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April 3, 2015

BY HAND DELIVERY

Larine A. Moore
U.S. Department of Energy
FE-34
P.O. Box 44375
Washington, DC 20026-4375

Re: Cameron LNG, LLC Application for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries

Dear Ms. Moore:

Enclosed please find the Application of Cameron LNG, LLC for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement countries and a check for $50.00 in remittance of the filing fee. Please contact me if you have any questions regarding this submission.

Sincerely,

Brett A. Snyder

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Enclosure

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

Cameron LNG, LLC	)))	**FE Docket No. 15- 67 -LNG**

APPLICATION OF CAMERON LNG, LLC FOR LONG-TERM, MULTI-CONTRACT AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE AGREEMENT COUNTRIES

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April 3, 2015

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

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APPLICATION OF CAMERON LNG, LLC FOR LONG-TERM, MULTI-CONTRACT AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE AGREEMENT COUNTRIES

Pursuant to Section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the regulations of the Department of Energy ("DOE"),[2] Cameron LNG, LLC ("Cameron LNG") submits this application ("Application") to DOE, Office of Fossil Energy ("DOE/FE") for a long-term, multi-contract authorization to export up to 152 billion cubic feet ("Bcf") per year (approximately equal to 2.95 million metric tons per annum ("MTPA")) of liquefied natural gas ("LNG") produced from domestic sources. Cameron LNG seeks this authorization for a 20-year period commencing on the earlier of the date of first commercial export or seven years from the date the requested authorization is granted by DOE/FE.

In this Application, Cameron LNG seeks authorization to export LNG from the Cameron LNG terminal in Cameron and Calcasieu Parishes, Louisiana ("Cameron Terminal") to any country (i) with which the United States does not have a Free Trade Agreement ("FTA") requiring national treatment for trade in natural gas (ii) that has or will develop the capacity to import LNG delivered by ocean-going carrier, and (iii) with which trade is not prohibited by U.S. law or policy. Cameron LNG is requesting this authorization both on its own behalf and as agent

1 15 U.S.C. § 717b (2010).
2 10 C.F.R. Part 590 (2014).

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for other parties who hold title to the LNG at the time of export.[3] As discussed more fully below, under the DOE Office of Fossil Energy's ("DOE/FE") new rules regarding the processing of non-FTA applications, because this project has already undergone a full review under the National Environmental Policy Act in FE Docket No. 11-162-LNG and FERC Docket No. CP13-25-000, no further environmental review is warranted, and therefore this Application is ready for final DOE/FE action immediately.

In support of this Application, Cameron LNG respectfully states the following:

I. COMMUNICATIONS AND CORRESPONDENCE

Any notices, pleadings or other communications concerning this Application should be addressed to:

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3 Cameron LNG has also separately filed for authorization to export an additional 152 Bcf per year to FTA countries. *See Cameron LNG, LLC*, FE Docket No. 14-204-LNG.

The contact for any reports required in connection with the requested authorization is as follows:

John O'Leary
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II. DESCRIPTION OF THE APPLICANT

The exact legal name of Cameron LNG is Cameron LNG, LLC. Cameron LNG is a limited liability company organized under the laws of Delaware. Cameron LNG is an indirect subsidiary of Sempra Energy, GDF SUEZ S.A., Mitsui & Co., Ltd., Mitsubishi Corporation, and Nippon Yusen Kabushiki Kaisha.[4] Cameron LNG's executive offices are located at 2925 Briarpark Drive, Suite 1000, Houston, Texas 77042. Cameron LNG is currently engaged in the business of owning and operating the Cameron Terminal in Cameron and Calcasieu Parishes, Louisiana.

Cameron LNG holds two export authorizations from DOE/FE. First, Cameron LNG holds an authorization to export up to 620 Bcf per year of LNG, which is equivalent to approximately 12 MTPA, to any country with which the United States has, or in the future may enter into, an FTA requiring national treatment for trade in natural gas. DOE/FE granted Cameron LNG that authorization in Order No. 3059, dated January 17, 2012.[5] Second, Cameron LNG holds an authorization to export up to 620 Bcf per year of LNG to any country that has developed or in the future develops the capacity to import LNG via ocean-going carrier and with which the United States does not have an FTA requiring national treatment for trade in natural

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4 *See Cameron LNG, LLC*, Order No. 3452, FE Docket No. 14-001-CIC (June 27, 2014).

5 *Cameron LNG, LLC*, DOE/FE Order No. 3059 (Jan. 17, 2012).

gas and LNG. DOE/FE granted Cameron LNG that authorization on September 10, 2014 in Order No. 3391-A.[6] Cameron LNG's FTA and non-FTA export authorizations are not additive to one another.

On December 18, 2014, Cameron LNG filed an application in FE Docket No. 14-204-LNG to export an additional 152 Bcf per year to FTA countries.[7] That application is pending. This application is for corresponding authorization to export to non-FTA countries.

On February 23, 2015, Cameron LNG submitted an application in FE Docket No. 15-36-LNG to export an additional 515 Bcf of LNG per year to FTA countries, explaining that it is planning to construct two additional liquefaction trains (Trains 4 and 5).[8] That application is pending.

III. DESCRIPTION OF CAMERON LNG TERMINAL AND LIQUEFACTION PROJECT

In this Application, Cameron LNG seeks a long-term authorization to export additional volumes of domestically produced LNG from the Cameron Terminal. Cameron LNG is constructing and developing natural gas processing and liquefaction facilities to receive and liquefy domestic natural gas at the Cameron Terminal for export to foreign markets (the "Liquefaction Project"). The Liquefaction Project facilities will be integrated into the existing Cameron Terminal facilities. Cameron LNG hereby incorporates by reference the description of the Cameron Terminal and the Liquefaction Project set forth in Cameron LNG's application in FE Docket No. 11-162-LNG[9] and in DOE/FE Order No. 3391-A.[10]

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6 *Cameron LNG, LLC*, DOE/FE Order No. 3391-A, FE Docket No. 11-162-LNG (Sept. 10, 2014).

7 Application of Cameron LNG, LLC for Long-Term Authorization to Export Liquefied Natural Gas to Free Trade Agreement Countries, *Cameron LNG, LLC*, FE Docket No. 14-204-LNG (Dec. 18, 2014). That application also relies on the NEPA analysis adopted in FE Docket No. 11-162-LNG and FERC Docket No. CP13-25-000.

8 Application of Cameron LNG, LLC for Long-Term Authorization to Export Liquefied Natural Gas to Free Trade Agreement Countries at 4, *Cameron LNG, LLC*, FE Docket No. 15-13-LNG (Feb. 23, 2015).

9 *See* Application at 3-5, *Cameron LNG, LLC*, FE Docket No. 11-162-LNG (Dec. 21, 2011).

10 *See* Order No. 3391-A at 10-15.

On June 19, 2014, the Federal Energy Regulatory Commission ("FERC") issued an order authorizing Cameron LNG to site, construct, and operate the initial liquefaction and export facilities ("FERC Order") at the Cameron Terminal.[11] As authorized by FERC, the aggregate maximum liquefaction capacity of the Liquefaction Project facilities under optimal conditions is 3,981 cubic meters per hour, which equates to approximately 14.95 MTPA.[12]

IV. AUTHORIZATION REQUESTED

In this Application, Cameron LNG requests long-term, multi-contract authorization to export up to 152 Bcf per year (approximately 2.95 MTPA) of domestically produced LNG from the Cameron Terminal. This authorization is requested for a 20-year term commencing on the earlier of the date of first commercial export or seven years from the date on which the authorization is granted by the DOE. Cameron LNG seeks authorization to export LNG to any country (i) with which the United States does not have an FTA requiring the national treatment for trade in natural gas, (ii) that has or will develop the capacity to import LNG delivered by ocean-going carrier, (iii) with which trade is not prohibited by U.S. law or policy. The authorization sought herein is independent of the authorization Cameron LNG sought and received from DOE/FE in Order No. 3391-A.

The volume of exported LNG for which Cameron LNG seeks authorization in this Application is incremental to the 620 Bcf per year authorized by DOE/FE in DOE/FE Order No. 3391-A in FE Docket No. 11-162-LNG.[13] In the FERC Order, FERC approved Cameron LNG's Liquefaction Project with a maximum capacity of 14.95 MTPA.[14] In its application in FE Docket No. 11-162-LNG, Cameron LNG sought and received authorization to export up to 12

11 *Cameron LNG, LLC*, 147 FERC ¶ 61,230 (2014).
12 *Id.* at P 8.
13 *Cameron LNG, LLC*, DOE/FE Order No. 3391-A, FE Docket No. 11-162-LNG (Sept. 10, 2014).
14 *Cameron LNG, LLC*, 147 FERC ¶ 61,230 at P 8 (2014).

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MTPA or 620 Bcf per year, *i.e.*, 2.95 MTPA less than the maximum capacity of the facility. In this Application, Cameron LNG seeks authorization to export the remaining 2.95 MTPA, or 152 Bcf per year using the same conversion factor. If this Application is approved, Cameron LNG would have an aggregate non-FTA export authorization of 772 Bcf per year, which is equivalent to 14.95 MTPA. This would enable Cameron LNG to export LNG at a volume that equates to the peak capacity of the Liquefaction Project facilities at optimal conditions, which FERC determined is the appropriate measure of liquefaction capacity to be set forth in an application to be considered by FERC under Section 3 of the NGA.[15]

Cameron LNG requests authorization to export LNG on its own behalf (by holding title to the LNG at the time of export) or by acting as agent for others who themselves hold title to the LNG at the point of export. In those instances in which Cameron LNG exports LNG on its own behalf, Cameron LNG will either take title to the gas at a point upstream of the Cameron Terminal or will purchase LNG from a customer of the Cameron Terminal prior to export. In other cases, Cameron LNG will act as agent for the customers of the Cameron Terminal without taking title to facilitate the export of the customer's LNG. To ensure that all exports are permitted and lawful under U.S. laws and policies, Cameron LNG will comply with all DOE/FE requirements for an exporter or agent.

In Order No. 3391-A, DOE/FE approved Cameron LNG's proposal to register each LNG title holder for whom Cameron LNG seeks to export LNG as agent.[16] As approved therein, the registration is to include a written statement by the title holder acknowledging and agreeing to comply with all applicable requirements included in its export authorization. DOE/FE also approved Cameron LNG's proposal to file under seal with DOE/FE any relevant long-term

[15] *Sabine Pass Liquefaction, LLC*, 146 FERC ¶ 61,117 at P 12 (2014).

[16] *Cameron LNG, LLC*, DOE Order No. 3391-A at Section XIII.K (2014).

commercial agreements that it reached with the LNG title holders on whose behalf the exports were performed. Cameron LNG seeks the same agent authority as that provided in Order No. 3391-A.

Cameron LNG also requests that DOE/FE not require the submission with this Application of transaction-specific information, pursuant to Section 590.202(b) of the DOE's regulations.[17] DOE/FE has previously found that, given the stage of development for these projects, it was appropriate for the applicants to submit such information "when practicable" (*i.e.*, when the contracts reflecting such information are executed). In Order No. 3391-A, DOE/FE required Cameron LNG to submit transaction-specific information within 30 days of the execution of the applicable agreements. The submittal of the transaction-specific information identified in section 590.202(b) at the time the applicable agreements are executed is appropriate in light of current market conditions and contracting practices.

The long-term authorization requested in this application is necessary in order to enable Cameron LNG to export the maximum production capacity of the Liquefaction Project facilities for the full length of time for which Cameron LNG is already authorized to export LNG from the facilities.

Cameron LNG submits that this Application is ready for final action and, therefore, warrants a public interest evaluation at this time. In August 2014, DOE revised its procedures for considering LNG export applications.[18] DOE explained that it "will no longer act in the published order of precedence, but will act on applications in the order they become ready for final action." DOE stated that an application is ready for final action when a NEPA review

[17] *See, e.g.*, *Cameron LNG, LLC*, DOE Order No. 3391 (2014); *Sabine Pass Liquefaction, LLC*, DOE Order No. 2833 (2010). The transaction-specific information described in the regulations includes long-term supply agreements and long-term export agreements.

[18] *Procedures for Liquefied Natural Gas Export Decisions*, 79 Fed. Reg. 48132, 48135 (Aug. 15, 2014).

process is complete and when DOE has sufficient information on which to base a public interest determination. DOE determined that an application requiring an Environmental Impact Statement ("EIS") is "ready for final action" "30 days after publication of a Final EIS."[19] As explained below in Part VI, the volume of exports requested in this Application has already been subject to complete NEPA review. FERC staff issued an EIS on April 30, 2014, which considered the environmental impact of Liquefaction Project facilities with a capacity of 14.95 MTPA, and DOE/FE adopted that analysis in Order No. 3391-A.[20] Accordingly, Cameron LNG submits that the authorization sought herein is "ready for final action" and requests that DOE/FE review the requested authorization promptly.

V. PUBLIC INTEREST ANALYSIS

A. Applicable Legal Standard

The DOE/FE has the power to approve or deny applications to export LNG pursuant to specific authorization in Section 3 of the Natural Gas Act.[21] The general standard for review of export applications to non-FTA countries is established by Section 3(a), which provides that:

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

19 *Id.*

20 *Cameron LNG, LLC*, DOE Order No. 3391-A at 72-84 (2014).

21 15 U.S.C. § 717b. This authority is delegated to the Assistant Secretary for FE pursuant to Redelegation Order No. 00.002.04D (Nov. 6, 2007).

In applying this statute, DOE/FE has consistently found that Section 3(a) creates a rebuttable presumption that proposed exports of natural gas are in the public interest. For that reason, DOE/FE must grant the export application unless opponents of an export authorization establish an affirmative showing based on evidence in the record that the export would be inconsistent with the public interest.[22]

DOE has issued a set of Policy Guidelines setting out the criteria that it employs in evaluating applications for natural gas imports.[23] While nominally applicable to natural gas import cases, the DOE has found that the same policies apply to natural gas export applications.[24] The goals of the Policy Guidelines are to minimize federal control and involvement in energy markets and to promote a balanced and diverse energy resource system. The Guidelines provide that:

> The market, not government, should determine the price and other contract terms of imported [or exported] natural gas. The federal government's primary responsibility in authorizing imports [or exports] will be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[25]

Historically, the DOE has also been guided by DOE Delegation Order No. 0204-111 ("Delegation Order"). The Delegation Order stated that exports of natural gas are to be regulated primarily "based on a consideration of the domestic need for the gas to be exported and such other matters [found] in the circumstances of a particular case to be appropriate."[26]

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22 Order No. 1473 at 13 n.42 (citing *Panhandle Producers and Royalty Owners Ass'n v. ERA*, 822 F.2d 1105, 1111 (D.C. Cir. 1987)); *see also Sabine Pass Liquefaction, LLC*, DOE Order No. 2961 (2011).

23 *Policy Guidelines and Delegation Orders Relating to the Regulation of Imported Natural Gas,* 49 Fed. Reg. 6684 (Feb. 22, 1984) ("Policy Guidelines").

24 *Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE Order No. 1473 (1999).

25 *Id.*

26 *Department of Energy*, Delegation Order No. 0204-111 (Feb. 22, 1982).

Both the Policy Guidelines and the principles underlying the Delegation Order presume that competitive markets largely free of governmentally-imposed restrictions will benefit the public:

> The government, while ensuring that the public interest is adequately protected, should not interfere with buyers' and sellers' negotiation of the commercial aspects of import [and export] arrangements. The thrust of this policy is to allow the commercial parties to structure more freely their trade arrangements, tailoring them to the markets served.[27]

Although the Delegation Order is no longer in effect, DOE has noted in recent orders that its "review of export applications in decisions under current delegated authority has continued to focus on the domestic need for the natural gas proposed to be exported; whether the proposed exports pose a threat to the security of domestic natural gas supplies; and any other issue determined to be appropriate, including whether the arrangement is consistent with DOE's policy of promoting competition in the marketplace by allowing commercial parties to freely negotiate their own trade arrangements."[28]

In granting recent authorizations, DOE has indicated that the following additional considerations are relevant in determining whether proposed exports are in the public interest: whether the exports will be beneficial for regional economies, the extent to which the exports will foster competition and mitigate trade imbalances with the foreign recipient nations, and the degree to which the exports would encourage efficient management of U.S. domestic natural resources.[29] As demonstrated below, the export of domestically produced LNG as proposed in this Application satisfies each of these considerations.

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27 Policy Guidelines at 6685.

28 *Sabine Pass Liquefaction, LLC*, Order No. 2961 (2011).

29 *See, e.g., Cameron LNG, LLC*, Order No. 3391 at 125-135 (2014); *Sabine Pass Liquefaction, LLC*, Order No. 2961 at 34-38 (2011)

B. Domestic Need for Gas to be Exported

Drilling productivity gains and extraction technology enhancements have enabled rapid growth in supplies from unconventional gas-bearing shale formations in the United States. Natural gas proved resources in the United States increased by 10% (31.3 Tcf) in 2013 and reached a high of 354 Tcf.[30] In light of these substantial resource additions and the comparatively minor increases in domestic natural gas demand, there are more than sufficient natural gas resources to accommodate both domestic demand and the exports proposed in this Application throughout the 20-year term of the requested authorization.

As U.S. natural gas resources and production have increased, U.S. natural gas prices have fallen significantly. The annual average Henry Hub spot price for natural gas exceeded $5.00 per MMBtu from 2003 to 2008, but has remained below that level in the years since, falling from $8.86 per MMBtu in 2008 to $4.39 per MMBtu in 2014.[31] In its most recently calculated reference case, the EIA estimates that the annual average wellhead price for natural gas, stated in 2009 dollars, will remain under $5.00 per MMBtu through at least 2024, and rise to only $6.49 per MMBtu by 2035.[32] Prices for natural gas in the U.S. market are now substantially below those of most other major gas-consuming countries. While U.S. gas prices have fallen, prices for LNG in other major gas consuming countries have actually increased over the past decade, moving generally in line with world oil prices. The result is that domestic gas can be liquefied and exported to foreign markets on a very competitive basis. As discussed below, such exports

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[30] U.S. Crude Oil and Natural Gas Proved Reserves, 2013 at 10 (Dec. 2014), *available at* http://www.eia.gov/naturalgas/crudeoilreserves/pdf/uscrudeoil.pdf.

[31] *See* Energy Information Administration, *Natural Gas Spot and Futures Prices, available at* http://www.eia.gov/dnav/ng/ng_pri_fut_s1_a.htm.

[32] Energy Information Administration, *2014 Annual Energy Outlook, Reference Case* (Apr. 2014).

can be expected to have only a nominal effect on U.S. prices. These effects are well within the range of historical prices during the last 18 years.[33]

1. U.S. Natural Gas Supply

Domestic gas production and reserves collectively provide for an abundant domestic supply of natural gas. Domestic gas production has been on a significant upward trend in recent years as rapid growth in supply from unconventional discoveries has more than compensated for declines in production from conventional onshore and offshore fields. The EIA estimates that U.S. dry gas production was 2,197,834 Mcf in August 2014, a 5.8% increase compared to August 2013 dry production of 2,091,626 Mcf.[34] Increased drilling productivity in certain prolific shale gas formations, including the Marcellus and Haynesville shales, has enabled domestic production to continue expanding despite a reduction in the number of wells drilled.

In its *Annual Energy Outlook 2014*, the EIA noted that U.S. production of dry natural gas is about 11% higher than in the prior year's analysis, "primarily reflecting the continued growth in shale gas production."[35] The EIA expects this increase in shale gas production to continue through 2040, when it will comprise approximately half of total domestic dry production.[36] The EIA has significantly increased its estimate of shale gas production in 2015, 2020, 2025, 2030, and 2040 compared with EIA's projections in the *Annual Energy Outlook 2013*. For example, the EIA revised its projection of shale gas production in 2015 from 8.85 Tcf to 9.96 Tcf. Similarly, the EIA revised its projection of shale gas production in 2040 from 16.70 Tcf to 19.82 Tcf.[37] In addition, these projections are substantially higher than the 7.0 Tcf for 2015 and the

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[33] Energy Information Administration, *Henry Hub Natural Gas Spot Price, available at* http://www.eia.gov/dnav/ng/hist/rngwhhda.htm.
[34] Energy Information Administration *Natural Gas Gross Withdrawals and Production, available at* http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm
[35] Energy Information Administration, *Annual Energy Outlook 2014.*
[36] Energy Information Administration, *Annual Energy Outlook 2014.*
[37] *See* Energy Information Administration, *Annual Energy Outlook 2014* at Table A-14, p 143 (Apr. 2014).

12.0 Tcf for 2035 that were reflected in the *Annual Energy Outlook 2011*, which DOE/FE considered when granting Cameron LNG authorization to export LNG in Order No. 3391.

The growth in shale gas production has been accompanied by an increase in the overall volume of U.S. natural gas resources. For example, in 2014, the EIA estimated the technically recoverable natural gas resources in the United States at 2,266 Tcf.[38]

This growth in U.S. natural gas resources is reflected in other recent academic and industry evaluations. The Potential Gas Committee in April 2013 determined that the United States possesses future available gas supply of 2,688.5 Tcf, which is an increase of over 500 Tcf from the Potential Gas Committee's projections in April 2011. Of that, the Potential Gas Committee projects 1,073 Tcf to be derived from shale gas production, which is 40% of the total available supply.[39]

These studies and reports indicate that the United States has a 90-year to an over 100-year inventory of recoverable natural gas resources. This inventory is expected to continue growing as further advancements in drilling technology are deployed to exploit additional shale gas development opportunities.

2. U.S. Natural Gas Demand

Since the turn of the century, growth in the demand for natural gas in the United States has been minimal. According to data published by the EIA, natural gas demand in 2013 was only 11% higher than in 2000.[40] In its *Annual Energy Outlook 2014*, the EIA estimated long-

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38 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2014*, Table 9.2, *available at* http://www.eia.gov/forecasts/aeo/assumptions/pdf/oil_gas.pdf (2014).

39 U.S. Potential Gas Committee 2010, "The Potential Supply of Natural Gas in the United States," *available at* http://www.potentialgas.org/PGC%20Press%20Conf%202011%20slides.pdf (Apr. 2011). The PGC consists of members, advisors and representatives from the exploration, production, pipeline and distribution sectors of the natural gas industry, together with observers from various professional and industry trade associations, research organizations, and government agencies, and from Canada and Mexico. The PGC functions independently but with the guidance and administrative support of the Potential Gas Agency at the Colorado School of Mines.

40 Energy Information Administration, *Natural Gas Consumption by End Use available at*

term annual U.S. demand growth of only 0.8%, with demand expected to reach 31.6 Tcf in 2040 (compared to 24.3 Tcf of actual demand in 2011).[41]

The consensus of estimates by the EIA and academic and industry experts is that the United States has between 2,000 and 2,384 Tcf of recoverable natural gas resources. Even at 100% utilization, the Liquefaction Project, implementing both the authorization sought herein combined with the authorization granted in Order No. 3391-A, would result in maximum natural gas requirements of 15.44 Tcf over the 20-year term of the requested authorization. This represents only 0.64% to 0.77% of total estimated recoverable U.S. natural gas resources.

3. Impact on Domestic Gas Prices

In October 2014, EIA issued a report analyzing the effect of increased levels of LNG exports on domestic energy markets.[42] The report was issued in response to a DOE/FE May 29, 2014 request in which DOE/FE requested EIA to assess how specified scenarios of increased exports of LNG could affect domestic energy markets, focusing on consumption, production, and prices.

EIA's report analyzed LNG exports under five different circumstances. Those circumstances are:

- The *Annual Energy Outlook 2014* Reference case;
- The High Oil and Gas Resource ("HOGR") case, which reflects more optimistic assumptions about domestic natural gas supply prospects than the Reference case;
- The Low Oil and Gas Resource ("LOGR") case, which reflects less optimistic assumptions about domestic oil and natural gas supply prospects than the Reference case;

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http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

41 Energy Information Administration, *Annual Energy Outlook 2014*, Table A13.

42 Energy Information Administration, *Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets*, *available at* http://www.eia.gov/analysis/requests/fe/pdf/lng.pdf.

- The High Economic Growth ("HEG") case, in which the U.S. gross domestic product grows at an average annual rate 0.4 percentage points higher than in the Reference case, resulting in higher domestic energy demand; and

- The Accelerated Coal and Nuclear Retirements ("ACNR") case, in which higher costs for running existing coal and nuclear plants result in accelerated capacity retirements, resulting in more reliance on natural gas to fuel electricity generation than in the Reference case

In each of the five circumstances, EIA considered how different export volume scenarios would impact domestic natural gas prices. DOE/FE requested that EIA consider the impact of LNG exports sourced from the lower 48 states at a volume of 12 Bcf/d, 16 Bcf/d, and 20 Bcf/d each year beginning in 2015.[43]

Depending on the circumstance and volume scenario, EIA concluded that average domestic natural gas prices increases at the producer level would range from 1% to 18% between a 2015 and 2040 time period.[44] For example, in the LOGR circumstance, which reflects the most conservative analysis of price impacts, EIA concluded that domestic natural gas prices would increase between 10% (in the 12 Bcf/d scenario) to 18% (in the 20 Bcf/d scenario). In the HOGR circumstance, however, EIA concluded that domestic natural gas prices would ***decrease*** 1% in the 12 Bcf/d scenario and increase only 3% in the 20 Bcf/d scenario.

