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June 15, 2015

Submitted electronically to fergas@hq.doe.gov

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

Re: Port Arthur LNG, LLC
FE Docket No. 15 - 96 - LNG
Application for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries

Dear Ms. Moore:

Port Arthur LNG, LLC ("Port Arthur LNG") hereby submits for filing with the U.S. Department of Energy, Office of Fossil Energy, its application for long-term authorization to export liquefied natural gas ("LNG") (the "Application") in an amount up to the equivalent of 517 billion cubic feet of natural gas per year. The requested authorization would permit Port Arthur LNG to export LNG to any country (i) with which the United States does not have a Free Trade Agreement requiring national treatment for trade in natural gas, (ii) which has or will develop the capacity to import LNG delivered by ocean-going carrier, and (iii) with which trade is not prohibited by United States law or policy.

Port Arthur LNG is electronically transmitting a PDF of the application materials and, on the same day, is hand delivering the application materials provided electronically. The hand delivered submission will include a paper copy of the original Application, three additional paper copies of the Application, and a check in the amount of $50.00 in payment of the applicable filing fee. A photocopy of the check is included with the electronic submission.

Please acknowledge receipt of this Application by email to jessica.fore@bakerbotts.com. Should you have any questions, please do not hesitate to contact me at (202) 639.7727.

Respectfully submitted,

Jessica Fore
Counsel for Port Arthur LNG, LLC

cc: Benjamin Nussdorf, DOE
William Rapp, Port Arthur LNG, LLC

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

	)	
Port Arthur LNG, LLC	)	**Docket No. 15-96-LNG**
	)	

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

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

Port Arthur LNG, LLC) **Docket No. 15-96-LNG**

APPLICATION OF PORT ARTHUR 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 United States Department of Energy's ("DOE") regulations,[2] Port Arthur LNG, LLC ("Port Arthur LNG") hereby submits this application ("Application") to the Department of Energy Office of Fossil Energy ("DOE/FE") for long-term, multi-contract authorization to export a maximum of 517 billion cubic feet ("Bcf") per year of liquefied natural gas ("LNG") (equivalent to approximately 10 million metric tons per annum ("MTPA")) for a 20-year term to commence on the earlier of the date of first commercial export or a date seven years from the issuance of a final order granting the requested authorization.

Port Arthur LNG seeks this authorization to export domestically produced LNG from the natural gas processing, liquefaction and export project it intends to construct, own, and operate in Port Arthur, Texas (the "Project") 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) which has or will develop the capacity to import LNG delivered by ocean-going carrier, and (iii) with which trade is not prohibited by United States law or policy. Port Arthur LNG requests

[1] 15 U.S.C. § 717b.

[2] 10 C.F.R. Part 590.

this authorization both on its own behalf and as agent for other parties who will hold title to the LNG at the time of export.

This Application is the second part of Port Arthur LNG's planned two-part export authorization request. On March 20, 2015, Port Arthur LNG filed a separate application with the DOE/FE for long-term, multi-contract authorization to export LNG to those countries with which the United States has an FTA requiring the national treatment of trade in natural gas. That request is presently pending with the DOE/FE in Docket No. 15-53-LNG.

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

I. COMMUNICATIONS

All communications and correspondence regarding this Application should be directed to:

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II. DESCRIPTION OF THE APPLICANT

The exact legal name of the applicant is Port Arthur LNG, LLC. Port Arthur LNG is a limited liability company organized and existing under the laws of the state of Delaware. Port Arthur LNG is a wholly-owned, indirect subsidiary of Sempra Energy, a California corporation.

The Project will be located on a project site within a 2,842-acre parcel of land owned in fee by an affiliate of Port Arthur LNG — Port Arthur LNG Holdings, LLC ("Port

Arthur Holdings").[3] Port Arthur LNG intends to lease or purchase the project site from Port Arthur Holdings. Port Arthur Holdings is a limited liability company formed under the laws of the state of Delaware and a wholly-owned, indirect subsidiary of Sempra Energy.

Port Arthur LNG has its principal place of business at 2925 Briarpark Drive, Suite 900, Houston, TX 77042. Sempra Energy and Port Arthur Holdings each has its principal place of business at 101 Ash Street, San Diego, CA 92101.

III. EXECUTIVE SUMMARY

The Project is proposed for the purpose of liquefying surplus natural gas in the United States for export as LNG to foreign markets. Port Arthur LNG expects the first LNG exports from the Project in 2021. The Project is proposed at the site of the Port Arthur LNG terminal previously permitted as an import facility.[4] Port Arthur LNG has already submitted a request to initiate the Federal Energy Regulatory Commission ("FERC") pre-filing process for the proposed Project facilities. The FERC issued a letter approving this request on March 31, 2015.

Abundant supplies of natural gas from the United States are available to serve both domestic natural gas needs and the needs of the Project for the proposed 20-year term. The use of domestically-sourced natural gas for Port Arthur LNG exports would not significantly reduce the volume of natural gas potentially available for domestic consumption. The U.S. Energy Information Administration's ("EIA's") forecasts, as well as the ICF International

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[3] A copy of the deed for the site is included in the docket for Port Arthur LNG's FTA application, DOE/FE Docket No. 15-53-LNG, and is incorporated herein by reference.

[4] *Port Arthur LNG, LP*, 115 FERC ¶61,344 (2006). Due to changes in market conditions after issuance of this order, Port Arthur elected not to proceed with construction of the import and re-gasification terminal. *See Port Arthur LNG, LP*, 136 FERC ¶ 61,196 (2011).

(“ICF”) Report commissioned by Port Arthur LNG,[5] illustrate that there is abundant U.S. natural gas supply currently and during the Project’s proposed timeframe for exports. The robust supply of natural gas, largely as a result of increased levels of production from unconventional resources, is forecasted to exceed demand. The ICF Report indicates that LNG exports from the Project will result in minimal impact on the price of natural gas for U.S. consumers over the analysis period of 2018 to 2040.

The Project presents numerous benefits to the public, including increased U.S. economic activity, tax revenues and job creation during both the construction and operation phases of the Project. Through 2040, the estimated total economic gains associated with the Project are approximately $9.7 billion annually for the United States economy,[6] including $1.4 billion annually for the Texas economy.[7] These economic gains are measured in terms of increased net gross domestic product and state product including multiplier effects. In addition, approximately 787,000 job-years will be created for the United States economy and 89,000 job-years will be created for the Texas economy.[8]

On an international level, the Project will favorably influence the balance of trade that the United States has with its international trading partners. The expected value of the exports from the Project is estimated to reduce the U.S. balance of trade deficit by $4.8 billion annually between 2018 and 2040.[9]

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[5] ICF International, *Economic Impacts of the Port Arthur Liquefaction Project: Information for DOE Non-FTA Permit Application* (June 5, 2015) (hereinafter, “ICF Report”). The ICF Report is included as Appendix A.
[6] *Id.* at 50.
[7] *Id.* at 54.
[8] *Id.* at 47, 52.
[9] *Id.*at 49.

IV. PROJECT FACILITIES

Port Arthur LNG seeks long-term authorization to export domestically produced LNG from the Project, which will be constructed under authorization of Section 3 of the NGA. The Project will be located in Port Arthur, Texas. The FERC previously approved the Project site for use as an LNG import and re-gasification terminal.[10] The Project facilities are anticipated to include feed gas pre-treatment facilities, two natural gas liquefaction trains, three 160,000 cubic meter LNG storage tanks, marine facilities for vessel berthing and loading, refrigerant make-up and condensate product storage, truck loading and unloading areas, and equipment for self-generation of electrical power. Each of the natural gas liquefaction trains will be capable of producing up to 5 MTPA of LNG for export, for a total capacity of up to 10 MTPA. The Project facilities would permit natural gas to be received by pipeline at the Project, and then processed, liquefied, stored and loaded from the LNG storage tanks into LNG vessels berthed at the marine facilities.

V. AUTHORIZATION REQUESTED

Port Arthur LNG requests long-term, multi-contract authorization to export a maximum of 10 MTPA (equivalent to approximately 517 Bcf per year) of domestically produced LNG from the Project to any country (i) with which the United States does not have an FTA requiring national treatment for trade in natural gas, (ii) which has or will develop the capacity to import LNG delivered by ocean-going carrier, and (iii) with which trade is not prohibited by United States law or policy. This authorization is requested for a 20-year term to commence on the earlier of the date of first commercial export or a date seven years from the issuance of a final order granting the requested authorization.

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[10] *Port Arthur LNG, LP*, 115 FERC ¶61,344 (2006).

Port Arthur LNG requests such export authorization on its own behalf and as agent for others. To ensure all exports are permitted and lawful under United States laws and policies, Port Arthur LNG will comply with all DOE/FE requirements for an exporter or agent. In Order No. 2913, the DOE/FE determined that where an applicant proposes to export as an agent for others, the applicant must register the other entity with the DOE/FE.[11] Consistent with the DOE/FE Order No. 2913 and the procedures and requirements described therein, Port Arthur LNG will register with the DOE/FE each LNG title holder for whom Port Arthur LNG seeks to export LNG as agent. Port Arthur LNG will also provide the DOE/FE with a written statement by the title holder acknowledging and agreeing to (i) comply with all requirements in Port Arthur LNG's long-term export authorization and (ii) include those requirements in any subsequent purchase or sale agreement entered into for the exported LNG by that title holder.[12] Further, Port Arthur LNG will file under seal with the DOE/FE any relevant long-term commercial agreements Port Arthur LNG enters into with the LNG title holders on whose behalf the exports will be performed.

The DOE/FE regulations require applicants to submit information regarding the terms of transactions, including long-term supply agreements and long-term export agreements.[13] The DOE/FE has previously found, however, that applicants need only supply such contract-specific information "when practicable,"[14] permitting applicants to submit such information if and when such contracts are executed.[15] Port Arthur LNG requests that the DOE/FE make the same finding in this proceeding. Participants in the United States wholesale gas market do not

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[11] *Freeport LNG Development, L.P.*, DOE/FE Order No. 2913 (Feb. 10, 2011).
[12] *Id.*
[13] 10 C.F.R. § 590.202(b)(4).
[14] *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2833 (Sept. 7, 2010).
[15] *See, e.g.*, *Jordan Cove Energy Project, L.P.,* DOE/FE Order No. 3413 (Mar. 24, 2014); and *Cameron LNG, LLC*, DOE/FE Order No. 3391 (Feb. 11, 2014).

typically enter into the types of long-term gas purchase and sale agreements that were prevalent at the time the DOE/FE originally adopted this requirement. As discussed below, abundant, reliable and economical supplies of domestic gas are available without the need to enter into long-term supply agreements. Further, Port Arthur LNG has not yet entered into agreements for the use of, or the sale of LNG produced by, the Project facilities because a long-term export authorization is necessary to finalize long-term agreements with prospective customers. Permitting Port Arthur LNG to submit the transaction-specific information identified in Section 590.202(b) of the DOE/FE regulations at the time the applicable agreements are executed is appropriate in light of current market conditions and contracting practices.

Port Arthur LNG intends to apply separately for short-term export authorization to export LNG volumes required to commission each LNG train prior to the commencement of the first commercial export ("Commissioning Period"). Therefore, Port Arthur LNG requests that commissioning volumes[16] not be counted against the maximum level of volumes sought to be authorized for export in this Application.[17] In addition, Port Arthur LNG respectfully requests that export of commissioning volumes during the Commissioning Period will not trigger the commencement of the term of the long-term authorization.[18]

VI. EXPORT SOURCES

Abundant supplies of natural gas in the United States are available to serve domestic natural gas needs as well as the proposed Project.[19] Natural gas for the proposed

[16] *See Freeport LNG Expansion, L.P.*, DOE/FE Docket No. 10-161-LNG, DOE/FE Order No. 3282-C at 90 (November 14, 2014) (defining "Commissioning Volumes" to mean the "volume of LNG that is produced and exported under a short-term authorization during the initial start-up of each LNG train, before each LNG train has reached its full steady-state capacity and begun its commercial exports pursuant to . . . long-term contracts or LTAs").
[17] *See id.*
[18] *See Freeport LNG Expansion, L.P.,* DOE/FE Docket Nos. 10-161-LNG & 11-161-LNG, DOE/FE Order Nos. 3282-B & 3357-A, at 6 (June 6, 2014).
[19] *See* ICF Report at 15.

exports can be sourced from basins throughout the United States, including the Appalachian, Gulf Coast, Mid-Continent, and Rocky Mountain regions, providing the Project with supply diversity and optionality for the benefit of its customers. Port Arthur Pipeline, LLC ("Port Arthur Pipeline"), an affiliate of Port Arthur LNG,[20] will construct, own and operate new natural gas pipeline facilities that will connect the Project to numerous interstate and intrastate pipelines.[21] Through these pipeline interconnections, Port Arthur LNG will have economical access to the national natural gas supply and pipeline system. This will enable the Project to access major natural gas supply basins in the United States. Given the size of traditional natural gas resources in close proximity to the Project, as well as the rapid growth in emerging unconventional gas and oil resources throughout the United States, the Project will have a choice of diverse and reliable alternative gas supplies.

The sources of natural gas for the Project will include vast supplies available from the Gulf Coast producing regions. The EIA reports that, in 2014, these regions collectively produced and made available to the national market 11 trillion cubic feet ("Tcf") (approximately 30.0 Bcf/d) of natural gas, which was 40% of the United States total for that year.[22] According to the 2015 Report of the Potential Gas Committee, the United States Gulf Coast region is estimated to have traditional gas resources of 536 Tcf.[23]

Emerging unconventional supply areas, such as the Barnett, Haynesville, Eagle Ford, Fayetteville and Woodford shale gas formations, represent attractive sources of supply for

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[20] Port Arthur Pipeline is a limited liability company formed under the laws of Delaware and a wholly-owned indirect subsidiary of Sempra Energy. Its principal place of business is 101 Ash Street, San Diego, California 92101.

[21] A copy of the map depicting the proposed route for the natural gas pipeline facilities is included in the docket for Port Arthur LNG's FTA application, DOE/FE Docket No. 15-53-LNG, and is incorporated herein by reference.

[22] Energy Information Administration, *Natural Gas Marketed Production, available at* http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.

[23] U.S. Potential Gas Committee 2015, "The Potential Supply of Natural Gas in the United States," *available at* http://www.potentialgas.org.

the Project. Technological improvements in natural gas exploration, drilling and production have resulted in significant reductions in the costs of developing shale resources and making shale gas production economically viable. The latest EIA estimate of shale gas resources in the Barnett, Haynesville and Eagle Ford formations alone is approximately 352 Tcf.[24] Shale gas and tight oil production accounted for 46% of total United States production in 2013 (24.40 Tcf).[25] Looking forward, the EIA projects shale gas and tight oil production will account for an estimated 55% of total domestic dry production by 2040.[26]

Abundant supplies of natural gas in regions outside of the Gulf Coast are also available to serve domestic natural gas needs and the Project. The Appalachian basin, which encompasses both the Marcellus and Utica supply regions, represents one of the most extensive potential sources of natural gas supply in the United States. As a result of the increased production of natural gas in the Marcellus and Utica shale plays over the past five years, the Appalachian Basin has the highest growth rate for dry natural gas production in the United States.[27] According to the EIA, the Marcellus and Utica shale plays were estimated to have 480 Tcf of remaining and undeveloped resources in 2013, which is the highest recoverable resource of any region in the United States.[28] In response to the increased production in the Appalachian region, the natural gas pipeline industry is modifying pipeline systems to drive a shift in directional flow that will allow pipelines originally built and used to move gas into the Northeast

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[24] Energy Information Administration, *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States* at Table A-1 *available at* http://www.eia.gov/analysis/studies/worldshalegas/.
[25] Energy Information Administration, *Annual Energy Outlook 2015* (April 2015).
[26] *Id.*
[27] Energy Information Administration, *Natural Gas Weekly Update: Appalachian Basin Infrastructure Growth Will Make Marcellus/Utica Gas Available to Broader Market* (Mar. 18, 2015) *available at* http://www.eia.gov/naturalgas/weekly/archive/2015/03_19/index.cfm.
[28] Energy Information Administration, *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States* at Table A-1 *available at* http://www.eia.gov/analysis/studies/worldshalegas/.

to now provide new markets for excess gas out of the Northeast.[29] Appalachian gas production, in addition to Gulf Coast gas production, is therefore well situated to satisfy domestic requirements for natural gas.

When these new resources are added to conventional producing formations, it is evident that the United States has more than sufficient supply to accommodate the proposed exports form the Project. In 2014, the EIA estimated the technically recoverable natural gas resources in the United States at 2,266 Tcf.[30] This growth in U.S. natural gas resources is reflected in other recent academic and industry evaluations. The Potential Gas Committee in April 2015 determined that the U.S. possesses future available gas supply (reserves and resources) of 2,852 Tcf, which is an increase of over 161 Tcf (+6%) from the Potential Gas Committee's projections in April 2013 and a 1,540 Tcf increase (+117%) relative to a comparable estimate of 2004 U.S. future gas supply. The assessments of the Potential Gas Committee represent potential natural gas resources expected that, in the judgment of its members, can be recovered by future drilling under conditions of adequate economic incentives in terms of price/cost relationships, and current or foreseeable technology.[31] These reports indicate that the United States has a 90-year to an over 100-year inventory of recoverable natural gas resources.

The Project is well-positioned to take advantage of the abundant natural gas resources in this country. The Project will access natural gas supplies from the numerous interstate and intrastate pipelines and gas storage facilities that are in proximity to the Project

[29] Energy Information Administration, *Natural Gas Weekly Update: Appalachian Basin Infrastructure Growth Will Make Marcellus/Utica Gas Available to Broader Market* (Mar. 18, 2015) *available at* http://www.eia.gov/naturalgas/weekly/archive/2015/03_19/index.cfm.

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

[31] Potential Gas Committee, *Potential Supply of Natural Gas in the United States* (December 31, 2014).

site. These pipelines and storage facilities are part of an interconnected gas transmission network that will enable the Project to access supplies from both conventional resources and the recent and substantial shale gas discoveries in Texas and Louisiana as well as other shale plays throughout the United States.

Natural gas to be exported from the Project will be purchased in a market that has sufficient liquidity and capacity to accommodate a variety of purchase arrangements, including spot market transactions and long-term supply arrangements. Natural gas markets are particularly liquid in the Gulf Coast region of Texas and Louisiana as a result of the key market centers in the area and the availability of readily accessible incremental gas supplies. In 2013, only 4.6 Tcf (41%) of the 11.3 Tcf of marketed gas production from Texas, Louisiana, and the Gulf of Mexico was delivered to consumers in those two states.[32]

Moreover, the Project will not be limited to particular geographical supply areas when contracting for gas supply. There are 12 major natural gas market centers in Louisiana and Texas.[33] These market centers provide ample liquidity to accommodate a wide and geographically diverse range of gas supply arrangements.

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[32] Energy Information Administration, *Natural Gas Monthly* (February 2015), Tables 7 and 16 *available at* http://www.eia.gov/naturalgas/monthly/.

[33] Energy Information Administration, *Natural Gas Market Centers: A 2008 Update* (April 2009) *available at* http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2009/ngmarketcenter/ngmarketcenter.pdf.

VII. PUBLIC INTEREST ANALYSIS

A. Applicable Legal Standard

The DOE/FE has the power to approve or deny applications to export natural gas pursuant to specific authorization in Section 3 of the NGA.[34] The general standard for review of applications to export 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.[35]

In applying this provision, the DOE/FE has consistently found that Section 3(a) creates a rebuttable presumption that proposed exports of natural gas are in the public interest.[36] The DOE/FE must grant a non-FTA export application unless opponents of the application make an affirmative showing based on evidence in the record that the export would be inconsistent with the public interest.[37]

The DOE/FE's prior decisions have looked to the 1984 Policy Guidelines setting out the criteria to be employed in evaluating applications for natural gas imports.[38] While nominally applicable to natural gas import cases, the DOE/FE has found these Policy Guidelines

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[34] 15 U.S.C. § 717b. This authority is delegated to the Assistant Secretary for Fossil Energy pursuant to Redelegation Order No. 00.002.4D (Nov. 6, 2007).
[35] 15 U.S.C. § 717b(a).
[36] *See e.g. Cameron LNG, LLC*, DOE/FE Order No. 3391 (Feb. 11, 2014); *see also LNG Development Company, LLC (d/b/a Oregon LNG)*, DOE/FE Order No. 3465 (July 31, 2014).
[37] *Phillips Alaska Natural Gas Corporation and Marathon Oil* Company, 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/FE Order No. 2961 (May 20, 2011).
[38] *Policy Guidelines and Delegation Orders Relating to the Regulation of Imported Natural Gas*, 49 Fed. Reg. 6684 (Feb. 22, 1984) (hereinafter "Policy Guidelines").

to be applicable to applications for the export of natural gas as well.[39] The goals of the Policy Guidelines are to minimize federal control and involvement in energy markets and to promote a balanced and mixed energy resource system. The Guidelines provide that:

> The market, not government, should determine the price and other contract terms of imported [or exported] gas . . . The federal government's primary responsibility in authorizing imports [or exports] should 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.[40]

Historically, the DOE/FE's review has also been guided by DOE Delegation Order No. 0204-111 ("Delegation Order"). According to the Delegation Order, 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."[41] Although the Delegation Order is no longer in effect, the DOE/FE's review of export applications continues to focus on: (i) the domestic need for natural gas proposed to be exported; (ii) whether the proposed exports pose a threat to the security of domestic natural gas supplies; (iii) whether the arrangement is consistent with the DOE/FE's policy of promoting market competition; and (iv) any other factors bearing on the public interest.[42]

The DOE/FE 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

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[39] *Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE/FE Order No. 1473 (April 2, 1999).
[40] *Policy Guidelines* at 6685.
[41] *Department of Energy*, Delegation Order No. 0204-111 (Feb. 22, 1982).
[42] *See Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961 (May 20, 2011); *Cameron LNG, LLC,* DOE/FE Order No. 3391-A (Sept. 10, 2014).

and mitigate trade imbalances with the foreign recipient nations, and the degree to which the exports would encourage efficient management of United States domestic natural resources.[43]

As demonstrated below, the export of domestically produced LNG as proposed in this Application satisfies each of these considerations.

