Gulf LNG Liquefaction Company, LLC
a Kinder Morgan, GE company

August 31, 2012

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

Re: Gulf LNG Liquefaction Company, LLC
FE Docket No. 12 - 101 - LNG
Application for Long-Term Authorization, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries

Dear Mr. Anderson,

Gulf LNG Liquefaction Company, LLC ("GLLC") hereby submits for filing with the U.S. Department of Energy, Office of Fossil Energy, one original and three copies of its application for long-term, multi-contract authorization to export liquefied natural gas ("LNG"). In this application, GLLC is seeking long-term, multi-contract authorization to engage in exports of up to 11.5 million tons per annum of LNG (equivalent to approximately 1.5 billion cubic feet per day) per year produced from domestic sources. The requested authorization would permit GLLC to export LNG from the Gulf LNG Energy, LLC Terminal, located in Pascagoula, Mississippi, to any country that has or in the future develops the capacity to import LNG via ocean-going carrier and with which the United States does not prohibit trade but also does not have a free trade agreement requiring national treatment for trade in natural gas over a twenty year period.

A check in the amount of $50.00 is enclosed in payment of the applicable filing fee.

Please contact me or Margaret Coffman if you have any questions regarding this application.

Respectfully submitted,

Gulf LNG Liquefaction Company, LLC

Patricia S. Francis

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Counsel for Gulf LNG Liquefaction Company, LLC

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

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Gulf LNG Liquefaction Company, LLC	)	**Docket No. 12-101-LNG**
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APPLICATION OF GULF LNG LIQUEFACTION COMPANY, LLC FOR LONG-TERM, MULTI-CONTRACT AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE AGREEMENT COUNTRIES

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Table of Contents

Page

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DEPARTMENT OF ENERGY
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Gulf LNG Liquefaction Company, LLC	)	**Docket No. 12 - ___ - LNG**
	)	

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

Pursuant to Section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the regulations of the Department of Energy ("DOE"), 10 C.F.R. § 590, Gulf LNG Liquefaction Company, LLC ("GLLC" or "GLNG") submits this application ("Application") to the DOE Office of Fossil Energy ("DOE/FE") for long-term authorization to export up to 11.5 million tons per annum of liquefied natural gas ("LNG") (approximately equivalent to 1.5 billion cubic feet of gas per day ("Bcf/d")) produced from domestic sources for a 20-year period commencing on the earlier of the date of first export or ten years from the date the requested authorization is granted.

GLLC seeks authorization to export LNG from the Gulf LNG Energy, LLC[2] terminal in Jackson County, Mississippi, near the City of Pascagoula ("Gulf LNG Terminal") to any country that has or in the future develops the capacity to import LNG via ocean-going carrier and with which the United States does not prohibit trade but also does not have a free trade agreement

[1] 15 U.S.C. § 717b (2006).

[2] Gulf LNG Energy, LLC and Gulf LNG Liquefaction Company, LLC are both subsidiaries of Gulf LNG Holdings, LLC.

("FTA") requiring national treatment for trade in natural gas. GLLC is requesting this authorization both on its own behalf and as agent for other parties who themselves hold title to the LNG at the time of export.

This Application represents the second part of GLLC's two-part export authorization request. On May 2, 2012, GLLC filed in FE Docket No. 12-47-LNG its application requesting long-term, multi-contract authorization to export up to 11.5 million tons per year of domestically produced LNG (equivalent to approximately 1.5 Bcf/d) for a 25-year period commencing upon the earlier of the date of first export or the tenth anniversary of the date authorization is granted by DOE/FE. GLLC requested that such long-term authorization provide for export to any country with which the United States currently has, or in the future may enter into, a FTA requiring national treatment for trade in natural gas, and which has or in the future develops the capacity to import LNG via ocean-going carrier. GLLC requested authorization to export LNG on its own behalf and also as agent for third parties. DOE/FE granted this authorization in Order No. 3104. Through the combination of the two applications, GLLC requests authorization to export up to 11.5 million tons per year (equivalent to approximately 1.5 Bcf/d) of domestic natural gas as LNG to any country with which trade is not prohibited by United States law or policy.

I. EXECUTIVE SUMMARY

In support of this Application, GLLC respectfully states the following:

This Application demonstrates that exports of LNG from the Gulf LNG Terminal will be in the public interest. As set forth below:

- Exports from the GLLC Export Project will involve the sale of gas in volumes and at prices responsive to market needs.
- There are more than adequate gas reserves to supply the U.S. market, even if one assumes the existence of exports from GLLC, exports from other projects in the amount of an additional 6.2 bcf/d and aggressive growth in demand for natural gas vehicles.
- Natural gas to be exported from the GLLC Export Project may be sourced from a variety of conventional and unconventional supply basins by using the highly efficient and integrated U.S. natural gas pipeline grid.
- The impact of LNG exports as proposed by GLLC on the price of domestic gas will be minimal, expected to average less than 8%, as demonstrated in the attached Market Analysis Study prepared by Navigant Consulting, Inc. at the request of GLLC.
- The GLLC Export Project will create economic benefits to the local and regional economies in the Southeast surrounding the project location in Jackson County, MS, as well as the national economy, as demonstrated in the attached Economic Impact Assessment Study prepared by Navigant Economics at the request of GLLC.
- LNG exports will lead to less volatility in domestic natural gas markets and increased stability that benefits producers and consumers by levelizing demand.
- LNG exports will benefit the United States by contributing toward a decreased trade deficit and advancing U.S. interests abroad.
- The GLLC Export Project will have relatively small environmental impacts because the construction will take place wholly within a brownfield development area.

In sum, as shown in this Application, the authorization for long-term, multi-contract exports of LNG to non-FTA countries by GLLC is in the public interest and should be approved.

II. COMMUNICATIONS

Any notices, pleadings or other communications regarding this Application should be directed to the following persons:[3]

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

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III. DESCRIPTION OF THE APPLICANT AND THE EXISTING LNG FACILITY

The exact legal name of the applicant is Gulf LNG Liquefaction Company, LLC. GLLC is a limited liability company formed under the laws of Delaware with its principal place of business at 569 Brookwood Village, Birmingham, Alabama 35209. GLLC is a wholly owned subsidiary of Gulf LNG Holdings Group, LLC ("Gulf LNG Holdings"). Kinder Morgan, Inc., indirectly through its wholly-owned subsidiary, Southern Gulf LNG Company, LLC, owns a

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[3] GLLC requests waiver of Section 590.202(a) of DOE's regulations, 10 C.F.R. § 590.202(a) (2012), to the extent necessary, to include outside counsel on the official service list in this proceeding.

fifty percent interest in Gulf LNG Holdings.[4] GE Energy Financial Services, a unit of GE, directly and indirectly owns a forty-six percent interest in Gulf LNG Holdings. Other investors, including, Atlas Energy, LP, Magnetar Capital, Tortoise Capital Resources Corp. and Triangle Peak Partners Private Equity, LP, as well as funds and accounts under management by BlackRock Investment Management, LLC, indirectly own the remaining four percent interest of Gulf LNG Holdings.

On October 28, 2005, Gulf LNG Energy, LLC filed an application with the Federal Energy Regulatory Commission ("FERC") under Section 3 of the Natural Gas Act requesting authority to site, construct and operate a LNG import terminal in Jackson County, Mississippi.[5] Concurrently, Gulf LNG Pipeline, LLC filed an application under Section 7(c) of the Natural Gas Act to construct, own, and operate an approximately five mile-long pipeline from the proposed LNG terminal.[6] FERC authorized the construction of the terminal and pipeline (collectively, the "Gulf LNG Terminal") on February 16, 2007.[7] The Gulf LNG Terminal commenced service on October 1, 2011.[8]

IV. <u>DESCRIPTION OF EXPORT PROPOSAL</u>

The Export Project will include natural gas processing and liquefaction facilities to

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[4] Kinder Morgan, Inc. is the largest midstream energy and largest natural gas pipeline company in North America. It is also the fourth largest energy company in North America with a combined enterprise value of over $90 billion.

[5] *See Gulf LNG Energy, LLC*, 118 FERC ¶ 61,128 (2007).

[6] *Id.*

[7] *Id.*

[8] *See* Letter Order issued in CP06-12 and CP06-13 on September 26, 2011.

receive, liquefy, store and export domestic natural gas at the Gulf LNG Terminal. The Export Project facilities will be integrated into the existing terminal facilities. Today, the Gulf LNG Terminal includes (1) berthing and accommodations for a single LNG vessel and unloading facilities and piping and appurtenances; (2) an LNG storage and vaporization facility (including two storage tanks capable of storing a total of approximately 320,000 cubic meters (m^3) of LNG), vaporization units and associated piping and control equipment; (3) associated utilities, infrastructure, and support systems; and (4) a 5.02 mile send-out pipeline extending to the interstate pipelines of Destin Pipeline Company, L.L.C., Gulfstream Natural Gas System, L.L.C., and a joint venture pipeline of Florida Gas Transmission Company, LLC and Transcontinental Gas Pipe Line Company, LLC and to the Pascagoula Gas Processing Plant operated by BP America Production Company. Through its direct connections with interstate pipelines, the Gulf LNG Terminal connects to the nationally integrated interstate pipeline grid. The Gulf LNG Terminal has a peak sendout capacity of 1.5 Bcf per day.[9]

The new facilities proposed as part of the Export Project will include natural gas pre-treatment, liquefaction, storage and export facilities with a capacity of up to 11.5 million tons per year of LNG (approximately equivalent to 1.5 Bcf/d), plus enhancements to the existing equipment and additional utilities. The Export Project facilities would permit gas to be (i) received by pipeline at the Gulf LNG Terminal, with these pipelines having indirect access to the nationally integrated interstate pipeline grid, (ii) liquefied, and (iii) loaded from the terminal's storage tanks onto vessels berthed at the existing terminal. The Export Project will be designed to allow GLLC to be capable of providing bi-directional service. Thus, once the Export Project facilities are operational, the Gulf LNG Terminal will have the capability to (i) liquefy

[9] *See Gulf LNG Energy, LLC*, 118 FERC ¶ 61,128 (2007).

domestic gas for export or (ii) import LNG for delivery to domestic markets. GLLC does not expect the Export Project to result in vessel traffic to or from the facility in excess of that currently authorized for the existing import facility.

The new facilities proposed would be subject to review and approval by the Commission. Upon completion of initial facility planning and design, GLLC will request that the Commission initiate the mandatory pre-filing review process for the Export Project. It is anticipated that this request will be made before the end of 2013.

V. <u>AUTHORIZATION REQUESTED</u>

GLLC requests long-term, multi-contract authorization to export up to 11.5 million tons per annum per year of domestically produced LNG (equivalent to approximately 1.5 Bcf/d) for a 20-year period commencing upon the earlier of the date of first export or the tenth anniversary of the date authorization is granted by DOE/FE.[10] GLLC seeks authorization to export LNG from its Gulf LNG Terminal to any country that has or in the future develops the capacity to import LNG via ocean-going carrier and with which the United States does not prohibit trade but also does not have a FTA requiring national treatment for trade in natural gas.

GLLC is requesting this authorization both on its own behalf and as agent for other parties who themselves hold title to the LNG at the time of export. To ensure that all exports are permitted and lawful under U.S. laws and policies, GLLC will comply with all DOE

[10] This timing is consistent with the timing requested by GLLC and approved by DOE/FE in the *Order Granting Long-Term Multi-Contract Authorization To Export Liquefied Natural Gas By Vessel From The Gulf LNG Terminal To Free Trade Agreement Nations*. *Gulf LNG Liquefaction Company, L.L.C.*, FE Docket No. 12-47-LNG, Order No. 3104, at 5 (June 15, 2012).

requirements for an exporter or agent. In Order No. 2913,[11] the DOE approved a proposal to register each LNG title holder for whom the applicant sought to export LNG as agent. The applicant also proposed that this registration include a written statement by the title holder acknowledging and agreeing to comply with all applicable requirements included in its export authorization and to include those requirements in any subsequent purchase or sale agreement entered into by that title holder. The applicant further stated that it would file under seal with the DOE any relevant long-term commercial agreements that it reached with the LNG title holders on whose behalf the exports were performed.

The DOE found that this proposal was an acceptable alternative to the non-binding policy adopted in Order No. 2859[12] that title to all LNG authorized for export must be held by the authorization holder at the point of export. In approving this alternative approach, the DOE noted that the applicant's requested registration process and contract terms would ensure that the title holder was aware of all DOE requirements and would provide DOE with a record of all authorized exports and direct contact information and a point of contact with the title holder.[13]

Therefore, when acting as agent, GLLC will register with the DOE each LNG title holder for whom GLLC seeks to export as agent, and will provide the DOE with a written statement by the title holder acknowledging and agreeing to (i) comply with all requirements in GLLC's long-term export authorization, and (ii) include those requirements in any subsequent purchase or sale agreement entered into by the title holder. GLLC will also file under seal with DOE any relevant

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[11] *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, FE Docket No. 10-160-LNG, Order No. 2913 (Feb. 10, 2011).

[12] *The Dow Chemical Company*, FE Docket No. 10-57-LNG, Order No. 2859 (Oct. 5, 2010).

[13] *Freeport LNG Development, L.P.*, FE Docket No. 11-51-LNG, Order No. 2986 (July 19, 2011).

long-term commercial agreements it enters into with the LNG title holders on whose behalf the exports are performed.

In recent orders granting long-term authorizations to export LNG to FTA countries requiring national treatment for trade in natural gas, the DOE has found that the applicants were not required to submit, with their applications, transaction-specific information, as specified in Section 590.202(b) of the DOE's regulations.[14] The DOE found that, given the stage of development for these projects, it was appropriate for the applicants to submit such information "when practicable" (i.e., when the contracts reflecting such information are executed). GLLC requests that the DOE make the same finding for this Application.

GLLC also requests that the export authorization recognize that the required environmental review will be conducted by the Commission in conjunction with its review of the request for authorization of the construction and operation of the Export Project facilities. If necessary, DOE's authorization may be conditioned upon satisfactory completion of the Commission's environmental review. This potential condition is consistent with DOE/FE's recent order in *Sabine Pass*,[15] where DOE/FE recognized that the Commission, as lead agency conducting the environmental review, has authority over the siting, construction and operation of the export facilities, with DOE/FE as a cooperating agency.

The long-term authorization requested in this Application is necessary in order to permit GLLC to incur the substantial costs of developing the Export Project and to secure customer

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[14] *See, e.g., Cameron LNG,* LLC, FE Docket No. 11-145-LNG, Order No. 3059 (Jan. 17, 2012); and *Sabine Pass Liquefaction, LLC,* FE Docket No. 10-85-LNG, Order No. 2833 (Sep. 7, 2010). The transaction specific information described in the regulations includes long-term supply agreements and long-term export agreements.

[15] *Sabine Pass Liquefaction, LLC*, FE Docket No. 10-111-LNG, Order No. 2961-A (Aug. 7, 2012) ("DOE/FE Order No. 2961-A").

contracts. Terms for the use of the liquefaction and other facilities will be set forth in agreements with customers of the Export Project.

VI. EXPORT SOURCES

GLLC seeks authorization to export natural gas sourced through the integrated U.S. natural gas pipeline system. As a result of the Gulf LNG Terminal's direct access to multiple major interstate pipelines and indirect access to the national gas pipeline grid, the Export Project's customers will have a wide variety of stable and economical supply options from which to choose. Indeed, the Export Project is not dependent upon a particular source of gas or even a particular supply basin. Rather, customers will have access to the nationally integrated gas pipeline market for supply, providing maximum flexibility to source gas for export based on then prevailing supply and market conditions. One of the Commission's primary goals when promulgating Order No. 636 was to ensure that all parties had access to the interstate pipeline grid so willing buyers and sellers can meet in a competitive, national market to transact the most efficient deals possible.[16] In Order No. 637, the Commission recognized the success to date of its effort to facilitate a competitive and well-functioning market for the sale and purchase of gas. [17] The successful development of a national, competitive and efficient natural gas market can be seen in both DOE/FE's and the Commission's recent findings regarding the source of supply for

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[16] *Promotion of a More Efficient Capacity Release Market*, Order No. 712, FERC Stats. & Regs. ¶ 31,271, at P 2 (2008), *order on reh'g*, Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008), *order on reh'g*, Order No. 712-B, 127 FERC ¶ 61,051 (2009).

[17] *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. ¶ 31,091, at 31,250-55 (2000) (discussing the development of natural gas markets since the issuance of Order No. 636), *clarified*, Order No. 637-A, FERC Stats. & Regs. ¶ 31,099 (2000), *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062 (2000), *aff'd in part and remanded in part*, *Interstate Natural Gas Ass'n of Am. v. FERC*, 285 F.3d 18 (D.C. Cir. 2002).

the Sabine Pass LNG export project. The agencies recognized that multiple direct and indirect pipeline interconnects that transport gas from diverse conventional and non-conventional supply sources will be able to provide natural gas to the Sabine Pass LNG export project.[18] Similarly, natural gas to be exported from the GLLC Export Project may be sourced and transported from anywhere in the highly competitive U.S. natural gas marketplace.

VII. EXPORTS FROM GLLC WILL PROMOTE THE PUBLIC INTEREST

A. Summary of Argument

GLLC's Export Project is consistent with the public interest and therefore the authorizations requested in this Application should be granted. DOE/FE is obligated by statute to grant such authorizations unless there is a finding that the exports for which authorization are sought "will not be consistent with the public interest." This Application demonstrates that the requested export authorization is not inconsistent with the public interest.

DOE/FE's primary consideration is whether the exports will be transacted on a market-driven, competitive basis. That is the case here: the owners of gas or the holders of capacity at the Export Project facilities will make decisions whether to export gas based on then prevailing market conditions in the domestic market and the destination markets. Indeed, with export capability at the Gulf LNG Terminal, both exports and imports will be subject to the ultimate market test: those with capacity at the terminal will decide whether the market warrants imports of LNG, exports of LNG or neither. While the GLLC transactions will be competitive, market-based transactions consistent with DOE/FE's public interest policy, GLLC is aware of the ongoing debate over whether LNG exports will cause price increases in the domestic market

[18] DOE/FE Order No. 2961-A at 28; *Sabine Pass Liquefaction, LLC, et al*, 140 FERC ¶ 61,076. at PP 9-10 (2012).

that run counter to the public interest. In order to address such concerns, GLLC commissioned Navigant Consulting, Inc. ("Navigant") to undertake a study of the potential impact to domestic supply and prices that might result from LNG exports. The Navigant Market Analysis Study, attached to this Application as Appendix A, considered the possible impacts that the GLLC Export Project might have on natural gas supply and pricing. Navigant's analysis also assumed the existence of additional LNG exports from other projects as well as an aggressive increase in natural gas demand due to the use of natural gas in transportation vehicles. Importantly, even in the High Demand Base Case, which assumes 6.2 Bcf/d of LNG exports in addition to GLLC's requested 1.5 Bcf/d and makes aggressive assumptions about natural gas vehicle demand, the impact on domestic prices over the term of the requested authorization is minimal.

Significantly, Navigant concludes that LNG exports will actually encourage a more reliable and stable domestic natural gas market with less volatility, which will benefit all market participants. By providing an additional outlet for supply, LNG exports will help levelize the peaks and valleys historically common to the natural gas industry. In other words, LNG exports will reduce the price volatility that can lead producers to curtail production and reduce investment when prices are declining, which, in turn, leads prices to subsequently spike when production falls too low. Moreover, the GLLC Export Project will not rely on any particular source of gas, but rather, through the nationally integrated gas pipeline grid, and will be able to access gas supplies from a variety of producing basins within the U.S.

In addition, GLLC commissioned Navigant Economics to perform an Economic Impact Assessment Study. As described below and in Appendix B, the study shows that the GLLC Export Project will create material economic benefits in the Southeast region where the Export Project is to be located. During both the construction and operation phases, the GLLC Export

Project will contribute to and stimulate the local and regional economy. In addition to the economic benefits of the project, because development of the GLLC Export Project will take place wholly within a brownfield development area, the environmental impacts of the project will be minimal. Finally, the export of LNG provides broader benefits to the public interest as discussed below.

In short, and as demonstrated below, the GLLC Export Project warrants prompt approval based on the applicable legal standard and facts in the record. Quite simply, granting the LNG export authority requested in this Application is in the public interest.

B. <u>Applicable Legal Standard</u>

Pursuant to Section 3 of the NGA, DOE/FE is required to authorize exports to a foreign country unless there is a finding that such exports "will not be consistent with the public interest."[19] Specifically, Section 717b(a) of the NGA states in relevant part:

> (a) Mandatory authorization order
> [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 Commission authorizing it to do so. <u>The Commission shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest</u>.[20]

In applying this statute, DOE/FE has consistently found that Section 717b(a) creates a rebuttable presumption that proposed exports of natural gas are in the public interest.[21] For that

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[19] 15 U.S.C. § 717b(a) (2006).

[20] *Id.* (emphasis added).

[21] *Sabine Pass Liquefaction, LLC,* FE Docket No. 10-111-LNG, Order No. 2961, at 28 (May 29, 2011) ("DOE/FE Order No. 2961").

reason, DOE/FE must grant the export application unless opponents of an export authorization make an affirmative showing based on evidence in the record that the export would be inconsistent with the public interest.

Further, in evaluating an export application, DOE/FE applies the principles described in DOE Delegation Order No. 0204-111, which focuses primarily on domestic need for the gas to be exported, and the Secretary's natural gas policy guidelines ("Policy Guidelines"),[22] (which have been held to apply to the export of natural gas),[23] and which presume the normal functioning of the competitive market will benefit the public. Although DOE Delegation Order No. 0204-111 is no longer in effect, DOE/FE's review of export applications in decisions under current delegated authority has continued to focus on the domestic need for natural gas proposed to be exported; whether the proposed exports pose a threat to the security of domestic natural gas supplies; and any other issue determined to be appropriate, including whether the arrangement is consistent with DOE's policy of promoting competition in the marketplace by allowing commercial parties to freely negotiate their own trade arrangements.[24] Indeed the Policy Guidelines provide that "the policy cornerstone of the public interest standard is competition. Competitive [export] arrangements are an essential element of the public interest, and natural gas [exported] under agreements that provide for the sale of gas in volumes and at prices responsive

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[22] *Policy Guidelines and Delegation Orders Relating to the Regulation of Imported Natural Gas*, 49 Fed. Reg. 6,684 (Feb. 22, 1984).

[23] *Phillips Alaska National Gas Corporation and Marathon Oil Company*, FE Order No. 1473 (April 2, 1999) (2 FE ¶ 70,317 (1999).

[24] In this regard, in DOE/FE Order No. 2961, the first and currently only, DOE/FE order authorizing exports of lower-48 domestically produced LNG to non-FTA countries, DOE/FE reinforced that although DOE Delegation Order No. 0204-111 is no longer in effect, it continues to focus on the principles set forth therein in reviewing export application. *See* DOE/FE Order No. 2961 at 29.

to market demands largely meets the public interest test."[25]

In granting recent authorizations, DOE has indicated that the following additional considerations are relevant in determining whether proposed exports are in the public interest: whether the exports will be beneficial for regional economies, the extent to which the exports will foster competition and mitigate trade imbalance with the foreign recipient nations, and the degree to which the exports would encourage efficient management of United States domestic natural resources.[26] As discussed below, the export of domestically produced LNG as proposed in this Application satisfies each of these considerations.

C. Analysis of Domestic Need for Gas to be Exported

Navigant's Market Analysis Study and publicly available information demonstrate that North America has significant natural gas resources available at prices that are sufficient to meet projected domestic needs and up to 11.5 million tons per annum over the 20-year period covered in GLLC's request for export authority.

1. United States Natural Gas Supply Overview

Domestic gas production and reserves collectively provide for an abundant domestic supply of natural gas. The Energy Information Agency ("EIA") estimates that domestic natural gas production will grow more quickly than domestic demand for consumption.[27] Domestic gas production has been on a significant upward trend in recent years as rapid growth in supply from unconventional discoveries has more than compensated for declines in production from

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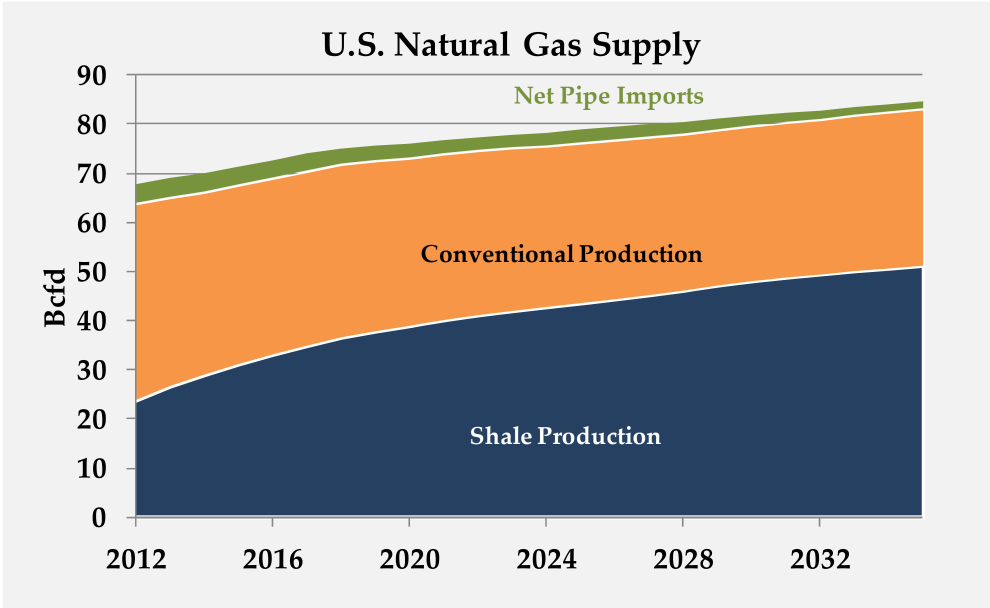
[25] Policy Guidelines, *supra* note 22, at 7.

[26] DOE/FE Order No. 2961, at 34-38.

[27] Energy Information Administration, Annual Energy Outlook 2012 (June 2012) at 92, *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf ("EIA AEO Outlook").

conventional onshore and offshore fields.[28]



Shale gas production has increased by an average annual rate of 17 percent from 2000 to 2006 and by 48 percent from 2006 to 2010.[29] Increased drilling productivity in certain prolific shale gas formations, including the Marcellus and Haynesville shales, has enabled domestic production to continue expanding despite a reduction in the number of wells drilled. Moreover, new shale resources plays are still being discovered. Navigant describes several plays that appeared in an analysis that EIA performed in 2011 that did not appear in similar analysis in 2010.[30]

A number of reports have attempted to identify the total amount of technically recoverable shale gas resources available in the United States. The Massachusetts Institute of

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[28] Navigant Consulting Inc., Gulf LNG Export Project Market Analysis Study, at 11 (Aug. 22, 2012) ("Navigant Market Analysis Study" or "Market Supply Study").

[29] Brookings Energy Security Initiative, Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas at 3 (May 2012), *available at* http://www.brookings.edu/research/reports/2012/05/02-lng-exports-ebinger ("Brookings Report").

[30] Navigant Market Analysis Study, *supra* note 28, at 15.

Technology estimated in *The Future of Natural Gas* that the U.S. has a mean recoverable shale gas resource base of approximately 650 Tcf.[31] Other study estimates of the total amount of technically recoverable shale gas resources range from less than 700 Tcf to over 1,800 Tcf.[32] This inventory is expected to continue growing as further advancements in drilling technology are deployed to exploit additional shale gas development opportunities.

The growth in shale production has been accompanied by an increase in the overall volume of U.S. natural gas resources. In April 2011, the Potential Gas Committee raised its prior estimates of the U.S. technically recoverable gas resource base by 61 Tcf to 1,898 Tcf at year-end 2010.[33] Similarly, the MIT Report estimates that the United States has a mean remaining resource base of approximately 2,100 Tcf.[34] Based off 2011 U.S. demand of 24 Tcf per year, the U.S. alone has enough gas resources to supply demand for up to more than 90 years.[35]

2. United States Natural Gas Demand Overview

As evidenced by the plummeting U.S. natural gas price, domestic natural gas demand continues to be outpaced by the available supply.

a. Industrial Sector

Consumption of natural gas in the U.S. by industrial end-users has steadily declined over

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[31] Massachusetts Institute of Technology, The Future of Natural Gas, at 7 (2011), *available at* http://web.mit.edu/mitei/research/studies/naturalgas.html ("MIT Report").

[32] Brookings Report, *supra* note 29, at 4-5.

[33] *See* Press Release, Potential Gas Committee, Potential Gas Committee Reports Substantial Increase in Magnitude of U.S. Natural Gas Resources Base, at 1 (April 27, 2011), *available at* http://potentialgas.org/download/pgc-press-release-april-2011.pdf.

[34] MIT Report, *supra* note 31, at 30.

[35] Market Supply Study, *supra* note 28, at 13.

the last 15 years, from a peak of 8.51 Tcf in 1997 to 6.7 Tcf in 2011.[36] This decline can be attributed to the industrial sector's price sensitivity resulting from the use of natural gas as a feedstock and the price volatility of the natural gas market in the late 1990s and 2000s.[37] With the shale gas boom, and resulting decrease in the price of natural gas, many anticipate an increase in industrial demand.[38] EIA's recent data projects that the U.S. industrial sector demand will increase by under 0.5% per year to 7.0 Tcf in 2035 in its Reference Case.[39] Similarly, Navigant projects industrial demand to grow annually by an average of 0.4%.[40] Accordingly, many expect an increase in U.S. industrial production due to the low price of natural gas.

b. Residential and Commercial Sectors

EIA projects a 6% decline in residential consumption of natural gas to 4.64 Tcf in 2035 in its Reference Case.[41] In 2010, EIA documented that gas demand per U.S. residential household has been in decline since the 1990s due to appliance efficiency gains, improvements in building construction, population shift towards warmer regions, higher commodity prices, and an increase in the share of natural gas customers who do not use natural gas as their primary space-heating fuel.[42]

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[36] EIA AEO Outlook, *supra* note 27, at Table 13.

[37] Brookings Report, *supra* note 29, at 17.

[38] *See id.* and Market Supply Study, *supra* note 28, at 21.

[39] EIA AEO Outlook, *supra* note 27, at 92 and Table 26.

[40] Market Supply Study, *supra* note 28, at 21.

[41] EIA AEO Outlook, *supra* note 27, at 92 and Table 26.

[42] EIA, *Trends in U.S. Residential Natural Gas Consumption*, at 1 (June 2010), *available at* http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf.

c. Electricity Sector

The electric generating sector has been the primary domestic natural gas consuming sector to experience consistent growth in recent years because of the increased supply of natural gas, and therefore lower prices, and by environmental concerns over coal-fired generation.[43] Preliminary data released by the EIA in July 2012 reflects that generation from natural gas-fired plants is virtually equal to generation from coal-fired plants for April 2012 for the first time.[44] EIA projects natural gas consumption for electric power generation to grow by 0.8% to 8.96 Tcf in 2035 in its Reference Case.[45] Although the EIA projects natural gas consumption for electric power generation to grow, the amount of growth will likely depend on commodity price competition and additional Environmental Protection Agency regulations.

d. Transportation Sector

Natural gas consumed for residential and commercial transportation accounts for a small portion of domestic demand. In 2010, less than 40,000 heavy duty vehicles (or 0.4% of the heavy duty vehicle market) were fueled by natural gas.[46] A widespread conversion to natural gas heavy duty vehicles remains unlikely without significant subsidies or mandates due to a lack of refueling infrastructure and an incremental cost premium for LNG trucks of approximately $70,000.[47] Navigant projects vehicle demand for natural gas to grow annually by an average of

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[43] Brookings Report, *supra* note 29, at 15.

[44] Market Supply Study, *supra* note 28, at 25-26.

[45] EIA AEO Outlook, *supra* note 27, at 92 and Table 26

[46] *Id.*

[47] Brookings Report, *supra* note 29, at 19.

0.2%.[48]

3. Navigant Supply Study

In addition to publicly available information and forecasts, GLLC commissioned Navigant to assess the potential supply, demand, and pricing impact on U.S. natural gas markets under two major scenario analyses through 2035, which is the timeframe for GLLC's proposed exports.[49] Under each scenario analyzed, there is more than adequate supply for domestic markets along with LNG exports and the impact of exports on domestic pricing is minimal.

The first scenario, "Base Case," is based exclusively on Navigant's twice annual long-term forecast. The Base Case was developed from Navigant's Spring 2012 Reference Case, which projects natural gas forward prices and monthly basis differentials at 90 market points throughout the entire North American grid.[50] The Base Case assumes that the two authorized LNG export facilities in North America will be operational by the time the GLLC Export Project is in service: Sabine Pass LNG in Louisiana and Kitimat LNG near Prince Rupert, British Columbia.[51] The "GLNG Exports Case" tests the effect of exporting natural gas in liquefied form from the 1.5 Bcf/d capacity GLLC facility beginning in December 2018 against the Base Case. The "Aggregate Exports Case" expands upon the GLNG Exports Case by including an additional 2.5 Bcf/d of generic export capacity. The generic export capacity is distributed throughout the United States with 1.0 Bcf/d each of additional LNG export capacity along the

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[48] Market Supply Study, *supra* note 28, at 22.

[49] *Id.* at 1.

[50] *Id.* at 34.

[51] *Id.* at 37.

West Coast and the Gulf of Mexico and 0.5 Bcf/d along the East Coast.[52] This Aggregate Exports Case therefore assumes the existing authorized facilities in place plus the GLLC Export Project plus additional exports from projects other than the GLLC Export Project.

The second scenario, the "High Demand Base Case," incorporates aggressive assumptions about natural gas demand through the phase-in of natural gas vehicles (NGVs) and the additional 3.5 Bcf/d of generic LNG exports projected in the Aggregate Exports Case.[53] The "High Demand Base Case Plus GLNG @ 1.5 Bcfd" tests the effects of exporting natural gas in liquefied form from the 1.5 Bcf/d capacity GLLC facility beginning in December 2018 against the High Demand Base Case.[54]

a. Supply Impacts

The modeling in the Navigant Market Analysis Study shows that little effect would be seen on the supply of natural gas in the U.S. Under the Base Case, Navigant projects U.S. gas supply to increase slightly from 68.2 Bcf/d in 2012 to 83.5 Bcf/d in 2035.[55] Under the GLNG Exports Case and GLNG Aggregate Exports Case, U.S. gas supply will slightly increase to an estimated 83.7 Bcf/d and 84.1 Bcf/d in 2035, respectively.[56] U.S. gas supply increases to a total of 88.1 and 88.3 Bcf/d in 2035 under the High Demand Base Case and the High Demand Base Case Plus GLNG @ 1.5 Bcf/d, respectively.[57] The Export Project would have a minor positive

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[52] *Id.* at 50.

[53] *Id.* at 55.

[54] *Id.* at 58.

[55] *Id.* at 42.

[56] *Id.* at 45, 50.

[57] *Id.* at 55, 58.

impact on natural gas supplies in the U.S. Contrary to the concerns expressed that LNG exports will deplete U.S. resources, the demand induced by such exports will incentivize production, yielding net positives across all scenarios. As discussed below, the steady demand created by LNG exports will stabilize demand, reduce price volatility and contribute toward a more predictable natural gas market that will benefit producers and consumers alike.

b. Demand Impacts

The modeling in the Navigant Market Analysis Study shows there would be little effect on the overall total of demand for natural gas in the U.S.[58] Similarly, LNG exports at GLLC have virtually no effect on the distribution of demand among the major sectors of the domestic economy.[59] The Navigant Market Analysis Study shows almost no difference between the Base Case and the GLNG Exports Case.[60] For the Aggregate Exports Case, the difference is an approximate 0.4 Bcf/d increase in demand due to liquefaction plant fuel losses.[61] Similarly, the Navigant Market Analysis Study reflects virtually no difference between the High Demand Base Case and the High Demand Base Case Plus GLNG @ 1.5 Bcfd.[62] These differing scenarios show that the GLLC Project will have an insignificant impact on the demand for natural gas in the U.S. market across all scenarios tested. The proposed quantities of gas for the Project will in fact have a minimal impact on the U.S. market as a whole.

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[58] *See id.* at 53, 61.

[59] *Id.* at 47, 52, 60.

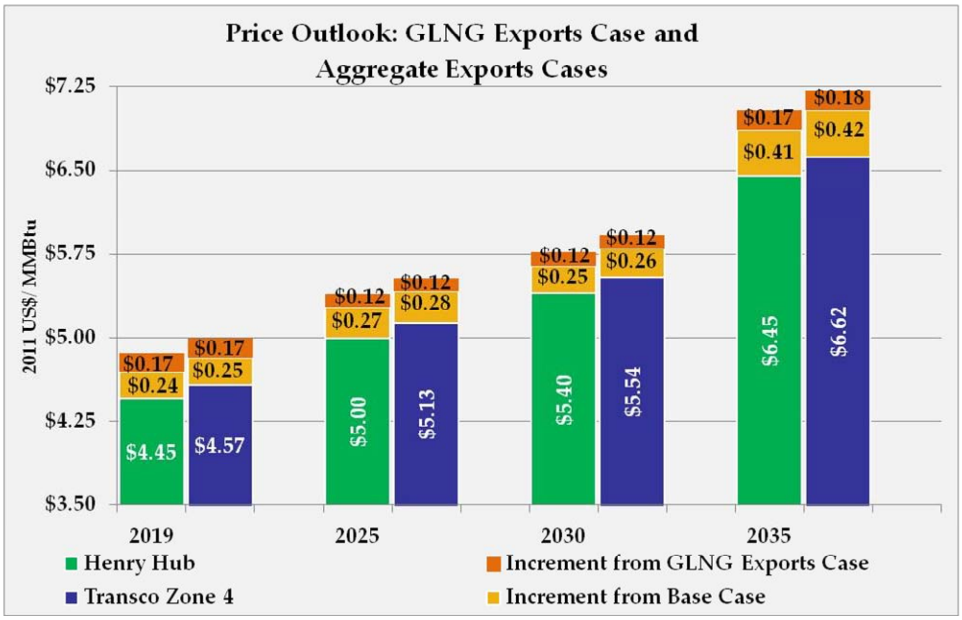
[60] *Id.* at 47.

[61] *Id.* at 52.

[62] *Id.* at 60.

c. The Effect of GLLC Exports on Natural Gas Prices Is Minimal

The Navigant Market Analysis Study considers GLLC's impact on Transcontinental Pipeline Company (Transco) Zone 4 prices and on Henry Hub prices, and shows that the impact is minimal for all throughout the twenty-year term. The average price increase of the GLNG Exports Case versus the Base Case is $0.28 per MMBtu for Henry Hub and $0.29 per MMBtu for Transco Zone 4, representing a 2.2% and 2.3% difference, respectively.[63]



As part of the average overall residential retail rate, the $0.29 represents an even smaller percentage because of the additional costs to consumers from the distribution utility for pipeline, storage, and distribution system costs, as well as the utility rate of return.[64] For example, a consumer in Mississippi pays an additional $2.73 per MMBtu on top of the cost of gas for natural gas service, so the 29 cents actually translates to only 3.6% of an average total cost of

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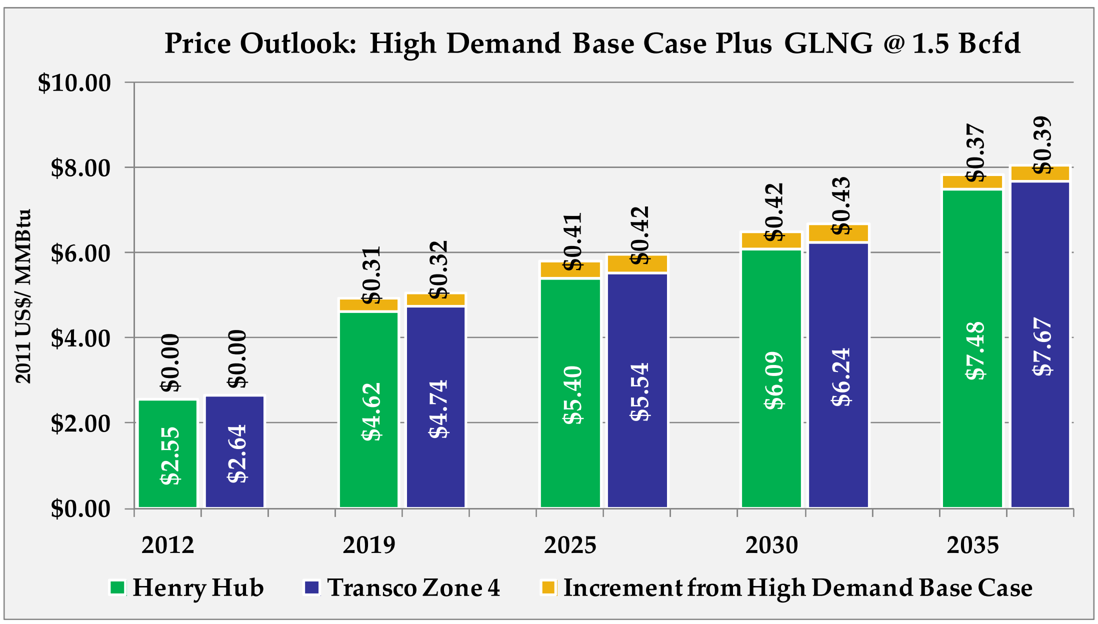
[63] *Id.* at 48.

[64] *Id.*

$8.10 per MMBtu.[65] The average price increase of the Aggregate Exports Case versus the GLNG Exports Case is $0.12 for Henry Hub and $0.13 for Transco Zone 4, or about 2.2% and 2.3, respectively.[66]

Prices at Transco Zone 4 and Henry Hub in the High Demand Base Case Plus GLNG @ 1.5 Bcfd remain near or below $6.00 per MMBtu through 2025 and 2026, respectively, and below $7.00 per MMBtu through 2032.[67] The average price increase for the High Demand Base Case Plus GLLC @ 1.5 Bcfd versus the High Demand Base Case is $0.38 per MMBtu for Henry Hub and $0.39 per MMBtu for Transco Zone 4 versus average High Demand Base Case prices over the term of $5.77 and $5.92, respectively, or 6.7%.[68]



In sum, the projected price increase resulting from any of the GLLC export cases,

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[65] *Id.* at 48-49.

[66] *Id.* at 53.

[67] *Id.* at 61.