In the Reference case, which relies on data from EIA's *Annual Energy Outlook 2014*, EIA concluded that average domestic natural gas prices would increase between 4% and 11% between the 2015 and 2040 time period. Importantly, EIA also concluded that the percentage change in prices that residential and commercial customers pay would be "significantly lower."[45] EIA explained that "[t]hese lower values are because delivered prices include transportation charges (for most customers) and distribution charges (especially for residential and commercial

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43 *Id.* at p. 5.
44 *Id.* at p. 14.
45 *Id.* at p. 15.

customers) that do not vary significantly across export scenarios."[46] As a result, in the Residential circumstance, for example, EIA concluded that the average delivered domestic natural gas impact for residential consumers would range between 2% and 5%. In all circumstances and scenarios, the average delivered domestic natural gas impact for residential consumers was estimated to range from 1% to 9%.

Cameron LNG also commissioned the independent consulting firm of ICF International to assess the impact of the proposed LNG exports on natural gas prices. ICF conducted an economic impact analysis ("ICF Report")[47] to assess the effects of the export volume requested under this application as compared to the base case authorization Cameron LNG received in Order Nos. 3059 and 3391-A. ICF's market overview and methodology are found in sections 3 and 4, respectively, of its report, and the results are in section 5.

ICF finds that under the base case, natural gas prices at Henry Hub are expected to increase gradually from 2015 to 2038.[48] This gradual increase in gas prices, driven largely by the power sector, supports development of new sources of supply but does not discourage demand growth.[49] With the introduction of the 152 Bcf per year export volumes that are the subject of this application, the price at Henry Hub increases on average by less than $0.03 per MMBtu between 2016 and 2038 and by $0.03 per MMBtu from 2020 to 2038, the period in which Cameron LNG will be exporting such volumes.[50] These increases over the base case are less than one-half of one percent.

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46 *Id.*

47 Economic Impacts of Cameron Liquefaction Trains 1-3 Supplemental Volumes: Information for DOE Non-FTA Permit Application (Mar. 9, 2015), attached hereto at Appendix C.

48 *See* ICF Report at 21.

49 *See id.* at 3, 20.

50 *See id.* at 44.

C. Other Public Interest Considerations

1. Economic Assessment

In its application in FE Docket No. 11-162-LNG, resulting in FE Order Nos. 3391 and 3391-A, Cameron LNG submitted an Economic Impact Assessment ("Economic Assessment") that assessed and quantified the substantial public benefits that will result from the Liquefaction Project.[51] Cameron LNG explained that the Economic Assessment was derived from price forecasts from the EIA and regional input-output multipliers from the U.S. Bureau of Economic Analysis, and found that the Liquefaction Project will substantially benefit national, regional, and local economies and improve the United States' balance of trade.

As explained above, Cameron LNG's instant application is for authorization to export LNG at a volume that reflects the peak capacity of the Liquefaction Project facilities at optimal conditions, which FERC has determined is the appropriate measure of liquefaction capacity to be set forth in an application to be considered by FERC under Section 3 of the NGA. The public interest benefits that were set forth in the Economic Assessment are equally applicable to this application. Cameron LNG hereby incorporates by reference the Economic Assessment.

2. ICF Report

To further assess and quantify the public benefits that will result from the incremental export volume requested herein, Cameron LNG engaged ICF to prepare the ICF Report, which is attached as Appendix C to this Application. The ICF Report, which is derived from comprehensive natural gas resource estimates, finds that the incremental volumes will substantially benefit national, regional and local economies and improve the United States' balance of trade.

ICF's methodology consisted of the following steps:

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51 *See* Application, *Cameron LNG, LLC*, FE Docket No. 11-162-LNG (Dec. 21, 2011).

- Assessing natural gas and liquids production (including lease condensate, ethane, propane, butane, and pentanes plus) and upstream investment changes. ICF estimated natural gas and liquids production changes using the ICF Gas Market Model ("GMM") based on the additional natural gas needed for LNG exports. The GMM also solved for changes to natural gas prices and demand levels. ICF then translated the natural gas and liquids production changes from the GMM into annual capital and O&M expenditures that will be required for that additional production.
- Quantifying LNG facility and upstream capital and operating expenditures. Based on Cameron LNG's cost estimates, ICF assessed the annual capital and operating expenditures that will be required to support the LNG exports.
- Creating IMPLAN[52] input-output matrices. ICF entered both LNG facility and upstream expenditures to the IMPLAN input-output model to assess the economic impacts for the United States and Louisiana. For example, for a given value of annual expenditures on drilling and new gas wells the model calculated a certain number of direct employees (*e.g.*, natural gas production employees), indirect employees (*e.g.*, drilling equipment manufacturers), and induced employees (*e.g.*, consumer industry employees).
- Quantifying economic impacts. ICF assessed the impact of LNG exports at the national and Louisiana levels for the forecasted level of expenditures. This included direct, indirect, and induced impacts on gross domestic product (GDP), employment, taxes and balance of trade.

ICF estimates an increase in annual LNG plant operating costs of $4.2 million by 2038, or an annual average of $3.8 million between 2016 and 2038.[53] These additional operating costs

[52] IMPLAN is an economic impact assessment software system.
[53] ICF Report at 40.

over the base case are due to such costs as increased port fees, insurance costs, and equipment replacements. The incremental export volume of 0.42 Bcf/d (152 Bcf per year) will result in the following:

- **Production of natural gas and liquids.** The incremental export volumes will result in an increase in U.S. natural gas production of 0.41 Bcf/d over the base case by 2038, or 0.35 Bcf/d on an average annual basis between 2016 and 2038.[54]

  Liquids production (including lease condensate, ethane, propane, butane, and pentanes plus) is expected to increase by an additional 20,000 barrels per day (b/d) over the base case on average between 2016 and 2038.[55]
- **Production values.** Cumulative natural gas and liquids production value totals $49.6 billion higher than the base case between 2016 and 2038, or nearly $2.2 billion annually over the period.[56]
- **Upstream capital expenditures.** There will be an increase in upstream capital expenditures as more production is needed to meet LNG export demand. Over the forecast period 2016 to 2038, there is a total incremental impact on U.S. upstream capital expenditures of $6.75 billion as compared to the base case, or approximately $290 million annually.[57]
- **Natural gas consumption.** The incremental export volumes correspond to a slight decrease in U.S. domestic natural gas consumption of 0.03 Bcf/d over the base case in 2038.[58] The decrease is due largely to a contraction in power generation gas use.[59]

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54 *Id.* at 36.
55 *Id.* at 37.
56 *Id.* at 45.
57 *Id.* at 41.
58 *Id.* at 43.
59 *Id.*

- **Employment.** Total U.S. employment, including direct jobs in the oil and gas industry, indirect jobs in the industries that serve the oil and gas industry, and induced jobs from the effect of spending new job wages, will increase by an average of just over 9,200 annual job-years between 2016 and 2038, giving a cumulative job-year impact of nearly 212,000 job-years, due to the export volumes requested in this application.[60] Employment in Louisiana is expected to increase by nearly 630 job-years annually between 2016 and 2038, resulting in a cumulative job impact of close to 14,500 job-years over the period for the state.[61]
- **Taxes.** ICF estimates that federal, state, and local government revenues increase more than $1.3 billion annually as a result of the incremental export volumes, or $30.9 billion cumulative over the 23-year forecast period between 2016 and 2038.[62] Government revenues within Louisiana are expected to increase by $44.3 million over the base case annually over the forecast period, indicating a cumulative impact of more than $1.0 billion.[63]
- **Gross Domestic Product.** The additional LNG volumes are estimated to result in a $3.9 billion annual average increase to the U.S. economy over the 2016-2038 period, or a cumulative impact of $89.1 billion.[64]
- **Trade deficit.** The additional LNG volumes are expected to result in a $1.6 billion annual average decrease in the U.S. balance of trade deficit, or a cumulative impact of $37.7 billion.[65]

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60 *Id.* at 46.
61 *Id.* at 50.
62 *Id.* at 47.
63 *Id.* at 51.
64 *Id.* at 48.
65 *Id.* at 49.

The ICF Report plainly shows the numerous public interest benefits that would result from the export volumes requested herein.

3. DOE/FE Export Study

Finally, DOE/FE also relied on the information contained in its two-part LNG Export Study[66] when analyzing the public interest benefits of Cameron LNG's application in FE Docket No. 11-162-LNG.[67] Cameron LNG hereby incorporates by reference the analysis in Order Nos. 3391 and 3391-A.[68]

VI. REVIEW OF ENVIRONMENTAL IMPACTS

In the FERC Order, FERC authorized Cameron LNG to site, construct, and operate the Liquefaction Project facilities at the capacity of 14.95 MTPA.[69] The FERC Order was the final step of a comprehensive and detailed environmental review by FERC of the Liquefaction Project. During the course of that review, consistent with the requirements of the National Environmental Policy Act, FERC acted as the lead agency for environmental review, with the DOE/FE acting as a cooperating agency.

FERC staff issued a final Environmental Impact Statement ("EIS") on April 30, 2014. The EIS, which was based on a capacity of 14.95 MTPA, addressed the Liquefaction Project's impact on geology; soils; water resources; wetlands; vegetation; wildlife and aquatic resources; threatened, endangered, and other special status species; land use, recreation, and visual resources; socioeconomics; cultural resources; air quality and noise; safety; cumulative impacts;

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66 *See* 2012 LNG Export Study, 77 Fed. Reg. 73,627 (Dec. 11, 2012), available at http://energy.gov/sites/prod/files/2013/04/f0/fr_notice_two_part_study.pdf (Federal Register Notice of Availability of the LNG Export Study); LNG Export Study – Related Documents, available at http://energy.gov/fe/downloads/lng-export-study-related-documents (EIA Analysis (Study - Part 1) & (NERA Economic Consulting Analysis (Study - Part 2)).

67 *See* Order No. 3391-A at 7, 15-19.

68 *See id.*; Order No. 3391 at 23-124.

69 *Cameron LNG, LLC*, 147 FERC ¶ 61,230 (2014).

and alternatives.[70] The EIS concluded that the Liquefaction Project would result in "mostly temporary and short-term environmental impacts," and that the "impacts will be reduced to less-than-significant levels" with the implementation of proposed mitigation measures.[71] As a result, FERC approved Cameron LNG's proposed Liquefaction Project facilities subject to certain environmental conditions set forth in Appendix A of FERC's order.

In Order No. 3391-A, DOE/FE adopted the EIS and discussed additional environmental issues raised,[72] including those addressed in the Addendum[73] and LCA GHG Report.[74] Thus, the environmental review under NEPA necessary for this Application has already been completed. This Application does not implicate any change in the facilities or operations already analyzed. It merely seeks to have Cameron LNG's export authorizations match the capacity of the Liquefaction Project, which was set forth in the EIS. In light of DOE/FE's review and comprehensive environmental assessment of the Liquefaction Project at 14.95 MTPA, no additional environmental review is required.

VII. APPENDICES

The following appendices are included with this Application:

Appendix A	Verification
Appendix B	Opinion of Counsel
Appendix C	ICF Report

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70 *Id.* at P 57.
71 *Id.* at P 58.
72 *See* Order No. 3391-A at 5-6, 71-83.
73 Dep't of Energy, *Addendum to Environmental Review Documents Concerning Exports of Natural Gas From the United States*, 79 Fed. Reg. 48,132 (Aug. 15, 2014).
74 Dep't of Energy, *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States*, 79 Fed. Reg. 32,260 (June 4, 2014).

VIII. CONCLUSION

For the reasons set forth above, Cameron LNG respectfully requests that the DOE issue an order granting Cameron LNG authorization, on its own behalf and as agent for other parties, to export for a period of 20 years (commencing on the earlier of the date of first commercial export or seven years from the date the requested authorization is granted) up to 152 Bcf per year (equivalent to approximately 2.95 MTPA) of LNG of domestically produced LNG to any country with which the United States does not have an FTA and with which trade is not prohibited by U.S. law or policy.

Respectfully submitted,

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Counsel for Cameron LNG, LLC

Dated: April 3, 2015

APPENDIX A

VERIFICATION

County of Harris)
)
State of Texas)

BEFORE ME, the undersigned authority, on this day personally appeared John O'Leary, who, having been by me first duly sworn, on oath says that he is Chief Operating Officer for Cameron LNG, LLC, and is duly authorized to make this Verification on behalf of such company, that he has read the foregoing instrument, and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

John O'Leary

SWORN TO AND SUBSCRIBED before me on the 1st day of April 2015.

Notary Public

SUSSETTE ALEXANDER
Notary Public, State of Texas
My Commission Expires
August 06, 2017

DB1/ 81316615.8

APPENDIX B

OPINION OF COUNSEL

April 1, 2015

Mr. John A. Anderson
Office of Fossil Energy
U.S. Department of Energy
Docket Room 3F-056, FE 50
Forrestal Building
1000 Independence Avenue, S.W.
Washington, DC 20585

RE: Cameron LNG, LLC Application for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries

Dear Mr. Anderson:

This opinion of counsel is submitted pursuant to Section 590.202(c) of the regulations of the U.S. Department of Energy, 10 C.F.R. § 590.202(c) (2014). I am counsel to Cameron LNG, LLC ("Cameron LNG"). I have reviewed the organizational and internal governance documents of Cameron LNG and it is my opinion that the proposed export of natural gas as described in the application filed by Cameron LNG, to which this Opinion of Counsel is attached as Appendix B, is within the company powers of Cameron LNG.

Respectfully submitted,

Blair Woodward
Counsel to Cameron LNG, LLC

APPENDIX C

ICF INTERNATIONAL

Economic Impacts of Cameron Liquefaction Trains 1-3 Supplemental Volumes: Information for DOE Non-FTA Permit Application

March 23, 2015

Submitted by:
ICF International

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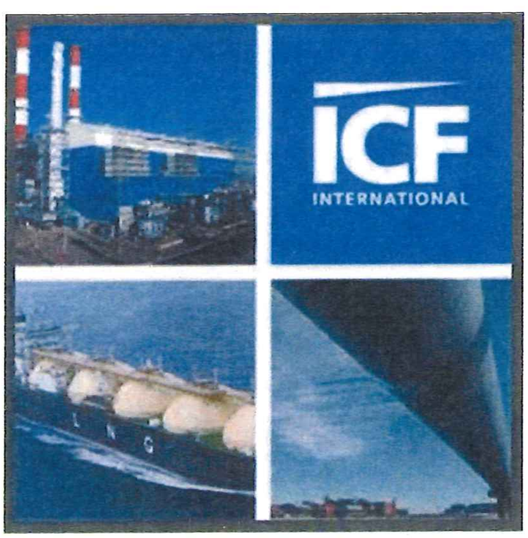


Table of Contents

List of Exhibits

1 Executive Summary

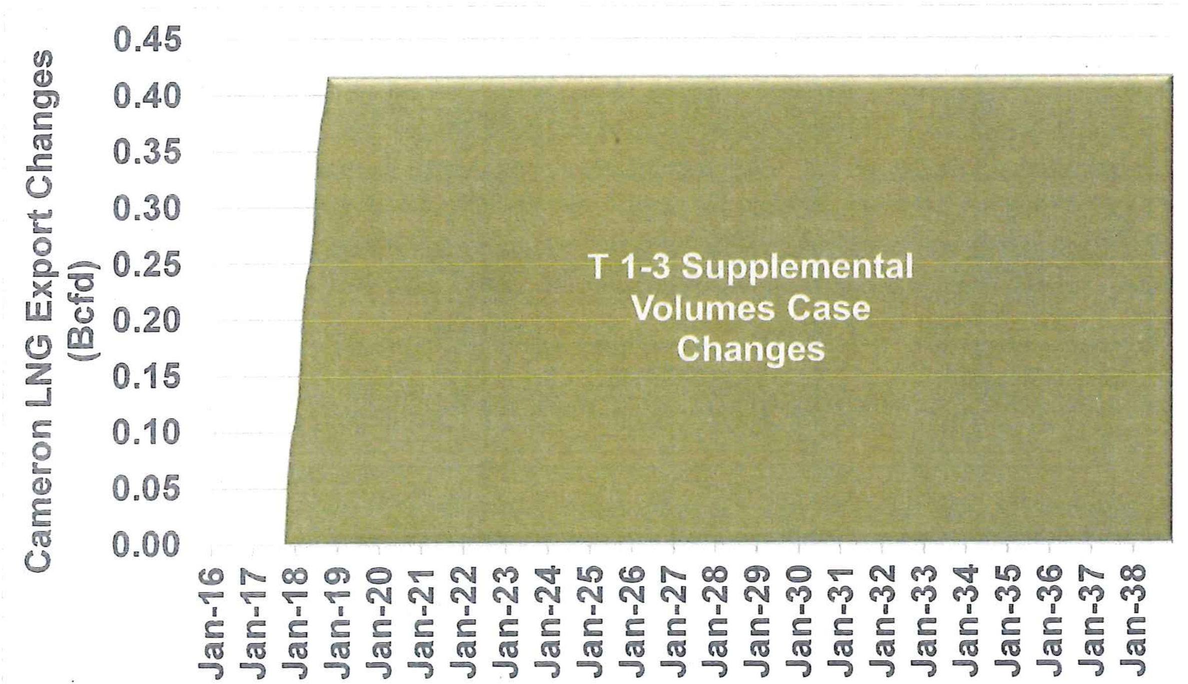
1.1 Introduction

ICF conducted economic impact analysis on behalf of Cameron LNG to assess impacts of LNG export scenarios, Specifically for this report, ICF assessed two Cameron LNG export cases[1]:

1) **Base Case** assumption of currently approved trains 1-3 volumes of 620 billion cubic feet (Bcf) per year, or 1.70 billion cubic feet per day (Bcfd).
2) **Trains 1-3 Supplemental Volumes Case** assumption of an additional 152 Bcf per year, or 0.42 Bcfd higher than the Base Case due to the supplemental volumes from trains 1-3. This gives a total volume of 772 Bcf per year, or 2.12 Bcfd, including Base Case volumes.

The results in this report show the changes between the Base Case and alternative case resulting from the incremental LNG export volumes. The exhibit below shows the assumed LNG export volume changes due to the Trains 1-3 supplemental volumes.

Exhibit 1-1: Trains 1-3 Cameron LNG Export Changes



Note: These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

Source: ICF

[1] These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

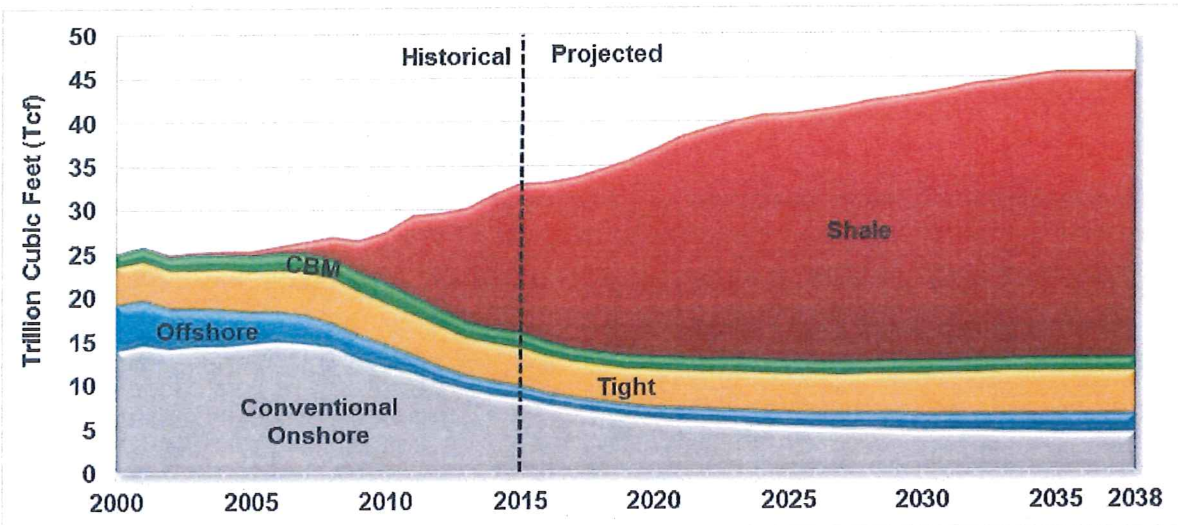
ICF was tasked with assessing the economic and employment impacts of Cameron LNG Trains 1-3 Supplemental Volumes Case. In order to assess these impacts, ICF used an input-output economic model. The methodology consisted of the following steps:

- **Assess natural gas and liquids production and investment changes:** We first estimated natural gas and liquids (including oil, condensate, and natural gas liquids (NGLs), including ethane, propane, butane, and pentanes plus) production changes using the ICF Gas Market Model (GMM) based on the additional natural gas needed for LNG exports. The GMM also solved for changes to natural gas prices and demand levels. The added production volumes were assessed both on a national- and Louisiana-level. ICF then translated the natural gas and liquids production changes from the GMM into annual capital and operating expenditures that will be required for that additional production.
- **Quantify LNG plant and upstream capital and operating expenditures:** Based on Cameron LNG's cost estimates, ICF assessed the annual capital and operating expenditures that will be required to support the LNG exports.
- **Create IMPLAN input-output matrices:** ICF entered both LNG plant and upstream expenditures to the IMPLAN input-output model to assess the economic impacts for the U.S. and Louisiana of a given level of expenditures. For instance, the model found that $100 million in annual expenditures on drilling and completing new gas wells would support a certain number of direct employees (e.g., natural gas production employees), indirect employees (e.g., drilling equipment manufacturers), and induced employees (e.g., consumer industry employees).
- **Quantify economic and employment impacts:** ICF assessed the impact of LNG exports for the national and Louisiana levels for the forecasted level of expenditures. This included direct, indirect, and induced impacts on gross domestic product (GDP), employment, taxes, and balance of trade.

1.2 Key U.S. and Canadian Natural Gas Market Trends

U.S. and Canadian natural gas production has grown considerably over the past several years, led by unconventional production, and is expected to grow further over the next 20 years or more (see Exhibit 1-2). Much of the future natural gas production growth comes from increases in gas-directed (non-associated) drilling, including gas-directed drilling activity in the Marcellus and Utica shales, which will account for over half of the incremental production. In Canada, essentially all incremental production growth comes from development of shale and other unconventional resources.

Exhibit 1-2: U.S. and Canadian Gas Supplies



Source: ICF

In terms of demand-side dynamics, the power sector is the largest single source of incremental domestic gas consumption, though near-term gas market growth is driven by growth in export markets (LNG and Mexican exports). Significant power sector gas demand growth is expected to continue, particularly after 2015, as natural gas capacity replaces coal capacity, with accelerated growth after 2020 when federal carbon regulation is expected to be initiated. After 2030, nuclear power plant retirements start a new round of growth in natural gas consumption.

Increased demand growth will push gas prices above $5 per MMBtu[2] after 2020, with long-term prices are expected to range between $6 and $7 per MMBtu. Prices are high enough to foster sufficient supply development to meet growing demand, but not so high to throttle the demand growth.

U.S. and Canadian LNG exports are projected to reach 11.5 Bcfd by 2025, with LNG exports from the U.S. Gulf Coast expected to reach 9.2 Bcfd, based on ICF's review of approved projects. These volumes do not include the supplemental Cameron train 1-3 exports associated with this economic impact analysis.

Continued low oil prices are expected to moderate growth of associated gas production from oil plays. While associated gas production has increased due to growth in domestic oil production, it still accounts for only 18 percent of total gas production.

1.3 Key Study Results

For each case, ICF examined the economic and employment impacts between 2016 and 2038 on both a national level and Louisiana state level. Impacts included natural gas and liquids[3]

[2] All dollar figure results in this report are in 2015 real dollars, unless otherwise specified.
[3] Includes oil, condensate, and natural gas liquids (NGLs), such as ethane, propane, butane, and pentanes plus.

production, LNG plant and upstream capital and operating expenditures, natural gas consumption, natural gas and liquids prices, production value, LNG plant and upstream employment, government revenues, value added, and the U.S. balance of trade.

1.3.1 Trains 1-3 Supplemental Volumes Results

The trains 1-3 export supplemental volumes of 0.42 Bcfd over the current authorized LNG export volumes could mean 9,200 jobs on an annual basis for the U.S. economy, 630 of which will take place in Louisiana. In addition, the incremental LNG export volumes will mean $3.9 billion in annual value added to the U.S. economy, or $285.6 million to the state of Louisiana. The U.S. will also see $1.3 billion in annual government revenue streams, or $44.3 million in Louisiana state and local taxes. In terms of cumulative impacts, the supplemental volumes will mean a total of nearly 212,000 job-years over the forecast period between 2016 and 2038, or nearly 14,500 in Louisiana. The supplemental volumes are also expected to create $89.1 billion in cumulative value added for the U.S. economy, or $6.6 billion for the state of Louisiana. The U.S. federal, state, and local governments will see a total of $30.9 billion over the forecast period, including $1.0 billion in Louisiana.

Exhibit 1-3: the T 1-3 Supplemental Volumes Case Economic and Employment Impacts

Region	2016-2038 Average Annual Impact			2016-2038 Cumulative Impact		
	Jobs (Job-years)	Value Added (2015$ Million)	Government Revenues (2015$ Million)	Jobs (Job-years)	Value Added (2015$ Million)	Government Revenues (2015$ Million)
U.S.	9,216	$ 3,875.4	$ 1,343.0	211,966	$ 89,133.6	$ 30,889.5
Louisiana	629	$ 285.6	$ 44.3	14,464	$ 6,568.8	$ 1,018.2

Source: ICF

2 Introduction

Cameron LNG tasked ICF International with assessing the economic and employment impacts of additional liquefied natural gas (LNG) exports from its Hackberry, LA LNG export facility. This study assessed two cases[4]:

1) **Base Case** assumption of currently approved trains 1-3 volumes of 620 billion cubic feet per year, or 1.70 billion cubic feet per day (Bcfd).
2) **Trains 1-3 Supplemental Volumes Case** assumption of an additional 152 Bcf per year, or 0.42 Bcfd higher than the Base Case due to the supplemental volumes from trains 1-3. This gives a total volume of 772 Bcf per year, or 2.12 Bcfd, including Base Case volumes.