B. Domestic Need for Natural Gas to be Exported

The Project is proposed in view of considerable growth in domestic natural gas resources and production. In particular, drilling productivity gains and extraction technology enhancements have enabled significant growth in supplies from unconventional gas-bearing shale formations in the United States. According to the EIA, natural gas proved reserves have increased by 65 Tcf (24%) between 2009 and 2013 and estimates of recoverable natural gas resources have increased by 519 Tcf (30%) between 2009 and 2014.[44] In light of the substantial addition of resources 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 fell from \$8.85 per MMBtu in 2008 to \$4.39 per MMBtu in 2014.[45] Most recently, in the first four

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[43] *See, e.g.*, *Sabine Pass Liquefaction, LLC,* Order No. 2961, at 34-38 (May 20, 2011).
[44] Energy Information Administration, *Natural Gas Reserves Summary as of December 31, 2014*, *available at* http://www.eia.gov/dnav/ng/ng_enr_sum_a_EPG0_R11_BCF_a.htm; Energy Information Administration, *Assumptions to the Annual Energy Outlook 2014*, Table 9.2, *available at* http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf; Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009, Table 9.2, available at* http://www.eia.gov/forecasts/archive/aeo09/assumption/pdf/0554(2009).pdf.
[45] Energy Information Administration, *Natural Gas Spot and Futures Prices*, *available at* http://www.eia.gov/dnav/ng/ng_pri_fut_s1_a.htm.

months of 2015, the decline in prices accelerated, to an average of $2.83 per MMBtu.[46] In its most recently calculated reference case, the EIA estimates that the Henry Hub spot price for natural gas, stated in 2013 dollars, will remain well under $5.00 per MMBtu through at least 2020.[47] Prices for natural gas in the U.S. market are now substantially below those of most other major gas-consuming countries. While United States gas prices have fallen, prices for LNG in other major gas-consuming countries have continued to move generally in line with world oil prices. The result is that domestic gas can be liquefied and exported to foreign markets on a competitive basis. As discussed below, such exports can be expected to have only a nominal effect on U.S. prices.

1. Domestic Natural Gas Supply

U.S. natural gas production has grown considerably over the past several years, led by unconventional production. In its *Annual Energy Outlook 2015*, the EIA noted that U.S. production of dry natural gas increased by 35% from 2005 to 2013 with production growth resulting largely from the development of shale gas resources in the lower 48 states.[48] The EIA further estimates that U.S. dry gas production increased by 5.7% from 2.1 Tcf in August 2013 to 2.2 Tcf in August 2014.[49] Increased drilling productivity in certain prolific shale gas formations, including the Marcellus and Haynesville plays, has enabled domestic production to continue expanding despite a reduction in the number of wells drilled.[50]

This growth trend is expected to continue over the next 25 years. Total U.S. dry gas production is projected to grow to 35.5 Tcf by 2040, with a 1.4% annual growth rate between

[46] Energy Information Administration, *Henry Hub Natural Gas Spot Price*, *available at* http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.
[47] Energy Information Administration, *Annual Energy Outlook 2015*(Apr. 2015).
[48] *Id*.
[49] Energy Information Administration, *Natural Gas Gross Withdrawals and Production, available at* http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm.
[50] Energy Information Administration, *Drilling Productivity Report for Key Tight Oil and Shale Gas Regions* (May 11, 2015) *available at* http://www.eia.gov/petroleum/drilling/.

2012 and 2040.[51] Much of the future natural gas production growth is expected to come from unconventional production of shale resources, including horizontal drilling and multi-stage hydraulic fracturing. Specifically, the EIA found that shale gas production in the lower 48 states will increase by 73%, from 11.3 Tcf in 2013 to 19.6 Tcf in 2040 and will comprise approximately 54% of total domestic production in 2040.[52] The EIA has also significantly increased its estimates of shale gas production through 2035 as compared to its projections in the *Annual Energy Outlook 2014*. For example, the EIA revised its projection of shale gas production in 2030 from 16.92 Tcf to 17.85 Tcf and in 2035 from 18.50 Tcf to 18.85 Tcf.[53]

This growth in shale production has been accompanied by an increase in the overall volume of United States natural gas resources. The EIA's estimates of recoverable natural gas resources have increased by 519 Tcf (30%) between 2009 and 2014.[54] According to ICF–the independent consulting firm commissioned by Port Arthur LNG to assess the domestic market and economic impacts of the proposed Project–there were 3,749 Tcf of technically recoverable gas in the lower-48 U.S. states as of year-end 2013, 1,922 Tcf of which was attributable to shale gas.[55] A large component of the technically recoverable resource is economic at relatively low wellhead prices. ICF estimates that 944 Tcf of this gas resource could economically be developed with gas prices at $5.00 per MMBtu using today's

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[51] Energy Information Administration, *Annual Energy Outlook 2015* (Apr. 2015).
[52] *Id.*
[53] *Id.* at Table A14.
[54] Energy Information Administration, *Natural Gas Reserves Summary* as of December 31, 2014, *available at* http://www.eia.gov/dnav/ng/ng_enr_sum_a_EPG0_R11_BCF_a.htm; Energy Information Administration, *Assumptions to the Annual Energy Outlook 2014*, Table 9.2, *available at* http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf; Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, Table 9.2, *available at* http://www.eia.gov/forecasts/archive/aeo09/assumption/pdf/0554(2009).pdf.
[55] ICF Report at 15. ICF's gas resource estimate is higher than most published assessments as it includes resource categories that are excluded in other analyses. Such resources may eventually be 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 resources into ICF's market forecasts has little effect on results in the near term because current and drilling forecast for the next 20 years will be in the "core" or "near-core" areas which are reflected in other published analyses. *Id.*

technology.[56] This "current technology" 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. With the advancement in drilling technology that will exploit additional shale gas development opportunities, further increases are anticipated in the amount of the technically recoverable resource that can be economically developed. ICF estimates that by extrapolating recent technological advances into the future the amount of gas in the Lower 48 that are economic at $5.00/MMBtu would increase by 54% to 1,452 Tcf by 2040.[57]

2. Domestic Natural Gas Demand

Although domestic demand for natural gas is anticipated to grow, such demand will continue to be outpaced by available supply. For example, though demand for natural gas has increased since 2009, production of natural gas has increased faster due to the shale gas revolution.[58] According to data published by the EIA, natural gas demand was only 15% higher in 2014 than in 2000.[59] In its *Annual Energy Outlook 2015*, the EIA estimates long-term annual U.S. demand growth of only 0.5%, with demand expected to reach 29.70 Tcf in 2040, as compared to 25.53 Tcf in 2012.[60] In contrast, total U.S. dry gas production during the same period is projected to almost double, with a 1.4% annual growth rate.[61]

[56] *Id.* at 13.
[57] *Id.* at 31.
[58] The Brattle Group, *Understanding Natural Gas Markets*, at 3 (Sept. 2014), *available at* http://www.api.org/~/media/files/oil-and-natural-gas/natural-gas-primer/understanding-natural-gas-markets-primer-high.pdf.
[59] Energy Information Administration, *Natural Gas Consumption by End Use*, *available at* http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.
[60] Energy Information Administration*, Annual Energy Outlook 2015* (Apr. 2015) at Table A13.
[61] *Id.*

Growth in demand for natural gas through 2040 is expected to be primarily driven by the power sector due, in part, to environmental regulations.[62] ICF forecasts an increase in gas use in the power generation market from 31% of total consumption in 2014 to 44% by 2040.[63] Similarly, the EIA forecasts that energy consumption in the electric power sector will increase on average by 0.5% per year to 9.38 Tcf in 2040 from 9.11 Tcf in 2012 in the Reference case.[64]

Relatively small growth is anticipated in the industrial sector's demand for natural gas, as reducing energy intensity, or energy input per unit of industrial output, remains a top priority for manufacturers.[65] The EIA estimates that energy consumption in the industrial sector will increase by an average of 0.6% per year to 8.66 Tcf in 2040 from 7.21 Tcf in 2012 in the Reference case.[66] Energy efficiency gains are expected to somewhat offset gas demand growth in the residential and commercial sectors.[67] Energy consumption in the commercial sector will increase only by 0.4% per year to 3.61 Tcf in 2040 from 2.90 Tcf in 2012 in the EIA Reference case.[68] The residential sector is forecasted to have a modest decline in natural gas consumption to 4.20 Tcf in 2040 as opposed to 4.15 Tcf in 2012, in part due to more energy efficient appliances and vehicles.[69]

Under the ICF Base Case, which assumes no exports from the Project, U.S. and Canadian natural gas consumption in 2040 is expected to be 41.8 Tcf (LNG and pipeline exports included). This Base Case projection assumes U.S. LNG exports in a total amount of 3.3 Tcf by

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[62] ICF Report at 20.
[63] *Id*.
[64] Energy Information Administration, *Annual Energy Outlook 2015* (Apr. 2015).
[65] ICF Report at 21.
[66] Energy Information Administration, *Annual Energy Outlook 2015* (Apr. 2015).
[67] ICF Report at 21.
[68] Energy Information Administration, *Annual Energy Outlook 2015* (Apr. 2015).
[69] *Id*.

2025 and net pipeline exports of 2.2 Tcf by 2025.[70] Despite the projected growth in domestic demand through the forecast period of 2040, U.S. natural gas resources, especially unconventional supply from shale resources, are wholly adequate to satisfy domestic demand as well as the added demand of LNG exports from the Project, even when other LNG exports are assumed.

3. Impact on Domestic Prices of Natural Gas

Analyses performed and commissioned by the DOE demonstrate that LNG exports from the United States would not result in adverse economic impacts to U.S. consumers. In 2012, the DOE released a two part study evaluating the impacts of LNG exports on the U.S. economy (the "LNG Export Study").[71] Part 1 of the LNG Export Study, conducted by the EIA, evaluated the potential micro-economic impacts of LNG exports on domestic energy consumption, production, and prices. As a result of Part 1 of the LNG Export Study, the EIA projected that natural gas prices would rise over time even without additional LNG exports.[72]

Part 2 of the LNG Export Study, conducted by NERA Economic Consulting ("NERA"), assessed the macroeconomic impacts, including on domestic natural gas prices, under a range of global natural gas supply and demand scenarios, including scenarios with unlimited LNG exports.[73] In each of the scenarios analyzed, NERA found that the United States would experience net economic benefits from increased LNG exports.[74] With regard to the effect of natural gas prices, NERA further projected that "price changes attributable to LNG

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[70] ICF's estimate of the number of export projects entering the market is based upon their assessment of world LNG demand and other international sources of LNG supply. ICF Report at 21.
[71] Energy Information Administration, *Effect of Increased Natural Gas Exports on Domestic Energy Markets, as Requested by the Office of Fossil Energy* (Jan. 2012).
[72] *Id.*
[73] NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States* (Dec. 3, 2012) (hereinafter the "NERA Study").
[74] *Id*. at 6.

exports remain in a relatively narrow range across the entire range of scenarios."[75] NERA's conclusions were distinguishable from those in the EIA study because the EIA study did not consider macroeconomic effects[76] and the study utilized data provided in the EIA's Annual Energy Outlook 2011, which underestimated gas production levels. The effects of this underestimation are even more pronounced today: Annual Energy Outlook 2011 forecasted dry gas production levels of 26.32 Tcf by 2035[77], compared with a projected 2035 production level of 34.14 Tcf (a 30% increase) in the Annual Energy Outlook 2015 Reference case.[78]

NERA also concluded that natural gas markets in the United States would balance in response to increased natural gas exports largely through increased natural gas production.[79] It further explained that "[t]he market limits how high U.S. natural gas prices can rise under pressure of LNG exports, because importers will not purchase U.S. exports if the U.S. wellhead price rises above the cost of competing supplies."[80] In contrast, Part 1 of the LNG Export Study did not consider whether the quantities of exports could be sold at high enough world prices to support the calculated domestic prices.[81] Accordingly, the price increases forecasted by NERA were generally lower than those forecasted in Part 1 of the LNG Export Study.[82] NERA also indicated that the peak natural gas export levels and resulting price increases analyzed by Part 1

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[75] *Id.* at 2.
[76] *Id.* at 3.
[77] Energy Information Administration, *Annual Energy Outlook 2011* (Apr. 2011).
[78] Energy Information Administration, *Annual Energy Outlook 2015* (Apr. 2015).
[79] NERA Study at 6.
[80] *Id.*.
[81] *Id.* at 3.
[82] *See id.* at 4 ("NERA replaced the export levels specified by DOE/FE and prices estimated by EIA with lower levels of exports (and, *a fortiori prices*) . . ."); *See also id.* at 10 ("U.S. natural gas prices do not reach the highest levels projected by EIA.").

of the LNG Export Study are "not likely,"[83] namely because U.S. exports would fall far short of the levels of exports assumed in the EIA Study.[84]

Even in the export scenarios that led to the most significant theoretical price increases projected by the EIA, NERA found net benefits to U.S. consumers. Specifically, NERA found that:

> Across the scenarios, U.S. economic welfare consistently increases as the volume of natural gas exports increased. This includes scenarios in which there are unlimited exports. The reason for this is that even though domestic natural gas prices are pulled up by LNG exports, the value of those exports also rises so that there is a net gain for the U.S. economy measured by a broad metric of economic welfare or by more common measures such as real household income or real GDP. Although there are costs to consumers of higher energy prices and lower consumption and producers incur higher costs to supply the additional natural gas for export, these costs are more than offset by increases in export revenues along with a wealth transfer from overseas received in the form of payments for liquefaction services. The net result is an increase in U.S. households' real income and welfare.[85]

NERA further found that the net economic benefits became greater with higher levels of exports.[86] Specifically, with greater LNG exports, the value of those exports rises so that there is a net gain for the U.S. economy measured by a metric of economic welfare or by real household income or real Gross Domestic Product.[87]

The EIA issued an updated study in 2014, commissioned by the DOE, that evaluated the effects on U.S. energy markets of increased LNG exports, ranging from 12 Bcf/d to 20 Bcf/d.[88] The Updated LNG Export Study projected that, under the *Annual Energy Outlook*

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[83] *Id.* at 9.
[84] *Id.* at 12.
[85] *Id*. at 6.
[86] *Id.* at 12.
[87] *Id.* at 6; *See also Cameron LNG, LLC*, DOE/FE Order No. 3391 (Feb. 11, 2014).
[88] Energy Information Administration, *Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets* (Oct. 29, 2014) (hereinafter Updated LNG Export Study).

2014 Reference Case, the increased LNG export levels analyzed would lead to a 2% to 5% increase in residential natural gas prices between 2015 and 2040 compared to baseline projections.[89] This forecast is less than the predicted 3% to 7% average increase in residential natural gas prices between 2015 and 2035 that the EIA had previously projected for a lower level of exports under the Annual Energy Outlook 2011 Reference Case. The Updated LNG Export Study found that, even if exports of LNG are greater than forecasted, increased energy production spurs investment, which more than offsets the adverse impact of somewhat higher energy prices when the export scenarios are applied.[90] The Updated LNG Export Study further noted that the model relied upon by the EIA is focused on the U.S. energy system and the domestic economy and does not address several key international linkages that may increase economic benefits further.[91]

In an independent analysis commissioned by Port Arthur LNG, ICF found that the price impacts due to additional LNG exports produced by Port Arthur LNG will be minimal. As a consequence of growing gas demand and increased reliance on new sources of supply, gas prices are expected to increase in the future, even without any exports from Port Arthur LNG.[92] Nevertheless, because unconventional production will increasingly be relied upon to offset declining conventional production,[93] and the cost of production of unconventional natural gas is estimated to be much lower on a per-unit basis than conventional sources,[94] the natural gas price increase resulting from increased demand will be minimal.[95] In the ICF Base Case, gas prices at Henry Hub are expected to increase gradually from approximately $4.42/MMBtu in 2014 to

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[89] *Id.* at 12.
[90] *Id.*
[91] *Id.*
[92] ICF Report at 24.
[93] *Id.* at 9.
[94] *Id.* at 10.
[95] *Id.* at 24.

$7.29/MMBtu in 2040.[96] As a result, prices will be high enough to foster sufficient supply development to meet growing demand, but not so high as to discourage the demand growth.[97]

The ICF Report supports the conclusion that the exports proposed in this Application will have a minimal impact on domestic natural gas prices. According to ICF, by 2040, the increase in the Henry Hub natural gas price attributable to Port Arthur LNG is only $0.08/MMBtu, from an estimated 2040 price of $7.29/MMBtu (with some LNG exports, but not the Project) to a 2040 price with the Project of $7.37/MMBtu.[98]

C. Other Public Interest Considerations

1. Local, Regional, and National Economic Benefits

With an estimated capital cost of approximately $7 billion, the Project will stimulate local, regional, and national economies through direct, indirect, and induced job creation, increased economic activity and tax revenues.

The construction and operation of the Project will result in significant employment impacts across a number of industries both locally and nationwide. Including direct, indirect, and induced employment, the Project will result in the creation of an average of nearly 34,200 jobs for the U.S. economy annually from 2018 through 2040.[99] Additionally, the Project is expected to result in approximately 3,900 jobs annually in Texas over the same forecast period.[100] ICF estimates that, as a result of this substantial job creation, the Project will lead to a cumulative impact of almost 787,000 job-years for the United States economy as a whole and 89,000 job-years for the Texas economy through 2040.[101]

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[96] *Id.*
[97] *Id.*
[98] *Id.* at 45.
[99] *Id.* at 47.
[100] *Id.* at 52.
[101] *Id.* at 47, 52.

Further, Port Arthur LNG exports will increase tax revenues on both the state and federal level. Total government revenues in Texas (including fees and taxes on personal income, corporate income, sales, property, oil and gas severance, and employment) are estimated to increase by $176 million annually through 2040 with the Project.[102] This equates to a cumulative impact on Texas government revenues of approximately $4.0 billion.[103] LNG exports from Port Arthur LNG are estimated to result in an increase in collective government revenues of $3.4 billion annually.[104] This translates to a cumulative impact of $77.4 billion of governmental revenue over the forecast period between 2018 and 2040.[105]

The Project will make a significant contribution to the national economy. The additional LNG volumes exported from Port Arthur LNG could add $9.7 billion to the U.S. economy annually over the 23-year period from 2018 through 2040, resulting in a cumulative contribution of $222.4 billion including the value of associated liquids produced with incremental natural gas and multiplier effects.[106] In Texas alone, the Project is expected to add $1.4 billion to the economy annually ($31.8 billion over the forecast period).[107]

The Project will result in substantial local, regional and national net economic benefits. With the U.S. economy still experiencing sub-par growth eight years after the 2007 financial crisis, the Project will be an important source of new capital investment and job creation. The positive impacts of the Project will first be realized prior to the commencement of construction (when orders for equipment and engineering and other services are placed) and will continue during construction and over the 20-year export term.

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[102] *Id.* at 53.
[103] *Id.*
[104] *Id.* at 49.
[105] *Id.*
[106] *Id.* at 50.
[107] *Id.* at 54.

2. Increased Exports and International Trade

According to ICF, Port Arthur LNG will generate an expected cumulative value of approximately $110.7 billion of LNG exports over the requested 20-year export term, which will favorably influence the balance of trade that the United States has with its international trading partners. In 2014, the United States trade deficit increased to $505 billion, reflecting $2.3 trillion in exports and $2.9 trillion in imports.[108] The United States imported over $289 billion in crude oil and petroleum products in 2014, a significant contributing factor to the United States total trade deficit during that year. According to ICF, the expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $4.8 billion annually between 2018 and 2040, based on the value of LNG export volumes, liquids produced in association with incremental natural gas and other trade effects.[109]

LNG exports will increasingly diversify the global supply of energy resources, which will support the geopolitical security interests of the United States by providing energy supply alternatives to its allies. The export of domestically produced LNG will promote liberalization of the global gas market by fostering increased liquidity and trade at prices established by market forces. Though the price of LNG has recently been volatile, the overall trend in the price of LNG in Asian markets has been significantly higher than that of U.S. LNG. The International Energy Agency ("IEA") reports that natural gas prices in Asia are four times those in North America, and can be as high as five times in winter.[110] Moreover, the IEA expects Asian demand to grow by as much as the current total production in the United States.[111]

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[108] U.S. Department of Commerce Bureau of Economic Analysis, *U.S. International Trade in Goods and Services* (Dec. 2014) *available at* http://www.bea.gov/newsreleases/international/trade/2015/trad1214.htm.

[109] ICF Report at 51.

[110] International Energy Agency, *The Asian Quest for LNG in a Globalising Market*, *available at* http://www.iea.org/publications/freepublications/publication/PartnerCountrySeriesTheAsianQuestforLNGinaGlobalisingMarket.pdf.