[68] *Id.*

including the cases assuming maximum exports plus increased transportation usage, are small.[69] Indeed, other factors having nothing to do with GLLC specifically or the export of LNG generally are more likely to have a greater impact on gas prices at Transco Zone 4 or Henry Hub than is the export of LNG from GLLC.[70]

4. The Supply-Demand Balance Demonstrates That Exports of LNG Will Not Harm the Public Interest

The Navigant Market Analysis Study supports the conclusion that the exports proposed in this Application will have a minimal impact on domestic natural gas prices. Further, any upward pressure on prices due to increased demand for exports would likely be offset by a reduction in domestic price volatility. In recent years, low market prices have resulted in domestic producers deferring the drilling of new wells or completion of wells that have already been drilled. If history is a guide, this sharp cutback in the development of new gas wells, ultimately, will lead to a sharp rebound in natural gas prices. This cycle of sharp natural gas price fluctuations will be reduced by the entry of LNG export facilities such as the GLLC Export Project. The ability to allow the market to allocate gas usage through expanded exports of natural gas as LNG when U.S. natural gas prices drop and reduced natural gas exports when U.S. natural gas prices rise

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[69] A recent study by the James A. Baker III Institute for Public Policy at Rice University supports the conclusion that GLLC's exports will have a minimal impact on natural gas prices. The study finds that exporting LNG from the United States will not have a significant impact on prices domestically and that the total volume of exports will likely fall short of the volumes assumed by those who have argued that exports will have a detrimental impact on U.S. prices. Kenneth B. Medlock III, James A. Baker III Institute for Public Policy, *US LNG Exports: Truth and Consequence* (Aug. 2012) ("Baker Institute Study").

[70] *Id.* at 33. While the Baker Institute Study mentions the weather (*e.g.*, an abnormally warm winter causing natural gas prices to decrease), other recognized factors that have been known to impact prices at Transco Zone 4, Henry Hub or in the U.S. generally include hurricanes, pipeline outages, the availability of storage capacity and other factors that routinely move prices by a larger margin than the estimated impacts of LNG exports.

will work to stabilize U.S. natural gas prices. Such stability will help smooth out investment in the production of natural gas in the U.S. In short, exports of domestic LNG will provide an additional market for U.S. production, thereby encouraging exploration, development and production at times when domestic demand alone might not.

Customers of the Export Project will have flexibility to reduce their exports and instead redirect gas to the domestic market if demand and market prices indicate a sufficient need for incremental supplies. Just as the LNG exported from the Export Project is not tied to any particular source of gas, the increased production and reserves are not, in other words, irrevocably or unilaterally dedicated to foreign destinations. Consistent with the Policy Guidelines finding that competitive export arrangements are essential to the public interest (and indeed is the primary public consideration),[71] market signals in the United States will play a key role in the determination of whether such gas will be consumed in the United States or delivered to a foreign market. Succinctly, the market will decide based on competitive factors, whether gas will be exported or used domestically. Authorization to allow GLLC to proceed with the Export Project will not prevent the importation of LNG when market forces dictate. GLLC is poised to provide service under either demand scenario. Supplemental natural gas production initially expected to be liquefied and exported will likely reduce volatility in the U.S. natural gas market by sustaining robust levels of domestic exploration and production and providing an additional source of supply during periods of high domestic demand. This will serve to reduce the likelihood and magnitude of sudden and significant increases in domestic gas prices.

The Navigant Market Analysis Study and publicly available information demonstrate that the U.S. has sufficient natural gas resources available at modest prices to meet projected

[71] Policy Guidelines, *supra* note 22, at 7-8.

domestic demand over the 20-year period requested by GLLC in this Application.

D. Other Public Interest Considerations

1. Benefits to U.S., Regional and Local Economies

GLLC commissioned Navigant Economics to assess the economic impact of the GLLC Export Project in the Southeast region.[72] Expenditures related to the development, support and construction (collectively, "Construction") of the GLLC Export Project are estimated to cost $6,993.4 million.[73] GLLC projects that $1,473.7 million of the Construction activities would be spent within a 75-mile radius circle around the City of Pascagoula in of Mississippi and Alabama (the "Local Gulf LNG Economic Area").[74] Similarly, GLLC projects that the operation and maintenance of the GLLC Export Project will be $328.3 million annually.[75] Customers of the GLLC Export Project will spend an estimated $2,542.1 million annually on purchasing natural gas for the GLLC Export Project.[76]

According to the Economic Impact Assessment, the GLLC Project will significantly stimulate local, regional and national economies during both construction and operation phases. Job creation, indirect spending and tax revenue will all see positive growth as a result.

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[72] Navigant Economics's projected economic impacts result from the use of the well-established RIMS II modeling system and a frequently used Navigant Tax Revenue Model. The resulting projected economic impacts are a function of the assumptions made and accordingly may be modified as assumptions are refined. GLLC anticipates that the economic impacts included in its forthcoming Commission application may differ from those set forth herein because project details will be further defined and refined at that point.

[73] Navigant Economics, Gulf LNG Export Project Economic Impact Assessment Study, at 1 (Aug. 31, 2012) ("Economic Impact Assessment").

[74] *Id.* at 3.

[75] *Id.*

[76] *Id.*

a. Economic Impacts

Navigant Economics calculated the number of jobs created, the incremental wage income associated with these jobs, and the value added (i.e., the contribution to gross domestic product) using the RIMS II regional modeling system, developed and maintained by the Bureau of Economic Analysis of the U.S. Department of Commerce.[77] The RIMS II Model is widely used to assess the regional economic impacts of a wide variety of private and public sector projects.[78] Over the six and a half year construction timeframe, Navigant Economics estimated that the GLLC Export Project will create 1,813 full-time equivalent jobs in Jackson County, earning $64.4 million each year on average.[79] The estimated average annual value added of the jobs in Jackson County is $137.3 million.[80] For the Local Gulf LNG Economic Area, the GLLC Export Project creates an additional 2,889 full-time equivalent jobs, earning $102.2 million dollars each year, and adding $188.7 million each year on average.[81]

The continuing economic impact from the operation of the GLLC Export Project will be significant. Navigant Economics projects that the operation and maintenance of the GLLC Export Project will create 1,637 new full-time equivalent jobs in Jackson County.[82] Similarly, employee earnings and value added are $71.7 million higher and $227 million higher,

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[77] *Id.* at 20.

[78] *Id.*

[79] *Id.* at 29.

[80] *Id.*

[81] *Id.*

[82] *Id.* at 39.

respectively, in Jackson County than without the facilities.[83] Regarding the Local Gulf LNG Economic Area, in each year, there will be 2,678 more full-time equivalent jobs, $118.2 million more employee earnings, and $322.4 million more value added than would have been the case absent outlays associated with the operation and maintenance of the GLLC Export Project.[84] The increase in the number of jobs in Jackson County amounts to 2.5% and 0.4% in the Local Gulf LNG Economic Area of the number of jobs in 2010 in each respective location.[85]

An even greater number of jobs, and far greater overall economic benefits, will result from the exploration and production of the 1.5 Bcf per day of gas required for the GLLC Export Project. GLLC customers will purchase natural gas from mostly outside of the Local Gulf LNG Economic Area. The natural gas purchases will create, each year, 23,684 new jobs, $1,553 million more employee earnings, and $3,511.7 million more value added than would have been the case absent these natural gas purchases.[86]

b. Additional Tax Revenues Generated

Navigant Economics calculated the impacts on federal, state, and local tax revenues generated as a consequence of the direct benefits using its Tax Revenue Model.[87] The GLLC Export Project will pay an incremental $16.0 in property taxes annually during construction of the GLLC Export Project.[88] The States of Mississippi and Alabama would obtain incremental

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[83] *Id.*

[84] *Id.*

[85] *Id.* at 42.

[86] *Id.* at 39.

[87] *Id.* at 2.

[88] *Id.* at 49.

tax revenues (in addition to the Jackson County property taxes) of $138.3 million.[89] Nationally, during construction, federal tax revenues will increase by $1,677.8 million[90] and the state and local tax revenues will increase by $910.1 million.[91]

After the GLLC Export Project goes in service, the facilities will pay $43.5 million in property taxes annually to Jackson County.[92] Additionally, the States of Mississippi and Alabama will obtain incremental tax revenues (separate from the Jackson County property taxes) each year of $36.7 million due to new facilities and the natural gas purchased for the GLLC Export Project.[93] Nationally, federal tax revenues will increase by $516 million[94] and state and local tax revenues will increase by $318.9 million.[95]

2. International Considerations

a. The Market for LNG

Not only will exports of LNG create economic benefits at home, but there is a real need for U.S. exports of LNG abroad. Countries in Asia depend heavily on the importation of LNG from outside the region, particularly from the Middle East and Russia, to meet their total demand

[89] *Id.* at 45.

[90] *Id.* at 43.

[91] *Id.* at 45.

[92] *Id.* at 49.

[93] *Id.* at 48.

[94] *Id.* at 47.

[95] *Id.* at 48.

for natural gas.[96] With demand expected to grow and limited excess capacity on the part of the region's traditional suppliers, imports of LNG from the U.S. will become increasingly important in meeting the region's energy needs.[97] Similarly, in Europe, where many countries rely heavily, if not solely, on the importation of Russian gas at high, oil-indexed prices, there is an immediate need for alternative sources of supply and alternative pricing to be introduced into the marketplace.[98] Whether to meet demand or to introduce alternative sources into the Atlantic Basin or Pacific Basin LNG markets, there are destination markets where U.S. sourced LNG can compete for market share.

b. Balance of Trade

Allowing for the exportation of LNG will have a beneficial impact on the balance of payments of the U.S. with the rest of the world, thereby reducing the overall U.S. trade deficit. According to the U.S. Department of Commerce, Bureau of Economic Analysis, in 2011, the total U.S. trade deficit was $560 billion (comprised of approximately $2.1 trillion in exports minus approximately $2.66 trillion in imports).[99] Petroleum products alone accounted for $326.1 billion of that overall deficit.[100] If approved, the export authorization for GLLC would help reduce the U.S. trade deficit by up to $5.1 billion per year over the 20-year period which

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[96] Brookings Report, *supra* note 29 at 21-22 (citing *BP Statistical Review of World Energy, 2011* (June 2011)), available at http://www.bp.com/sectionbodycopy.do?categoryId=7500&contentId=7068481).

[97] *Id.* at 22-23.

[98] *Id.* at 24-25; Baker Institute Study, *supra* note 69, at 7.

[99] *See* Bureau of Economic Analysis, *U.S. International Trade in Goods and Services: Annual Revision for 2011* (June 8, 2012), *available at* http://www.census.gov/foreign-trade/Press-Release/2011pr/final_revisions/11final.pdf.

[100] *Id.* at 15.

amounts to 1.1% of the 2011 U.S. trade deficit.[101] These types of potential benefits to the U.S. trade deficit and balance of payments have been expressly recognized by DOE in its prior decisions, when it approved other requests to export LNG from the United States. DOE's prior conclusions are equally applicable here.[102] Given the substantial impact the negative trade balance of the United States in petroleum products has on its overall trade deficit and balance of payments, approving GLLC's request to export LNG will have a positive impact on both.

c. Geopolitical Benefits

The export of domestically produced LNG from the GLLC Project will promote liberalization of the global gas market by fostering increased liquidity and trade prices established by market forces. The current natural gas trade has developed in three primary markets: North America, Europe and Asia. There is substantial trade within these markets, but limited trade between these markets. The pricing structure within each market is significantly different. In North America, natural gas is traded in a highly liquid and competitive market and prices are very transparent. The European and Asian markets are dominated by natural gas price linkage to the valuation of competing crude oil products. Also, LNG contracts for these markets are predominantly indexed to crude oil. By introducing additional LNG from market-based structures, GLLC increases the potential for global decoupling of oil-parity pricing. The

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[101] *See* Economic Impact Assessment, *supra* note 73, at 51.

[102] *See, e.g.*, *ConocoPhillips*, FE Docket No. 09-29-LNG, Order No. 2731, at 10 (Nov. 30, 2009) ("exportation of LNG will help to improve the United States' balance of payments with destination countries"); DOE/FE Order No. 2961 at 30; *Freeport LNG Dev. L.P.*, FE Docket No. 08-70-LNG, Order No. 2644, at 12 (May 28, 2009) ("mitigation of balance of payment issues to the benefit of United States interests will result from a grant of the application [to export LNG]"); *ConocoPhillips Alaska Nat. Gas Corp. and Marathon Oil Co.*, FE Docket No. 07-02-LNG,, Order No. 2500, at 58 (June 3, 2008) ("we find that mitigation of balance of payment issues may result from a grant of the instant application [to export LNG]").

Brookings Report notes that even

> [w]ithout exporting natural gas, the U.S. shale gas 'revolution' has already had a positive impact on the liquidity of global LNG markets. Many LNG cargoes that were previously destined for gas-thirsty U.S. markets were diverted and served spot demand in both the Atlantic and Pacific Basins. The increased availability of LNG cargoes has helped create a looser LNG market for other consumers. This in turn has helped apply downward pressure to the terms of oil-linked contracts resulting in the renegotiation of some contracts, particularly in Europe. Increased availability of LNG cargoes also accelerated a recent trend of increasing reliance of consumers on spot LNG markets.[103]

A liquid natural gas market is beneficial to U.S. and global economic interests and, at the same time, advances security interests through diversity of supply and resilience to disruptions.[104] The gas supply available to Europe is restricted to a small group of supplying countries. The availability of increased LNG to Europe will help reduce dependence on gas delivered by pipeline from Russia.[105] Russia's ability to threaten gas supply to Europe for geopolitical purposes is reduced materially the more that alternatives to such Russian gas are made available. LNG need not be in such quantity to displace all Russian gas to create a moderating impact so long as there is enough to ensure that a Russian threat of cut off would not be devastating to European gas consumers. In short, the competitive threat of LNG available for

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[103] Brookings Report, *supra* note 29, at 38 (internal reference omitted).

[104] MIT Report, *supra* note 31, at 14 ("Greater international market liquidity would be beneficial to U.S. interests. U.S. prices for natural gas would be lower than under current regional markets, leading to more gas use in the U.S. Greater market liquidity would also contribute to security by enhancing diversity of global supply and resilience to supply disruptions for the U.S. and its allies. These factors ameliorate security concerns about import dependence."). *See also id.* at xvii ("For reasons of both economy and global security, the U.S. should pursue policies that encourage an efficient integrated global gas market with transparency and diversity of supply, and governed by economic considerations.").

[105] Brookings Report, *supra* note 29, at 41-43 (Russia provides approximately one-third of the natural gas used in Europe).

European markets has a positive impact on U.S. geopolitical interests because it provides a moderating effect on Russian's ability to restrict gas supply to Europe for geopolitical purposes and it alleviates a potential stress point to an economy that is already under pressure for other reasons. Thus, even though the amount of supply from the GLLC Export Project will be a small percentage of the global LNG capacity, the entrance of additional LNG supplies will significantly diversify the global gas market.[106]

Asian countries are also diversifying their energy portfolios to replace nuclear power with safer alternatives. For example, Japan alone imported 3.8 Tcf of natural gas in 2010, well before the tragedy of Fukushima and the resulting move away from nuclear power. The Japanese government continues to negotiate with the United States for a free trade waiver.[107] The GLLC Export Project could not only help meet this increasing demand, but it will help the United States enhance its strategic influence over the region.

d. Additional International Benefits

DOE/FE has recognized certain "difficult to quantify" impacts of an authorization to export LNG that "redound to the benefit of the United States."[108] These international impacts are equally applicable to a license for GLLC to export LNG. The positive impacts include: (1) promoting international markets and development of additional resources domestically and

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[106] Michael Ratner et al., Congressional Research Service, *Europe's Energy Security: Options and Challenges to Natural Gas Supply Diversification*, at 26 (Mar. 13, 2012) ("Any volumes of LNG from the United States would benefit the market, including Europe, by offering a new supplier to consumers. For parts of Europe, especially the Baltic region and Central Europe, where the United States enjoys strong and friendly relations, any decision to export U.S. LNG to that region would be welcomed as a potential offset to their dependence on Russian Gas."), *available at* http://www.fas.org/sgp/crs/row/R42405.pdf.

[107] *Id.* at 43.

[108] DOE/FE Order No. 2961, at 37.

internationally;[109] (2) enabling overseas generators to switch from oil or coal to cleaner natural gas with its environmental benefits;[110] (3) assisting countries with limited resources to broaden and diversify their supply base, which will contribute to transparency, efficiency and liquidity of international natural gas markets and encourage liberalized trade and greater diversification of global supplies;[111] and, (4) decoupling international natural gas prices from oil prices, leading to lower natural gas prices.[112]

VIII. ENVIRONMENTAL IMPACT

The Export Project will have minimal environmental impacts.[113] Although the GLLC Export Facilities will be constructed on property adjacent to the existing import facilities, the project will be located wholly in a brownfield development area. Given this project scope, GLLC anticipates that the Commission will prepare an Environmental Impact Statement (EIS) as part of its environmental review. GLLC further anticipates that, given the disturbed nature of the existing area, the EIS will not identify material issues. The Commission conducted an environmental review of the Gulf LNG Terminal site in connection with authorization of the siting, construction, and operation of the Terminal in Docket No. CP06-12-000. Any additional

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[109] Brookings Report, *supra* note 29, at 35 (explaining that the increased production of gas in response to exports would result in an increase in the production of natural gas liquids and have a positive effect on U.S. industry).

[110] *Id.* to 44 (noting that the International Energy Agency estimates that "natural gas in general has the potential to reduce carbon dioxide emissions by 740 million tonnes in 2035, nearly half of which could be achieved by the displacement of coal in China's power-generation portfolio").

[111] *Id.* at 43

[112]DOE/FE Order No. 2961, at 37.

[113] *See, e.g., Sabine Pass Liquefaction, LLC, et al*, 139 FERC ¶ 61,039, at P 29 (2012).

environmental impacts associated with construction and operation of the Export Project will be reviewed by the Commission and the applicable state and federal permitting agencies (e.g., United States Army Corps of Engineers, Mississippi Department of Environmental Quality, and Coast Guard, among others) as part of the permitting process for the Export Project. Consistent with its practice regarding other applications, DOE/FE will be a cooperating agency in the Commission's environmental review.[114] Notwithstanding that DOE/FE will be a cooperating agency, GLLC will keep DOE/FE apprised of the progress of the environmental review conducted by the Commission.

Having previously received authorization to export to FTA countries, GLLC is currently in the process of evaluating the necessary infrastructure modifications and additions necessary to accommodate both FTA and Non-FTA exports. Following such evaluation, GLLC will initiate the pre-filing review process at the Commission for the proposed Export Project facilities. This will be the initial step in a comprehensive and detailed environmental review by the Commission of the Export Project as required by the National Environmental Policy Act ("NEPA").[115] It is anticipated that, consistent with the requirements of NEPA, the Commission will act as the lead agency for environmental review, with the DOE acting as cooperating agency.[116] GLLC therefore respectfully requests that the DOE/FE issue an order approving this Application, with such approval subject to completion by the Commission of a satisfactory environmental review of the Project.

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[114] DOE/FE Order No. 2961-A, at 27.

[115] National Environmental Policy Act, Pub. L. No. 91-190, 83 Stat. 852 (1969).

[116] *See, e.g.,* DOE/FE Order No. 2961-A, at 27.

IX. APPENDICES

The following appendices are included with this Application:

Appendix A   Navigant Consulting – Market Analysis Study

Appendix B   Navigant Economics - Economic Impact Analysis Study

Appendix C   Verification

Appendix D   Opinion of Counsel

X. CONCLUSION

For the reasons set forth above, GLLC respectfully requests that the DOE issue an order granting GLLC authorization to export up to 11.5 million tons per year of LNG (approximately equivalent to 1.5 Bcf/d) produced from domestic sources for a 20-year period commencing on the earlier of the date of first export or ten years from the date the requested authorization is granted from its Gulf LNG Terminal to any country that has or in the future develops the capacity to import LNG via ocean-going carrier and with which the United States does not prohibit trade but also does not have a FTA requiring national treatment for trade in natural gas. GLLC is requesting this authorization both on its own behalf and as agent for other parties who themselves hold title to the LNG at the time of export.

Respectfully submitted,

Gulf LNG Liquefaction Company, LLC

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August 31, 2012

APPENDIX A

NAVIGANT CONSULTING – MARKET ANALYSIS STUDY

NAVIGANT

GULF LNG EXPORT PROJECT MARKET ANALYSIS STUDY

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August 27, 2012

Disclaimer: This report was prepared by Navigant Consulting, Inc. for the benefit of Gulf LNG Liquefaction Company, L.L.C. This work product involves forecasts of future natural gas demand, supply, and prices. Navigant Consulting applied appropriate professional diligence in its preparation, using what it believes to be reasonable assumptions. However, since the report necessarily involves unknowns, no warranty is made, express or implied.

Table of Contents

List of Figures

List of Tables

Executive Summary

Domestically produced natural gas has become an abundant fuel in North America. In fact, gas supply is currently surplus to demand and that surplus to demand is expected to continue. This is primarily due to the advent of economically-producible shale gas as a result of the application of technological breakthroughs, particularly over the last four years. Specifically, the development of horizontal drilling and hydraulic fracturing, existing technologies which were combined together and have been continually improved, has yielded dramatically increased production and fundamentally changed the North American natural gas supply outlook. The current consensus[1] is that North American gas resources are more than adequate to satisfy domestic demand for longer than the time frame covered by this report (2035). It is Navigant's assessment that North American gas resources are ample, reflecting a large surplus to current demand levels, and clearly sufficient to support the creation and ongoing operation of a domestic LNG export industry through the study period, including GLNG's proposed liquefaction facilities. Indeed, based on the analyses described in this study, we estimate that the price impact of GLNG exports will be minimal. Moreover, it is Navigant's further assessment that LNG exports will serve to enhance price stability in the North American market, benefiting North American market participants through reduced price volatility.

Before 2008, the general consensus was that domestic North American gas supplies would be unable to keep pace with growing demand, and that liquefied natural gas would have to be imported from foreign supply sources. Now, the situation in North America has reversed from an expectation of domestic supply deficit to an expectation of domestic supply abundance, and indeed currently surpluses. Prices that were expected to be high and volatile are now expected to be moderate and relatively stable as a result of the potential of unconventional gas shale development through technology.

In fact, as supply abundance creates the potential for an unbalanced market leading potentially to stagnation of gas asset development, LNG exports can be an important contributor to the long-term sustainability of the gas market by contributing to demand levels that will incent important production and distribution investments The fundamental rationale for exporting natural gas, as noted by the Brookings Institution, is that "the U.S. price is lower than the price in target markets, where natural gas is often purchased on more expensive long-term contracts that are indexed to the price of oil, leading to an opportunity for arbitrage."[2]

In order to effectively assess the market impact of GLNG's proposed liquefaction facilities, Navigant developed five scenarios to test the potential effect that the GLNG export project may have on natural gas prices, given certain assumptions regarding future supply, demand, infrastructure development, and economic activity. The scenarios are grouped and evaluated in two separate analyses. Analysis One is based on Navigant's Reference Case view of likely supply and demand levels, and comprises the Base Case, the GLNG Exports Case, and the Aggregate Exports Case; Analysis Two represents an

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[1] Navigant's groundbreaking 2008 publication of the 'North American Natural Gas Supply Assessment' for the American Clean Skies Foundation first identified the rapidly expanding development of natural gas from shale gas resources.

[2] "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas", C. Ebinger, K. Massy and G. Avasarala, Energy Security Initiative at Brookings Institution, Policy Brief 12-01, May 2012, p. 20.

alternative, high-demand view of the future, driven by higher levels of assumed usage of natural gas vehicles as well as higher levels of U.S. LNG exports, and comprises the High Demand Base Case and the High Demand Base Case Plus GLNG @ 1.5 Bcfd, both cases being developed to test the impacts of the project on higher demand scenarios. The estimated impact of GLNG exports on Transcontinental Pipeline Company (Transco) Zone 4 prices and on the national market (as measured at Henry Hub) is minimal.

ANALYSIS ONE

Analysis One is based on Navigant's Spring 2012 Reference Case view of likely supply and demand levels:

Base Case

The **Base Case** was derived from Navigant's Spring 2012 Reference Case and includes as active the two LNG liquefaction and export facilities approved by DOE and the Canadian National Energy Board (Sabine Pass in Louisiana and Kitimat near Prince Rupert, British Columbia, respectively) at the time of modeling.

The forecast projects that prices at Henry Hub remain at or below $5.00 per MMBtu through 2025. After 2025, prices rise more due to generally increasing costs of additional domestic production. Henry Hub reaches $6.45 per MMBtu in 2035. Prices at Tranco Zone 4 show a small positive basis to Henry Hub, averaging about $0.14 per MMBtu, throughout the forecast period.

GLNG Exports Case

The **GLNG Exports Case** tests the effects of exporting LNG from the 1.5 Bcfd capacity GLNG export facility beginning December 2018 against the Base Case. All other inputs and assumptions remain the same as in the Base Case.

The estimated impact for GLNG exports on prices at Transco Zone 4 and on the national market (as measured at Henry Hub) is minimal. Prices at Transco Zone 4 and Henry Hub in the GLNG Exports Case remain below $6.00 per MMBtu through 2031 and 2032, respectively. The average price increase versus the Base Case over the term of the forecast is $0.28 per MMBtu for Henry Hub, and $0.29 per MMBtu for Transco Zone 4 versus average Base Case prices over the term of $5.23 and $5.37, respectively, or 5.4%. As another point of reference, the GLNG Exports Case price forecast at Henry Hub is actually below the EIA's Annual Energy Outlook 2012 Reference Case forecast that includes no LNG exports of domestically produced natural gas, averaging $5.51 per MMBtu versus $5.98 per MMBtu over the study period.

When compared to the average overall residential retail rate, the 29 cents represents an even smaller percentage because of the additional costs to consumers from the distribution utility for pipeline, storage, and distribution system costs, as well as the utility rate of return. For example, a consumer in Mississippi pays an additional $2.73 per MMBtu on top of the cost of gas for natural gas service, so the 29 cents actually translates to only 3.6% of an average total cost of $8.10per MMBtu.

Aggregate Exports Case

The **Aggregate Exports Case** builds on the GLNG Exports Case. In the Aggregate Exports Case, other U.S. LNG exports are assumed in addition to Sabine Pass, Kitimat, and GLNG. This includes an additional 1.0 Bcfd each of LNG export capacity in the Gulf of Mexico and on the U.S. West Coast, and 0.5 Bcfd on the U.S. East Coast, for a total generic export capacity of 2.5 Bcfd. Several such LNG export facilities have been proposed, and more may be. Therefore, Navigant makes no judgment as to which specific ones will be approved and ready to operate by the start-up date of GLNG, and models these export volumes generically. The addition of 2.5 Bcfd of LNG export capacity in addition to Kitimat, Sabine Pass, and GLNG stimulates supply production in the U.S.

The forecast projects that prices at Henry Hub in the Aggregate Exports Case remain below $5.00 per MMBtu through 2021, near or below $6.00 per MMBtu through 2032, and just exceed $7.00 per MMBtu in 2035, at $7.04. Incremental increases at Henry Hub versus the GLNG Exports Case average about $0.12 over the study period, or about 2.2%. Prices at Transco Zone 4 in the Aggregate Exports Case remain near or below $5.00 per MMBtu through 2020, near or below $6.00 per MMBtu through 2031, and exceed $7.00 per MMBtu only in 2035, at $7.22. Incremental increases at Transco Zone 4 versus the GLNG Exports Case average about $0.13 over the study period, or about 2.3%.

Analysis One

Year	Metric	Base Case	GLNG Exports Case	Aggregate Exports Case
2012	*Henry Hub*	$2.55	$2.55	$2.55
	Transco Zone 4	$2.64	$2.64	$2.64
2019	*Henry Hub*	$4.45	$4.69	$4.86
	Transco Zone 4	$4.57	$4.82	$4.99
2025	*Henry Hub*	$5.00	$5.27	$5.39
	Transco Zone 4	$5.13	$5.42	$5.54
2035	*Henry Hub*	$6.45	$6.86	$7.04
	Transco Zone 4	$6.62	$7.04	$7.22

ANALYSIS TWO

Analysis Two represents an alternative, high-demand view of the future, driven by higher levels of assumed usage of natural gas vehicles as well as higher levels of U.S. LNG exports. The two cases in Analysis Two are developed to test the impacts of GLNG's Project on higher demand scenarios:

High Demand Base Case

The **High Demand Base Case** represents an alternative scenario to the Base Case in order to reflect the more aggressive assumptions for natural gas vehicle (NGV) phase-in used by the EIA in its AEO 2010 high case for heavy duty NGVs, as well as the addition of the generic LNG export facilities from the Aggregate Exports Case from the previous analysis. It is Navigant's view that, at this time, aggressive assumptions regarding the future of use of natural gas do not need to include future regulations on greenhouse gas emissions since legislation restricting greenhouse gas emissions is currently stalling. A related setback is a U.S. appeals court decision on August 21, 2012 overturning a proposed rule to reduce harmful emissions from coal-burning power plants.[3] The additional natural gas demand for NGVs in the High Demand Base Case gradually ramps up, starting in 2015, to 4.2 Bcfd in 2035. With respect to the LNG export capacity, the High Demand Base Case includes the two Base Case facilities, Sabine Pass LNG modeled at 2.2 Bcfd and Kitimat LNG modeled at 1.5 Bcfd. By adding the 2.5 Bcfd of generic LNG export additions presented in the Aggregate Exports Case, the total becomes 6.2 Bcfd of North American LNG export capacity.

The forecast projects that prices at Henry Hub remain near or below $5.00 per MMBtu through 2023. After 2023, prices rise more due to generally increasing marginal costs of additional domestic production. Henry Hub reaches $7.48 per MMBtu in 2035. Prices at Transco Zone 4 show a small positive basis to Henry Hub, averaging about $0.15 per MMBtu, throughout the forecast period.

High Demand Base Case Plus GLNG @ 1.5 Bcfd

The **High Demand Base Case Plus GLNG @ 1.5 Bcfd** tests the effects of exporting LNG from the 1.5 Bcfd capacity GLNG export facility against the High Demand Base Case. All other inputs and assumptions remain the same as in the High Demand Base Case.

The effects of GLNG exports in Analysis Two, incorporating the alternative High Demand Base Case, which includes natural gas vehicle (NGV) demand, are minimal at both Transco Zone 4 and Henry Hub, similar to the Analysis One results. The forecast projects that prices at Transco Zone 4 and Henry Hub in the High Demand Base Case Plus GLNG @ 1.5 Bcfd remain near or below $6.00 per MMBtu through 2025 and 2026, respectively, and below $7.00 per MMBtu through 2032. The average price increase versus the High Demand Base Case over the term of the forecast is $0.38 per MMBtu for Henry Hub, and $0.39 per MMBtu for

[3] The U.S. Court of Appeals for the D.C. Circuit vacated the EPA's Cross-State Air Pollution Rule on August 21, 2012 in Docket No. 11-1302.

Transco Zone 4 versus average High Demand Base Case prices over the term of $5.77 and $5.92, respectively, or 6.7%.

Analysis Two			
Year	**Metric**	**High Demand Base Case**	**High Demand Base Case Plus GLNG @ 1.5 Bcfd**
2012	*Henry Hub*	$2.55	$2.55
	Transco Zone 4	$2.64	$2.64
2019	*Henry Hub*	$4.62	$4.92
	Transco Zone 4	$4.74	$5.06
2025	*Henry Hub*	$5.40	$5.81
	Transco Zone 4	$5.54	$5.97
2035	*Henry Hub*	$7.48	$7.85
	Transco Zone 4	$7.67	$8.06

While Navigant believes that the demand levels in the two High Demand cases are at the higher end of what may likely develop in the market, it is nevertheless interesting to note that the absolute price levels in the highest demand case (including GLNG) are still below $7.00 per MMBtu for all but the last three years of the forecast, and they exceed $8.00 per MMBtu only in 2035 at Transco Zone 4, at $8.06.

Several facts support Navigant's findings of a minimal impact by GLNG exports at Transco Zone 4 and Henry Hub prices and on the national market:

- Current dry gas production in the U.S. is up over 30% since 2005, from about 49.5 Bcfd for 2005 to more than 65 Bcfd during 2012.

    Note: Navigant furthermore projects U.S. dry gas production alone (excluding Canada) to grow an additional 28% to 83.2 Bcfd by 2035 in the Base Case. Production could go higher in response to demand from proposed LNG liquefaction facilities and/or independent increases in the robust supply resource base.

- The EIA's estimate in its Annual Energy Outlook 2012 of dry natural gas resources in the United States is 2,203Tcf.[4] This is more than 90 years of supply at 2011 usage rates of approximately 24 Tcf per year. The EIA's recoverable resource estimate of 2,203 Tcf (as of 2010) is virtually the same as Navigant's 2008 estimate after adjustment downward to account for two years of production (2,207 Tcf, down from 2,247 Tcf). Even at Navigant's projected 2035 rate of consumption of 83.5 Bcfd (30.5 Tcf per year), this represents more than 72 years of supply. (The difference between U.S. demand of 83.5 Bcfd and U.S. production of 83.2 Bcfd is made up primarily by pipeline imports from Canada, net of a small amount of LNG exports.)

[4] Assumptions to the Annual Energy Outlook 2012, Table 9.2 (June 2012).

- The size of the potential recoverable shale gas resource is substantial. Estimates made in 2011 by Rice University, Massachusetts Institute of Technology, and the Potential Gas Committee put the U.S. recoverable shale gas resource (mean estimates) at 521 Tcf, 650 Tcf, and 687 Tcf, respectively. These estimates all exceed EIA's most recent estimate of 482 Tcf. [5] Most recently, the International Energy Agency's May 2012 Special Report on unconventional gas put remaining recoverable shale gas resources in the U.S. at 24 Tcm, or 840 Tcf, more than the EIA's superceded AEO 2011 value.[6] Navigant's 2008 estimate of technically recoverable shale gas resources ranged from a mean assessment of 274 Tcf to a "maximum" assessment, based on producer information, of 842 Tcf. Thus, while the EIA's Reference Case (its "baseline") shale gas resource estimate is arguably low, it still exceeds the conservative mean estimate from Navigant's original study.

- New shale discoveries have regularly been identified. For example, several plays now appear on the 2011 version of the EIA map that did not appear on the 2010 version, including the Niobrara, Heath, Tuscaloosa, Excello-Mulky, and Monterey in California. The areal extent of others, notably the Eagle Ford, has enlarged significantly. As future shale development proceeds and more data becomes available, production potential is often revised upward. For example, Dr. Terry Engelder of Penn State University estimated the recoverable shale gas for the Marcellus shale play at 50 Tcf in May 2008, but came out with a revised estimate at 489 Tcf in August 2009 as additional data became available. At the March 2012 Penn State University workshop to reconcile the various EIA resource estimates, Dr. Engelder maintained his Marcellus estimate at the 489 Tcf,, and two consulting companies put forth Marcellus resource estimates with midpoints at 400 Tcf and 579 Tcf,[7] much more in line with EIA's AEO 2011 Marcellus estimate of 410 Tcf than its reduced estimate of 141 Tcf in AEO 2012.

- As there is an integrated North American natural gas market, it is also important to note the ample size of the estimates of various Canadian natural gas resources. For example, estimates of recoverable natural gas for the three major shale gas plays in British Columbia range from about 200 Tcf to about 500 Tcf, while additional Canadian unconventional natural

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[5] In EIA's Annual Energy Outlook (AEO) 2012, in both the Early Release and the Final Release, the Reference Case estimate of unproven shale gas resources was lowered to 482 Tcf from the AEO 2011 estimate of 827 Tcf; even after this decrease, at current consumption levels this amounts to more than 19 years of gas supply. This lowered estimate is a matter of considerable controversy and concern expressed by industry and other experts in the Marcellus shale, for which the EIA's estimate was reduced from 410 Tcf to 141 Tcf. It has spawned at least one recent workshop at Penn State University, on March 19, 2012, to attempt to reconcile EIA figures with those of the United States Geological Survey. See also "The EIA-USGS Gas Resource Revisions—What Do They Mean?", NG Market Notes, March 2012, R. Smead, Navigant Consulting (http://media.navigantconsulting.com/emarketing/Documents/Energy/NG_Notes_Mar2012.pdf)

[6] "Golden Rules for a Golden Age of Gas", International Energy Agency, Special Report, May 29, 2012, Table 3.1. The IEA also noted, with respect to the EIA's AEO 2012 shale gas resource estimate reduction, that "[s]trictly speaking, the USGS and US EIA numbers cannot be compared as USGS reports undiscovered gas resources while US EIA reports total recoverable resources, which differ from undiscovered by proven resources and discovered-but-undeveloped resources". See id. at footnote 5.

[7] "New Figures on Shale Gas Optimistic", Pittsburg Tribune-Review, March 20, 2012, referring to IHS and ICF presentations (http://www.pittsburghlive.com/x/pittsburghtrib/news/s_787326.html).

gas resources include several other shale gas, tight gas, and coal-bed methane plays estimated at about 275 Tcf of recoverable natural gas.

- Because of the manufacturing-type profile of shale gas production, production rates can be better matched to demand growth. The certainty of production allows shale gas to be managed in response to demand. If demand is growing, additional zones and/or shale wells can be drilled and fractured to meet that demand and to mitigate the initial production or IP decline rates from earlier wells. If demand subsides, drilling rates can be reduced or discontinued completely in response to the negative market signal.

In all scenarios Navigant prepared for GLNG in this analysis, natural gas maintains its steep discount to the price of crude oil on a heating value equivalent basis. In 2035, Navigant forecasts the price of West Texas Intermediate crude oil to be $173 per barrel, which is equivalent to $29.83 per MMBtu. Even in the High Demand Base Case Plus GLNG @ 1.5 Bcfd (resulting in the highest modeled gas prices), gas prices only attain $7.85 per MMBtu in the national market at Henry Hub and $8.06 per MMBtu in the regional Southeast market closest to the GLNG export project, both in 2035. The price comparison of natural gas to oil is important to the longer term competitiveness of natural gas in North America. Unlike in the global market, North American gas and oil prices are disconnected from each other, allowing for the relatively cheaper fuel to displace the relatively more expensive fuel, at least in markets where gas and oil are alternate energy sources – like in some regional residential and commercial heating markets and some parts of the industrial market.

Conclusion

As noted above, Navigant has found the estimated price impacts of GLNG exports to be minimal, in either the Base Case or High Demand Base Case analyses. Results are summarized below.

Analysis One

Year	Metric	Base Case	GLNG Exports Case	Aggregate Exports Case
2012	*Henry Hub*	$2.55	$2.55	$2.55
	Transco Zone 4	$2.64	$2.64	$2.64
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	Transco Zone 4	$4.57	$4.82	$4.99
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2035	*Henry Hub*	$6.45	$6.86	$7.04
	Transco Zone 4	$6.62	$7.04	$7.22

Analysis Two			
Year	**Metric**	**High Demand Base Case**	**High Demand Base Case Plus GLNG @ 1.5 Bcfd**
2012	*Henry Hub*	$2.55	$2.55
	Transco Zone 4	$2.64	$2.64
2019	*Henry Hub*	$4.62	$4.92
	Transco Zone 4	$4.74	$5.06
2025	*Henry Hub*	$5.40	$5.81
	Transco Zone 4	$5.54	$5.97
2035	*Henry Hub*	$7.48	$7.85
	Transco Zone 4	$7.67	$8.06

Navigant's market view is that domestic supply is abundant to such a degree that it will support domestic market requirements as well as export demand for LNG shipped from North America. LNG exports offer the potential for a steady, reliable baseload market which will serve to underpin ongoing supply development. The existence of growing domestic and export demand will also tend to support additional supply development and as a result tend to reduce price volatility.

Additionally, key industrial sectors that require natural gas feedstocks, such as the petrochemical industry, will find that enhanced stability of the natural gas market will favor capital investment decisions for plant and equipment, leading to increases in economic activity. Similarly, potential conversions of industrial processes from electric power to natural gas would be enhanced by stable natural gas supply and prices. Such conversions would effectively substitute natural gas usage for some coal-fired power generation, leading to greenhouse gas reductions.

Supply Outlook to 2035

Overall natural gas supply growth in the U.S. continues to be remarkable. Due to the vast size of the shale gas resource and the high reliability of shale gas production, natural gas supply can be effectively managed to be synchronized with demand, even as natural gas demand grows. This is predominantly attributable to the presence of prolific supplies of unconventional gas which can now be produced economically. Unconventional gas includes shale gas, tight sands gas, coalbed methane, and gas produced in association with shale oil. The ramping rates of gas shale production growth has been the biggest contributor to overall gas supply growth over the last several years.

Before the advent of significant shale gas production, the U.S. natural gas industry's history reflected periods of "boom and bust" cycles. Investment in both production and usage seesawed on the market's perception of future prices. That perception was driven in part by uncertainty and risk around the exploration process of finding and developing gas supply to meet demand, both for the short and long term. Due to the uncertainty of the exploration process (and at times the limited availability of capital to fund such discovery), gas supply suffered from periods where it was "out of phase" with demand for natural gas by gas-fired electric generating facilities and other users on the demand side, causing prices to rise and fall dramatically. This in itself caused other, second-tier ramifications impacting the investment cycle for supply. For example, the pipeline infrastructure that is required to connect supply and demand is another large-scale investment that at times has suffered from underutilization or has become a bottleneck, as a result of the second order effects of uncoordinated cycles of supply and demand investment.

These factors all contribute to natural gas price volatility, or the upward and downward swinging of prices in the short and even medium-term, as opposed to longer-term price movements that would more accurately be called trends. The volatility itself affects investment decisions, amplifying the feedback loop of uncertainty. In the end, price volatility has been a major cause of limits on the more robust expansion of natural gas as a fuel supply source, despite its advantages over other energy forms as an environmentally clean, abundant and affordable energy resource. The dependability of shale gas production as a result of its abundance, as well as its reduced exploration risk as compared to conventional gas resources, has the potential to improve the alignment between supply and demand, which will in turn tend to lower price volatility. Thus, the vast shale gas resource not only has the potential to support a larger demand level than what has heretofore been seen in North America, but at prices that are less volatile.

Navigant expects gas production to continue to grow steadily throughout the forecast period. Our forecast for production, based on the Base Case, is shown in Figure 1. Navigant projects that North American production will be 106.1 Bcfd by the year 2035 (net LNG imports are too small to appear on the chart). By that year, U.S. production alone is projected to be 83.2 Bcfd, as shown in Figure 2 (LNG imports and exports are too small to appear on the chart).