The results in this report show the changes in economic metrics between the Base Case and alternative case resulting from the incremental LNG export volumes. ICF assessed the U.S. and state-level Louisiana changes between 2016 and 2038, including:

- Natural gas production.
- Liquids production, including oil, condensate, and natural gas liquids (NGLs), including ethane, propane, butane, and pentanes plus.
- LNG plant capital expenditures.
- LNG plant operating expenditures.
- Upstream capital expenditures to support the natural gas and liquids production.
- Upstream operating expenditures.
- Natural gas consumption.
- Henry Hub natural gas prices.
- Natural gas and liquids production value.
- Employment.
- Federal, state, and local government revenues.
- Value added.
- U.S. Balance of Trade.

This study includes the following sections:

1) Executive Summary
2) Introduction
3) Base Case U.S. and Canadian Natural Gas Market Overview
4) Study Methodology
5) Trains 1-3 Supplemental Volumes Energy Market and Economic Impact Results
6) Bibliography
7) Appendices

[4] These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

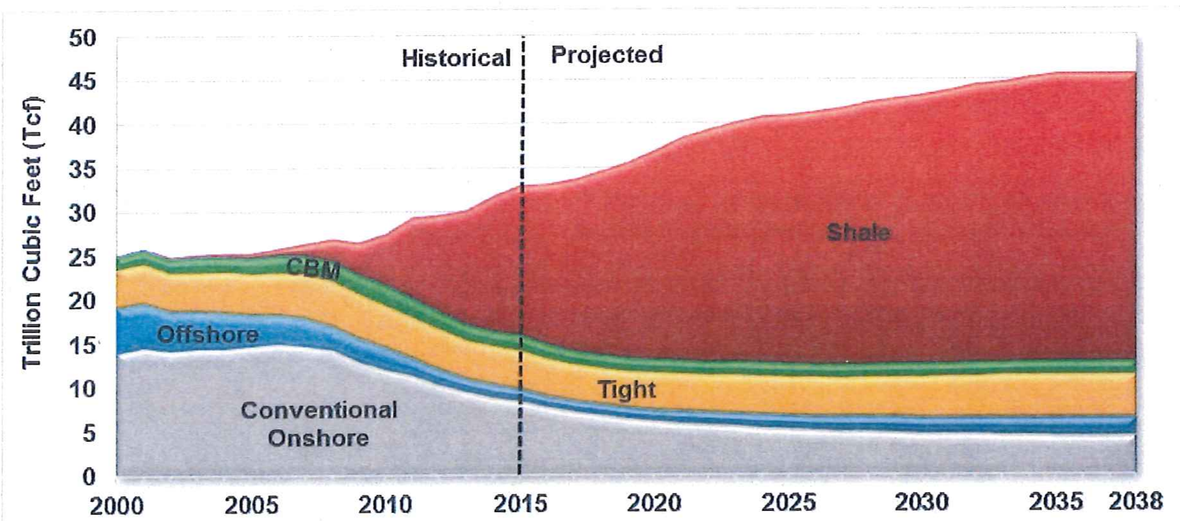
3 Base Case U.S. and Canadian Natural Gas Market Overview

This section discusses U.S. and Canadian Base Case natural gas market forecasts, starting with natural gas supply trends, including ICF's resource base assessment and comparisons with other assessments. The section then discusses trends in U.S. and Canadian demand through 2038, including pipeline and LNG export trends. The section concludes with forecasts on U.S. and Canadian natural gas pipeline and international trade and natural gas prices.

3.1 U.S. and Canadian Natural Gas Supply Trends

Over the past five years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production, and is expected to grow further through 2038 and beyond (see Exhibit 3-1). Unconventional production technologies (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional production expected to offset declining conventional production. These production changes will call for significant infrastructure investments to create pathways between new supply sources and demand markets.

Exhibit 3-1: U.S. and Canadian Gas Supplies

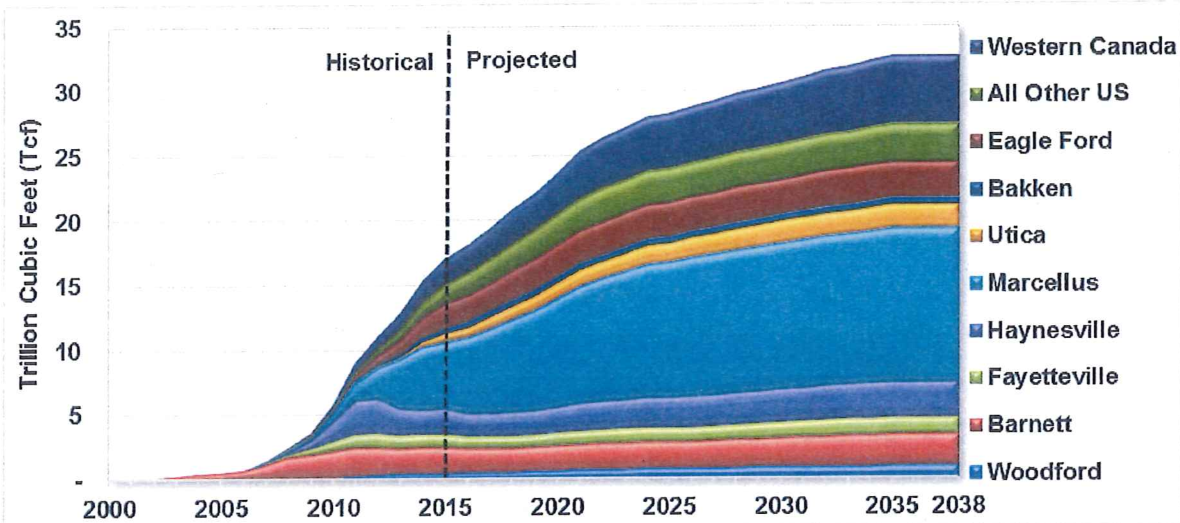


Source: ICF

Production from U.S. and Canadian shale formations will grow from about 5.8 Tcf (15.9 Bcfd) in 2010 to nearly 32.6 Tcf (89.3 Bcfd) by 2038 (see exhibit above). The major shale formations in the U.S. and Canada are located in the U.S. Northeast (Marcellus and Utica), the Mid-continent (Barnett, Woodford, Fayetteville, and Haynesville), southern Texas (Eagle Ford), and western Canada (Montney and Horn River). The Bakken Shale, which in the U.S. spans parts of North Dakota and Montana, is primarily an oil formation, but also has significant natural gas volumes.

There are other shale formations in the U.S. that have not yet been evaluated or developed for gas production.

Exhibit 3-2: U.S. and Canadian Shale Gas Production



Note: Haynesville production includes production from other shales in the vicinity (e.g., the Bossier Shale).

Source: ICF

3.1.1 Natural Gas Production Costs

ICF estimates that production of unconventional natural gas (including shale gas, tight gas, and coalbed methane (CBM) will generally be much lower cost on a per-unit basis than conventional sources.[5] The gas supply curves show the incremental cost of developing different types of gas resources, as well as for the resource base in total. While the emerging stage of shale gas production, as well as the site-specific nature of unconventional production costs, mean uncertain production costs, shale plays such as the Marcellus are proving to be among the least expensive (on a per-unit basis) natural gas sources.

ICF has developed supply cost curves for the U.S. and Canada. These curves represent the aggregation of discounted cash flow analyses at a highly granular level. Resources included in the curve are all of the resources discussed above – proven reserves, growth, new fields, and unconventional gas. The unconventional GIS plays are represented in the curves by thousands of individual discounted cash flow (DCF) analyses.

Conventional and unconventional gas resources are determined using different approaches due to the nature of each resource. For example, conventional new fields require new field wildcat exploration while shale gas is almost all development drilling. Offshore undiscovered

[5] Unconventional refers to production that requires some form of stimulation within the well to produce gas economically. Conventional wells do not require stimulation.

conventional resources require special analysis related to production facilities as a function of field size and water depth.

The basic ICF resource costs are determined first "at the wellhead" prior to gathering, processing, and transportation. Then, those cost factors are added to allow costing at points farther downstream of the wellhead. Costs can be adjusted to a "Henry Hub" basis for certain type of analysis that consider the remoteness of the resource.

Supply Costs of Conventional Oil and Gas

Conventional undiscovered fields are represented by a field size distribution. Such distributions are typically compiled at the "play" level. Typically, there are a few large fields and many small fields remaining in a play. In the model, these play-level distributions are aggregated into 5,000-foot drilling depth intervals onshore and by water depth intervals offshore. Fields are evaluated in terms of barrels of oil equivalent, but the hydrocarbon breakout of crude oil, associated gas, non-associated gas, and gas liquids is also determined. All areas of the Lower-48, Canada, and Alaska are evaluated.

Costs involved in discovering and developing new conventional oil and gas fields include the cost of seismic exploration, new field wildcat drilling, delineation and development drilling, and the cost of offshore production facilities. The model includes algorithms to estimate the cost of exploration in terms of the number and size of discoveries that would be expected from an increment of new field wildcat drilling.

Supply Costs of Unconventional Oil and Gas

ICF has developed models to assess the technical and economic recovery from shale gas and other types of unconventional gas plays. These models were developed during a large-scale study of North America gas resources conducted for a group of gas-producing companies, and have been subsequently refined and expanded. North American plays include all of the major shale gas plays that are currently active. Each play was gridded into 36 square mile units of analysis. For example, the Marcellus Shale play contains approximately 1,100 such units covering a surface area of almost 40,000 square miles.

The resource assessment is based upon volumetric methods combined with geologic factors such as organic richness and thermal maturity. An engineering based model is used to simulate the production from typical wells within an analytic cell. This model is calibrated using actual historical well recovery and production profiles.

The wellhead resource cost for each 36-square-mile cell is the total required wellhead price in dollars per MMBtu needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes, and income taxes.

Wellhead economics are based upon discounted cash flow analysis for a typical well that is used to characterize each cell. Costs include drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, and such costs are based upon cost per stage and number of stages. Per-foot drilling costs were based upon analysis of industry and published data. The American Petroleum Institute (API) Joint Association Survey of Drilling Costs and Petroleum Services Association of Canada (PSAC) are sources of drilling and completion cost data, and the U.S. Energy Information Administration (EIA) is a source for operating and equipment costs.[6,7,8] Lateral length, number of fracturing stages, and cost per fracturing stage assumptions were based upon commercial well databases, producer surveys, investor slides, and other sources.

In developing the aggregate North American supply curve, the play supply curves were adjusted to a Henry Hub, Louisiana basis by adding or subtracting an estimated differential to Henry Hub. This has the effect of adding costs to more remote plays and subtracting costs from plays closer to demand markets than Henry Hub.

The cost of supply curves developed for each play include the cost of supply for each development well spacing. Thus, there may be one curve for an initial 120-acre-per-well development, and one for a 60-acre-per-well. This approach was used because the amount of assessed recoverable and economic resource is a function of well spacing. In some plays, down-spacing may be economic at a relatively low wellhead price, while in other plays, economics may dictate that the play would likely not be developed on closer spacing. The factors that determine the economics of infill development are complex because of varying geology and engineering characteristics and the cost of drilling and operating the wells.

The initial resource assessment is based on current practices and costs and therefore does not include the potential for either upstream technology advances or drilling and completion cost reductions in the future. Throughout the history of the gas industry, technology improvements have resulted in increased recovery and improved economics. In ICF's oil and gas drilling activity and production forecasting, assumptions are typically made that well recovery improvements and drilling cost reductions will continue in the future and will have the effect of reducing supply costs. Thus, the current study anticipates there will be more resources available in the future than indicated by a static supply curve based on current technology.

Aggregate Cost of Supply Curves

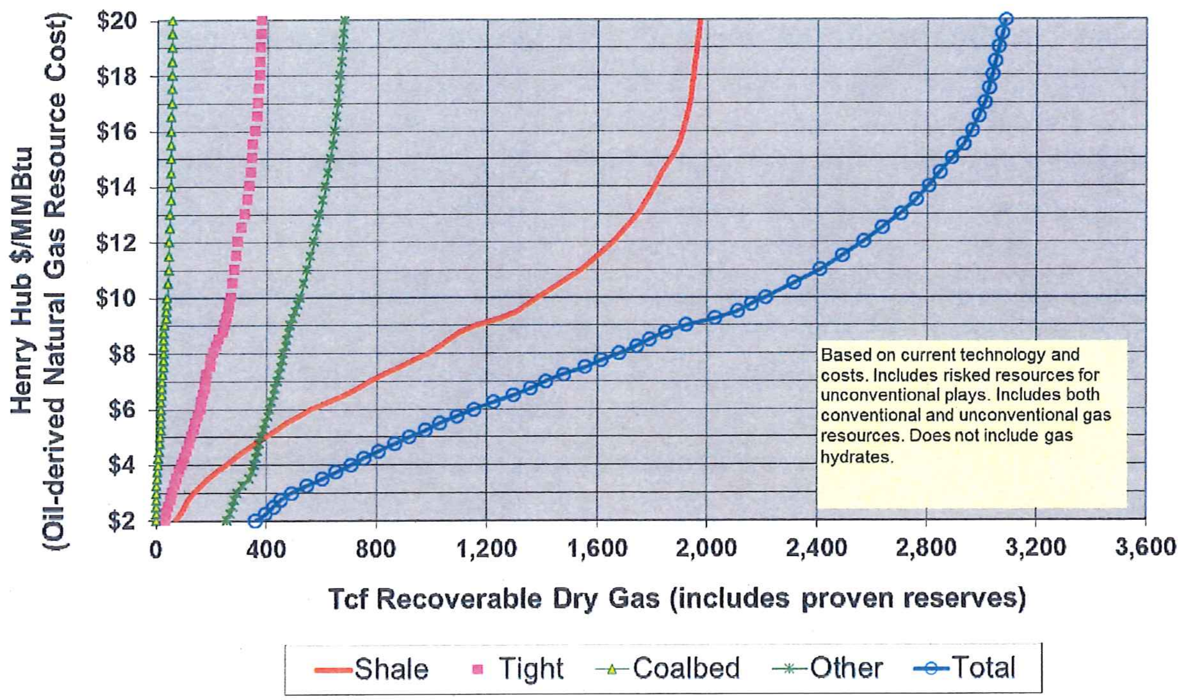
North American supply cost curves (based on current technology) on a "Henry Hub" price basis are presented in the exhibit below. The supply curves were developed on an "oil-derived" basis. That is to say that the liquids prices are fixed in the model (crude oil at $75 per barrel) and the gas prices in the curve represent the revenue that is needed to cover those costs that were not covered by the liquids in the DCF analysis. The rate of return criterion is 8 percent, in real terms. Current technology is assumed in terms of well productivity, success rates, and drilling costs.

[6] American Petroleum Institute. "2012 Joint Association Survey of Drilling Costs". API, various years: Washington, DC.
[7] Petroleum Services Association of Canada (PSAC). "2009 Well Cost Study". PSAC, 2009. Available at: http://www.psac.ca/
[8] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs". EIA, 2011: Washington, DC. Available at: http://www.eia.gov/petroleum/reports.cfm

For the Lower-48, 2,200 Tcf of gas resource is available at $10.00 per MMBtu or less. For Canada there is 500 Tcf at $10.00 per MMBtu or less. At $5.00 per MMBtu, 900 Tcf is available in the Lower-48 and approximately 150 Tcf is available in Canada.

This analysis shows that a large component of the technically recoverable resource is economic at relatively low wellhead prices. This assessment is conservative in that it assumes no improvement in drilling and completion technology and cost reduction, while in fact, large improvements in these areas have been made historically and are expected in the future.

Exhibit 3-3: U.S. Lower-48 Gas Supply Curves



Source: ICF

3.1.2 ICF Resource Base Estimates

ICF has assessed conventional and unconventional North American oil and gas resources and resource economics. ICF's analysis is bolstered by the extensive work we have done to evaluate shale gas, tight gas, and coalbed methane in the U.S. and Canada using engineering and geology-based geographic information system (GIS) approaches. This highly granular modeling includes the analysis of all known major North American unconventional gas plays and the active tight oil plays. Resource assessments are derived either from credible public sources or are generated in-house using ICF's GIS-based models.

The following resource categories have been evaluated:

> ***Proven reserves*** – defined as 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.

Reserve appreciation – defined as the quantities of oil and gas that are expected to be proven in the future through additional drilling in existing conventional fields. ICF's approach to assessing reserve appreciation has been documented in a report for the National Petroleum Council.[9]

Enhanced oil recovery (EOR) – defined as the remaining recoverable oil volumes related to tertiary oil recovery operations, primarily CO_2 EOR.

New fields or undiscovered conventional fields – defined as future new conventional field discoveries. Conventional fields are those with higher permeability reservoirs, typically with distinct oil, gas, and water contacts. Undiscovered conventional fields are assessed by drilling depth interval, water depth, and field size class.

Shale gas and tight oil – **Shale gas** volumes are recoverable volumes from unconventional gas-prone shale reservoir plays in which the source and reservoir are the same (self-sourced) and are developed through hydraulic fracturing. **Tight oil** plays are shale, tight carbonate, or tight sandstone plays that are dominated by oil and associated gas and are developed by hydraulic fracturing.

Tight gas sand – defined as the remaining recoverable volumes of gas and condensate from future development of very low-permeability sandstones.

Coalbed methane – defined as the remaining recoverable volumes of gas from the development of coal seams.

Exhibit 3-4 and Exhibit 3-5 summarize the current ICF gas and crude oil assessments for the U.S. and Canada. Resources shown are "technically recoverable resources." This is defined as the volume of oil or gas that could technically be recovered through vertical or horizontal wells under existing technology and stated well spacing assumptions without regard to price using current technology. The assessment basis is year-end 2013 (as this is the latest date for published proved reserves).

[9] U.S. National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," http://www.npc.org/

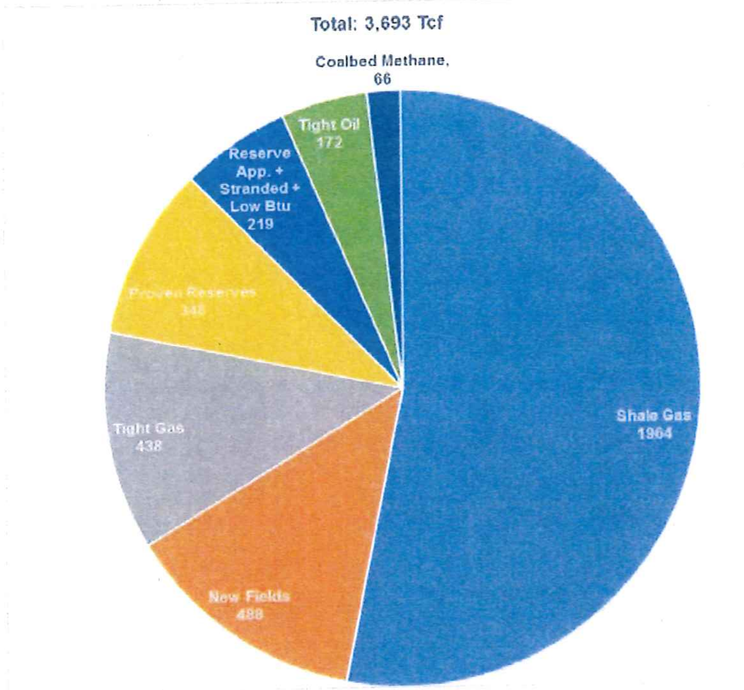
Exhibit 3-4: ICF North America Technically Recoverable Oil and Gas Resource Base Assessment (current technology)

(Tcf of Dry Total Gas and Billion Barrels of Liquids as of year-end 2013; excludes Canadian and U.S. oil sands)

Lower 48	Total Gas Tcf	Crude and Cond. Bn Bbls
Proved reserves	346	34
Reserve appreciation and low Btu	219	23
Stranded frontier	0	0
Enhanced oil recov.	0	42
New fields	488	68
Shale gas and condensate	1,964	31
Tight oil (non -GIS)	172	54
Tight gas	438	4
Coalbed methane	66	0
Lower 48 Total	**3,693**	**256**
Canada		
Proved reserves	72	4.9
Reserve appreciation and low Btu	29	3.0
Stranded frontier	40	0.0
Enhanced oil recov.	0	3.0
New fields	219	12.0
Shale gas and condensate	699	0.3
Tight oil	114	20.3
Tight gas (with conv.)	0	0.0
Coalbed methane	76	0.0
Canada Total	**1,249**	**44**
Lower-48 and Canada Total	**4,942**	**299**

Sources: ICF, EIA (proved reserves)

Exhibit 3-5: Lower-48 Gas Resources



Source: ICF

3.1.3 Resource Base Estimate Comparisons

The ICF gas resource base is significantly higher than most published assessments. A comparison of Lower-48 resources by category is shown in Exhibit 3-6. For example, the ICF Lower-48 shale gas assessment of 1,964 Tcf can be compared to the EIA's 489 Tcf or the Potential Gas Committee's 1,073 Tcf.

The ICF natural gas resource base assessment for the U.S. lower 48 states is higher than many other sources, primarily due to our bottom-up assessment approach and the inclusion of resource categories (including infill wells) that are excluded in other analyses. These additional resources in the ICF assessments tend to be in the lower-quality fringes of currently active play areas or associated with lower-productivity infill wells that may eventually be drilled between current adjacent well locations. Therefore, the additional resources are often higher cost and get added to the upper end of the natural gas supply curves. Such resources may eventually get exploited if natural gas prices increase substantially or if upstream technological advances improve well recovery and decrease costs enough to make these resources economic. The inclusion of these fringe and infill resources into the ICF forecasts has little effect on results in the near term because current drilling and the drilling forecast for the next 20 years will be in the "core" and "near-core" areas. Therefore, removing the fringe/infill resources will not have a great effect on model runs projecting market results through 2040.

There are several other reasons for the magnitude of the differences:

- More plays are included. ICF includes all major shale plays that have significant activity. Although, in recent years EIA has published resources for most major plays, the ICF analysis is more complete. Examples of plays assessed by ICF but not by EIA are the Paradox Basin shales and Gulf Coast Bossier. ICF also has a more comprehensive evaluation of tight oil and associated gas.

- ICF includes the entire shale play, including the oil portion. Several plays such as the Eagle Ford have large liquids areas.
- ICF employs a bottom-up engineering evaluation of gas-in-place (GIP) and original oil-in-place (OOIP). Assessments based upon in-place resources are more comprehensive.
- ICF looks at infill drilling (or new technologies that can substitute for infill wells) that increase the volume of reservoir contacted. Infill drilling impacts are critical when evaluating unconventional gas. ICF shale resources are based upon the first level of infill drilling, with primary spacing based upon current practices. In other words, if the current practice is 120 acres and 1,000 feet spacing between horizontal well laterals, our assessment assumes an ultimate spacing can be (if justified by economics) 60 acres and 500 feet spacing between laterals.
- For conventional new fields, ICF includes areas of the Outer Continental Shelf (OCS) that are currently off-limits, such as the Atlantic and Pacific OCS.
- ICF evaluates all hydrocarbons at the same time (i.e., dry gas, NGLs, and crude and condensate). While not affecting gas volumes, it provides a comprehensive assessment.
- ICF employs an explicit risking algorithm based upon the proximity to nearby production and factors such as thermal maturity or thickness.

Exhibit 3-6: Comparison of Published Lower-48 Gas Resource Assessments

TCF of technically recoverable gas; excludes proved reserves

Group	Shale Gas	Tight Oil	Tight Gas	Coalbed	Conventional	Unproved Total
ICF (current)	**1,964**	**172**	**438**	**66**	**707**	**3,347**
EIA AEO, 2014	489	49	365	120	637	1,660
USGS (current)	393	---	190	71	---	---
Potential Gas Committee, 2013	1,073	---	(with conv.)	101	955	2,129
Advanced Resources Inc., 2012	1,219	---	561	124	730	2,634
EIA AEO, 2011	827	---	369	117	703	2,016
Potential Gas Committee, 2011	687	---	(with conv.)	102	858	1,647
MIT, 2011	631	---	173	115	951	1,870
Advanced Resources Inc., 2010	660	---	471	85	831	2,047

Source: ICF

It should also be noted that ICF volumes of technically recoverable resources include large volumes of currently uneconomic resources on the fringes of the major plays, although we generally did not include shale reservoirs with a net thickness of less than 50 feet. A detailed comparison of the ICF, EIA, and U.S. Geological Survey (USGS) shale assessments by region is presented in Exhibit 3-7. The exhibit provides a better understanding of the differences in the major assessments. Most of the difference is with the Marcellus, Utica, Haynesville, and Fort Worth Barnett Shale plays. Another area of difference relates to plays such as the Paradox Basin and Bossier Shale that ICF has assessed but the other groups generally do not.

ICF has evaluated the USGS Marcellus assessment in order to determine the factors that contribute to their low assessment. We concluded that USGS used incorrect well recovery assumptions that are far lower than what is currently being seen in the play. In addition, the well spacing assumptions differ from current practices. The high ICF Barnett Shale assessment is the result of our including a very large fringe area of low-quality resource. The great majority of this fringe area is uneconomic, so the comparison is not for an equivalent play area.

