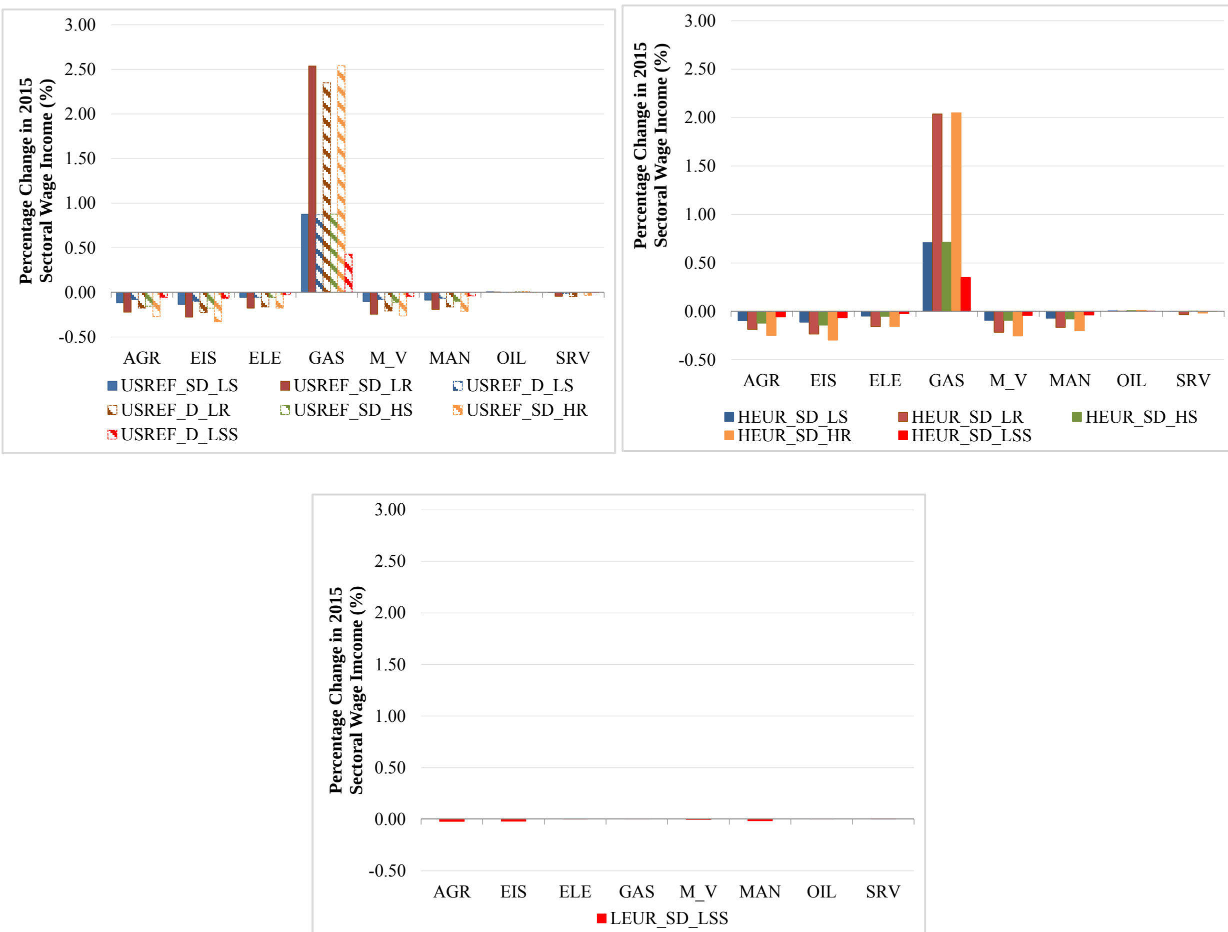


7. Wage Income and Other Components of Household Income

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

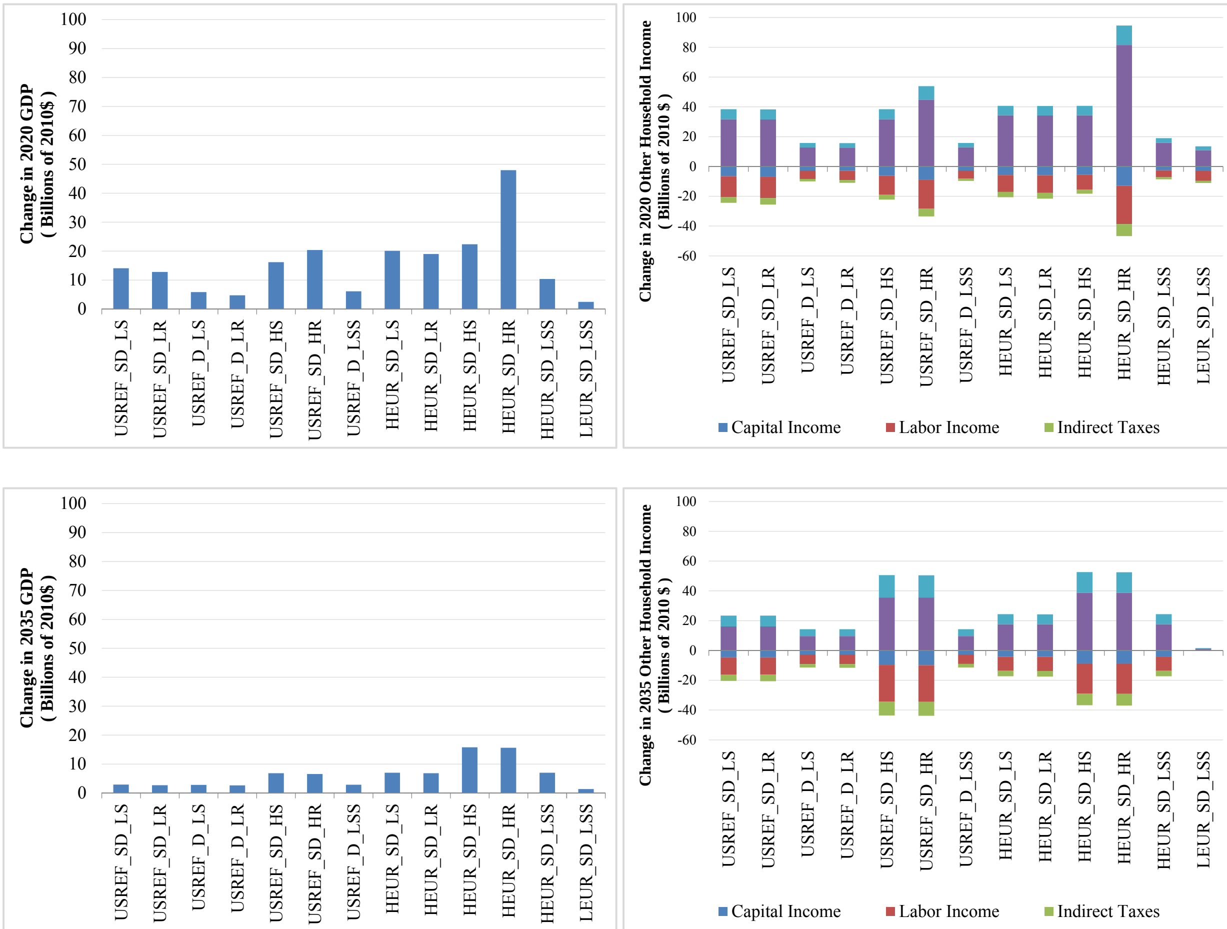


Figure 40 shows a snapshot of changes in GDP and household income components in 2020 and 2035. GDP impacts in 2020 provide the largest increase, while 2035 impacts provide a picture of the long run changes. Capital income, wage income, and indirect tax revenues drop in all scenarios, while resource income 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]

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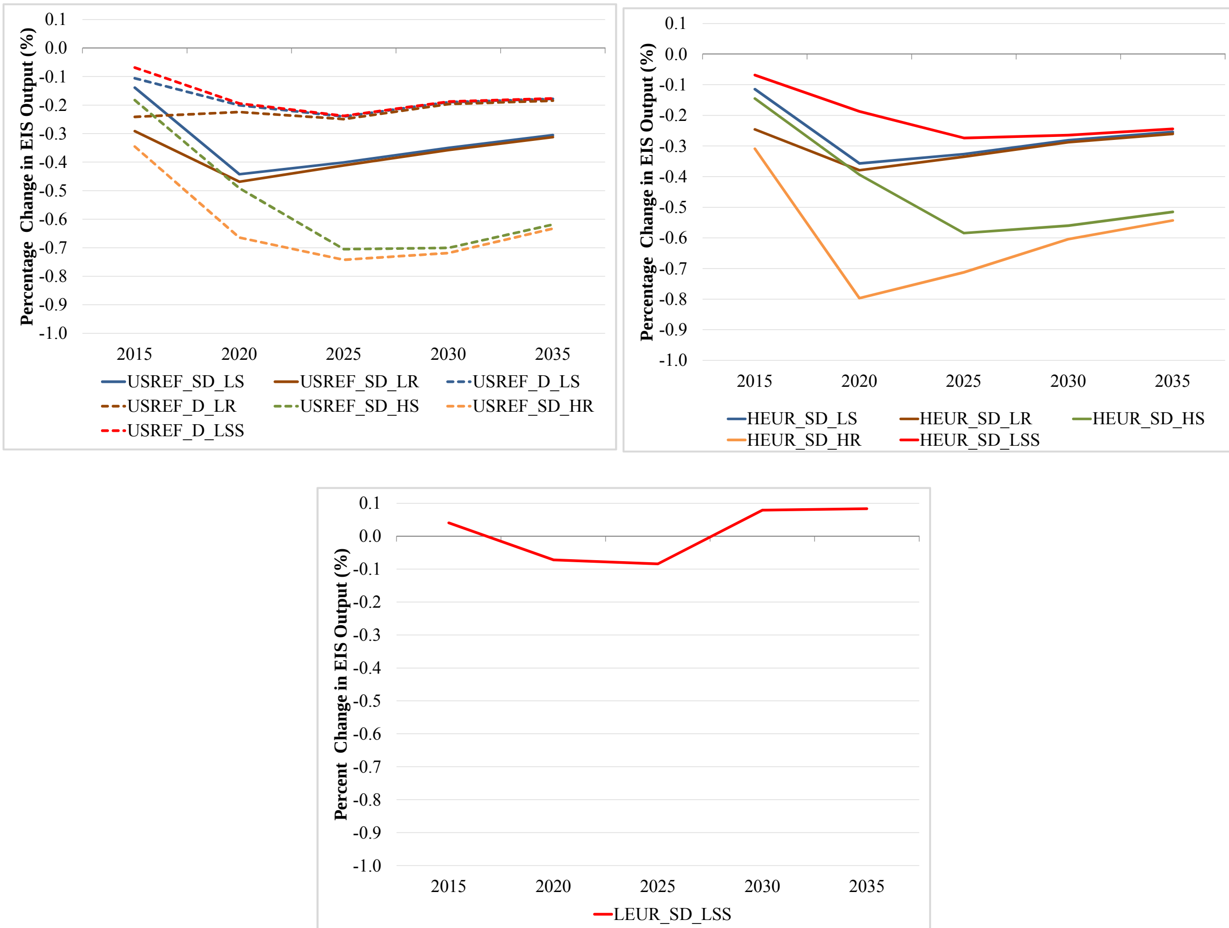
[26] IMPLAN dataset provides inter-industry production and financial transactions for all states of the U.S. (www.implan.com).

[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.

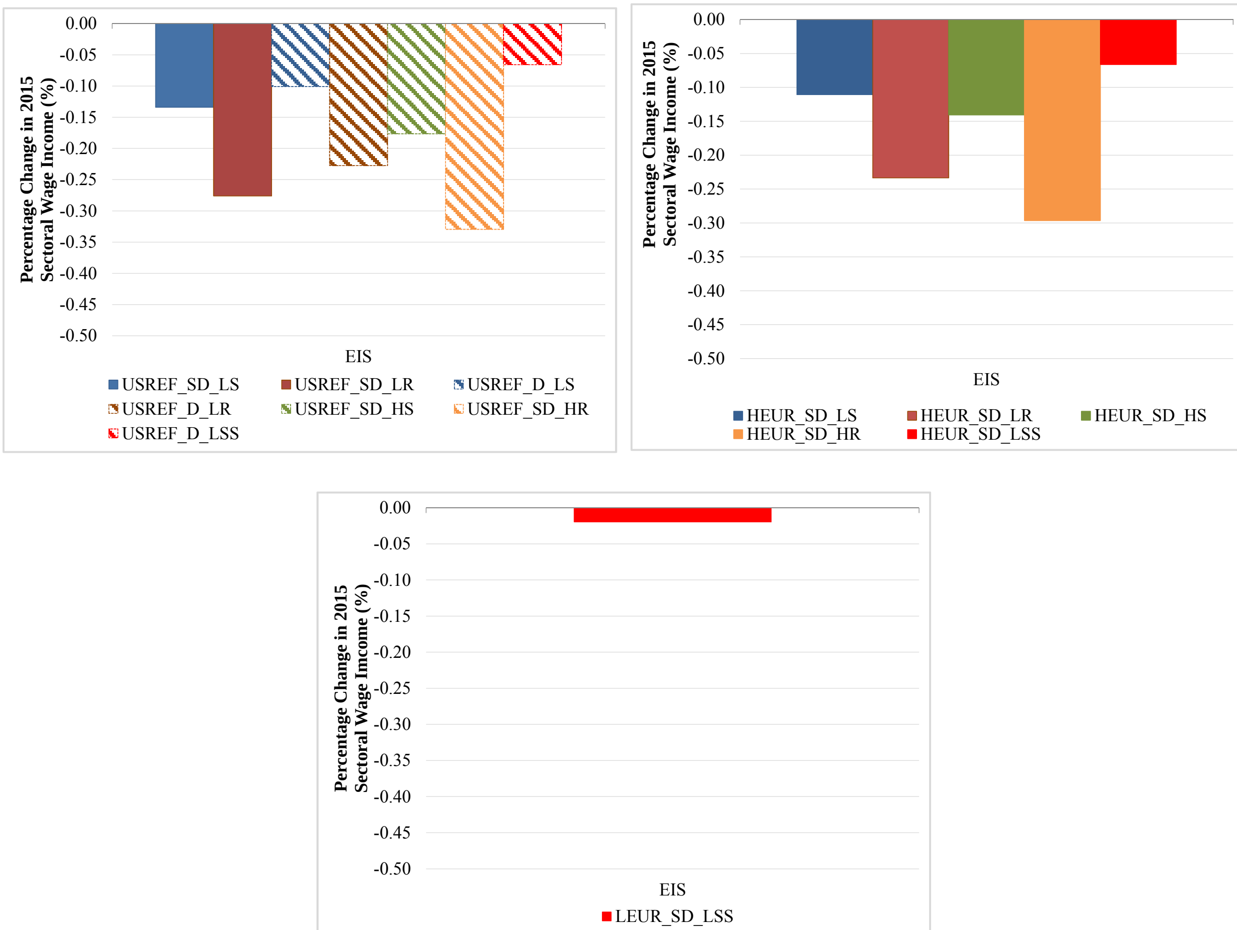
Figure 41: Percentage Change in EIS Output for NERA Core Scenarios



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.

[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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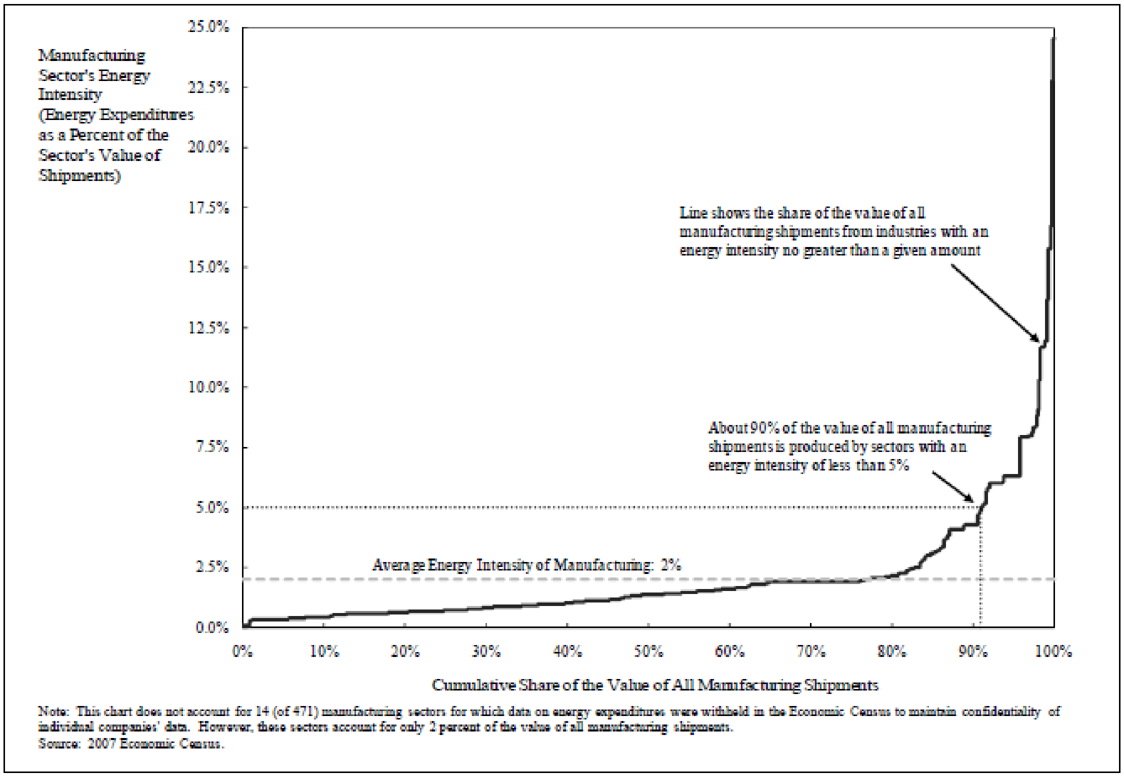
30 "The Effects of H.R.2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," An Interagency Report Responding to a Request from Senators Bayh, Specter, Stabenow, McCaskill, and Brown December 2, 2009.

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.

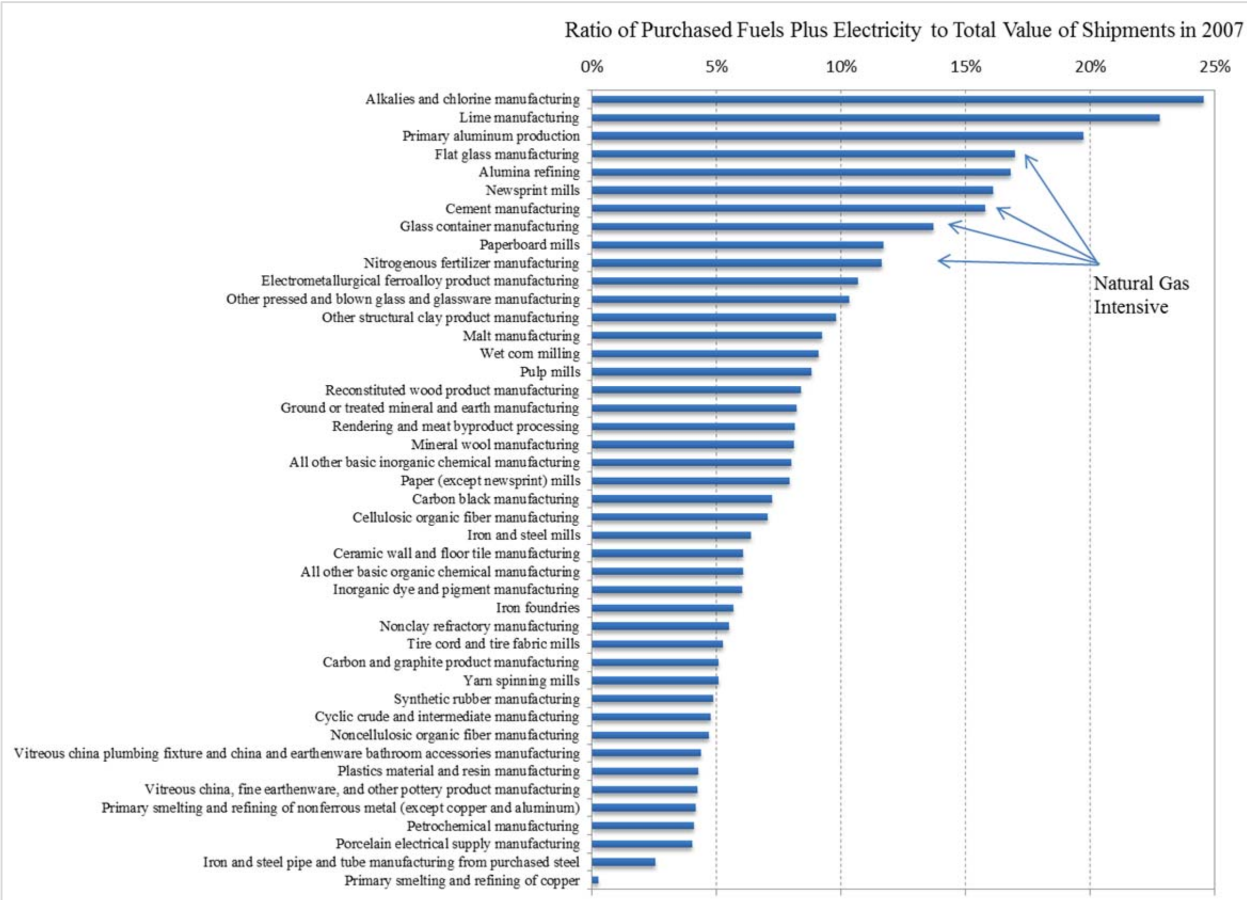
4. Vulnerable Industries are not High Value-Added Industries

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

[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

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[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]

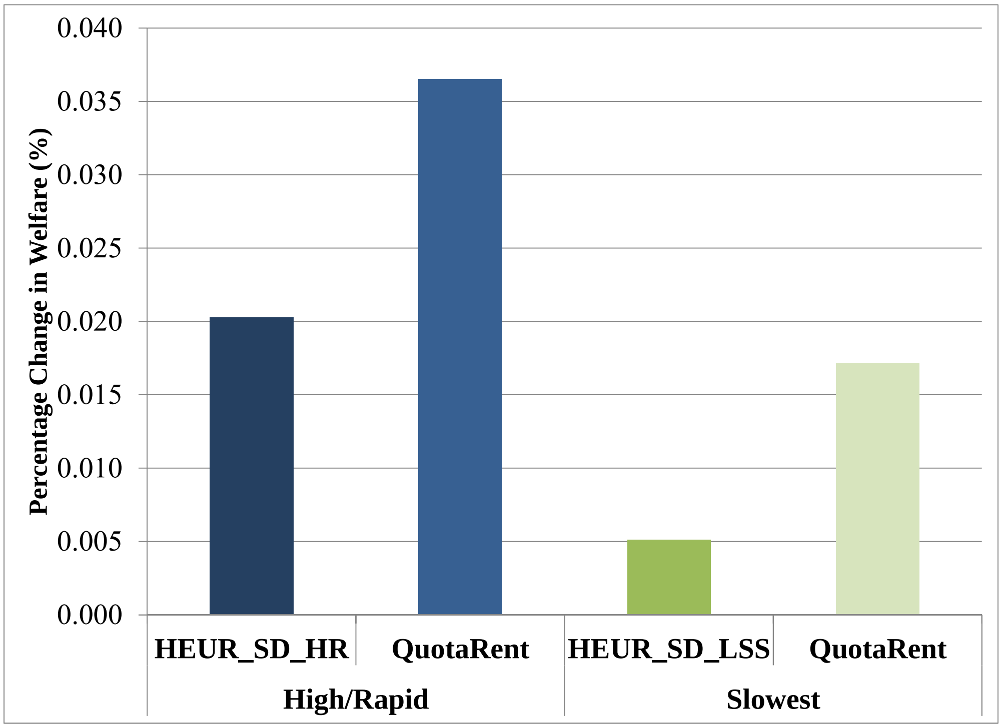
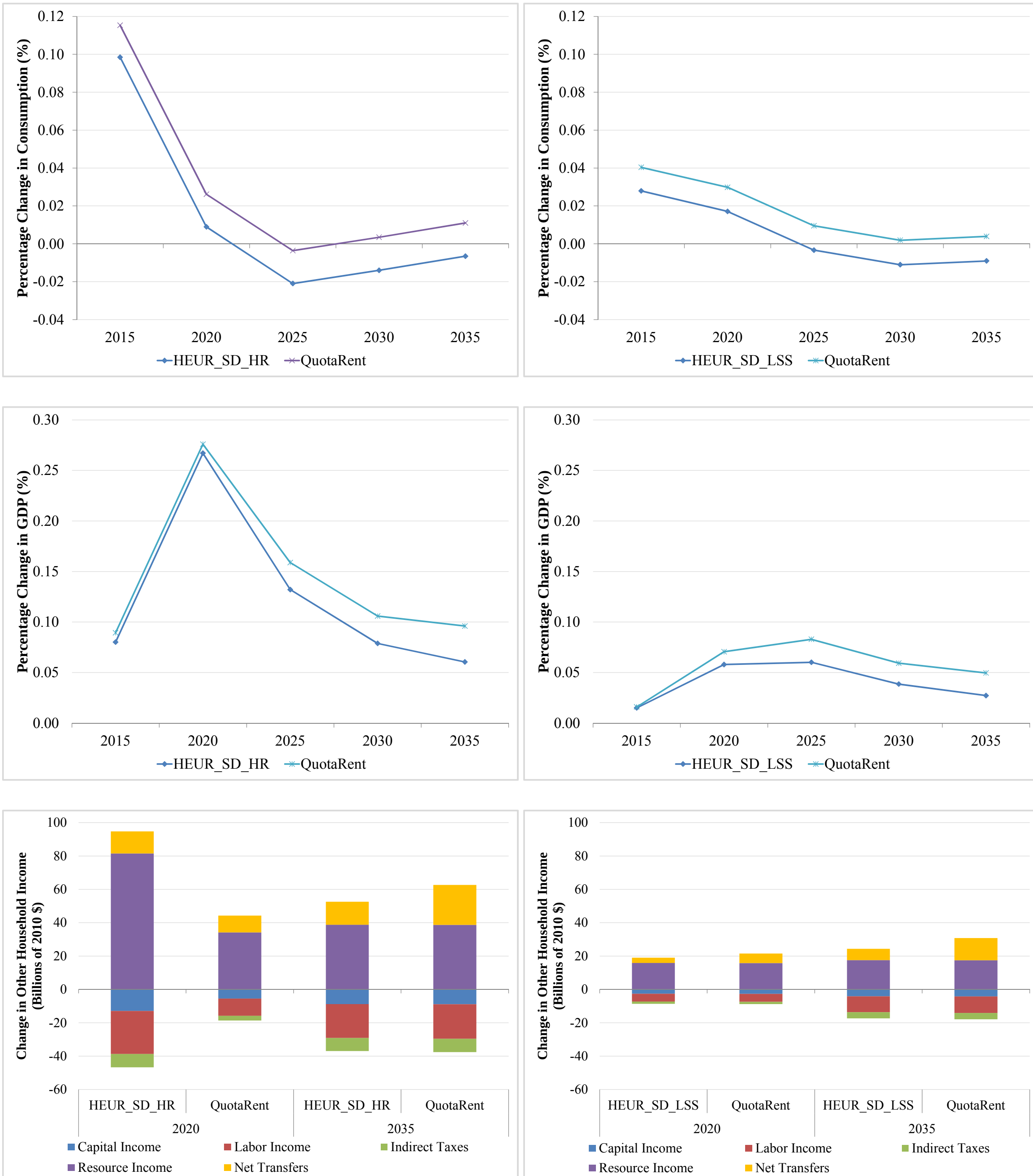


Figure 49 shows the change in impacts on aggregate consumption, GDP, and other household income for different quota rent sensitivities. The additional income from quota rents makes consumers wealthier, leading to increased expenditures on goods and services. This increase in economic activity leads to 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.

$$\text{Equivalent Annual Cost} = \frac{\text{Asset Price} \times \text{Discount Rate}}{1-\left(1+\text{Discount Rate}\right)^{-\text{Number of Periods}}}$$

[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

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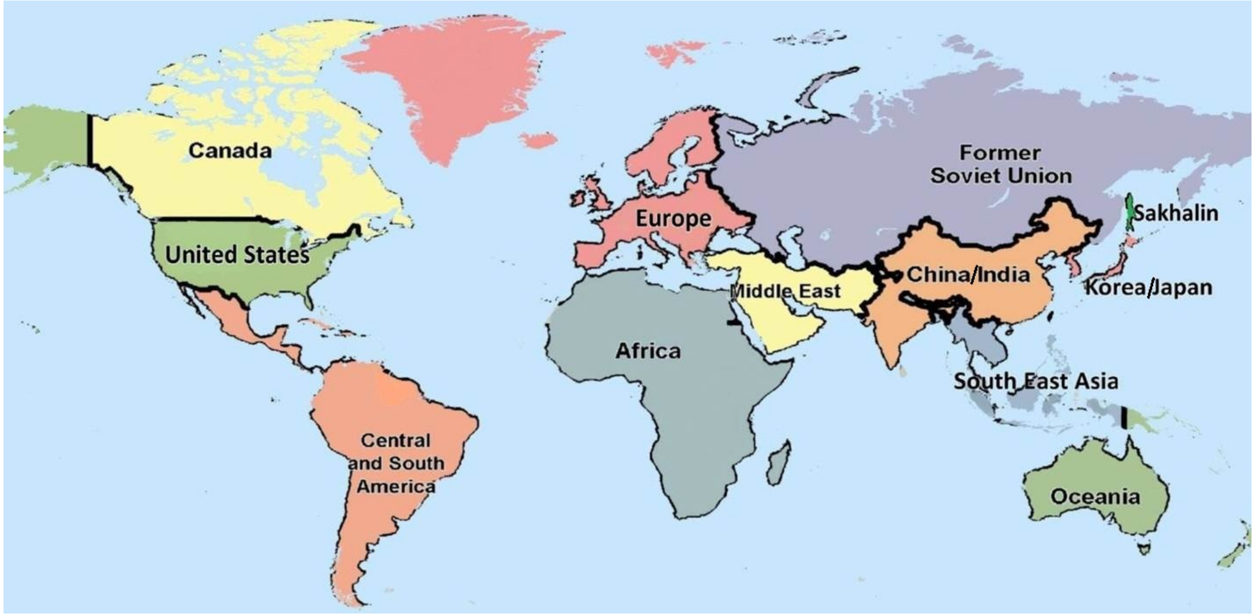
[48] "The LNG Industry 2010," GIIGNL. Available at: www.giignl.org/fr/home-page/publications.

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

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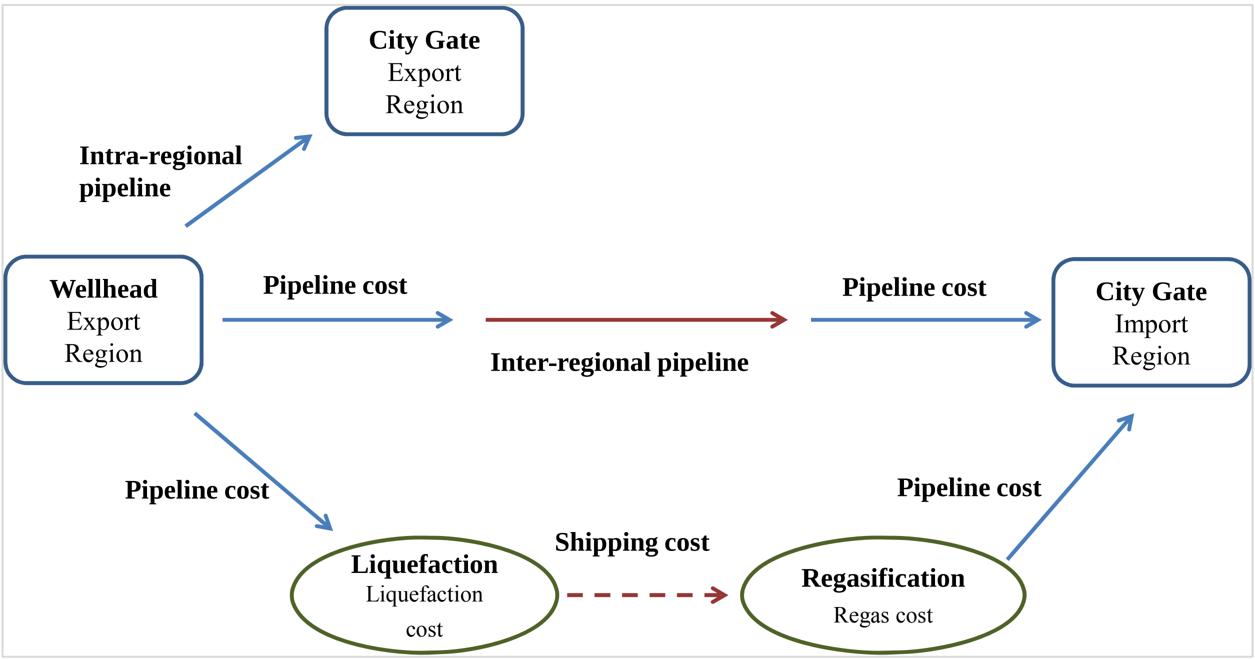
50 German BAFA natural gas import border price, Belgium Zeebrugge spot prices, TTF Natural Gas Futures contracts, *etc*.

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 ($Demand_0(d)$).

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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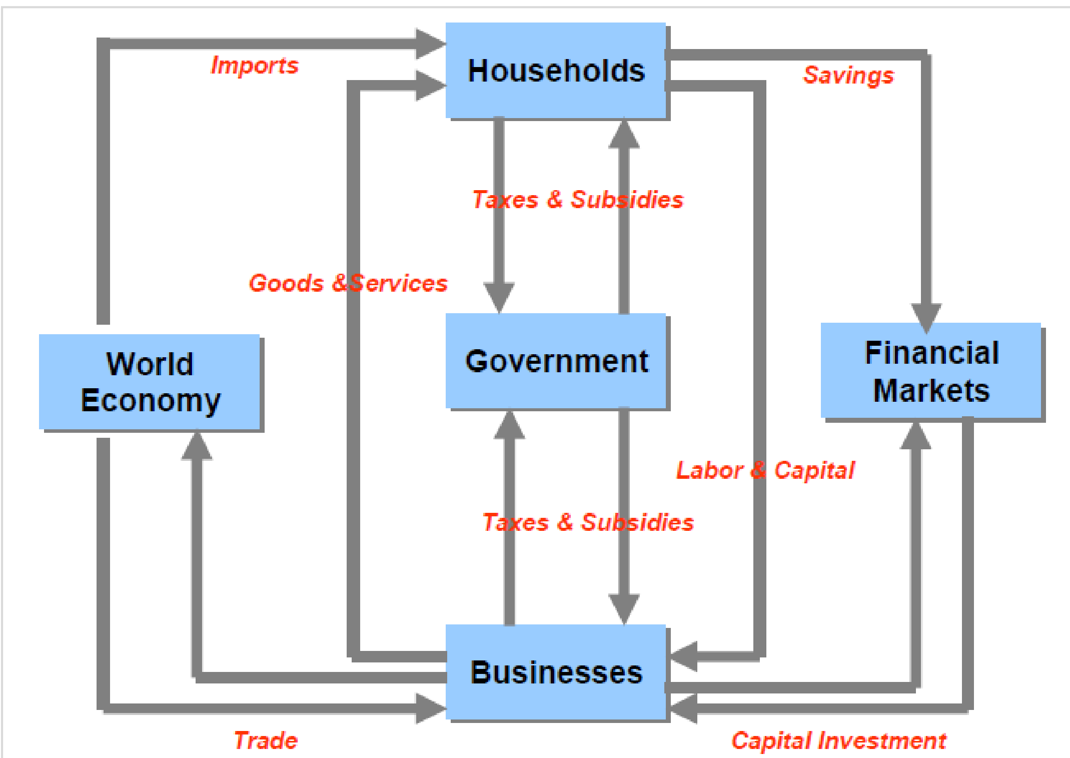
[53] IMPLAN produces unique set of national structural matrices. The structural matrices form the bais for the inter-industry flows which we use to characterize the production, household, and government transactions, see www.implan.com.

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.

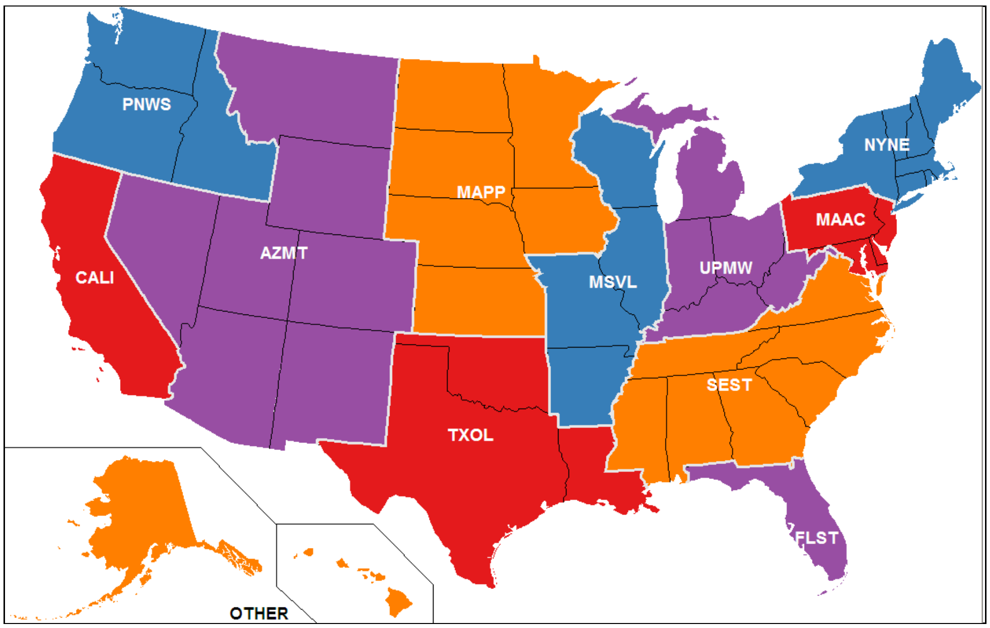
Figure 72: Circular Flow of Income



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.

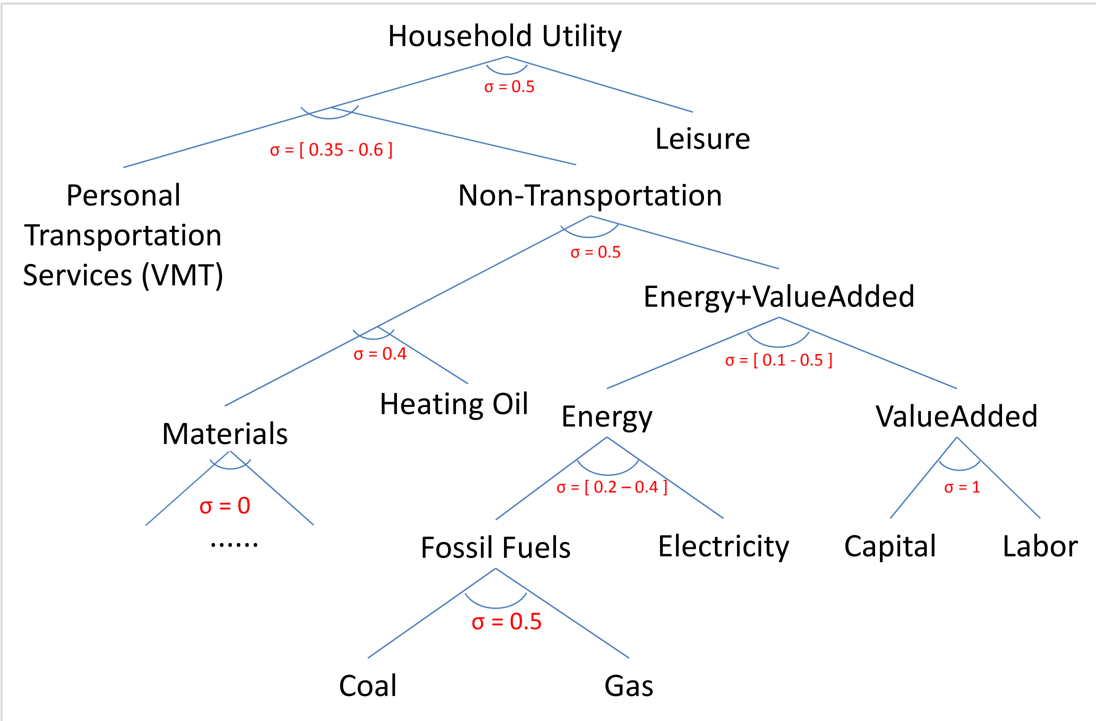
The CES nesting structure defines how inputs to a production activity compete with each other. In the generic production structure, intermediate inputs are aggregated in fixed proportion with a composite of energy and value-added inputs. The energy input aggregates fossil and non-fossil energy sources, 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.