[111] *Id.*

By introducing additional market-based price structures, the Project will help to reduce premiums charged to economies which do not currently have sufficient energy supply alternatives and reduce gas price volatility around the world.

3. Environmental Benefits

LNG exports can have significant environmental benefits as natural gas is cleaner burning than other fossil fuels. According to the Environmental Protection Agency, as compared to the average air emissions from coal-fired generation, natural gas produces half as much carbon dioxide, less than a third as much nitrogen oxides, and one percent as much sulfur oxides.[112] An increased supply of natural gas made possible through LNG exports can help countries move away from less environmentally friendly fuels by displacing the current consumption of coal in power generation and deterring the construction of additional coal-fired generation capacity. Exporting LNG to countries where natural gas can displace coal consumption supports the United States' climate goals and bolsters the United States' position globally with respect to climate change.

VIII. ENVIRONMENTAL IMPACTS

The construction and operation of the Project will be subject to authorization by the FERC. On March 20, 2015, Port Arthur LNG submitted a request to initiate the FERC pre-filing process for the proposed Project facilities. The FERC issued a letter approving this request on March 31, 2015. This constituted the initial step in a comprehensive and detailed environmental review by FERC of the proposed Project under the National Environmental Policy Act of 1969 ("NEPA")[113] prior to authorizing the construction of the Project facilities. Since

[112] United States Environmental Protection Agency, *Electricity from Natural Gas*, *available at* http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html#footnotes.
[113] 42 U.S.C. §§ 4321, *et seq*.

then, Port Arthur LNG has held two open houses to explain the Project, identify interests, and resolve concerns of interested stakeholders early in the review process and has held regular conference calls with FERC Staff.

As required by NEPA and the FERC's regulations, Port Arthur LNG will design the Project facilities to minimize or mitigate any adverse environmental impacts. During the pre-filing period, Port Arthur LNG will submit 13 publicly available resource reports to FERC which will assess the impacts of the Project on existing land, water, and air resources and discuss measures to mitigate potential impacts. The environmental impacts for the Project are anticipated to be very similar to those analyzed and addressed in 2005 for the LNG import terminal,[114] where the site of the Project was found to be an acceptable location for siting a LNG facility and to have minimal adverse impacts.[115] These known impacts will be accounted for and addressed early while planning and developing the Project.

In addition to the authorization from the DOE/FE sought in this Application and the authorizations from the FERC, Port Arthur LNG will seek the necessary permits from, and consultations with, other federal, state, and local agencies.

IX. RELATED AUTHORIZATIONS

The siting, construction, and operation of the Project is subject to approval by FERC pursuant to Section 3 of the NGA. As discussed above, on March 31, 2015, FERC accepted Port Arthur LNG's request to commence the mandatory pre-filing process at FERC for the Project and Port Arthur LNG is currently actively engaged in that process. Port Arthur LNG anticipates that it will file its formal application with FERC by no later than October 31, 2015,

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[114] *See Port Arthur LNG, LP*, 115 FERC § 61,344 (2006).
[115] *See* Final Environmental Impact Statement for the Port Arthur LNG Project, FERC Docket No. CP15-83-000 (Apr. 28, 2006).

and will request that FERC issue authorization for the siting, construction, and operation of Project by October 31, 2016.

X. APPENDICES

The following appendices are included with this Application:

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

XI. CONCLUSION

For the reasons set forth above, Port Arthur LNG respectfully requests that the DOE issue an order granting Port Arthur LNG authorization to export for a 20-year term on its own behalf and as an agent for others, approximately 517 Bcf/year (equivalent to 10 MTPA) of domestically produced LNG to any country (i) with which the United States does not have an FTA requiring national treatment for trade in natural gas, (ii) which has or will develop the capacity to import LNG delivered by ocean-going carrier, and (iii) with which trade is not prohibited by United States law or policy.

Respectfully submitted,

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APPENDIX A

Economic Impacts of the Port Arthur Liquefaction Project: Information for DOE Non-FTA Permit Application

ICF INTERNATIONAL

June 5, 2015

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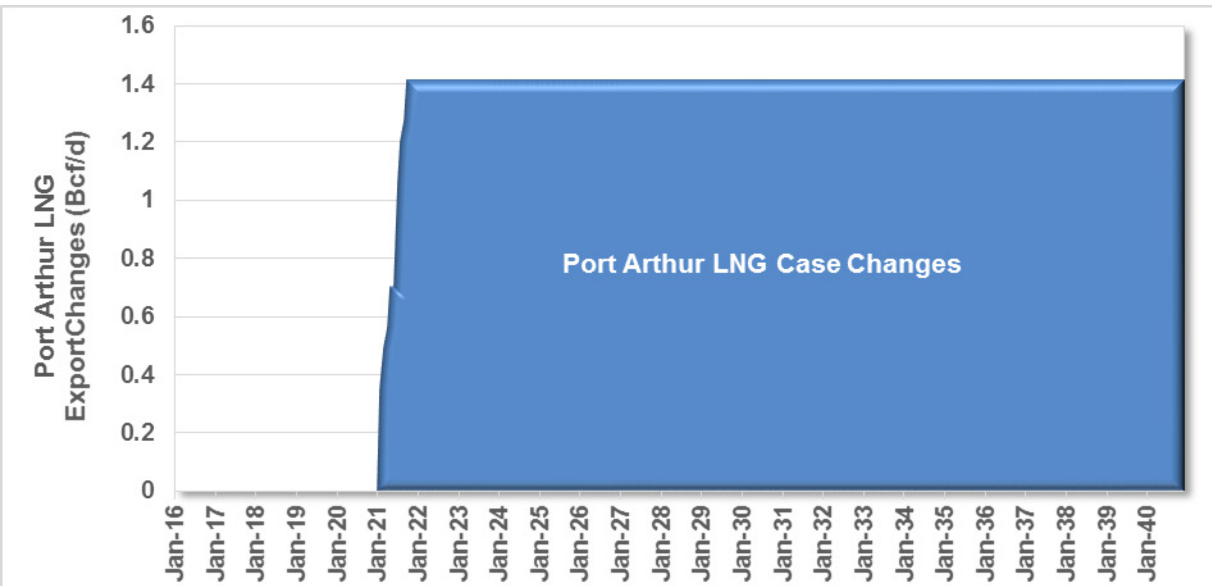
List of Exhibits

1 Executive Summary

1.1 Introduction

ICF conducted an analysis on behalf of Port Arthur LNG to assess the market and economic impacts of the proposed Port Arthur LNG export terminal (Port Arthur), located in Port Arthur, Texas. The LNG terminal is proposed to come on-line in 2021, with proposed capacity of 517[1] Bcf per year (10 million metric tons per annum), or 1.42 Bcfd, as shown in Exhibit 1-1: Port Arthur LNG Export Volumes.

Exhibit 1-1: Port Arthur LNG Export Volumes



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

Source: ICF

ICF was tasked with assessing the energy market impacts, as well as the economic and employment impacts of the Port Arthur terminal. In order to assess these impacts, ICF conducted two alternative scenario runs using its proprietary Gas Market Model (GMM):

1) **Base Case** - no Port Arthur terminal;
2) **Port Arthur LNG Case** - Base Case with 1.42 Bcfd additional export volumes from Port Arthur.

The changes of natural gas and liquids production value, investment, capital and operating expenditure between these two cases are inputs into IMPLAN, an input-output economic model for assessing the economic and employment impacts. Specifically, the analysis methodology consisted of the following steps:

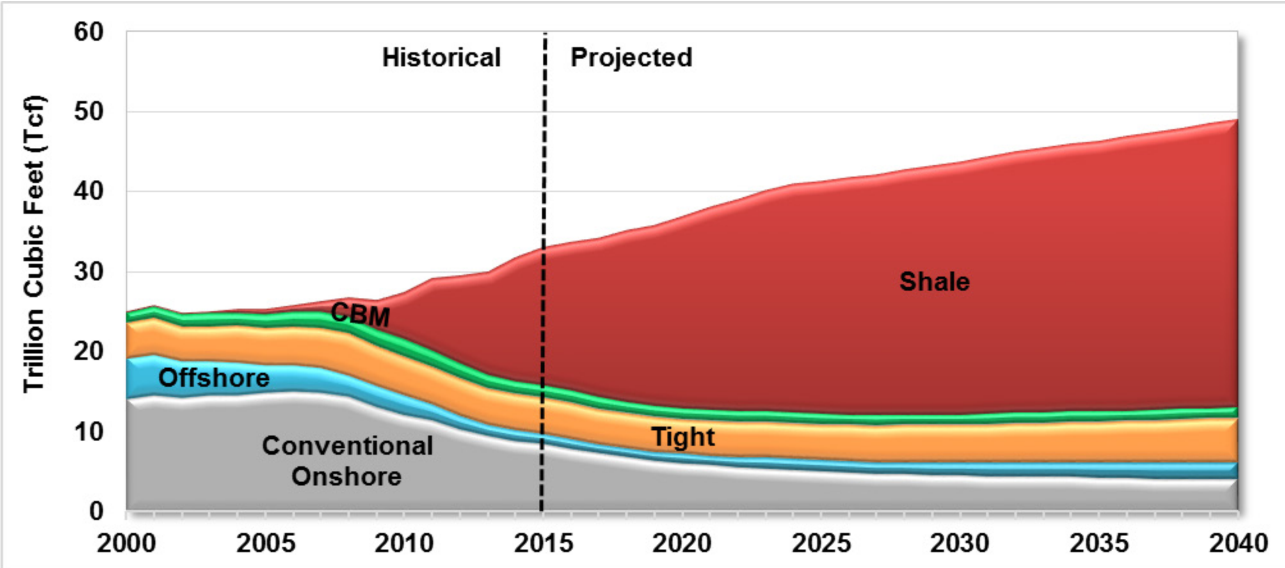
[1] This volume does not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

- **Assess natural gas and liquids production changes:** From the GMM run results, we first estimated natural gas and liquids (including oil, condensate, and natural gas liquids (NGLs) – such as ethane, propane, butane, and pentanes plus) production changes to meet the additional natural gas supplies needed for Port Arthur exports. GMM also solved for changes to natural gas prices and demand levels. The incremental production volumes from the U.S. supply basins and from Texas were separately estimated.
- **Quantify upstream and the plant capital and operating expenditures:** ICF translated the natural gas and liquids production changes from GMM into annual capital and operating expenditures that will be required for the additional production. In addition, based on Port Arthur LNG's cost estimates, ICF assessed the annual capital and operating expenditures required to support the LNG exports at the terminal.
- **Create IMPLAN input-output matrices:** ICF utilized the LNG plant and upstream expenditures as inputs to the IMPLAN input-output model to assess their economic impacts for the U.S. and Texas. The model quantifies the economic stimulus impacts from capital and operational investments. For example, any amount of 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 the economic and employment impacts:** Results of IMPLAN allows ICF to estimate the impacts of the projected incremental expenditures from supporting Port Arthur exports on the national and Texas economies. The impacts include direct, indirect, and induced impacts on gross domestic product (GDP), employment, taxes, and international 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, especially from shale resources. The growth trend is expected to continue over the next 25 years (see Exhibit 1-2: U.S. and Canadian Gas Supplies). Much of the future natural gas production growth comes from increases in gas-directed (non-associated) drilling, specifically gas-directed horizontal drilling 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 the long-term, the power sector presents 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 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. LNG exports are projected to reach 9.1 Bcfd by 2025, with volumes from the Gulf Coast expected to reach 8.9 Bcfd, based on ICF's review of approved projects. These volumes do not include the additional Port Arthur export volumes associated with this economic impact analysis.

[2] All dollar figure results in this report are in 2015 real dollars, unless otherwise specified.

1.3 Key Study Results

ICF's analysis shows that the Port Arthur LNG terminal has minimal impact on the U.S. natural gas price. The Henry Hub natural gas price is expected to increase by $0.07/MMBtu on average for the forecast period of 2018 to 2040, averaging $5.97/MMBtu over the forecast period, with the Port Arthur terminal, compared with $5.90/MMBtu without the terminal, as shown in Exhibit 1-3. The Port Arthur LNG Case natural gas prices at Henry Hub are expected to reach $7.29/MMBtu in the Base Case and $7.37 in the Port Arthur LNG Case by 2040, indicating a price increase of $0.08/MMBtu attributable to the Port Arthur LNG export volumes of 1.42 Bcfd.

The Port Arthur LNG terminal is expected to have minimal impact on the U.S. supply availability and market price because the volume represents a very small amount of the North American natural gas resources and total market demand. Total export volumes from the terminal over the 20-year period from 2021 to 2040 is approximately 10 Tcf. This represents under 1.0% of Lower 48 and Canadian natural gas resources that can be produced with current technology at less than $5.00/MMBtu, and about 1.6% of the total U.S. domestic natural gas consumption during the same period.

Exhibit 1-3: Natural Gas Price Impact of the Port Arthur Terminal

Year	Henry Hub Natural Gas Price (2015$/MMBtu)		
	Base Case	Port Arthur LNG Case	Port Arthur LNG Case Change
2018	$ 4.03	$ 4.03	$ -
2021	$ 5.16	$ 5.20	$ 0.046
2026	$ 5.36	$ 5.44	$ 0.083
2025	$ 5.18	$ 5.27	$ 0.091
2030	$ 6.09	$ 6.16	$ 0.068
2040	$ 7.29	$ 7.37	$ 0.087
2018-2040 Avg	*$ 5.90*	*$ 5.97*	*$ 0.069*

Source: ICF

ICF's analysis concluded that Port Arthur LNG export volumes could lead to significant economic impacts, on average, creating 34,200 annual jobs for the U.S. economy, approximately 3,900 in Texas between 2018 and 2040. This means a cumulative impact through 2040 of almost 787,000 job-years for the U.S. and over 89,000 job-years for Texas. In addition, the project could add nearly $9.7 billion to the U.S. economy annually ($222.4 billion over the forecast period), and $1.38 billion annually in Texas ($31.8 billion over the forecast period). The additional Port Arthur LNG exports would also increase tax revenues. At the U.S. level, federal, state, and local governments are expected to receive an additional $3.4 billion annually; and Texas state and local taxes are expected to increase by $176 million annually. Throughout the 23-year forecast period, the U.S. will receive $77.4 billion additional revenue from taxes and Texas will receive $4.0 billion.

Exhibit 1-4: Economic and Employment Impacts of the Port Arthur LNG Terminal

Region	2018-2040 Average Annual Impact			2018-2040 Cumulative Impact		
	Jobs (Jobs)	Value Added (2015$ Million)	Government Revenues (2015$ Million)	Jobs (Job-years)	Value Added (2015$ Million)	Government Revenues (2015$ Million)
U.S.	34,208	$ 9,668.7	$ 3,366.9	786,773	$ 222,380.2	$ 77,439.4
Texas	3,881	$ 1,383.1	$ 175.7	89,253	$ 31,812.1	$ 4,040.1

Source: ICF

2 Introduction

Port Arthur LNG tasked ICF International with assessing the economic and employment impacts of additional liquefied natural gas (LNG) exports from its Port Arthur, TX LNG export facility.

Exhibit 2-1 and Exhibit 2-2 show Port Arthur's location and preliminary layout, respectively.

Exhibit 2-1: Port Arthur LNG Location Map

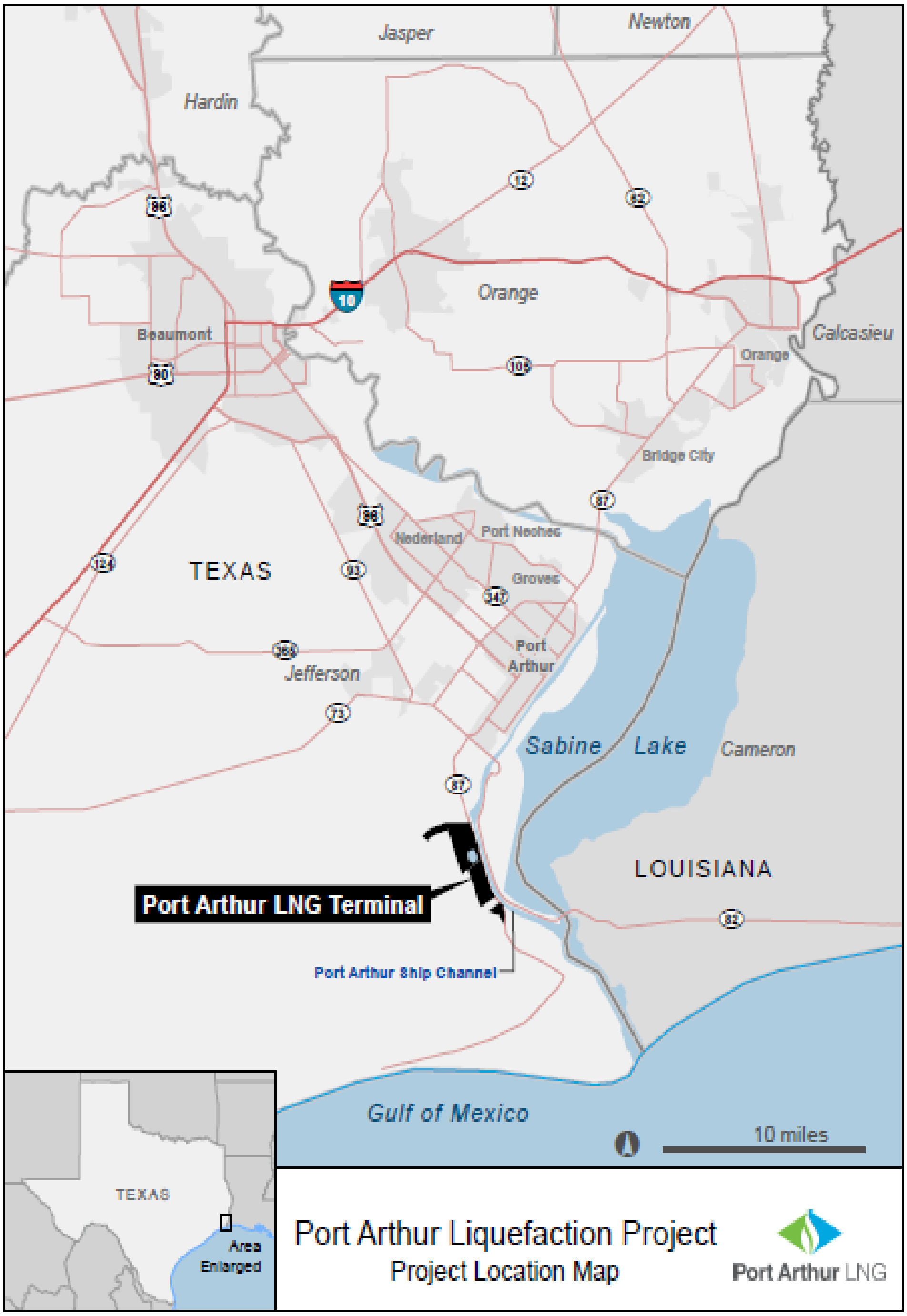
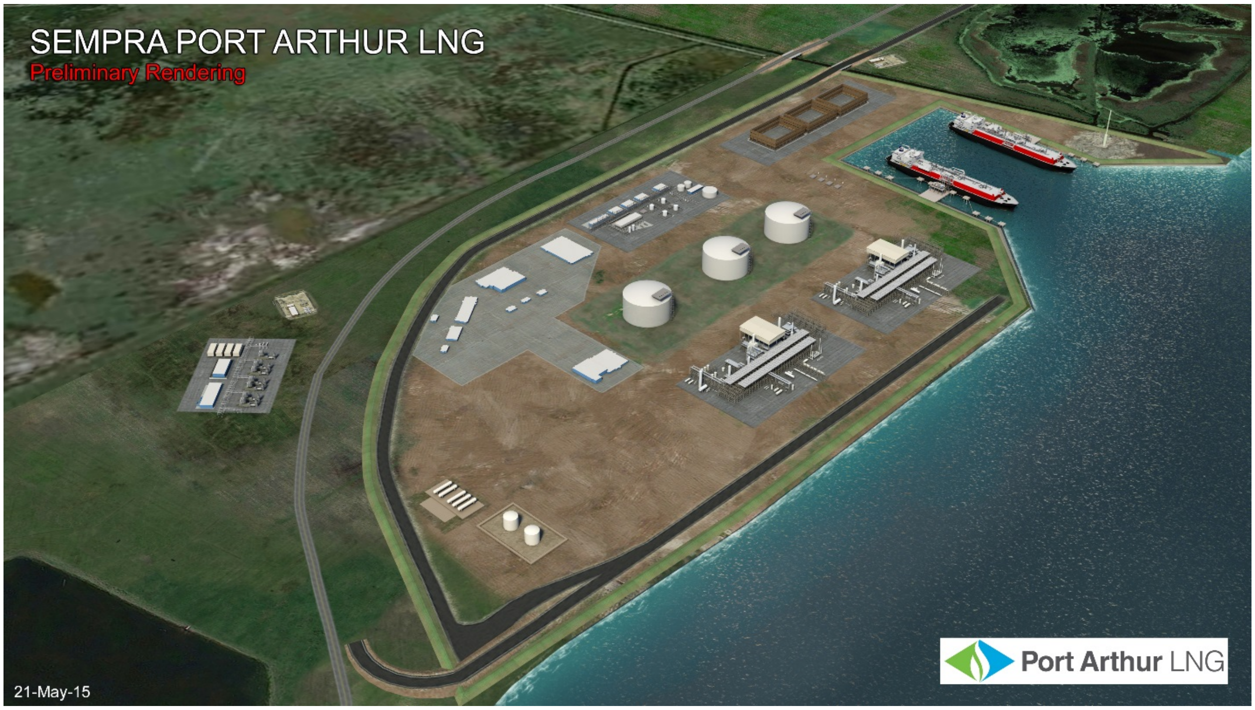


Exhibit 2-2: Port Arthur LNG Preliminary Layout



For this analysis, ICF ran its proprietary natural gas market fundamental GMM model with and without the 1.42 Bcfd terminal and estimated the changes between the two scenarios for the total U.S. and Texas:

- 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.

