energy API

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June 26, 2013

Via E-Mail and Hand Delivery
The Honorable Ernest Moniz
U.S. Department of Energy
Forrestal Bldg, 1000 Independence Ave., SW
Washington, DC 20585

Re: LNG Export Authorization Process

Dear Secretary Moniz:

The American Petroleum Institute (API) is a national trade association representing more than 500 member companies involved in all aspects of the oil and natural gas industry in the United States. Our members include owners and operators of liquefied natural gas (LNG) import and export facilities in the United States and around the world, as well as owners and operators of LNG vessels, global LNG traders, and manufacturers of essential technology and equipment used all along the LNG value chain. Our members also have extensive experience with the drilling and completion techniques used in shale gas development and in producing America's natural gas resources in a safe and environmentally responsible manner.

From the outset, API has been an active stakeholder engaged with the Department of Energy (DOE) in its review of pending and anticipated LNG export applications, including the Department's study of the economic impacts of LNG exports (2012 LNG Export Study), and has provided constructive comments and input at every possible opportunity. For example, API engaged ICF International to conduct its own analysis of the economic impacts of LNG exports, a copy of which is enclosed for your review. Just as the DOE's 2012 LNG Export Study found, ICF International concluded that the net effects on U.S. GDP and employment from LNG exports are projected to be positive while having only moderate impacts on domestic U.S. natural gas prices. I urge you to consider ICF International's analysis as you undertake your own review of pending LNG export applications.

API applauds the Department's recently issued order authorizing the Freeport LNG terminal to export LNG to non-Free Trade Agreement (non-FTA) nations.[1] We agree with the DOE's findings and

[1] *Freeport LNG Expansion, L.P.*, DOE/FE Order No. 3282, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Freeport LNG Terminal on Quintana Island, Texas to Non-Free Trade Agreement Nations (May 17, 2013) (the "Freeport order").

welcome this positive step towards reviewing and approving all pending applications as expeditiously as possible. In particular, we are pleased that the DOE has concluded that the 2012 "LNG Export Study is fundamentally sound and supports the proposition that the [Freeport] authorization would not be inconsistent with the public interest."[2]

In addition to the 2012 LNG Export Study, the conclusions of which DOE unambiguously ratified in the Freeport order, each of the remaining pending non-FTA LNG Export application dockets contain comments in support of the respective application, arguments filed by various intervenor-protestors opposing the application, and responses from the applicant to such protests. As DOE explained in the Freeport order, it "must grant such an application unless opponents of the application overcome th[e] presumption" in favor of a proposed export with "an affirmative showing of inconsistency with the public interest."[3] However, DOE also found that no party to the Freeport proceeding submitted evidence "sufficient to rebut the statutory presumption that the requested authorization is consistent with the public interest."[4] The arguments opposing applications presented in each of the remaining non-FTA LNG export application dockets are substantially similar – if not identical – to those put forth in the Freeport docket. Thus, according to DOE, those arguments would be similarly insufficient to rebut the Natural Gas Act's presumption in favor of LNG exports.[5]

DOE also states in the Freeport order that it "will assess the cumulative impacts of each succeeding request for export authorization on the public interest with due regard to the effect on domestic natural gas supply and demand fundamentals."[6] After a review of all of the pending non-FTA LNG export application dockets, in API's view, none of the intervenor-protesters have demonstrated (or even attempted to demonstrate) any negative "cumulative impacts" of any individual proposed export volume on "domestic natural gas supply and demand fundamentals." Nor, we submit, could they, as the 2012 LNG Export Study, ICF International's analysis, and many other authorities[7] have shown. Because no intervenor-protestor in the remaining proceedings has demonstrated a negative cumulative impact, and therefore cannot rebut the Natural Gas Act's presumption that LNG exports are in the public interest, we strongly urge you to approve all pending non-FTA LNG export applications without delay.

We appreciate your prompt attention to this important matter. Should you have any questions, please do not hesitate to contact me.

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[2] *Id*. at 110.
[3] *Id*. at 6.
[4] *Id*. at 110.
[5] *Id*. ("Were we to decide this Application solely on the contents of the Application and the comments and protest received in response to the Notice of Application, [DOE] would be required to grant the Application").
[6] *Id*. at 112-13.
[7] *See, e.g.,* Kenneth Medlock, "U.S. LNG Exports: Truth and Consequence" (Aug. 10, 2012), *available at* http://bakerinstitute.org/publications/US%20LNG%20Exports%20-%20Truth%20and%20Consequence%20Final_Aug12-1.pdf; Charles Ebinger, et al., "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas" (May 2, 2012), *available at* http://www.brookings.edu/~/media/research/files/reports/2012/5/02%20lng%20exports%20ebinger/0502_lng_exports_ebinger; Navigant Consulting, "Jordan Cove LNG Export Project Market Analysis Study" (Jan. 2012), *available at* http://www.jordancoveenergy.com/pdf/Navigant_Jordan_Cove_LNG_Export_Study_012012.pdf; Deloitte Center for Energy Solutions, "Made in America: The Economic Impact of LNG Exports from the United States" (Dec. 20, 2011), *available at* http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Energy_us_er/us_er_MadeinAmerica_LNGPaper_122011.pdf.

Sincerely,

Jack Gerard
President and CEO, API

cc: Christopher Smith, Acting Assistant Secretary, Fossil Energy
Gregory Woods, General Counsel

Attachment

U.S. LNG Exports:

Impacts on Energy Markets and the Economy

Submitted by:
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May 15, 2013

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Key Findings on Economic Impacts of U.S. LNG Exports

In order to inform the current policy debate surrounding the granting of licenses for U.S. exports of liquefied natural gas (LNG), the American Petroleum Institute (API) commissioned ICF International to undertake a study of the energy market and economic impacts of LNG exports. The following table shows the key findings in terms of the average change in employment, GDP, and natural gas prices attributed to LNG exports between 2016 and 2035. Employment and GDP impacts are incremental changes relative to the Zero Exports Case.

Key Economic Impacts Relative to the Zero Exports Case

Impact (2016-2035 Averages)*	LNG Export Case (Change from Zero Exports Case)		
	ICF Base Case (up to ~4 Bcfd)	Middle Exports Case (up to ~8 Bcfd)	High Exports Case (up to ~16 Bcfd)
Employment Change (No.)	73,100-145,100	112,800-230,200	220,100-452,300
GDP Change (2010$ Billion)	$15.6-$22.8	$25.4-$37.2	$50.3-$73.6
Henry Hub Price (2010$/MMBtu)	$5.03	$5.30	$5.73
Henry Hub Price Change (2010$/MMBtu)	$0.32	$0.59	$1.02

*Source: ICF estimates. Note: * Includes direct, indirect, and induced impacts*

The main conclusions of this study are:

- The net effects on U.S. employment from LNG exports are projected to be positive with average net job growth of 73,100 to 452,300 between 2016 and 2035, including all economic multiplier effects. This wide estimated range reflects the fact that the net job impacts will depend, in part, on how much "slack" there is in the economy and how much the demand for LNG-export-related labor will "crowd out" other labor demands. Manufacturing job gains average between 7,800 and 76,800 net jobs between 2016 and 2035, including 1,700-11,400 net job gains in the specific manufacturing sectors that include refining, petrochemicals, and chemicals.
- The net effect on annual U.S. GDP of LNG exports is expected to be positive at about $15.6 to $73.6 billion annually between 2016 and 2035, depending on LNG export case and GDP multiplier effect. This includes the impacts of additional hydrocarbon liquids that would be produced along with the natural gas, greater petrochemical (olefins) production using more abundant natural gas liquids feedstock, and all economic multiplier effects.
- LNG exports are projected to have moderate impacts on domestic U.S. natural gas prices of about $0.32 to $1.02 per million British Thermal Units (MMBtu) on average between 2016 and 2035. This results in 2016-2035 average Henry Hub natural gas price estimates of between $5.03 and $5.73/MMBtu, depending on LNG export case.
- An international comparison of project cost and transportation cost differentials reveals that U.S. LNG exports (if they were not limited by government regulations) would likely fall within the range of 4 to 16 Bcfd through 2035. This indicates that U.S. LNG exports would have 12% to 28% market share of new LNG contract volumes in 2025 and market share of 8% to 25% in 2035.
- LNG exports are expected to lead to a rebalancing of U.S. natural gas markets in the form of domestic production increases (79%-88%), a reduction in domestic consumption (21% to 27%), and changes in pipeline trade with Canada and Mexico (7%-8%). The sum of the three supply sources exceed actual LNG export volumes by roughly 15% to account for fuel used during processing, transport, and liquefaction.
- Incremental U.S. dry gas production comes from many sources with varying levels of natural gas liquids content. By 2035, ICF estimates incremental liquids volumes increase between 138,000 barrels per day (bpd) and 555,000 bpd, attributable to LNG exports in the 4 to 16 Bcfd range.

This study also assessed a number of other LNG studies, including NERA's LNG export impact study done on behalf of the U.S. Department of Energy (DOE). This ICF study adds credence to the NERA results that there are positive benefits to U.S. GDP from LNG exports and that those benefits increase as the volume of exports rise. However, this study concludes that those GDP gains are expected to be larger than estimated by NERA. In addition, this study estimates considerable net job gains from LNG exports.

Contents

Glossary

Abbreviations

AEO	EIA Annual Energy Outlook
Bcf/day (or Bcfd)	Billion cubic feet of natural gas per day
Btu	British thermal unit, used to measure fuels by their energy content.
DES	Delivered Ex Ship
EIA	U.S. Energy Information Administration, a statistical and analytical agency within the U.S. Department of Energy
FOB	Free on Board
GDP	Gross Domestic Product
GTL	Gas-to-liquids
LNG	Liquefied Natural Gas
Mcf	Thousand cubic feet (volume measurement for natural gas)
MMcf	Million cubic feet (of natural gas)
MMBtu	Million British Thermal Units. Equivalent to approximately one thousand cubic feet of gas
MMBOE	Million barrels of oil equivalent wherein each barrel contains 5.8 million Btus.
MMbbl	Million barrels of oil or liquids
NAICS Codes	North American Industrial Classification System Codes
NGL	Natural Gas Liquids
Tcf	Trillion cubic feet of natural gas

Terms Used

Consumer Surplus – an economic concept equal to the area below the demand curve down to a horizontal line drawn at the market price. Used in this report to measure the benefits provided to consumers brought about by lower natural gas prices, lower electricity costs, and lower manufacturing prices.

Direct Impacts – immediate impacts (e.g., employment or value added changes) in a sector due to an increase in output in that sector.

Horizontal Drilling – the practice of drilling a horizontal section in a well (used primarily in a shale or tight oil well), typically thousands of feet in length.

Indirect Impacts – impacts due to the industry inter-linkages caused by the iteration of industries purchasing from other industries, brought about by the changes in direct output.

Induced Impacts – impacts on all local and national industries due to consumers' consumption expenditures rising from the new household incomes that are generated by the direct and indirect effects flowing through to the general economy. The term is used in industry-level input-output modeling and is similar to the term Multiplier Effect used in macroeconomics.

Multiplier Effect – describes how an increase in some economic activity produces a cascading effect through the economy by producing "induced" economic activity. The multiplier is applied to the total of direct and indirect impacts to estimate the total impact on the economy. The term is used in macroeconomics and is similar to the term Induced Impacts as used in industry-level input-output modeling.

Natural Gas Liquids – components of natural gas that are in gaseous form in the reservoir, but can be separated from the natural gas at the wellhead or in a gas processing plant in liquid form. NGLs include ethane, propane, butanes, and pentanes.

Original Gas-in-Place – industry term that specifies the amount of natural gas in a reservoir (including both recoverable and unrecoverable volumes) before any production takes place.

Original Oil-in-Place – industry term that specifies the amount of oil in a reservoir (including both recoverable and unrecoverable volumes) before any production takes place.

Oil and Gas Value Chain

- **Upstream Oil and Gas Activities** – consist of all activities and expenditures relating to oil and gas extraction, including exploration, leasing, permitting, site preparation, drilling, completion, and long term well operation.
- **Midstream Oil and Gas Activities** – consist of activities and expenditures downstream of the wellhead, including gathering, gas and liquids processing, and pipeline transportation.

- **Downstream Oil and Gas Activities** – activities and expenditures in the areas of refining, distribution and retailing of oil and gas products.

Oil and Gas Resource Terminology

- **Conventional gas resources** – generally defined as those associated with higher permeability fields and reservoirs. Typically, such as reservoir is characterized by a water zone below the oil and gas. These resources are discrete accumulations, typified by a well-defined field outline.

- **Economically recoverable resources** – represent that part of technically recoverable resources that is expected to be economic, given a set of assumptions about current or future prices and market conditions.

- **Proven reserves** – the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology.

- **Technically recoverable resources** – represent the fraction of gas in place that is expected to be recoverable from oil and gas wells without consideration of economics.

- **Unconventional gas resources** – defined as those low permeability deposits that are more continuous across a broad area. The main categories are coalbed methane, tight gas, and shale gas, although other categories exist, including methane hydrates and coal gasification.

- **Shale gas and tight oil** – recoverable volumes of gas, condensate, and crude oil from development of shale plays. Tight oil plays are those shale plays that are dominated by oil and associated gas, such as the Bakken in North Dakota.

- **Coalbed methane** (CBM) – recoverable volumes of gas from development of coal seams (also known as coal seam gas, or CSG).

- **Tight gas** – recoverable volumes of gas and condensate from development of very low permeability sandstones.

Conversion Factors

Volume of Natural Gas

1 Tcf = 1,000 Bcf

1 Bcf = 1,000 MMcf

1 MMcf = 1,000 Mcf

Energy Content of Natural Gas (1 Mcf is one thousand cubic feet)

1 Mcf = 1.025 MMBtu

1 Mcf = 0.177 barrels of oil equivalent (BOE)

1 BOE = 5.8 MMBtu = 5.65 Mcf of gas

Energy Content of Crude Oil

1 barrel = 5.8 MMBtu = 1 BOE

1 MMBOE = 1 million barrels of crude oil equivalent

Energy Content of Other Liquids

Condensate

1 barrel = 5.3 MMBtu = 0.91 BOE

Natural Gas Plant Liquids

1 barrel = 4.0 MMBtu = 0.69 BOE (actual value varies based on component proportions)

Example Gas Compositions and Conversion Factors (based on 14.7 psi pressure base)

Natural Gas Component	US Pipeline Gas Composition (%)	LNG Made from US Pipeline Gas (%)	LNG from Australia NWS Gas Composition (%)	Btu/scf	Pounds/ Mscf
Methane	95.91%	97.56%	87.3%	1,030	42.3
Ethane	1.45%	1.48%	8.3%	1,743	79.3
Propane	0.48%	0.49%	3.3%	2,480	116.3
C_4+	0.16%	0.16%	1.0%	3,216	153.3
CO_2 *	1.70%	0.00%	0.0%	-	116.0
N_2	0.30%	0.31%	0.0%	-	73.8
Sum	100.00%	100.00%	100.00%		
Btu/scf	1,030	1,048	1,159		
Pounds / Mscf	44.50	43.26	48.95		
Metric tonnes per million scf	20.18	19.62	22.20		
Bil. scf per million metric tonnes	49.54	50.96	45.04		
Bil scf/day per mm MT/year (Bcfd/MTPA)	0.136	0.140	0.123		
MTPA/Bcfd	7.37	7.16	8.10		

Source: ICF estimates

* US pipelines have 2% or 3% limit on inerts (carbon dioxide and nitrogen). To make LNG all CO_2 must be removed.

List of Exhibits

1 Executive Summary

In order to inform the current policy debate surrounding the granting of licenses for U.S. exports of liquefied natural gas (LNG), the American Petroleum Institute (API) commissioned ICF International to undertake a study of the energy market and economic impacts of LNG exports.

The scope of this study is to estimate impacts of LNG exports on the U.S. economy and international LNG trade for the timeframe through the year 2035 using the databases, algorithms, and models typically employed by ICF in analyzing U.S. and international natural gas markets. The secondary purpose is to put the estimates of economic impacts presented in this study in the context of other studies and to explain why differences in results may occur.

Four fixed LNG export scenarios were analyzed in ICF's proprietary Gas Market Model (GMM), which provides forecasts of North American natural gas markets. Cases include one assuming no exports, another case based upon ICF's own Second Quarter 2013 Base Case, and two additional LNG export cases that assumed moderately higher and significantly higher amounts of LNG exports as compared to the ICF Base Case.

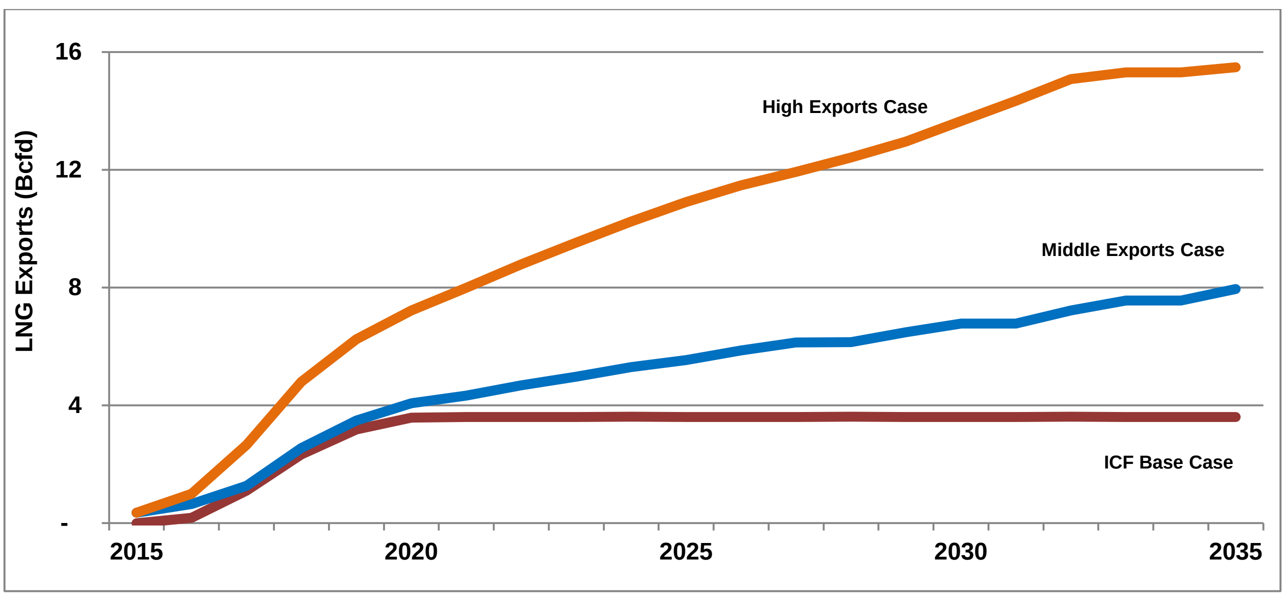
i. *Zero Exports Case:* designated as the "Reference Case" for this study

ii. *ICF Base Case:* ~4 Bcfd of U.S. LNG exports in 2035

iii. *Middle Exports Case:* ~8 Bcfd of U.S. LNG exports in 2035

iv. *High Exports Case:* ~16 Bcfd of U.S. LNG exports in 2035

Exhibit 1-1: LNG Export Cases *Relative to Zero LNG Exports Case*



Source: ICF estimates

The following exhibit shows the key findings in terms of the annual average change in natural gas prices, GDP, and employment attributed to LNG exports between 2016 and 2035. Note that the GDP and employment impacts are incremental changes relative to the Zero Exports Case.

Exhibit 1-2: Key Economic Impacts Relative to the Zero Exports Case

Impact (2016-2035 Averages)*	LNG Export Case (Change from Zero Exports Case)		
	ICF Base Case (up to ~4 Bcfd)	Middle Exports Case (up to ~8 Bcfd)	High Exports Case (up to ~16 Bcfd)
Employment Change (No.)	73,100-145,100	112,800-230,200	220,100-452,300
GDP Change (2010$ Billion)	$15.6-$22.8	$25.4-$37.2	$50.3-$73.6
Henry Hub Price (2010$/MMBtu)	$5.03	$5.30	$5.73
Henry Hub Price Change (2010$/MMBtu)	$0.32	$0.59	$1.02

*Source: ICF estimates. Note: * Includes direct, indirect, and induced impacts*

Some key conclusions from this study include:

- The net effects on U.S. employment are anticipated to be positive with net job growth of between 73,100 to 452,300 jobs on average between 2016 and 2035, including all economic multiplier effects. Manufacturing job gains average between 7,800 and 76,800 net jobs between 2016 and 2035, including 1,700-11,400 net job gains in the specific manufacturing sectors that include refining, petrochemicals, and chemicals.
- The net effect on U.S. GDP are expected to be positive at about $15.6 to $73.6 billion per year on average between 2016 and 2035, including the impacts of associated liquids production, increases in the petrochemical manufacturing of olefins, and all economic multiplier effects.
- LNG exports are expected to have moderate impacts on domestic natural gas prices of about $0.32 to $1.02 per million British Thermal Units (MMBtu) on average between 2016 and 2035.

Other conclusions are discussed below.

Findings on World LNG Market Penetration and Impacts of U.S. LNG Exports

International competition: The U.S. faces considerable competition for LNG sales abroad, with at least 63 international LNG export projects planned or under construction, with combined LNG export capacity of 50.5 Bcfd. Many of these projects have free-on-board (FOB) costs[1] of $9/MMBtu or less. FOB costs include the cost of the natural gas feedstock, liquefaction costs, and the costs associated with loading the LNG on ship for transport; however, these costs do not include shipping costs to the destination.

Uncertainty concerning LNG trade: Uncertainty regarding world economic growth, government policies toward LNG imports and pricing, greenhouse gas (GHG) mitigation policies, subsidization policies for renewables, and development of the world's unconventional

[1] Also referred to as freight-on-board (FOB) costs.

natural gas resources make LNG trade forecasting difficult. ICF expects incremental growth in world LNG trade to range from 27-36 Bcfd by 2025, and 39-57 Bcfd by 2035

Reductions in existing liquefaction capacity will add new contract demand: Additional volumes beyond this incremental demand will have to be newly contracted over the next 23 years because not all existing LNG liquefaction plants will be able to operate at current levels due to insufficient natural gas reserves or the desire of the host governments to dedicate reserves to domestic consumption. Factoring this in, the range of total new contract volumes (incremental demand plus make up of lost productivity) is 30 to 39 Bcfd by 2025 and 45 to 63 Bcfd by 2035.

Planned LNG outside of US can satisfy near-term demand: This means that the 50.5 Bcfd of non-U.S. projects now under construction or planned (without any contribution from U.S. LNG) could satisfy the low end of projected world demand past 2035, the midpoint of projected demand through 2033, and the high end of demand through about 2029.

U.S. LNG exports provide many benefits for international buyers: The desirability of U.S. LNG to would-be buyers is affected by factors other than just the volumes to be contracted and the immediate price comparisons among alternative suppliers. The U.S. is attractive to buyers because the U.S. provides:

- Geographic diversification of supply sources.
- A politically stable supply source.
- An opportunity for purchasers of natural gas to invest in upstream/midstream/liquefaction facilities. This creates new investment opportunities, provides the ability to achieve physical price hedges (i.e., reduce price volatility), and allows investors to gain experience in unconventional gas development. For foreign companies that already have nonconventional gas positions in the U.S., participation in LNG projects as buyers and/or investors offers them a way of more quickly monetizing and increasing the value of those assets.
- Access to index (Henry Hub) pricing of LNG to produce lower and possibly more stable average LNG costs.
- An opportunity to induce more players into the LNG supply business to increase competition and lower prices further in the long-term.

U.S. LNG exporters potential to gain international market share: Assuming the international competitive market environment discussed above and with the expectation that U.S. Gulf Coast natural gas prices (in the absence of LNG exports) will range somewhere from $5 to $6 per MMBtu through 2035, an international comparison of project costs and transportation costs differentials reveals that U.S. LNG exports (if they were not limited by government regulations) would likely fall within the range of 4 to 16 Bcfd. This indicates that

U.S. LNG exports would have 12% to 28% market share of new LNG contract volumes in 2025 and market share of 8% to 25% in 2035.[2]

LNG pricing uncertainties: Pricing on LNG is a complex matter and there is no clear, widely held view of how LNG pricing will evolve in the future -- with or without U.S. exports. Uncertainties exist on the questions of:

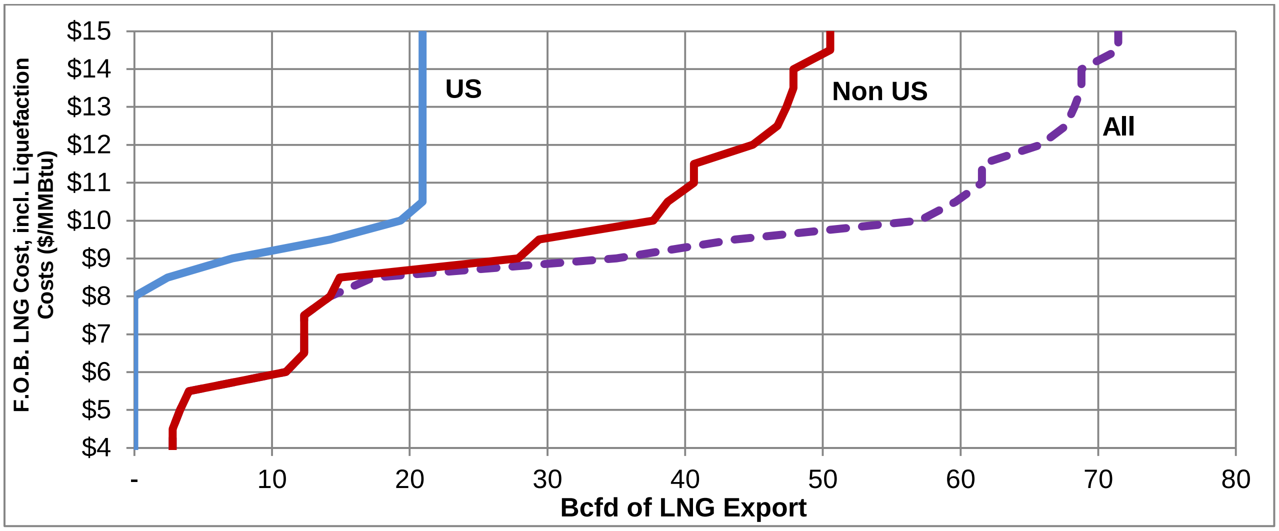
- What portion of new long-term contracts will be priced based on oil or other alternative fuel indices *versus* market-area indices (such as European hub prices) *versus* supply-area indices (like Henry Hub). Traditionally, LNG export prices often have been indexed to oil or oil products (on a delivered energy basis).
- What the pricing level will be (for example, 85% of Japanese Crude Cocktail (JCC) on a delivered Btu basis versus 70% of JCC). In other words, even if LNG continues to be indexed to oil, the relationship may change considerably due to market competition.
- How prices may vary across geographic markets – in particular Japan/Korea/Taiwan *versus* other Asian markets *versus* Europe.
- How price formulas will interact with other contract provisions such as take-or-pay levels, redirection rights, price floors/ceilings, and price redetermination clauses.

U.S. LNG exports could lower marginal costs for new LNG contracts: Given the large potential market share for U.S. LNG, economic theory suggests that the entry of the U.S. LNG exports into the market could put substantial downward pressure on world LNG long-term contract prices. We concluded that with the new U.S. LNG projects added to the supply curve the marginal cost of new contract delivered prices circa 2025 could fall by $1 to $3 per MMBtu depending on the world LNG demand levels. Stated in other terms, the entry of the U.S. into the world market could drop marginal costs for new LNG contracts roughly by $0.30 per MMBtu for each one Bcfd of U.S. exported volumes circa 2025 (assuming all demand-side considerations are held constant).

[2] Based on ICF range of 3.6-10.9 Bcfd in U.S. LNG exports by 2025, and 3.6-15.5 Bcfd by 2035, and total new contract demand (including both new demand and new volumes to replace LNG plant retirements) of 30 Bcfd in the low case and 39 Bcfd in the high case in 2025, and 45 Bcfd in the low case and 63 Bcfd in the high case in 2035.

Exhibit 1-3: Supply Curve of LNG Supply Projects under Construction or Proposed

(Prices include the costs of feedstock gas, liquefaction, and fuel used for liquefaction)



Source: ICF estimates

Note 1: These prices include the cost of liquefaction and fuel used for liquefaction, and are thus higher than spot or contract prices for pipeline natural gas.

Note 2: Includes projects far enough along the planning process and with sufficient public data to be judged by ICF to be viable. Not every proposed project has been added to these curves.

LNG delivered pricing assumed at 76%-79% of crude pricing (on Btu basis): Depending on market conditions, new contract prices may or may not fully reflect such changes in marginal costs. Recent long-term LNG contracts in Asia have been signed at delivered prices approximately 85% of crude oil on a Btu basis. At our assumed long-term oil price of $95/bbl, this implies $13.90/MMBtu delivered. Given the competition from new sources likely to be available in the next several year from the U.S. and other countries, this level of pricing is likely not sustainable and so our principal pricing assumption for this study for delivered prices into Asia is an average somewhere between $12.49/MMBtu and $12.96/MMBtu (76% to 79% of crude on a Btu basis) through 2035. With assumed shipping costs of $2.64/MMBtu, this implies that the average FOB value of LNG in the U.S. Gulf Coast would range from $9.85/MMBtu to $10.32/MMBtu in that period.

Findings on Domestic Energy Market Impacts of U.S. LNG Exports

Natural Gas Pricing: In terms of average price increases, the three export cases averaged between $0.32/MMBtu and $1.02/MMBtu between 2016 and 2035 at Henry Hub. See Exhibit 10-1 in Appendix A for more details.

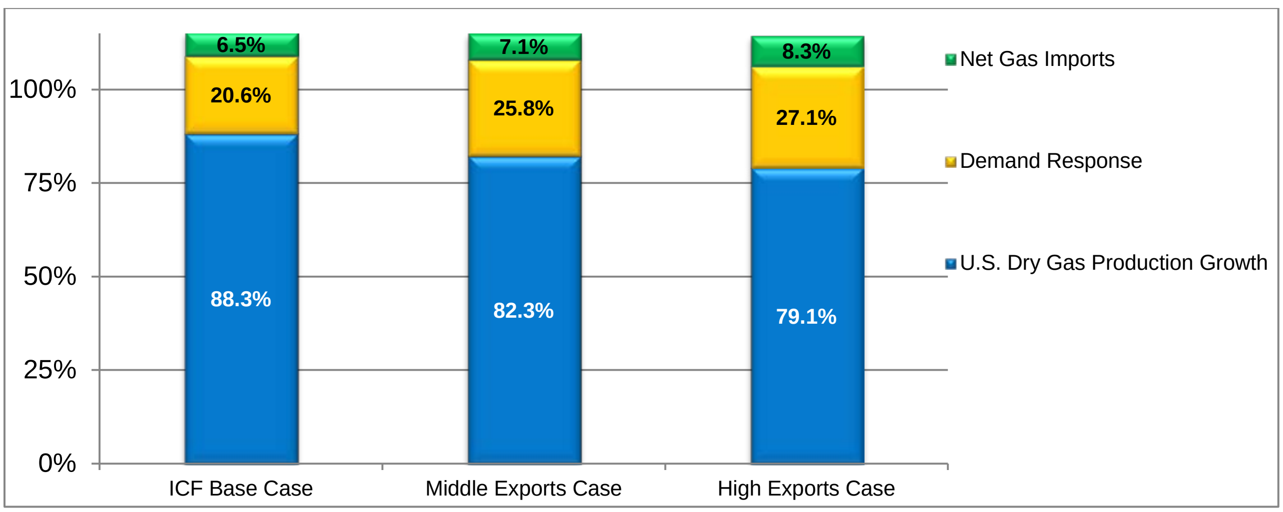
Exhibit 1-4: Wholesale Natural Gas Price Changes Relative to Zero Exports Case

Case	Natural Gas at Henry Hub (2016-2035 Avg)
ICF Base Case	
Avg Price Increase ($/MMBtu)	$0.32
Avg Price Increase/Bcfd ($/MMBtu)	$0.10
Middle Exports Case	
Avg Price Increase ($/MMBtu)	$0.59
Avg Price Increase/Bcfd ($/MMBtu)	$0.11
High Exports Case	
Avg Price Increase ($/MMBtu)	$1.02
Avg Price Increase/Bcfd ($/MMBtu)	$0.10

Source: ICF estimates

Supply Sources that Offset Export Volumes: LNG exports require some combination of additional supplies, in the form of domestic production increases, a reduction in consumption (i.e., demand response), and changes in pipeline trade with Canada and Mexico. ICF modeling shows that for each of the three export cases, the majority of the incremental LNG exports (79%-88%) is offset by increased domestic natural gas production. Another 21% to 27% stems from consumer demand response (i.e., price increases lead to a certain decrease in domestic gas demand). For context, these demand reduction volumes are the equivalent of 1%-4% of U.S. natural gas demand in 2012. In addition, about 7%-8% comes from shifts in the trade with Canada (more exports into the U.S.) and Mexico (fewer imports from the U.S.). The sum of the three supply sources exceed actual LNG export volumes by roughly 15% to account for fuel used during processing, transport, and liquefaction.

Exhibit 1-5: Supply Sources that Rebalance Markets



Source: ICF estimates

Note: Each 1.0 Bcfd of LNG exports requires total dry wellhead supplies of 1.15 Bcfd for liquefaction, lease and plant fuel, and LNG exports.

NGLs: Incremental U.S. dry gas production is expected to come from many sources with varying levels of natural gas liquids content. By 2035, ICF estimates incremental liquids volume increase between 138,000 barrels per day (bpd) and 555,000 bpd, attributable to LNG exports (relative to no exports). For context, in 2012, the U.S. total liquids production equals 2.4 million barrels per day.[3]

Petrochemicals: The incremental volume increase in ethane (feedstocks for ethylene production) will increase ethylene production by between 2,100 tonnes/day and 8,600 tonnes/day by 2035.[4] For reference, a world-scale ethylene plant would have a capacity of 2,740 tonnes/day, meaning LNG exports and the associated increase in ethane production would support roughly one to three additional world-scale ethylene plants.

GTLs: GTL production economics are sensitive to the price of its main feedstock, natural gas (i.e., methane). Forecasted GTL production is expected to drop between 40 tonnes/day and 800 tonnes/day by 2035 with LNG exports, or at most 3% of planned production levels. Currently, the U.S. has no GTL production operations.

Methanol and Ammonia: LNG exports have a negligible effect on methanol and ammonia production, according to ICF's modeling assumptions wherein the price of these products are high enough to keep new and existing plants profitable even at the higher feedstock prices resulting from LNG exports.

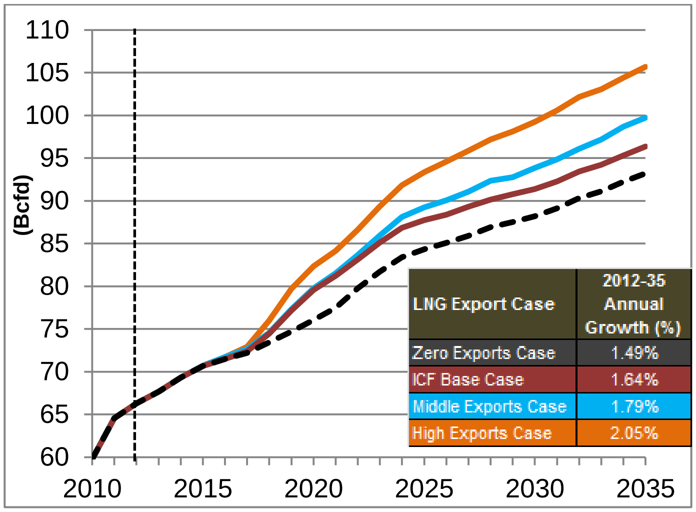
Electricity and Coal: Wholesale electricity prices are projected to modestly increase with LNG exports because natural gas is on the margin (that is, the last dispatched generation resource, which sets the wholesale electricity price) for a large percent of the time throughout the U.S. Electricity demand and production is expected to decline between 20,000-70,000 GWH by 2035 in each LNG export case, relative to the Zero Export Case, as a result of price-induced demand reductions. This represents a reduction of 0.4%-1.4% in electricity demand, relative to the Zero Export Case. Coal production is projected to see a slight increase of 5-15 million short tons annually by 2035. In none of the cases did natural gas prices increase to the level that would make new coal-fired power plants economic.

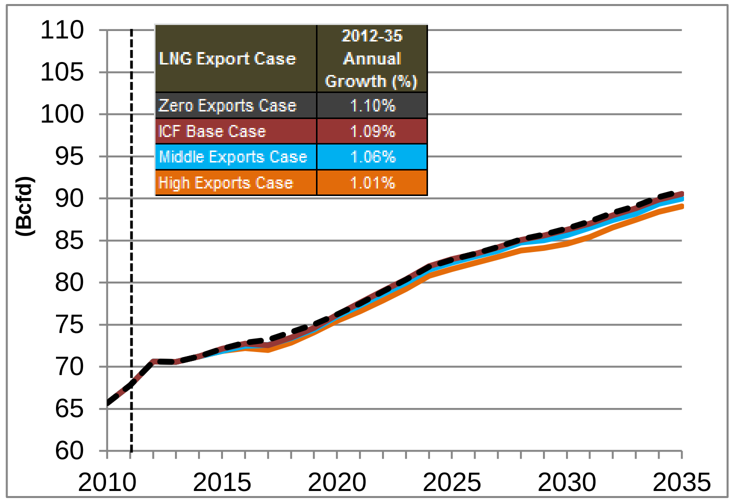
[3] EIA's preliminary U.S. Natural Gas Plant Field Production (Monthly).

[4] The majority of ethane is removed before transportation to meet pipeline quality standards.

Exhibit 1-6: U.S. Domestic Natural Gas Market Changes by LNG Export Case

U.S. Domestic Gas Production Changes *U.S. Domestic Gas Consumption Changes*



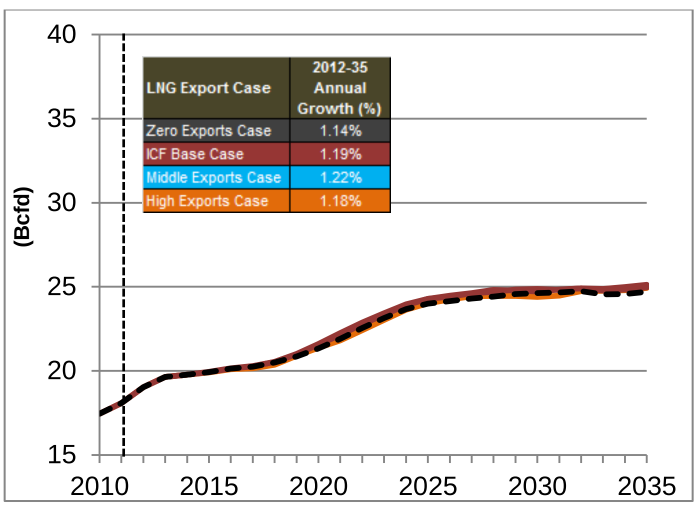


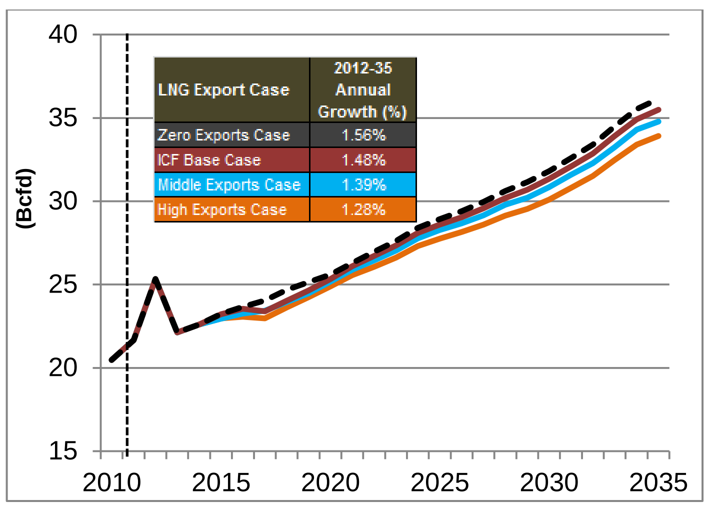
Source: ICF estimates

Note: "U.S. Domestic Gas Consumption Changes" chart (right) does not include LNG export volumes, but does include domestic fuel used for liquefaction.

Exhibit 1-7: Selected U.S. Natural Gas Market Changes by LNG Export Case

U.S. Industrial Gas Consumption Changes *U.S. Power Sector Gas Consumption Changes*





Source: ICF estimates

Findings on Domestic Employment Impacts of U.S. LNG Exports

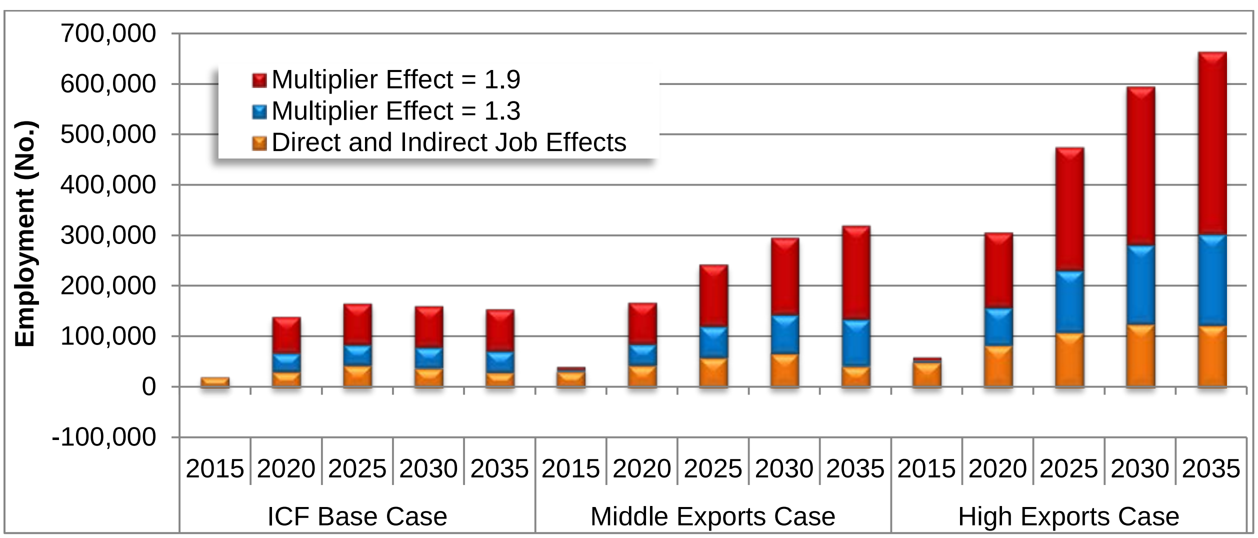
<u>Direct and Indirect Employment:</u> New jobs associated with oil and natural gas exploration and production comprise the largest share of employment gains or between 46,000 and 186,000 annual jobs by 2035, depending on the LNG case. Jobs related to LNG production make up another 2,000 to 10,000 annual jobs by 2035. Changes in petrochemicals processing produce another net 420-1,700 jobs by 2035. Coal-switching generates another 1,300-4,000 annual jobs in 2035, attributable to longer lives and greater dispatch of coal-fired power plants, given the increase in natural gas prices. In terms of direct and indirect job losses attributable to LNG exports, those related to reduced purchases of miscellaneous consumer goods (as more of consumers' income goes to natural gas and electricity bills) is expected to be the largest component leading to a drop of 7,100-27,000 annual jobs by 2035. Additionally, higher gas prices imply less production in some energy-intensive industries, leading to net employment contractions of 5,000-21,500 in annual jobs by 2035, relative to the Zero Exports Case. Despite these employment contractions, total net direct and indirect employment is expected to increase to between 30,000 and 122,000 annual jobs by 2035.

LNG exports lead to increases in manufacturing jobs, stemming from increased demand for manufacturing of equipment and materials needed for natural gas production. Significant job growth occurs within the tools and machinery manufacturing sector, which is expected to see 3,800-30,300 jobs by 2035, while the iron and steel manufacturing sector is projected to grow by an additional 2,300-9,600 jobs in 2035. Other key manufacturing sectors with strong growth include petroleum/petrochemical manufacturing, which is anticipated to see net job gains of 530-3,100 jobs in 2035, and the chemicals/rubber/glass manufacturing sector, which is expected to see 600-9,500 net job gains in 2035, relative to the Zero Exports Case.

Multiplier Effect Employment: Induced employment (generated by consumer spending filtering through the economy) is largely concentrated in the services (i.e., consumer activities) sector. Induced employment totals 42,000-125,000 annual jobs by 2035 in the ICF Base Case, and reaches between 181,000 and 543,000 additional jobs by 2035 in the High Exports Case.

Total Employment Changes: All LNG export cases show net employment gains, relative to no exports. The exhibit below shows total employment changes by LNG export case. Total employment changes reach nearly 307,000 annual jobs by 2020, or 665,000 annual jobs by 2035 in the High Exports Case, including direct, indirect, and induced employment.

Exhibit 1-8: Total Impacts on Employment by LNG Export Case



Source: ICF estimates

Finding on the U.S. Economic Impacts of U.S. LNG Exports

LNG Value: The value of LNG exports is expected to reach nearly $11 billion annually in 2020 and $12 billion annually in 2035 under the ICF Base Case, and estimated to rise to $27 billion in the Middle and $53 billion and High Exports Case by 2035.

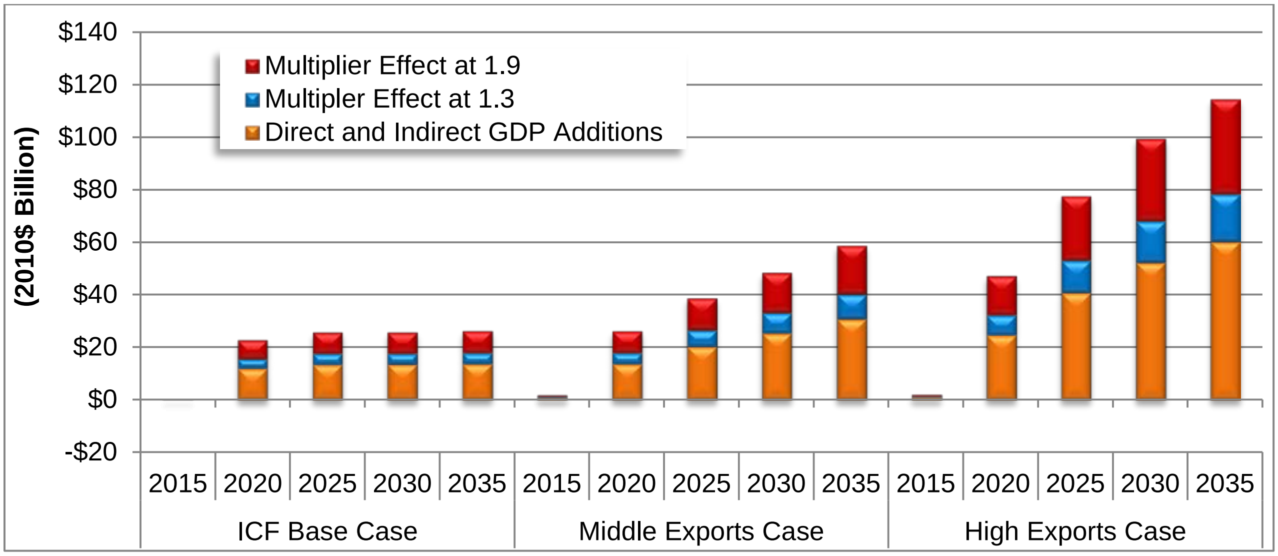
NGL Value: Incremental NGL (non-feedstock) sales are projected to be worth $2.4-$4.4 billion annually by 2020, and between $2.2 billion and $8.9 billion, depending on the LNG export case, relative to no LNG exports in 2035. ICF assumed 16% of shipment value is comprised of imported intermediate goods and services, given historical U.S. trade trends. Therefore, total GDP contributions are assumed at 84% of NGL sales, or between $1.9 billion and $7.5 billion in 2035.

Petrochemicals and Industrial Production Value: In terms of the change in petrochemical production value attributable to LNG exports, ethylene/polyethylene is expected to see the highest gains, while propylene/polypropylene is expected to make up a smaller share. While total petrochemical production value changes is anticipated to range between $1.3 billion and $5.0 billion in 2035, deductions for imported intermediate goods and services result in calculated U.S. GDP additions of between $1.1 billion and $4.2 billion in 2035 for incremental petrochemical production attributable to varying volumes of LNG exports.

Direct and Indirect GDP Contributions: The majority of direct and indirect GDP gains come from LNG production and export, followed by gains from additional NGL, lease condensate, crude oil and petrochemical production. There are gains in GDP from higher revenue to natural gas and electricity producers, which is nearly completely offset by GDP losses from less consumer spending on domestically produced consumer goods and services, as consumers must allocate a larger part of their incomes for natural gas and electricity. Also, there is a decrease in GDP associated with high-energy-intensity industrial production, attributable to the increase in natural gas and electricity prices. Total net direct and indirect activities, nonetheless, contribute between $14 and $60 billion annual gains by 2035, relative to the Zero Exports Case, despite losses in certain energy-intensive sectors.

Total Economic Impacts: Total economic impacts include the direct and indirect GDP changes addressed above, as well as the induced effects through the multiplier effect. As the direct and indirect GDP additions filter through the economy, the additional economic activity generates consumer spending through each round of activity. The LNG, NGL, petrochemical, and certain manufacturing activities are expected to see highest net GDP gains. ICF estimates that the ICF Base Case of up to 4 Bcfd in LNG exports are anticipated to result in an additional $16-$23 billion in annual GDP contributions by 2020, and $18-$26 billion in direct, indirect, and induced economic activity by 2035. The Middle Exports Case of 8 Bcfd in LNG exports results in additional economic activity totaling $18-$26 billion annually by 2020, and $41-$59 billion in 2035, while the High Exports Case of 16 Bcfd in LNG exports mean additional economic activity of between $32-$47 billion annually by 2020, and $78-115 billion in the final forecast year.

Exhibit 1-9: Total Impacts on GDP by LNG Export Case



Source: ICF estimates

<u>Government Revenues:</u> Increased government revenues resulting from LNG exports are expected to be in the form of federal, state, and local taxes on GDP gains associated with additional economic activity, as well as additional royalty payments to the government for natural gas production taking place on government lands. State and local taxes (which include severance taxes associated with natural gas production) comprise the largest share of government revenues, with federal taxes making up a smaller portion. A slight increase in federal royalties is anticipated to comprise the remaining source. In sum, government revenues (on and induced gains) reach between $6.4-$9.3 billion in the ICF Base Case, $14.3-$20.8 billion in the Middle Exports Case, and $27.9-$40.4 billion annually in the High Exports Case by 2035.

Key Distinctions from Other Studies

GDP growth positively correlated with growth in LNG exports: Any comprehensive macroeconomic modeling system based on standard economic theory should yield zero or positive GDP changes when LNG export limits are removed and economically justified trade is allowed to proceed. There are expected to be zero GDP impact when export limits are nonbinding (that is, there is no economic reason to export anyway) and an increasingly positive GDP effect as greater export volumes are modeled as being economically justified. The same conclusion would hold for any commodity whose trade restrictions are lifted - not just natural gas. This is why economists have indicated for many decades that freer trade improves the economies of both trading partners. However, while any model is expected to show positive GDP effects from lifting LNG export bans, the amount of those effects will vary based on modeling methodology and underlying assumptions.

Assumptions on gas resource and long-run supply curve affect results: Generally speaking, the lowest price increases on a scale of $/MMBtu per Bcfd of exports are associated with the most price-elastic representation of domestic gas supply. This is a function of both long-term supply curves (showing how much costs go up as the resource is depleted, assuming constant factor costs) and short-run drilling activity effects (representing the time it takes to build up extra natural gas wellhead deliverability and how short-term factor costs increase as drilling activity per unit of time goes up). This ICF report generally shows similar or lower export-induced natural gas price increases than the EIA and NERA reports (despite forecasting a much bigger non-export gas market) because we assume a larger natural gas resource base and flatter long-run supply curve. On other hand, this report shows larger natural gas price increases than the Deloitte studies, due, in part, to the fact that the Deloitte modeling methodology ignores the time and effort needed to build extra wellhead natural gas deliverability and short-term factor cost effects.

Larger natural gas market assumed: This ICF study assumes a larger natural gas market to begin with than studies such as NERA's, due to assumed greater economic growth rates and more growth in industrial gas use. The incremental difference between the ICF Base Case and the AEO 2013 Early Release forecast for U.S. gas consumption is the equivalent to 12 Bcfd by 2035. The difference with the AEO 2011 forecast in 2035 equates to an additional 18 Bcfd in U.S. natural gas consumption. This means that in the ICF study the requirements for gas supply are greater even before LNG exports are considered and thus the "stress test" of exports is more severe.

The ICF estimates of GDP gains are larger than in NERA study due to differences in methodology and assumptions: This ICF study shows larger positive GDP effects from LNG exports of a given magnitude compared to the NERA study, though both studies confirm the economic concept that removing international trade barriers (i.e., allowing LNG exports) will yield positive economic benefits to the U.S. economy. Key factors leading to a bigger GDP impact in this study are a more elastic gas supply curve, an accounting for the impacts of incremental liquids and olefins production, the representation of the price responsiveness of trade with Canada and Mexico, and different assumptions regarding how the domestic labor market and the U.S. current account trade deficit respond to LNG trade.

Additional liquids production contribute to GDP gains: The economic effects of additional hydrocarbon liquids produced in association with incremental natural gas volumes are very important parts of the economic impacts of LNG export and is usually missing from other studies reviewed here. This liquids production directly adds to GDP and provides feedstocks that will likely be used in the U.S. chemical industry with additional value added economic results.

Assumptions on pricing of petrochemical products are important for estimation of impacts on methane feedstock users: The key industrial uses of natural gas as a feedstock compete on a world market wherein many products are tied to the price of oil. Under the assumption used in this study of continued high oil prices ($95/bbl) this study concludes that U.S. production of methanol, ammonia, and GTLs will largely go forward even with the natural gas price increases associated with significant LNG exports. This fact combined with the expected boost in chemical production spurred by more NGLs production plus the general increase in the size of the U.S. economy, which adds to demand for all product (including chemicals), leads to the conclusion that LNG exports are expected to have a small positive net effect on chemical sector output and jobs. Other studies may not show this result because they ignore the effects of the additional NGL production and may overstate the degree to which reductions in industrial natural gas consumption are expected to be needed to rebalance the natural gas market.