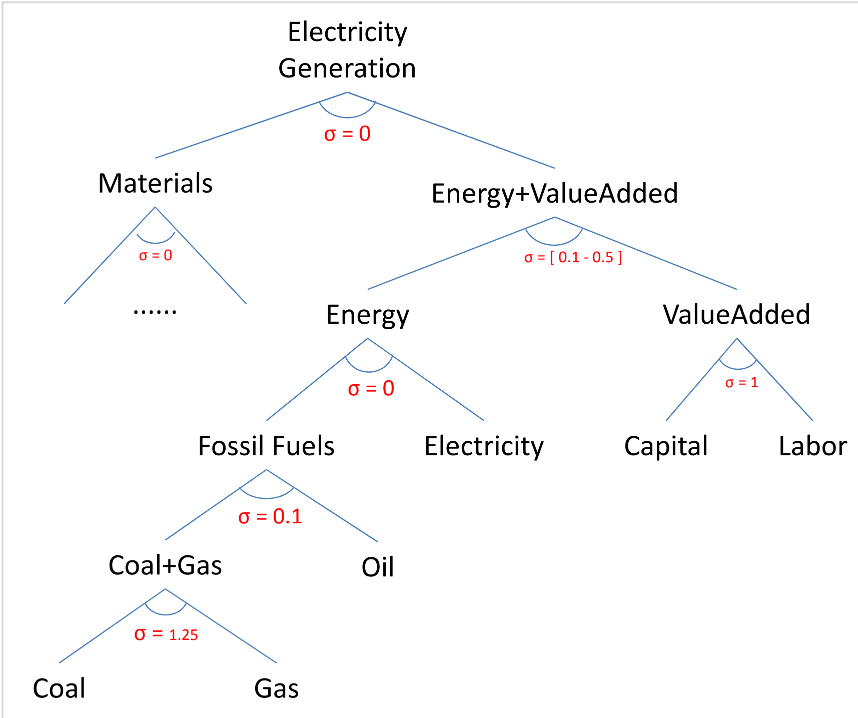
Figure 75: N$_{ew}$ERA Household Representation



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

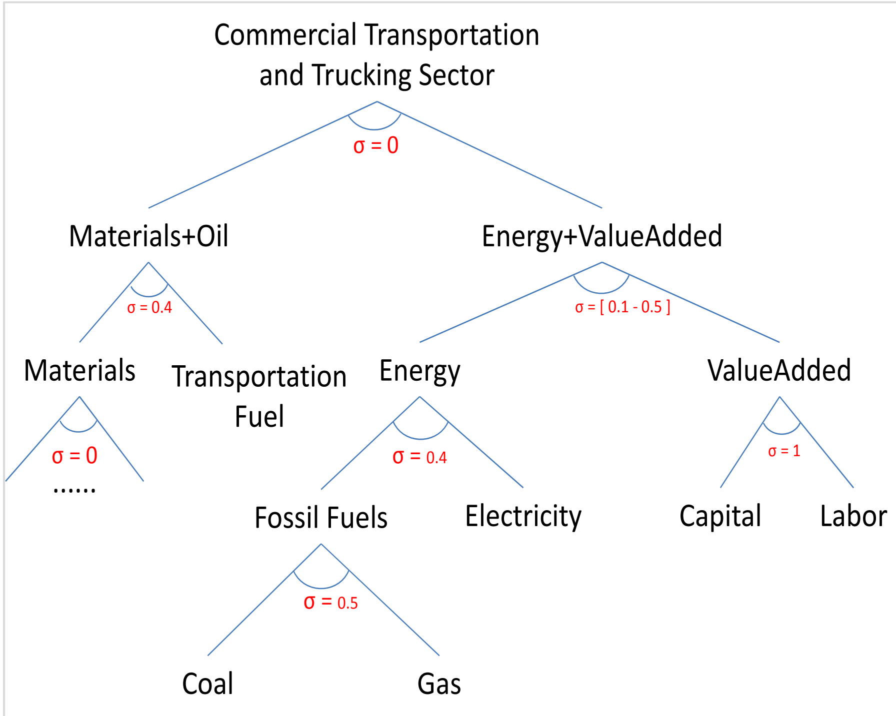
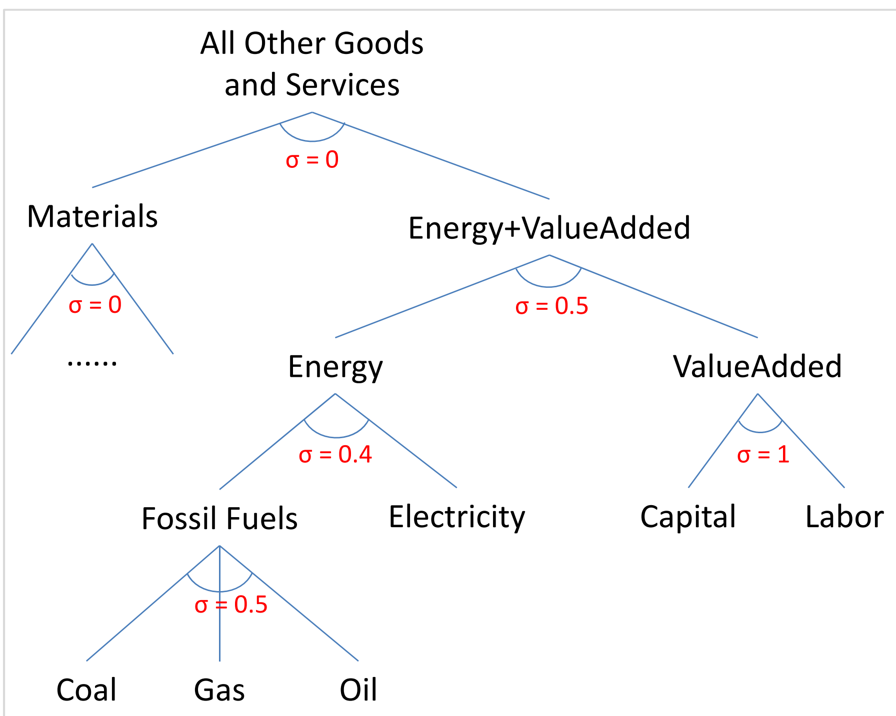


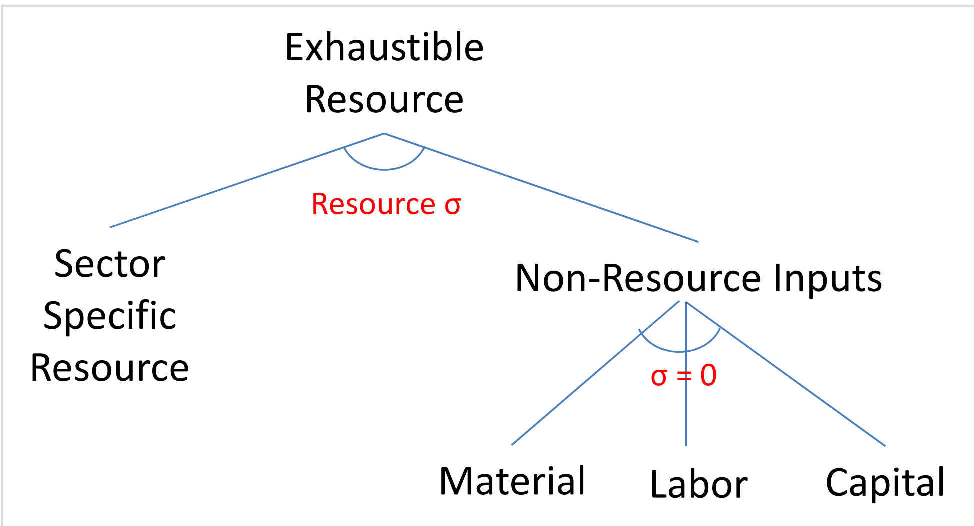
Figure 78: N_{ew}ERA Other Production Sector Representation



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

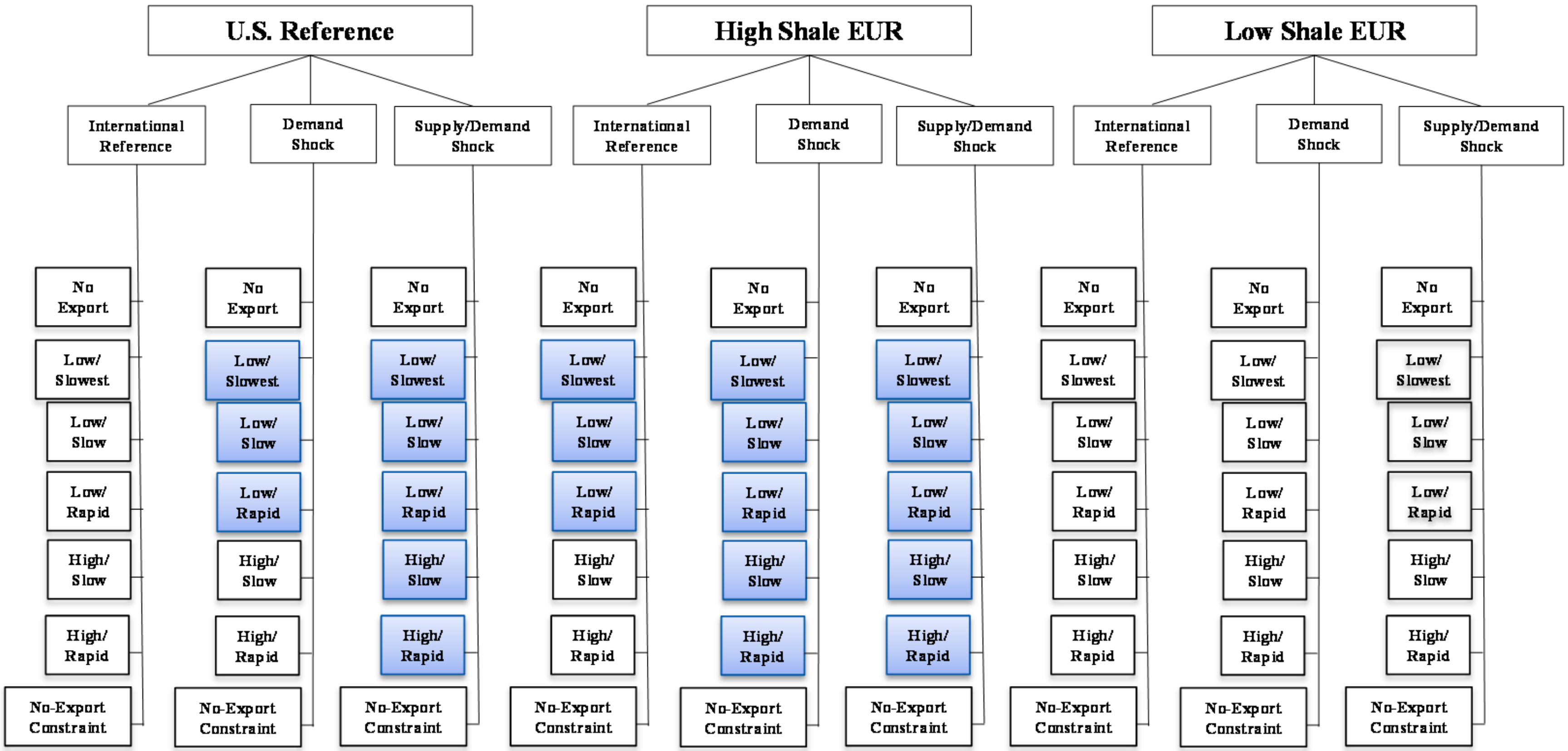


Figure 81: Detailed Results from Global Natural Gas Model, USREF_INTREF_NX

	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

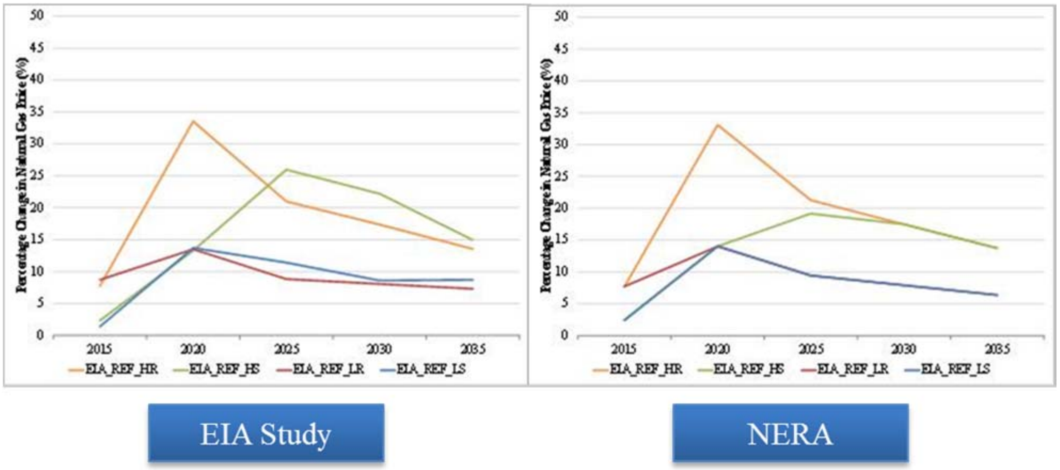


Figure 166: High EUR Natural Gas Price Percentage Changes

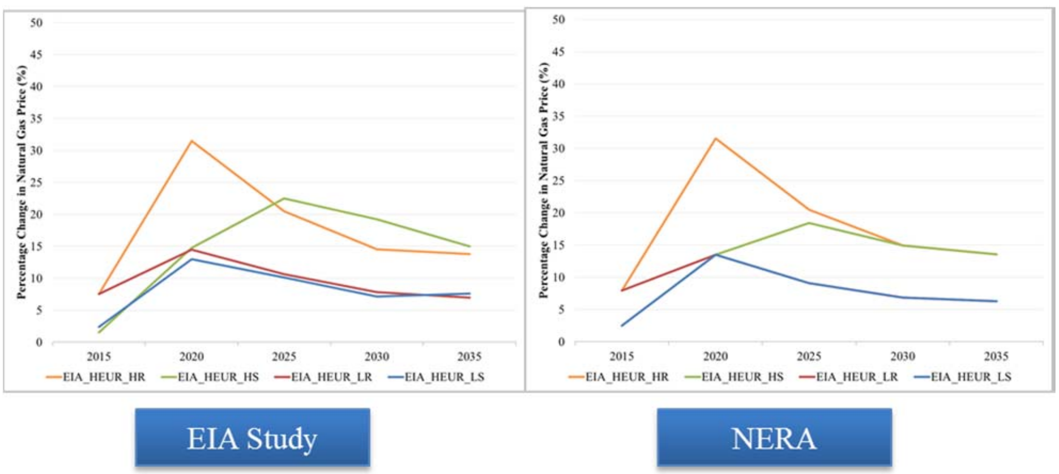
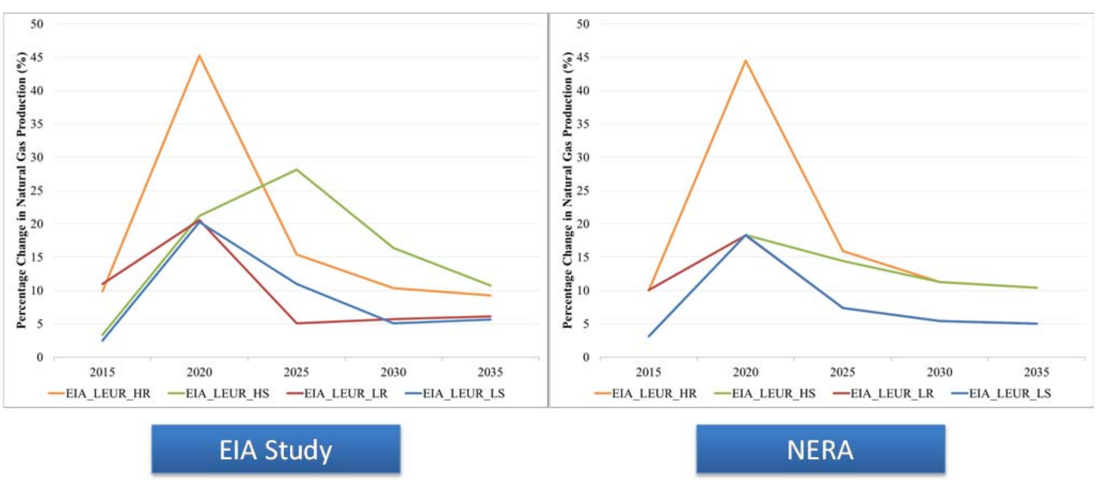


Figure 167: Low EUR Natural Gas Price Percentage Changes



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

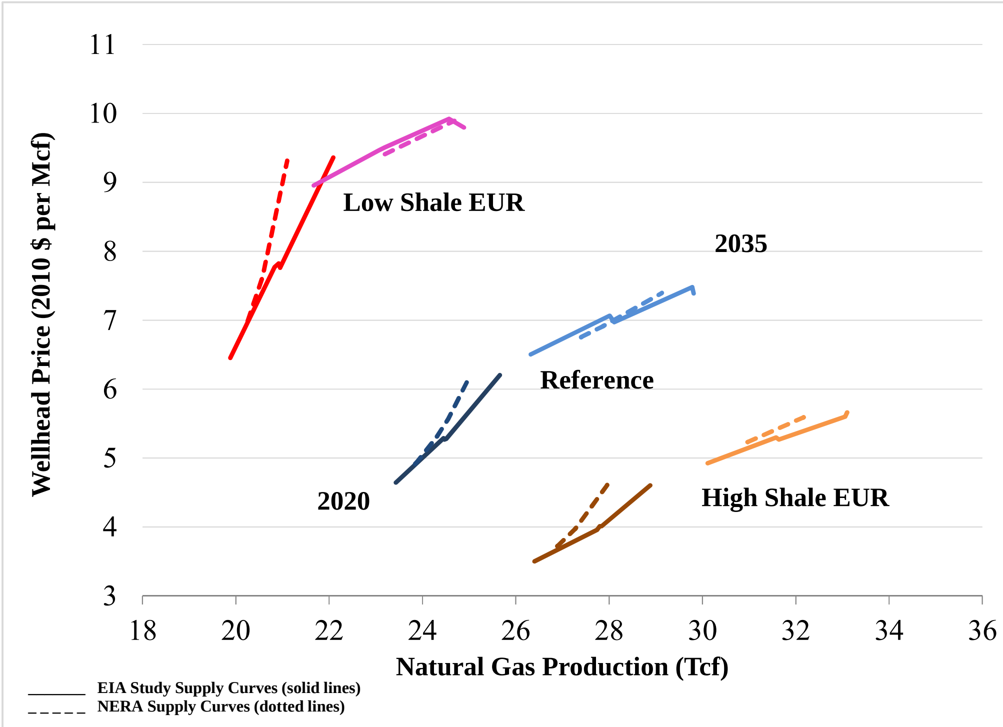
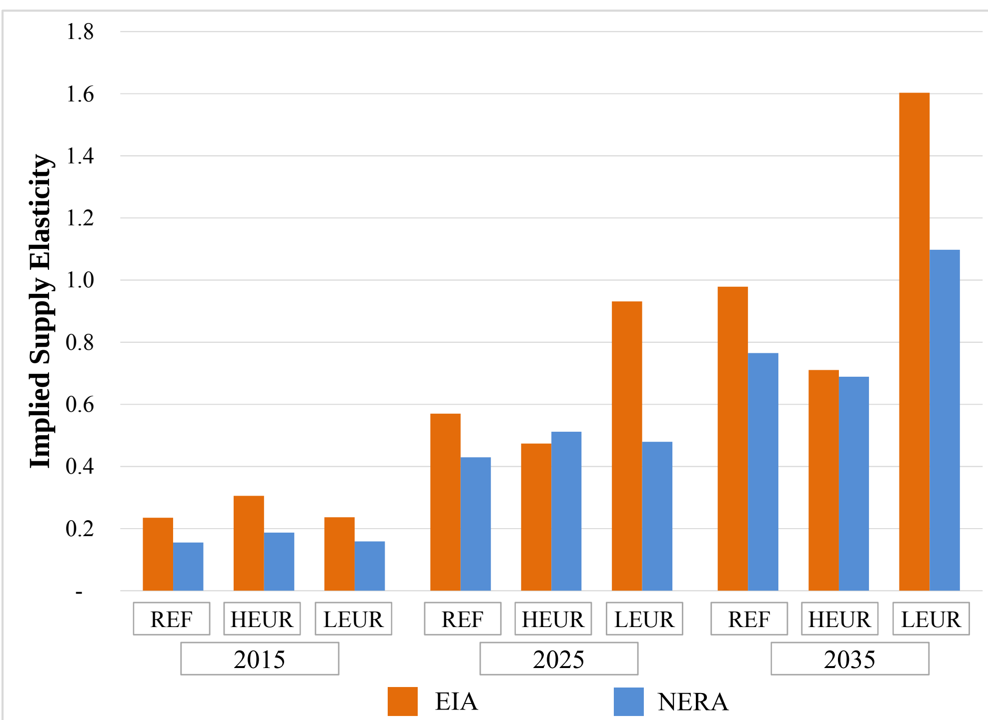


Figure 169: Implied Elasticities of Supply for Cases



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

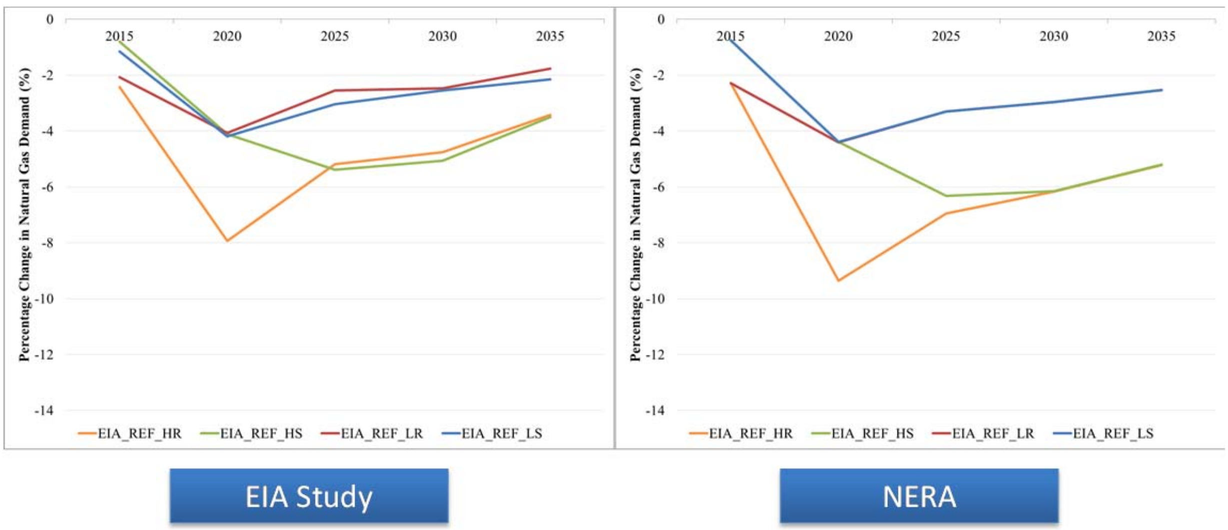


Figure 171: High EUR Natural Gas Demand Percentage Changes

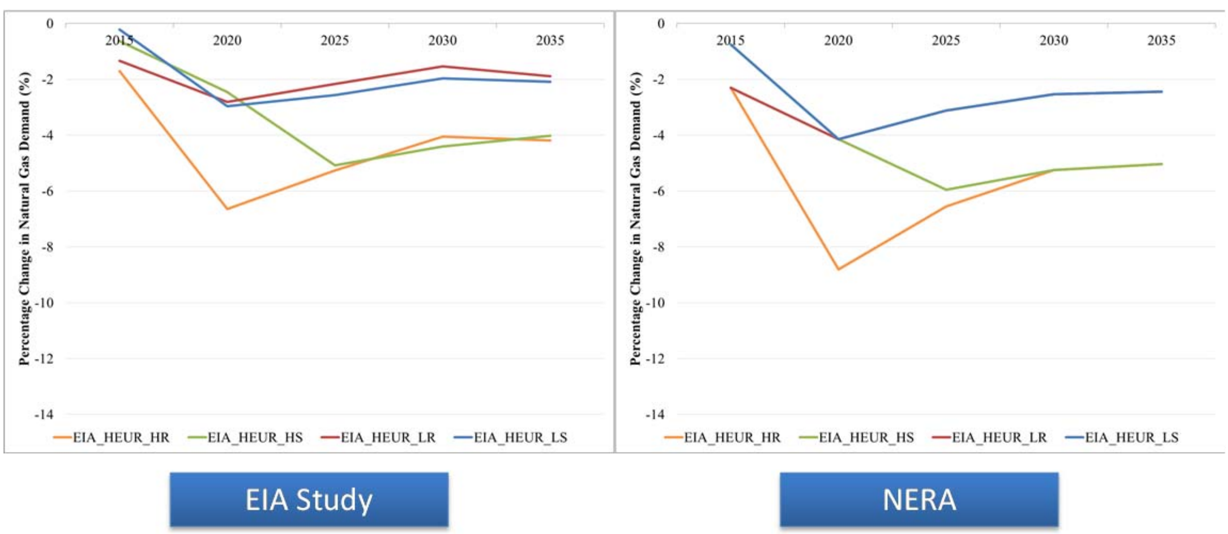
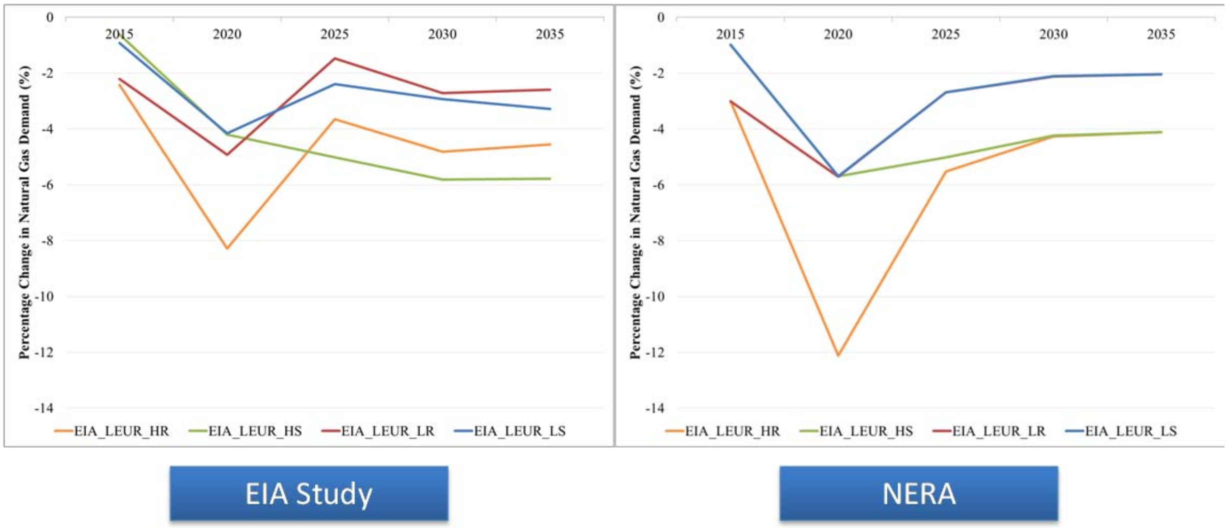


Figure 172: Low EUR Natural Gas Demand Percentage Changes



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

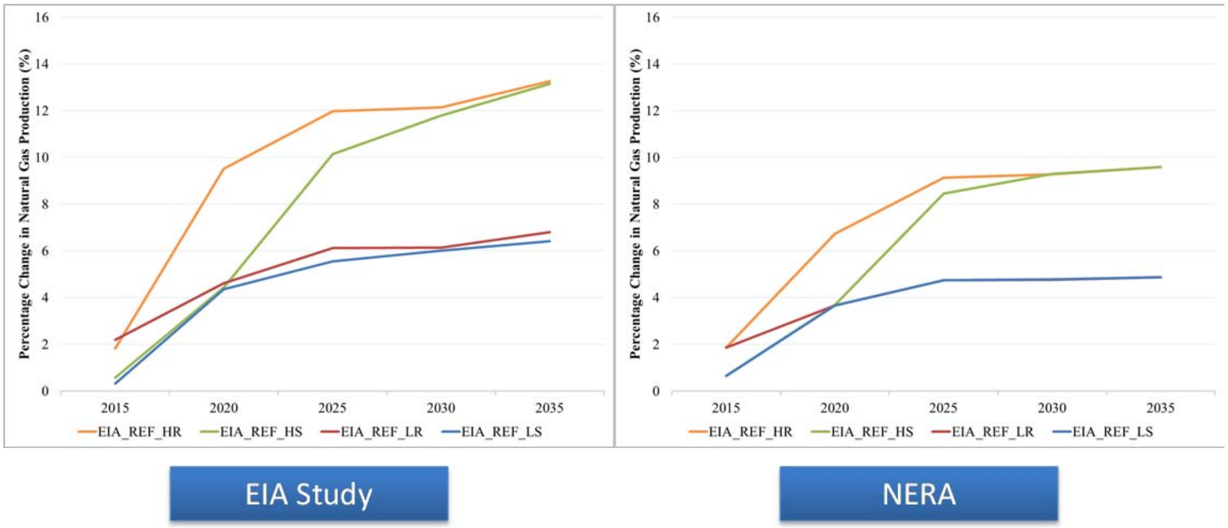


Figure 174: High EUR Natural Gas Production Percentage Changes

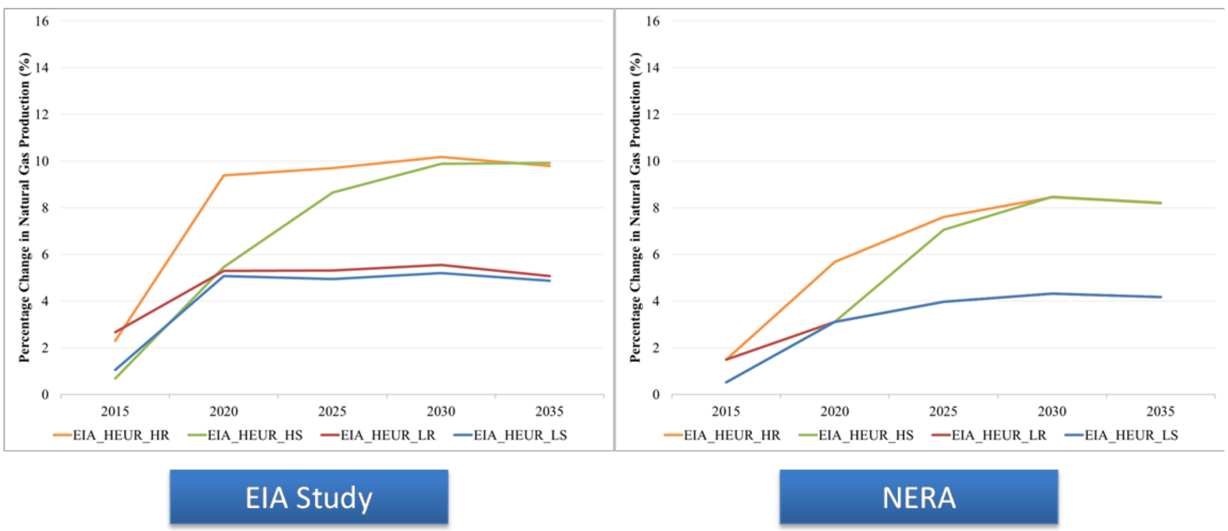
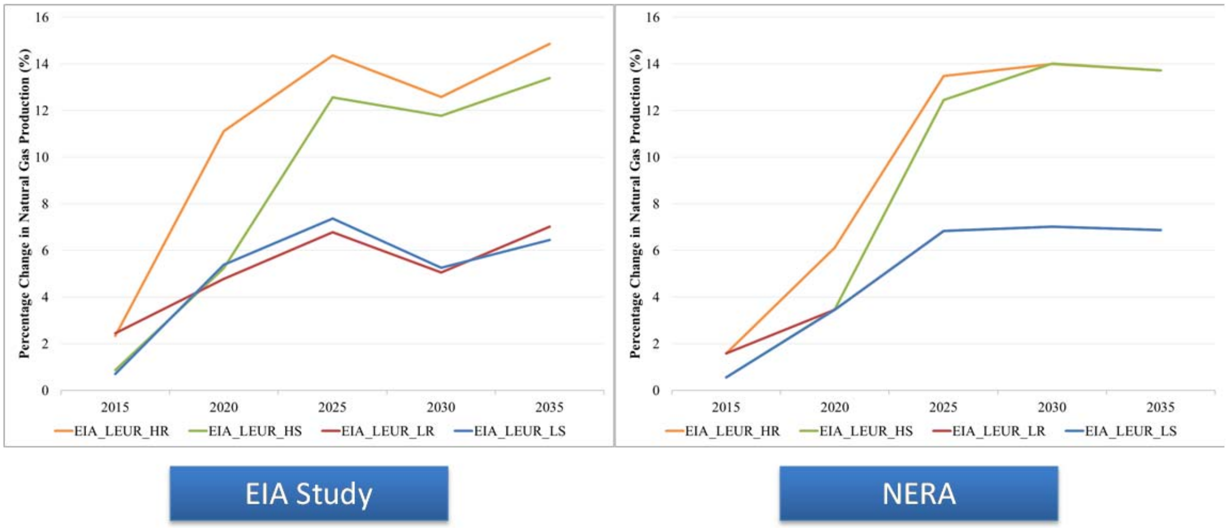


Figure 175: Low EUR Natural Gas Production Percentage Changes



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

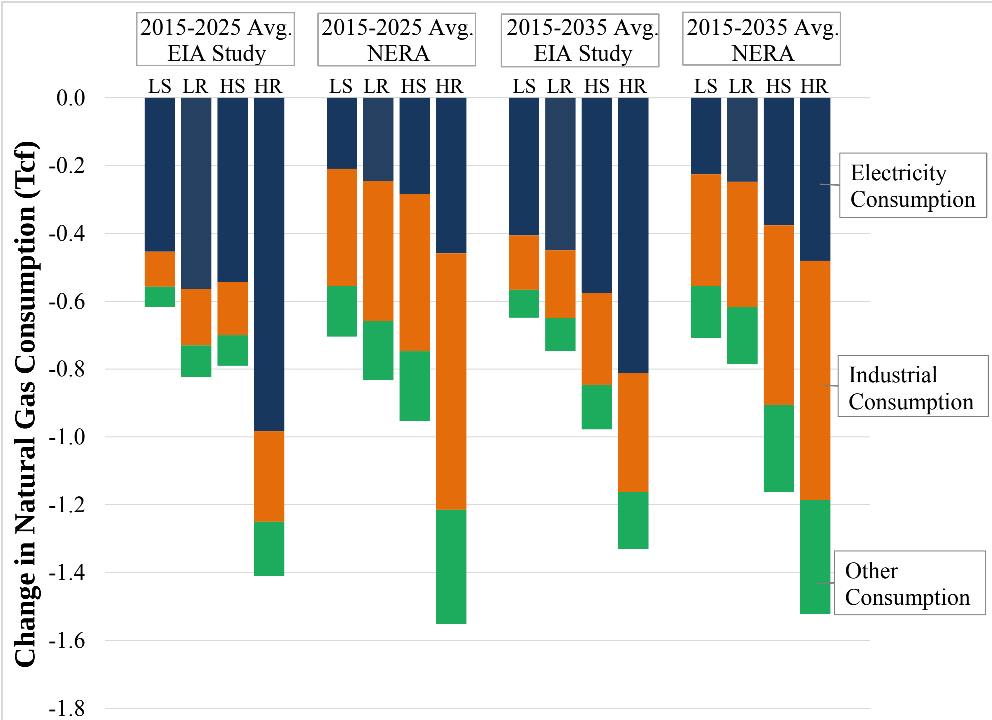


Figure 177: High EUR Average Change in Natural Gas Consumed by Sector

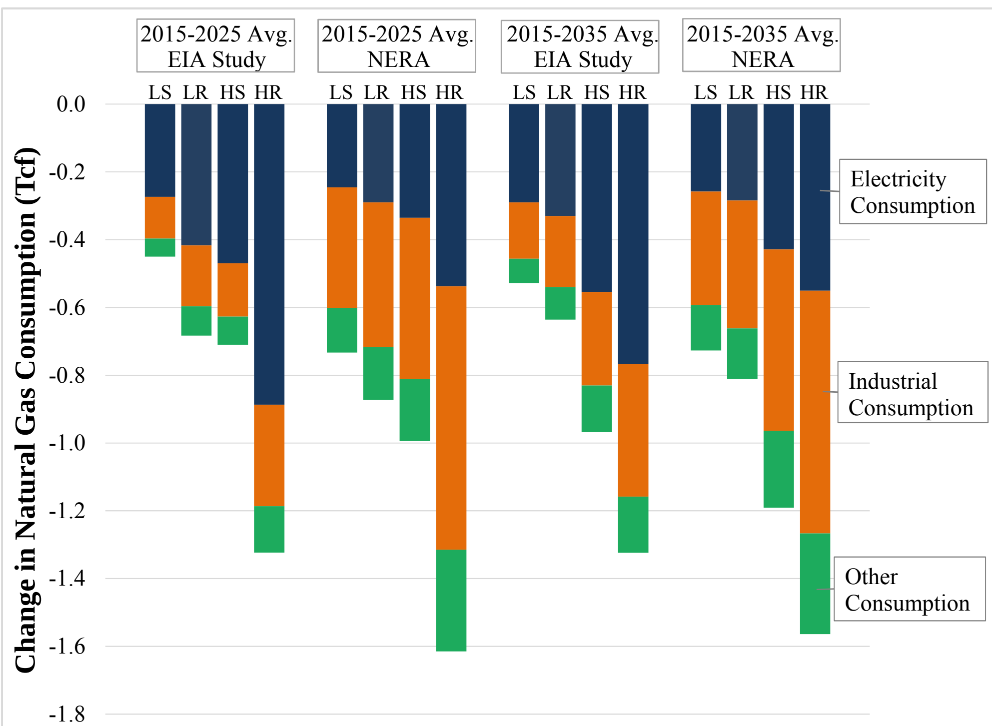
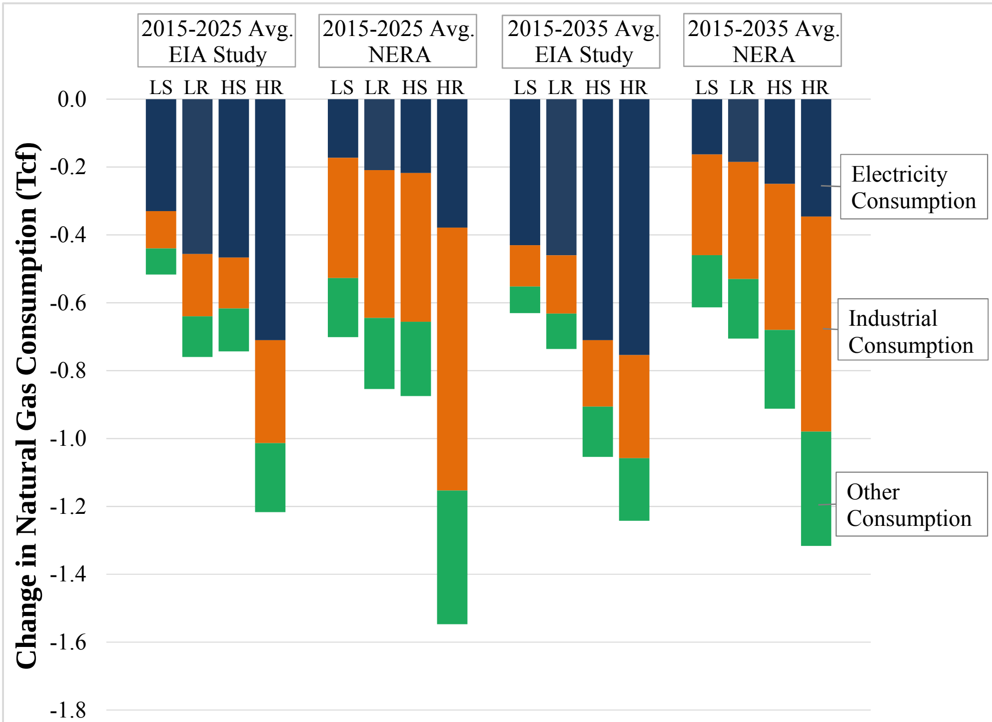


Figure 178: Low EUR Case Average Change in Natural Gas Consumed by Sector



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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January 24, 2013

U.S. Department of Energy (FE–34)
Office of Natural Gas Regulatory Activities
Office of Fossil Energy
Forrestal Building, Room 3E-042
Independence Ave SW,Washington, DC 20585
LNGStudy@hq.doe.gov.

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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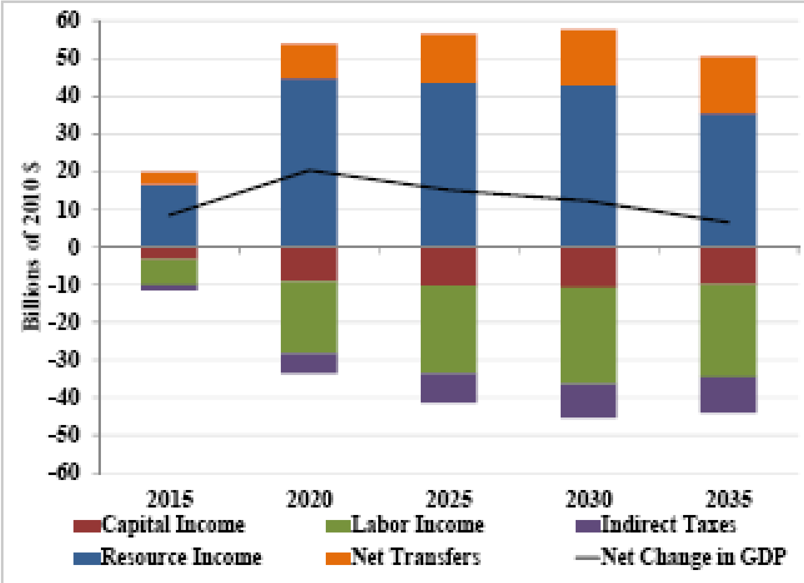
public interest. It can and must do so by complying with NEPA, which requires federal agencies to consider and disclose the "environmental impacts" of proposed agency actions. 42 U.S.C. § 4332(C)(i). NEPA requires preparation of an "environmental impact statement" (EIS) where, as is the case with LNG 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

[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

[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%

[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

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[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

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[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.

Synapse
Energy Economics, Inc.

Will LNG Exports Benefit the United States Economy?

January 23, 2013

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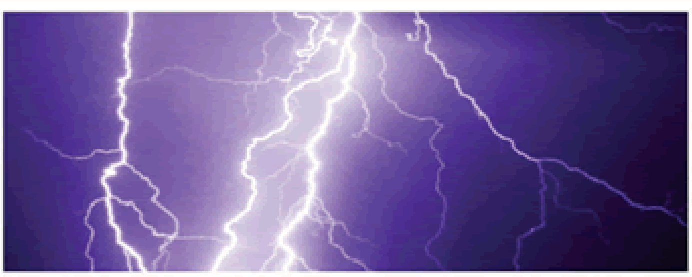

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1. Overview

DOE is considering whether large scale exports of liquefied natural gas (LNG) are in the public interest. As part of that inquiry, DOE has commissioned a team of researchers from NERA Economic Consulting, led by W. David Montgomery, to prepare a report entitled "Macroeconomic Impacts of LNG Exports from the United States" (hereafter, the NERA Report) in December 2012.[1] Unfortunately, that report suffers from serious methodological flaws which lead it to significantly underestimate, and, in some cases, to entirely overlook, many negative impacts of LNG exports on the U.S. economy.