Exhibit 3-7: Play-level Shale Gas Comparison

Technically Recoverable Resource, Tcf

		ICF	AEO 2014	USGS Current
Appalachia				
Marcellus		698	119	84
Huron		35	0	0
Other Devonian		15	21	10
Utica		322	37	38
	subtotal	1,070	177	132
Midcontinent				
Arkoma Fayetteville		44	30	13
Arkoma Caney		19	1	1
Arkoma Woodford		39	7	11
Anadarko Woodford (CANA)		37	9	16
	subtotal	139	47	41
Gulf Coast and Permian				
Haynesville		410	71	60
Bossier Shale		51	0	0
Fort Worth Barnett		89	20	26
Eagle Ford		91	53	52
Gulf Coast Pearsall		0	8	9
W. Texas Barnett/Woodford		23	16	35
Floyd/Conasauga		0	2	2
	subtotal	664	170	184
Rockies				
Green River Hilliard, etc		9	11	0
Uinta Mancos		0	11	0
San Juan Lewis		0	10	0
Paradox Basin		34	0	0
	subtotal	43	32	0
Michigan and Illinois		10	57	11
Other Lower- 48		38	6	25
Total		**1,964**	**489**	**393**

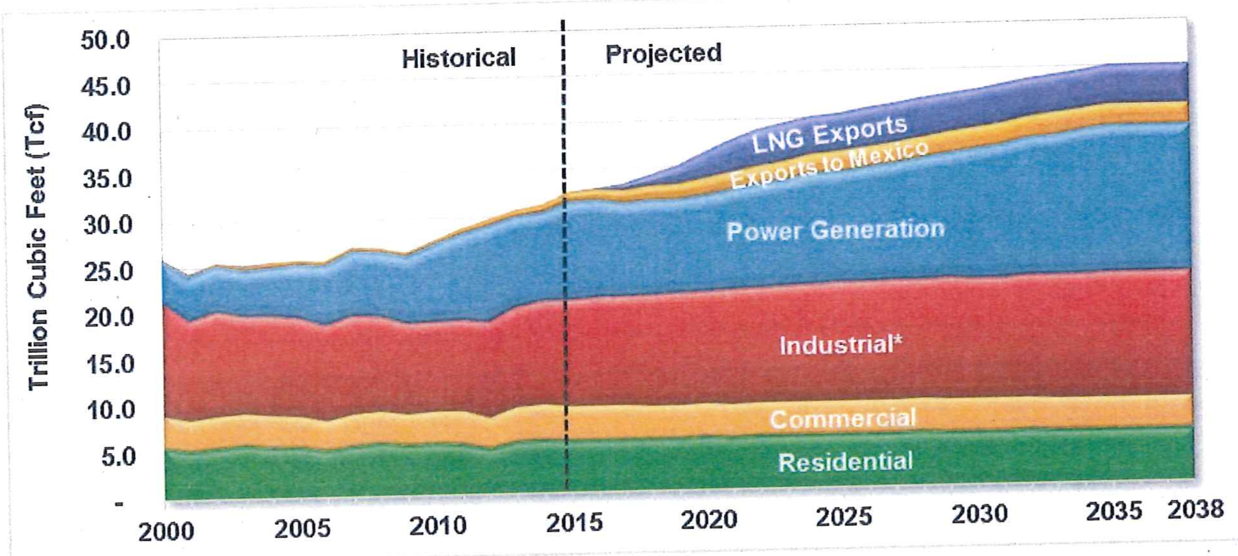
Source: Various compiled by ICF

3.2 U.S. and Canadian Natural Gas Demand Trends

While new LNG export facilities in the U.S. and Canada are expected to come online starting in 2016, power generation will see the bulk of incremental natural gas consumption growth over the foreseeable future, along with some growth in the industry sector, led by gas-intensive end uses such as petrochemicals, fertilizers, and transportation (compressed natural gas vehicles and LNG vehicles).

Incremental power sector gas use between 2014 and 2038 is expected to comprise the largest share of total *incremental* U.S. and Canadian gas growth over the period, with gas-fired power generation expected to increase significantly over time. Growth in gas demand for power generation is driven by a number of factors. In the past 15 years, there have been 460 gigawatts (GW) of new gas-fired generating capacity built in the U.S. and Canada, and much of that capacity is underutilized and readily available to satisfy incremental electric load growth. Electricity demand has historically been linked to Gross Domestic Product (GDP). Prior to the 2007-2008 global recession, demand for electricity was growing at about two percent per year. Over the next twenty years, although GDP is forecast to grow at 2.6 percent annually from 2016 onward, electricity demand growth is expected to average only about 1.2 percent per year, mainly due to implementation of energy efficiency measures. Even at this lower growth rate, annual electricity sales are expected to increase to nearly 4,484 Terawatt-hours (TWh) per year by 2020, or growth nearing 10.6 percent over 2010 levels (3,700 TWh annually).

Exhibit 3-8: U.S. and Canadian Gas Consumption by Sector and Exports



Source: ICF

* Includes pipeline fuel and lease & plant

The expanding use of natural gas in the power sector is driven in part by environmental regulations, primarily in the United States. 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 – include the 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 CO_2 reflecting the continuing lack of consensus in Congress and the time it may take for direct regulation of CO_2 to be implemented. The case generally leads to retirement and replacement of some coal-generating capacity with gas-based capacity. ICF also assumes that all current state renewable portfolio standards are met and other forms of generation are fairly flat. We also assume existing nuclear units have a maximum lifespan of 60 years, which results in 17 GW of nuclear retirements by 2035. The Base Case forecasts an increase in gas use in the power generation market from 33 percent of the total in 2014 to 44 percent by 2038. This growth in gas-fired generation and the accompanying growth in gas consumption is the primary driver of gas demand growth throughout the forecast period.

Industrial demand accounts for 28 percent of total gas use growth in U.S. and Canadian natural gas demand during the 2014-2038 period. A large share of the industrial gas demand increase is from development of the western Canadian oil sands. Excluding natural gas use for oil sands, the growth in industrial sector gas demand in the Base Case is relatively small, as reducing energy intensity (i.e., energy input per unit of industrial output) remains a top priority for manufacturers.

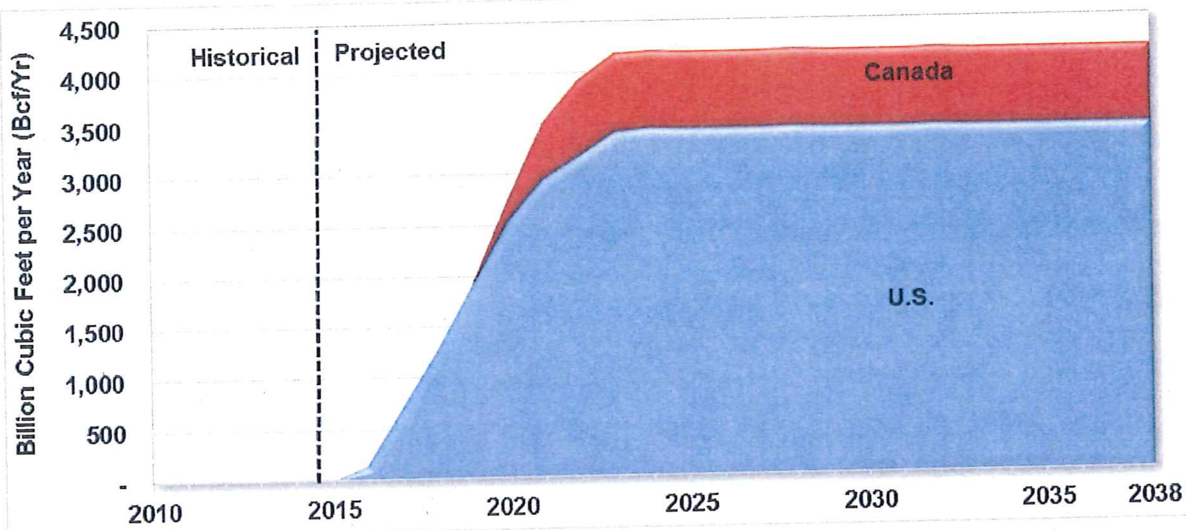
Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the residential and commercial sectors, which lead to lower per-customer gas consumption. Gas use by natural gas vehicles (NGVs) is included in the commercial sector. The Base Case assumes that the growth of NGVs is primarily in fleet vehicles (e.g., urban buses), and vehicular gas consumption is not a major contributor to total demand growth. In addition, pipeline exports to Mexico are expected to increase to over 2.4 Tcf (6.7 Bcfd) by 2038, up from 730 Bcf/year (2.0 Bcfd) in 2014.

3.2.1 LNG Export Trends

LNG exports are expected to provide additional markets for both Canadian and U.S. natural gas production. In Canada, the National Energy Board (NEB) has granted approval for nine projects located on the West Coast. Several other LNG projects in British Columbia are in various stages of development, but have not yet received NEB approval. In the U.S., the U.S. Department of Energy (DOE) has received 38 applications to export LNG to non-Free Trade Agreement (FTA) countries. Most of the major LNG-consuming countries, including Japan, do not have free trade agreements with the U.S. So far, eight facilities (five located on the U.S. Gulf Coast) have received approval for both FTA and non-FTA exports.

The number of LNG facilities that may eventually enter the market remains highly uncertain. Based on our assessment of world LNG demand and other international sources of LNG supply, this study projects completion of a total of 12 U.S. and Canadian export plants between 2016 and 2021 (three in Canada, eight on the U.S. Gulf Coast, and one on the East Coast), exporting a total of 4.2 Tcf (11.4 Bcfd) by 2023 in LNG exports (see exhibit below).

Exhibit 3-9: U.S. and Canadian LNG Exports



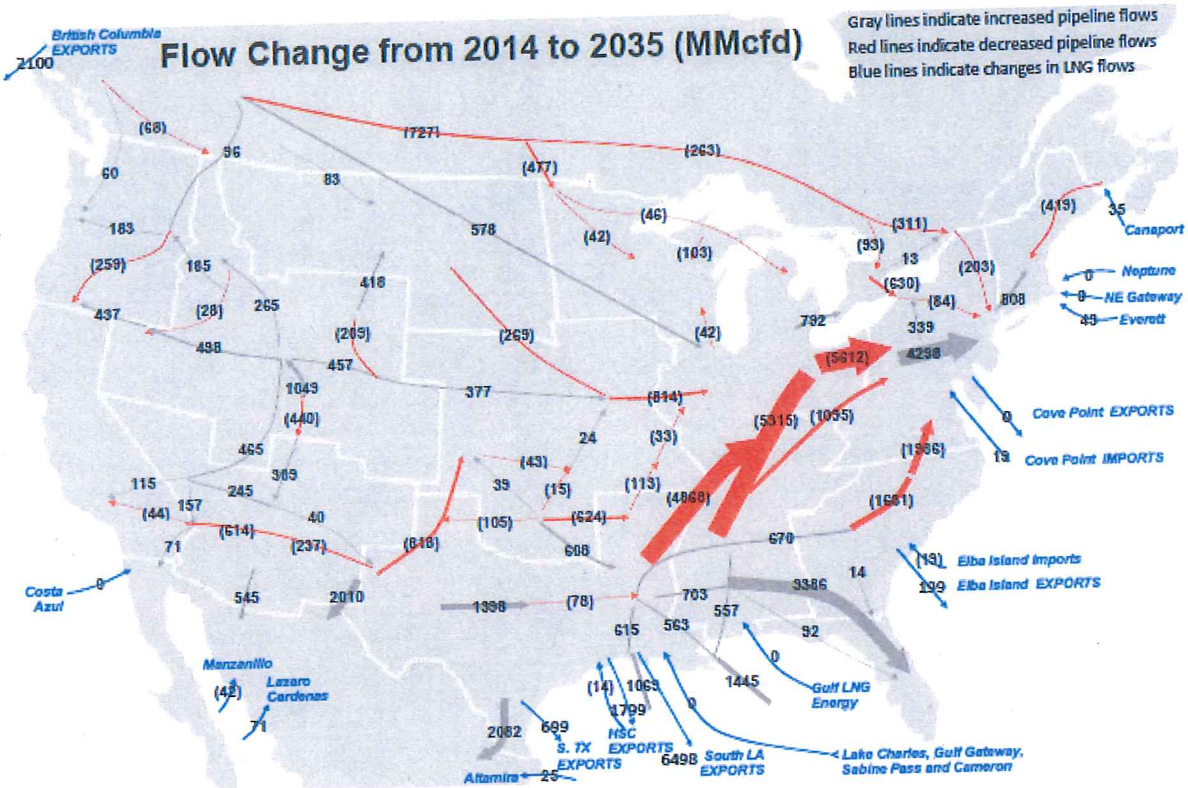
Source: ICF

3.3 U.S. and Canadian Natural Gas Midstream Infrastructure Trends

As regional gas supply and demand continue to shift over time, there are likely to be significant changes in interregional pipeline flows. The exhibit below shows the projected changes in interregional pipeline flows from 2013 to 2035 in the Base Case. The map shows the United States divided into regions. The arrows show the changes in gas flows over the pipeline corridors between the regions between the years 2013 and 2035, where the gray arrows indicate increases in flows and red arrows indicate decreases. The blue lines indicate changes in LNG flows.

The map below illustrates how gas supply developments will drive major changes in U.S. and Canadian gas flows. The growth in Marcellus Shale gas production in the Mid-Atlantic Region will displace gas that once was imported into that region, hence the red arrows entering the Mid-Atlantic Region from points north (Canada), Midwest (Ohio), and South Atlantic (North Carolina). In effect, the Mid-Atlantic Region becomes a major producer of gas and supplies gas to consumers throughout the East Coast. The flow of natural gas from Alberta through eastern Canada to the eastern U.S. will decline as Marcellus production displaces both imports from Canada and flows from the U.S. Gulf Coast. While the red arrows from the Gulf Coast to the U.S. Northeast indicate that gas continues to flow into the U.S. Northeast, Marcellus gas over the past five years has significantly narrowed those volumes, a trend that will continue over the foreseeable future.

Exhibit 3-10: Projected Change in Interregional Pipeline Flows



Source: ICF GMM® Q1 2015

The large increases in flows eastward from the West South Central Region (Texas, Louisiana, and Arkansas) are due to growing shale gas production in the region. However, most of this gas is consumed in the East South Central Region (Mississippi, Alabama, Tennessee, and Kentucky) and South Atlantic Region (Florida to North Carolina) where demand is growing. In addition, natural gas will be exported from the West South Central in the form of LNG starting in 2016. The growing Marcellus gas production in the Mid-Atlantic Region will also displace gas flows from the West South Central Census Region to the South Atlantic states.

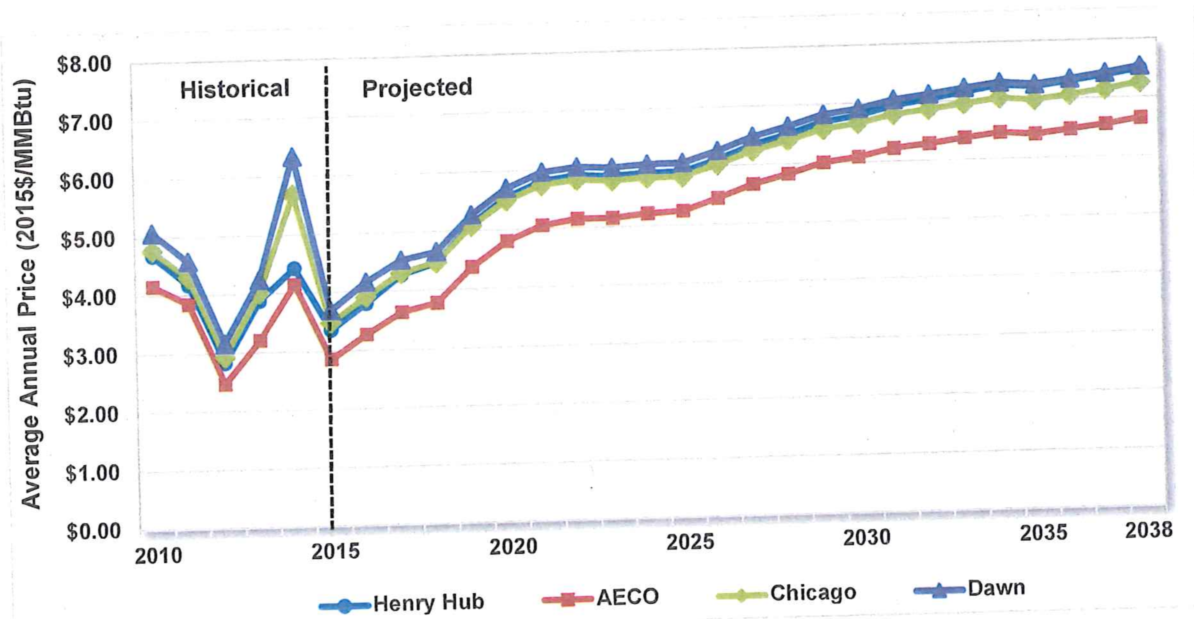
Gas flows out of western Canada are projected to decline. Growth in production from shale gas resources in British Columbia (BC) and Alberta will be more than offset by declines in conventional gas production in Alberta until 2020, as well as growth in natural gas demand in western Canada. Strong industrial demand growth in western Canada for producing oil from oil sands will keep more gas in the western provinces. The planned LNG export terminals in British Columbia will also draw off gas supply once exports of LNG begin. Pipeline flows west out of the Rocky Mountains will increase to northern California. The completion of the Ruby Pipeline in 2011 allowed Rocky Mountain gas to displace gas coming from Alberta on Gas Transmission Northwest.

3.4 Natural Gas Price Trends

With growing gas demand and increased reliance on new sources of supply, the Base Case forecasts higher gas prices from current levels. Nevertheless, the cost of producing shale gas moderates the price increase. In the Base Case, gas prices at Henry Hub are expected to increase gradually, climbing from approximately $4.43 per MMBtu in 2014 to $7.49 per MMBtu in 2038 (in 2015 dollars) (see exhibit below). This gradual increase in gas prices supports development of new sources of supply, but prices are not so high as to discourage demand growth. The price increase over the forecast period is driven by Base Case gas demand growth from several sources including gas-fired power generation, industrial gas use, pipeline exports to Mexico, and LNG exports. This growth in demand requires the exploitation of lower-quality natural gas resources and leads to higher drilling levels and an increase in drilling and completion factor costs. These depletion and factor cost effects are partly offset by upstream technological advances, but some real cost escalation is expected to be needed to meet the fast-growing demand expected in the ICF Base Case.

Gas prices throughout The U.S. and Canada are expected to remain moderate; however, in some regions other market dynamics will influence regional prices. The price difference (or basis) between Henry Hub and Alberta, for example, is projected to narrow in 2013-2015, thereafter widening somewhat through around 2020. As more gas is produced in the U.S. Northeast from shale resources, the market price in this region is expected to decline, relative to Henry Hub.

Exhibit 3-11: GMM Average Annual Prices for Selected Markets

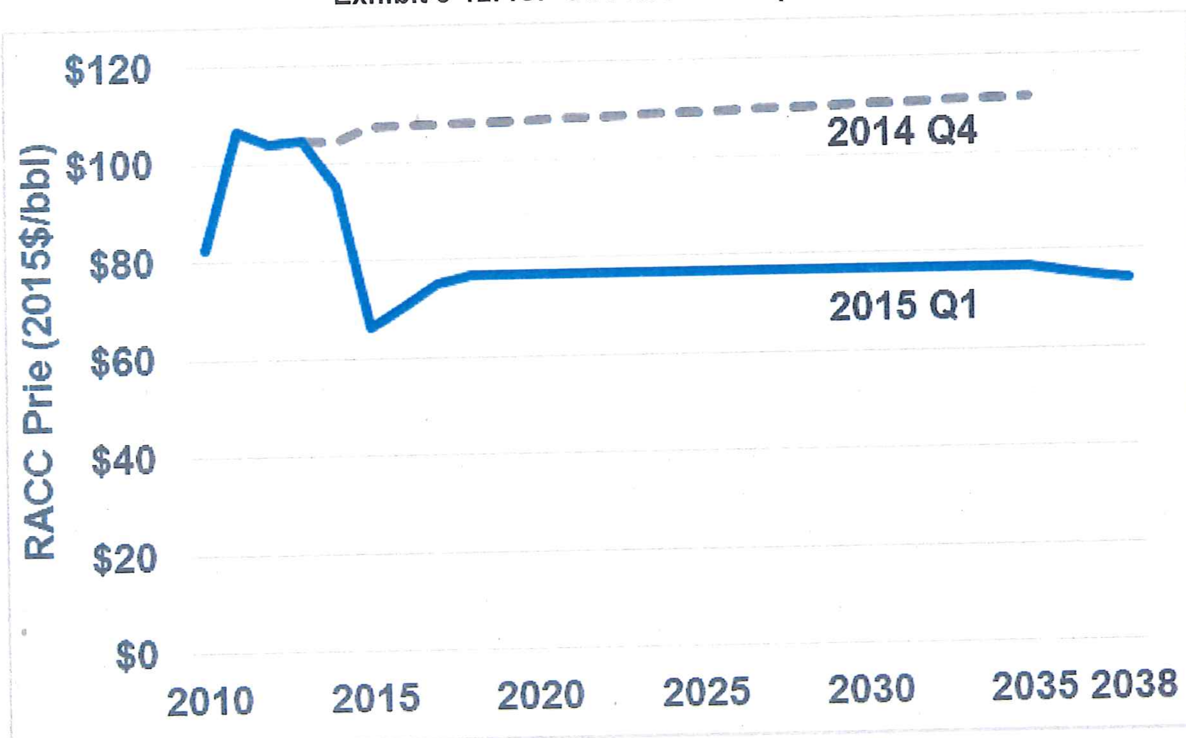


Source: ICF

3.5 Oil Price Trends

In the wake of recent market declines, ICF has revised its oil price assumption downward from a real price of over $100/bbl due to the ongoing global supply surplus and slowing economic growth. The revised assumption is based on futures trading patterns over the past quarter. ICF assumes that oil prices will follow a trajectory starting with the December spot price and will rise to a constant real level reflecting a liquid traded mid-term price in the futures market of approximately $77/bbl (2015 dollars) after 2017, as shown in the exhibit below.

Exhibit 3-12: ICF Oil Price Assumptions



Source: ICF

4 Study Methodology

This section describes ICF's methodologies in assessing U.S. and Canadian natural gas market dynamics, resource base assessments, and energy and economic impact modeling.

4.1 Resource Assessment Methodology

ICF assessments combine components of publicly available assessments by the USGS and the Bureau of Ocean Energy Management (BOEM/formerly the Mineral Management Service, MMS), industry assessments such as that of the National Petroleum Council, and our own proprietary work. As described in the previous section, in recent years, we have done extensive work to evaluate shale gas, tight gas, and coalbed methane using engineering-based geographic information system (GIS) approaches. This has resulted in the most comprehensive and detailed assessment of North America gas and oil resources available. It includes GIS analysis of over 30 unconventional gas plays.

On the resource cost side, ICF uses discounted cash flow analysis at various levels of granularity, depending upon the category of resource. For undiscovered fields, the analysis is done by field size class and depth interval, while for unconventional plays, DCF analysis is generally done on each 36-square-mile unit of play area. Exhibit 4-1 is a map of the U.S. Lower-48 ICF oil and gas supply regions.