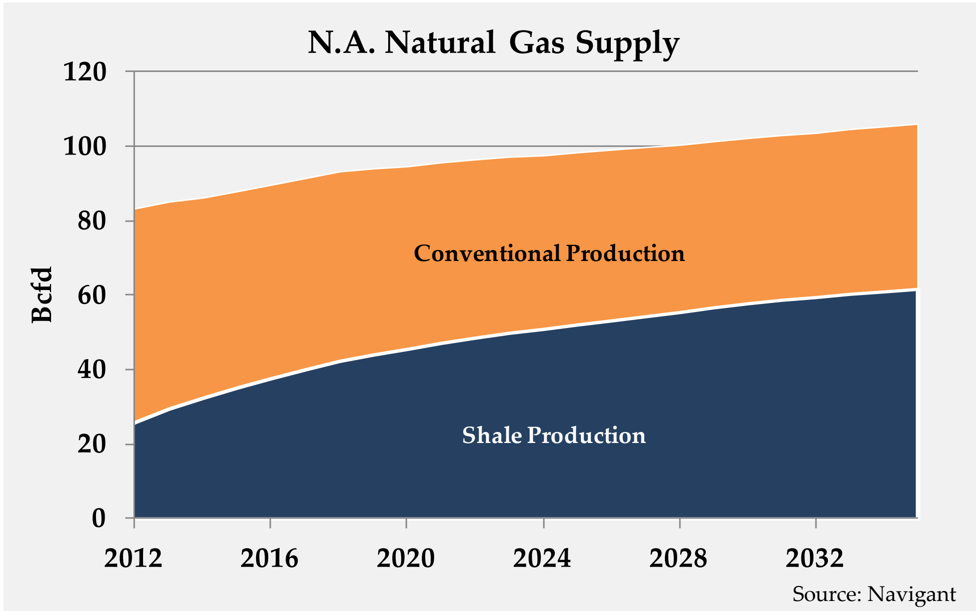

Figure 1: North American Natural Gas Supply Projection

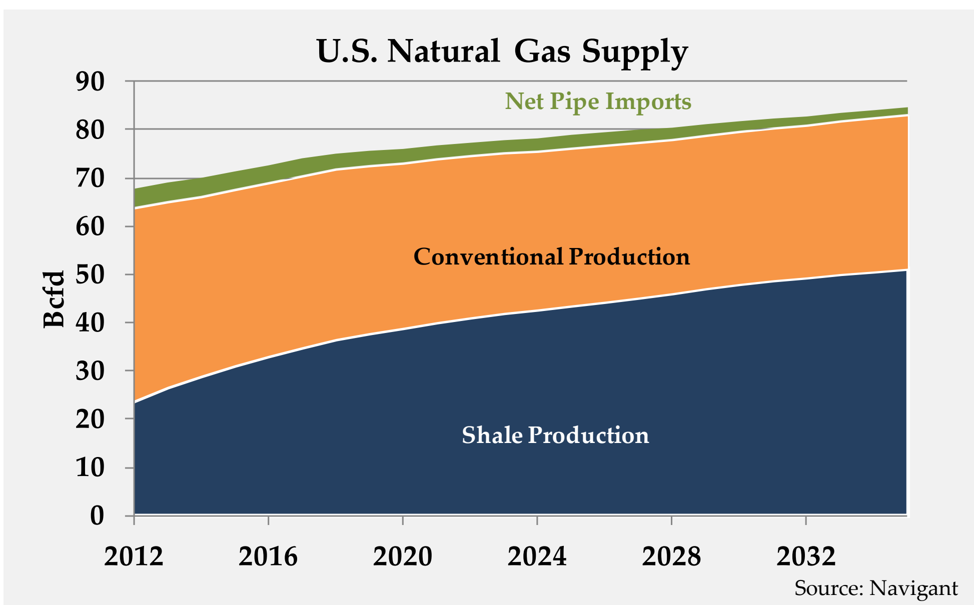

Figure 2: U.S. Natural Gas Supply Projection

The majority of production growth is likely to be driven by unconventional gas development, as opposed to conventional gas, which has been in decline. For example, plans to develop large known deposits of conventional frontier gas, such as the Mackenzie Valley Pipeline Project in Arctic Canada and the Alaska Pipeline Project, have been put in jeopardy due not to any change in the resource itself but to the high costs of those projects relative to unconventional resource development opportunities closer to markets. In Navigant's modeling for GLNG, neither the Mackenzie Valley

Pipeline Project nor the Alaska Pipeline Project is forecasted to be on-stream during the term of our analysis (to 2035). We note that the Alaska Pipeline Project parties and the State of Alaska have agreed on a revised project plan focused on a pipeline that delivers gas from Alaska's North Slope to the south coast of the state where it could be liquefied into LNG instead of connecting the pipeline to the larger North American grid in Canada.[8] (A portion of the flow would be used to meet the needs of the City of Anchorage). In addition, the partners in the Mackenzie Valley Pipeline Project recently announced the decision to suspend funding of the project due to a continued decline of market conditions.[9] It should be noted, however, that while undeveloped frontier sources are not being modeled by Navigant in our current forecasts, the resources themselves obviously will continue to exist and could become available supplies in the future whenever the economics of supply and demand deem their development feasible.

While conventional natural gas supplies are not forecasted to be increasing, in the regional markets closest to the GLNG export project conventional supplies have been and will continue to be important. In the Texas/Louisiana area, for example, Navigant estimates conventional natural gas made up almost 52% of regional production in 2011, and is forecasted in the Base Case to still make up 25% of total production in 2035, figures that don't even reflect the large conventional production in the Outer Continental Shelf in the Gulf of Mexico, which itself amounted to over 5 Bcfd of production in 2011, and is connected directly to the transmission pipelines serving GLNG.

Factors Underpinning the Forecasted Increase in Gas Supply

In 2008, Navigant first identified the rapidly expanding development of natural gas from shale. While geologists and natural gas production companies had been aware of shale gas resources for years, such resources had been uneconomic to recover. The advent of the ability to effectively develop the shale gas resource more fully as described below is the driving factor behind today's robust outlook for the natural gas market.

Improvements in Hydraulic Fracturing and Horizontal Drilling

Natural gas prices increased substantially in the first decade of this century, culminating in significantly higher prices in 2007-2008, as shown in Figure 3. These increasing prices induced a boom in LNG import facility construction in the late 1990s and 2000s, which was very conspicuous due to the size of the facilities. As late as 2008, conventional wisdom held that North American gas production would have to be supplemented increasingly by imported LNG owing to domestic North American supply resource decline.

Far less conspicuously, high prices also supported the development of horizontal drilling and hydraulic fracturing, existing technologies which were combined together and continually improved, yielding dramatically increased production, reduced costs, and improved finding and development economics of the industry. In mid-2008, when Navigant released its groundbreaking natural gas report,[10] domestic gas production from shale began to overtake imported LNG as the new gas supply

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[8] March 30, 2012 press release by Alaska Gov. Sean Parnell.

[9] April 5, 2012 press release by ConocoPhillips.

[10] North American Natural Gas Supply Assessment, prepared for the American Clean Skies Foundation, July 4, 2008, available at http://www.navigant.com/~/media/Site/Insights/Energy/NCI_Natural_Gas_Resource_Report.ashx

of choice in North America. The evolution of the cost-effective technologies brought together was the key to unlocking the potential of the gas shale resource.

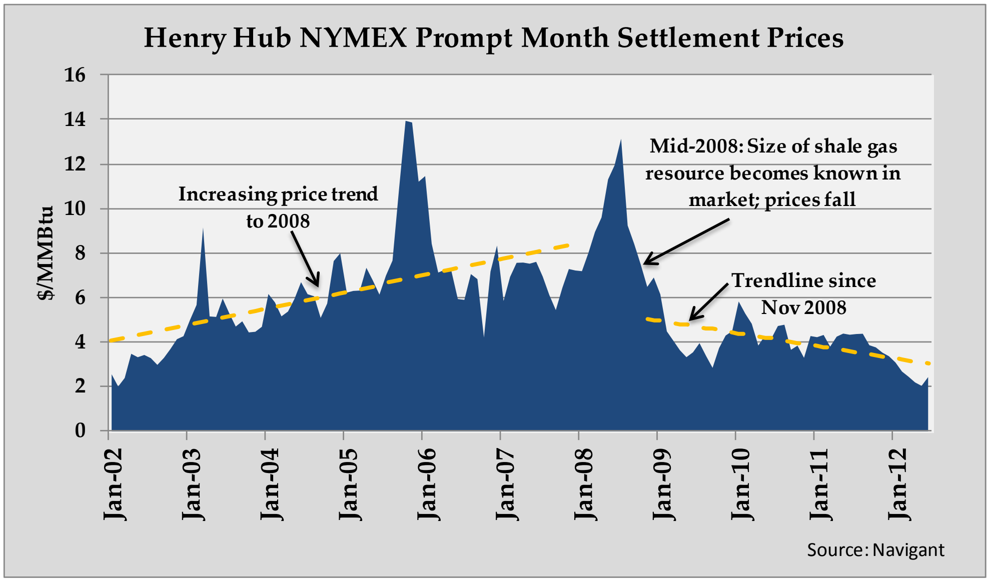

Figure 3: Henry Hub Price History

Shale gas production efficiency has continued to improve over time. In many locations, 10 wells can be drilled on the same pad. The lengths of horizontal runs, once limited to several hundred feet, can now reach up to 10,000 feet. The number of fracture zones reportedly has increased from four to up to 24 in some instances.

Improvements continue in other aspects of hydraulic fracturing technology. Much attention is being focused on water usage and disposal. Numerous states, including Arkansas, Colorado, Idaho, Montana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, West Virginia and Wyoming have passed legislation that requires the contents of chemicals used in the hydraulic fracturing process to be disclosed.[11] The U.S. Environmental Protection Agency is investigating the potential impacts of hydraulic fracturing on drinking water resources, with a report of initial results due by the end of 2012. Range Resources pioneered the use of recycled flowback water, and by October 2009 was successfully recycling 100% in its core operating area in southwestern Pennsylvania. Range shared its knowledge with the Marcellus Shale Coalition, and by the following year 60% of water used by Marcellus shale operators was recycled, saving significant amounts of money by reducing the need for treatment, trucking, sourcing, and disposal activities.[12] Water quality and water recycling continues to be a prime topic, with Texas recently permitting a mobile recycling system technology,[13] and Pennsylvania recently revising its liquid waste "general permit" to establish alternative, higher water quality criteria that would allow processed water to be managed, stored and transported as freshwater,[14] which should incentivize additional processing of flowback water. Additional reductions in water usage are being achieved through the use of liquefied petroleum gas

[11] According to Fracfocus.org website.
[12] "Citizen Range", Oil & Gas Investor, August 2010.
[13] March 26, 2012 press release, Water Rescue Services Holdings, LLC.
[14] March 21, 2012 press release, Pennsylvania Department of Environmental Protection.

(LPG) fracking,[15] and may also result from the proposed use of coal mine drainage for hydrofracking in specific areas where coal mines are near gas shale resources.[16]

These efforts to continue to improve water management will tend to enhance the ability of shale operations to expand, as noted in the IEA's Special Report on unconventional gas entitled "Golden Rules for a Golden Age of Gas." There are two main premises of the IEA report: 1) that increasing the public acceptance of shale gas through application of environmentally responsible practices will lead to large increases in the overall size of the gas market, and 2) that the cost of applying such practices in large-scale development projects can actually lead to net cost savings as a result of efficiency savings from economies of scale and more optimally directed hydraulic fracturing.[17]

Size of the Shale Gas Resource

U.S.

The geographic scope of the U.S.'s shale gas resource can be seen in the map from the Energy Information Administration, shown in Figure 4. In Navigant's study on the subject of emerging North American shale gas resources released in 2008, we estimated the maximum recoverable reserves from shale in the U.S. to be 842 trillion cubic feet (Tcf), boosting the maximum recoverable reserves for all of the U.S. to 2,247 Tcf.[18] This is sufficient to satisfy U.S. current annual demand of approximately 24 Tcf per year for 92 years. Despite lowering its shale gas resource estimate in its *Annual Energy Outlook* 2012 to 482 Tcf (which, as previously mentioned, is a matter of some controversy between the EIA, USGS, and other experts), the EIA's estimate of *total* dry natural gas resources in the United States at 2,203 Tcf, more than 90 years of supply at current usage rates.

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[15] According to GasFrac Energy Services, Inc., its LPG fracking technology has been used successfully for several years, and eliminates both freshwater requirements and disposal issues for hydrofracking waste water by substituting LPG as the frac fluid. Investor presentation, March 2012.

[16] A Pennsylvania Senate committee has approved draft legislation to encourage the use of coal mine water in hydrofracking by offering liability protection to drillers. According to its sponsor, the bill will not only conserve freshwater sources, but also help in cleaning up acid mine drainage. Thedailyreview.com, May 30, 2012.

[17] IEA Special Report, supra note 6, at pp. 10, 60.

[18] *North American Natural Gas Supply Assessment*, note 10, supra.

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Figure 4: EIA North American Shale Play Map (2011)

In 2011, the Potential Gas Committee of the Colorado School of Mines released its latest estimate for the potentially recoverable natural gas resource in North America at 1,898 Tcf, for a total U.S. gas supply figure of 2,170 Tcf after inclusion of the EIA's most recent dry natural gas proved reserves estimate of 273 Tcf;[19] the 2,170 Tcf supply estimate represents an increase of 89 Tcf over their previous evaluation. In total, this is enough to supply domestic needs at 2011 usage rates for 89 years. Of the potential gas resource, 687 Tcf, or 36%, is shale gas.[20] In the final version of its June 2011 study ***The Future of Natural Gas***, the Massachusetts Institute of Technology stated that "The mean projection of the recoverable shale gas resource [in the U.S., excluding Canada] is approximately 650 Tcf . . . . approximately 400 Tcf [of which] could be economically developed with a natural gas price at or below $6 per MMBtu at the well-head."[21] In May 2011 materials summarizing its World Gas Trade Model, Rice University's James A. Baker III Institute for Public Policy cited its estimated of total U.S.

[19] EIA data, dry natural gas proved reserves (as of 1/1/2010), see Assumptions to the AEO 2012, June 2012; total supply is the sum of potential resources and proved reserves.

[20] April 27, 2011 press release by Potential Gas Committee, http://potentialgas.org/

[21] Massachusetts Institute of Technology, *The Future of Natural Gas*, Ernest J. Moniz, et al, Chapter 1, p. 7, http://web.mit.edu/mitei/research/studies/naturalgas.html

shale gas technically recoverable resource (mean estimate) as 521 Tcf. [22] In the International Energy Agency 2012 Special Report on shale gas, it placed an estimate of 24 Tcm on remaining recoverable shale gas resources in the U.S. This figure converts to 840 Tcf, more than the 827 Tcf figure from the AEO 2011 that the EIA had already reduced to 482 Tcf in its AEO 2012 Early Release.[23] In any event, as the EIA has noted, "[a]lthough the Marcellus shale resource estimate will be updated for every AEO, revisions will not necessarily have a significant impact on projected natural gas production, consumption, or prices."[24]

New shale resource plays are still being discovered. For example, several plays now appear in the 2011 analysis by the EIA that did not appear in similar analysis in 2010. These include the Niobrara, Heath, Tuscaloosa, Excello-Mulky, and Monterey. The areal extent of others, notably the Eagle Ford, has enlarged significantly. North America appears to be in the early phases of discovery for the resource.

The Marcellus Shale formation in central Appalachia is notable in any discussion of the North American gas resource base. The Marcellus was not well known in 2007. Dr. Terry Engelder, a Professor of Geosciences at The Pennsylvania State University and one of the leading scientists in the study of the Marcellus, estimated in 2009 that the Marcellus has a 50% chance of containing 489 Tcf of recoverable gas, following his 2008 estimate at 50 Tcf. [25] Such upward revisions have become the norm as development proceeds in a play and additional data becomes available, notwithstanding the reduction in EIA's AEO 2012 Marcellus resource estimate from 410 Tcf to 141 Tcf. Another example of this process is the USGS raising its estimate of undiscovered technically recoverable shale gas resources in the Marcellus play from 2 Tcf to 84 Tcf. In 2011, the entire United States used about 24 Tcf per year, or less than 5% of Dr. Engelder's estimate of the Marcellus's potential production.[26] Other recent estimates for the Marcellus resource include studies by consulting companies IHS (midpoint estimate at 400 Tcf), and ICF (midpoint estimate of 579 Tcf).[27]

To illustrate the size of the shale gas resource across the U.S., its rapid development, and increasing efficiency, consider the following: U.S. total natural gas production increased from about 50.2 Bcfd in May 2006 to about 64.7 Bcfd in May 2012, even as overall rig counts fell from about 1380 to 595. This is an increase in gas production of 29% in six years. The increase in overall gas production has been driven by shale gas, as evidenced by the increase in horizontal drill rig counts despite the decrease in vertical (conventional) rig counts. See Figure 5 and Figure 6.

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[22] T*he Rice World Gas Trade Model: Development of a Reference Case*, Kenneth B. Medlock III, James A Baker III Institute for Public Policy, Rice University, May 9, 2011, slide 17.

[23] See note 5, supra.

[24] Annual Energy Outlook, EIA, June 2012, p. 64.

[25] Basin Oil & Gas magazine, August 2009, p. 22, available at http://www.geosc.psu.edu/~engelder/references/link155.pdf

[26] EIA, Natural Gas Consumption by End Use, annual table, release date 5/31/2011, available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[27] "New Figures on Shale Gas Optimistic", Pittsburg Tribune-Review, March 20, 2012 (http://www.pittsburghlive.com/x/pittsburghtrib/news/s_787326.html).

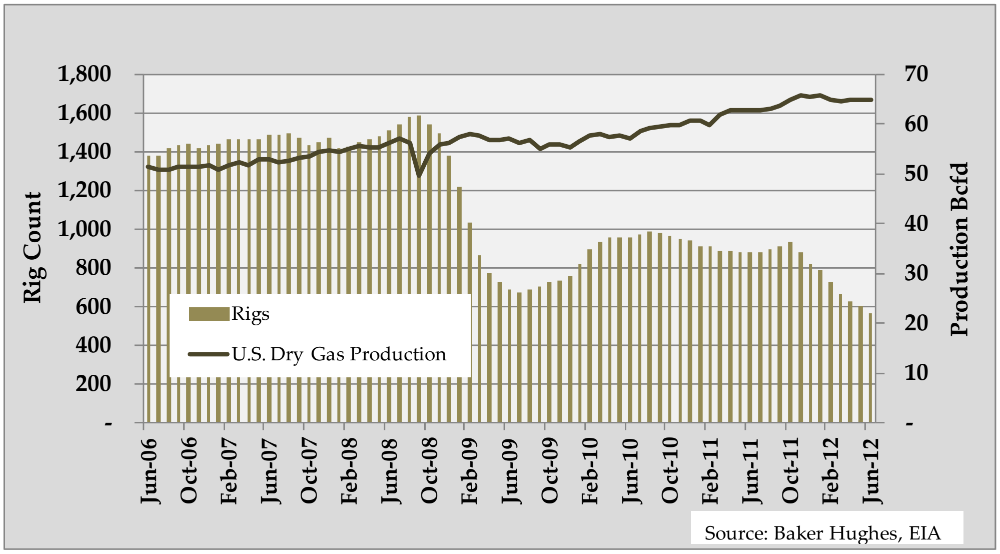

Figure 5: U.S. Gas Production and Rig Count History

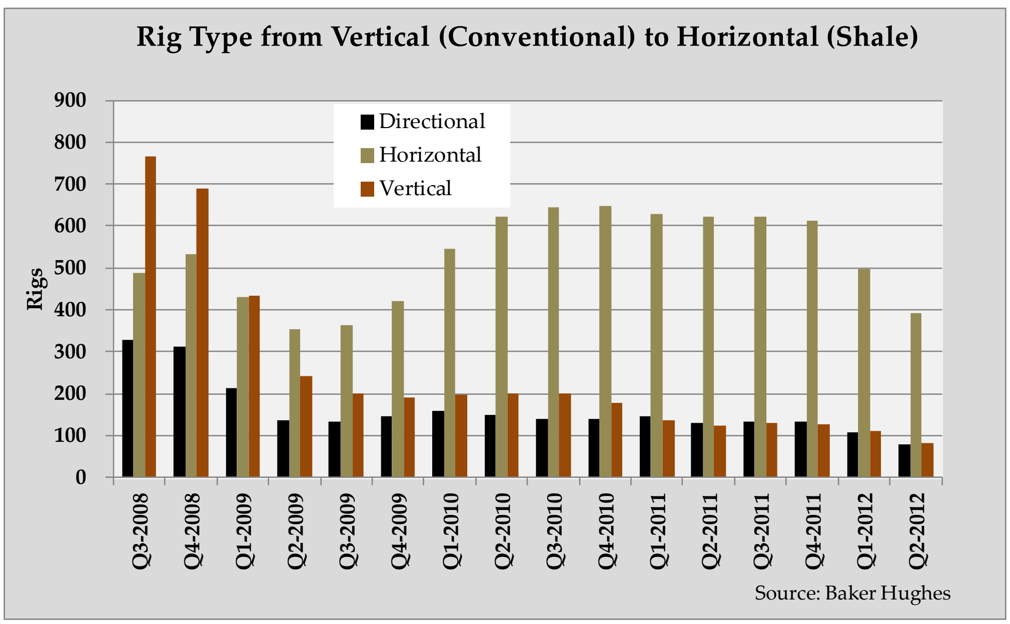

Figure 6: U.S. Gas Rig Type Shift

The growth in shale gas production has been prolific, as shown in the graph in Figure 7. Total shale gas output, on a dry basis, from the six major basins under development in the U.S. plus "other shale" grew from 4.3 Bcfd in May 2007 to 25.3 Bcfd in May 2012, an increase of more than 485% in five years. As can also be seen in Figure 8, each new shale play shows strong ramp-up, reflective of shale gas being a relatively new resource in the early stages of development, with a steady accumulation of actively producing wells as additional drilling occurs. An example of expectations for such increasing production trends are two recent studies by Penn State University; the first, from 2010, estimates that production from the Marcellus could grow from 500 MMcfd at the end of 2009 to

13.5 Bcfd by 2020,[28] and then the second study, from 2011, estimates that Marcellus production could increase from 2 Bcfd in 2010 to 17.5 Bcfd in 2020.[29]

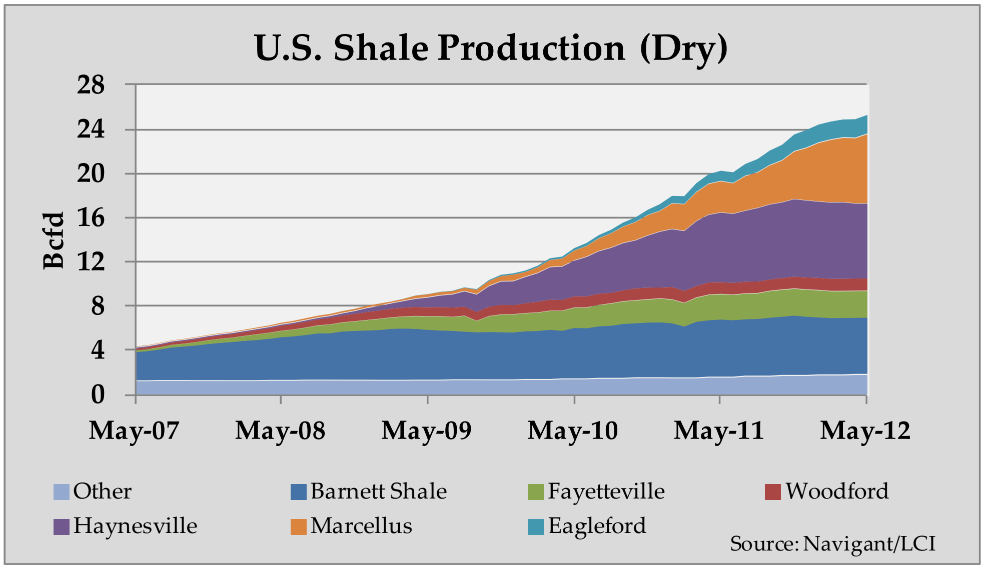

Figure 7: U.S. Shale Production (Dry) 2007-2012

Canada

Before outlining the specifics of the Canadian natural gas resource base, it is instructive to note the clearly stated policy of the Province of British Columbia in favor of accelerated development of its natural gas resources. In its Natural Gas Strategy document, as well as a complementary LNG strategy, both released in February 2012 as part of the overall Province Jobs Plan, the Province presented its goals of building three LNG export facilities by 2020, and estimated an accompanying increase in gas production from the current level of 1.2 Tcf per year to over 3 Tcf per year in 2020. Further, the Province's strategy includes the diversification of its gas markets, including development of supplies to meet new gas demand in North America.[30] This proactive support of the provincial government is a good indicator of the likely ultimate development of shale gas resources in Canada, and can be viewed as a potential beneficial scenario for U.S. shale gas development if it receives similar policy support.

Currently, the three major Canadian shale gas plays are the Horn River Basin, the Montney, and the Cordova Embayment, primarily in northeastern British Columbia. Recent estimates of marketable/recoverable natural gas in these plays total between 213 Tcf and 491 Tcf, a range from about 43% up to a full 100% of the Dr. Engelder's estimate of recoverable natural gas in the Marcellus,

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[28] *The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update*, Considine, Watson and Blumsack, Penn State University, May 24, 2010, p. 18-19, available at http://www.energyindepth.org/wp-content/uploads/2009/03/PSU-Marcellus-Updated-Economic-Impact.pdf.

[29] *The Pennsylvania Marcellus Natural Gas Industry: Status, Economic Impacts and Future Potential*, Considine, Watson, and Blumsack, Penn State University, July 20, 2011, Figure 15.

[30] In fact, the government announced on June 21, 2012 that it intends to reclassify natural gas used to generate electricity to power LNG export facilities as a "clean energy source" that would count towards meeting renewable energy standards and help facilitate LNG exports.

the most significant U.S. play.[31] Canada also has significant additional unconventional gas resources, including gas-in-place estimates of 500 Tcf for WCSB coal-bed methane,[32] 530 Tcf for Alberta Deep Basin tight gas,[33] 100 Tcf for the Colorado shale formation in the WCSB, 120 Tcf for the Utica shale formation in Quebec, and 130 Tcf for the Horton Bluff shale formation in the Maritimes; at a 20% recoverable gas rate, these resources would represent an additional 275 Tcf of recoverable natural gas.[34]

As indicated by the above, there is little doubt that the shale gas resource in North America is extremely large. It is Navigant's view that the size of the shale gas resource in North America is more than adequate to serve all forecast domestic demand through the study period to 2035 as well as the demand added by GLNG's proposed liquefaction facilities at Pascagoula. It has also been our finding that the price impact of such increased demand is not significant, as we show following in our findings based on results of our market modeling assessment.

Character of the Shale Gas Resource

The shale gas resource has a generally lower-risk profile when compared to conventional gas supply that reinforces its future growth potential. Finding economically producible amounts of conventional gas has historically been expensive due largely to geologic risk. Conventional gas is usually trapped in porous rock formations, typically sandstone, under an impermeable layer of cap rock, and is produced by drilling through the cap into the porous formation, to produce the gas. Despite advances in technology, finding and producing conventional gas involves a significant degree of geologic risk, with the possibility that a well will be a dry hole or will produce at very low volumes that do not allow the well to be economic.

In unconventional shale gas, exploration risk is significantly reduced. Resource plays have become much more certain to be produced in commercial quantities. The reliability of discovery and production has led shale gas development to be likened more to a manufacturing process rather than an exploration process with its attendant risk. This ability to control the production of gas by managing the drilling and production process potentially allows supplies to be produced in concert with market demand requirements and economic circumstances.

Gas in a shale formation is contained in the rock itself. It does not accumulate in pockets under cap rock, but tends to be distributed in relatively consistent quantities over great volumes of the shale. The most advanced gas shale drilling techniques allow a single well-pad to be used to drill multiple horizontal wells up to two miles in length into a given formation, with each bore producing gas.

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[31] *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, May 2011, British Columbia Ministry of Energy and Mines and the National Energy Board, p. 11, estimating Horn River at 78 Tcf; T*he Rice World Gas Trade Model: Development of a Reference Case*, Kenneth B. Medlock III, James A Baker III Institute for Public Policy, Rice University, May 9, 2011, slide 17, estimating Montney at 65 Tcf; RBC Capital Markets Equity Research, Horn River Shale Gas – Awakening the Northern Giant, September 27 2010, p. 5, estimating Horn River at 200 Tcf, Montney at 221 Tcf, and Cordova at 70 Tcf.

[32] See http://www.energy.alberta.ca/NaturalGas/Gas_Pdfs/FactSheet_NGFacts.pdf

[33] See "Assessment of Canada's Natural Gas Resource Base", Canadian Society for Unconventional Gas, March 2010, Table 3.

[34] See "A Primer for Understanding Canadian Shale Gas", National Energy Board of Canada, Energy Briefing Note, November 2009, p. 15.

Since the shale formations can be dozens or even hundreds of miles long and often several hundred feet thick, the risk of not finding a producible formation is much lower compared to some types of conventional gas structures.

The horizontal well, properly located in the target formation, is enabled to produce gas volumes large enough to be economic through the use of hydraulic fracturing. As is the case with most shale wells, initial production (IP) rates are high, but drop off steeply within the first two years. However, once a well has declined to 10-20% of initial production, recent history has shown that production will then continue from that lower rate with a very slow subsequent decline for a period of 20 years or more.

The certainty of production allows shale gas to be managed in response to demand. If demand is growing, additional zones and/or shale wells can be drilled and fractured to meet that demand and to mitigate the initial production or IP decline rates from earlier wells. If demand subsides, drilling rates can be reduced or discontinued completely in response to the negative market signal.

Shale gas development has been further reinforced recently by the fact that some shale formations also contain natural gas liquids (NGLs), which strengthens the economic prospects of shale. Natural gas is generally produced when NGLs are produced. Therefore, gas production is being incented not only by the economics of natural gas itself, but by NGL prices, which generally track crude oil prices. Oil prices currently offer a significant premium to natural gas on a per-MMBtu basis. Oil at $85 per barrel equates to about $14.65 per MMBtu, compared to gas prices that are $2.50 per MMBtu.

While the cost of producing commercial quantities of gas does vary from play to play, and even within a play, the overall trend has been for drilling and completion costs to decline as producers gain knowledge of the geology, develop efficiencies and leverage investments in upstream drilling and completion activities across greater volumes of gas. In some pure dry gas shale plays, recently costs have been reported as below $3.00 and even below $2.00 per MMBtu to find and develop. These costs appear to be at the lower end of the spectrum of costs for the development of gas shale. Most shale gas plays appear to be economic today within the $3.00 to $5.00 range.[35]

In NGL-rich (wet) and crude oil plays such as the Eagle Ford, the cost to produce gas can be much lower, as long as the price of the NGLs and oil production supports drilling. As noted previously, the price of liquids is more than five times higher than the price of natural gas on a per-MMBtu basis. Navigant forecasts indicate that NGL and crude oil prices will be significantly higher than natural gas on a per MMBtu basis for the term of the GLNG analysis.

The EIA, in its *International Energy Outlook 2011,* projects worldwide demand for liquid fuels to grow from 84 million barrels a day in 2009 to 112 million barrels per day in 2035, driven largely by strong economic growth and increasing demand for liquids in the transportation and industrial sectors in Asia, the Middle East, and Central and South America. The EIA forecasts oil prices to increase to $148 per barrel in 2011 dollars (converted from $145 in 2010 dollars) by 2035.[36] This is approximately $25.52 per MMBtu and compares to gas prices in 2035 that Navigant forecasts to be $6.45 per MMBtu in the Base Case. High oil prices are expected to encourage liquids production, which will in any event be accompanied by additional associated gas production.

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[35] See Progress Energy, Presentation to National Bank Financial Markets Energy Conference, February 14, 2012, slide 12, citing Morgan Stanley analysis.

[36] *Annual Energy Outlook 20*12, EIA.

Comparison of Navigant's Shale Gas Supply Outlook to Other Outlooks

Comparison of Navigant's Shale Gas Supply Outlook to Other Outlooks

In Figure 8, the Base Case shale production forecast calls for much more gas to be brought on between now and 2020 than does EIA in its *Annual Energy Outlook 2012*. The Base Case indicates an increase in shale production from 2011 to 2020 of 95% (almost doubling), while the EIA increase would be about 42%. Navigant believes even its own estimates to be conservative. After 2020, growth rates between the Navigant and EIA forecasts are roughly parallel. As the graph also shows, while both Navigant and EIA increased their post-2020 estimates for shale production by roughly the same amounts between their 2010-vintage and 2011-vintage outlooks, EIA's further increase in its shale production forecast in its 2012-vintage outlook outpaced Navigant's most recent forecast increase. However, despite this additional increase, EIA's forecast trails the Navigant forecast because of the difference in the pre-2020 period.

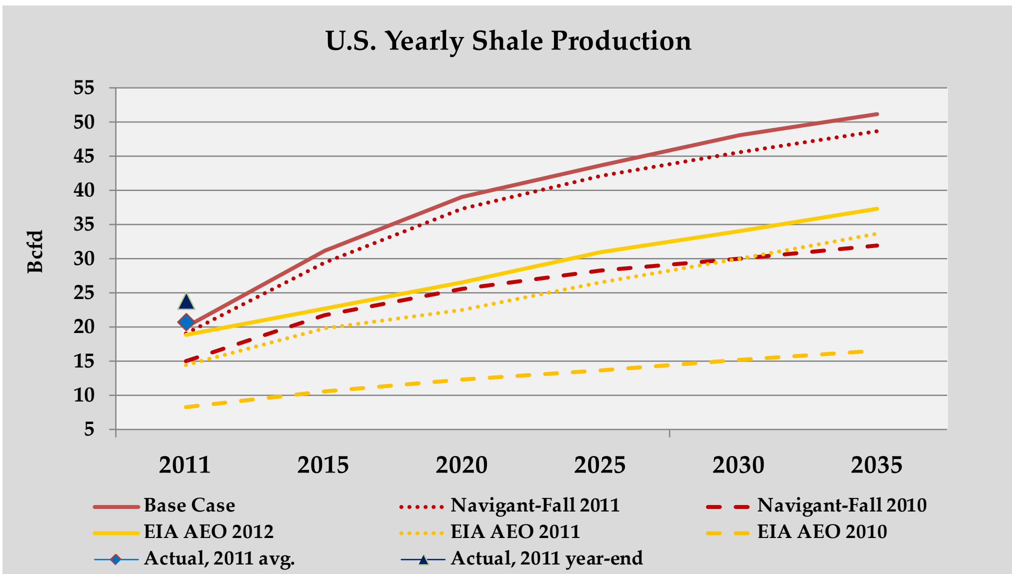

Figure 8: Supply Outlook Comparison: Navigant and EIA

Year	GLNG	Navigant		EIA		
	Base Case	Fall 2011	Fall 2010	AEO 2012	AEO 2011	AEO 2010
2011	19.9	19.0	15.0	18.7	14.3	8.3
2015	31.2	29.4	21.7	22.6	19.7	10.5
2020	38.9	37.3	25.5	26.5	22.5	12.4
2025	43.6	42.1	28.2	30.8	26.5	13.5
2030	48.1	45.7	30.0	34.0	30.0	15.1
2035	51.2	48.6	31.9	37.3	33.6	16.4

Table 1: Supply Outlook Comparison: Navigant and EIA

The growth in gas production has been so rapid that many forecasters, including EIA, have had difficulty keeping up with the ramping gas shale resource. For example, dry shale production in the U.S. at the beginning of 2011, before the release of AEO 2011, was already 17.9 Bcfd. EIA's forecast for the following year, 2012, was only 15.8 Bcfd, and therefore had already been greatly eclipsed by actual production months before the forecast period.

Demand Is Likely to Increase Steadily but Not Dramatically

Reliable demand is a key to underpinning reliable supply and a sustainable gas market, but will not fully develop unless supply is there to support it. Demand and supply are interrelated parts of the same dynamic. In Navigant's view, demand is likely to increase steadily over the coming years, due to both demand-side and supply-side factors.

On the demand side, the inherent benefit of natural gas as an electric generation fuel causes Navigant's projection that the majority of the total growth in natural gas demand will come from the electric generation (EG) sector of the market. EG demand is expected to grow at an annual rate of 1.6% through most of the study period, with a higher rate of 3.4% through 2019. These expectations are based mainly on the expected replacement of coal-fired generation with lower GHG-emitting gas-fired generation, described later in this report. An additional factor is the ability of gas-fired generation to easily provide the necessary electrical ancillary services to help integrate expected new renewable generation.

Navigant projects industrial demand in North America to grow annually by an average 0.4%, driven largely by demand from the prolific oil sands development in Alberta and a slowly recovering economy in general. While there are uncertainties as to the pace of Alberta oil sands development, Navigant believes that increased oil sands development will occur, requiring increased consumption of natural gas in the process. Navigant also expects its industrial sector gas demand forecast to increase in its next forecast release, based on signs of companies in the petrochemical and fertilizer industries in particular looking at investing in new facilities in the U.S. given the low current natural gas prices as well as increasing NGL supplies. Even if industrial sector demand were to increase, however, the size of the natural gas resource base is so large the impact on the gas market is not expected to be significant.

Residential, commercial, and vehicle demand for natural gas is expected to grow very modestly, at an average 0.2% annually, inclusive of population growth, as a result of increasing energy efficiency efforts in these sectors.

Navigant's sectoral outlook for natural gas demand growth from its Base Case is shown in Figure 9.

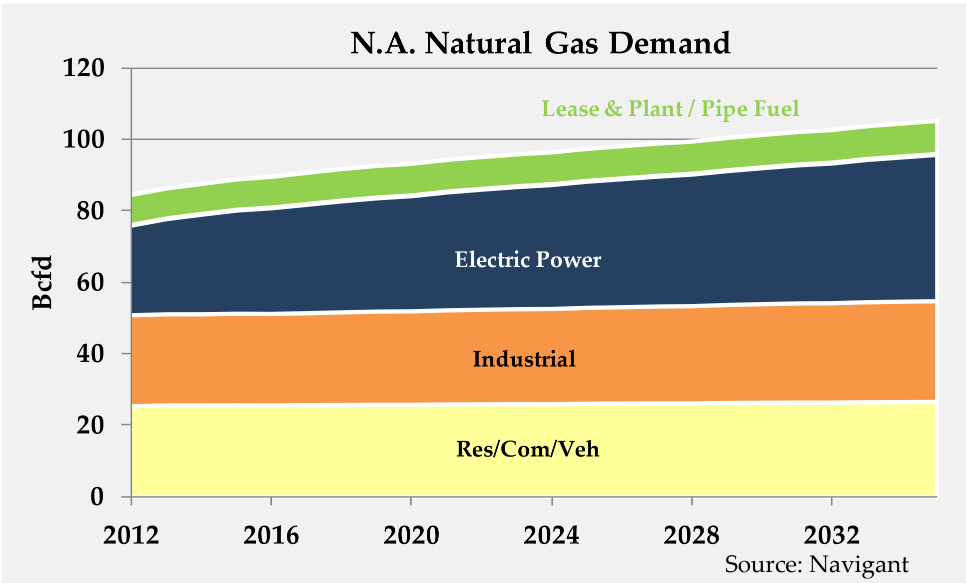

Figure 9: North American Natural Gas Demand Projection

The key supply-side factor enabling steadily growing gas demand is the abundance of reliable and economic supply options. With the advent of significant shale gas resources, end-use infrastructure and pipeline project developers can be assured that gas will be available to meet growing market demand. Further, the prospect of steadily growing and reliable supply portends relatively low price volatility. Because of the manufacturing-type profile of shale gas production, production rates can be better matched to demand growth. Lower price volatility, like supply growth, is supportive of long-life end-use infrastructure development and pipeline and mid-stream processing projects to meet increasing demand.

Demand growth in the North American gas market is supported by the existing pipeline network. The delivery infrastructure for natural gas is mature and, with the exception of a few highly urban areas such as greater New York City, relatively cost-effective and quick to expand.

As supply abundance creates the potential for an unbalanced market leading potentially to stagnation of gas asset development, LNG exports can be an important contributor to the long-term sustainability of the gas market by contributing to demand levels that will incent important production and distribution investments. While only one of the nine major projects that have applied for approval to export U.S.-sourced LNG (in addition to GLNG) is anticipated to start up before 2016, LNG exports should provide a new market, at least in the mid-term, for excess natural gas supplies and may even overtake fuel switching from coal plant retirements as the primary incremental natural gas demand for balancing current oversupply conditions.

In addition to the Base Case, as part of its analysis Navigant developed an alternative case -- the High Demand Base Case -- to reflect potentially higher natural gas demand due to faster market penetration of natural gas vehicles. NGVs offer several important benefits versus traditional gasoline-powered vehicles since natural gas is cheaper, cleaner, and the fuel is domestically produced. For example, Clean Energy Fuels Corp., the largest provider of natural gas fuel for transportation in North America, reports that in 2011 in California, its CNG sold on average for almost 30% less per gasoline gallon equivalent than retail gasoline ($2.70 per gallon versus $3.82), and its LNG sold on average for 35% less per diesel gallon equivalent than retail diesel ($2.60 per gallon versus $4.08).[37] Clean Energy estimates annual per vehicle fuel cost savings for California truck fleets based on 2011 prices from about $21,000 to $27,000, depending on truck type.[38] With respect to GHGs, a "well-to-wheels" analysis from the California Energy Commission indicates that the life-cycle GHG emissions (including emissions for fuel procurement and equipment manufacture as well as actual driving) for NGVs, expressed on a grams per mile basis, are up to about 30% lower than for conventional light-duty vehicles and up to about 23% lower than for conventional heavy-duty vehicles.[39]

While the benefits of NGVs are clear, challenges for the NGV industry certainly exist. Adoption of the technology has been hindered by the classic "chicken and egg" problem: without extensive fueling infrastructure, increasing the number of NGVs could be difficult, but so is funding infrastructure with little existing demand. Because much of the potential benefit of NGVs can be realized by heavy-duty trucks, however, a more limited amount of new infrastructure, sufficient to serve focused corridors on the interstate highway system, appears to have become a more feasible solution to the chicken and egg issue. Clean Energy is in the midst of creating its Natural Gas Highway, to be comprised of an initial backbone of 150 LNG stations linking major freight trucking corridors, with 70 stations expected to be open by the end of 2012.[40] Other indicators of progress in the movement to adopt more NGVs are new technological commitments in the area, such as the announcements by GMC and Chrysler to build factory original equipment manufacturer (OEM) CNG-powered (bi-fuel) pickup trucks in 2012,[41] and the partnerships created by Chesapeake Energy Corporation to improve NGV technology. Specifically, Chesapeake has announced a partnership with 3M to create new CNG tank technology that is lighter, cheaper, safer, and bigger,[42] and with General Electric to deploy modular CNG compression stations and to develop home refueling solutions.[43] Another important factor is the expected new generation of NGV engines specifically

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[37] Clean Energy Fuels Corp, 2011 Form 10-K, pp. 5-6. Gasoline gallon equivalent and diesel gallon equivalent are different due to different fuel characteristics.

[38] Id, at 7.

[39] See "Full Fuel Cycle Assessment: Well-To-Wheels Energy Inputs, Emissions, and Water Impacts", California Energy Commission, Consultant's Report, June 2007, CEC-600-2007-004-REV. Figure A-2 shows light duty CNG at 302 g/mi versus gasoline at 431 g/mi. Figures A-9 and A-11 show heavy duty CNG at 2,515 g/mi versus diesel at 3,255 g/mi.

[40] Clean Energy Fuels Corp, 2011 Form 10-K, p.4.

[41] March 5, 2012 press release, "2013 GMC and Chevrolet Bi-Fuel Pickups Unveiled "; March 6, 2012 press release, "Ram to Build North America's Only OEM Compressed Natural Gas-powered Pickup".

[42] February 21, 2012 press release, "3M and Chesapeake Energy Corporation Partner to Create New CNG Tank Technology".