NERA finds that LNG exports would be very good for the United States in every scenario they examined:

> …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. (NERA Report, p.1)

The measure of benefits used by NERA, however, reflects only the totals for the U.S. economy as a whole. In fact, the NERA study finds that natural gas exports are beneficial to the natural gas industry alone, at the expense of the rest of the U.S. economy—reducing the size of the U.S. economy excluding LNG exports.

This white paper examines the NERA Report, and identifies multiple problems and omissions in its analyses of the natural gas industry and the U.S. economy:

- NERA's own modeling shows that LNG exports in fact cause GDP to decline in all other economic sectors.
- Although NERA does not calculate employment figures, the methods used in previous NERA reports would indicate job losses linked to export of tens to hundreds of thousands.
- NERA undervalues harm to the manufacturing sector of the U.S. economy.
- NERA ignores significant economic burdens from environmental harm caused by export.
- NERA ignores the distribution of LNG-export benefits among different segments of society, and makes a number of questionable and unrealistic economic assumptions:
    - In NERA's model, everyone who wants a job has one; by definition, LNG exports cannot cause unemployment.
    - All economic benefits of LNG export return to U.S. consumers without any leakage to foreign investors.
    - Changes to the balance of U.S. trade are constrained to be very small.

[1] W. David Montgomery, et al., *Macroeconomic Impacts of LNG Exports from the United States,* December 2012. http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf

- NERA's modeling of economic impacts is based entirely on the proprietary $N_{ew}ERA$ model, which is not available for examination by other economists.
- NERA's treatment of natural gas resources and markets makes selective use of data to portray exports in a favorable light. In some cases, the NERA Report uses older data when newer revisions from the same sources were available; at times, it disagrees with other analysts who have carefully studied the same questions about the gas industry.

Even if NERA's flawed and incomplete analysis were to be accepted at face value, its conclusion that opening LNG exports would be good for the United States as a whole is not supported by its own modeling. Instead, NERA's results demonstrate that manufacturing, agriculture, and other sectors of the U.S. economy would suffer substantial losses. The methodology used to estimate job losses in other NERA reports, if applied in this case, would show average losses of wages equivalent to up to 270,000 jobs lost in each year.

2. LNG exports: Good for the gas industry, bad for the United States

According to the NERA Report, LNG exports would benefit the natural gas industry at the expense of the rest of the U.S. economy. Two sets of evidence illustrate this point: a comparison of natural gas export revenues with changes in gross domestic product (GDP), and a calculation, employed by NERA in other reports, of the "job-equivalents" from decreases in labor income. Applying this calculation to the NERA Report analysis suggests that opening LNG exports would result in hundreds of thousands of job losses. These losses would not be confined to narrow sections of U.S. industry, as NERA implies.

The NERA Report presents 13 "feasible" economic scenarios for LNG export, with projections calculated by NERA's proprietary $N_{ew}ERA$ model for 2015, 2020, 2025, 2030, and 2035. The scenarios differ in estimates of the amount of natural gas that will ultimately be recovered per new well: seven scenarios (with labels beginning with USREF) use the estimate from the federal Energy Information Administration's AEO 2011; five (beginning with HEUR) assume 150 percent of the AEO level; and one (beginning with LEUR) assumes 50 percent of the AEO level. In the LEUR scenario, LNG exports are barely worthwhile; in the HEUR scenarios, exports are more profitable than in the USREF scenarios.

LNG exports cause U.S. GDP (excluding LNG exports) to fall

Careful analysis of these LNG export scenarios reveals that the gain in GDP predicted by the NERA Report is driven—almost entirely—by revenues to gas exporters and gas companies; the remainder of the economy declines.

On average (across the five reporting years), export revenues were 74 percent or more of GDP growth in every scenario; in the eight scenarios with average or low estimated gas recovery per well, export revenues averaged more than 100 percent of GDP growth. In the median scenario, export revenues averaged 169 percent of GDP growth; in the worst case, export revenues averaged 240 percent of GDP growth.

Table 1 compares natural gas export revenues to the increase in GDP for each scenario.[2] When export revenues are greater than 100 percent of GDP growth, the size of the U.S. economy, excluding gas exports, is shrinking. For instance, for the year 2035 in the first two scenarios in Table 1, LNG export revenues are almost $9 billion higher than in the reference case, while GDP—which includes those export revenues along with everyone else's incomes—is only $3 billion higher. Thus, as a matter of arithmetic, everyone else's incomes (i.e., GDP excluding LNG export revenues) must have gone down by almost $6 billion. (If your favorite baseball team scored 3 more home runs this year than last year, and one of its players scored 9 more than he did last year, then it must be the case that the rest of the team scored 6 fewer.)

Similarly, in every case where natural gas export revenues exceed 100 percent of the increase in GDP—cases that appear throughout Table 1—the export revenues are part of GDP, so the remainder of GDP must have gone down.

Table 1: LNG Exports as a Share of GDP Gains[3]

Scenario	Exports as Percent of GDP Gains					
	2015	2020	2025	2030	2035	average
USREF_D_LSS	72%	75%	193%	225%	286%	170%
USREF_D_LS	50%	89%	193%	225%	286%	169%
USREF_D_LR	62%	112%	257%	338%	429%	240%
USREF_SD_LS	50%	77%	204%	258%	468%	211%
USREF_SD_LR	59%	90%	244%	258%	702%	271%
USREF_SD_HS	50%	67%	140%	216%	429%	180%
USREF_SD_HR	59%	75%	158%	216%	501%	202%
HEUR_SD_LSS	19%	38%	69%	109%	152%	77%
HEUR_SD_LS	24%	40%	82%	109%	152%	81%
HEUR_SD_LR	31%	42%	82%	123%	152%	86%
HEUR_SD_HS	24%	37%	64%	106%	142%	74%
HEUR_SD_HR	28%	39%	74%	111%	142%	79%
LEUR_SD_LSS	0%	164%	*NA*	*NA*	158%	107%

NA - not applicable (GDP did not increase over the no-export reference case)
Source: Author's calculations based on NERA Report, Figures 144-162.

As Table 1 demonstrates, export revenues exceed GDP growth: GDP (not including gas exports) is shrinking by 2030 or earlier in all scenarios, and by 2025 or earlier in all scenarios using the AEO assumption about gas recovery per well (i.e., USREF). In other words, after the initial years of construction of export facilities, when construction activities may create some local economic

[2] The increase in GDP is the difference between the scenario GDP projections and the GDP in the corresponding no-export reference case (for USREF, HEUR, or LEUR assumptions). Data from NERA Report, pp.179-197.

[3] In the second term in the scenario names, international cases are defined by increases in global demand and/or decreases in global supply: D=International Demand Shock, SD=International Supply/Demand Shock. In the third term in the scenario names, export cases for quantity/growth are defined as follows: LSS=Low/Slowest, LS=Low/Slow, LR=Low/Rapid, HS=High/Slow, HR=High/Rapid.

benefits, gas exports create increased income for the gas industry, at the expense of everyone else.[4]

Loss of labor income from LNG exports is equivalent to huge job losses

NERA avoids predicting the employment implications of LNG export, and downplays the aggregate billions of dollars in decreased labor income predicted by its report. In fact, using NERA's own methods, the following analysis shows the potential for hundreds of thousands of job losses per year.

In other reports using the N_{ew}ERA model, NERA has reported losses of labor income in terms of "job-equivalents." This may seem paradoxical, since the N_{ew}ERA model assumes full employment, as discussed later in this white paper. As NERA has argued elsewhere, however, a loss of labor income can be expressed in terms of job-equivalent losses, by assuming that it consists of a loss of workers earning the average salary.[5] In other words, a given decrease in labor income can be interpreted as a loss of workers who would make that income.

This method can be applied to the losses of labor income projected for each of the 13 scenarios in the NERA Report. These losses are expressed as percentages of gross labor income; we have assumed that NERA's "job-equivalent losses" represent the same percentage of the labor force. For example, we assume the loss of 0.1 percent of gross labor income in scenario HEUR_SD_HS in 2020 is equivalent to job losses of 0.1 percent of the projected 2020 labor force of 159,351,000 workers, or roughly 159,000 job-equivalent losses.[6]

The results of this analysis are shown in Table 2. Job-equivalent losses, averaged across the five reporting years, range from 36,000 to 270,000 per year; the median scenario has an average job-equivalent loss of 131,000 per year. We do not necessarily endorse this method of calculation of labor impacts, but merely note that NERA has adopted it in other reports using the same model. If NERA had used this method in the NERA Report analysis, it would have shown that LNG exports have the potential to significantly harm employment in many sectors.

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[4] Other modeled results in the record cast further doubt on NERA's study. See Wallace E. Tyner, "Comparison of Analysis of Natural Gas Export Impacts," January 14, 2013. http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/30_Wallace_Tyner01_14_13.pdf

[5] See, e.g., NERA's Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector, October 2012, p. ES-6: "Job-equivalents are calculated as the total loss in labor income divided by the average salary." http://www.nera.com/nera-files/PUB_ACCCE_1012.pdf

[6] The Bureau of Labor Statistics projects annual growth of the civilian labor force at 0.7% per year from 2010 to 2020 (Mitra Toosi. "Labor force projections to 2020: a more slowly growing workforce." Monthly Labor Review, January 2012. http://www.bls.gov/opub/mlr/2012/01/art3full.pdf.) We have used the same annual growth rate to project the labor force through 2035.

Table 2: Employment equivalents of reduced labor income

	Job-equivalent loss, NERA method					
	2015	2020	2025	2030	2035	average
USREF_D_LSS	15,000	77,000	108,000	77,000	62,000	68,000
USREF_D_LS	31,000	77,000	108,000	77,000	62,000	71,000
USREF_D_LR	108,000	92,000	108,000	77,000	62,000	89,000
USREF_SD_LS	31,000	200,000	169,000	139,000	123,000	132,000
USREF_SD_LR	123,000	215,000	169,000	139,000	123,000	154,000
USREF_SD_HS	31,000	185,000	292,000	292,000	246,000	209,000
USREF_SD_HR	108,000	292,000	308,000	292,000	246,000	249,000
HEUR_SD_LSS	15,000	62,000	108,000	108,000	92,000	77,000
HEUR_SD_LS	15,000	169,000	139,000	108,000	92,000	105,000
HEUR_SD_LR	108,000	169,000	139,000	108,000	92,000	123,000
HEUR_SD_HS	15,000	154,000	246,000	215,000	200,000	166,000
HEUR_SD_HR	92,000	385,000	292,000	231,000	200,000	240,000
LEUR_SD_LSS	0	92,000	77,000	0	0	34,000
Labor force	*153,889,000*	*153,889,000*	*153,889,000*	*153,889,000*	*153,889,000*	

Source: Author's calculations based on NERA Report, Figures 144-162.

NERA downplays their estimated shifts in employment from one sector to another saying that is smaller than normal rates of turnover in those industries, but, of course, normal labor turnover is enormous. It is true that job losses caused by LNG exports will be less than the annual total of all retirements, voluntary resignations, firings, layoffs, parental and medical leaves, new hires, moves to new cities and new jobs, and switching from one employer to another for all sorts of reasons: Throughout the entire U.S. labor force normal turnover amounts to almost 40 million people each year.[7] The comparison of job losses to job turnover is irrelevant.

Harm to U.S. economy is not confined to narrow sections of industry, as NERA implies

The NERA Report emphasizes the fact that only a few branches of industry are heavily dependent on natural gas (NERA Report, pp.67-70). This discussion is described as an attempt "to identify where higher natural gas prices might cause severe impacts such as plant closings" (p.67). The NERA Report makes two principal points in this discussion. First, it quotes a 2009 study of the expected impacts of the Waxman-Markey proposal for climate legislation, which found that only a limited number of branches of industry would be harmed by higher carbon costs; NERA argues that price increases caused by LNG exports will have an even smaller but similarly narrow effect on industry. Second, NERA observes that industries where value added (roughly the sum of wages and profits) makes up a large fraction of sales revenue are unlikely to have high energy costs, while industries with high energy costs probably have a low ratio of value added to sales.

[7] "Job Openings and Labor Turnover," Bureau of Labor Statistics, November 2012, Table 3. http://www.bls.gov/news.release/pdf/jolts.pdf

Both points may be true, but they are largely irrelevant to the evaluation of LNG exports. NERA's use of the Waxman-Markey study is inappropriate, as Representative Markey himself has pointed out, because that proposed bill directed significant resources to industries harmed by higher costs to mitigate any negative impact.[8] No such mitigation payments are associated with LNG export, so relying upon Waxman-Markey examples to downplay potential economic damage is inappropriate. If those exports increase domestic gas prices, industry will be harmed both by higher electricity prices and by higher costs for direct use of natural gas. Further, it is true that direct use of natural gas is relatively concentrated, but it is concentrated in important sectors; as the natural gas industry itself explains, "Natural gas is consumed primarily in the pulp and paper, metals, chemicals, petroleum refining, stone, clay and glass, plastic, and food processing industries."[9] These are not small or unimportant sectors of the U.S. economy.[10] In any case, discussion of sectors where higher natural gas prices might cause "severe impacts such as plant closings" is attacking a straw man; NERA's own calculations imply moderate harm would be imposed throughout industry, both by rising electricity prices and by the costs of direct gas consumption—offset by benefits exclusively concentrated in the hands of the natural gas industry.

Similarly, it does not seem particularly important to know whether industries that use a lot of natural gas have high or low ratios of value added to sales. Are aluminum, cement, fertilizer, paper, and chemicals less important to the economy because they have many purchased inputs, and therefore low ratios of value added to sales?

3. Costs and benefits from LNG exports are unequally distributed

As the results above show, LNG exports essentially transfer revenue away from the rest of the economy and into the hands of companies participating in these exports. This shift has significant economic implications that are not addressed in the NERA Report's analysis.

The NERA Report asserts that "all export scenarios are welfare-improving for U.S. consumers" (NERA Report, p.55). While LNG exports will result in higher natural gas prices for U.S. residents, NERA projects that these costs will be outweighed by additional income received from the exports—and thus, "consumers, in aggregate are better off as a result of opening LNG exports." (NERA Report, p.55) Or, to put this another way, the gains of every resident of the United States, added together, will be greater than the losses of every resident of the United States, added together. The distribution of these benefits and costs—who will suffer costs and who will reap gains—is discussed only tangentially in the NERA Report, but is critical to a complete understanding of the effects of LNG exports on the U.S. economy. A closer look reveals that LNG exports benefit only a very narrow section of the economy, while causing harm to a much broader group.

[8] Letter from Rep. Markey to Secretary Steve Chu (Dec. 14, 2012).
[9] http://www.naturalgas.org/overview/uses_industry.asp.
[10] Other commenters also point out that NERA does not even appear to have included some gas-dependent industries, including fertilizer and fabric manufacture, in its analysis. *See* Comments of Dr. Jannette Barth (Dec. 14, 2012).

Focus on "net impacts" ignores key policy issues

The results presented in the NERA Report focus on the net impacts on the entire economy—combining together everyone's costs and benefits—and on the "welfare" of the typical or average family, measured in terms of equivalent variation.[11] NERA dismisses the need to discuss the distribution of the costs and benefits among groups that are likely to experience very different impacts from LNG exports, stating that: "[t]his study addresses only the net economic effects of natural gas price changes and improved export revenues, not their distribution." (NERA Report, p.211) NERA alludes to an unequal distribution of costs and benefits in its results, but does not present a complete analysis:

> 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 liquefactions services. The net result is an increase in U.S. households' real income and welfare. (NERA Report, p.6)

Instead, the NERA Report combines the economic impacts of winners and losers from LNG exports. In the field of economics, this method of asserting that a policy will improve welfare for society as a whole as long as gains to the winners are greater than costs to the losers is known as the "Kaldor-Hicks compensation principle" or a "potential Pareto improvement." The critiques leveled at cost-benefit analyses that ignore important distributional issues have as long a history as these flawed methods. Policy decisions cannot be made solely on the basis of aggregated net impacts: costs to one group are never erased by the existence of larger gains to another group. The net benefit to society as a whole shows only that, if the winners choose to share their gains, they have the resources to make everyone better off than before—but not that they *will* share their gains. In the typical situation, when the winners choose to keep their winnings to themselves, there is no reason to think that everyone, including the losers, is better off.

As previous congressional testimony by W. David Montgomery—the lead author of the NERA Report—on the impacts of cap-and-trade policy support explained it: "There are enough hidden differences among recipients of allowances within any identified group that it takes far more to compensate just the losers in a group than to compensate the average. Looking at averages assumes that gainers compensate losers within a group, but that will not occur in practice."[12]

[11] One of the complications in estimating the costs and benefits of a policy with the potential to impact prices economy-wide, is that simply measuring changes in income misses out on the way in which policy-driven price changes affect how much can be bought for the same income. (For example, if a policy raises incomes but simultaneously raises prices, it takes some careful calculation to determine whether people are better or worse off.) The NERA Report uses a measure of welfare called "equivalent variation," which is the additional income that the typical family would have to receive today (when making purchases at current prices) in order to be just as well off as they would be with the new incomes and new price levels under the proposed policy. It can be thought of as the change in income caused by the policy, adjusted for any change in prices caused by the policy.

[12] Prepared Testimony of W. David Montgomery, before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation, June 9, 2009.
http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.

Wage earners in every sector except natural gas will lose income

In every scenario reviewed in the NERA Report, labor income rises in the natural gas industry, and falls in every other industry.[13] Economy-wide, NERA finds that “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.” (NERA Report, p.63)[14] Even without a detailed distributional analysis, the NERA Report demonstrates that some groups will lose out from LNG exports:

> Overall, both total labor compensation and income from investment are projected to decline, and income to owners of natural gas resources will increase… 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. (NERA Report, p.2)

NERA’s “might not participate in these benefits” could and should be restated more accurately as “will bear costs.” Although NERA doesn’t acknowledge it, most Americans will not receive revenues from LNG exports; many more Americans will experience decreased wages and higher energy prices than will profit from LNG exports.

Wage earners in every major sector except for natural gas will lose income, and, as domestic natural gas prices increase, households and businesses will have to pay more for natural gas (for heat, cooking, etc.), electricity, and other goods and services with prices that are strongly impacted by natural gas prices. The NERA Report briefly mentions these price effects:

> 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. (NERA Report, p.13-14)

Additional analysis required to understand electricity price impacts

There are no results presented in the NERA Report to display the effect of changes in electricity prices on consumers. Negative effects on the electricity sector itself are shown in NERA’s Figure 38, but changes in electric rates and electricity bills, and the distributional consequences of these changes, are absent from the results selected for display in this report. NERA certainly could have conducted such an analysis. NERA’s October 2012 report on recent and anticipated EPA regulations affecting the U.S. electricity sector using the N$_{ew}$ERA model displayed electricity price impacts for eleven regions and three scenarios.[15]

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[13] See NERA Report, Figure 39.
[14] See NERA Report, Figure 40.
[15] Harrison, et al., Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector, October 2012. NERA Economic Consulting. See Table 17. http://www.nera.com/67_7903.htm.

Dr. Montgomery previous testimony also presents increases in household electric utility bills.[16] He describes a “decline in purchasing power” for the average household, claiming that “the cost for the average family will be significant” and “generally the largest declines in household purchasing power are occurring in the regions with the lowest baseline income levels.”[17] A careful distributional analysis would greatly improve the policy relevance of the NERA Report’s economic impact projections.

Benefits of stock ownership are not as widespread as NERA assumes

There is no evidence to support NERA’s implication that the benefits of stock ownership are broadly shared among U.S. families across the economic spectrum—and therefore no evidence that they will “participate” in benefits secured by LNG exports.

NERA’s claim of widespread benefits is not supported by data from the U.S. Census Bureau. In 2007, just before the financial crash, only about half of all families owned any stock, including indirect holdings in retirement accounts. Indeed, only 14 percent of families with the lowest incomes (in the bottom 20 percent) held any stock at all, compared to 91 percent of families with the highest incomes (the top 10 percent).[18]

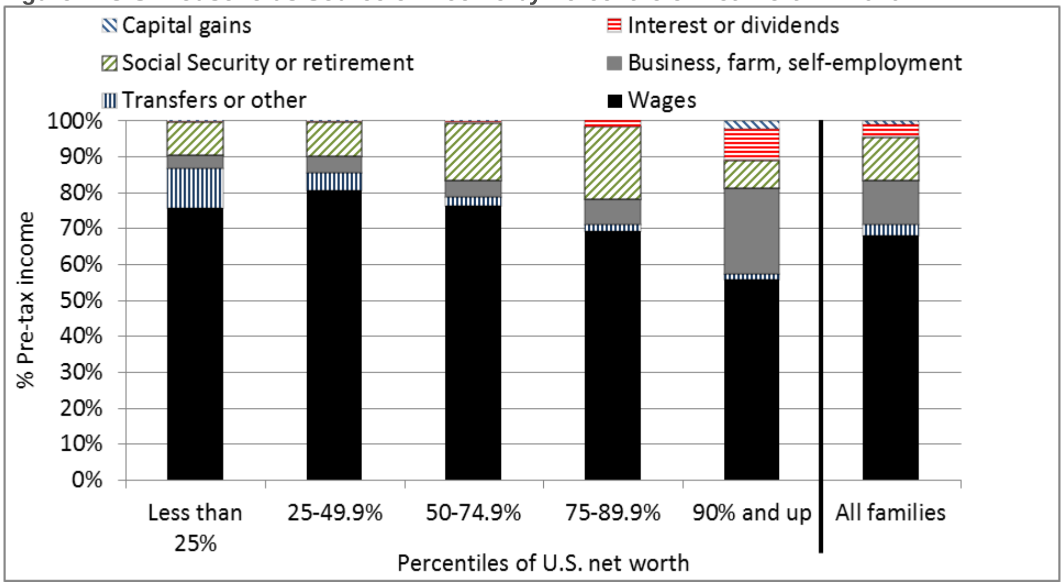
For most households the primary source of income is wages. According to the Federal Reserve, 68 percent of all family income in 2010 (the latest data available) came from wages, while interest, dividends and capital gains only amounted to 4.5 percent (see Figure 1). Families with the least wealth (the bottom 25 percent) received 0.2 percent of their income from interest, dividends, and capital gains, compared to 11 percent for the wealthiest families (the top 10 percent).

[16] Prepared Testimony of W. David Montgomery, before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation, June 9, 2009.
http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.

[17] Ibid.

[18] U.S. Census Bureau, Statistical Abstract of the United States: 2012, 2012. See Table 1211.
http://www.census.gov/compendia/statab/2012/tables/12s1211.pdf.

Figure 1: U.S. Households Source of Income by Percentile of Net Worth in 2010



Source: Federal Reserve, Changes in U.S. Family Finances from 2007 to 2010: Evidence from the Survey of Consumer Finances, Table 2.

And yet the NERA Report appears to assume that the benefits of owning stock in natural gas export companies are widespread, explaining that:

> U.S. consumers receive additional income from…the LNG exports provid[ing] additional export revenues, and…consumers who are owners of the liquefaction plants, receiv[ing] 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. (NERA Report, p.55)

In the absence of detailed analysis from NERA, it seems safe to assume that increases to U.S. incomes from LNG exports will accrue to those in the highest income brackets. Lower income brackets, where more income is derived from wages, are far more likely to experience losses in income—unless they happen to work in the natural gas industry—and natural gas extraction currently represents less than 0.1 percent of all jobs in the United States.[19] At the same time, everyone will pay more on their utility bills.

[19] Share of jobs in oil and gas extraction. Data for the share of jobs in the natural gas industry alone is not available but would, necessarily, be smaller. Support activities for mining represents an additional 0.25 percent of jobs, petroleum and coal products 0.08 percent, and pipeline transportation 0.03 percent. Taken together, these industries, which include oil, coal and other mining operations, represent 0.5 percent of all U.S. employment. Bureau of Economic Analysis, Full-Time and Part-Time Employees by Industry, 2011 data. http://bea.gov/iTable/iTable.cfm?ReqID=5&step=1

NERA's assumption that all income from LNG exports will return to U.S. residents is incorrect

In the N_{ew}ERA analysis, two critical assumptions assure that all LNG profits accrue to U.S. residents. First, "Consumers own all production processes and industries by virtue of owning stock in them." (NERA Report, p.55) The unequal distribution of stock ownership (shown as interest, dividend, and capital gains income in the Federal Reserve data in Figure 1) is not made explicit in the NERA Report, nor is the very small share that natural-gas-related assets represent in all U.S.-based publically traded stock.[20] In discussing impacts on households' wealth, NERA only mention that "if they, or their pensions, hold stock in natural gas producers, they will benefit from the increase in the value of their investment." (NERA Report, p.13) A more detailed distributional analysis would be necessary to determine the exact degree to which LNG profits benefit different income groups; however, it is fair to conclude that lower-income groups and the middle class are much less likely to profit from LNG exports than higher-income groups that receive a larger portion of income from stock ownership.

Second, the NERA Report assumes that "all of the investment in liquefaction facilities and natural gas drilling and extraction comes from domestic sources." (NERA Report, p.211) This means that the N_{ew}ERA model implausibly assumes that all U.S.-based LNG businesses are solely owned by U.S. residents. There is no evidence to support this assumption. On the contrary, many players in this market have significant foreign ownership shares or are privately held, and may be able to move revenues in ways that avoid both the domestic stock market and U.S. taxes. Cheniere Energy, the only LNG exporter licensed in the United States, is currently building an export terminal on the Gulf of Mexico for $5.6 billion—$1 billion of which is coming from investors in China and Singapore.[21] Cheniere's largest shareholders include holding companies in Singapore and Bermuda, as well as a hedge fund and a private equity firm, which in turn have a mix of domestic and foreign shareholders.[22] This situation is not atypical. As illustrated in Figure 2, 29 percent (by Bcf/day capacity) of the applications for U.S. LNG export licenses are foreign-owned, including 6 percent of total applications from foreign governments. Additionally, 70 percent of domestic applicants are publicly owned and traded, most of which have both domestic and foreign stock holders. Gas extraction companies, similarly, operate with a diverse mix of foreign and domestic investment, and of public and private ownership structures. NERA's claim that profits from LNG exports will be retained in the United States is unfounded.

NERA certainly could have addressed this issue in its analysis. Dr. Montgomery's previous testimony on cap-and-trade assumed that "all auction revenues would be returned to households,

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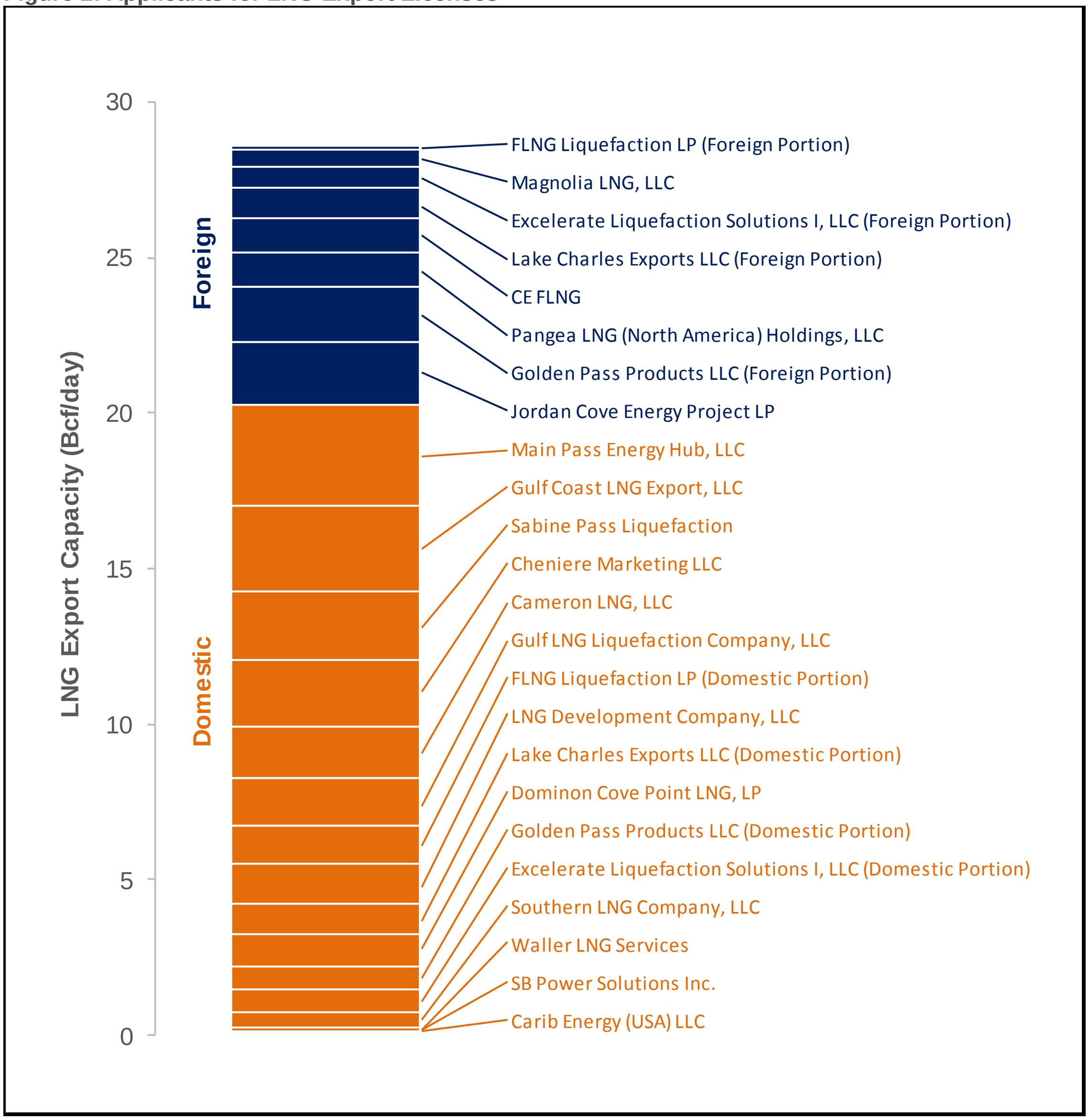
[20] NYSE companies involved in LNG export applications account for 5.8 percent of the total market capitalization, but this includes the value of shares from Exxon Mobil—by itself 2.9 percent of the NYSE market cap—as well as several other corporations with diverse business interests, such as General Electric, Dow, and Seaboard (owner of Butterball Turkeys among many other products). Reuters Stocks website, downloaded January 22, 2013 (following marketclose), http://www.reuters.com/finance/stocks. World Federation of Exchanges, "2012 WFE Market Highlights" (January 2013), page 6. http://www.world-exchanges.org/files/statistics/2012%20WFE%20Market%20Highlights.pdf.

[21] "UPDATE 2-China, Singapore wealth funds invest $1 bln in US LNG export plant-source." Reuters, August 21, 2012. http://www.reuters.com/article/2012/08/21/cic-cheniere-idUSL4E8JL0SC20120821

[22] Ownership data from NASDAQ for Cheniere Energy, Inc. (LNG). http://www.nasdaq.com/symbol/lng/ownership-summary#.UPmZgCfLRpU.

except for the allowance allocations that are given to foreign sources."[23] This assumption led him to conclude that, for the cap-and-trade program, a "large part of the impact on household costs is due to wealth transfers to other countries."[24] This level of analytical rigor should have been applied when estimating the U.S. domestic benefits from opening natural gas exports.

Figure 2: Applicants for LNG Export Licenses



[23] Prepared Testimony of W. David Montgomery, before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation, June 9, 2009, http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.

[24] Ibid.

Source: See Appendix A for a full list of sources.

Opening LNG export will also incur environmental costs

The discussion of LNG exports in the NERA Report, and most of our analysis of the report, is concerned with monetary costs and benefits: Exports cause an increase in natural gas prices, boosting incomes in the natural gas industry itself while increasing economic burdens on the rest of the economy. There are, in addition, environmental impacts of natural gas production and distribution that do not have market prices, but may nonetheless become important if LNG exports are expanded. Increases in exports are likely to increase production of natural gas, entailing increased risks of groundwater pollution and other environmental problems potentially associated with hydraulic fracturing ("fracking"). Increases in production, transportation of natural gas from wells to export terminals, and the liquefaction process itself, all increase the risks of leaks of natural gas, a potent greenhouse gas that contributes to global warming. These environmental impacts should be weighed, alongside the monetary costs and benefits of export strategies, in evaluation of proposals for LNG exports.

Clearly, as NERA itself acknowledges, the NERA Report would benefit from more detailed analysis of the distribution of costs and benefits from opening LNG exports: "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." (NERA Report, p.211)

4. Dependence on resource exports has long-run drawbacks

The harm that LNG exports cause to the rest of the U.S. economy, even in NERA's model, are consistent with an extensive body of economic literature warning of the dangers of resource-export-based economies.

If NERA's economic modeling is accepted at face value, it implies that the United States should embrace resource exports, even at the expense of weakening the rest of the economy. GDP, net incomes, and "welfare" as measured by NERA would all rise in tandem with LNG exports. There would be losses in manufacturing and other sectors, especially the energy-intensive sectors of paper and pulp, chemicals, glass, cement, and primary metal (iron, steel, aluminum, etc.) manufacturing (NERA Report, p. 64). But NERA asserts that these would be offset by gains in the natural gas industry. There would be losses of labor income, equivalent to a decline of up to 270,000 average-wage jobs per year. But, according to NERA, these losses would be offset by increased incomes for resource (natural gas) owners.

For those who are indifferent to the distribution of gains and losses—or who imagine that almost everyone owns a share of the natural gas industry—the shift away from manufacturing and labor income toward raw material exports could be described as good for the country as a whole. (So, too, could any shift among types of income, as long as its net result is an increase in GDP.) The rising value of the dollar relative to other currencies would allow affluent Americans to buy more imports, further increasing their welfare, even as the ability of industry to manufacture and export from the United States would decline.

There is, however, a longer-term threat of LNG exports to the U.S. economy: NERA's export scenarios would accelerate the decline of manufacturing and productivity throughout the country, pushing the nation into increased dependence on raw material exports. Developing countries have often struggled to escape from this role in the world economy, believing that true economic development requires the creation of manufacturing and other high-productivity industries. International institutions such as the IMF and the World Bank have often insisted that developing countries can maximize their short-run incomes by sticking to resource exports.

NERA is in essence offering the same advice to the United States: Why strive to make things at home, if there is more immediate profit from exporting raw materials to countries that can make better use of them? Europe, China, Japan, and Korea have much more limited natural resources per capita, but they are very good at making things out of resources that they buy from the United States and other resource-rich countries. In the long run, which role do we want the United States to play in the world economy? Do we want to be a resource exporter, with jobs focused in agriculture, mining, petroleum and other resource-intensive industries? Or do we want to export industrial goods, with jobs focused in manufacturing and high-tech sectors?

Economists have recognized that resource exports can impede manufacturing, even in a developed country; the problem has been called the "resource curse" or the "Dutch disease." The latter name stems from the experience of the Netherlands after the discovery of natural gas resources in 1959; gas exports raised the value of the guilder (the Dutch currency in pre-Euro days), making other Dutch exports less competitive in world markets and resulting in the eventual decline of its manufacturing sector.[25] In other countries, the "resource curse" has been associated with increased corruption and inequality; countries that depend on a few, very profitable resource exports may be less likely to have well-functioning government institutions that serve the interests of the majority.[26] Protecting an economy against the resource curse requires careful economic management of prospective resource exports.

In particular, it may be more advantageous in the long run to nurture the ability to manufacture and export value-added products based on our natural resources—even if it is not quite as profitable in the short run. The NERA Report is notably lacking in analysis of this strategy; there are no scenarios exploring promotion of, for example, increased use of natural gas in the chemical industry and increased exports of chemicals from the United States. The 25-year span of NERA's analysis provides for scope to develop a longer-term economic strategy with a different pattern of winners and losers. The benefits in this case might extend well beyond the narrow confines of the natural gas industry itself.

5. Unrealistic assumptions used in NERA's N$_{ew}$ERA model

Despite its sunny conclusions, the NERA Report indicates that LNG exports pose serious challenges to the U.S. economy. It is troubling, then, that the underlying modeling in the report is notably difficult to assess, and is reliant on a number of unrealistic assumptions.

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[25] "The Dutch Disease." *The Economist*, November 26, 1977, pp. 82-83.

[26] Papyrakis and Gerlagh. "The resource curse hypothesis and its transmission channels." *Journal of Comparative Economics*, 2004, 32:1 p.181-193; Mehlum, Moene and Torvik. "Institutions and the Resource Curse." *The Economic Journal*, 2006, 116:508 p.1-20.

The NERA Report relies on NERA Consulting's proprietary model, called N$_{ew}$ERA. Detailed model assumptions and relationships have never been published; we are not aware of any use of the model, or even evaluation of it in detail, by anyone outside NERA.

According to the NERA Report, N$_{ew}$ERA is a computable general equilibrium (CGE) model. Such models typically start with a series of assumptions, adopted for mathematical convenience, that are difficult to reconcile with real-world conditions. The base assumptions of the N$_{ew}$ERA model are described as follows: "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." (NERA Report, p. 103)

Here we discuss the implications of each of these assumptions, together with two additional critical modeling assumptions described elsewhere in the NERA Report: limited changes to the balance of trade, and sole U.S. financing of natural gas investments.

Full employment

The full employment assumption, common to most (though not all) CGE models, means that in every year in every scenario, anyone who wants a job can get one. This assumption is arguably appropriate—or at least, introduces only minor distortions—at times of very high employment such as the late 1990s. It is, however, transparently wrong under current conditions, when unemployment rates are high and millions of people who want jobs cannot find them.

The NERA Report expands on its Pollyannaish vision of the labor market, saying:

> 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 policy projection… 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. (NERA Report, p.110)

It also includes, in its "Key Findings," the statement that: "LNG exports are not likely to affect the overall level of employment in the U.S." (NERA Report, p.2)

In fact, this is an assumption—baked into the model—and not a finding. N$_{ew}$ERA, by design, never allows policy changes to affect the overall assumed level of employment. The unemployment rate must, by definition, always be low and unchanging in NERA's model.

For this reason, 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. Addressing that question requires a different modeling framework, one that recognizes the existence of involuntary unemployment (when people who want jobs cannot find them) and allows for changes in employment levels. (Despite N$_{ew}$ERA's full employment assumption, NERA has used the model results to calculate the "job-equivalents" lost to other environmental policies, as discussed above. Had NERA seriously addressed the question, as we discussed earlier, it might have discovered serious job loss potential.)

Perfect foresight

N_{ew}ERA, like other CGE models, assumes that decision-makers do not make systematic errors (that is, errors that bias results) when predicting the future. This is a common assumption in economic modeling and, while more complex theories regarding the accuracy of expectations of the future do exist, they only rarely enter into actual modeling of future conditions.

Zero profit condition

A more puzzling assumption is the “zero profit condition,” mentioned in the quote above. Analyzing fossil fuel markets under the assumption of zero profits sounds like a departure from the familiar facts of modern life. The picture is less than clear, since the N_{ew}ERA model includes calculations of both capital income and “resource” income (the latter is received by owners of resources such as natural gas); these may overlap with what would ordinarily be called profits. Without a more complete description of the N_{ew}ERA model, it is impossible to determine exactly how it treats profits in the fossil fuel industries. In any case, the business media are well aware of the potential for profits in natural gas; a recent article, based in part on the NERA Report, includes the subheading “How LNG Leads to Profits.”[27]

Invariable monetary policy

N_{ew}ERA also assumes that economy-wide interest rates and other monetary drivers will stay constant over time. Changes to monetary policy could, of course, have important impacts on modeling results, but forecasting these kinds of changes may well be considered outside of the scope of NERA’s analysis. That being said, several of NERA’s classes of scenarios involve supply and demand shocks to the economy as a whole: exactly the kind of broad-based change in economic conditions that tends to provoke changes in monetary policy.

Limited changes to the balance of trade

NERA’s treatment of foreign trade involves yet another unrealistic assumption:

> 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. (NERA Report, p.109)

Although U.S. exports increase in many scenarios, NERA assumes that there can be very little change in the balance of trade. Instead, increases in exports largely have the effect of driving up the value of the dollar relative to other currencies (NERA Report, p. 110). This assumption results in a benefit to consumers of imports, who can buy them more cheaply; conversely, it harms exporters, by making their products more expensive and less competitive in world markets.

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[27] Ben Gersten, “Five U.S. Natural Gas Companies Set to Soar from an Export Boom,” December 14, 2012. http://moneymorning.com/tag/natural-gas-stocks/

Sole U.S. financing of natural gas investments

Finally, NERA assumes that all income from natural gas investments will be received by U.S. residents: "[F]inancing of investment was assumed to originate from U.S. sources." (NERA Report, p.5) This improbable assumption, discussed in more detail above, means that benefits of investment in U.S. LNG export facilities and extraction services return, in full, to the United States. As discussed earlier, under the more realistic assumption that LNG exports are in part financed by foreign investors, some of the benefits of U.S. exports would flow out of the country to those investors.

6. Use of stale data leads to underestimation of domestic demand for natural gas

An additional important concern regarding the NERA Report is its use of unnecessarily outdated data from the rapidly changing U.S. Energy Information Administration (EIA) *Annual Energy Outlook* natural gas forecasts. Inexplicably, the NERA Report failed to use the EIA's most recent data, even though it had done so in prior reports.

The following timeline of EIA data releases and NERA reports illustrates this point:

- April 2011: EIA's Final **AEO 2011**[28] published
- December 2011: EIA's **AEO 2012**[29] Early Release published
- June 2012: EIA's Final **AEO 2012**[30] published
- October 2012: NERA's "Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector"[31] N_{ew}ERA model report published using **AEO 2012** data
- December 3, 2012: NERA's "Macroeconomic Impacts of LNG Exports from the United States"[32] N_{ew}ERA model report published using **AEO 2011** data
- December 5, 2012: EIA's **AEO 2013** Early Release published[33]

NERA's October 2012 N_{ew}ERA report on regulations affecting the electricity sector used AEO 2012 data, but its December 2012 report on LNG exports used older, AEO 2011 data. Days after NERA's December 2012 release of its LNG analysis, EIA released its AEO 2013 data.