Upstream and midstream impacts affect manufacturing industries: The “industrial renaissance” that is frequently associated with new gas and oil drilling and completion technologies needs to be understood both as a result of lower energy prices (making U.S. manufacturing of energy-intensive goods relatively more competitive) but also as a direct stimulus to the industries that supply the upstream and midstream sectors with equipment and materials. A number of studies either do not include the impact of LNG exports (through increases in domestic gas and oil production) on the industrial sector, or understate the impact, resulting in lower economic impacts than this ICF study finds. A large boost to jobs in general and to manufacturing jobs specifically forecast in this study as a result of LNG exports come about because the oil and gas sector itself requires a significant amount of materials and equipment that would be made domestically.

2 Introduction

The current policy debate over granting licenses for permitting LNG exports has focused on the energy and economic impacts of LNG exports on the North American gas market, the cost of natural gas, and the impacts on gas-intensive industries and employment. At present the Department of Energy (DOE) has suspended processing applications on approximately 11 billion cubic feet per day (Bcfd) of proposed LNG export non-free-trade-agreement (non-FTA) permits and has recently issued an economic impact study[5] to provide information on possible economic impacts of LNG exports. Behind the export license applicants now at DOE stand a number of other potential projects queuing up for submitting non-FTA applications. While the numbers of would-be exporters and volumes is large, many observers expect that only a few of the projects will ever go into service due to the limited size of the LNG market and competition with non-U.S. LNG exporting countries.

The American Petroleum Institute (API) commissioned ICF International to undertake this study of the energy market and economic impacts of LNG exports in order to provide information to the current policy debate surrounding the granting of licenses for U.S. exports of liquefied natural gas (LNG). The specific questions that were posed for this study included the following:

- How big will the international LNG market be and what is the realistic range of LNG exports from the U.S. that can be expected between now and 2035?
- What is the outlook for LNG prices and how might the entry of the U.S. as an LNG exporter affect international LNG markets and prices?
- How will the U.S. natural gas market and energy markets adjust to LNG exports in terms of natural gas price increases, additional domestic natural gas production, and reductions in domestic natural gas consumption?
- How would natural gas price changes caused by LNG exports affect electricity prices, the fuel mix for power generation, and the overall level of electricity consumption?
- How would the U.S. industries most dependent on natural gas and electricity adjust to the energy price impacts of LNG exports?
- What effect will U.S. LNG exports have on domestic production of natural gas liquids (ethane, propane, butanes, pentanes plus), lease condensate, and crude oil?
- To what degree might increased availability and possibly lower prices for ethane, propane, and other liquid/liquefiable petrochemical feedstocks impact the chemical and associated industries?

[5] NERA Economic Consulting. "Macroeconomic Impacts of LNG Exports from the United States." The U.S. Department of Energy (DOE), 3 December 2012: Washington, D.C. Available at: http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf

- How will these changes to the natural gas, energy, and industrial markets affect the overall U.S. economy? In particular, what economic sectors will be positively or negatively impacted and what will be the overall, net effects on U.S. GDP, employment, and government revenues?
- How do the results of this study differ from other studies of U.S. LNG exports?
- What are the key analytic issues involved in estimating the economic impacts of LNG exports and how do the various published studies tackle those issues? What models or algorithms are used to make these estimates and what underlying assumption are most important in determining the results?
- Given the differences in scope, methodology, assumptions and results of various studies, how should stakeholders, policymakers and the public interpret such studies?

In order to address these questions in a logical fashion, this study is presented in the following sections:

- Section 1: Executive Summary
- Section 2: Introduction
- Section 3: Study Methodology and Assumptions
- Section 4: Global LNG Export Trends
- Section 5: Energy Market Impacts
- Section 6: Economic and Employment Impacts on the U.S. Economy
- Section 7: Comparison of Studies on U.S. LNG Exports
- Section 8: Key Conclusions

3 Study Methodology and Assumptions

The following section discusses ICF's approach to assessing the economic impacts of LNG exports on the U.S. economy, as well as key assumptions made. In summary terms, the methodology consists of the following eight steps.

1. Develop four scenarios for future U.S. LNG export levels based on a review of studies of future LNG markets and an analysis of relative economics for U.S. LNG supply projects *versus* projects planned in other countries.
2. Analyze those LNG export scenarios using the ICF Gas Market Model (GMM) to determine North American energy market impacts.
3. Translate those GMM results into the immediate or "first round" effects on demand and output of goods and services in the U.S. economy. This leads to what is referred to here as the "direct and indirect GDP effects."
4. Use the IMPLAN input-output matrices to determine job impacts from the immediate changes in U.S. output of goods and services. This leads to what is referred to here as the "direct and indirect job effects."
5. Apply a range of multiplier effects to the direct and indirect GDP changes to assess the induced economic activity, as people who earn income through the direct and indirect activity spend that income. The range in multiplier effects represents uncertainties regarding the possible future "slack" in the economy and how much of a "crowding out" effect there might be in factor[6] markets if the new demands for labor and other factors stemming from LNG exports cannot be met entirely with new workers and other factors. This estimate of additional GDP is referred to as the "induced GDP effect."
6. Use the IMPLAN input-output matrices to determine job impacts from induced GDP. This is referred to as the "induced job effect."
7. Estimate government revenues and other economic metrics.
8. Compile results from other studies of LNG exports and compare their results with each other and with this study.

Each of these steps is described more fully below in this section. Also, at the end of this section is a discussion of general economic and pricing assumption used for this study. This includes a discussion of historical energy and chemical product prices, as well as how assumptions for future prices were made.

3.1 Step 1: Develop Export Scenarios

ICF developed four LNG export scenarios including one case assuming no exports, another case based upon ICF's own Base Case and two additional LNG export cases that assumed

[6] Factors of production are defined by economists to be inputs such as labor, land, capital, materials, energy, and technical knowhow that are used in producing goods and services.

moderately higher and significantly higher amounts of LNG exports as compared to the ICF Base Case.

These LNG export scenarios were derived through analysis of published studies of future LNG market size and a competitive analysis of the costs of planned LNG liquefaction projects in the U.S. and around the world. These same sources were used to estimate the volume of LNG that might be sold from the U.S. and how the U.S. entry as an exporter into the LNG market might affect international LNG prices. The four cases include:

i. *Zero Exports Case:* designated as the "Reference Case" for this study
ii. *ICF Base Case:* ~4 Bcfd LNG exports
iii. *Middle Exports Case:* ~8 Bcfd LNG exports
iv. *High Exports Case:* ~16 Bcfd LNG exports

More information regarding the derivation of these four LNG export cases is provided in Section 4 of this report.

3.2 Step 2: Model Export Scenarios using ICF's Gas Market Model

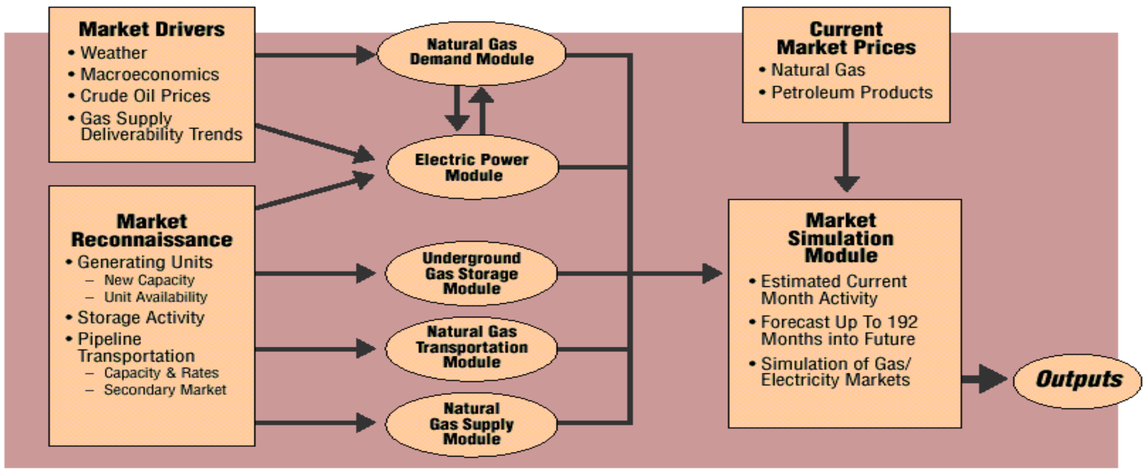
The main analytic tool used for this study was ICF's nationally recognized Gas Market Model (GMM®). ICF ran each LNG export case through its GMM model to assess the natural gas supply, demand, and pricing impacts of each case, relative to the Zero Exports Case.

The GMM was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions, such as when major new sources of gas supply are delivered into the marketplace. Subsequently, GMM has been used to complete strategic planning studies for many private sector companies. In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients, advisory councils and government agencies, including for the Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA), America's Natural Gas Alliance (ANGA), Natural Gas Supply Council (NGSA), the National Petroleum Council (NPC), the Edison Electric Institute (EEI), the American Chemistry Council (ACC), the U.S. Environmental Protection Agency (EPA), U.S. Department of Energy (DOE), U.S. Department of Homeland Security (DHS), Natural Resources Defense Council (NRDC), the Clean Air Task Force (CATF), and the American Council for an Energy-Efficient Economy (ACEEE).

Overall, the GMM solves for monthly market-clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply side of the equation, production is determined by production and storage cost curves that reflect costs as a function of production and storage utilization. Costs are also influenced by pipeline discount curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand side of the equation, costs are represented by a curve that captures the fuel-switching and fuel-consumption behavior of end users at different price levels. The model balances supply and demand at all nodes in the model at the market-clearing prices, determined by the shape of the supply curves. Unlike other commercially available models for the gas industry, ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to ensure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

As illustrated in the exhibit below, the GMM takes a range of factors, such as macroeconomics, weather, natural gas deliverability, storage, and power generation growth, into account to assess a given impact (e.g., LNG exports) on North American natural gas markets.

Exhibit 3-1: GMM Model Structure



The specific market effects of LNG exports quantified in the GMM included:

- Gas production changes in various North American basins caused by shifts in natural gas prices.
- Gas consumption changes by region and sector caused by shifts in gas prices (including details on fuel substitution, conservation, and reduced industrial output).
- Gas flow adjustments among regions caused by the new demand for gas at liquefaction plants, price-induced changes in regional gas production and in regional gas consumption.
- Changes in regional delivered-to-pipeline natural gas prices and changes to regional end-user prices.
- Adjustments to regional electricity prices, sales volumes, and power generation input fuel mix.

3.3 Step 3: Translate GMM Results into Changes in Outputs of Goods and Services in the U.S. Economy

In this step ICF translated the GMM results into the immediate or "first round" effects on demand and outputs of goods and services in the U.S. economy. Such changes in outputs are measured in terms of "value of shipments" and "valued added." Value of shipments is the total value (price times quantity) of what an industry produces. Valued added subtracts out the value of imported intermediate goods and services and is a measure of contribution to Gross Domestic Product (GDP). Calculating the value added to the U.S. economy differs from calculating that of a specific industry. The value added for a specific industry must deduct the costs of the intermediate goods and services whether imported or domestic. On the other hand, the value added for the aggregate GDP includes domestic intermediate goods and services because they also are part of U.S. GDP, and so, only imported intermediate goods are subtracted.

Therefore, the key outcome of this step is a measure of what we call here “direct and indirect GDP” effects.

ICF tracked the following types of first-order changes in energy and other markets caused by increasing levels of LNG exports:

- The increased output of LNG. This leads to greater demand in the industries related to the construction and operation of the liquefaction plants.
- Greater natural gas production. This leads to greater demand for exploration and production services, equipment, and materials, and for midstream services (gas gathering, processing, and transmission).
- Greater output of hydrocarbon liquids produced in association with the additional natural gas. This leads to the greater demand for upstream and midstream services, equipment, and materials.
- Greater output of ethylene and propylene (and their derivatives) caused by more abundant and possibly lower priced ethane and propane. This leads to greater demand in the industries related to the construction and operation of such chemical plants.
- Reduction in the output of industries using natural gas (methane) as a chemical feedstock. This leads to reduced demand in the industries related to the construction and operation of such chemical plants.
- Reduction in output of non-feedstock industries that use a large amount of natural gas and electricity, relative to the value of the products they produce.
- Changes in the level of electricity production (from the fuel-switching and conservation effects of higher electricity prices) and the change in mix of fuels used to fuel power plants.
- Changes to consumer spending caused by higher natural gas and electric bills, as well as the higher cost of energy-intensive goods. This reduces the demand for and output of miscellaneous consumer goods and leads to reductions in the output in those sectors that produce intermediate goods and services that go into consumer products.
- Increased spending by households and businesses on energy conservation technologies and alternative fuels.
- Changes to spending by income earners in the natural gas and electricity generation value chains caused by higher natural gas and electric prices. This increases output in

miscellaneous consumer goods and leads to increases in output in those sectors that produce intermediate goods and services that go into consumer products.

In each instance, ICF first determined the physical unit and dollar value change in demand/output for the final products.[7] The change in GDP was calculated as the value of the final product less the estimated contribution from imported intermediate goods. Only changes in final products are counted toward changes in GDP to simplify the calculations and to avoid possible double-counting if the value added of feedstock/fuel, intermediate goods, and the final product were separately taken into account. The methods used to estimate change in output quantities are described below. In some cases the results came directly out of the GMM results and in other cases, output changes were computed from GMM results.

3.3.1 Estimation of Output Changes for Energy-Intensive Industries (excluding some methane feedstock industries)

With the exception of ammonia, methanol, and GTLs (discussed below), the effects of changes in natural gas and electricity prices on industrial output were estimated using own-price demand elasticities and the assumption that increases in natural gas and electricity prices would be fully reflected as changes in manufactured product prices. The assumed own-price elasticities for domestic U.S. production were based on each industry's degree of exposure to international trade and were calculated to be in the range of -0.7 to -1.9. An elasticity of -0.7 would reflect an industry with a low degree of international exposure while an elasticity of -1.9 would reflect high exposure. This indicates that a 1% increase in product price results in a drop in the quantity demanded of between 0.7%-1.9%.

The manufacturing industries included in this analysis are those shown in Exhibit 3-2. The data in this table comes primarily from the Annual Survey of Manufacturers (ASM) for 2011. The one piece of data <u>not</u> from the ASM is the estimate of natural gas consumption which is an ICF estimate based on various sources, including the EIA's Manufacturing Energy Consumption Survey (MECS) for 2006 and preliminary 2010 results. Note that each row[8] may represent a different level of aggregation with 6-digit North American Industrial Classification System (NAICS) code representing the most disaggregation and the 3-digit NAICS code providing the highest level of aggregation for an industry. The total for all manufacturing shown in the last row is equal to the sum of all the 3-digit rows.

Price elasticity of demand indicates consumer responsiveness to price changes. A price increase has a negative relationship with quantity demanded, as consumers will demand less in

[7] The term "final product" in this context refers to the last product in the value chain tracked in the ICF accounting system. For example, if ethane is converted to ethylene and the ethylene processed into polyethylene, then only the value of the final product (polyethylene) -- less any contribution of imported intermediate goods and services -- is counted toward GDP.

[8] The industrial aggregation represented by each row was selected to match the aggregation method used in the Energy Information Administration's Manufacturers Energy Consumption Survey (MECS) of 2006. The detailed results of the 2010 MECS were not available when this study was done, but the preliminary national-level 2010 MECS results were also factored into the calculations.

light of a price increase. The demand elasticity (E_d) relationship with price, P, and quantity demanded, Q_d, is as follows:

$$Ed = \frac{P}{Qd} \, x \, \frac{\Delta Qd}{\Delta \mathrm{P}}$$

Products that have no substitutes are considered perfectly inelastic ($E_d = 0$), while products with an own-price elasticity of demand between 0 and -0.49 are considered relatively inelastic (i.e., significant price changes will have little effect on quantities demanded). Products with own-price elasticity between -0.5 and -1.0 are considered relatively elastic and those below -1.0 are considered very elastic.

Exhibit 3-2: Selected 2011 Statistics by Manufacturing Sector

NAICS	MECS Aggregation	Natural Gas (Bcf)	Electricity (mm kWh)	Employment (1,000)	Annual Payroll ($mm)	Shipment Value ($b)	Value Added ($b)	Electric & Gas Costs ($mm)	Electric & Gas Costs as % VoS
311	Food	788	90,585	1,359	$52,828	$710	$265	$9,650	1.4%
3112	Grain and Oilseed Milling	148	18,485	50	$2,864	$94	$29	$1,722	1.8%
311221	Wet Corn Milling	72	7,683	8	$522	$16	$6	$699	4.4%
3112-Other	Balance of Grain and Oilseed Milling	76	10,802	43	$2,342	$78	$23	$1,023	1.3%
31131	Sugar Manufacturing	24	1,172	13	$680	$10	$3	$187	1.9%
3114	Fruit and Vegetable Preserving and Specialty Food	115	9,030	161	$6,307	$65	$29	$1,203	1.9%
3115	Dairy Product	101	10,205	131	$6,302	$106	$32	$1,203	1.1%
3116	Animal Slaughtering and Processing	205	28,838	474	$15,121	$196	$54	$2,675	1.4%
311-Other	Balance of Food	195	22,855	529	$21,555	$240	$116	$2,659	1.1%
312	Beverage and Tobacco Products	58	9,308	140	$7,272	$137	$83	$991	0.7%
3121	Beverages	54	8,350	126	$6,360	$98	$51	$910	0.9%
3122	Tobacco	4	958	14	$912	$39	$33	$82	0.2%
313	Textile Mills	50	12,608	103	$3,840	$31	$13	$1,006	3.2%
314	Textile Product Mills	10	3,255	107	$3,544	$22	$10	$277	1.3%
315	Apparel	6	968	95	$2,655	$13	$6	$109	0.8%
316	Leather and Allied Products	3	405	27	$870	$6	$2	$51	0.9%
321	Wood Products	64	20,216	325	$11,863	$71	$29	$1,736	2.5%
32111	Sawmills	11	6,724	66	$2,621	$19	$7	$536	2.8%
3212	Veneer, Plywood, and Engineered Woods	28	6,638	57	$2,270	$14	$5	$564	4.1%
3219	Other Wood Products	23	6,201	195	$6,681	$35	$16	$579	1.7%
321-Other	Balance of Wood Products	2	653	7	$291	$2	$1	$58	2.7%
322	Paper	523	66,915	346	$19,305	$176	$82	$6,101	3.5%
322110	Pulp Mills	19	1,315	7	$520	$5	$2	$166	3.2%
322121	Paper Mills, except Newsprint	169	21,511	49	$3,318	$36	$19	$1,828	5.1%
322122	Newsprint Mills	6	7,660	17	$1,166	$13	$7	$409	3.2%
322130	Paperboard Mills	188	22,066	35	$2,568	$28	$14	$1,989	7.0%
322-Other	Balance of Paper	140	14,363	239	$11,733	$94	$40	$1,749	1.9%
323	Printing and Related Support	52	13,363	457	$19,727	$83	$49	$1,342	1.6%
324	Petroleum and Coal Products	993	50,403	98	$8,723	$837	$126	$7,300	0.9%
324110	Petroleum Refineries	942	46,799	62	$6,582	$795	$112	$6,781	0.9%
324199	Other Petroleum and Coal Products	0	522	3	$207	$5	$2	$35	0.8%

NAICS	MECS Aggregation	Natural Gas (Bcf)	Electricity (mm kWh)	Employment (1,000)	Annual Payroll ($mm)	Shipment Value ($b)	Value Added ($b)	Electric & Gas Costs ($mm)	Electric & Gas Costs as % VoS
324-Other	Balance of Petroleum and Coal Products	52	3,083	33	$1,933	$38	$13	$484	1.3%
325	Chemicals	1,669	155,249	694	$49,818	$777	$375	$16,211	2.1%
325110	Petrochemicals	124	8,472	9	$920	$92	$41	$1,005	1.1%
325120	Industrial Gases	99	17,495	10	$653	$7	$4	$1,380	18.9%
325181	Alkalies and Chlorine	89	11,368	6	$503	$7	$4	$898	12.6%
325182	Carbon Black	16	507	2	$125	$2	$1	$103	4.9%
325188	Other Basic Inorganic Chemicals	51	22,275	30	$2,313	$26	$16	$1,304	5.1%
325192	Cyclic Crudes and Intermediates	15	2,566	6	$483	$10	$2	$207	2.1%
325193	Ethyl Alcohol	94	2,717	3	$242	$5	$1	$568	11.3%
325199	Other Basic Organic Chemicals	355	16,975	69	$5,317	$111	$27	$2,517	2.3%
325211	Plastics Materials and Resins	334	25,193	58	$4,324	$85	$25	$2,885	3.4%
325212	Synthetic Rubber	22	1,674	9	$676	$10	$3	$219	2.1%
325222	Noncellulosic Organic Fibers	40	4,841	12	$580	$7	$2	$449	6.2%
325311	Nitrogenous Fertilizers	285	3,773	4	$336	$9	$5	$1,485	17.2%
325312	Phosphatic Fertilizers	10	1,648	6	$403	$10	$4	$146	1.4%
325412	Pharmaceutical Preparation	35	6,932	133	$11,000	$146	$104	$649	0.4%
325992	Photographic Film, Paper, Plate, and Chemicals	7	793	14	$857	$9	$4	$87	1.0%
325-Other	Balance of Chemicals	93	28,020	323	$21,087	$240	$132	$2,434	1.0%
326	Plastics and Rubber Products	127	51,536	675	$29,362	$205	$92	$4,280	2.1%
327	Nonmetallic Mineral Products	427	35,399	334	$15,697	$93	$51	$4,286	4.6%
327211	Flat Glass	22	1,694	8	$382	$3	$1	$214	7.7%
327212	Other Pressed and Blown Glass and Glassware	39	2,654	16	$813	$4	$3	$338	8.0%
327213	Glass Containers	63	3,737	14	$836	$5	$3	$511	10.3%
327215	Glass Products from Purchased Glass	4	3,118	39	$1,839	$10	$5	$248	2.5%
327310	Cements	15	8,962	12	$767	$5	$3	$595	11.1%
327410	Lime	10	1,681	4	$256	$2	$1	$149	6.5%
327420	Gypsum	50	1,434	7	$391	$3	$1	$330	10.6%
327993	Mineral Wool	26	3,261	15	$805	$5	$3	$326	6.0%
327-Other	Balance of Nonmetalic Mineral Products	197	8,858	218	$9,606	$55	$30	$1,577	2.9%
331	Primary Metals	500	136,496	374	$21,758	$280	$98	$8,982	3.2%

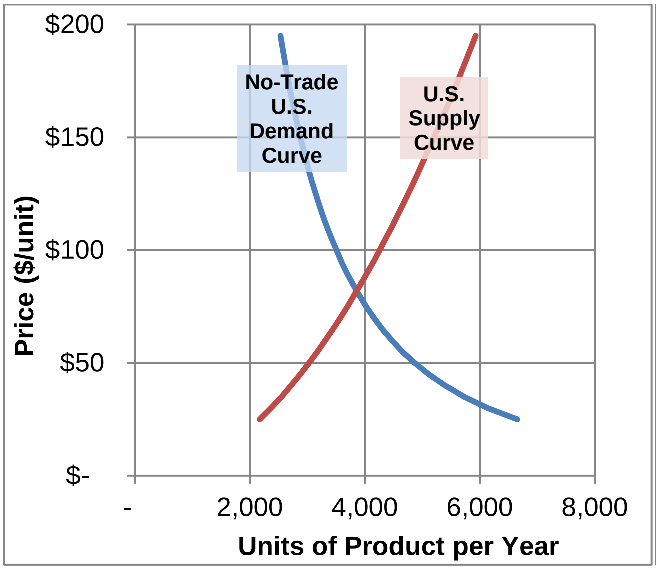
NAICS	MECS Aggregation	Natural Gas (Bcf)	Electricity (mm kWh)	Employment (1,000)	Annual Payroll ($mm)	Shipment Value ($b)	Value Added ($b)	Electric & Gas Costs ($mm)	Electric & Gas Costs as % VoS
331111	Iron and Steel Mills	235	53,822	99	$7,142	$112	$39	$3,675	3.3%
331112	Electrometallurgical Ferroalloy Products	1	3,111	3	$221	$3	$1	$156	4.5%
3312	Steel Products from Purchased Steel	26	4,789	40	$2,192	$27	$8	$440	1.6%
3313	Alumina and Aluminum	123	40,024	51	$2,862	$39	$10	$2,202	5.7%
331314	Secondary Smelting and Alloying of Aluminum	29	4,369	5	$260	$6	$1	$216	3.5%
331315	Aluminum Sheet, Plate and Foils	36	3,871	19	$1,162	$18	$4	$340	1.8%
331316	Aluminum Extruded Products	17	1,427	19	$855	$7	$3	$183	2.5%
3313-Other	Other Alumina and Aluminum	40	35,947	9	$585	$7	$2	$1,682	23.9%
3314	Nonferrous Metals, except Aluminum	54	15,434	57	$3,351	$68	$24	$1,051	1.6%
3315	Foundries	62	13,726	124	$5,989	$31	$17	$1,189	3.8%
331511	Iron Foundries	20	7,004	52	$2,503	$13	$7	$554	4.2%
331521	Aluminum Die-Casting Foundries	13	1,584	13	$623	$3	$2	$164	5.0%
331524	Aluminum Foundries, except Die-Casting	11	928	15	$743	$4	$2	$113	2.9%
3315-Other	Other Foundaries	18	4,210	44	$2,120	$11	$6	$358	3.2%
332	Fabricated Metal Products	265	43,616	1,286	$62,575	$327	$173	$4,631	1.4%
333	Machinery	121	25,798	965	$54,218	$366	$177	$2,546	0.7%
334	Computer and Electronic Products	64	27,808	817	$59,944	$338	$208	$2,356	0.7%
334413	Semiconductors and Related Devices	20	12,185	95	$7,547	$81	$65	$808	1.0%
334-Other	Other Computer and Electronic Products	45	15,623	721	$52,396	$257	$143	$1,548	0.6%
335	Electrical Equip., Appliances, and Components	48	12,756	328	$16,961	$120	$59	$1,116	0.9%
336	Transportation Equipment	192	57,951	1,235	$77,482	$690	$264	$4,515	0.7%
336111	Automobiles	19	4,459	60	$3,937	$85	$22	$302	0.4%
336112	Light Trucks and Utility Vehicles	27	4,577	61	$4,467	$122	$29	$347	0.3%
3364	Aerospace Product and Parts	39	19,899	402	$32,579	$183	$105	$1,407	0.8%
336411	Aircraft	11	9,936	165	$13,980	$93	$53	$563	0.6%
3364-Other	Other Aerospace Product and Parts	28	9,963	237	$18,598	$90	$53	$845	0.9%
336-Other	Balance Transportation Equipment	107	29,017	713	$36,500	$300	$108	$2,458	0.8%
337	Furniture and Related Products	25	5,444	320	$11,931	$62	$33	$574	0.9%
339	Miscellaneous	40	10,760	565	$29,147	$156	$100	$1,076	0.7%
Total		**6,023**	**830,841**	**10,694**	**$559,518**	**$5,498**	**$2,295**	**$70,252**	**1.4%**

Source: Annual Survey of Manufacturers, 2011, and with exception of gas use as estimated by ICF, based on various sources, including the EIA's Manufacturing Energy Consumption Survey, 2006 and preliminary 2010.

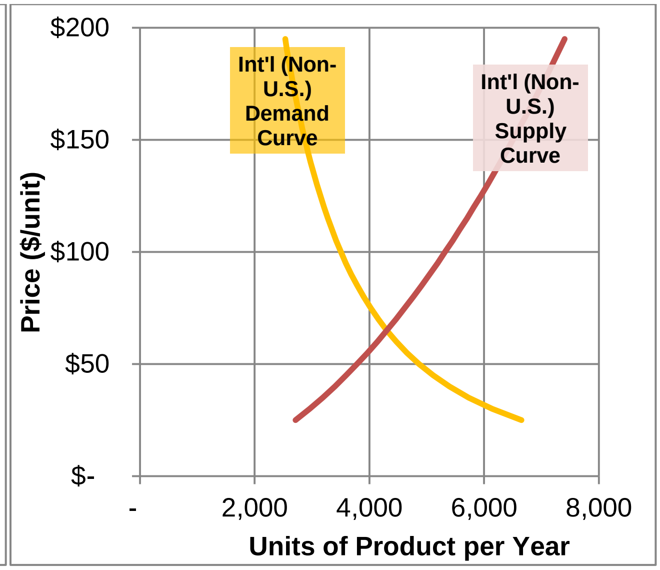
In an open economy, international trade offers a number of substitutes for products offered in a domestic economy. Thus, significant international trade within a sector results in more price elasticity for domestic production, which is a flattening of the demand curves (see Exhibit 3-3 below).

Exhibit 3-3: International Trade Impact on U.S. Demand Curve

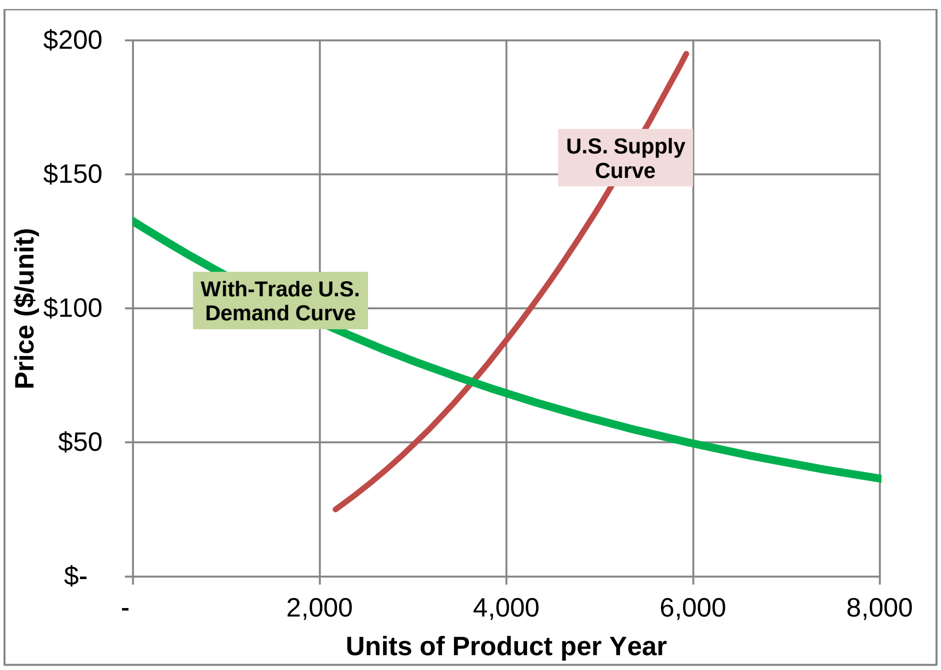
U.S. Supply and Demand for Product "X" with No Trade



International (Non-U.S.) Supply and Demand for Product "X"



Supply and Demand for Product "X" with International Trade



Note: No-trade demand elasticity assumes constant -0.5 and supply elasticity of 0.5.

ICF estimated own-price elasticity for each industrial sector starting with the assumptions that in the absence of international trade demand elasticity would be -0.5. That elasticity was then adjusted upward (in absolute value) to account for the degree of international trade as measured by trade intensity. (See Exhibit 3-4). Note that the demand elasticity was computed on a 3-digit NAICS code[9] basis and then applied to the corresponding 3- to 6-digit aggregations shown in Exhibit 3-2.

[9] North American Industrial Classification System (NAICS) codes are used by North American statistical agencies to classify economic activities by sector. It supersedes the older Standard Industrial Classification (SIC) codes.

Exhibit 3-4: Own Price Elasticity of Demand by Manufacturing Sector

NAICS	Industry	2011 Exports ($mm)	2011 Imports ($mm)	2012 Exports ($mm)	2012 Imports ($mm)	2011 Shipment Value ($mm)	2011 Int'l Trade Intensity	Assumed Demand Elasticity for U.S. Production
311	Food And Kindred Products	$58,668	$50,118	$63,404	$54,170	$710,366	14.3%	(0.71)
312	Beverages And Tobacco	$6,202	$17,017	$6,846	$18,190	$136,888	15.1%	(0.73)
313	Textile And Fabrics	$9,063	$7,314	$8,574	$7,608	$31,473	42.2%	(1.13)
314	Textile Mill Products	$2,742	$16,943	$2,855	$17,233	$22,081	50.4%	(1.26)
315	Apparel And Accessories	$3,203	$82,118	$3,289	$81,186	$12,860	89.8%	(1.85)
316	Leather And Allied Products	$2,838	$33,912	$2,833	$36,167	$5,598	93.0%	(1.90)
321	Wood Products	$5,567	$11,321	$5,905	$13,009	$70,558	20.6%	(0.81)
322	Paper Products	$24,745	$21,896	$24,434	$21,283	$175,877	23.6%	(0.85)
323	Printing, Publishing & Similar Products	$6,036	$5,242	$5,978	$5,266	$82,707	12.8%	(0.69)
324	Petroleum And Coal Products	$100,319	$141,244	$110,725	$135,872	$836,813	24.7%	(0.87)
325	Chemicals	$187,657	$216,035	$188,564	$209,868	$776,817	40.7%	(1.11)
326	Plastic And Rubber Products	$27,133	$39,736	$28,560	$43,349	$204,515	27.4%	(0.91)
327	Nonmetallic Mineral Products	$10,051	$17,753	$10,128	$18,524	$92,968	25.1%	(0.88)
331	Primary Metal Products	$65,266	$102,992	$73,769	$100,974	$280,153	43.9%	(1.16)
332	Fabricated Metal Products	$36,744	$53,528	$40,114	$59,927	$326,797	23.7%	(0.86)
333	Machinery, Except Electrical	$142,994	$133,770	$150,509	$146,947	$365,735	55.4%	(1.33)
334	Computers and Electronic Products	$123,463	$342,594	$123,456	$354,092	$337,861	68.5%	(1.53)
335	Electrical Equipment, Appliances and Components	$34,142	$75,761	$36,914	$81,132	$120,023	56.1%	(1.34)
336	Transportation Equipment	$200,735	$267,865	$226,200	$313,891	$690,437	48.9%	(1.23)
337	Furniture and Fixtures	$4,348	$26,259	$4,902	$28,565	$61,972	34.7%	(1.02)
339	Miscellaneous Manufactured Commodities	$43,055	$104,216	$44,653	$102,022	$156,101	56.6%	(1.35)
Manufacturing Total		**$1,095,096**	**$1,767,633**	**$1,163,293**	**$1,849,273**	**$5,498,599**	**39.4%**	**(1.09)**

Source: U.S. Census Bureau, 2011. Available at: http://www.census.gov/foreign-trade/data/index.html. Annual Survey of Manufacturers, 2011.

Note: International Trade intensity is defined as (Exports + Imports) / (Value of Shipments + Imports)

3.3.2 Estimation of Output Changes for Ammonia, Methanol and GTLs

Specific algorithms are used in the GMM to model the economics of natural gas use to make ammonia, methanol, and gas to liquids (also called GTLs, the primarily product of which is diesel fuel). These algorithms combine the capital, non-feedstock operating cost, and feedstock cost into a levelized cost per metric tonnes of product and compare that cost to an assumed selling price to determine the quantity of new capacity built and capacity utilization in any given year.

The assumed selling prices for fuels and chemicals derived from natural gas or NGLs were usually based on historical relationships to crude oil and the ICF Base Case assumption of a long-run Brent crude oil price of $95.00 per barrel in real 2010 U.S. dollars. The long-term selling prices are shown below in units of dollars per metric tonnes, dollars per barrel, or both.

Exhibit 3-5: Long-run Liquid Fuel and Chemical Price Assumptions

(Location: U.S. Gulf Coast, Mont Belvieu for NGLs)

Product	Units	Long-run Prices
Crude Oil (Brent or similar quality)	$/bbl	$95.00
Ethane (M.B.)	$/bbl	$28.04
Propane (M.B.)	$/bbl	$50.36
Butane (M.B.)	$/bbl	$64.39
Pentanes+ (M.B.)	$/bbl	$86.62
Lease Condensate	$/bbl	$90.72
Methanol	$/bbl	$44.44
GTL (distillate, naphtha, lubes, waxes)	$/bbl	$126.83
Methanol	$/tonne	$352.35
Ammonia	$/tonne	$400.00
GTL (distillate, naphtha, lubes, waxes)	$/tonne	$951.19
Polyethylene	$/tonne	$1,368.00
Polypropylene	$/tonne	$1,413.00

Source: ICF estimates

A logit function was used to represent what percent of planned capacity is built in the future based on the ratio of projected product values versus projected cost of production. See Exhibit 3-6 below for assumed characteristics and costs of new petrochemical plants. (The list of actual planned plants and their capacities used for this analysis is in Appendix C.)

Exhibit 3-6: Characteristics of Industrial Plants Using Natural Gas or NGL Feedstocks

Type of Plant	Feedstock Input	Example Plant Characteristics						
		Output Size	Units for Output	Feedstock Input	Units for Input	Plant Capital Cost (2010$ mm)	Direct Employees for Operation	Direct and Indirect Construction Employment (person-years)
GTL (diesel, waxes, etc.)	Natural Gas	100,000	Barrels per day	947	MMcf/d [10]	$14,000	850	70,000
Liquefied Natural Gas (LNG) [11]	Natural Gas	923	MMcf/d	1,037	MMcf/d	$4,780	200	34,300
Methanol	Natural Gas	2,500	Metric tonnes per day	82	MMcf/d	$680	150	4,900
Ammonia (Anhydrous)	Natural Gas	1,500	Metric tonnes per day	44	MMcf/d	$510	150	3,675
Ethane to Polyethylene	Ethane, other NGLs	2,740	Metric tonnes per day	60,274	Barrels per day	$2,000	800	14,384

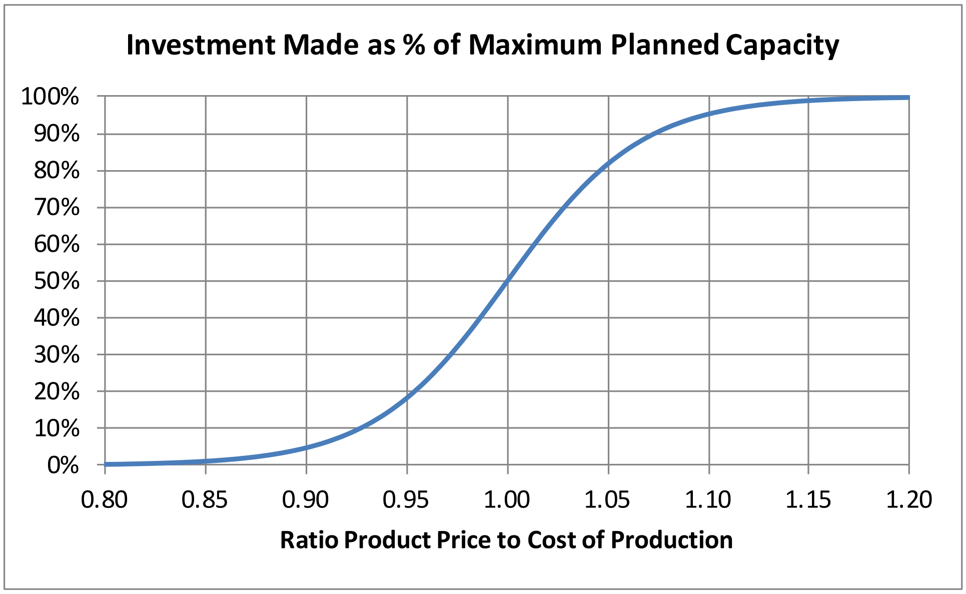
Source: ICF estimates

[10] Million cubic feet per day

[11] Capital cost given for new greenfield LNG plant. Conversion of an existing import terminal would have approximately 65% of these costs.

The logit function used for the new plant investment decision is shown below as Exhibit 3-7. This indicates that when the cost of production (estimated with a 10.3% real before tax return on capital) is exactly equal to the projected price of the chemical product, one-half of the planned capacity will be built. As the natural gas price goes up, the ratio of chemical product value to cost goes down (because the denominator is increasing) and less new capacity is predicted to be built. In the real world, such capacity expansion decisions are a step function, as whole plants are either built or not. However, in the GMM, these decisions are represented probabilistically with the logit function and so a smooth investment curve is created. The probabilistic treatment reflects possible variations among market participants in terms of capital costs, operating costs, feedstock costs, equity and debt interest rates, and expectations for future product prices. When that ratio grows to 1.2, then essentially all planned capacity is built.

Exhibit 3-7: Logit Function for New Chemical Plant Investments

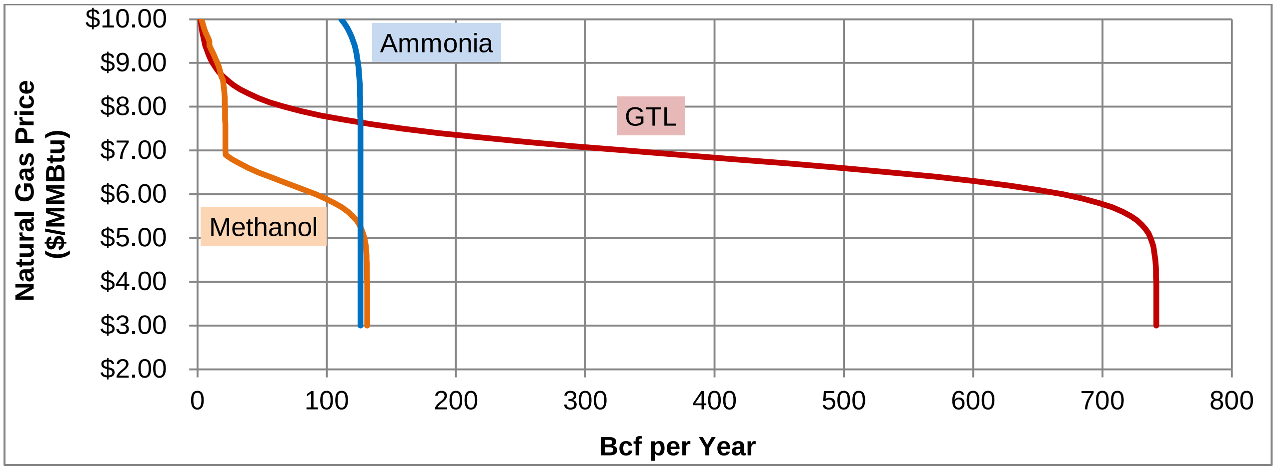


Source: ICF estimates

Given our assumptions for future chemical product prices and chemical plant capital and operating cost, the gas demand curves for new plants shown in Exhibit 3-8 were created to indicate natural gas demand of new plants as a function of natural gas prices.

Gas demand for <u>existing</u> ammonia and methanol plants was also estimated in the GMM using a similar methodology except that the capital costs for existing plants was assumed to be a “sunk cost” that did not factor into the cost of production.

Exhibit 3-8: Gas Demand Curve for New Methane-feedstock Plants (2025)

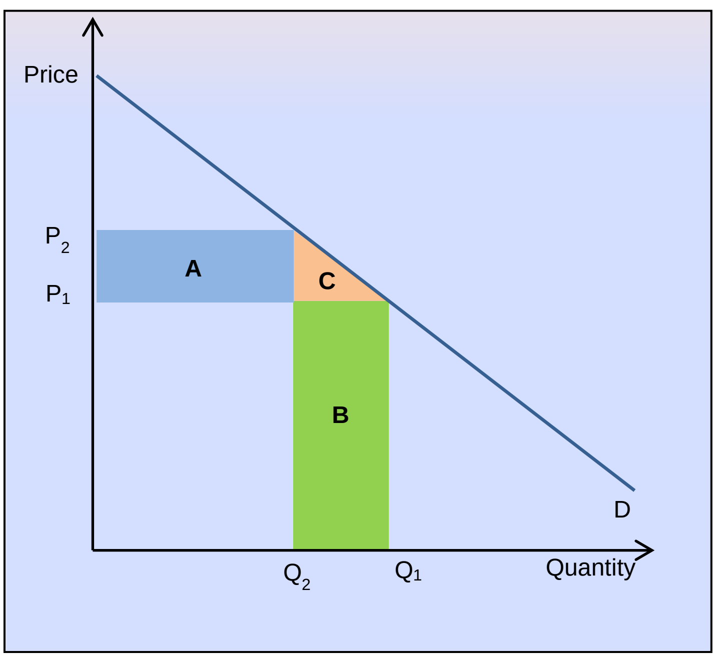


Source: ICF estimates

3.3.3 Estimation of Output Changes Related to Spending Changes by Energy Consumers and Suppliers

There are many economic consequences of LNG exports stemming from spending changes among existing users and suppliers of natural gas and electricity as prices change. For example, the additional demand for natural gas due to exports will increase its price and reduce the amount of natural gas used by existing gas customers. Specifically for households, higher gas prices cause increases in spending on alternative fuels and energy conservation while reducing spending on consumer goods. This process can be illustrated more fully using the exhibit below, which shows a generalized natural gas demand curve.

Exhibit 3-9: Generalized Demand Curve



The points and areas of the exhibit above can be interpreted as follows:

> *P_1= gas price in reference case (before a given increase in LNG exports)*
>
> *Q_1 = quantity of gas consumed in reference case*
>
> *P_2= gas price in impact case (after increase in LNG exports)*
>
> *Q_2 = quantity of gas consumed in impact case*
>
> *A = higher cost of gas at new volume = $(P_2-P_1)*Q_2$*
>
> *B = reduced value of gas caused by conservation and fuel switching = $(Q_1-Q_2)*P_1$*
>
> *C = "triangle" portion of reduced consumer surplus = $(Q_1-Q_2)*(P_2-P_1)/2$*

In addition, we can define the portion of (B+C) spent on goods and services for conservation and fuel switching as "α." The remaining part of (B+C) or "1-α" is that part of (B+C) which represents "doing without energy services" and is redirected to spending on miscellaneous consumer goods (or retained as business profits in the case of commercial/industrial gas customers). For the calculations presented in this report α is assumed to be 0.75.

<u>Residential Sector</u>

In looking at the direct impacts of higher natural gas prices on households which use natural gas (before, factoring in the consequences of higher prices for electricity and consumer goods) the following spending impacts are calculated for residential gas demand:

> *(A-B) = increased household spending on natural gas*
>
> *(B+C)*α= increased household spending on alternative fuels and conservation*
>
> *(A+C)-((B+C)*(1-α)) = reduced household spending on miscellaneous consumer goods*
>
> *(A-B) + [(B+C)*α] – [(A+C)-((B+C)*(1-α) = 0 = zero total change in household spending*

Note that the change in total household spending is calculated to be zero as increased spending on natural gas, alternative fuels, and conservation are exactly equal to reduced spending on consumer goods. This assumption will hold true as long as changes in natural gas prices do not affect household savings rates. If higher natural gas prices were to reduce household savings, then the drop in spending on miscellaneous consumer goods (and resulting job losses) would not be as large. Also note that changes to consumer spending are divided into a portion attributed to imports (16%) and a portion (84%) attributed to domestic value added (i.e., U.S. GDP contributions).

<u>Commercial and Industrial Sectors</u>

In the ICF analysis of spending and output changes related to commercial and industrial customers, the same sort methodology is employed except that an allocation is made regarding how much of the higher gas costs (the "*β* " factor) is passed on to consumers in the form or higher prices on consumer goods and services and how much ("1- β ") is absorbed by the businesses in the form a lower earnings by business owners. In the ICF analysis, the portion of higher prices eventually passed onto consumers is assumed to be 25% and (like household utility bills) is assumed to lead to a reductions in consumer spending on miscellaneous consumer goods. The remaining amounts (1- β = 75%) are calculated as reduced income to business owners, which after accounting for income taxes and savings, leads to reduced spending on miscellaneous consumer goods. As with the direct residential sector impacts, consumer spending here is divided into a portion attributed to imports (16%) and a portion (84%) attributed to domestic value added.

Therefore, for existing commercial and industrial users of natural gas who continue to use natural gas and/or switch to other fuels and who do not change their level of output, the following spending changes are computed for commercial and industrial gas demand:

(A-B) = increased business spending on natural gas

*(B+C)*α= increased business spending on alternative fuels and conservation*

[(A+C)-((B+C)(1-α))]*(1-β) = reduced business earnings, which after accounting for incomes taxes, savings and imports, reduce consumer spending on miscellaneous consumer goods*

[(A+C)-((B+C)(1-α))]*(β) = higher business costs passed on to consumers and (further) reductions in consumer spending on miscellaneous consumer goods*

Note that these calculations are for businesses or lines of business that continue to produce goods at the same level as before. For these gas users, there are no changes to output, but a reduction in profits. The employment at those industries is also unchanged. On the other hand, to model industrial gas users who reduce production due to higher natural gas or electricity prices, ICF uses the "logit function" calculations shown above for the key feedstock industries (ammonia, methanol and GTLs) and "elasticity function" for energy intensive industrial sectors to determine how much industrial production is lost. In those instances, the effects of higher natural gas prices that lead to some loss of industrial output also reduce associated jobs and value added.

Power Generation Sector and Electricity Consumers

The change in demand for natural gas to generate electricity is modeled in the GMM to reflect slightly lower coal power plant retirements and an increase in coal unit dispatch caused by higher natural gas prices. In none of the cases did natural gas prices increase to the level that would make new coal-fired power plants economic. The GMM also reflects lower overall demand for electricity caused by higher electricity prices. The net results are less natural gas use and greater reliance on coal and electricity end-use conservation.

Higher natural gas prices will cause electricity prices to go up because natural gas-fired power plants are often the marginal sources of electricity which set competitive electricity prices. In regions without competitive price setting, higher natural prices will increase electricity prices through cost of service mechanism at vertically integrated electric utilities that burn natural gas. The approximate effect of natural gas prices on average U.S. retail electricity prices is shown in the exhibit below. For example, an increase in natural gas prices of $0.25/MMBtu would increase electricity prices by about 0.11 cents per kWh, which is about 1.1% of 2011 average retail electricity prices.

Exhibit 3-10: Approximate Effect of Natural Gas Prices on Electricity Prices

Natural Gas Price Increase ($/MMBtu)	Approximate Change in Average Electricity Price (cents per kWh)	Approximate Change in Average Retail Electricity Price (%)
$0.25	0.11	1.1%
$0.50	0.22	2.2%
$0.75	0.32	3.3%
$1.00	0.43	4.4%
$1.25	0.54	5.5%
$1.50	0.65	6.5%

Source: ICF estimates

Note: Percent change is based on overage electricity price reported by EIA for 2011 of 9.9 cents per kWh.

As with the economic effect of natural gas prices, price increases for electricity will cause increases in spending on electricity, increased spending on conservation/alternative fuels and decreased spending on miscellaneous consumer goods. For the residential sector this can represented with the following relationships where the subscript "e" is used to indicate areas defined on an electricity demand curve chart.

$(A_e$-$B_e)$ *= increased household spending on electricity*

$(B_e+C_e)*\alpha$ *= increased household spending on alternative fuels to electricity and conservation of electricity*

$(A_e+C_e)-((B_e+C_e)*(1-\alpha))$ *= reduced household spending on miscellaneous consumer goods*

The relationships modeled for the commercial and commercial sectors also parallel those for natural gas:

$(A_e$-$B_e)$ *= increased business spending on electricity*

$(B_e+C_e)*\alpha$ *= increased business spending on alternative fuels to electricity and conservation of electricity*

$[(A_e+C_e)-((B_e+C_e)*(1-\alpha))]*(1-\beta)$ = reduced business earnings, which after accounting for incomes taxes, savings and imports, reduce consumer spending on miscellaneous consumer goods

$[(A_e+C_e)-((B_e+C_e)*(1-\alpha))]*(\beta)$ = higher business costs passed on to consumers and (further) reductions in consumer spending on miscellaneous consumer goods

Natural Gas Supply Chain Earnings

The added expenditures on natural gas by existing households, businesses and power generators caused by higher gas prices, will lead to greater revenues and earnings to natural gas supply chain companies and asset owners. This is modeled by ICF for the residential, commercial, industrial and power sector gas demand as:

$(A\text{-}B)_R + (A\text{-}B)_C + (A\text{-}B)_I + (A\text{-}B)_P$ = increased gas supply chain earnings, which after accounting for incomes taxes, savings and imports, increase consumer spending on miscellaneous consumer goods

These revenues initially go to U.S. royalty owners, gas producers, oil field supply and service companies and governments (higher severance, income and property taxes) but later spread throughout the U.S. economy. A small portion also goes to Canadian gas producers who export more volumes into the U.S. as the U.S. LNG exports increase.

Electricity Supply Chain Earnings

The added expenditures on electricity by existing households and businesses consumers will lead to greater revenues to electricity gas supply chain companies. However, this extra revenue will be partly (and in some cases fully) offset by higher costs for natural gas and other generating costs (for example, coal and coal plant operating costs). This is modeled by ICF for the sum of residential, commercial and industrial electricity consumption as:

$(A_e\text{-}B_e)_R + (A_e\text{-}B_e)_C + (A_e\text{-}B_e)_I + (A_e\text{-}B_e)_P$ – (Higher Generator Gas Costs) – (Higher Generator Other Costs) = increased electricity supply chain earnings, which after accounting for incomes taxes, savings and imports, increase consumer spending on miscellaneous consumer goods.

These earning initially go to electricity generators (especially coal, nuclear and renewables), power plant service companies, coal producers and transporters and governments (higher income and property taxes). All changes in electricity earnings are assumed to be to U.S. electricity generators.

It is very important to note that the spending increases resulting from higher incomes in the natural gas and electric supply chains is smaller by about half than the corresponding spending decreases from consumers having to pay higher gas and electric bills and pay more for energy-intensive goods. This is because the larger incomes to the supply chain income earners are reduced by taxes and savings before spending occurs. This phenomenon explains why reduced net spending on miscellaneous consumer goods is the largest single source of job losses (before taking into account compensating factors) calculated in this analysis.

3.4 Step 4: Use the IMPLAN Input-Output Matrices to Determine Direct and Indirect Value Added and Job Impacts by Sector

Given the changes in U.S. outputs determined in Step 3, ICF analyzed the direct and indirect economic impacts on value added (GDP), jobs, and taxes by sector using input-output relationships developed with the Impact Analysis for Planning (IMPLAN) model of the U.S. economy. This input-output (I-O) model is based on a social accounting matrix that incorporates all flows within the U.S. economy, and is used to assess the aggregate economic impacts associated with changes in an industry's output. For example, additional LNG exports will require additional natural gas exploration and production services, equipment, and materials. Those direct impacts will be followed by indirect impacts as intermediate inputs for those items (e.g., steel production to make casing and iron mining to make steel) also will see higher demand.

These I-O relationships can be extracted into matrices that indicate the number of direct and indirect jobs in sector X per million dollars of output in sector Y. A matrix can also be defined as the number of direct and indirect jobs in sector X per physical unit of output in sector Y. Similar matrices can be constructed showing the value added in sector X per million dollars or per unit of production in sector Y. By multiplying these matrices by the output changes estimates in Step 3, ICF estimated the value added and job impacts by sector for each of the three non-zero LNG export scenarios versus the Zero Export Case.