4.1.1 Conventional Undiscovered Fields

Undiscovered fields are assessed by 5,000-foot drilling depth intervals and a distribution of remaining fields by USGS "size class." Hydrocarbon ratios are applied to convert barrel of oil equivalent (BOE) per size class into quantities of recoverable oil, gas, and NGLs. U.S. and Canadian conventional resources are based largely on USGS and BOEM (formerly MMS) (and various agencies in Canada) assessments made over the past 15 years. The USGS provides information on discovered and undiscovered oil and gas and number of fields by field size class. The ICF assessments were reviewed by oil and gas producing industry representatives in the U.S. and Canada as part of the 2003 National Petroleum Council study.[10]

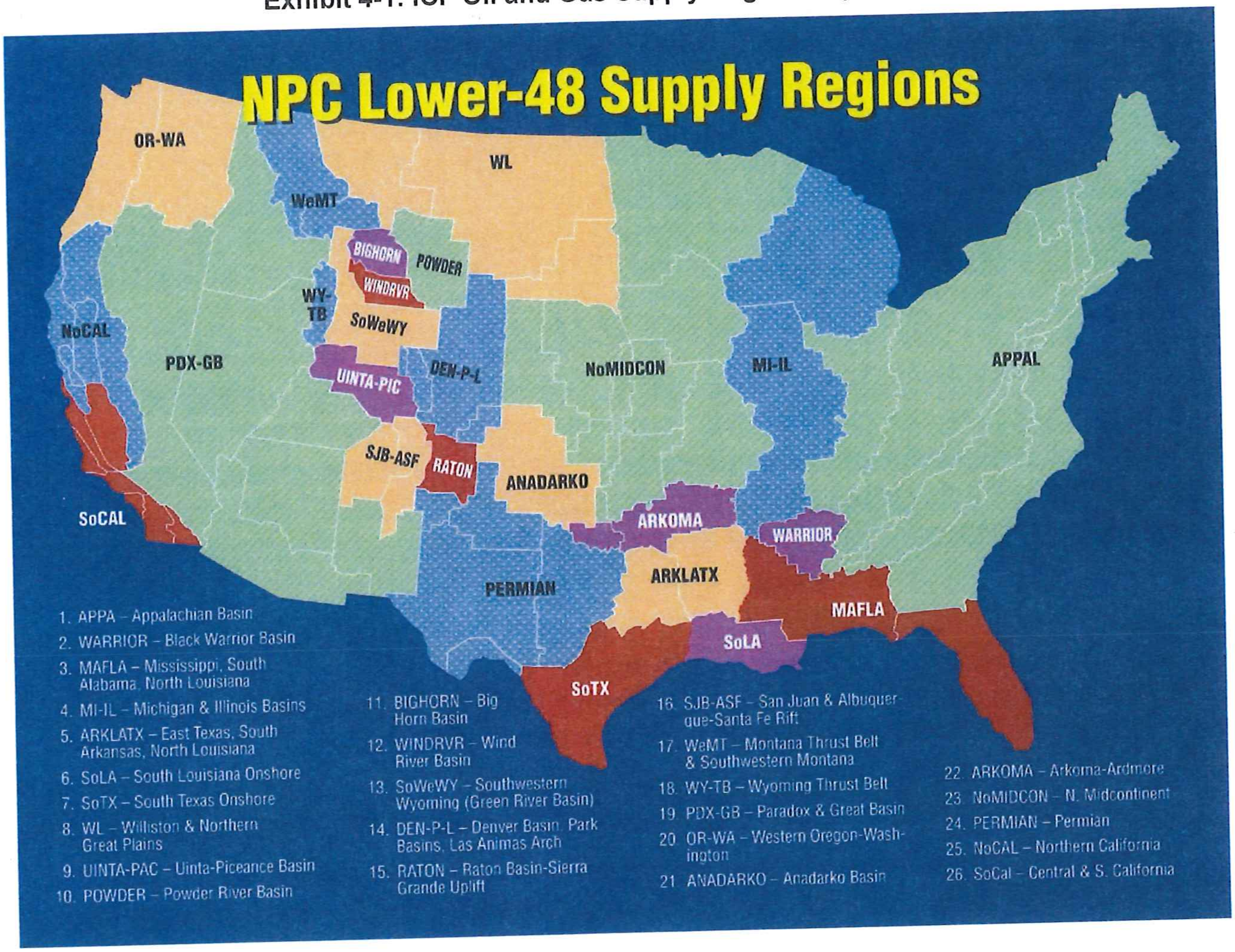
4.1.2 Unconventional Oil and Gas

Unconventional oil and gas is defined as continuous deposits in low-permeability reservoirs that typically require some form of well stimulation such as hydraulic fracturing and/or horizontal drilling. ICF has assessed future North America unconventional gas and liquids potential, represented by **shale gas, tight oil, tight sands, and coalbed methane**. Prior to the shale gas revolution, ICF relied upon a range of sources for our assessed volumes, including USGS, the National Petroleum Council studies, and in-house work for various clients. In recent years, we

[10] U.S. National Petroleum Council (NPC). "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy". NPC, 2003. Available at: http://www.npc.org/

developed our GIS method of assessing shale and other unconventional resources. The current assessment is a hybrid assessment, using the GIS-derived data where we have it.

Exhibit 4-1: ICF Oil and Gas Supply Region Map



Source: NPC

ICF developed a GIS-based analysis system covering 32 major North American unconventional gas plays. The GIS approach incorporates information on the geologic, engineering, and economic aspects of the resource. Models were developed to work with GIS data on a 36-square-mile unit basis to estimate unrisked and risked gas-in-place, recoverable resources, well recovery, and resource costs at a specified rate of return. The GIS analysis focuses on gas and NGLs and addresses the issue of lease condensate and gas plant liquids, both in terms of recoverable resources and their impact on economics.

The ICF unconventional gas GIS model is based upon mapped parameters of depth, thickness, organic content, and thermal maturity, and assumptions about porosity, pressure gradient, and other information. The unit of analysis for gas-in-place and recoverable resources is a 6-by-6 mile or 36-square-mile grid unit. Gas-in-place is determined for free gas, adsorbed gas, and gas dissolved in liquids, and well recovery is modeled using a reservoir simulator.[11] Gas resources and recovery per well are estimated as a function of well spacing. Exhibit 4-2 is a listing of the GIS plays in the model.

Exhibit 4-2: ICF Unconventional Plays Assessed Using GIS Methods

no.	Play	Play Area Sq. Mi.	Assess-ment well spacing (acres)
	Shale		
1	Appalachian Marcellus Shale	39,100	40
2	Appalachian Huron Shale	22,941	80
3	NY Utica Shale	14,280	80
4	Ft. Worth Barnett Shale	26,300	40
5	Gulf Coast Haynesville Shale	7,400	40
6	Gulf Coast Bossier Shale	2,830	40
7	Texas Eagle Ford Shale	9,097	60
8	West Texas Barnett Shale	4,500	40
9	West Texas Woodford Shale	4,500	40
10	Arkoma Fayetteville Shale	2,600	60
11	Arkoma Woodford Shale	1,863	40
12	Arkoma Moorefield Shale	520	80
13	Arkoma Caney Shale	6,340	80
14	Anadarko Woodford Shale	1,776	40
15	Uinta Mancos Shale	7,100	20
16	Paradox Gothic Shale	1,350	80
17	Paradox Cane Creek Shale	3,110	40
18	Green River Vermillion Baxter Shale	180	20
19	Green River Hilliard Shale	4,350	20
	L-48 GIS- assessed shale total	**160,137**	

	Play	Play Area Sq. Mi.	Assess-ment well spacing (acres)
20	WCSB Montney Siltstone	13,700	40
21	WCSB Horn River Muskwa/Evie Shale	5,100	80
22	WCSB Cordova Embayment Shale	1,544	160
23	Quebec Utica Shale	1,600	80
24	New Brunswick Frederick Brook Sh.	120	80
	Canada GIS-assessed shale total	**22,064**	
	Tight Gas		
25	Anadarko Granite Wash Tight	3,533	213
26	Uinta Mesaverde Tight	4,721	10
27	Uinta Wasatch Tight	2,045	10
28	Green River Lance Tight	16,200	5
29	Green River Mesaverde/Almond Tight	13,400	20
	L-48 GIS-assessed tight total	**39,899**	
	Coalbed Methane		
30	**San Juan Fruitland CBM (L-48 GIS total)**	**6,599**	**160**
31	WCSB Horseshoe Canyon CBM	24,730	80
32	WCSB Mannville CBM	46,758	320
	Canada GIS-assessed CBM total	**71,488**	

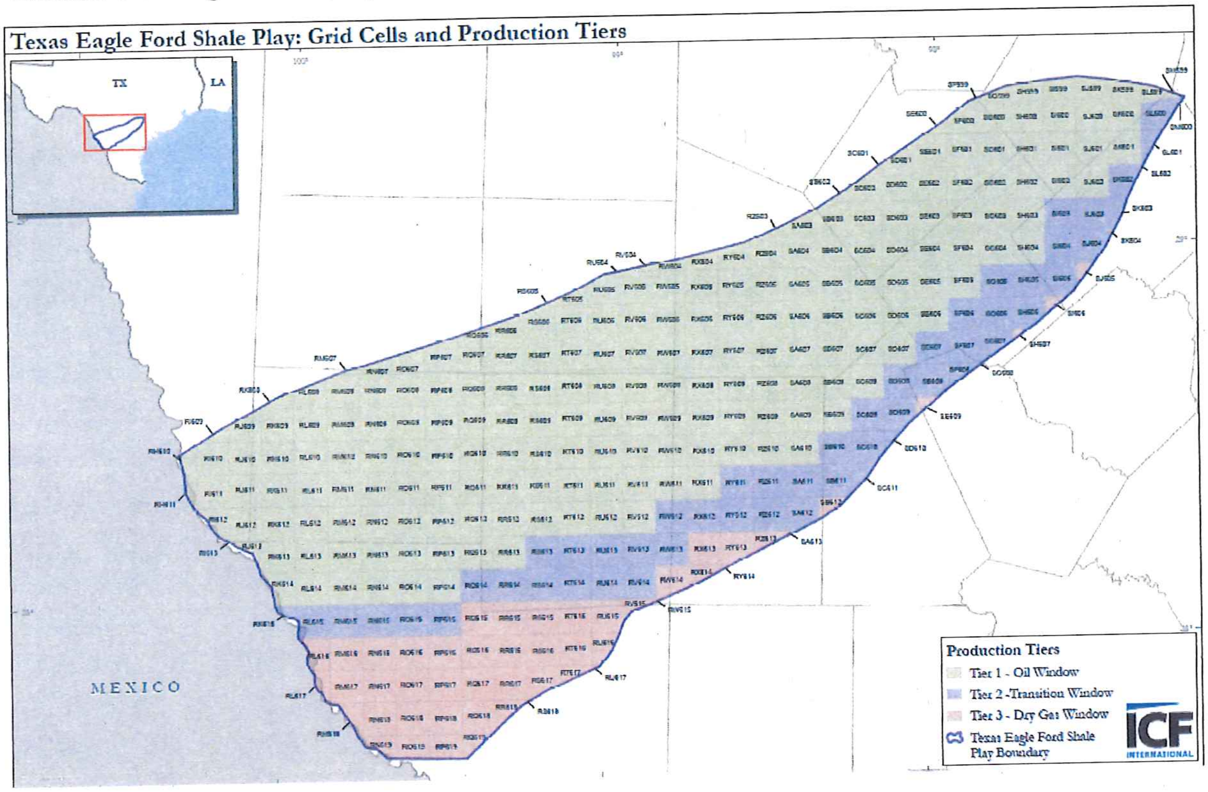
Source: ICF

Exhibit 4-3 shows an example of the granularity of analysis for a specific play. This map shows the six-mile grid base and oil and gas production windows for the Eagle Ford play in South Texas. Economic analysis is also performed on a 36-square-mile unit basis and is based upon discounted cash flow analysis of a typical well within that area. Model outputs include risked and unrisked gas-in-place, recoverable resources as a function of spacing, and supply versus cost curves.

One of the key aspects of the analysis is the calibration of the model with actual well recoveries in each play. These data are derived from ICF analysis of a commercial well-level production database. The actual well recoveries are compared with the model results in each 36-square-mile model cell to calibrate the model. Thus, results are not just theoretical, but are ground-truthed to actual well results.

[11] Free gas is gas within the pores of the rock, while adsorbed gas is gas that is bound to the organic matter of the shale and must be desorbed to produce.

Exhibit 4-3: Eagle Ford Play Six-Mile Grids and Production Tiers (Oil, Wet Gas, Dry Gas)



Source: ICF

Tight Oil

Tight oil production is oil production from shale and other low-permeability formations including sandstone, siltstone, and carbonates. The tight oil resource has emerged as a result of horizontal drilling and multi-stage fracturing technology. Tight oil production in both the U.S. and Canada is surging. Production in 2014 was approximately 3.5 to 4.0 million barrels per day (MMbpd) in the U.S., up from less than 250,000 barrels per day (bpd) in 2007, and 350,000 bpd in Canada. The 3.5 MMbpd of U.S. tight oil production is dominated by the Bakken, Eagle Ford, and Permian Basin. The Eagle Ford volumes include a large amount of lease condensate.

Tight oil production impacts both oil and gas markets. Tight oil contains a large amount of associated gas, which affects the North American price of natural gas. Growing associated gas production has resulted in the need for a great deal of midstream infrastructure expansion.

Tight oil resources may be represented by previously undeveloped plays, such as the Bakken shale, and in other cases may be present on the fringes of old oil fields, as is the case in western Canada. ICF assessments are based upon map areas or "cells" with averaged values of depth, thickness, maturity, and organics. The model takes this information, along with assumptions about porosity, pressure, oil gravity, and other factors to estimate original-oil-in-place and gas-in-place, recovery per well, and risked recoverable resources of oil and gas. The results are compared to actual well recovery estimates. A discounted cash flow model is used to develop a cost of supply curve for each play.

4.1.3 Technology and Cost Assumptions

An important aspect of the resource assessment is the underlying assumptions about technology. The ICF economic resource assessment is based upon existing technology. This is a conservative assumption, as has been demonstrated by the very rapid technology growth in shale gas and tight oil development in just five years.

In recent years, there have been great gains in technology related to the drilling of long horizontal laterals, expanding the number and effectiveness of stimulation stages, use of advanced proppants and fluids, and the customization of fracture treatments based upon real-time microseismic monitoring.

In general, lateral lengths and the number of stimulation stages are increasing in most plays. This increases the cost per well over prior configurations. However, the gas recovery is much greater than the increased cost, resulting in lower costs per unit of production.

Drilling costs have been reduced largely due to increased efficiency and the higher rate of penetration. In some cases, the number of rig days to drill a well is a fraction of what it was several years ago. A factor that has limited the reduction in drilling costs has been the rig day rate, which has been relatively high due to large demand for specialized rigs. However, with recent declines in oil prices and drilling activity, rig rates and some other cost factors are expected to decline significantly.

4.2 Energy and Economic Impacts Methodology

Cameron LNG tasked ICF with assessing the economic and employment impacts of additional LNG exports from its Hackberry, LA LNG export plant. This study assessed two cases[12]:

1) **Base Case** assumption of currently approved trains 1-3 volumes of 620 billion cubic feet per year, or 1.70 billion cubic feet per day (Bcfd).
2) **Trains 1-3 Supplemental Volumes Case** assumption of an additional 152 Bcf per year, or 0.42 Bcfd higher than the Base Case due to the supplemental volumes from trains 1-3. This gives a total volume of 772 Bcf per year, or 2.12 Bcfd, including Base Case volumes.

The results in this report show the changes in impacts between the Base Case and alternative case resulting from the incremental LNG export volumes. ICF assessed the economic impacts of additional LNG exports from Cameron LNG for two cases. The methodology consisted of the following steps:

Step 1 – Natural gas and liquids production: We first ran the ICF Gas Market Model to determine supply, demand, and price changes in the natural gas market. The natural gas and liquids production changes required to support the additional LNG exports were assessed on both a national and Louisiana level.

[12] These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

Step 2 – LNG plant capital and operating expenditures: Based on Cameron LNG's cost estimates, ICF determined the annual capital and operating expenditures that will be required to support the LNG exports.

Step 3 – Upstream capital and operating expenditures: ICF then translated the natural gas and liquids production changes from the GMM into annual capital and operating expenditures that will be required to support the additional production.

Step 3 – IMPLAN input-output matrices: ICF entered both LNG plant and upstream expenditures into the IMPLAN input-output model to assess the economic impacts for the U.S. and Louisiana. For instance, if the model found that $100 million in a particular category of expenditures generated 390 direct employees, 140 indirect employees, and 190 induced employees (i.e., employees related to consumer goods and services), then we would apply those proportions to forecasted expenditure changes. If forecasted expenditure changes totaled $10 million one year, according to the model proportions, that would generate 39 direct, 14 indirect, and 19 induced employees in the year the expenditures were made.

Step 4 – Economic impacts: ICF assessed the impact of LNG exports for the national and Louisiana levels. This included direct, indirect, and induced impacts on gross domestic product, employment, taxes and other measures.

Exhibit 4-4: Impact Definitions

Classification of Impact Types

Direct – represents the immediate impacts (e.g., employment or output changes) due to the investments that result in direct demand changes, such as expenditures needed for the construction of LNG liquefaction plant or the drilling and operation of a natural gas well.

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

Induced – represents the impacts on all local and national industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes.

Definitions of Impact Measures

Output – represents the value of an industry's total output increase due to the modeled scenario (in millions of constant dollars).

Employment – represents the jobs created by industry, based on the output per worker and output impacts for each industry.

Total Value Added – is the contribution to Gross Domestic Product (GDP) and is the "catch-all" for payments made by individual industry sectors to workers, interests, profits, and indirect business taxes. It measures the specific contribution of an individual sector after subtracting out purchases from all suppliers.

Tax Impact – breakdown of taxes collected by the federal, state and local government institutions from different economic agents. This includes corporate taxes, household income taxes, and other indirect business taxes.[13]

Key model assumptions are based on ICF analysis of the industry and previous work, and include:

- Cameron LNG export volumes
- LNG plant capital and operating expenditures
- Per-well upstream capital costs
- Fixed and variable upstream operating costs per well
- Tax rates

The following set of exhibits show the key model assumptions.

[13] The tax impacts are not part of the GDP accounting framework used for the other impacts. These are calculated in IMPLAN using standard assumptions about tax rates.

Exhibit 4-5: Cameron LNG Exports by Case (Bcfd)

Year	Base Case	The T 1-3 Supplemental Volumes Case	The T 1-3 Supplemental Volumes Case Changes
2016	-	-	-
2017	0.06	0.07	0.01
2018	1.22	1.52	0.30
2019	1.70	2.12	0.42
2020	1.70	2.12	0.42
2021	1.70	2.12	0.42
2022	1.70	2.12	0.42
2023	1.70	2.12	0.42
2024	1.70	2.12	0.42
2025	1.70	2.12	0.42
2026	1.70	2.12	0.42
2027	1.70	2.12	0.42
2028	1.70	2.12	0.42
2029	1.70	2.12	0.42
2030	1.70	2.12	0.42
2031	1.70	2.12	0.42
2032	1.70	2.12	0.42
2033	1.70	2.12	0.42
2034	1.70	2.12	0.42
2035	1.70	2.12	0.42
2036	1.70	2.12	0.42
2037	1.70	2.12	0.42
2038	1.70	2.12	0.42
2016-2038 Average	*1.53*	*1.91*	*0.38*

Source: Cameron LNG, ICF

Exhibit 4-6: Cameron LNG plant Capital and Operating Expenditures by Case

Year	T 1-3 Supplemental Volumes Case Changes	
	LNG Capital Costs (2015$ MM)	LNG Operating Costs (2015$ MM)
2010	$0.00	$0.00
2011	$0.00	$0.00
2012	$0.00	$0.00
2013	$0.00	$0.00
2014	$0.00	$0.00
2015	$0.00	$0.00
2016	$0.00	$0.00
2017	$0.00	$0.25
2018	$0.00	$3.34
2019	$0.00	$4.22
2020	$0.00	$4.22
2021	$0.00	$4.22
2022	$0.00	$4.22
2023	$0.00	$4.22
2024	$0.00	$4.22
2025	$0.00	$4.22
2026	$0.00	$4.22
2027	$0.00	$4.22
2028	$0.00	$4.22
2029	$0.00	$4.22
2030	$0.00	$4.22
2031	$0.00	$4.22
2032	$0.00	$4.22
2033	$0.00	$4.22
2034	$0.00	$4.22
2035	$0.00	$4.22
2036	$0.00	$4.22
2037	$0.00	$4.22
2038	$0.00	$4.22

Source: Cameron LNG, ICF

Exhibit 4-7: Assumed Federal, State, and Local Tax Rates

Year	Federal Tax Rate on GDP (%)	Weighted Average State and Local Tax Rate on GDP (% of own-source) (%)	Louisiana State and Local Own Taxes as % of State Income (%)
2010	14.6%	15.1%	15.5%
2011	15.0%	14.9%	15.4%
2012	15.3%	14.5%	15.5%
2013	16.7%	14.5%	15.5%
2014	17.5%	14.5%	15.5%
2015	17.7%	14.5%	15.5%
2016	18.7%	14.5%	15.5%
2017	19.1%	14.5%	15.5%
2018	19.1%	14.5%	15.5%
2019	19.2%	14.5%	15.5%
2020	19.3%	14.5%	15.5%
2021	19.4%	14.5%	15.5%
2022	19.5%	14.5%	15.5%
2023	19.6%	14.5%	15.5%
2024	19.7%	14.5%	15.5%
2025	19.8%	14.5%	15.5%
2026	19.9%	14.5%	15.5%
2027	20.0%	14.5%	15.5%
2028	20.1%	14.5%	15.5%
2029	20.2%	14.5%	15.5%
2030	20.3%	14.5%	15.5%
2031	20.4%	14.5%	15.5%
2032	20.5%	14.5%	15.5%
2033	20.6%	14.5%	15.5%
2034	20.7%	14.5%	15.5%
2035	20.8%	14.5%	15.5%
2036	20.9%	14.5%	15.5%
2037	21.0%	14.5%	15.5%
2038	21.1%	14.5%	15.5%

Source: ICF extrapolations from Tax Policy Center historical figures

Exhibit 4-8: Liquids Price Assumptions

Year	RACC Price (2015$/bbl)	Condensate Price (2015$/bbl)	Ethane Price (2015$/bbl)	MB Propane Price (2015$/bbl)	Butane Price (2015$/bbl)	Pentanes Plus (2015$/bbl)
2010	$ 82.33	$ 82.33	$ 27.16	$ 48.93	$ 55.80	$ 75.06
2011	$ 106.57	$ 106.57	$ 24.22	$ 61.46	$ 72.23	$ 97.17
2012	$ 103.92	$ 103.92	$ 16.39	$ 42.19	$ 70.43	$ 94.75
2013	$ 104.73	$ 104.73	$ 22.50	$ 42.03	$ 70.99	$ 95.49
2014	$ 95.09	$ 95.09	$ 25.67	$ 43.74	$ 64.45	$ 86.70
2015	$ 66.13	$ 66.13	$ 19.46	$ 35.05	$ 44.82	$ 60.29
2016	$ 70.59	$ 70.59	$ 22.02	$ 37.42	$ 47.85	$ 64.37
2017	$ 74.85	$ 74.85	$ 22.18	$ 39.68	$ 50.73	$ 68.25
2018	$ 76.73	$ 76.73	$ 22.33	$ 40.68	$ 52.01	$ 69.96
2019	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2020	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2021	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2022	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2023	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2024	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2025	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2026	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2027	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2028	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2029	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2030	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2031	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2032	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2033	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2034	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2035	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2036	$ 75.74	$ 75.74	$ 22.35	$ 40.15	$ 51.33	$ 69.06
2037	$ 74.84	$ 74.84	$ 22.09	$ 39.67	$ 50.72	$ 68.24
2038	$ 74.04	$ 74.04	$ 21.85	$ 39.25	$ 50.18	$ 67.51

Source: ICF

Exhibit 4-9: Other Key Model Assumptions

Assumption	U.S.	Louisiana
Upstream Capital Costs ($MM/Well)	$7.7	$10.6
Upstream Operating Costs ($/barrel of oil equivalent, BOE)	$3.19	$3.19
Royalty Payment (%)	16.7%	21.9%
LNG Tanker Capacity (Bcf/Ship)		3.60 (135,000-170,000 m^3)
U.S. Port Fee ($/Port Visit)		$100,000
Cameron LNG Liquefaction Fee ($/MMBtu)		$3.00

Source: Various compiled or estimated by ICF

4.3 IMPLAN Description

The IMPLAN model is an input-output model based on a social accounting matrix that incorporates all flows within an economy. The IMPLAN model includes detailed flow information for hundreds of industries. By tracing purchases between sectors, it is possible to estimate the economic impact of an industry's output (such as the goods and services purchased by the oil and gas upstream sector) to impacts on related industries.

From a change in industry spending, IMPLAN generates estimates of the direct, indirect, and induced economic impacts. Direct impacts refer to the response of the economy to the change in the final demand of a given industry to those directly involved in the activity, in this case, the direct expenditures associated with an incremental drilled well. Indirect impacts (or supplier impacts) refer to the response of the economy to the change in the final demand of the industries that are dependent on the direct spending of industries for their input. Induced impacts refer to the response of the economy to changes in household expenditure as a result of labor income generated by the direct and indirect effects.

After identifying the direct expenditure components associated with LNG plant and upstream development, the direct expenditure cost components (identified by their associated North American Industry Classification System (NAICS) code) are then used as inputs into the IMPLAN model to estimate the total indirect and induced economic impacts of each direct cost component.

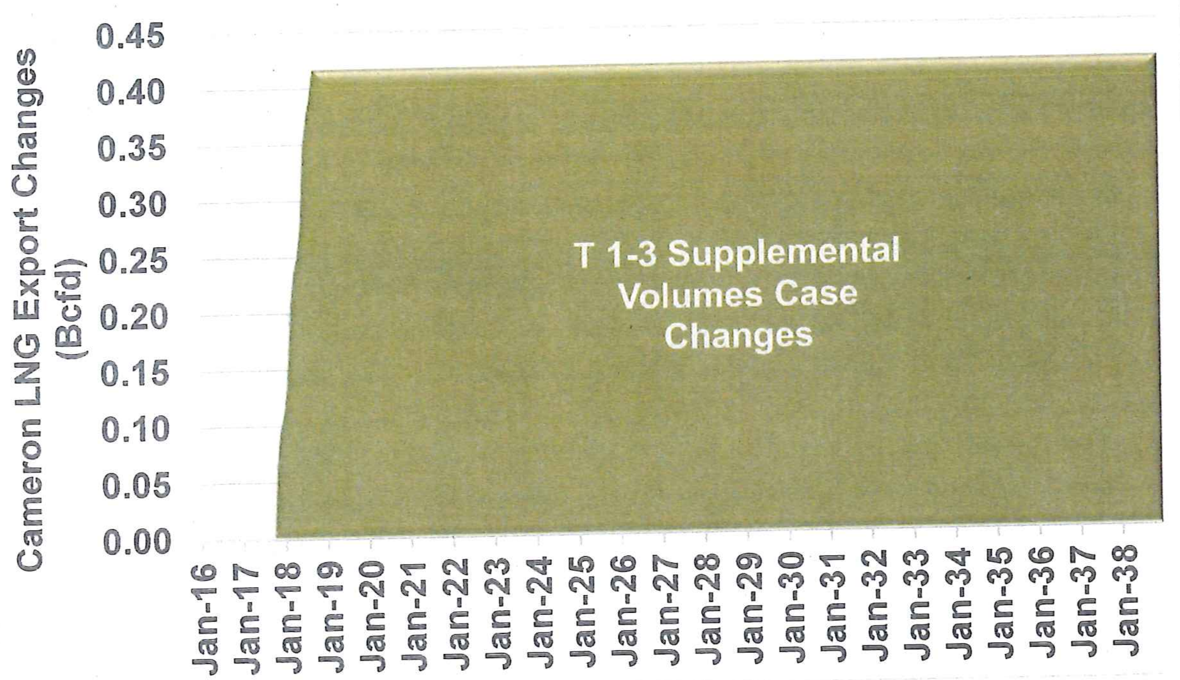
Direct, Indirect, and Induced Economic Impacts

ICF assessed the economic impact of LNG exports on three levels: direct, indirect, and induced impacts. Direct industry expenditures (e.g., natural gas drilling and completion expenditures) produce a domino effect on other industries and aggregate economic activity, as component industries' revenues (e.g., cement and steel manufacturers needed for well construction) are stimulated along with the direct industries. Such secondary economic impacts are defined as "indirect." In addition, further economic activity, classified as "induced," is generated in the economy at large through consumer spending by employees in direct and indirect industries.