[43] March 7, 2012 press release, "GE and Chesapeake Energy Corporation Announce Collaboration to Speed Adoption of Natural Gas as Transportation Fuel".

designed to provide ample power for use in heavy-duty trucking fleets, such as a new 12-liter engine from Cummins Westport currently under field testing.[44]

Along with infrastructure and technology advancements, stakeholder perceptions can be important. For example, the Governors of 13 states recently sent a joint letter to U.S. auto manufacturers announcing their upcoming Request for Information intended to help the states develop their planned solicitation to procure natural gas vehicles to serve the aggregate of their states' vehicle fleets.[45] On the other hand, a recent survey of large industrial freight carrier senior executives by a leading transportation management services provider found that only 22.5% believe LNG is a viable alternative for current diesel engines, and only 2.9% were actively promoting adoption of LNG by their company.[46]

Competition from Oil and Other Fuels

Annual average natural gas prices are projected to increase slowly in the Base Case from $2.55 per MMBtu in 2012 to $6.45 per MMBtu in 2035. On a per-MMBtu basis, this is expected to be well below oil prices and competitive with coal prices, which are also expected to increase over time.

Oil

In earlier times, gas and oil competed for some of the same markets, particularly in the electric generation and industrial markets. For the past 20 years, however, oil has become increasingly pushed out of those markets due to gas's lower cost and superior environmental profile. Oil is now used chiefly as a transportation fuel. The prices of gas and oil are generally acknowledged to have decoupled in North America, as they serve largely separate markets. This is illustrated in Figure 10.

[44] February 20, 2012 press release, "Cummins Westport Announces New Heavy Duty Natural Gas Engine: ISX12 G Natural Gas Engine Targets Regional Trucking, Vocational and Refuse Markets in North America".
[45] Letter of April 27, 2012 signed by governors of Oklahoma, Colorado, Wyoming, Pennsylvania, Utah, New Mexico, Kentucky, Ohio, Louisiana, Maine, West Virginia, Texas and Mississippi.
[46] April 26, 2012 press release, "PLS Logistics Services Liquefied Natural Gas (LNG) Carrier Survey: High Level of Awareness, but Obstacles to LNG Use in Industrial Trucking Remain".

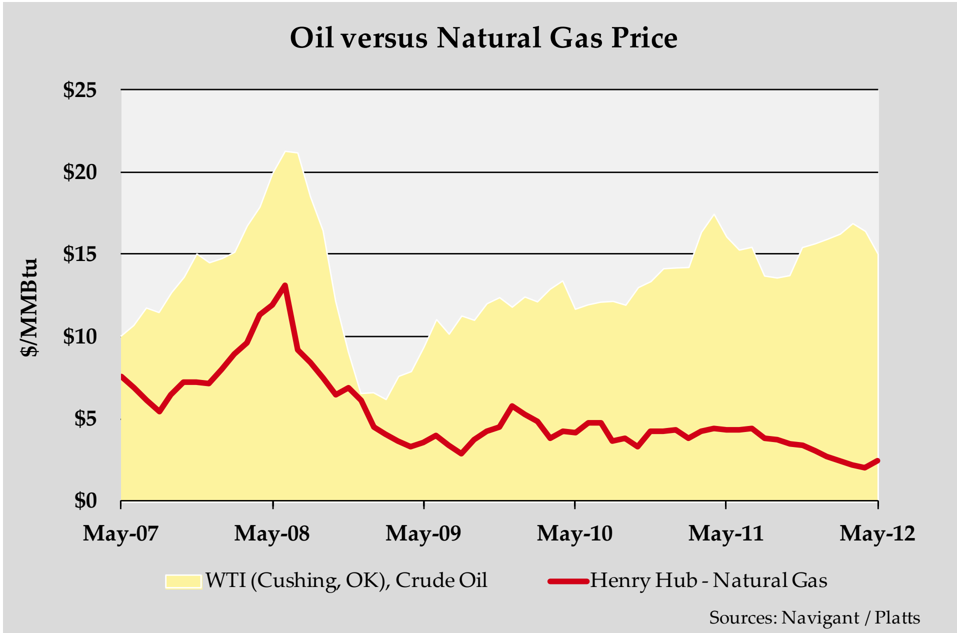

Figure 10: Comparison of Oil and Gas Prices per MMBtu

In any case, the price of oil is likely to continue to be at a significant premium to natural gas. Natural gas is domestically plentiful, relative to demand, while oil is not, notwithstanding the discovery of some significant recent oil shale resources in places like North Dakota and Texas. The U.S. currently imports more than 60% of the oil it consumes.[47] Conventional oil resources in the U.S. have largely already been identified. While there is recent positive news regarding oil production in the U.S., it is unlikely that the current voracious demand for oil in the U.S. could be met without continued significant reliance on foreign oil supply, especially given restrictions still in place on offshore drilling in the wake of Deepwater Horizon in the Gulf of Mexico. Since North American oil prices are tied to the world price for crude oil, a matter not apt to change in the forseeable future, while North American natural gas prices are set in North America, owing in part to the lack of physical connection of North America to global gas markets, Navigant expects the oil price premiums relative to natural gas to continue in the future. Even eventually when LNG export projects have come on stream, it is highly unlikely that the volumes ultimately exported will be large enough relative to the North American gas market that any significant tie between the North American and global gas markets will even then exist.

Coal

Coal is still widely used for electric generation. However, due largely to slowly tightening U.S. environmental regulations, natural gas has been steadily displacing coal as a percentage of megawatt hours generated in the U.S., as shown in Figure 11. While coal accounted for 53% of annual electric generation in 1997, it accounted for only 42% in 2011. Natural gas, on the other hand, accounted for 14% of electric generation in 1997, and grew to 25% by 2011. Preliminary data released by the EIA on July 6, 2012 show that, for the first time, generation from natural gas-fired plants is virtually equal to

[47] 2011 data from Petroleum Supply Annual, Volume 1, U.S. Energy Information Administration, available at http://www.eia.gov/petroleum/supply/annual/volume1/pdf/table1.pdf

generation from coal-fired plants for April. Each fuel was reported as providing 32% of total generation.[48]

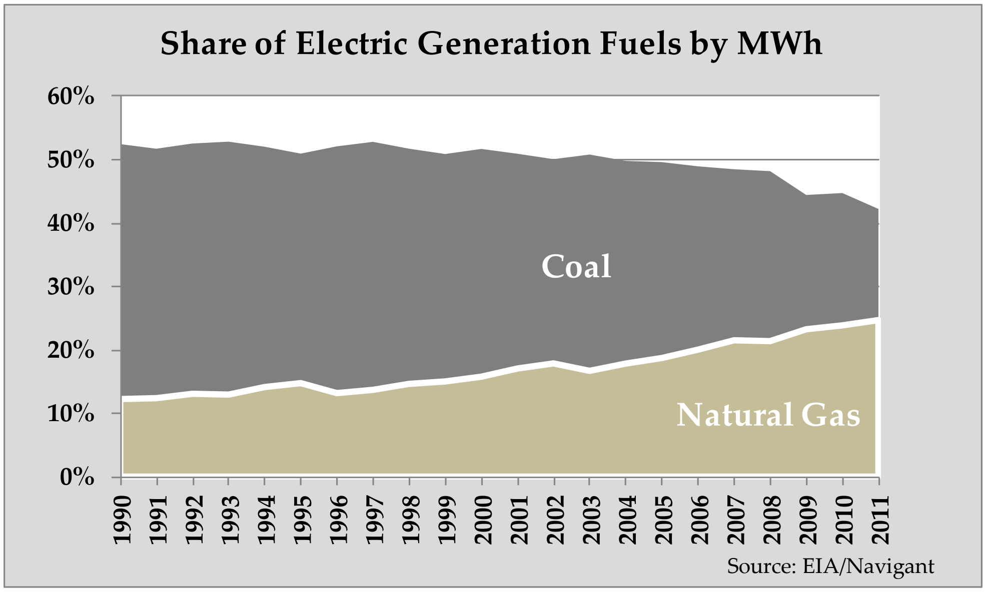

Figure 11: Coal and Natural Gas as a Percent of Total Megawatt Hours Generated

Some of the recent displacement of coal by gas as an electric generation fuel is driven by the relative supply economics of gas and coal prices. The delivered cost of coal per kilowatt hour of generation has recently averaged significantly more than that of natural gas in the Central Appalachian region. This relationship is perpetuated in the forward price curves of the two commodities as of June 2012, as shown in Figure 12, where gas maintains a $1.00 to $1.50 per MMBtu discount to coal.

Analysis by Navigant indicates that the volume of coal-to-gas switching in the U.S. will increase from the 2.0 Bcfd that has already switched to more than 4.0 Bcfd by 2017. This switching has been based on commodity price competition, not on any new regulatory or government mandates such as national energy or other policies like cap-and-trade policies that have been delayed.

[48] EIA, Today in Energy, July 6, 2012.

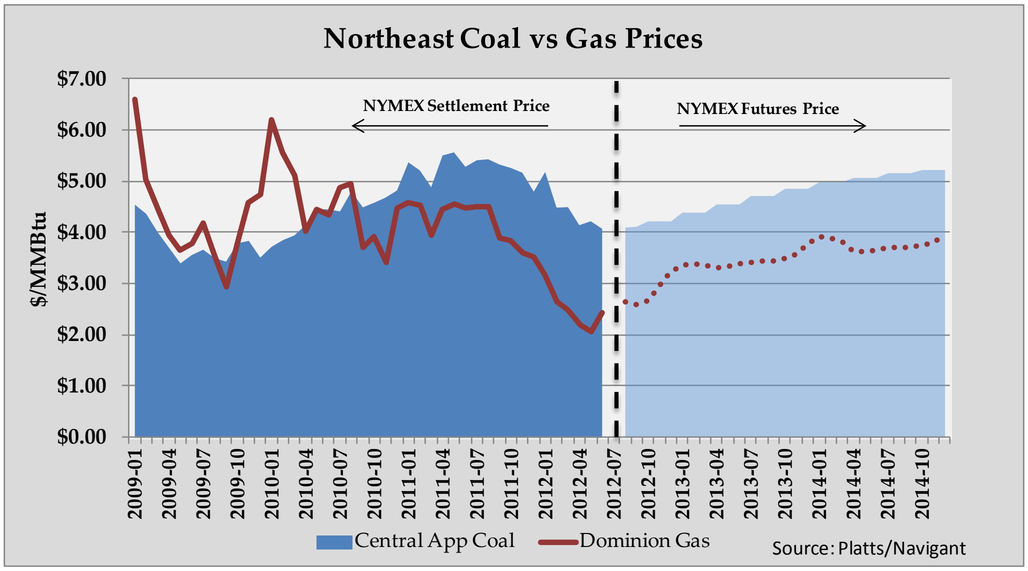

Figure 12: Comparison of Electric Generation Fuel Costs

Additional switching may be driven by other factors. Clean coal in the form of carbon capture and sequestration (CCS), which could eventually assist the coal generation sector, has run into further delays, as seen with American Electric Power's July 14, 2011 announcement to discontinue its CCS pilot project at its Mountaineer coal-fired power plant in West Virginia,[49] and other projects in Canada, Scotland, Italy and Germany have been abandoned, as well, due to unfavorable economics given the markets for natural gas, CO2, and emission reduction credits.[50]

Coal-fired electric generation is likely to continue to be under pressure from increasingly stringent environmental regulations. On February 16, 2012, the EPA published its final rule on Mercury and Air Toxics Standards (MATS). The MATS rule establishes numerical emission limits for mercury and other toxics from coal-fired and oil-fired electric generating units; EPA estimates that 40% of coal-fired units covered by the rule do not currently use advanced controls. While the U.S. Court of Appeals for the D.C. Circuit recently rejected the EPA's Cross-State Air Pollution Rule (CSAPR),[51] which would have required the reduction of power plant emissions of SO2 and NOx that contribute to ozone and/or fine particulate pollution in other states, the decision's ultimate effect on coal-fired generation is uncertain, especially given that MATS is viewed as a much more onerous regime than CSAPR.[52]

Companies have responded to the economic and regulatory pressures impacting coal-fired generation by retiring coal-fired generation units. Figure 13, below, shows the planned retirements of the 31,500 MW of additional, currently announced coal-fired retirements.[53] As can be seen, the vast

[49] AEP press release, "AEP Places Carbon Capture Commercialization on Hold, Citing Uncertain Status of Climate Policy, Weak Economy," July 14, 2011, available at http://www.aep.com/newsroom/newsreleases/?id=1704.
[50] "TransAlta Abandoning Canada Carbon Capture Project", Bloomberg.com, April 27, 2012.
[51] EME Homer City Generation v. EPA, US. Court of Appeals for the D.C Circuit Case No. 11-1302, August 21, 2012 decision.
[52] *See* D.C. Circuit Vacates Cross-State Air Pollution Rule", Van Ness Feldman Alert, August 23, 2012, at p. 3.
[53] Based on data from Ventyx Energy Velocity, July 2012.

majority of these announced retirements will have occurred prior to 2019, when the GLNG export facility is expected to be on-line. Consequently, most of the coal-to-gas switching due to announced retirements will have already occurred, and if so, the additional demand represented by LNG exports should provide a welcome boost to offset the slowing of incremental gas demand from coal plant retirements, helping to move the gas market towards sustainability.

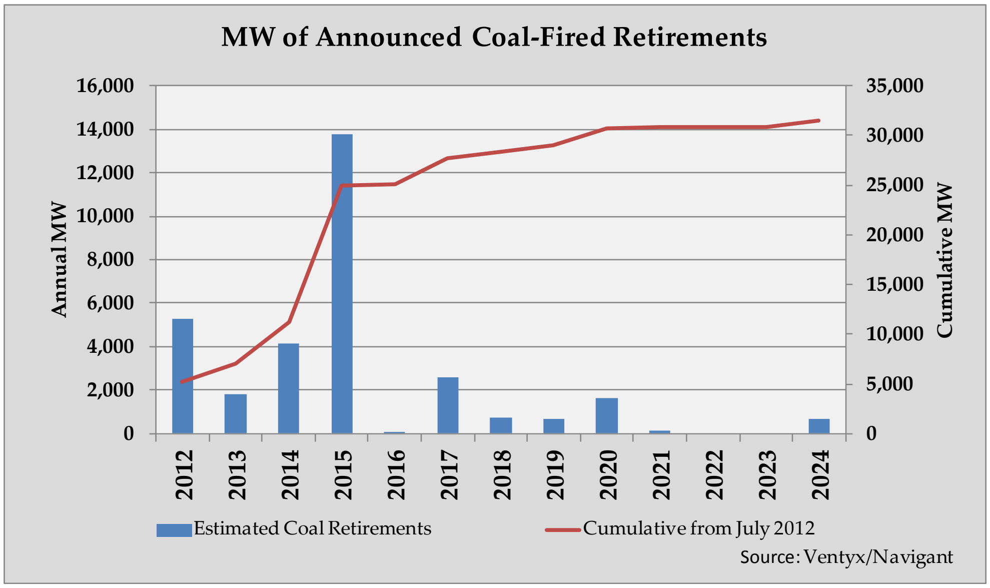

Figure 13: Trajectory of Announced Coal-Fired Generation Retirements

Nuclear, Renewables, and Efficiency

The disaster at the Fukushima nuclear generating facility in Japan in early 2011 has pushed utilities in North America to reexamine the safety of the existing nuclear generation fleet, and has resulted in additional demand for natural gas in Asia in the form of LNG. Several states have conducted nuclear power workshops to assess the possible complications of a similar disaster in this country.[54] While the eventual impact of the Fukushima disaster on the U.S. nuclear industry is still too early to assess with any precision, clearly one of the options being considered is additional gas-fired generation.

With respect to renewables, natural gas is well-positioned to support renewable generation. For the support of wind and solar generation, dispatchable gas-fired generation is ideal to "shape" the output profile of power supplies by following load variations, as well as to "firm" or support the intermittency of both these forms of renewable electric generation by providing available peaking capacity. For 'shaping' purposes for the development of the emerging wind industry, natural gas looks to be critical to wind industry development.

[54] E.g. California Energy Commission, Committee Workshop on California Nuclear Power Plant Issues, July 26, 2011.

Risks to the Supply and Demand Forecasts

While the gas supply outlook is strong, and Navigant expects that production will have the capacity to grow, there are risks in the development of the resource that will need to be met.

Environmental Issues

Hydraulic fracturing of shale formations to produce gas (or oil) has become a topic of discussion inside and outside the industry. Concern has been raised over its possible environmental impact resulting from water use, water well contamination, and water and chemical disposal techniques.

Hydraulic fracturing has been used for years as a means to increase production, whether gas or oil, or whether shale or conventional. It is, however, with gas shale where the process, in combination with horizontal drilling, has had the most dramatic effect on production to date.

The industry has taken positive steps to address the issue of potential water contamination. For example, *FracFocus.org*, a voluntary registry for disclosing hydraulic fracturing chemicals, was recently formed and, as noted earlier, many states now require the mandatory disclosure of hydraulic fracturing chemicals. [55] In addition, the U.S. Environmental Protection Agency is studying the impact of hydraulic fracturing on drinking water, and is expected to issue an interim report in 2012.

In general, the incentives for operators to use efficient water management and best practices in the hydraulic fracturing process aligns well with the interests of regulators and the environment. The process of water handling and treatment can add to the cost of the well in certain cases (e.g., where water is in short supply) but nevertheless becomes part of the process of the modern gas well operator. As noted on page 13, significant efforts are already underway to improve water management techniques, including reuse in the production of shale gas. As reported in the July 2011 edition of the Journal of Petroleum Technology, flowback water is being treated on site and recycled not merely to comply with regulations but to reduce water acquisition and trucking costs in many places.[56]

The Natural Gas Subcommittee of the Secretary of Energy Advisory Board (SEAB) in its first "90-Day Report", recommended that drillers fully disclose the chemicals used in hydraulic fracturing, and institute several other practices designed to assure the environmental acceptability of hydraulic fracturing. [57] The SEAB 90-day report also states that "Natural gas is a cornerstone of the U.S. economy…[and]…there are many reasons to be optimistic that continuous improvement of shale gas production in reducing existing and potential undesirable impacts can be a cooperative effort among the public, companies in the industry, and regulators."[58] In November 2011, the SEAB released its Second 90-Day Report, discussing implementation plans for its recommendations and reiterating that concerted and sustained action will be needed to minimize shale gas impacts and risks.[59]

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[55] See note 11, supra.

[56] Journal of Petroleum Technology, July 2011, pp. 49-51

[57] The SEAB Shale Gas Production Subcommittee Ninety-Day Report – August 11, 2011, available at http://www.shalegas.energy.gov/resources/081111_90_day_report.pdf

[58] Ibid, pp. 1, 9.

[59] The SEAB Shale Gas Production Subcommittee Second Ninety-Day Report – November 18, 2011

Navigant expects hydraulic fracturing to be subject to continuing scrutiny and increasing disclosure requirements. This should help mitigate concerns about environmental risks so that shale resource development in North America can continue. In some regions, such as New York State, where the Marcellus play lies beneath the New York City watershed, opposition to hydraulic fracturing may continue. While outcomes in specific jurisdictions cannot be predicted, the vastness of the resource, both in terms of the natural gas volume estimates previously discussed and the geographic dispersion of shale plays across the country as shown in Figure 4, means that even if some localized limitations or delays occur with respect to production, there should still be an ample resource available to meet demands, especially in light of the general acknowledgment by producers of the need to operate in a sustainable fashion.

The area of greenhouse gas emissions is a potential risk factor on natural gas demand, although the most recent EPA action only deals with new rather than existing power plants and is not expected to lead to retirements or to impact planned gas-fired development. Specifically, on March 27, 2012, the EPA proposed a carbon pollution standard for new power plants, based on natural gas combined cycle technology (NGCC); the EPA's regulatory impact analysis noted that NGCC units are projected to meet the standard by virtue of their inherent design, and also that since no new conventional coal-fired boilers are projected to be built, the proposed standards will actually not result in any emission reductions.[60] The EPA's choice of NGCC as the emissions standard for new power plants indicates a lower chance that GHG regulation would inhibit natural gas use.[61] On the flip side, the current policy climate is that GHG regulation at this time is less of a priority in the country, and estimating additional coal-switching beyond what is already captured in Navigant's base case modeling is perhaps of lesser urgency compared to even the recent past. This is not to say that a policy change towards carbon regulation cannot reemerge, but, at this time, there appears to be a lower probability of regulation-driven increases in natural gas usage. The emissions profile of natural gas has a clear comparative advantage versus other fossil fuels, including coal. The increasing displacement of coal use by natural gas will be a positive development for the environment, and in the end will be supportive of gas development.

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[60] "*Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*", Environmental Protection Agency, March 2012 (EPA-452/R-12-001), pg. 5-15.

[61] Other commentary presenting beneficial metrics on natural gas and GHG includes: 1) the research firm IHS Cambridge Energy Research Associates' statement that "[e]stimates used by the United States Environmental Protection Agency (EPA) and others for greenhouse gas emissions from upstream shale gas production are likely significantly overstated."(*Recent Estimates for Greenhouse Gas Emissions from Shale Gas Production are Likely Significantly Overstated, IHS CERA Study Finds*, IHS Cambridge Energy Research Associates, August 24, 2011, available at http://press.ihs.com/press-release/recent-estimates-greenhouse-gas-emissions-shale-gas-production-are-likely-significantl); 2) The National Energy Technology Laboratory (NETL) statement in May 2011 that natural gas baseload power generation has a life cycle global warming potential that is 54% lower than coal baseload generation; NETL included shale gas in its analysis.(*Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States*, Timothy J. Skone, May 12, 2011, slide 34, http://www.netl.doe.gov/energy-analyses/pubs/NG_LC_GHG_PRES_12MAY11.pdf);and 3) A recent study conducted by the University of Maryland found that "arguments that shale gas is more polluting than coal are largely unjustified" and that "the greenhouse footprint of shale gas and other unconventional gas resources is about 11% higher than that of conventional gas for electricity generation, and still 56% that of coal." (*The greenhouse impact of unconventional gas for electricity generation*, Nathan Hultman, Dylan Rebois, Michael Scholten, and Christopher Ramig, October 25, 2011, available at http://iopscience.iop.org/1748-9326/6/4/044008)

Commodity Prices / Reallocation of Drilling Capital

Will the higher price of oil and NGLs and resulting shift of drilling resources from gas cause a drop-off in gas supply? Within the drilling industry, there is and has been a shift from gas to natural gas liquids (NGLs, such as ethane and propane, which are typically priced based on oil prices) and oil drilling, owing to the decided price advantage for producers at a given heat value. This shift can be seen in drilling rig numbers. The number of oil rigs in the U.S. operating as of the end of June is up from 847 in 2011 to 1,369 in 2012, or 62%.[62]

Despite the shift to oil-directed drilling and the fact that gas prices at Henry Hub have declined below $3.00 per MMBtu and oil prices have hovered in the $15.00 to $17.00 per MMBtu range (approximately $90 to $100 per barrel), gas production is continuing to increase. Although the number of horizontal gas rigs in the U.S. drilling on any one day has declined on average in the past year from 606 to 347 (comparing June 2011 to June 2012),[63] or 43%, dry U.S. gas production has increased from 62.8 Bcfd to 64.7, or 3.0%, over that same period.[64] Several factors are behind this phenomenon. First, technology improvements in shale gas production have increased well outputs as lateral lengths and fracture zones have increased. In addition, the shift to oil directed drilling has led to additional production of gas "associated" with that oil production and supporting total increasing gas production levels.

The fundamental attributes of the natural gas industry, including shale gas, should allow the market to balance supply and demand. Navigant's Base Case price forecast indicates a gradual increase from $3.50 to $6.00 per MMBtu over the next 20 years, only reaching $6.45 per MMBtu in the last year of the forecast. At these levels, gas prices will continue to be extremely competitive with oil, which Navigant projects to be significantly more costly than gas per MMBtu throughout the forecast period.

[62] Smith Bits.

[63] Id.

[64] EIA Short-Term Energy Outlook Table 5a.

Overview of Proposed Energy Operations of GLNG Export Project

The proposed Gulf LNG export project is located in Pascagoula, Mississippi. In 2005, GLNG applied for FERC approval in Docket Nos. CP06-12-000 and CP06-13-000 to construct an LNG import facility ("Gulf LNG Terminal") and associated natural gas pipeline ("Gulf LNG Pipeline"), respectively. FERC authorized construction of the terminal and pipeline in 2007[65], and the facilities commenced service on October 1, 2011. GLNG intends to build natural gas processing and liquefaction facilities at the existing Terminal site.

In May 2012, GLNG filed an application with the Department of Energy in Docket No. 12-47-LNG to export up to 1.5 Bcfd domestically-produced LNG to countries with which the United States has entered, or in the future enters, into a Free Trade Agreement (FTA). On June 15, 2012, the Department of Energy provided authorization for GLNG's FTA application in DOE/FE Order No. 3104. GLNG intends to file an application in 2012 to export LNG to non-FTA countries.

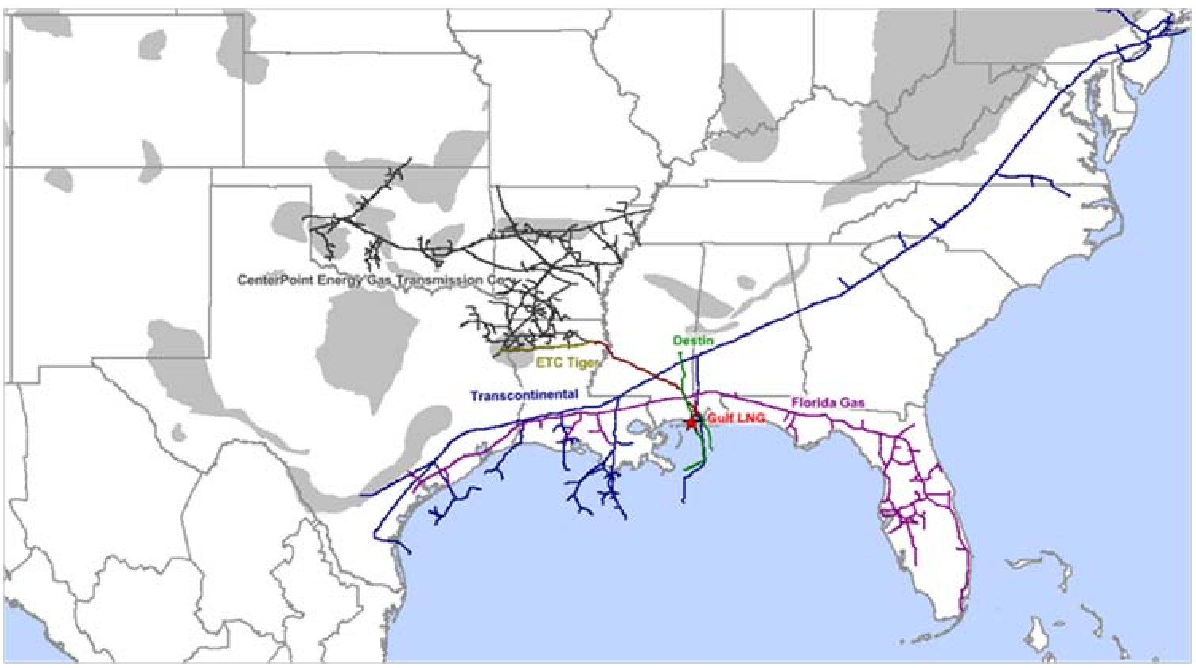

Figure 14: GLNG Location Map

The GLNG export facility will consist of liquefaction equipment sized to export up to 1.5 Bcfd of LNG. The liquefaction equipment is currently estimated to begin operations in December 2018, at a capacity of up to 1.5 Bcfd.

The Gulf LNG Pipeline was originally intended as a 5.02-mile, 36-inch diameter pipeline to carry natural gas derived from imported LNG from Jackson County to interconnects with the Destin and Gulfstream natural gas interstate pipelines. GLNG plans to modify the Gulf LNG Pipeline to

[65] See Gulf LNG Energy LLC, 118 FERC 61,128 (2007).

transport gas from the pipeline interconnects to the GLNG liquefaction facility at Pascagoula, as well as from the GLNG Terminal to the pipeline interconnects. It has an expected on-line date of December, 2018.

The natural gas feedstock for GLNG can be drawn from a wide variety of domestic sources. Because of its pipeline connections with the Transco, which in turn is linked with other major pipeline infrastructure, the GLNG facility will have access to multiple gas resources across the United States, including prolific shale plays like the Marcellus and Haynesville, as well as the regional concentration of conventional production in the Gulf area.

While the Marcellus does not currently physically provide supply to the southern U.S., it can affect gas flows through virtual backhaul arrangements with pipelines connected to the play, such as Transco. Though future possible developments are only speculative, one scenario could be for pipeline capacity that has traditionally brought supplies to the Northeast from the Gulf to be reversed, enabling Marcellus supplies to serve southern markets. For Marcellus to continue growing at 2 Bcfd to 3 Bcfd per year consistently, Marcellus gas has to find other markets beyond just the Northeast. In this scenario of ongoing production growth from the Marcellus, it appears that some reversing of the interstate pipelines (or portions thereof) that bring gas to the NE from the Gulf would be indicated, so that those pipelines could take Marcellus gas to other areas (primarily the Southeast, where we see demand growth potential from coal retirements,the MidWest Chicago area and the Henry Hub area to a lesser extent). For now, two large projects have been announced to facilitate reversals: 1) Williams' Atlantic Access Pipeline (2.0 Bcfd 2015, year-end startup); and 2) Texas Eastern's TEAM 2014 project (0.6 Bcfd, 2014 proposed start-up). Low capacity rates on the new Rockies Express Pipeline (REX) have also opened the door towards discussions of reversing REX – a remarkable consideration given the size and relatively recent on-stream date of the REX pipeline.

Access to markets for the expanding production from the Haynesville play on the Texas-Louisiana border area has been improving, with both intrastate and interstate pipelines installing new or expanded capacity to serve producers there. For example, Energy Transfer Partners' ETC Tiger Pipeline, connecting the Carthage and Perryville Hubs with 2 Bcfd of capacity, came on line in 2010. Centerpoint Energy Gas Transmission's Carthage to Perryville pipeline, with 1.9 Bcfd of capacity, came on line in 2007. The Perryville Hub has grown immensely in recent years, with receipt capacity of over 6 Bcfd and delivery capacity of over 10 Bcfd, and interconnections with 17 pipelines, according to EIA.[66] Haynesville shale gas arriving in Perryville could move to GLNG through the existing interstate pipeline system to which GLNG is connected. In addition, other shale plays in the region, including the Barnett and Fayetteville plays can find their way to GLNG via the existing interstate pipeline system. Further as discussed on Page 11, conventional sources of natural gas production in the Texas/Louisiana area made up almost 52% of regional production in 2011and will continue to be an important supply source for the long term.

[66] "Natural Gas Market Centers: A 2008 Update", EIA, April 2009, pg. 6; there have also been subsequent additions after the EIA study.

Modeling Overview and Assumptions

Twice a year, Navigant produces a long-term forecast of monthly natural gas prices, demand, and supply for North America. The forecast incorporates Navigant's extensive work on North American unconventional gas supply, including the rapidly growing gas shale supply resources. It projects natural gas forward prices and monthly basis differentials at 90 market points, and pipeline flows throughout the entire North American grid. Current projections go through 2035. Navigant's Spring 2012 Reference Case Forecast (issued in April 2012) was the starting point of the GLNG Export Project analysis.

The GLNG Export Project analysis is divided into two major scenario analyses. The first is based on Navigant's Base Case, which builds on Navigant's Spring 2012 Reference Case forecast released in April 2012. This first analysis reflects Navigant's view of a baseline case of reasonably expected supply and demand conditions in the North American natural gas market. The second analysis incorporates higher assumed natural gas demand stemming from more aggressive assumptions about phase-in of natural gas vehicles (NGVs), as well as modeling additional generic LNG exports. Additional modeling cases are then developed in order to examine the effect of LNG exports in the two alternative base case scenarios.

Price projections for purposes of this report focus on two areas: Henry Hub, which is the underlying physical location of the natural gas NYMEX futures contract and the key North American pricing reference point, and Transco Zone 4 in the Southeastern U.S., a natural gas market point in the vicinity of the export facility. All prices are adjusted for future inflation and are shown in constant 2011 dollars.

Gas volumes (by state or region), imports and exports (including gas by pipeline and LNG by terminal), storage, sectoral gas demand, and prices are modeled on a monthly basis. Annual averages are generally presented for the purposes of this report.

The following basic assumptions remain constant for all scenarios, unless otherwise noted.

Supply

All domestically-sourced supply in the Base Case model comes from currently established basins in North America. The forecasts assume no new gas supply basins beyond those already identified as of Spring 2012. This should be regarded as a conservative assumption, given the rate at which new shale resources have been identified over the past few years and the history of increasing estimates of the North American natural gas resource base.

The Base Case supply projection is that U.S. domestically-produced natural gas supply will grow from 63.9 Bcfd in 2012 to 83.2 Bcfd in 2035, an increase of 30%.

As a rule, Navigant's approach towards production capacity is the same for all cases modeled for GLNG. Estimates of production capacity are based largely on empirical production data. For example, the Utica Shale, a very large but undeveloped liquids-rich resource co-located with the Marcellus on the East Coast, is assumed to produce only 3.3 Bcfd in 2035. It is arguable that the Utica Shale could be producing multiples of that number by that date, given the rapid ramp-up in development of other liquids-rich shales such as the Eagle Ford in Texas. Nevertheless, Navigant's conservative approach towards assessing supply results in a relatively small production forecast for the Utica shale. Similarly, no increase in production is modeled for gas that may be produced from other basins that may yet be developed.

Navigant's model also allows for additional supply to come into North America through existing LNG import projects. The model solves for such imports as a response to demand and the price of gas in North America, and the estimated LNG imports over the forecast period only utilize about 5% of the import projects' capacity.

Demand

Navigant's basic modeling assumption is that demand will be met because natural gas supply will respond dynamically to demand in a reasonably short time—months, not years. The shale gas resource is so large that it can be readily produced more or less on demand in sufficient quantities to meet gas demands if economics and policy are supportive.

Gas demand growth in our forecasts is enhanced by growth in the deployment of renewable electric generation. Gas, which is transported continually in pipelines, is far more suited to respond in real time to support intermittent generation from wind and photovoltaics than is coal. Coal-to-liquids and coal-to-gas technologies still appear to be expensive and energy-intensive. Oil and its products are not seen as viable electric generation fuels due to price as well as their significantly less favorable GHG impacts. Navigant sees the price of oil maintaining its current multiple premium to that of gas per MMBtu for the duration of the study period. While renewable technologies will improve and may be augmented by improved electrical storage, and coal technologies may also improve, gas-fired generation will increasingly be the dominant mode of smoothing intermittent electric generation for the foreseeable future.

As mentioned above, the High Demand Base Case adds incremental natural gas demand from a faster assumed phase-in of NGVs, based on an EIA scenario analysis with more aggressive assumptions for market penetration by heavy-duty NGVs. Incremental generic LNG export capacity, to be discussed in the Aggregate Exports Case, is also added into the High Demand Base Case. Navigant views its High Demand Base Case as its name suggests: a high demand/high price case at the upper end of reasonably possible current assumptions.

Navigant's market view is that domestic supply is abundant to such a degree that it will support domestic market requirements as well as export demand for LNG shipped from North America. LNG exports offer the potential for a steady, reliable baseload market which will serve to underpin ongoing supply development. The existence of growing domestic and export demand will also tend to support additional supply development and as a result tend to reduce price volatility. While our modeling shows that the U.S. will be a net exporter of LNG, it also shows that LNG imports will continue on a limited basis. The model makes no assumptions about international prices. Imports are assumed to respond to prices in our North American market model. In any event, LNG imports tend to be minimal over the time horizon of the study due to supply abundance in North America.

All cases assume that fuel switching from coal to gas has occurred for economic reasons, extrapolating a trend recently observed in the market.

With respect to the concern of some that exporting LNG from North America may somehow link domestic gas prices to overseas gas pricing, which has historically been tied to higher-priced oil, Navigant believes it is very unlikely that exports at the levels probable from North America would lead to significant impacts on prices in North America. Modeling done by Navigant supports such finding.

Infrastructure

Navigant's modeling was based upon the existing North American pipeline and LNG import terminal infrastructure, augmented by planned expansions that have been publicly announced and that are identified on Exhibit B. Pipelines are modeled to have sufficient capacity to move gas from supply sources to demand centers. Some local expansions have been assumed and built into the model in future years to relieve expected bottlenecks. In these cases, supply has been vetted to provide a reasonable expectation that it will be available.

In general, no unannounced infrastructure projects were introduced into the model. This means that no specific new infrastructure has been applied to the model except as it directly supports the feasibility of modeled export projects, or has been announced. This is a highly conservative assumption. It is likely that in actuality some measure of new pipeline capacity will be constructed to support the ongoing development of the gas supply resource and the accompanying demand for those supplies. In the absence of specific information, Navigant limits its infrastructure expansion to those instances where an existing pipeline has become constrained. The remedy consists of adding sufficient capacity to the existing infrastructure in order to relieve the constraint only.

Some proposed pipeline projects have been excluded from the Base Case model as noted earlier, most notably the Mackenzie Valley Pipeline in northern Canada, which we believe to be uneconomic and faces large environmental challenges, and the Alaska Pipeline Project. In Appendix B, we attach a complete list of all future pipelines and projected capacity levels that are included in the model.

Storage facilities in the model reflect actual in-service facilities as of Spring 2012, as well as a number of announced storage facilities that are judged likely to be in operation in the near future. No unannounced storage facilities were introduced into the model. The inventory, withdrawal, and injection capacities of storage facilities are based on the most recent information available, and are not adjusted in future years. Assuming no new storage facilities beyond those announced and judged likely to be built is a highly conservative assumption.

These conservative assumptions that limit future new pipeline and storage within the model tend to put upward pressure on prices as supply and demand grow, especially in the later years of the forecast.

LNG Facilities

No assumptions are made regarding international prices for natural gas. Navigant's market model allows each LNG facility to import or export in response to domestic prices exclusively.

It is important to note that the Base Case includes two specific LNG export facilities, totaling 3.7 Bcfd of export capacity. These are the Sabine Pass export facility in Louisiana and the Kitimat facility on the coast of British Columbia, Canada. Sabine Pass is assumed to have four liquefaction trains with a capacity of approximately 0.5 Bcfd each. The first Sabine Pass train begins operation in May of 2015, with the second coming on in January 2016, the third in February 2017, and the final train in October 2017. Kitimat was assumed to begin operations at a capacity of approximately 0.7 Bcfd in October 2015, increasing to 1.5 Bcfd in 2017. [67] These export facilities are assumed to be operating at a 90% load factor year-round in all scenarios. This is a conservative assumption, since 90% is what is operationally possible, and actual load factors are expected to be lower. The likelihood is that the LNG export facilities will operate initially and perhaps during certain seasonal periods at less than 90% of capacity, thereby requiring less gas and thus resulting in an even smaller impact than what is assumed in the analysis.

The GLNG Exports Case adds the GLNG export facility to the two facilities already included in the Base Case. The assumptions for the GLNG export facility are for 1.5 Bcfd of liquefaction capacity coming on-line in December 2018.

In order to provide a stress case to examine the effect of exporting more domestically sourced LNG, additional LNG export capacity is included in the Aggregate Exports Case. Generic facilities were developed to represent possible additional liquefaction demand without presupposing which specific facilities may be approved and successfully constructed. LNG export assumptions per case are shown below. Each facility is phased in over the 2015-2019 timeframe, as each liquefaction train is assumed to be completed.

ANALYSIS ONE

LNG Facility	Export Capacity (Bcfd)	Location	Base Case	GLNG Exports Case	Agg. Exports Case
Sabine Pass	2.2	Cameron Parish, LA	•	•	•
Kitimat	1.5	District of Kitimat-Stikine, BC	•	•	•
Gulf LNG	1.5	Pascagoula, Mississippi		•	•
Gulf Coast	1.0	Generic			•
West Coast	1.0	Generic			•
East Coast	0.5	Generic			•
Total	**7.7**				

ANALYSIS TWO

LNG Facility	Export Capacity (Bcfd)	Location	High Demand Base Case	High Demand Base Case Plus GLNG @ 1.5 Bcfd
Sabine Pass	2.2	Cameron Parish, LA	•	•
Kitimat	1.5	District of Kitimat-Stikine, BC	•	•
Gulf LNG	1.5	Pascagoula, Mississippi		•
Gulf Coast	1.0	Generic	•	•
West Coast	1.0	Generic	•	•
East Coast	0.5	Generic	•	•
Total	**7.7**			

Table 2: LNG Export Capacity Assumed Online

LNG import capacity is assumed to be 18.5 Bcfd from 2015 onward. The load factor of each facility is solved by the model as a function of domestic supply and demand. The model is calibrated to

[67] More recent materials from Apache Corp. released after we performed our modeling indicate that deliveries will not begin until 2017. See Investor Day Presentation, June 14, 2012, page 64.

minimize LNG imports in light of the modeled export activity. This assumes that a reduction in exports is likely to occur before significant imports occur if U.S. prices at any time would attract overseas LNG, as the domestic suppliers and exporters would take advantage of the arbitrage with domestic supply. Some imported LNG would still be expected to occur, as overseas shippers may have contractual obligations or other motivations to ship to the U.S. In the New England area, the present-day constraints on pipeline infrastructure are assumed to remain; therefore, LNG imports occur in the model in the Boston area much as they do today.

Other Assumptions

Oil Prices

Figure 15 shows the prices of West Texas Intermediate crude oil assumed in the model. The price of oil is assumed to escalate in a constant manner beginning in 2015. Prior to 2015, Navigant used an average of settles in the NYMEX WTI futures contract to establish a forward projection. The price of WTI in 2015 is $110 per barrel, in 2011 dollars. In 2035, the price per barrel is $173. For comparison, the EIA's AEO 2012 Reference Case projects the price of low-sulfur light crude oil to be $120 per barrel in 2015 and $148 in 2035 (converted to 2011 dollars).