Direct Impacts represent the immediate impacts (e.g., employment or output changes) in Sector A due to greater demand for and output from Sector A.

Indirect Impacts represent the impacts outside of Sector A in those industries that supply or contribute to the production of intermediate goods and services to Sector A.

Induced or "Multiplier Effect" Impacts represent the cumulative impacts of spending of income earned in the direct and indirect sectors and subsequent spending of income in each successive round. Examples include a restaurant worker who takes a vacation to Florida, or a store owner who sends children to college, based on higher income that arises from the initial activity of LNG exports.

3.5 Step 5: Apply a Range of Multiplier Effects to Estimate Induced Economic Activity

In Step 5 ICF applied a range of multiplier effects to the direct and indirect GDP changes to assess the induced economic activity as people who earn income through the direct and indirect activity spend that income and then the income produced in that second round of spending gets spent in a third round and, so on. This estimate of additional GDP is referred to as the "multiplier effect GDP" or "induced GDP effect." The range in multiplier effects applied by ICF represents uncertainties regarding the possible future "slack" in economy and how much of a "crowding out" effect there might be in labor and other factor markets if the net new demands for labor stemming from LNG exports cannot be met entirely with new workers and other factors[12]. The tables and chart present in this report show results for multipliers of 1.0 (direct and indirect impacts only), 1.3, and 1.9. Section 7 of this report presents a discussion on multiplier effect estimates and how the approach used in this report (input-output analysis plus a range of multiplier effects) differs from the approach of computable general equilibrium (CGE) models, such as the one used in the NERA report to DOE.

Estimation of Multiplier Effect

This study employs a range of multiplier effects to estimate the lower-bound and upper-bound for "induced" activities in the U.S. economy, resulting from the spending of personal income generated by the direct and indirect activities. The equation below shows the hypothetical GDP multiplier effect from any incremental increase of purchases (from business investment, exports, government spending, etc.) MPC is marginal propensity to consume, and is estimated at 0.900 using a post-World War II average for the U.S. This means that for every dollar of personal income generated, $0.90 goes toward consumption, and the remaining $0.10 is saved. The MPI is the marginal propensity to import, estimated at 0.162, based on the average for recent years. The effective tax rate is $0.269 per dollar of income/GDP. Inputting the MPC, MPI, and tax rate into the equation below shows that every dollar of income stemming from direct and indirect activity hypothetically could produce a total of $1.984, meaning that $0.984 is "induced" economic activity, or the amount produced as the multiplier effect.

$$\Delta GDP = \Delta Exports * 1 / (1-MPC*(1-TAX) + MPI)$$

Multiplier Effect Input	Value
Marginal Propensity to Consume after Taxes (MPC)	0.900
Marginal Propensity to Import (MPI)	0.162
Tax Rate	0.269
Resulting Multiplier	**1.984**

Because of this uncertainty in the multiplier effect, a range is used in this study. A value of1.9 is used as the multiplier for the upper-bound limit, and 1.3 [1.6 – (1.9-1.6)] for the lower-bound estimate.

Source: American Clean Skies Foundation (ACSF), based on analysis conducted by ICF International. "Tech Effect: How Innovation in Oil and Gas Exploration is Spurring the U.S. Economy." ACSF, October 2012: Washington, D.C. Available at: http://www.cleanskies.org/wp-content/uploads/2012/11/icfreport_11012012_web.pdf

This study attempts to quantify the net economic impacts of an exogenous change to the U.S. economy (i.e., a policy to permit LNG exports) by calculating the resulting output change in various products (e.g., increasing LNG exports, liquids production, petrochemical manufacturing, and decreases in electricity consumption and consumer spending). Then, the multiplier effect range is applied – the lower-bound (1.3) representing significant crowding out effect, while the upper-bound (1.9) is consistent with a very slack economy and/or an elastic supply of labor and other factors of production. After that, both measures of GDP impacts (direct and indirect alone *versus* direct, indirect, and induced) are then converted to job impacts using input-output relationships, wherein the number of jobs per dollar of value added vary among economic sectors.

[12] Factors of production are defined by economists to be inputs such as labor, land, capital, and technical knowhow that are used in producing goods and services.

The input-output analysis that is discussed in the later sections of this report shows that the net result of LNG exports would be an increase in the demand for labor. In theory, this extra demand could be accommodated by the following processes:

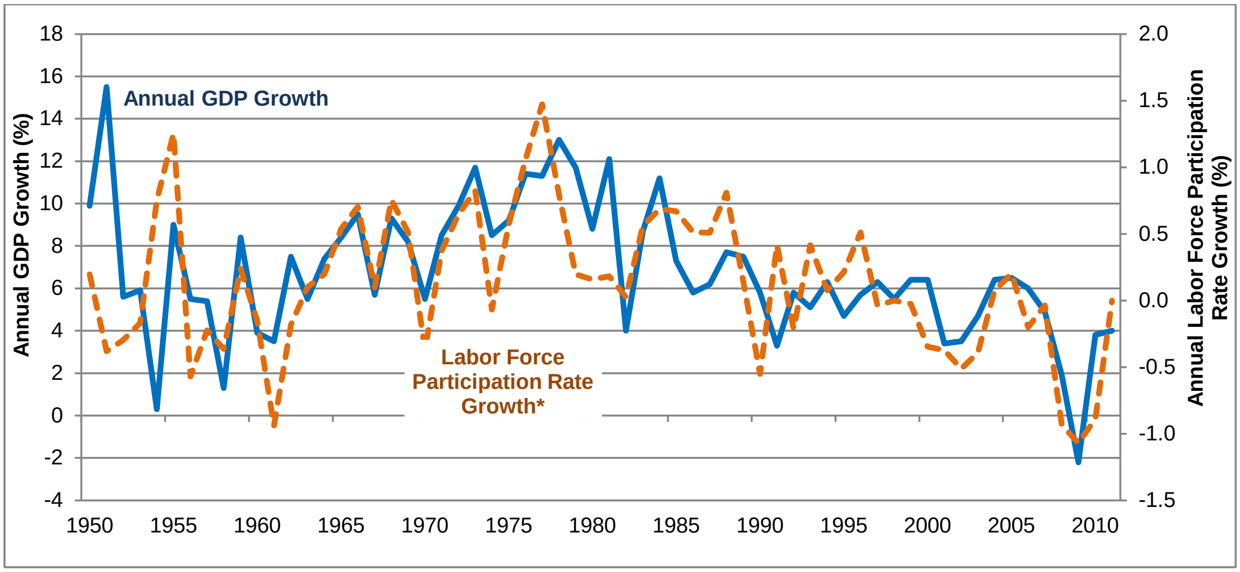
1. Reduced unemployment (i.e., people in the labor force who cannot find a job will be able to find a job). This method of adjustment would be most prominent when there is a high unemployment rate.
2. Increased labor participation rates (i.e., more people will join or stay in the labor force due to higher wages and less time needed to obtain employment).
3. Longer hours worked (i.e., people with jobs will work longer hours, such as moving from part-time to full-time employment).
4. Greater immigration (i.e., more foreign workers will come to or stay in the U.S.).
5. Crowding out (i.e., the sectors with growing demand will increase wages and entice workers to leave their current jobs. The sectors losing workers then could adjust by substituting capital or other factors of production for labor and/or by reducing their production levels).

The input-output approach used in this report assumes that processes 1 to 4 will be dominant and that the demand for more workers in LNG-related sectors will be met to a large degree without constraining other sectors. Some empirical evidence for this view appears below:

1) GDP growth promotes labor participation rate increases

The exhibit below shows how closely labor force participation rates are correlated with GDP growth. The chart below illustrates that growth in GDP induces more people to enter the labor force, while weak GDP growth is accompanied by a decline in the labor force participation rate, as more people, unable to find employment, exit the labor force. Thus, sectors that promote GDP growth also promote net job growth, which are particularly important during times of weak GDP growth when many people have left the workforce.

Exhibit 3-11: GDP Growth and Lagged* Labor Force Participation Impact



Sources: U.S. Bureau of Economic Analysis (BEA). "National Economic Accounts: Gross Domestic Product." BEA, 2013: Washington, D.C. Available at: http://www.bea.gov/national/. U.S. Bureau of Labor Statistics (BLS). "Labor Force Statistics from the Current Population Survey." BLS, 2013: Washington, D.C. Available at: http://data.bls.gov/timeseries/LNS11300000.

* Lagged one year

2) Wage growth (due to increased labor demand) induces increase labor supply

Economists often define two labor supply elasticities to measure changes to employment as a function of wages:

1. Extensive margin elasticity: More people enter the work force when wages increase
2. Intensive margin elasticity: People work more hours when wages increase

Estimates of these two labor supply elasticity rates are reported by two prominent studies that have surveyed the available literature.[13, 14] These two studies give total mean labor supply elasticity of 0.40 and 0.75, respectively, indicating that a wage increase of 1% increases labor supply by between 0.40% and 0.75%, taking into account both the intensive and extensive margins.

ICF's estimate of future U.S. employment is derived from the U.S. Bureau of Labor Statistics assessment of job growth through 2020, which shows U.S. employment growth of 14.3%

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[13] Chet, Raj; Adam Guren, Day Manoli, and Andrea Weber. "Are Micro and Macro Labor Supply Elasticities Consistent? A Review of Evidence on the Intensive and Extensive Margins." University of California, Los Angeles, May 2011: Los Angeles. Available at: http://www.econ.ucla.edu/dsmanoli/extmarg_aerpp.pdf

[14] Reichling, Felix; Charles Whalen. "Review of Estimates of the Frisch Elasticity of Labor Supply." Congressional Budget Office, October 2012: Washington, D.C. Available at: http://www.cbo.gov/publication/43676

between 2010 to 2020, totaling 20.5 million new jobs by 2020.[15] This 14.3% ten-year growth in U.S. employment equates to an annual job growth of 1.35% over the period. Assuming this 1.35% per annum (p.a.) rate of growth in total employment continues through 2035, total U.S. employment would be 183.6 million jobs in 2035. As shown in Section 6.2.3, ICF's estimate for direct, indirect, and induced LNG export employment increases contribute between 72,000 and 665,000 annual jobs by 2035, depending on LNG export scenario and multiplier effect. This equates to between 0.04% and 0.36% of total U.S. employment in 2035 and, as discussed in Section 6.2.3, is assumed to be feasible without significantly constraining other sectors.

3.6 Step 6: Use IMPLAN Input-Output Matrices to Determine Induced Job Impacts

The induced economic spending estimated in Step 5 was allocated among economic sectors based on IMPLAN's input-output matrices for household spending. These matrices included direct spending on such things as housing, transportation, food, clothing, entertainment and so on and the indirect effects on the economic sectors that supply intermediate goods and services used to make consumer goods and services. The IMPLAN matrices were also used in Step 6 to estimate the job impacts from induced GDP. This estimate is referred to as the "induced job" effect.

3.7 Step 7: Estimate Government Revenues and Other Economic Metrics

In this calculation step, ICF assessed government revenues based on incomes taxes, severance taxes, property taxes as well as government royalties from incremental natural gas and liquids production on government lands. As with most other calculated impact values, all government revenue estimates are presented as incremental changes relative to the Zero Exports reference case. In Step 7 ICF also calculated various other metrics to be presented in the report such as net GDP change per Bcfd of exports, number of net jobs added per Bcfd of exports, net GDP change per each net new job added, and so on.

3.8 Step 8: Compile and Compare Results from Other Studies

The final step on the study was to compile results from other published studies that attempt to quantify the impact of LNG exports on U.S. natural gas prices and the economy. ICF then compared their results with each other and with this study. However, making direct comparisons among such studies was challenging because the studies looked at different issues, used various modeling methodologies, and were based on widely different assumptions. Where possible the results were put on a comparable basis into comparisons tables. These comparisons are shown and discussed in Section 7 of this report.

[15] U.S. Bureau of Labor Statistics (BLS). "Employment Projections: 2010-2020 Summary." U.S. Department of Labor, 1 February 2012: Washington, D.C. Available at: http://bls.gov/news.release/ecopro.nr0.htm

3.9 Study Assumptions for General Energy Market Conditions and Prices

As was stated earlier in this section, the primary North American energy market effects of LNG export were assessed in this study using ICF's Gas Market Model (GMM). Given each of the four, fixed LNG export scenarios, the GMM was solved for monthly market-clearing prices considering the interaction between supply and demand curves at each of the model's North American nodes. In order to run the model, various assumptions needed to be made about such items as general economic conditions and the prices of fuels competing with natural gas. The underlying assumptions for North American natural gas market factors (e.g., economic growth rates, oil prices, natural gas resource base and costs) were those contained in the Second Quarter 2013 ICF Base Case. The following detail the key assumptions made for this study.

3.9.1 GMM Assumptions and ICF Base Case Results

- GDP Growth: Our assumptions include the BEA's Q1 through Q3 2012 GDP growth estimates. For 2013 and 2014, we assume U.S. GDP growth of 2.3% and 2.9%, respectively, based on the Wall Street Journal's January 2013 Survey of Economists. From 2015 forward, we assume U.S. GDP grows at 2.6% per year.
- Oil Prices: U.S. oil price (Brent or similar quality) is assumed to be $95 per barrel (in 2010$).
- Demographic Trends: Demographic trends consistent with trends during the past 20 years. U.S. population growth averages about 1% per year.
- Power Generation Growth: Electric load growth averages 1.2% per year.
- Environmental Regulations: ICF's Base Case reflects one plausible outcome of EPA's proposals for major rules that have been drawing the attention of the power industry – these include Mercury & Air Toxics Standards Rule (MATS), water intake structures (often referred to as 316(b)), and coal combustion residuals (CCR, or ash). It also includes a charge on CO2 reflecting the continuing lack of consensus in Congress and the time it may take for direct regulation of CO2 to be implemented. The case generally leads to retirement and replacement of some coal generating capacity with gas generating capacity.
- Power Plant Mix: Renewables up to meet state RPS's, coal generation down, and other forms of non-gas generation are fairly flat. Gas generation grows to fill the gap between electric load and the total amount of generation from other types of generation.
- Assumes a maximum lifespan of 60 years for all nuclear units: This results in 11 GW of nuclear retirements between 2029 and 2035.
- Energy Efficiency Programs: Adoption of DSM programs and conservation and efficiency measures continue, consistent with recent history.
- Weather: Weather assumed to be consistent with the average of the past 20 years.

- Forecasts: Forecast months beginning January 2013 are assumed to be consistent with the 20-year average.
- Natural Gas Production: Current U.S. and Canada gas production from over 300 trillion cubic feet of proven gas reserves.
- Natural Gas Supply Restrictions: Gas supply development is permitted to continue at recently observed activity levels – no significant restrictions on permitting and fracturing beyond current restrictions.
- Supply Disruptions: No significant hurricane disruptions to natural gas supply (disruption consistent with a 20-year average).
- Midstream Activity: Near-term midstream infrastructure development assumed per project announcements. Unplanned projects included when market signals need of capacity, and there are no significant delays in permitting and construction.
- Natural Gas Resource Base: In total, the U.S. and Canada have over 4,000 Tcf of resource that can be economically developed using current exploration and production (E&P) technologies (see exhibit below). Over 50% of the assumed resource is shale gas. At current levels of consumption, this is enough resource for about 150 years. As technologies improve and new discoveries are made, the total gas resource is likely to grow.

Exhibit 3-12: U.S. and Canadian Natural Gas Resource Base

(Tcf of Economically Recoverable Resource, assuming current E&P technologies)

Resource Base Type	Total Gas (Tcf)	Crude and Cond. (Bil Bbl)
Lower 48		
Proved reserves	297	21
Reserve appreciation and low Btu	204	23
Stranded frontier	0	0
Enhanced oil recov.	0	42
New fields	488	68
Shale gas and condensate	1,964	31
Tight oil	88	25
Tight gas	438	4
Coalbed methane	66	0
Lower 48 Total	**3,545**	**214**
Canada		
Proved reserves	61	4
Reserve appreciation	29	3
Stranded frontier	40	0
Enhanced oil recov.	0	3
New fields	219	12
Shale gas and condensate	601	0
Tight oil	116	20
Tight gas (with conv.)	0	0
Coalbed methane	76	0
Canada Total	**1,142**	**43**
Lower-48 and Canada Total	**4,687**	**257**

Source: ICF GMM

In recent years, ICF has extensively evaluated shale gas and tight oil resources, both in terms of technical and economic recovery. This work has been sponsored by private companies, industry associations and government agencies. We have evaluated the geology, historic production and costs of all major U.S. and Canadian plays. This analysis shows that these resources are geographically widespread, and are economic to develop at moderate wellhead prices. The ICF analysis of these emerging natural gas and oil resources is done using a geographical information system (GIS) process that evaluates the resource at a highly granular level, accounting for variations in geologic factors, resource quality and economics within plays. This GIS process has been applied to resource assessments for plays covering over 435,000 square miles.

This ICF analysis reflects recent upstream technology advances including those in the following areas:

- Horizontal drilling and steering
- Multi-stage hydraulic fracturing
- Fracturing fluids and techniques
- Seismic and other geophysical analyses of drilling locations

- Reductions in environmental impacts (multi-well pads, water conservation and recycling, reformulation of additives, reduced emission completions (RECs), etc.)

These upstream technology advances have enlarged the U.S. economic resource base by expanding areas where drilling can take place, increasing recovery factors and reducing capital and operating costs per unit of production.

The ICF natural gas resource assessment, particularly for shale gas, is higher than other published assessments. The difference results from the inclusion of more plays and from our more inclusive and extensive geological and engineering approach to resource assessment. The ICF Lower-48 natural gas assessment of roughly 3,500 Tcf in recoverable gas can be compared to the EIA's estimate of roughly 1,480 Tcf[16], or ICF's own assessment of 1,100 Tcf in 2008. The ICF assessment is based upon extensive geologic, engineering, and economic analysis. Our well recovery estimates and development and production forecasts are supported by actual production and estimated ultimate recovery (EUR) per well results where historical data are available. Other differences from EIA's estimate include:

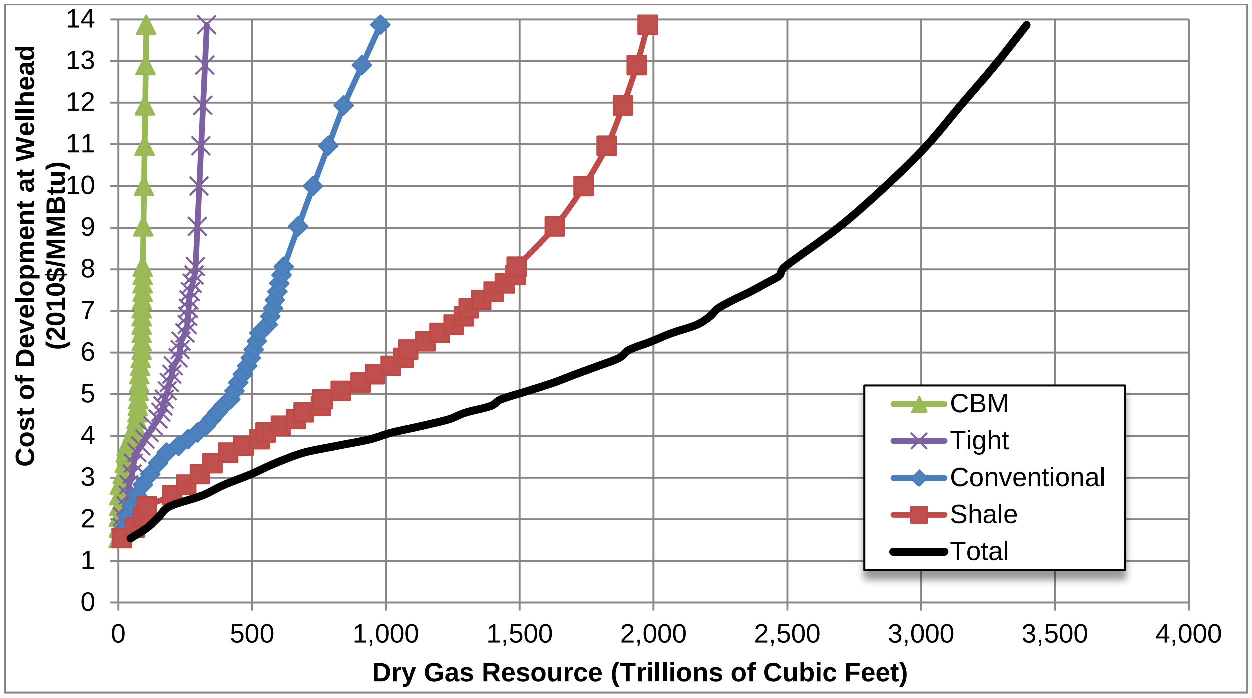
- More plays are included by ICF. ICF includes all major shale plays that have significant activity or industry interest.
- ICF includes the entire shale play, including the oil portion. Several plays such as the Eagle Ford have a large liquids area. The oil portion of the play may contain large volumes of associated gas.
- ICF employs a bottom-up engineering evaluation of gas-in-place, original oil in place (OOIP), and recoverable hydrocarbons. This analysis is based upon mapped geological parameters and well accepted reservoir simulation and modeling methods.
- ICF looks at infill drilling and the latest current technologies that increase the volume of reservoir contacted.
- ICF includes conventional gas in the areas of the OCS that are currently off-limits, such as the Atlantic OCS. Some of this resource may be made available, but it is not a large part of our resource base.
- ICF evaluates all hydrocarbons at the same time (dry gas, NGLs, crude, and condensate). The inclusion of liquids is a critical aspect of prospect economics and has a large impact on the supply curve.
- The ICF resource is a "risked" resource. ICF employs an explicit risking algorithm based upon the proximity to nearby production and factors such as thermal maturity or thickness.

Supply Cost Assumptions: The existing North America resource base includes about 1,500 Tcf of gas that is economically recoverable at $5 per MMBtu. Shale gas accounts for over half of the gas economically recoverable at $5 per MMBtu. The total cost of developing new

[16] EIA NEMS oil and gas supply assumptions, August 2012, Table 9.2, p. 113.

resource as depicted in these curves includes exploration, development and O&M costs (both fixed and variable cost) and takes into account the value of associated liquids.

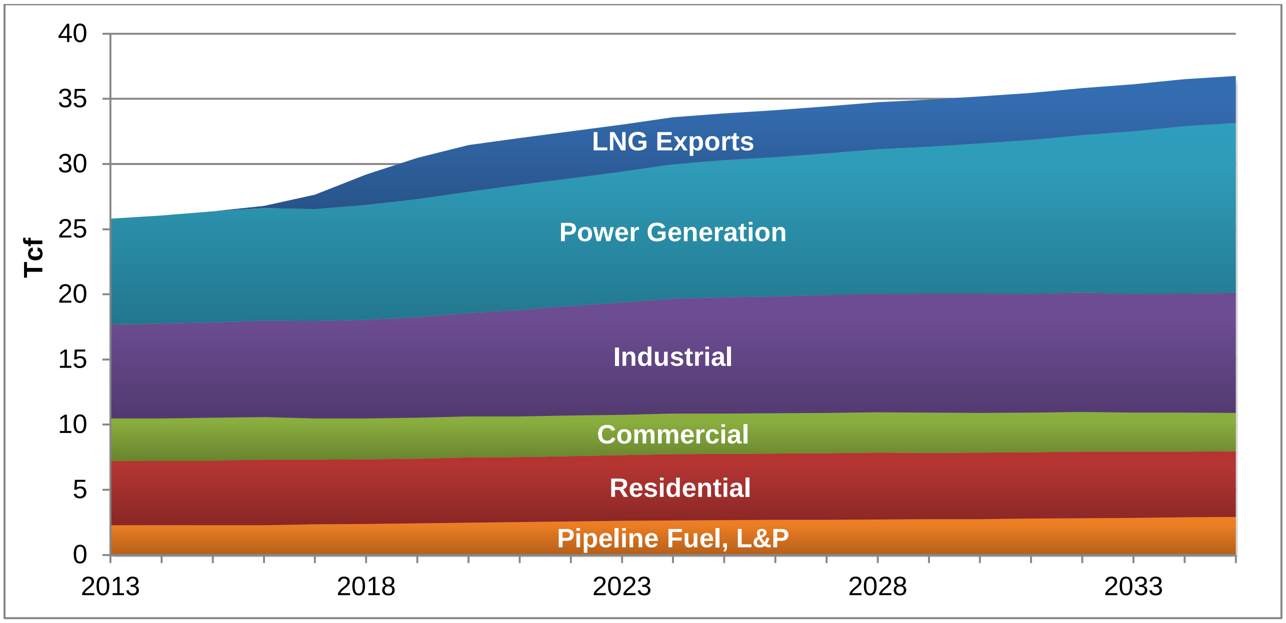
Exhibit 3-13: North American Gas Supply Curves



Source: ICF GMM

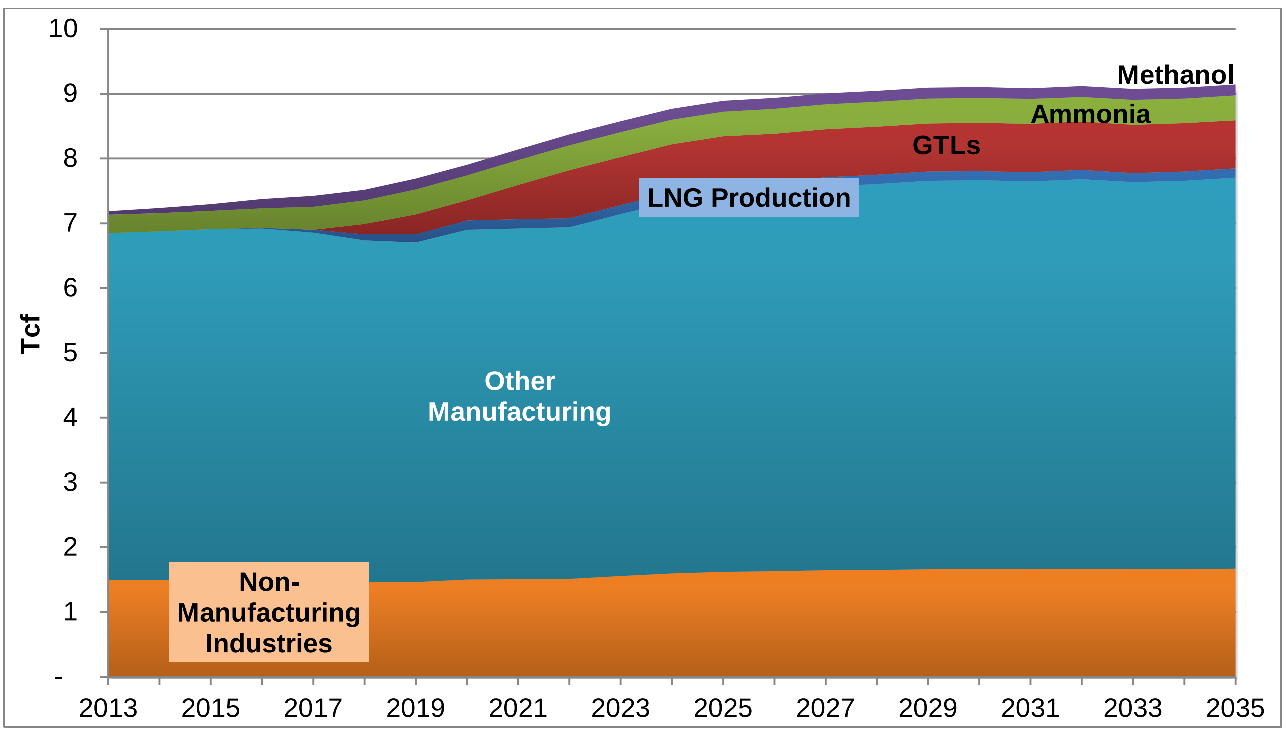
<u>Size and Composition of U.S. Gas Market</u>: Exhibit 3-14 below projects gas use by sector from the ICF Base Case. (In Exhibit 3-14 “LNG Exports” is the amount of gas actually loaded onto LNG tankers whereas fuel used within the U.S. liquefaction plants is contained within the “Industrial” sector.) The industrial gas use is broken out further in Exhibit 3-15, which shows that gas-intensive manufacturing industries such as GTLs and ammonia are projected to increase through 2035. (In Exhibit 3-15, “LNG Production” includes only the fuel required for liquefaction.)

Exhibit 3-14: U.S. Natural Gas Use by Sector (ICF Base Case)



Source: ICF GMM

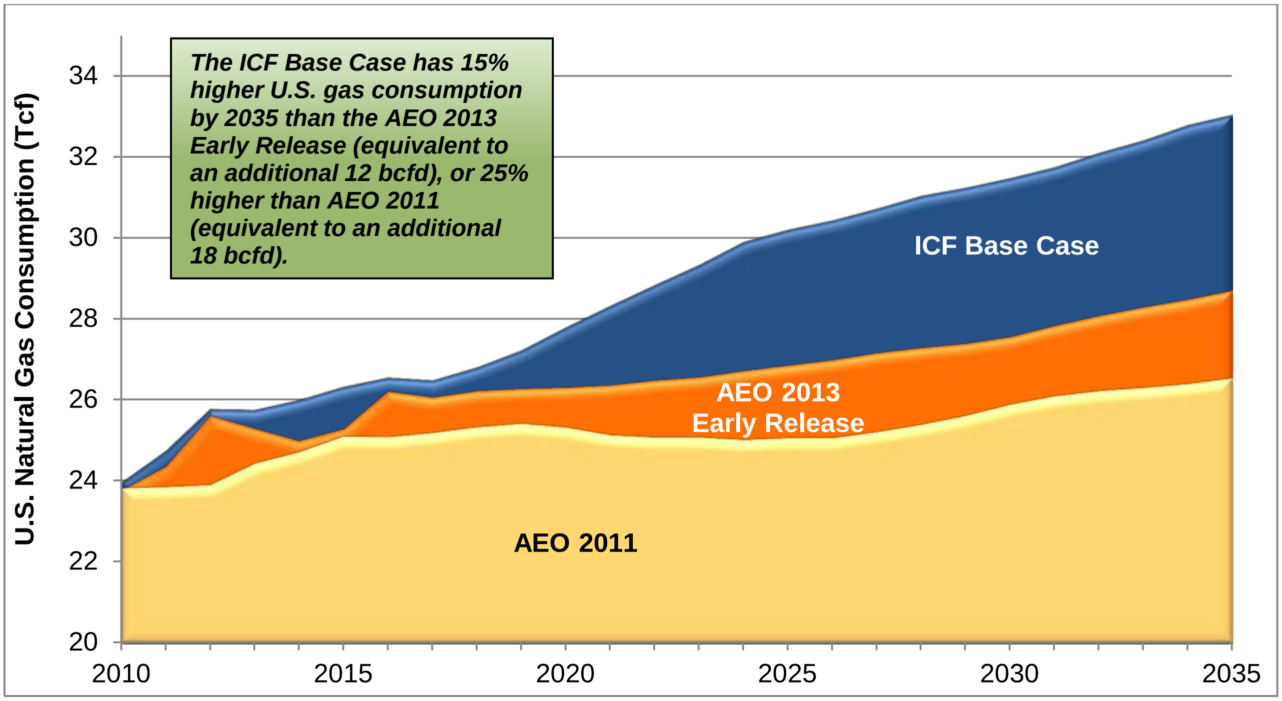
Exhibit 3-15: Breakout of U.S. Industrial Sector Gas Use (ICF Base Case)



Source: ICF GMM

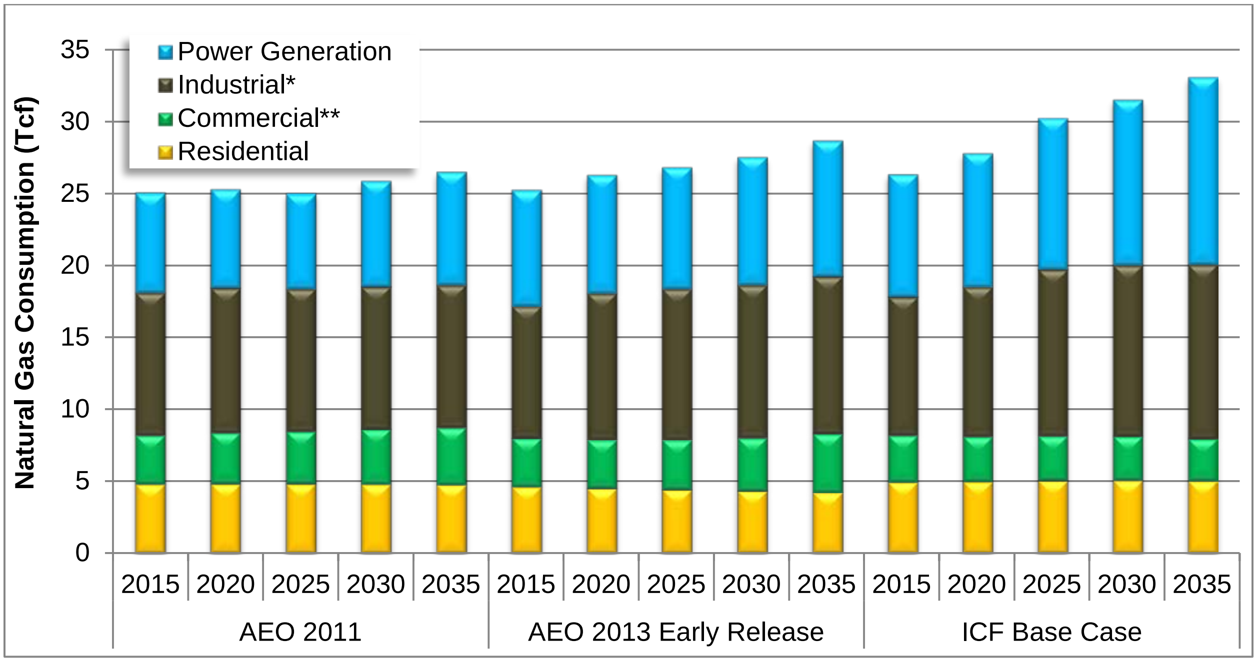
The ICF outlook for U.S. gas use is compared to EIA's Annual Energy Outlook (AEO) for the last two years in Exhibit 3-16 and Exhibit 3-17. The ICF forecast is significantly larger than either EIA forecast, primarily in the industrial and power sectors. These differences are due to ICF assumptions of a) faster economic and electricity demand growth, b) more industrial demand growth from new industrial plants, and c) a larger and more price-elastic representation of U.S. gas supplies that accommodates natural gas demand growth with only moderate price increases. The ICF Base Case shows 15% higher U.S. gas consumption by 2035 than the AEO 2013 Early Release (equivalent to an additional 12 Bcfd). Compared to the older AEO (used as the basis for the NERA report to DOE) the ICF Base Case is 25% higher than AEO 2011 (equivalent to an additional 18 Bcfd).

Exhibit 3-16: U.S. Natural Gas Consumption Comparisons



Source: ICF GMM, EIA

Exhibit 3-17: Natural Gas Consumption Comparisons by Sector



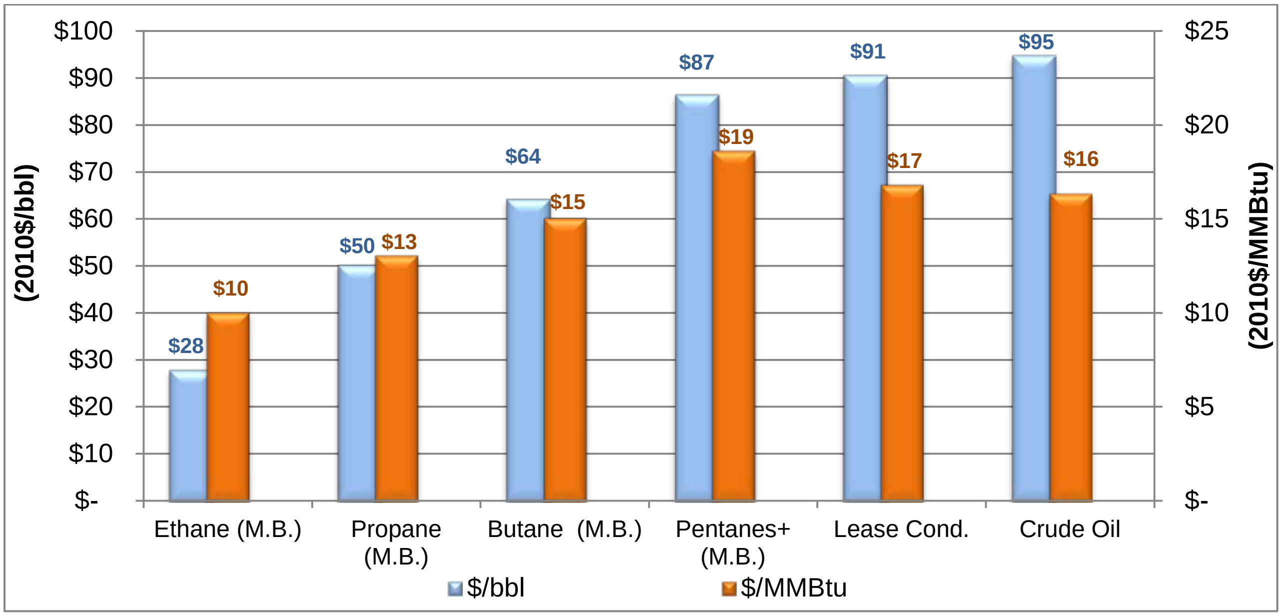
Source: ICF GMM, EIA

3.9.2 Price Assumptions for Hydrocarbon Liquids and Petroleum and Chemical Products

This study's assumed selling prices for fuels and chemicals derived from natural gas or NGLs were usually based on historical relationships to crude oil and the ICF Base Case assumption of a long-run Brent crude oil price of $95.00 per barrel in real 2010 U.S. dollars. The long-term selling prices were shown above in Exhibit 3-5 in units of dollars per metric tonnes, dollars per barrel, or both. These prices are also displayed below in Exhibit 3-18 and Exhibit 3-19 in graphical form.

Exhibit 3-18: Long-run Oil and Derivatives Price Averages

(assumed for all years 2013-2035)

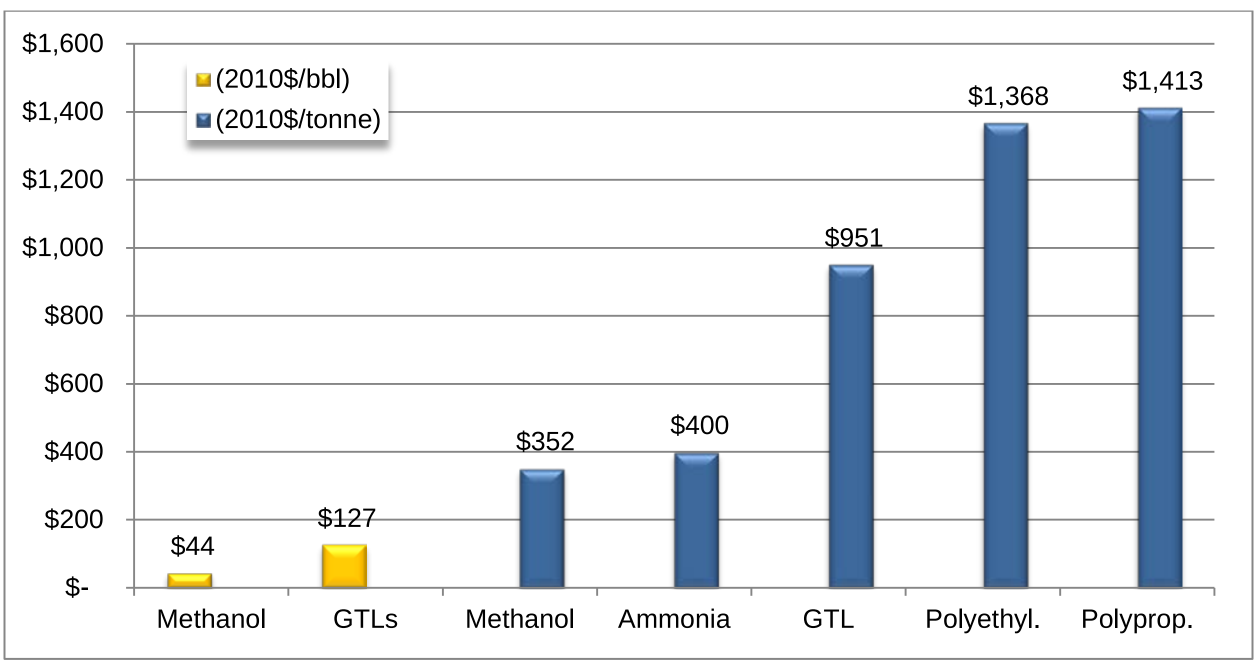


Source: ICF estimates

Note: M.B. indicates price at Mont Belvieu, TX.

Exhibit 3-19: Petrochemical Product Prices

(assumed for all years 2013-2035)



Source: ICF estimates

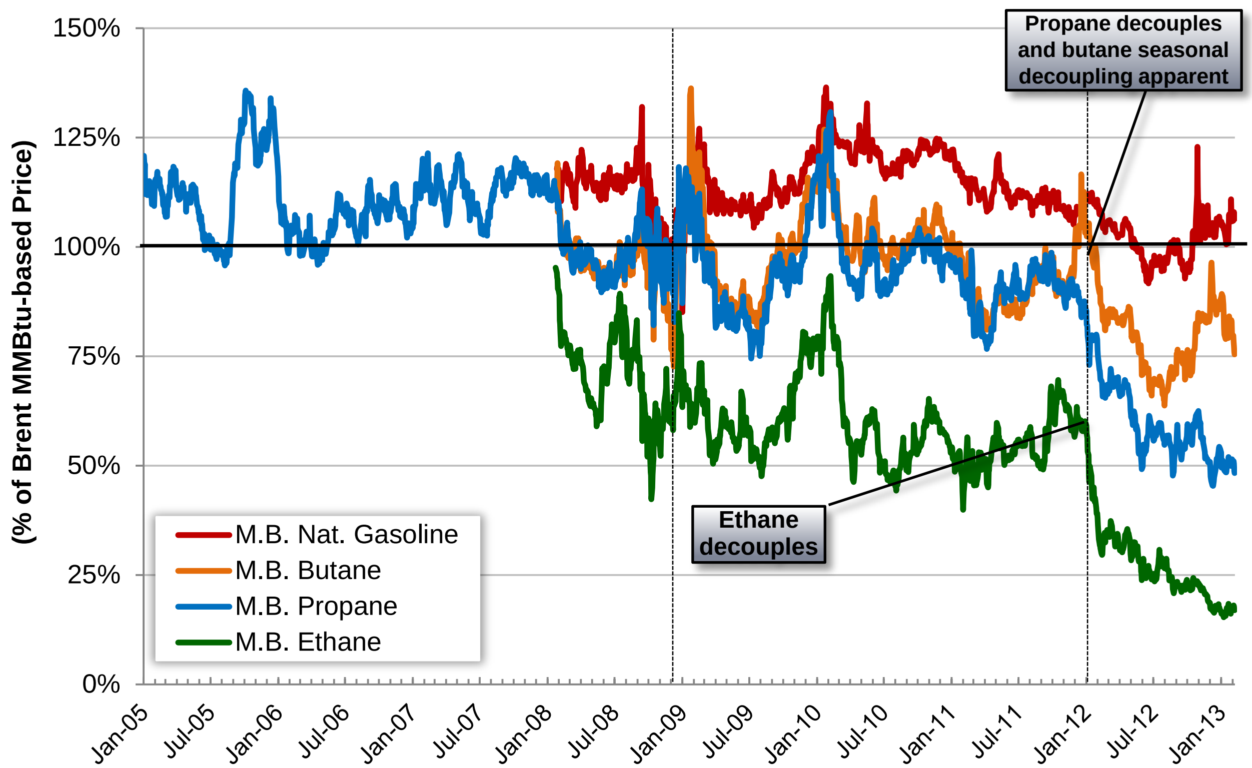
Crude and NGLs

The $95/bbl crude oil assumption is an input of the GMM, developed by ICF based on historical and forecasted supply and demand trends. NGL prices were estimated based on their linkages with oil prices. In terms of NGLs, liquids are a valuable byproduct of natural gas production. NGLs are hydrocarbons that are produced with natural gas in most areas. NGLs are in gaseous form at the wellhead and must be processed out of the gas. Components of NGLs include ethane, propane, butanes, pentanes-plus (also called natural gasoline). Lease condensate is produced at the lease separator of a gas well and is similar to a very light crude oil.

About 75% of NGLs in the U.S. come from gas processing plants, while the remainder comes from oil refining. As gas production from shale has increased, the output of U.S. gas plant NGLs has grown in parallel, and is expected to increase in the future with shale gas production. NGLs are used in a wide range of applications, including petrochemical plants, space heating, motor fuels, and gasoline blending. Exports of NGLs are expected become significant in the future. Ethane, which represents the highest volume NGL component, is a key feedstock for the production of ethylene, which is used to manufacture a wide range of commercial and consumer plastic products. Propane is used in the petrochemical industry, as well as for heating and as a motor fuel.

An important aspect of NGL production from shale gas is that on a heating value basis, NGLs have for much of recent history been much more valuable than natural gas. The difference in price is significant enough to drive drilling activity toward so-called wet gas and tight oil plays. While NGLs such as ethane and propane have recently somewhat decoupled from oil prices, given the ample supply available since 2009, attributable to the shale gas revolution, the future value is assumed in this study to return toward close linkage to oil prices, albeit at a lower relative ratio than historically experienced since the U.S. is expected to be a substantial net exporter of propane and butane (see exhibit below).

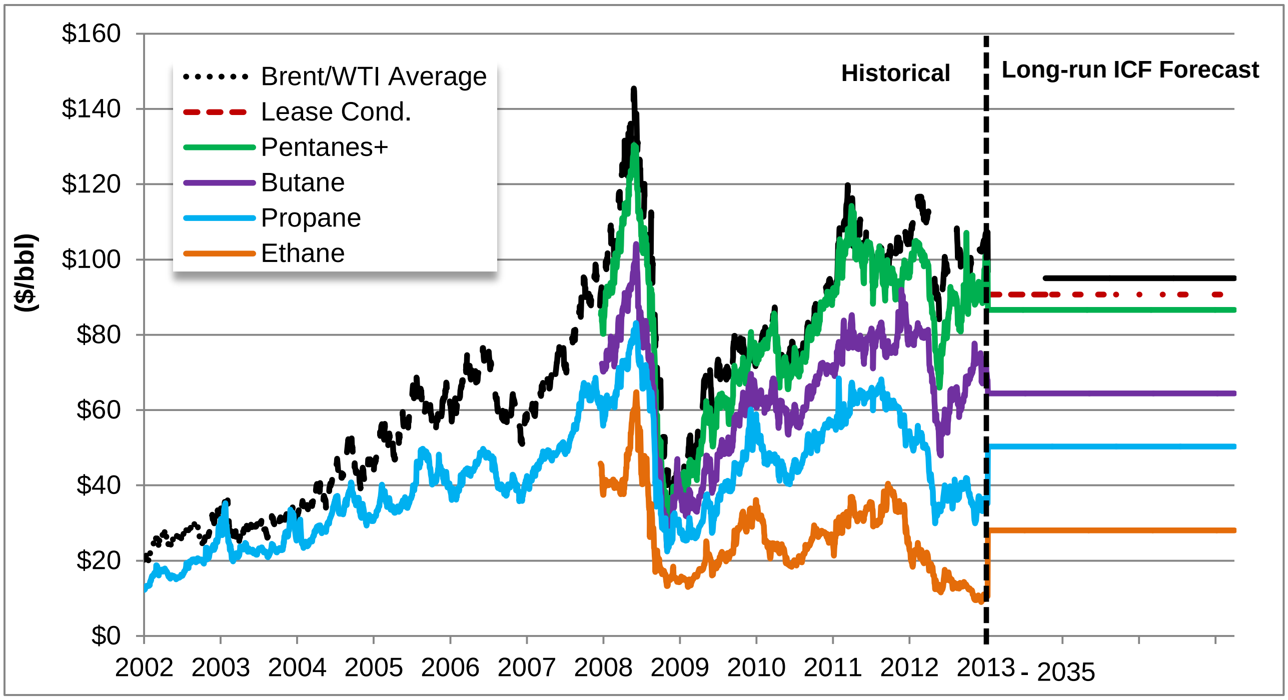
Exhibit 3-20: NGL Prices relative to Brent Crude (MMBtu-based Prices)



Source: Bloomberg, through February 11, 2013.

The following exhibit shows historical prices for NGLs and crude, as well as the long-run prices assumed for this study.

Exhibit 3-21: Crude Oil and NGL Prices



Source: Bloomberg, 2/4/2013, nominal prices; long-run average price forecasts made by ICF

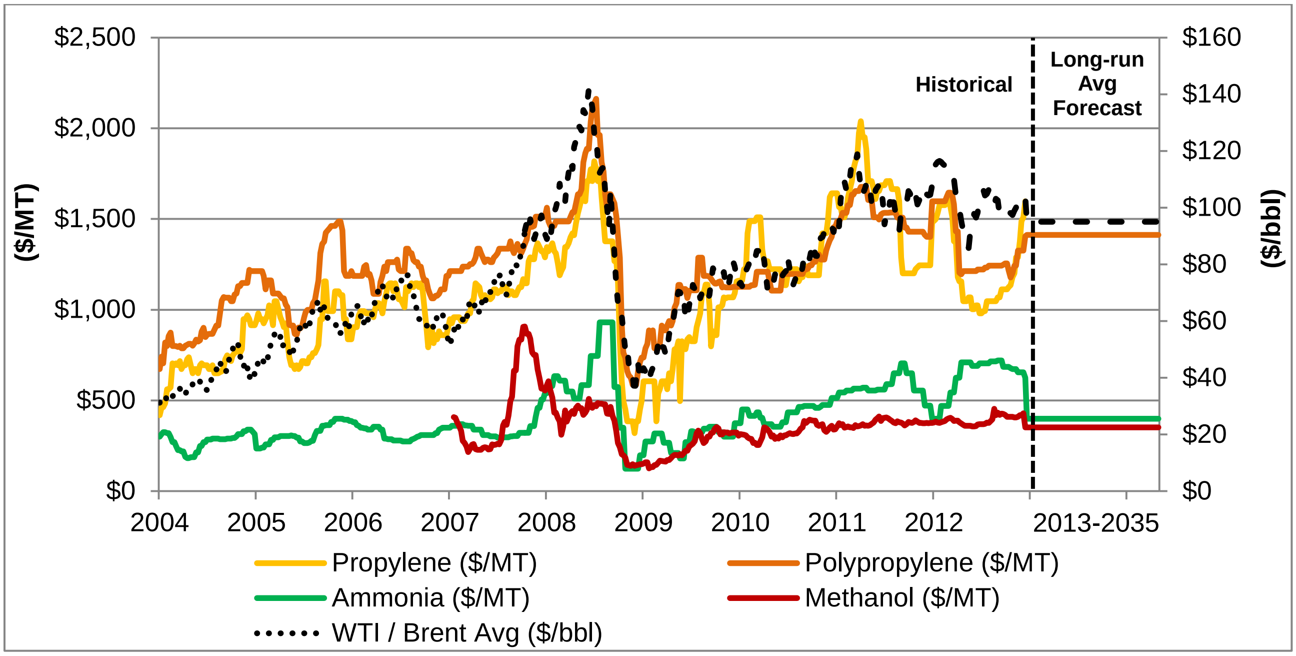
Note: Historical NGL prices based on daily spot prices at Mont Belvieu. Propane and butane prices are non-LDH (Louis Dreyfus Highbridge Energy).

<u>Pricing of Petrochemical Products</u>

Products made from natural gas and NGLs include methanol, ammonia, GTLs, polyethylene (derived from ethylene), and polypropylene (derived from propylene). The sustained low U.S. natural gas prices seen over the past few years, brought on by the ample shale gas supplies in North America, have prompted a number of petrochemical manufacturing companies to expand or consider moving operations to the U.S., which will continue to make an impact on the U.S. economy.

The chart below shows the historical prices of selected products, as well as for crude. The chart illustrates the relative impact of changes in crude pricing on various products. Products such as polyethylene and polypropylene show a strong historical relationship with crude price because such product are made in many cases within the U.S. and, even more frequently overseas, from petroleum feedstock such as gas oil and naphtha. The following exhibit includes historical prices for selected petrochemicals, as well as the long-run averages assumed by ICF for forecasting purposes. The petrochemical product prices are all denominated in dollars per metric tonnes (left-hand axis), while the WTI/Brent crude prices are in dollars per barrel (right-hand axis).