5 Trains 1-3 Supplemental Volumes Energy Market and Economic Impact Results

This section details the results of the Cameron LNG Base Case versus the T 1-3 Supplemental Volumes Case impacts. The findings between the Base Case and the T 1-3 Supplemental Volumes Case result from the 0.42 Bcfd LNG export delta between the cases, as shown below.

Exhibit 5-1: Trains 1-3 Cameron LNG Export Changes



Note: These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

Source: ICF

5.1 U.S. Impacts

This section discusses the impacts of LNG exports in the Base Case and the T 1-3 Supplemental Volumes Case in terms of changes in production volumes, capital and operating expenditures, economic and employment impacts, government revenues, and balance of trade. Below discusses the U.S. impacts of the LNG export cases on the U.S. economy, as well as energy market impacts.

Overall, in order to accommodate the incremental increases in LNG exports, the U.S. natural gas market rebalances through three sources: increasing U.S. natural gas production, a contraction in U.S. domestic natural gas consumption, and an increase in natural gas pipeline imports from Canada and Mexico. In addition to the incremental LNG export volumes of 0.42 Bcfd, the market also must rebalance for liquefaction and fuel losses, estimated at 10 percent of incremental export volumes. Thus, the market will rebalance to 110 percent of incremental export volumes, as shown in the exhibit below, which shows the flow sources.

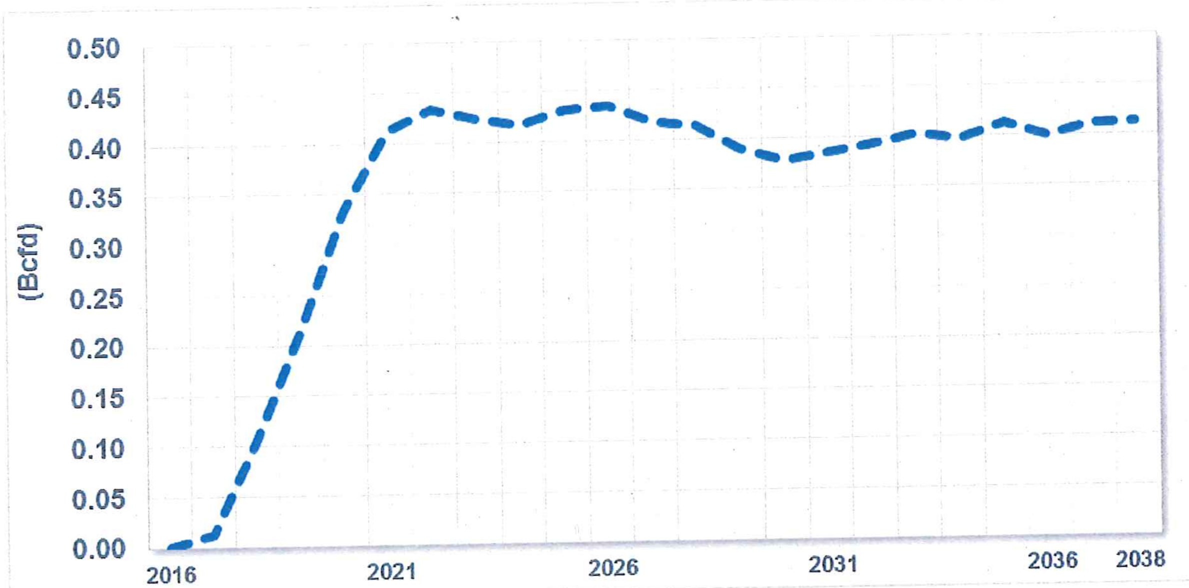
Exhibit 5-2: U.S. Flow Impact Contribution to LNG Exports

Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)
96%	8%	6%	110%

Source: ICF

Exhibit 5-3 illustrates that the T 1-3 Supplemental Volumes Case causes an increase in U.S. natural gas production of 0.41 Bcfd over the Base Case by 2038. Between 2016 and 2038, U.S. natural gas production is expected to increase on an average annual basis of 0.35 Bcfd over the Base Case to accommodate the additional LNG exports.

Exhibit 5-3: U.S. Natural Gas Production Impacts

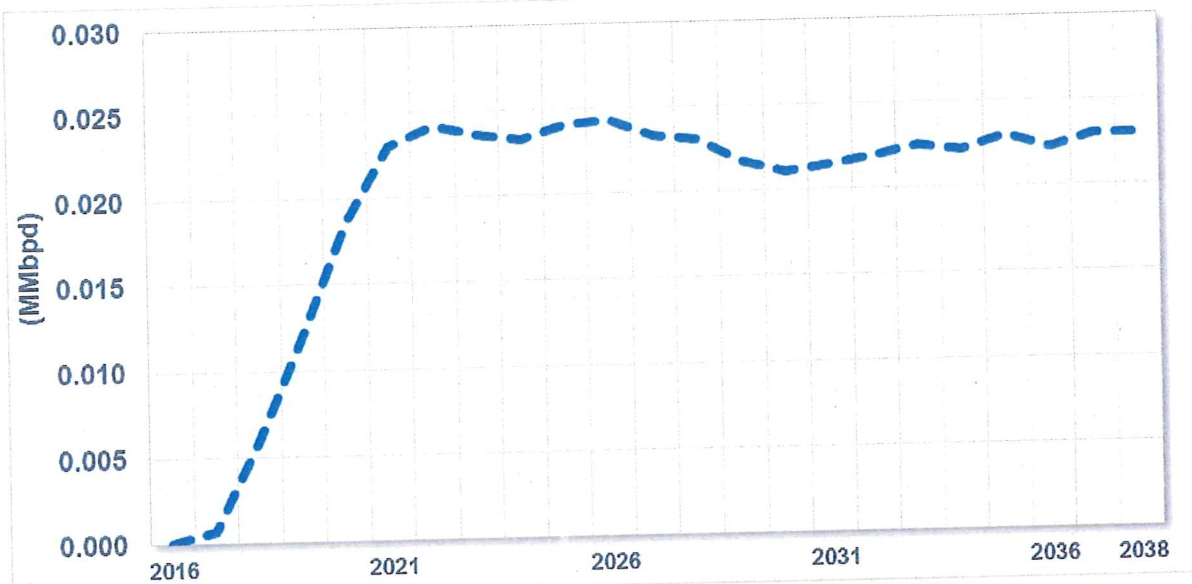


Year	Natural Gas Production (Bcfd) T 1-3 Supplemental Volumes Case Change
2016	0.00
2021	0.41
2026	0.43
2031	0.39
2036	0.40
2038	0.41
2016-2038 Avg	*0.35*

Source: ICF

As seen in Exhibit 5-4, the T 1-3 Supplemental Volumes Case U.S. crude oil, lease condensate, and natural gas liquids production is expected to exceed Base Case levels by 0.02 MMbpd in 2038. Between 2016 and 2038, the T 1-3 Supplemental Volumes Case U.S. natural gas liquids production is expected to increase on an annual average by 0.02 MMbpd over the Base Case as a result of increased natural gas production needed for the additional LNG exports.

Exhibit 5-4: U.S. Liquids Production Changes



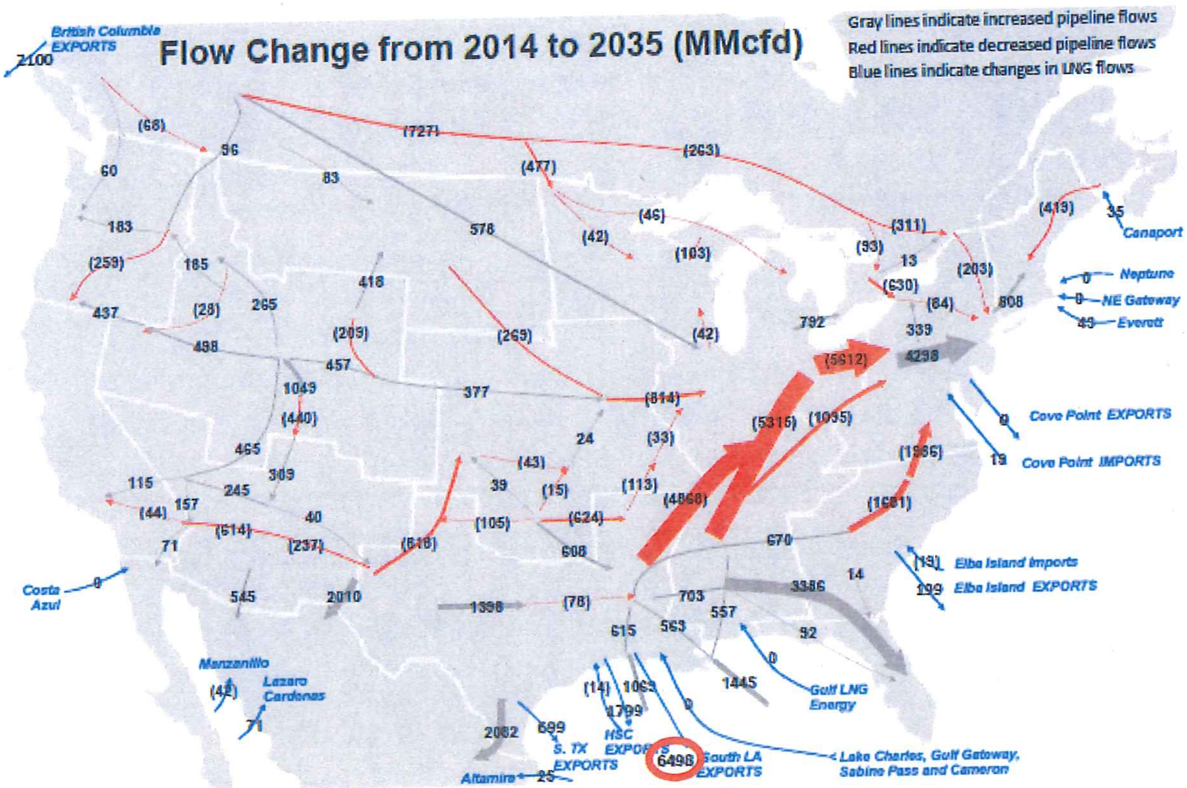
Year	Liquids Production (MMbpd)
	T 1-3 Supplemental Volumes Case Change
2016	0.00
2021	0.02
2026	0.02
2031	0.02
2036	0.02
2038	0.02
2016-2038 Avg	*0.02*

Note: Liquids includes natural gas liquids (NGLs), oil, and condensate.

Source: ICF

As seen in Exhibit 5-5, Base Case U.S. natural gas flow patterns between 2014 and 2035 show shifting supply and demand dynamics in the market. As Marcellus and Utica supplies grow to become the most economic source of gas, flows from WCSB and the Gulf Coast are displaced. Gas flows are expected to change from the historical Gulf Coast to Northeast patterns. By 2035, over 7 Bcfd of natural gas is expected to reverse flows and go south from the Marcellus towards the Gulf Coast and Southeast markets. Gulf Coast LNG exports will be a major driver for this trend as LNG demand goes up in the near term. The red circle on the exhibit below indicates the Louisiana export volumes of 6.5 Bcfd (not including 10 percent fuel for liquefaction) in the Base Case.

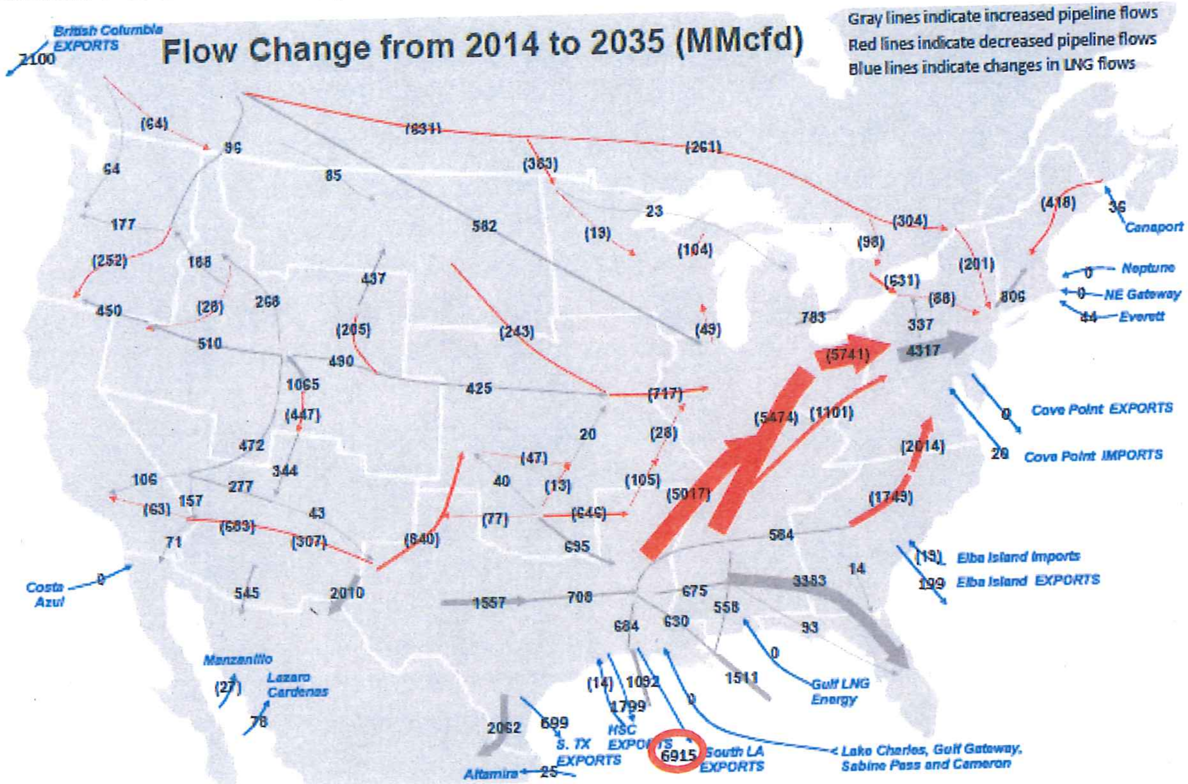
Exhibit 5-5: Base Case U.S. Natural Gas Market Flow Changes



Source: ICF

The map below shows the U.S. natural gas flows in the T 1-3 Supplemental Volumes Case. The flows are similar to Base Case flows, though, as indicated by the red circle below Louisiana LNG exports will see an increase in exports of 0.42 Bcfd in the T 1-3 Supplemental Volumes Case, relative to the Base Case.

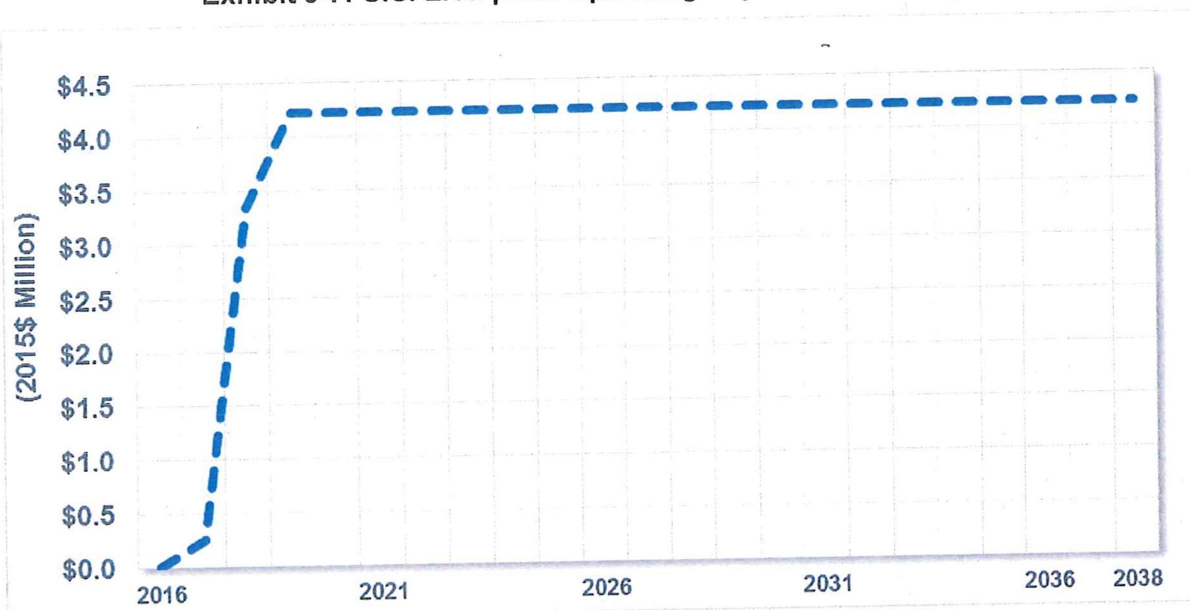
Exhibit 5-6: the T 1-3 Supplemental Volumes Case U.S. Natural Gas Market Flow Changes



Source: ICF

Exhibit 5-7 shows the impact on LNG plant operating expenditures (which exclude the cost of natural gas feedstock and include employee costs, materials, maintenance, insurance, and property taxes). The T 1-3 Supplemental Volumes Case incremental operating expenditures over the Base Case include additional port fees, as the incremental volumes will require additional shiploads, which incur fees estimated at $100,000 per ship. Over the forecast period of 2016 to 2038, there is a total incremental impact on operating expenditures of $88.0 million in the T 1-3 Supplemental Volumes Case as compared to the Base Case. U.S. LNG plant operating expenditures average $3.8 million more annually in the T 1-3 Supplemental Volumes Case as compared to the Base Case.

Exhibit 5-7: U.S. LNG plant Operating Expenditure Changes

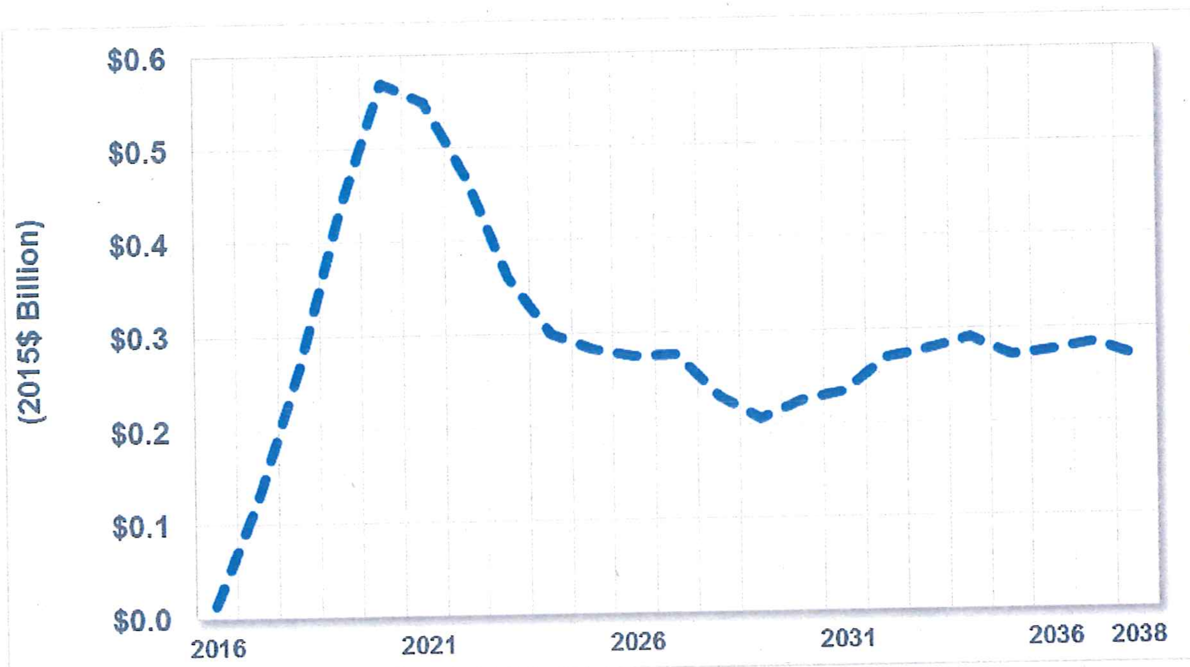


Year	LNG Facility Operating Expenditures (2015$ Million)
	T 1-3 Supplemental Volumes Case Change
2016	$ -
2021	$ 4.2
2026	$ 4.2
2031	$ 4.2
2036	$ 4.2
2038	$ 4.2
2016-2038 Avg	*$ 3.8*
2016-2038 Sum	**88.0**

Source: ICF

Exhibit 5-8 illustrates the impacts of the additional LNG export volumes on U.S. upstream capital expenditures. There is a spike in investment in the early years as more drilling is needed to add the extra deliverability needed as LNG production ramps up. Once full LNG production is reached, fewer new wells are required to sustain production. Over the forecast period of 2016 to 2038, there is a total incremental impact on U.S. upstream capital expenditures of $6.8 billion in the T 1-3 Supplemental Volumes Case as compared to the Base Case. U.S. upstream capital expenditures average $290 million more annually in the T 1-3 Supplemental Volumes Case as compared to the Base Case.

Exhibit 5-8: U.S. Upstream Capital Expenditure Changes

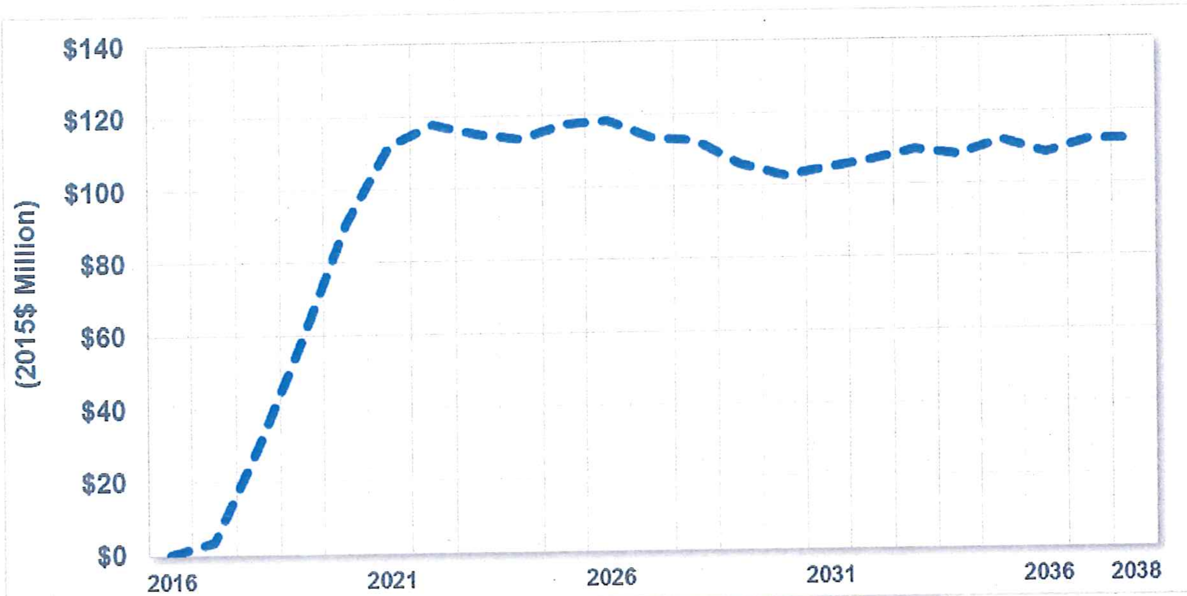


Year	Upstream Capital Expenditures (2015$ Billion)	
	T 1-3 Supplemental Volumes Case Change	
2016	$	0.01
2021	$	0.55
2026	$	0.27
2031	$	0.23
2036	$	0.27
2038	$	0.27
2016-2038 Avg	*$*	*0.29*
2016-2038 Sum	$	**6.75**

Source: ICF

Exhibit 5-9 illustrates the impacts of additional volumes on U.S. upstream operating expenditures. Over the forecast period of 2016 to 2038, there is a total incremental impact on U.S. upstream opperating expenditures of $2.2 billion in the T 1-3 Supplemental Volumes Case as compared to the Base Case. U.S. upstream opperating expenditures average $94.9 million more annually in the T 1-3 Supplemental Volumes Case as compared to the Base Case, due to the incremental demand from additional export volumes.