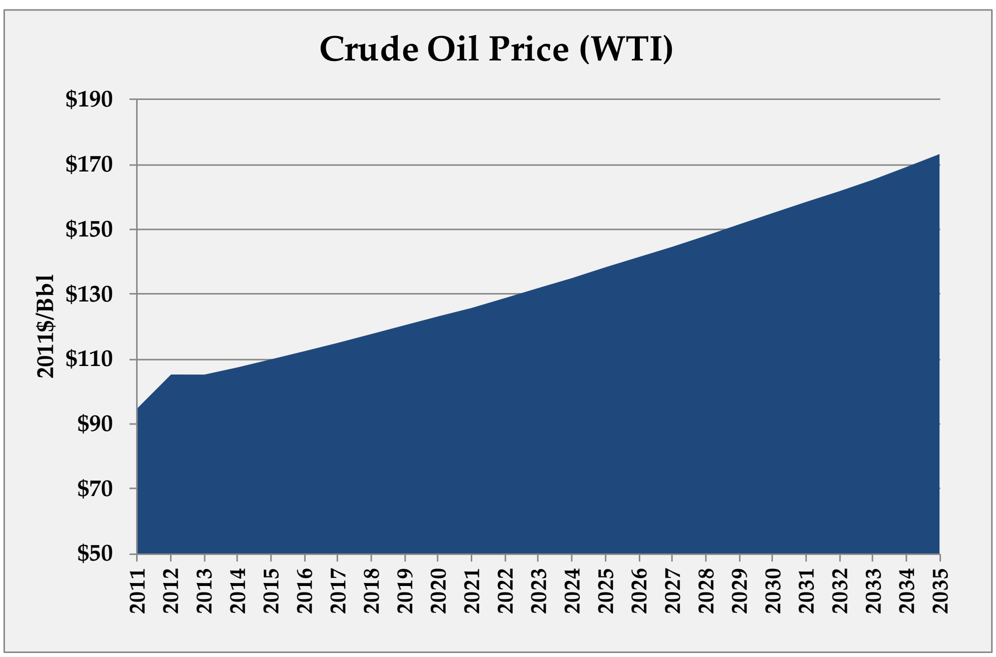

Figure 15: WTI Price Assumed in Natural Gas Price Forecast

Economic Growth

Navigant uses GDP figures from the Congressional Budget Office's Budget and Economic Outlook of January 2012. To extend the outlook beyond the last year, the final year GDP growth rate of 2.4% is continued to the end of the forecast period.

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1.70%	2.20%	1.00%	3.60%	4.90%	4.20%	3.30%	2.80%	2.60%	2.50%	2.40%	2.40%

Table 3: Economic Growth Assumptions

Natural Gas Vehicles

Natural gas vehicle demand is embedded with residential and commercial demand, and is roughly similar to EIA projections from its 2012 Annual Energy Outlook Early Release for the Base Case. The EIA 2010 Annual Energy Outlook high case for heavy-duty NGVs is essentially used as NGV demand for the High Demand Base Case.[68]

Price Points

Prices for Henry Hub, the key pricing point of the North American gas futures market, are modeled in all outputs. In addition, the market point at Transco Zone 4 represents the Southeast market. As noted in the Executive Summary, Navigant also calculated a representation of a U.S. "national" price using the average of all U.S. market points in the model.

[68] At the time of the modeling, the AEO 2010 analysis was EIA's most recent NGV high-case scenario. Navigant added the incremental volume for high case NGVs from the AEO 2010 analysis to the volumes in the AEO 2012 reference case, which had only de minimis changes from the AEO 2010 reference case.

Scenario Descriptions

Analysis One	
Base Case (no GLNG exports)	The **Base Case** is developed from Navigant's Spring 2012 Reference Case Forecast of April 2012. The Spring 2012 Forecast incorporates Navigant's work on North American gas shale supply resources. The Base Case assumes that two other LNG export facilities in North America will be operational prior to and concurrent with GLNG: Sabine Pass in Louisiana and Kitimat in British Columbia. Sabine Pass is modeled with export capacity of 0.5 Bcfd of gas in LNG form beginning in May 2015, ramping up to 2.2 Bcfd by October 2017. Kitimat is modeled with export capacity of 0.7 Bcfd beginning in October 2015, ramping up to 1.5 Bcfd in 2017.
GLNG Exports Case (= Base Case plus 1.5 Bcfd GLNG exports)	The **GLNG Exports Case** augments the Base Case with exports from the 1.5 Bcfd capacity GLNG export facility beginning December 2018. Minor infrastructure adjustments were made to accommodate the new facility. The effects on prices are the specific focus.
Aggregate Exports Case (= GLNG Exports Case plus 2.5 Bcfd generic exports)	The **Aggregate Exports Case** adds to the GLNG Exports Case 2.5 Bcfd of additional LNG export capacity. In the Gulf of Mexico, 1.0 Bcfd of generic LNG export capacity is assumed. On the U.S. West Coast, 1.0 Bcfd of generic export capacity is assumed. On the U.S. East Coast, 0.5 Bcfd of generic export capacity is assumed. In total, all North American LNG export facilities modeled in the Aggregate Exports Case when all export facilities are fully online is approximately 7.7 Bcfd. Minor infrastructure adjustments were made to accommodate the new facilities, as well as additional supply in the Horn River Basin and Haynesville shale plays. The effects on prices are the specific focus.
Analysis Two	
High Demand Base Case	The **High Demand Base Case** adds to the Base Case additional demand to reflect the overall level of NGV natural gas demand assumed by the EIA in its high NGV demand scenario in its AEO 2010 analysis. The additional NGV demand in the High Demand Base Case ramps up to 4.2 Bcfd in 2035. In addition, the 2.5 Bcfd of generic LNG export capacity from the Aggregate Exports Case is added, for total LNG export capacity of 6.2 Bcfd. Minor infrastructure adjustments were made to accommodate the new facilities, as well as a generalized increase in supply across the U.S.
High Demand Base Case Plus GLNG @ 1.5 Bcfd	The **High Demand Base Case Plus GLNG @ 1.5 Bcfd** augments the High Demand Base Case with exports from the 1.5 Bcfd capacity GLNG export facility beginning December 2018. Minor infrastructure adjustments were made to accommodate the new facilities. The effects on prices are the specific focus.

Base Case

The **Base Case** was derived from Navigant's Spring 2012 Reference Case, and includes two LNG liquefaction and export facilities as active. Sabine Pass LNG in Louisiana, the only liquefaction facility that has received DOE authority to export LNG to both FTA and non-FTA countries, is specifically modeled, with a capacity of 2.2 Bcfd. The first of four trains is assumed to come online in 2015, operating at 90% average capacity. Capacity ramps up to the full 2.2 Bcfd by late 2017. Similarly, Kitimat LNG near Prince Rupert, British Columbia, the only LNG export facility approved by the Canadian National Energy Board at the time of modeling, is assumed to have the first of its two trains come on line in 2015, operating at 90% average capacity, with maximum capacity of 1.5 Bcfd installed in 2017.

Supply

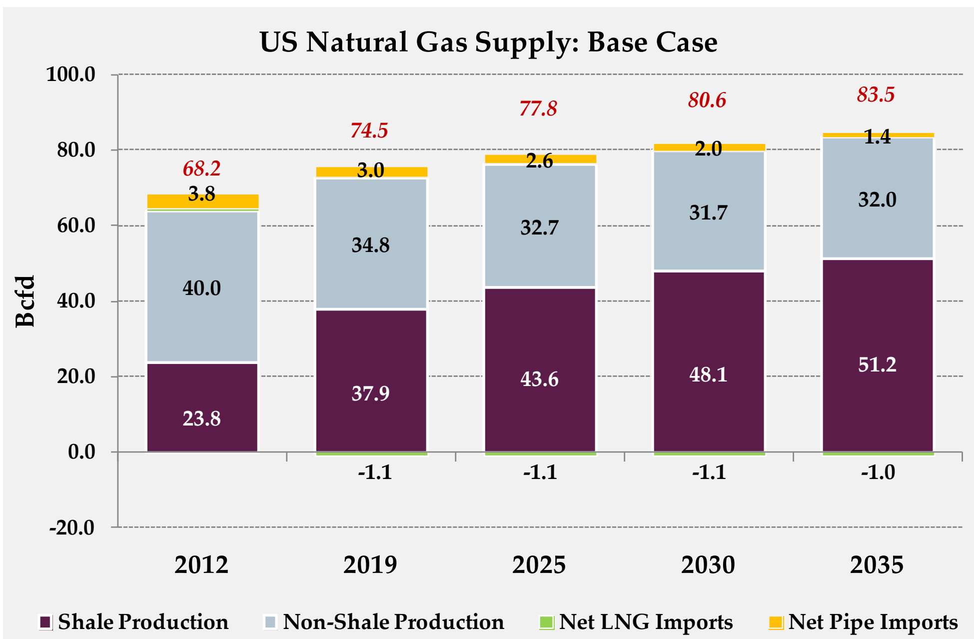

Figure 16: Base Case Supply

As shown in Figure 16, above, by 2019, net LNG imports to the U.S. are negative, as the U.S. becomes a net exporter of LNG.[69]

[69] The exports from the U.S. appear as negative numbers below the zero line on the supply graph. Due to scale, the column areas associated with the exports are not visible.

Demand

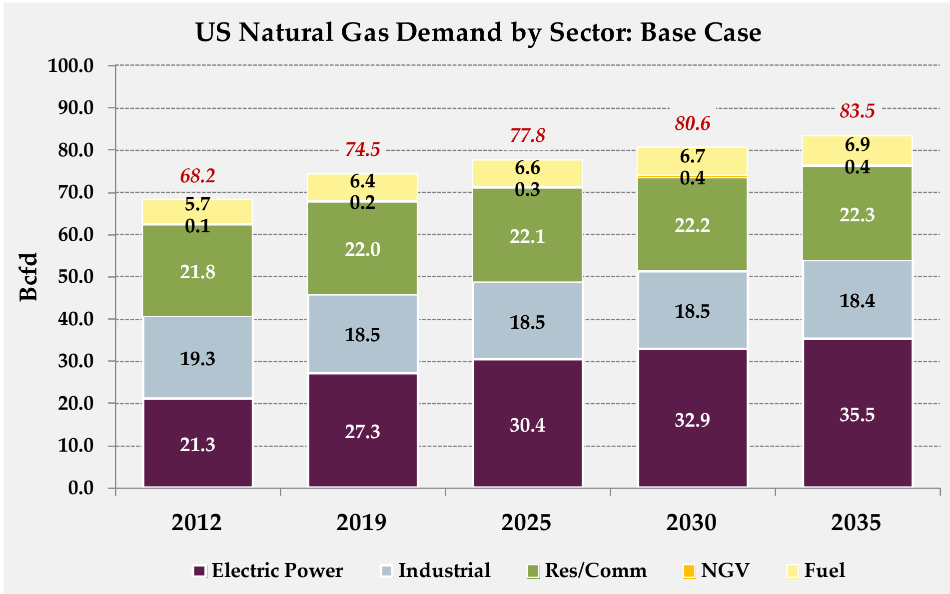

Figure 17: Base Case Demand

As shown in Figure 17, above, domestic U.S. demand is satisfied across the planning horizon in balance with supply, depicted in Figure 16.

Resultant Gas Prices

As shown in Figure 18, prices at Henry Hub remain at or below $5.00 per MMBtu through 2025. After 2025, prices rise more due to generally increasing marginal costs of additional domestic production. Henry Hub reaches $6.45 per MMBtu in 2035. Prices at Transco Zone 4 show a small positive basis to Henry Hub, averaging about $0.14 per MMBtu, throughout the forecast period.

For comparison, the U.S. EIA's AEO 2012 Reference Case price forecast for Henry Hub for 2035 (the last year of its forecast) is $7.52 per MMBtu in 2011 dollars (converted from $7.37 in 2010 dollars).[70]

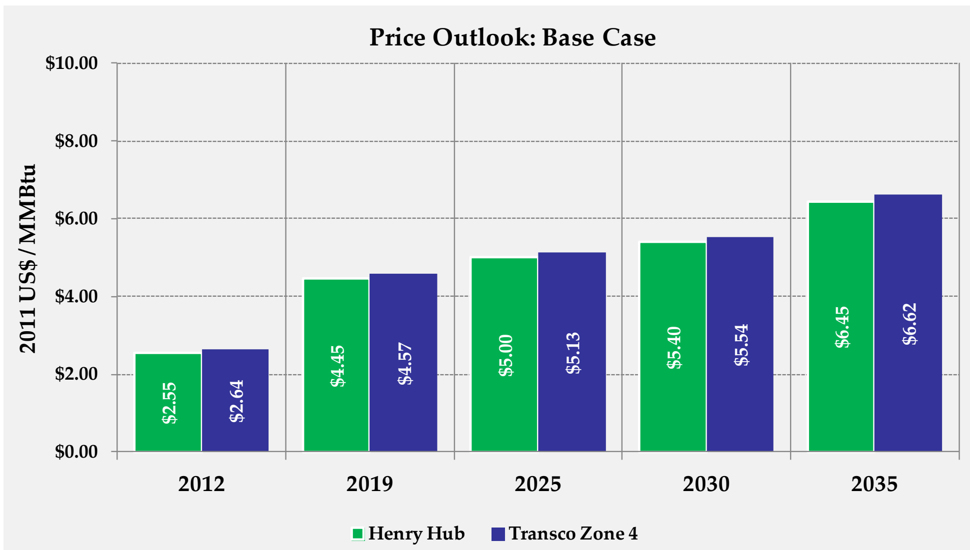

Figure 18: Base Case Prices

[70] EIA Annual Energy Outlook 2012, interactive table Natural Gas Supply, Disposition, and Prices, Reference Case.

GLNG Exports Case

The **GLNG Exports Case** tests the effects of exporting LNG from the 1.5 Bcfd capacity GLNG export facility beginning December 2018 against the Base Case.[71] All other inputs and assumptions remain the same as in the Base Case. On an annual basis, a 10% maintenance downtime produces average LNG export volumes of 1.35 Bcfd.

Supply

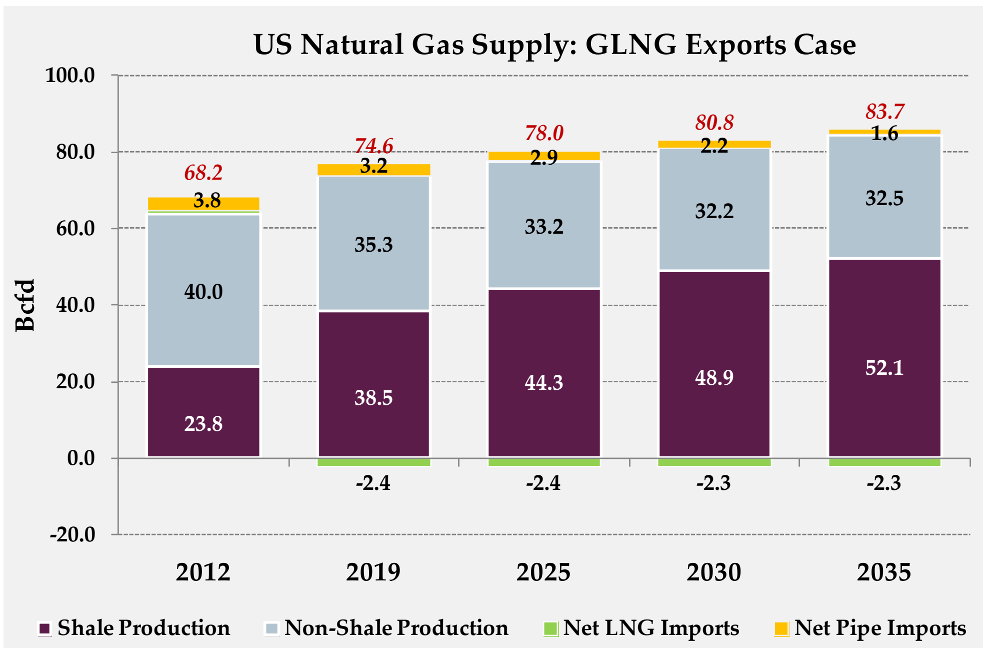

Figure 19: GLNG Exports Case Supply

As can be seen by comparing Figure 19, above, to Figure 16, as well as shown in Table 4, below, the addition of LNG exports from GLNG increases U.S. natural gas production by about the same amount, with small increases in net pipeline imports sufficient to also cover incremental pipeline fuel and plant losses (totals are not exact due to round-off)

[71] While it is possible that some other LNG export facility could export the 1.5 Bcfd incremental quantity assumed in the GLNG Exports Case in the absence of GLNG, the purpose of this analysis is to review the impact of GLNG as the specific assumed facility.

Year	Metric	Base Case	GLNG Exports Case	Difference
2012	*Shale Production*	23.8	23.8	0.0
	Non-shale Production	40.0	40.0	0.0
	Net LNG Imports	0.6	0.6	0.0
	Net Pipe Imports	3.8	3.8	0.0
	Total Supply	**68.2**	**68.2**	**0.0**
2019	*Shale Production*	37.9	38.5	0.7
	Non-shale Production	34.8	35.3	0.6
	Net LNG Imports	-1.1	-2.4	-1.3
	Net Pipe Imports	3.0	3.2	0.2
	Total Supply	**74.5**	**74.6**	**0.2**
2025	*Shale Production*	43.6	44.3	0.7
	Non-shale Production	32.7	33.2	0.5
	Net LNG Imports	-1.1	-2.4	-1.3
	Net Pipe Imports	2.6	2.9	0.2
	Total Supply	**77.8**	**78.0**	**0.2**
2035	*Shale Production*	51.2	52.1	0.8
	Non-shale Production	32.0	32.5	0.4
	Net LNG Imports	-1.0	-2.3	-1.3
	Net Pipe Imports	1.4	1.6	0.2
	Total Supply	**83.5**	**83.7**	**0.2**

Table 4: Changes in U.S. Supply from Base Case to GLNG Exports Case[72]

[72] "Total supply" includes a small net storage and balancing component. Due to this, the sum of dry production, LNG, and pipe imports may not equal total supply.

Demand

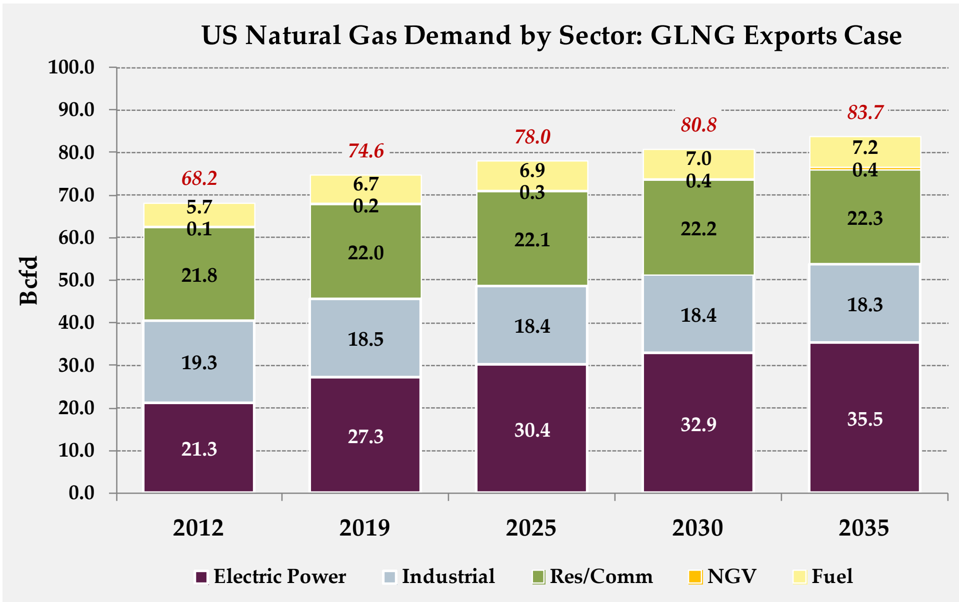

Figure 20: GLNG Exports Case Demand

As can be seen by comparing Figure 20 to Figure 17, LNG exports at GLNG have virtually no effect on the distribution of demand among the major sectors. As can also be seen in Table 5, below, there is almost no difference between the Base Case and the GLNG Exports Case besides a small increment of plant fuel loss.

Year	Metric	Base Case	GLNG Exports Case	Difference
2012	*Electric Power*	21.3	21.3	0.0
	Industrial	19.3	19.3	0.0
	Res/Comm	21.8	21.8	0.0
	NGV	0.1	0.1	0.0
	Total Consumption	**68.2**	**68.2**	**0.0**
2019	*Electric Power*	27.3	27.3	0.0
	Industrial	18.5	18.5	-0.1
	Res/Comm	22.0	22.0	0.0
	NGV	0.2	0.2	0.0
	Total Consumption	**74.5**	**74.6**	**0.2**
2025	*Electric Power*	30.4	30.4	0.0
	Industrial	18.5	18.4	-0.1
	Res/Comm	22.1	22.1	0.0
	NGV	0.3	0.3	0.0
	Total Consumption	**77.8**	**78.0**	**0.2**
2035	*Electric Power*	35.5	35.5	0.0
	Industrial	18.4	18.3	-0.1
	Res/Comm	22.3	22.3	0.0
	NGV	0.4	0.4	0.0
	Total Consumption	**83.5**	**83.7**	**0.2**

Table 5: Changes in U.S. Demand from Base Case to GLNG Exports Case[73]

Resultant Gas Prices

Prices at Transco Zone 4 and Henry Hub in the GLNG Exports Case remain below $6.00 per MMBtu through 2031 and 2032, respectively. The average price increase versus the Base Case over the term of the forecast is $0.28 per MMBtu for Henry Hub, and $0.29 per MMBtu for Transco Zone 4 versus average Base Case prices over the term of $5.23 and $5.37, respectively, or 5.4%. Figure 21 and Table 6, below, summarize these impacts. When compared to the average overall residential retail rate, the 29 cents represents an even smaller percentage because of the additional costs to consumers from the distribution utility for pipeline, storage, and distribution system costs, as well as the utility rate of return. For example, a consumer in Mississippi pays an additional $2.73 per MMBtu on top of the cost of gas for natural gas service, so the 29 cents actually translates to only 3.6% of an average total cost of $8.10 per MMBtu.[74]

[73] "Total consumption" includes pipeline fuel, and lease and plant fuel. Due to this, the sum of sector demands may not equal total consumption.

[74] Under Centerpoint Energy's current residential rate schedule for Mississippi, the average rate beyond the cost of gas comes to $2.73 per MMBtu, based on a $9 per month customer charge, and a volumetric charge of $1.00

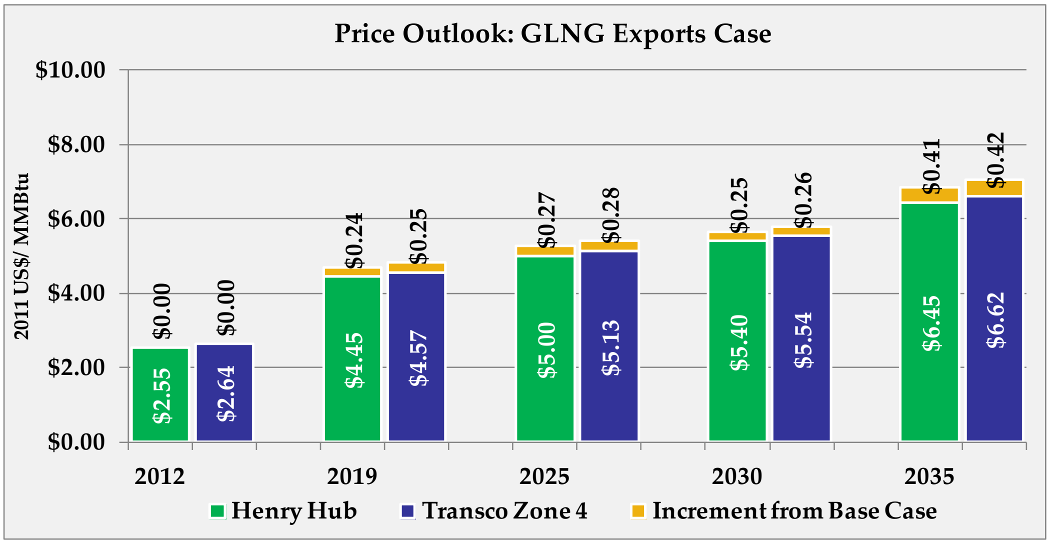

Figure 21: GLNG Exports Case Prices

		A	B	C=A-B	D=A/B-1
Year	*Metric*	**GLNG Exports Case**	**Base Case**	*Absolute Difference*	*Percentage Difference*
2012	*Henry Hub*	**$2.55**	**$2.55**	*$0.00*	*0.0%*
	Transco Zone 4	**$2.64**	**$2.64**	*$0.00*	*0.0%*
2019	*Henry Hub*	**$4.69**	**$4.45**	*$0.24*	*5.4%*
	Transco Zone 4	**$4.82**	**$4.57**	*$0.25*	*5.4%*
2025	*Henry Hub*	**$5.27**	**$5.00**	*$0.27*	*5.5%*
	Transco Zone 4	**$5.42**	**$5.13**	*$0.28*	*5.5%*
2035	*Henry Hub*	**$6.86**	**$6.45**	*$0.41*	*6.3%*
	Transco Zone 4	**$7.04**	**$6.62**	*$0.42*	*6.4%*

Table 6: Changes in Price from Base Case to GLNG Exports Case

per MMBtu above "cost of gas", assuming consumption at the state's average 52 therms per month. The 29 cents would therefore only be 3.6% of the total retail rate for residential gas consumers.

Aggregate Exports Case

The **Aggregate Exports Case** builds on the GLNG Exports Case. In the Aggregate Exports Case, other U.S. LNG exports are assumed in addition to Sabine Pass, Kitimat, and GLNG. This includes an additional 1.0 Bcfd each of LNG export capacity in the Gulf of Mexico and on the U.S. West Coast, and 0.5 Bcfd on the U.S. East Coast, for a total generic export capacity of 2.5 Bcfd. Several such LNG export facilities have been proposed, and more may be. Therefore, Navigant makes no judgment as to which specific ones will be approved and ready to operate by the start-up date of GLNG, and models these export volumes generically.

Supply

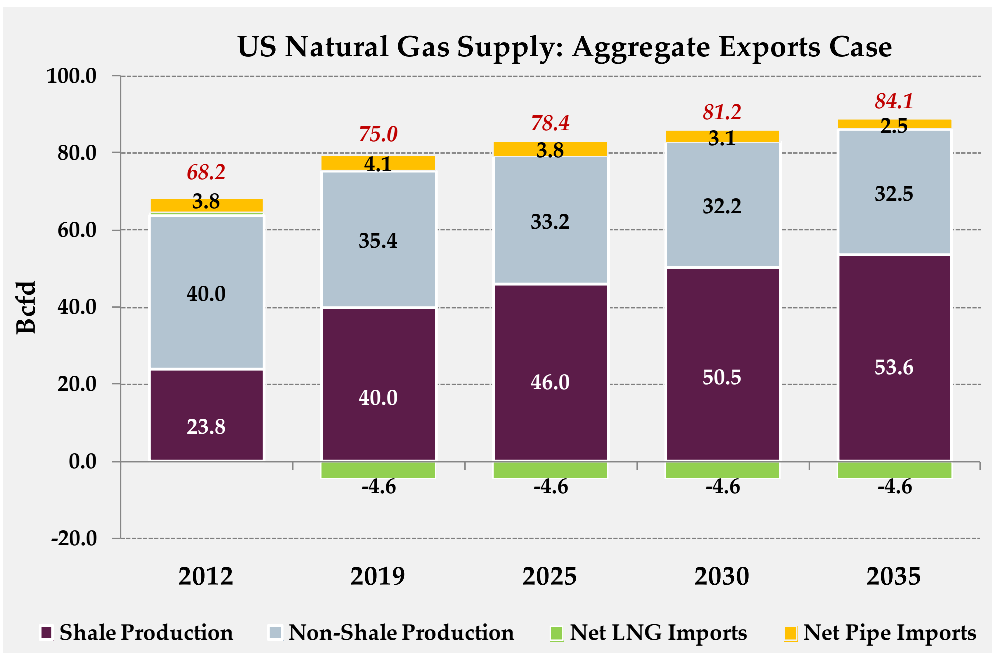

Figure 22: Aggregate Exports Case Supply

The addition of 2.5 Bcfd of LNG export capacity in addition to Kitimat, Sabine Pass, and GLNG stimulates supply production in the U.S. For example, in 2019, shale production rises from 38.5 Bcfd in the GLNG Exports Case to 40.0 Bcfd. Similarly, non-shale U.S. production rises from 35.3 Bcfd to 35.4 Bcfd, for a total increase in dry production of about 1.6 Bcfd. Pipeline imports increase from 3.2 Bcfd in 2019 to 4.1 Bcfd. Total supply, after exports (after changes in storage and a balancing component) increases by about 0.4 Bcfd in 2019. These impacts can be seen by comparing Figure 22, above, to Figure 19, and are summarized in Table 7, below.

Year	Metric	GLNG Exports Case	Aggregate Exports Case	Difference
2012	*Shale Production*	23.8	23.8	0.0
	Non-shale Production	40.0	40.0	0.0
	Net LNG Imports	0.6	0.6	0.0
	Net Pipe Imports	3.8	3.8	0.0
	Total Supply	**68.2**	**68.2**	**0.0**
2019	*Shale Production*	38.5	40.0	1.4
	Non-shale Production	35.3	35.4	0.1
	Net LNG Imports	-2.4	-4.6	-2.2
	Net Pipe Imports	3.2	4.1	1.0
	Total Supply	**74.6**	**75.0**	**0.4**
2025	*Shale Production*	44.3	46.0	1.7
	Non-shale Production	33.2	33.2	0.1
	Net LNG Imports	-2.4	-4.6	-2.2
	Net Pipe Imports	2.9	3.8	0.9
	Total Supply	**78.0**	**78.4**	**0.4**
2035	*Shale Production*	52.1	53.6	1.6
	Non-shale Production	32.5	32.5	0.1
	Net LNG Imports	-2.3	-4.6	-2.2
	Net Pipe Imports	1.6	2.5	0.9
	Total Supply	**83.7**	**84.1**	**0.4**

Table 7: Changes in U.S. Supply from GLNG Exports Case to Aggregate Exports Case[75]

[75] "Total supply" includes a small net storage and balancing component. Due to this, the sum of dry production, LNG, and pipe imports may not equal total supply.

Demand

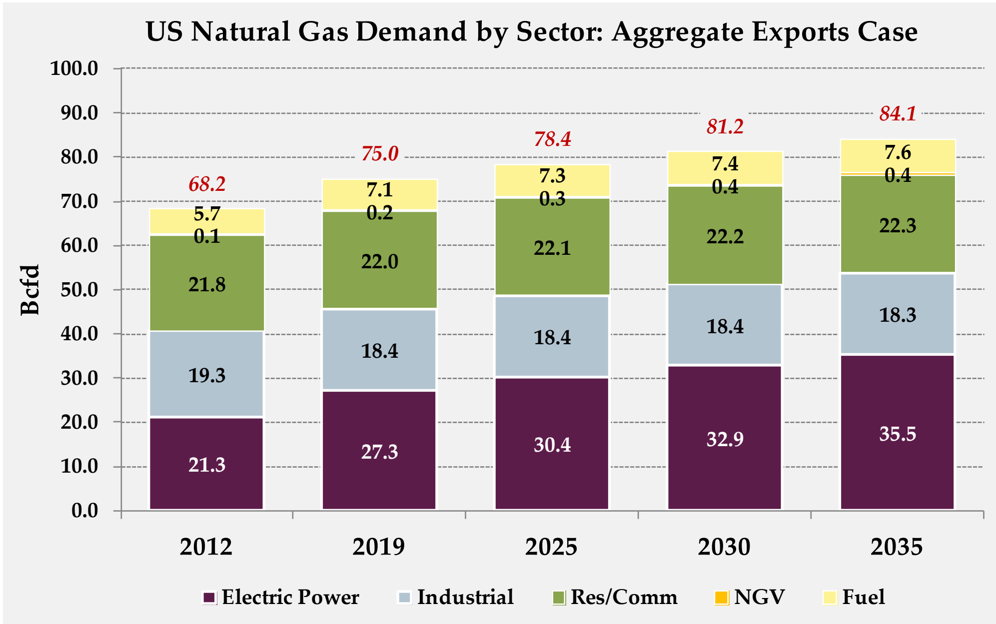

Figure 23: Aggregate Exports Case Demand

The Aggregate Exports Case adds approximately 0.4 Bcfd increase in fuel demand across the U.S. Otherwise, the distribution of demand is unaffected. These impacts can be seen by comparing Figure 23, above, to Figure 20, and are summarized in Table 8, below.

Year	Metric	GLNG Exports Case	Aggregate Exports Case	Difference
2012	*Electric Power*	21.3	21.3	0.0
	Industrial	19.3	19.3	0.0
	Res/Comm	21.8	21.8	0.0
	NGV	0.1	0.1	0.0
	Total Consumption	**68.2**	**68.2**	**0.0**
2019	*Electric Power*	27.3	27.3	0.0
	Industrial	18.5	18.4	0.0
	Res/Comm	22.0	22.0	0.0
	NGV	0.2	0.2	0.0
	Total Consumption	**74.6**	**75.0**	**0.4**
2025	*Electric Power*	30.4	30.4	0.0
	Industrial	18.4	18.4	0.0
	Res/Comm	22.1	22.1	0.0
	NGV	0.3	0.3	0.0
	Total Consumption	**78.0**	**78.4**	**0.4**
2035	*Electric Power*	35.5	35.5	0.0
	Industrial	18.3	18.3	0.0
	Res/Comm	22.3	22.3	0.0
	NGV	0.4	0.4	0.0
	Total Consumption	**83.7**	**84.1**	**0.4**

Table 8: Changes in U.S. Demand from GLNG Exports Case to Aggregate Exports Case[76]

Resultant Gas Prices

Prices at Henry Hub in the Aggregate Exports Case remain below $5.00 per MMBtu through 2021, near or below $6.00 per MMBtu through 2032, and just exceed $7.00 per MMBtu in 2035, at $7.04. Incremental increases at Henry Hub versus the GLNG Exports Case average about $0.12 over the study period, or about 2.2%. Prices at Transco Zone 4 in the Aggregate Exports Case remain near or $5.00 per MMBtu through 2020, near or below $6.00 per MMBtu through 2031, and exceed $7.00 per MMBtu only in 2035, at $7.22. Incremental increases at Transco Zone 4 versus the GLNG Exports Case average about $0.13 over the study period, or about 2.3%. Figure 24 and Table 9, below, summarize these impacts.

[76] "Total consumption" includes pipeline fuel, and lease and plant fuel. Due to this, the sum of sector demands may not equal total consumption.

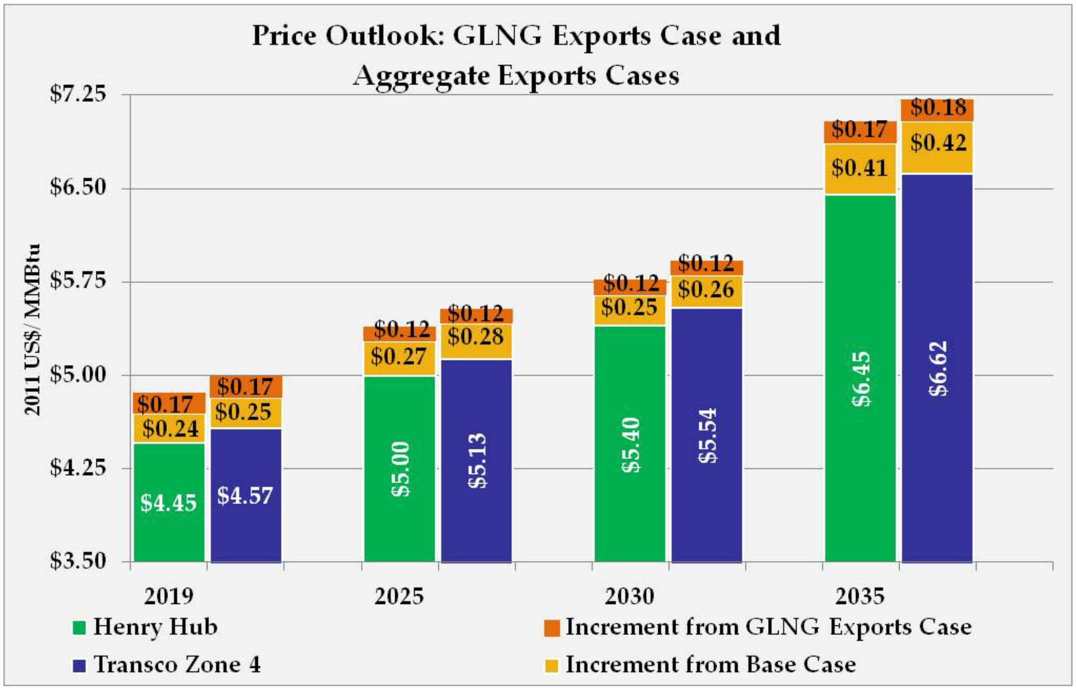

Figure 24: Aggregate Exports Case Prices

		A	B	C=A-B	D=A/B-1
Year	*Metric*	**Aggregate Exports Case**	**GLNG Exports Case**	*Absolute Difference*	*Percentage Difference*
2012	*Henry Hub*	**$2.55**	**$2.55**	*$0.00*	*0.0%*
	Transco Zone 4	**$2.64**	**$2.64**	*$0.00*	*0.0%*
2019	*Henry Hub*	**$4.86**	**$4.69**	*$0.17*	*3.6%*
	Transco Zone 4	**$4.99**	**$4.82**	*$0.17*	*3.5%*
2025	*Henry Hub*	**$5.39**	**$5.27**	*$0.12*	*2.2%*
	Transco Zone 4	**$5.54**	**$5.42**	*$0.12*	*2.2%*
2035	*Henry Hub*	**$7.04**	**$6.86**	*$0.17*	*2.5%*
	Transco Zone 4	**$7.22**	**$7.04**	*$0.18*	*2.5%*

Table 9: Changes in Prices from GLNG Exports Case to Aggregate Exports Case

High Demand Base Case

The **High Demand Base Case** represents an alternative scenario to the Base Case in order to reflect the more aggressive assumptions for natural gas vehicle (NGV) phase-in used by the EIA in its AEO 2010 high case for heavy duty NGVs, as well as the addition of the generic LNG export facilities from the Aggregate Exports Case from the previous analysis.[77] The additional natural gas demand for NGVs in the High Demand Base Case gradually ramps up, starting in 2015, to 4.2 Bcfd in 2035. EIA assumed a 40% share of heavy duty vehicle fuel demand by NGVs in 2035, up from 1.8% in its reference case.[78]

With respect to the LNG export capacity, the High Demand Base Case includes the two Base Case facilities, Sabine Pass LNG modeled at 2.2 Bcfd and Kitimat LNG modeled at 1.5 Bcfd. With the 2.5 Bcfd of generic LNG export additions presented in the Aggregate Exports Case, the total becomes 6.2 Bcfd of North American LNG export capacity. The High Demand Base Case then becomes the starting point for Analysis Two.

Supply

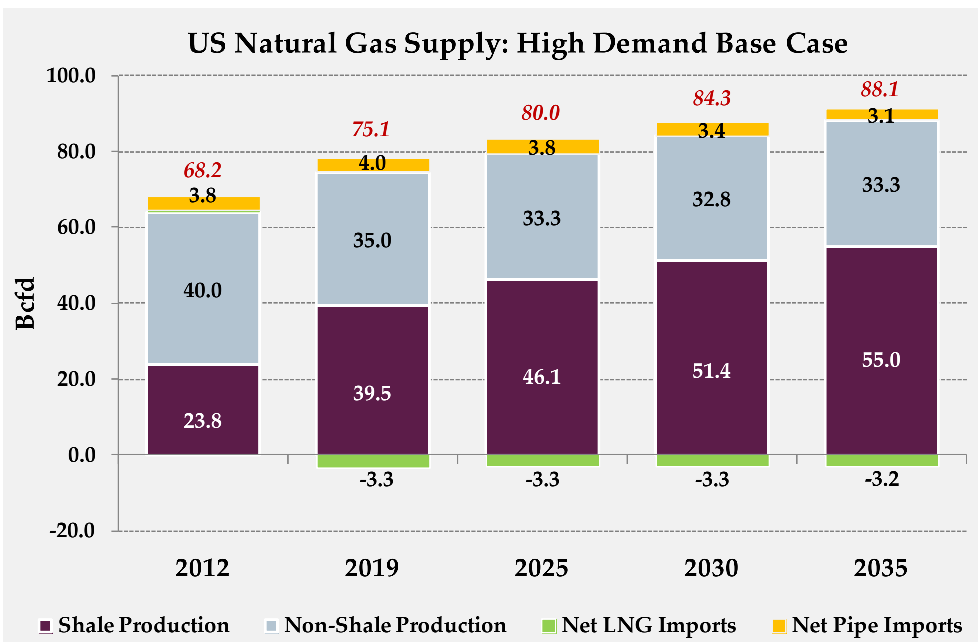

Figure 25: High Demand Base Case Supply

As shown in Figure 25, above, net LNG imports to the U.S. are negative by 2019, as the U.S. becomes a net exporter of LNG.

[77] At the time of the modeling for this analysis, the AEO 2010 analysis was the latest work by EIA on NGVs; subsequent to Navigant's modeling, the EIA released its AEO 2012, which contained a new NGV analysis based on an additional 0.5 Bcfd of NGV gas demand in 2035.
[78] EIA AEO 2010, pg. 36.

Demand

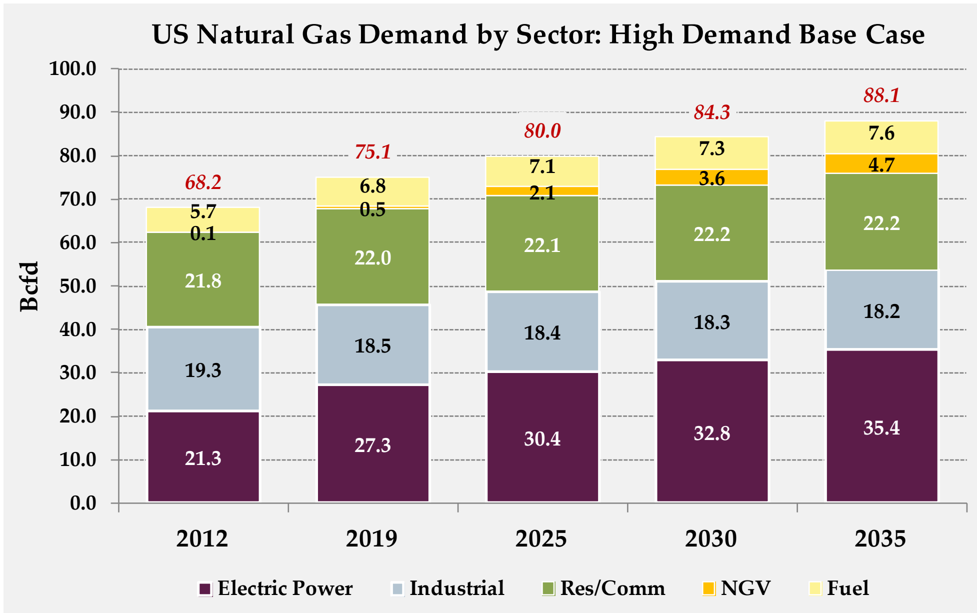

Figure 26: High Demand Base Case Demand

As shown in Figure 26, above, domestic U.S. demand is satisfied across the planning horizon in balance with supply, depicted in Figure 25.