By choosing to use stale data in its report, NERA changed the outcome of its analysis in significant ways. There have been important changes to EIA's natural gas forecasts in each recent AEO release. Even between AEO 2011 (used in NERA's LNG analysis) and AEO 2012 (which was available but not used by NERA), projected domestic consumption, production, and export of

[28] EIA, Annual Energy Outlook 2011, 2011. http://www.eia.gov/forecasts/archive/aeo11/er/
[29] EIA, *Annual Energy Outlook 2012 Early Release*, 2012. http://www.eia.gov/forecasts/archive/aeo12/er/
[30] EIA, *Annual Energy Outlook 2012,* 2012. http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf
[31] David Harrison, et al., *Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector*, October 2012. http://www.nera.com/nera-files/PUB_ACCCE_1012.pdf
[32] W. David Montgomery, et al., *Macroeconomic Impacts of LNG Exports from the United States*, December 2012. http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf
[33] EIA, *Annual Energy Outlook 2013 Early Release*, 2013. http://www.eia.gov/forecasts/aeo/er/

natural gas rise, imports fall, and projected (Henry Hub) gas prices take a deeper drop in the next decades than previously predicted.

NERA's use of the older AEO 2011 data results in an underestimate of domestic demand for natural gas. The assumed level of domestic demand for natural gas is critical to NERA's modeling results; higher domestic demand—as predicted by more recent AEO data—would decrease the amount of natural gas available for export and would increase domestic prices. Domestic natural gas prices—both in the model's reference case baseline and its scenarios assuming LNG exports—are a key determinant of U.S. LNG's profitability in the global market.

7. Conclusions and policy recommendations

NERA's study of the macroeconomic impacts of LNG exports from the United States is incomplete, and several of its modeling choices appear to bias results towards a recommendation in favor of opening LNG exports. NERA's imagined future clashes with the obvious facts of economic life.

NERA's own modeling shows that LNG exports depress growth in the rest of the U.S. economy.

- NERA's results demonstrate that when LNG exports are opened, the size of the U.S. economy (excluding these export revenues) will shrink. An example helps to illustrate this point: In some cases, when LNG export revenues are $9 billion, GDP is $3 billion larger than in the no-export reference case. This means that GDP excluding gas exports has shrunk by almost $6 billion.
- Using a methodology adopted by NERA in other N_{ew}ERA analyses, job-equivalent losses from opening LNG exports can be estimated as ranging from 36,000 to 270,000 per year; the median scenario has an average job-equivalent loss of 131,000 per year.
- NERA's assumption that all income from LNG exports will return to U.S. residents is simply incorrect, and results in an overestimate of the benefits that will accrue to U.S.-based resource owners.
- Most American households do not own significant amounts of stock in general, and natural gas stocks represent just a tiny fraction of total stock ownership. The benefits to the typical American household from a booming gas industry are too small to measure.
- Higher prices for natural gas and electricity, and declining job prospects outside of the natural gas industry, would cause obvious harm to people throughout the country.
- NERA's export strategy would have the effect of maximizing short-run incomes at the expense of long-term economic stability. If NERA's export scenarios were to be carried out as federal policy, the result would be an acceleration of the decline of U.S. manufacturing and productivity, and an increased national dependence on raw material exports. Too strong of a dependence on resource exports—a problem often called the "resource curse" or the "Dutch disease"—can weaken the domestic manufacturing sector, even in a developed country.
- In the long run, it may prove more advantageous to nurture U.S. manufacture and export of value-added products made from our natural resources—even if it is not quite as

profitable in the short run. For example, surplus natural gas could be used to increase the U.S. manufacture and export of products, such as chemicals, that use natural gas as a raw material.

- The NERA Report has significant methodological issues. The proprietary N_{ew}ERA model is not available for examination by reviewers outside of NERA. The application of this type of closed-source model to U.S. federal policy decisions seems inappropriate.
- The limited documentation provided by NERA points to several unrealistic modeling assumptions, including: decision-makers' perfect foresight regarding future conditions; zero profits in the production of goods and services; no change to monetary policy, even in the face of economy-wide demand and supply shocks; and constraints on how much the U.S. balance of trade can shift in response to opening LNG exports.
- Full employment—also assumed in NERA's modeling—is not guaranteed, and nothing resembling full employment has occurred for quite a few years. At the writing of this white paper, the U.S. unemployment rate stood at 7.8 percent of the labor force (that is, of those actively employed or seeking work).[34] Furthermore, unemployed factory workers do not automatically get jobs in natural gas production, or in other industries.
- The NERA Report used outdated AEO 2011 data when AEO 2012 data were available. These older data underestimate U.S. domestic consumption of natural gas. Accurate modeling of domestic demand for natural gas is essential to making a creditable case for the benefits of opening LNG exports.

The Department of Energy is charged with determining whether or not approving applications—and thus opening U.S. borders—for LNG exports is in the public interest. At this important juncture in the development of U.S. export and resource extraction policy, a higher standard for data sources, methodology, and transparency of analysis is clearly required. Before designating LNG exports as beneficial to the U.S. public, the Department of Energy must fully exercise its due diligence by considering a far more complete macroeconomic analysis, including a detailed examination of distributional effects.

[34] December 2012 unemployment rate; U.S. Bureau of Labor Statistics, *Labor Force Statistics from the Current Population Survey*, Series ID: LNS14000000, Seasonal Unemployment Rate. http://data.bls.gov/timeseries/LNS14000000.

Appendix A

This appendix contains source information for Figure 2: Applicants for LNG Export Licenses.

Table A-1: Source information for Figure 3

Company	Status	Publicly traded?	Source	Quantity	FTA Applications (Docket Number)	Non-FTA Applications (Docket Number)
Golden Pass Products LLC	Foreign / Domestic	yes: XOM ExxonMobil	Golden Pass Products LLC is a joint venture between ExxonMobil Corp and Qatar Petroleum http://online.wsj.com/article/SB1000087239639044437510457759576067871806 8.html#articleTabs%3Darticle	2.6 Bcf/d(d)	Approved (12-88 -LNG)	Under DOE Review (12-156-LNG)
Lake Charles Exports, LLC	Foreign / Domestic	yes: SUG Southern Union Company, Foreign: BG Bg Group on London Stock Exchange	Lake Charles Exports LLC is a jointly owned subsidiary of Southern Union Company and BG Group http://www.fossil.energy.gov/programs/gasregulation/authorizations/2011_applications/11_59_lng.pdf	2.0 Bcf/d (e)	Approved (11-59-LNG)	Under DOE Review (11-59-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (h)	Foreign / Domestic	Foreign: stock 9532:JP (Osaka Gas Co., Japan)	Osaka Gas's subsidiary Turbo LNG, LLC has a 10% stake in FLNG Development, which is a parent company for Freeport LNG Expansion, L.P, which in turn is a parent company of FLNG Liquafaction LP http://www.freeportlng.com/ownership.asp	1.4 Bcf/d (d)	Approved (12-06-LNG)	Under DOE Review (11-161-LNG)
Main Pass Energy Hub, LLC	Domestic	yes: MMR Freeport-MacMoRan Exploration Co.	Freeport-MacMoRan Exploration Co. owns a 50% stake in Main Pass Energy Hub, LLC http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/12_114_lng.pdf	3.22 Bcf/d	Approved (12-114-LNG)	n/a
Gulf Coast LNG Export, LLC (i)	Domestic	privately held	97% owned by Michael Smit, 1.5 % each by trusts http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/12_05_lng.pdf	2.8 Bcf/d(d)	Approved (12-05-LNG)	Under DOE Review (12-05-LNG)
Sabine Pass Liquefaction, LLC	Domestic	yes: CQP Cheniere Energy Partners L.P	Sabine Pass Liquefaction is a subsidiary of Cheniere Energy Partners L.P http://www.chenierenergypartners.com/liquefaction_project/liquefaction_project.shtml	2.2 billion cubic feet per day (Bcf/d) (d)	Approved (10-85-LNG)	#N/A
Cheniere Marketing, LLC	Domestic	yes: LNG Cheniere Energy Inc.	Cheniere Marketing is a subsidiary of Cheniere Energy Inc. http://www.cheniere.com/corporate/about_us.shtml	2.1 Bcf/d(d)	Approved (12-99-LNG)	Under DOE Review (12-97-LNG)

Table A-1: Source information for Figure 3 (Continued)

Company	Status	Publicly traded?	Source	Quantity	FTA Applications (Docket Number)	Non-FTA Applications (Docket Number)
Cameron LNG, LLC	Domestic	yes: SRE Sempra Energy	Cameron LNG is a Sempra affiliate http://cameron.sempralng.com/about-us.html	1.7 Bcf/d (d)	Approved (11-145-LNG)	#N/A
Gulf LNG Liquefaction Company, LLC	Domestic	yes: KMI Kinder Morgan and GE General Electric (GE Energy Financial Services, a unit of GE)	KMI owns 50 pct stake in Gulf LNG Holdings http://www.kindermorgan.com/business/gas_pipelines/east/LNG/gulf.cfm. GE Energy Financial Services, directly and indirectly, controls its 50 percent stake in Gulf LNG http://www.geenergyfinancialservices.com/transactions/transactions.asp?transaction=transactions_archoldings.asp	1.5 Bcf/d(d)	Approved (12-47-LNG)	Under DOE Review (12-101-LNG)
Excelerate Liquefaction Solutions I, LLC	Foreign / Domestic	Foreign: stock RWE.DE domestic: privately held	Owned by Excelerate Liquefaction Solutions, source: http://www.gpo.gov/fdsys/pkg/FR-2012-12-06/html/2012-29475.htm . Those are owned by Excelerate Energy, LLC (same source). THAT is owned 50% by RWE Supply & Tradding and 50% by Mr. George B. Kaiser (an individual). George Kaiser is the American $10B George Kaiser: http://en.wikipedia.org/wiki/George_Kaiser and http://excelerateenergy.com/about-us	1.38 Bcf/d(d)	Approved (12-61-LNG)	Under DOE Review (12-146-LNG)
LNG Development Company, LLC (d/b/a Oregon LNG)	Domestic	privately held	Owned by Oregon LNG source: http://www.gpo.gov/fdsys/pkg/FR-2012-12-06/html/2012-29475.htm	1.25 Bcf/d(d)	Approved (12-48-LNG)	Under DOE Review (12-77-LNG)
Dominion Cove Point LNG, LP	Domestic	yes: D Dominion	source: https://www.dom.com/business/gas-transmission/cove-point/index.jsp	1.0 Bcf/d (d)	Approved (11-115-LNG)	#N/A
Southern LNG Company, L.L.C.	Domestic	yes: KMI Kinder Morgan	KMI owns El Paso Pipeline Partners source: http://investor.eppipelinepartners.com/phoenix.zhtml?c=215819&p=irol-newsArticle&id=1624861 . El Paso Pipeline Partners owns El Paso Pipeline Partners Operating Company source: http://investing.businessweek.com/research/stocks/private/snapshot.asp?privcapId=46603039 . El Paso Pipeline Partners Operating Company owns Southern LNG page 2 of http://www.ferc.gov/whats-new/comm-meet/2012/051712/C-2.pdf	0.5 Bcf/d(d)	Approved (12-54-LNG)	Under DOE Review (12-100-LNG)

Table A-1: Source information for Figure 3 (Continued)

Company	Status	Publicly traded?	Source	Quantity	FTA Applications (Docket Number)	Non-FTA Applications (Docket Number)
Waller LNG Services, LLC	Domestic	privately held	Wholly owned by Waller Marine: http://www.marinelog.com/index.php?option=com_content&view=article&id=3196:waller-marine-to-develop-small-scale-lng-terminals&catid=1:latest-news . Waller Marine private: http://www.linkedin.com/company/waller-marine-inc.	0.16 Bcf/d	Approved (12-152-LNG)	n/a
SB Power Solutions Inc.	Domestic	yes: SEB Seaboard	p. 2 of http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2012/ord3105.pdf	0.07 Bcf/d	Approved (12-50-LNG)	#N/A
Carib Energy (USA) LLC	Domestic	privately held	http://companies.findthecompany.com/l/21346146/Carib-Energy-Usa-Llc-in-Coral-Springs-FL	0.03 Bcf/d: FTA 0.01 Bcf/d: non-FTA (f)	Approved (11-71-LNG)	#N/A

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February 25, 2013

U.S. Department of Energy (FE–34)
Office of Natural Gas Regulatory Activities
Office of Fossil Energy
Forrestal Building, Room 3E-042
Independence Ave SW, Washington, DC 20585
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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,

[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

[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

[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:

[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

Nathan Matthews
Ellen Medlin
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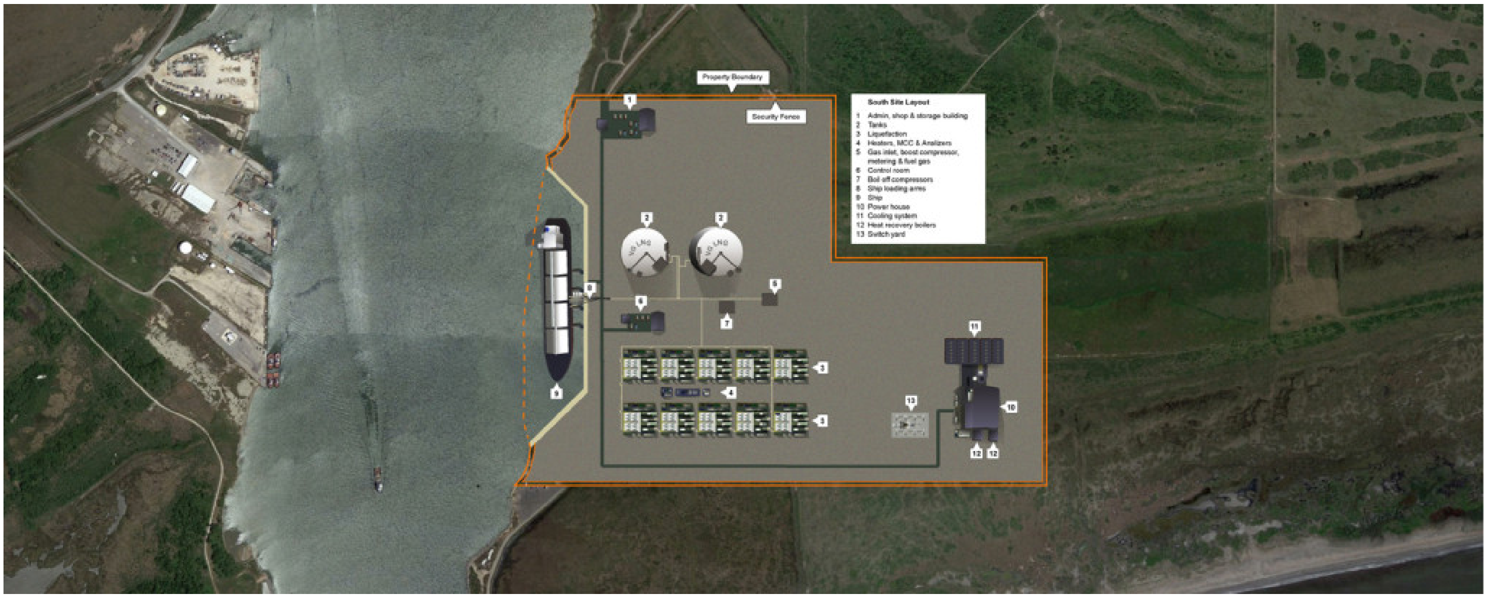
Venture Global LNG



Conceptual Site Layout

Venture Global LNG is developing a liquefied natural gas (LNG) export facility on a 109 acre site in Cameron, Louisiana, south of Lake Charles, Louisiana. The project will be developed in two phases, with an initial export capacity of 5 MTPA.

Venture Global LNG intends to be a long term, low cost producer of LNG by utilizing highly efficient and low cost, modular, mid-scale LNG liquefaction technology. Project development is supported by a team of world class LNG vendors, international and local counsel, nationally recognized environmental and energy industry consultants and global financial advisors.

Our site is ideally located directly adjacent to the Calcasieu Ship Channel, a shipping lane maintained year round by the US Army Corps of Engineers. The site has over 2,000 feet of Ship Channel frontage, and is very close to the Gulf of Mexico. Our site is within miles of several major interstate and intrastate pipelines and is roughly in the middle of one of the most robust and liquid trading areas for pipeline quality natural gas in the country. Our location assures that our customers, international LNG off-takers, may obtain access to low cost natural gas from North American reserves, both on-shore and off-shore, conventional and unconventional.

The site is secured under option and lease agreements for up to a 70-year term. We are not aware of any adverse environmental or subsurface conditions for site development and permitting. We currently expect a smooth, orderly process with FERC's pre-filing and filing procedures; including USDOT (including MARAD), USCG, USACE and LA state agencies.

Venture Global LNG's internationally recognized equipment, procurement and construction (EPC) vendor will engineer, design, construct, deliver and test modular LNG trains utilizing single mixed refrigerant cooling systems. We will be installing a moon pool and berthing terminal at our site, accommodating vessels with an LNG carrying capacity up to up to 180,000 m3. We plan to install two full containment LNG storage units for up to 24 days of production, with a capacity of 165,000 m3 each.

On September 27, 2013, the USDOE granted our FTA export license for 5 MTPA. Our non-FTA application is pending.

Venture Global LNG anticipates commencement of commercial operations and first LNG deliveries in the summer of 2018.

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.

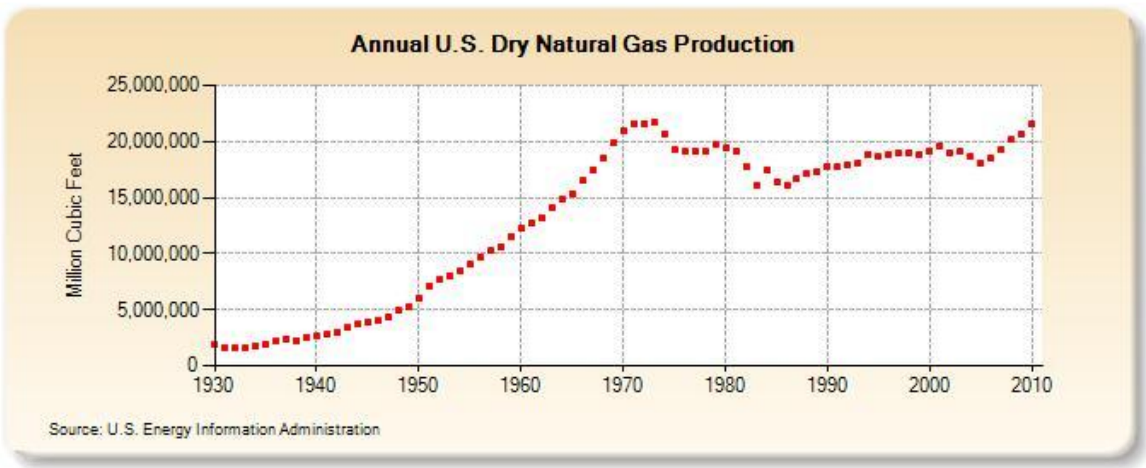


Figure 1: US Dry Natural Gas Production 1930-2010

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?"

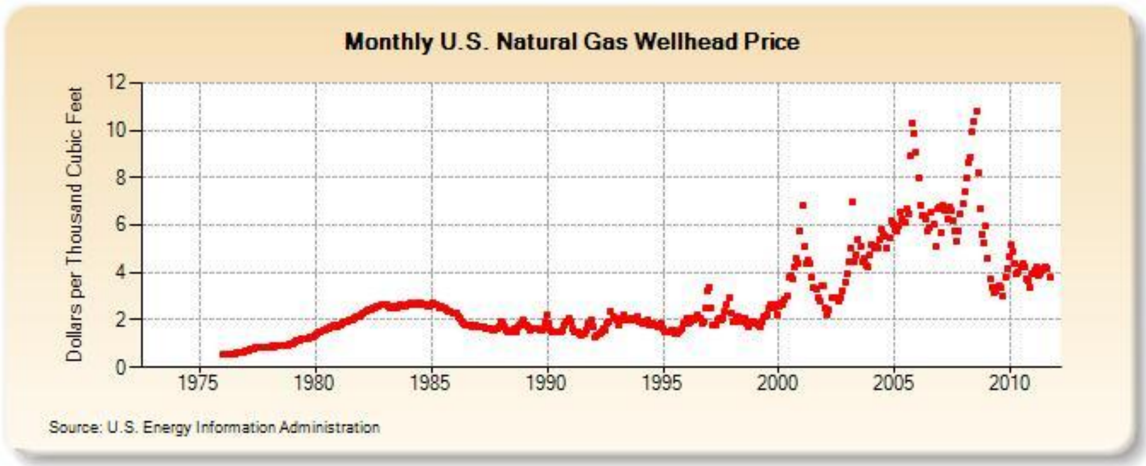


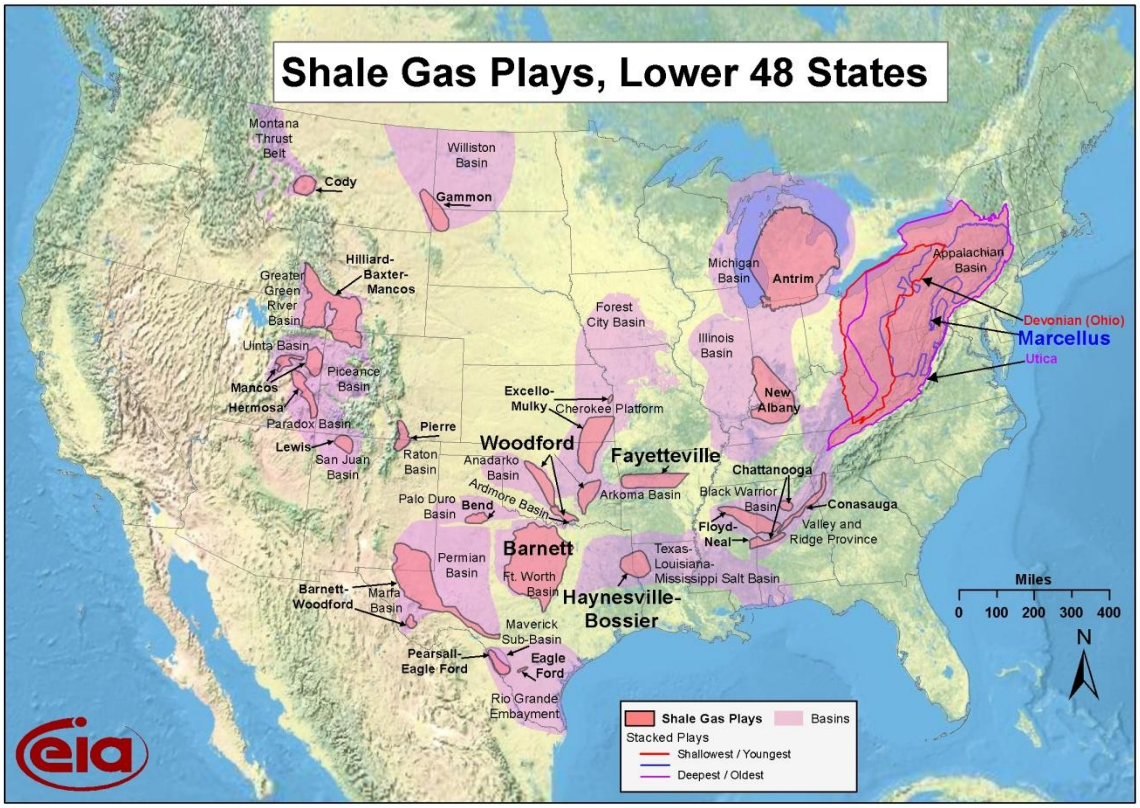
Figure 2: Monthly Natural Gas Wellhead Prices 1975-2010

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.

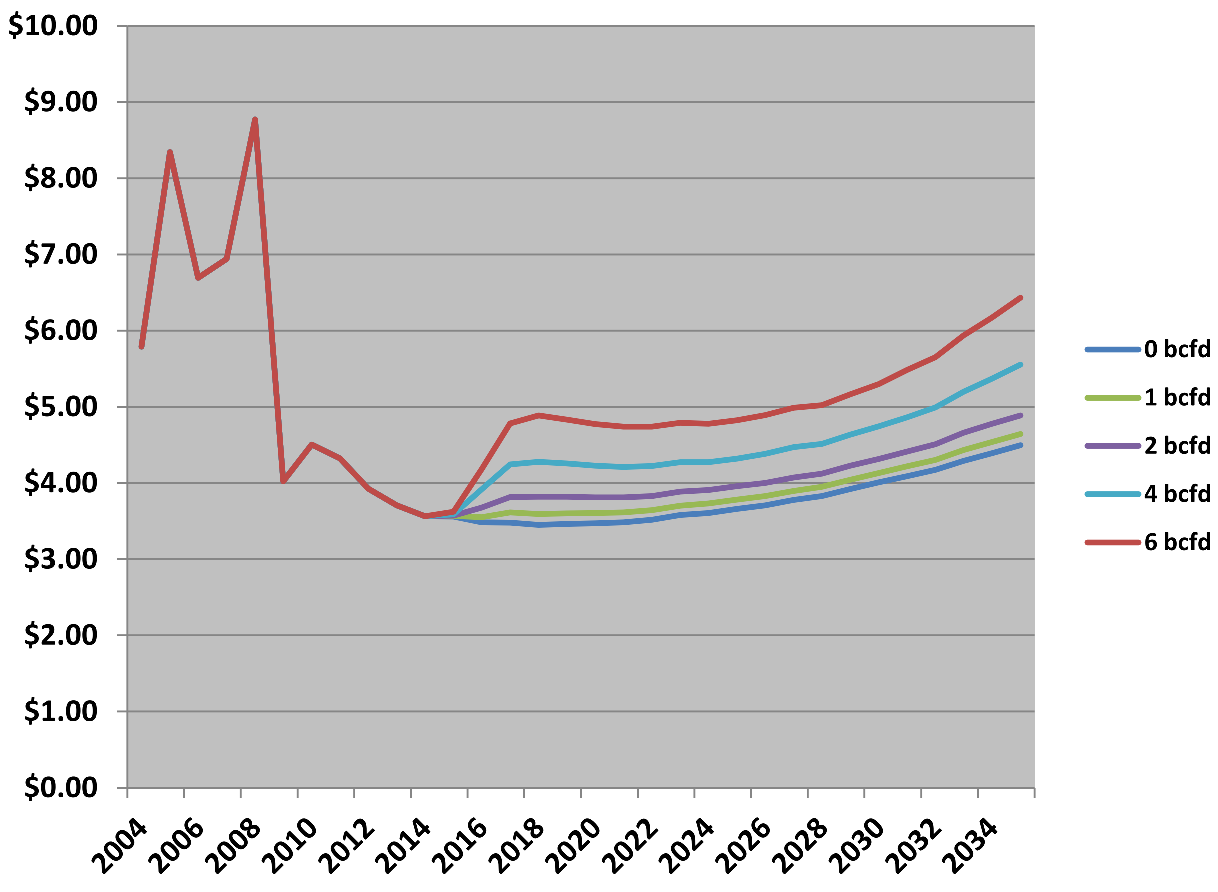


Figure 4: Annual Average Henry Hub Gas Price Forecast: 0, 1, 2, 4, and 6 bcf/day exports

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.

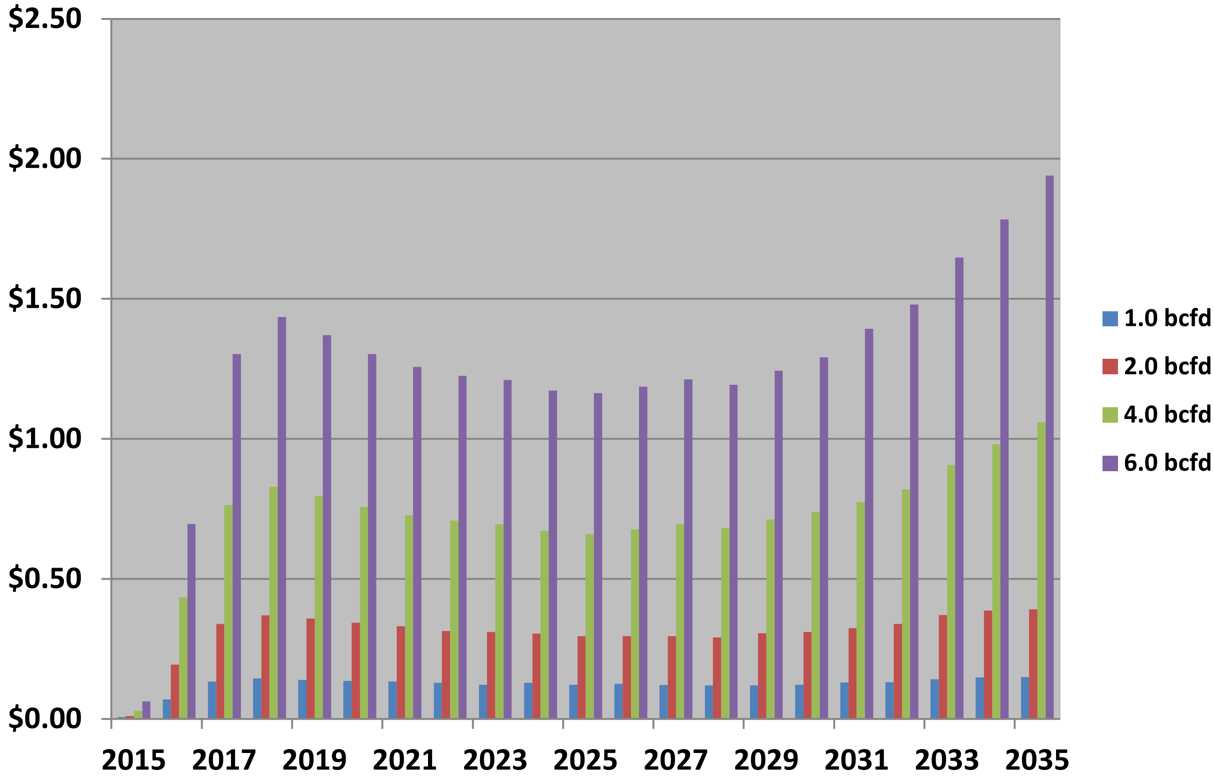


Figure 5: Price Impact at Henry Hub Due to Various Levels of Gulf Coast LNG Exports

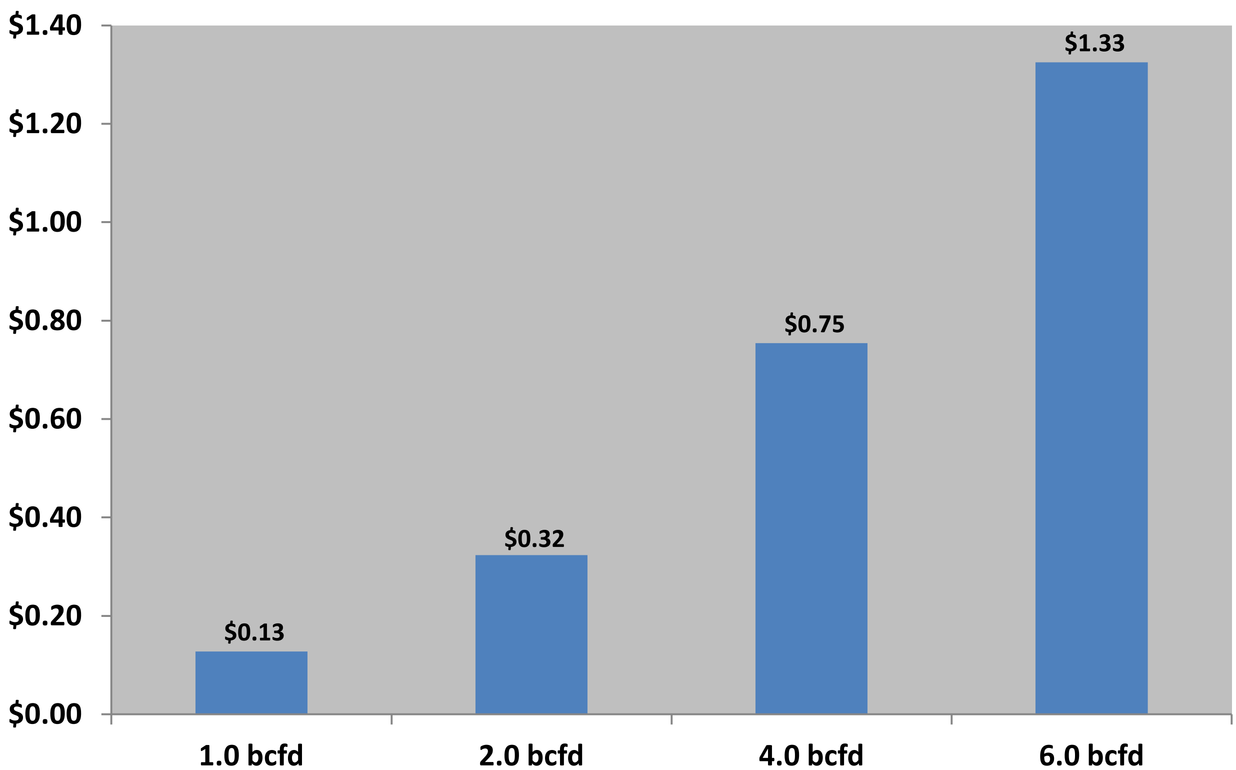


Figure 6: Average Price Impact at Henry Hub 2016-2035 of Different Gulf LNG Export Levels

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.

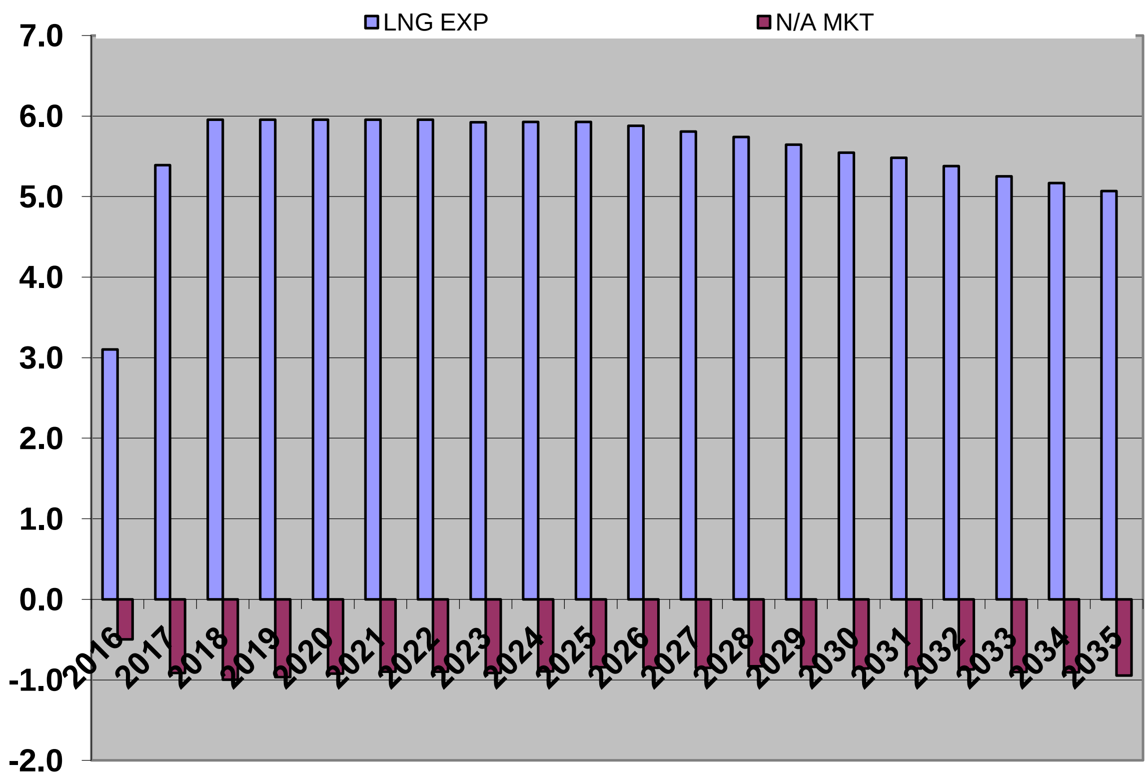


Figure 7: Impact of LNG Exports on Deliveries to the North American Market

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.

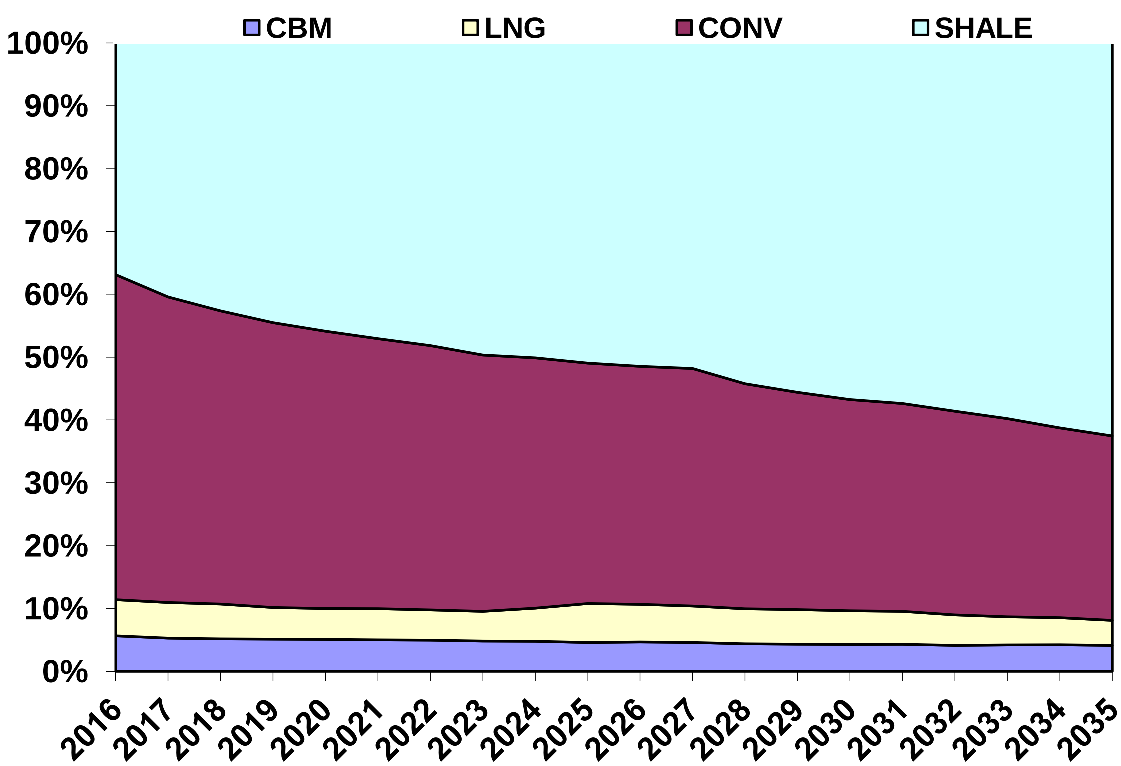


Figure 8: Share of New Supply Required in 6 bcf/day LNG Exports Scenario

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.

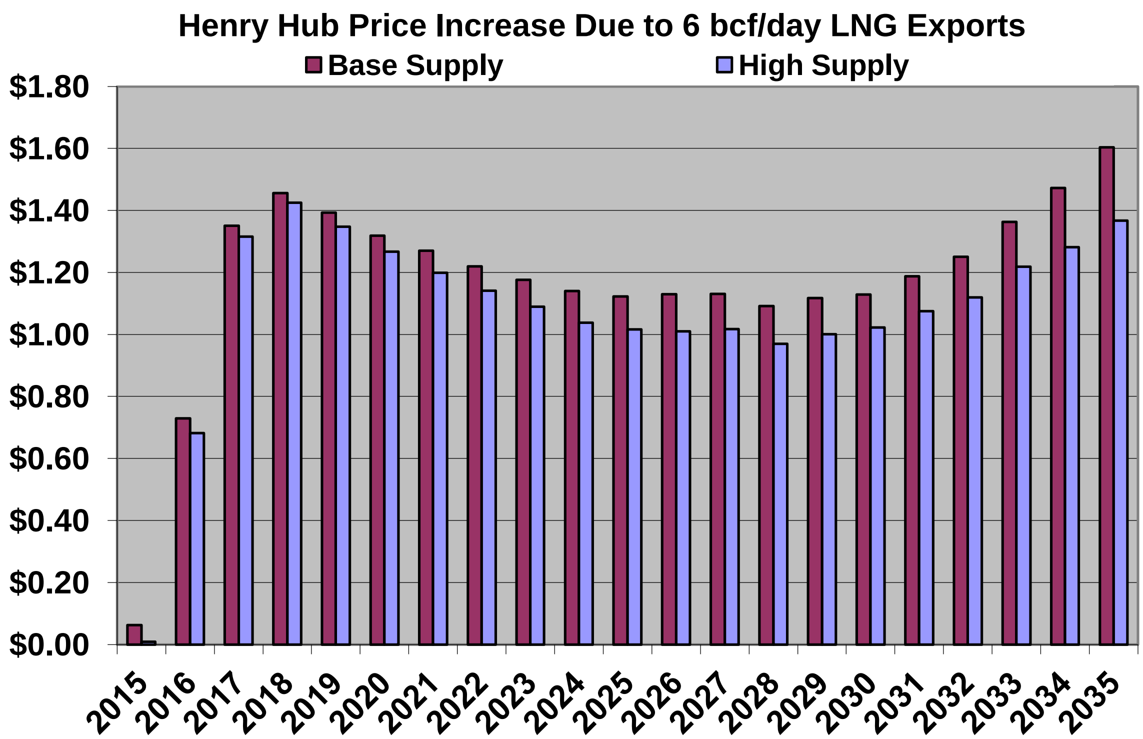


Figure 9: Sensitivity of Henry Hub Price Effect to Supply Capacity Growth

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 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.