The changes in LNG plant capital and operating expenditure and upstream capital and operating expenditures were inputted into the IMPLAN model to estimate the terminal's impacts on the U.S. and Texas economy. The economic metrics include:

- Employment
- Federal, state, and local government revenues
- Value added
- U.S. Balance of Trade

This report is organized as follows.

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

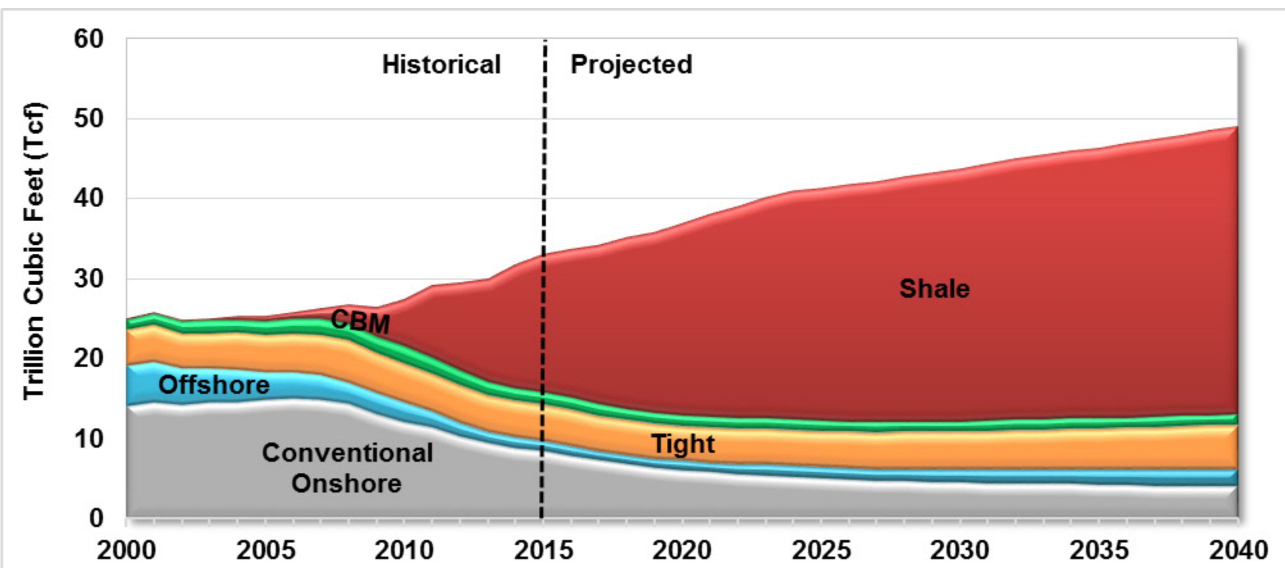
3 Base Case U.S. and Canadian Natural Gas Market Overview

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 2040, 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 2040 and beyond (see Exhibit 3-1). Recent unconventional production technology advances (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.

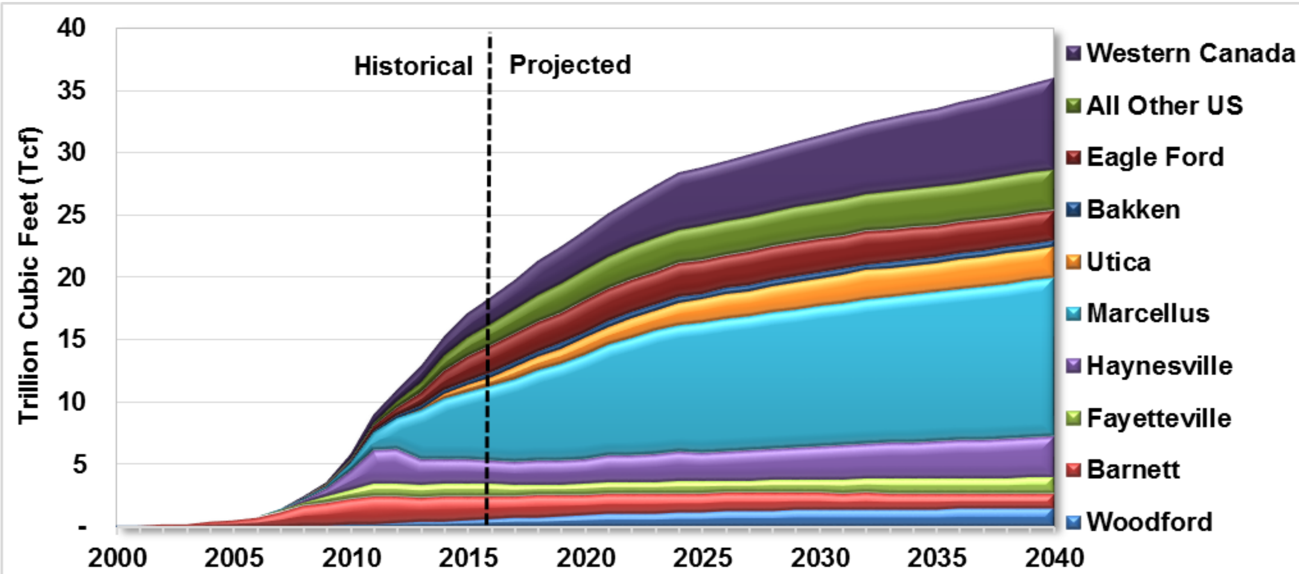
Exhibit 3-1: U.S. and Canadian Gas Supplies



Source: ICF GMM® Q2 2015

Production from U.S. and Canadian shale formations will grow from about 5.8 Tcf (15.9 Bcfd) in 2010 to nearly 35.8 Tcf (98 Bcfd) by 2040 (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 and North Gulf States (Woodford, Fayetteville, Barnett, and Haynesville), South Texas (Eagle Ford), and west 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 with natural gas volumes. ICF did not include potential 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 GMM® Q2 2015

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.[3] 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 resource 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

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

exploration while shale gas is almost all development drilling. Offshore undiscovered 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 considers 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.[4,5,6] 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 option. 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 Exhibit 3-3. 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

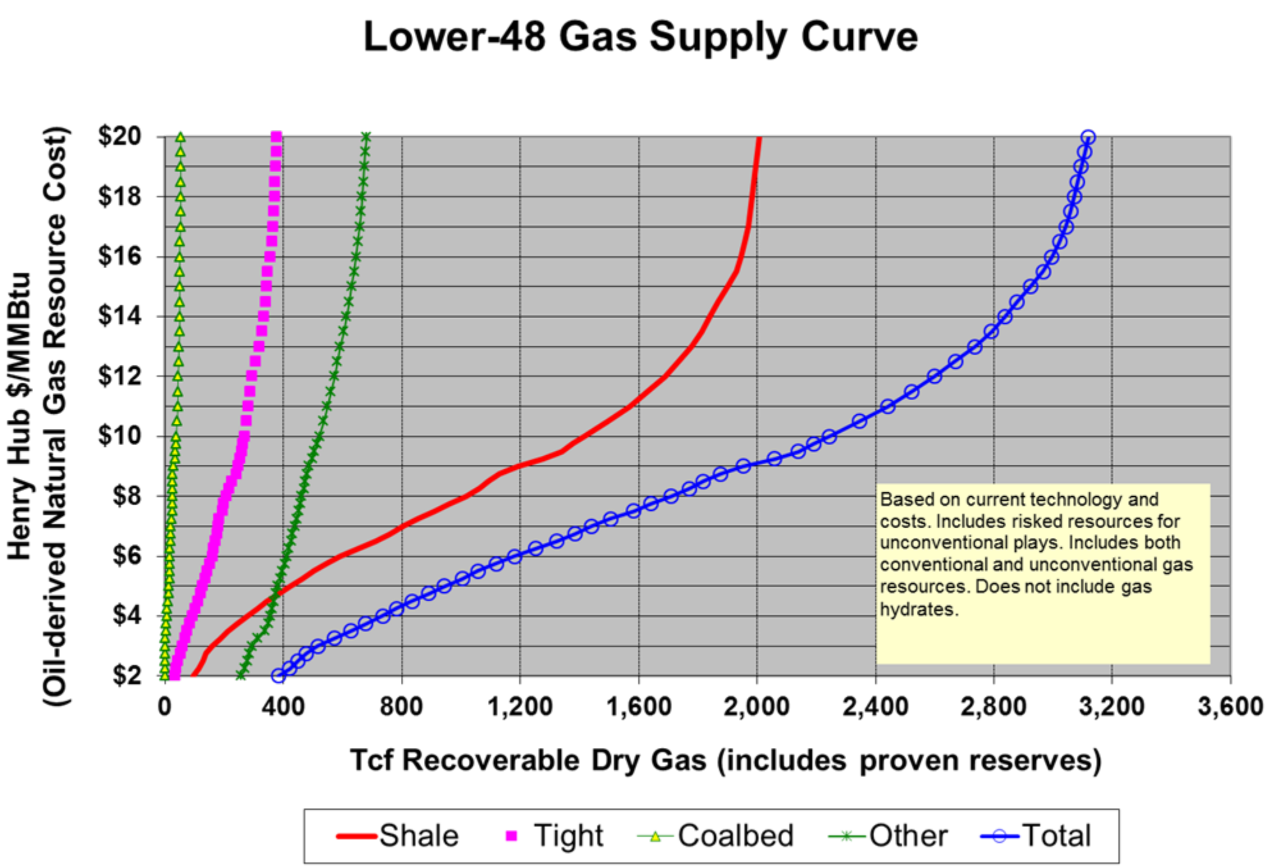
[4] American Petroleum Institute. "2012 Joint Association Survey of Drilling Costs". API, various years: Washington, DC.
[5] Petroleum Services Association of Canada (PSAC). "2009 Well Cost Study". PSAC, 2009. Available at: http://www.psac.ca/
[6] U.S. Energy Information Administration. "Oil and Gas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

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.

For the Lower-48, 2,244 Tcf of gas resource is available at $10.00 per MMBtu or less. For Canada there is 481 Tcf at $10.00 per MMBtu or less. At $5.00 per MMBtu, 944 Tcf is available in the Lower-48 and approximately 149 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 supply curve 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. (See section 4.1.3 for discussion of technology trends assumed in this study.)

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.[7]
>
> ***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** on the following page, summarize the current ICF gas and crude oil assessments for the U.S. and Canada. Resources shown are "technically recoverable

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

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).

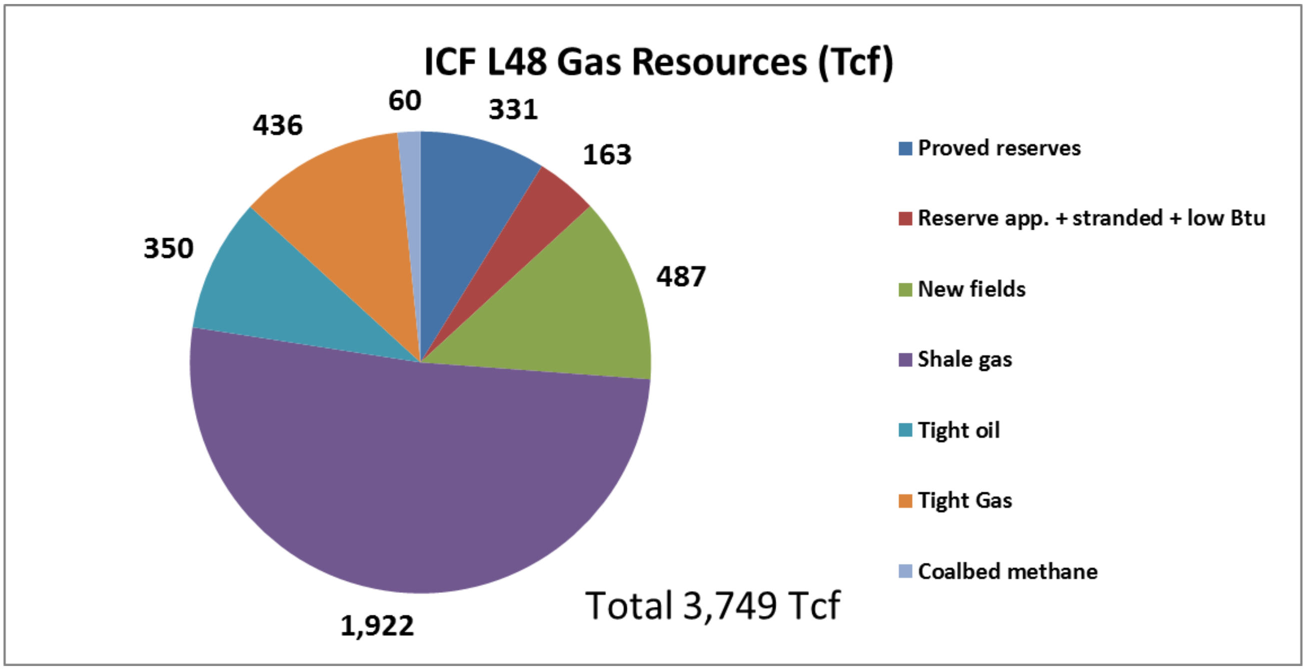
Exhibit 3-4: ICF North America Technically Recoverable Oil and Gas Resource Base Assessment (current technology)

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

Lower 48	Dry Total Gas Tcf	Crude and Cond. Bn bbls
Proved reserves	331	34
Reserve appreciation and low Btu	163	17
Stranded frontier	0	0
Enhanced oil recovery	0	42
New fields	487	71
Shale gas and condensate	1,922	31
Tight oil (excl. shale gas resource)	350	114
Tight gas	436	4
Coalbed methane	60	0
Lower 48 Total	**3,749**	**313**
Canada		
Proved reserves	72	4.2
Reserve appreciation and low Btu	29	2.9
Stranded frontier	40	0.0
Enhanced oil recovery	0	3.0
New fields	219	11.8
Shale gas and condensate	546	0.3
Tight oil (excl. shale gas resource)	183	32.5
Tight gas (with conventional)	0	0.0
Coalbed methane	75	0.0
Canada Total	**1,164**	**55**
Lower-48 and Canada Total	**4,913**	**368**

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 1,922 Tcf can be compared to the EIA's 489 Tcf or the Potential Gas Committee's 1,253 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

ICF, April 2015
TCF of technically recoverable gas; excludes proved reserves of 341 Tcf as of year end 2013

Group	Shale Gas	Tight Oil	Tight Gas	Coalbed	Conventional	Unproved Total	Including Proved
ICF, 2015	**1,922**	**350**	**436**	**60**	**650**	**3,418**	**3,749**
ICF, 2014	**1,964**	**172**	**438**	**66**	**707**	**3,347**	---
EIA AEO, 2014	489	49	365	120	637	1,660	---
USGS and BOEM (current)	384	14	200	73	481	1,152	---
Potential Gas Committee, 2015	1,253	---	(with conv.)	101	919	2,273	---
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	---

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 March 2015

		ICF	AEO 2014	USGS Current
Appalachia				
Marcellus		689	119	84
Huron		42	0	0
Other Devonian		15	21	10
Utica		445	37	38
	subtotal	1,191	177	132
Midcontinent				
Arkoma Fayetteville		32	30	13
Arkoma Caney		20	1	1
Arkoma Woodford		38	7	11
Anadarko Woodford (CANA)		36	9	16
	subtotal	126	47	41
Gulf Coast and Permian				
Haynesville		278	71	60
Bossier Shale		49	0	0
Fort Worth Barnett		46	20	26
Eagle Ford		90	53	52
Gulf Coast Pearsall		0	8	9
W. Texas Barnett/Woodford		23	16	35
Floyd/Conasauga		0	2	2
	subtotal	486	170	184
Rockies				
Green River Hilliard, etc		10	11	0
Uinta Mancos		0	11	0
San Juan Lewis		0	10	0
Paradox Basin		34	0	0
	subtotal	44	32	0
Michigan and Illinois		10	57	11
Other Lower- 48		65	6	16
Total		**1,922**	**489**	**384**

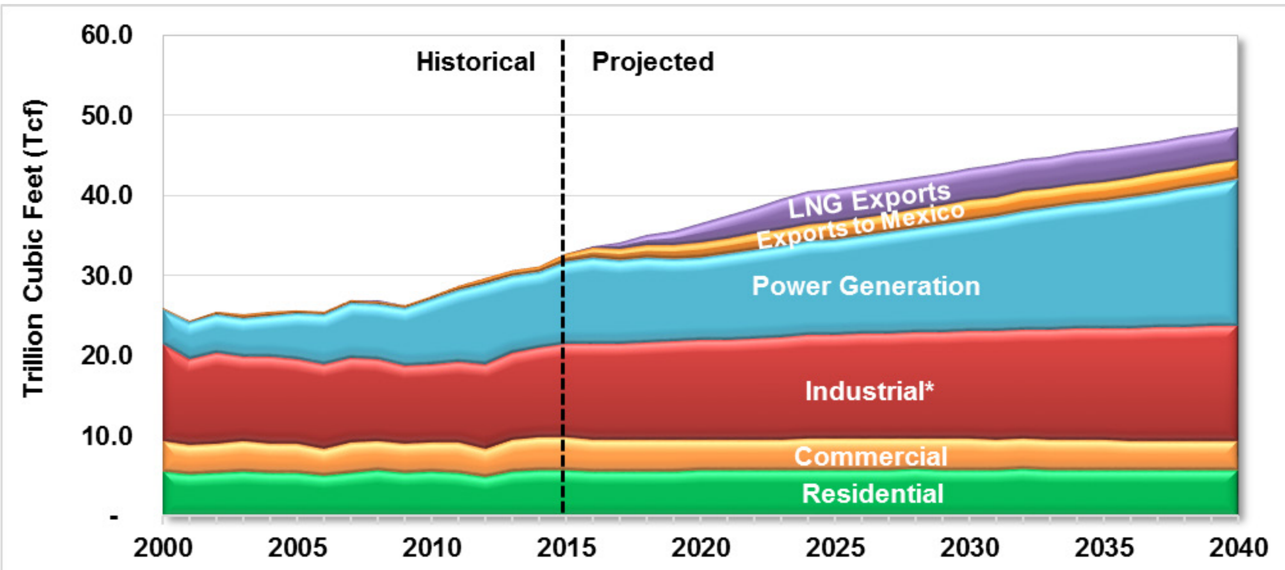
Source: Various compiled by ICF

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 late 2015 or early 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 and LNG used in vehicles and off-road equipment). Exhibit 3-8 below shows ICF's U.S. and Canadian consumption forecast by sector.

Incremental power sector gas use between 2014 and 2040 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 load 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 4,100 Terawatt-hours (TWh) per year by 2020, or growth nearing 11 percent over 2010 levels (3,700 TWh annually).

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



Source: ICF GMM® Q2 2015

* 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 31 percent of total consumption in 2014 to 44 percent by 2040. 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 during the 2014-2040 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.

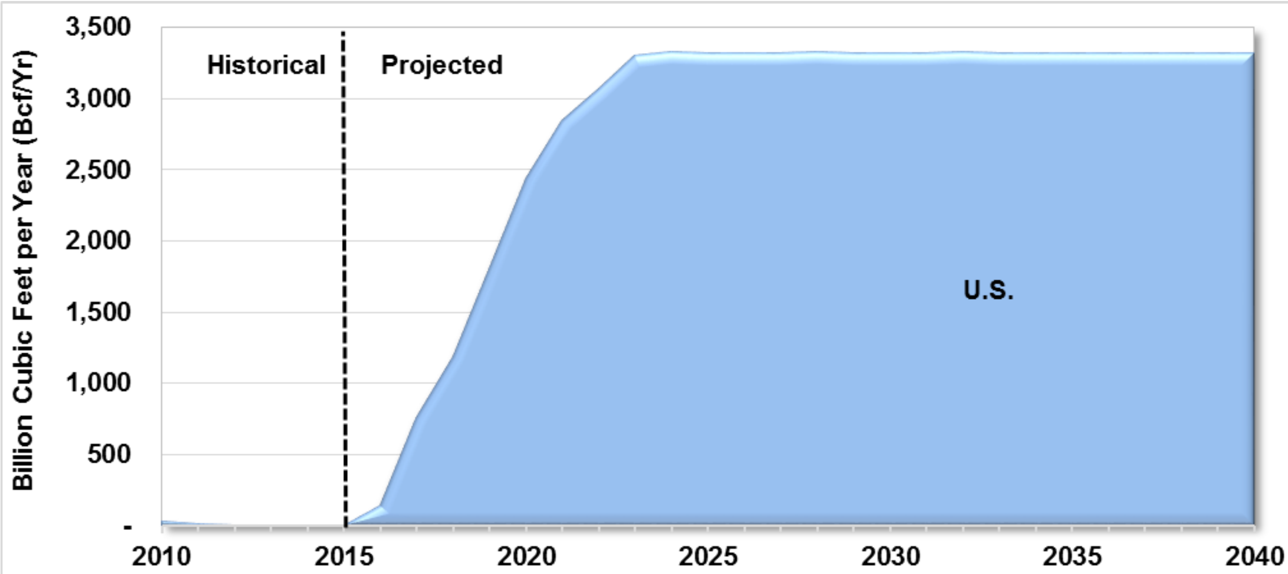
Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the 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 2040, up from 730 Bcf/year (2.0 Bcfd) in 2014.