Resultant Gas Prices

As shown in Figure 27, prices at Henry Hub remain below $5.00 per MMBtu through 2023. After 2023, prices rise more due to generally increasing marginal costs of additional domestic production. Henry Hub reaches $7.48 per MMBtu in 2035. Prices at Transco Zone 4 show a small positive basis to Henry Hub, averaging about $0.15 per MMBtu, throughout the forecast period.

For comparison, the U.S. EIA's AEO 2012 Reference Case price forecast for Henry Hub for 2035 (the last year of its forecast) is $7.52 per MMBtu in 2011 dollars (converted from $7.37 in 2010 dollars).[79]

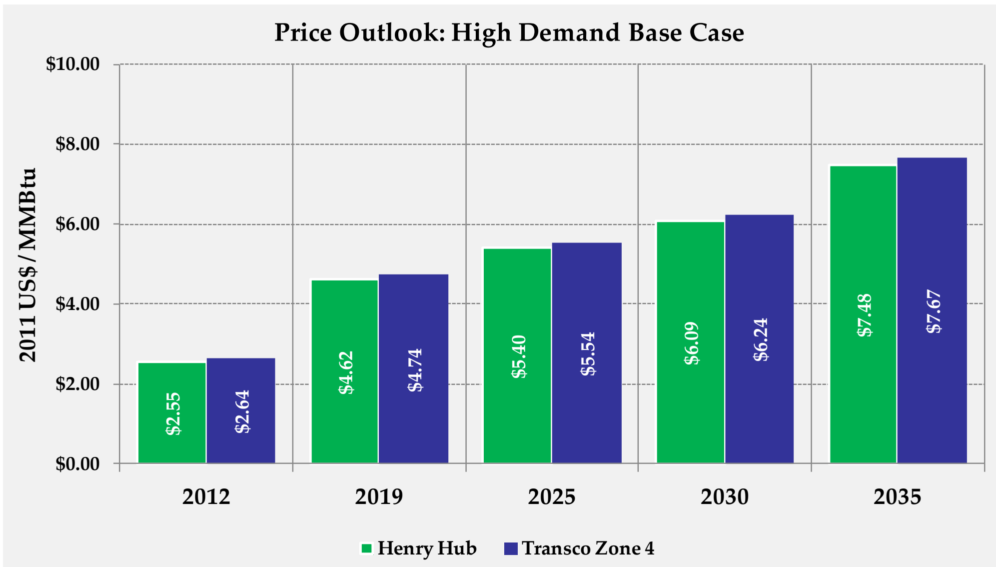

Figure 27: High Demand Base Case Prices

[79] EIA Annual Energy Outlook 2012, interactive table Natural Gas Supply, Disposition, and Prices, Reference Case.

High Demand Base Case Plus GLNG @ 1.5 Bcfd

The **High Demand Base Case Plus GLNG @ 1.5 Bcfd** tests the effects of exporting LNG from the 1.5 Bcfd capacity GLNG export facility against the High Demand Base Case.[80] All other inputs and assumptions remain the same as in the High Demand Base Case. On an annual basis, a 10% maintenance downtime produces average LNG export volumes of 1.35 Bcfd.

Supply

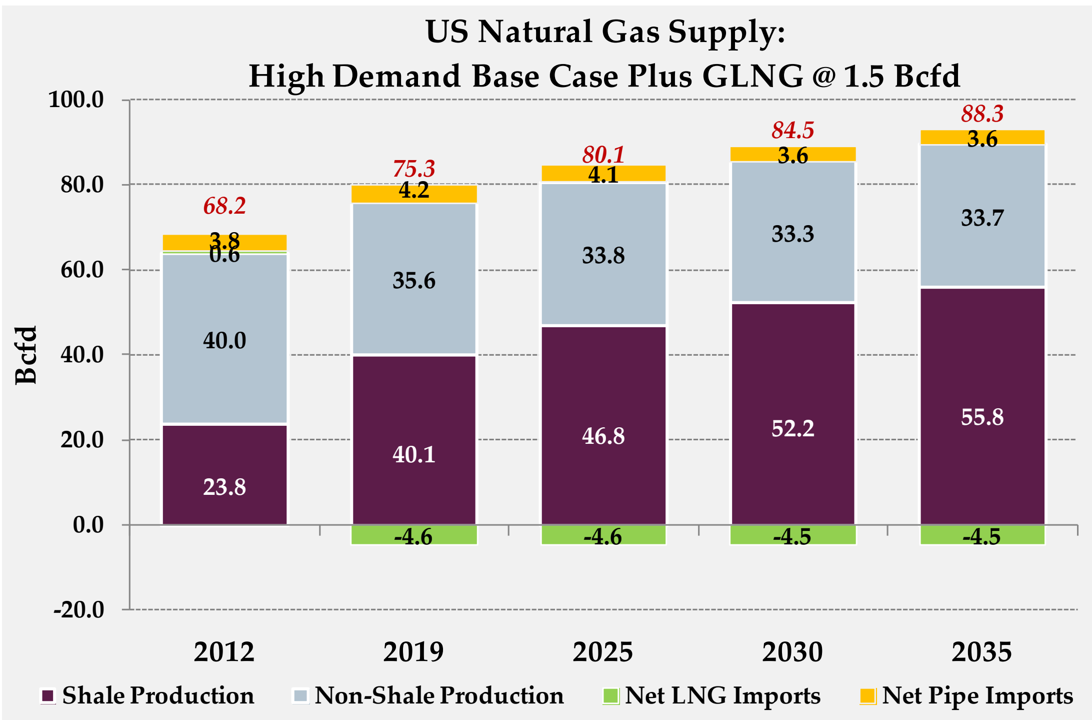

Figure 28: High Demand Base Case Plus GLNG @ 1.5 Bcfd Supply

As can be seen by comparing Figure 28, above, to Figure 27, as well as shown in Table 10, the addition of LNG exports from GLNG increases U.S. natural gas production by about the same amount, with small increases in net pipeline imports sufficient to also cover incremental pipeline fuel and plant losses (totals are not exact due to round-off).

[80] While it is possible that some other LNG export facility could export the 1.5 Bcfd incremental quantity assumed in the High Demand Base Case Plus GLNG @ 1.5 Bcfd in the absence of GLNG, the purpose of this analysis is to review the impact of GLNG as the specific assumed facility.

Year	Metric	High Demand Base Case	High Demand Base Case Plus GLNG @ 1.5 Bcfd	Difference
2012	*Shale Production*	23.8	23.8	0.0
	Non-shale Production	40.0	40.0	0.0
	Net LNG Imports	0.6	0.6	0.0
	Net Pipe Imports	3.8	3.8	0.0
	Total Supply	**68.2**	**68.2**	**0.0**
2019	*Shale Production*	39.5	40.1	0.7
	Non-shale Production	35.0	35.6	0.6
	Net LNG Imports	-3.3	-4.6	-1.3
	Net Pipe Imports	4.0	4.2	0.2
	Total Supply	**75.1**	**75.3**	**0.2**
2025	*Shale Production*	46.1	46.8	0.7
	Non-shale Production	33.3	33.8	0.5
	Net LNG Imports	-3.3	-4.6	-1.3
	Net Pipe Imports	3.8	4.1	0.2
	Total Supply	**80.0**	**80.1**	**0.2**
2035	*Shale Production*	55.0	55.8	0.7
	Non-shale Production	33.3	33.7	0.4
	Net LNG Imports	-3.2	-4.5	-1.3
	Net Pipe Imports	3.1	3.6	0.4
	Total Supply	**88.1**	**88.3**	**0.2**

Table 10: Changes in U.S. Supply from the High Demand Base Case to the High Demand Base Case Plus GLNG @ 1.5 Bcfd[81]

[81] "Total supply" includes a small net storage and balancing component. Due to this, the sum of dry production, LNG, and pipe imports may not equal total supply.

Demand

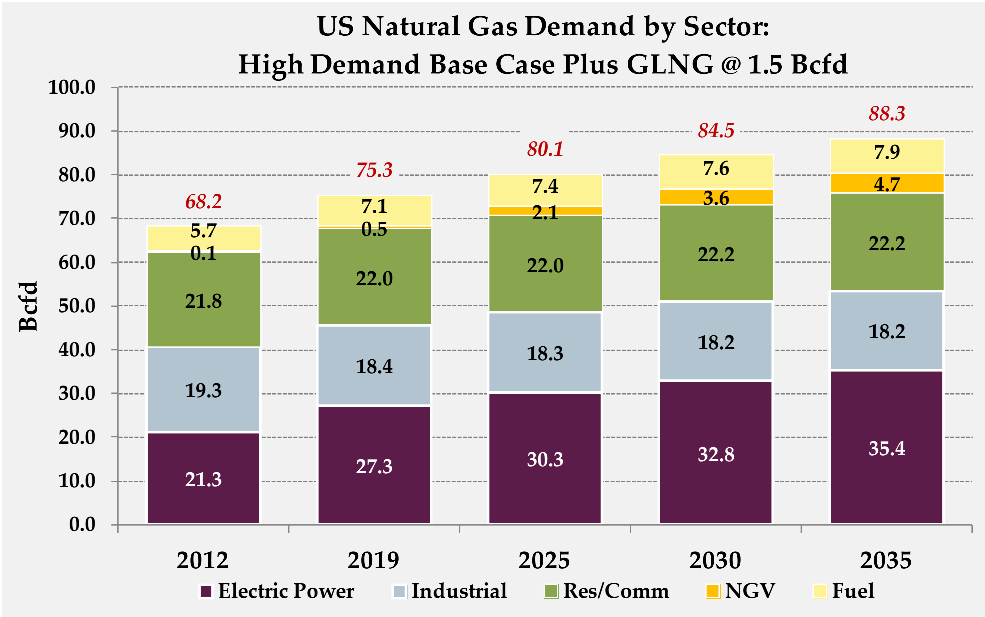

Figure 29: High Demand Base Case Plus GLNG @ 1.5 Bcfd Demand

As can be seen by comparing Figure 29 to Figure 26, LNG exports at GLNG have virtually no effect on the distribution of demand among the major sectors. This is shown in Table 11, where there is almost no difference between the High Demand Base Case and the High Demand Base Case Plus GLNG @ 1.5 Bcfd, except for a small increment of plant fuel loss.

Year	Metric	High Demand Base Case	High Demand Base Case Plus GLNG @ 1.5 Bcfd	Difference
2012	*Electric Power*	21.3	21.3	0.0
	Industrial	19.3	19.3	0.0
	Res/Comm	21.8	21.8	0.0
	NGV	0.1	0.1	0.0
	Total Consumption	**68.2**	**68.2**	**0.0**
2019	*Electric Power*	27.3	27.3	0.0
	Industrial	18.5	18.4	-0.1
	Res/Comm	22.0	22.0	0.0
	NGV	0.5	0.5	0.0
	Total Consumption	**75.1**	**75.3**	**0.2**
2025	*Electric Power*	30.4	30.3	0.0
	Industrial	18.4	18.3	-0.1
	Res/Comm	22.1	22.0	0.0
	NGV	2.1	2.1	0.0
	Total Consumption	**80.0**	**80.1**	**0.2**
2035	*Electric Power*	35.4	35.4	0.0
	Industrial	18.2	18.2	-0.1
	Res/Comm	22.2	22.2	0.0
	NGV	4.7	4.7	0.0
	Total Consumption	**88.1**	**88.3**	**0.2**

Table 11: Changes in U.S. Demand from the High Demand Base Case to the High Demand Base Case Plus GLNG @ 1.5 Bcfd[82]

Resultant Gas Prices

Prices at Transco Zone 4 and Henry Hub in the High Demand Base Case With GLNG remain near or below $6.00 per MMBtu through 2025 and 2026, respectively, and below $7.00 per MMBtu through 2032. The average price increase versus the High Demand Base Case over the term of the forecast is $0.38 per MMBtu for Henry Hub, and $0.39 per MMBtu for Transco Zone 4 versus average High Demand Base Case prices over the term of $5.77 and $5.92, respectively, or 6.7%. Figure 30 and Table 12, below, summarize these impacts.

[82] "Total consumption" includes pipeline fuel, and lease and plant fuel. Due to this, the sum of sector demands may not equal total consumption.

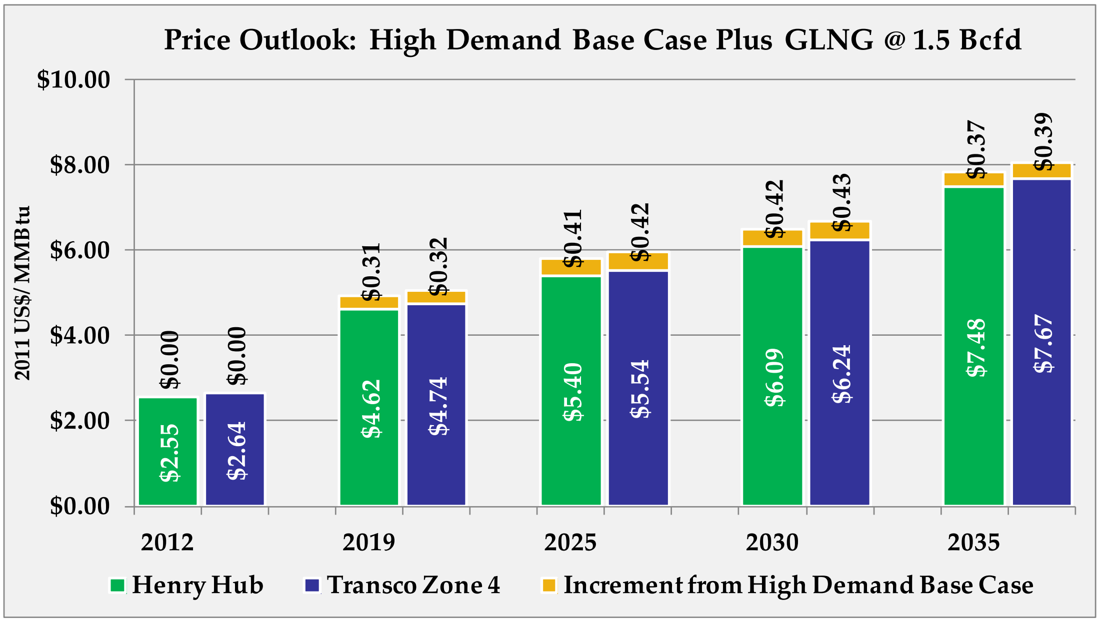

Figure 30: High Demand Base Case Plus GLNG @ 1.5 Bcfd Prices

		A	B	*C=A-B*	*D=A/B-1*
Year	**Metric**	**High Demand Base Case Plus GLNG @ 1.5 Bcfd**	**High Demand Base Case**	***Absolute Difference***	***Percentage Difference***
2012	*Henry Hub*	**$2.55**	**$2.55**	*$0.00*	*0.0%*
	Transco Zone 4	**$2.64**	**$2.64**	*$0.00*	*0.0%*
2019	*Henry Hub*	**$4.92**	**$4.62**	*$0.31*	*6.7%*
	Transco Zone 4	**$5.06**	**$4.74**	*$0.32*	*6.8%*
2025	*Henry Hub*	**$5.81**	**$5.40**	*$0.41*	*7.6%*
	Transco Zone 4	**$5.97**	**$5.54**	*$0.42*	*7.6%*
2035	*Henry Hub*	**$7.85**	**$7.48**	*$0.37*	*4.9%*
	Transco Zone 4	**$8.06**	**$7.67**	*$0.39*	*5.0%*

Table 12: Changes in Prices from High Demand Base Case to High Demand Base Case Plus GLNG @ 1.5 Bcfd

Appendix A: Abbreviations and Acronyms

AEO	Annual Energy Outlook (EIA publication)
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
CCS	Carbon capture and sequestration
CSAPR	Cross-State Air Pollution Rule
DOE	Department of Energy
DOE/FE	Department of Energy / Office of Fossil Energy
Dth	Dekatherm
EG	Electric generation
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
FTA	Free Trade Agreement
GLNG	Gulf LNG Liquefaction Company, LLC
GPCM	Gas Pipeline Competition Model
GW	Gigawatt (one billion watts; 1,000 megawatts)
IEA	International Energy Agency
IP	Initial production
LNG	Liquefied natural gas
Mcf	Thousand cubic feet (approx. 1.0 MMBtu)
MMBtu	Million British thermal units
MMcf	Million cubic feet
MW	Megawatt (one million watts)
NEB	National Energy Board (Canada)
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
NGV	Natural gas vehicle
SEAB	Secretary of Energy Advisory Board
Tcf	Trillion cubic feet
USGS	United States Geological Survey

Appendix B: Future Infrastructure in Reference Case

Storage New and Expansion Projects 2012 and Beyond			
Storage Facility	State	Date	Working Capacity (MMcf)
Aliso Canyon (Expansion)	CA	Apr-13	86,000
Cadeville	LA	Jun-12	11,500
Copiah	MS	Apr-14	3,000
Crowville	LA	Jul-13	7,500
Crowville (Expansion)	LA	Jul-15	15,000
Golden Triangle (Expansion)	TX	Jun-13	12,000
Leaf River (Expansion)	MS	Apr-13	24,000
Leaf River (Expansion)	MS	Apr-14	32,000
McIntosh (Expansion)	AL	Nov-12	16,000
MoBay	AL	Jun-12	50,000
Pine Prairie (Expansion)	LA	May-13	42,000
Pine Prairie (Expansion)	LA	May-16	45,000
Ryckman Creek	WY	Apr-12	19,000
Ryckman Creek (Expansion)	WY	Apr-13	35,000
Tricor Ten Section Hub	CA	Jan-12	22,400
Western Energy Hub	UT	Apr-12	5,600
Windy Hill (Expansion)	CO	Apr-12	12,000
Windy Hill (Expansion)	CO	Apr-13	18,000
Windy Hill (Expansion)	CO	Apr-14	24,000
Windy Hill (Expansion)	CO	Apr-15	32,000

Future Pipelines and Expansions in Reference Case					
Pipeline	Date	Capacity (MMcfd)	Pipeline	Date	Capacity (MMcfd)
Algonquin (Algonquin J)	12-Jan	400	Enterprise Tex (Valero/Teco)	14-Jun	200
Midcontinent Express Z1	12-Jan	200	LNG Manzanillo Header	14-Jul	500
PNGT (N & S of Westbrook)	12-Jan	310	Algonquin (NJ NY)	14-Nov	799
Transco Z6 (PA)	12-Jan	500	Tenn Z5 NJ	14-Nov	636
Transco Z6 (PA)	12-Apr	300	Iroquois NY Narc	14-Nov	500
Equitrans WV-PA Line	12-Jul	314	Transco Z6 Rockaway Lateral	14-Nov	625
Stagecoach Hub (N & S Lat)	12-Jul	50	Transco Z6 Atlantic Access	14-Dec	1,100
Stagecoach Hub (MARC I)	12-Jul	550	CrossTex North Texas	15-Jan	750
Transco Z6 (PA)	12-Jul	300	El Paso (Samalayuca)	15-Jan	312
Transco Z6 (PA)	12-Oct	300	Enterprise Jonah Gath (WY)	15-Jan	600
Alliance Pipeline BC	12-Nov	300	Florida Gas (Panhandle/Z3)	15-Jan	500
Millennium Phase I	12-Nov	150	Gulf Crossing	15-Jan	1,000
Millennium Phase II	12-Nov	525	Texas Gas (Fayetteville)	15-Jan	150
NWP (Plymouth)	12-Nov	239	Wyoming Interstate (ML)	15-Jan	225
NWP (Stanfield)	12-Nov	239	Pacific Trail	15-Oct	1500
NWP (Washougal)	12-Nov	239	Westcoast (ML)	15-Oct	841
Tenn Z5 NJ Rcpt	12-Nov	350	Westcoast (Ft St John ML)	15-Oct	401
Tenn Z5 NY	12-Nov	250	Westcoast (Pine River)	15-Oct	258
Texas Eastern (M3)	12-Nov	190	Westcoast (St2 / St2 to PNG)	15-Oct	1,500
Texas Eastern (Team Marietta Ext)	12-Nov	190	Questar (Fidlar to KRGT)	18-Jan	400
Texas Eastern (Team Rcpt)	12-Nov	190	Rockies Express (REX Z1 Wam)	18-Jan	332
Transco Z6 NE Connector	12-Nov	688	White River Hub	18-Jan	500
Transco Z6 (PA)	13-Jan	200	Wyoming Interstate (Kanda Lat)	18-Jan	400
Transco Z5	13-Jan	142	Kern River (CA/Mainline/NV)	20-Jan	500
El Paso Sonora LNG Lateral	13-Apr	800	Kern River (Opal to Muddy Ck)	20-Jan	440
Empire (Millennium/Tioga)	13-Sep	350	KM Mexico	20-Jan	425
Empire (Chippewa/ML)	13-Sep	175	KM Texas Pipeline (AguaDulce)	20-Jan	250
Alliance Pipeline (CAN BC)	13-Nov	300	Mojave-Kern Common Facilities	20-Jan	200
NFGS (Leidy Hub/ML)	13-Nov	425	Nova (Gordondale/Prairie ML)	20-Jan	4,500
Tenn Z4	13-Nov	636	Tenn Z0 Rio Bravo	20-Jan	315
Tenn Z5 NY	13-Nov	350	Tenn Z6 East MA	20-Jan	285
TETCO TEAM 2013	13-Nov	500	Tenn Z6 West MA	20-Jan	306
Texas Eastern NJ NY Exp	13-Nov	800	Wyoming Interstate (ML)	20-Jan	500
Transco Z6 (Leidy to NYC)	13-Nov	250	Cypress Pipeline	20-May	500
Eagle Ford (Generica)	14-Jan	2000	El Paso Natural Gas (Arizona S)	22-Jan	350
Florida Gas (Mkt Northern)	14-Jan	500	Nova (TCPL BC Groundbirch)	22-Jan	1,344
Southern Crossing	14-Jan	400	White River Hub	23-Jan	500

Future Pipelines and Expansions in Reference Case, cont					
Pipeline	Date	Capacity (MMcfd)	Pipeline	Date	Capacity (MMcfd)
Florida Gas (Panhandle)	25-Jan	247	Florida Gas (Panhandle/Z3)	30-Jan	430
KM Border Pipeline	25-Jan	300	Florida Gas (Z2)	30-Jan	460
PEMEX – SW	25-Jan	300	Kern River (CA/ML/NV)	30-Jan	500
SoCal Northern Zone	25-Jan	250	Kern River (Opal to Muddy Ck)	30-Jan	500
Transwestern (Top. to Calpine)	25-Jan	80	Florida Gas (Panhandle/Z3)	33-Jan	500
DCP E TX Carthage Gathering	27-Jan	250			

Appendix C: Supply Disposition Tables

U.S. Supply Disposition (Bcfd) – *Base Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	63.9	3.8	0.6	4.4	-0.1	0.0	**68.2**
2013	65.1	3.8	0.7	4.5	-0.1	0.0	**69.5**
2014	66.2	3.7	0.7	4.5	0.0	0.0	**70.6**
2015	67.7	3.6	0.4	4.0	0.0	0.0	**71.6**
2016	69.1	3.5	-0.2	3.2	0.0	0.0	**72.3**
2017	70.5	3.5	-0.8	2.8	0.0	0.0	**73.2**
2018	71.9	3.0	-1.1	2.0	0.0	0.0	**73.9**
2019	72.6	3.0	-1.1	1.9	0.0	0.0	**74.5**
2020	73.2	2.8	-1.1	1.7	0.0	0.0	**74.9**
2021	74.0	2.7	-1.1	1.6	0.0	0.0	**75.6**
2022	74.7	2.5	-1.1	1.5	0.0	0.0	**76.2**
2023	75.3	2.5	-1.1	1.4	0.0	0.0	**76.7**
2024	75.6	2.5	-1.1	1.5	0.0	0.0	**77.1**
2025	76.2	2.6	-1.1	1.6	0.0	0.0	**77.8**
2026	76.8	2.6	-1.0	1.5	0.0	0.0	**78.4**
2027	77.4	2.5	-1.0	1.5	0.0	0.0	**78.9**
2028	78.1	2.3	-1.1	1.3	0.0	0.0	**79.3**
2029	78.9	2.2	-1.0	1.1	0.0	0.0	**80.0**
2030	79.7	2.0	-1.1	0.9	0.0	0.0	**80.6**
2031	80.5	1.8	-1.0	0.8	0.0	0.0	**81.2**
2032	81.0	1.7	-1.0	0.6	0.0	0.0	**81.6**
2033	81.9	1.5	-1.0	0.5	0.0	0.0	**82.4**
2034	82.6	1.4	-1.0	0.4	0.0	0.0	**82.9**
2035	83.2	1.4	-1.0	0.4	-0.1	0.0	**83.5**

U.S. Supply Disposition (Bcfd) – *Gulf LNG Exports Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	63.9	3.8	0.6	4.4	-0.1	0.0	**68.2**
2013	65.1	3.8	0.7	4.5	-0.1	0.0	**69.5**
2014	66.2	3.7	0.7	4.5	0.0	0.0	**70.6**
2015	67.7	3.6	0.4	4.0	0.0	0.0	**71.6**
2016	69.1	3.5	-0.2	3.2	0.0	0.0	**72.3**
2017	70.5	3.5	-0.8	2.8	0.0	0.0	**73.2**
2018	72.0	3.1	-1.2	1.9	0.0	0.0	**73.9**
2019	73.9	3.2	-2.4	0.8	0.0	0.0	**74.6**
2020	74.4	3.0	-2.4	0.6	0.0	0.0	**75.1**
2021	75.3	2.9	-2.4	0.5	0.0	0.0	**75.8**
2022	76.0	2.8	-2.4	0.4	0.0	0.0	**76.4**
2023	76.6	2.7	-2.4	0.3	0.0	0.0	**76.9**
2024	76.9	2.7	-2.4	0.4	0.0	0.0	**77.3**
2025	77.5	2.9	-2.4	0.5	0.0	0.0	**78.0**
2026	78.1	2.8	-2.3	0.5	0.0	0.0	**78.5**
2027	78.7	2.7	-2.3	0.4	0.0	0.0	**79.1**
2028	79.3	2.5	-2.3	0.2	0.0	0.0	**79.5**
2029	80.2	2.4	-2.3	0.1	0.0	0.0	**80.2**
2030	81.0	2.2	-2.3	-0.2	0.0	0.0	**80.8**
2031	81.7	2.0	-2.3	-0.3	0.0	0.0	**81.4**
2032	82.4	1.9	-2.3	-0.5	0.0	0.0	**81.8**
2033	83.2	1.7	-2.3	-0.6	0.0	0.0	**82.6**
2034	83.9	1.6	-2.3	-0.7	0.0	0.0	**83.2**
2035	84.5	1.6	-2.3	-0.7	-0.1	0.0	**83.7**

U.S. Supply Disposition (Bcfd) – *Aggregate Exports Case*							
		NET IMPORTS					
Year	**Dry Production**	**Net Pipeline Imports**	**Net LNG Imports**	**Total Net Imports**	**Net Storage**	**Balancing Item**	**Consump-tion**
2012	63.9	3.8	0.6	4.4	-0.1	0.0	**68.2**
2013	65.1	3.8	0.7	4.5	-0.1	0.0	**69.5**
2014	66.2	3.7	0.7	4.5	0.0	0.0	**70.6**
2015	67.8	3.7	0.1	3.8	0.0	0.0	**71.6**
2016	69.4	3.6	-0.7	2.9	0.0	0.0	**72.3**
2017	71.0	4.3	-2.1	2.3	0.1	0.0	**73.3**
2018	72.8	3.9	-2.5	1.4	-0.1	0.0	**74.1**
2019	75.4	4.1	-4.6	-0.5	0.1	0.0	**75.0**
2020	76.1	3.9	-4.6	-0.7	0.0	0.0	**75.4**
2021	77.0	3.8	-4.6	-0.8	0.0	0.0	**76.2**
2022	77.7	3.7	-4.6	-0.9	0.0	0.0	**76.7**
2023	78.3	3.6	-4.6	-1.0	0.0	0.0	**77.3**
2024	78.6	3.7	-4.6	-0.9	0.0	0.0	**77.7**
2025	79.2	3.8	-4.6	-0.8	0.0	0.0	**78.4**
2026	79.8	3.7	-4.6	-0.9	0.0	0.0	**78.9**
2027	80.4	3.6	-4.6	-0.9	0.0	0.0	**79.5**
2028	81.0	3.5	-4.6	-1.1	0.0	0.0	**79.9**
2029	81.9	3.3	-4.6	-1.3	0.0	0.0	**80.6**
2030	82.7	3.1	-4.6	-1.5	0.0	0.0	**81.2**
2031	83.4	3.0	-4.6	-1.6	0.0	0.0	**81.8**
2032	84.0	2.8	-4.6	-1.8	0.0	0.0	**82.2**
2033	84.9	2.6	-4.6	-1.9	0.0	0.0	**82.9**
2034	85.5	2.6	-4.6	-2.0	0.0	0.0	**83.5**
2035	86.2	2.5	-4.6	-2.0	-0.1	0.0	**84.1**

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U.S. Supply Disposition (Bcfd) – *High Demand Base Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	63.9	3.8	0.6	4.4	-0.1	0.0	**68.2**
2013	65.1	3.8	0.7	4.5	-0.1	0.0	**69.5**
2014	66.2	3.7	0.7	4.5	0.0	0.0	**70.6**
2015	67.9	3.7	0.1	3.8	0.0	0.0	**71.6**
2016	69.4	3.6	-0.7	2.9	0.0	0.0	**72.4**
2017	71.1	4.3	-2.1	2.3	0.1	0.0	**73.4**
2018	72.9	3.9	-2.4	1.5	-0.1	0.0	**74.3**
2019	74.5	4.0	-3.3	0.6	0.0	0.0	**75.1**
2020	75.3	3.8	-3.3	0.5	0.0	0.0	**75.7**
2021	76.3	3.7	-3.3	0.4	0.0	0.0	**76.7**
2022	77.2	3.6	-3.3	0.3	0.0	0.0	**77.5**
2023	78.0	3.6	-3.3	0.3	0.0	0.0	**78.3**
2024	78.6	3.7	-3.3	0.4	0.0	0.0	**78.9**
2025	79.4	3.8	-3.3	0.6	0.0	0.0	**80.0**
2026	80.3	3.9	-3.3	0.6	0.0	0.0	**80.9**
2027	81.2	3.8	-3.3	0.6	0.0	0.0	**81.7**
2028	82.0	3.7	-3.3	0.4	0.0	0.0	**82.4**
2029	83.2	3.6	-3.3	0.3	0.0	0.0	**83.5**
2030	84.2	3.4	-3.3	0.1	0.0	0.0	**84.3**
2031	85.1	3.3	-3.3	0.0	0.0	0.0	**85.1**
2032	85.8	3.1	-3.2	-0.1	0.0	0.0	**85.7**
2033	86.9	3.0	-3.2	-0.2	0.0	0.0	**86.6**
2034	87.6	3.0	-3.2	-0.2	0.0	0.0	**87.4**
2035	88.3	3.1	-3.2	-0.1	-0.1	0.0	**88.1**

U.S. Supply Disposition (Bcfd) – *High Demand Base Case Plus GLNG @ 1.5 Bcfd*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	63.9	3.8	0.6	4.4	-0.1	0.0	**68.2**
2013	65.1	3.8	0.7	4.5	-0.1	0.0	**69.5**
2014	66.2	3.7	0.7	4.5	0.0	0.0	**70.6**
2015	67.9	3.7	0.1	3.8	0.0	0.0	**71.6**
2016	69.4	3.6	-0.7	2.9	0.0	0.0	**72.4**
2017	71.1	4.3	-2.1	2.3	0.1	0.0	**73.4**
2018	73.0	4.0	-2.5	1.4	-0.1	0.0	**74.3**
2019	75.7	4.2	-4.6	-0.4	0.1	0.0	**75.3**
2020	76.5	4.0	-4.6	-0.6	0.0	0.0	**75.9**
2021	77.6	3.9	-4.6	-0.7	0.0	0.0	**76.9**
2022	78.4	3.8	-4.6	-0.8	0.0	0.0	**77.7**
2023	79.3	3.8	-4.6	-0.8	0.0	0.0	**78.5**
2024	79.8	3.9	-4.6	-0.7	0.0	0.0	**79.1**
2025	80.7	4.1	-4.6	-0.5	0.0	0.0	**80.1**
2026	81.5	4.1	-4.6	-0.5	0.0	0.0	**81.0**
2027	82.4	4.0	-4.5	-0.5	0.0	0.0	**81.9**
2028	83.3	3.9	-4.5	-0.7	0.0	0.0	**82.6**
2029	84.4	3.8	-4.5	-0.8	0.0	0.0	**83.6**
2030	85.5	3.6	-4.5	-1.0	0.0	0.0	**84.5**
2031	86.3	3.5	-4.5	-1.1	0.0	0.0	**85.2**
2032	87.1	3.4	-4.5	-1.2	0.0	0.0	**85.9**
2033	88.0	3.3	-4.5	-1.2	0.0	0.0	**86.8**
2034	88.8	3.3	-4.5	-1.2	0.0	0.0	**87.6**
2035	89.4	3.6	-4.5	-0.9	-0.1	0.0	**88.3**

Appendix D: Consumption Disposition Tables

U.S. Natural Gas Consumption by End Use (Bcfd) – *Base Case*							
Year	Lease & Plant Fuel	Pipeline & Distribu-tion Use	Res/ Comm	Industrial	Vehicle Fuel	Electric Power	Total Consump-tion
2012	3.4	2.3	21.8	19.3	0.1	21.3	**68.2**
2013	3.5	2.3	21.9	19.1	0.1	22.6	**69.5**
2014	3.5	2.3	22.0	18.9	0.1	23.8	**70.6**
2015	3.6	2.4	22.0	18.8	0.1	24.7	**71.6**
2016	3.7	2.4	21.9	18.7	0.2	25.4	**72.3**
2017	3.7	2.5	21.9	18.6	0.2	26.2	**73.2**
2018	3.8	2.6	21.9	18.6	0.2	26.8	**73.9**
2019	3.8	2.6	22.0	18.5	0.2	27.3	**74.5**
2020	3.8	2.6	22.0	18.5	0.2	27.8	**74.9**
2021	3.9	2.6	22.0	18.5	0.2	28.4	**75.6**
2022	3.9	2.6	22.1	18.5	0.2	28.9	**76.2**
2023	3.9	2.6	22.1	18.5	0.3	29.4	**76.7**
2024	3.9	2.6	22.0	18.4	0.3	29.8	**77.1**
2025	3.9	2.6	22.1	18.5	0.3	30.4	**77.8**
2026	3.9	2.6	22.1	18.5	0.3	30.9	**78.4**
2027	4.0	2.6	22.1	18.5	0.3	31.4	**78.9**
2028	4.0	2.6	22.1	18.4	0.4	31.8	**79.3**
2029	4.0	2.7	22.2	18.5	0.4	32.4	**80.0**
2030	4.0	2.7	22.2	18.5	0.4	32.9	**80.6**
2031	4.0	2.7	22.2	18.5	0.4	33.4	**81.2**
2032	4.0	2.7	22.2	18.4	0.4	33.8	**81.6**
2033	4.1	2.7	22.3	18.5	0.4	34.4	**82.4**
2034	4.1	2.7	22.3	18.4	0.4	35.0	**82.9**
2035	4.1	2.8	22.3	18.4	0.4	35.5	**83.5**

U.S. Natural Gas Consumption by End Use (Bcfd) – *Gulf LNG Exports Case*							
Year	Lease & Plant Fuel	Pipeline & Distribu-tion Use	Res/ Comm	Industrial	Vehicle Fuel	Electric Power	Total Consump-tion
2012	3.4	2.3	21.8	19.3	0.1	21.3	**68.2**
2013	3.5	2.3	21.9	19.1	0.1	22.6	**69.5**
2014	3.5	2.3	22.0	18.9	0.1	23.8	**70.6**
2015	3.6	2.4	22.0	18.8	0.1	24.7	**71.6**
2016	3.7	2.4	21.9	18.7	0.2	25.4	**72.3**
2017	3.7	2.5	21.9	18.6	0.2	26.2	**73.2**
2018	3.8	2.6	21.9	18.5	0.2	26.7	**73.9**
2019	3.9	2.8	22.0	18.5	0.2	27.3	**74.6**
2020	3.9	2.8	21.9	18.4	0.2	27.8	**75.1**
2021	3.9	2.8	22.0	18.4	0.2	28.4	**75.8**
2022	3.9	2.9	22.0	18.4	0.2	28.9	**76.4**
2023	4.0	2.9	22.0	18.4	0.3	29.4	**76.9**
2024	4.0	2.9	22.0	18.4	0.3	29.8	**77.3**
2025	4.0	2.9	22.1	18.4	0.3	30.4	**78.0**
2026	4.0	2.9	22.1	18.4	0.3	30.9	**78.5**
2027	4.0	2.9	22.1	18.4	0.3	31.4	**79.1**
2028	4.0	2.9	22.1	18.3	0.4	31.8	**79.5**
2029	4.0	2.9	22.2	18.4	0.4	32.4	**80.2**
2030	4.1	2.9	22.2	18.4	0.4	32.9	**80.8**
2031	4.1	2.9	22.2	18.4	0.4	33.4	**81.4**
2032	4.1	2.9	22.2	18.4	0.4	33.8	**81.8**
2033	4.1	3.0	22.2	18.4	0.4	34.4	**82.6**
2034	4.2	3.0	22.3	18.4	0.4	34.9	**83.2**
2035	4.2	3.0	22.3	18.3	0.4	35.5	**83.7**

U.S. Natural Gas Consumption by End Use (Bcfd) – *Aggregate Exports Case*							
Year	Lease & Plant Fuel	Pipeline & Distribu-tion Use	Res/ Comm	Industrial	Vehicle Fuel	Electric Power	Total Consump-tion
2012	3.4	2.3	21.8	19.3	0.1	21.3	**68.2**
2013	3.5	2.3	21.9	19.1	0.1	22.6	**69.5**
2014	3.5	2.3	22.0	18.9	0.1	23.8	**70.6**
2015	3.6	2.4	22.0	18.8	0.1	24.7	**71.6**
2016	3.7	2.5	21.9	18.6	0.2	25.4	**72.3**
2017	3.8	2.7	21.9	18.6	0.2	26.1	**73.3**
2018	3.8	2.8	21.9	18.5	0.2	26.8	**74.1**
2019	3.9	3.2	22.0	18.4	0.2	27.3	**75.0**
2020	3.9	3.2	21.9	18.4	0.2	27.8	**75.4**
2021	4.0	3.2	22.0	18.4	0.2	28.3	**76.2**
2022	4.0	3.2	22.0	18.4	0.2	28.9	**76.7**
2023	4.0	3.2	22.0	18.4	0.3	29.4	**77.3**
2024	4.0	3.2	22.0	18.3	0.3	29.8	**77.7**
2025	4.0	3.2	22.1	18.4	0.3	30.4	**78.4**
2026	4.1	3.2	22.1	18.4	0.3	30.9	**78.9**
2027	4.1	3.3	22.1	18.4	0.3	31.4	**79.5**
2028	4.1	3.2	22.1	18.3	0.4	31.8	**79.9**
2029	4.1	3.3	22.2	18.4	0.4	32.4	**80.6**
2030	4.1	3.3	22.2	18.4	0.4	32.9	**81.2**
2031	4.1	3.3	22.2	18.4	0.4	33.4	**81.8**
2032	4.1	3.3	22.2	18.4	0.4	33.8	**82.2**
2033	4.2	3.3	22.2	18.4	0.4	34.4	**82.9**
2034	4.2	3.3	22.3	18.3	0.4	34.9	**83.5**
2035	4.2	3.4	22.3	18.3	0.4	35.5	**84.1**

U.S. Natural Gas Consumption by End Use (Bcfd) – *High Demand Base Case*							
Year	**Lease & Plant Fuel**	**Pipeline & Distribu-tion Use**	**Res/ Comm**	**Industrial**	**Vehicle Fuel**	**Electric Power**	**Total Consump-tion**
2012	3.4	2.3	21.8	19.3	0.1	21.3	**68.2**
2013	3.5	2.3	22.0	19.1	0.1	22.6	**69.5**
2014	3.5	2.3	22.0	18.9	0.1	23.8	**70.6**
2015	3.6	2.4	22.0	18.8	0.2	24.7	**71.6**
2016	3.7	2.5	21.9	18.6	0.2	25.4	**72.4**
2017	3.8	2.7	21.9	18.6	0.3	26.1	**73.4**
2018	3.8	2.8	22.0	18.5	0.4	26.7	**74.3**
2019	3.9	2.9	22.0	18.5	0.5	27.3	**75.1**
2020	3.9	3.0	22.0	18.4	0.7	27.8	**75.7**
2021	3.9	3.0	22.0	18.5	0.9	28.4	**76.7**
2022	4.0	3.0	22.0	18.4	1.2	28.9	**77.5**
2023	4.0	3.0	22.0	18.4	1.5	29.4	**78.3**
2024	4.0	3.0	22.0	18.4	1.8	29.8	**78.9**
2025	4.1	3.0	22.1	18.4	2.1	30.4	**80.0**
2026	4.1	3.1	22.1	18.3	2.4	30.8	**80.9**
2027	4.1	3.1	22.1	18.3	2.8	31.3	**81.7**
2028	4.1	3.1	22.0	18.3	3.1	31.8	**82.4**
2029	4.2	3.1	22.2	18.3	3.4	32.3	**83.5**
2030	4.2	3.1	22.2	18.3	3.6	32.8	**84.3**
2031	4.2	3.1	22.2	18.3	3.9	33.4	**85.1**
2032	4.2	3.2	22.1	18.3	4.1	33.8	**85.7**
2033	4.3	3.2	22.2	18.3	4.3	34.4	**86.6**
2034	4.3	3.2	22.2	18.3	4.5	34.9	**87.4**
2035	4.3	3.2	22.2	18.2	4.7	35.4	**88.1**

U.S. Natural Gas Consumption by End Use (Bcfd) – *High Demand Base Case Plus GLNG @ 1.5 Bcfd*							
Year	**Lease & Plant Fuel**	**Pipeline & Distribu-tion Use**	**Res/ Comm**	**Industrial**	**Vehicle Fuel**	**Electric Power**	**Total Consump-tion**
2012	3.4	2.3	21.8	19.3	0.1	21.3	**68.2**
2013	3.5	2.3	22.0	19.1	0.1	22.6	**69.5**
2014	3.5	2.3	22.0	18.9	0.1	23.8	**70.6**
2015	3.6	2.4	22.0	18.8	0.2	24.7	**71.6**
2016	3.7	2.5	21.9	18.6	0.2	25.4	**72.4**
2017	3.8	2.7	21.9	18.6	0.3	26.1	**73.4**
2018	3.8	2.8	21.9	18.5	0.4	26.7	**74.3**
2019	3.9	3.2	22.0	18.4	0.5	27.3	**75.3**
2020	4.0	3.2	21.9	18.3	0.7	27.8	**75.9**
2021	4.0	3.2	22.0	18.4	0.9	28.3	**76.9**
2022	4.0	3.2	22.0	18.3	1.2	28.8	**77.7**
2023	4.1	3.3	22.0	18.3	1.5	29.3	**78.5**
2024	4.1	3.3	22.0	18.3	1.8	29.8	**79.1**
2025	4.1	3.3	22.0	18.3	2.1	30.3	**80.1**
2026	4.1	3.3	22.1	18.2	2.4	30.8	**81.0**
2027	4.2	3.3	22.1	18.2	2.8	31.3	**81.9**
2028	4.2	3.3	22.0	18.2	3.1	31.7	**82.6**
2029	4.2	3.4	22.1	18.2	3.4	32.3	**83.6**
2030	4.2	3.4	22.2	18.2	3.6	32.8	**84.5**
2031	4.3	3.4	22.1	18.2	3.9	33.3	**85.2**
2032	4.3	3.4	22.1	18.2	4.1	33.8	**85.9**
2033	4.3	3.4	22.2	18.2	4.3	34.4	**86.8**
2034	4.4	3.5	22.2	18.2	4.5	34.9	**87.6**
2035	4.4	3.5	22.2	18.2	4.7	35.4	**88.3**

APPENDIX B

NAVIGANT ECONOMICS – ECONOMIC IMPACT ANALYSIS STUDY

NAVIGANT

GULF LNG EXPORT PROJECT
ECONOMIC IMPACT ASSESSMENT STUDY

Prepared for:
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August 31, 2012

Disclaimer: This report was prepared by Navigant Economics for the benefit of Gulf LNG Liquefaction Company, LLC ("Gulf LNG"). This work product involves forecasts of the economic impacts associated with the development/construction and operation of Gulf LNG's planned liquefied natural gas (LNG) facility near Pascagoula, Mississippi. Navigant Economics applied appropriate professional diligence in the preparation of these forecasts using what it believes to be reasonable assumptions. However, since the report necessarily involves unknowns, no warranty is made, express or implied.