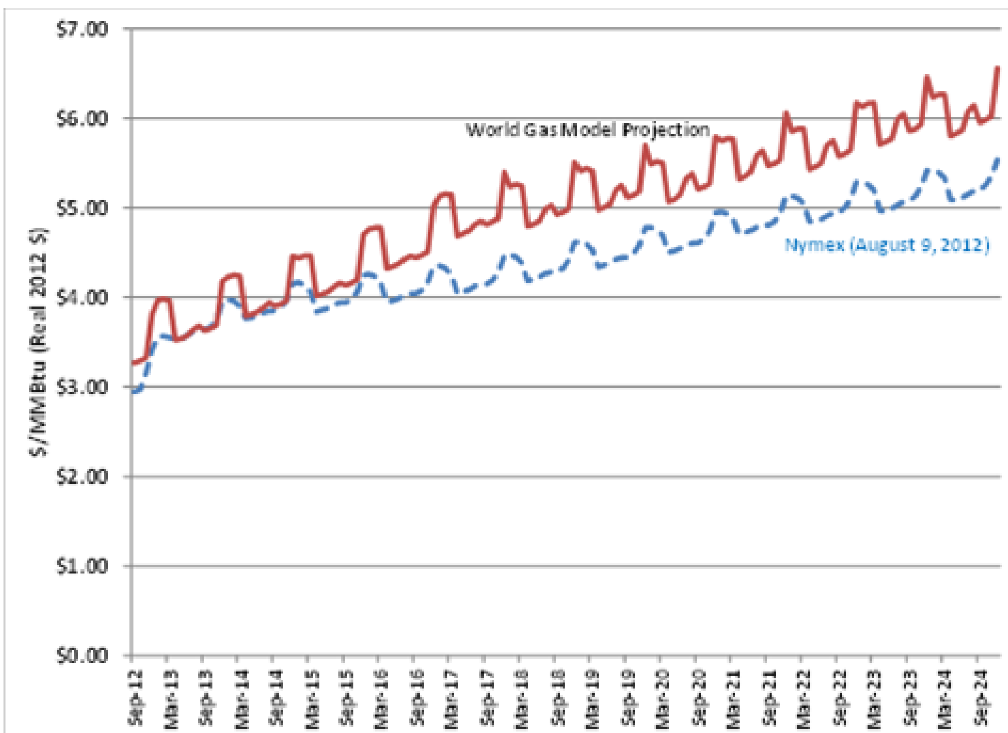
According to our projections, 12 Bcfd of LNG exports are projected to increase the average U.S. citygate gas price by 4.3% and Henry Hub price by 7.7% on average over a twenty year period (2018-37). This indicates that the projected level of exports is not likely to induce scarcity on domestic markets. 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.

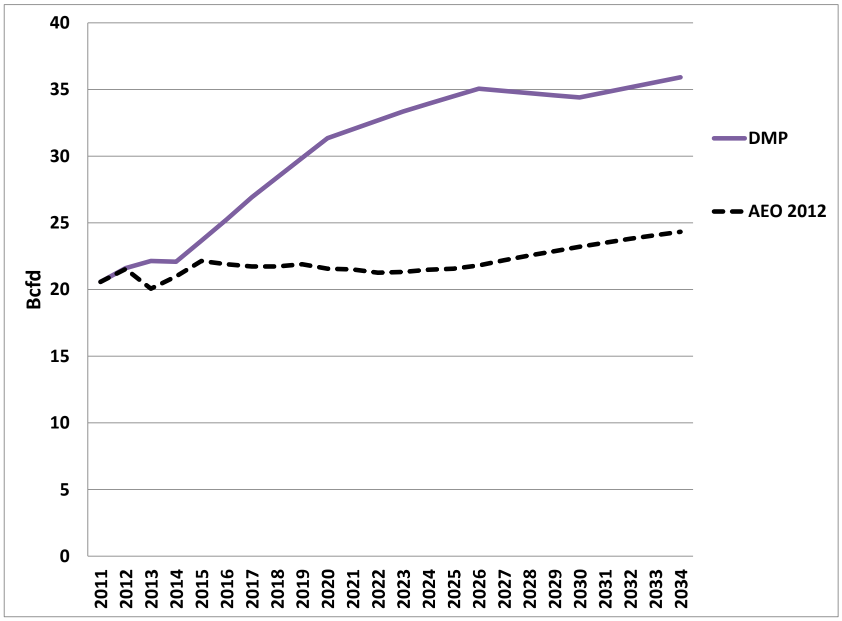
One possible reason why our price projection in the longer term is higher than market expectation, as reflected by the Nymex futures prices, is because of our projected rapid increase in gas demand for power generation. Based on our electricity model projections, we forecast natural gas consumption for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

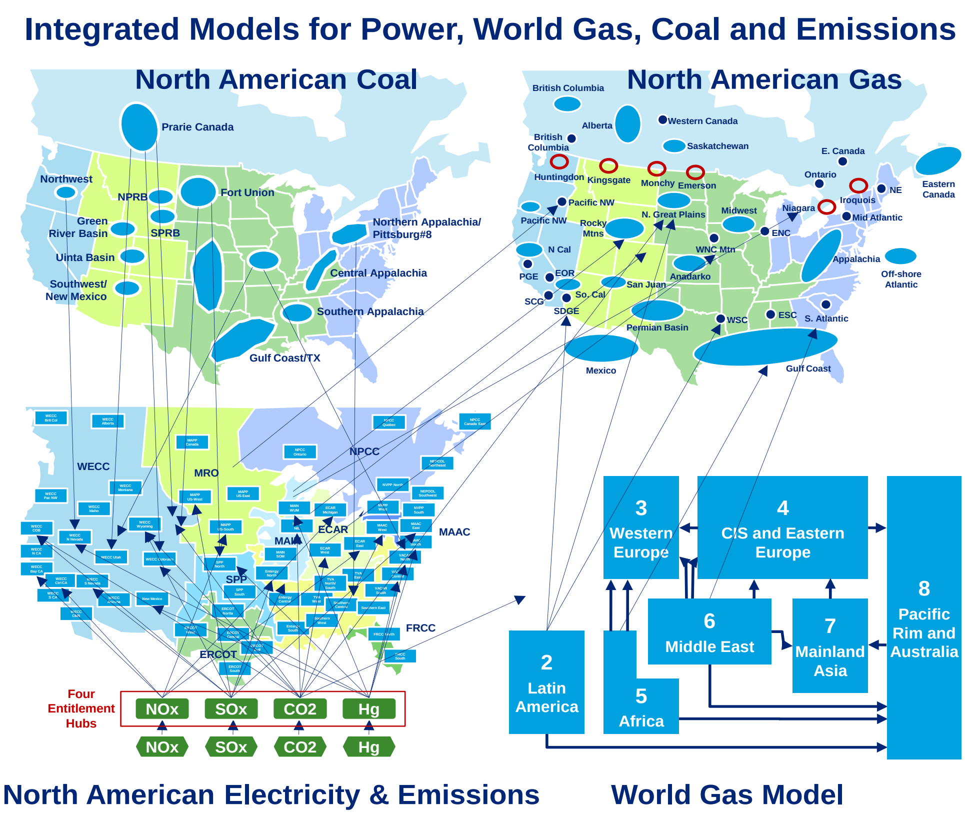
[3] Approximately the average consumer price index over the past 5 years according to the Bureau of Labor Statistics.

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.

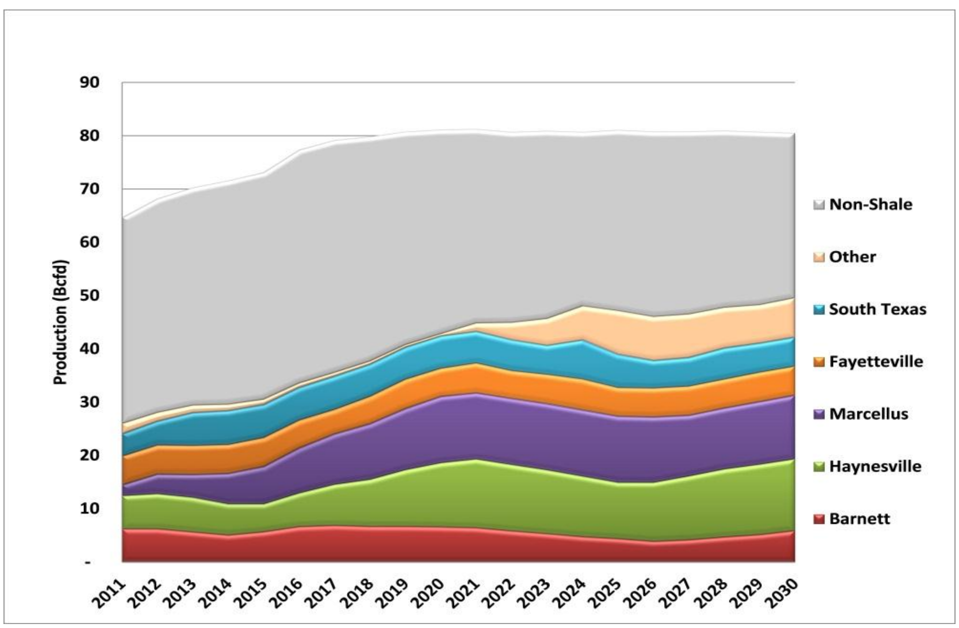
Buffering the price impact of LNG exports is the large domestic resource base, particularly shale gas which we project to be an increasingly important component of domestic supply. As shown in Figure 6, the Reference Case projects shale gas production, particularly in the Marcellus Shale in Appalachia 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)

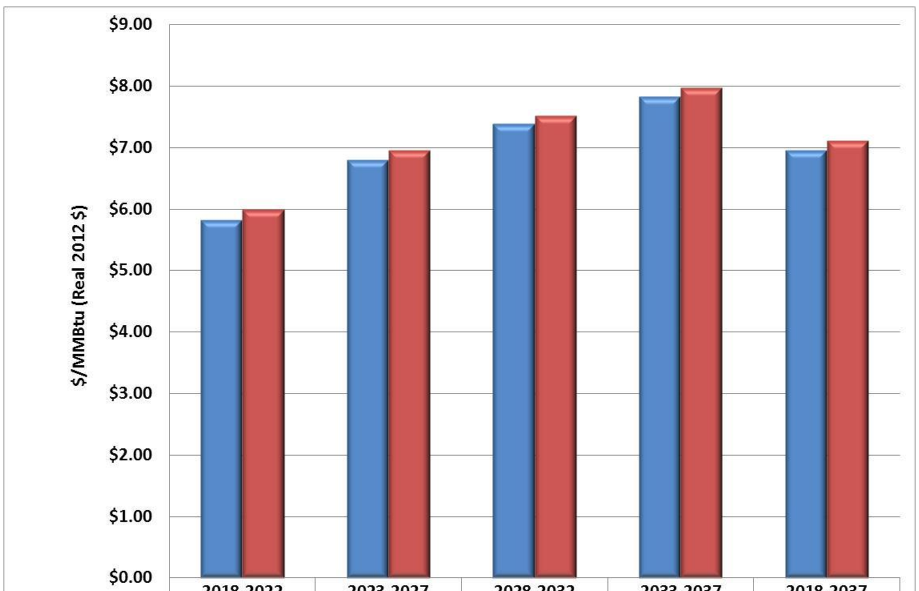
Export Case	Average US Citygate	Henry Hub	New York
1.33 Bcfd	$ 0.03	$ 0.03	$ 0.02
3 Bcfd	$ 0.07	$ 0.11	$ 0.06
6 Bcfd	$ 0.15	$ 0.26	$ 0.14
9 Bcfd	$ 0.22	$ 0.36	$ 0.23
12 Bcfd	$ 0.30	$ 0.50	$ 0.29

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.

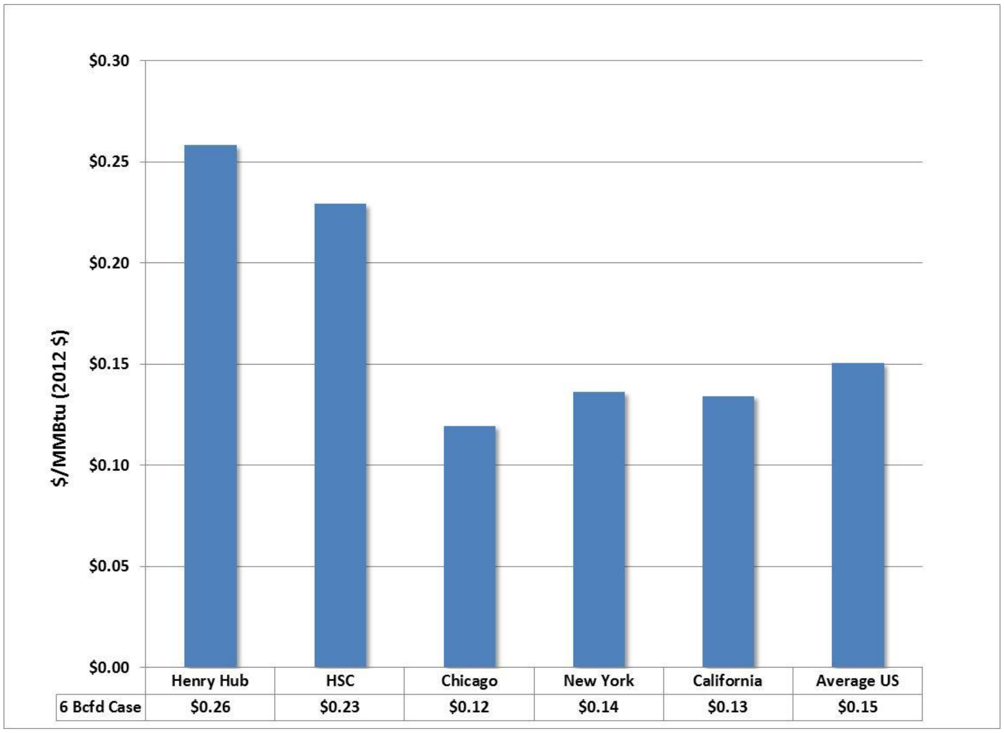
Similarly, Figures 8 and 9 corresponding to the other export cases (1.33, 3.0, 9.0 and 12.0 Bcfd) are shown in the Appendix.

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)



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.

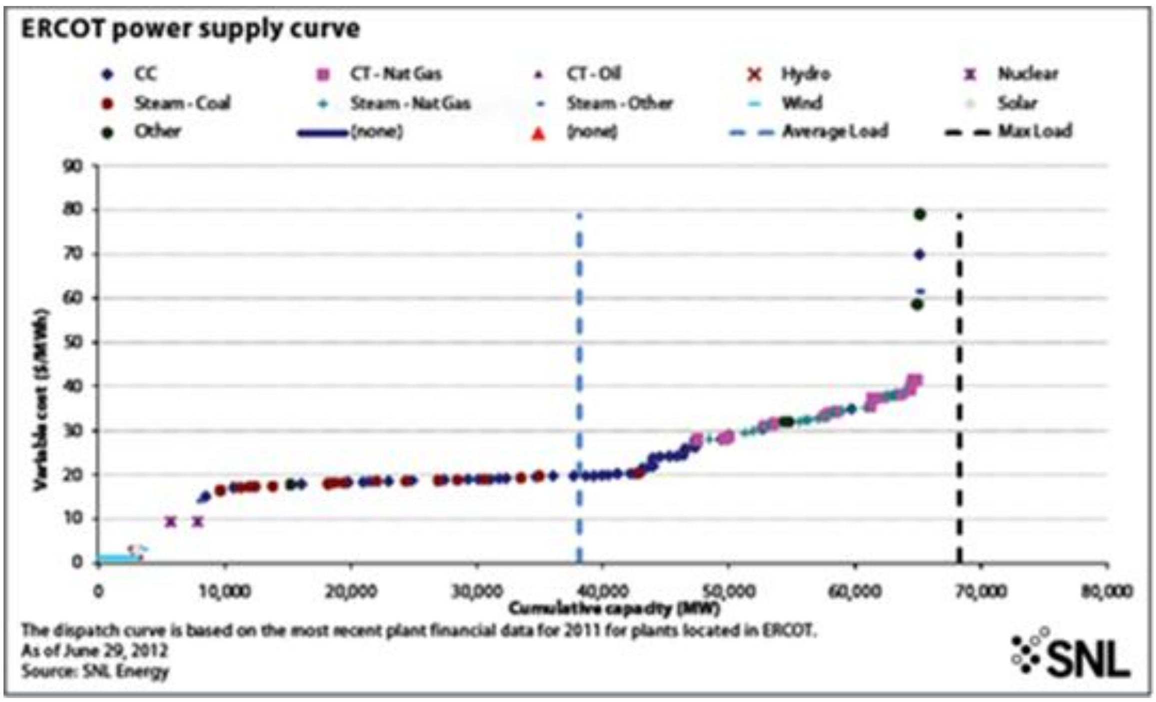
A similar comparison for electricity shows that the projected average (2018-2037) electricity prices increase by 0.8% in ERCOT (the Electric Reliability Council of Texas), under the 6 Bcfd export case. The impact on electricity prices is much less than the 4.0% Henry Hub gas price impact. For power markets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

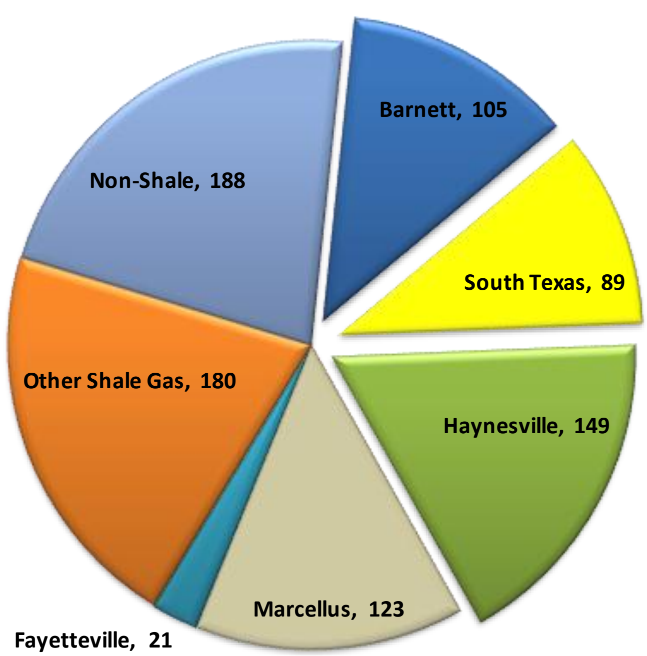


Incremental production impact in Texas from Lavaca Bay export

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)

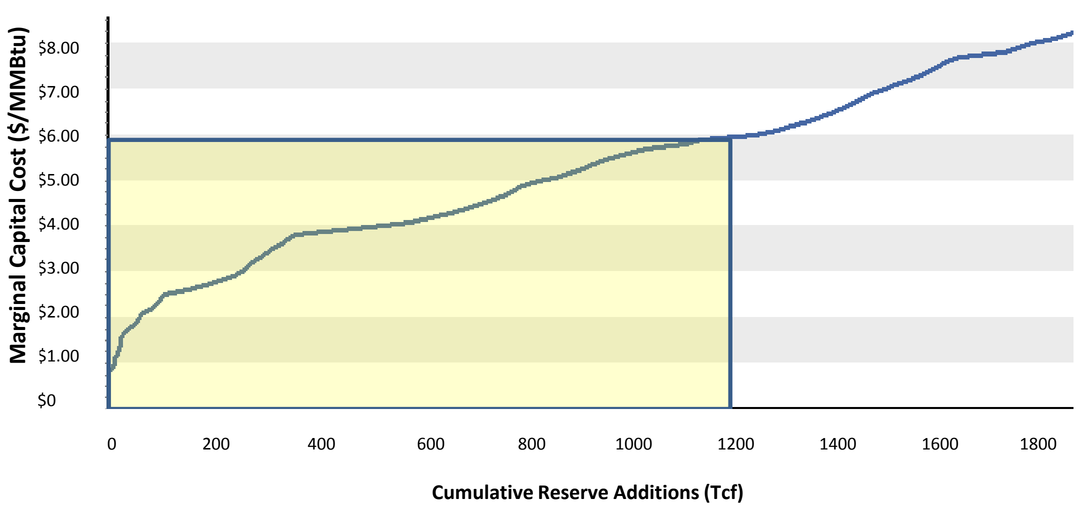


Large domestic supply buffers impact

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.

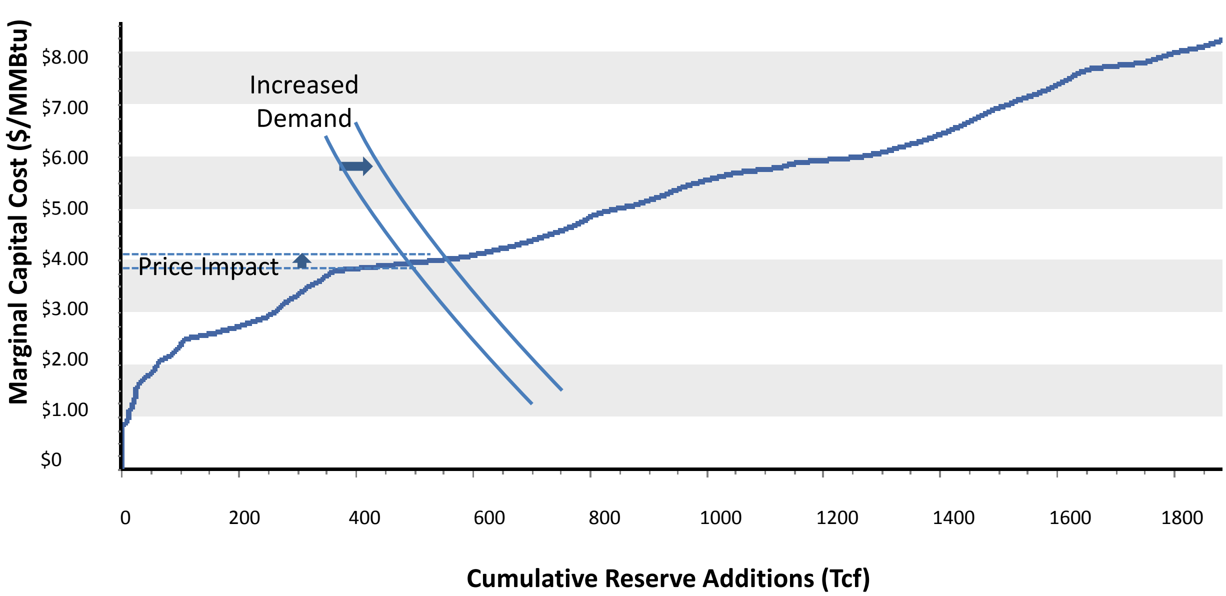
Figure 12: Aggregate U.S. natural gas supply curve (2012 $)



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)

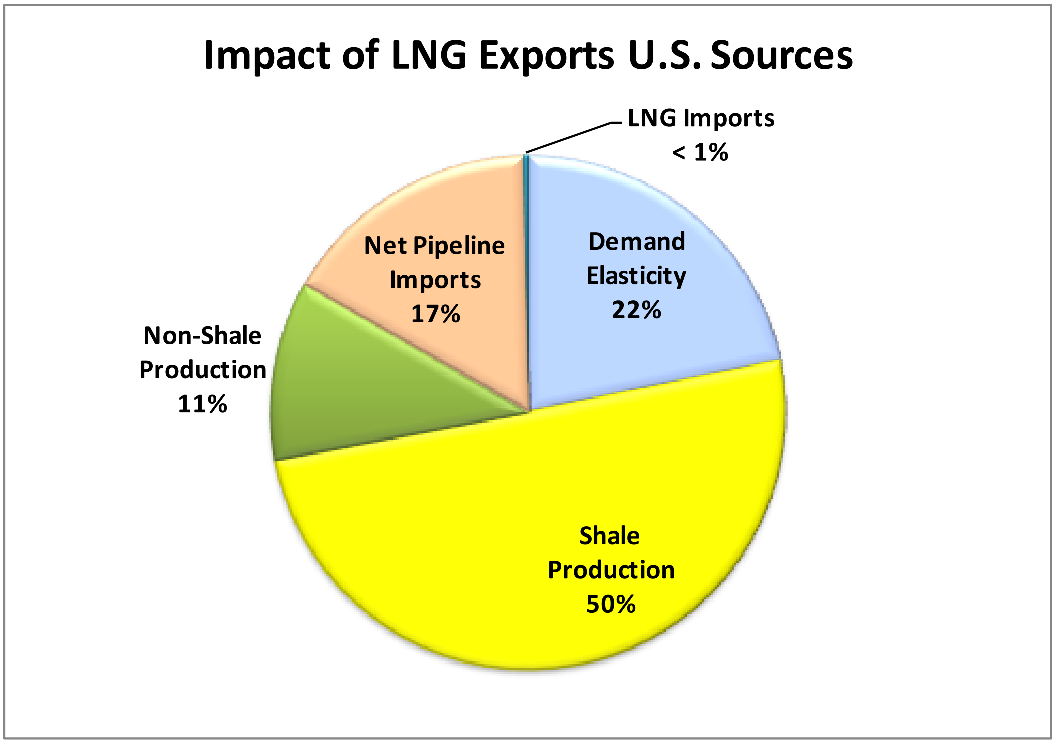


Finally, there is an insignificant increment, less than 1%, coming from LNG imports. Having both LNG imports and exports is not necessarily contradictory since there is variation in price by terminal (e.g., Everett terminal near Boston will likely see higher prices than will Gulf terminals) and by time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

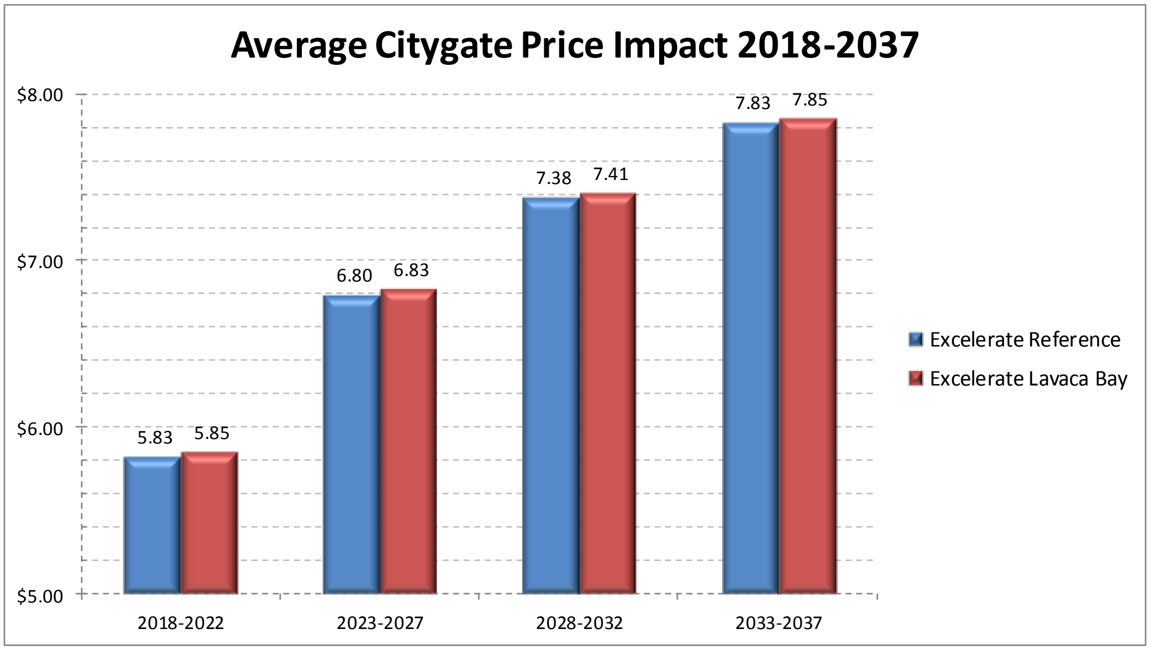
The importance of timing is evident in EIA's projections. The projected price impact is highly dependent on how quickly export volumes are assumed to ramp up. Furthermore, in all cases, the impacts are the greatest in the early years of exports. The impacts dissipate over time as supplies are assumed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

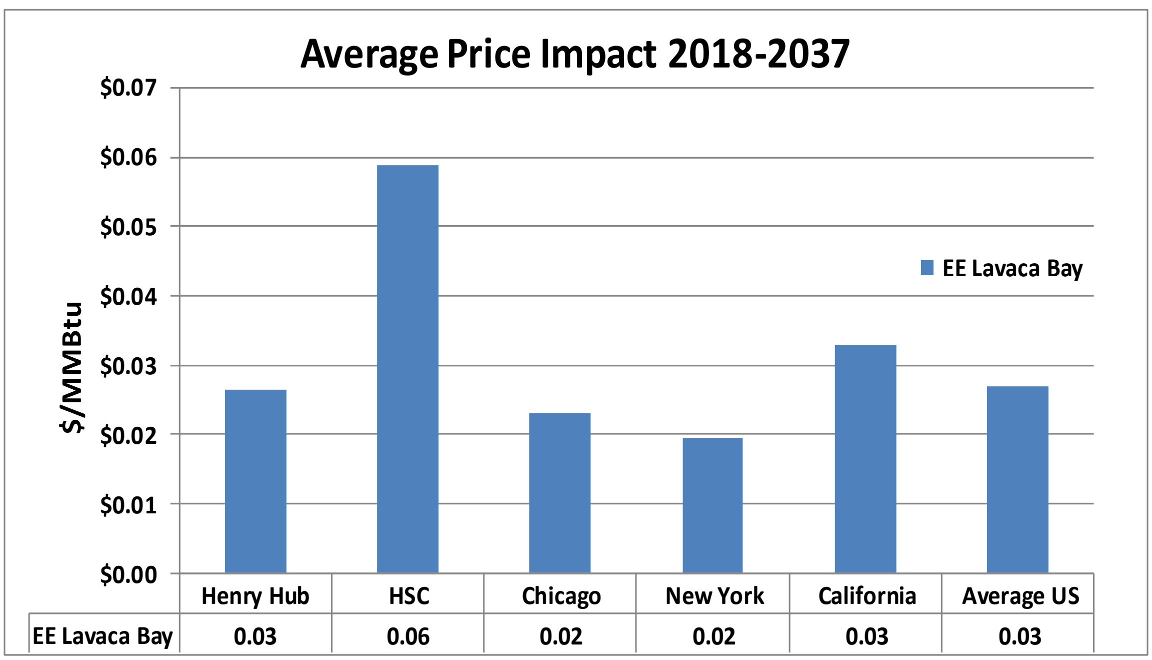
Natural gas producers are highly sophisticated companies with analytical teams monitoring and forecasting market conditions. Producers, well aware of the potential LNG export projects, are looking forward to the opportunity to supply these projects.

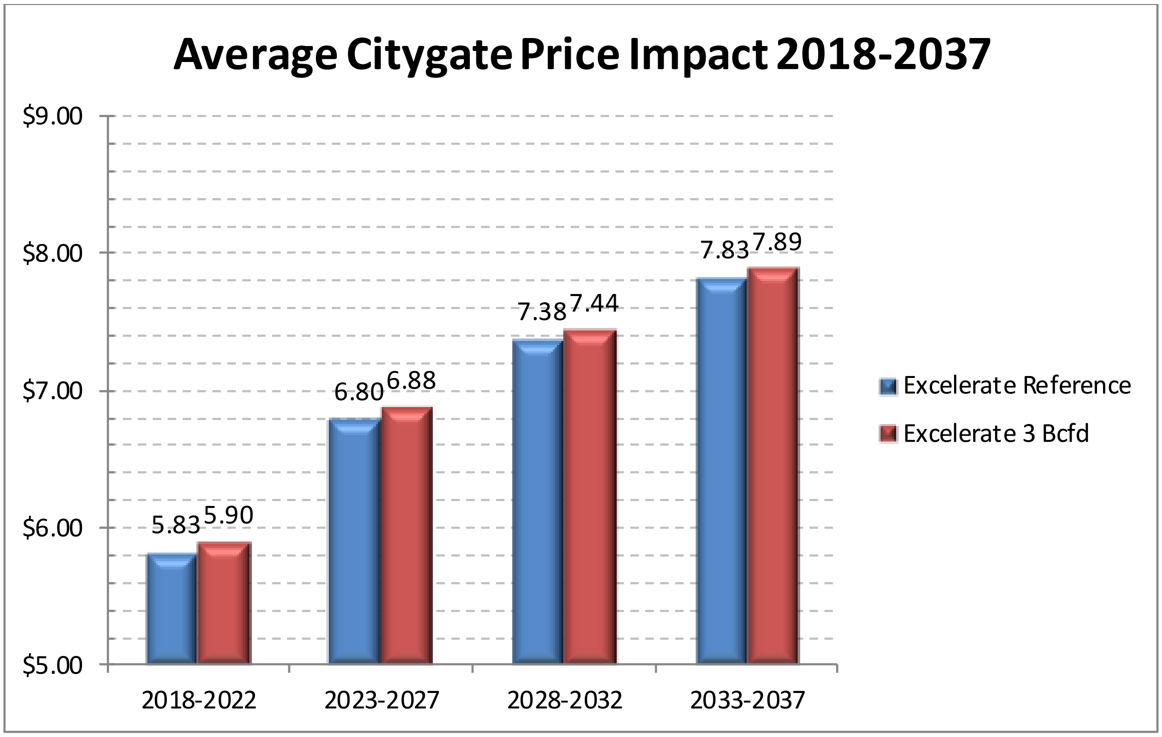
[5] Linear programming ("LP") is a mathematical technique for solving a global objective function subject to a series of linear constraints

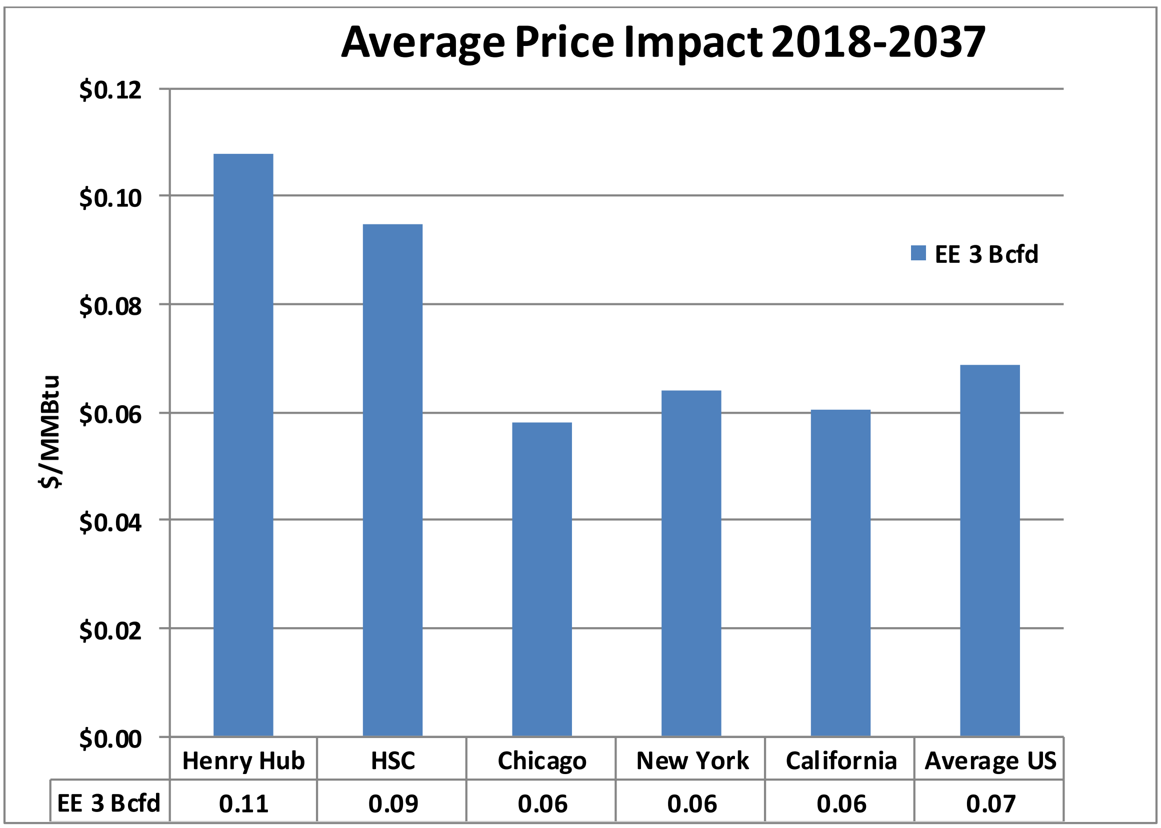
[6] "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas," Brookings Institution (2012).