3.2.1 LNG Export Trends

The U.S. Department of Energy (DOE) has received 43 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, seven applications at six sites (four sites located on the U.S. Gulf Coast) have received final 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, the Base Case of this study assumes completion of a total of 9 U.S. export facilities between late 2015 and 2021 (eight on the U.S. Gulf Coast, and one on the East Coast), exporting a total of 3.3 Tcf (9.1 Bcfd) by 2025 (see exhibit below). For the 8.9 Bcfd LNG exports volumes out of the Gulf, ICF assumed that Sabine Pass, Freeport, Cameron and Corpus Christi terminals will operate near their planned capacity while the export volumes at other proposed terminals at less advanced stages are risk-weighted.

Exhibit 3-9: U.S. LNG Export Assumptions



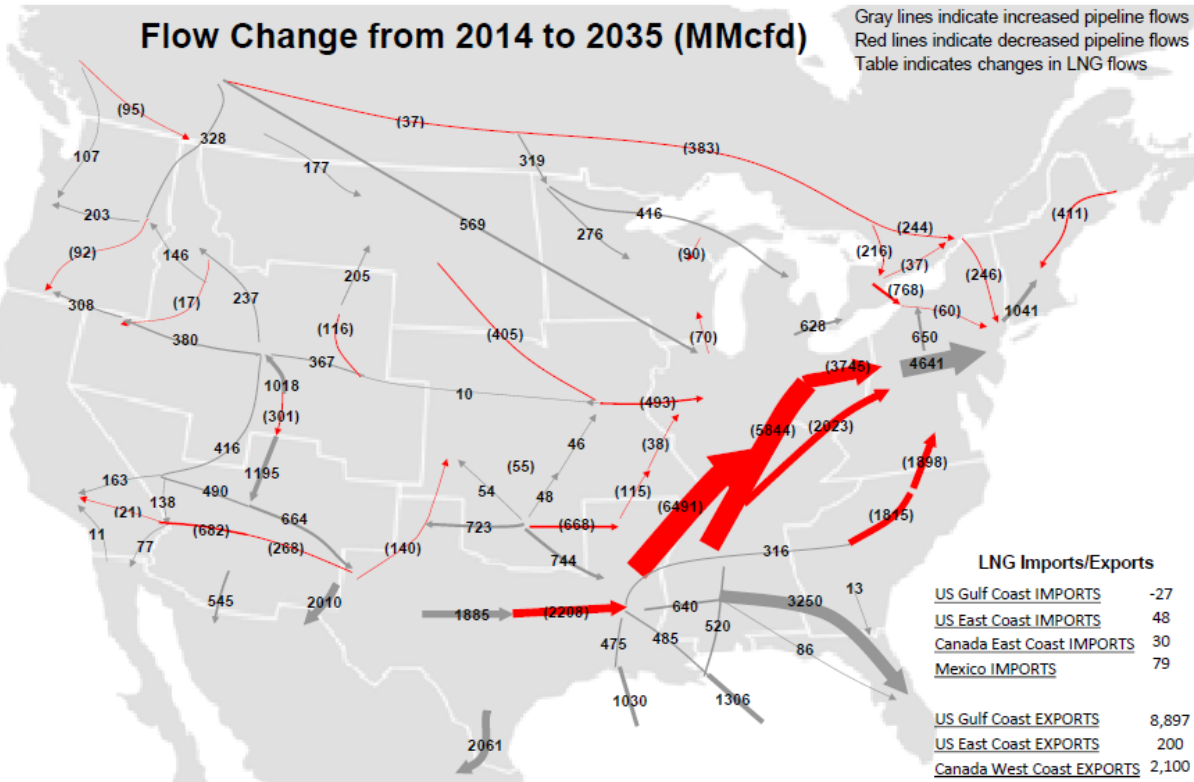
Source: ICF GMM® Q2 2015

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. Exhibit 3-10 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.

Exhibit 3-10 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® Q2 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.

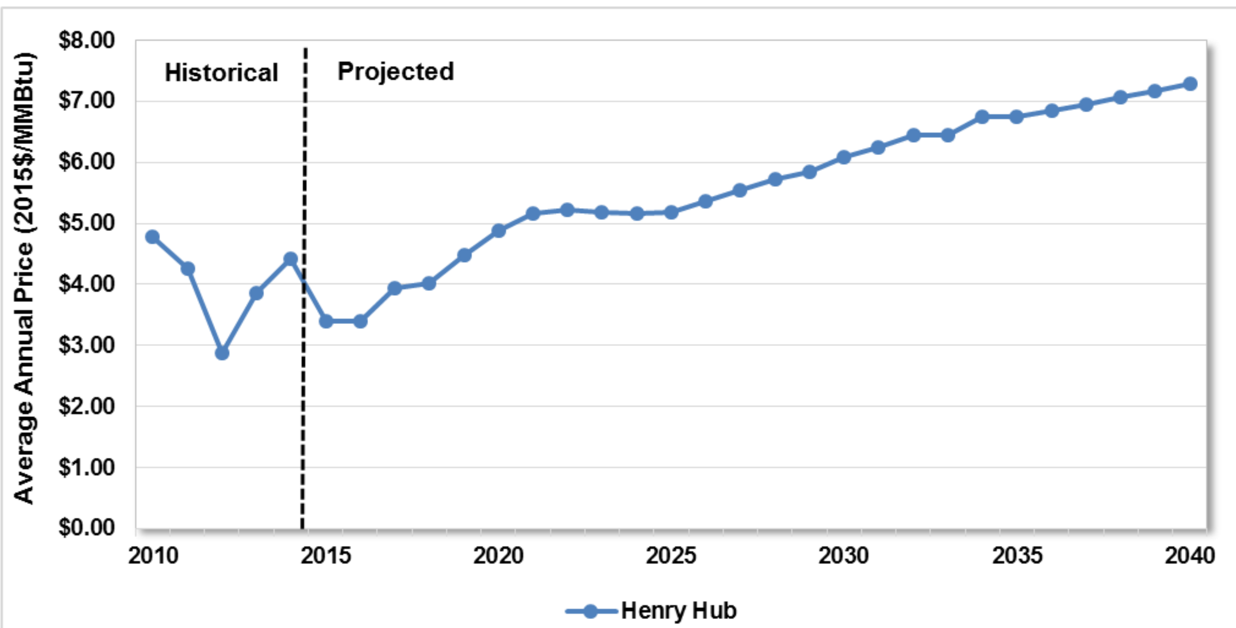
Eastward flows out of western Canada are projected to decline. Growth in production from shale gas resources in British Columbia (BC) and Alberta will be more than offset by declines in conventional gas production in Alberta until 2020, as well as growth in natural gas demand in western Canada. Strong 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 $4.42 per MMBtu in 2014 to $7.29 per MMBtu in 2040 (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. 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. are expected to remain moderate, as shown in Exhibit 3-11.

Exhibit 3-11: GMM Average Annual Prices for Henry Hub

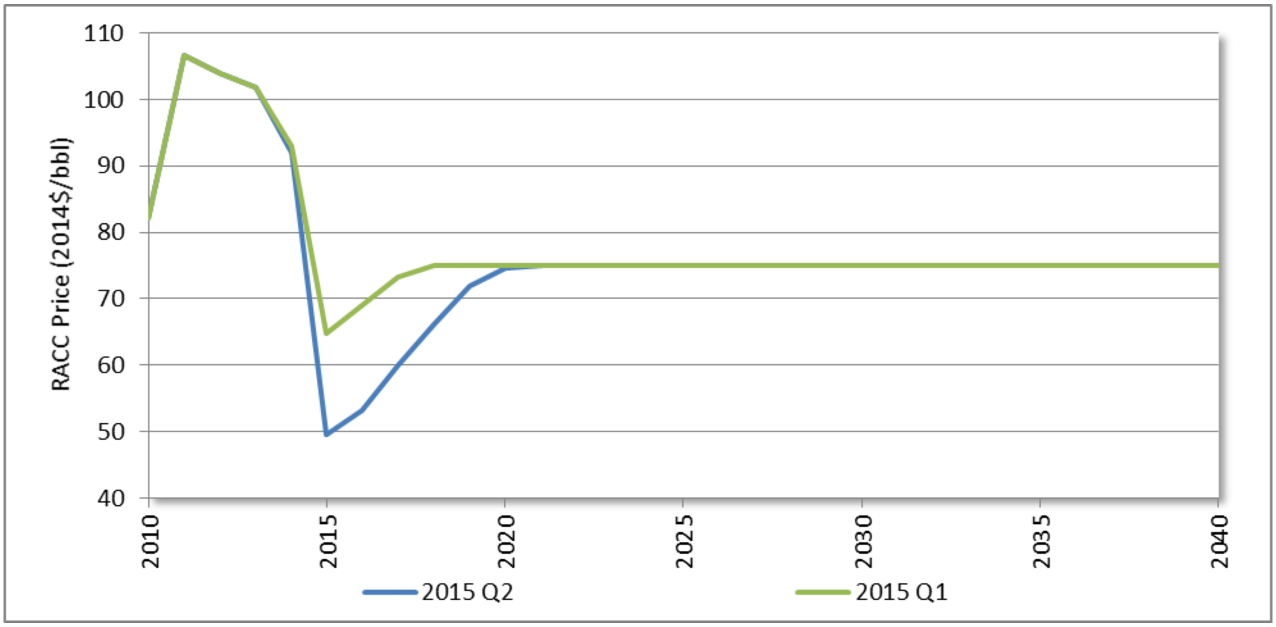


Source: ICF

3.5 Oil Price Trends

In the wake of recent market declines, ICF has revised its near-term oil price assumption downward from a real price of near $65/bbl to $50/bbl due to the ongoing global supply surplus and slowing economic growth in the second quarter of 2015. 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 March spot price and will rise to a constant real level reflecting a liquid traded mid-term price in the futures market of approximately $75/bbl (2014 dollars) after 2020, the long-term cost of marginal supplies, 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, ICF has 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.[8]

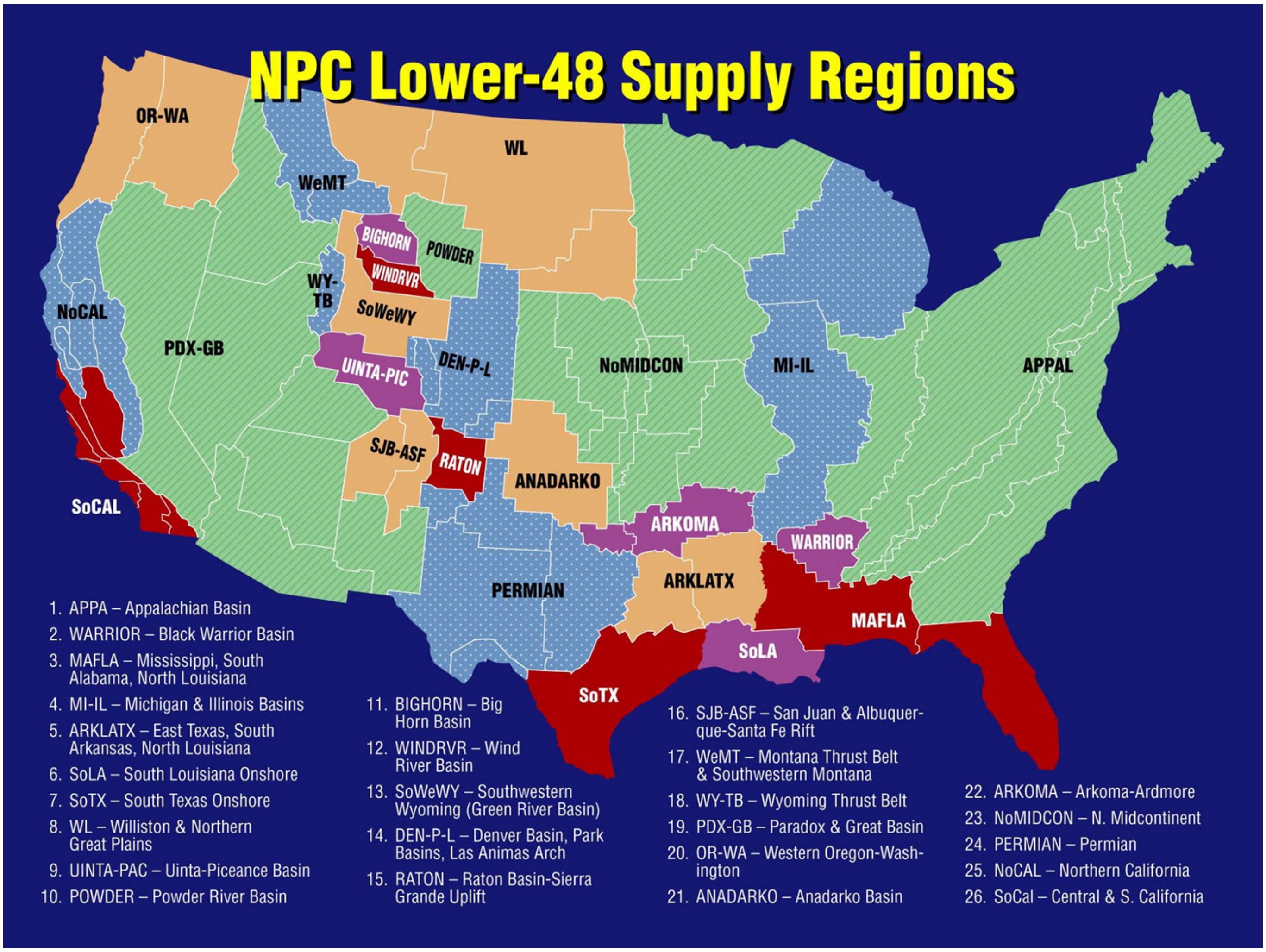
4.1.2 Unconventional Oil and Gas

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

[8] 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.[9] 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**	

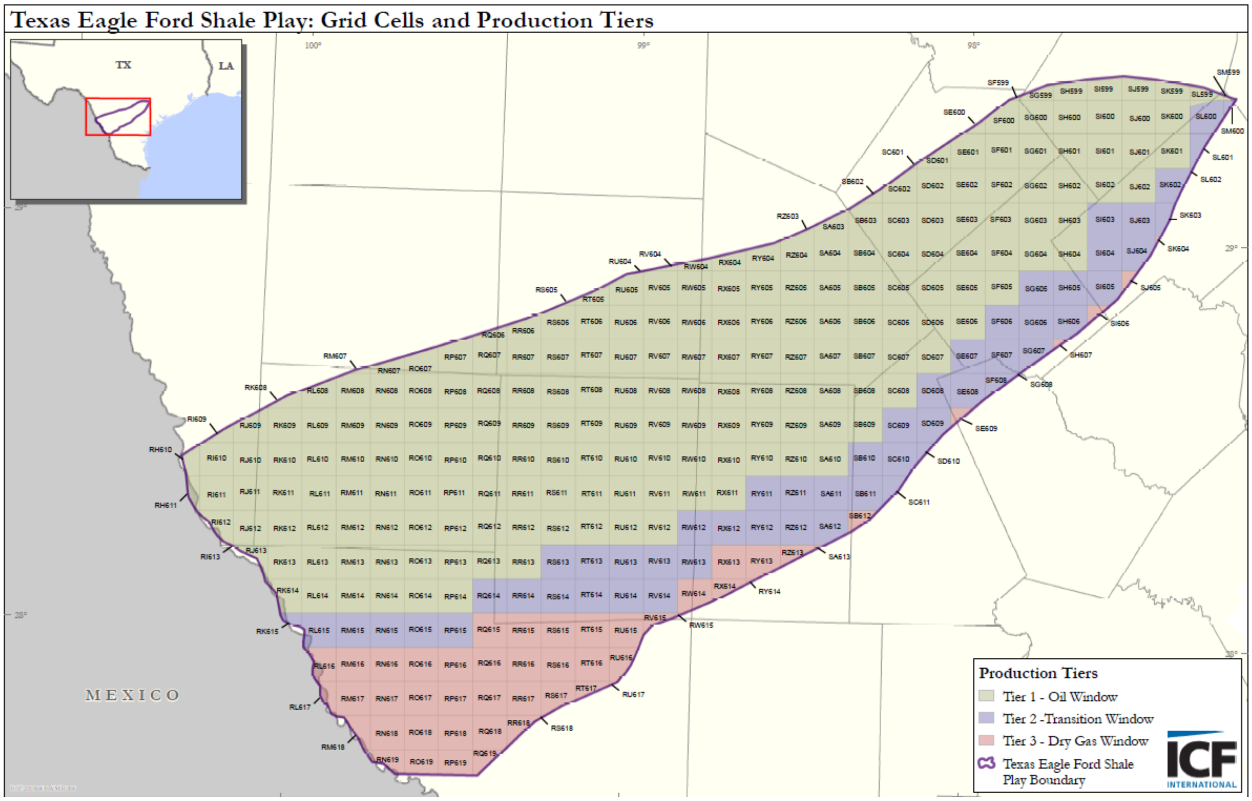
Source: ICF

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.

[9] 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 2013 was 3.3 million barrels per day (MMbpd) in the U.S., up from almost zero in 2007, and 250,000 bpd in Canada. Current U.S. tight oil production is over 4 MMbpd. 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 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 basic ICF economic resource assessment and gas supply curves are 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 the last 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.

ICF expects that drilling costs will continue to be 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 have declined significantly.

ICF examines trends in estimated ultimate recovery (EUR) over time to determine how well recoveries are affected by well design and other technology factors and how average EURs are affected by changes in mix of well locations within a play. To estimate the contributions of changing technologies ICF employs the “learning curve” concept used in several industries. The “learning curve” concept says that we can describe the aggregate influence of learning and technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or EUR per well) for each doubling of cumulative output volume of other measure of maturity.

The most technologically immature resources, wherein technologies advances are among the fastest, include gas shales and tight oil developed using horizontal multi-stage hydraulically fractured wells, When looking at EURs for horizontal gas shale or tight oil wells, ICF estimates what the percent change in EUR is for each doubling of the cumulative North American horizontal multi-stage fracked wells. We first measure EUR on a per-well basis to look at total effects and then EUR per 1,000 feet of lateral to separate out the effect of lateral length. This statistical analysis is done using a “stacked regression” wherein each geographic part of the play is treated separately to determine the regression intercepts but all areas are looked at together to estimate a single regression coefficient (representing technological improvements) for the play.

Generally speaking we find that the total technology learning curve shows roughly 20 percent improvement in EUR per well for each doubling of cumulative horizontal multistage fracked wells. When we take out the effect of lateral lengths by fitting EUR per 1,000 feet of lateral rather than EUR per well, we find the learning curve effect is roughly 14 percent per doubling of cumulative wells. In other words about one-third of the observed total 20% improvement in EUR per well doubling is due to increase lateral lengths and about two-thirds is due to other technologies such as better selection of well locations, denser spacing of frack stages, improved fracture materials and designs and so on.

The net effect of assuming that these technology trends continue in the future is to increase the amount of natural gas that is available at any given price. In other words, the gas supply curve "shifts down and to the right." The amount of the shift depends on what price point and future year are being estimated and which forecast case is being examined. The forecasted pace of drilling affects the cumulative learning impact in any given year as more drilling leads to faster technology advances as the effect is estimated based on cumulative wells drilled. As an example, for the two forecast cases examined here (the ICF Base Case and the Port Arthur LNG Case) the upstream technology effects through 2040 add approximately 508 Tcf of Lower 48 gas supplies that are economic at $5.00/MMBtu (1,452 Tcf with 2040 technology compared to 944 Tcf with 2014 technology). Generally speaking, by 2040 the upstream technology assumptions used in the GMM add roughly 50 percent to 60 percent to economic resources in the $5.00 to $7.00/MMBtu price range of the Lower 48 gas supply curve.

4.2 Energy and Economic Impacts Methodology

Port Arthur LNG tasked ICF with assessing the economic and employment impacts of additional LNG exports from its Port Arthur, TX LNG export facility. This study analyzed two cases[10]:

1) **Base Case** with the assumption of no Port Arthur LNG export volumes.
2) **Port Arthur LNG Case** with the assumption of an additional 517 Bcf per year, or 1.42 Bcfd higher than the Base Case due to the new construction of Trains 1 and 2 at Port Arthur.

The results in this report show the changes between the Base Case and alternative case resulting from the incremental LNG export volumes. 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 Texas level.

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

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

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 4 – 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 Texas. 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 5 – Economic impacts: ICF assessed the impact of LNG exports for the national and Texas levels. This included direct, indirect, and induced impacts on gross domestic product, employment, taxes, and other measures.

Exhibit 4-4: Economic 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.

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

- Port Arthur 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.