Exhibit 5-9: U.S. Upstream Operating Expenditure Changes

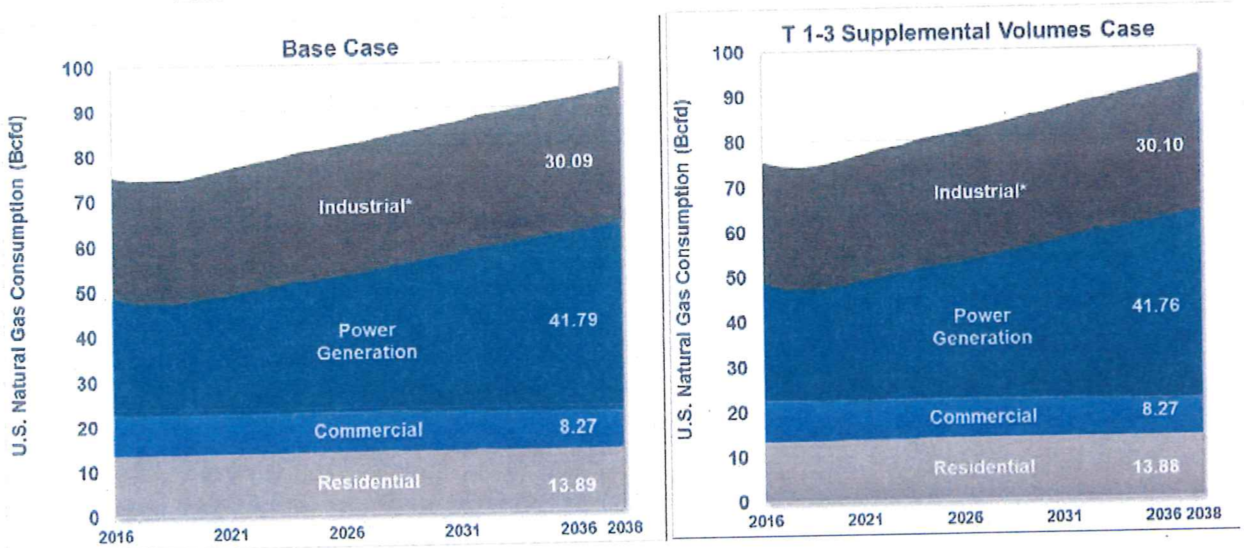


Year	Upstream Operating Expenditures (2015$ Million)	
	T 1-3 Supplemental Volumes Case Change	
2016	$	0.0
2021	$	112.0
2026	$	118.1
2031	$	104.7
2036	$	108.4
2038	$	112.0
2016-2038 Avg	*$*	*94.9*
2016-2038 Sum	**$**	**2,181.7**

Source: ICF

Exhibit 5-10 illustrates the impacts of additional volumes on expected U.S. natural gas consumption by sector and LNG exports. The T 1-3 Supplemental Volumes Case reflects a total U.S. natural gas demand of 0.42 Bcfd (plus liquefaction fuel use of 10 percent, thus totaling 0.46 Bcfd) higher than the Base Case. These findings indicate that LNG exports of 0.42 Bcfd reduce U.S. domestic natural gas consumption by 0.03 Bcfd in 2038, or comprise an average of 8 percent of the T 1-3 incremental export volumes, with the remainder coming from additional U.S. natural gas production and natural gas imports through the forecast period. The contraction in consumption comes from the power sector and a slight decrease in residential natural gas use, relative to the Base Case.

Exhibit 5-10: U.S. Domestic Natural Gas Consumption by Sector



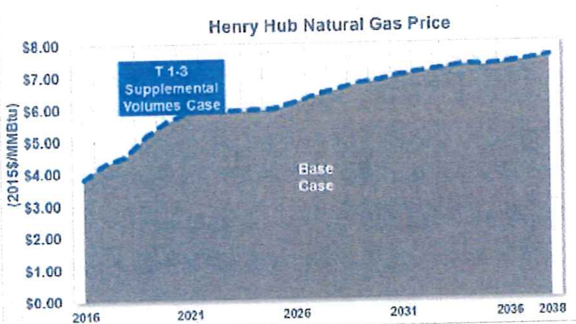
* Includes pipeline fuel and lease & plant

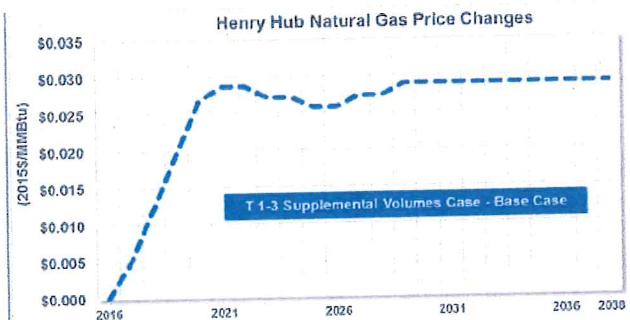
Note: Charts above do not include LNG exports or liquefaction fuel.

Source: ICF

Exhibit 5-11 shows the impacts of additional LNG export volumes on the average annual price per MMBtu of natural gas at Henry Hub. The prices increase slightly in the T 1-3 Supplemental Volumes Case as a result of incremental demand from additional LNG export volumes. The T 1-3 Supplemental Volumes Case is expected to see a 2038 Henry Hub natural gas price of \$7.52/MMBtu by 2038, compared with a Base Case price of \$7.49, indicating a difference of \$0.03/MMBtu attributable to the T 1-3 Supplemental Volumes of 0.42 Bcfd. The impact is most acute in 2020 after LNG exports begin, however the price impact is relatively marginal between 2016 and 2038 at an annual average increase of \$0.03/MMBtu in the T 1-3 Supplemental Volumes Case as compared to the Base Case. Between 2020 and 2038, Henry Hub natural gas prices are expected to increase an average of \$0.03/MMBtu over the Base Case.

Exhibit 5-11: Annual Average Henry Hub Natural Gas Price Changes



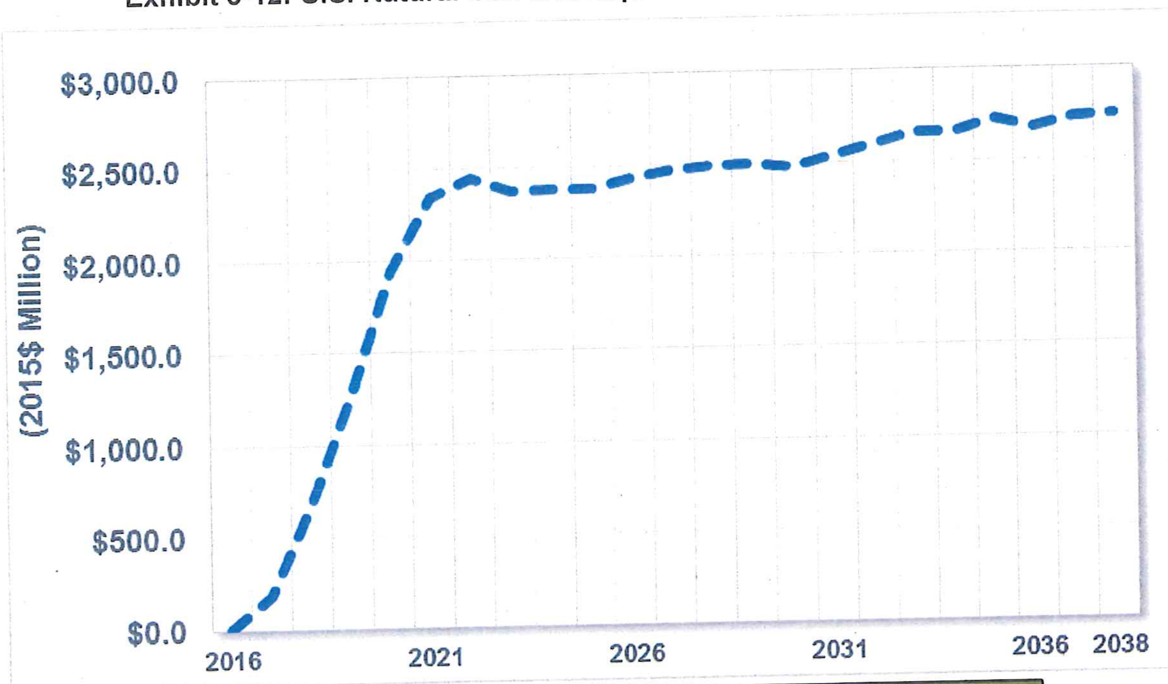


Year	Henry Hub Natural Gas Price (2015\$/MMBtu)		
	Base Case	T 1-3 Supplemental Volumes Case	T 1-3 Supplemental Volumes Case Change
2016	\$ 3.80	\$ 3.80	\$ 0.000
2021	\$ 5.82	\$ 5.85	\$ 0.029
2026	\$ 6.11	\$ 6.14	\$ 0.026
2031	\$ 6.96	\$ 6.98	\$ 0.029
2036	\$ 7.30	\$ 7.33	\$ 0.029
2038	\$ 7.49	\$ 7.52	\$ 0.029
2016-2038 Avg	*\$ 6.21*	*\$ 6.24*	*\$ 0.025*

Source: ICF

Exhibit 5-12 illustrates the impacts of additional volumes on the U.S. natural gas and liquids production value, which increases as a result of additional LNG export volumes and higher natural gas prices as seen in the T 1-3 Supplemental Volumes Case. Over the forecast period 2016 to 2038 the natural gas and liquids production value in the T 1-3 Supplemental Volumes Case sums to $49.6 billion higher than the Base Case. Production values are expected to average nearly $2.2 billion larger annually in the T 1-3 Supplemental Volumes Case as compared to the Base Case between 2016 and 2038.

Exhibit 5-12: U.S. Natural Gas and Liquids Production Value Changes



Year	Natural Gas and Liquids Production Value (2015$ Million)
	T 1-3 Supplemental Volumes Case Change
2016	$ 1.3
2021	$ 2,337.4
2026	$ 2,428.5
2031	$ 2,536.6
2036	$ 2,672.4
2038	$ 2,741.9
2016-2038 Avg	*$ 2,157.5*
2016-2038 Sum	**$ 49,621.9**

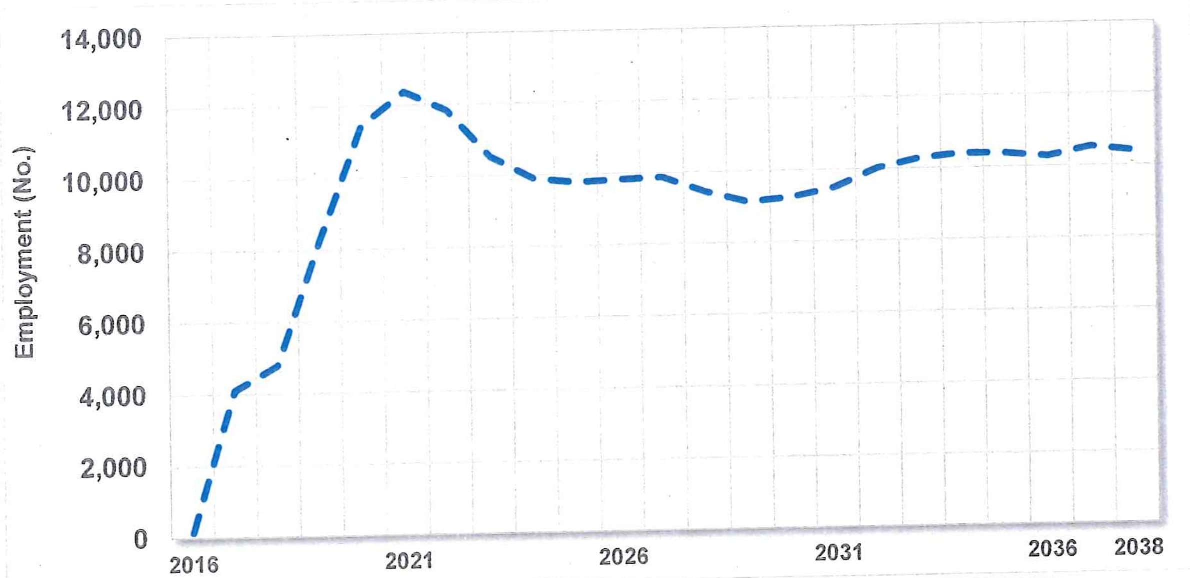
Note: Liquids includes natural gas liquids (NGLs), oil, and condensate.

Source: ICF

Exhibit 5-13 shows the impacts of additional volumes on total U.S. employment changes.[14] The employment impacts are across all industries nationwide, and include direct, indirect, and induced employment. For example, the employment changes include direct and indirect jobs related to additional oil and gas production (such as drilling wells, drilling equipment, trucks to and from the drilling sites, and construction workers), as well as induced jobs. Induced jobs are created when direct and indirect employment increases, and direct and indirect workers spend their higher incomes, creating induced impacts throughout the economy.

Employment numbers are expected to increase as a result of additional LNG export volumes, as well as the indirect and induced employment impacts. The number of anticipated average annual jobs between 2016 and 2038 is 9,200 jobs greater in the T 1-3 Supplemental Volumes Case than in the Base Case. Over the forecast period the incremental LNG exports are expected to increase relative to the Base Case by nearly 212,000 job-years.

Exhibit 5-13: Total U.S. Total Employment Changes

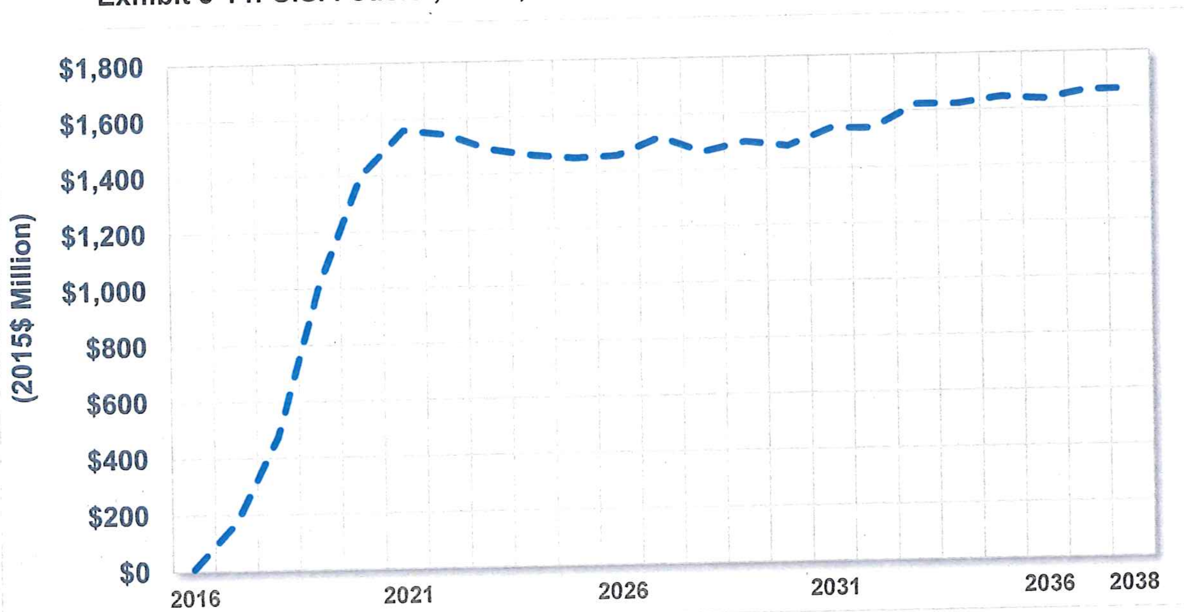


Year	Employment (No.)
	T 1-3 Supplemental Volumes Case Change
2016	149
2021	12,360
2026	9,805
2031	9,480
2036	10,258
2038	10,379
2016-2038 Avg	*9,216*
2016-2038 Sum	**211,966**

Source: ICF

Exhibit 5-14 shows the impact of the additional LNG exports on U.S. federal, state, and local government revenues. Collective government revenues increase $1.3 billion annually as a result of the T 1-3 Supplemental Volumes Case incremental LNG export volumes, or $30.9 billion cumulative over the 23-year forecast period between 2016 and 2038.

Exhibit 5-14: U.S. Federal, State, and Local Government Revenue Changes



Year	Government Revenues (2015$ Million)	
	T 1-3 Supplemental Volumes Case Change	
2016	$	7.3
2021	$	1,557.7
2026	$	1,454.4
2031	$	1,540.3
2036	$	1,632.2
2038	$	1,663.2
2016-2038 Avg	$	*1,343.0*
2016-2038 Sum	$	**30,889.5**

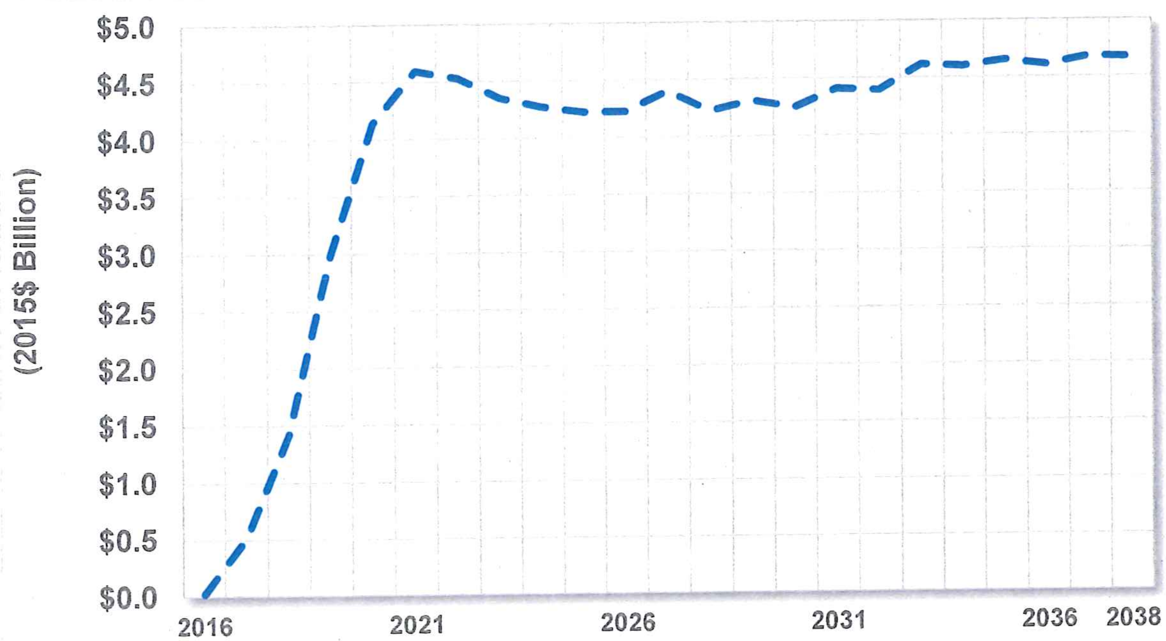
Source: ICF

[14] Note that one job in this report refers to a job-year.

Exhibit 5-15 shows the impacts of additional LNG exports on total U.S. value added (that is, additions to U.S. GDP). The value added is the total U.S. output changes attributable to the incremental LNG exports minus purchases of imported intermediate goods and services. Based on U.S. historical averages across all industries, about 16 percent of output is made of imported goods and services. The value for imports used in the ICF analysis differs by industry and is computed from the IMPLAN matrices.

Total value added increases substantially as a result of the additional LNG export volumes assumed in the T 1-3 Supplemental Volumes Case. The additional LNG volumes in the T 1-3 Supplemental Volumes Case result in a $3.9 billion annual average increase to the U.S. economy over the 2016-2038 23-year period. The cumulative value added over the period between the Base Case and the T 1-3 Supplemental Volumes Case totals $89.1 billion.

Exhibit 5-15: Total U.S. Value Added Changes

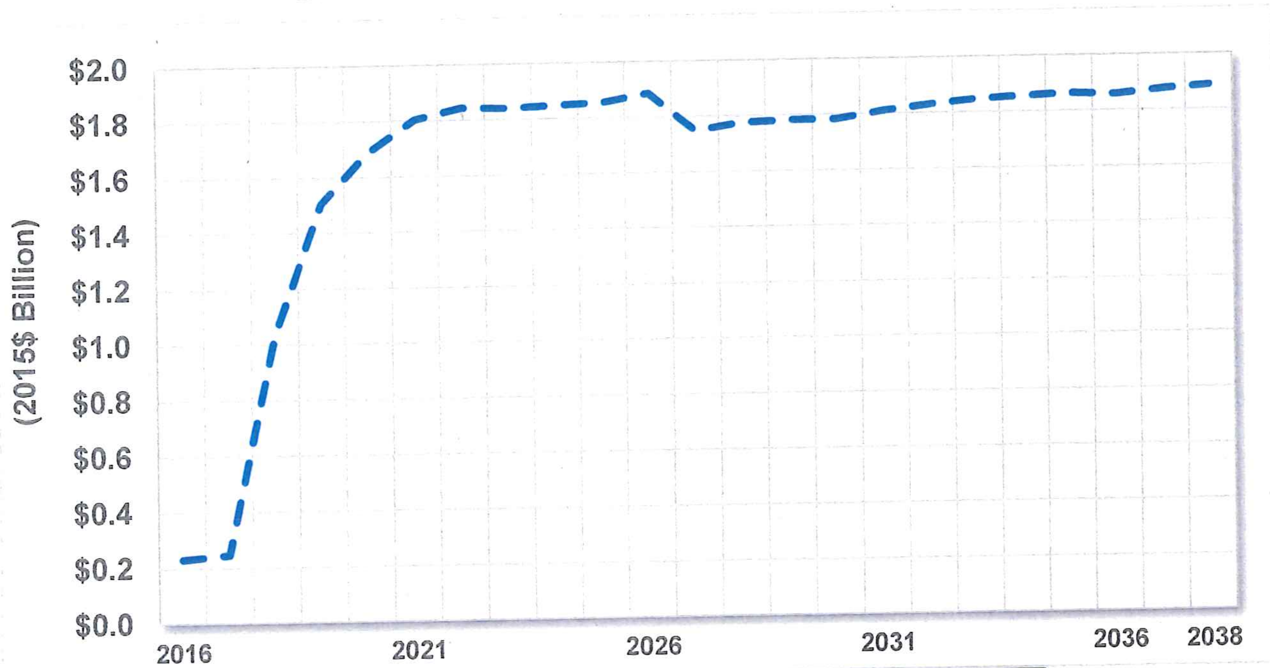


Year	Total Value Added (2015$ Billion)	
	T 1-3 Supplemental Volumes Case Change	
2016	$	0.0
2021	$	4.6
2026	$	4.2
2031	$	4.4
2036	$	4.6
2038	$	4.7
2016-2038 Avg	*$*	*3.9*
2016-2038 Sum	**$**	**89.1**

Source: ICF

The incremental LNG exports are expected to reduce the U.S. balance of trade deficit by $1.6 billion annually between 2016 and 2038, based on the value of LNG export volumes, or a cumulative value of $37.7 billion. The improved balanced of trade is primarily a result of the LNG exports themselves (encompassing the natural gas feedstock used to make the LNG, the LNG liquefaction process, and the port services) and the additional hydrocarbon liquids production that is assumed to either substitute for imported liquids or be exported.

Exhibit 5-16: U.S. Balance of Trade Changes



Year	Balance of Trade (2015$ Billion)	
	T 1-3 Supplemental Volumes Case Change	
2016	$	0.2
2021	$	1.8
2026	$	1.9
2031	$	1.8
2036	$	1.9
2038	$	1.9
2016-2038 Avg	*$*	*1.6*
2016-2038 Sum	$	**37.7**

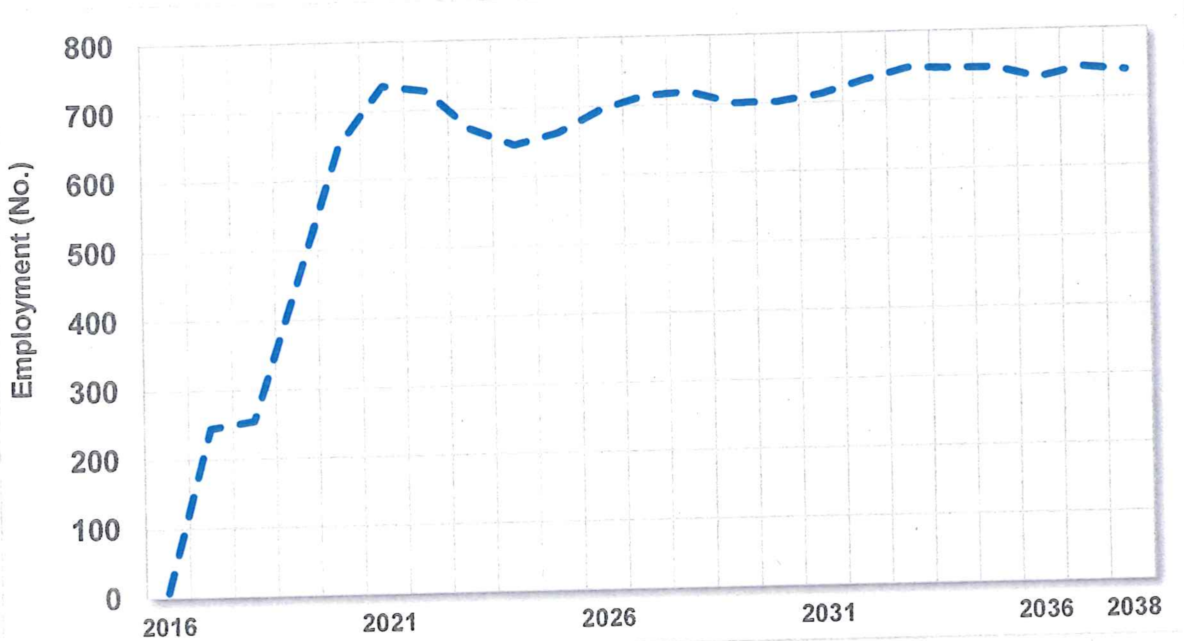
Source: ICF

5.2 Louisiana Impacts

This section discusses impacts of the additional T 1-3 Supplemental Volumes Case volumes on the economy of Louisiana, as well as the energy market impacts.