Appendix A: Price Impact Charts for other Export Cases






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
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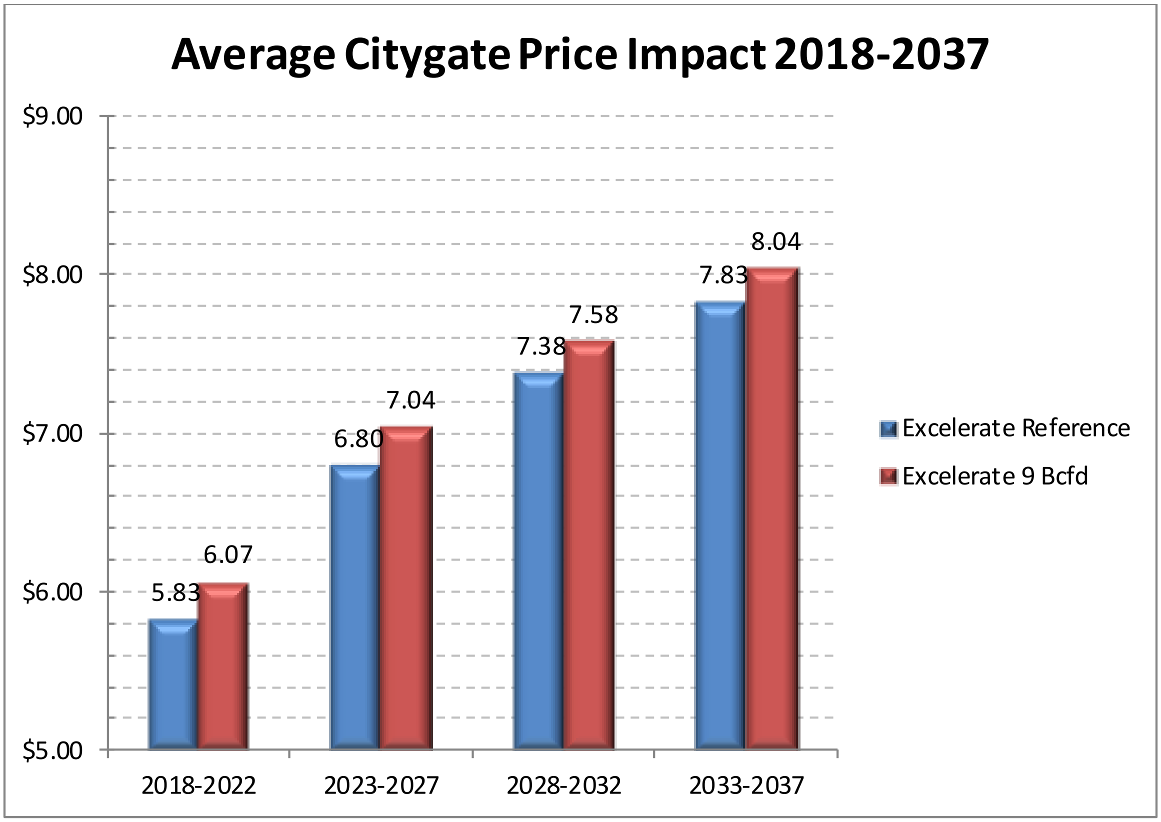
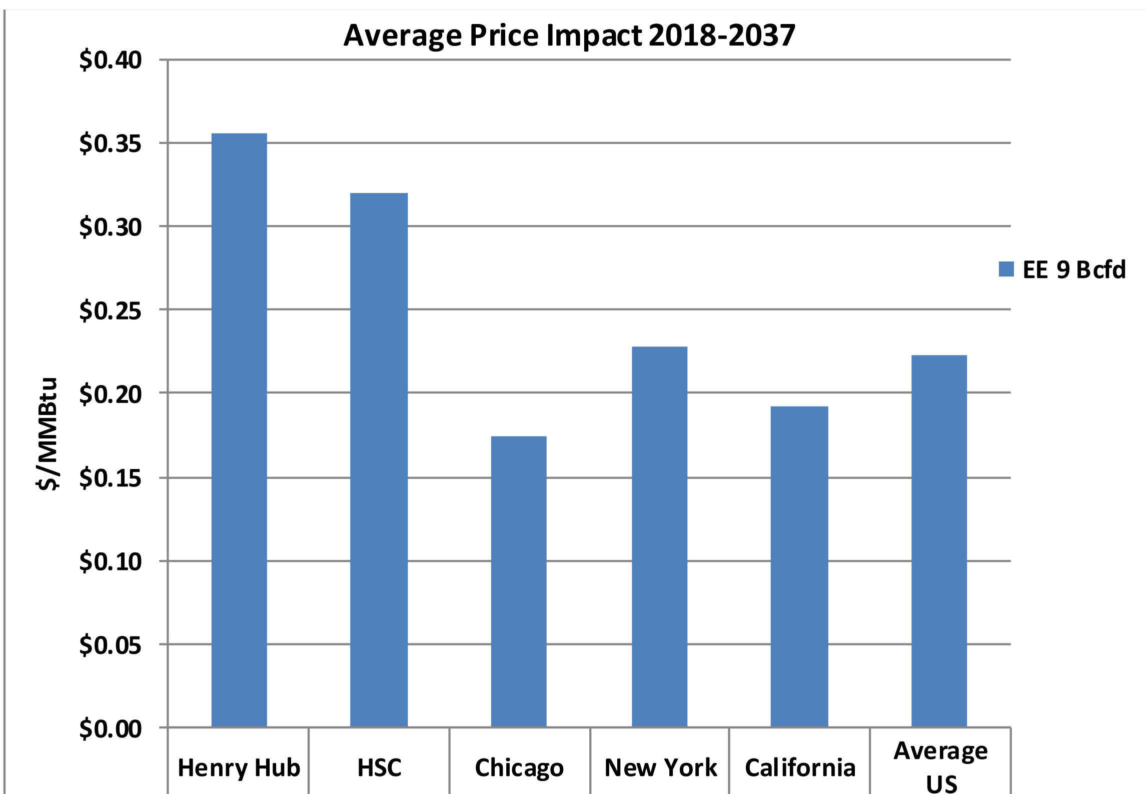
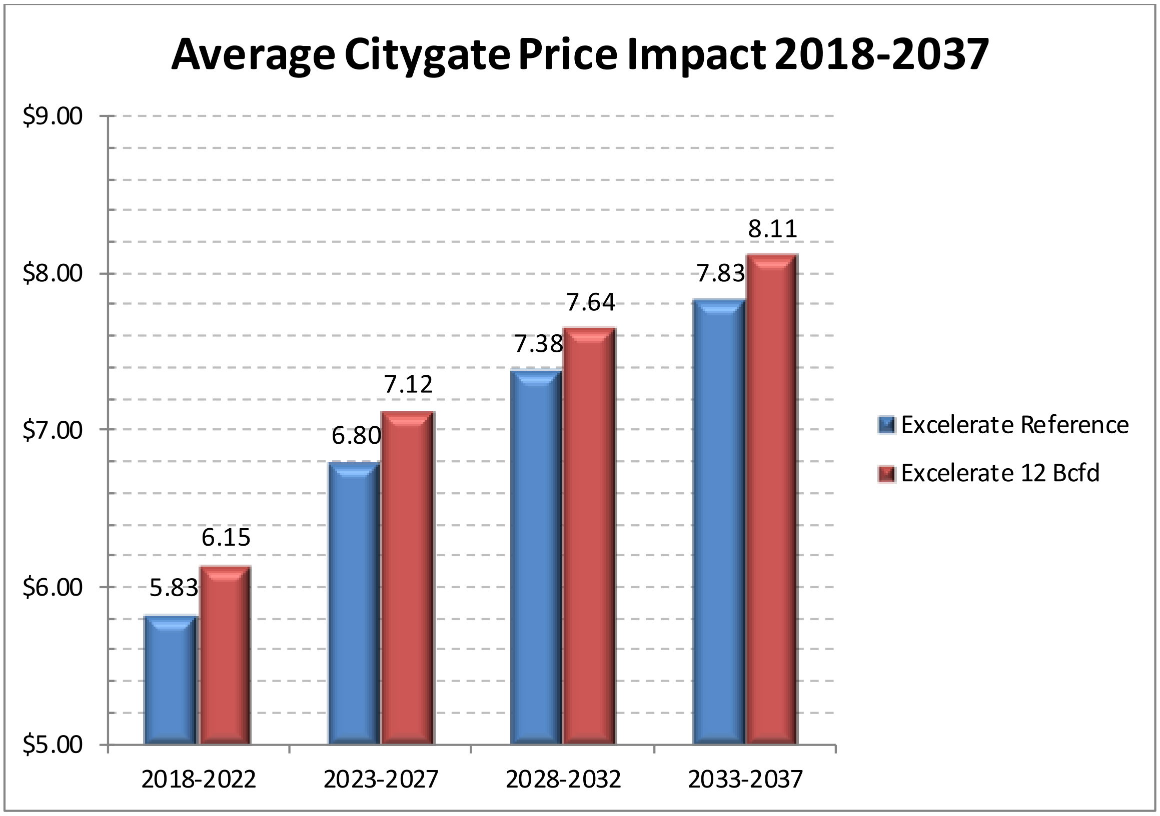
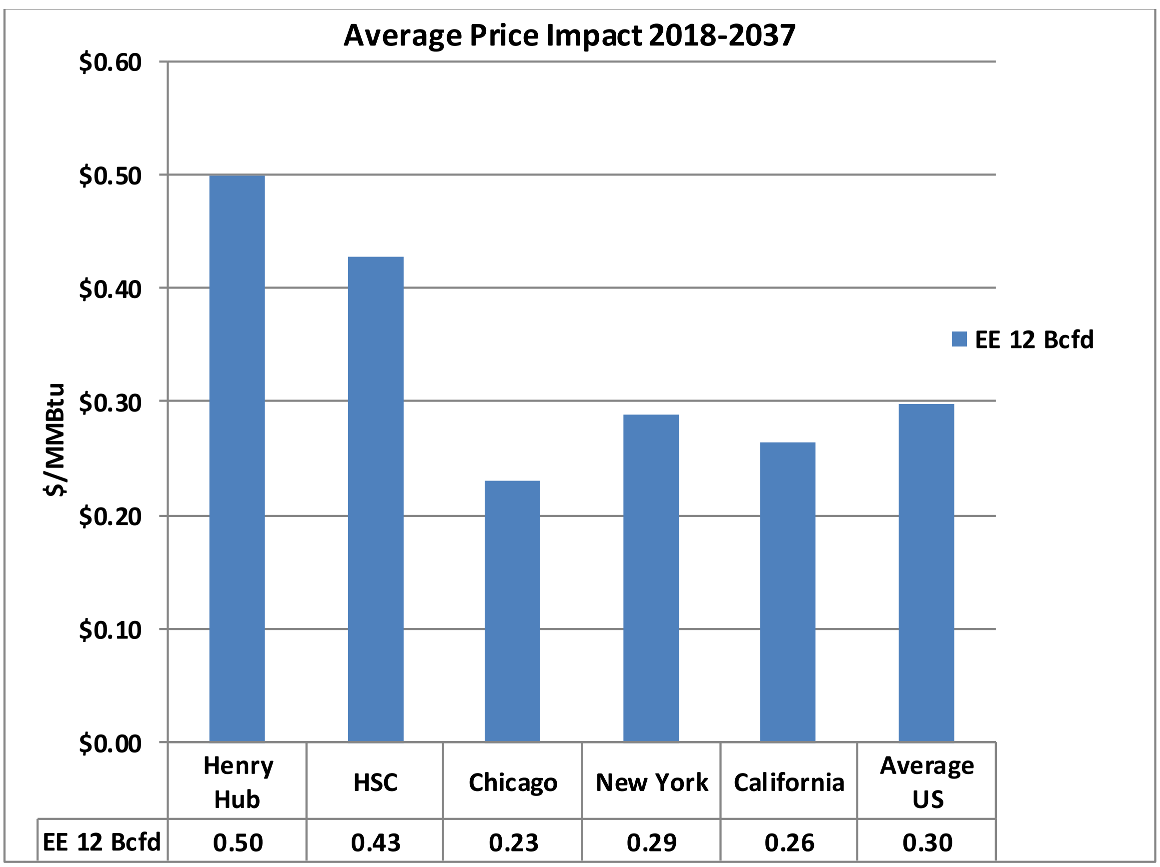




	Henry Hub	HSC	Chicago	New York	California	Average US
EE 9 Bcfd	0.36	0.32	0.17	0.23	0.19	0.22


Average Citygate Price Impact 2018-2037
$9.00
$8.00
$7.00
$6.00
$5.00
5.83
6.15
6.80
7.12
7.38
7.64
7.83
8.11
2018-2022
2023-2027
2028-2032
2033-2037
Excelerate Reference
Excelerate 12 Bcfd


Average Price Impact 2018-2037
$/MMBtu
$0.60
$0.50
$0.40
$0.30
$0.20
$0.10
$0.00
EE 12 Bcfd
Henry Hub
HSC
Chicago
New York
California
Average US
EE 12 Bcfd
0.50
0.43
0.23
0.29
0.26
0.30

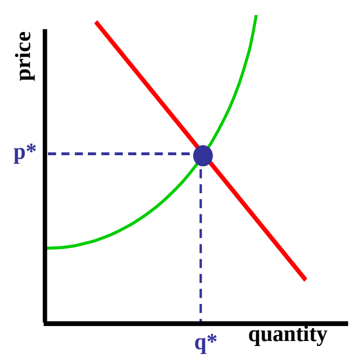
Appendix B: DMP's World Gas Model and data

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.

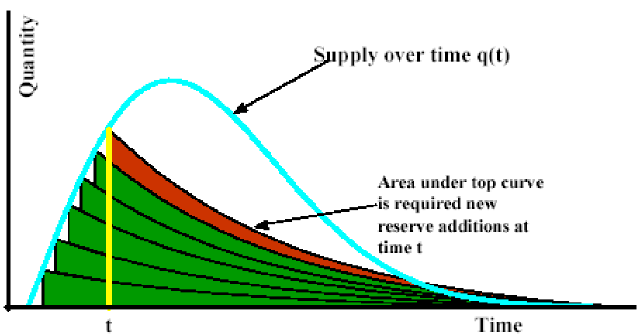
WGM simulates how regional interactions among supply, transportation, and demand interact to determine market clearing prices, flowing volumes, reserve additions, and pipeline entry and exit through 2046. The WGM divides the world into major geographic regions that are connected by marine freight. Within 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



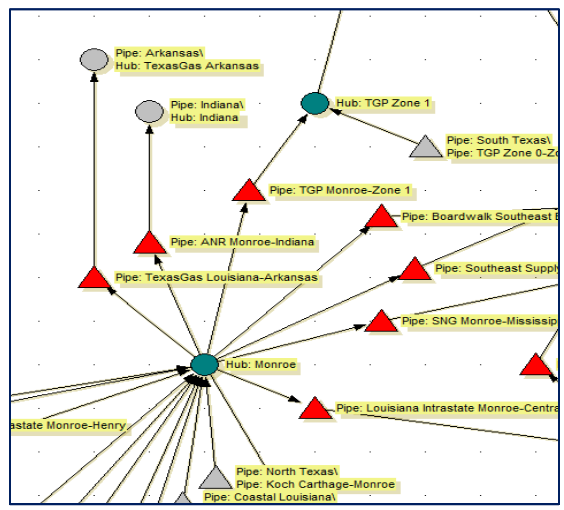
arise from the competition among these 1000 disparate, profit-seeking agents. This is the essence of microeconomic theory and competitive markets — people vying in markets for profits — and MarketBuilder rigorously approaches the problem from this perspective. In contrast, LP models postulate a single 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

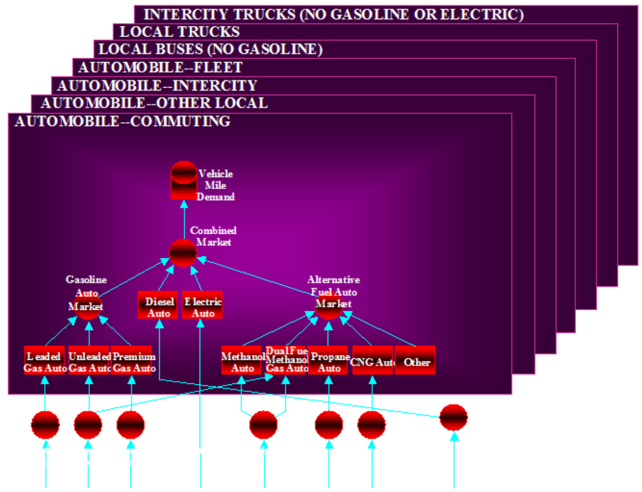


particular, we relied on USGS' world oil and gas supply data including proved reserves, conventional undiscovered resources, growth of reserves in existing fields, continuous and unconventional deposits, deep water potential, and exotic sources. Derived from detailed probabilistic analysis of the world 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.



Long Term* Applications Received by DOE/FE to Export**
Domestically Produced LNG from the Lower-48 States (as of June 11, 2014)
All Changes Since April 18, 2014 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)	Approved (10-161-LNG)
Lake Charles Exports, LLC	2.0 Bcf/d [e]*	Approved (11-59-LNG)	Approved (11-59-LNG)
Carib Energy (USA) LLC	0.03 Bcf/d: FTA 0.06 Bcf/d: non-FTA [f]	Approved (11-71-LNG)	Under DOE Review (11-141-LNG)
Dominion Cove Point LNG, LP	1.0 Bcf/d: FTA 0.77 Bcf/d: non-FTA	Approved (11-115-LNG)	Approved (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)	Approved (12-32-LNG)
Cameron LNG, LLC	1.7 Bcf/d [d]	Approved (11-145-LNG)	Approved (11-162-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC [h]	1.4 Bcf/d: FTA 0.4 Bcf/d: non-FTA [k]	Approved (12-06-LNG)	Approved (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: FTA 0.19 Bcf/d: non-FTA	Approved (12-152-LNG)	Under DOE Review (13-153-LNG)

Long Term* Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of June 11, 2014)**

All Changes Since April 18, 2014 Update Are In Red

Company	Quantity [a]	FTA Applications [b] (Docket Number)	Non-FTA Applications [c] (Docket Number)
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[j]	Approved (12-183-LNG)	n/a
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[d]	Approved (13-06-LNG)	Under DOE Review (13-161-LNG)
Freeport-McMoRan Energy LLC	3.22 Bcf/d**	Approved (13-26-LNG)	Under DOE Review (13-26-LNG)
Sabine Pass Liquefaction, LLC	0.28 Bcf/d[d]	Approved (13-30-LNG)	Under DOE Review (13-30-LNG)
Sabine Pass Liquefaction, LLC	0.24 Bcf/d[d]	Approved (13-42-LNG)	Under DOE Review (13-42-LNG)
Venture Global LNG, LLC	0.67 Bcf/d[d]	Approved (13-69-LNG)	Under DOE Review (13-69-LNG)
Advanced Energy Solutions, L.L.C.	0.02 Bcf/d	Approved (13-104-LNG)	n/a
Argent Marine Management, Inc.	0.003 Bcf/d	Approved (13-105-LNG)	n/a
Eos LNG LLC	1.6 Bcf/d[d]	Approved (13-115-LNG)	Under DOE Review (13-116-LNG)
Barca LNG LLC	1.6 Bcf/d[d]	Approved (13-117-LNG)	Under DOE Review (13-118-LNG)
Sabine Pass Liquefaction, LLC	0.86 Bcf/d[d]	Approved (13-121-LNG)	Under DOE Review (13-121-LNG)
Delfin LNG LLC	1.8 Bcf/d[d]	Approved (13-129-LNG)	Under DOE Review (13-147-LNG)
Magnolia LNG, LLC	0.54 Bcf/d: FTA[j] 1.08 Bcf/d: Non-FTA[j]	Approved (13-131-LNG)	Under DOE Review (13-132-LNG)
Annova LNG LLC	0.94 Bcf/d	Approved (13-140-LNG)	n/a
Texas LNG LLC	0.27 Bcf/d[d]	Approved (13-160-LNG)	Under DOE Review (13-160-LNG)
Louisiana LNG Energy LLC	0.28 Bcf/d	Pending Approval (14-19-LNG)	Under DOE Review (14-29-LNG)
Alturas LLC	0.2 Bcf/d	Pending Approval (14-55-LNG)	n/a
Strom Inc.	0.02 Bcf/d[d]	Pending Approval (14-56-LNG)	n/a
Strom Inc.	0.02 Bcf/d[d]	n/a	Under DOE Review (14-57-LNG)
Strom Inc.	0.02 Bcf/d[d]	n/a	Under DOE Review (14-58-LNG)
SCT&E LNG, LLC	0.54 Bcf/d	Pending Approval (14-72-LNG)	n/a
Total of all Applications Received		**39.31 Bcf/d(*)(**)**	**35.95 Bcf/d (*)(**)**

Long Term*** Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of June 11, 2014)

All Changes Since April 18, 2014 Update Are In Red

* 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.

*** On June 11, 2014, two companies were removed from this table, since they had short-term export (2-year) applications. These companies are Clean Energy (0.14 Bcf/d), and Air Flow North America Corp. (0.001 Bcf/d).

- **(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. Carib's requested amendment to its application on 12/12/2012, included a revised volume equivalent to 0.06 Bcf/d from 0.01 Bcf/d of natural gas.
- **(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) The Magnolia LNG Facility is limited to 1.08 Bcf/d. FTA and Non-FTA volumes are not additive.

(k) FLEX applied for a second authorization to export 1.4 Bcf/d to FTA and Non-FTA countries. DOE/FE authorized 1.4 Bcf/d to FTA countries before FLEX filed with FERC. DOE authorized 0.4 Bcf/d to Non-FTA countries, which authorizes a total volume of 1.8 Bcf/d to Non-FTA countries in the two FLEX Non-FTA orders. The FLEX application with FERC is for a total facility capacity of 1.8 Bcf/d.

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

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

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[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

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[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.

ORIGINAL

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)

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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.

From:	Darby, Joan
To:	LNGStudy
Subject:	2012 LNG Export Study
Date:	Thursday, January 24, 2013 3:20:42 PM
Attachments:	2013-01-24 Jordan Cove Energy Project LP Comments on LNG Export Study.pdf

Please find attached the comments of Jordan Cove Energy Project, L.P. on the LNG Export Study.

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January 24, 2013

By Email
LNGStudy@hq.doe.gov

Mr. John Anderson
U.S. Department of Energy (FE-34)
Office of Natural Gas Regulatory Activities
Office of Fossil Energy
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Mr. Edward Myers
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Re: 2012 LNG Export Study
and
Jordan Cove Energy Project, L.P., FE Docket No. 12-32-LNG

Dear Mr. Anderson and Mr. Myers:

The U.S. Department of Energy (DOE) issued a "Notice of availability of 2012 LNG Export Study and request for comments" (Notice) that was published in the Federal Register on December 11, 2012 (77 Fed. Reg. 73627). The Notice invited "comments regarding the LNG Export Study that will help to inform DOE in its public interest determinations of the authorizations sought in the 15 pending applications" (77 Fed. Reg. at 73629), one of which is the Application of Jordan Cove Energy Project, L.P. (Jordan Cove) pending in the above-referenced docket. In response to DOE's invitation, Jordan Cove submits the following: (1) the overall evaluation of the LNG Export Study by Navigant Consulting, Inc. (Navigant), which is set forth in the January 22, 2012 letter from Navigant to Jordan Cove attached to this letter as an appendix; and (2) comments pertinent to the LNG Export Study as it applies specifically to Jordan Cove's Application, which are also based on an analysis by Navigant and which are set forth immediately below.

Both reports comprising the LNG Export Study – the January 2012 Energy Information Administration analysis focuses on impacts on domestic energy markets and the December 2012 NERA Economic Consulting analysis focused on impacts on the U.S. economy – are devoid of regional assessments. Because the LNG Export Study analyzes LNG exports only from the U.S. Gulf Coast, it tends to overestimate price impacts of exporting LNG and it fails to identify, and consequently overlooks, economic contributions that would be made by LNG exports from an export project like Jordan Cove situated on the U.S. West Coast.

Jordan Cove will export LNG sourced from more abundant and less costly regional gas supplies that are not accessible to Gulf Coast projects, namely resources from Western Canada and the U.S. Rockies. The lower average delivered supply cost of the natural gas supplies available to Jordan Cove means that, had LNG exports from Jordan Cove's West Coast terminal been included in the LNG Export Study, the forecasted price impacts would likely have been mitigated. Stated differently, the underlying assumption of only Gulf-sourced LNG exports likely resulted in price impacts being overestimated in the LNG Export Study

As a U.S. West Coast terminal, Jordan Cove will also have the advantage of shorter distances and less sailing time (without a Panama Canal transit) to the high-demand Asian markets for LNG and consequently the advantage of significantly lower shipping costs. Indeed, the NERA analysis estimated shipping costs to those markets from Canadian West Coast LNG terminals at $1.23/MMBtu, which is $1.31 less than (and less than half of) its estimate of $2.54/MMBtu for shipping costs to Asia from the U.S. Gulf Coast. The NERA analysis found that Canadian exports to Asia would nevertheless have an overall higher cost due to liquefaction capital costs. NERA estimated the loaded liquefaction cost element for Canadian projects at $3.88/MMBtu and for U.S. Gulf Coast projects at $2.14/MMBtu. While U.S. West Coast "greenfield" projects would have higher capital costs than U.S. Gulf Coast "brownfield" projects, their costs would not approach those of projects located in remote and rugged Kitimat, British Columbia. Assuming that Jordan Cove's loaded liquefaction cost element would be mid-way between the Canadian and U.S. Gulf Coast figures estimated by NERA, it would be $3.01/MMBtu or $0.87 more than the Gulf Coast figure. Jordan Cove's shipping cost advantage of $1.31/MMBtu more than makes up for its higher liquefaction costs, leaving Jordan Cove with an overall cost advantage of $0.44/MMBtu over U.S. Gulf Coast projects. Jordan Cove's cost advantage not only means that Asian buyers would benefit from a lower delivered cost of LNG, but also that the U.S. would reap greater economic benefits.

Because the LNG Export Study does not account for U.S. West Coast projects being able to export LNG at a lower overall delivered cost, it underestimates economic benefits in at least two ways. Since NERA's modeling is based only on Gulf-sourced LNG exports that would have higher delivered costs, it potentially understates the equilibrium export volumes, and therefore the associated economic benefits. In addition to such a volume-driven increase in economic benefits, the inclusion of U.S. West Coast projects like Jordan Cove in the LNG Export Study would have produced an increase in economic benefits due to the composition of the delivered cost of LNG. Simply stated, the relative portion of the price paid for a U.S. LNG export flowing to the U.S. terminal, as opposed to the portion flowing to the non-U.S. shipping company, would be greater if the export is from the U.S. West Coast instead of from the U.S. Gulf Coast. Thus, the substitution of Jordan Cove's higher liquefaction capital costs (which lead to economic benefits) for a U.S. Gulf Coast project's higher shipping costs (which do not lead to economic benefits) results in more economic benefits being kept in the U.S.

In sum, DOE should, as the LNG Export Study does not, recognize the economic contributions that would be unique to LNG exports from an export project like Jordan Cove situated on the U.S. West Coast as compared to projects on the other U.S. coasts. Most importantly, DOE should not put Jordan Cove at any disadvantage as it competes in the market, not only with U.S.

projects but also with proposed Canadian projects, to determine which export projects will be constructed and become operational. LNG exports from Canada (which would displace LNG exports from the U.S.) would have the same impacts on North American natural gas prices as LNG exports from the U.S., but the economic benefits of those exports would accrue to Canada and be lost to the United States. On the other hand, exports of Canadian gas via Jordan Cove will have the most limited impacts on U.S. prices of any proposed export terminal and, in constructing and operating its terminal, Jordan Cove will make a tremendous investment in a currently economically depressed region of the country, with the attendant employment and economic benefits accruing to the United States.

Thank you for your consideration of Jordan Cove's comments.

Sincerely,

/s/ Beth L. Webb

Beth L. Webb
Joan M. Darby

Attorneys for
Jordan Cove Energy Project, L.P.

cc: DOE/FE, Marc Talbert, marc.talbert@hq.doe.gov

NAVIGANT

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January 22, 2013

Mr. Bob Braddock
Jordan Cove Energy Project, L.P.
125 W. Central Avenue, Suite 380
Coos Bay, OR 97420

Dear Mr. Braddock:

As you are aware, Navigant Consulting, Inc. (Navigant) has been involved in a number of liquefied natural gas (LNG) export projects including Jordan Cove Energy Project, L.P. (JCEP) in helping LNG project developers with their applications to the Department of Energy (DOE) for export of LNG to Non-Free Trade Agreement countries. Our involvement with the projects including JCEP has been primarily to assess the market impact of individual export projects as well as to investigate the pipeline infrastructure and natural gas supply that will be used to serve the requirements of the liquefaction terminals as proposed by the projects. In our analysis, we used Navigant's North American market model built on architecture provided by the GPCM® Natural Gas Market Forecasting System to perform analysis of the impact upon the existing market including prices over the long term.

In performing such analysis for JCEP, as well as other projects located on both coasts and in the Gulf of Mexico, Navigant has a number of comments we would like to make to the Office of Fossil Energy (FE) of the Department of Energy (DOE), which invited comments regarding the LNG Export Study commissioned by the DOE. We invite you to include Navigant's comments in your filing to the DOE in the subject proceeding. While we believe such comments are appropriate for JCEP's project, the comments below are relevant to all LNG export projects currently filed before the DOE for Non-Free Trade approval.

1. That the global market is best suited to determine the 'appropriate' level of U.S. LNG exports.

Rather than relying on any artificially-imposed limits on LNG export volumes, the DOE should allow the global marketplace to determine how much LNG export capacity should be built, who should build it, where it should be built, and ultimately what volumes of LNG exports should occur. The detailed, macroeconomic component of the DOE's LNG Export Study[1] analyses serves to confirm that LNG exports will provide positive net economic benefits to the U.S. under all modeled scenarios, with increasing benefits associated with the increasing levels of LNG exports that result under the unconstrained export scenarios.[2]

- Arbitrary export level assumptions can yield infeasible study results.

  Whereas the EIA analysis incorporated static, *a priori* assumptions on LNG export volumes, the subsequent NERA analysis component of the DOE's LNG Export Study determined the LNG export levels within its global natural gas market model. As noted by the NERA analysis, "… 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."[3] Thus, "[b]ecause the [NERA] study [in some cases] estimated lower export volumes than were specified by [DOE] for the EIA study, U.S. natural gas prices [projected by NERA] do not reach the highest levels projected by EIA."[4]

  For example, LNG exports as projected by the NERA analysis for the EIA Low Shale case never exceed 2.5 bcfd (well below both the 6 bcfd and the 12 bcfd export assumptions driving the EIA price forecasts), and this is the case that produced the most extreme pricing and price change results in the EIA analysis.[5] Thus, EIA's projected average wellhead price increase of 20 percent over the 20-year study for the 12 bcfd export level in the Low Shale case drops to less than 3 percent in NERA's analysis where global gas market modeling results in only achievable LNG export levels.

- Even if DOE were to permit all the applications, the market will decide which facilities get built.

  Obtaining a permit to export is no guarantee that a facility will be built. Companies routinely make their "final investment decision" subsequent to permitting activities. More importantly, market participants (investors, producers, consumers) will optimize

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[1] DOE uses the term "LNG Export Study" to refer to two reports prepared at its direction: 1) the January 2012 analysis by the Energy Information Administration ("EIA") entitled "Effect of Increased Natural Gas Exports on Domestic Energy Markets," requested by the DOE's Office of Fossil Energy in August 2011 ("EIA analysis"); and 2) the December 2012 analysis by NERA Economic Consulting ("NERA") entitled "Macroeconomic Impacts of LNG Exports from the United States," commissioned by DOE under contract ("NERA analysis").
[2] NERA analysis, p. 1.
[3] NERA analysis, p. 3.
[4] NERA analysis, p. 10.
[5] For example, the Low Shale EUR case with the rapid introduction of 12 bcfd of exports resulted in a 54 percent increase versus the baseline wellhead price for the Low Shale EUR case in 2018 (EIA analysis, p. 9), and the Low Shale EUR case baseline average wellhead price over the term of the analysis was itself 40 percent higher than in the Reference case, at $7.37 versus $5.28/MMBtu (EIA analysis, Table B5).

project development activities more efficiently than would any centralized policy or planning direction via regulatory processes. This reality is confirmed by DOE in its 2011 Order conditionally granting export authorization for the Sabine Pass LNG project, in which DOE reiterated that its policy goals include "minimizing federal control and involvement in energy markets" so as to "minimiz[e] regulatory impediments to a freely operating market."[6]

- <u>Even if some overcapacity occurs (for example, due to changes in the market), the market will still decide what levels of exports should occur.</u>

  NERA's modeling effort indicates competitive export levels (that is, LNG export levels that result from the free interplay of supply and demand conditions) could be more or less than the EIA assumptions, but that price levels would remain in a competitive long-term equilibrium range, not linked to oil prices.

  NERA's analysis shows that even with no constraints on the upper end of LNG exports, there would not be any LNG exports in NERA's Low Shale case (with its higher price forecasts in the EIA analysis) except for in the Supply Shock plus Demand Shock international scenario, where exports peak at only 2.5 bcfd (in 2025).

  With plentiful gas supplies (e.g. High Shale case), while exports could exceed the 12 bcfd assumed by EIA, the U.S. price levels themselves still stayed below $6.00/MMBtu by 2035 for all NERA's international scenarios. Even NERA's Supply Shock plus Demand Shock international scenario, with average exports of about 17 bcfd, resulted in average wellhead prices over the 20-year study term of only $5.23/MMBtu.

  Under the EIA's U.S. Reference case, the only scenario where unconstrained exports ever exceeded 12 bcfd is the Supply Shock plus Demand Shock international scenario, where the average wellhead prices from 2015 through 2035 were still less than $6.30/MMBtu (and about $0.10/MMBtu less than for the EIA's Reference Case at a constant 12 bcfd).

- <u>Regardless of modeling estimates, there are likely practical and competitive limits to how much of new LNG capacity will be located in the U.S.</u>

  The global LNG market size in 2010 was about 27 bcfd in imports and exports[7], and is estimated by the International Energy Agency to roughly double in size by 2035. Assuming new U.S. capacity of about half of worldwide growth would be highly optimistic. Navigant's market view is that U.S. LNG export capacity will likely range from 6 to 8 bcfd. We also suggest export opportunities as being time sensitive, and rather than increasing in the future, the LNG export market for export from the U.S. may

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[6] See DOE/FE Order No. 2961 (Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations), May 20, 2011, at 28.

[7] See NERA analysis, p. 19.

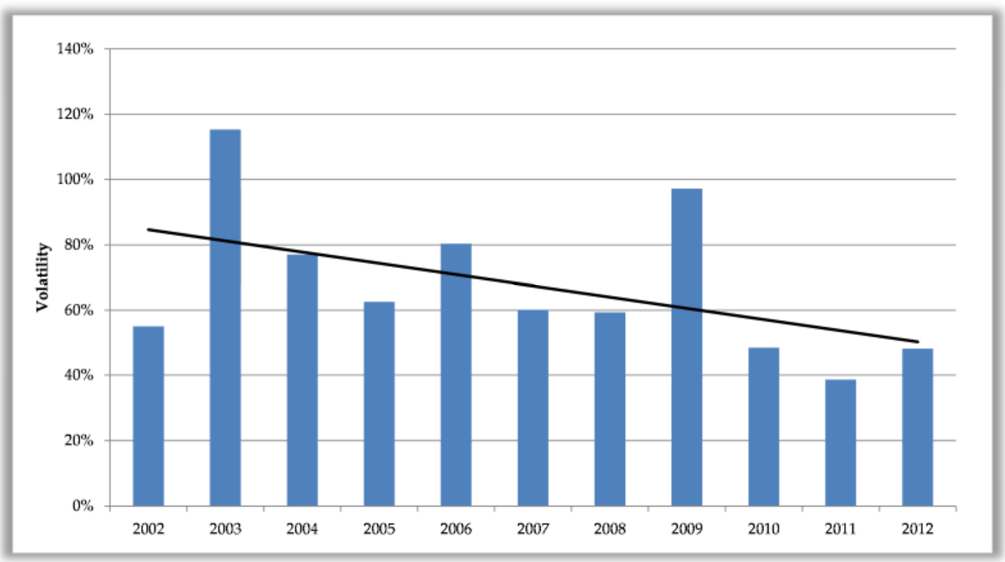
decrease due to supply development in other areas around the world from both known and unknown gas resources.

- <u>There are drawbacks that would result from 'under-permitting' by DOE.</u>

  In addition to the economic benefits of LNG exports, as detailed in the NERA analysis, LNG exports, to the extent they are permitted, will help foster the increasing stability of the domestic natural gas market. Because of the lower exploration and production risk associated with shale gas production resulting from the manufacturing-like nature of shale gas production, once shale plays have been identified, increasing levels of shale gas production should help to lower the volatility of the domestic gas market. LNG exports that increase natural gas demand thus provide two important benefits.

  First, new demand will help stabilize the current over-supply conditions in the domestic marketplace towards a market where supply and demand are in equilibrium. Second, new demand will increase the size of the natural gas market, leading to a continued increase in shale gas' share of total natural gas production, which will lower the price volatility of the gas market by increasing the overall supply responsiveness of the market. As shown in Figure 1 below, recent data seems to support decreasing levels of gas price volatility that correspond well with the recent increases in shale gas production levels. Artificially limiting the amount of LNG exports would be seen to slow the development of shale gas resources, and thus also slow potential future reductions in market price volatility.

Figure 1. Annualized Daily Volatility (Henry Hub)



Source: Navigant

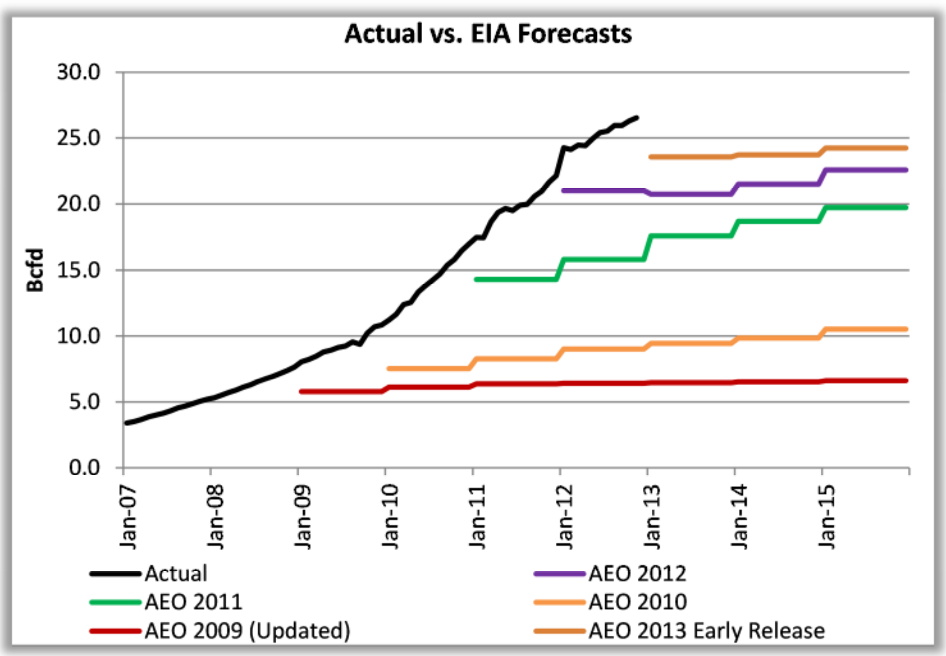
With respect to market policy, a restrictive approach to LNG export approval (i.e., potential under-permitting by DOE) would be inconsistent with the DOE's stated preference[8] for free-market approaches to regulatory oversight. An LNG export authorization process that implies the picking of winners by the regulatory process itself, as opposed to the marketplace, would limit competitive forces and not result in the optimization of project development.

2. The 2011 Reference Case U.S. natural gas supply volume assumptions used in the DOE's LNG Export Study are now drastically understated, and updated assumptions would only strengthen the showing of LNG export benefits.

The EIA's2011 Reference Case supply assumptions used in both analyses drastically understate the reality of today's abundant supply of shale gas. The 2011 Reference Case used was the Annual Energy Outlook (AEO) 2011 forecast shown in Figure Two, below. While the AEO 2011 shale gas production forecasts were already too low with respect to then-existing production levels when made, the continuing strong growth in actual production levels has made the forecast shortfall even larger for subsequent forecast years.

As can be seen in Figure 2, below, the AEO 2011 forecast for 2011 shale gas production (14.3 bcfd) was already eclipsed by actual shale production levels mid-way through 2010; at year-end 2010, actual production levels exceeded the AEO 2011 forecast for 2011 by more than 18 percent. In fact, the AEO 2011 forecast for 2013 shale gas production (17.6 bcfd) was already eclipsed by actual production levels in early 2011. As actual production levels have steadily continued their strong increases, year-end 2012 production levels of 26.5 bcfd were over 50 percent higher than the AEO 2011 forecast for 2013.

Figure 2. U.S. Shale Gas Production (Dry)

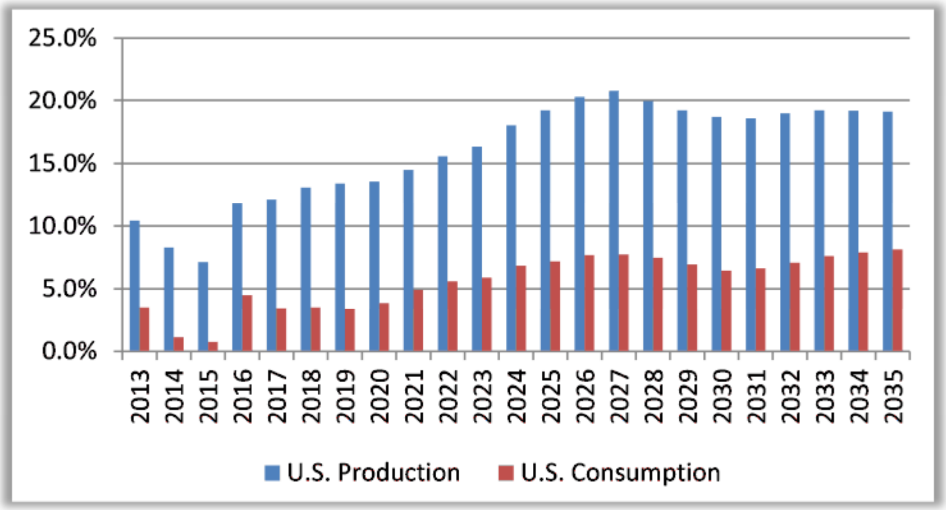


Source: Navigant, EIA

[8] See note 6, supra.

While some criticisms of the DOE's LNG Export Study have focused on the fact that the AEO 2011 *demand assumptions* have been surpassed by those of the AEO 2013, it is important to note that the increase in forecast total natural gas consumption has been far outpaced by the increase in the AEOs' natural gas production forecasts, as shown in Figure 3, below. For the period of 2013-2035, there was an average percentage increase in forecast total domestic natural gas consumption between AEO 2011 and AEO 2013 of 5.6 percent, while the increase in forecast total natural gas production was 16 percent. This important context helps explain why the more recent AEO 2013 assumptions actually indicate the beneficial market impacts that come along with LNG exports.

Figure 3. Percent Increase in Forecasted U.S. Natural Gas Production and Consumption, AEO 2013 vs. DOE Export Study (AEO 2011)



Source: Navigant

Comparing the AEO 2013 forecasts to the AEO 2011 forecasts illustrates an interesting shift in the domestic supply-demand balance. While the entire forecast period of AEO 2011 was characterized by domestic consumption exceeding total production, with a shortfall averaging about 4.0 bcfd from 2013 through 2035 being made up by LNG and pipeline imports to the U.S., in AEO 2013 that situation reverses itself by 2020. More specifically, an initial period of production shortfalls, averaging about 2.7 bcfd, becomes a period of production surpluses averaging about 4.9 bcfd from 2020 through 2035. This period of production surplus, relative to domestic total consumption, coincides generally with the ramping up of LNG exports from about 0.7 bcfd to an average of 3.4 bcfd during 2022 through 2035. Furthermore, the AEO 2013 assumptions of increasing natural gas production relative to domestic consumption and increasing LNG exports, relative to AEO 2011, are associated with a 20 percent lower average natural gas price level from 2013 through 2035 as measured at Henry Hub under AEO 2013 than under AEO 2011.

Thus, the use of a supply forecast more in line with current actual production levels than is the Reference Case (e.g. the AEO 2013 projection) would be expected to result in lower domestic gas prices than estimated in the DOE's LNG Export Study, and consequently increased LNG export volumes to global markets, which would lead to even higher economic benefits to the U.S.

3. Continual increase of production forecasts reflects the underlying natural gas resource abundance.

In any discussion of natural gas production forecasts, it is always instructive to note the key underlying factor behind the continually more optimistic and impressive production forecasts, and that is the reality of today's shale gas boom. The development of horizontal drilling and hydraulic fracturing, existing technologies which were combined together and have been continually improved, has yielded dramatically increased production and fundamentally changed the North American natural gas supply outlook. With U.S. shale gas resources estimated at up to 35 years of annual U.S. natural gas consumption at current levels,[9] pushing U.S. total natural gas resource estimates up to more than 90 years of supply, it is evident that a new era of natural gas sufficiency has arrived. Other estimates of the U.S. and North American natural gas resource base that have been prepared by other industry associations and government institutions are even higher.

Navigant is hopeful that these comments will be helpful for the DOE as it gets set to make decisions of high importance to the LNG export projects, to the natural gas industry, to other parties reliant upon abundant and clean natural gas as a fuel source, and to the country as a whole.

Respectfully submitted,

Gordon Pickering
Director, Energy
Navigant Consulting, Inc.

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[9] See e.g. "Golden Rules for a Golden Age of Gas," International Energy Agency, Special Report, May 29, 2012, Table 3.1, putting U.S. shale gas recoverable resources at 24 tcm, or 840 tcf.

AEO2014 Early Release Overview

Executive summary

Projections in the *Annual Energy Outlook 2014 (AEO2014)* Reference case focus on the factors that shape U.S. energy markets through 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. The early release provides a basis for the examination and discussion of energy market trends and serves as a starting point for analysis of potential changes in U.S. energy policies, rules, or regulations or possible technology breakthroughs. Readers are encouraged to review the full range of cases that will be presented when the complete *AEO2014* is released in 2014, exploring key uncertainties in the Reference case.

Major highlights of the *AEO2014* Reference case include:

Growing domestic production of natural gas and crude oil continues to reshape the U.S. energy economy, with crude oil production approaching the historical high achieved in 1970 of 9.6 million barrels per day

Ongoing improvements in advanced technologies for crude oil and natural gas production continue to lift domestic supply and reshape the U.S. energy economy. Domestic production of crude oil (including lease condensate) increases sharply in the *AEO2014* Reference case, with annual growth averaging 0.8 million barrels per day (MMbbl/d) through 2016, when it totals 9.5 MMbbl/d (Figure 1). While domestic crude oil production is expected to level off and then slowly decline after 2020 in the Reference case, natural gas production grows steadily, with a 56% increase between 2012 and 2040, when production reaches 37.6 trillion cubic feet (Tcf).The full *AEO2014* will include cases that represent alternative oil and natural gas resource and technology assumptions.

Low natural gas prices boost natural gas-intensive industries

Industrial shipments grow at a 3.0% annual rate over the first 10 years of the projection and then slow to 1.6% annual growth for the rest of the projection. Bulk chemicals and metals-based durables account for much of the increased growth in industrial shipments in *AEO2014*. Industrial shipments of bulk chemicals, which benefit from an increased supply of natural gas liquids, grow by 3.4% per year from 2012 to 2025 in *AEO2014*, as compared with 1.9% in the *Annual Energy Outlook 2013 (AEO2013)* Reference case. The projection assumes growing competition from abroad that flattens output growth in energy-intensive industries after 2030.