Exhibit 3-22: Key End Product Prices Relative to Oil Prices



Source: Bloomberg, 2/4/2013, nominal prices; long-run average price forecasts made by ICF

Methanol: Methanol is considered a subset of Other Basic Organic Chemicals, production of which is very gas-intensive, as methanol production relies on natural gas as both a feedstock and a process fuel, though methanol can be produced from a number of feedstocks, including natural gas and naphtha. Methanol plants are typically located near cheap natural gas supplies. Methanol is used to produce plastic, synthetic fibers, paints, adhesives, and other chemical products, is also used in biodiesel production (in a similar way ethanol is used in gasoline), and is used in wastewater treatment plants. Use of methanol has historically been tied to oil prices, given that feedstocks are often oil-based; thus, the methanol price assumed for this study is largely based on the linear regression between oil and methanol.[17]

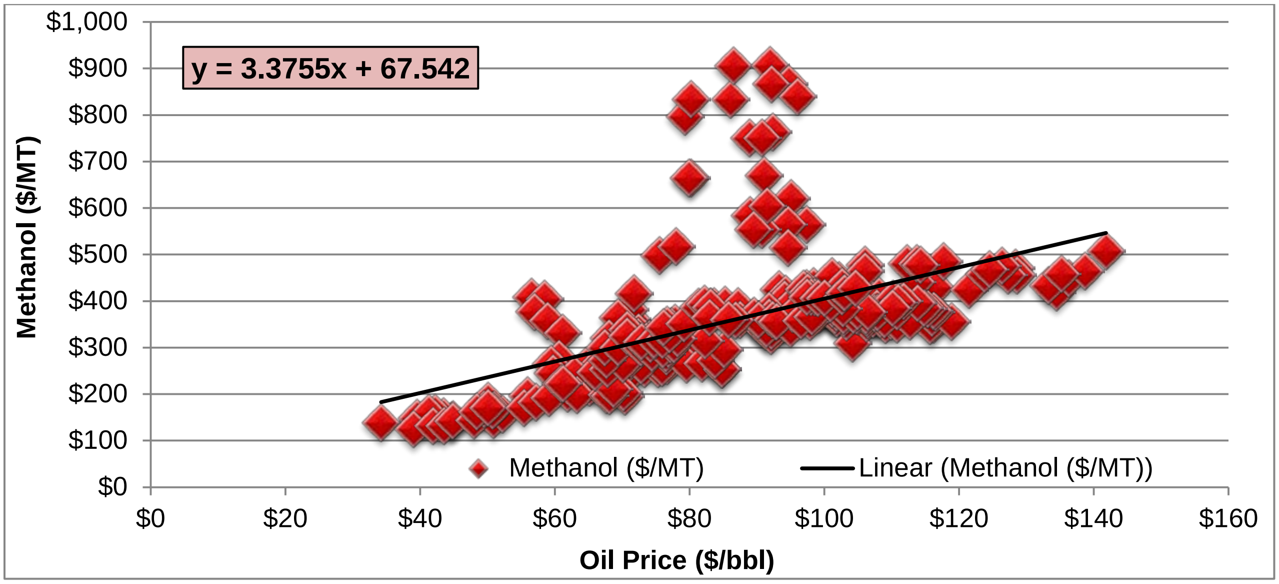
U.S. methanol production capacity totaled 845,000 metric tonnes at the start of 2012, after declining from 7 million metric tonnes in 1999, as natural gas price increases curbed U.S. production of methanol over the past decade. High gas prices, relative to international competitors such as Trinidad & Tobago, which offered low gas prices to large-scale industrial users, precipitated the decline in U.S. methanol manufacturing.[18] The recent drop in U.S. natural gas prices has persuaded a number of methanol companies to expand or relocate operations to the U.S., however. As shown in Appendix C, combined output capacity for five publicly-announced new methanol plants (all located on the U.S. Gulf Coast) totals 4.6 million

[17] American Clean Skies Foundation (ACSF), based on analysis conducted by ICF International. "Tech Effect: How Innovation in Oil and Gas Exploration is Spurring the U.S. Economy." ACSF, October 2012: Washington, D.C. Available at: http://www.cleanskies.org/wp-content/uploads/2012/11/icfreport_11012012_web.pdf

[18] Jordan, Jim. "How Methanol Got its Groove Back. The U.S. Methanol Renaissance." RBN Energy, 23 February 2012. Available at: http://www.rbnenergy.com/How-Methanol-Got-its-Groove-Back

metric tons. In particular, Methanex, a company that had moved its methanol production facilities out of North America to Punta Arenas, Chile, plans to reopen two plants in Geismar, Louisiana.[19]

Exhibit 3-23: Methanol versus Oil Price Regression



Source: Bloomberg, 2/4/2013

Ammonia: The largest consumer of ammonia in the U.S. is the fertilizer industry, which makes up roughly 90% of total U.S. ammonia consumption. Ammonia is used directly to manufacture fertilizers, and is used to make nitrogenous fertilizers (e.g., ammonium nitrate, UAN solution, and urea). Other uses for ammonia include pharmaceuticals, plastics, explosives, refrigerants, and emission control systems. U.S. ammonia plants currently consume 32.7 MMBtu of natural gas per metric tonne of ammonia produced, though energy-efficient new plants will require just 30.0 MMBtu/metric tonne.[20]

Ammonia production costs are highly dependent upon natural gas prices, the main feedstock in ammonia production. U.S. production of ammonia peaked in 1998, after which natural gas prices rose from $2/MMBtu to over $8/MMBtu between 2000 and 2007, resulting in the closure of 27 U.S. ammonia plants (and a drop in annual ammonia capacity of 25% to 13 million metric

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[19] Kaskey, Jack. "Shale-Gas Boom Spurs Chilean Methanol Plant's Move to U.S." Bloomberg, 18 January 2012: Houston, TX. Available at: http://www.bloomberg.com/news/2012-01-18/shale-gas-boom-spurs-methanex-to-relocate-idled-chilean-plant-to-louisiana.html

[20] American Clean Skies Foundation (ACSF), based on analysis conducted by ICF International. "Tech Effect: How Innovation in Oil and Gas Exploration is Spurring the U.S. Economy." ACSF, October 2012: Washington, D.C. Available at: http://www.cleanskies.org/wp-content/uploads/2012/11/icfreport_11012012_web.pdf

tonnes.[21] Ammonia capacity in the U.S. is concentrated near cheap fuel/feedstocks (i.e., the U.S. Gulf Coast) or key agricultural markets (i.e., the Midwest).[22]

While ammonia prices have historically been linked to regional natural gas prices, U.S. ammonia prices have remained significantly higher than gas prices over the past few years, despite the historic decline in U.S. natural gas pricing. This price "stickiness" is a function of the international nature of ammonia. While U.S. producers have gained from low U.S. natural gas prices, international producers are faced with higher regional natural gas prices (a primary production cost), meaning that international ammonia prices reflect the international natural gas input costs. Given the international nature of ammonia trade, the drop in U.S. natural gas prices over the past few years has not meant a significant drop in U.S. ammonia prices, as illustrated in the exhibit below. This study is based on an assumption that ammonia prices will be $400 per metric tonnes in the future.

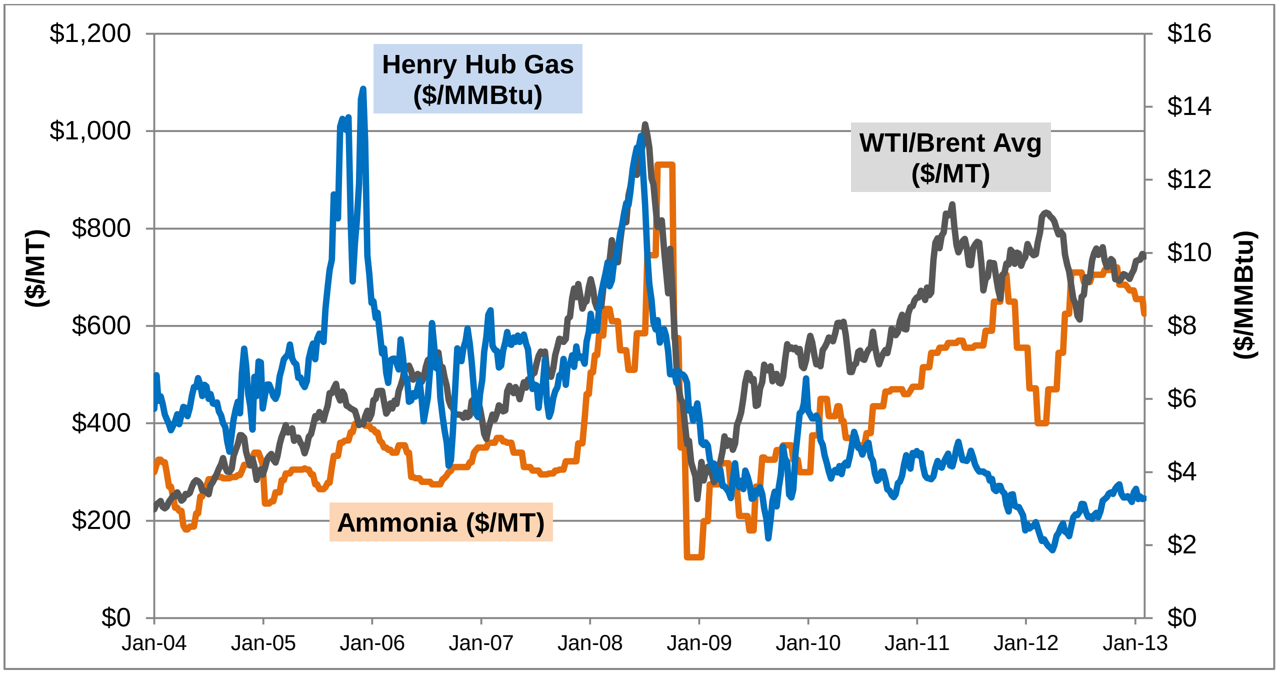
As of 2010, the U.S. accounted for only 6% of world ammonia production, with international ammonia production concentrated in Asia and the Middle East. Given the sustained low natural gas prices in the U.S., however, U.S. ammonia producers have a cost advantage, relative to international competitors. Reflecting this trend, seven ammonia producers have announced plans to either build new ammonia plants in the U.S. or restart operations, which will result in a total of 4.8 million metric tonnes in additional ammonia output over the next several years.[23]

[21] Vroomen, Harry. "Natural Gas and the U.S. Fertilizer Industry." The Fertilizer Institute, Washington, DC, July 15, 2010. P. 10. Available at: http://consumerenergyalliance.org/wp/wp-content/uploads/2010/07/Vroomen-CEA-Natural-Gas-Committee-July-15-2010-presentation-at-TFI-hv.pdf

[22] American Clean Skies Foundation (ACSF), based on analysis conducted by ICF International. "Tech Effect: How Innovation in Oil and Gas Exploration is Spurring the U.S. Economy." ACSF, October 2012: Washington, D.C. Available at: http://www.cleanskies.org/wp-content/uploads/2012/11/icfreport_11012012_web.pdf

[23] American Clean Skies Foundation (ACSF), based on analysis conducted by ICF International. "Tech Effect: How Innovation in Oil and Gas Exploration is Spurring the U.S. Economy." ACSF, October 2012: Washington, D.C. Available at: http://www.cleanskies.org/wp-content/uploads/2012/11/icfreport_11012012_web.pdf

Exhibit 3-24: Weekly Average Ammonia, Natural Gas, and Oil Spot Prices



Sources: Ammonia – Bloomberg, 3/26/2013, "Green Market Fertilizer Price Ammonia Tampa Mt C&F." Natural Gas – EIA, 2013, "Henry Hub Weekly Average Spot Prices." WTI/Brent – Bloomberg, 2/7/2013.

GTLs: A gas-to-liquids (GTL) plant typically uses the Fischer-Tropsch (FT) process, which converts natural gas and other gaseous hydrocarbons into products such as gasoline, diesel fuel, naphtha, lubricating oils, and waxes. Until the recent drop in U.S. natural gas prices, large-scale GTL production in the Lower-48 States was never considered economic, with production restricted to large natural gas exporters such as Qatar. In light of the low U.S. natural gas prices, two tentative U.S. Gulf Coast-based GTL plants (Sasol and Royal Dutch Shell) will potentially open in the next decade, with combined annual output totaling 11 million tonnes, or 240,000 barrels/day.

This study assumes an average GTL product selling price per barrel that is 134% of the price for crude oil, or $126.83/bbl. This assumes that about 66% of output from a GTL plant is diesel priced at 125% of crude and other products making up 34% of production are priced at an average of 150% of crude on a per-barrel basis.

As shown in Exhibit 3-25, this assumed split of final GTL products is based on an assumption that about 80% of the GTL production will be hydrocracked into lighter products while the other 20% is sold with large fractions of lubricating oils and waxes. While lubes and waxes do not requiring hydrocracking and fetch higher prices than diesel or naphtha, the limited size of their markets may restrict how much is produced at any given location. If this turns out not to be a limiting factor and the maximum amounts of lubes and waxes are produced, then the average value of the GTL products could be approximately 196% of crude on a per-barrel basis ($186.20/bbl).

Exhibit 3-25: Split of GTL Product Outputs Based on GTL Process

End Product	No Hydro-cracking	With Hydro-cracking	20/80 Composite
LPG	2.0%	4.0%	3.6%
Naphtha	8.0%	25.5%	22.0%
Diesel	50.0%	69.5%	65.6%
Lubes	30.0%	0.5%	6.4%
Wax	10.0%	0.5%	2.4%
All outputs	100.0%	100.0%	100.0%
Average Product Value*	**196%**	**118%**	**134%**

Source: ICF estimates

* Average product value per barrel as percent of crude price per barrel

Polyethylene and Polypropylene: Ethylene is an olefin used to manufacture plastics and polymers. Polyethylene is ethylene's main intermediate product, and comprises over 50% of U.S. ethylene use. These products can be made from feedstocks such as ethane, the price for which is a main determinant in the manufacturing economics. U.S. ethylene capacity is expected to grow over 40%, from the current 27 million metric tonnes to 38 million metric tonnes over the next several year, most of which will be located in the U.S. Gulf Coast region (the U.S.' main petrochemical manufacturing hub). Some new plants may be located closer to shale gas resources such as the Marcellus and Utica shales (in Ohio, Pennsylvania, and West Virginia), reflecting the changing dynamic of U.S. natural gas markets.[24]

Products such as polyethylene and polypropylene are secondary products derived from the olefins, ethylene and propylene, respectively. Historically, oil-based feedstocks such as naphtha were used as the primary input for these products, thus the end product prices are linked to oil prices. For this study, product prices were determined using linear regression between oil prices[25] (as the independent variable, *X*), and the end product price (as the dependent variable, *Y*). The two exhibits below illustrate the regression between polyethylene and polypropylene as dependent variables and oil prices and the independent variable. As mentioned earlier, $95/bbl is assumed in this study for the long-run oil price. This results in projected polyethylene prices of $1,368/metric tonne and polypropylene prices of $1,413/metric tonne.

Recently, growing volumes of ethane and propane (byproducts of the shale gas revolution) have become available, and have increasingly replaced oil-based feedstocks in the U.S. This gives U.S. petrochemical producers an advantage in the international market, where typical feedstock prices remain oil-based.

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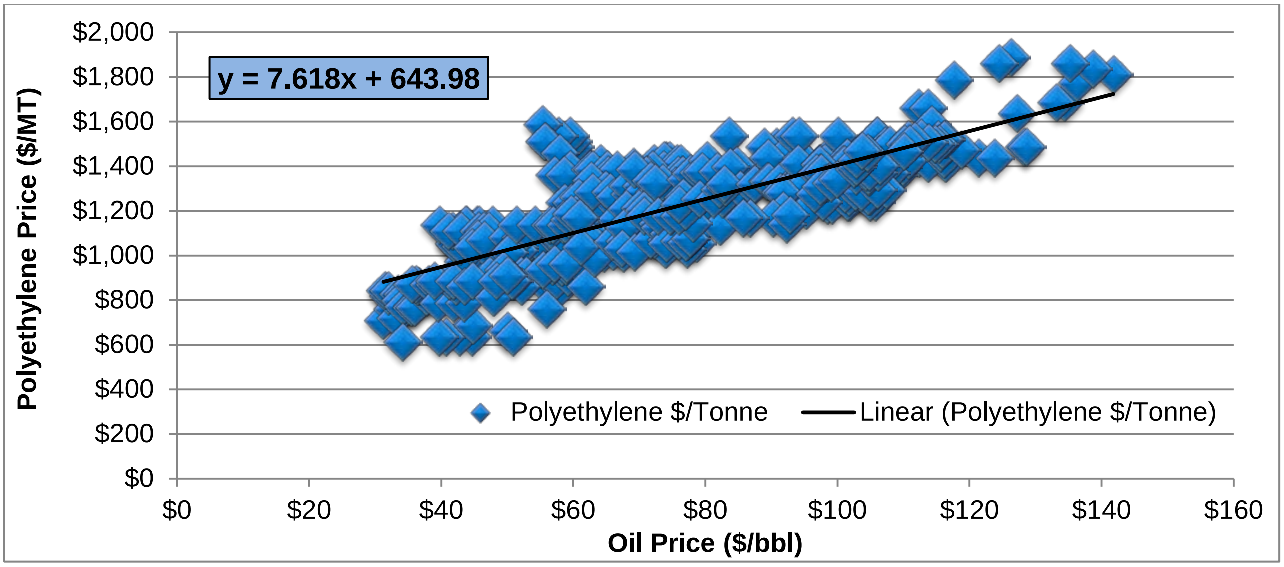
[24] American Clean Skies Foundation (ACSF), based on analysis conducted by ICF International. "Tech Effect: How Innovation in Oil and Gas Exploration is Spurring the U.S. Economy." ACSF, October 2012: Washington, D.C. Available at: http://www.cleanskies.org/wp-content/uploads/2012/11/icfreport_11012012_web.pdf

[25] An average between WTI and Brent crudes was assumed for the oil prices.

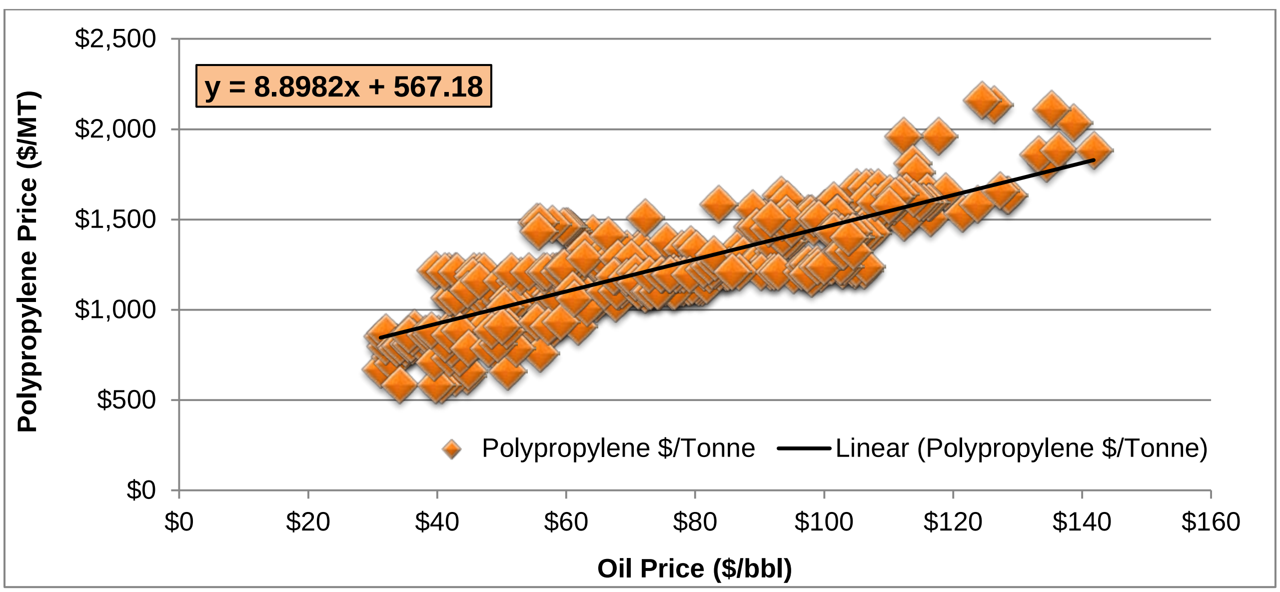
The level of ethane demand is influenced by crude oil and natural gas prices. If the crude oil price is high relative to the natural gas price, then the oil-based ethylene feedstock (naphthas and gas oils) price is also relatively higher, and thus ethane becomes a more profitable feedstock choice resulting in high levels of demand for ethane.

Exhibit 3-26: Polyethylene versus Oil Price Regression



Source: Bloomberg, 2/4/2013

Exhibit 3-27: Polypropylene versus Oil Price Regression



Source: Bloomberg, 2/4/2013

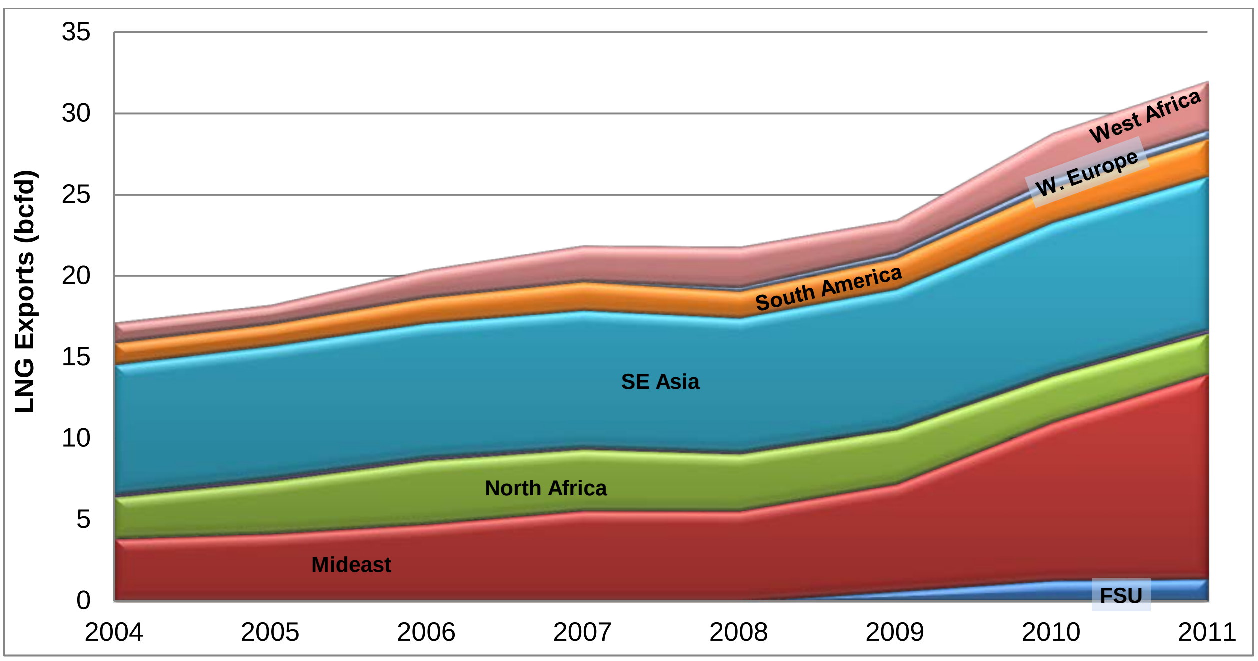
4 Global LNG Export Trends

This section discusses the historical supply and demand dynamics of global LNG trade, as well as ICF's assessment of North American competitiveness with regard to potential LNG exports. The section also describes the possible future international LNG market, including the many uncertainties associated with forecasting LNG trade volumes and prices.

4.1 Historical Supply and Demand

World LNG trade has grown rapidly over the past decade, increasing from 17 Bcfd in 2004 to 32 Bcfd in 2011, as shown in the exhibit below. During that time, the bulk of LNG export growth came from the Mideast, which grew almost 9 Bcfd, nearing 13 Bcfd in 2011. Growth in LNG trade averaged 9% between 2004 and 2011. LNG comprised 10% of global natural gas consumption in 2011 (up from 6% in 2004). A total of 20 countries exported LNG in 2011, compared to 12 in 2004. In 2011, the largest exporting countries were Qatar, Algeria, Indonesia, Malaysia, Australia, Trinidad and Tobago, and Nigeria. Growth in gas exports occurred in Qatar, Australia, and Nigeria. Exports from Qatar have grown from 2.3 Bcfd to 9.9 Bcfd and exports from Australia have grown from 1.2 to 2.5 Bcfd. Nigerian exports have expanded recently by over 1 Bcfd.

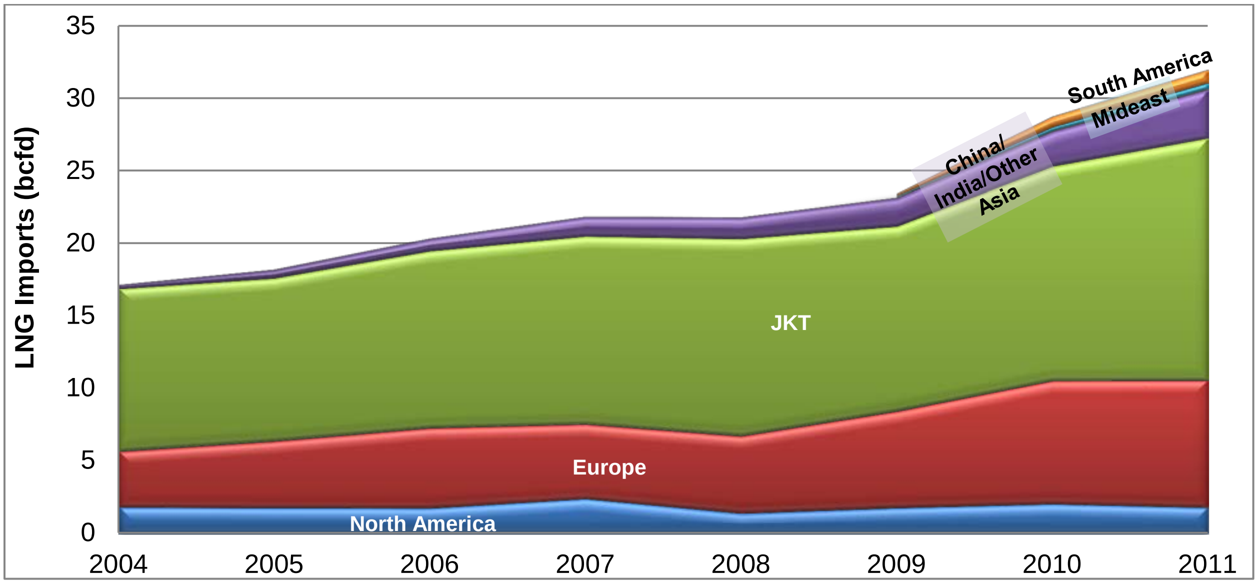
Exhibit 4-1: World LNG Supply by Region (2004-2011)



Source: Various compiled by ICF

The exhibit below shows world LNG imports by region. Regionally, the greatest demand is in the Japan, South Korea, and Taiwan region (JKT). This is followed by Europe, China, and India. Demand growth in recent years has been dominated by JKT and China/Other Asia, which together comprised nearly 60% of incremental growth over the period. European demand had increase greatly in recent years but has flattened, comprising one-third of incremental demand growth over the period. There is small but growing demand in South America and the Mideast. U.S. demand grew slightly through 2007 before declining as a result of the shale gas revolution.

Exhibit 4-2: Historical World LNG Imports by Region (2004-2011)



Source: Various compiled by ICF

Note: JKT refers to Japan, South Korea, and Taiwan.

4.2 Published LNG Demand Forecasts

ICF has evaluated several recently published LNG demand forecasts. The following reports or presentations were evaluated:

- Poten and Partners (2010)
- Credit Suisse (2012)
- Facts Global Energy (2012)
- CERI (2013)

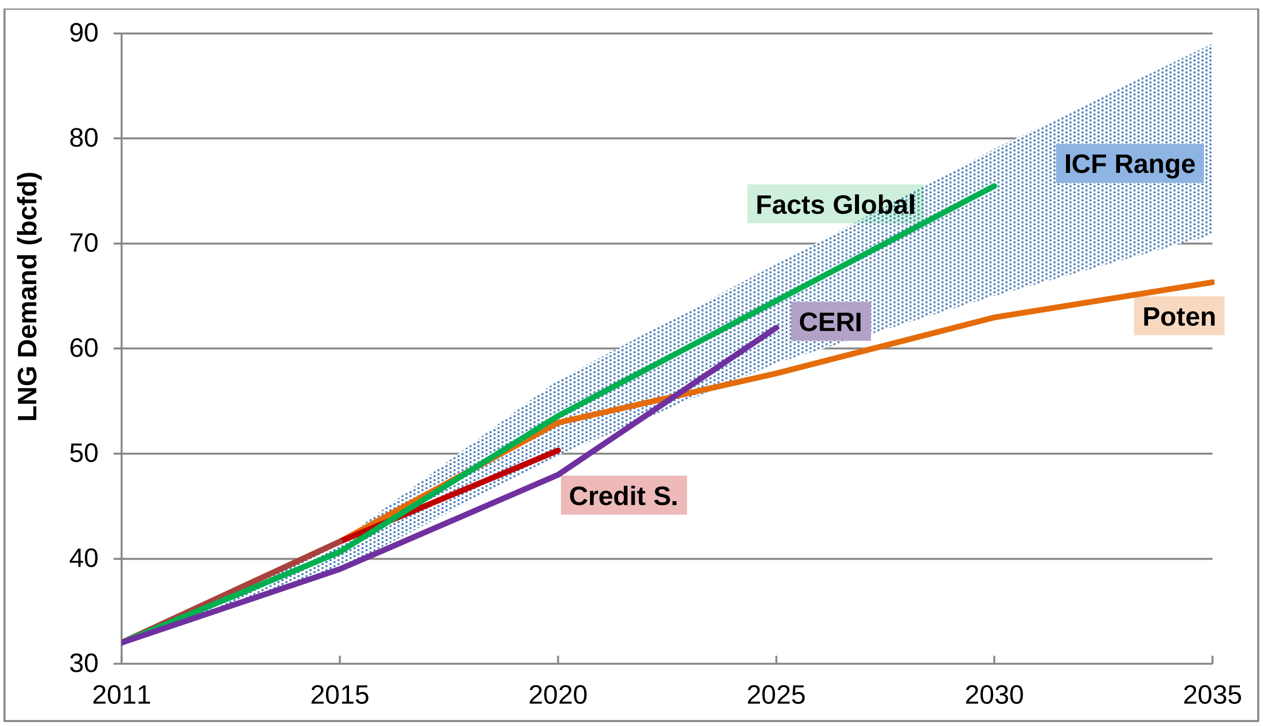
The Poten and Partners study forecast world demand to increase from 26.7 Bcfd in 2010 (the actual volume in 2010 was 28.8) to 63.4 Bcfd in 2035. The Credit Suisse study forecast 50.7 Bcfd by 2020, and the Facts Global study forecast 75.3 Bcfd by 2030. The recently published CERI study forecasts an increase to 62 Bcfd by 2025. ICF has evaluated each of these studies and the results of this comparison are presented in the exhibit below. The charts present the forecasts on the basis of calibration to the actual 2011 world volume of 32 Bcfd. Thus, the exhibit shows the calculated change relative to the actual 2011, not the forecast volumes published in the reports, with the exception of the CERI report, which had access to actual 2011 data.

The overall world demand growth from 2011 to 2025 as an average of the forecasts exceeds 32 Bcfd. The growth between 2011 and 2025, depending on the study, comes to an average annual growth of 1.8-2.3 Bcfd annually (compared with an average annual growth of 2.1 Bcfd between 2004 and 2011. Facts Global assumes incremental LNG growth of 43 Bcfd between 2011 and 2030 (annual average increase of 2.3 Bcfd), while Poten and Partners assumes much slower growth, reaching 63 and 66 Bcfd in 2030 and 2035, respectively (indicating annual average increases of between 1.4 and 1.6 Bcfd).

These LNG studies assessed assume between 39% to half of incremental growth in LNG demand will be in Asia, while Europe will make up nearly a quarter. The remaining regions (i.e., the Middle East and the Americas) will make up another 29%-37%.

There is considerable uncertainty about what the level of LNG trade will be over the next two decades because many of the key drivers (such as world economic growth, government policies toward LNG imports and pricing, greenhouse gas (GHG) mitigation policies, subsidization policies toward renewables, and the pace of development of the world's unconventional natural gas resources) are themselves uncertain. Given these uncertainties, a reasonable expectation for incremental growth in world LNG trade over 2011 levels is 27 to 36 Bcfd by 2025 and 39 to 57 Bcfd by 2035.

Exhibit 4-3: World LNG Demand Projections*



Sources: Poten (2010), Credit Suisse (2012), Facts Global Energy (2012), CERI (2013)

* Calibrated to actual 2011 LNG demand. This chart includes only growth in LNG consumption and does not include effects on total demand of declining available capacity at existing liquefaction facilities due to depleting or redirected reserves.

Additional volumes beyond the 39-57 Bcfd in incremental consumption will have to be newly contracted over the next 23 years because not all existing LNG liquefaction plants will be able to operate at current levels due to insufficient natural gas reserves or the desire of the host governments to dedicate reserves to domestic consumption. Assuming that such new contracts to make up for depleted or redirected reserves will total about 6 Bcfd by 2035, the range of total new contract volumes (incremental consumption plus make up of lost productivity) is 30 to 39 Bcfd by 2025 and 45 to 63 Bcfd by 2025.

4.3 Potential LNG Export Projects

The U.S. faces considerable competition for LNG sales from various sources around the world. For this study, ICF compiled information on 63 LNG export projects that are under construction or are being planned outside the U.S. These projects have a combined LNG export capacity of 50.5 Bcfd and most have attractive economics with calculated free-on-board (FOB) costs of $9/MMBtu or less (see exhibit below). Australia makes up nearly three-quarters of the international projects under construction (8.2 Bcfd out of total capacity under construction of 11.3 Bcfd), with a number of other projects in the planning phase, as well. In addition to these known projects, new projects will be conceived of and planned in the coming years, providing further competition to U.S. projects.

It is noteworthy that the 50.5 Bcfd of non-U.S. projects now under construction or planned (without any contribution from U.S. LNG) could satisfy the low end of projected world demand past 2035, the midpoint of projected demand through 2033, and the high end of demand through about 2029. Hence U.S. exports in the near-term will be displacing planned projects in other countries. While it is possible that some of these 63 projects outside of the U.S. may fall through, it is quite likely that other projects will be built.

Exhibit 4-4: International LNG Projects

Country	LNG Project Name	Planned Startup	Capacity (MM TPA*)	Capacity (Bcfd)
Facilities in Construction Phase				
Algeria	Arzew GL3-Z	2015	4.7	0.63
Algeria	Skikda expansion	2013	4.6	0.61
Angola	Angola LNG	2012	5.2	0.69
Australia	AP LNG (Origin)	2016	4.5	0.6
Australia	Gladstone LNG	2015	7.8	1.04
Australia	Gorgon LNG T1-3	2015	15	2
Australia	Ichthys LNG	2016	8.4	1.12
Australia	Pluto LNG	2012	4.8	0.64
Australia	Prelude FLNG	2016	3.5	0.47
Australia	QC LNG	2015	8.5	1.13
Australia	Wheatstone	2016	9	1.2
Indonesia	Donggi Senoro LNG	2015	2	0.27
PNG	PNG LNG	2015	6.6	0.88
Total in Construction Phase			***84.6***	***11.3***
Facilities in Planning Phase				
Angola	Angola LNG T2	2021	5	0.67
Australia	AP LNG (Origin) T2	2017	4.5	0.6
Australia	Arrow	2023	8	1.07
Australia	Bonaparte	2016	2	0.27
Australia	Browse	2016	3.5	0.47
Australia	Fisherman's L.	2023	1.5	0.2
Australia	Gorgon LNG T4	2018	5	0.67
Australia	Pluto LNG T2	2017	4.3	0.57
Australia	Pluto LNG T3	2018	4.3	0.57
Australia	QCLNG Train 3	2017	4.3	0.57
Australia	Scarborough	2022	6	0.8
Australia	Sunrise LNG	2017	3.5	0.47
Australia	Tassie Shoal	2020	3	0.4
Australia	Wheatstone T3	2020	4.5	0.6
Brazil	Santos FLNG	2017	3.5	0.47
Canada	BC LNG Douglas Channel	2017	2	0.27
Canada	Kitimat LNG	2017	10	1.33
Canada	Petronus Prince Rupert	2018	7.5	1
Canada	Shell LNG Canada	2018	10	1.33
Eq Guinea	EG LNG T2	2018	4.4	0.59
Indonesia	Abadi FLNG 1	2016	2.5	0.33
Indonesia	Abadi FLNG 2	2019	2.5	0.33
Indonesia	Sengkang LNG	2014	2	0.27

Country	LNG Project Name	Planned Startup	Capacity	Capacity
Facilities in Planning Phase (cont.)				
Indonesia	Sulawesi LNG	2014	2	0.27
Indonesia	Tangguh T3	2019	3.8	0.51
Iran	Iran LNG	2020	10.5	1.4
Iraq	Shell Basra FLNG T1	2022	4.5	0.6
Iraq	Shell Basra FLNG T2	2022	4.5	0.6
Malaysia	Bintulu Train 9	2016	2.5	0.33
Malaysia	PFLNG1 (Sarawak)	2015	1.2	0.16
Malaysia	PFLNG1 (Sabah)	2016	1.5	0.2
Mozambique	Mozambique LNG 1,2	2018	9	1.2
Mozambique	Mozambique LNG 3,4	2021	9	1.2
Mozambique	Mozambique LNG 5,6	2024	9	1.2
Mozambique	Mozambique LNG 7,8	2027	9	1.2
Mozambique	Mozambique LNG 9,10	2030	9	1.2
Nigeria	Brass LNG	2016	10	1.33
Nigeria	NLNG Train 7	2021	8.4	1.12
Nigeria	NLNG Train 8	2024	8.4	1.12
Nigeria	Olokola	2022	5	0.67
Norway	Snøhvit T2	2018	4.2	0.56
PNG	Gulf LNG Interoil	2022	4	0.53
PNG	PNG LNG T3	2017	3.3	0.44
Qatar	Debottleneck	2021	12	1.6
Russia	Sakhalin 2 T3	2019	5	0.67
Russia	Shtokman (Ph 1)	2022	7.5	1
Russia	Shtokman (other)	2025	12.5	1.67
Russia	Vladivostok	2018	10	1.33
Russia	Yamal LNG	2018	16.5	2.2
Tanzania	Tanzania LNG	2019	8	1.07
Total in Planning Phase			***294.1***	***39.2***
Total in Construction and Planning Phases			**378.7**	**50.5**

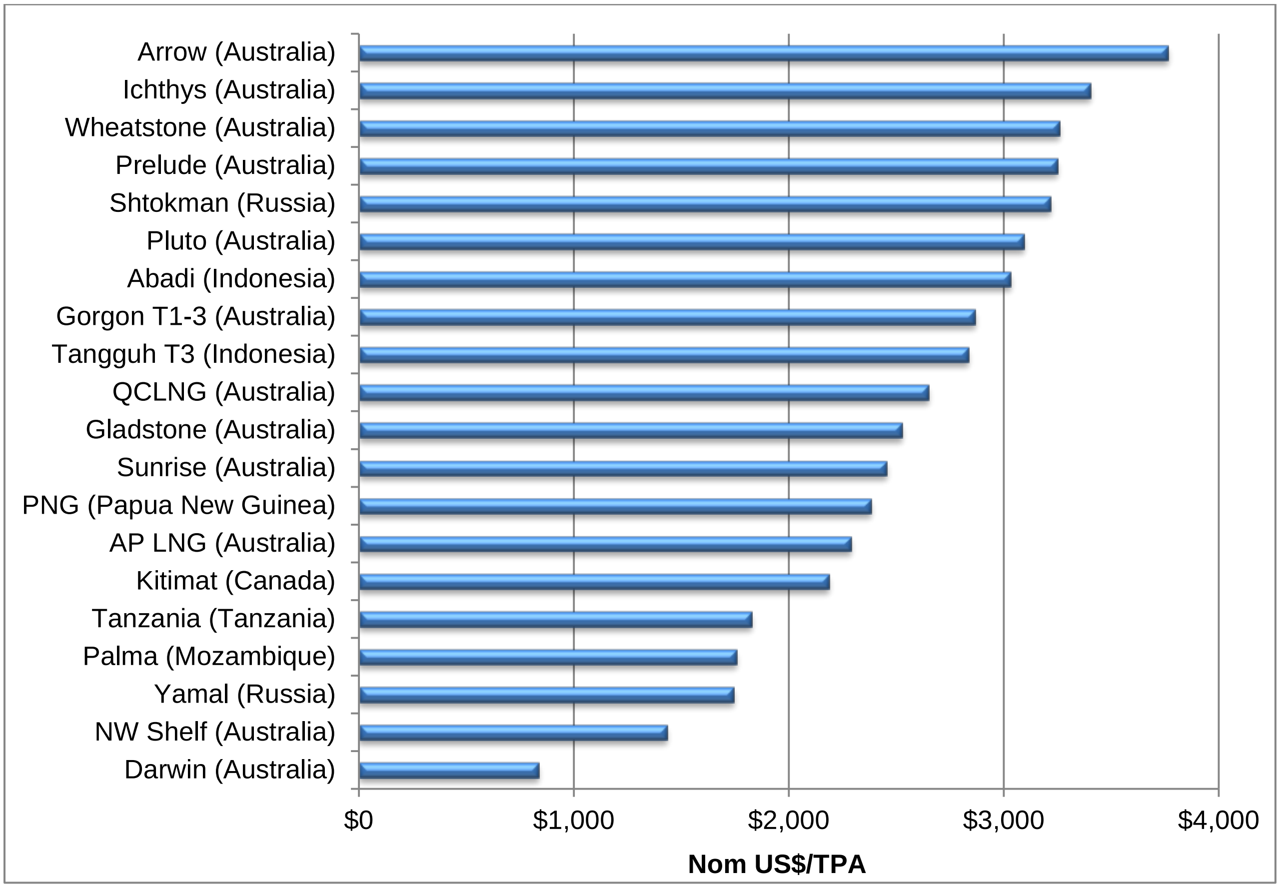
Sources: Various compiles by ICF

* Denotes million metric tonnes per annum

4.4 LNG Project Economics

Capital costs are a key consideration in assessing the international competitiveness of LNG projects. The following exhibit shows the capital costs per short ton of annual production for selected projects. The projects range from $835/annual ton to nearly $3,800/annual ton, with an average of $2,500/ton. These costs include capital costs for development of the gas reserves, gas processing plant and transportation facilities to the liquefaction plant in addition to the cost of the liquefaction plant and port facilities themselves.

Exhibit 4-5: Capital Costs of Selected LNG Export Facilities



Source: Various sources compiled by ICF

The cost on new U.S. LNG export terminals would be in the range of $700 to $1,000 per TPA for the terminals themselves. (The conversion of existing import terminals might be expected to be 2/3 of these greenfield costs. However terminal owners will want to recovery all of their capital costs). The capital cost of supplying gas to the terminal, of course, will depend on North American natural gas market conditions. For example, a delivered gas price around $6.00/MMBtu implies upstream and midstream investment cost around $2/Mcf which is about $2,038 per TPA for a 20-year project life.[26]

However, for comparison purposes with international projects, one should note that capital costs for LNG projects are usually quoted (as in Exhibit 4-5) for capital expenditures only up to the point of first gas production. In other words, "sustaining capital investments" that occur after the liquefaction plants starts usually are not included. These other capital cost are not large for LNG projects sourced from conventional gas, but can be very significant for projects using coalbed methane or gas shales, where substantial numbers of new wells need to be drilled throughout the project life to sustain deliverability. Using the convention of counting only capital

[26] This is calculated as: one metric tonne/year * 50.94 Mcf/metric tonnes * $2/Mcf * 20 years = $2038/metric tonne.

expenditures up to date of first production U.S. greenfield projects could be said to have comparable costs $1,200 to $1,600 per TPA but will require a much larger than average sustaining capital investment.

4.5 Possible Market Penetration of U.S. LNG Exports

Economic theory suggests that the entry of U.S. LNG exports into the market could put downward pressure on world LNG long-term contract prices if the U.S. supplies were economically competitive and substantial volumes were exported. To investigate the issues of possible U.S. market penetration rates and price impacts, ICF created a simple "LNG new project supply curve" made by stacking up under-construction and planned projects in order of estimated minimum required FOB price. This means the FOB price needed to recover all capital investment over the life of the project, operating costs, cost of capital and taxes. We first created a curve including U.S. projects and then created a second curve excluding U.S. projects. We then compared how far up the curves one would have to go to satisfy world incremental demand for LNG (taking into account shipping costs to each market).

The U.S. supply curve was constructed assuming delivered-to-pipeline natural gas prices from the Zero Export Case, a transportation charge to liquefaction plants of about $0.25/MMBtu, liquefaction terminal cost of $2.50/MMBtu, and terminal fuel use of 10%. The price response from our GMM model runs (about $0.10 per Bcfd of incremental exports) was used to create the upward sloping curve representing how higher levels of exports would raise natural gas prices and, therefore, the FOB price needed to make those different levels of U.S. exports economic.

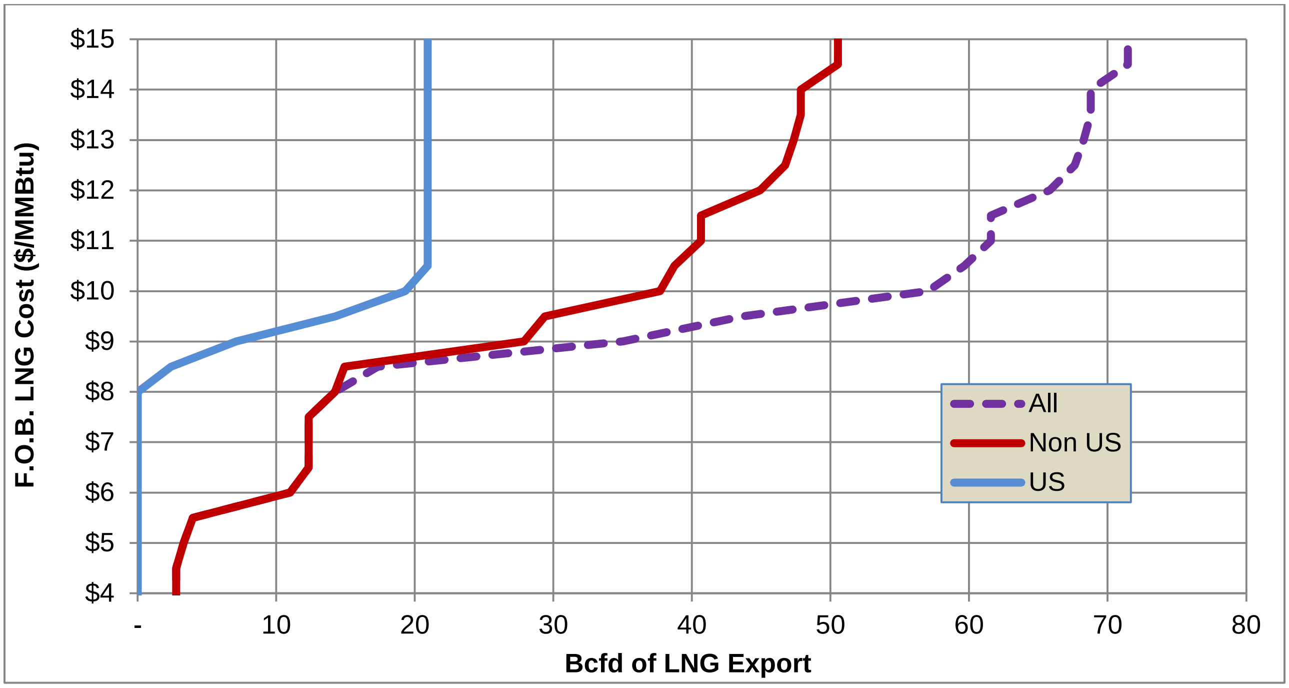
Assuming the LNG market conditions discussed above and with the expectation that U.S. Gulf Coast natural gas prices (in the absence of LNG exports) will range somewhere from $5 to $6 per MMBtu through 2035, one might expect U.S. LNG exports (if not limited by government regulations) to reach 4 to 16 Bcfd. Based on such an analysis, U.S. LNG exports would have 12% to 28% market share of new LNG contract volumes in 2025 and market share of 8% to 25% in 2035.[27]

4.6 Uncertainties in LNG Pricing and Price Impacts of U.S. LNG Exports

From the LNG supply curve exercise described above we conclude that with the new U.S. LNG projects added to the supply curve the marginal cost of new contract delivered prices circa 2025 could fall from $1 to $3 per MMBtu, depending on the world LNG demand levels. Stated in other terms, the entry of the U.S. into the world market would drop marginal costs for new LNG contracts by roughly $0.30 per MMBtu for each one Bcfd of U.S. exported volumes circa 2025 (assuming fixed demand-side circumstances).

[27] Based on ICF range of 3.6-10.9 Bcfd in U.S. LNG exports by 2025, and 3.6-15.5 Bcfd by 2035, and total new contract demand (including both new demand and new volumes to replace LNG plant retirements) of 30 Bcfd in the low case and 39 Bcfd in the high case in 2025, and 45 Bcfd in the low case and 63 Bcfd in the high case in 2035.

Exhibit 4-6: Supply Curve of LNG Supply Projects under Construction or Proposed



Source: ICF estimates

Note 1: These prices include the cost of liquefaction and fuel used for liquefaction, and are thus higher than spot or contract prices for pipeline natural gas.

Note 2: Includes projects far enough along the planning process and with sufficient public data to be judged by ICF to be viable. Not every proposed project has been added to these curves.

Depending on market conditions, new contract prices may or may not fully reflect marginal costs or changes in marginal costs. Recent long-term LNG contracts in Asia have been signed at delivered prices approximately 85% of crude oil (on a Btu basis) or over $15.00/MMBtu delivered. At our assumed long-term oil price of $95/bbl, this factor of 85% comes to $13.90/MMBtu delivered. Given the competition from new sources likely to be available in the next several year from the U.S. and other countries, this pricing level is probably not sustainable and so our principal pricing assumption for this study, delivered prices into Asia, will likely average somewhere between $12.49/MMBtu and $12.96/MMBtu (76% to 79% of crude on a Btu basis) through 2035. With assumed shipping costs of $2.64/MMBtu, this means the average F.O.B value of LNG in the U.S. Gulf Coast would range from $9.85/MMBtu to $10.23/MMBtu over the period. (See Section 6 for a sensitivity case in which U.S. costs set world LNG prices and LNG prices are lower.)

However, pricing of international LNG is a complex matter and there is no clear, widely held view of how LNG pricing will evolve in the future -- with or without U.S. exports. Uncertainties exist on the questions of:

- What portion of new long-term contracts will be priced based on oil or other alternative fuel indices versus market-area indices (such as European hub prices) versus supply-area indices (like Henry Hub),

- What the pricing level will be (for example, 85% of Japanese Crude Cocktail (JCC) on a delivered Btu basis versus 70% of JCC),
- How prices may vary across geographic markets – in particular Japan/Korea/Taiwan versus other Asian markets versus Europe, and
- How price formulas will interact with other contract provisions such as take-or-pay levels, redirection rights, price floors/ceilings, and price redetermination clauses.

A further complication is that the desirability of U.S. LNG to would-be buyers is affected by factors other than just the volumes to be contracted and the immediate price comparisons among alternative suppliers. The U.S. is attractive to buyers for a number of reasons, including:

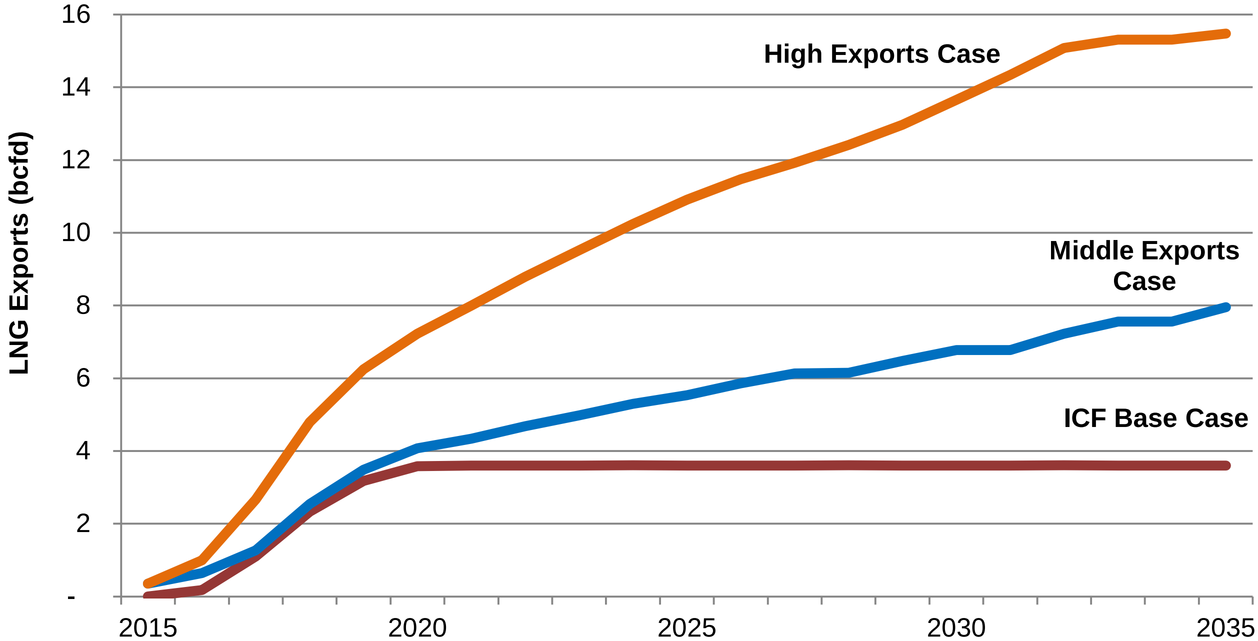
- Geographic diversification of supply sources:
- A politically stable supply source
- An opportunity to make upstream/midstream/liquefaction investments to achieve physical price hedges (that is, reduce price volatility) and to gain experience in unconventional gas development
- For foreign companies that already have nonconventional gas positions in the U.S., participation in LNG projects as buyers and/or investors offers them a way of more quickly monetizing and increasing the value of those assets
- Access to gas market index (Henry Hub) pricing of LNG to produce lower and possibly more stable (portfolio theory and option theory) average LNG costs
- An opportunity to induce more players into the LNG supply business to increase competition and lower prices further in the long-term.

This suggested that, absent regulatory constraints, a certain amount of U.S. LNG exports would take place even if the underlying economics were less favorable than indicated by the data and assumptions used in this study.

4.7 LNG Export Cases for this Study

The LNG export scenarios used in this report were created taking into account the range of new LNG demand globally and the range of possible U.S. market penetration rates to supply this market as presented above. This study compares the energy and economic impacts of three LNG export scenarios (ICF Base Case of 4 Bcfd, Middle Exports Case of 8 Bcfd, and High Exports Case of 16 Bcfd), relative to the Zero Exports Case. The exhibit below shows the annual LNG export values assumed for each case.

Exhibit 4-7: LNG Export Cases (relative to Zero LNG Exports Case)



Source: ICF estimates

5 Energy Market Impacts

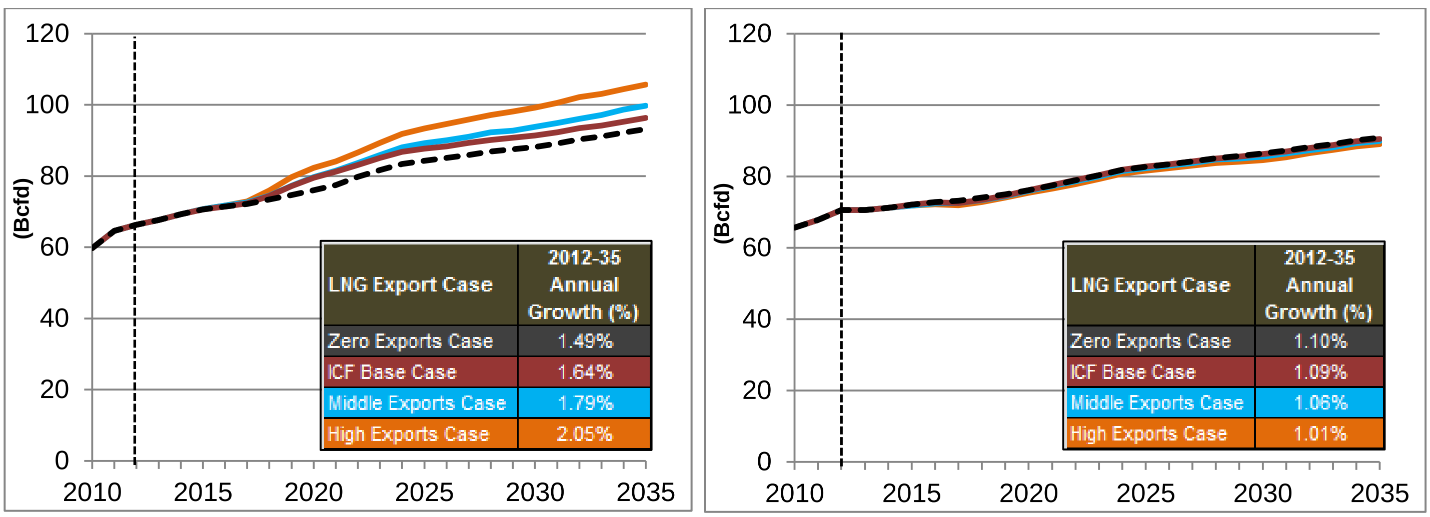
This section describes the energy market impacts on volumes and prices of each LNG export scenario, relative to the Zero Exports Case. The key volumes changes discussed in this section are natural gas production, natural gas demand, net natural gas trade with Canada/Mexico, hydrocarbon liquids produced in association with extra natural gas, petrochemical volumes, electricity demand, electricity generation by fuel type and coal production. The key price results related to natural gas and the factors affecting those price changes are presented in this section.