Table of Contents

Table of Figures

List of Tables

List of Tables (Cont.)

Appendices

Executive Summary

Introduction

Gulf LNG Liquefaction Company, LLC (“Gulf LNG” or “GLNG”) is considering adding liquefaction and export capabilities to the existing Gulf LNG liquefied natural gas (LNG) terminal located in Jackson County, Mississippi, near the City of Pascagoula (the “Gulf LNG Export Project” or “Gulf LNG Export Facility"). The new facilities proposed as part of the project will include natural gas pre-treatment, liquefaction, and export facilities with a capacity of up to 11.5 million tons per year of LNG, or approximately 1.5 billion cubic feet per day (Bcfd), plus enhancements to the existing equipment and additional utilities. The project would permit gas to be received by pipeline at the Gulf LNG terminal, liquefied, and loaded from the terminal’s storage tanks onto vessels berthed at the existing marine facility. The expected running rate for the facility is 1.35 Bcfd which takes into account an estimated 10% downtime due to maintenance.

The combined development, support, and construction (“Construction”) activities for the facility are expected to begin in the second half of 2012 and be completed in the second half of 2018 (a six and a half (6½) year period). The total expected construction expenditures are currently estimated to be $6,993.4 million.[1] When the Gulf LNG Export Facility begins operating at the beginning of 2019, the combined operation and maintenance (“Operation”) outlays by Gulf LNG each year is estimated to be $328.3 million, and the cost of purchasing the natural gas by Gulf LNG’s customers is estimated to be $2,542.1 million.

The projected economic impacts set forth herein result from the use of the well-established RIMS II modeling system and a frequently used Navigant Tax Revenue Model. The resulting projected economic impacts are a function of the assumptions made and accordingly may be modified as assumptions are refined. GLNG anticipates that the economic impacts included in its forthcoming Federal Energy Regulatory Commission Section 3 application may differ from those set forth herein because project details will be further defined and refined at that point.

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1 As the construction process moves forward, this estimate will be refined and could increase or decrease.

This study evaluates the economic impacts that would occur as a result of the Construction of the Gulf LNG Export Facility and as a result of the Operation of this facility. The specific economic impacts of the project that are calculated are the number of jobs created, the incremental wage income associated with these jobs, the value added (i.e., the contribution to gross domestic product), and the federal, state, and local tax revenues generated.[2] These economic impacts are calculated for Jackson County, the Local Gulf LNG Economic area which includes the counties within Mississippi and Alabama that lie within a 75-mile radius circle around the City of Pascagoula, the States of Mississippi and Alabama, and the United States.

These economic impacts are calculated using the RIMS II regional modeling system which was developed and is maintained by the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce. This regional modeling system calculates the economic impacts on employment (jobs), employee earnings, and regional value added (which is the regional equivalent of U.S. Gross Domestic Product or GDP) due to the Construction and Operation of the Gulf LNG Export Facility. A Tax Revenue Model that Navigant developed is used to calculate the impacts on federal, state, and local tax revenues generated as a consequence of these economic impacts. The Navigant Tax Revenue Model has been utilized in numerous economic impact studies.

Overview

The economic impacts of the Gulf LNG Export Facility's Construction and Operation extend beyond Jackson County throughout the U.S. because purchased materials, equipment, and natural gas feedstock (inputs) during the Construction and Operation of the facility are produced throughout the U.S. Further, the wage income of the workers hired locally and at the locations where the purchased inputs are produced are spent on consumer goods produced throughout the U.S. The largest relative

[2] Employment is measured in terms of full-time equivalent jobs. If an employer hires a full-time employee to work 40 hours per week and a part-time employee to work 20 hours per week, the full-time worker and half-time worker combined would be counted as 1½ full-time equivalent jobs. Employment over multiple years is measured in job-years, (e.g., one more employee for a period of three years is counted as three job-years of employment). Employee earnings include wages and salaries, proprietors' income, directors' fees, and employer contributions for health insurance. Value added by an industry is the total income generated within that industry and equals the sum of: (1) wages, salaries, and benefits; (2) profits of the industry; (3) depreciation; (4) net interest paid; (5) excise taxes paid; and (6) business transfer payments (mostly bad debt). Value added by an industry is also equal to the value of the goods and services sold by the industry less the value of goods and services purchased from other industries. The sum of value added across all industries in the U.S. equals U.S. gross domestic product or U.S. GDP. The sum of value added across all the industries in a region is the regional value added or regional GDP.

(percentage) economic impacts occur locally (i.e., in Jackson County and in the Local Gulf LNG Economic Area), but the largest absolute (number of jobs or dollars) economic impacts occur outside the local area.

The Gulf LNG expenditures related to the Construction of the Gulf LNG Export Facility are currently expected to be $6,993.1 million of which $1,473.7 million (21.1%) would be spent within the Local Gulf LNG Economic Area and $5,519.8 million (78.9%) would be spent outside this area. These expenditures are spread over six and a half years (6½) years. The annual Gulf LNG expenditures related to the Operation of the Gulf LNG Export Facility are estimated to be $328.3 million, of which, $308.4 million (93.4%) would be spent within the Local Gulf LNG Economic Area. In addition, each year Gulf LNG's customers would purchase 1.485 Bcfd of natural gas feedstock for the plant at an estimated annual cost of $2,542.1 million. The natural gas feedstock would be produced almost entirely outside of the Local Gulf LNG Economic Area (98.0% is produced outside the local area).

During the six and a half (6½) year Construction period (2nd half of 2012 through 2nd half of 2018), the jobs created (measured in full-time equivalent job years) in the Local Gulf LNG Economic Area will be 20,226 and throughout the U.S. will be 115,137. At the peak of Construction activity in 2015, a total of 7,192 new jobs are created in the Local Gulf LNG Economic Area. Over the entire six and a half (6½) year period, the full-time annual average full-time equivalent jobs created will be 2,889 in the Local Gulf LNG Economic Area and 16,448 throughout the U.S. Over the entire six and a half (6 ½) year period, these new jobs will generate $715.1 million of employee earnings in the Local Gulf LNG Economic Area and $5,912.6 million throughout the U.S. In terms of state and local tax revenues generated over the six and a half (6½) year period, Jackson County would obtain $104.1 million in incremental property tax revenues. The States of Mississippi and Alabama would obtain incremental tax revenues (in addition to the Jackson County property taxes) of $138.3 million. At the national level, over the six and a half (6½) year period, federal tax revenues will increase by $1,677.8 million and the state and local tax revenues will increase by $910.1 million.

The Gulf LNG Export Facility is assumed to begin operating at the beginning of 2019. In each year of its operation, the full-time equivalent jobs (Jobs) created as a consequence of the outlays by Gulf LNG will be 2,380 in the Local Gulf LNG Economic Area and 3,463 throughout the U.S. In addition, as a consequence of the natural gas purchases by Gulf LNG's customers, 297 jobs will be created in the Local Gulf LNG Economic Area and 23,684 jobs will be created throughout the U.S. The combined impact on jobs of the Gulf LNG outlays and its customers' purchases of natural gas will be 2,678 jobs created in the Local Gulf LNG Economic Area and 27,148 jobs created throughout the U.S. The corresponding increase in employee earnings will be $118.2 million in the Local Gulf LNG Economic Area and $1,738.6 million throughout the U.S. In terms of associated tax revenues each year, Gulf LNG will pay $43.5 million in property taxes to Jackson County. As a consequence of the Gulf LNG outlays and its customers' purchases of natural gas, the States of Mississippi and Alabama will obtain incremental tax revenues (in addition to the Jackson County property taxes) of $36.7 million. At the national level, federal tax revenues will increase by $516.0 million and state and local tax revenues will increase by $318.9 million.

In addition to the increases in economic activity and tax revenues due to the Construction and Operation of the Gulf LNG Export Facility, there are other economic benefits provided by this facility. First, the existence of LNG export facilities will tend to stabilize the U.S. natural gas market and promote the development of increased usage of natural gas and increased natural gas production to meet this demand. Second, the exports of LNG will provide much needed international trade revenues thereby making a sustainable contribution to ultimately reducing the very large U.S. trade deficit. The estimated value of annual LNG exports from the Gulf LNG Export Facility is $5,100 million which amounts to 1.1 percent of the 2011 U.S. trade deficit on current account.[3]

Summary of the Economic Impact Results Obtained

Table ES-1 below presents the total and average annual economic benefits due to the Construction of the Gulf LNG Export Project over a six and a half (6 ½) year period (second half of 2012 through second half of 2018). Panel I of this table shows the total increases in employment, employee earnings, and value added (gross domestic product) due to the Construction of the project over six

3 See the discussion of the positive effects on the U.S. trade balance on page 51.

and a half (6 ½) years.[4] Panel II of this table shows the corresponding average annual values during this six and a half (6 ½) year period. Focusing first on Jackson County and on the Local Gulf LNG Economic Area, Table ES-1 below shows that the Construction of the Gulf LNG Export Project will create, over the six and a half (6 ½) year period, a total of 12,692 job-years of employment or an average of 1,813 new jobs per year in Jackson County in each year of the Construction effort (i.e., on average, there will be 1,813 more jobs in each of the six and a half (6 ½) years than there would have been absent the project). Over the six and a half (6 ½) year period, in Jackson County, employees' earnings will be $450.8 million higher and value added will be $960.9 million higher. On average over this period in Jackson County, employee earnings each year will be $64.4 million higher and value added will be $137.3 million higher. The average annual increments to employment, employee earnings, and value added in Jackson County amount to 2.7%, 1.8%, and 2.0% of their 2010 levels, respectively.

Regarding the Local Gulf LNG Economic Area, over the six and a half (6 ½) year period, the Construction of the Gulf LNG Export Project will create 20,226 job-years of employment, $715.1 million of incremental employee earnings, and $1,320.6 million more value added. On average over this six and a half (6 ½) year period in the Local Gulf LNG Economic Area, there will be 2,889 more jobs each year, $102.2 million more employee earnings each year, and $188.7 million more value added each year than would have been the case absent the project. These increments to employment, employee earnings, and value added in the Local Gulf LNG Economic Area amount to 0.5%, 0.4%, and 0.4% of their 2010 levels, respectively.

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[4] Employment is measured in terms of full-time equivalent jobs. If an employer hires a full-time employee to work 40 hours per week and a part-time employee to work 20 hours per week, the full-time worker and half-time worker combined would be counted as 1½ full-time equivalent jobs. Employment over multiple years is measured in job-years, (e.g., one more employee for a period of three years is counted as three job-years of employment). Employee earnings include wages and salaries, proprietors' income, directors' fees, and employer contributions for health insurance. Value added by an industry is the total income generated within that industry and equals the sum of: (1) wages, salaries, and benefits; (2) profits of the industry; (3) depreciation; (4) net interest paid; (5) excise taxes paid; and (6) business transfer payments (mostly bad debt). Value added by an industry is also equal to the value of the goods and services sold by the industry less the value of goods and services purchased from other industries. The sum of value added across all industries in the U.S. equals U.S. gross domestic product or U.S. GDP. The sum of value added across all the industries in a region is the regional value added or regional GDP.

At the national level over the six and a half (6½) year period, the Construction effort will create 115,137 job-years of employment, $5,912.6 million of incremental employee earnings, and $10,659.7 million of incremental value added. On average over this six and a half (6 ½) year period, there will be 16,448 more jobs each year, $844.7 million more employee earnings each year, and $1,522.8 million more value added each year than would have been the case absent the Construction of the export facility.

Table ES-1

Economic Benefits by Region Due to the Construction of the Gulf LNG Export Facility (2nd Half of 2012 through 2nd Half of 2018: Six and One-Half Years)

I. Total Economic Benefits

Region	Employment (Number of Full-Time Equivalent Job-Years[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
Jackson County, MS	12,692	$450.8	$960.9
Local Gulf LNG Economic Area	20,226	$715.1	$1,320.6
Mississippi and Alabama	23,469	$849.9	$1,534.1
United States	115,137	$5,912.6	$10,659.7

II. Average Annual Economic Benefits

Region	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
Jackson County, MS	1,813	$64.4	$137.3
Percentage of 2010 Value	2.7%	1.8%	2.0%
Local Gulf LNG Economic Area	2,889	$102.2	$188.7
Percentage of 2010 Value	0.5%	0.4%	0.4%
Mississippi and Alabama	3,353	$121.4	$219.2
United States	16,448	$844.7	$1,522.8

Note: [1]The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year. Job-years is the sum of the number of annual jobs over a two and a half year period. A job-year equals one full-time equivalent job held for one year. If 50 full-time equivalent jobs were created for each year for 5 years, the total employment over that 5 year period would be 250 job-years.

Source: RIMS II Calculations.

Table ES-2 below presents by region the annual increments to employment, employee earnings, and value added due to the Operation of the Gulf LNG Export Facility from 2019 forward.[5] The Operation of the Gulf LNG Export Facility will involve outlays by Gulf LNG and purchases of natural gas by Gulf LNG's customers. Table ES-2 below presents the calculated economic impacts of these two types of outlays separately as well as the combined effects of both types of outlays. Focusing first on Jackson County and on the Local Gulf LNG Economic Area. Panel I of Table ES-2 below shows that the outlays by Gulf LNG associated with the Operation of the Gulf LNG facility will create each year of its operation 1,637 new jobs in Jackson County (i.e., each year there will be 1,637 more jobs than there would have been absent the outlays by Gulf LNG associated with the Operation of the facility). Also, each year in Jackson County, employee earnings will be $71.7 million higher and value added will be $227.0 million higher. These increments to Jackson County employment, employee earnings, and value added amount to 2.5%, 2.0%, and 3.3% of their 2010 levels, respectively. Regarding the Local Gulf LNG Economic Area, in each year, there will be 2,380 more jobs, $102.6 million more employee earnings, and $275.3 million more value added than would have been the case absent outlays by Gulf LNG associated with the Operation of the Gulf LNG Export Facility. These increases in the Local Gulf LNG Economic Area employment, employee earnings, and value added amount to 0.4%, 0.4%, and 0.6% of their 2010 levels, respectively. At the national level, in each year, there will be 3,463 more jobs, $185.6 million more employee earnings, and $442.4 million more value added than would have been the case absent the outlays by Gulf LNG associated with the Operation of the Gulf LNG Export Facility.

Panel II of Table ES-2 below shows the annual economic impacts due to the purchase of natural gas by Gulf LNG's customers. Most of these economic benefits occur outside the Local Gulf LNG Economic Area (none occur within Jackson County). Throughout the U.S., purchases of natural gas by Gulf LNG's customers create, each year, 23,684 new jobs, $1,553.0 million more employee earnings, and $3,511.7 million more value added than would have been the case absent these natural gas purchases. Panel III of Table ES-2 below shows the combined economic impacts of the outlays by Gulf LNG and the purchases of natural gas by Gulf LNG's customers. At the national level, for each year of the Gulf LNG's export facility's operation, these combined economic benefits are 27,148 new

[5] The employment, employee earnings, and value added measures in Table ES-2 are defined above.

jobs, $1,738.6 million more employee earnings, and $3,954.0 million more value added than would have occurred absent the Operation of the Gulf LNG Export Facility.

Table ES-2

Average Annual Economic Benefits by Region Due to the Operation of the Gulf LNG Export Facility (2019 Forward)

Region	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
I. Operating Costs Incurred by Gulf LNG			
Jackson County, MS	1,637	$71.7	$227.0
Percentage of 2010 Value	2.5%	2.0%	3.3%
Local Gulf LNG Economic Area	2,380	$102.6	$275.3
Percentage of 2010 Value	0.4%	0.4%	0.6%
Mississippi and Alabama	2,712	$118.1	$306.0
United States	3,463	$185.6	$442.4
II. Natural Gas Costs of Customers			
Jackson County, MS	0	$0.0	$0.0
Percentage of 2010 Value	0.0%	0.0%	0.0%
Local Gulf LNG Economic Area	297	$15.7	$47.2
Percentage of 2010 Value	0.0%	0.1%	0.1%
Mississippi and Alabama	818	$42.2	$141.8
United States	23,684	$1,553.0	$3,511.7
III. Total Operating and Natural Gas Costs			
Jackson County, MS	1,637	$71.7	$227.0
Percentage of 2010 Value	2.5%	2.0%	3.3%
Local Gulf LNG Economic Area	2,678	$118.2	$322.4
Percentage of 2010 Value	0.4%	0.4%	0.7%
Mississippi and Alabama	3,530	$160.4	$447.9
United States	27,148	$1,738.6	$3,954.0

Note: [1]The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year.

Source: RIMS II Calculations.

The increases in economic activity due to the Construction and Operation of the Gulf LNG Export Project will generate increased federal, state, and local tax revenues. Table ES-3 below shows, for the six and a half (6 ½) year Construction period, the total and average annual tax revenue increases due to the Construction of the project. Table ES-4 below shows the annual incremental tax revenues due to the Operation of the facility for each year of the facility's operation beginning in 2019. Separate increments to tax revenues are calculated due to the outlays by Gulf LNG (Panel I) and due to the purchase of natural gas by Gulf LNG's customers (Panel II). Table ES-4 also combines these two increments in tax revenues in Panel III. The increases in Table ES-3 are relative to the values that would occur if the facility were not constructed, and the increases in Table ES-4 are relative to the values that would occur if the facility did not operate. Tables ES-3 and ES-4 also show the property taxes that the Gulf LNG facility expects to pay Jackson County.

Table ES-3

Federal, State, and Local Tax Revenues Due to the Construction of the Gulf LNG Export Facility in Millions of Dollars (2nd Half of 2012 through 2nd Half 2018: Six and One-Half Years)

Region	Total Federal Tax Revenue	Total State and Local Tax Revenue[1]	Property Taxes
I. Total Tax Revenues			
Jackson County, MS	$132.0	$60.6	$104.1
Local Gulf LNG Economic Area	$203.8	$118.5	---
Mississippi and Alabama	$241.2	$138.3	---
United States	$1,677.8	$910.1	---
II. Average Annual Tax Revenues			
Jackson County, MS	$20.3	$9.3	$16.0
Local Gulf LNG Economic Area	$31.4	$18.2	---
Mississippi and Alabama	$37.1	$21.3	---
United States	$258.1	$140.0	---

Note: [1]Does not include property taxes.

Source: RIMS II Calculations.

Table ES-4

Average Annual Federal, State, and Local Tax Revenues Due to the Operation of the Gulf LNG Export Facility in Millions of Dollars (2019 Forward)

Region	Total Federal Tax Revenue	Total State and Local Tax Revenue[1]	Property Taxes
I. Operating Costs Incurred by Gulf LNG			
Jackson County, MS	$23.0	$13.2	$43.5
Local Gulf LNG Economic Area	$31.6	$23.2	---
Mississippi and Alabama	$36.1	$25.9	---
United States	$55.7	$35.3	---
II. Natural Gas Costs of Customers			
Jackson County, MS	$0.0	$0.0	$0.0
Local Gulf LNG Economic Area	$5.0	$3.1	---
Mississippi and Alabama	$13.8	$10.8	---
United States	$460.4	$283.6	---
III. Total Operating and Natural Gas Costs			
Jackson County, MS	$23.0	$13.2	$43.5
Local Gulf LNG Economic Area	$36.6	$26.3	---
Mississippi and Alabama	$49.9	$36.7	---
United States	$516.0	$318.9	---

Note: [1]Does not include property taxes.

Source: RIMS II Calculations.

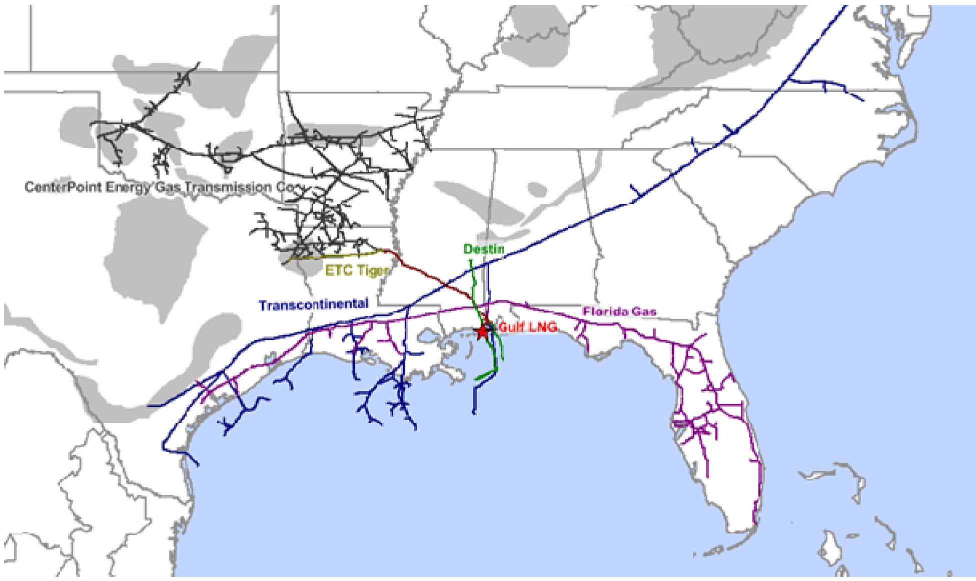
Gulf LNG Project Description

Description of Gulf LNG Facility

The proposed Gulf LNG Export Project is located in Jackson County, Mississippi, near the City of Pascagoula. In 2005, Gulf LNG Energy, LLC and Gulf LNG Pipeline, LLC applied for Federal Energy Regulatory Commission ("FERC") approval in Docket Nos. CP06-12-000 and CP06-13-000 to construct an LNG import facility ("Gulf LNG Terminal") and the associated natural gas pipeline ("Gulf LNG Pipeline"), respectively. FERC authorized construction of the terminal and pipeline in 2007[6], and the facilities commenced service on October 1, 2011. Gulf LNG intends to build natural gas liquefaction and export facilities at the existing terminal site. In May 2012, Gulf LNG filed an application with the Department of Energy in Docket No. 12-47-LNG to export up to 11.5 million tons per year, or approximately 1.5 Bcfd, of LNG to countries with which the United States has entered, or in the future enters, into a Free Trade Agreement (FTA). On June 15, 2012, the Department of Energy provided authorization for GLNG's application in DOE/FE Order No. 3104. GLNG intends to file an application in 2012 to export LNG to non-FTA countries.

6 See Gulf LNG Energy LLC, 118 FERC 61,128 (2007).

Figure 1: Gulf LNG Location Map



The Gulf LNG Export Project will include natural gas pre-treatment, liquefaction, and export facilities, plus enhancements to the existing equipment and additional utilities. The project would permit gas to be received by pipeline at the Gulf LNG terminal, liquefied, and loaded from the terminal's storage tanks onto vessels berthed at the existing marine facility. The project is planned to be placed in service starting in December 2018. The associated 5.02-mile, 36-inch diameter Gulf LNG Pipeline was originally intended to carry natural gas derived from imported LNG from the Gulf LNG Terminal to downstream interconnections with the Destin, Transco and Gulfstream natural gas interstate pipelines. Gulf LNG plans to modify the Gulf LNG Pipeline to allow it to transport gas from the Destin and Transco pipeline interconnections to the Gulf LNG liquefaction facility, thereby making the terminal and pipeline bi-directional. The modified Gulf LNG Pipeline has an expected in-service date of December 2018. The Gulf LNG liquefaction facility will have access to multiple natural gas resources across the United States, including prolific shale plays like the Marcellus and Haynesville, as well as the regional concentration of conventional production in the U.S. Gulf Coast area.

Gulf LNG Export Project's Local Economic Area

The local economic area surrounding the Gulf LNG Export Project is illustrated in Figure 2 below. The project is located in Jackson County, Mississippi, near the City of Pascagoula. Jackson and George Counties in Mississippi define the Pascagoula Metropolitan Statistical Area ("MSA")[7] which is the cross-hatched blue area in Figure 2. Immediately to the west of the Pascagoula MSA is the Gulfport-Biloxi MSA which is the plain blue area in Figure 2. The Gulfport-Biloxi-Pascagoula Combined Statistical Area ("CSA")[8] is the combination of the plain and cross-hatched blue areas (i.e., the entire blue area). The counties in the green area contain counties in Mississippi that are within a 75-mile radius of Pascagoula (i.e., the "Additional Counties in the Local Mississippi Economic Area"). The counties of Forrest and Perry are in the Hattiesburg MSA, Pearl River County is in the Picayune µSA, and Greene County is not located in a MSA or µSA. The combined blue and green areas are the "Local Mississippi Economic Area." Immediately to the east of the Pascagoula MSA is the Mobile-Daphne-Fairhope CSA (i.e., the plain and cross-hatched red areas) which contains the counties of Mobile and Baldwin, Alabama and is referred to as the "Local Alabama Economic Area." In turn, Mobile County is defined as the Mobile, MSA (the cross-hatched red area) and Baldwin County is defined as the Daphne-Fairhope µSA (the plain red area). Therefore, the Mobile-Daphne-Fairhope CSA is the combination of the Mobile MSA and the Daphne-Fairhope µSA. Finally, the Gulf LNG

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7 MSAs are defined by the U.S. Office of Management and Budget ("OMB"). The general concept behind an MSA is that it is an area containing a population center (i.e., a city) and that there is substantial economic interaction between this population center and the area contained within the MSA. See OMB, *Standards for Defining Metropolitan and Micropolitan Statistical Areas*, December 27, 2000, http://www.whitehouse.gov/sites/default/files/omb/fedreg/metroareas122700.pdf

8 CSAs are defined by the U.S. Office of Management and Budget ("OMB") as a grouping of adjacent MSAs and/or Micropolitan Statistical Areas ("µSAs"), where the Greek letter mu represents "micro-"). CSAs are defined based on social and economic ties measured by commuting patterns between adjacent MSAs and/or µSAs. A µSA is defined by the U.S. Office of Management and Budget as an area containing a relatively small population center with a population of 10,000 to 49,999. As is the case for an MSA, the concept behind a µSA is that there is substantial economic interaction between the population center and the area contained within the µSA. See OMB, *Standards for Defining Metropolitan and Micropolitan Statistical Areas*, December 22, 2000, http://www.whitehouse.gov/sites/default/files/omb/fedreg/metroareas122700.pdf.

Economic Area consists of the blue, green, and red areas (i.e., the Local Mississippi Economic Area and the Local Alabama Economic Area).

Figure 2: The Gulf LNG Project's Local Economic Area

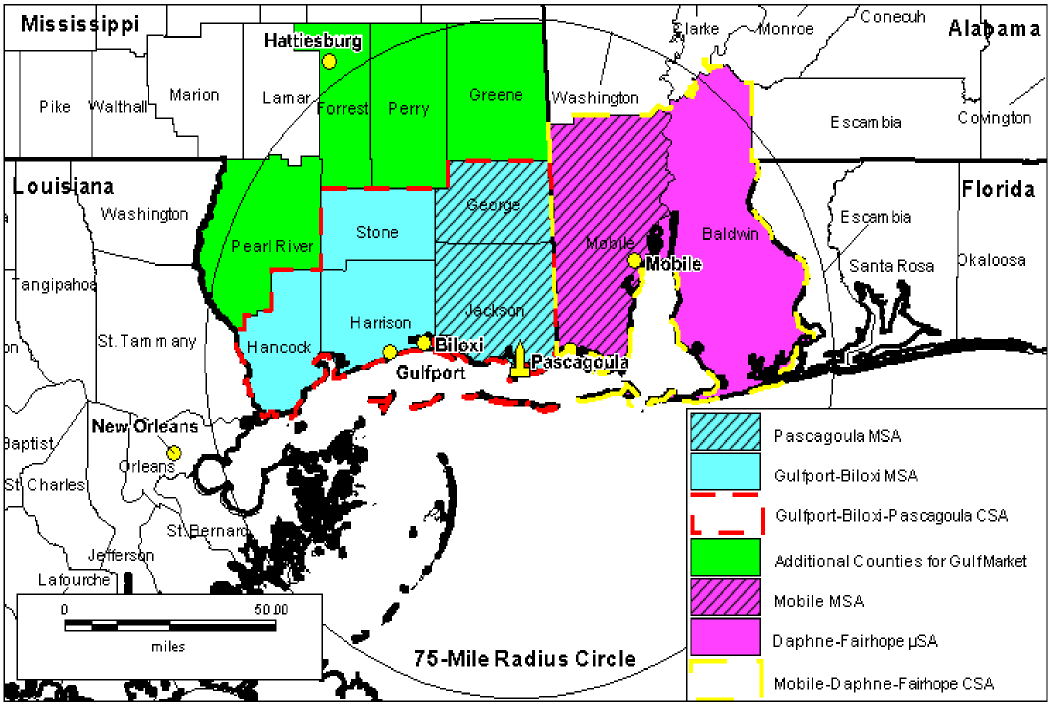


Table 1 below presents estimated 2011 population for the Gulf LNG Economic Area and its component areas. In 2011, the estimated population of the Gulf LNG Economic Area was 1,173,657, of which 574,363 (49%) were in the Local Mississippi Economic Area and 599,294 (51%) were in the Local Alabama Economic Area. Within the Local Mississippi Economic Area, the 2011 estimated population for the Pascagoula MSA is 162,790 (28%), for the Gulfport-Biloxi MSA is 253,511 (44%), and for the Additional Counties in the Local Mississippi Economic Area is 158,062 (28%). Within the Pascagoula MSA, the 2011 estimated population for Jackson County is 139,901 (86%). Within Jackson County, the 2011 estimated population for the City of Pascagoula is 22,429 (16%). Within the Local Alabama Economic Area, the 2011 estimated population for the Mobile MSA is 412,577 (69%) and for the Mobile-Daphne µSA is 186,717 (31%). Within the Mobile MSA, the 2011 estimated population for the City of Mobile is 194,914 (47%).

Table 1

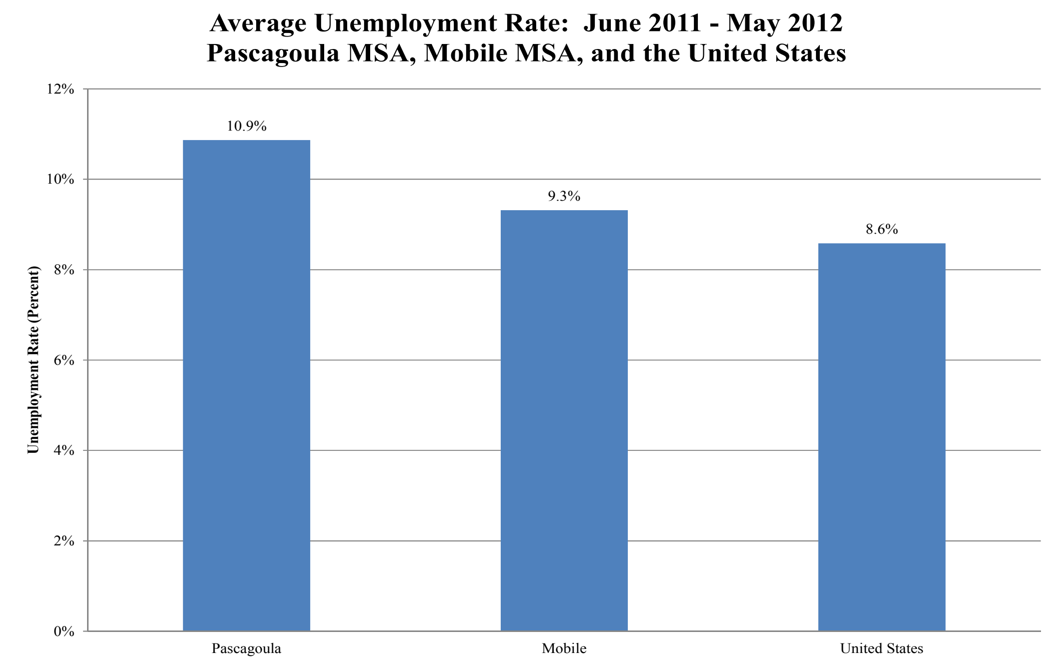
U.S. Census Population Estimates for the Gulf LNG Economic Area: July 1, 2011

State	County	Metropolitan Area	2011 (July 1 Estimate)
Mississippi	Jackson County		139,901
Mississippi	George County		22,889
		Pascagoula MSA	162,790
Mississippi	Harrison County		191,040
Mississippi	Hancock County		44,649
Mississippi	Stone County		17,822
		Gulfport-Biloxi MSA	253,511
		Gulfport-Biloxi-Pascagoula CSA	416,301
Mississippi	Pearl River County		55,718
Mississippi	Forrest County		75,842
Mississippi	Perry County		12,164
Mississippi	Greene County		14,338
		Additional Counties in the Local Mississippi Economic Area	158,062
		Local Mississippi Economic Area	574,363
Alabama	Mobile County	Mobile MSA	412,577
Alabama	Baldwin County	Daphne-Fairhope µSA	186,717
		Local Alabama Economic Area (Mobile-Daphne-Fairhope CSA)	599,294
		Gulf LNG Economic Area	1,173,657

Source: U.S. Census Bureau, Population Estimates, County Totals Vintage 2011 (http://www.census.gov/popest/data/counties/totals/2011/index.html)

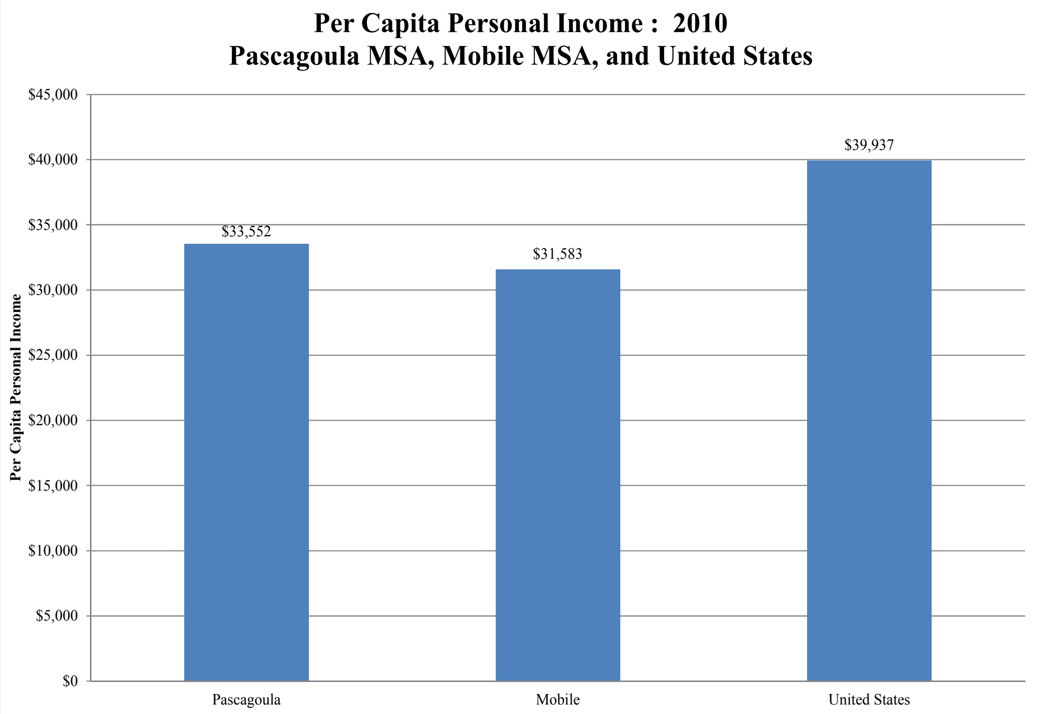
Figures 3 and 4 below compare economic conditions in the Pascagoula and Mobile MSAs with nationwide economic conditions. Figure 3 compares the average of the monthly unemployment rates during the June 2011 through May 2012 period for the Pascagoula MSA, the Mobile MSA, and the United States. The unemployment rate in the Pascagoula MSA is 10.9% which is more than 2 percentage points higher than in the United States (8.6%). The unemployment rate in the Mobile MSA is 9.4% which is 0.7 percentage points higher than in the United States. Figure 4 compares 2010 per capita personal income for the Pascagoula MSA, the Mobile MSA, and the United States. Per capita personal income in the Pascagoula MSA is 16% below that in the U.S., while per capita personal income in the Mobile MSA is 21% below that in the U.S. These comparisons of economic conditions indicate that both the Pascagoula and Mobile MSAs could obtain substantial economic benefits as a consequence of the Construction and Operation of the Gulf LNG Export Project.

Figure 3



Source: Federal Reserve Bank of St. Louis http://research.stlouisfed.org/.

Figure 4



Source: Federal Reserve Bank of St. Louis http://research.stlouisfed.org/; Bureau of Economic Analysis http://bber.unm.edu/econ/us-pci.htm.

Analytical Methodology

Separate economic impact calculations are performed for the Construction of the Gulf LNG Export Facility and for the Operation of this facility. To perform these calculations, Navigant utilized two modeling tools: the RIMS II Model, developed and maintained by the U.S. Department of Commerce, Bureau of Economic Analysis,[9] and the Tax Revenue Model, constructed by Navigant Economics. The RIMS II Model is used to calculate the jobs created, wage income generated, and value added (gross domestic product) created as a result of the development/construction of the facility and, separately, as a result of the operation of the facility. The economic impacts evaluated are those that occur due to economic activities at and near the existing Gulf LNG facility (i.e., the "direct effects") as well as those that arise due to the economic activities of Gulf LNG's suppliers (i.e., the "indirect effects"). In addition, the economic impacts evaluated include those that occur due to the spending of the wage and other personal income generated by the economic activities at the facilities of Gulf LNG and its suppliers (i.e., the "induced effects"). The overall economic impact arising from the Construction and Operation of the Gulf LNG Export Project equals the sum of its direct, indirect, and induced effects. Given these calculated economic impacts, the Navigant Tax Revenue Model is used to calculate the federal, state, and local tax revenues generated as a result of the Construction of the facility and, separately, as a result of the Operation of the facility. These economic impacts and tax revenues are calculated for Jackson County, for the Gulf LNG Economic Area and its Mississippi and Alabama components, for the States of Mississippi and Alabama, and for the U.S.

To perform the economic impact calculations within the RIMS II Model, data are required on the outlays by Gulf LNG during the Construction of the facility and also during the Operation of the facility. These data were provided to Navigant by Gulf LNG. The Construction phase of the Gulf LNG project is expected to begin in the second half 2012 and continue through the end of 2018 assuming a facility in-service date of late 2018. The Construction effort involves development/support tasks and construction tasks. The development/support tasks begin in the second half of 2012 and continue through the end of 2018. The development/support tasks include

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[9] See Bureau of Economic Analysis, *Regional Input-Output System (RIMS II)*, March 10, 2010, [http://www.bea.gov/regional/rims/brfdesc.cfm]

work done prior to the start of the construction tasks, in conjunction with the construction tasks, and during the start-up phase of operation in late 2018. The specific development/support tasks include planning and preparation prior to the start of the construction tasks, support while the construction tasks are being performed, and assessment during the start-up phase of operation. The construction tasks for the Gulf LNG facility are expected to begin in the second half of 2014 and be completed by late 2018. The data collected for the Construction and Operation phases of the Gulf LNG Export Project include direct employment and/or wages and benefits associated with this direct employment plus details of other outlays sufficient to identify the industry that would provide the product or service purchased.[10] GLNG anticipates that the economic impacts included in its forthcoming Federal Energy Regulatory Commission Section 3 application may differ from those set forth herein because project details will be further defined and refined at that point.

The data required for the Tax Revenue Model include information on tax revenues and economic measures which serve as a proxy for the tax base (i.e. tax revenues equal a tax rate times the tax base) for the federal, state, and local taxes. The taxes included in the Tax Revenue Model are personal income taxes, corporate income taxes, sales taxes, and miscellaneous other taxes. Property tax revenues are estimated based on project specific data and local property tax laws.

In the next section of this report, the RIMS II Model and the Tax Revenue Model are discussed in detail.

10 The RIMS II Model identifies 62 industry groups. The specific outlays are assigned to these industry groups.

Description of the RIMS II Model and the Tax Revenue Model

The RIMS II Model

The RIMS II Model is widely used to assess the regional economic impacts of a wide variety of private and public sector projects.[11] These projects include: (1) the opening and closing of manufacturing plants; (2) the opening and closing of military bases; (3) construction of roads, office buildings, housing, retail stores, sports facilities, airports and port facilities; (4) the overall economic contributions of universities and hospitals; and (5) numerous other projects.[12] The RIMS II Model was developed and is maintained by the U.S. Department of Commerce, Bureau of Economic Analysis.[13] The development of the RIMS II Model occurred during the 1970s and 1980s.[14] The RIMS II Model is based on the detailed national and regional (down to the county level) industry data collected by the U.S. Department of Commerce and the ongoing national input-output data collection and modeling efforts of the U.S. Department of Commerce, Bureau of Economic Analysis.[15] The last update of the RIMS II Model occurred in 2008 and was based on 2006 regional industrial data and the 1997 national benchmark input-output data.[16]

The RIMS II Model calculates the economic impacts of a new project such as the Gulf LNG Export Project using a proven input-output modeling approach.[17] In assessing the economic impacts of a

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[11] *See* U.S. Department of Commerce, Bureau of Economic Analysis, *Regional Multipliers*, Third Edition, March 1997 https://www.bea.gov/scb/pdf/regional/perinc/meth/rims2.pdf (hereinafter "BEA Regional Multipliers"), pages 1-2 and 11-18; Zoe O. Ambargis, *RIMS II: Regional Input-Output Modeling System,* Presentation at University of Nevada Regional Economic Workshop, Reno, NV, September 29, 2009 http://www.google.com/url?sa=t&rct=j&q=2009%20rims%20ii%20update&source=web&cd=1&sqi=2&ved=0CE8QFjAA&url=http%3A%2F%2Fworkshops.reaproject.org%2F2009%2FReno-Nevada%2Fpresentations%2FAmbargis-RIMS.ppt&ei=feAKUK6fKMr50gGjw5GOBA&usg=AFQjCNGPm5mwlcSDkmrDoP91jmtGrfD-Mw, (hereinafter "BEA RIMS II Presentation"), page 2.