The higher level of industrial shipments leads to more natural gas consumption (including lease and plant fuel) in the U.S. industrial sector, increasing from 8.7 quadrillion British thermal units (Btu) in 2012 to 10.6 quadrillion Btu in 2025 in *AEO2014*, compared to 9.8 quadrillion Btu in 2025 in *AEO2013*.

Light-duty vehicle energy use declines sharply, reflecting slow growth in vehicle miles traveled and accelerated improvement in vehicle efficiency

AEO2014 includes a new, detailed demographic profile of driving behavior by age and gender as well as new lower population growth rates based on updated U.S. Census Bureau projections. As a result, annual increases in vehicle miles traveled (VMT) for light-duty vehicles (LDVs) in the *AEO2014* Reference case average 0.9% from 2012 to 2040, compared to 1.2% per year in *AEO2013* over the same period. The rising fuel economy of LDVs more than offsets the modest growth in VMT, and LDV energy consumption declines in the *AEO2014* Reference case from 16.0 quadrillion Btu in 2012 to 12.1 quadrillion Btu in 2040, as compared with the *AEO2013* total of 13.0 quadrillion Btu in 2040 (Figure 2). The full *AEO2014* will include an Issues in Focus discussion of VMT projections that addresses the implications of alternative VMT scenarios.

Figure 1. U.S. petroleum and other liquid fuels supply by source, 1970-2040 (million barrels per day)

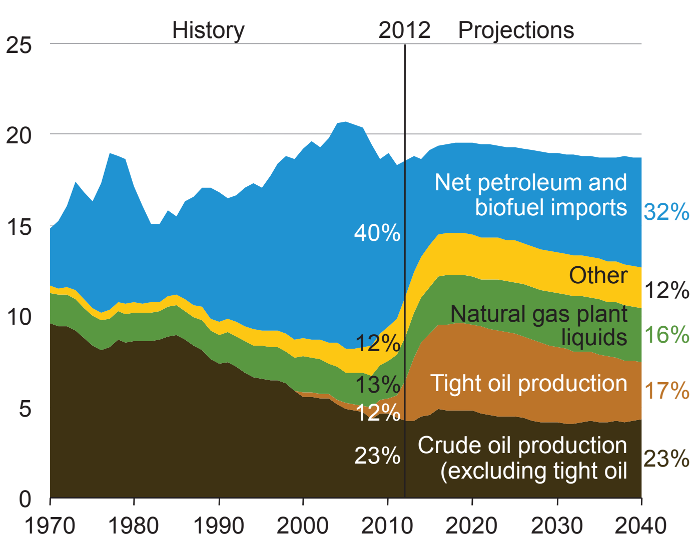
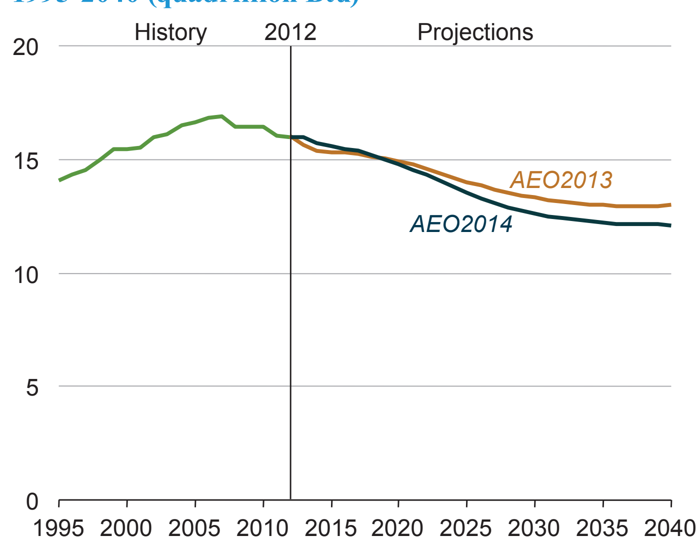


Figure 2. Energy consumption by light-duty vehicles in the United States, *AEO2013* and *AEO2014*, 1995-2040 (quadrillion Btu)



Natural gas overtakes coal to provide the largest share of U.S. electric power generation

Projected low prices for natural gas make it a very attractive fuel for new generating capacity. In some areas, natural gas-fired generation replaces generation formerly supplied by coal and nuclear plants. In 2040, natural gas accounts for 35% of total electricity generation, while coal accounts for 32% (Figure 3). Generation from renewable fuels, unlike coal and nuclear power, is higher in the *AEO2014* Reference case than in *AEO2013*. Electric power generation with renewables is bolstered by legislation enacted at the beginning of 2013 extending tax credits for various renewable technologies; which was passed after the *AEO2013* Reference case had been completed, but was considered in an alternative case in *AEO2013*. The full *AEO2014* will include a variety of cases addressing the implications of alternative market conditions and policies for the electricity generation mix.

Higher natural gas production also supports increases in exports of both pipeline and liquefied natural gas

In addition to increases in domestic consumption in the industrial and electric power sectors, U.S. exports of natural gas also increase in the *AEO2014* Reference case (Figure 4). U.S. exports of liquefied natural gas (LNG) increase to 3.5 Tcf in 2029 and remain at that level through 2040. Pipeline exports of U.S. natural gas to Mexico grow by 6% per year, from 0.6 Tcf in 2012 to 3.1 Tcf in 2040, and pipeline exports to Canada grow by 1.2% per year, from 1.0 Tcf in 2012 to 1.4 Tcf in 2040. Over the same period, U.S. pipeline imports from Canada fall by 30%, from 3.0 Tcf in 2012 to 2.1 Tcf in 2040, as more U.S. demand is met by domestic production. Projected exports are sensitive to assumptions regarding conditions in U.S. and global natural gas markets. The full *AEO2014* will include cases that illustrate the sensitivity of projected natural gas exports to alternative resource, economic, and price scenarios.

With strong growth in domestic crude oil and natural gas production, U.S. use of imported fuels falls sharply

In the *AEO2014* Reference case, U.S. domestic energy production increases from 79.1 quadrillion Btu in 2012 to 102.1 quadrillion Btu in 2040, and net use of imported energy sources, which was 30% in 2005, falls from 16% of total consumption in 2012 to 4% in 2040. In the *AEO2013* Reference case, domestic energy production reached a total of 98.5 quadrillion Btu, and energy imports is projected to decline as a percentage of consumption to 9% in 2040. The larger increase in domestic energy production in *AEO2014* is primarily a result of higher projections of production of natural gas and biomass/other renewables. Crude oil production (including lease condensate) increases from 13.9 quadrillion Btu in 2012 to a peak of 20.5 quadrillion Btu in 2019 before dropping to 16.0 quadrillion Btu in 2040.

With domestic crude oil production rising to 9.5 MMbbl/d in 2016, the import share of U.S. petroleum and other liquids supply falls to about 25%. Domestic production begins to decline after 2019, and the import share of total petroleum and other liquids supply grows to 32% in 2040, still lower than the 2040 level of 37% in the *AEO2013* Reference case. The alternative cases in the full *AEO2014* will illustrate how different assumptions about resources, markets, and policies can dramatically impact projections of import dependence.

Improved efficiency of energy use in the residential and transportation sectors and a shift away from carbon-intensive fuels for electricity generation keep U.S. energy-related carbon dioxide emissions below their 2005 level through 2040

In the *AEO2014* Reference case, total U.S. energy-related emissions of carbon dioxide (CO_2) remain below the 2005 level in every year through 2040. Projected emissions in 2020 and 2040 are, respectively, about 9% and 7% below the 2005 level.

In *AEO2014*, CO_2 emissions associated with U.S. industrial activity (including CO_2 emissions associated with the generation of electricity used in the industrial sector) begin to surpass emissions from the transportation sector in the middle of the next

Figure 3. Electricity generation from natural gas and coal, 2005-2040 (billion kilowatthours)

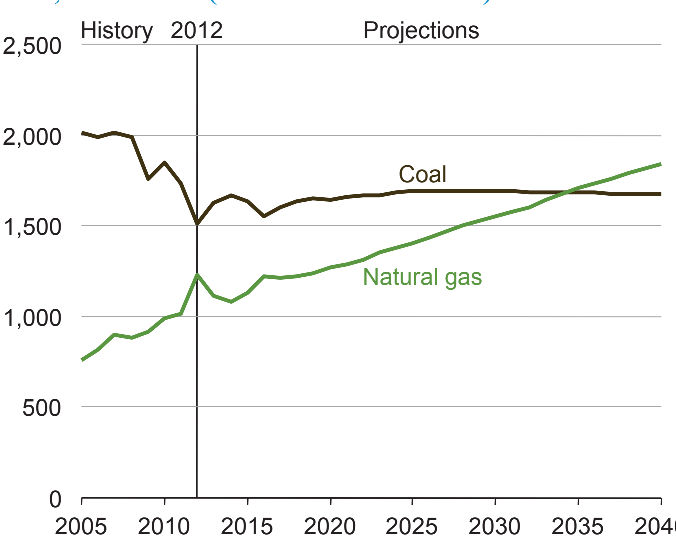
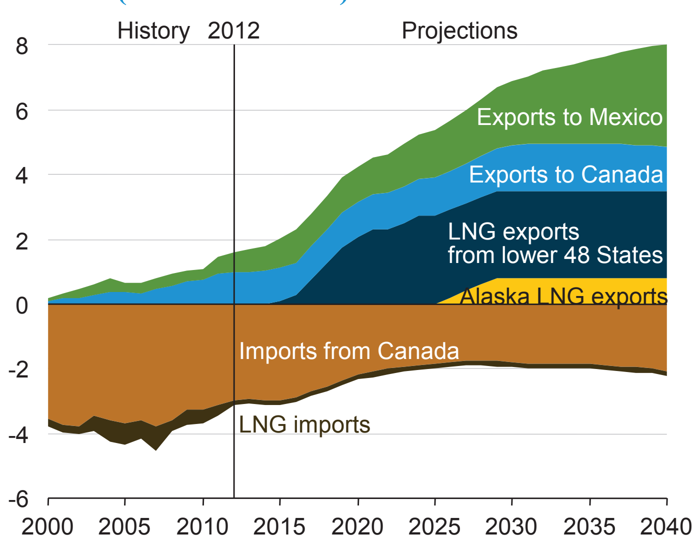


Figure 4. U.S. natural gas imports and exports, 2000-40 (trillion cubic feet)



decade for the first time since the late 1990s. In the transportation sector, as a result of new fuel economy standards, biofuel mandates, and shifts in consumer behavior, emissions from transportation sector use of petroleum and other liquids generally decline or remain stable from 2012 through 2040. Emissions from energy use in the commercial sector increase more rapidly than in the residential sector, and in 2040 emissions from these two sectors are about equal. In the electric power sector, CO_2 emissions from coal combustion decline after 2029 as more power plants are fueled by lower-carbon fuels, including natural gas and renewables. However, the lower level of CO_2 emissions in the electric power sector because of the reduced role for coal is partially offset by less projected generation from nuclear power. Generation from nuclear power in *AEO2014* is 10% below levels in *AEO2013* in 2040 as a result of increased nuclear plant retirements.

Projected growth in real gross domestic product is slightly slower than in AEO2013, but projected per capita GDP and disposable income are higher than in AEO2013 because of a reduced projection for U.S. population growth

Annual growth of real gross domestic product (GDP) from 2012 to 2040 averages 2.4% in the *AEO2014* Reference case, slightly below the *AEO2013* Reference case growth rate over the same period. However, industrial output growth is higher in *AEO2014*, averaging 2.1% per year from 2012 to 2040. Industries that supply equipment for increased natural gas production, as well as industries benefitting from lower natural gas prices, account for much of the higher growth in manufacturing. On a per capita basis, projected annual growth rates for real GDP and disposable income in *AEO2014*, both averaging 1.7% per year, are above the comparable rates in *AEO2013*, reflecting lower projected population growth rate estimates (0.7% in *AEO2014* compared to 0.9% in *AEO2013*) for the 2012-40 period provided by the U.S. Census Bureau.

Introduction

In preparing the *AEO2014* Reference case, the U.S. Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview presents the *AEO2014* Reference case and compares it with the *AEO2013* Reference case released in April 2013 (see Table 1 on pages 17-18). Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete *AEO2014* publication is released, to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

To provide a basis against which alternative cases and policies can be compared, the *AEO2014* Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws that include sunset dates do, in fact, expire at the time of those sunset dates). This assumption clarifies the relationship of the Reference case to other *AEO2014* cases and enables policy analysis with less uncertainty regarding unstated legal or regulatory assumptions.

As in past editions, the complete *AEO2014* will include additional cases, many of which reflect the effects of extending a variety of current energy programs beyond their current expiration dates and the permanent retention of a broad set of programs that currently are subject to sunset provisions. In addition to the alternative cases prepared for *AEO2014*, EIA has examined proposed policies at the request of Congress over the past few years. Reports describing the results of those analyses are available on EIA's website.[1]

Key updates made for the *AEO2014* Reference case include the following:

Macroeconomic

- Revised U.S. Census Bureau population projections.[2] The population projection for 2040 in the *AEO2014* Reference case is almost 6% below the 2040 projection used for the *AEO2013* Reference case. Most of the revision in overall population growth results from a lower projection for net international migration, with younger age groups showing the largest differences from the earlier projection. The slower rate of population growth leads to less labor force growth, which contributes to slower GDP growth.

Residential, commercial, and industrial

- Revised base year residential equipment stocks and energy consumption for space heating, space cooling, and water heating, based on data from EIA's 2009 Residential Energy Consumption Survey (RECS), the most recent data available.[3] Estimates of appliance stocks and energy consumption for several miscellaneous electric loads also were updated, based on a report by Navigant Consulting Inc., to better reflect recent changes and trends in the residential sector.[4]

[1]See "Congressional & Other Requests," http://www.eia.gov/analysis/reports.cfm?t=138.

[2]The new population projections were released on December 12, 2012. See U.S. Department of Commerce, "U.S. Census Bureau Projections Show a Slower Growing, Older, More Diverse Nation a Half Century from Now" (Washington, DC: December 12, 2012), http://www.census.gov/newsroom/releases/archives/population/cb12-243.html.

[3]U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS): 2009 RECS Survey Data, Public Use Microdata File (Washington, DC: January 2013), http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.

[4]Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for the U.S. Department of Energy, U.S. Energy Information Administration.

- Updated and expanded representation of miscellaneous electric loads in the commercial sector, as well as personal computers and data center servers, based on the Navigant report, reflecting recent and expected trends in electronics use.[5]
- Updated costs and improved representation of residential lighting applications, including wider representation of light emitting diode (LED) lighting and outdoor lighting, based on the 2009 RECS and two U.S. Department of Energy (DOE) reports.[6, 7]
- Revised handling of the regional efficiency standard for residential furnaces, based on an ongoing legal appeal of the standard. The regional standard scheduled to take effect in 2013 is not included in *AEO2014* because of a court challenge and proposed settlement that would vacate the standard in question and require DOE to develop new residential furnace standards.
- Revised commercial capacity factors governing annual usage of major end-use equipment, based on an EIA-contracted analysis.
- Updated manufacturing sector data to reflect the 2010 Manufacturing Energy Consumption Survey (MECS).[8]
- Revised outlook for industrial production to reflect the effects of increased shale gas production and lower natural gas prices, resulting in faster growth for industrial production and energy consumption. The industries primarily affected include energy-intensive bulk chemicals and primary metals, both of which provide products used by the mining and other downstream industries such as fabricated metals and machinery. The bulk chemicals industry is also a major user of natural gas and, increasingly, hydrocarbon gas liquid (HGL) feedstocks.[9]
- Expanded process flow models for the cement and lime industry and the aluminum industry, allowing technologies based on energy efficiency to be incorporated, as well as enhancement of the cement model to include renewable fuels.

Transportation

- Implemented a new approach to VMT projections for LDVs, based on an analysis of VMT by age cohorts and the aging of the driving population over the course of the projection, which resulted in a significantly lower level of VMT growth after 2018 compared with *AEO2013*. On balance, demographic trends (such as an aging population and decreasing rates of licensing and travel among younger age groups) combine with employment and income factors to produce a 30% increase in VMT from 2012 to 2040 in *AEO2014* compared with 41% growth in *AEO2013*.
- Added LNG as a potential fuel choice for freight rail locomotives and domestic marine vessels, resulting in significant penetration of natural gas as a fuel for freight rail (35% of freight rail energy consumption in 2040) but relatively minor penetration in domestic marine vessels (2% of domestic marine energy consumption in 2040).
- Adopted a new approach for estimating freight travel demand by region and commodity for heavy-duty vehicles (HDVs), rail, and domestic marine vessels, as well as updated fuel efficiencies for freight rail and domestic marine vessels.
- Updated handling of flex-fuel vehicle (FFV) fuel shares to better reflect consumer preferences and industry response. FFVs are necessary to meet the renewable fuels standard (RFS), but the phase-out of corporate average fuel economy (CAFE) credits for their sale, as well as limited demand from consumers, reduces their market penetration.
- Revised attributes for battery electric vehicles—including (1) product availability, (2) electric drive fuel efficiency, and (3) non-battery system costs by vehicle size class, battery size, and added battery cost per kilowatthour based on vehicle power-to-energy ratio for vehicle type—applied to hybrid electric, plug-in hybrid electric, and all-electric vehicles.

Oil and natural gas production and product markets

- Revised network pricing assumptions based on benchmarking of regional natural gas hub prices to historical spot natural gas prices, basing flow decisions on spot prices, setting variable tariffs based on historical spot natural gas price differentials, and estimating the price of natural gas to the electric power sector off a netback from the regional hub prices.[10]

[5]Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for the U.S. Department of Energy, U.S. Energy Information Administration.

[6]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf.

[7]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *2010 U.S. Lighting Market Characterization* (Washington, DC: January 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2010-lmc-final-jan-2012.pdf.

[8]U.S. Energy Information Administration, "Manufacturing Energy Consumption Survey (MECS): 2010 MECS Survey Data" (Washington, DC: March 19, 2013), http://www.eia.gov/consumption/manufacturing/data/2010/.

[9]Growing production of wet natural gas and lighter crude oil has focused attention on natural gas liquids (NGL). EIA has developed and adopted a neutral term—"hydrocarbon gas liquid" (HGL)—to equate the supply (natural gas plant liquids [NGPL] + liquefied refinery gases [LRG]) and market (NGL + refinery olefins) terms. For example, liquefied petroleum gas (LPG) is currently defined by EIA as ethane, propane, normal butane, and isobutane and their olefins (ethylene, propylene, butylene, and isobutylene). This definition is inconsistent with definitions used by other federal agencies, international organizations, and trade groups, in that it implies that all the products are in a liquid state (ethane typically is not) and are used in the same way (higher-value olefins are used differently). Part of the HGL implementation redefines LPG to include only propane, butane, and isobutane and to exclude ethane and refinery olefins. The tables included in *AEO2014* have been relabeled to conform to this newly adopted definition.

[10]Estimating natural gas prices to the electricity generation sector based on hub prices, rather than the citygate prices as was done in prior years, is a better reflection of current market conditions, in which many large natural gas consumers are outside the citygate.

- Allowed secondary flows of natural gas out of the Middle Atlantic region to change dynamically in the model based on relative prices, which enables a larger volume of natural gas from the Middle Atlantic's Marcellus formation to supply neighboring regions.
- Developed the estimated ultimate recovery of tight oil and shale gas on the basis of county-level data.[11]
- Updated oil and gas supply module that explicitly reports technically recoverable resources of liquids in natural gas, enabling estimation of dry and wet natural gas.
- Improved representation of the dynamics of U.S. gasoline and diesel exports versus U.S. demand, through adoption of endogenous modeling.[12]
- Added representation of the U.S. crude oil distribution system (pipelines, marine, and rail), to allow crude oil imports to go to logical import regions for transport to refineries, which enables crude imports and domestic production to move among refining regions and keeps imports of Canadian crude oil from flowing directly to U.S. Gulf refiners.[13]
- Revised production outlook for nonpetroleum other liquids—gas-to-liquids, coal-to-liquids (CTL), biomass-to-liquids, and pyrolysis[14]—with lower production levels than in *AEO2013*, as more recent experience with these emerging technologies indicates higher costs than previously assumed.[15]
- Revised representation of CO_2-enhanced oil recovery (EOR) that better integrates the electricity, oil and gas supply, and refining modules.[16]

Electric power sector

- Revised approach to reserve margins, which are set by region on the basis of North American Electric Reliability Corporation/ Independent System Operator requirements,[17] and capacity payments, which are calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity in the electricity model.
- Revised handling of spinning reserves, with the required levels set explicitly depending on the mix of generating technologies used to meet peak demand by region, to allow better representation of capacity requirements and costs in regions or cases with high penetration of intermittent loads.
- Revised assumptions concerning the potential for unannounced retirement of nuclear capacity in several regions to better reflect the impact of rising operating costs and low electricity prices. Announced nuclear retirements are already incorporated as planned.
- Updated handling of Mercury and Air Toxics Standards (MATS)[18] covering the electric power sector to reflect potential upgrades of electrostatic precipitators, requirements for plants with dry scrubbers to employ fabric filters, and revised costs for retrofits of dry sorbent injection and fabric filters.
- Updated treatment of the production tax credit (PTC) for eligible renewable electricity generation technologies—consistent with the American Taxpayer Relief Act of 2012 (ATRA) passed in January 2013[19]—including revision of PTC expiration dates for each PTC-eligible technology to reflect the concept of projects being declared "under construction" as opposed to being placed "in service" and extension of the expiration date of the PTC for wind generation projects by one year.

Economic growth

Macroeconomic projections in the *Annual Energy Outlook (AEO)* are trend projections, with no major shocks assumed and with potential growth determined by the economy's supply capability. Growth in aggregate supply depends on increases in the labor force, growth of capital stocks, and improvements in productivity. Long-term demand growth depends on labor force growth,

[11] After accounting for infrastructure constraints and general development patterns, oil and natural gas resources in "sweet spots" are developed earlier than lower quality resources, based on net present value.

[12] High U.S. crude oil production and low fuel costs have given U.S. refiners a competitive advantage over foreign refiners, as evidenced by high U.S. refinery utilization and increasing U.S. exports of gasoline and diesel fuel.

[13] Oil imports from Canada now are required to go to Petroleum Administration for Defense District (PADD) 2 (Midwest: North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky, and Tennessee); PADD 4 (Rocky Mountain: Montana, Idaho, Wyoming, Utah, and Colorado); and PADD 5 (West Coast: Washington, Oregon, Nevada, California, Arizona, Alaska, and Hawaii) for redistribution through the crude oil distribution infrastructure.

[14] Pyrolysis is defined as the thermal decomposition of biomass at high temperatures (greater than 400°F, or 200°C) in the absence of air.

[15] EIA undertook detailed assessments of these technologies in order to characterize key parameters considered in the model, such as capital cost, contingency factors, construction time, first year of operation, plant life, plant production capacity, efficiency, and feedstock and other operating costs.

[16] When considering CO_2 EOR, the oil and gas supply module assesses a location and the availability and price of CO_2 from power plants and CTL facilities. The electric power plants now consider the market size and prices for CO_2 captured. The refining module assesses a location and the availability and price of CO_2 from CTL facilities. The power sector now assesses opportunities for plants equipped with carbon capture and storage, as the CO_2 produced at these facilities can be used for EOR operations. This enables the model to solve dynamically for the capture of CO_2 and the production of oil from anthropogenic CO_2 EOR.

[17] North American Electric Reliability Corporation, *2013 Summer Reliability Assessment* (Atlanta, GA: May 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013SRA_Final.pdf.

[18] U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)," http://www.epa.gov/mats.

[19] U.S. House of Representatives, 112th Congress, Public Law 112-240, "American Taxpayer Relief Act of 2012," Sections 401-412 (Washington, DC: January 2, 2013), http://www.gpo.gov/fdsys/pkg/PLAW-112publ240/pdf/PLAW-112publ240.pdf.

income growth, and population growth. *AEO2014* uses the U.S. Census Bureau's December 2012 middle population projection. The U.S. Census Bureau revised its population projections primarily to reflect lower assumptions regarding international net migration.

In *AEO2014*, U.S. population is expected to grow at an annual rate of 0.7% from 2012 to 2040, or 0.2 percentage points lower than the 0.9% average annual population growth rate in *AEO2013*. As shown in Figure 5, most of the change from *AEO2013* to *AEO2014* is in the younger age cohorts. Real GDP, labor force, and productivity in *AEO2014* grow by average annual rates of 2.4%, 0.6%, and 1.8%, respectively, from 2012 to 2040.

Total industrial production growth (which includes manufacturing, construction, agriculture, and mining) in *AEO2014* is higher than projected in *AEO2013*, primarily as a result of more rapid growth in manufacturing output, with most of the difference accounted for by machinery, transportation equipment, fabricated metals, and bulk chemicals. Those industries, in addition to being trade-sensitive, supply equipment or raw materials used in oil and gas production or otherwise benefit from lower natural gas prices. In 2040, the manufacturing share of total gross output is 18% in *AEO2014*, compared with 16% in *AEO2013*.

Energy prices

Crude oil

Oil prices are influenced by several factors, including some that have mainly short-term impacts. Other factors, such as expectations about future world demand for petroleum and other liquids and production decisions by the Organization of the Petroleum Exporting Countries (OPEC), can affect prices over the longer term. Supply and demand in the world oil market are balanced through responses to price movements, with considerable complexity in the evolution of underlying supply and demand expectations. For petroleum and other liquids, the key determinants of long-term supply and prices can be summarized in four broad categories: the economics of non-OPEC supply; OPEC investment and production decisions; the economics of other liquids supply; and world demand for petroleum and other liquids.

Key assumptions driving global crude oil markets in the *AEO2014* Reference case over the projection period include: average economic growth of 1.9% per year for major U.S. trading partners[20] and average economic growth of 4.0% per year for other U.S. trading partners. Growth in petroleum and other liquids use occurs almost exclusively outside the Organization for Economic Cooperation and Development (OECD) member countries, with 1.8% average annual growth in petroleum and other liquids consumption by non-OECD countries, including significantly higher average annual consumption growth in both China and India.

Petroleum and other liquids production in *AEO2014* from non-OPEC countries, particularly the United States, increases to levels above those in *AEO2013*. As a result, the OPEC market share declines to less than 40% in the near term before starting to rise again after 2016. The Brent crude oil spot price decreases from $112 per barrel (bbl) in 2012 to $92/bbl in 2017 in the Reference case (in 2012 dollars), then increases to $141/bbl in 2040 (or about $235/bbl in nominal dollars) as growing demand leads to the development of more costly resources (Figure 6). However, those resources are not as costly to develop as projected in *AEO2013*.

Figure 5. Comparisons of population growth by projection period and age cohort in the *AEO2014* and *AEO2013* Reference cases (*AEO2014* growth minus *AEO2013* growth)

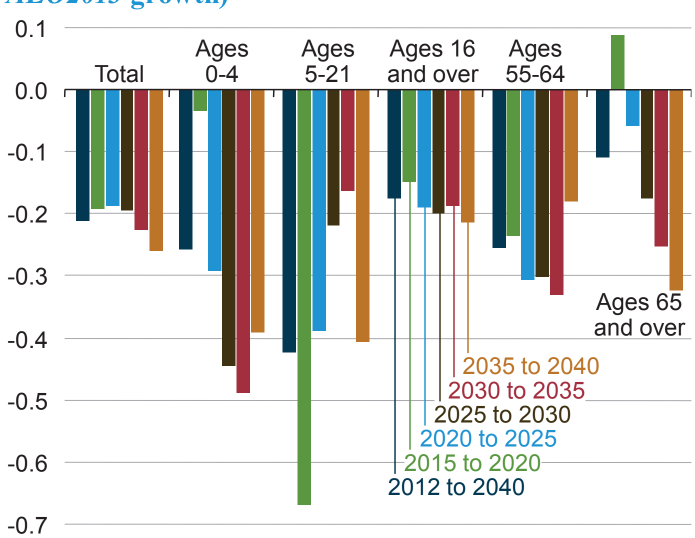
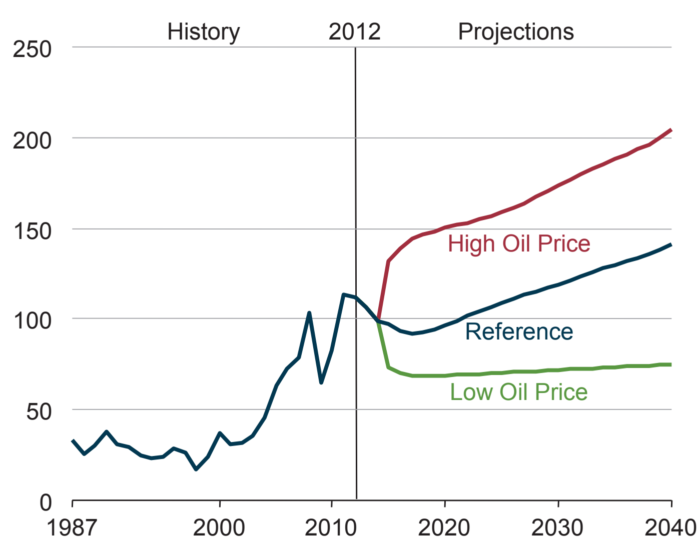


Figure 6. Average annual Brent spot crude oil prices in three cases, 1987-2040 (2012 dollars per barrel)



[20]Major trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone.

Petroleum and other liquids products

With lower crude oil prices and lower gasoline demand projected in the *AEO2014* Reference case, the real end-use price of motor gasoline in the United States declines to $3.03 per gallon (2012 dollars) in 2017, then rises to $3.90 per gallon in 2040 (compared to $4.40 per gallon in 2040 in *AEO2013*). The end-use price of diesel fuel in the transportation sector follows a similar pattern, dropping to $3.50 per gallon in 2017 and then rising to $4.73 per gallon in 2040 (compared to $5.03 per gallon in *AEO2013*). Although both gasoline and diesel prices dip modestly in the early years of the projection period, they increase steadily thereafter. The diesel share of total domestic petroleum and other liquids production rises, and the gasoline share falls, mostly as a result of the greenhouse gas (GHG) and CAFE standards for LDVs beginning in model year 2017. Increasing demand for diesel puts pressure on refiners to increase diesel yields and results in a rising difference between diesel prices and gasoline prices from 2017 to 2025.

Legislated targets for cellulosic fuels use mandated by the Energy Independence and Security Act of 2007 (EISA2007) are not attained, as the U.S. Environmental Protection Agency (EPA)[21] continues to make use of the flexibility provided in the statute to adjust those requirements.

Natural gas

The Henry Hub spot price for natural gas in the *AEO2014* Reference case is higher than projected in *AEO2013* through 2037, with price increases in the near term driven by faster growth of consumption in the industrial and electric power sectors and, later, growing demand for export at LNG facilities. A sustained increase in production follows, leading to slower price growth over the rest of the projection period.

The Henry Hub spot natural gas price in *AEO2014* reaches $4.80 per million Btu (MMBtu) (2012 dollars) in 2018, which is 77 cents/MMBtu higher than in *AEO2013*. The stronger near-term price growth is followed by a lagged increase in supply from producers, eventually causing prices to settle at $4.38/MMBtu in 2020, which is still notably higher than in *AEO2013*.

After 2020, increases in natural gas spot prices are driven by continued but slower growth in U.S. demand and net exports. The Henry Hub spot natural gas price rises to $7.65/MMBtu in 2040, an increase of $3.28 from 2020 but 4% below the 2040 price projection in *AEO2013*. In *AEO2014*, production grows to 37.5 Tcf in 2040, compared with 33.1 Tcf in *AEO2013*. A price increase starting in 2033 is far less pronounced than was projected in *AEO2013*, in part because the growth in net exports from the United States slows significantly.

Regional spot price projections throughout the United States follow the same general pattern as the Henry Hub spot price. However, the average Lower 48 spot price generally increases at a slightly slower rate than the Henry Hub spot price, because regional production growth outside those areas that serve the Henry Hub is projected to be somewhat faster than the growth in production that serves the Henry Hub.

Coal

The average minemouth price of coal increases by 1.4% per year in the *AEO2014* Reference case, from $1.98/MMBtu in 2012 to $2.96/MMBtu in 2040 (2012 dollars). The upward trend of coal prices primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. The upward trend in the minemouth price of coal in the *AEO2014* Reference case is similar to the trend in the *AEO2013* Reference case, but the average price through the projection period in *AEO2014* is generally lower, primarily reflecting a lower price outlook for coking coal.

Relative to minemouth prices, the average delivered price of coal to all sectors (excluding exports) increases at a slightly slower pace of 1.0% per year, from $2.60/MMBtu in 2012 to $3.43/MMBtu in 2040. The slower growth rate primarily reflects modest growth in average coal transportation rates, which increase by 0.2% per year in *AEO2014*—from $0.83/MMBtu in 2012 to $0.89/MMBtu in 2040—as a result of gradually increasing fuel costs and changes over time in the pattern of coal distribution.

U.S. coal exports, which have surged in recent years from 50 million short tons in 2005 to a record 126 million short tons (MMst) in 2012, have become an increasingly important source of revenue for both U.S. coal producers and coal transportation companies (primarily railroads and barge companies). In 2012, coal export revenues totaled about $15 billion, representing about 25% of all U.S. coal revenues, despite the fact that coal exports in 2012 represented only 12% of total U.S. production (short tons). In the *AEO2014* Reference case, U.S. coal export prices increase by 1.2% per year, to $6.40/MMBtu in 2040.

Electricity

Following the decline of natural gas prices since 2008, real average delivered prices for electricity have dropped consistently (although more gradually) since 2009, to 9.8 cents per kilowatthour (kWh) in 2012. Retail electricity prices are influenced by fuel prices, and particularly by natural gas prices. However, the relationship between retail electricity prices and natural gas prices is complex, and many factors influence the degree to which, and the timeframe over which, they are linked. Those factors include the share of natural gas generation in a region, the level of costs associated with the electricity transmission and distribution systems,

[21] U.S. Environmental Protection Agency, "2014 Standards for the Renewable Fuel Standard Program: Proposed Rule," 40 CFR Part 80 [EPA-HQ-OAR-2013-0479; FRL-9900-90-OAR], RIN 2060-AR76, *Federal Register,* Vol. 78, No. 230 (Washington, DC: November 29, 2013), pp. 71732-71784, http://www.gpo.gov/fdsys/pkg/FR-2013-11-29/pdf/2013-28155.pdf.

the mix of competitive versus cost-of-service pricing, and the number of customers who purchase power directly from wholesale power markets. As a result, it can take time for changes in fuel prices to affect electricity prices, and the impacts can vary from region to region.

In the *AEO2014* Reference case, electricity prices are higher throughout the projection than they were in the *AEO2013* Reference case. Natural gas prices for electricity generators are higher than those in *AEO2013* in the first few years but fairly similar in the long term. Reliance on natural gas-fired generation remains strong, as a result of additional near-term retirements of coal-fired and nuclear capacity, and natural gas prices continue to influence electricity prices. In the long term, both natural gas prices and electricity prices rise. Electricity prices, which in 2030 are 10.4 cents/kWh (2012 dollars) in the *AEO2014* Reference case, compared with 9.9 cents/kWh in the *AEO2013* Reference case, continue rising to 11.1 cents/kWh in 2040 in *AEO2014*, compared with 11.0 cents/kWh in the *AEO2013* Reference case.

The *AEO2014* Reference case includes an updated calculation of electricity prices in competitive regions that better represents payments required to maintain reserve capacity, contributing to higher projected electricity prices relative to *AEO2013*. In addition, the updated regional reserve margin requirements in *AEO2014* generally are higher and thus more costly than those in *AEO2013*.

Delivered energy consumption by sector[22]

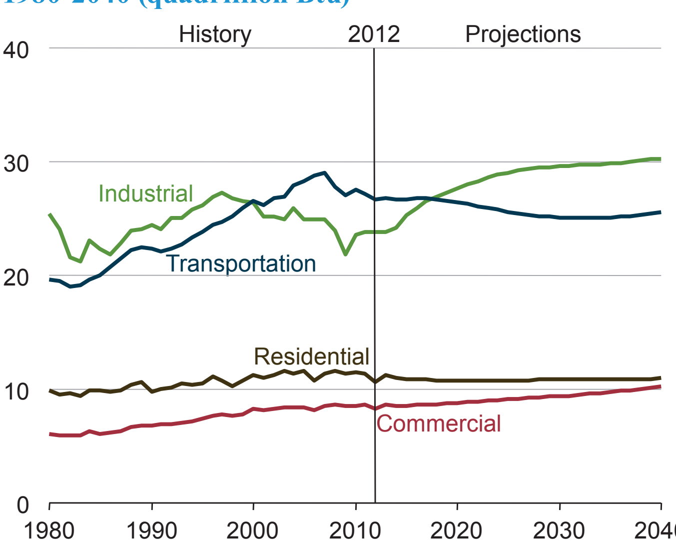
Transportation

Delivered energy consumption in the transportation sector declines from 26.7 quadrillion Btu in 2012 to 25.5 quadrillion Btu in 2040 in the *AEO2014* Reference case (Figure 7) because of a significant decline in energy consumption by LDVs that more than offsets growth in energy consumption for other modes. The decline in transportation sector delivered energy consumption is markedly different from the historical trend of 1% average annual growth in transportation energy consumption from 1975 to 2012.[23] Transportation energy consumption is considerably lower in *AEO2014* than projected in the *AEO2013* Reference case (27.1 quadrillion Btu in 2040) with energy consumption by nearly all transportation modes reduced in *AEO2014* as a result of lower macroeconomic indicators, higher energy efficiency, changing demographics, and a revised calculation of VMT.

LDV energy consumption declines in the *AEO2014* Reference case from 16.0 quadrillion Btu in 2012 to 12.1 quadrillion Btu in 2040, compared with 13.0 quadrillion Btu in 2040 in the *AEO2013* Reference case. GHG emission standards and CAFE standards increase new LDV fuel economy through model year 2025 and beyond, with more fuel-efficient new vehicles gradually replacing older vehicles on the road and raising the fuel efficiency of the LDV stock by an average of 2.0% per year, from 21.5 miles per gallon (mpg) in 2012 to 37.2 mpg in 2040. The higher fuel economy of LDVs more than offsets increases in VMT that average 0.9% per year from 2012 to 2040, a reduction from the *AEO2013* projection that reflects changes in driving behavior related to changing demographics. The average fuel economy of the vehicle stock is higher, and travel by LDVs is lower in *AEO2014* than projected in *AEO2013*. The large decline in LDV energy consumption in *AEO2014* shrinks the LDV modal share of total transportation energy consumption from 60% in 2012 to 47% in 2040.

LDVs powered by motor gasoline remain the dominant vehicle type in the *AEO2014* Reference case, retaining a 78% share of new LDV sales in 2040, down from their 82% share in 2012. The fuel economy of LDVs powered by motor gasoline continues to increase, and advanced technology fuel efficiency subsystems are added, such as micro hybridization, which is installed on 42% of new motor gasoline LDVs in 2040. The numbers of LDVs powered by fuels other than gasoline, such as diesel, electricity, or E85, or equipped with hybrid drive trains, such as plug-in hybrid or gasoline hybrid electric, increase modestly from 18% of new sales in 2012 to 22% in 2040. Ethanol FFVs account for 11% of overall vehicle sales in 2040, followed by hybrid electric vehicles (excluding micro hybrids) at 5% of new sales in 2040, up from 3% in 2012, diesel vehicles at 4% in 2040, up from 2% in 2012, and plug-in hybrid vehicles and electric vehicles at about 1% each, both up from negligible shares in 2012. New vehicle sales shares are generally similar in *AEO2014* and *AEO2013* but with moderate variation. In *AEO2013*, the new vehicle sales share of motor gasoline vehicles was 80% in 2040 (with 36% of those vehicles including micro hybridization), followed by 7% for ethanol FFVs, 6% for hybrid electric, 3% for diesel, 2% for plug-in hybrids, and 1% for electric vehicles. The differences from *AEO2013* to *AEO2014* result from different fuel prices,

Figure 7. Delivered energy consumption by sector, 1980-2040 (quadrillion Btu)



[22]The amount of energy delivered to the sector; no adjustment is made for the fuels consumed to produce electricity or district sources.
[23]S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Data Book*, ORNL-6989 (Edition 32 of ORNL-5198) (Oak Ridge, TN: July 2013), Chapter 2, Table 2.1, "U.S. Consumption of Total Energy by End-Use Sector, 1973-2012."

updated manufacturer product offerings, changing technology attributes, and an updated view of consumer perceptions of infrastructure availability for E85 vehicles.

Delivered energy demand for HDVs in *AEO2014* increases from 5.3 quadrillion Btu in 2012 to 7.5 quadrillion Btu in 2040, similar to the 2040 level of 7.6 quadrillion Btu in *AEO2013,* and represents the largest growth among all transportation modes. Growth in industrial output in *AEO2014* leads to solid growth in HDV VMT, averaging 1.9% per year from 2012 to 2040. HDV energy demand is tempered somewhat by an average 0.5% annual increase in fuel economy from 2012 to 2040 as a result of GHG emission and fuel efficiency standards for medium- and heavy-duty vehicles and engines. Competitive natural gas prices significantly increase the demand for LNG and compressed natural gas in *AEO2014*, from an insignificant share in 2012 to 8% of HDV energy consumption in 2040, which is less than the 13% share projected in *AEO2013* because of the lower prices of competing fuels in *AEO2014*. The rapid growth of energy consumption by HDVs in *AEO2014* increases their modal share of total transportation energy consumption from 20% in 2012 to 29% in 2040.

Energy demand for aircraft grows in the *AEO2014* Reference case from 2.5 quadrillion Btu in 2012 to 2.7 quadrillion Btu in 2040, which is less than the *AEO2013* projection of 2.9 quadrillion Btu in 2040. Personal air travel (billion seat-miles) grows by an average of 0.7% per year in *AEO2014*, but improved fuel efficiency (by an average of 0.5% per year) reduces the effect on energy consumption. The difference between *AEO2014* and *AEO2013* stems from lower demand for personal air travel in *AEO2014* as a result of lower economic growth. The aircraft share of total transportation energy consumption in *AEO2014* increases from 9% in 2012 to 11% in 2040.

Energy consumption by marine vessels increases from 0.9 quadrillion Btu in 2012 to 1.0 quadrillion Btu in 2040 in *AEO2014*, reflecting the impacts of increased foreign trade on international shipping and higher incomes on recreational boating. Pipeline energy use rises modestly, from 0.7 quadrillion Btu in 2012 to 0.8 quadrillion Btu in 2040, as increasing volumes of natural gas are produced but closer to end-use markets. Rail energy consumption remains nearly flat at 0.5 quadrillion Btu from 2012 to 2040 in *AEO2014*, as a result of a plateau in coal shipments and increases in fuel efficiency, which offset growth in rail transportation of other industrial commodities.