5.1 Total Market Changes

The following exhibits show total changes by each LNG export case for domestic U.S. gas production and domestic U.S. consumption. The values for domestic consumption exclude exported LNG volumes but do include gas consumed in the U.S. for LNG liquefaction

Exhibit 5-1: U.S. Domestic Natural Gas Market Changes by LNG Export Case

U.S. Domestic Gas Production Changes *U.S. Domestic Gas Consumption Changes*

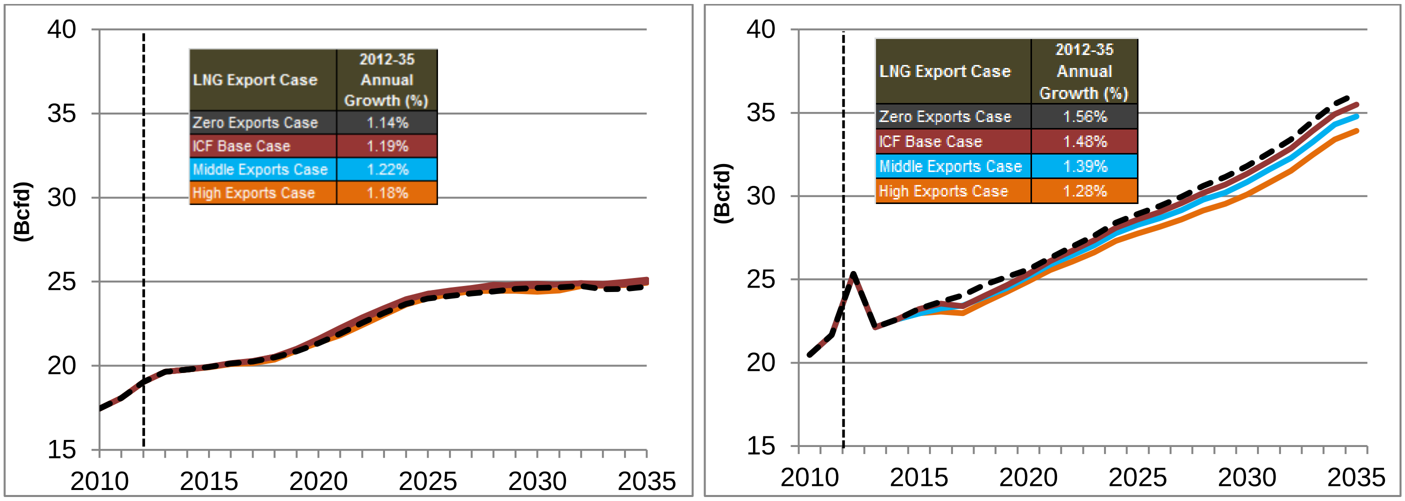


Source: ICF estimates

Note: "U.S. Domestic Gas Consumption Changes" chart (right) does not include LNG export volumes, but does include domestic fuel used for liquefaction.

Exhibit 5-2: Selected U.S. Natural Gas Market Changes by LNG Export Case

U.S. Industrial Gas Consumption Changes *U.S. Power Sector Gas Consumption Changes*

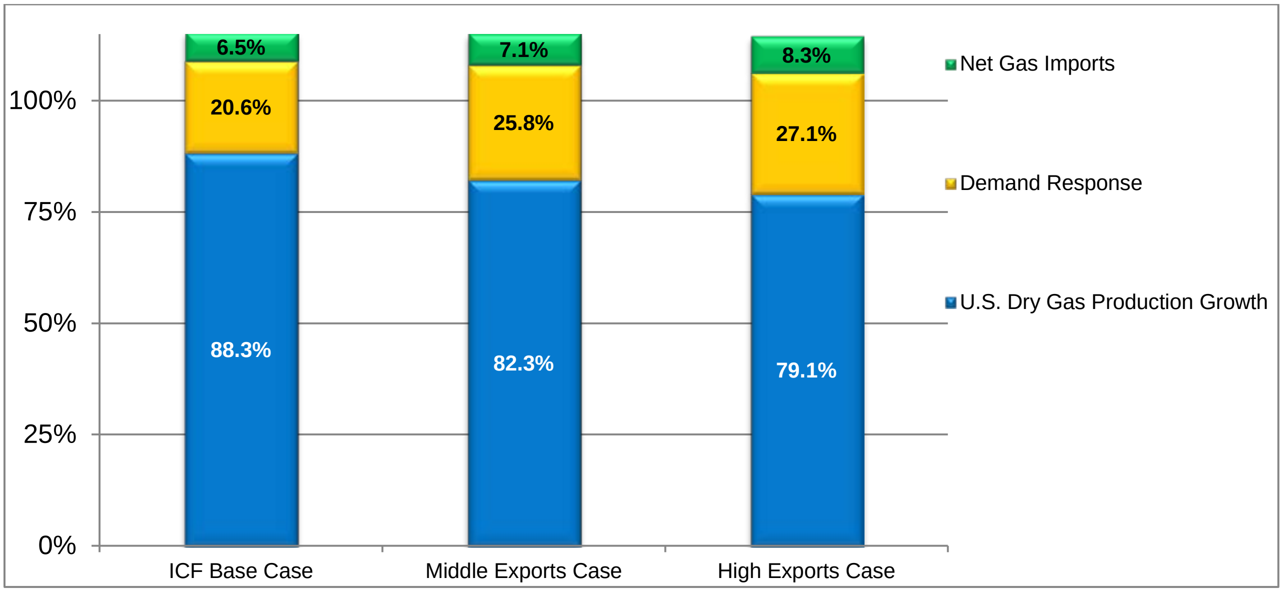


Source: ICF estimates

5.2 Volume Changes that Rebalance the Natural Gas Market

In order to accommodate LNG exports, the U.S. gas markets must rebalance with some combination of production increases, a reduction in consumption (i.e., demand response), and a change in net pipelines imports. Each producer and consumer responds differently to price changes to produce a full set of market responses. The exhibit below shows that for each of the three export cases, the majority of the incremental LNG exports (79%-88%) is expected to be derived from increased domestic natural gas production. Another 21% to 27% stems from consumer demand response (i.e., price increases lead to a certain decrease in domestic gas demand). In addition, 7% to 8% of the remaining rebalancing supply is from changes to net imports (primarily Canadian gas imports and some reduction in exports to Mexico). The three supply sources exceed actual LNG export volumes by roughly 15% to account for fuel losses during processing, transport, and liquefaction.

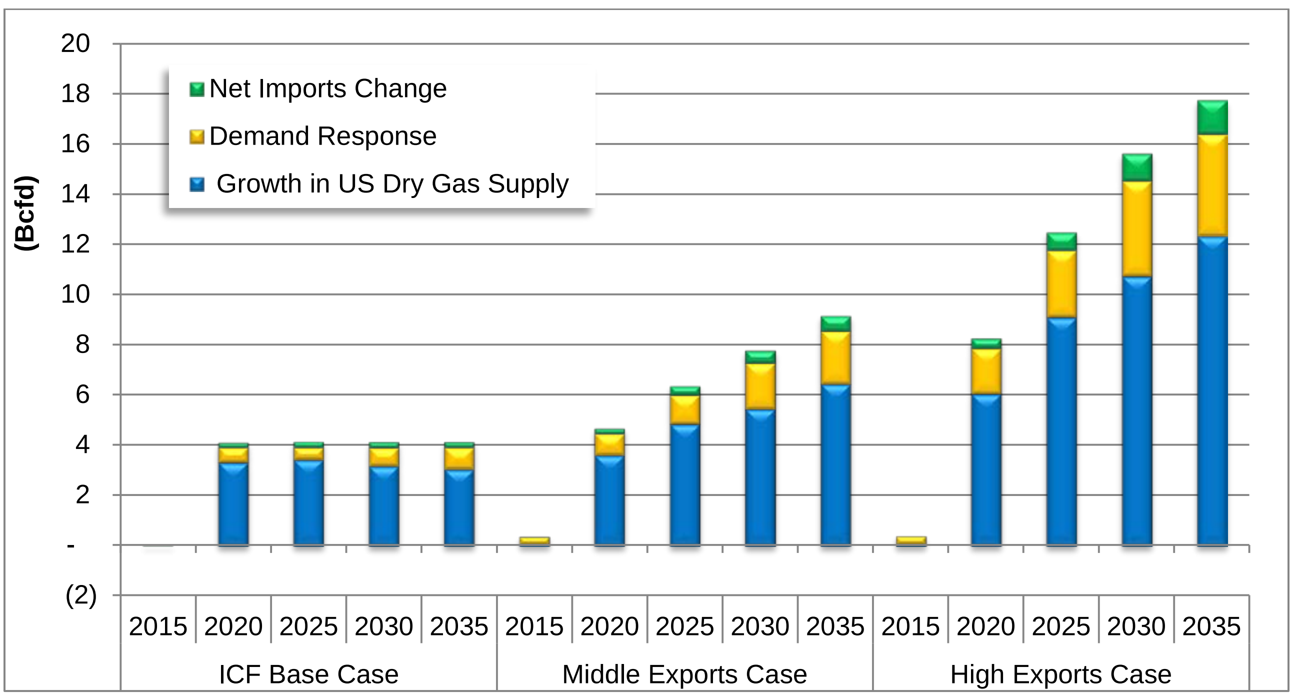
Exhibit 5-3: Supply Sources that Rebalance Markets



Source: ICF estimates

Note: Each 1.0 Bcfd of LNG exports requires total dry wellhead supplies of 1.15 Bcfd for liquefaction, lease and plant fuel, and LNG exports.

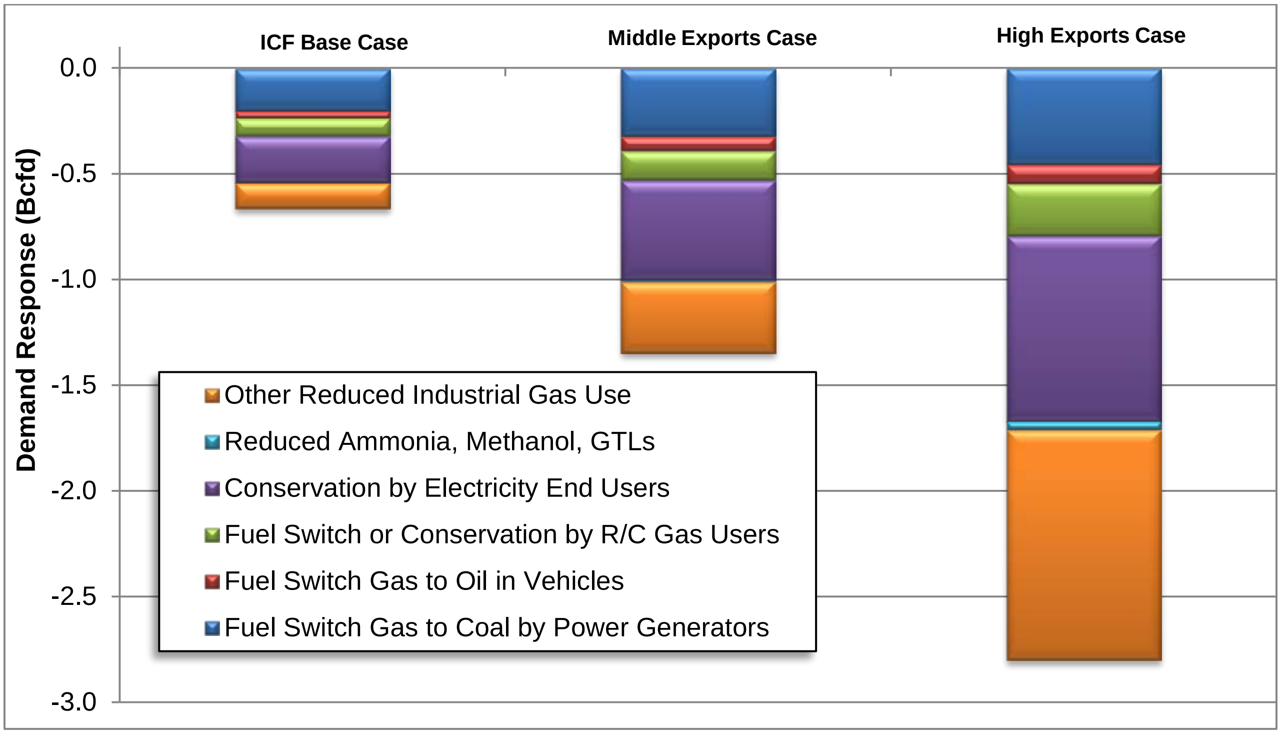
Exhibit 5-4: Change in Supply Sources for Export Cases by Year



Source: ICF estimates

Demand response, which makes up between 21% and 27% of the incremental gas supply to support LNG exports for the three scenarios, averages between 660 MMcfd in the ICF Base Case and 2.7 Bcfd in the High Exports Case. For context, these volumes are the equivalent of 1%-4% of U.S. natural gas demand in 2012, which neared 26 Tcf. Note that while total U.S. gas consumption will increase, more than offsetting these demand responses, values herein represent the *incremental* difference in volume impacts from the Zero Exports Case, rather than absolute changes. The largest demand response sources are the power and industrial sectors. Power sector demand is affected both by fuel switching (mostly to coal) and reductions in demand for electricity caused by higher electricity prices.

Exhibit 5-5: Breakdown of Demand Response Changes (average 2016-2035)



Source: ICF estimates

5.3 Volume Impacts for Liquids and Petrochemical Production

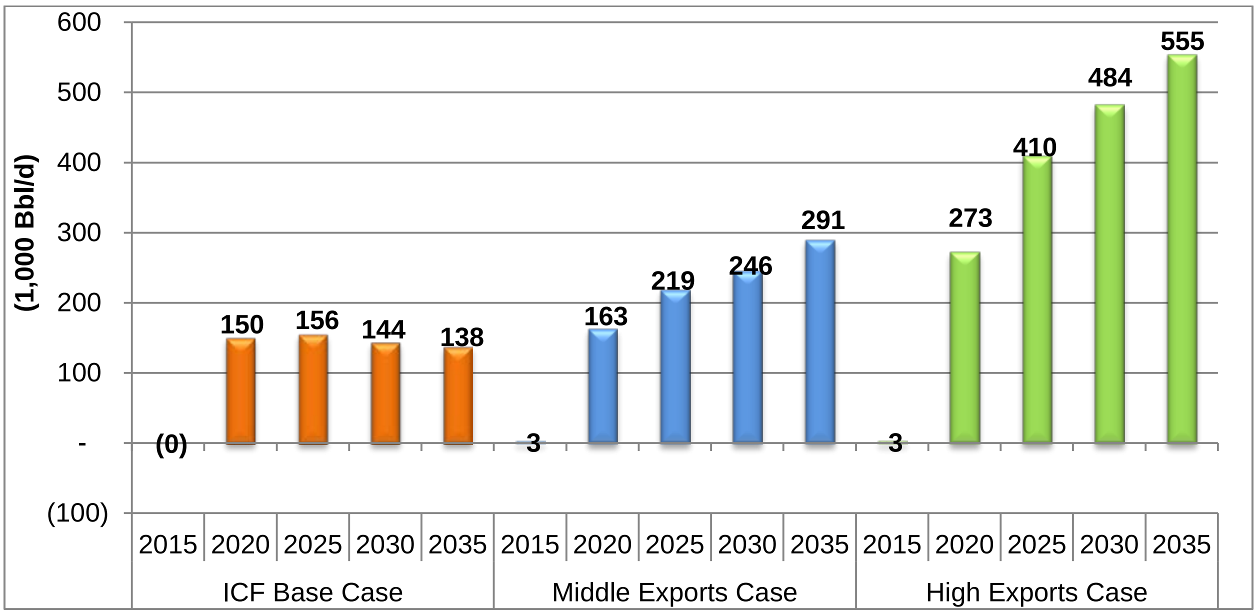
5.3.1 NGL, Lease Condensate and Crude Volumes

As incremental U.S. dry gas production increases in response to higher prices created by LNG exports, shale gas production and other unconventional nonassociated and associated gas production will likely make up the majority of incremental production. A large number of nonassociated gas plays around the U.S. are characterized as “wet” gas plays, which are known for their natural gas liquids content. In contrast, “dry” gas plays produce natural gas with few liquids.

Major plays around the U.S. have varying levels of natural gas liquids content and composition. Major shale plays with high liquids content include the Eagle Ford in South Texas, the Granite Wash tight gas play in western Oklahoma, the Bakken tight oil play in North Dakota, parts of the Marcellus shale in Pennsylvania, and the Utica shale in Ohio. The Permian Basin of West Texas and southeastern New Mexico is emerging as a major player in tight oil and NGL production. The Niobrara in the Rockies and Monterey play of Southern California also has significant potential for liquids.

The exhibit below shows the incremental increase in NGL, condensate and crude oil volumes estimated each LNG export case. As mentioned earlier, these volumes are not absolute changes, but rather the incremental difference from the Zero Export Case. More data on production by type of liquid may be found in Appendix C.

Exhibit 5-6: Liquids Volume Changes



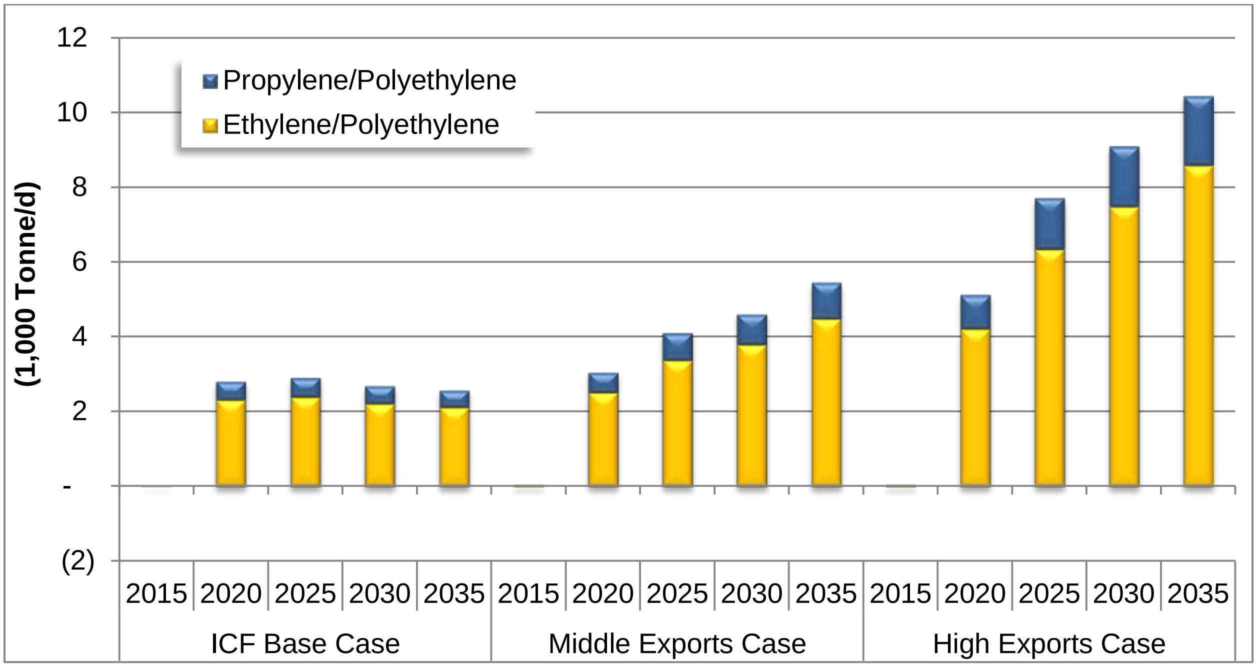
Source: ICF estimates

Note: Liquids include condensate/crude oil, ethane (100% of production assumed to go into ethylene production), propane (25% of production assumed to go into propylene production), butane, pentanes+.

5.3.2 Petrochemical Product Volumes

The incremental volume increase in ethane and propane will lead to higher production of ethylene and propylene and their derivatives production, relative to the Zero Export Case. ICF assumes that all incremental ethane will go into ethylene production, given the high value for that use, as well as the fact that pipeline quality control dictate that a majority of ethane be removed to maintain reliable pipeline operation and to ensure the gas has consistent burning characteristics. When NGLs are removed from natural gas to produce pipeline quality gas, they are available for other markets, including petrochemicals. Also we assume that 25% of propane increases will go into propylene/polypropylene production, the remainder of which will go toward various domestic uses and to exports (see Exhibit 5-7). The ethylene/ polyethylene production gains reach 2,100 tonnes/day in the ICF Base Case, 4,500 tonnes/day in the Middle Case, and 8,600 tonnes/day in the High Case by 2035. For reference, ICF assumes a new ethylene/polyethylene plant to have a capacity of 2,740 tonnes/day, meaning LNG exports require nearly 1 to 3 additional ethylene/polyethylene plants.

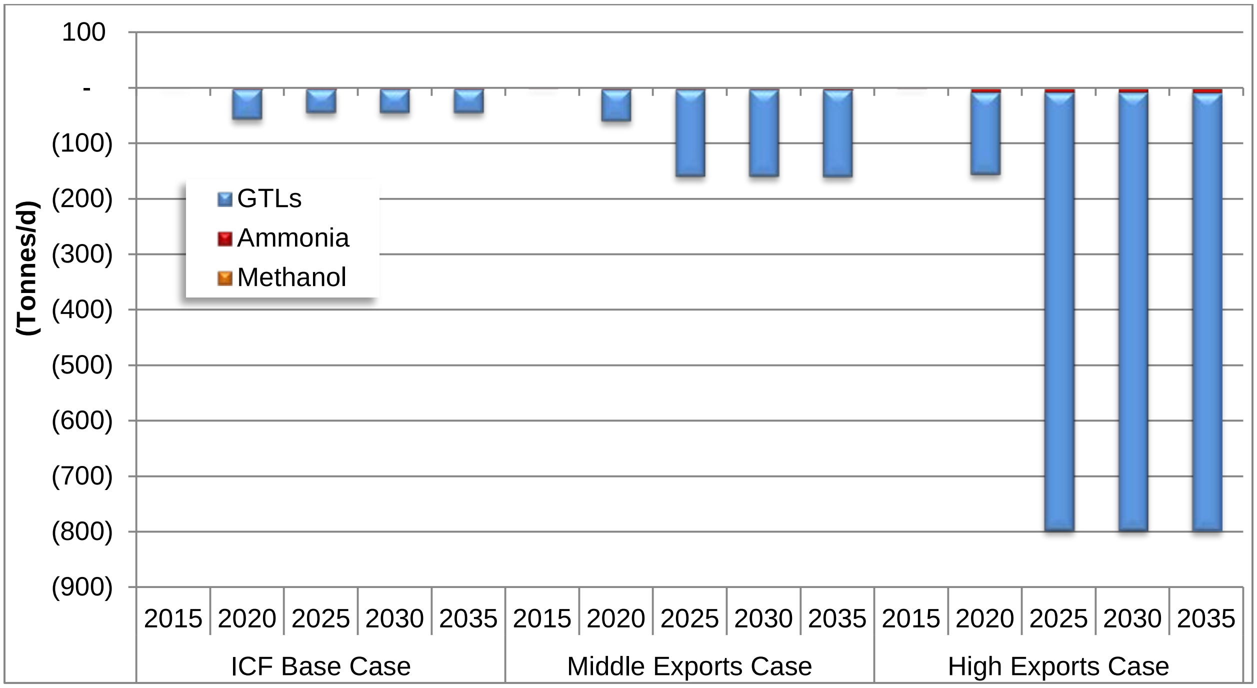
Exhibit 5-7: Changes in U.S. Ethylene and Propylene Production



Source: ICF estimates

GTL production economics are sensitive to the price of its main feedstock, natural gas (i.e., methane). However, with the moderate price increases resulting from the cases examined here, forecasted GTL production will drop at most 3% of planned production levels. As shown in Exhibit 5-8, the ICF Base Case and Middle Exports Case will see a drop in U.S. GTL production between 40 and 160 tonnes per day by 2035, attributed to the increase in gas prices of LNG exports. The High Exports Case, however, assumes a drop of nearly 800 tonnes per day of GTL production by 2035. As illustrated in Exhibit 5-8 below, LNG exports have a negligible effect on ammonia and methanol production because new investments remain economic due to high product values linked to $95/bbl oil.

Exhibit 5-8: GTL, Ammonia, and Methanol Volume Changes

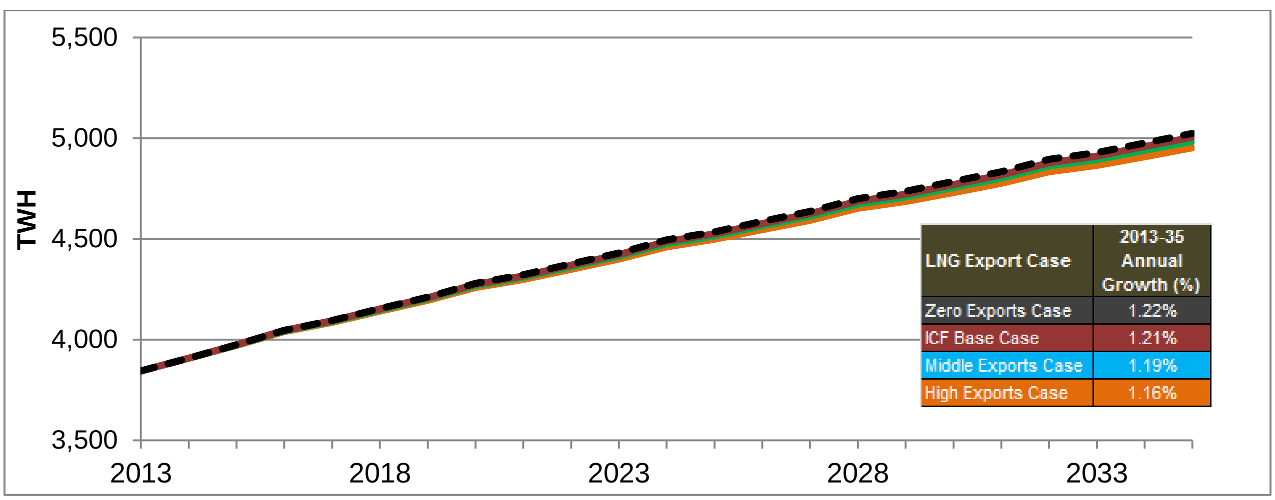


Source: ICF estimates

5.4 Electricity and Coal Production Impacts

Overall electricity demand and production will increase over the forecast period in all cases, but the rate of growth declines as LNG exports increase. Exhibit 5-9 and Exhibit 5-10 show the total changes in U.S. power generation attributed to LNG exports, as well as the change in coal- and natural gas-fired power generation.

Exhibit 5-9: U.S. Power Generation Changes by LNG Export Case

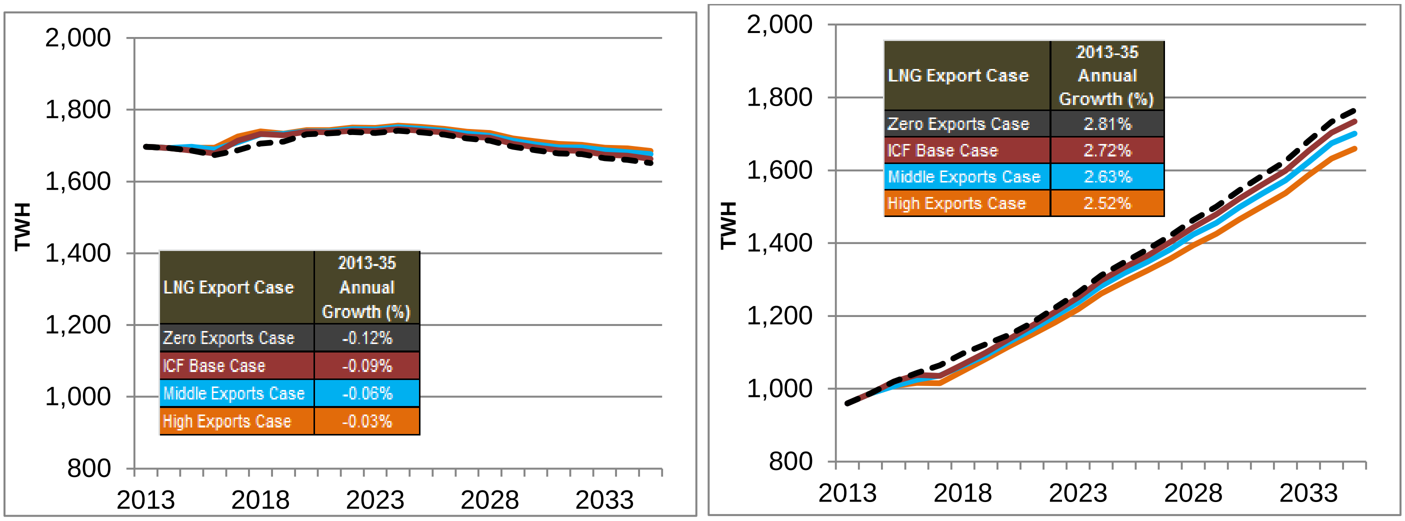


LNG Export Case	2013-35 Annual Growth (%)
Zero Exports Case	1.22%
ICF Base Case	1.21%
Middle Exports Case	1.19%
High Exports Case	1.16%

Source: ICF estimates

Exhibit 5-10: Change in U.S. Power Generation for Selected Sources by LNG Export Case

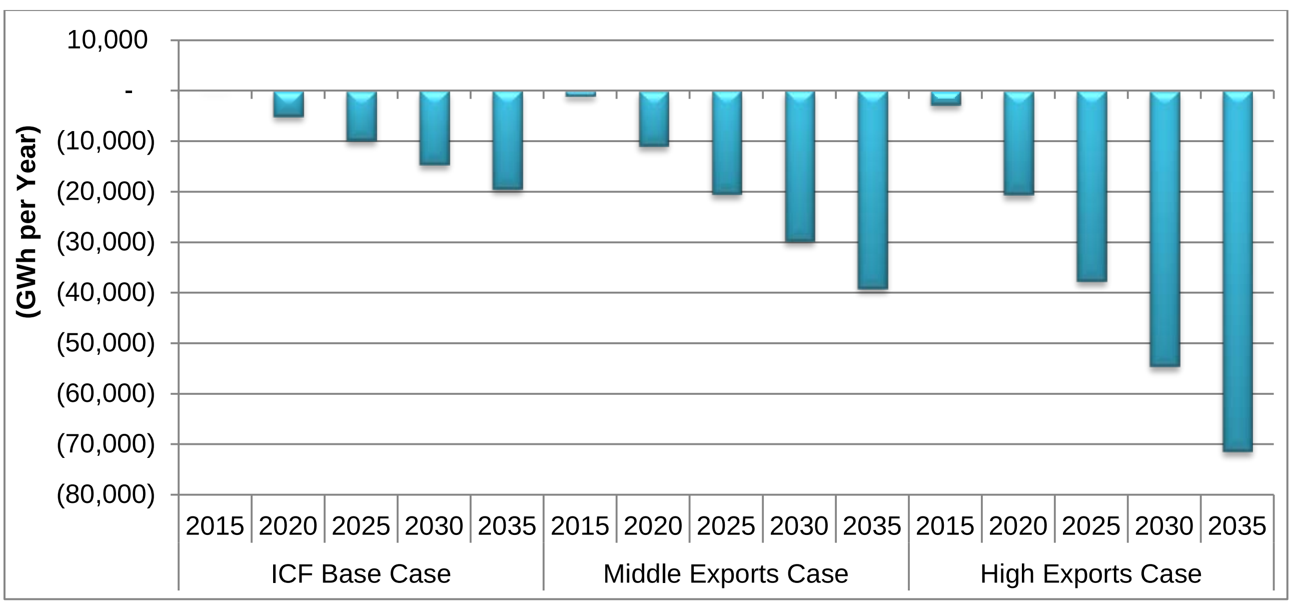
U.S. Coal-fired Power Generation *U.S. Gas-fired Power Generation*



Source: ICF estimates

The two exhibits below show differences in electricity production in each LNG export case, relative to the Zero Export Case, caused electricity price increases. In contrast, electricity production from coal will see small increases, due to slightly fewer coal plant retirements and greater dispatch of coal at the expense of natural gas.

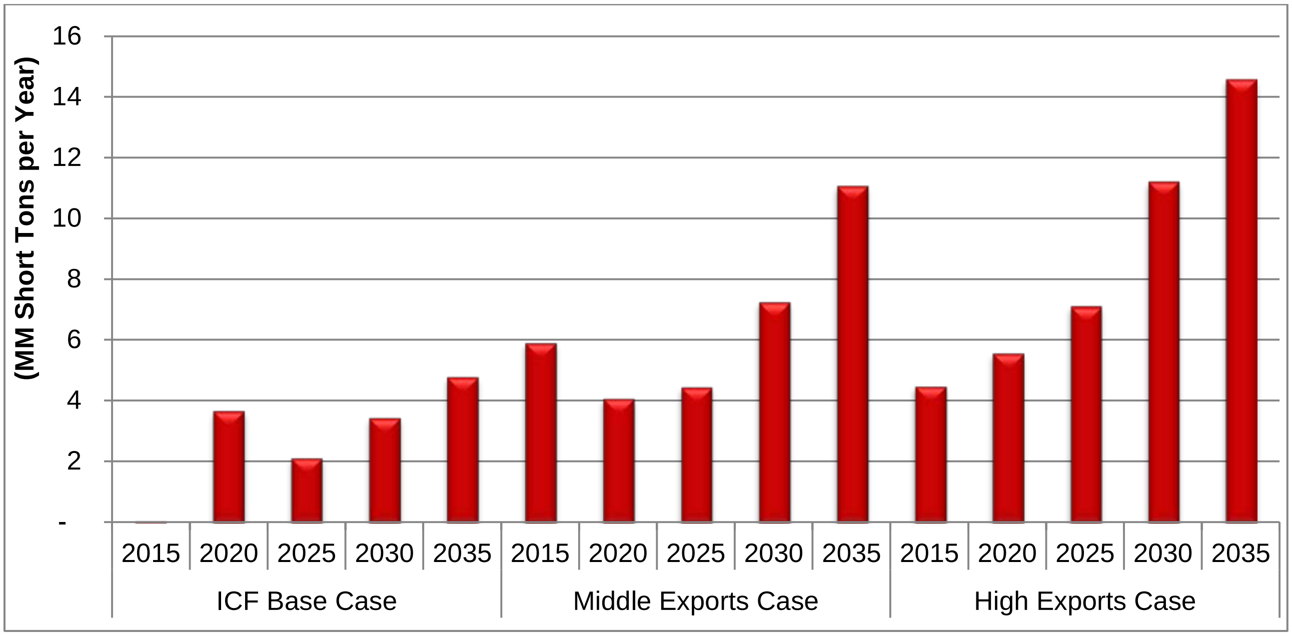
Exhibit 5-11: Change in Electricity Production* from Zero Export Case



Source: ICF estimates

* Includes production from all sources

Exhibit 5-12: Change in Coal Production from Zero Exports Case

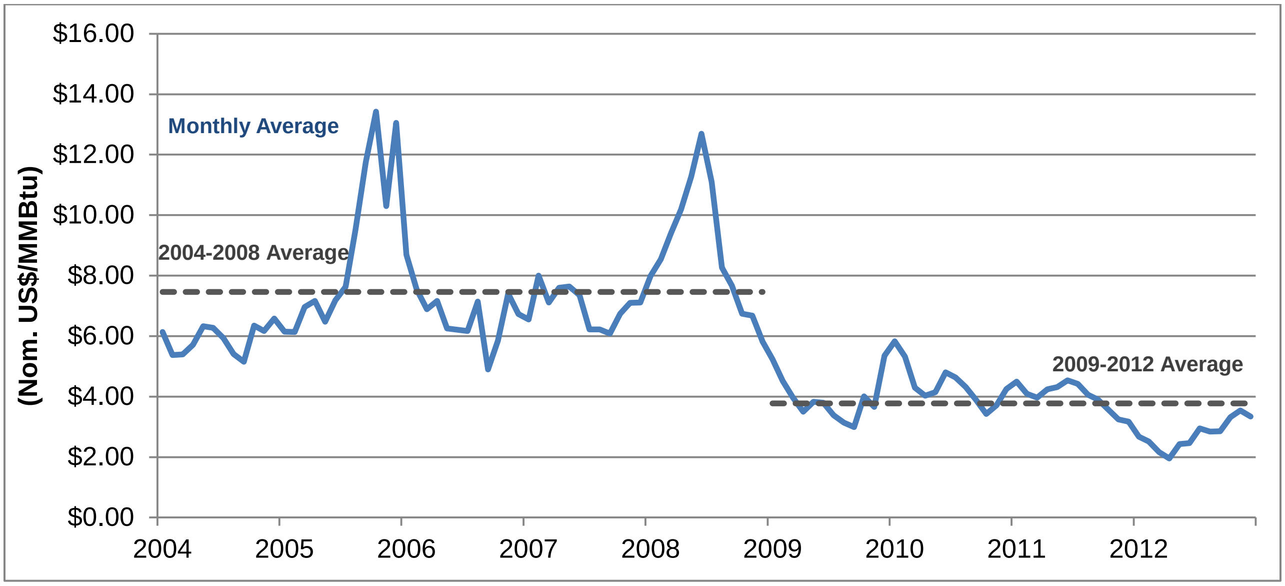


Source: ICF estimates

5.5 Natural Gas Price Impacts

Over the past several years, U.S. natural gas prices have dropped precipitously due to the abundant supplies available with upstream technological advancements (i.e., horizontal drilling, hydraulic fracturing), as shown in the exhibit below. These upstream developments have fundamentally altered the U.S. natural gas outlook, with low gas prices expected to sustain over the foreseeable future.

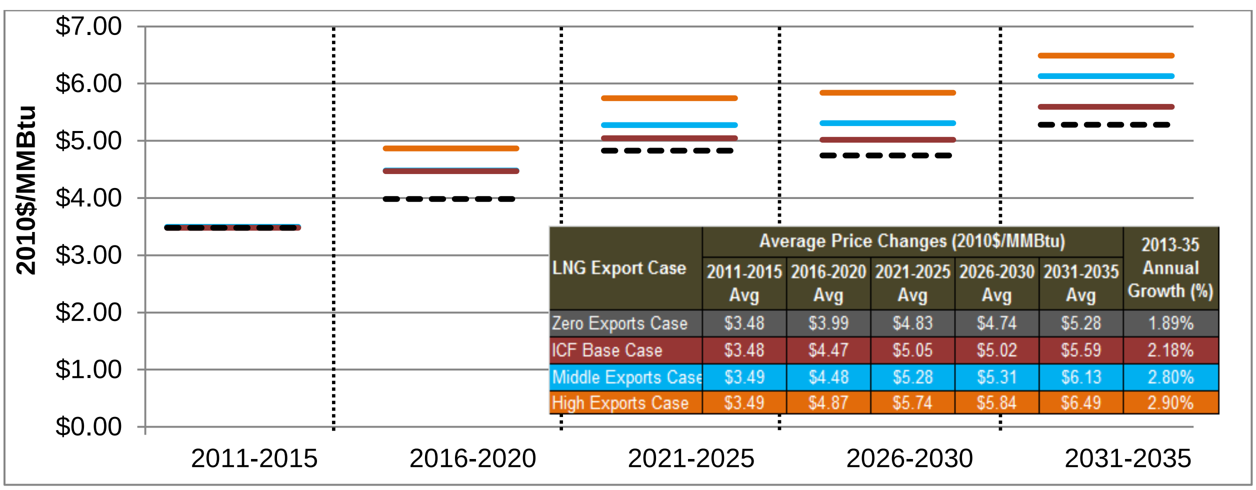
Exhibit 5-13: Monthly Average Spot Price at Henry Hub (Nom$/MMBtu)



Source: The U.S. Energy Information Administration (EIA). "Henry Hub Gulf Coast Natural Gas Spot Price." EIA, 16 January 2013: Washington, D.C. Available at: http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

The exhibit below illustrates five-year average Henry Hub natural gas prices by LNG export scenario, as forecasted by ICF.

Exhibit 5-14: Henry Hub Natural Gas Price Changes by LNG Export Case



LNG Export Case	Average Price Changes (2010$/MMBtu)					2013-35 Annual Growth (%)
	2011-2015 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	
Zero Exports Case	$3.48	$3.99	$4.83	$4.74	$5.28	1.89%
ICF Base Case	$3.48	$4.47	$5.05	$5.02	$5.59	2.18%
Middle Exports Case	$3.49	$4.48	$5.28	$5.31	$6.13	2.80%
High Exports Case	$3.49	$4.87	$5.74	$5.84	$6.49	2.90%

Source: ICF estimates

The impact of LNG exports on U.S. natural gas prices varies by export case, with Henry Hub natural gas prices between 2016 and 2035 on average increasing:

- $0.32/MMBtu in the ICF Base Case
- $0.59/MMBtu in the Middle Exports Case

- $1.02/MMBtu in the High Exports Case

National average delivered-to-pipeline price increases weighted either by production or demand tend to be lower than impacts at the Henry Hub, which is near to the Gulf Coast locations where most of the LNG exports would take place. In the ICF Base Case prices at Henry Hub are expected to rise on average 7% between 2016 and 2035, relative to the Zero Exports Case, while production and consumption-weighted national average prices rose just 5% and 6%, respectively. Similarly, in the Mid and High Cases, Henry Hub prices rose 13% and 22%, respectively, while production and consumption-weighted national average price increases rose at roughly 10% in the Mid Case and 20% in the High Case.

In terms of average price increase per Bcfd of natural gas exported, the three export cases averaged between $0.10-$0.11/MMBtu per Bcfd at Henry Hub, and between $0.08-$0.10/MMBtu per Bcfd at the national average level weighted by production and consumption.

Exhibit 5-15: Wholesale Natural Gas Price Changes Relative to Zero Exports Case
(2016-2035 Average)

Case	Natural Gas at Henry Hub	National Average Weighted by Production	National Average Weighted by Consumption
ICF Base Case			
Avg Price Delta (∆$/MMBtu)	$0.32	$0.26	$0.27
Avg Export Delta (∆Bcfd)	3.22	3.22	3.22
Avg Price Delta/Bcfd (∆$/MMBtu)	$0.10	$0.08	$0.08
Middle Exports Case			
Avg Price Delta (∆$/MMBtu)	$0.59	$0.48	$0.50
Avg Export Delta (∆Bcfd)	5.27	5.27	5.27
Avg Price Delta/Bcfd (∆$/MMBtu)	$0.11	$0.09	$0.10
High Exports Case			
Avg Price Delta (∆$/MMBtu)	$1.02	$0.97	$0.91
Avg Export Delta (∆Bcfd)	10.37	10.37	10.37
Avg Price Delta/Bcfd (∆$/MMBtu)	$0.10	$0.09	$0.09

Source: ICF estimates

The exhibit below presents results for the price effects to natural gas consumers in the residential, commercial, industrial, and power generation sectors. These data are presented in terms of percent change in the delivered gas price per million Btu of natural gas. Note that since the transmission and distribution charges are typically higher in the residential and commercial sectors, the percent change impacts in delivered prices stemming from LNG export are lower as a percent compared to industrial and power consumers who pay lower transmission and distribution charges. See Appendix B for price impacts by state for residential, commercial, industrial, and power sector users.

Exhibit 5-16: Price Impacts to Gas Consumers by Sector

(% increase per MMBtu consumed over Zero Exports Case)

Sector	Average Delivered Natural Gas Price Changes (%)				
	2016 to 2020	2021 to 2025	2026 to 2030	2031 to 2035	2016-35
ICF Base Case vs. Zero Exports Case					
Residential	5.3%	2.9%	3.5%	3.1%	3.6%
Commercial	5.9%	3.1%	3.8%	3.3%	3.9%
Industrial	8.5%	4.6%	5.4%	5.0%	5.7%
Power	9.7%	4.9%	5.8%	5.3%	6.1%
Middle Exports Case vs. Zero Exports Case					
Residential	6.3%	4.8%	6.0%	7.4%	6.2%
Commercial	6.9%	5.2%	6.6%	8.1%	6.8%
Industrial	9.9%	7.6%	9.5%	12.2%	10.0%
Power	11.3%	8.0%	10.3%	13.1%	10.8%
High Exports Case vs. Zero Exports Case					
Residential	11.2%	9.9%	11.4%	11.3%	11.0%
Commercial	12.4%	10.9%	12.4%	12.1%	12.0%
Industrial	17.9%	16.2%	19.1%	17.3%	17.6%
Power	20.1%	16.8%	20.0%	18.8%	18.9%

Source: ICF estimates

5.6 Decomposition of Natural Gas Price Effects

The exhibit below shows the Henry Hub price impacts for each case decomposed into four key factors:

- Resource depletion price effect: Accounts for the fact that increased depletion of natural gas to accommodate exports drives the U.S. up its long-run supply curve, increasing long-run marginal costs (as calculated using fixed factor costs and with no lags between when the extra supplies are needed and when they are made available).
- Drilling activity price effect: Accounts for higher prices needed to accommodate short-term factor cost increases that usually accompany increased drilling activity and the price effects of the delay between when price signals change (due to higher demand) and when drilling activity and wellhead deliverability respond to accommodate that demand.
- Demand response: The theoretical price increase that is avoided because some demand for natural gas contracts as prices increase. This can also be thought of as how much higher prices would have gone up if natural gas demand were modeled as being completely price inelastic. This represents the approximate price changes avoided by demand reductions and imports that occurred because gas demand was reduced and net imports increased. If there were no demand reduction, then resource depletion plus drilling activity cost effects would have been higher by those amounts.

- International pipeline trade effect: The theoretical price increase that is avoided by adjustments made to net natural gas imports. This can also be thought of as how much higher prices would have gone up if pipeline trade with Canada and Mexico were modeled as fixed between the no export reference case and each LNG export scenario. This also represents the approximate price changes avoided by demand reductions and imports that occurred because gas demand was reduced and net imports increased. If there were no net import increase, then resource depletion plus drilling activity cost effects would have been higher by those amounts.

Exhibit 5-17: Decomposition of Natural Gas Price Impacts

(2016-2035 annual average change in 2010$/MMBtu)

Export Case	Modeled Henry Hub Price Impacts			Theoretical Price Impacts Avoided	
	Resource Depletion Price Effect	Drilling Activity Price Effect	Total Price Change	Demand Reduction Effect	Trade Effect
ICF Base Case	$0.08	$0.25	**$0.32**	$0.06	$0.02
Middle Exports Case	$0.11	$0.48	**$0.59**	$0.10	$0.05
High Exports Case	$0.21	$0.82	**$1.02**	$0.22	$0.11

Source: ICF estimates

The importance of decomposing the price effects is that it helps explain what portion of price results are contributed by various factors. It is also useful in comparing modeling result from various studies, which sometime ignore or treat very differently each of these factors. For example, in the NERA study for DOE, trade with Canada and Mexico was held constant among the runs. Had this study made the same (we think unrealistic) assumption, then estimated natural gas price increase would have been about $0.02 to $0.11 higher.

5.7 Electricity Price Impacts

Wholesale electricity prices are expected to go up modestly with LNG exports because natural gas is on the margin (that is, the last dispatched generation resource, which sets the wholesale electricity price) for a large percent of the time throughout the U.S. For the ICF Base Case, electricity prices are expected to increase $0.0014/kWh on average between 2016 and 2035 (or an increase of 1.4% in the average retail electricity price), relative to the Zero Exports Case. The High Exports Case is expected to see an increase in the average electricity price over the period of $0.0044/kWh, or an increase in average retail electricity prices of 4.5%, relative to the Zero Exports Case.

Exhibit 5-18: Average Electricity Price Impacts for 2016-2035

(Relative to Zero Exports Case)

LNG Export Case	Average Natural Gas Price Increase (2010$/MMBtu)	Average Electricity Price Change (2010$/kWh)	Average Retail Electricity Price Change (%)
ICF Base Case (up to ~4 Bcfd)	$0.32	$0.0014	1.4%
Middle Exports Case (up to ~8 Bcfd)	$0.59	$0.0025	2.6%
High Exports Case (up to ~16 Bcfd)	$1.02	$0.0044	4.5%

Source: ICF estimates

6 Economic and Employment Impacts on the U.S. Economy

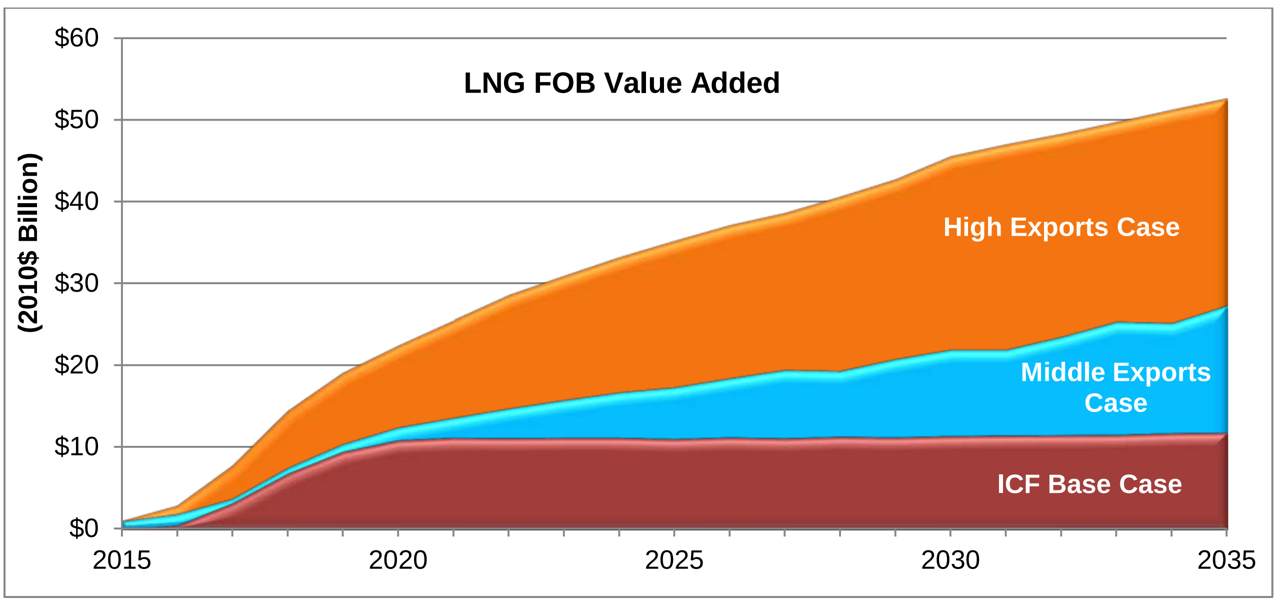
The following section describes the economic and employment impacts of LNG exports, relative to the Zero Export Case. See Appendix A for more detailed results tables.

6.1 Economic Impacts of LNG Exports

The two main economic metrics presented are the value of incremental products produced (also called value of shipments) and value added (also called contribution to GDP). The difference between these two metrics is the contribution of imported intermediate goods and services, which need to be left out of any value added or GDP estimation. As in the prior section, results usually are presented as differences between each LNG exports case versus the no export reference case.

The contribution to GDP from the LNG exports is shown in Exhibit 6-1. After discounting the value of imported gas, the GDP contribution of LNG exports reaches nearly $12 billion in 2035 under the ICF Base, $27 billion in the Middle Case and $53 billion in High Exports Case.

Exhibit 6-1: LNG Exports' Contribution to the U.S. GDP relative to Zero Exports Case



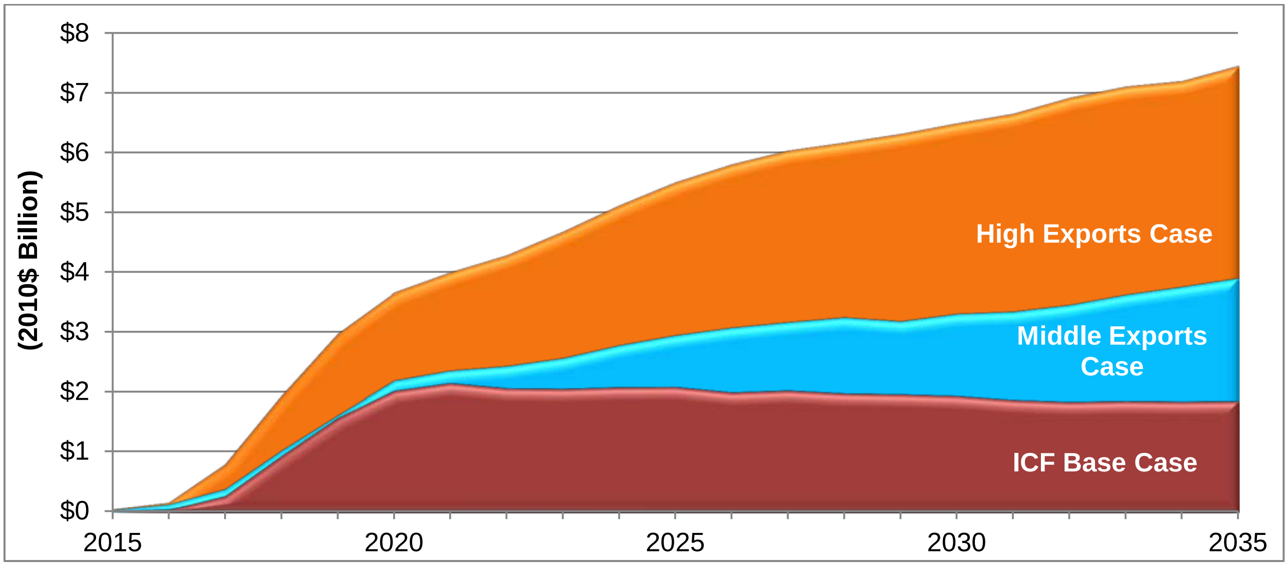
Source: ICF estimates

6.1.1 NGL Value Impacts

Incremental NGL (non-feedstock) sales are expected to be worth between $2.2 billion and $8.9 billion, depending on the LNG export case, relative to the Zero Exports Case. ICF assumed 16% of shipment value is comprised of input imports, given historical U.S. trade trends; thus, total GDP contributions are assumed at 84% of NGL sales, or between $1.9 billion and $7.5 billion.