Exhibit 5-17 shows the impacts of LNG export volumes on Louisiana total employment changes, including direct, indirect, and induced jobs. Employment numbers increase as a result of additional LNG export volumes and can be attributed to the construction and operation of the added LNG exports and to the added natural gas production that will take place in the state and in other state to which Louisiana companies offer support services. The T 1-3 Supplemental Volumes Case exhibits an increase of nearly 630 jobs on an average annual basis from 2016 to 2038 as compared to the Base Case. This equates to a cumulative impact of close to 14,500 Louisiana job-years over the 23-year forecast period through 2038.

Exhibit 5-17: Louisiana Total Employment Changes

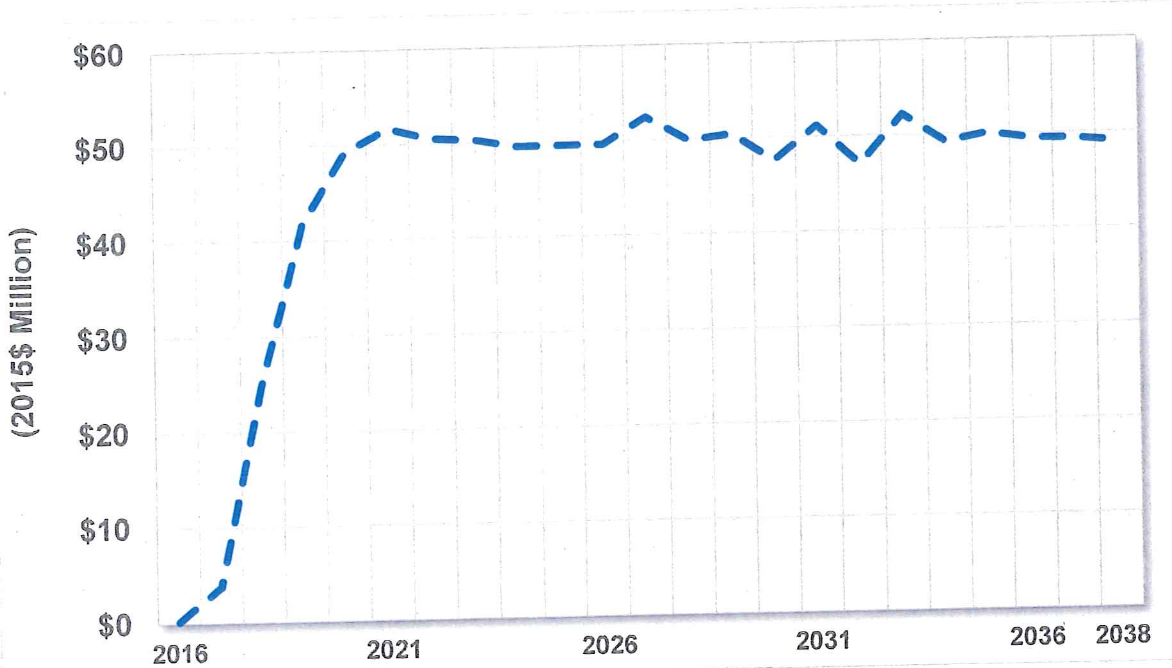


Year	Employment (No.) T 1-3 Supplemental Volumes Case Change
2016	7
2021	735
2026	695
2031	711
2036	729
2038	738
2016-2038 Avg	629
2016-2038 Sum	**14,464**

Source: ICF

Exhibit 5-18 shows the impacts of LNG export volumes on Louisiana state and local government revenue changes, as well as federal government revenues taking place within Louisiana. Total Louisiana government revenues increase as a result of the additional LNG export volumes assumed in the T 1-3 Supplemental Volumes Case. Relative to the Base Case, the additional LNG volumes in the T 1-3 Supplemental Volumes Case result in a $44.3 million average annual increase to government revenues throughout the 23-year forecast period through 2038, or a cumulative impact of $1.0 billion within Louisiana.

Exhibit 5-18: Louisiana Government Revenue Changes

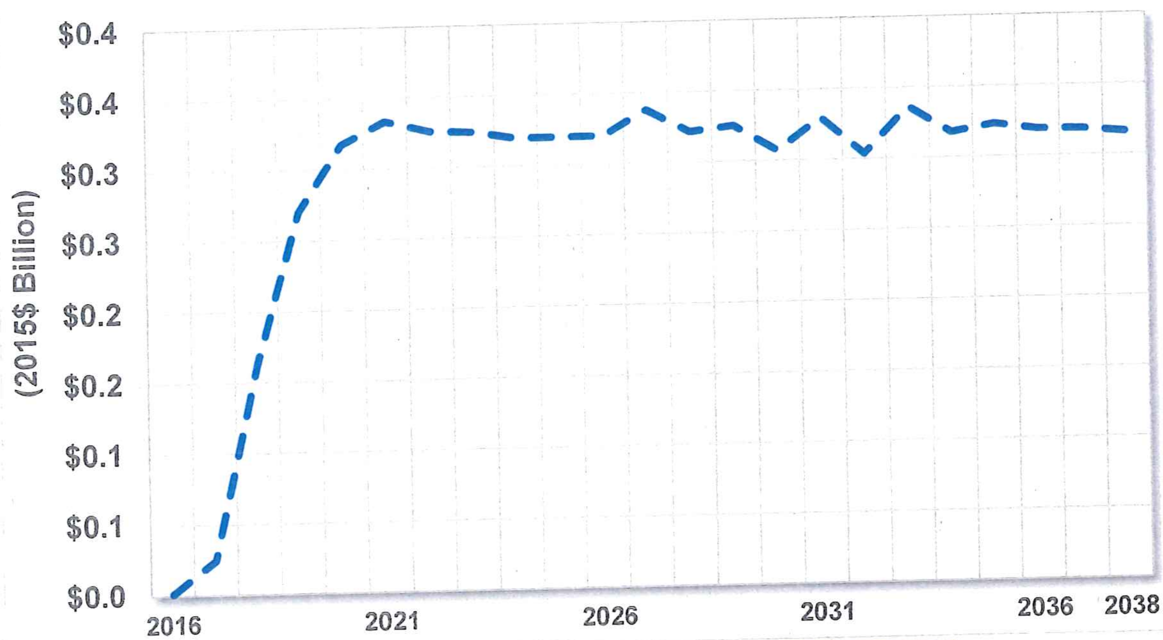


Year	Government Revenues (2015$ Million)	
	T 1-3 Supplemental Volumes Case Change	
2016	$	0.1
2021	$	51.7
2026	$	49.5
2031	$	51.1
2036	$	49.4
2038	$	49.0
2016-2038 Avg	*$*	*44.3*
2016-2038 Sum	**$**	**1,018.2**

Source: ICF

Exhibit 5-19 shows the impacts of LNG export volumes on total Louisiana value added to gross state product (GSP) changes. Louisiana value added increases substantially as a result of the additional LNG export volumes assumed in the T 1-3 Supplemental Volumes Case. Throughout the study period 2016 to 2038, the additional LNG volumes in the T 1-3 Supplemental Volumes Case result in a $300 million annual average increase to government revenues, relative to the Base Case. The total differential of value added to Louisiana over the study period between the Base Case and the T 1-3 Supplemental Volumes Case is expected to total $6.6 billion.

Exhibit 5-19: Total Louisiana Value Added Changes



Year	Total Value Added (2015$ Billion)
	T 1-3 Supplemental Volumes Case Change
2016	$ 0.0
2021	$ 0.3
2026	$ 0.3
2031	$ 0.3
2036	$ 0.3
2038	$ 0.3
2016-2038 Avg	*$ 0.3*
2016-2038 Sum	**$ 6.6**

Source: ICF

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7 Appendices

Appendix A: LNG Economic Impact Study Comparisons

This section explores ICF's assessment of LNG export impacts on the U.S. economy versus previous studies performed by ICF and others. This study differs from previous ICF studies in that productivity of new wells has improved due to upstream technology advances. This means that fewer wells need to be drilled and less upstream expenditures are needed per Bcfd of LNG exports than calculated in past ICF analyses. The lower expenditures translate into few upstream job gains. In addition, GDP gains per Bcfd of LNG exports are lower, relative to past studies, largely due to lower assumed crude oil, condensate, and natural gas liquids prices, which reduce the value of liquids produced along with the gas used as a feedstock and fuel in the liquefaction plants. In addition, due to higher well productivity rates (driven by upstream technology advances) this study finds that U.S. gas production is more elastic and thus a smaller reduction in gas consumption is needed to rebalance the market to accommodate LNG exports.

ICF International's May 2013 study for the American Petroleum Institute looked at impacts of LNG exports on natural gas markets, GDP, employment, government revenue, and balance of trade.[15] The four cases considered include no exports compared to 4, 8, and 16 Bcfd of exports. LNG exports are expected to increase domestic gas prices in all cases, raising Henry Hub prices by $0.32 to $1.02 (in 2010 dollars) on average during the 2016-2035 period. GDP and employment see net positive gains from LNG exports, as employment changes reach up to 665,000 annual jobs by 2035 while GDP gains could reach $78-115 billion in 2035. Different sectors feel varying effects from LNG exports. In the power sector, electricity prices are expected to increase moderately with gas prices. The petrochemicals industry benefits from the incremental 138,000-555,000 bpd of NGL production due to the drilling boost fueled by higher gas demand.

NERA's December 2012 study for the EIA looked at four LNG export cases from 6 Bcfd to unconstrained LNG exports using four EIA Annual Energy Outlook (AEO) 2011 scenarios.[16] In the unconstrained LNG export scenario, the study found that the U.S. can support up to 22.9 Bcfd of LNG exports. Gas price impacts range from zero to $0.33 per thousand cubic feet (Mcf) (in 2010 dollars), peaking in the earlier years and are higher in high production cases. Overall, LNG exports have positive impacts on the economy, boosting the GDP by up to 0.26 percent by 2020 and do not change total employment levels. According to NERA, sectors likely to suffer from gas price increases due to intensive gas use will experience small output and employment losses.

[15] ICF International. "U.S. LNG Exports: Impacts on Energy Markets and the Economy". ICF International, May 15, 2013: Fairfax, VA. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf
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NERA provided an update to its December 2012 study in March 2014 for Cheniere, using the AEO and International Energy Outlook (IEO) 2013 scenarios.[17] The report examined various export cases from no exports to 53.4 Bcfd in the High Oil and Gas Resource Case with no export constraints. The U.S. continues to maintain a low natural gas price advantage even when exports are not constrained. GDP gains could reach as much as $10-$86 billion by 2038 and are positive across all cases. LNG exports also lower the number of unemployed by 45,000 between 2013 and 2018. NERA's March 2014 report acknowledged the contribution of LNG exports to increasing NGL production and thus lowering feedstock prices for the petrochemicals industry. Electric sector growth will likely slow somewhat, however, compared to the No Exports Case.

The EIA released its first study of LNG export impacts on energy markets in January 2012, looking at four export scenarios from 6 to 12 Bcfd based on AEO 2011 case assumptions.[18] The study found that LNG exports lead to gas price increases by up to $1.58/Mcf by 2018 while boosting gas production by 60 to 70 percent of LNG export levels. Within the power sector, gas-fired generation sees the most dramatic decline while coal and renewable generation show small increases. This study did not look at economic impacts of LNG exports.

The EIA's October 2014 study revisited five AEO 2014 cases with elevated levels of LNG exports between 12 and 20 Bcfd, a sharp increase from the range considered in the EIA's January 2012 study.[19] Relative to the January 2012 study, LNG exports further increase average gas prices by 8 to 11 percent depending on the case, and boosts natural gas production by 61 percent to 84 percent of the LNG export level. Imports from Canada increase slightly while domestic consumption declines by less than 2 Bcfd on average mostly in power generation and industrial consumption. The overall impact on the economy is positive, with GDP increased by 0.05 percent. Consumer spending on gas and electricity increases by "modest" levels, about 1-8 percent for gas and 0-3 percent for electricity compared to the January 2012 results.

Charles River Associates (CRA) released a study on LNG export impacts for Dow Chemical Company in February 2013 with different methodologies and conclusions from the studies mentioned above.[20] Examining export cases from 20 Bcfd to 30 Bcfd by 2030, CRA argued that LNG export can raise gas prices to between $8.80 to $10.30/MMBtu by 2030, significantly above the reference price of $6.30/MMBtu. Electricity price impacts are also much greater than other studies, about 60 percent to 170 percent above the No Exports Case. CRA also compared economic values of gas use in manufacturing versus in LNG exports, finding that manufacturing creates much higher output and more jobs than LNG export. CRA also compared economic

[17] NERA Economic Consulting. "Updated Macroeconomic Impacts of LNG from the United States". NERA, March 24, 2014: Washington, DC. Available at: http://www.nera.com/content/dam/nera/publications/archive2/PUB_LNG_Update_0214_FINAL.pdf
[18] U.S. Energy Information Administration. "Effect of Increased Natural Gas Exports on Domestic Energy Markets". EIA, January 2012: Washington, DC. Available at: http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf
[19] U.S. Energy Information Administration. "Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets". EIA, October 2014: Washington, DC. Available at: http://www.eia.gov/analysis/requests/fe/pdf/lng.pdf
[20] Charles River Associates (CRA). "U.S. LNG Exports: Impacts on Energy Markets and the Economy". ICF International, May 15, 2013: Fairfax, VA. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf

values of gas use in manufacturing versus in LNG exports, finding that manufacturing creates much higher output and more jobs than do LNG exports.

See the exhibit below for more details by study.

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Cameron LNG (ICF 2015)	Trains 1-3 supplemental volumes of 0.42 Bcfd in LNG exports	0.4 Bcfd incremental increase in LNG exports	$0.03	$0.07	96%	8%	6%	110%	1.5	21,900	$420,000	Increasing exports at Cameron LNG is anticipated to lead to value added and job increases for the U.S.
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%	75%	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	North American shale growth can support development of Sabine Pass LNG facility. Gas price impact of LNG export is modest.
		2 Bcfd LNG exports	$0.35	$0.18	55%	-1%	55%	100%	N/A		N/A	

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
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%	0%	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)	N/A (separate reports on GDP impact attributed to regional, trade, upstream but no total)	Gas price impacts of Jordan Cove are "negligible". Jordan Cove creates positive economic and employment benefits for Oregon and Washington states.
		5.9 Bcfd [3 Bcfd incremental LNG exports (in addition to Base Case Bcfd and 0.9 Bcfd incremental)]	$0.38 (3.9 Bcfd)	$0.10	80%	11%	12%	116%	N/A			

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
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%	80%	1.34-1.90 (based on GDP)	Construction: more than 3000 Operation:20 - 30 permanent 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) (attached Altos study). 1.5 Bcfd project	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	Freeport has "minimal" gas price impacts. The project creates 17,000-21,000 new jobs and contributes $3.6-$5.2 billion for the economy.

Facility	Summary of Analysis	Case	Impact LNG Exports										Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact		
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs		
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%	103%	N/A	N/A	N/A		Gas price impacts vary depending on the level of exports and pace of export ramp-up and moderate over time in all cases. Drilling and production get a boost while power and industrial gas use decline somewhat.
		5.3 Bcfd - 11.2 Bcfd (High Shale)	$0.38-$0.87	$0.07-$0.12	61%-64%	34%-37%	5%	103%	N/A	N/A	N/A		
		5.3 Bcfd - 11.2 Bcfd (Low Shale)	$0.77-$1.65	$0.15-$0.17	55%-60%	32%-37%	11%-12%	104%	N/A	N/A	N/A		
		5.3 Bcfd - 11.2 Bcfd (High GDP)	$0.55-$1.26	$0.10-$0.12	71%-72%	29%-30%	2%-3%	103%	N/A	N/A	N/A		
EIA (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%	N/A	Not likely to affect overall employment	N/A		LNG export leads to higher gas prices, with impacts ranging from $0.14 to $1.61/Mcf. The economy reaps positive benefits from LNG exports across all cases.
		12 Bcfd (Reference)	$1.20		51%	49%	0%	100%	N/A				
		Unlimited Bcfd (Reference)	$1.58		50%	50%	0%	100%	N/A				
	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%	N/A				
		12 Bcfd (High EUR)	$0.84		49%	51%	0%	100%	N/A				
		Unlimited Bcfd (High EUR)	$1.08 - $1.61		46%	54%	0%	100%	N/A				
	Single scenario with LNG exports reaching 1.42 Bcfd	6 Bcfd (Low EUR)	$0.14 (1 Bcfd)	$0.14	51%	49%	0%	115%	N/A				

Facility	Summary of Analysis	Case	Impact LNG Exports										Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact		
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs		
EIA (2014 Update)	5 export cases with supply and demand assumptions based on AEO 2014 and DOE	Reference	$0.30 - $0.50	N/A	61-84%	10-18%	N/A	N/A	N/A	Change in nonfarm employment less than 0.1 million, representing up to 0.1% increase relative to the baseline	N/A		LNG exports result in positive economic benefits, enough to overcome the impact of higher gas prices.
		High Oil and Gas Resource	0 - $0.20	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A		
		Low Oil and Gas Resource	$0.90 - $1.40	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A		
		High Macroeconomic Growth	$0.30 - $0.60	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A		
		Accelerated Coal and Nuclear	$0.30 - $0.60	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A		
NERA (2014 Update)	5 cases with export ranging from 6 to unlimited	6 Bcfd (Reference)	$0.43/MM Btu by 2038	$0.07	61%	38-39%	0%	99-100%	N/A	LNG Exports could reduce unemployment by 45,000 before the economy returns to full employment by 2018.	N/A		LNG export leads to gas price increases. It also leads to gains in GDP, employment, and the chemical sectors.
		Unlimited Bcfd (Reference)	$0.36-$1.33	$0.02-$0.03	63%	36-104%	0%	99-167%	N/A				
	7 cases with export ranging from 6 to unlimited	6 Bcfd (High Oil and Gas Resource)	$0.16	$0.03	65-168%	33-34%	0%	98-202%	N/A				
		12 Bcfd (High Oil and Gas Resource)	$0.30-$0.34	$0.03	65-67%	33-35%	0%	98-102%	N/A				
		Unlimited Bcfd (High Oil and Gas)	$0.96-$1.38	$0.96	68%	32%	0%	100%	N/A				
	2 cases with	6 Bcfd (Low Oil and Gas)	$0.90	$0.15	59%	41%	0%	100%	N/A				
		Unlimited Bcfd (Low Oil and Gas)	$1.78	$0.03	58%	42%	0%	100%	N/A				

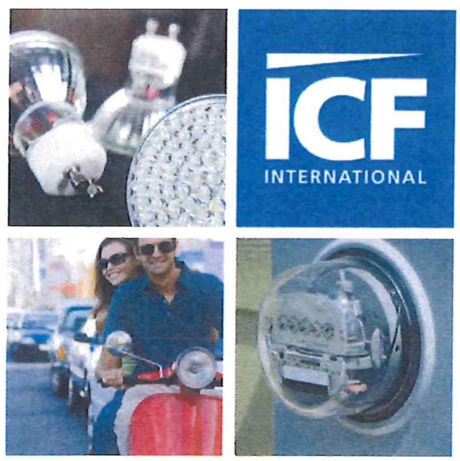
Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
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	GDP-based M.E. not given. Indirect value not estimated. Employment-based M.E.: 30 (each direct job leads to 30 jobs along the supply chain)	N/A	N/A	LNG export increases gas prices significantly. Gas use in manufacturing yields higher benefits than in LNG exports. Impacts on gas and NGL production and the economy are not given.
		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		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		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	N/A	2012-2025 avg: 41,768 per Bcfd. Multiplier not given.	2012-2025 avg: $35,357/job in 2011 dollars	LNG exports have mixed impacts on the economy, peaking in the earlier years due to infrastructure investments. Gas price impacts range from $0.60-$2.00/MMBtu.
		6 Bcfd	About $2.00 (2012-2025)	$0.33	N/A	N/A	N/A	N/A	N/A	2012-2025 avg: 67,236 per Bcfd. Multiplier not given.	2012-2025 avg: $46,349/job in 2011 dollars	

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
API (ICF)	ICF Base Case	4 Bcfd	$0.35	$0.10	88%	21%	7%	115%	1.3; 1.9 (based on GDP)	2015-2035 avg: M.E. = 1.3: 17,800, M.E. = 1.9: 35,200	2015-2035 avg: M.E. = 1.3: $208,600, M.E. = 1.9: $150,900	LNG exports have moderate gas price impacts. Depending on the scenario LNG exports increase employment by up to 452,300 and GDP by $73.6 billion by on average during 2016-2035.
	Middle Exports Case	8 Bcfd	$1.19	0.11	82%	26%	7%	115%	1.3; 1.9 (based on GDP)	2015-2035 avg: M.E. = 1.3: 13,700, M.E. = 1.9: 28,000	2015-2035 avg: M.E. = 1.3: $207,100, M.E. = 1.9: $149,300	
	High Exports Case	12 Bcfd	$1.33	$0.10	79%	27%	8%	115%	1.3; 1.9 (based on GDP)	2015-2035 avg: M.E. = 1.3: 13,400, M.E. = 1.9: 27,400	2015-2035 avg: M.E. = 1.3: $208,800, M.E. = 1.9: $150,200	

Facility	Summary of Analysis	Case	Impact LNG Exports: Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	Main Conclusions
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Cameron LNG (Black & Veatch)	1 Bcfd demand curve shift relative to EIA cases	Various	$0.088/Mcf by 2025		67.8% (by 2025)		N/A		from RIMS II (Department of Commerce)	construction: 63,000; operation:53000	$211,000 /job	Gas price impacts are small, between $0.064 and $0.088/Mcf. Terminal generates 1.1 million job-years and $45 billion economic value over project lifetime.

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Golden Pass (Perryman Group)	Refer to Deloitte's Mkt Point report for price impacts	N/A	N/A	N/A	N/A	N/A	N/A	N/A		3,860 permanent jobs for 2bcfd export	1.9 billion in 2012 dollars avg for all jobs	The project generate over $31 billion GDP and 324,000 job-years over the project life.
Southern LNG (Navigant)	3 North America LNG cases and 2 demand cases	Base Case (3.7 Bcfd)	N/A	N/A	N/A	N/A	N/A	N/A	RIMS II multipliers			North American gas resources can support the SLNG terminal. LNG exports have minimal gas price impacts and improve price stability.
		SLNG Export Case (base + 0.5)	$0.14/MM Btu by 2025	$0.28	60%	0%	N/A	N/A		during operation: 8933 avg	$145,136 .01	
		Aggregate Export Case (base + 3.5)	$0.39/MM Btu by 2025	$0.10	60%	15%	N/A	N/A				
		High Demand Base Case	$0.59/MM Btu	$1.18			N/A	N/A				
		High Demand Base Case + SLNG	$0.82/MM Btu	$1.64			N/A	N/A				
Pangea LNG (Black & Veatch for price and Perryman for economic impacts)	4 demand cases	Base Case			N/A	N/A	N/A	N/A				The project has limited impact on U.S. gas prices and bring significant economic benefits, including $1.4 billion in GDP and 17,230 person-years of employment.
		Pangea Export Case	$0.17/MM Btu (2018-27)	$0.14	N/A	100%	N/A	N/A		29860 permanent jobs in total	2.7 billion in total	
		High LNG Export	$0.26/MM Btu	0.09	N/A	100%	N/A	N/A				
		High LNG Export + Pangea	$0.37/MM Btu	0.09	N/A	N/A	N/A	N/A				

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Magnolia LNG (Berkeley Research Group)	6 gas market cases	Reference Case (4.6 Bcfd)										Project has negligible market and price impacts. Impacts increase with higher LNG and demand levels.
		Magnolia Scenario (5.7 bcfd)	$0.14/MM Btu by 2035	$0.13	45%	18%	9%	73%	N/A	N/A	N/A	
		Moderate LNG Scenario (9.9 Bcfd)	$0.49/MM Btu	$0.09	77%	15%	6%	98%	N/A	N/A	N/A	
		High LNG Scenario (13.9 Bcfd)	$0.90/MM Btu	$0.10	69%	16%	1%	86%	N/A	N/A	N/A	
		High Demand/ Moderate LNG (9.9 Bcfd)	$0.93/MM Btu	$0.18	138%	53%	0%	191%	N/A	N/A	N/A	
		High Demand/ High LNG (13.9 Bcfd)	$1.40/MM Btu	$0.15	109%	22%	0%	130%	N/A	N/A	N/A	
Downeast LNG (Resource Report by ICF, Market Impacts by Concentric Energy Advisors, Economic Impacts by Todd Gabe)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	County-level multiplier: 1.25 (output), 2.00 (employment) State-level multiplier: 1.59 (output), 2.73 (employment)	3525 jobs statewide during construction, 310 jobs statewide during operations	N/A	Downeast unlikely to have material impacts on North American prices or in the Northeast region. The project would have positive impacts on employment and the economy.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