Exhibit 4-5: Port Arthur LNG Export Volume Assumptions (Bcfd)

Year	Base Case	Train 1	Train 2	Port Arthur LNG Total
2021	-	0.64	0.59	**1.23**
2022	-	0.71	0.71	**1.42**
2023	-	0.71	0.71	**1.42**
2024	-	0.71	0.71	**1.42**
2025	-	0.71	0.71	**1.42**
2026	-	0.71	0.71	**1.42**
2027	-	0.71	0.71	**1.42**
2028	-	0.71	0.71	**1.42**
2029	-	0.71	0.71	**1.42**
2030	-	0.71	0.71	**1.42**
2031	-	0.71	0.71	**1.42**
2032	-	0.71	0.71	**1.42**
2033	-	0.71	0.71	**1.42**
2034	-	0.71	0.71	**1.42**
2035	-	0.71	0.71	**1.42**
2036	-	0.71	0.71	**1.42**
2037	-	0.71	0.71	**1.42**
2038	-	0.71	0.71	**1.42**
2039	-	0.71	0.71	**1.42**
2040	-	0.71	0.71	**1.42**

Note: LNG export volumes do not include liquefaction fuel or losses.

Source: Port Arthur LNG, ICF

Exhibit 4-6: Port Arthur LNG Plant Capital and Operating Expenditures

Year	The Port Arthur LNG Case Changes	
	LNG Capital Costs (2015$ MM)	LNG Operating Costs (2015$ MM)
2010	$0	$0
2011	$0	$0
2012	$0	$0
2013	$0	$0
2014	$0	$0
2016	$0	$0
2016	$0	$0
2017	$0	$0
2018	$1,900	$0
2019	$2,100	$0
2020	$2,100	$0
2021	$1,000	$104
2022	$0	$143
2023	$0	$143
2024	$0	$143
2025	$0	$144
2026	$0	$144
2027	$0	$144
2028	$0	$144
2029	$0	$144
2030	$0	$144
2031	$0	$144
2032	$0	$144
2033	$0	$144
2034	$0	$144
2035	$0	$144
2036	$0	$144
2037	$0	$144
2038	$0	$144
2039	$0	$143
2040	$0	$143

Source: Port Arthur 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) (%)	Texas State and Local Own Taxes as % of State Income (%)
2010	14.6%	15.1%	13.4%
2011	15.0%	14.9%	12.9%
2012	15.3%	14.5%	12.7%
2013	16.7%	14.5%	12.7%
2014	17.5%	14.5%	12.7%
2015	17.7%	14.5%	12.7%
2016	18.7%	14.5%	12.7%
2017	19.1%	14.5%	12.7%
2018	19.1%	14.5%	12.7%
2019	19.2%	14.5%	12.7%
2020	19.3%	14.5%	12.7%
2021	19.4%	14.5%	12.7%
2022	19.5%	14.5%	12.7%
2023	19.6%	14.5%	12.7%
2024	19.7%	14.5%	12.7%
2025	19.8%	14.5%	12.7%
2026	19.9%	14.5%	12.7%
2027	20.0%	14.5%	12.7%
2028	20.1%	14.5%	12.7%
2029	20.2%	14.5%	12.7%
2030	20.3%	14.5%	12.7%
2031	20.4%	14.5%	12.7%
2032	20.5%	14.5%	12.7%
2033	20.6%	14.5%	12.7%
2034	20.7%	14.5%	12.7%
2035	20.8%	14.5%	12.7%
2036	20.9%	14.5%	12.7%
2037	21.0%	14.5%	12.7%
2038	21.1%	14.5%	12.7%
2039	21.2%	14.5%	12.7%
2040	21.3%	14.5%	12.7%

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$/bbl)	Propane Price (2015$/bbl)	Butane Price (2015$/bbl)	Pentanes Plus (2015$/bbl)
2010	$ 84	$ 84	$ 28	$ 49	$ 57	$ 77
2011	$ 109	$ 109	$ 25	$ 61	$ 74	$ 99
2012	$ 106	$ 106	$ 17	$ 42	$ 72	$ 97
2013	$ 104	$ 104	$ 22	$ 42	$ 70	$ 95
2014	$ 95	$ 95	$ 26	$ 44	$ 64	$ 87
2015	$ 49	$ 49	$ 20	$ 20	$ 34	$ 45
2016	$ 54	$ 54	$ 20	$ 22	$ 37	$ 50
2017	$ 61	$ 61	$ 20	$ 26	$ 41	$ 56
2018	$ 67	$ 67	$ 21	$ 26	$ 46	$ 61
2019	$ 73	$ 73	$ 22	$ 26	$ 50	$ 67
2020	$ 76	$ 76	$ 23	$ 25	$ 52	$ 70
2021	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2022	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2023	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2024	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2025	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2026	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2027	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2028	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2029	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2030	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2031	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2032	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2033	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2034	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2035	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2036	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2037	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2038	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2039	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2040	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70

Source: ICF

Exhibit 4-9: Other Key Model Assumptions

Assumption	U.S.	Texas
Upstream Capital Costs ($MM/Well)	$7.7	$8.1
Upstream Operating Costs ($/barrel of oil equivalent, BOE)	$3.19	$3.19
Royalty Payment (%)	17.0%	17.0%
LNG Tanker Capacity (Bcf/Ship)		3.60
U.S. Port Fee ($/Port Visit)		$100,000
Port Arthur LNG Liquefaction Fee ($/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, for example, 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.

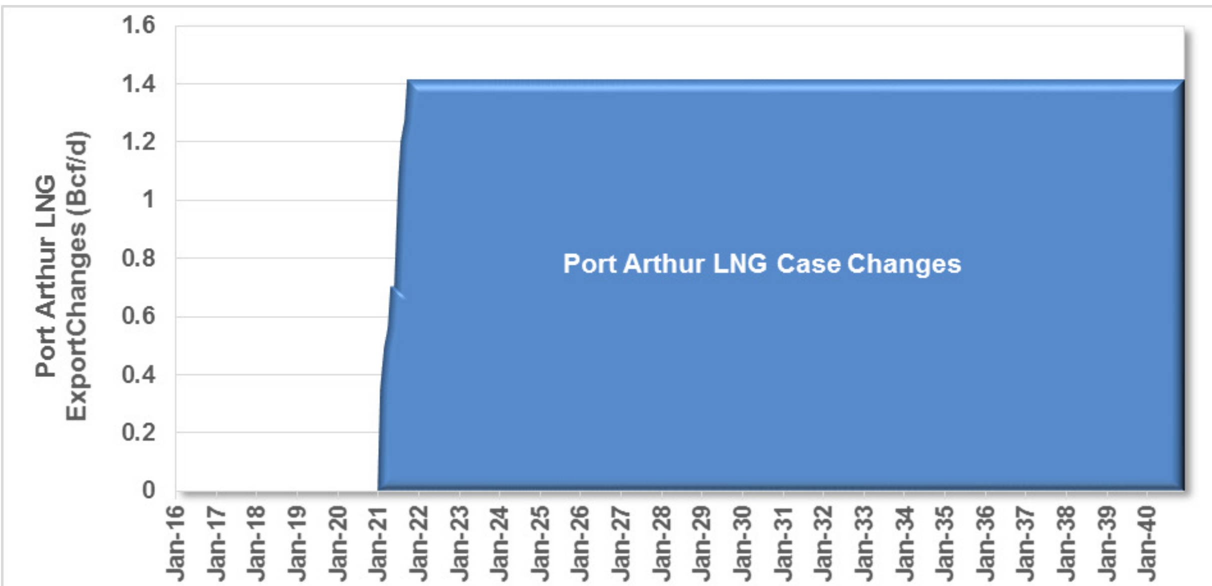
Direct, Indirect, and Induced Economic Impacts

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 and business owners in direct and indirect industries.

5 Port Arthur LNG Energy Market and Economic Impact Results

This section describes the economic and employment impacts between the Base Case and the Port Arthur LNG Case. Specifically, differentials between the two cases result from an additional 1.42 Bcfd (see exhibit below) in LNG exports assumed from Port Arthur LNG from Trains 1 and 2.

Exhibit 5-1: Port Arthur 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 Energy Market and Economic Impacts

This section discusses the impacts of LNG exports in the Base Case and the Port Arthur LNG Case in terms of changes in production volumes, capital and operating expenditures, economic and employment impacts, government revenues, and balance of trade.

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 net natural gas pipeline imports from Canada and Mexico (see Exhibit 5-2). In addition to the incremental LNG export volumes of 1.42 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.

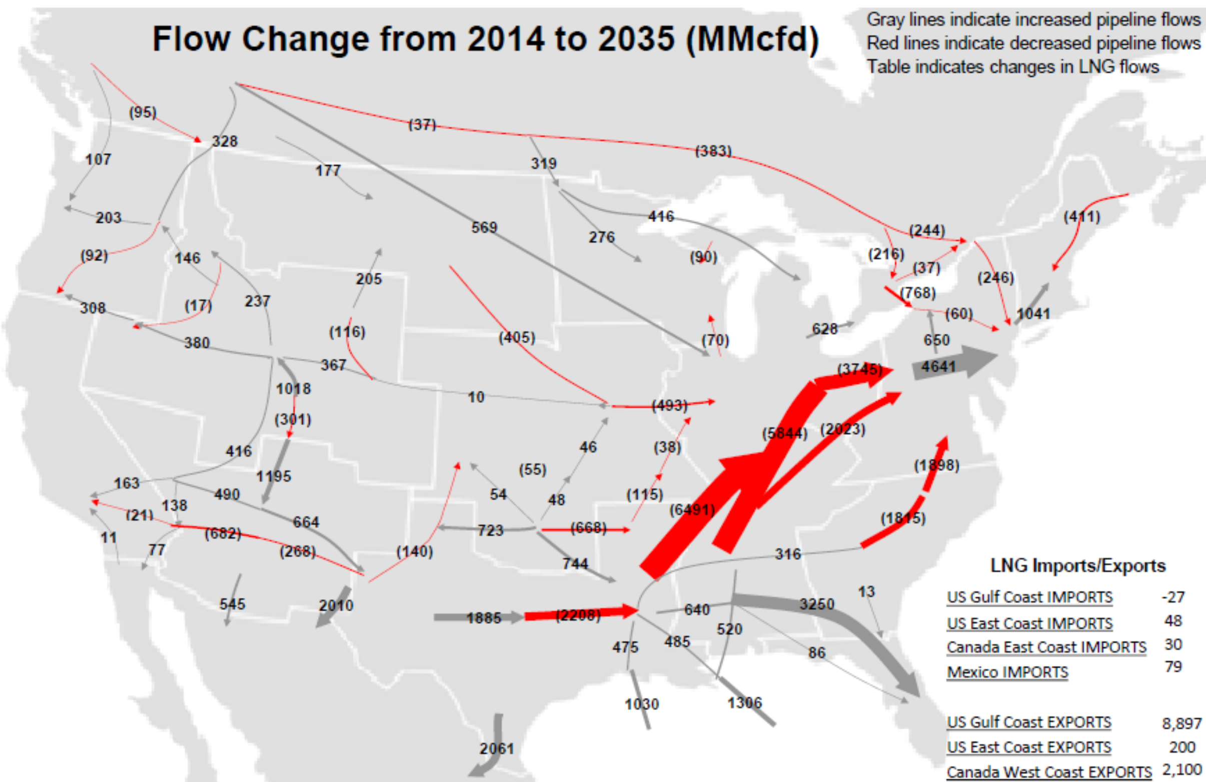
Exhibit 5-2: U.S. Flow Impact Contribution to LNG Exports

2021-2040 Average Supply Sources (%)			
Production Increase	Demand Decrease	Net Gas Pipeline Imports	Total Share of LNG Exports
95%	7%	8%	110%

Source: ICF

As mentioned in the previous section, the map below shows Base Case natural gas market flows, with Texas LNG export volumes of 2.5 Bcfd (1.8 Bcfd in East Texas and 0.7 Bcfd in South Texas).

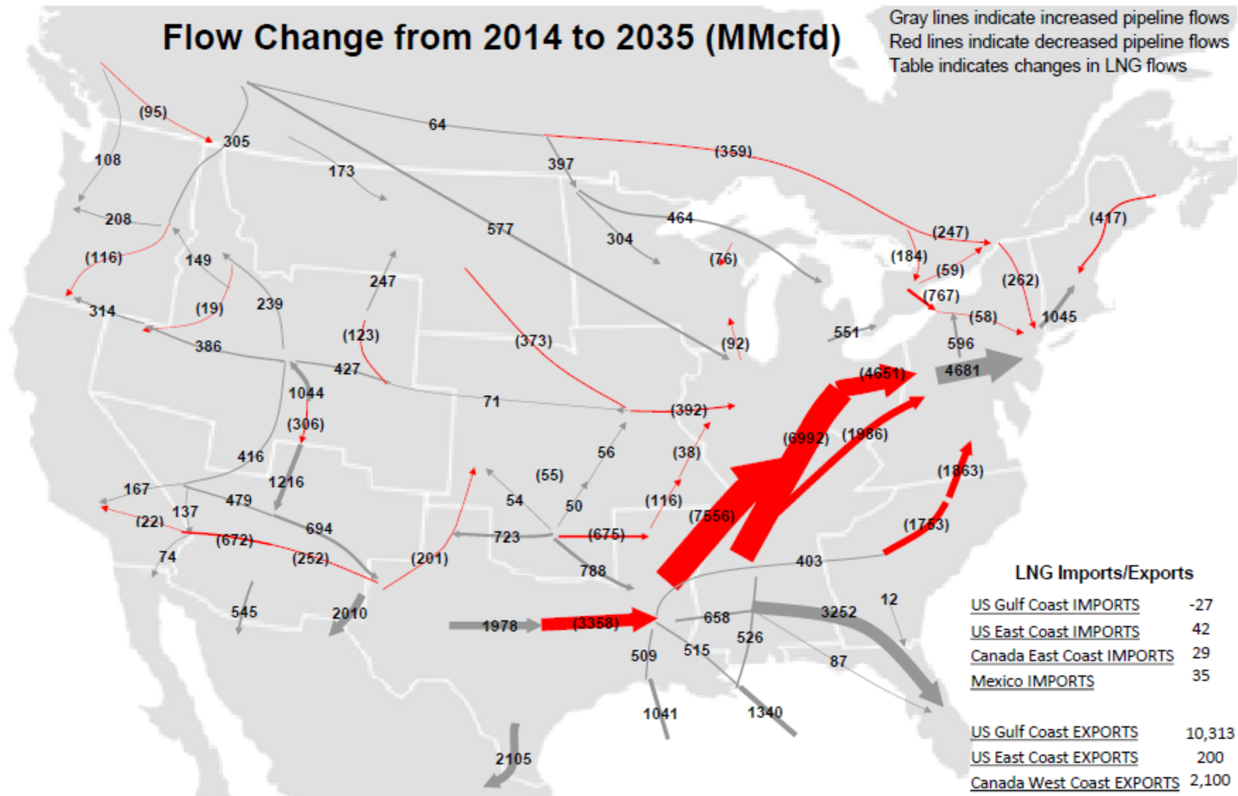
Exhibit 5-3: Base Case U.S. Natural Gas Market Flow Changes



Source: ICF

The map below shows the Port Arthur LNG Case U.S. natural gas flows which overall are similar to Base Case Flows. However, Texas export volumes are 3.9 Bcfd in the Port Arthur LNG Case, compared to 2.5 Bcfd in the Base Case. Total U.S. Gulf Coast LNG export flow changes are 10.3 Bcfd, compared to 8.9 Bcfd in the Base Case.

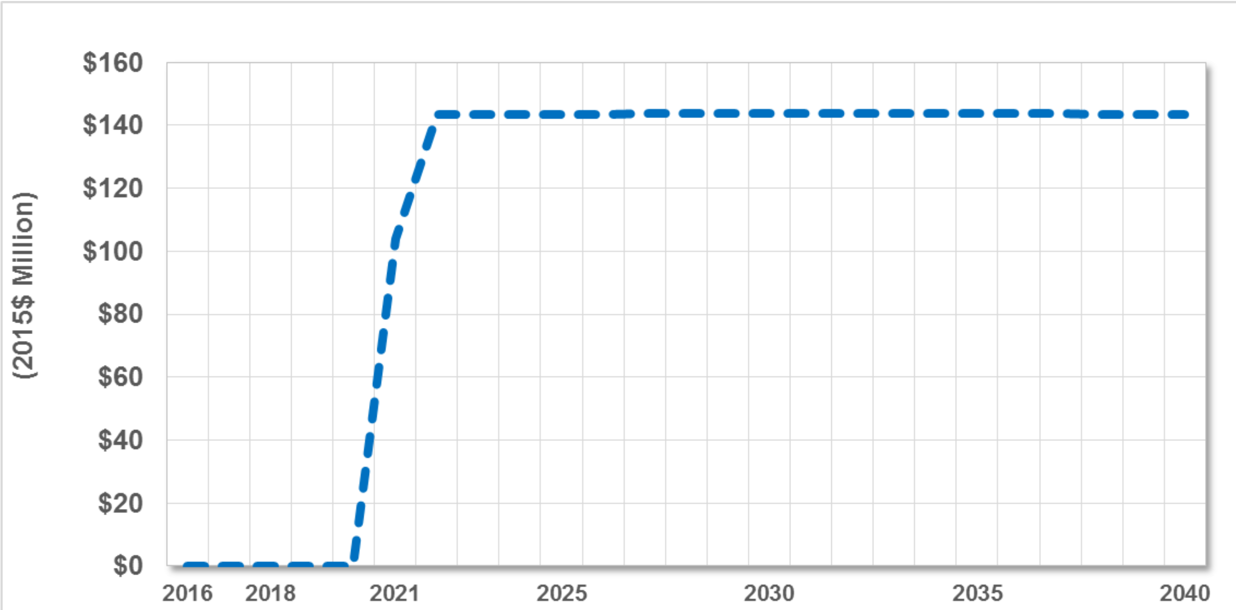
Exhibit 5-4: The Port Arthur LNG Expansion Case U.S. Natural Gas Market Flow Changes



Source: ICF

The exhibit below (Exhibit 5-5) shows the impact on LNG plant operating expenditures (excluding the cost of natural gas feedstock but including employee costs, materials, maintenance, insurance, and property taxes). Port fees paid by the shipper during the tanker loading process are also included here. Over the study period of 2018 to 2040, there is a total cumulative impact on operating expenditures of $2.83 billion in the Port Arthur LNG Case as compared to the Base Case. During that period, LNG plant operating expenditures average $123.2 million higher annually in the Port Arthur LNG Case, as compared to the Base Case. Adding in pipeline O&M brings that total difference to $144 million per year.

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

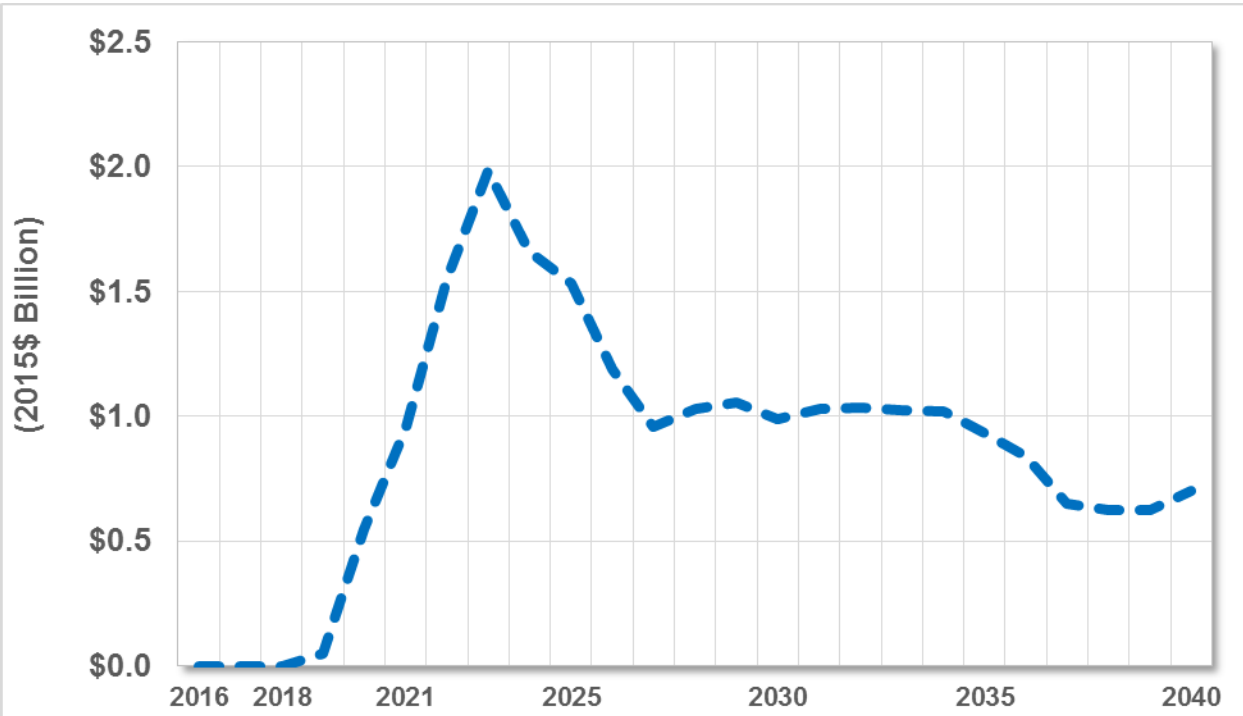


Year	LNG Facility Operating Expenditures (2015$ Million)	
	Port Arthur LNG Case Change	
2018	$	-
2021	$	104
2026	$	144
2025	$	144
2030	$	144
2040	$	143
2018-2040 Avg	*$*	*123*
2018-2040 Sum	**$**	**2,833**

Source: ICF

The exhibit below (Exhibit 5-6) illustrates the impacts of the additional LNG export volumes on U.S. upstream capital expenditures. Investment peaks in the early years as more new wells are drilled 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 2018 to 2040, the cumulative impact on U.S. upstream capital expenditures totals near $22 billion in the Port Arthur LNG Case as compared to the Base Case. U.S. upstream capital expenditures average almost $1 billion higher annually in the Port Arthur LNG Case than in the Base Case.