Exhibit 6-2: NGL (non-feedstock) Change in GDP Contributions

(other than to petrochemical plants)



Source: ICF estimates

While all ethane volumes are assumed for use in ethylene/polyethylene production, thus creating no “final product” sale value under the accounting conventions of this report, 25% of propane is allotted for polypropylene production, thus its value is made up of 75% of assumed incremental volumes recovered. All volumes of butane, pentanes plus, and condensate/crude are assumed sold as such. While condensate and crude made up 19% of assumed incremental liquids volumes, they comprised the largest share of incremental liquids value (40%) in each case, given their higher values.

Exhibit 6-3: Proportion of NGL Volume and Value Assumed

NGL	Assumed Proportion	
	Incremental Volume (%)	Shipment Value (%)
Ethane Value *(100% counted as polyethylene)*	34%	0%
Propane Value *(25% counted as polypropylene)*	23%	20%
Butane Value	13%	19%
Pentanes+ Value	11%	21%
Condensate & Crude Oil Value	19%	40%
Total	**100%**	**100%**

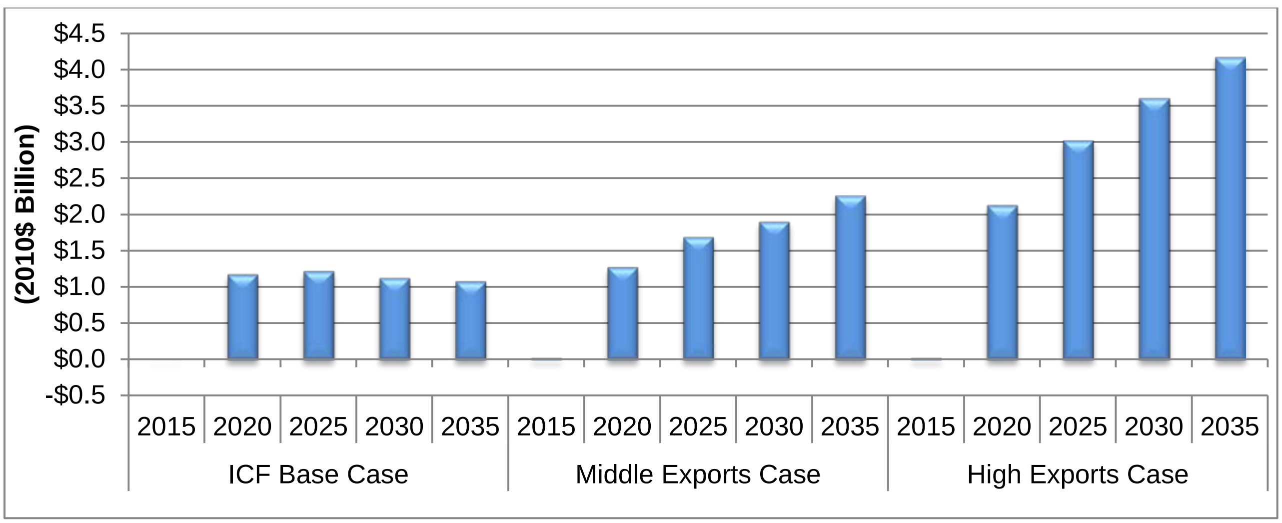
Source: ICF estimates

6.1.2 Petrochemical and Industrial Production Value Impacts

LNG exports are not expected to affect methanol or ammonia production, as these end products maintain cost-competitiveness in the LNG export scenarios, despite natural gas price increases. ICF forecasts that total methanol manufacturing gas consumption in the U.S. are expected to require 360 MMcfd (132 Bcf) in natural gas feedstock by 2018, and sustain that feedstock level over the forecast period (in all scenarios, including the Zero Exports Case). For reference, as of 2013, U.S. methanol manufacturing gas use totaled 59 MMcfd (22 Bcf), indicating an average annual growth rate of 8.6% between 2013 and 2035. U.S. ammonia manufacturing gas consumption totaled nearly 70 MMcfd (25 Bcf annually) in 2013, and is expected to reach 345 MMcfd (126 Bcf annually) in 2019, and sustain over the forecast period, indicating an annual average growth rate of 7.6% between 2013 and 2035. See Section 5 for more details on energy market and petrochemical volume trends.

In terms of the change in petrochemical production value attributable to LNG exports, ethylene/polyethylene are expected to see the highest gains (making up roughly 83%-86% of total petrochemical gains), while propylene/polypropylene are expected to make up a smaller share. GTLs are expected to see a slight drop in shipment value in the Middle and High Exports cases (between $100-$300 million by 2035). While total petrochemical production value changes are expected to range between $1.3 billion and $5.0 billion, with import deductions incremental petrochemical production attributable to LNG exports are expected to add between $1.1 billion and $4.2 billion in 2035 to the U.S. GDP.

Exhibit 6-4: Change in Petrochemicals GDP Contributions

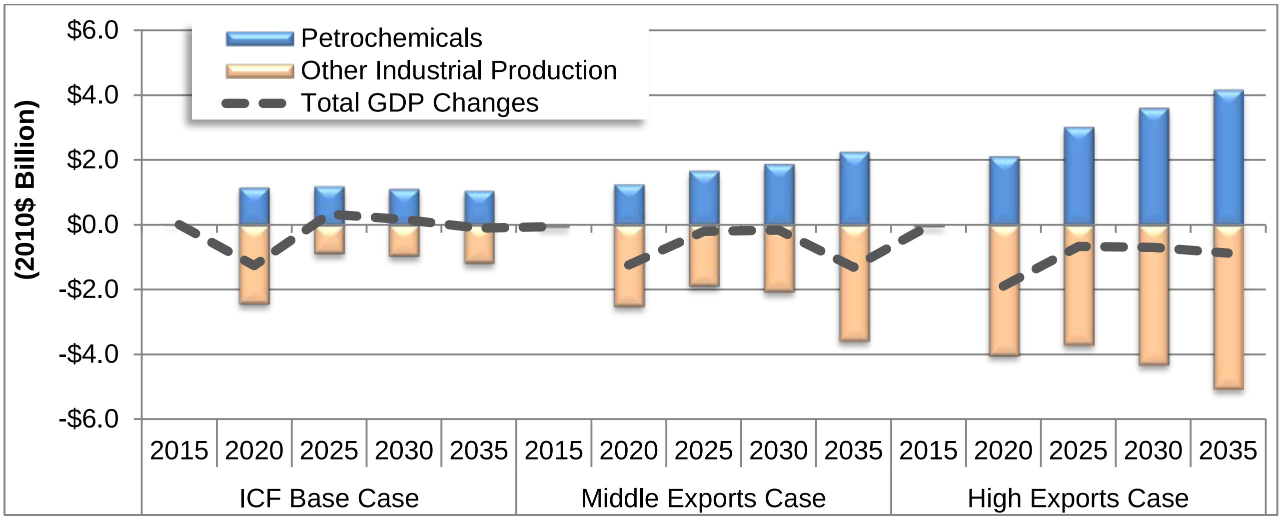


Source: ICF estimates

Note: Change in GDP contributions for methanol and ammonia from zero exports case negligible.

Given the price-sensitive nature of industrial manufacturing, an increase in natural gas and electricity prices are expected to mean a drop in industrial production (other than the specific petrochemicals discussed above), particularly among gas-intensive and electricity-intensive industries. LNG exports, relative to the no exports, are expected to result in lower GDP contributions by between $1.2 billion and $5.1 billion, slightly exceeding the petrochemicals' change in GDP gains (as shown in the exhibit below).

Exhibit 6-5: Petrochemical and Industrial Production Change in GDP Contributions



Source: ICF estimates

Note: Change in GDP contributions for methanol and ammonia from zero exports case negligible.

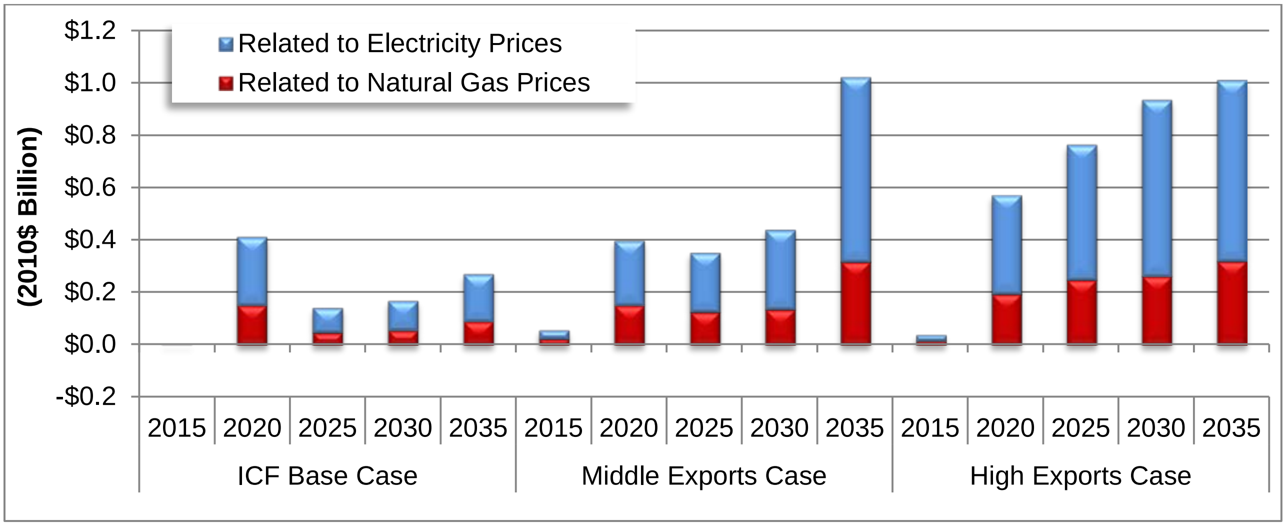
6.1.3 GDP Impacts of Spending Changes by Energy Consumers and Suppliers

The natural gas price increase brought on by LNG exports results in a shift in consumer spending towards natural gas, conservation and alternative fuels and way from miscellaneous consumer goods and services. At the same time, those higher prices increase revenue and earnings along the natural gas supply chain, which after accounting for income taxes, savings and spending on imports, increases spending on miscellaneous consumer goods. The gas supply chain earnings initially go to U.S. royalty owners, gas producers, oil field supply and service companies and governments (higher severance, income and property taxes) but later spread throughout the U.S. economy. A small portion also goes to Canadian gas producers who export more volumes into the U.S. when U.S. LNG exports increase.

A similar process takes place in electricity markets as consumer shift spending away from miscellaneous consumer goods towards electricity, conservation and alternative fuels to electricity. The added expenditures on electricity by existing households and businesses consumers will lead to greater revenues to electricity gas supply chain companies. However, this extra revenue will be partly (and in some cases fully) offset by higher costs for natural gas and other generating costs (for example, coal and coal plant operating costs). These earning initially go to electricity generators (especially coal, nuclear and renewables), power plant service companies, coal producers and transporters and governments (higher income, gross receipts and property taxes). All changes in electricity earnings are assumed to be to U.S. electricity generators.

The overall effect of these spending changes on GDP is very small because increases and decrease in spending are very similar. However, there is small net increase in GDP because the domestic content in natural and electricity production is larger than the domestic content of miscellaneous consumer goods.

Exhibit 6-6: GDP Effects of Spending Changes by Energy Consumers and Suppliers

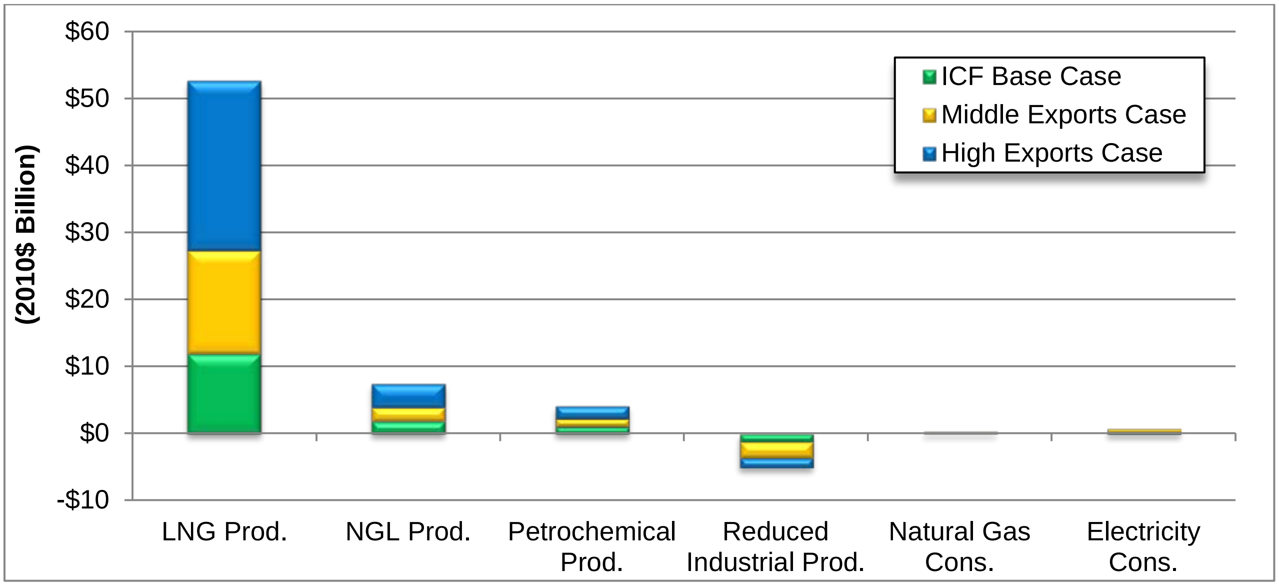


Source: ICF estimates

6.1.4 Total Economic Impacts

Total economic impacts include the direct and indirect GDP changes addressed above, as well as the induced effects through the multiplier effect. In terms of the impact from direct and indirect GDP changes, the majority of gains come from LNG production and export, as shown below, followed by the change in gains from additional NGL and petrochemical production. Impacts on natural gas and electricity consumers/producers result in slight increases in GDP gains; there is a decrease in GDP gains associated with industrial production, attributable to the increase in natural gas and electricity prices.

Exhibit 6-7: Changes in Direct and Indirect GDP Gains

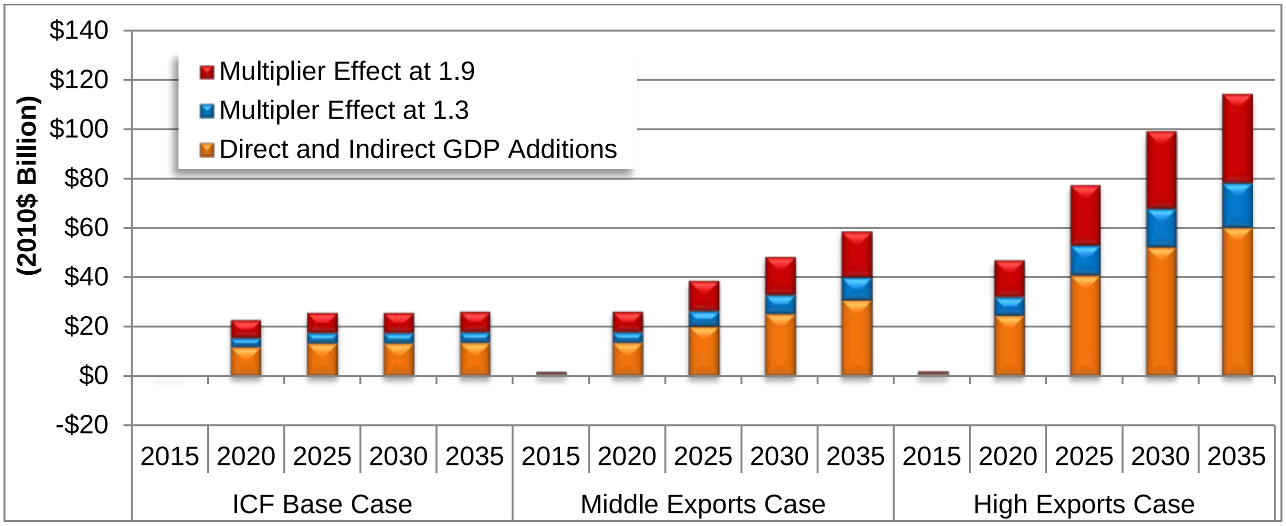


Source: ICF estimates

The exhibit below shows the change in GDP gains from direct, indirect, and induced economic activity. As mentioned earlier, we included a range of multiplier effects from 1.3 to 1.9. (The values for direct and indirect effects alone can be thought of as representing a third case with a multiplier effect of 1.0) As the direct and indirect GDP additions filter through the economy, the additional economic activity generates consumer spending throughout multiple rounds of spending.

ICF estimates that the ICF Base Case of 4 Bcfd in LNG exports are expected to result in an additional $18 billion to $26 billion in direct, indirect, and induced economic activity by 2035. The Middle Exports Case of 8 Bcfd in LNG exports results in additional economic activity totaling $40 billion to $59 billion in 2035, while the High Exports Case of 16 Bcfd in LNG exports will mean additional economic activity of between $78 billion and $115 billion that year.

Exhibit 6-8: Total GDP Impacts

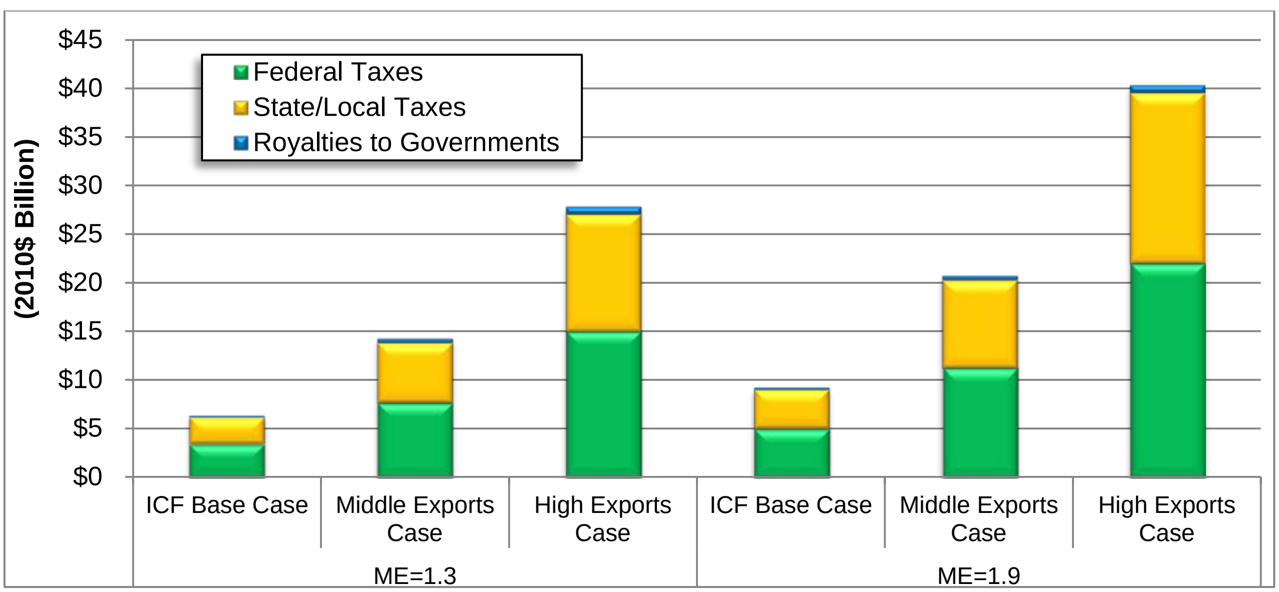


Source: ICF estimates

6.1.5 Government Revenues

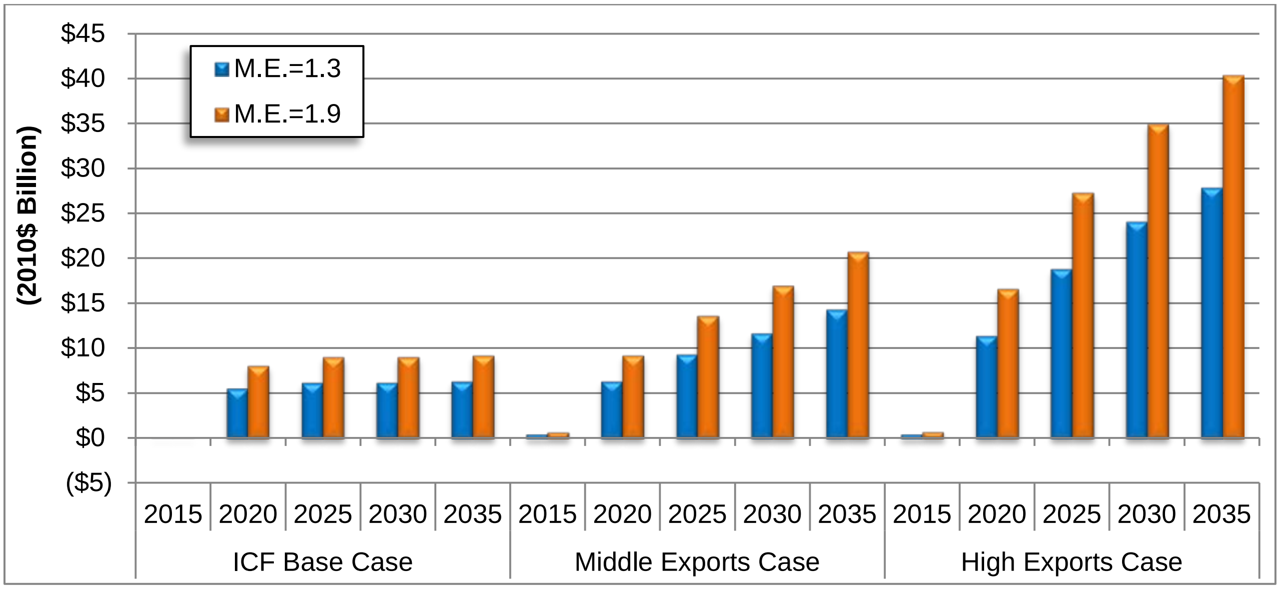
Increased government revenues resulting from LNG exports are expected to be in the form of federal, state, and local taxes on GDP gains associated with additional economic activity, as well as additional royalty payments to the government for natural gas production taking place on government lands. State and local taxes (which include severance taxes on natural gas and liquids production) comprise the largest share of government revenues, with federal taxes making up a smaller portion. A slight increase in federal royalties are expected to comprise the remaining source (as shown in the two exhibits below).

Exhibit 6-9: 2035 Government Revenues by Source



Source: ICF estimates

Exhibit 6-10: Total Government Revenues



Source: ICF estimates

6.2 Employment Impacts

The following section discusses the employment impacts of LNG exports.

6.2.1 Direct and Indirect Employment Impacts

The ICF methodology calculates direct and indirect job impacts (to the base case trend of no exports) by multiplying the change in production in a given sector (measured in dollars or physical units) times the labor needed per unit of production. We first look at the direct and indirect job impacts and then look at total job impacts, including induced jobs. Note that the induced jobs often outsize direct and indirect jobs, as the initial changes to output multiply through in the economy. Note that the first calculation of direct and indirect labor needed per unit of production indicates how many jobs are associated with changes in output from various sectors, but does not show in which sectors the jobs are ultimately located because many jobs are created in the sectors that supply goods and services to the sector whose output is changing.

Exhibit 6-11 shows the breakdown of direct and indirect employment relative to no LNG exports. The chart shows jobs that originate from the changes in activity within the indicated sectors regardless of which sector the jobs are in. For example, natural gas production requires direct jobs such as drilling equipment operators, but also stimulates jobs in indirect sectors such as steel (required for drill pipe manufacturing) and cement manufacturing (needed for well construction). While steel and cement manufacturing are not considered natural gas production sectors, this indirect activity is stimulated by the increase in natural gas production (designated for LNG exports), thus these indirect jobs are attributed as originating from higher oil and gas production sector activity in the exhibit below.

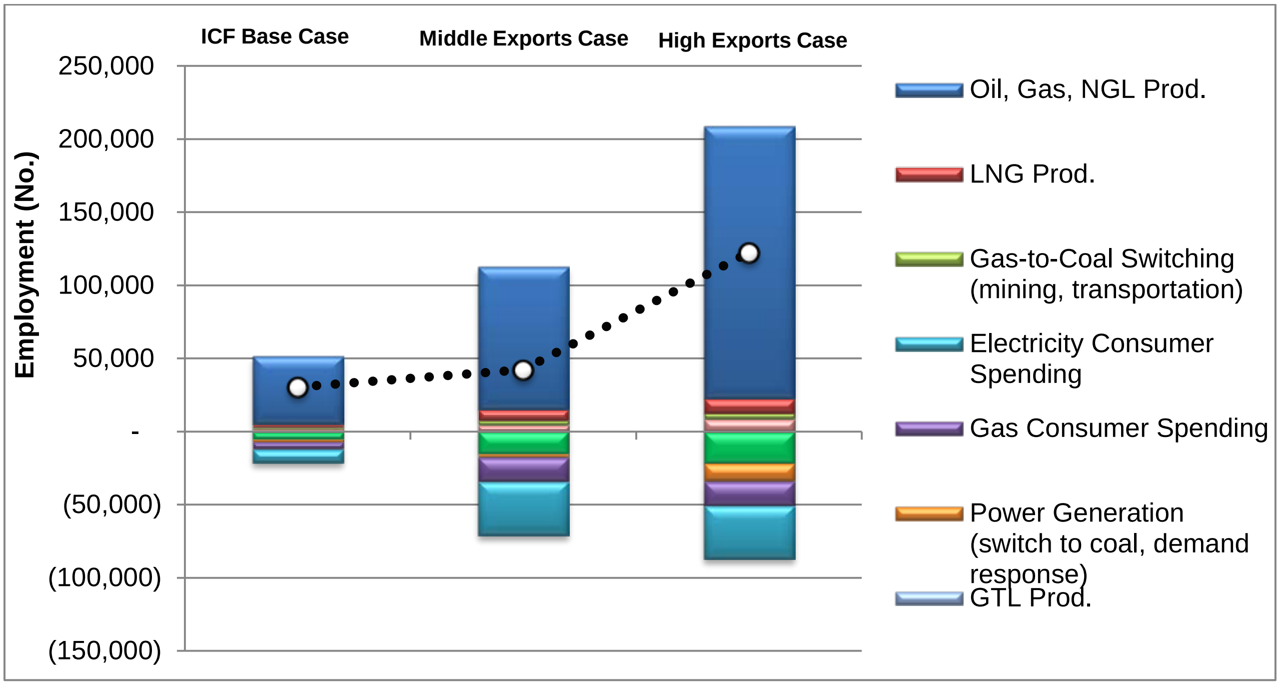
Oil and natural gas production comprises the largest share of employment gains, or between 46,000 and 186,000 annual jobs by 2035, depending on the LNG case. LNG production makes up another small share, between 2,000 and 10,000 annual jobs by 2035. Changes in petrochemicals processing require another 2,000-8,700 with LNG exports by 2035.

Coal-switching generates another 1,300-4,000 annual jobs in 2035, attributable to a small number of power generators switching to coal-fired power generation, given the increase in natural gas prices. A coal-fired power plant employs more operations and maintenance workers than a gas-fired plant. On a terawatt-hour (TWH) basis, the average coal power plant requires 133 job-years/TWH, while the average combined-cycle gas-fired plant needs 60 job-years/TWH, thus switching to coal would require more employees than the equivalent amount of generation from gas-fired generation.[28]

Natural gas and electricity consumer/supplier spending effects are expected to mean a drop of 14,000-53,000 annual direct and indirect job jobs by 2035 due primarily to reduced net purchases of miscellaneous consumer goods (not counting the job gains from induced job impacts discussed below). Additionally, higher gas prices are expected to mean a drop in industrial production, leading to employment contractions of 5,000-21,500 in annual jobs by 2035 (before counting induced job gains). Despite these employment contractions, total direct and indirect employment are expected to increase to between 30,000 and 122,000 annual jobs by 2035.

[28] U.S. Energy Information Administration (EIA). "National Energy Modeling System (NEMS) model cost factors." EIA, April 2010: Washington, D.C. Available at: http://www.eia.gov/oiaf/aeo/assumption/pdf/electricity_tbls.pdf

Exhibit 6-11: Activities that are Sources of Direct and Indirect Job Changes Relative to the Zero LNG Exports Case (2035)

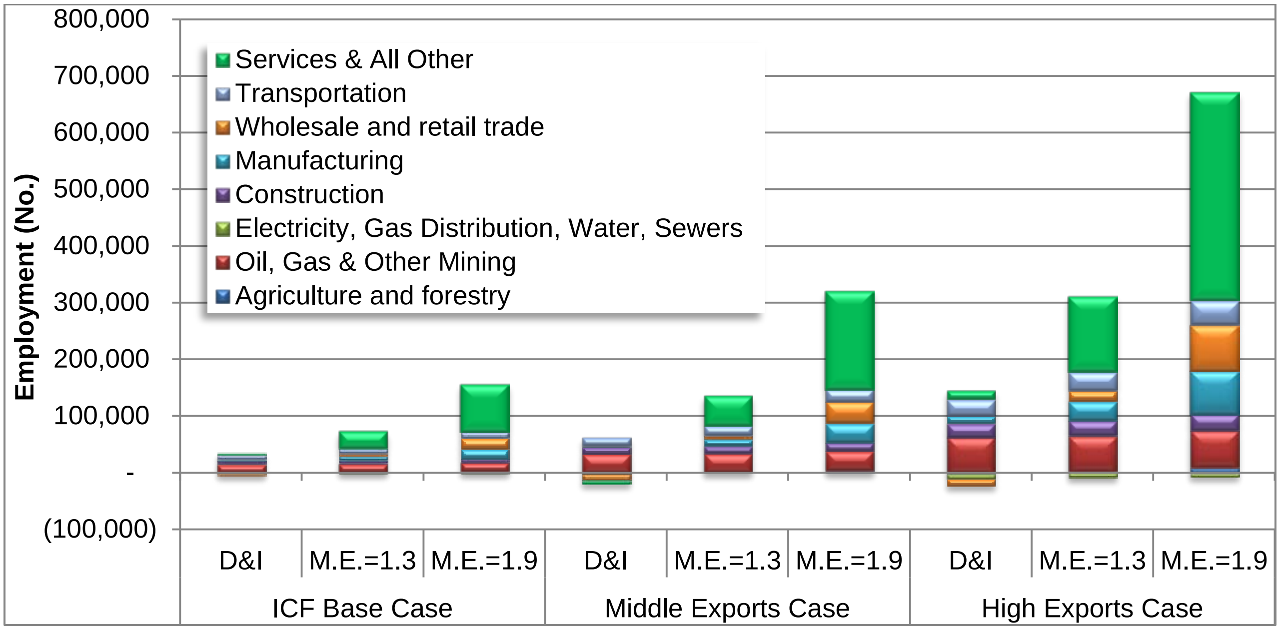


Source: ICF estimates

6.2.2 Multiplier Effect and Total Employment Impacts

As shown in the exhibit below, induced employment (generated by many rounds of consumer spending working through the economy) is largely concentrated in the services (i.e., consumer goods and services) sector and the manufacturing sectors related to consumer goods. Induced employment totals 42,000-125,000 annual jobs in 2035 in the ICF Base Case, and reaches between 181,000 and 543,000 additional jobs by 2035 in the High Exports Case.

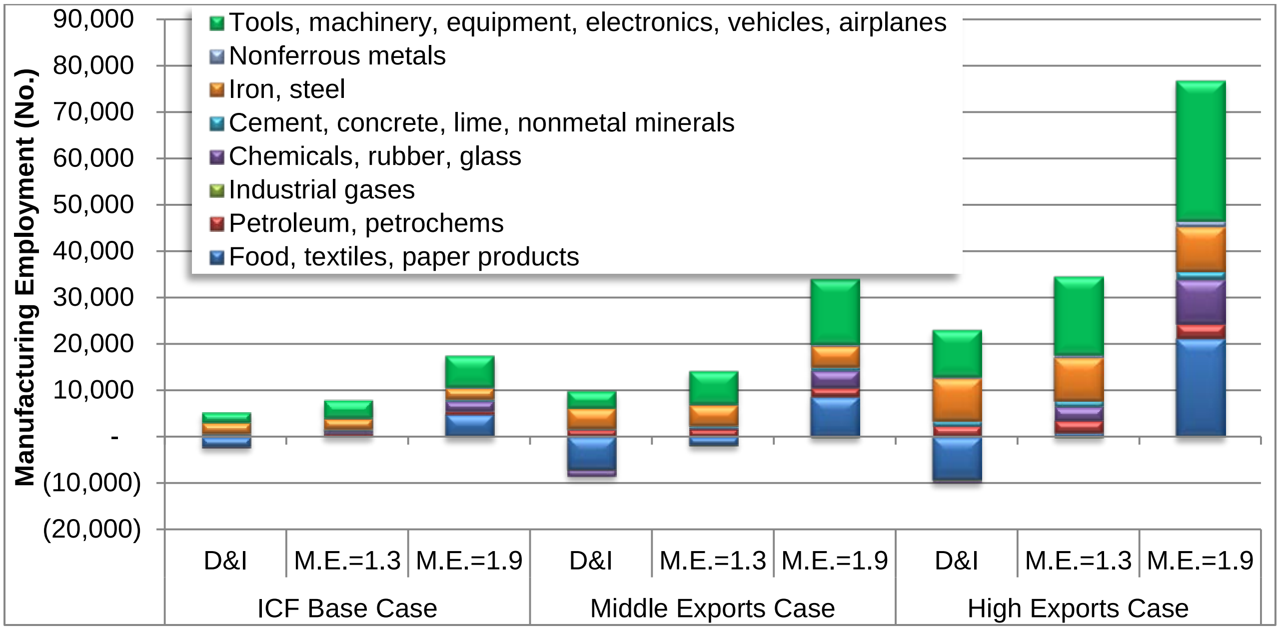
Exhibit 6-12: Change in Direct, Indirect, and Induced Employment by Sector (2035)



Source: ICF estimates

LNG exports also lead to increases in manufacturing-related jobs, as shown in the exhibit below. In particular, manufacturing of natural gas production equipment such as metals, cement, and machinery drives manufacturing changes. However, consumer-oriented manufacturing sectors such as food and textile manufacturing see a decline (relative to no LNG exports), as higher natural gas prices cause consumers to allocate a higher share of spending toward natural gas and electricity consumption, rather than miscellaneous consumer goods and services.

Exhibit 6-13: Changes in Direct, Indirect, and Induced Manufacturing Employment (2035)

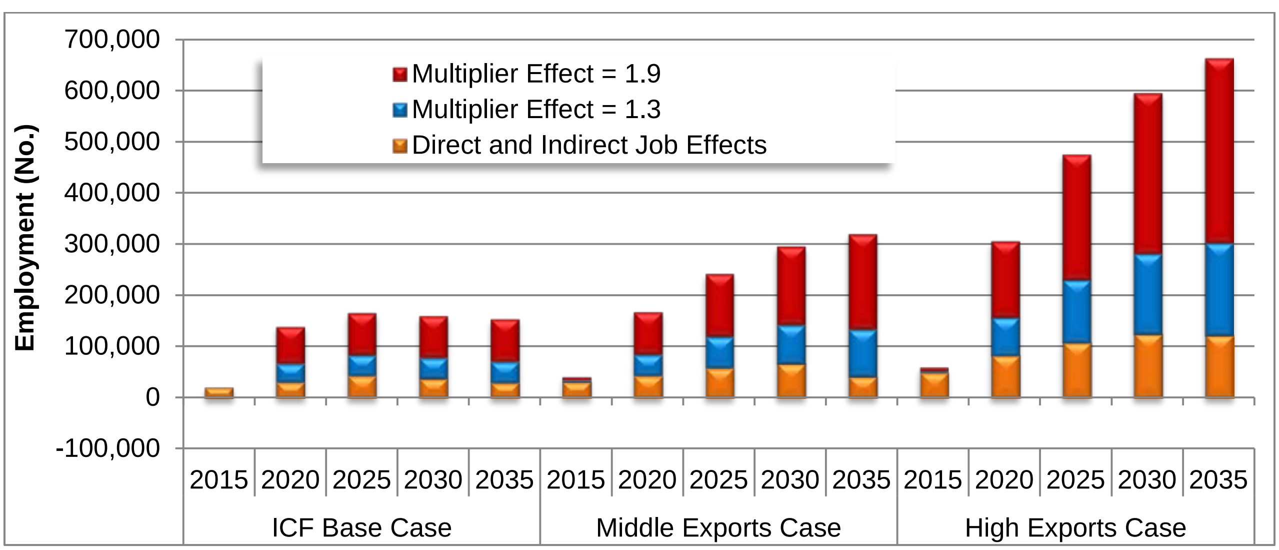


Source: ICF estimates

6.2.3 Total Employment Impacts

Total employment changes reach 665,000 annual jobs by 2035 in the High Exports Case, including direct, indirect, and induced employment. All LNG export cases indicate employment gains, relative to no exports.

Exhibit 6-14: Total Employment Impacts



Source: ICF estimates

6.2.4 Total Employment Impacts Relative to Size of Labor Market

As mentioned in Section 3.5, ICF's assessment of future U.S. employment is derived from the U.S. Bureau of Labor statistics forecasts of job growth through 2020, which shows U.S. employment growth of 14.3% between 2010 to 2020, totaling 20.5 million new jobs by 2020.[29] This 14.3% ten-year growth in U.S. employment equates to an annual job growth averaging 1.35% over the period, which was extrapolated through 2035 for this analysis. This results in total U.S. employment of 183.6 million U.S. jobs in 2035 (or 48.5 million new jobs between 2012 and 2035).

Direct, indirect, and induced LNG export employment increases contribute between 72,000 and 665,000 annual jobs by 2035, depending on LNG export scenario and multiplier effect. This equates to between 0.1% and 1.4% of incremental jobs between 2012 and 2035, or between 0.04% and 0.36% of total U.S. employment in 2035.

The increase in labor demand attributable to LNG exports could be accommodated by reduced unemployment rates, increased labor participation rates, longer hours worked, greater immigration, or crowding out effects. The exhibit below shows a theoretical calculation of how much higher wages would have to increase to bring more people into the workforce (i.e., extensive margin) and to increase hours worked per employee (i.e., intensive margin) such that the added net labor demand stemming from LNG exports could be met. These labor cost increases are all below 0.5% in 2035 (or less than a 0.025% per year over the forecast period) except for the High LNG Exports Case (16 bcfd) under the assumption that labor supply elasticity is only 0.4. However, even such modest wage increases would not be needed to the extent that the extra demand for labor could be accommodated through reduced unemployment rates, more foreign workers coming to the U.S. and/or substitution of capital and other factors of production for labor.

[29] U.S. Bureau of Labor Statistics (BLS). "Employment Projections: 2010-2020 Summary." U.S. Department of Labor, 1 February 2012: Washington, D.C. Available at: http://bls.gov/news.release/ecopro.nr0.htm

Exhibit 6-15: Total Employment Impacts on the U.S. Economy

LNG Export Case	2035 Annual New Jobs per I-O Analysis No.)	2035 New Jobs as Share of Total 2035 U.S. Employment (%)	LNG Export Jobs as Share of 2012 to 2035 Job Growth (%)	Wage Increase to Support Labor Demand Increase (%)	
				Labor Supply Elasticity = 0.75*	Labor Supply Elasticity = 0.40*
M.E. = 1.0 (Direct and Indirect Jobs Only)					
ICF Base Case (up to ~4 Bcfd)	30,431	0.02%	0.10%	0.02%	0.04%
Middle Case (up to ~8 Bcfd)	42,251	0.02%	0.10%	0.03%	0.06%
High Case (up to ~16 Bcfd)	122,462	0.07%	0.30%	0.09%	0.17%
M.E. = 1.3 (Direct, Indirect, and Induced Jobs)					
ICF Base Case (up to ~4 Bcfd)	72,045	0.04%	0.10%	0.05%	0.10%
Middle Case (up to ~8 Bcfd)	135,145	0.07%	0.30%	0.10%	0.18%
High Case (up to ~16 Bcfd)	303,308	0.17%	0.60%	0.22%	0.41%
M.E. = 1.9 (Direct, Indirect, and Induced Jobs)					
ICF Base Case (up to ~4 Bcfd)	155,275	0.08%	0.30%	0.11%	0.21%
Middle Case (up to ~8 Bcfd)	320,933	0.17%	0.70%	0.23%	0.44%
High Case (up to ~16 Bcfd)	665,000	0.36%	1.40%	0.48%	0.91%

Source: ICF estimates

* See Section 3.5 for sources of elasticity estimates. Calculations assume full employment even without LNG exports, no contribution from more foreign workers, and no capital-for-labor substitution. Wage increases taking those factors into account would be smaller.

6.3 Sensitivity Analysis of LNG Pricing

Because of the uncertainty regarding how the LNG market structure and pricing will evolve over the next two decades, ICF created a sensitivity case to explore the effect on key results if LNG were priced at lower levels. Those results are shown below in Exhibit 6-16. The Principal Case LNG assumption used in this report leads to weighted average delivered gas prices for 2016 to 2035 in Japan, Korea, and Taiwan of $12.49/MMBtu to $12.96/MMBtu or approximately 76% to 79% of crude oil prices on a Btu basis.[30]

This compares to recent long-term contract LNG prices which are approximately 85% of crude. This drop in LNG prices relative to crude oil is expected due to increased competition as new supplies from the U.S. and other regions such as East Africa enter the market. These delivered prices in the Principal Case translate into U.S. Gulf Coast FOB prices ranging from $9.85/MMBtu to $10.32/MMBtu. This pricing structure would leave a small premium between

[30] Note that the three LNG export volume cases for this study were created assuming that the international demand for LNG was changing among the volume cases due to such factors as faster economic growth, policies favoring natural gas use and slower development of unconventional gas in countries such as China and India. These assumptions shift the LNG demand curve to the right and lead to higher LNG prices for the cases with higher U.S. LNG exports. This is why we are showing increasing LNG prices as LNG export volumes go up. If the LNG export cases had been constructed in a different way (for example, by assuming that the LNG exports were driven by U.S. export quota limits) then the LNG pricing patterns might be different from those shown here.

the "cost" of LNG (that is, the Henry Hub price *plus* pipeline transport margin *plus* value of fuel consumed at the liquefaction plants *plus* cost of liquefaction) and FOB value of the LNG in the Gulf Coast.

If LNG were priced at lower levels consistent with the Sensitivity Case then delivered LNG prices in Asia would be $11.06/MMBtu to $11.99/MMBtu and the Gulf coast F.OB. prices would be $8.42/MMBtu to $9.35/MMBtu. These Sensitivity Case prices are set such that U.S. Gulf Coast LNG is the marginal price setter in Asia and so there is no premium between the "cost" of LNG and the FOB value of the LNG in the Gulf Coast.

The major differences in economic impacts stemming from these different LNG pricing assumptions are shown in Exhibit 6-16. As would be expected, assumptions for lower LNG prices reduce the GDP effects of LNG exports since the export earnings are lower as are the dollar values of the multiplier effects. For similar reasons, the positive employment effects are also reduced. However, these changes are relatively small because all of the internal U.S. energy market adjustments (such as greater natural gas and NGL production, fuel switching, energy conservation, and reduced industrial output) depend only on U.S. natural gas prices, which are determined by export volumes and are, thus, identical between the Principal and Sensitivity Cases.

Exhibit 6-16: Sensitivity of Key Results to LNG Pricing Assumptions

Result	ICF Base Case LNG Export Volumes		Middle Case LNG Export Volumes		High Case LNG Export Volumes	
	LNG Pricing Principal Case	LNG Pricing Sensitivity Case	LNG Pricing Principal Case	LNG Pricing Sensitivity Case	LNG Pricing Principal Case	LNG Pricing Sensitivity Case
LNG Pricing Assumptions (2016-2035 Average Annual Changes)						
Delivered LNG Pricing as Fraction of Crude*	76%	68%	78%	70%	79%	73%
Average DES LNG Value J/K/T (2010$/MMBtu)*	$12.49	$11.06	$12.71	$11.49	$12.96	$11.99
Average FOB Value U.S. Gulf Coast (2010$/MMBtu)*	$9.85	$8.42	$10.07	$8.85	$10.32	$9.35
Pricing Impact on GDP and Employment Changes (2016-2035 Average Annual Changes)						
M.E. = 1.3 Change in U.S. GDP (2010$b)	15.6	13.4	25.4	22.4	50.3	45.6
M.E. = 1.9 Change in U.S. GDP (2010$b)	22.8	19.6	37.2	32.8	73.6	66.6
M.E. = 1.3 Change in U.S. Employment (No.)	73,135	68,096	112,778	105,785	220,052	209,100
M.E. = 1.9 Change in U.S. Employment (No.)	145,086	129,971	230,216	209,237	452,345	419,490

Source: ICF estimates

* Weighted by LNG export volumes from 2016 to 2035.

7 Comparison of Studies on U.S. LNG Exports

There have been a number of studies attempting to quantify the impact of LNG exports on U.S. natural gas prices and the economy overall. However, making direct comparisons among such studies can be challenging because the studies look at different issues, using various modeling methodologies, and are based on widely different assumptions. Exhibit 7-3 at the end of this section summarizes some of the key differences in the assumptions and results of a number of LNG export economic impact studies. Most cases assessed range from 1-12 Bcfd in LNG exports, though the Dow Chemical report (conducted by Charles River Associates) assumed a high case of 20 Bcfd in LNG exports by 2025, and 35 Bcfd by 2030. To account for differences in assumed export volumes, many of the comparisons are made on a basis of per-Bcfd or per-MMBtu of exports.

Generally speaking, the lowest price increases on a scale of $/MMBtu per Bcfd of exports are associated with the most price-elastic representation of domestic gas supply. This is a function of both long-term supply curves (showing how much costs go up as the resource is depleted, assuming constant factor costs) and short-run drilling activity effects (representing how short-term factor costs increase as drilling activity per unit of time goes up). This ICF report generally shows similar or lower export-induced natural gas price increases than the EIA and NERA reports (despite forecasting a much bigger non-export gas market) because we assume a larger natural gas resource base and flatter long-run supply curve. See Section 3 for a discussion of ICF's GIS-based resource assessment and economic analysis processes.) On other hand, this report shows larger natural gas price increases than the Deloitte studies, due, in part, to the fact that the Deloitte modeling methodology ignores the time and effort needed to build extra wellhead natural gas deliverability and short-term factor cost effects.

In terms of natural gas price changes at Henry Hub, this report estimated a range of $0.10 to $0.11/MMBtu price increase per Bcfd of LNG exports. The range of estimates for the EIA report produced with the NEMS models was a gas price increase of $0.07 to $0.14/MMBtu per Bcfd of LNG exports. The NERA report conducted for DOE also estimated an increase of $0.07 to $0.14/MMBtu per Bcfd of LNG exports. The natural gas price impact reported in the Sabine Pass study conducted by Navigant study was $0.18/MMBtu per Bcfd, while the Dow Chemical report done by CRA indicated a range between $0.23/MMBtu per Bcfd for its 4 Bcfd LNG export case and $0.11/MMBtu per Bcfd in exports for its 35 Bcfd exports case. The RBAC report estimated a natural gas price increase of $0.20 to $0.33/MMBtu per Bcfd of LNG exports.

The ICF model rebalances the gas market to accommodate LNG export volumes with three sources; namely, domestic natural gas production increases (79%-88%), demand response (21%-27%), and natural gas imports from Canada and Mexico (7%-8%). The other studies ranged considerably in their results, with the EIA study showing a demand response of between 29%-39%, while Sabine Pass shows a negative demand response of 1% (i.e., increase in consumption attributable to LNG exports) and imports of 43%-55%. Jordan Cove's study showed imports making up for 95% of export volumes in the low cases and 12% in the higher cases. The NERA study derived LNG export supply nearly equally from incremental production increases and demand response. The NERA study had no impact from net changes to international pipeline flows, because they fixed pipeline trade by assumption to match their no-export case. The Dow Chemical report did not describe the supply sources.

NERA report comparisons

The NERA study used a general equilibrium model, called the NewERA Macroeconomic Model[31], which forecasted the macroeconomic policy, regulatory, and economic impacts resulting from energy sector movements (specifically, LNG exports on the U.S. economy). The NERA report derives lower GDP contributions from LNG exports than does this study, as shown in the exhibit below.

Exhibit 7-1: Economic Impact Comparisons by Study

Case	Export Level/ Growth	∆$GDP/ ∆Mcf LNG Exported
NERA Export Study for DOE		
Reference	2035: 3.75-15.75 Bcfd Avg: 2.74-10.58 Bcfd 0.5-3 Bcfd/yr growth	2035: $1.37-$11.76 Avg: $3.237-$6.538
High EUR	2035: 6-23 Bcfd Avg: 4.20-17.35 Bcfd 1-3 Bcfd/yr growth	2035: $3.20-$5.48 Avg: $6.291-$8.626
Low EUR	2035: 1.42 Bcfd Avg: 1.35 Bcfd 0.5 Bcfd/yr growth	2035: $1.92 Avg: $(0.687)
API LNG Export Study (ICF)		
ICF Base Case	2035: 3.6 Bcfd Avg: 3.1 Bcfd 0.6 Bcfd/yr growth over 6 yrs	D&I: $9.76 M.E.=1.3: $12.69 M.E.=1.9: $18.54
Middle Exports Case	2035: 8.0 Bcfd Avg: 5.0 Bcfd 0.4 Bcfd/yr growth over 20 yrs	D&I: $10.32 M.E.=1.3: $13.42 M.E.=1.9: $19.61
High Exports Case	2035: 15.5 Bcfd Avg: 9.9 Bcfd 0.8 Bcfd/yr growth over 20 yrs	D&I: $10.37 M.E.=1.3: $13.48 M.E.=1.9: $19.70

Source: Various compiled by ICF

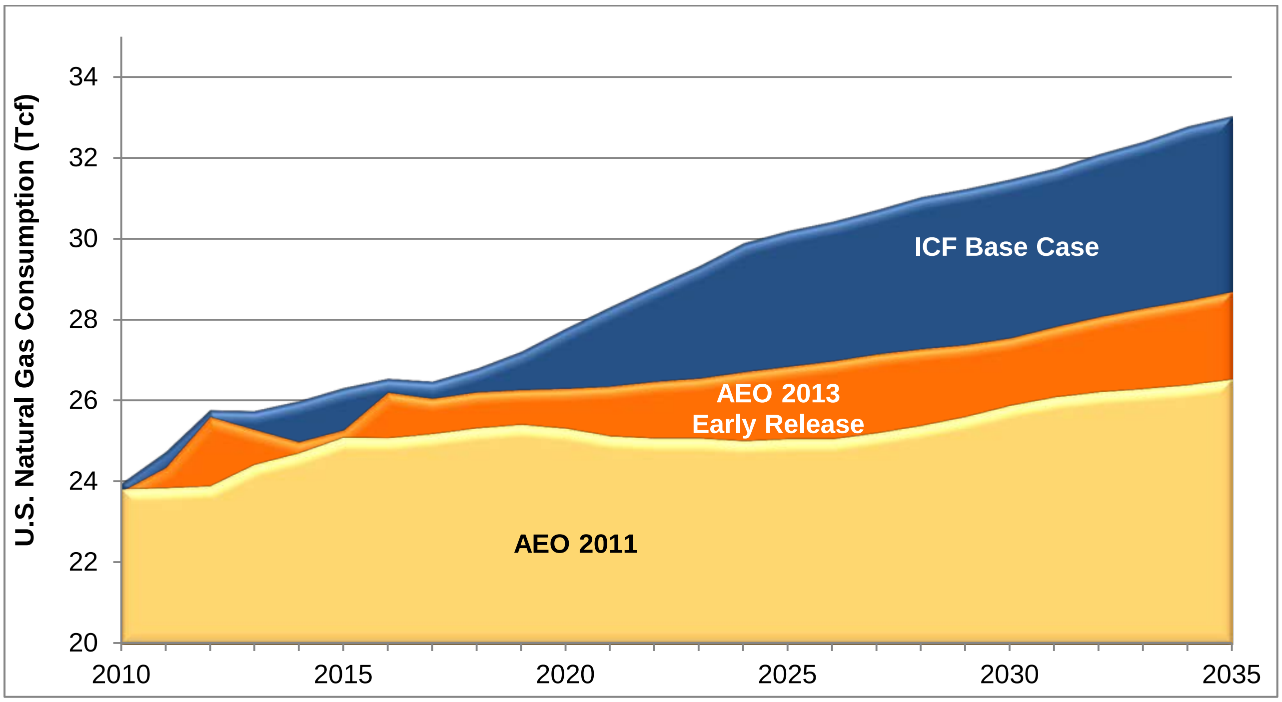
Factors include ICF's more elastic domestic gas supply representation with a higher resource base and EUR/well rates. One of the NERA alternate cases also assumes higher EUR per well, which significantly reduce natural gas price increases and boosts GDP contributions from LNG exports. Another difference between NERA and this study is the sources of rebalancing supply. As mentioned, the NERA report assumed nearly an even split between production increase and demand response, whereas ICF concludes that the bulk of LNG exports would be supplied from

[31] NERA Economic Consulting. "Macroeconomic Impacts of LNG Exports from the United States." The U.S. Department of Energy (DOE), 3 December 2012: Washington, D.C. Available at: http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf

additional domestic production and that pipeline trade with Canada and Mexico will also add to net supplies. More demand response will tend to decrease GDP contributions from LNG exports. Another important difference is that the NERA report did not consider the effects of greater liquids production that would accompany greater gas production.

This ICF study assumes a larger natural gas market to begin with, as shown in the exhibit below, due to assumed greater economic growth rates and more growth in industrial gas use. The incremental difference between the ICF Base Case and the AEO 2013 Early Release forecast for U.S. gas consumption is the equivalent to 12 Bcfd by 2035; the difference with the AEO 2011 forecast equates to an additional 18 Bcfd in U.S. natural gas consumption. This means that in the ICF study the requirements for gas supply are greater even before LNG exports are considered and thus the “stress test” of exports is more severe.

Exhibit 7-2: Natural Gas Consumption Comparisons



Sources: ICF GMM, EIA.

It is also important to note that this ICF study shows larger positive GDP effects from LNG exports compared to the NERA study, in part, because the NERA study employs a CGE model that is built on the assumptions of full employment and fixed international trade balances.