Other energy use in the transportation sector, which includes both lubricants and military energy use, increases from 0.8 quadrillion Btu in 2012 to 0.9 quadrillion Btu in 2040. Marine, pipeline, other transportation, and rail energy use all are relatively minor pieces of the overall transportation energy consumption picture in *AEO2014*, each accounting for less energy demand than in the *AEO2013* projections, as a result of lower economic growth in the *AEO2014* Reference case.

Industrial

Approximately one-third of total U.S. delivered energy in 2012, 23.6 quadrillion Btu, was consumed in the industrial sector, which includes manufacturing, agriculture, construction, and mining. In the *AEO2014* Reference case, total industrial delivered energy consumption grows to 30.2 quadrillion Btu in 2040—1.5 quadrillion Btu, or 5%, higher than the *AEO2013* Reference case projection. The industrial sector becomes the largest energy consuming sector by 2018 and remains so for the rest of the projection period.

The growth rate for total industrial energy consumption in the *AEO2014* Reference case is greater than in *AEO2013* as a result of lower natural gas prices, which boost industrial production, and greater availability of natural gas liquids (NGL).[24] The industry that consumes the most energy is bulk chemicals, where total energy consumption grows from 5.5 quadrillion Btu in 2012 to 7.0 quadrillion Btu in 2040. In the *AEO2014* Reference case, energy consumption by the bulk chemicals industry in 2040 is 1.2 quadrillion Btu higher than projected in *AEO2013*.

Total manufacturing shipments in the *AEO2014* Reference case also increase more rapidly than in the *AEO2013* Reference case, from $4.5 trillion in 2012 to $8.4 trillion in 2040, or 87%. The growth rate for shipments in energy-intensive manufacturing is one-half the rate for non-energy-intensive manufacturing, reflecting the continuing shift toward less energy-intensive manufacturing, such as transportation equipment, computers, and other durable metal goods. The rate of growth in all manufacturing industries is higher from 2012 to 2025 than after 2025, as a result of increased international competition in the later years of the projection.

Shipments in the energy-intensive industries—refining, food, paper, bulk chemicals, glass, cement and lime, iron and steel, and aluminum—grow from $1.6 trillion in 2012 to $2.3 trillion in 2040 in the *AEO2014* Reference case, an annual rate of growth of 1.3%, compared to 1.0% in the *AEO2013* Reference case. The rate of increase in *AEO2014* is much faster from 2012 to 2025 (2.0% per year) than from 2025 to 2040 (0.7% per year). Shipments of bulk chemicals, iron and steel, and aluminum peak in the late 2020s and decline thereafter, as export growth slows. Total energy consumption in the energy-intensive industries increases by 0.7% per year from 2012 to 2040, with almost all the growth occurring in the 2012-25 period.

Energy use for heat and power in the energy-intensive industries grows from 11.5 quadrillion Btu in 2012 to 13.1 quadrillion Btu in 2040, averaging 0.9% per year from 2012 to 2025 and 0.1% per year from 2025 to 2040. With energy intensity declining in the energy-intensive industries, largely because of improvements in efficiency, the growth of energy use for heat and power is slower than the growth of shipments. In the bulk chemicals and petroleum refining industries, demand for feedstocks—which include HGL,[25] petroleum (usually naphtha), and natural gas—grows by 1.3% per year on average, from 3.5 quadrillion Btu in 2012 to 5.0

[24]Natural gas liquids include ethane, propane, normal butane, isobutane, and pentanes plus.

[25]HGL includes NGL, ethane, propane, normal butane, isobutane, natural gasoline (pentanes plus), and olefins.

quadrillion Btu in 2040, with average increases of 2.9% per year from 2012 to 2025 followed by a decline from 2025 to 2040 averaging 0.1% per year.

Only the bulk chemical industry uses liquid feedstocks (HGL and petrochemical feedstocks), which are used to produce organic chemicals, inorganic chemicals, resins, synthetic rubber, and fibers. With demand for bulk chemicals higher in the *AEO2014* Reference case than in *AEO2013*, consumption of liquid feedstocks also is higher in *AEO2014*. HGL feedstocks and petrochemical feedstocks (naphtha and heavier inputs) often can be interchanged to some degree, depending on price and the product slate. In the *AEO2014* Reference case, HGL feedstock consumption totals 2.2 quadrillion Btu in 2012, 2.9 quadrillion Btu in 2025, and 2.7 quadrilion Btu in 2040; and petrochemical feedstock use totals 0.8 quadrillion Btu in 2012, 1.5 quadrillion Btu in 2025, and 1.6 quadrillion Btu in 2040.

Shipments from the nonenergy-intensive manufacturing sector increase by 2.7% per year from $2.9 trillion in 2012 to $6.1 trillion in 2040 in the *AEO2014* Reference case, with growth rates of 3.2% per year from 2012 to 2025 and 2.3% per year after 2025. Energy consumption for nonenergy-intensive manufacturing grows from 3.6 quadrillion Btu in 2012 to 4.9 quadrillion Btu in 2040, averaging 1.0% per year—the same rate as in the *AEO2013* Reference case. In parallel with the growth of shipments, energy consumption in the nonenergy-intensive manufacturing sector grows more rapidly from 2012 to 2025 (1.3% per year) than from 2025 to 2040 (0.8% per year).

In the nonmanufacturing industries—agriculture, construction, and mining—shipments grow by 1.6% per year from 2012 to 2040 in the *AEO2014* Reference case, slightly less than the annual growth rate of 1.8% in the *AEO2013* Reference case over the same period. Growth in the *AEO2014* Reference case averages 2.8% per year from 2012 to 2025 and slows to 0.7% per year after 2025. Energy consumption by nonmanufacturing industries grows by 1.2% per year, from 4.8 quadrillion Btu in 2012 to 6.8 quadrillion Btu in 2040. While energy intensity declines somewhat in the agriculture and construction industries, it increases in the mining industry as exploration activities move over time to less desirable—and more energy-intensive—resources.

Residential

Residential delivered energy consumption remains roughly constant in the *AEO2014* Reference case from 2012 to 2040. However, consumption levels are lower than those in *AEO2013* for most fuels. In addition to lower population growth projections, the lower consumption levels in the *AEO2014* Reference case are explained in part by incorporation of the 2009 RECS data, which include characteristic information such as the mix of building types in each region of the country, equipment stocks, and appliance saturation levels, as well as energy consumption estimates for three major end uses—space heating, space cooling, and water heating. In addition, weather-related demand elasticities for heating and cooling also have been updated to better align *AEO* projections with those in EIA's *Short-Term Energy Outlook.*

The *AEO2014* Reference case removes the 2013 federal efficiency standard for condensing gas furnaces, based on challenges to the DOE rulemaking, first by an association of natural gas utilities and later by equipment distributors. Although natural gas use tends to be lower when the standard is included, consumption in the *AEO2014* Reference case (without the standard) is lower than in *AEO2013* (with the standard) through most of the projection period, largely because of changes in the end-use allocations from the 2009 RECS.

An EIA-contracted report[26] provides updated estimates of the installed stock and consumption of several miscellaneous electric loads, including televisions, computers, and related equipment. This update generally resulted in lower electricity consumption for these appliances than was projected in the *AEO2013* Reference case.

For *AEO2014*, outdoor lighting was added to the residential model as a separate application. In addition, cost and performance attributes for most residential lighting types were updated on the basis of EIA-contracted technology reports[27] and market studies from DOE.[28] Lower costs and wider availability of LEDs result in lower energy consumption after 2020 in *AEO2014* relative to *AEO2013*.

Commercial

Commercial sector delivered energy consumption grows from 8.3 quadrillion Btu in 2012 to 10.2 quadrillion Btu in 2040 in the *AEO2014* Reference case, similar to the *AEO2013* Reference case despite slower growth in the near term. Commercial electricity consumption increases by 0.8% per year from 2012 to 2040 in *AEO2014*, lower than the 1.0% average annual growth in commercial floorspace, in part because projected demand for cooling and lighting is lower than in *AEO2013*. Also, more rapid reductions in energy use for personal computers than previously estimated, largely because of a shift to more efficient portable devices, result in a projected 5.6% annual decline in electricity demand for commercial PC equipment in the *AEO2014* Reference case. Following

[26] Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in NEMS* (Washington, DC, May 2013), prepared for the U.S. Department of Energy, U.S. Energy Information Administration.

[27] U.S. Energy Information Administration, "Updated Buildings Sector Appliance and Equipment Costs and Efficiency" (Washington, DC: August 7, 2013), http://www.eia.gov/analysis/studies/buildings/equipcosts/.

[28] U.S. Department of Energy, Energy Efficiency & Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf, and *2010 U.S. Lighting Market Characterization* (Washington, DC: January 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2010-lmc-final-jan-2012.pdf.

slower-than-expected adoption of new data centers as a result of the recent recession, installations of new data center servers increase more in *AEO2014* than in *AEO2013*.

Growth of natural gas consumption in the commercial sector averages roughly 0.7% per year from 2012 to 2040, similar to the *AEO2013* Reference case.

Energy consumption by primary fuel

Total primary energy consumption grows by 12% in the *AEO2014* Reference case, from 95 quadrillion Btu in 2012 to 106 quadrillion Btu in 2040—1.3 quadrillion Btu less than in *AEO2013* (Figure 8). The fossil fuel share of energy consumption falls from 82% in 2012 to 80% in 2040, as consumption of petroleum-based liquid fuels declines, largely as a result of slower growth in VMT and increased vehicle efficiency.

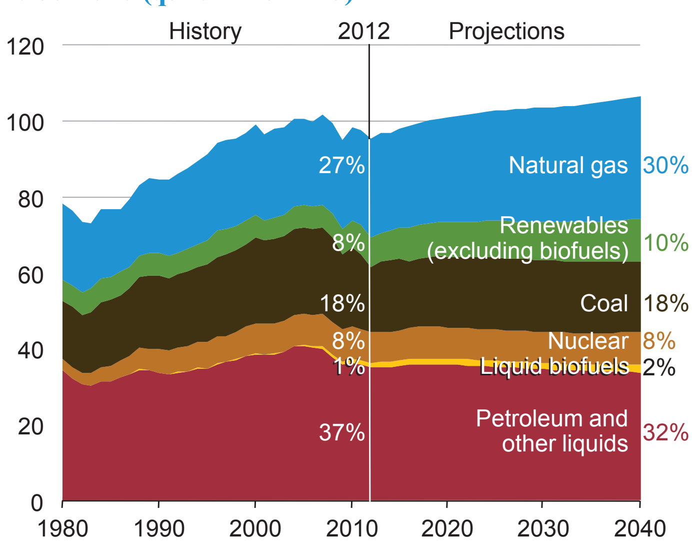
Total U.S. consumption of petroleum and other liquids, which was 35.9 quadrillion Btu (18.5 MMbbl/d) in 2012, increases to 36.9 quadrillion Btu (19.5 MMbbl/d) in 2018, then declines to 35.4 quadrillion Btu (18.7 MMbbl/d) in 2034 and remains at that level through 2040. Total consumption of domestically produced biofuels increases slightly through 2022 and then remains relatively flat. Production of cellulosic biofuels is currently well under 1% of the EISA2007 targets.[29] With the PTC for cellulosic biofuels scheduled to expire at the end of 2013, production of cellulosic biofuels remains below the EISA2007 target through the projection period. Within the transportation sector, which dominates demand for petroleum and other liquids, there is a shift from motor gasoline (losing more than 10% of its share of total transportation petroleum and other liquids demand over the projection) to distillate (gaining slightly less than 10% of the total). The increased use of compressed natural gas and LNG in vehicles also offsets about 3% of petroleum and other liquids consumption in the transportation sector in 2040.

Domestic natural gas consumption in the *AEO2014* Reference case rises from 25.6 Tcf in 2012 to 31.6 Tcf in 2040 (about 2.1 Tcf higher than in the *AEO2013* Reference case). The largest share of the growth is for electricity generation. Demand for natural gas in the electric power sector increases from 9.3 Tcf in 2012 to 11.2 Tcf in 2040, with a portion of the growth attributable to the retirement of 50 gigawatts of coal-fired capacity by 2021. Natural gas consumption in the industrial sector is also higher in *AEO2014* than was projected in *AEO2013*, as a result of the rejuvenation of the industrial sector as it benefits from surging shale gas production that is accompanied by slower growth of natural gas prices. Industries such as bulk chemicals, which use natural gas as a feedstock, are more strongly affected than others. In the residential sector, natural gas consumption declines throughout the projection.

Total coal consumption increases from 17.3 quadrillion Btu (891 MMst) in 2012 to 18.7 quadrillion Btu (979 MMst) in 2040 in the *AEO2014* Reference case. Coal consumption, mostly for electric power generation, falls off in 2016, the first year of the MATS. After 2016, coal-fired electricity generation increases slowly over the next 10 years as the remaining coal-fired capacity is used more intensively, but little capacity is added. Coal consumption in the electric power sector in 2040 is 17.3 quadrillion Btu (909 MMst) in the *AEO2014* Reference case. This level is about 1.4 quadrillion Btu (75 MMst) lower than in the *AEO2013* Reference case. No coal is consumed for CTL technology in the *AEO2014* Reference case.

With the implementation of the federal RFS for transportation fuels and state renewable portfolio standards for electricity generation, consumption of marketed renewable fuels grows by 1.4% per year in the *AEO2014* Reference case. Marketed renewable energy includes wood, municipal waste, other biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal solid waste, biomass, solar, and wind power in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 1.5 quadrillion Btu is included with petroleum and other liquid fuels consumption in 2040. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.9 quadrillion Btu in 2012 to 4.5 quadrillion Btu in 2040, with biomass accounting for 27% of the growth and wind 39%. Generation of electricity from solar photovoltaic energy shows the fastest growth, starting from a small base and accounting for 7.5% of total electricity generation from all nonhydropower renewable energy sources in 2040.

Figure 8. U.S. primary energy consumption by fuel, 1980-2040 (quadrillion Btu)



Energy intensity

From 1992 to 2012, energy use per dollar of GDP declined on average by 1.9% per year, in large part because of shifts within the economy from manufactured goods to the service sectors,

[29]Based on 2010, 2011, 2012, and 2013 evaluations of the volumes of cellulosic biofuels available, EPA substantially reduced the cellulosic biofuels obligation under the RFS for those years, with the 2013 obligation set at 6 million ethanol-equivalent gallons, less than 1% of the legislated target of 1 billion gallons.

which use relatively less energy per dollar of GDP. The dollar-value increase in the service sectors (in constant dollar terms) was almost 12 times the corresponding increase for the industrial sector over the same period. As a result, the share of total shipments accounted for by the industrial sector fell from 30% in 1992 to 22% in 2012 (including a slight increase from 2009 to 2012). In the *AEO2014* Reference case, the industrial share of total shipments increases to 24% in 2016, after which it declines again, at a very slow rate, to 23% in 2040. Energy use per 2005 dollar of GDP declines by 43% from 2012 to 2040 in *AEO2014* as the result of a continued shift from manufacturing to services (and, even within manufacturing, to less-energy-intensive manufacturing industries), rising energy prices, and the adoption of policies that promote energy efficiency.

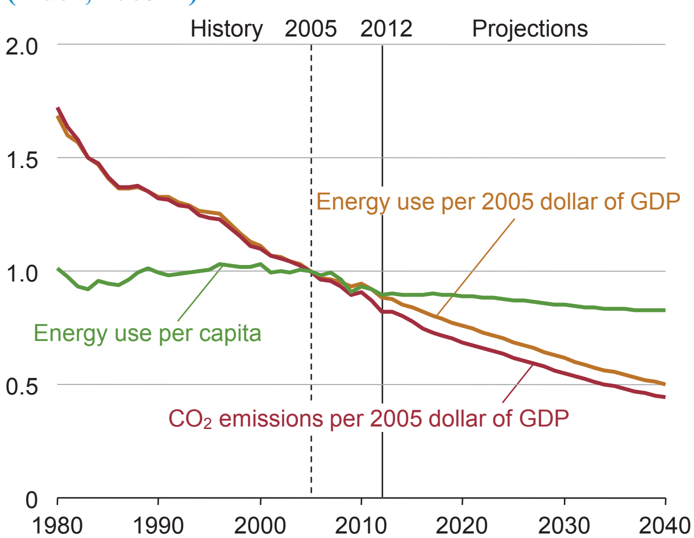
U.S. energy use per capita was fairly constant from 1990 to 2007 but began to fall after 2007. In the *AEO2014* Reference case, energy use per capita continues to decline as a result of improvements in energy efficiency (e.g., new appliance and CAFE standards) and changes in the ways energy is used in the U.S. economy. Total U.S. population increases by 21% from 2012 to 2040, but energy use grows by only 12%, with energy use per capita declining by 8% from 2012 to 2040 (Figure 9).

CO_2 emissions per 2005 dollar of GDP have historically tracked closely with energy use per dollar of GDP. In the *AEO2014* Reference case, however, with lower-carbon fuels accounting for a growing share of total energy use, CO_2 emissions per dollar of GDP decline more rapidly than energy use per dollar of GDP, to 56% below their 2005 level in 2040 (or by 2.3% per year).

Energy production and imports

Net imports of energy decline both in absolute terms and as a share of total U.S. energy consumption in the *AEO2014* Reference case (Figure 10). The decline in energy imports reflects increased domestic production of petroleum and natural gas, along with demand reductions resulting from rising energy prices and gradual improvement in vehicle efficiency. At the same time, natural gas exports increase (as domestic supplies increase and it becomes attractive to liquefy the natural gas for export), along with exports of motor gasoline (as demand declines and refiners are left with more than they can sell domestically) and exports of crude oil (as lighter domestic crude oil is swapped for the heavier crudes more commonly run in modern refineries). The net import share of total U.S. energy consumption is 4% in 2040, compared with 16% in 2012 and about 30% in 2005.

Figure 9. Energy use per capita, energy use per dollar of GDP, and emissions per dollar of GDP, 1980-2040 (index, 2005=1)



Petroleum and other liquids

U.S. production of crude oil (including lease condensate) in the *AEO2014* Reference case increases from 6.5 MMbbl/d in 2012 to 9.6 MMbbl/d in 2019, 22% higher than in *AEO2013* (Figure 11). Despite a decline after 2019, U.S. crude oil production remains at or above about 7.5 MMbbl/d through 2040. Higher production volumes result mainly from increased onshore oil production, predominantly from tight (very-low-permeability) formations. Offshore crude oil

Figure 10. Total energy production and consumption, 1980-2040 (quadrillion Btu)

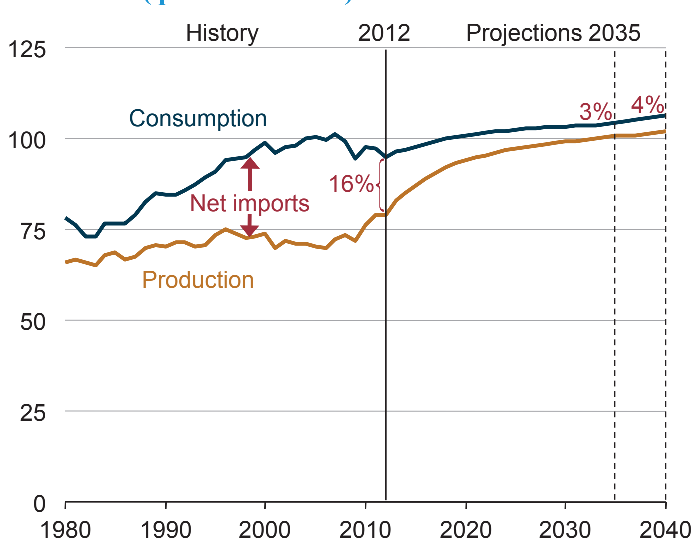
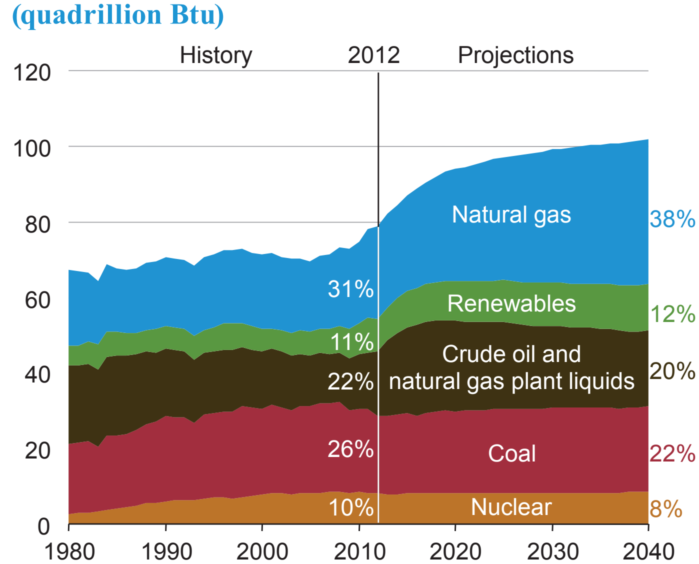


Figure 11. U.S. energy production by fuel, 1980-2040 (quadrillion Btu)



provides a steady supply of domestic crude oil production, ranging between 1.6 and 2.0 MMbbl/d from 2015 through 2040, as the pace of development activity quickens and new, large development projects, predominantly in the deepwater and ultra-deepwater portions of the Gulf of Mexico, are brought into production.

The faster growth of tight oil production through 2020 in the *AEO2014* Reference case results in higher domestic crude oil production than in *AEO2013* throughout the projection. The pace of oil-directed drilling in the near term is much stronger than in *AEO2013*, as producers locate and target the sweet spots of plays currently under development and find additional tight formations that can be developed with the latest technologies. In the *AEO2014* Reference case, tight oil production increases from 2.3 MMbbl/d in 2012 (35% of total U.S. crude oil production) to 4.8 MMbbl/d in 2021 (51% of the total). As in *AEO2013*, tight oil production declines in *AEO2014* after 2021, as more development moves into less-productive areas.

U.S. use of imported petroleum and other liquid fuels continues to decline in *AEO2014* mainly as a result of increased domestic oil production. Imported petroleum and other liquid fuels as a share of total U.S. use reached 60% in 2005 before dipping below 50% in 2010 and falling further to 40% in 2012. The import share continues to decline to 25% in 2016 and then rises to about 32% in 2040 in the *AEO2014* reference case, as domestic production of tight oil begins to decline in 2022 (Figure 12).

Natural gas

Cumulative production of dry natural gas from 2012 to 2040 in the *AEO2014* Reference case is about 11% higher than in *AEO2013*, primarily reflecting continued growth in shale gas production resulting from the dual application of horizontal drilling and hydraulic fracturing. Another contributing factor is ongoing drilling in shale and other plays with high concentrations of NGL and crude oil, which in energy-equivalent terms have a higher value than dry natural gas. Cumulative production levels for tight gas and onshore associated-dissolved gas from oil formations exceed those in *AEO2013* through 2040 by 9% and 36%, respectively, making material contributions to the overall increase in production. Natural gas prices above $6/MMBtu toward the end of the projection period encourage drilling in less-productive but still-profitable areas in tight oil, shale oil, and natural gas formations. Lower 48 offshore natural gas production fluctuates between 1.7 Tcf and 2.9 Tcf per year, similar to the pattern in *AEO2013*. The multiyear decline in offshore natural gas production was reversed in 2012, with 15 new deepwater projects coming on line during the year.

In the *AEO2014* Reference case, the United States becomes a net exporter of LNG in 2016, and it becomes an overall net exporter of natural gas in 2018, two years earlier than in *AEO2013*. U.S. exports of LNG from new liquefaction capacity are expected to surpass 2 Tcf by 2020 and increase to 3.5 Tcf in 2029. Net pipeline imports from Canada fall steadily until 2033, and then increase through 2040. Net pipeline exports to Mexico grow by more than 400% in the Reference case, with additional pipeline infrastructure added to enable the Mexican market to receive more pipeline natural gas from the United States.

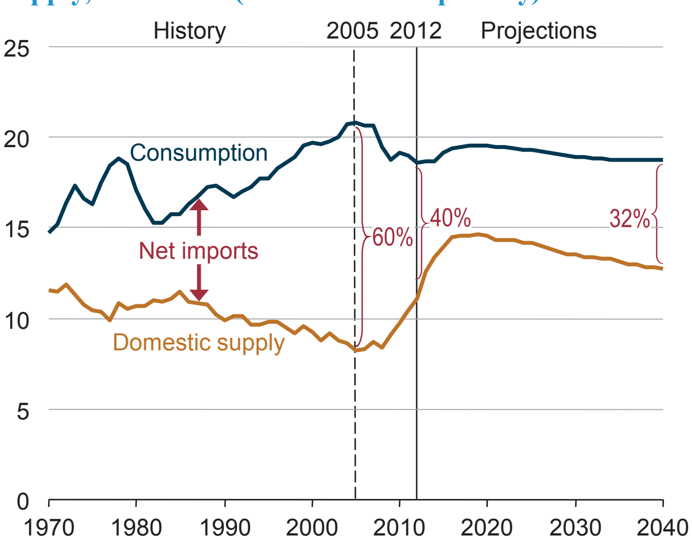
U.S. cumulative net LNG exports from 2012 to 2040 are up by 160% in *AEO2014* compared with *AEO2013*, supported by increased use of LNG in markets outside America, strong domestic production, and low U.S. natural gas prices relative to other global markets.

Coal

Total U.S. coal production grows at an average rate of 0.3% per year in the *AEO2014* Reference case, from 20.6 quadrillion Btu (1,016 MMst) in 2012 to 22.6 quadrillion Btu (1,121 MMst) in 2040. U.S. electricity generation accounted for 91% of total U.S. coal consumption (in Btu) in 2012. Coal production declined by more than 7% in 2012, from 1,096 MMst in 2011, mostly in response to gas-on-coal competition. In the Reference case, production recovers to 1,062 MMst by 2015, in response to a rise in natural gas prices along with a moderate increase in electricity demand. A wave of coal-fired generating capacity retirements in response to MATS requirements coincides with a secondary drop in coal production to 1,022 MMst in 2016. Total production then increases gradually to 1,127 MMst in 2030 before stabilizing as a result of limits on achievable long-term capacity utilization rates for available coal units compared to *AEO2013*.

Coal production from the Eastern Interior region in the *AEO2014* Reference case increases at a faster rate than projected in *AEO2013*, because of an improved productivity outlook, with 2020 production 27 MMst (18%) higher and 2040 production 58 MMst (34%) higher than projected in *AEO2013*. Lower overall coal consumption and improved competitiveness of coal produced in the Eastern Interior region compared to *AEO2013* lead to lower outlooks for Northern Appalachian and Powder River Basin coal production, as well as an accelerated decline in Central Appalachian production in *AEO2014*. As a result of changes to CTL cost assumptions, no CTL coal consumption or related production is projected in

Figure 12. U.S. petroleum and other liquid fuels supply, 1970-2040 (million barrels per day)



AEO2014, compared with 0.3 quadrillion Btu in 2040 in *AEO2013*. Expectations for total U.S. coal exports in *AEO2014* are generally similar to those in *AEO2013*, with an increase from 126 MMst in 2012 to 161 MMst by 2040.

Electricity generation

Total electricity consumption in the *AEO2014* Reference case, including both purchases from electric power producers and on-site generation, grows from 3,826 billion kWh in 2012 to 4,954 billion kWh in 2040, an average annual rate of 0.9% that is about the same as in the *AEO2013* Reference case. While growth in electricity consumption is similar overall, growth in the industrial sector is much stronger than in *AEO2013*, while growth in the residential sector is weaker.

The combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of environmental rules dampens future coal use. The *AEO2014* Reference case continues to assume implementation of the Clean Air Interstate Rule (CAIR)[30] as a result of an August 2012 federal court move to vacate the Cross-State Air Pollution Rule.[31] In addition, *AEO2014* continues to assume the implementation of MATS in 2016. Once MATS is in place, sulfur dioxide levels are reduced to well below the levels required by CAIR, and mercury emissions drop to 6.1 tons in 2016 from 30.8 tons in 2011 when the rule was finalized.

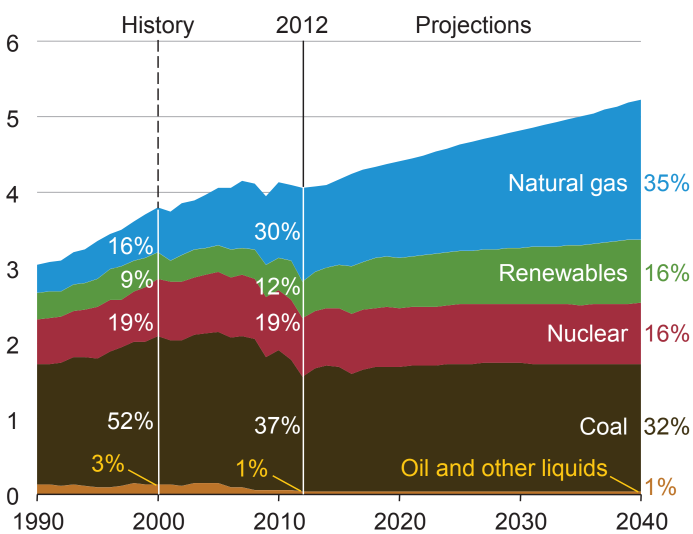
Coal-fired power generation over the next few years is slightly higher in *AEO2014* than in the *AEO2013* Reference case because of higher natural gas prices during that period, as well as pending nuclear retirements that necessitate additional baseload generation. After 2020, generation from coal flattens out and remains lower than projected in *AEO2013*, because more coal-fired capacity is retired and fewer new coal plants are built (Figure 13).

Coal-fired electricity generation has traditionally been the largest component of electricity generation, representing 37% of total generation in 2012. By 2035, however, natural gas generation is projected to surpass coal generation. Coal and natural gas each represent 34% of total generation in 2035, but by 2040 the coal share drops to 32%, and the natural gas share increases to 35%. Market concerns about GHG emissions continue to dampen the expansion of coal-fired capacity in the *AEO2014* Reference case, even with the assumption of current laws and policies. Low fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in construction costs for new coal-fired power plants. As retirements far outpace new additions, total coal-fired generating capacity falls from 310 gigawatts (GW) in 2012 to 262 GW in 2040 in the *AEO2014* Reference case. As with all projections, projected generation shares are highly sensitive to both fuel prices and changes in policies and regulations. Alternative cases in the full *AEO2014* will quantify these sensitivities.

In the first few years of the projection, electricity generation using natural gas is slightly lower in the *AEO2014* Reference case than in the *AEO2013* Reference case because of higher natural gas prices in *AEO2014*. By 2017, however, natural gas-fired generation is higher in *AEO2014* than in the *AEO2013* Reference case, and the difference continues to grow. Additional retirements of coal and nuclear plants result in the need for new capacity, and new natural gas-fired plants are much cheaper to build than coal, nuclear, or renewable plants. In 2020, natural gas-fired generation in *AEO2014* is 7% higher than in *AEO2013*, and in 2040 it is 16% higher.

Electricity generation from nuclear power plants grows by 5% in the *AEO2014* Reference case, from 769 billion kWh in 2012 to 811 billion kWh in 2040, accounting for about 16% of total generation in 2040 (compared with 19% in 2012). Nuclear generating capacity decreases from 102 GW in 2012 to 98 GW in 2020 as new construction (5.5 GW) and uprates at existing plants (0.7 GW) are more than offset by retirements in several regions where existing nuclear units are facing challenging economic conditions. After 2025, a small amount of new nuclear capacity comes on line as natural gas prices rise. In 2040, overall nuclear capacity is back up to 102 GW. *AEO2014* incorporates updated information from EIA data collections regarding planned nuclear plant construction and capacity uprates at existing units.

Figure 13. Electricity generation by fuel, 1990-2040 (trillion kilowatthours)



Increased generation with renewable energy, excluding hydropower, accounts for 28% of the overall growth in electricity generation from 2012 to 2040 in the *AEO2014* Reference case. Generation from renewable resources grows in response to federal tax credits, state-level policies, and federal requirements to use more biomass-based transportation fuels, some of which can produce electricity as a byproduct of their production processes. In the final decade of the projection, however, renewable generation growth is driven by increasing cost competiveness with other nonrenewable technologies.

[30]U.S. Environmental Protection Agency, "Clean Air Interstate Rule (CAIR)" (Washington, DC: December 19, 2012), http://www.epa.gov/cair/.

[31]U.S. Environmental Protection Agency, "Fact Sheet: The Cross-State Air Pollution Rule: Reducing the Interstate Transport of Fine Particulate Matter and Ozone" (Washington, DC: July 2011), http://www.epa.gov/airtransport/pdfs/CSAPRFactsheet.pdf.

Compared to the *AEO2013* Reference case, renewable generation is higher throughout most of the projection period, particularly in the near term, because of the inclusion of the energy provisions of the ATRA. This law, among other things, extends several tax credits for utility-scale renewables and redefines the qualification criteria, resulting in more construction of wind-powered generating capacity in the near term.

Reported renewable capacity already under construction has increased in recent years and is represented in *AEO2014*. Growth in renewable generation is supported by many state requirements, as well as regulations on CO_2 emissions in California. The share of U.S. electricity generation coming from renewable fuels (including conventional hydropower) grows from 12% in 2012 to 16% in 2040 in the *AEO2014* Reference case, even with federal subsidies for renewable generation assumed to expire as enacted. Extensions of such subsidies could have a large impact on renewable generation. The long-run projections for renewable capacity are also sensitive to natural gas prices and the relative costs of alternative generation sources.

Energy-related CO_2 emissions

In the *AEO2014* Reference case, total U.S. energy-related CO_2 emissions in 2040 equal 5,599 million metric tons, 92 million metric tons (1.6%) lower than in *AEO2013*. However, the carbon intensity of the economy in 2040 is slightly (0.6%) higher in *AEO2014* as compared with *AEO2013*. Projected energy-related CO_2 emissions in 2020 and 2040 are, respectively, about 9% and 7% below the 2005 level, compared to 9% and 5% below the 2005 level in *AEO2013*.

The lower GDP projection in *AEO2014* is partly the result of a lower population growth rate, and GDP per capita in 2040 is almost 4% higher in *AEO2014* than in *AEO2013*. Energy use per capita and energy-related CO_2 emissions per capita are higher in *AEO2014* than in *AEO2013* (about 5% in 2040). Also, higher levels of energy consumption and CO_2 emissions per dollar of GDP in *AEO2014* occur with a sectoral shift in the share of energy consumption from the residential, commercial, and transportation sectors toward the industrial sector, which generally is more energy- and carbon-intensive than other sectors of the economy. Over the projection period from 2012 to 2040, industrial emissions grow at an average annual rate of 0.6% in *AEO2014*, and industrial energy-related CO_2 emissions in 2040 are 133 million metric tons higher in *AEO2014* than in *AEO2013*.

When examining the electric power sector, excluding combined heat and power, there are offsetting factors in comparing *AEO2014* and *AEO2013*. Coal use for generation is 7.9% lower in 2040 (141 billion kWh) in *AEO2014* compared to *AEO2013* as a result of increased retirements of coal capacity and replacement with natural gas and renewables. However, nuclear generation, which has no CO_2 emissions, is also 10.1% (91 billion kWh) lower in 2040 in *AEO2014* compared to *AEO2013* because of more nuclear retirements in *AEO2014*. This offsets the CO_2 reduction achieved by switching from coal to natural gas and renewables. In total, the carbon intensity of the electric power sector is lower in *AEO2014* as generation declines by 0.2% (9 billion kWh), but emissions are 1.9% lower in 2040.

List of Acronyms

AEO	*Annual Energy Outlook*
AEO2013	*Annual Energy Outlook 2013*
AEO2014	*Annual Energy Outlook 2014*
ATRA	American Taxpayer Relief Act of 2012
bbl	Barrels
Btu	British thermal units
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CO_2	Carbon dioxide
CTL	Coal-to-liquids
DOE	U.S. Department of Energy
E85	Motor fuel containing up to 85% ethanol
EIA	U.S. Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FFV	Flexible fuel vehicle
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatts
HDV	Heavy-duty vehicle
HGL	Hydrocarbon gas liquid
kWh	Kilowatthour
LDV	Light-duty vehicle
LED	Light emitting diode
LNG	Liquefied natural gas
LPG	Liquefied petroleum gases
LRG	Liquefied refinery gases
MATS	Mercury and Air Toxics Standards
MECS	Manufacturing Energy Consumption Survey
MMbbl/d	Million barrels per day
MMBtu	Million Btu
MMst	Million short tons
NEMS	National Energy Modeling System
NGL	Natural gas liquids
NGPL	Natural gas plant liquids
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
PTC	Production tax credit
RECS	Residential Energy Consumption Survey
RFS	Renewable fuel standard
Tcf	Trillion cubic feet
VMT	Vehicle-miles traveled

Table 1. Comparison of projections in the *AEO2014* and *AEO2013* Reference cases, 2011-2040

Energy and economic factors	2011	2012	2025 *AEO2014*	2025 *AEO2013*	2040 *AEO2014*	2040 *AEO2013*
Primary energy production (quadrillion Btu)						
Crude oil and natural gas plant liquids	15.31	17.08	23.03	18.70	19.99	17.01
Dry natural gas	23.04	24.59	32.57	29.22	38.37	33.87
Coal	22.22	20.60	22.36	22.54	22.61	23.54
Nuclear/Uranium	8.26	8.05	8.15	9.54	8.49	9.44
Hydropower	3.11	2.67	2.84	2.86	2.90	2.92
Biomass	3.90	3.78	5.08	5.27	5.61	6.96
Other renewable energy	1.70	1.97	3.09	2.32	3.89	3.84
Other	0.80	0.41	0.24	0.85	0.24	0.89
Total	**78.35**	**79.15**	**97.36**	**91.29**	**102.09**	**98.46**
Net imports (quadrillion Btu)						
Petroleum and other liquid fuels[a]	18.78	16.55	11.41	15.89	13.65	15.99
Natural gas (- indicates exports)	2.03	1.58	-3.41	-1.56	-5.81	-3.55
Coal/other (- indicates exports)	-2.32	-2.86	-3.16	-3.02	-3.69	-2.95
Total	**18.49**	**15.26**	**4.85**	**11.31**	**4.15**	**9.49**
Energy consumption by fuel (quadrillion Btu)						
Petroleum and other liquid fuels[a]	36.56	35.87	36.28	36.87	35.35	36.07
Natural gas	24.91	26.20	28.97	27.28	32.32	29.83
Coal	19.62	17.34	19.03	19.35	18.75	20.35
Nuclear/Uranium	8.26	8.05	8.15	9.54	8.49	9.44
Hydropower	3.11	2.67	2.84	2.86	2.90	2.92
Biomass	2.60	2.53	3.74	3.82	4.26	4.91
Other renewable energy	1.70	1.97	3.09	2.32	3.89	3.84
Other	0.35	0.39	0.35	0.30	0.35	0.29
Total	**97.11**	**95.02**	**102.45**	**102.34**	**106.31**	**107.64**
Energy consumption by sector, including losses in electricity generation (quadrillion Btu)[b]						
Residential	21.39	20.10	20.58	21.08	21.48	23.08
Commercial	18.05	17.61	18.77	19.04	20.88	21.13
Industrial	30.46	30.54	37.43	35.46	38.33	36.16
Transportation	27.21	26.77	25.67	26.75	25.62	27.27
Total	**97.11**	**95.02**	**102.45**	**102.34**	**106.31**	**107.64**
Petroleum and other liquid fuels (million barrels per day)						
Domestic crude oil production	5.66	6.49	9.00	6.79	7.48	6.13
Other domestic production	4.71	4.60	5.14	5.63	5.22	5.83
Net imports	8.57	7.50	5.12	7.08	6.02	7.00
Consumption	18.92	18.49	19.27	19.50	18.73	18.95
Natural gas (trillion cubic feet)						
Dry gas production + supplemental gas	22.61	24.12	31.93	28.65	37.61	33.21
Net imports (- indicates exports)	1.96	1.51	-3.41	-1.58	-5.80	-3.55
Consumption	24.38	25.64	28.35	26.87	31.63	29.54

Table 1. Comparison of projections in the *AEO2014* and *AEO2013* Reference cases, 2011-2040 (continued)

			2025		2040	
Energy and economic factors	2011	2012	*AEO2014*	*AEO2013*	*AEO2014*	*AEO2013*
Coal (million short tons)						
Production and waste coal	1,109	1,027	1,128	1,134	1,139	1,195
Net exports	96	118	135	124	160	123
Consumption	1,003	891	993	1,010	979	1,071
Prices (2012 dollars)						
Brent spot crude oil (dollars per barrel)	113.24	111.65	108.99	119.45	141.46	165.57
West Texas Intermediate spot crude oil (dollars per barrel)	96.55	94.12	106.99	117.41	139.46	163.54
Natural gas at Henry Hub (dollars per million Btu)	4.07	2.75	5.23	4.96	7.65	7.97
Domestic coal at minemouth (dollars per short ton)	41.74	39.94	49.67	52.94	59.16	62.37
Average electricity price (cents per kilowatthour)	10.1	9.8	10.1	9.7	11.1	11.0
Economic indicators						
Real gross domestic product (billion 2005 dollars)	13,299	13,593	18,769	18,985	26,670	27,277
GDP chain-type price index (2005 = 1.000)	1.134	1.154	1.421	1.429	1.913	1.871
Real disposable personal income (billion 2005 dollars)	10,150	10,304	14,162	14,259	19,724	19,785
Value of industrial shipments (billion 2005 dollars)	5,926	6,147	8,778	8,548	10,994	10,616
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.30	6.99	5.46	5.39	3.99	3.95
Population (millions)	312.3	314.6	347.0	356.5	380.5	404.4
Energy-related carbon dioxide emissions (million metric tons)	**5,498**	**5,290**	**5,526**	**5,501**	**5,599**	**5,691**

[a]Includes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel.
[b]Electric power sector consumption is distributed to the end-use sectors.

Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Both coal consumption and coal production include waste coal consumed in the electric power and industrial sectors.

Sources: AEO2014 National Energy Modeling System, run REF2014.D102413A; and AEO2013 National Energy Modeling System, run REF2013.D102312A.