Exhibit 5-6: U.S. Upstream Capital Expenditure Changes

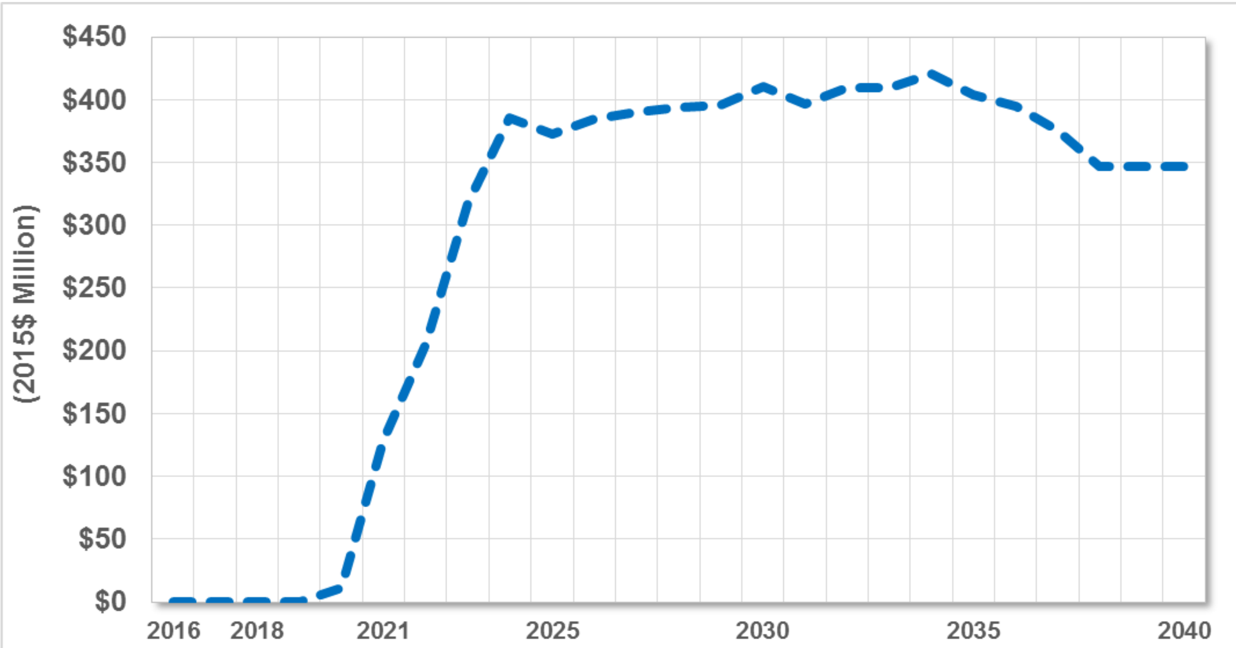


Year	Upstream Capital Expenditures (2015$ Billion)
	Port Arthur LNG Case Change
2018	$ -
2021	$ 0.95
2026	$ 1.19
2025	$ 1.53
2030	$ 0.99
2040	$ 0.70
2018-2040 Avg	*$ 0.96*
2018-2040 Sum	**$ 21.97**

Source: ICF

As shown below (Exhibit 5-7), U.S. upstream operating expenditures increase $7.2 billion on a cumulative basis, or on average $315 million annually in the Port Arthur LNG Case as compared to the Base Case between 2018 and 2040.

Exhibit 5-7: U.S. Upstream Operating Expenditure Changes

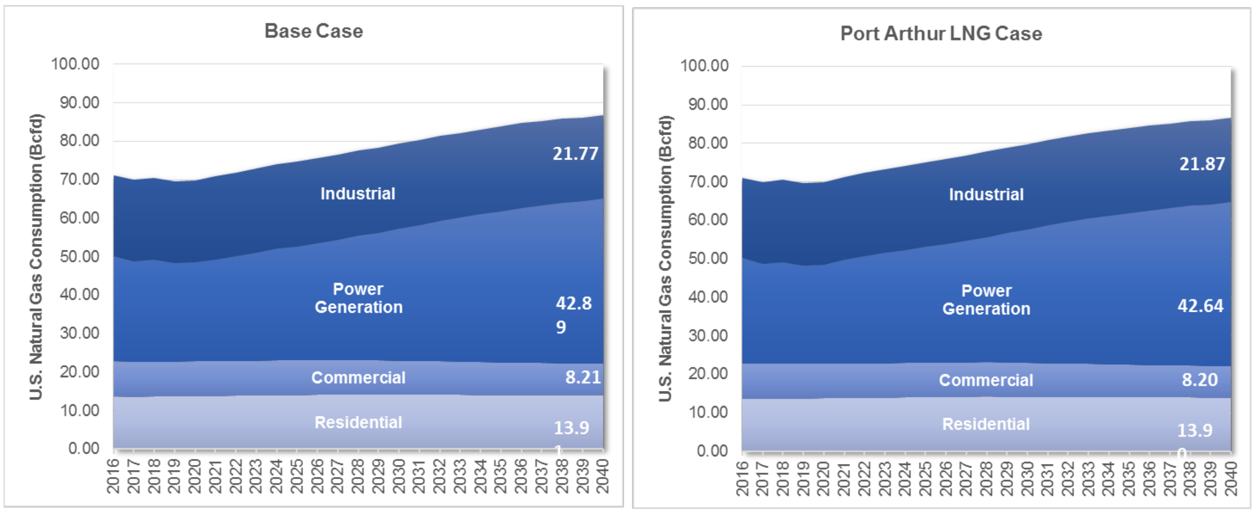


Year	Upstream Operating Expenditures (2015$ Million) Port Arthur LNG Case Change
2018	$ -
2021	$ 128
2026	$ 385
2025	$ 373
2030	$ 410
2040	$ 346
2018-2040 Avg	*$ 315*
2018-2040 Sum	**$ 7,246**

Source: ICF

The charts below (Exhibit 5-8) shows the Base Case and the Port Arthur LNG Case U.S. natural gas consumption. The additional LNG export volumes of 1.42 Bcfd (plus liquefaction fuel use of 10 percent, thus totaling 1.56 Bcfd) are expected to only result in a very small reduction in U.S. natural gas consumption of 0.16 Bcfd in 2040. Most of this reduction comes from power sector gas use decline, followed by slight declines in residential and commercial gas use. This contraction in U.S. domestic natural gas consumption is the equivalent to 7% percent of the Port Arthur LNG incremental export volumes. Additional U.S. natural gas production and net natural gas imports over the forecast period in the Port Arthur LNG Case equal 103% of the export volumes of Port Arthur LNG.

Exhibit 5-8: U.S. Domestic Natural Gas Consumption by Sector



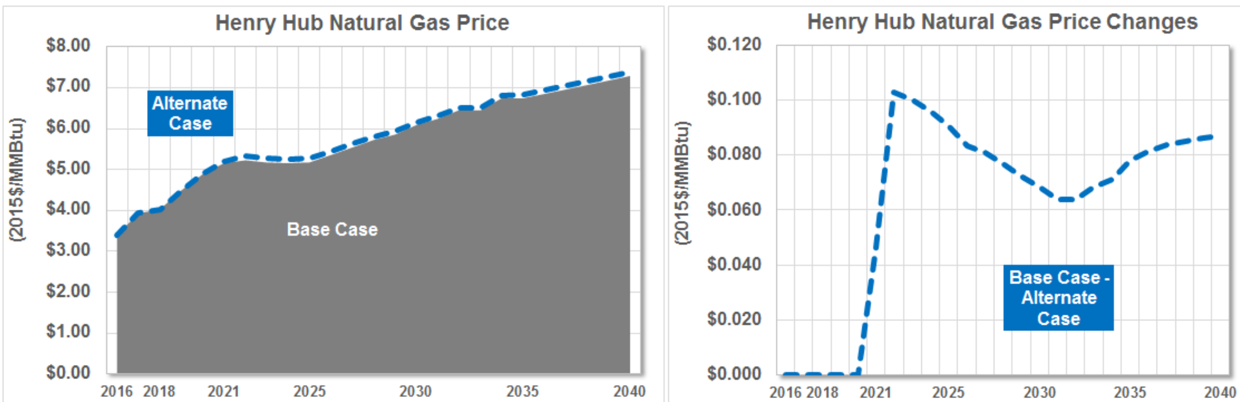
* Industrial demand does not includes pipeline fuel and lease & plant

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

Source: ICF

The Henry Hub natural gas price is expected to increase by $0.07/MMBtu on average over the forecast period through 2040, averaging $5.97/MMBtu over the forecast period, compared with $5.90/MMBtu in the Base Case, as shown in Exhibit 5-9. The Port Arthur LNG Case natural gas prices at Henry Hub are expected to reach $7.29/MMBtu in the Base Case and $7.37 in the Port Arthur LNG Case by 2040, indicating a natural gas price increase of $0.08/MMBtu attributable to the Port Arthur LNG export volumes of 1.42 Bcfd.

Exhibit 5-9: Annual Average Henry Hub Natural Gas Price Changes

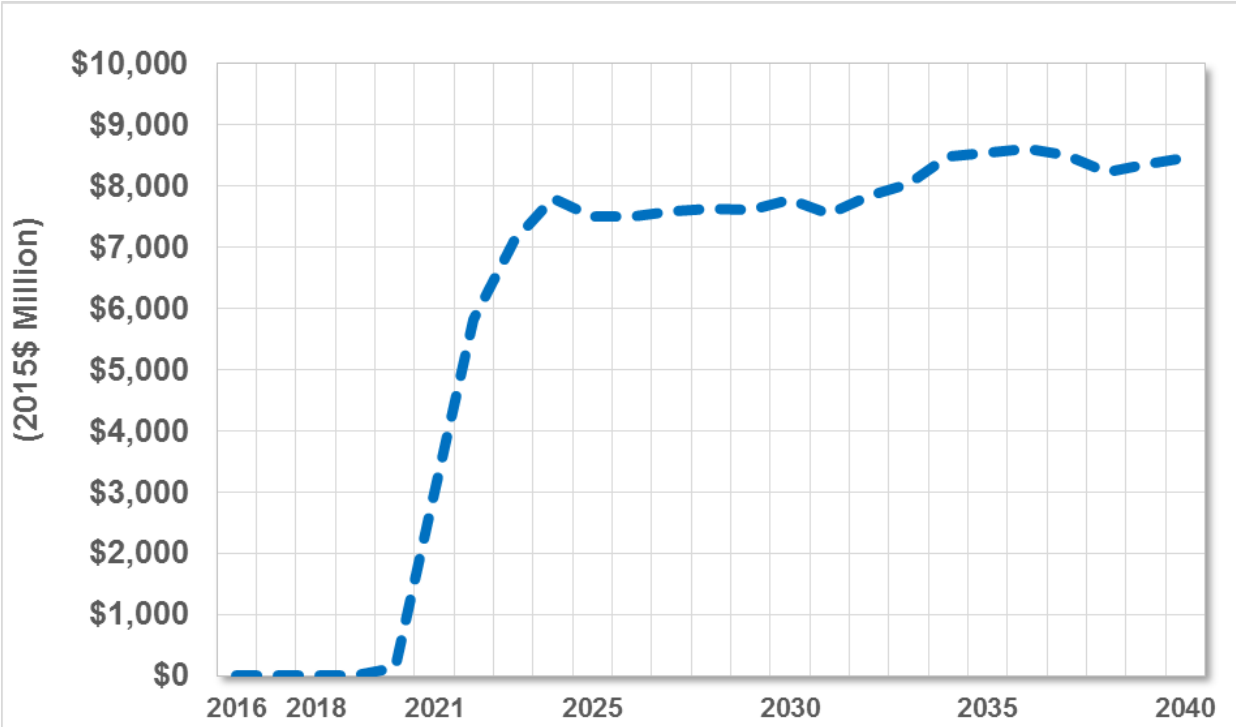


Year	Henry Hub Natural Gas Price (2015$/MMBtu)		
	Base Case	Port Arthur LNG Case	Port Arthur LNG Case Change
2018	$ 4.03	$ 4.03	$ -
2021	$ 5.16	$ 5.20	$ 0.046
2026	$ 5.36	$ 5.44	$ 0.083
2025	$ 5.18	$ 5.27	$ 0.091
2030	$ 6.09	$ 6.16	$ 0.068
2040	$ 7.29	$ 7.37	$ 0.087
2018-2040 Avg	*$ 5.90*	*$ 5.97*	*$ 0.069*

Source: ICF

U.S. natural gas and liquids production value increases as a result of additional LNG export volumes and higher prices as seen in the Port Arthur LNG Case (see Exhibit 5-10). Over the forecast period 2018 to 2040, the cumulative impact on natural gas and liquids production value in the Port Arthur LNG Case is $152 billion. This represents an average increase of $6.6 billion per year in the Port Arthur LNG Case as compared to the Base Case between 2018 and 2040.

Exhibit 5-10: U.S. Natural Gas and Liquids Production Value Changes



Natural Gas and Liquids Production Value (2015$ Million)	
Year	**Port Arthur LNG Case Change**
2018	$ -
2021	$ 2,989.0
2026	$ 7,500.9
2025	$ 7,493.9
2030	$ 7,776.1
2040	$ 8,451.4
2018-2040 Avg	*$ 6,608.6*
2018-2040 Sum	**$ 151,996.7**

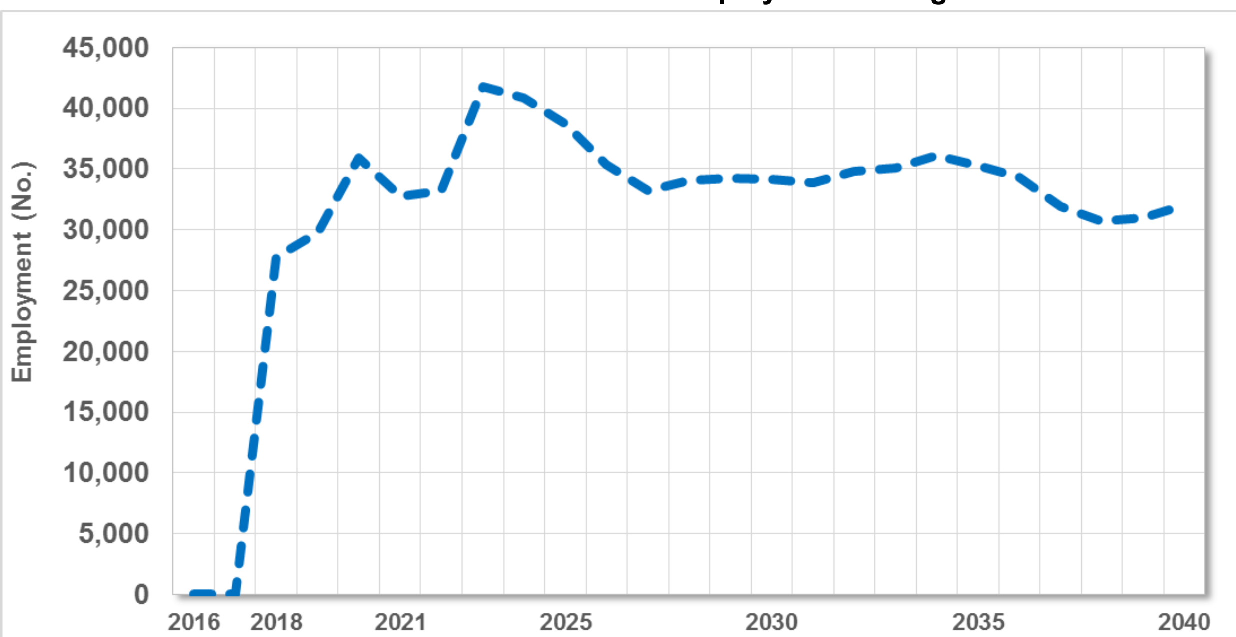
Note: Liquids includes natural gas liquids (NGLs), oil, and condensate.

Source: ICF

Exhibit **5-11** shows the impacts of additional volumes on total U.S. employment.[11] 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, 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.

The construction and operation of Port Arthur LNG will likely increase employment through direct, indirect and induced employment impacts. Average annual job increase between 2018 and 2040 is over 34,200 jobs. Over the forecast period the added LNG export terminals are expected to increase job-years relative to the Base Case by over 787,000 job-years cumulative.

Exhibit 5-11: Total U.S. Total Employment Changes



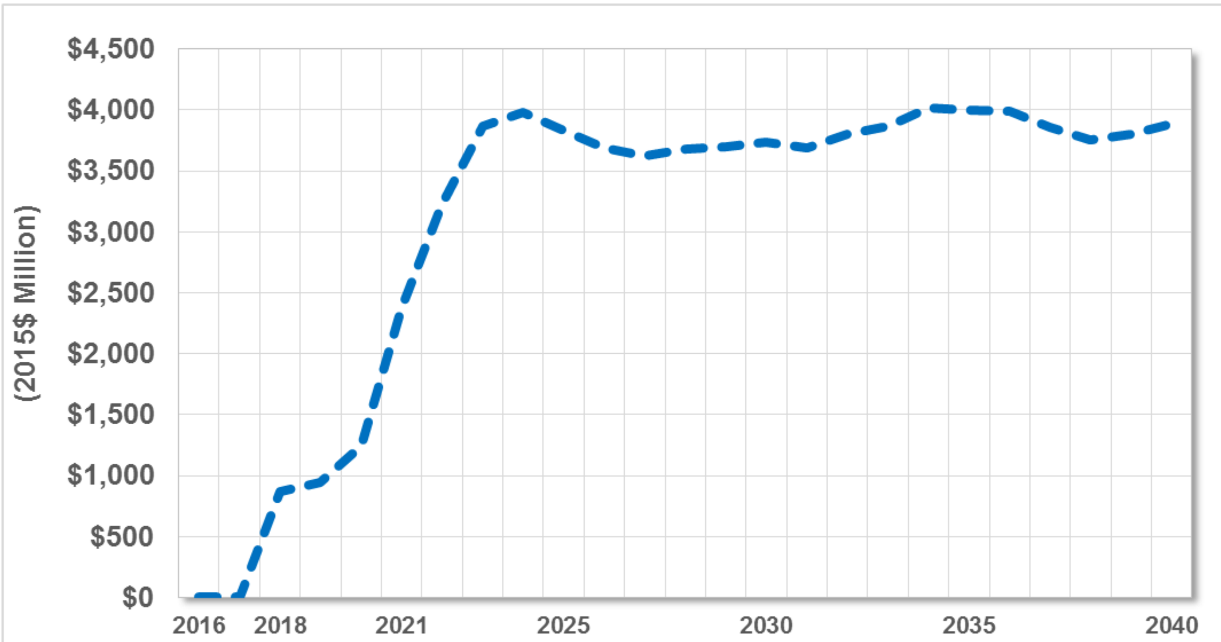
[11] Note that one job in this report refers to a job-year.

Year	Employment (No.)
	Port Arthur LNG Case Change
2018	27,771
2021	32,718
2026	35,318
2025	38,674
2030	34,157
2040	31,972
2018-2040 Avg	*34,208*
2018-2040 Sum	**786,773**

Source: ICF

Exhibit 5-12 shows the impact of the additional LNG exports on U.S. federal, state, and local government revenues. Collective government revenues increase $3.4 billion annually as a result of the Port Arthur LNG Case additional LNG export trains. This translates to a cumulative impact of $77.4 billion over the forecast period between 2018 and 2040.