Exhibit 7-3: Energy Market Impact Comparisons by Study

Facility	Summary of Analysis	Case	LNG Exports Impacts: Henry Hub Price Change Relative to Reference Case ($/MMBtu)	Henry Hub Price Change ($/MMBtu per 1 Bcfd)	Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd): Prod. Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)
Price and Supply Source Assumptions								
Sabine Pass (Navigant)	5 cases examining different levels of U.S. demand and LNG export ranging from 0 to 2 Bcfd (only 2 relevant cases - 1 Bcfd exports, 2 Bcfd exports)	1 Bcfd LNG exports	$0.18	$0.18	58%	-1%	43%	100%
		2 Bcfd LNG exports	$0.35	$0.18	55%	-1%	55%	109%
Jordan Cove (Navigant)	7 cases examining different levels of U.S. demand and LNG exports ranging from 2.7 to 7.1 Bcfd	2.9 Bcfd [0.9 Bcfd incremental LNG exports from Jordan Cove (in addition to 2 Bcfd assumed in the base case)]	$0.03 (0.9 Bcfd)	$0.03	14%	7%	95%	116%
		5.9 Bcfd [3 Bcfd incremental LNG exports (in addition to base case 2 Bcfd and 0.9 Bcfd incremental)]	$0.38 (3.9 Bcfd)	$0.10	80%	11%	12%	103%
Freeport (Deloitte)	Single scenario, with and without	6 Bcfd LNG exports	$0.12 citygate national average, $0.22 at HH (2016-2035)	$0.02 (citygate), $0.04 (HH)	63%	17%	20%	100%
EIA (NEMS Modeling)	Total of 16 cases with 4 export scenarios examining impacts of either 6 or 12 Bcfd of exports phased in at a rate of 1 Bcfd per year or 3 Bcfd per year	5.3 Bcfd - 11.2 Bcfd (AEO Ref)	$0.55-$1.22	$0.10-$0.12	61%-64%	36%-39%	2%-3%	100%-106%
		5.3 Bcfd - 11.2 Bcfd (High Shale)	$0.38-$0.87	$0.07-$0.12	61%-64%	34%-37%	5%	102%-108%
		5.3 Bcfd - 11.2 Bcfd (Low Shale)	$0.77-$1.65	$0.15-$0.17	55%-60%	32%-37%	11%-12%	100%-109%
		5.3 Bcfd - 11.2 Bcfd (High GDP)	$0.55-$1.26	$0.10-$0.12	71%-72%	29%-30%	2%-3%	102%-105%

Facility (cont.)	Summary of Analysis	Case	LNG Exports Impacts: Henry Hub Price Change Relative to Reference Case ($/MMBtu)	($/MMBtu per 1 Bcfd)	Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd): Prod. Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)
Price and Supply Source Assumptions (cont.)								
DOE (NERA)	8 cases examining different levels of U.S. demand and LNG export ranging from 3.75 to 15.75 Bcfd	6 Bcfd (Reference)	$0.34-$0.60	$0.09 to $0.10	51%	49%	0%	100%
		12 Bcfd (Reference)	$1.20		51%	49%	0%	100%
		Unlimited Bcfd (Reference)	$1.58		50%	50%	0%	100%
	7 cases examining different levels of U.S. demand and LNG exports ranging from 6 to 23 Bcfd	6 Bcfd (High EUR)	$0.42	$0.07	50%	50%	0%	107%
		12 Bcfd (High EUR)	$0.84		49%	51%	0%	100%
		Unlimited Bcfd (High EUR)	$1.08 - $1.61		46%	54%	0%	100%
	Single scenario with LNG exports reaching 1.42 Bcfd	6 Bcfd (Low EUR)	$0.14 (1 Bcfd)	$0.14	51%	49%	0%	100%
Dow Chemical (CRA)	3 export scenarios with CRA Base Demand (adjusted AEO 2013 for industrial demand)	4 Bcfd LNG export (AEO export), CRA Base Demand	$0.90 (2013-2030)	$0.23 (using 4 Bcfd)	N/A	N/A	N/A	N/A
		9 Bcfd LNG exports by 2025 and 20 Bcfd by 2030 layered on CRA Base Demand	$2.50 (2013-2030)	$0.13 (using 20 Bcfd)	N/A	N/A	N/A	N/A
		20 Bcfd LNG exports by 2025 and 35 Bcfd by 2030 layered on CRA Base Demand	$4.00 (2013-2030)	$0.11(using 35 Bcfd)	N/A	N/A	N/A	N/A
RBAC, REMI	2 export scenarios: 3 Bcfd and 6 Bcfd relative to a no export scenario	3 Bcfd	About $0.60 (2012-2025)	$0.20	N/A	N/A	N/A	N/A
		6 Bcfd	About $2.00 (2012-2025)	$0.33	N/A	N/A	N/A	N/A
API (ICF)	ICF Base Case	Up to ~4 Bcfd	$0.35	$0.10	88%	21%	7%	116%
	Middle Exports Case	Up to ~8 Bcfd	$1.19	$0.11	82%	26%	7%	115%
	High Exports Case	Up to ~16 Bcfd	$1.33	$0.10	79%	27%	8%	114%

Facility (cont.)	Summary of Analysis	Case	LNG Exports Impacts		
			Multiplier Effect (GDP Multiplier)	Employment Impact (Jobs/Bcfd Exports)	GDP Impact (ΔGDP/ ΔJobs)
Economic Impacts					
Sabine Pass (Navigant)	5 cases examining different levels of U.S. demand and LNG export ranging from 0 to 2 Bcfd (only 2 relevant cases - 1 Bcfd exports, 2 Bcfd exports)	1 Bcfd LNG exports	N/A	Construction: 3000 (or 1500 per Bcfd) Upstream: 30,000 - 50,000 (or 15,000-25,000/Bcfd) for "regional and national economies"	N/A
		2 Bcfd LNG exports	N/A		N/A
Jordan Cove (Navigant)	7 cases examining different levels of U.S. demand and LNG exports ranging from 2.7 to 7.1 Bcfd	2.9 Bcfd [0.9 Bcfd incremental LNG exports from Jordan Cove (in addition to 2 Bcfd assumed in the base case)]	N/A	Construction: 1768 direct, 1530 indirect, 1838 induced (5136 total or 6188 per Bcfd) Operation: 99 direct, 404 indirect, 182 induced (736 total or 887 per Bcfd) Upstream: 20359 average, 27806 through 2035, 39366 through 2045 (in attached ECONorthwest study or 33501 per Bcfd through 2035) 0.83 Bcfd project	N/A (separate reports on GDP impact attributed to regional, trade, upstream but no total)
		5.9 Bcfd [3 Bcfd incremental LNG exports (in addition to base case 2 Bcfd and 0.9 Bcfd incremental)]	N/A		
Freeport (Deloitte)	Single scenario, with and without	6 Bcfd LNG exports	1.34-1.90 (based on GDP)	Construction: more than 3000 Operation: 20 -30 permanent jobs added to number needed to operate as an import terminal Indirect: 2015-2040 avg: M.E. = 1.34: 18,211 (or 12,141 per Bcfd) 2015-2040 avg: M.E. = 1.55: 20,929 (or 13,953 per Bcfd) 2015-2040 avg: M.E. = 1.90: 16,852 (or 11,235 per Bcfd)	2015-2040 avg: M.E. = 1.34: $200,000 2015-2040 avg: M.E. = 1.55: $201,300 2015-2040 avg: M.E. = 1.90: $306,432

<table>
<tr><th rowspan="2">Facility (cont.)</th><th rowspan="2">Summary of Analysis</th><th rowspan="2">Case</th><th colspan="3">LNG Exports Impacts</th></tr>
<tr><th>Multiplier Effect (GDP Multiplier)</th><th>Employment Impact (Jobs/Bcfd Exports)</th><th>GDP Impact (∆GDP/ ∆Jobs)</th></tr>
<tr><td colspan="6">Economic Impacts (cont.)</td></tr>
<tr><td rowspan="7">DOE (NERA)</td><td rowspan="3">8 cases examining different levels of U.S. demand and LNG export ranging from 3.75 to 15.75 Bcfd</td><td>6 Bcfd (Reference)</td><td>N/A</td><td rowspan="7">Study used a CGE model in which full employment was assumed for all scenarios and so employment differences among export scenarios were insignificant</td><td rowspan="7">N/A</td></tr>
<tr><td>12 Bcfd (Reference)</td><td>N/A</td></tr>
<tr><td>Unlimited Bcfd (Reference)</td><td>N/A</td></tr>
<tr><td rowspan="3">7 cases examining different levels of U.S. demand and LNG exports ranging from 6 to 23 Bcfd</td><td>6 Bcfd (High EUR)</td><td>N/A</td></tr>
<tr><td>12 Bcfd (High EUR)</td><td>N/A</td></tr>
<tr><td>Unlimited Bcfd (High EUR)</td><td>N/A</td></tr>
<tr><td>Single scenario with LNG exports reaching 1.42 Bcfd</td><td>6 Bcfd (Low EUR)</td><td>N/A</td></tr>
<tr><td rowspan="2">RBAC, REMI</td><td rowspan="2">2 export scenarios: 3 Bcfd and 6 Bcfd relative to a no export scenario</td><td>3 Bcfd</td><td>N/A</td><td>2012-2025 avg:
41,768 per Bcfd. Multiplier not given.</td><td>2012-2025 avg:
$35,357/job in 2011 dollars</td></tr>
<tr><td>6 Bcfd</td><td>N/A</td><td>2012-2025 avg:
67,236 per Bcfd. Multiplier not given.</td><td>2012-2025 avg:
$46,349/job in 2011 dollars</td></tr>
<tr><td rowspan="3">API (ICF)</td><td>ICF Base Case</td><td>Up to ~4 Bcfd</td><td>1.3-1.9</td><td>2016-2035 avg:
M.E. = 1.3: 32,200
M.E. = 1.9: 54,300</td><td>2016-2035 avg:
M.E. = 1.3: $207,100
M.E. = 1.9: $150,300</td></tr>
<tr><td>Middle Exports Case</td><td>Up to ~8 Bcfd</td><td>1.3-1.9</td><td>2016-2035 avg:
M.E. = 1.3: 25,200
M.E. = 1.9: 47,000</td><td>2016-2035 avg:
M.E. = 1.3: $214,100
M.E. = 1.9: $153,900</td></tr>
<tr><td>High Exports Case</td><td>Up to ~16 Bcfd</td><td>1.3-1.9</td><td>2016-2035 avg:
M.E. = 1.3: 24,700
M.E. = 1.9: 46,600</td><td>2016-2035 avg:
M.E. = 1.3: $216,500
M.E. = 1.9: $155,400</td></tr>
</table>

Source: Various compiled by ICF

Note: The EIA study using NEMS modeling did not include economic or employment impacts.

8 Key Conclusions

The main conclusion of this report is that LNG exports will have net gains to the economy, in terms of GDP and employment gains. LNG exports are expected to have net positive effects on U.S. employment, with projected net job growth of between 73,100 to 452,300 jobs on average between 2016 and 2035, including all economic multiplier effects. Manufacturing job gains average between 7,800 and 76,800 net jobs between 2016 and 2035, including 1,700-11,400 net job gains in the specific manufacturing sectors that include refining, petrochemicals, and chemicals. In terms of per Bcfd in LNG exports, the study concludes that the net effect on U.S. employment is expected to also be positive with net job growth of 25,000 to 54,000 average annual jobs per one Bcfd of LNG exports, including all economic multiplier effects.

The net effect on U.S. GDP are expected to be positive at about $15.6 to $73.6 billion per year on average between 2016 and 2035, including the impacts of associated liquids production, increases in the petrochemical manufacturing of olefins, and all economic multiplier effects. This study also estimates that the net effect on annual U.S. GDP are expected to be positive at about $4.7 to $7.0 billion per one Bcfd of exports on average between 2016 and 2035, including the impacts of additional liquids and olefins production, and all economic multiplier effects.

LNG exports are expected to have moderate impacts on domestic natural gas prices of about $0.32 to $1.02 per million British Thermal Units (MMBtu) on average between 2016 and 2035. Another key conclusion of this study is that LNG exports are expected to have moderate impacts on domestic natural gas prices of about $0.08 to $0.11/MMBtu for each one Bcfd of exports.

The other conclusions that can be derived from this study incorporating our comparison to other studies include the following:

- **<u>This ICF study and the other studies reviewed here indicate domestic natural gas prices will increase due to LNG exports</u>:** All the studies show some degree of U.S. natural gas price increase in cases where LNG exports are allowed to proceed (or are otherwise assumed to take place). However, there is a wide range of price impact results (measured on a scale of $/MMBtu per Bcfd of exports) that stem from varying modeling methods and assumptions.
- **<u>Assumptions on gas resource and long-run supply curve affect results:</u>** Generally speaking, the lowest price increases on a scale of $/MMBtu per Bcfd of exports are associated with the most price-elastic representation of domestic gas supply. This is a function of both long-term supply curves (showing how much costs go up as the resource is depleted, assuming constant factor costs) and short-run drilling activity effects (representing the time it takes to build up extra natural gas wellhead deliverability and how short-term factor costs increase as drilling activity per unit of time goes up). This ICF report generally shows similar or lower export-induced natural gas price increases than the EIA and NERA reports (despite forecasting a much bigger non-export gas market)

because we assume a larger natural gas resource base and flatter long-run supply curve. On other hand, this report shows larger natural gas price increases than the Deloitte studies, due, in part, to the fact that the Deloitte modeling methodology ignores the time and effort needed to build extra wellhead natural gas deliverability and short-term factor cost effects.

- **GDP growth positively correlated with growth in LNG exports:** Any comprehensive macroeconomic modeling system based on standard economic theory should yield zero or positive GDP changes when LNG export limits are removed and economically justified trade is allowed to proceed. There are expected to be zero GDP impact when export limits are nonbinding (that is, there is no economic reason to export anyway) and an increasingly positive GDP effect as greater export volumes are modeled as being economically justified. The same conclusion would hold for any commodity whose trade restrictions are lifted - not just natural gas. This is why economists have indicated for many decades that freer trade improves the economies of both trading partners. However, while any model is expected to show positive GDP effects from lifting LNG export bans, the amount of those effects will vary based on modeling methodology and underlying assumptions.

- **The ICF estimates of GDP gains are larger than in NERA study due to differences in methodology and assumptions:** This ICF study shows larger positive GDP effects from LNG exports of a given magnitude compared to the NERA study, though both studies confirm the economic concept that removing international trade barriers (i.e., allowing LNG exports) will yield positive economic benefits to the U.S. economy. Key factors leading to a bigger GDP impact in this study are a more elastic gas supply curve, an accounting for the impacts of incremental liquids and olefins production, the representation of the price responsiveness of trade with Canada and Mexico, and different assumptions regarding how the domestic labor market and the U.S. current account trade deficit respond to LNG trade.

- **Additional liquids production contribute to GDP gains:** The economic effects of additional hydrocarbon liquids produced in association with incremental natural gas volumes are very important parts of the economic impacts of LNG export and is usually missing from other studies reviewed here. This liquids production directly adds to GDP and provides feedstocks that will likely be used in the U.S. chemical industry with additional value added economic results.

- **Assumptions on pricing of petrochemical products are important for estimation of impacts on methane feedstock users:** The key industrial uses of natural gas as a feedstock compete on a world market wherein many products are tied to the price of oil. Under the assumption used in this study of continued high oil prices ($95/bbl) this study concludes that U.S. production of methanol, ammonia, and GTLs will largely go forward even with the natural gas price increases associated with significant LNG exports. This fact combined with the expected boost in chemical production spurred by more NGLs production plus the general increase in the size of the U.S. economy, which adds to demand for all product (including chemicals), leads to the conclusion that LNG exports are expected to have a small positive net effect on chemical sector output and jobs. Other studies may not show this result because they ignore the effects of the additional NGL production and may overstate the degree to which reductions in industrial natural gas consumption are expected to be needed to rebalance the natural gas market.

- **Upstream and midstream impacts affect manufacturing industries:** The "industrial renaissance" that is frequently associated with new gas and oil drilling and completion technologies needs to be understood both as a result of lower energy prices (making U.S. manufacturing of energy-intensive goods relatively more competitive) but also as a direct stimulus to the industries that supply the upstream and midstream sectors with equipment and materials. A number of studies either do not include the impact of LNG exports (through increases in domestic gas and oil production) on the industrial sector, or understate the impact, resulting in lower economic impacts than this ICF study finds. A large boost to jobs in general and to manufacturing jobs specifically forecast in this study as a result of LNG exports come about because the oil and gas sector itself requires a significant amount of materials and equipment that would be made domestically.

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10 Appendices

Appendix A: ICF Main Results Tables

Appendix B: Price Impacts by State and Consumer Area

Appendix C: Planned Industrial Facilities

Appendix A: ICF Main Results Tables

Exhibit 10-1: Natural Gas Average Prices and Price Changes (versus Zero Exports Case)

Natural Gas Price Changes	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Natural Gas at Henry Hub	$/MMBtu	$4.47	$5.05	$5.02	$5.59	$4.48	$5.28	$5.31	$6.13	$4.87	$5.74	$5.84	$6.49
NG Price Averaged by Production by Node	$/MMBtu	$4.33	$4.83	$4.78	$5.30	$4.35	$5.06	$5.02	$5.69	$4.71	$5.46	$5.48	$6.45
NG Price Averaged by Consumption by Node	$/MMBtu	$4.54	$5.07	$5.03	$5.60	$4.56	$5.30	$5.28	$6.03	$4.92	$5.71	$5.72	$6.43
Price Chg from Zero Exports Case: NG at Henry Hub	$/MMBtu	$0.48	$0.22	$0.27	$0.31	$0.50	$0.45	$0.57	$0.85	$0.88	$0.91	$1.10	$1.21
Price Chg from Zero Exports Case: NG Price Avg by Production	$/MMBtu	$0.45	$0.15	$0.20	$0.22	$0.47	$0.38	$0.45	$0.62	$0.83	$0.79	$0.91	$1.37
Price Chg from Zero Exports Case: NG Price Avg by Consumption	$/MMBtu	$0.46	$0.17	$0.22	$0.24	$0.47	$0.39	$0.47	$0.67	$0.84	$0.80	$0.91	$1.07

Exhibit 10-2: Liquids, Petrochemical, Coal, and Electricity Volume Balances (versus Zero Exports Case)

Volume Changes	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
LNG Export Volume Changes and Supply Sources													
LNG Export Volume	MMcfd	2,074	3,602	3,602	3,602	2,404	4,966	6,279	7,412	4,385	9,491	12,486	15,102
Liquefaction Plant Inlet NG Volume	MMcfd	2,298	3,991	3,991	3,990	2,663	5,502	6,956	8,213	4,858	10,514	13,833	16,737
Increase in Upstream Volumes*	MMcfd	59	184	177	177	78	228	284	333	136	362	481	565
Wellhead Dry NG Volume	MMcfd	2,357	4,175	4,168	4,167	2,742	5,730	7,239	8,546	4,994	10,877	14,313	17,302
Growth in US Dry Gas Supply	MMcfd	1,595	3,453	3,274	3,055	1,772	4,330	5,284	5,986	3,162	7,808	10,196	11,688
Net Change in Canadian Imports to US	MMcfd	109	229	243	252	123	336	458	582	254	642	870	884
Net Change in Mexican Imports to US	MMcfd	(0)	-	0	-	-	-	0	0	(0)	-	16	772
Net Change in US Consumption	MMcfd	(653)	(494)	(651)	(860)	(847)	(1,064)	(1,497)	(1,978)	(1,578)	(2,427)	(3,232)	(3,959)
Change in Net (Supply + Demand Reductions)	MMcfd	2,357	4,175	4,168	4,167	2,742	5,730	7,239	8,546	4,994	10,877	14,313	17,302
Fuel Switch Gas to Coal by Power Generators	MMcfd	(404)	(83)	(137)	(186)	(443)	(170)	(274)	(398)	(602)	(261)	(405)	(553)
Fuel Switch Gas to Oil in Vehicles	MMcfd	(10)	(28)	(43)	(58)	(15)	(48)	(87)	(127)	(23)	(69)	(115)	(154)
Fuel Switch or Conservation by R/C Gas Users	MMcfd	(84)	(115)	(69)	(60)	(92)	(162)	(144)	(156)	(172)	(285)	(272)	(250)
Conservation by Electricity End Users	MMcfd	(33)	(185)	(285)	(385)	(128)	(386)	(580)	(795)	(267)	(719)	(1,078)	(1,455)
Reduced Industrial Gas Use from Changed Production of Ammonia, GTLs, and Methanol	MMcfd	(1)	(5)	(3)	(3)	(1)	(11)	(11)	(11)	(7)	(41)	(55)	(55)
Other Reduced Industrial Gas Use	MMcfd	(121)	(79)	(114)	(168)	(168)	(287)	(401)	(491)	(507)	(1,052)	(1,307)	(1,491)
Sum of Change in US Consumption	MMcfd	(653)	(494)	(651)	(860)	(847)	(1,064)	(1,497)	(1,978)	(1,578)	(2,427)	(3,232)	(3,959)
Liquids Volume Changes													
Ethane Recovery	bbl/d	24,467	52,973	50,229	46,878	27,188	66,428	81,070	91,838	48,510	119,791	156,435	179,316
Propane Recovery	bbl/d	16,344	35,387	33,553	31,315	18,162	44,375	54,156	61,349	32,405	80,022	104,500	119,785
Butane Recovery	bbl/d	9,525	20,622	19,554	18,249	10,584	25,860	31,560	35,752	18,884	46,633	60,899	69,806
Pentanes+ Recovery	bbl/d	7,713	16,699	15,834	14,778	8,571	20,941	25,557	28,951	15,292	37,763	49,315	56,528
Condensate & Crude Oil	bbl/d	13,781	29,838	28,293	26,405	15,315	37,417	45,665	51,730	27,324	67,475	88,116	101,004
Liquids Total	bbl/d	71,829	155,519	147,463	137,626	79,820	195,022	238,006	269,621	142,416	351,684	459,265	526,438
Liquids Total	boe/d	48,553	105,123	99,677	93,028	53,954	131,825	160,880	182,250	96,266	237,721	310,439	355,845
Oil & Gas and NGLs	boe/d	330,376	715,305	678,250	633,005	367,129	896,996	1,094,702	1,240,111	655,037	1,617,559	2,112,372	2,421,335

Volume Changes (cont.)	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Petrochemical Volume Changes													
Methanol Production	tonne/d	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)
Ammonia Production	tonne/d	(1)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(9)	(7)	(7)	(7)
GTL Production	tonne/d	(26)	(62)	(43)	(43)	(27)	(177)	(156)	(156)	(120)	(719)	(788)	(788)
Ethylene/Polyethylene Production	tonne/d	1,112	2,408	2,283	2,131	1,236	3,020	3,685	4,175	2,205	5,446	7,111	8,152
Propylene/Polypropylene Production	tonne/d	239	517	491	458	266	649	792	897	474	1,170	1,528	1,751
Coal and Electricity Volume Changes													
Coal Production	MM Short Tons/Y	9	2	3	4	10	4	6	9	14	6	9	13
Electricity Production	GWH/Y	(3,030)	(7,938)	(12,751)	(17,533)	(7,011)	(16,632)	(26,056)	(35,413)	(13,533)	(30,887)	(47,865)	(64,690)

* Includes natural gas and associated liquids (ethane, propane, butane, pentanes+, condensate, and crude oil) production

Exhibit 10-3: Effects on Value of Shipments and Value Added/GDP (versus Zero Export Case)

Shipment Value and Value Added/GDP Changes	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Related to LNG Sales													
LNG Export FOB Value of Shipments	$b/year	$7.3	$12.9	$12.9	$13.3	$8.4	$18.0	$22.8	$28.2	$15.7	$35.3	$46.7	$58.4
Foreign Contribution: Imports for Domestic Gas and LNG Production	$b/year	$0.6	$1.3	$1.3	$1.3	$0.7	$1.7	$2.1	$2.6	$1.3	$3.3	$4.3	$5.4
Foreign Contribution: Increased Can/Mix Net Gas	$b/year	$0.5	$0.4	$0.4	$0.4	$0.5	$0.6	$0.7	$0.9	$1.0	$1.3	$1.5	$3.2
LNG's Contribution to US GDP	$b/year	$6.2	$11.2	$11.3	$11.6	$7.2	$15.7	$20.0	$24.7	$13.4	$30.8	$41.0	$49.8
Related to Natural Gas Liquids Sales (other than to petrochemicals)													
Ethane Value (100% counted as polyethylene)	$b/year	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Propane Value (25% counted as polypropylene)	$b/year	$0.2	$0.5	$0.5	$0.4	$0.3	$0.6	$0.8	$0.9	$0.5	$1.1	$1.4	$1.7
Butane Value	$b/year	$0.2	$0.5	$0.5	$0.4	$0.3	$0.6	$0.7	$0.8	$0.4	$1.1	$1.4	$1.6
Pentanes+ Value	$b/year	$0.2	$0.5	$0.5	$0.5	$0.3	$0.7	$0.8	$0.9	$0.5	$1.2	$1.6	$1.8
Condensate & Crude Oil Value	$b/year	$0.5	$1.0	$0.9	$0.9	$0.5	$1.2	$1.5	$1.7	$0.9	$2.2	$2.9	$3.3
Liquids Total Value of Shipments	$b/year	$1.2	$2.5	$2.4	$2.2	$1.3	$3.1	$3.8	$4.3	$2.3	$5.6	$7.4	$8.4
Liquids Contribution to GDP (value added in US)	$b/year	$1.0	$2.1	$2.0	$1.9	$1.1	$2.6	$3.2	$3.6	$1.9	$4.7	$6.2	$7.1
Related to GTLs and Petrochemicals													
Methanol Production	$b/year	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Ammonia Production	$b/year	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
GTL Production	$b/year	$0.0	$0.0	$0.0	$0.0	$0.0	-$0.1	-$0.1	-$0.1	$0.0	-$0.3	-$0.3	-$0.3
Ethylene/Polyethylene Production	$b/year	$0.6	$1.2	$1.1	$1.1	$0.6	$1.5	$1.8	$2.1	$1.1	$2.7	$3.6	$4.1
Propylene/Polypropylene Production	$b/year	$0.1	$0.3	$0.3	$0.2	$0.1	$0.3	$0.4	$0.5	$0.2	$0.6	$0.8	$0.9
Petrochem Total Value of Shipments	$b/year	$0.7	$1.5	$1.4	$1.3	$0.7	$1.8	$2.2	$2.5	$1.3	$3.1	$4.1	$4.7
Petrochem Contribution to US GDP	$b/year	$0.6	$1.2	$1.2	$1.1	$0.6	$1.5	$1.8	$2.1	$1.1	$2.6	$3.4	$4.0

Shipment Value, Value Added, and GDP Changes (cont.)	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Related to Industrial Production Other Than GTLs and Petrochemicals													
Contribution to GDP from Reduced Industrial Production	$b/year	-$1.3	-$1.0	-$1.0	-$1.0	-$1.4	-$1.7	-$2.0	-$2.8	-$2.5	-$3.2	-$3.9	-$4.7
Spending on Natural Gas (Final Consumers Only)	$b/year	$6.8	$2.3	$3.3	$3.5	$7.0	$5.4	$6.7	$9.6	$11.9	$10.1	$11.7	$13.9
Spending on incremental conservation, fuel switching	$b/year	$0.3	$0.3	$0.3	$0.4	$0.3	$0.7	$0.9	$1.2	$0.9	$2.1	$2.5	$3.1
Increased Business Costs Passed onto Consumers	$b/year	$1.2	$0.5	$0.6	$0.7	$1.2	$1.0	$1.3	$1.9	$2.1	$2.0	$2.4	$2.9
Related to Spending Changes by Gas Consumers and Suppliers													
Lower Consumer Spending on Misc. G&S	$b/year	-$3.5	-$1.3	-$1.7	-$1.9	-$3.6	-$3.0	-$3.7	-$5.2	-$6.4	-$6.1	-$7.0	-$8.2
Reduced Business Earnings	$b/year	-$3.6	-$1.4	-$1.8	-$2.0	-$3.7	-$3.1	-$3.9	-$5.6	-$6.4	-$6.1	-$7.2	-$8.8
Net Consumer Spending on Misc. G&S and Conservation	$b/year	-$3.26	-$0.97	-$1.41	-$1.47	-$3.30	-$2.31	-$2.81	-$4.01	-$5.50	-$4.00	-$4.52	-$5.08
Net Spending Caused by Reduced Business Earnings	$b/year	-$2.4	-$0.9	-$1.2	-$1.3	-$2.4	-$2.0	-$2.6	-$3.7	-$4.2	-$4.0	-$4.7	-$5.8
Net Consumer Spending	$b/year	-$5.6	-$1.9	-$2.6	-$2.8	-$5.7	-$4.3	-$5.4	-$7.7	-$9.7	-$8.0	-$9.3	-$10.9
Domestic Consumer Goods	$b/year	-$4.7	-$1.6	-$2.2	-$2.4	-$4.8	-$3.7	-$4.5	-$6.4	-$8.2	-$6.7	-$7.8	-$9.2
Imported Consumer Goods	$b/year	-$0.9	-$0.3	-$0.4	-$0.5	-$0.9	-$0.7	-$0.9	-$1.2	-$1.6	-$1.3	-$1.5	-$1.7
Net US GDP Effect from Natural Gas Consumers	$b/year	-$5.9	-$2.0	-$2.8	-$3.1	-$6.1	-$4.7	-$5.8	-$8.3	-$10.3	-$8.8	-$10.2	-$12.2
Increased Revenue to Gas Supply Chain	$b/year	$6.8	$2.3	$3.3	$3.5	$7.0	$5.4	$6.7	$9.6	$11.9	$10.1	$11.7	$13.9
Spending of Supplier Revenue	$b/year	$4.5	$1.5	$2.1	$2.3	$4.6	$3.6	$4.4	$6.3	$7.8	$6.6	$7.7	$9.2
Domestic Spending of Supplier Revenue	$b/year	$3.8	$1.3	$1.8	$1.9	$3.9	$3.0	$3.7	$5.3	$6.6	$5.6	$6.5	$7.7
Imported Spending of Supplier Revenue	$b/year	$0.7	$0.2	$0.3	$0.4	$0.7	$0.6	$0.7	$1.0	$1.3	$1.1	$1.2	$1.5
Net GDP Effect of Spending Changes by Gas Consumers and Suppliers	$b/year	$0.2	$0.1	$0.1	$0.1	$0.2	$0.1	$0.2	$0.2	$0.3	$0.2	$0.3	$0.3

Shipment Value, Value Added, and GDP Changes (cont.)	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Related to Spending Changes by Electricity Consumers and Suppliers													
Spending on Electricity (Final Consumers Only)	$b/year	$9.6	$4.2	$5.4	$6.3	$9.6	$8.6	$11.1	$17.9	$16.9	$17.5	$21.5	$24.1
Spending on incremental conservation, fuel switching	$b/year	$0.1	$0.4	$0.6	$0.9	$0.3	$0.8	$1.3	$1.9	$0.7	$1.6	$2.5	$3.5
Increased Business Costs Passed onto Consumers	$b/year	$1.5	$0.7	$0.9	$1.1	$1.5	$1.5	$1.9	$3.1	$2.7	$3.0	$3.7	$4.3
Lower Consumer Spending on Misc. G&S	$b/year	-$5.2	-$2.5	-$3.2	-$3.8	-$5.3	-$5.0	-$6.6	-$10.6	-$9.4	-$10.2	-$12.8	-$14.7
Reduced Business Earnings	$b/year	-$4.6	-$2.1	-$2.8	-$3.3	-$4.6	-$4.4	-$5.8	-$9.2	-$8.2	-$8.9	-$11.2	-$12.8
Net Consumer Spending on Misc. G&S and Conservation	$b/year	-$5.08	-$2.05	-$2.58	-$2.92	-$4.98	-$4.18	-$5.30	-$8.68	-$8.72	-$8.62	-$10.36	-$11.28
Net Spending Caused by Reduced Business Earnings	$b/year	-$3.0	-$1.4	-$1.8	-$2.2	-$3.0	-$2.9	-$3.8	-$6.0	-$5.4	-$5.9	-$7.3	-$8.4
Net Consumer Spending		-$8.1	-$3.5	-$4.4	-$5.1	-$8.0	-$7.1	-$9.1	-$14.7	-$14.1	-$14.5	-$17.7	-$19.7
Domestic Consumer Goods	$b/year	-$6.8	-$2.9	-$3.7	-$4.3	-$6.7	-$5.9	-$7.6	-$12.4	-$11.8	-$12.2	-$14.9	-$16.6
Imported Consumer Goods	$b/year	-$1.3	-$0.6	-$0.7	-$0.8	-$1.3	-$1.1	-$1.5	-$2.4	-$2.3	-$2.3	-$2.8	-$3.2
Net US GDP Effect from Electricity Consumers	$b/year	-$8.3	-$3.6	-$4.7	-$5.4	-$8.3	-$7.4	-$9.6	-$15.5	-$14.6	-$15.2	-$18.7	-$21.0
Increased Revenue to Electricity Supply Chain		$9.6	$4.2	$5.4	$6.3	$9.6	$8.6	$11.1	$17.9	$16.9	$17.5	$21.5	$24.1
Spending of Supplier Revenue	$b/year	$6.3	$2.8	$3.5	$4.1	$6.3	$5.6	$7.3	$11.8	$11.1	$11.5	$14.2	$15.9
Domestic Spending of Supplier Revenue	$b/year	$5.3	$2.3	$3.0	$3.5	$5.3	$4.7	$6.1	$9.9	$9.3	$9.7	$11.9	$13.3
Imported Spending of Supplier Revenue	$b/year	$1.0	$0.4	$0.6	$0.7	$1.0	$0.9	$1.2	$1.9	$1.8	$1.8	$2.3	$2.5
Net GDP Effect of Spending Changes by Electricity Consumers and Suppliers	$b/year	$0.3	$0.1	$0.1	$0.2	$0.3	$0.2	$0.3	$0.5	$0.5	$0.5	$0.6	$0.6
Sum of GDP Effects													
Sum of Direct and Indirect GDP Effects (M.E.=1.0)	$b/year	$6.9	$13.7	$13.7	$13.8	$8.0	$18.5	$23.6	$28.3	$14.7	$35.6	$47.5	$57.1
Multiplier Effect at 1.3	$b/year	$2.1	$4.1	$4.1	$4.1	$2.4	$5.5	$7.1	$8.5	$4.4	$10.7	$14.3	$17.1
Multiplier Effect at 1.9	$b/year	$6.2	$12.3	$12.3	$12.4	$7.2	$16.6	$21.2	$25.5	$13.2	$32.0	$42.8	$51.3
Total GDP Change with Multiplier Effect at 1.3	$b/year	$8.9	$17.8	$17.7	$17.9	$10.4	$24.0	$30.6	$36.8	$19.1	$46.3	$61.8	$74.2
Total GDP Change with Multiplier Effect at 1.9	$b/year	$13.1	$26.0	$25.9	$26.2	$15.2	$35.1	$44.7	$53.7	$27.9	$67.6	$90.3	$108.4
Total GDP in $/MMBtu of LNG Exported M.E. at 1.0	$/MMBtu	$9.0	$10.4	$10.4	$10.5	$9.0	$10.2	$10.3	$10.5	$9.0	$10.3	$10.4	$10.4
Total GDP in $/MMBtu of LNG Exported M.E. at 1.3	$/MMBtu	$11.7	$13.5	$13.5	$13.6	$11.7	$13.2	$13.4	$13.6	$11.7	$13.4	$13.6	$13.5
Total GDP in $/MMBtu of LNG Exported M.E. at 1.9	$/MMBtu	$17.1	$19.8	$19.7	$19.9	$17.1	$19.3	$19.5	$19.9	$17.1	$19.5	$19.8	$19.7

Exhibit 10-4: Effects on Employment (versus Zero Export Case)

Employment Changes	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Activities that are the Sources of Jobs Changes													
Related to Oil, Gas, NGL Production	Direct & Indirect Jobs	24,117	52,217	49,512	46,209	26,800	65,481	79,913	90,528	47,818	118,082	154,203	176,757
Related to LNG Production	Direct & Indirect Jobs	19,600	2,084	2,049	1,996	24,063	12,348	11,428	10,045	44,809	27,847	26,862	14,374
Related to Switch to Coal	Direct & Indirect Jobs	2,557	522	865	1,178	2,800	1,071	1,731	2,515	3,807	1,652	2,563	3,493
Related to Gas Consumer Accounts	Direct & Indirect Jobs	(9,373)	(2,777)	(4,064)	(4,218)	(9,482)	(6,633)	(8,067)	(11,517)	(15,793)	(11,481)	(13,000)	(14,599)
Conservation	Direct & Indirect Jobs	2,259	2,626	2,633	3,654	2,874	5,972	7,555	10,342	7,642	17,503	21,052	26,285
Miscellaneous Consumer Goods	Direct & Indirect Jobs	(29,657)	(10,744)	(14,513)	(15,984)	(30,590)	(25,361)	(31,135)	(44,007)	(53,808)	(51,064)	(59,054)	(68,961)
Business Dividends	Direct & Indirect Jobs	(19,756)	(7,503)	(10,174)	(11,209)	(20,267)	(17,097)	(21,447)	(30,646)	(35,300)	(33,457)	(39,721)	(48,775)
Producer Revenue	Direct & Indirect Jobs	37,781	12,844	17,990	19,321	38,501	29,854	36,960	52,795	65,673	55,537	64,723	76,851
Related to Electricity Consumer Accounts	Direct & Indirect Jobs	(14,609)	(5,890)	(7,409)	(8,384)	(14,312)	(12,020)	(15,244)	(24,939)	(25,053)	(24,785)	(29,782)	(32,425)
Conservation	Direct & Indirect Jobs	1,217	3,325	5,332	7,631	2,813	7,027	11,014	15,711	5,508	13,273	20,624	29,043
Miscellaneous Consumer Goods	Direct & Indirect Jobs	(43,921)	(20,543)	(26,991)	(32,139)	(44,649)	(42,164)	(55,574)	(88,612)	(78,742)	(85,722)	(107,682)	(123,825)
Business Dividends	Direct & Indirect Jobs	(25,158)	(11,767)	(15,461)	(18,409)	(25,575)	(24,152)	(31,833)	(50,757)	(45,104)	(49,102)	(61,681)	(70,927)
Producer Revenue	Direct & Indirect Jobs	53,253	23,094	29,710	34,533	53,099	47,268	61,149	98,719	93,284	96,766	118,956	133,284
Related to Power Generation (switch to coal, lower demand)	Direct & Indirect Jobs	14,616	(1,032)	(1,223)	(1,612)	13,927	(2,274)	(2,693)	(2,818)	16,850	(6,281)	(8,923)	(11,845)
Methanol Production	Direct & Indirect Jobs	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Ammonia Production	Direct & Indirect Jobs	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
GTL Production	Direct & Indirect Jobs	(51)	(1)	(7)	(7)	(152)	(52)	(27)	(27)	(553)	(397)	(136)	(136)
Ethylene/Polyethylene Production	Direct & Indirect Jobs	3,029	1,873	1,650	1,687	3,405	3,296	3,353	3,923	5,917	6,455	6,814	7,346
Propylene/Polypropylene Production	Direct & Indirect Jobs	651	402	354	362	732	708	720	843	1,271	1,387	1,464	1,578
Other Industrial Output Changes	Direct & Indirect Jobs	(5,535)	(4,178)	(4,140)	(4,380)	(5,774)	(7,151)	(8,294)	(11,914)	(10,658)	(13,454)	(16,429)	(19,988)
Total Direct & Indirect Job Effects (M.E.=1.0)	Direct & Indirect Jobs	35,000	43,221	37,586	32,830	42,006	54,773	62,820	56,637	68,412	99,022	123,633	124,553
Jobs from Multiplier Effect = 1.3	M.E. Jobs	20,611	41,017	40,945	41,330	24,032	55,352	70,641	84,851	44,063	106,767	142,609	171,147
Jobs from Multiplier Effect = 1.9	M.E. Jobs	61,833	123,051	122,834	123,991	72,097	166,056	211,923	254,554	132,190	320,301	427,827	513,441
Total Job Changes M.E.=1.3	All Jobs	55,611	84,238	78,530	74,161	66,038	110,125	133,461	141,488	112,476	205,790	266,242	295,700
Total Job Changes M.E.=1.9	All Jobs	96,833	166,272	160,420	156,821	114,103	220,829	274,742	311,191	200,602	419,324	551,460	637,994
Total Direct & Indirect M.E. =1	$GDP/Job	220,894	319,216	366,902	423,382	200,729	338,822	378,943	522,293	221,710	359,838	384,359	459,376
Total Job Changes M.E.=1.3	$GDP/Job	148,735	211,412	226,451	241,878	148,158	217,669	229,749	260,654	158,952	224,346	231,931	250,782

Total Job Changes M.E.=1.9	$GDP/Job	116,315	156,270	161,731	166,964	121,526	158,545	162,848	172,530	127,162	160,976	163,700	169,848
Employment Changes	**Units**	**ICF Base Case**				**Middle Exports Case**				**High Exports Case**			
		2016-2020 Avg	**2021-2025 Avg**	**2026-2030 Avg**	**2031-2035 Avg**	**2016-2020 Avg**	**2021-2025 Avg**	**2026-2030 Avg**	**2031-2035 Avg**	**2016-2020 Avg**	**2021-2025 Avg**	**2026-2030 Avg**	**2031-2035 Avg**
Job Impacts by Aggregated Sector (before and after multiplier effect)													
Jobs by Aggregated Sector M.E. = 1.0													
Agriculture and forestry	Direct & Indirect Jobs	(390)	(84)	(183)	(273)	(403)	(328)	(466)	(819)	(740)	(755)	(946)	(1,213)
Oil, Gas & Other Mining	Direct & Indirect Jobs	9,455	17,167	16,506	15,651	10,521	21,863	26,926	30,806	18,056	39,324	51,551	59,360
Electricity, Gas Distribution, Water, Sewers	Direct & Indirect Jobs	13,130	(472)	(679)	(1,061)	12,553	(1,474)	(1,739)	(1,815)	15,310	(4,598)	(6,649)	(9,093)
Construction	Direct & Indirect Jobs	5,724	4,689	4,873	5,348	7,117	8,722	10,453	12,305	13,513	18,141	22,189	24,137
Manufacturing	Direct & Indirect Jobs	3,480	4,546	4,013	3,616	5,292	7,003	7,837	5,479	9,867	14,319	17,068	14,820
Wholesale and retail trade	Direct & Indirect Jobs	(3,446)	(818)	(1,681)	(2,461)	(3,559)	(2,968)	(4,203)	(7,315)	(6,522)	(6,773)	(8,502)	(10,887)
Transportation	Direct & Indirect Jobs	4,295	8,005	7,591	7,148	4,936	10,317	12,538	13,976	8,708	18,776	24,359	27,573
Services & All Other	Direct & Indirect Jobs	2,751	10,188	7,146	4,862	5,549	11,638	11,475	4,020	10,221	20,587	24,563	19,856
All Sectors for M.E. =1.0	Direct & Indirect Jobs	35,000	43,221	37,586	32,830	42,006	54,773	62,820	56,637	68,413	99,023	123,633	124,553
Jobs by Aggregated Sector M.E. = 1.3													
Agriculture and forestry	All Jobs	16	724	624	541	70	762	925	852	128	1,348	1,862	2,157
Oil, Gas & Other Mining	All Jobs	9,548	17,352	16,691	15,837	10,629	22,113	27,244	31,189	18,255	39,806	52,195	60,133
Electricity, Gas Distribution, Water, Sewers	All Jobs	13,206	(322)	(529)	(910)	12,641	(1,271)	(1,480)	(1,504)	15,471	(4,206)	(6,127)	(8,465)
Construction	All Jobs	5,888	5,015	5,199	5,677	7,308	9,163	11,015	12,980	13,863	18,991	23,324	25,499
Manufacturing	All Jobs	5,891	9,345	8,804	8,452	8,104	13,479	16,102	15,407	15,023	26,811	33,753	34,845
Wholesale and retail trade	All Jobs	118	6,274	5,398	4,685	596	6,603	8,011	7,356	1,096	11,687	16,156	18,705
Transportation	All Jobs	4,825	9,059	8,644	8,211	5,554	11,740	14,355	16,158	9,841	21,522	28,027	31,974
Services & All Other	All Jobs	16,118	36,789	33,700	31,667	21,135	47,537	57,289	59,050	38,798	89,831	117,051	130,853
All Sectors for M.E. =1.3	All Jobs	55,611	84,238	78,530	74,161	66,038	110,125	133,461	141,488	112,476	205,790	266,242	295,700

Employment Changes (cont.)	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Job Impacts by Aggregated Sector (before and after multiplier effect) (cont.)													
Jobs by Aggregated Sector M.E. = 1.9													
Agriculture and forestry	All Jobs	828	2,340	2,236	2,169	1,016	2,942	3,707	4,194	1,863	5,553	7,479	8,898
Oil, Gas & Other Mining	All Jobs	9,734	17,723	17,060	16,210	10,846	22,613	27,882	31,956	18,653	40,770	53,483	61,678
Electricity, Gas Distribution, Water, Sewers	All Jobs	13,357	(21)	(228)	(606)	12,817	(865)	(962)	(881)	15,794	(3,423)	(5,081)	(7,210)
Construction	All Jobs	6,216	5,668	5,851	6,335	7,691	10,044	12,140	14,331	14,565	20,691	25,594	28,224
Manufacturing	All Jobs	10,714	18,943	18,385	18,123	13,728	26,431	32,632	35,262	25,333	51,795	67,123	74,893
Wholesale and retail trade	All Jobs	7,245	20,458	19,557	18,978	8,907	25,743	32,438	36,698	16,333	48,608	65,470	77,888
Transportation	All Jobs	5,886	11,169	10,750	10,337	6,790	14,587	17,988	20,522	12,107	27,013	35,362	40,777
Services & All Other	All Jobs	42,853	89,992	86,810	85,276	52,307	119,333	148,917	169,110	95,953	228,318	302,029	352,847
All Sectors for M.E. =1.9	All Jobs	96,833	166,272	160,420	156,821	114,103	220,829	274,742	311,191	200,602	419,324	551,460	637,994

Employment Changes (cont.)	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Job Impacts by More Detailed Sector (before and after multiplier effect)													
Jobs by More Detailed Sector M.E. = 1.0													
Agriculture and forestry	Direct & Indirect Jobs	(390)	(84)	(183)	(273)	(403)	(328)	(466)	(819)	(740)	(755)	(946)	(1,213)
Oil and gas extraction	Direct & Indirect Jobs	2,455	5,355	5,065	4,718	2,742	6,708	8,173	9,211	4,896	12,095	15,785	18,054
Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying	Direct & Indirect Jobs	744	1,491	1,423	1,345	839	1,919	2,341	2,666	1,511	3,504	4,554	5,212
Other mining and support	Direct & Indirect Jobs	1,777	631	831	1,014	1,961	1,085	1,582	2,132	2,768	1,813	2,598	3,296
Drilling oil and gas wells	Direct & Indirect Jobs	1,108	2,395	2,271	2,120	1,232	3,004	3,666	4,154	2,196	5,416	7,073	8,108
Support activities for oil and gas operations	Direct & Indirect Jobs	3,371	7,294	6,916	6,454	3,747	9,147	11,163	12,643	6,684	16,496	21,541	24,689
Electric power generation, transmission, and distribution	Direct & Indirect Jobs	13,008	(750)	(938)	(1,300)	12,414	(1,818)	(2,156)	(2,273)	15,061	(5,217)	(7,456)	(10,007)
Natural gas distribution	Direct & Indirect Jobs	40	86	80	73	47	109	130	139	85	197	255	284
Water, sewage and other systems	Direct & Indirect Jobs	82	191	179	165	92	236	286	319	164	422	552	630
Construction, maintenance and repair	Direct & Indirect Jobs	5,724	4,689	4,873	5,348	7,117	8,722	10,453	12,305	13,513	18,141	22,189	24,137
Manufacturing: food, textiles, paper products	Direct & Indirect Jobs	(2,373)	(1,328)	(1,594)	(1,890)	(2,469)	(2,709)	(3,404)	(5,233)	(4,544)	(5,469)	(6,789)	(8,413)
Manufacturing: petroleum and petrochemicals	Direct & Indirect Jobs	2,754	427	445	481	3,413	1,953	1,921	1,817	6,395	4,405	4,466	2,944
Manufacturing: industrial gases	Direct & Indirect Jobs	(59)	(30)	(32)	(37)	(61)	(62)	(71)	(115)	(113)	(120)	(143)	(180)
Manufacturing: chemicals, rubber, glass	Direct & Indirect Jobs	(225)	109	26	(3)	(90)	68	14	(510)	(209)	214	196	(95)
Manufacturing: cement, concrete, lime, non-metal minerals	Direct & Indirect Jobs	120	294	289	282	200	413	516	454	382	846	1,086	1,098
Manufacturing: iron, steel and products	Direct & Indirect Jobs	1,018	2,700	2,559	2,366	1,208	3,293	4,061	4,330	2,133	5,978	7,871	8,833
Manufacturing: non-ferrous metals and products	Direct & Indirect Jobs	222	58	66	79	313	195	222	137	571	484	540	385
Manufacturing: tools, machinery, equipment, electronics, vehicles, airplanes	Direct & Indirect Jobs	2,023	2,317	2,254	2,338	2,779	3,852	4,579	4,599	5,252	7,982	9,840	10,249
Wholesale and retail trade	Direct & Indirect Jobs	(3,446)	(818)	(1,681)	(2,461)	(3,559)	(2,968)	(4,203)	(7,315)	(6,522)	(6,773)	(8,502)	(10,887)
Truck transportation	Direct & Indirect Jobs	3,427	6,526	6,219	5,875	3,896	8,427	10,268	11,603	6,942	15,371	19,955	22,717
Non-truck transportation, warehousing	Direct & Indirect Jobs	869	1,478	1,371	1,274	1,040	1,889	2,269	2,373	1,766	3,405	4,404	4,855
Publishing, telecommunications, information services	Direct & Indirect Jobs	28	294	207	135	89	295	294	82	152	491	606	494
Monetary, investment services, insurance	Direct & Indirect Jobs	2,661	2,413	2,126	2,035	3,519	4,012	4,436	4,051	6,489	8,066	9,560	9,217
Real estate, equipment rentals	Direct & Indirect Jobs	(374)	525	256	19	(293)	251	124	(613)	(569)	166	222	(207)
Legal and accounting services	Direct & Indirect Jobs	503	859	761	685	654	1,138	1,310	1,230	1,174	2,121	2,654	2,738
Architectural, engineering, design services	Direct & Indirect Jobs	4,331	2,719	2,911	3,319	5,430	5,757	6,819	8,017	10,353	12,326	14,780	15,596
IT, management, scientific, environmental, waste management services	Direct & Indirect Jobs	3,140	4,638	4,187	3,854	3,952	6,344	7,355	7,242	7,078	11,922	14,881	15,540

Employment Changes (cont.)	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Job Impacts by More Detailed Sector (before and after multiplier effect) (cont.)													
Jobs by More Detailed Sector M.E. = 1.0 (cont.)													
Educational, medical, hotel, food, miscellaneous services	Direct & Indirect Jobs	(7,646)	(1,743)	(3,704)	(5,514)	(7,958)	(6,688)	(9,462)	(16,486)	(14,725)	(15,408)	(19,307)	(24,732)
Postal, governmental services	Direct & Indirect Jobs	109	483	403	328	156	529	600	498	269	902	1,167	1,211
All Sectors for M.E. =1.0	Direct & Indirect Jobs	35,000	43,221	37,586	32,830	42,006	54,773	62,820	56,637	68,413	99,023	123,633	124,553
Jobs by More Detailed Sector M.E. = 1.3													
Agriculture and forestry	All Jobs	16	724	624	541	70	762	925	852	128	1,348	1,862	2,157
Oil and gas extraction	All Jobs	2,529	5,502	5,211	4,866	2,828	6,907	8,426	9,515	5,054	12,477	16,296	18,667
Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying	All Jobs	745	1,495	1,426	1,348	841	1,923	2,347	2,673	1,515	3,512	4,565	5,225
Other mining and support	All Jobs	1,790	657	857	1,040	1,976	1,120	1,627	2,186	2,796	1,881	2,688	3,404
Drilling oil and gas wells	All Jobs	1,108	2,395	2,271	2,120	1,232	3,004	3,666	4,154	2,196	5,416	7,073	8,108
Support activities for oil and gas operations	All Jobs	3,375	7,303	6,925	6,464	3,752	9,160	11,179	12,662	6,694	16,520	21,573	24,728
Electric power generation, transmission, and distribution	All Jobs	13,063	(640)	(829)	(1,190)	12,478	(1,671)	(1,968)	(2,047)	15,179	(4,933)	(7,077)	(9,552)
Natural gas distribution	All Jobs	53	113	107	100	63	145	177	195	114	268	349	397
Water, sewage and other systems	All Jobs	90	205	194	180	100	255	311	349	179	459	602	690
Construction, maintenance and repair	All Jobs	5,888	5,015	5,199	5,677	7,308	9,163	11,015	12,980	13,863	18,991	23,324	25,499
Manufacturing: food, textiles, paper products	All Jobs	(1,216)	975	706	431	(1,119)	400	564	(467)	(2,069)	528	1,221	1,199
Manufacturing: petroleum and petrochemicals	All Jobs	2,783	485	503	539	3,447	2,031	2,020	1,936	6,457	4,555	4,666	3,184
Manufacturing: industrial gases	All Jobs	(55)	(22)	(23)	(28)	(56)	(51)	(57)	(97)	(104)	(98)	(113)	(144)
Manufacturing: chemicals, rubber, glass	All Jobs	152	859	775	752	349	1,080	1,305	1,042	596	2,166	2,804	3,034
Manufacturing: cement, concrete, lime, non-metal minerals	All Jobs	147	348	343	337	232	487	610	567	441	988	1,276	1,327
Manufacturing: iron, steel and products	All Jobs	1,034	2,730	2,589	2,397	1,225	3,334	4,113	4,393	2,165	6,057	7,977	8,959
Manufacturing: non-ferrous metals and products	All Jobs	255	124	132	146	352	284	336	273	642	656	770	661
Manufacturing: tools, machinery, equipment, electronics, vehicles, airplanes	All Jobs	2,791	3,846	3,779	3,878	3,674	5,914	7,211	7,760	6,894	11,960	15,153	16,625
Wholesale and retail trade	All Jobs	118	6,274	5,398	4,685	596	6,603	8,011	7,356	1,096	11,687	16,156	18,705
Truck transportation	All Jobs	3,595	6,861	6,553	6,212	4,092	8,879	10,845	12,295	7,301	16,242	21,118	24,113
Non-truck transportation, warehousing	All Jobs	1,231	2,199	2,091	1,999	1,462	2,861	3,510	3,863	2,540	5,280	6,909	7,861
Publishing, telecommunications, information services	All Jobs	383	1,000	912	847	503	1,249	1,512	1,544	911	2,331	3,063	3,444
Monetary, investment services, insurance	All Jobs	4,344	5,762	5,469	5,410	5,481	8,532	10,204	10,979	10,087	16,784	21,204	23,190