Exhibit 5-12: U.S. Federal, State, and Local Government Revenue Changes



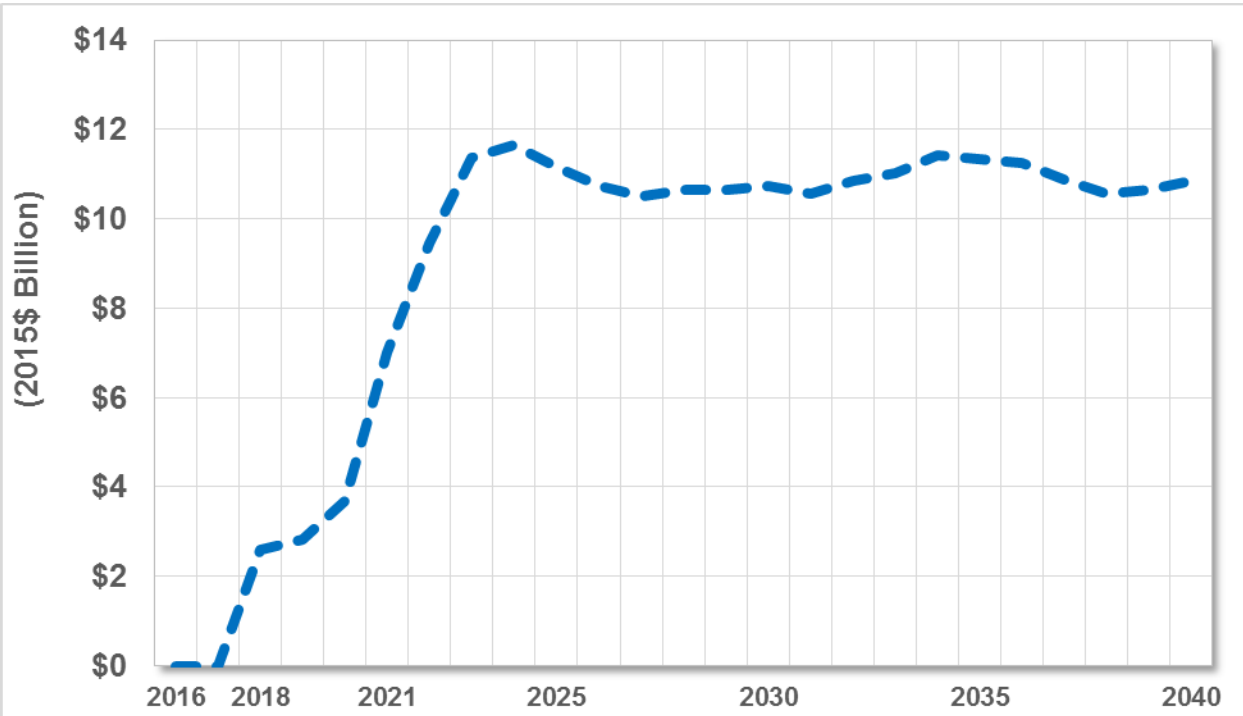
Year	Government Revenues (2015$ Million)	
	Port Arthur LNG Case Change	
2018	$	873.6
2021	$	2,374.8
2026	$	3,691.1
2025	$	3,832.8
2030	$	3,736.6
2040	$	3,885.2
2018-2040 Avg	*$*	*3,366.9*
2018-2040 Sum	**$**	**77,439.4**

Source: ICF

Exhibit 5-13 shows the impacts of additional LNG export 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 Port Arthur LNG Case. The additional LNG volumes in the Port Arthur LNG Case result in a $9.7 billion annual average increase of value added over the 2018-2040 23-year period. The cumulative value added over the period between the Base Case and the Port Arthur LNG Case Volumes Case totals $222.4 billion.

Exhibit 5-13: Total U.S. Value Added Changes

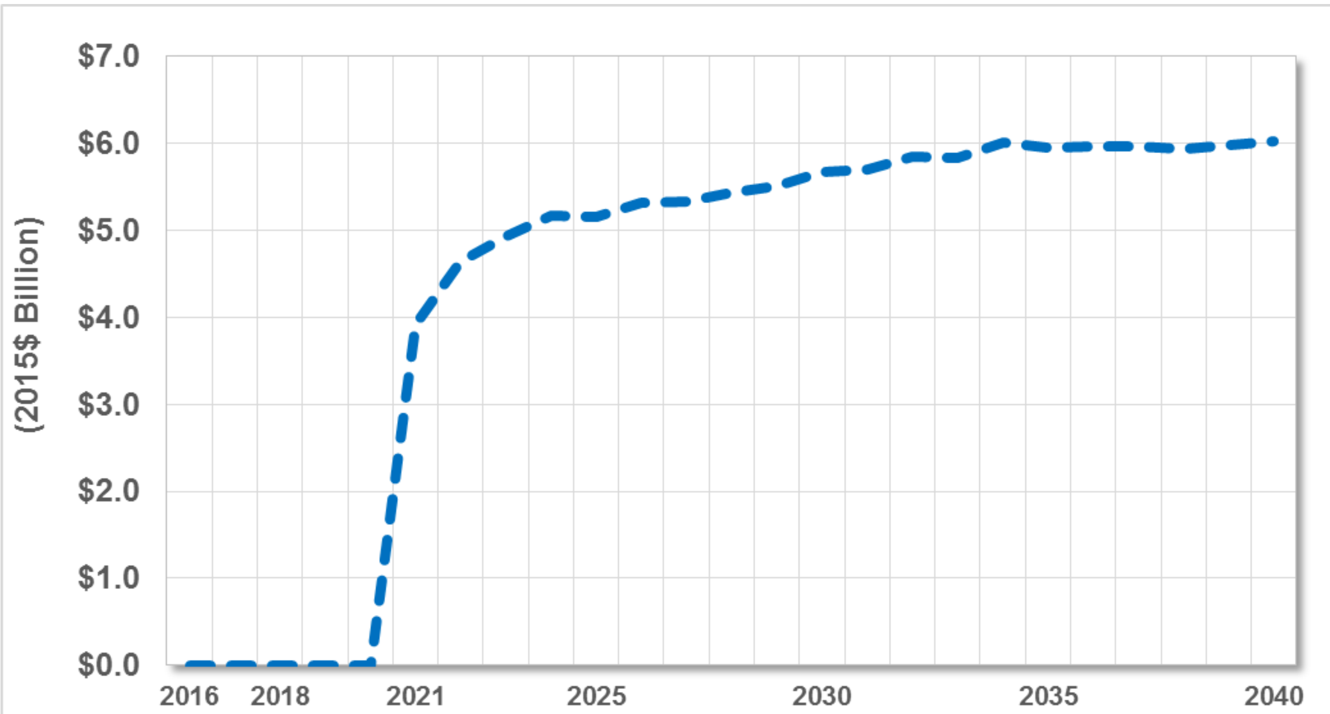


Year	Total Value Added (2015$ Billion)	
	Port Arthur LNG Case Change	
2018	$	2.6
2021	$	7.0
2026	$	10.7
2025	$	11.2
2030	$	10.7
2040	$	10.9
2018-2040 Avg	*$*	*9.7*
2018-2040 Sum	**$**	**222.4**

Source: ICF

Exhibit 5-14 shows that the expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $4.8 billion annually between 2018 and 2040, based on the value of LNG export volumes and incremental associated liquids production, or a cumulative value of $110.3 billion. The improved balance of trade effects begin in 2021 when the plant starts operating and are 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 which is assumed to either substitute for imported liquids or be exported.

Exhibit 5-14: U.S. Balance of Trade Changes



Year	Balance of Trade (2015$ Billion)
	Port Arthur LNG Case Change
2018	$ -
2021	$ 3.9
2026	$ 5.3
2025	$ 5.1
2030	$ 5.7
2040	$ 6.0
2018-2040 Avg	*$ 4.8*
2018-2040 Sum	**$ 110.3**

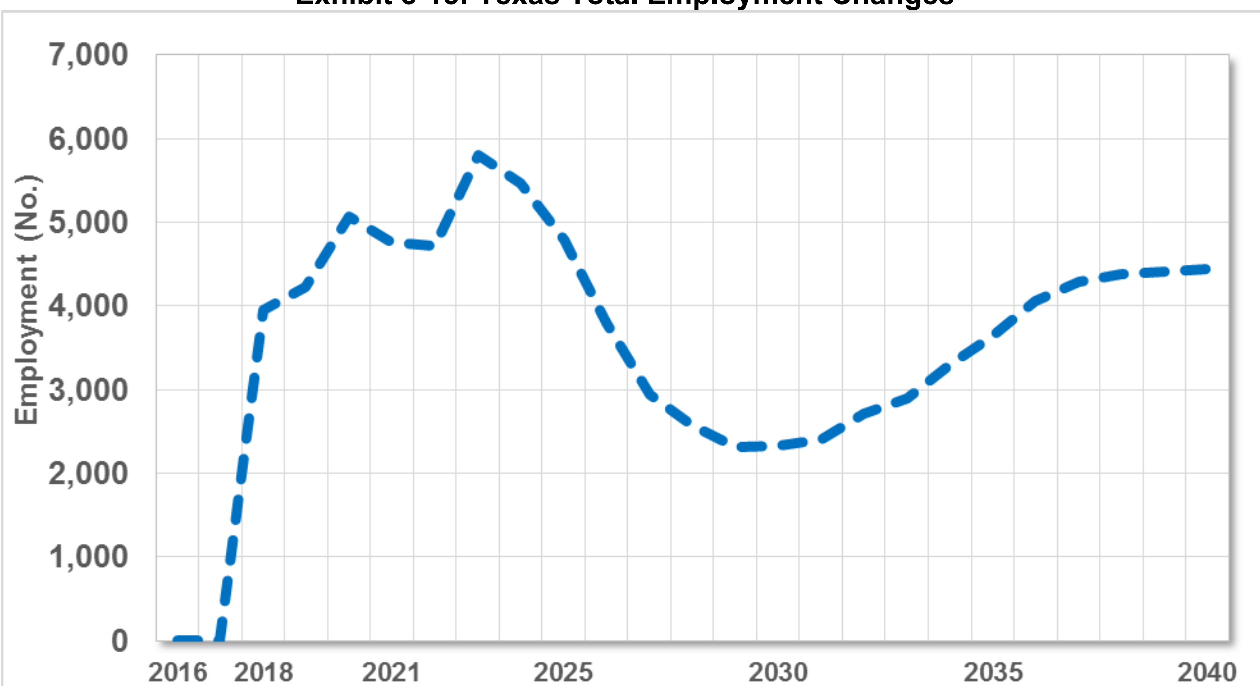
Source: ICF

5.2 Texas Impacts

The exhibits below describe the energy market and economic impacts of the LNG export cases in Texas.

Exhibit 5-15 shows the impacts of LNG export volumes on Texas total employment, 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 trains and to the added natural gas production that will take place in the state and in other states to which Texas companies offer support services. The Port Arthur LNG Case exhibits an increase of almost 3,900 jobs on an average annual basis from 2018 to 2040 as compared to the Base Case. This equates to a cumulative impact of over 89,000 Texas job-years over the 23-year forecast period through 2040.

Exhibit 5-15: Texas Total Employment Changes

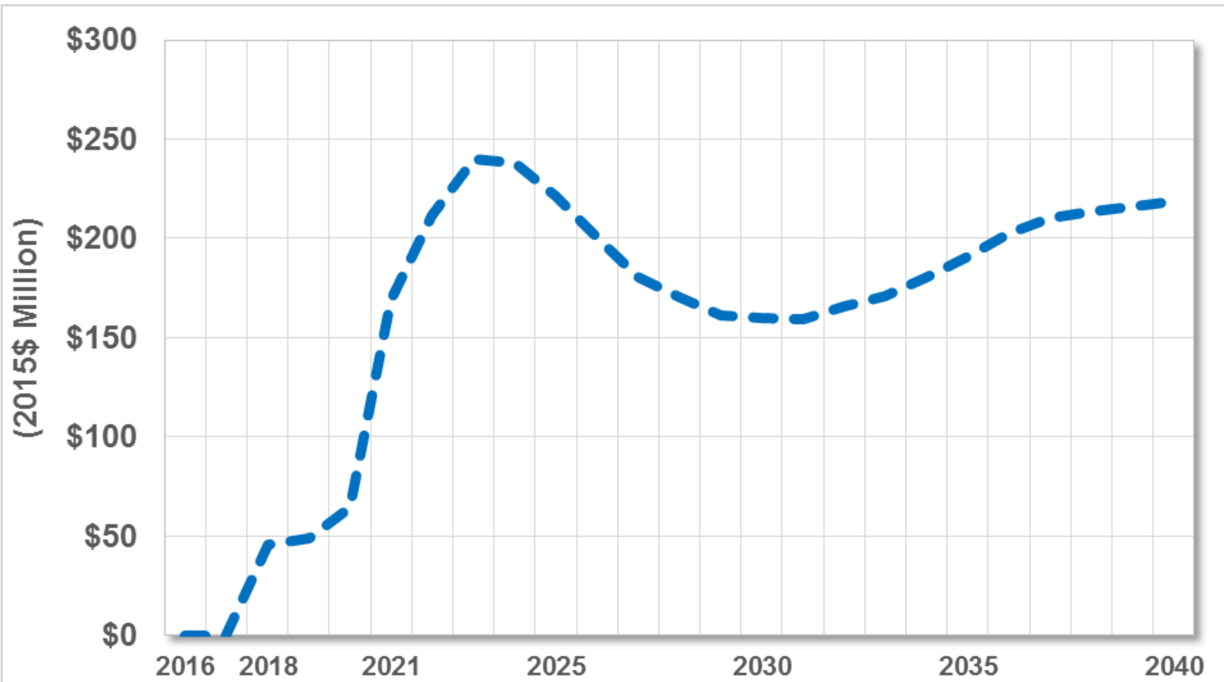


Year	Employment (No.) Port Arthur LNG Case Change
2018	3,946
2021	4,766
2026	3,803
2025	4,790
2030	2,324
2040	4,437
2018-2040 Avg	*3,881*
2018-2040 Sum	**89,253**

Source: ICF

Exhibit 5-16 shows the impacts of LNG export volumes on Texas state and local government revenues. Total Texas government revenues include all fees and taxes (personal income, corporate income, sales, property, oil & gas severance and employment) related to incremental activity in the construction and operation of the liquefaction plant; natural gas transportation; port services; oil & gas exploration, development and production; and induced consumer spending. Relative to the Base Case, the additional LNG volumes in the Port Arthur LNG Case result in a $176 million average annual increase to local and state Texas government revenues throughout the 23-year forecast period through 2040, or a cumulative impact of $4.0 billion.

Exhibit 5-16: Texas Government Revenue Changes

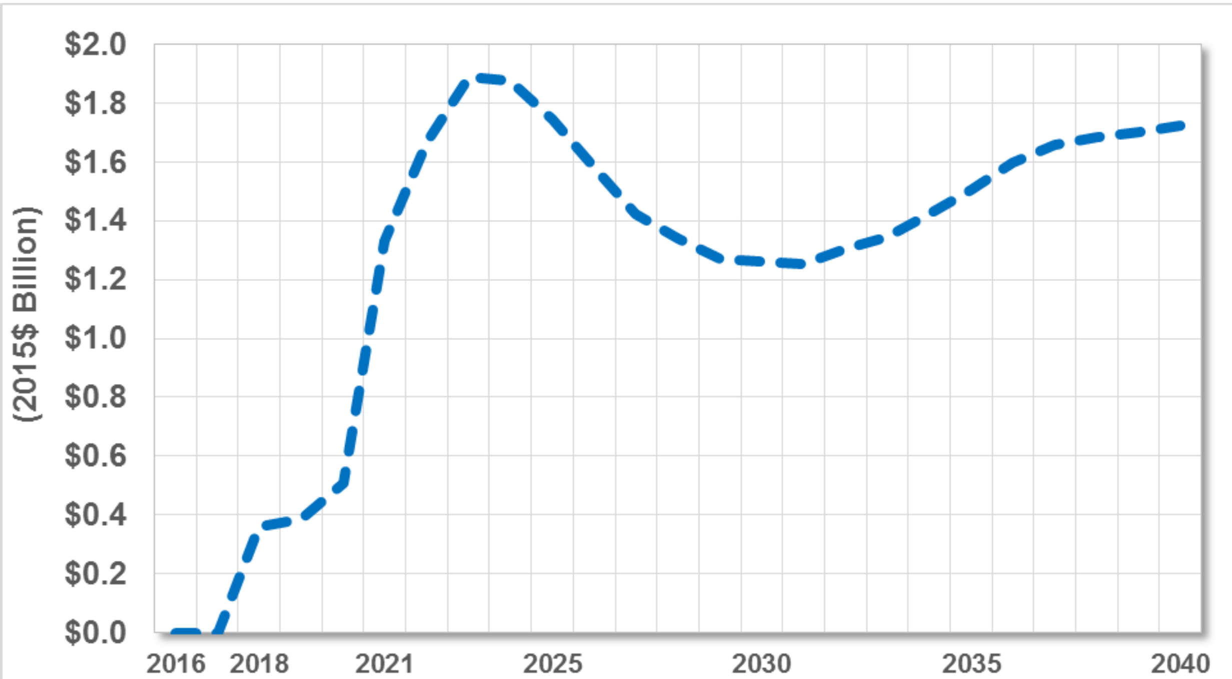


Year	Government Revenues (2015$ Million) Port Arthur LNG Case Change
2018	$ 45.5
2021	$ 169.1
2026	$ 200.4
2025	$ 221.4
2030	$ 160.1
2040	$ 218.5
2018-2040 Avg	*$ 175.7*
2018-2040 Sum	**$ 4,040.1**

Source: ICF

Exhibit 5-17 shows the impacts of LNG export volumes on total Texas value added (also called gross state product or GSP). Texas value added increases substantially as a result of the additional LNG export volumes assumed in the Port Arthur LNG Case. Throughout the study period 2018 to 2040 the additional LNG volumes in the Port Arthur LNG Case result in a $1.4 billion annual average increase to value added, relative to the Base Case. The total differential of value added to Texas over the study period between the Base Case and the Port Arthur LNG Expansion Case is $31.8 billion.

Exhibit 5-17: Total Texas Value Added Changes



Year	Total Value Added (2015$ Billion) Port Arthur LNG Case Change	
2018	$	0.4
2021	$	1.3
2026	$	1.6
2025	$	1.7
2030	$	1.3
2040	$	1.7
2018-2040 Avg	*$*	*1.4*
2018-2040 Sum	**$**	**31.8**

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.[12] 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 benefit 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.[13] 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 only small output and employment losses.

[12] 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.[14] 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.[15] 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.[16] 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.[17] 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 do LNG exports.

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[14] 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
[15] 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
[16] 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
[17] 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

See the exhibit on the next page 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/ΔJobs	
Port Arthur LNG (ICF)	Port Arthur LNG export of 1.42 Bcfd	1.42 Bcfd export	$0.07	$0.05	95%	7%	8%	110%	1.5	24,166	$282,649	Port Arthur LNG development leads to positive impact on the economy and employment.
Cameron LNG (ICF 2015)	Trains 4-5 expansion of 1.41 Bcfd	1.41 Bcfd incremental increase in LNG exports	$0.08	$0.06	94%	9%	7%	110%	1.5	25,200	$358,861	Increasing exports at Cameron LNG is anticipated to lead to value added and job increases for the U.S.
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.

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/ΔJobs	
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: Henry Hub Price Change Relative to Reference Case		Impact LNG Exports: Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Impact LNG Exports: Multiplier Effect	Impact LNG Exports: Employment Impact	Impact LNG Exports: 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**	
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/MMBtu 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									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	
Port Arthur 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/MMBtu 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/MMBtu by 2025	$0.10	60%	15%	N/A	N/A				
		High Demand Base Case	$0.59/MMBtu	$1.18			N/A	N/A				
		High Demand Base Case + SLNG	$0.82/MMBtu	$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/MMBtu (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/MMBtu	0.09	N/A	100%	N/A	N/A				
		High LNG Export + Pangea	$0.37/MMBtu	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.

ICF INTERNATIONAL

APPENDIX B

VERIFICATION

County of San Diego)
)
State of California)

BEFORE ME, the undersigned authority, on this 12th day of June, 2015, personally appeared Eduardo Pawluszek, who, having been by me first duly sworn, on oath says that he is Vice President of Port Arthur 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.

Eduardo Pawluszek
Vice President
Port Arthur LNG, LLC

CALIFORNIA ALL-PURPOSE ACKNOWLEDGMENT

CIVIL CODE § 1189

State of California }
County of San Diego }

On June 12, 2015 before me, Emma Castillo,
Date — Here Insert Name and Title of the Officer

personally appeared Eduardo Poruluszek
Name(s) of Signer(s)

who proved to me on the basis of satisfactory evidence to be the person~~(s)~~ whose name~~(s)~~ is/~~are~~ subscribed to the within instrument and acknowledged to me that he/~~she/they~~ executed the same in his/~~her/their~~ authorized capacity~~(ies)~~, and that by his/~~her/their~~ signature~~(s)~~ on the instrument the person~~(s)~~, or the entity upon behalf of which the person~~(s)~~ acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

EMMA CASTILLO
Commission # 2031157
Notary Public - California
San Diego County
My Comm. Expires Jun 27, 2017

Place Notary Seal Above

Signature: Emma Castillo
Signature of Notary Public

OPTIONAL

Though the information below is not required by law, it may prove valuable to persons relying on the document and could prevent fraudulent removal and reattachment of this form to another document.

Description of Attached Document

Title or Type of Document: Verification for DOE re: Port Arthur LNG

Document Date: June 12, 2015 Number of Pages: ______

Signer(s) Other Than Named Above: —

Capacity(ies) Claimed by Signer(s)

Signer's Name: Eduardo Poruluszek
☐ Corporate Officer — Title(s): Vice President
☐ Individual
☐ Partner — ☐ Limited ☐ General
☐ Attorney in Fact
☐ Trustee
☐ Guardian or Conservator
☐ Other: ______

Signer Is Representing: Port Arthur LNG

RIGHT THUMBPRINT OF SIGNER
Top of thumb here

Signer's Name: ______
☐ Corporate Officer — Title(s): ______
☐ Individual
☐ Partner — ☐ Limited ☐ General
☐ Attorney in Fact
☐ Trustee
☐ Guardian or Conservator
☐ Other: ______

Signer Is Representing: ______

RIGHT THUMBPRINT OF SIGNER
Top of thumb here

APPENDIX C

OPINION OF COUNSEL

June 15, 2015

Mr. John Anderson
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

RE: Port Arthur LNG, LLC Application for Long-Term, Multi-Contract 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 United States Department of Energy, 10 C.F.R. § 590.202(c) (2014). I am counsel to Port Arthur LNG, LLC ("Port Arthur LNG"). I have reviewed the organizational and internal governance documents of Port Arthur LNG and it is my opinion that the proposed export of natural gas as described in the application filed by Port Arthur LNG, to which this Opinion of Counsel is attached as Appendix B, is within the company powers of Port Arthur LNG.

Respectfully submitted,

William D. Rapp

William D. Rapp
Counsel to Port Arthur LNG, LLC