Real estate, equipment rentals	All Jobs	682	2,624	2,352	2,134	938	3,084	3,740	3,730	1,687	5,631	7,522	8,553

Employment Changes (cont.)	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Job Impacts by More Detailed Sector (before and after multiplier effect) (cont.)													
Jobs by More Detailed Sector M.E. = 1.3 (cont.)													
Legal and accounting services	All Jobs	866	1,580	1,481	1,412	1,076	2,111	2,552	2,721	1,949	3,998	5,161	5,747
Architectural, engineering, design services	All Jobs	4,414	2,884	3,076	3,486	5,527	5,981	7,104	8,360	10,531	12,758	15,356	16,288
IT, management, scientific, environmental, waste management services	All Jobs	4,806	7,954	7,497	7,196	5,895	10,819	13,066	14,102	10,640	20,553	26,410	29,376
Educational, medical, hotel, food, miscellaneous services	All Jobs	262	13,994	12,005	10,343	1,262	14,549	17,640	16,068	2,181	25,555	35,407	40,931
Postal, governmental services	All Jobs	364	990	909	839	453	1,213	1,472	1,546	813	2,221	2,929	3,325
All Sectors for M.E. =1.3	All Jobs	55,611	84,238	78,530	74,161	66,038	110,125	133,461	141,488	112,476	205,790	266,242	295,700
Jobs by More Detailed Sector M.E. = 1.9													
Agriculture and forestry	All Jobs	828	2,340	2,236	2,169	1,016	2,942	3,707	4,194	1,863	5,553	7,479	8,898
Oil and gas extraction	All Jobs	2,677	5,796	5,505	5,162	3,000	7,303	8,932	10,123	5,370	13,242	17,317	19,893
Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying	All Jobs	749	1,501	1,432	1,354	845	1,932	2,358	2,686	1,521	3,529	4,587	5,252
Other mining and support	All Jobs	1,816	709	909	1,092	2,006	1,190	1,716	2,293	2,852	2,016	2,868	3,621
Drilling oil and gas wells	All Jobs	1,108	2,395	2,271	2,120	1,232	3,004	3,666	4,154	2,196	5,416	7,073	8,108
Support activities for oil and gas operations	All Jobs	3,385	7,321	6,943	6,482	3,763	9,184	11,210	12,700	6,714	16,567	21,637	24,804
Electric power generation, transmission, and distribution	All Jobs	13,173	(422)	(611)	(970)	12,606	(1,377)	(1,592)	(1,596)	15,413	(4,365)	(6,318)	(8,641)
Natural gas distribution	All Jobs	80	167	160	155	94	218	269	306	171	408	536	621
Water, sewage and other systems	All Jobs	104	234	222	209	117	294	361	408	210	534	702	810
Construction, maintenance and repair	All Jobs	6,216	5,668	5,851	6,335	7,691	10,044	12,140	14,331	14,565	20,691	25,594	28,224
Manufacturing: food, textiles, paper products	All Jobs	1,100	5,583	5,306	5,074	1,580	6,618	8,499	9,064	2,881	12,521	17,241	20,425
Manufacturing: petroleum and petrochemicals	All Jobs	2,841	600	617	655	3,514	2,186	2,217	2,174	6,581	4,854	5,065	3,663
Manufacturing: industrial gases	All Jobs	(47)	(5)	(6)	(11)	(46)	(28)	(28)	(62)	(85)	(53)	(54)	(73)
Manufacturing: chemicals, rubber, glass	All Jobs	905	2,359	2,272	2,264	1,228	3,104	3,888	4,145	2,208	6,070	8,019	9,293
Manufacturing: cement, concrete, lime, non-metal minerals	All Jobs	202	458	453	448	296	635	798	793	558	1,273	1,656	1,783
Manufacturing: iron, steel and products	All Jobs	1,064	2,791	2,650	2,458	1,261	3,415	4,218	4,518	2,231	6,215	8,188	9,213
Manufacturing: non-ferrous metals and products	All Jobs	321	256	264	279	429	462	563	546	783	999	1,228	1,211
Manufacturing: tools, machinery, equipment, electronics, vehicles, airplanes	All Jobs	4,327	6,902	6,830	6,958	5,465	10,039	12,475	14,083	10,178	19,915	25,780	29,379
Wholesale and retail trade	All Jobs	7,245	20,458	19,557	18,978	8,907	25,743	32,438	36,698	16,333	48,608	65,470	77,888

Employment Changes (cont.)	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Truck transportation	All Jobs	3,931	7,530	7,221	6,886	4,484	9,782	11,997	13,679	8,020	17,983	23,444	26,904
Job Impacts by More Detailed Sector (before and after multiplier effect) (cont.)													
Jobs by More Detailed Sector M.E. = 1.9													
Non-truck transportation, warehousing	All Jobs	1,955	3,639	3,529	3,451	2,306	4,805	5,991	6,843	4,087	9,030	11,918	13,873
Publishing, telecommunications, information services	All Jobs	1,093	2,414	2,323	2,272	1,331	3,157	3,947	4,469	2,430	6,011	7,979	9,343
Monetary, investment services, insurance	All Jobs	7,709	12,460	12,155	12,159	9,406	17,571	21,739	24,835	17,282	34,218	44,492	51,138
Real estate, equipment rentals	All Jobs	2,792	6,823	6,544	6,365	3,398	8,750	10,971	12,416	6,198	16,561	22,121	26,074
Legal and accounting services	All Jobs	1,590	3,022	2,921	2,865	1,921	4,057	5,036	5,704	3,498	7,752	10,174	11,764
Architectural, engineering, design services	All Jobs	4,581	3,216	3,407	3,820	5,722	6,428	7,676	9,045	10,887	13,621	16,509	17,671
IT, management, scientific, environmental, waste management services	All Jobs	8,138	14,586	14,117	13,878	9,780	19,768	24,487	27,821	17,764	37,816	49,467	57,047
Educational, medical, hotel, food, miscellaneous services	All Jobs	16,077	45,467	43,423	42,056	19,703	57,022	71,844	81,176	35,991	107,479	144,834	172,256
Postal, governmental services	All Jobs	873	2,004	1,921	1,860	1,047	2,580	3,218	3,643	1,902	4,859	6,452	7,554
All Sectors for M.E. =1.9	All Jobs	96,833	166,272	160,420	156,821	114,103	220,829	274,742	311,191	200,602	419,324	551,460	637,994

Exhibit 10-5: Effects on Government Revenues (versus Zero Exports Case)

Government Revenue Changes	Units	ICF Base Case				Middle Exports Case				High Exports Case			
		2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg
Tax Receipt Changes													
Federal Tax Rate on GDP (%)	%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%
1.3 Molt. Weighted State and Local Rate on GDP (%)	%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
1.9 Mult. Weighted State and Local Rate on GDP (%)	%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
ME 1.3 Federal Taxes on GDP Additions	($b/yr)	$1.7	$3.4	$3.4	$3.4	$2.0	$4.6	$5.9	$7.1	$3.7	$8.9	$11.9	$14.2
ME 1.9 Federal Taxes on GDP Additions	($b/yr)	$2.5	$5.0	$5.0	$5.0	$2.9	$6.7	$8.6	$10.3	$5.4	$13.0	$17.3	$20.8
ME 1.3 State/Local Taxes on GDP Additions	($b/yr)	$1.4	$2.7	$2.7	$2.8	$1.6	$3.7	$4.7	$5.7	$2.9	$7.1	$9.5	$11.4
ME 1.9 State/Local Taxes on GDP Additions	($b/yr)	$2.0	$4.0	$4.0	$4.0	$2.3	$5.4	$6.9	$8.3	$4.3	$10.4	$13.9	$16.7
ME 1.3 Total Taxes on Incremental GDP Additions	($b/yr)	$3.1	$6.2	$6.1	$6.2	$3.6	$8.3	$10.6	$12.7	$6.6	$16.0	$21.4	$25.7
ME 1.9 Total Taxes on Incremental GDP Additions	($b/yr)	$4.5	$9.0	$9.0	$9.1	$5.3	$12.1	$15.5	$18.6	$9.7	$23.4	$31.3	$37.5
Federal Royalty Changes													
Incremental HC Production Government Royalties	($b/yr)	$0.1	$0.1	$0.1	$0.1	$0.1	$0.2	$0.2	$0.3	$0.3	$0.4	$0.5	$0.7
Total Government Revenue Changes													
ME 1.3 Total Taxes on Incremental GDP Additions	($b/yr)	$3.2	$6.3	$6.3	$6.3	$3.7	$8.5	$10.8	$13.1	$6.9	$16.4	$21.9	$26.4
ME 1.9 Total Taxes on Incremental GDP Additions	($b/yr)	$4.7	$9.1	$9.1	$9.2	$5.4	$12.3	$15.7	$18.9	$9.9	$23.8	$31.8	$38.2

Appendix B: Price Impacts by State and Consumer Sector

Exhibit 10-6: Price Impacts to Residential Gas Consumers

(% increase per MMBtu consumed over Zero Exports Case)

State	ICF Base Case					Middle Exports Case					High Exports Case				
	Residential Sector Percent N.G. Price Change					Residential Sector Percent N.G. Price Change					Residential Sector Percent N.G. Price Change				
	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35
AL	5.70%	3.30%	4.20%	3.90%	4.20%	6.50%	5.00%	7.00%	9.10%	7.10%	11.80%	10.60%	13.20%	14.80%	12.80%
AZ	4.50%	2.30%	2.90%	2.50%	2.90%	5.30%	3.80%	4.80%	6.00%	5.00%	9.50%	8.30%	9.50%	10.20%	9.50%
AR	6.20%	3.40%	4.20%	3.90%	4.30%	7.00%	5.20%	7.10%	9.00%	7.20%	12.60%	11.10%	13.40%	14.50%	13.10%
CA	4.40%	2.10%	2.60%	2.40%	2.80%	5.30%	3.70%	4.50%	5.90%	4.90%	9.60%	8.40%	9.60%	10.00%	9.40%
CO	5.70%	1.60%	1.40%	1.20%	2.20%	7.10%	2.80%	2.30%	4.50%	4.00%	12.80%	5.90%	6.10%	6.40%	7.50%
CT	3.40%	2.00%	2.40%	2.20%	2.50%	4.00%	3.50%	4.30%	5.40%	4.40%	7.20%	6.70%	7.60%	8.00%	7.40%
DE	4.60%	2.60%	3.10%	2.90%	3.20%	5.40%	4.50%	5.50%	6.90%	5.70%	9.60%	8.60%	9.60%	10.40%	9.60%
DC	4.60%	2.70%	3.20%	2.90%	3.30%	5.50%	4.50%	5.60%	7.00%	5.70%	9.80%	8.70%	9.70%	10.60%	9.70%
FL	4.30%	2.50%	3.20%	3.10%	3.20%	4.80%	3.80%	5.30%	7.30%	5.50%	8.70%	8.10%	10.20%	11.50%	9.80%
GA	7.60%	4.40%	5.40%	4.90%	5.40%	8.80%	6.60%	9.00%	11.40%	9.20%	15.70%	13.90%	17.00%	18.60%	16.60%
ID	4.80%	2.00%	2.40%	2.40%	2.80%	5.90%	3.90%	4.50%	6.10%	5.10%	10.70%	9.00%	10.10%	10.60%	10.10%
IL	6.00%	3.20%	3.90%	3.20%	3.90%	7.00%	5.10%	6.50%	7.50%	6.60%	12.70%	11.00%	12.60%	11.70%	12.00%
IN	5.40%	3.00%	3.80%	3.30%	3.80%	6.40%	4.80%	6.20%	7.60%	6.30%	11.40%	10.20%	11.80%	11.90%	11.40%
IA	5.80%	2.90%	3.60%	2.80%	3.60%	6.90%	4.80%	6.10%	6.70%	6.10%	12.40%	10.50%	12.10%	11.10%	11.50%
KS	6.30%	3.10%	3.90%	3.40%	4.00%	7.40%	5.10%	6.50%	8.20%	6.90%	13.30%	11.00%	12.80%	13.60%	12.70%
KY	7.00%	3.90%	4.90%	4.50%	5.00%	8.10%	6.10%	8.30%	10.50%	8.40%	14.50%	12.80%	15.30%	16.70%	15.00%
LA	5.90%	3.40%	4.20%	4.00%	4.30%	6.70%	5.20%	7.10%	9.30%	7.30%	12.10%	11.00%	13.60%	15.00%	13.10%
ME	5.10%	2.70%	3.30%	2.90%	3.40%	6.10%	4.90%	5.90%	7.10%	6.10%	10.80%	9.40%	10.40%	10.50%	10.30%
MD	5.00%	2.90%	3.40%	3.10%	3.50%	6.00%	4.80%	5.90%	7.50%	6.10%	10.60%	9.30%	10.30%	11.20%	10.40%
MA	4.00%	2.20%	2.70%	2.40%	2.80%	4.80%	3.90%	4.80%	5.90%	4.90%	8.50%	7.60%	8.40%	8.70%	8.30%
MI	6.00%	3.30%	4.00%	3.30%	4.00%	7.10%	5.40%	6.80%	7.90%	6.90%	12.70%	11.20%	12.80%	12.10%	12.20%
MN	6.00%	3.00%	3.70%	2.70%	3.60%	7.10%	5.00%	6.30%	6.60%	6.20%	12.80%	10.70%	12.40%	10.70%	11.60%
MS	6.80%	3.70%	4.80%	4.50%	4.80%	7.70%	5.70%	8.10%	10.60%	8.20%	13.80%	12.20%	15.30%	17.10%	14.90%
MO	5.90%	3.20%	3.90%	3.60%	4.10%	7.00%	5.10%	6.60%	8.30%	6.90%	12.60%	10.80%	12.70%	13.60%	12.50%
MT	5.60%	2.50%	3.10%	3.00%	3.40%	6.70%	4.60%	5.60%	7.60%	6.20%	12.20%	10.00%	11.00%	11.40%	11.10%
NE	6.30%	3.20%	3.90%	3.70%	4.10%	7.60%	5.30%	6.60%	8.50%	7.10%	13.80%	11.70%	13.60%	14.40%	13.50%
NV	4.90%	2.10%	2.60%	2.60%	2.90%	6.00%	4.00%	4.70%	6.30%	5.30%	11.00%	9.40%	10.60%	11.30%	10.60%
NH	4.80%	2.60%	3.20%	2.80%	3.30%	5.70%	4.60%	5.70%	6.90%	5.80%	10.20%	9.00%	10.00%	10.10%	9.80%

State	ICF Base Case Residential Sector Percent N.G. Price Change					Middle Exports Case Residential Sector Percent N.G. Price Change					High Exports Case Residential Sector Percent N.G. Price Change				
	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35
NJ	5.00%	2.80%	3.50%	3.20%	3.50%	6.00%	5.00%	6.20%	7.80%	6.40%	10.60%	9.50%	10.70%	11.60%	10.70%
NM	6.30%	2.90%	3.60%	3.20%	3.80%	7.40%	4.90%	6.30%	8.00%	6.70%	13.50%	11.00%	12.60%	13.40%	12.70%
NY	3.70%	2.10%	2.50%	2.40%	2.60%	4.50%	3.80%	4.60%	5.80%	4.70%	7.90%	7.20%	8.00%	8.60%	8.00%
NC	5.50%	3.40%	4.10%	3.70%	4.10%	6.30%	5.20%	7.00%	8.60%	6.90%	11.40%	10.70%	12.50%	13.00%	12.00%
ND	5.70%	2.50%	3.20%	2.80%	3.40%	6.80%	4.60%	5.70%	7.20%	6.10%	12.30%	10.10%	11.20%	10.80%	11.00%
OH	7.20%	4.20%	4.80%	4.30%	5.00%	8.20%	6.60%	8.40%	10.30%	8.50%	14.80%	13.40%	15.00%	15.30%	14.70%
OK	5.70%	3.00%	3.70%	3.30%	3.80%	6.70%	4.80%	6.20%	7.90%	6.50%	12.00%	10.30%	12.10%	13.00%	11.90%
OR	3.50%	1.60%	2.10%	0.40%	1.80%	4.20%	3.00%	3.80%	1.90%	3.10%	7.60%	6.50%	7.40%	2.50%	5.80%
PA	5.00%	2.80%	3.40%	3.10%	3.50%	5.90%	5.00%	6.20%	7.70%	6.30%	10.50%	9.50%	10.70%	11.60%	10.70%
RI	4.00%	2.20%	2.70%	2.40%	2.80%	4.70%	3.90%	4.80%	5.90%	4.90%	8.40%	7.60%	8.50%	8.70%	8.30%
SC	5.90%	3.50%	4.50%	4.30%	4.50%	6.70%	5.30%	7.50%	9.80%	7.60%	12.10%	11.20%	14.10%	16.40%	13.80%
SD	5.50%	2.70%	3.40%	2.70%	3.40%	6.50%	4.60%	5.90%	6.50%	5.90%	11.80%	10.00%	11.70%	10.70%	11.00%
TN	6.40%	3.60%	4.50%	4.20%	4.50%	7.30%	5.60%	7.60%	9.70%	7.70%	13.10%	11.80%	14.10%	15.50%	13.80%
TX	6.60%	3.60%	4.50%	4.20%	4.60%	7.60%	5.60%	7.60%	9.80%	7.80%	13.70%	11.90%	14.90%	9.80%	12.30%
UT	5.10%	2.00%	2.20%	1.90%	2.60%	6.30%	4.20%	4.60%	5.80%	5.20%	11.50%	9.80%	11.20%	11.90%	11.20%
VT	5.20%	2.80%	3.40%	3.00%	3.50%	6.10%	4.90%	6.10%	7.30%	6.20%	10.90%	9.60%	10.70%	10.80%	10.50%
VA	4.80%	2.80%	3.40%	3.10%	3.40%	5.70%	4.60%	5.80%	7.30%	6.00%	10.20%	9.00%	10.20%	11.00%	10.20%
WA	4.20%	1.90%	2.40%	1.30%	2.30%	5.00%	3.40%	4.20%	2.00%	3.50%	9.00%	7.40%	8.20%	1.50%	6.20%
WV	5.20%	2.90%	3.50%	3.20%	3.60%	6.10%	4.90%	6.20%	7.90%	6.40%	10.90%	9.60%	10.90%	11.50%	10.80%
WI	5.30%	2.90%	3.50%	2.80%	3.50%	6.30%	4.70%	5.90%	6.60%	5.90%	11.30%	9.90%	11.30%	10.10%	10.60%
WY	6.00%	2.30%	2.50%	2.10%	3.00%	7.50%	4.80%	5.20%	6.50%	5.90%	13.60%	11.30%	12.80%	13.40%	12.80%
US	5.30%	2.90%	3.50%	3.10%	3.60%	6.30%	4.80%	6.00%	7.40%	6.20%	11.20%	9.90%	11.40%	11.30%	11.00%

Exhibit 10-7: Price Impacts to Commercial Gas Consumers

(% increase per MMBtu consumed over Zero Exports Case)

State	ICF Base Case: Commercial Sector Percent N.G. Price Change					Middle Exports Case: Commercial Sector Percent N.G. Price Change					High Exports Case: Commercial Sector Percent N.G. Price Change				
	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35
AL	6.00%	3.50%	4.30%	4.10%	4.40%	6.80%	5.30%	7.30%	9.70%	7.50%	12.30%	11.20%	14.00%	15.40%	13.50%
AZ	5.20%	2.70%	3.30%	2.90%	3.40%	6.20%	4.50%	5.70%	7.20%	6.00%	11.20%	9.90%	11.40%	11.80%	11.10%
AR	6.50%	3.60%	4.50%	4.20%	4.60%	7.40%	5.60%	7.50%	9.70%	7.80%	13.30%	12.00%	14.50%	15.40%	14.00%
CA	4.30%	2.00%	2.50%	2.40%	2.70%	5.20%	3.70%	4.40%	5.80%	4.80%	9.30%	8.40%	9.50%	9.60%	9.20%
CO	6.30%	1.70%	1.40%	1.10%	2.30%	7.80%	3.00%	2.30%	4.70%	4.30%	14.10%	6.10%	6.30%	6.60%	7.90%
CT	4.80%	2.70%	3.30%	2.90%	3.30%	5.80%	4.70%	5.90%	7.20%	6.00%	10.20%	9.20%	10.30%	10.50%	10.10%
DE	5.40%	3.00%	3.60%	3.30%	3.70%	6.40%	5.30%	6.40%	8.10%	6.70%	11.40%	10.20%	11.10%	11.60%	11.10%
DC	4.90%	2.80%	3.30%	3.10%	3.50%	5.80%	4.70%	5.80%	7.50%	6.00%	10.20%	9.20%	10.20%	10.80%	10.10%
FL	5.60%	3.30%	4.10%	4.00%	4.20%	6.40%	5.10%	7.10%	9.80%	7.30%	11.40%	10.90%	13.90%	15.10%	13.10%
GA	7.60%	4.40%	5.30%	5.00%	5.40%	8.70%	6.70%	9.00%	11.60%	9.20%	15.60%	14.10%	17.20%	18.50%	16.60%
ID	5.20%	2.10%	2.60%	2.60%	3.00%	6.40%	4.20%	4.90%	6.50%	5.50%	11.70%	9.80%	10.90%	11.30%	10.90%
IL	6.00%	3.20%	3.90%	3.30%	3.90%	7.10%	5.20%	6.60%	7.70%	6.70%	12.80%	11.00%	12.70%	12.00%	12.10%
IN	6.10%	3.30%	4.20%	3.60%	4.20%	7.10%	5.30%	6.90%	8.40%	7.00%	12.80%	11.20%	13.10%	13.10%	12.60%
IA	6.40%	3.20%	4.00%	3.10%	4.00%	7.70%	5.30%	6.80%	7.50%	6.80%	13.90%	11.60%	13.40%	12.30%	12.70%
KS	7.20%	3.50%	4.30%	3.80%	4.50%	8.50%	5.80%	7.30%	9.20%	7.80%	15.40%	12.60%	14.40%	14.70%	14.30%
KY	7.40%	4.20%	5.00%	4.70%	5.20%	8.50%	6.50%	8.60%	10.90%	8.80%	15.30%	13.50%	15.90%	16.90%	15.60%
LA	6.00%	3.50%	4.30%	4.10%	4.40%	6.80%	5.40%	7.30%	9.80%	7.50%	12.20%	11.50%	14.10%	15.30%	13.50%
ME	5.40%	2.90%	3.40%	3.00%	3.60%	6.40%	5.10%	6.20%	7.50%	6.40%	11.40%	9.90%	10.90%	10.90%	10.80%
MD	5.40%	3.10%	3.60%	3.40%	3.80%	6.40%	5.10%	6.30%	8.10%	6.60%	11.30%	10.10%	11.20%	11.80%	11.10%
MA	5.20%	2.80%	3.40%	3.00%	3.50%	6.20%	4.90%	6.00%	7.30%	6.20%	10.90%	9.60%	10.60%	10.60%	10.40%
MI	5.70%	3.20%	3.90%	3.20%	3.90%	6.80%	5.10%	6.60%	7.70%	6.60%	12.10%	10.80%	12.40%	11.80%	11.80%
MN	6.80%	3.30%	4.10%	3.20%	4.10%	8.10%	5.60%	7.00%	7.80%	7.10%	14.50%	12.10%	13.80%	12.10%	13.00%
MS	7.20%	4.00%	5.10%	4.80%	5.10%	8.20%	6.10%	8.60%	11.40%	8.80%	14.70%	13.10%	16.50%	18.00%	15.80%
MO	6.30%	3.40%	4.20%	3.80%	4.30%	7.40%	5.40%	7.00%	8.80%	7.30%	13.40%	11.60%	13.50%	14.30%	13.30%
MT	5.80%	2.50%	3.20%	3.10%	3.50%	6.90%	4.70%	5.70%	7.80%	6.40%	12.50%	10.30%	11.30%	11.60%	11.40%
NE	6.20%	3.10%	3.80%	3.60%	4.00%	7.50%	5.30%	6.40%	8.40%	7.00%	13.50%	11.60%	13.50%	14.10%	13.20%
NV	5.00%	2.20%	2.70%	2.70%	3.00%	6.20%	4.30%	4.90%	6.60%	5.50%	11.30%	9.90%	11.10%	11.50%	11.00%
NH	5.20%	2.80%	3.40%	3.00%	3.50%	6.20%	4.90%	6.00%	7.30%	6.20%	11.00%	9.60%	10.60%	10.60%	10.40%
NJ	7.20%	3.90%	4.60%	4.20%	4.80%	8.60%	6.90%	8.30%	10.20%	8.60%	15.30%	13.20%	14.40%	14.50%	14.30%
NM	7.40%	3.40%	4.20%	3.70%	4.50%	8.80%	6.00%	7.40%	9.40%	8.00%	15.90%	13.30%	15.10%	15.00%	14.80%

State	ICF Base Case					Middle Exports Case					High Exports Case				
	Commercial Sector Percent N.G. Price Change					Commercial Sector Percent N.G. Price Change					Commercial Sector Percent N.G. Price Change				
	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35
NY	4.90%	2.70%	3.20%	3.00%	3.40%	5.90%	4.80%	5.90%	7.40%	6.10%	10.40%	9.40%	10.30%	10.50%	10.20%
NC	6.30%	3.90%	4.60%	4.10%	4.60%	7.30%	5.90%	7.70%	9.50%	7.80%	13.00%	12.20%	14.00%	14.00%	13.40%
ND	6.30%	2.80%	3.40%	3.00%	3.70%	7.60%	5.00%	6.20%	7.80%	6.70%	13.60%	11.10%	12.30%	11.70%	12.10%
OH	7.30%	4.20%	4.90%	4.40%	5.00%	8.30%	6.60%	8.60%	10.50%	8.70%	15.00%	13.50%	15.30%	15.70%	15.00%
OK	6.50%	3.30%	4.10%	3.60%	4.20%	7.60%	5.40%	6.90%	8.70%	7.20%	13.70%	11.60%	13.50%	14.00%	13.20%
OR	4.30%	2.00%	2.50%	0.80%	2.20%	5.20%	3.60%	4.50%	2.80%	3.90%	9.40%	7.90%	8.90%	3.80%	7.30%
PA	5.40%	2.90%	3.60%	3.30%	3.70%	6.40%	5.30%	6.60%	8.20%	6.80%	11.30%	10.20%	11.40%	12.10%	11.30%
RI	4.60%	2.50%	3.00%	2.70%	3.10%	5.40%	4.40%	5.50%	6.70%	5.60%	9.60%	8.60%	9.60%	9.70%	9.40%
SC	6.50%	3.90%	4.80%	4.50%	4.80%	7.50%	6.00%	8.10%	10.70%	8.30%	13.40%	12.60%	15.30%	16.90%	14.80%
SD	6.40%	3.10%	4.00%	3.10%	4.00%	7.60%	5.30%	6.70%	7.40%	6.80%	13.80%	11.60%	13.40%	12.20%	12.70%
TN	6.60%	3.70%	4.60%	4.30%	4.70%	7.50%	5.80%	7.80%	9.90%	7.90%	13.50%	12.10%	14.40%	15.50%	14.00%
TX	8.10%	4.40%	5.30%	4.90%	5.50%	9.30%	6.90%	9.00%	11.70%	9.40%	16.60%	14.60%	18.10%	12.90%	15.30%
UT	5.90%	2.30%	2.50%	2.20%	3.00%	7.30%	4.80%	5.20%	6.60%	5.90%	13.40%	11.30%	12.90%	13.50%	12.80%
VT	5.50%	2.90%	3.60%	3.20%	3.70%	6.50%	5.20%	6.50%	7.90%	6.60%	11.50%	10.20%	11.30%	11.40%	11.10%
VA	5.80%	3.30%	3.90%	3.60%	4.10%	6.80%	5.40%	6.80%	8.70%	7.10%	12.10%	10.80%	12.00%	12.60%	11.90%
WA	4.70%	2.10%	2.60%	1.90%	2.70%	5.70%	3.80%	4.60%	3.10%	4.20%	10.20%	8.30%	9.00%	2.70%	7.20%
WV	5.90%	3.20%	3.80%	3.50%	3.90%	6.80%	5.40%	6.80%	8.60%	7.00%	12.20%	10.70%	11.90%	12.10%	11.70%
WI	6.20%	3.20%	4.00%	3.20%	4.00%	7.30%	5.30%	6.80%	7.40%	6.70%	13.20%	11.30%	13.00%	11.50%	12.10%
WY	6.20%	2.40%	2.60%	2.20%	3.10%	7.80%	5.00%	5.40%	6.80%	6.20%	14.20%	11.80%	13.40%	13.90%	13.30%
US	5.90%	3.10%	3.80%	3.30%	3.90%	6.90%	5.20%	6.60%	8.10%	6.80%	12.40%	10.90%	12.40%	12.10%	12.00%

Exhibit 10-8: Price Impacts to Industrial Gas Consumers

(% increase per MMBtu consumed over Zero Exports Case)

State	ICF Base Case					Middle Exports Case					High Exports Case				
	Industrial Sector Percent N.G. Price Change					Industrial Sector Percent N.G. Price Change					Industrial Sector Percent N.G. Price Change				
	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35
AL	8.00%	4.70%	5.60%	5.30%	5.70%	9.10%	7.20%	9.70%	13.10%	10.10%	16.30%	15.30%	18.90%	19.70%	17.80%
AZ	7.10%	3.60%	4.30%	3.80%	4.50%	8.50%	6.20%	7.60%	9.30%	8.00%	15.30%	13.50%	15.20%	14.60%	14.60%
AR	8.50%	4.60%	5.30%	4.90%	5.60%	9.80%	7.30%	9.10%	11.70%	9.70%	17.40%	15.50%	18.10%	17.60%	17.20%
CA	7.60%	3.50%	4.10%	3.80%	4.50%	9.10%	6.20%	7.40%	9.40%	8.10%	16.50%	13.90%	15.40%	14.70%	15.00%
CO	7.70%	1.80%	0.80%	0.60%	2.30%	9.70%	2.80%	0.80%	4.80%	4.20%	17.20%	5.00%	4.50%	5.20%	7.20%
CT	6.50%	3.40%	4.00%	3.60%	4.20%	7.80%	6.00%	7.30%	8.90%	7.60%	13.70%	11.80%	12.80%	11.90%	12.50%
DE	6.00%	3.30%	3.80%	3.50%	4.00%	7.20%	5.70%	6.80%	8.60%	7.20%	12.60%	11.10%	11.90%	11.40%	11.70%
DC															
FL	6.80%	4.10%	5.10%	4.80%	5.10%	7.60%	6.30%	8.70%	12.10%	9.00%	13.70%	13.40%	17.20%	18.20%	15.90%
GA	7.60%	4.60%	5.40%	5.10%	5.50%	8.70%	7.10%	9.30%	12.80%	9.80%	15.60%	14.90%	18.30%	19.10%	17.30%
ID	6.50%	2.70%	3.20%	3.20%	3.70%	8.10%	5.30%	6.10%	8.30%	7.00%	14.60%	12.20%	13.40%	13.00%	13.20%
IL	7.20%	3.60%	4.30%	3.80%	4.50%	8.50%	6.10%	7.50%	9.00%	7.80%	15.30%	13.00%	14.70%	13.20%	13.90%
IN	7.40%	3.90%	4.70%	4.30%	4.90%	8.60%	6.40%	8.10%	10.30%	8.50%	15.30%	13.40%	15.30%	14.80%	14.70%
IA	6.60%	3.30%	3.90%	3.40%	4.10%	7.90%	5.60%	6.80%	8.30%	7.20%	14.10%	12.20%	13.70%	12.30%	13.00%
KS	8.70%	4.30%	5.10%	4.50%	5.40%	10.20%	7.20%	8.80%	11.20%	9.40%	18.30%	15.40%	17.30%	16.50%	16.80%
KY	8.40%	4.70%	5.40%	5.10%	5.70%	9.70%	7.50%	9.50%	12.00%	9.90%	17.20%	15.40%	17.50%	17.20%	16.90%
LA	11.10%	6.20%	7.10%	6.50%	7.40%	12.60%	9.50%	12.30%	16.10%	13.00%	22.40%	20.10%	24.20%	24.30%	23.00%
ME	6.90%	3.60%	4.10%	3.70%	4.40%	8.30%	6.30%	7.50%	9.10%	7.90%	14.60%	12.40%	13.30%	12.20%	13.00%
MD	6.40%	3.70%	4.20%	3.90%	4.40%	7.60%	5.90%	7.40%	9.50%	7.70%	13.50%	11.80%	13.10%	12.80%	12.80%
MA	6.30%	3.30%	3.80%	3.40%	4.00%	7.50%	5.80%	6.90%	8.50%	7.30%	13.20%	11.40%	12.20%	11.30%	11.90%
MI	6.80%	3.60%	4.30%	3.60%	4.40%	8.10%	6.00%	7.50%	8.80%	7.70%	14.50%	12.60%	14.20%	12.90%	13.50%
MN	6.30%	3.20%	3.80%	3.40%	4.00%	7.40%	5.40%	6.60%	8.40%	7.00%	13.30%	11.50%	12.90%	12.00%	12.40%
MS	8.00%	4.60%	5.70%	5.30%	5.80%	9.10%	7.20%	9.70%	13.20%	10.10%	16.30%	15.20%	19.10%	19.80%	17.90%
MO	7.10%	3.70%	4.30%	4.00%	4.60%	8.30%	6.00%	7.40%	9.40%	7.90%	14.90%	12.90%	14.50%	14.10%	14.10%
MT	6.00%	2.70%	3.20%	3.30%	3.60%	7.20%	5.00%	6.00%	8.40%	6.70%	13.00%	11.00%	11.90%	11.70%	11.90%
NE	7.30%	3.70%	4.30%	4.00%	4.60%	8.70%	6.20%	7.50%	9.70%	8.10%	15.60%	13.60%	15.30%	14.80%	14.80%
NV	4.60%	2.10%	2.50%	2.50%	2.80%	5.70%	4.00%	4.60%	6.20%	5.20%	10.30%	9.20%	10.30%	10.40%	10.10%
NH	6.10%	3.20%	3.80%	3.40%	4.00%	7.30%	5.60%	6.90%	8.50%	7.10%	12.80%	11.10%	12.10%	11.30%	11.70%
NJ	7.40%	4.00%	4.60%	4.20%	4.90%	8.80%	6.90%	8.40%	10.40%	8.80%	15.60%	13.50%	14.60%	13.80%	14.30%
NM	9.00%	4.10%	4.90%	4.30%	5.20%	10.70%	7.20%	8.70%	10.90%	9.40%	19.30%	15.90%	17.90%	16.80%	17.30%

State	ICF Base Case					Middle Exports Case					High Exports Case				
	Industrial Sector Percent N.G. Price Change					Industrial Sector Percent N.G. Price Change					Industrial Sector Percent N.G. Price Change				
	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35
NY	6.30%	3.30%	3.80%	3.50%	4.10%	7.50%	5.90%	7.00%	8.70%	7.40%	13.20%	11.60%	12.30%	11.60%	12.10%
NC	8.30%	5.00%	5.40%	4.80%	5.60%	9.50%	7.70%	9.30%	11.30%	9.60%	17.00%	16.00%	16.80%	15.50%	16.20%
ND	6.00%	2.70%	3.30%	3.30%	3.70%	7.20%	5.00%	6.00%	8.30%	6.70%	13.00%	11.00%	12.00%	11.70%	11.90%
OH	8.80%	4.80%	5.40%	4.80%	5.70%	10.20%	7.80%	9.60%	11.70%	10.00%	18.20%	15.90%	17.40%	16.50%	16.90%
OK	7.80%	4.00%	4.70%	4.20%	5.00%	9.10%	6.60%	8.10%	10.30%	8.60%	16.40%	14.10%	16.00%	15.30%	15.40%
OR	5.20%	2.30%	2.90%	2.10%	3.00%	6.30%	4.30%	5.30%	5.80%	5.40%	11.30%	9.50%	10.50%	7.90%	9.60%
PA	7.80%	4.10%	4.80%	4.40%	5.10%	9.40%	7.40%	8.90%	11.00%	9.30%	16.50%	14.40%	15.50%	14.70%	15.20%
RI	7.40%	3.80%	4.50%	4.00%	4.70%	8.90%	6.80%	8.20%	9.80%	8.50%	15.70%	13.40%	14.30%	13.10%	14.00%
SC	8.70%	5.20%	6.00%	5.50%	6.20%	9.90%	8.00%	10.40%	14.00%	10.90%	17.80%	16.70%	20.20%	20.90%	19.20%
SD	6.90%	3.50%	4.10%	3.70%	4.40%	8.20%	5.90%	7.30%	9.10%	7.70%	14.60%	12.60%	14.20%	13.20%	13.60%
TN	7.60%	4.40%	5.00%	4.70%	5.30%	8.80%	6.90%	8.70%	11.20%	9.10%	15.60%	14.20%	16.20%	16.10%	15.60%
TX	11.00%	5.80%	6.70%	6.20%	7.10%	12.60%	9.10%	11.60%	15.10%	12.40%	22.50%	19.30%	24.00%	17.10%	20.40%
UT	6.80%	2.60%	2.70%	2.30%	3.30%	8.50%	5.50%	5.90%	7.30%	6.70%	15.40%	13.10%	14.60%	14.20%	14.30%
VT	6.60%	3.50%	4.10%	3.80%	4.30%	7.80%	6.00%	7.40%	9.20%	7.70%	13.80%	11.90%	13.10%	12.30%	12.70%
VA	7.40%	4.10%	4.70%	4.20%	4.90%	8.70%	6.70%	8.10%	10.10%	8.50%	15.50%	13.30%	14.40%	13.70%	14.10%
WA	7.30%	3.00%	3.60%	3.80%	4.20%	8.80%	5.50%	6.50%	6.80%	6.80%	15.70%	12.20%	12.80%	7.40%	11.50%
WV	10.90%	5.50%	6.30%	5.50%	6.70%	12.70%	9.30%	11.40%	13.70%	11.90%	22.60%	18.50%	20.00%	18.10%	19.50%
WI	7.10%	3.70%	4.40%	4.00%	4.60%	8.30%	6.10%	7.60%	9.60%	8.00%	14.90%	12.80%	14.50%	13.80%	14.00%
WY	6.30%	2.40%	2.50%	2.20%	3.10%	7.90%	5.20%	5.50%	6.80%	6.30%	14.40%	12.30%	13.70%	13.20%	13.30%
US	8.50%	4.60%	5.40%	5.00%	5.70%	9.90%	7.60%	9.50%	12.20%	10.00%	17.90%	16.20%	19.10%	17.30%	17.60%

Exhibit 10-9: Price Impacts to Power Sector Gas Consumers

(% increase per MMBtu consumed over Zero Exports Case)

State	ICF Base Case: Power Sector Percent N.G. Price Change					Middle Exports Case: Power Sector Percent N.G. Price Change					High Exports Case: Power Sector Percent N.G. Price Change				
	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35
AL	9.80%	5.40%	6.60%	6.00%	6.70%	11.20%	8.30%	11.40%	15.10%	11.90%	20.00%	17.80%	22.40%	22.90%	21.00%
AZ	9.10%	4.00%	5.30%	4.30%	5.40%	10.90%	7.10%	9.20%	10.60%	9.50%	19.50%	15.90%	18.50%	16.60%	17.50%
AR	11.20%	5.70%	6.70%	6.00%	7.00%	12.90%	9.00%	11.50%	14.20%	12.10%	22.90%	19.20%	22.80%	21.40%	21.50%
CA	9.10%	4.00%	4.70%	4.30%	5.20%	10.90%	7.10%	8.40%	10.60%	9.30%	19.60%	16.00%	17.70%	16.70%	17.30%
CO	8.20%	1.80%	0.80%	0.50%	2.30%	10.30%	2.90%	0.70%	5.00%	4.40%	18.10%	5.00%	4.70%	5.20%	7.40%
CT	6.50%	3.40%	4.10%	3.70%	4.30%	7.80%	5.90%	7.40%	9.00%	7.60%	13.60%	11.70%	12.90%	12.30%	12.60%
DE	9.70%	5.00%	6.00%	5.20%	6.20%	11.60%	8.60%	10.60%	12.70%	11.00%	20.50%	16.80%	18.20%	17.20%	18.00%
DC															
FL	9.20%	5.10%	6.40%	6.00%	6.50%	10.40%	7.90%	11.20%	15.10%	11.50%	18.50%	17.00%	22.20%	22.80%	20.50%
GA	10.00%	5.50%	6.60%	5.90%	6.70%	11.40%	8.50%	11.40%	15.10%	11.90%	20.40%	18.00%	22.20%	22.90%	21.10%
ID	8.30%	3.10%	4.10%	3.90%	4.60%	10.10%	6.10%	7.50%	9.90%	8.40%	18.30%	13.90%	15.30%	15.30%	15.50%
IL	10.90%	4.80%	5.90%	4.90%	6.20%	13.00%	8.30%	10.30%	12.00%	10.80%	23.20%	17.80%	19.80%	17.30%	19.10%
IN	9.50%	4.70%	5.60%	5.00%	5.90%	11.10%	7.70%	9.60%	11.80%	10.20%	19.70%	16.10%	17.90%	16.90%	17.50%
IA	7.00%	3.10%	4.00%	3.60%	4.20%	8.30%	5.50%	7.00%	8.50%	7.30%	14.90%	11.90%	13.70%	12.50%	13.10%
KS	10.40%	4.80%	5.80%	5.00%	6.10%	12.30%	8.20%	10.10%	12.30%	10.80%	22.00%	17.50%	19.60%	18.00%	19.00%
KY	9.20%	4.80%	5.80%	5.20%	6.00%	10.50%	7.60%	10.10%	12.30%	10.30%	18.70%	15.80%	18.10%	17.60%	17.50%
LA	11.20%	6.10%	7.20%	6.60%	7.40%	12.90%	9.50%	12.50%	16.60%	13.20%	22.90%	20.10%	24.80%	24.90%	23.40%
ME	8.70%	4.30%	4.70%	4.10%	5.20%	10.30%	7.40%	8.40%	10.00%	9.00%	18.10%	14.70%	14.70%	13.60%	15.00%
MD	9.90%	5.00%	5.90%	5.20%	6.20%	11.70%	8.10%	10.30%	12.50%	10.70%	21.10%	16.40%	17.90%	16.80%	17.80%
MA	9.60%	4.60%	5.50%	4.70%	5.80%	11.40%	8.10%	9.90%	11.50%	10.30%	20.10%	16.10%	17.30%	15.70%	17.00%
MI	11.20%	5.20%	6.10%	5.00%	6.40%	13.40%	8.80%	10.60%	12.20%	11.20%	24.10%	18.70%	20.20%	17.50%	19.60%
MN	8.80%	3.80%	4.90%	4.20%	5.10%	10.40%	6.70%	8.40%	10.20%	8.90%	18.70%	14.30%	16.10%	14.60%	15.70%
MS	9.90%	5.50%	6.80%	6.10%	6.80%	11.20%	8.60%	11.80%	15.90%	12.30%	20.00%	18.40%	23.40%	23.80%	21.70%
MO	10.60%	4.90%	6.00%	5.40%	6.40%	12.50%	8.10%	10.30%	12.60%	10.90%	22.40%	17.30%	19.80%	18.50%	19.20%
MT	5.90%	2.50%	3.30%	3.20%	3.60%	7.10%	4.70%	5.90%	8.30%	6.60%	12.80%	10.40%	11.50%	12.20%	11.70%
NE	10.20%	4.60%	5.80%	5.00%	6.00%	12.00%	7.70%	9.90%	12.00%	10.40%	21.50%	16.60%	18.80%	17.60%	18.40%
NV	9.50%	4.00%	4.50%	4.40%	5.20%	11.70%	7.60%	8.50%	11.00%	9.70%	21.10%	17.30%	18.90%	17.70%	18.50%
NH	7.90%	3.90%	4.70%	4.10%	4.90%	9.30%	6.80%	8.40%	10.00%	8.70%	16.50%	13.50%	14.70%	13.60%	14.40%
NJ	9.50%	4.80%	5.80%	5.10%	6.00%	11.40%	8.40%	10.40%	12.40%	10.80%	20.20%	16.50%	17.80%	16.80%	17.60%
NM	9.40%	4.10%	5.20%	4.50%	5.50%	11.20%	7.40%	9.30%	11.40%	9.90%	20.10%	16.50%	19.00%	17.30%	18.10%

State	ICF Base Case					Middle Exports Case					High Exports Case				
	Power Sector Percent N.G. Price Change					Power Sector Percent N.G. Price Change					Power Sector Percent N.G. Price Change				
	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35	2016-2020	2021-2025	2026-2030	2031-2035	Avg 2016-35
NY	9.10%	4.30%	5.20%	4.60%	5.50%	10.80%	7.60%	9.40%	11.20%	9.80%	19.10%	15.20%	16.50%	15.10%	16.20%
NC	10.80%	6.00%	6.50%	5.70%	6.90%	12.40%	9.20%	11.30%	13.30%	11.70%	22.30%	19.60%	20.10%	18.00%	19.70%
ND	7.20%	2.90%	3.70%	3.50%	4.10%	8.60%	5.40%	6.70%	9.00%	7.50%	15.40%	12.00%	13.20%	13.30%	13.30%
OH	9.30%	4.80%	5.60%	5.00%	5.90%	10.90%	8.00%	9.90%	12.10%	10.30%	19.40%	16.30%	17.80%	16.80%	17.40%
OK	9.40%	4.50%	5.40%	4.80%	5.70%	11.10%	7.50%	9.40%	11.50%	9.90%	19.80%	16.20%	18.40%	17.10%	17.70%
OR	6.90%	2.60%	3.40%	1.90%	3.40%	8.20%	4.90%	6.30%	5.50%	6.10%	14.50%	11.10%	12.30%	7.40%	11.00%
PA	8.80%	4.40%	5.30%	4.80%	5.60%	10.60%	7.90%	9.80%	11.90%	10.10%	18.70%	15.40%	16.80%	16.10%	16.60%
RI	9.10%	4.50%	5.30%	4.60%	5.60%	10.80%	7.80%	9.50%	11.20%	9.90%	19.10%	15.40%	16.70%	15.20%	16.30%
SC	10.90%	6.00%	7.00%	6.30%	7.20%	12.40%	9.20%	12.30%	16.40%	13.00%	22.40%	19.70%	24.20%	24.70%	23.00%
SD	8.10%	3.60%	4.60%	4.00%	4.80%	9.60%	6.30%	7.90%	9.70%	8.40%	17.30%	13.40%	15.20%	14.00%	14.80%
TN	10.80%	5.60%	6.70%	5.90%	6.90%	12.50%	8.90%	11.50%	14.00%	11.90%	22.30%	18.20%	21.00%	20.20%	20.30%
TX	11.20%	5.70%	6.80%	6.20%	7.10%	12.90%	9.10%	11.90%	15.50%	12.60%	23.00%	19.50%	25.00%	18.70%	21.30%
UT	9.40%	3.10%	3.50%	2.80%	4.20%	11.60%	6.60%	7.30%	8.90%	8.40%	20.80%	15.80%	17.80%	17.70%	17.90%
VT	8.00%	4.00%	4.70%	4.20%	5.00%	9.40%	6.80%	8.50%	10.20%	8.80%	16.60%	13.50%	14.90%	13.90%	14.60%
VA	9.70%	5.00%	5.80%	5.20%	6.10%	11.40%	8.10%	10.20%	12.40%	10.60%	20.50%	16.30%	17.80%	16.80%	17.60%
WA	6.60%	2.50%	3.20%	3.60%	3.80%	7.90%	4.70%	5.70%	6.20%	6.00%	14.00%	10.50%	11.10%	6.80%	10.20%
WV	9.40%	4.80%	5.50%	4.90%	5.90%	11.00%	8.10%	10.00%	12.10%	10.40%	19.60%	16.00%	17.40%	16.10%	17.00%
WI	8.80%	4.10%	5.00%	4.40%	5.30%	10.40%	7.00%	8.80%	10.60%	9.20%	18.50%	14.90%	16.60%	15.10%	16.00%
WY	6.60%	2.20%	2.50%	2.10%	3.10%	8.20%	4.90%	5.30%	6.70%	6.20%	14.80%	11.70%	13.10%	13.40%	13.20%
US	9.70%	4.90%	5.80%	5.30%	6.10%	11.30%	8.00%	10.30%	13.10%	10.80%	20.10%	16.80%	20.00%	18.80%	18.90%

Appendix C: Planned Industrial Facilities

Exhibit 10-10: Publicly-Announced New/Restarted Nitrogen Fertilizer (Ammonia) Plants

Company	Project type/output	Output Volume (1,000 Metric Tonnes per year)	Natural Gas Consumption (MMBtu/d)	Location	Start-up Year	Status*
CF Industries	Expansion, UAN	150	12,000	Woodward County, OK	2011	C
LSB Industries	Expansion, UAN	255	21,000	Pryor County, OK	2012	C
PCS Nitrogen	Reopened, Ammonia	547	45,000	Geismar County, LA	2012	C
Dyno Nobel	New Ammonia	750	62,000	Waggaman, LA	2015 Q4	Q
Iowa Fertilizer Company	New, Ammonia, UAN, etc.	2,000	165,000	Lee County, IA	2015 Q4	U
Mosaic	New Ammonia	365	30,000	St. James Parish, LA	2016 Q1	F
CHS Inc.	New Ammonia	730	60,000	Jamestown, ND	2016 Q4	F
TOTAL		**4,798**	**395,000**	*Status: Proposed (Q), FEED (F), Permitted (P), Under Construction (U), Completed (C)		

Exhibit 10-11: Publicly-Announced New Methanol Plants

Company	Output Volume (1,000 Metric Tonnes per year)	Natural Gas Consumption (MMBtu/d)	Location	Start-up Year	Status*
Celanese Corporation	1,300	124,658	Clear Lake, TX	2015	F
Methanex	850	81,507	Geismar, LA	2014	U
Methanex	888	85,103	Geismar, LA	2015+	Q
LyondellBasell	780	74,795	Channelview, TX	2013	F
Orascom	750	71,918	Beaumont, TX	2012	C
Total	**4,568**	**437,979**	*Status: Proposed (Q), FEED (F), Permitted (P), Under Construction (U), Completed (C)		

Exhibit 10-12: Publicly-Announced New GTL Plants

Company	Output Volume (1,000 Metric Tonnes per year)	Natural Gas Consumption (MMBtu/d)	Location	Start-up Year
Sasol	4,000	800,000	Calcasieu Parish, LA	2017/2018
Royal Dutch Shell	7,000	1,400,000	LA or TX	2020+
Total	**11,000**	**2,200,000**		

Exhibit 10-13: Publicly-Announced New Direct-Reduced Iron (DRI) Plants

Company	Output Volume (Million Metric Tonnes per year)	Natural Gas Consumption (MMcfd)	Location	Start-up Year	Status*
Nucor	2.5	65.9	Convent, LA	2013 Q3	U
Voestalpine	2.0	52.7	Corpus Christi, TX	2016 Q1	F
Essar	1.8	47.4	Nashwauk, MN	2015	U
North Star BlueScope	1.0	26.4	Delta, OH	(?)	Q
Total	**7.3**	**192.4**	*Status: Proposed (Q), FEED (F), Permitted (P), Under Construction (U), Completed (C)		

Exhibit 10-14: Publicly-Announced Proposed New Ethylene Plants

Company	Output Volume (metric tonnes/yr)	Ethane Consumption (bbl/d)	Location	Start-up Year
Dow Chemical	1,500,000	95,000	Freeport, TX	2017
ExxonMobil	1,500,000	90,000	Baytown, TX	2016
Chevron Phillips Chemical	1,500,000	90,000	Baytown, TX	2017
Formosa Plastics	800,000	48,000	Point Comfort, TX	2016
Shell Chemical	1 - 2 million	60,000+	Monaca, PA	2017
Sasol	1,000,000	60,000	Lake Charles, LA	2013
Aither Chemical	400,000	24,000	PA/OH/WV	2016
Braskem	1 - 2 million	60,000+	TX/LA	?
Indorama Ventures	1 - 2 million	60,000+	TX/LA	2017
SABIC	1 - 2 million	60,000+	TX/LA	?
Occidental Petroleum	1 - 2 million	60,000+	TX/LA	?
Mexichem	1 - 2 million	60,000+	TX/LA	?
Total	**12.7 – 18.7 million**	**767,000 – 1,127,000**		

Exhibit 10-15: Publicly-Announced Proposed Ethylene Feedstock Conversions

Company	Output Volume (metric tonnes/yr)	Ethane Consumption (bbl/d)	Location	Start-up Year
LyondellBasell	226,800	13,608	Channelview, TX	2012
Dow Chemical	*700,000*	32,000	Plaquemine, LA	2014
Westlake	*195,000*	11,700	Calvert City, KY	2014
BASF-FINA	*1,000,000*	60,000	Port Arthur, TX	~2015
Dow Chemical	*850,000*	43,000	Freeport, TX	2016
Total	**2.97 million**	**160,308**		

Exhibit 10-16: Publicly-Announced Proposed Ethylene Expansions

Westlake	110,000	6,600	Lake Charles, LA	2012
INEOS	115,000	6,900	Chocolate Bayou, TX	2013
Williams	272,000	17,778	Geismar, LA	2013
Westlake	115,000	6,900	Lake Charles, LA	2014
LyondellBasell	244,500	14,670	Laporte, TX	2014
Total	**856,500**	**52,848**		

Exhibit 10-17: Publicly-Announced Proposed Propane Dehydration (PDH) Plants

Company	Output Volume (metric tonnes/yr)	Propane Consumption (bbls/day)	Location	Start-up Year
PetroLogistics	640,000	30,000	Houston, TX	2010
Dow Chemical	750,000	35,000	Freeport, TX	2015
Enterprise	685,000	35,000	Chambers County, TX	2015
Williams	455,000	21,000	Edmonton, AB	2016
Formosa Plastics	800,000	37,000	Point Comfort, TX	2016
Dow Chemical	550,000	25,000	Freeport, TX (?)	2018
Total	**3.9 million**	**183,000**		

Exhibit 10-18: Publicly-Announced Proposed Liquefied Petroleum Gas (LPG) Export Terminals

Company	LPG Export Capacity (bbls/day)	Location	Start-up Year
Enterprise	3,300	Houston Ship Channel, TX	2012
Enterprise	115,000	Houston Ship Channel, TX	2012
Targa	120,000	Galena Park, TX	2013
Vitol	96,000	Beaumont, TX	2013
ConocoPhillips	420,000	Baytown, TX	2014
Sunoco Logistics	40,000	Marcus Hook, PA	2014
Occidental	75,000	Corpus Christi, TX	2017
Total	**869,300**		