[12] For a discussion and some explanation of the RIMS II Model. *See* BEA RIMS II Presentation, pages 2 and 8-16 and BEA Regional Multipliers, pages 1-2 and 11-18.

[13] *See* BEA Regional Multipliers, pages 1-2.

[14] *Id*., page 1

[15] *Id*.

[16] *See* Bureau of Economic Analysis, *Survey of Current Business*, October 2008, Volume 88, Number 10, page iv http://www.bea.gov/scb/pdf/2008/10%20October/1008_takingacct.pdf.

[17] *See* BEA Regional Multipliers, pages 1 and 21-24.

new project within a region, the input-output modeling approach takes into account the linkages between industries within a regional economy. These linkages produce positive economic simulative effects from the new project throughout the region, as well as the positive spillover economic effects to other parts of the U.S. and also leakages to overseas economies via increased imports.[18]

The RIMS II Model takes into account 62 industry groups which are listed in Appendix A. To illustrate how the RIMS II Model would be used to estimate the regional economic impact of a new construction project, consider a hypothetical manufacturing plant that would cost $100 million to build. Suppose that the plant construction cost include $5 million for engineering design (RIMS II Industry 48), $45 million for construction (RIMS II Industry 7), $30 million for machinery (RIMS II Industry 12), $10 million for electricity equipment (RIMS II Industry 14), and $10 million for computer systems (RIMS II Industry 13). The $100 million of construction costs would be entered as demands for the services of the RIMS II industries 48, 7, 12, 14, and 13 in the amounts shown above. The RIMS II Model could calculate the total employment, associated wage income, and value added created as a result of the $100 million construction project. Further, in using the RIMS II Model to evaluate this hypothetical new construction project in a region, it is necessary to determine whether and to what extent the economic activity funded by the construction project would occur in the region or elsewhere. If the economic activity would not occur in the region, this outlay would not be included in the calculation of the economic impacts for the region. For example, if the engineering design work costing $5 million was not done by a firm in the region, then this $5 million would not be included in the calculation of the project's economic impacts on the region. However, if it were done elsewhere in the United States, it would have positive economic impacts on the rest of the United States. However, if the activity were to occur outside the United States, it would not have positive economic impacts on the rest of the United States.

18 *Id*.

The Navigant Tax Revenue Model

The Navigant Tax Revenue Model, which has been used in numerous prior economic impact studies, calculates the federal, state, and local tax revenues generated by an increase in economic activity. The tax revenue generated is calculated by applying an effective tax rate to the increase in a measure of economic activity (e.g., employee earnings or value added). For example, the Gulf LNG Export Project will generate increased employment at the Gulf LNG Terminal and increased indirect and induced employment at other locations. Federal, state, and local governments will experience increased tax revenues from the taxes on the wages generated by the increased employment. The effective tax rate is the amount of tax revenue collected relative to a measure of the tax base for that tax (e.g., wage income for income taxes).

There are four categories of federal, state, and local tax revenues covered by the Tax Revenue Model:

- Personal Income Taxes
- Corporate Profit Taxes
- Indirect Business Taxes
- Contributions for Social Insurance

Personal income taxes and contributions for Social Insurance are related to employee compensation (including benefits) and proprietors' income. Corporate profit taxes and indirect business taxes are related to value added (i.e., gross domestic product). At the federal level, indirect business taxes are excise taxes. At the state and local level, indirect business taxes are sales taxes.

At the national level, the effective federal, state, and local tax rates are calculated based on the U.S. National Income and Product Accounts prepared by the U.S. Department of Commerce, Bureau of Economic Analysis.[19] The federal effective tax rates are calculated in four categories, as follows:

- Federal or state and local personal income effective tax rate equals federal or state and local personal income tax receipts divided by national employee compensation (including benefits) and proprietors' income;

[19] See U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts (http://www.bea.gov/iTable/index_nipa.cfm). The data used in the effective tax rate calculations are national gross domestic product (NIPA Table 1.1.5), national personal income (NIPA Table 2.1), Federal taxes (NIPA Table 3.2), and national state and local taxes (NIPA Table 3.3).

- Federal or state and local corporate income effective tax rate equals federal or state and local corporate income tax receipts divided by national gross domestic product;
- Federal or state and local indirect business effective tax rate equals federal excise tax receipts or state and local sales tax receipts divided by national gross domestic product; and
- Federal or state and local contributions for Social Insurance effective tax rate equals federal or state and local contributions for Social Insurance divided by national employee compensation (including benefits) and proprietors' income.

Employee compensation (including benefits) and proprietors' income is the sum of wage and salary disbursements, supplements to wages and salaries, proprietors' income, and personal contributions for government social insurance. An excise tax is a federal tax imposed on the manufacture and distribution of certain non-essential consumer goods. Examples of excise taxes include environmental taxes, communications taxes, and fuel taxes. State and local property taxes are not included in the Tax Revenue Model.

At the individual state or local area level, state and local tax effective tax rates are computed for the same four categories as for the national level. The state and local effective tax rates are calculated as:

- State or local personal income effective tax rate equals state or local individual income tax receipts divided by state employee compensation;
- State or local corporate income effective tax rate equals state or local corporate income tax receipts divided by value added (gross domestic product);
- State or local indirect business effective tax rate equals state or local sales and gross receipt tax receipts divided by value added (gross domestic product); and
- State or local contributions for Social Insurance effective tax rate equals state or local unemployment compensation tax receipts divided by state employee compensation.

The individual state and local tax revenues data are collected by the U.S. Census Bureau.[20] State gross domestic product and personal income data are obtained from the Bureau of Economic Analysis.[21] State and local property taxes are not included in the Navigant Tax Revenue Model because the tax rates and tax base for property taxes differ greatly in different states and local areas which makes modeling intractable. Instead, estimates of property tax payments are developed based on the specific state and local tax laws applicable to the facility being evaluated. For the Gulf LNG expert facility, the property tax payments were estimated based on information provided by Gulf LNG.

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20 See U.S. Bureau of the Census, 2009 Annual Surveys of State and Local Government Finances (http://www2.census.gov/govs/state/09_methodology.pdf).

21 See U.S. Bureau of Economic Analysis, Regional Data (http://www.bea.gov/iTable/iTable.cfm?ReqID=70&step=1&isuri=1&acrdn=5).

The Expenditures Associated with the Construction and Operation of the Gulf LNG Export Project

Table 2 below shows the expenditures associated with the two phases of the Gulf LNG Export Project. These two phases are: (1) Construction; and (2) Operation. The Construction phase involves project planning, project design, oversight/supervision of facility construction, project finance through the completion of construction, evaluation of the completed facility during operation start-up, construction of the liquefaction and export facilities at the Gulf LNG Terminal, and conversion of the Gulf LNG Pipeline to bidirectional service. The costs for the Operation phase are provided for a year of operation and include the ongoing operating costs including normal ongoing maintenance and also the natural gas purchase costs incurred by the customers of the Gulf LNG facility. For each of the two project phases, the expenditure amounts are shown for: (1) total expenditures; (2) expenditures within the Local Gulf LNG Economic Area; and (3) expenditures outside the Local Gulf LNG Economic Area.

Table 2

The Expenditures Associated with the Construction and Operation of the Gulf LNG Export Facility

	Expenditures (Millions of Dollars)		
Project Phases	Total	Within Local Gulf LNG Economic Area	Outside Local Gulf LNG Economic Area
Construction (2nd Half 2012 - 2nd Half 2018)			
Development and Support Tasks	$1,080.6	$123.4	$957.2
Construction Tasks	$5,912.8	$1,350.3	$4,562.6
Total Costs of Construction	$6,993.4	$1,473.7	$5,519.8
Operation (Annually: 2019 Forward)			
Operating Costs Incurred by Gulf LNG	$328.3	$308.4	$19.8
Natural Gas Costs of Customers	$2,542.1	$51.9	$2,490.2
Total Costs of Operation	$2,870.3	$360.4	$2,510.0

Source: Gulf LNG.

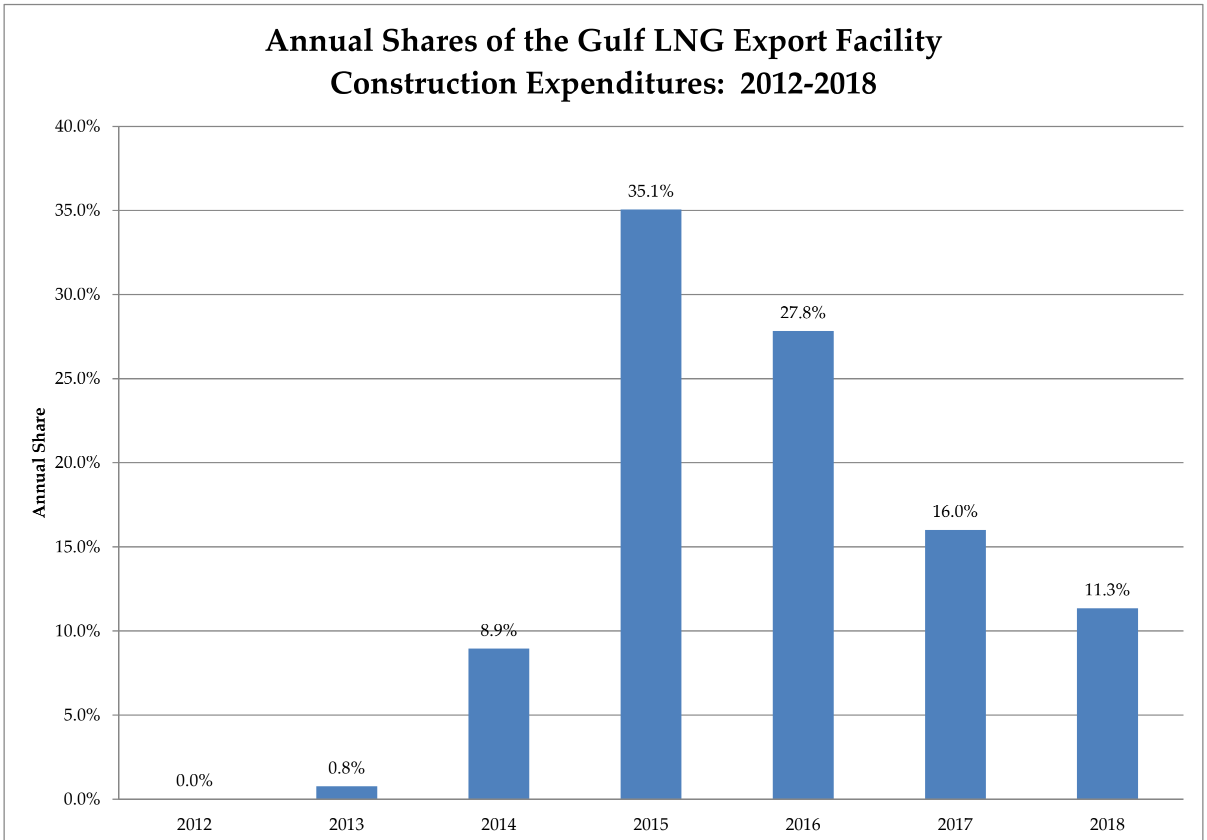
As shown in Table 2 above, the total expenditures on Construction are $6,993.4 million spread over six and a half (6½) years. The Construction expenditures within the Local Gulf LNG Economic Area of $1,473.7 million account for 21.1 percent of the total Construction expenditures. Appendix B disaggregates the Construction expenditures into development/support tasks and construction tasks by six-month periods running from the 2nd half of 2012 through the 2nd half of 2018. As shown in Table 2 above, the development and support task expenditures are $1,080.6 million accounting for 15.5 percent of the total Construction expenditures. These expenditures begin in the 2nd half of 2012 and continue through the 2nd half of 2018. The Construction task expenditures begin in the second half of 2014 and continue through the 2nd half of 2018. The Construction task expenditures total $5,912.8 million accounting for 84.5 percent of total Construction expenditures.

As shown in Table 2 above, the annual expenditures by Gulf LNG on Operations are estimated to be $328.3 million, of which, $308.4 million (93.9%) will be spent in the local area. In addition, Gulf LNG's customers will purchase 1.485 Bcfd of natural gas feedstock for the plant at an annual cost of $2,542.1 million.[22] As shown in Table 2 above, the expenditures for natural gas in the Local Gulf LNG Economic Area are $51.9 million (or 2.0%) of total natural gas costs. The estimated annual outlays by Gulf LNG and its customers of $2,870.3 million are expected to begin in 2019 and to continue for the expected economic life of the facility (i.e., 30 years).

Appendix B presents an allocation of the Construction expenditures into 6-month periods running from the 2nd half of 2012 to the 2nd half of 2018 and then combines these allocated expenditures. These allocated data are presented for the 6-month periods and annually from 2012 through 2018. The annual shares shown in Appendix B are used to allocate the overall economic benefits generated by the development and support efforts and the construction effort to calendar years. As illustrated in Figure 5 below, the largest economic benefits will occur in 2015 and 2016.

22 The natural gas purchases require, taking into account the estimated plant fuel loss, are 1.485 Bcfd. Gulf LNG's customers are expected to purchase the natural gas at the 2019 Henry Hub price of $4.69 per MMBtu.

Figure 5



Source: Gulf LNG.

Economic Impact Analysis Results

Economic Impacts Due to the Construction of the Gulf LNG Export Facility

Table 3 below presents the total and annual average economic effects on employment, employee earnings, and value added (gross domestic product) due to the Construction of the Gulf LNG Export Project over a six and a half (6 ½) year period (second half of 2012 through second half of 2018). Employment is measured in terms of full-time equivalent jobs. If an employer hires a full-time employee to work 40 hours per week and a part-time employee to work 20 hours per week, the full-time worker and half-time worker combined would be counted as 1½ full-time equivalent jobs. Employment over multiple years is measured in job-years (e.g., one more employee for a period of three years is counted as three job-years of employment). Employee earnings include wages and salaries, proprietors' income, directors' fees, and employer contributions for health insurance. Value added by an industry is the total income generated within that industry and equals the sum of: (1) wages, salaries, and benefits; (2) profits of the industry; (3) depreciation; (4) net interest paid; (5) excise taxes paid; and (6) business transfer payments (mostly bad debt). Value added by an industry is also equal to the value of the goods and services sold by the industry less the value of goods and services purchased from other industries. The sum of value added across all industries in the U.S. equals U.S. gross domestic product or U.S. GDP. The sum of value added across all the industries in a region is the regional value added or regional GDP.

Table 3

Economic Benefits by Region Due to the Construction of the Gulf LNG Export Facility Over Six and One-Half Years (2nd Half of 2012 through 2nd Half of 2018)

I. Total Economic Benefits

Region	Employment (Number of Full-Time Equivalent Job-Years[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
Jackson County, MS	12,692	$450.8	$960.9
Local Mississippi Economic Area	18,090	$625.5	$1,177.9
Local Gulf LNG Economic Area	20,226	$715.1	$1,320.6
Mississippi	20,989	$743.3	$1,368.2
Mississippi and Alabama	23,469	$849.9	$1,534.1
Rest of United States	91,668	$5,062.8	$9,125.7
United States	115,137	$5,912.6	$10,659.7

II. Average Economic Benefits

Region	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
Jackson County, MS	1,813	$64.4	$137.3
Local Mississippi Economic Area	2,584	$89.4	$168.3
Local Gulf LNG Economic Area	2,889	$102.2	$188.7
Mississippi	2,998	$106.2	$195.5
Mississippi and Alabama	3,353	$121.4	$219.2
Rest of United States	13,095	$723.3	$1,303.7
United States	16,448	$844.7	$1,522.8

Note: [1]The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year. Job-years is the sum of the number of annual jobs over a two and a half year period. A job-year equals one full-time equivalent job held for one year. If 50 full-time equivalent jobs were created for each year for 5 years, the total employment over that 5 year period would be 250 job-years.

Source: RIMS II Calculations.

Table 3 above shows the effects of the Gulf LNG Export Project by region. Our discussion of these results by region will focus on the effects in: (1) Jackson County, MS; (2) the Local Gulf LNG Economic Area; (3) the States of Mississippi and Alabama; and (4) the United States. The Construction effort occurs over the period from the second half of 2012 through the second half of 2018 which is a six and a half (6½) year period. Given that this is a multiyear period, the employee numbers in Panel I of Table 3 are the number of job-years. The average number of jobs per year shown in Panel II of Table 3 equals the job-year numbers in Panel I of Table 3 divided by six and a half (6½). Similarly, the employee earnings and value added values presented in Panel I Table 3 are totals over a six and a half (6½) year period, and the corresponding average annual values are shown in Panel II of Table 3.

To provide a basis for assessing the relative magnitude of the economic effects shown in Tables 3, as well as in other tables below, Table 4 below presents 2010 values for employment, employee earnings, and estimates for value added for Jackson County, the Local Gulf LNG Economic Area, the States of Mississippi and Alabama, and the United States. For Jackson County and the Local Gulf LNG Economic Area, the value added numbers in Table 4 below are based on published numbers for 2010 personal income in these two areas and the relationship between value added and personal income in the Pascagoula MSA for Jackson County and in the Pascagoula, Gulfport-Biloxi, and Mobile MSAs for the Local Gulf LNG Economic Area.

Table 4

2010 Jobs, Employee Earnings, and Value Added in Four Regions

Region	Employment (Number of Jobs[1])	Employee Earnings (Millions of Dollars)	Estimated Value Added (Millions of Dollars)
Jackson County[2]	66,121	$3,515	$6,852
Local Gulf LNG Economic Area[2]	616,078	$26,296	$47,216
States of Mississippi and Alabama	3,988,866	$170,067	$265,699
United States	173,767,400	$8,986,229	$14,416,601

Notes:
1 The number of jobs is the sum of the number of full-time jobs and the number of part-time jobs, which is greater than the number of full-time equivalent jobs.
2 Value added is estimated for Jackson County and the Local Gulf LNG Economic Area.

Source: Bureau of Economic Analysis, Regional Data (http://www.bea.gov/iTable/iTable.cfm?ReqID=70&step=1&isuri=1&acrdn=5).

As shown in Panel II of Table 3 above, for Jackson County, the average annual number of full-time equivalent jobs created is 1,813 which is 2.7% of the 66,121 total 2010 jobs (see Table 4 above). The average annual employee earnings in Jackson County of $64.4 million shown in Panel II of Table 3 is 1.8% of the 2010 employee earnings of $3,515 million shown in Table 4. Finally, the average annual value added created in Jackson County of $137.3 million is 2.0% of 2010 estimated value added of $6,852 million shown in Table 4 above. For the Local Gulf LNG Economic Area, as shown in Panel II of Table 3 above, the average annual number of full-time equivalent jobs created is 2,889 which is 0.5% of the 616,078 total 2010 jobs shown in Table 4. The average annual employee earnings created in the Local Gulf LNG Economic Area of $102.2 million is 0.4% of 2010 employee earnings of $26,296 million shown in Table 4. Finally, the average annual value added created in the Local Gulf LNG Economic Area of $188.7 million is 0.4% of the 2010 estimated value of $47,216 million shown in Table 4 above.

Tables 5, 6, 7, and 8 below show the calendar year values underlying the total values over the period from the second half of 2012 through the second half of 2018 presented in Panel I of Table 3 above for Jackson County, the Local Gulf LNG Economic Area, the States of Mississippi and Alabama, and the United States, respectively. These calendar year values are spread over six and a half (6½) years from 2012 through 2018. The largest calendar year impact occurs in 2015 followed by 2016.

Table 5

Jackson County, MS Economic Benefits by Year
Due to the Construction of the Gulf LNG Export Facility

	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
2012	2	$0.1	$0.1
2013	87	$2.6	$5.1
2014	1,131	$40.0	$85.1
2015	4,483	$160.7	$343.8
2016	3,547	$126.6	$270.4
2017	2,004	$69.9	$147.9
2018	1,438	$51.0	$108.5
Total	12,692	$450.8	$960.9

Note: [1]The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year. The total in the employment column is full-time equivalent job-years.

Source: RIMS II Calculations.

Table 6

Local Gulf LNG Economic Area Economic Benefits by Year Due to the Construction of the Gulf LNG Export Facility

	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
2012	3	$0.1	$0.2
2013	122	$3.7	$6.5
2014	1,796	$63.2	$116.7
2015	7,192	$256.2	$474.2
2016	5,673	$201.4	$372.4
2017	3,150	$109.7	$201.7
2018	2,288	$80.8	$149.1
Total	20,226	$715.1	$1,320.6

Note: [1]The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year. The total in the employment column is full-time equivalent job-years.

Source: RIMS II Calculations.

Table 7

Mississippi and Alabama Economic Benefits by Year
Due to the Construction of the Gulf LNG Export Facility

	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
2012	3	$0.1	$0.2
2013	132	$4.1	$7.0
2014	2,080	$75.0	$135.3
2015	8,375	$305.4	$552.4
2016	6,596	$239.8	$433.3
2017	3,630	$129.5	$232.8
2018	2,653	$95.9	$173.0
Total	23,469	$849.9	$1,534.1

Note: [1]The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year. The total in the employment column is full-time equivalent job-years.

Source: RIMS II Calculations.

Table 8

United States Economic Benefits by Year
Due to the Construction of the Gulf LNG Export Facility

	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
2012	22	$1.1	$2.1
2013	869	$44.6	$86.0
2014	10,296	$528.7	$955.4
2015	40,427	$2,076.1	$3,726.5
2016	32,073	$1,647.0	$2,962.3
2017	18,393	$944.5	$1,717.4
2018	13,058	$670.5	$1,210.0
Total	115,137	$5,912.6	$10,659.7

Note: [1]The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year. The total in the employment column is full-time equivalent job-years.

Source: RIMS II Calculations.

Focusing on Jackson County and on the Local Gulf LNG Economic Area, Table 9 below shows the average annual increases in the number of jobs, employee earnings, and value added due to the development, support, and construction of the Gulf LNG Export Project expressed as a percentage of the 2010 number of jobs, employee earnings, and value added in these two areas. In Jackson County, the increase in the average annual number of jobs during the six and a half (6½) year period is 2.7% versus a 6.8% increase in calendar year 2015 and a 5.4% increase in calendar year 2016. The fact that the percentage increase in the number of jobs is greater than the percentage increase in employee earnings indicates that the local jobs created are generally not professional skill jobs but instead trade skill level jobs.

Table 9

Annual Average Increases in Economic Activity Levels Due to the Construction of the Gulf LNG Export Facility As a Percentage of 2010 Economic Activity Levels (Percentages)

I. Jackson County, MS

Measure	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
Annual Average	2.7%	1.8%	2.0%
2015 Value	6.8%	4.6%	5.0%
2016 Value	5.4%	3.6%	3.9%

II. Local Gulf LNG Economic Area

Measure	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
Annual Average	0.5%	0.4%	0.4%
2015 Value	1.2%	1.0%	1.0%
2016 Value	0.9%	0.8%	0.8%

Note: [1]The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year.

Sources: Tables 3, 4, 5, and 6.

Economic Impacts Due to the Operation of the Gulf LNG Export Project

Table 10 below presents by region the annual increments to employment, employee earnings, and value added due to the Operation of the Gulf LNG Export Facility from 2019 forward.[23] The focus of our discussion is on: (1) Jackson County, MS; (2) the Local Gulf LNG Economic Area; (3) the States of Mississippi and Alabama; and (4) the United States. The Operation of the Gulf LNG Export Facility will involve outlays by Gulf LNG and purchases of natural gas by Gulf LNG's customers. Table 10 below presents the calculated economic impacts of these two types of outlays separately as well as the combined effects of both types of outlays. Focusing first on Jackson County and on the Local Gulf LNG Economic Area. Panel I of Table 10 below shows that the outlays by Gulf LNG associated within Operation of the Gulf LNG facility will create each year of its operation 1,637 new jobs in Jackson County (i.e., each year there will be 1,637 more jobs than there would have been absent the outlays by Gulf LNG associated with the operation of the facility). Also, each year in Jackson County, employee earnings will be $71.7 million higher and value added will be $227.0 million higher. Regarding the Local Gulf LNG Economic Area, in each year, there will be 2,380 more jobs, $102.6 million more employee earnings, and $275.3 million more value added than would have been the case absent outlays by Gulf LNG associated with the Operation of the Gulf LNG Export Facility. At the national level, in each year, there will be 3,463 more jobs, $185.6 million more employee earnings, and $442.4 million more value added than would have been the case absent the outlays by Gulf LNG associated with the Operation of the Gulf LNG Export Facility.

Panel II of Table 10 below shows the annual economic impacts due to the purchase of natural gas by Gulf LNG's customers. Most of these economic benefits occur outside the Local Gulf LNG Economic Area (none occur within Jackson County). Throughout the U.S., purchases of natural gas by Gulf LNG's customers create, each year, 23,684 new jobs, $1,553.0 million more employee earnings, and $3,511.7 million more value added than would have been the case absent these natural gas purchases. Panel III of Table 10 below shows the combined economic impacts of the outlays by Gulf LNG and the purchases of natural gas by Gulf LNG's customers. At the national level, for each year of the Gulf LNG's export facility's operation, these combined economic benefits are 27,148 new jobs, $1,738.6

[23] The employment, employee earnings, and value added measures in Table 10 are defined above in footnote 2 on page 2.

million more employee earnings, and $3,954.0 million more value added than would have occurred absent the Operation of the Gulf LNG Export Facility.

Table 10

Annual Economic Impacts by Region (2019 Forward) Due to the Operation of the Gulf LNG Export Facility

Region	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
I. Operating Costs Incurred by Gulf LNG			
Jackson County, MS	1,637	$71.7	$227.0
Local Mississippi Economic Area	2,165	$90.4	$241.4
Local Gulf LNG Economic Area	2,380	$102.6	$275.3
Mississippi	2,467	$104.1	$268.4
Mississippi and Alabama	2,712	$118.1	$306.0
Rest of United States	752	$67.5	$136.3
United States	3,463	$185.6	$442.4
II. Natural Gas Costs of Customers			
Jackson County, MS	0	$0.0	$0.0
Local Mississippi Economic Area	7	$0.4	$1.2
Local Gulf LNG Economic Area	297	$15.7	$47.2
Mississippi	462	$24.2	$81.5
Mississippi and Alabama	818	$42.2	$141.8
Rest of United States	22,866	$1,510.7	$3,369.8
United States	23,684	$1,553.0	$3,511.7
III. Total Operating and Natural Gas Costs			
Jackson County, MS	1,637	$71.7	$227.0
Local Mississippi Economic Area	2,172	$90.7	$242.6
Local Gulf LNG Economic Area	2,678	$118.2	$322.4
Mississippi	2,929	$128.3	$350.0
Mississippi and Alabama	3,530	$160.4	$447.9
Rest of United States	23,618	$1,578.2	$3,506.2
United States	27,148	$1,738.6	$3,954.0

Note: [1]The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year.

Source: RIMS II Calculations.

Table 11 below presents the ratio of the annual increase in the level of economic activity due to the Operation of the Gulf LNG Export Facility to the average annual increase in the level of economic activity due to the Construction of the Gulf LNG Export Facility. Focusing on panel III of Table 11, in the first two regions, the annual increase in employment is somewhat less due to the Operation of the facility than due to the Construction of the facility, but the opposite is true for the annual increases in employee earnings and value added. For the states of Mississippi and Alabama and for the U.S., the annual increases in all three measures of economic activity are larger due to the Operation of the facility than due to the Construction of the facility, particularly for the U.S. The large positive effect on the U.S. due to the Operation of the facility occurs because of the large amount of natural gas that is purchased by Gulf LNG customers from locations outside Mississippi and Alabama. Most of the natural gas purchased would probably come from Texas and Louisiana. In 2009, natural gas production in the States of Texas and Louisiana was 9,212 billion cubic feet (Bcf) and only 609 Bcf in the States of Mississippi and Alabama.[24] Jackson County had no natural gas production in 2009, and the Local Gulf LNG Economic Area had 2009 natural gas production of 201 Bcf. The relatively small amounts of natural gas production in the Local Gulf LNG Economic Area and in the States of Mississippi and Alabama is the reason why these two regions exhibit somewhat worse relative increases in their levels of economic activity than does the U.S.

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24 See EIA, Natural Gas Gross Withdrawals and Production (http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm).

Table 11

Ratio of the Annual Increase in Economic Activity Levels Due to the Operation of the Gulf LNG Export Facility to the Average Annual Increase in Economic Activity Levels Due to the Construction of the Facility

Four Regions	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
I. Operating Costs Incurred by Gulf LNG			
Jackson County, MS	0.90	1.11	1.65
Local Gulf LNG Economic Area	0.82	1.00	1.46
Mississippi and Alabama	0.81	0.97	1.40
United States	0.21	0.22	0.29
II. Natural Gas Costs of Customers			
Jackson County, MS	0.00	0.00	0.00
Local Gulf LNG Economic Area	0.10	0.15	0.25
Mississippi and Alabama	0.24	0.35	0.65
United States	1.44	1.84	2.31
III. Total Operating and Natural Gas Costs			
Jackson County, MS	0.90	1.11	1.65
Local Gulf LNG Economic Area	0.93	1.16	1.71
Mississippi and Alabama	1.05	1.32	2.04
United States	1.65	2.06	2.60

Note: [1] The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year.

Sources: Tables 3 and 10.

Focusing on Jackson County and on the Local Gulf LNG Economic Area, Table 12 below shows the annual increases in the number of jobs, employee earnings, and value added due to the Operation of the Gulf LNG Export Project expressed as a percentage of the 2010 number of jobs, employee earnings, and value added in these two areas. Focusing on Panel III of Table 12, the increase in the number of jobs in Jackson County amounts to 2.5% of the number of jobs in 2010 and in the Local Gulf LNG Economic Area amounts to 0.4% of the number of jobs in 2010. In Jackson County, the increase in employee earnings is 2.0% of 2010 levels, and the increase in value added is 3.3% of 2010 levels. For the Local Gulf LNG Economic Area, these two percentages are 0.4% and 0.7%, respectively.

Table 12

Annual Increases in Economic Activity Due to the Operation of the Gulf LNG Export Facility As a Percentage of 2010 Economic Activity Levels (Percentages)

Two Local Regions	Employment (Number of Full-Time Equivalent Jobs[1])	Employee Earnings (Millions of Dollars)	Value Added (Millions of Dollars)
I. Operating Costs Incurred by Gulf LNG			
Jackson County, MS	2.5%	2.0%	3.3%
Local Gulf LNG Economic Area	0.4%	0.4%	0.6%
II. Natural Gas Costs of Customers			
Jackson County, MS	0.0%	0.0%	0.0%
Local Gulf LNG Economic Area	0.0%	0.1%	0.1%
III. Total Operating and Natural Gas Costs			
Jackson County, MS	2.5%	2.0%	3.3%
Local Gulf LNG Economic Area	0.4%	0.4%	0.7%

Note: [1] The number of full-time equivalent jobs equals the number of hours worked by all employees in a year divided by the number of hours that would be worked by a full-time employee in a year.

Sources: Tables 2 and 10.

For the four types of federal taxes and for the aggregate of the four types of taxes, Table 13 below presents the total federal tax revenues generated due to the Construction of the Gulf LNG Export Project over a six and a half (6½) year period (second half of 2012 through second half of 2018). Table 13 also shows the aggregate federal tax revenues generated expressed as a percentage of the increase in value added due to the Construction of the Gulf LNG Export Project. Table 13 below shows the federal tax revenues generated due to the Construction of the project by region.

Table 13

Total Federal Tax Revenues Generated by Year by Region Due to the Construction of the Gulf LNG Export Facility Over Six and One-Half Years in Millions of Dollars (2nd Half of 2012 through 1st Half 2019)

Region	Personal Income Taxes	Corporate Profit Taxes	Indirect Business Taxes (Excise Taxes)	Contributions for Social Insurance	Total Federal Tax Revenue	Total Federal Tax Revenue as a Percentage of Value Added
I. Total Tax Revenues						
Jackson County, MS	$57.1	$21.5	$5.0	$48.3	$132.0	13.7%
Local Mississippi Economic Area	$79.2	$26.4	$6.2	$67.1	$178.9	15.2%
Local Gulf LNG Economic Area	$90.6	$29.6	$6.9	$76.7	$203.8	15.4%
Mississippi	$94.2	$30.7	$7.2	$79.7	$211.7	15.5%
Mississippi and Alabama	$107.7	$34.4	$8.0	$91.1	$241.2	15.7%
Rest of United States	$641.4	$204.5	$47.8	$542.9	$1,436.6	15.7%
United States	$749.1	$238.8	$55.9	$634.0	$1,677.8	15.7%
II. Average Annual Tax Revenues						
Jackson County, MS	$8.2	$3.1	$0.7	$6.9	$20.3	13.7%
Local Mississippi Economic Area	$11.3	$3.8	$0.9	$9.6	$27.5	15.2%
Local Gulf LNG Economic Area	$12.9	$4.2	$1.0	$11.0	$31.4	15.4%
Mississippi	$13.5	$4.4	$1.0	$11.4	$32.6	15.5%
Mississippi and Alabama	$15.4	$4.9	$1.1	$13.0	$37.1	15.7%
Rest of United States	$91.6	$29.2	$6.8	$77.6	$221.0	15.7%
United States	$107.0	$34.1	$8.0	$90.6	$258.1	15.7%

Sources: RIMS II Calculations and Tax Model.

Table 14 below shows the calendar year values for the aggregate federal tax revenues underlying the corresponding total aggregate values over the period second half of 2012 through first half of 2019 presented in Panel I of Table 13 above for Jackson County, the Local Gulf LNG Economic Area, the States of Mississippi and Alabama, and the United States. These calendar year values are spread over six and a half (6½) years from 2012 through 2018. The largest calendar year aggregate federal tax revenue increment occurs in 2015 followed by 2016.

Table 14

Total Federal Tax Revenues Generated by Year for Selected Regions Due to the Construction of the Gulf LNG Export Facility (Millions of Dollars)

	Jackson County, MS	Local Gulf LNG Economic Area	Mississippi and Alabama	United States
2012	$0.0	$0.0	$0.0	$0.3
2013	$0.8	$1.0	$1.1	$12.8
2014	$11.7	$18.0	$21.3	$150.1
2015	$47.1	$73.0	$86.7	$588.7
2016	$37.1	$57.4	$68.1	$467.2
2017	$20.4	$31.2	$36.7	$268.4
2018	$14.9	$23.0	$27.2	$190.3
Total	$132.0	$203.8	$241.2	$1,677.8

Sources: RIMS II Calculations and Tax Model.

For the four types of state and local taxes and for the aggregate of the four types of taxes, Table 15 below presents the total and average annual state and local tax revenues generated due to the Construction of the Gulf LNG Export Project over a six and a half (6½) year period (second half of 2012 through second half of 2018). Table 15 also shows the aggregate state and local tax revenues generated expressed as a percentage of the increase in value added due to the Construction of the Gulf LNG Export Project. Table 15 below shows the state and local tax revenues generated due to the development, support, and construction of the project by region.

Table 15

Total State and Local Tax Revenues Generated by Year by Region Due to the Construction of the Gulf LNG Export Facility Over Six and One-Half Years in Millions of Dollars (2nd Half of 2012 through 1st Half 2019)

Region	Personal Income Taxes	Corporate Profit Taxes	Indirect Business Taxes (Excise Taxes)	Contributions for Social Insurance	Total State and Local Tax Revenue	Total State and Local Tax Revenue as a Percentage of Value Added
I. Total Tax Revenues						
Jackson County, MS	$12.9	$3.4	$43.2	$1.2	$60.6	6.3%
Local Mississippi Economic Area	$17.9	$4.1	$84.1	$1.6	$107.8	9.1%
Local Gulf LNG Economic Area	$20.4	$4.6	$91.7	$1.8	$118.5	9.0%
Mississippi	$21.2	$4.8	$97.7	$1.9	$125.7	9.2%
Mississippi and Alabama	$24.3	$5.3	$106.5	$2.2	$138.3	9.0%
Rest of United States	$203.3	$31.1	$524.5	$12.9	$771.8	8.5%
United States	$227.6	$36.4	$631.0	$15.1	$910.1	8.5%
II. Average Annual Tax Revenues						
Jackson County, MS	$1.8	$0.5	$6.2	$0.2	$9.3	6.3%
Local Mississippi Economic Area	$2.6	$0.6	$12.0	$0.2	$16.6	9.1%
Local Gulf LNG Economic Area	$2.9	$0.7	$13.1	$0.3	$18.2	9.0%
Mississippi	$3.0	$0.7	$14.0	$0.3	$19.3	9.2%
Mississippi and Alabama	$3.5	$0.8	$15.2	$0.3	$21.3	9.0%
Rest of United States	$29.0	$4.4	$74.9	$1.8	$118.7	8.5%
United States	$32.5	$5.2	$90.1	$2.2	$140.0	8.5%

Note: Property taxes are not included.

Sources: RIMS II Calculations and Tax Model.

Table 16 below shows the calendar year values for the aggregate state and local tax revenues underlying the corresponding total aggregate values over the period of the second half of 2012 through the second half of 2018 as presented in Panel I of Table 15 above for Jackson County, the Local Gulf LNG Economic Area, the States of Mississippi and Alabama, and the United States. These calendar year values are spread over six and a half (6½) years from 2012 through 2018. The largest calendar year aggregate state and local tax revenue increment occurs in 2015 followed by 2016.

Table 16

Total State and Local Tax Revenues Generated by Year for Selected Regions Due to the Construction of the Gulf LNG Export Facility (Millions of Dollars)

	Jackson County, MS	Local Gulf LNG Economic Area	Mississippi and Alabama	United States
2012	$0.0	$0.0	$0.0	$0.2
2013	$0.3	$0.6	$0.6	$7.2
2014	$5.4	$10.5	$12.2	$81.5
2015	$21.7	$42.5	$49.8	$318.5
2016	$17.1	$33.4	$39.0	$253.1
2017	$9.3	$18.1	$21.0	$146.3
2018	$6.8	$13.4	$15.6	$103.3
Total	$60.6	$118.5	$138.3	$910.1

Note: Property taxes are not included.

Sources: RIMS II Calculations and Tax Model.

Tax Revenues Generated Due to the Operation of the Gulf LNG Export Project

For the four types of federal taxes and for the aggregate of the four types of taxes, Table 17 below shows by region the annual federal tax revenues generated due to the Operation of the Gulf LNG Export Project from 2019 forward. Table 17 also shows by region the aggregate federal tax revenues generated expressed as a percentage of the increase in value added due to the operation of the facility.

Table 17

Annual Federal Tax Revenues Generated by Region (2019 Forward) Due to the Operation of the Gulf LNG Export Facility
(Millions of Dollars)

Region	Personal Income Taxes	Corporate Profit Taxes	Indirect Business Taxes (Excise Taxes)	Contributions for Social Insurance	Total Federal Tax Revenue	Total Federal Tax Revenue as a Percentage of Value Added
I. Operating Costs Incurred by Gulf LNG						
Jackson County, MS	$9.1	$5.1	$1.2	$7.7	$23.0	10.1%
Local Mississippi Economic Area	$11.5	$5.4	$1.3	$9.7	$27.8	11.5%
Local Gulf LNG Economic Area	$13.0	$6.2	$1.4	$11.0	$31.6	11.5%
Mississippi	$13.2	$6.0	$1.4	$11.2	$31.8	11.8%
Mississippi and Alabama	$15.0	$6.9	$1.6	$12.7	$36.1	11.8%
Rest of United States	$8.6	$3.1	$0.7	$7.2	$19.6	14.3%
United States	$23.5	$9.9	$2.3	$19.9	$55.7	12.6%
II. Natural Gas Costs of Customers						
Jackson County, MS	$0.0	$0.0	$0.0	$0.0	$0.0	---
Local Mississippi Economic Area	$0.0	$0.0	$0.0	$0.0	$0.1	10.3%
Local Gulf LNG Economic Area	$2.0	$1.1	$0.2	$1.7	$5.0	10.5%
Mississippi	$3.1	$1.8	$0.4	$2.6	$7.9	9.7%
Mississippi and Alabama	$5.4	$3.2	$0.7	$4.5	$13.8	9.7%
Rest of United States	$191.4	$75.5	$17.7	$162.0	$446.6	13.3%
United States	$196.8	$78.7	$18.4	$166.5	$460.4	13.1%
III. Total Operating and Natural Gas Costs						
Jackson County, MS	$9.1	$5.1	$1.2	$7.7	$23.0	10.1%
Local Mississippi Economic Area	$11.5	$5.4	$1.3	$9.7	$27.9	11.5%
Local Gulf LNG Economic Area	$15.0	$7.2	$1.7	$12.7	$36.6	11.3%
Mississippi	$16.3	$7.8	$1.8	$13.8	$39.7	11.3%
Mississippi and Alabama	$20.3	$10.0	$2.3	$17.2	$49.9	11.1%
Rest of United States	$200.0	$78.6	$18.4	$169.2	$466.1	13.3%
United States	$220.3	$88.6	$20.7	$186.4	$516.0	13.1%

Sources: RIMS II Calculations and Tax Model.

For the four types of state and local taxes and for the aggregate of the four types of taxes, Table 18 below shows by region the annual state and local tax revenues generated due to the Operation of the Gulf LNG Export Project from 2019 forward. Table 18 also shows by region the aggregate state and local tax revenues generated expressed as a percentage of the increase in value added due to the operation and maintenance of the project.

Table 18

Annual State and Local Tax Revenues Generated by Region (2019 Forward) Due to the Operation of the Gulf LNG Export Facility
(Millions of Dollars)

Region	Personal Income Taxes	Corporate Profit Taxes	Indirect Business Taxes (Excise Taxes)	Contributions for Social Insurance	Total State and Local Tax Revenue	Total State and Local Tax Revenue as a Percentage of Value Added
I. Operating Costs Incurred by Gulf LNG						
Jackson County, MS	$2.0	$0.8	$10.2	$0.2	$13.2	5.8%
Local Mississippi Economic Area	$2.6	$0.8	$17.2	$0.2	$20.9	8.7%
Local Gulf LNG Economic Area	$2.9	$1.0	$19.0	$0.3	$23.2	8.4%
Mississippi	$3.0	$0.9	$19.2	$0.3	$23.4	8.7%
Mississippi and Alabama	$3.4	$1.1	$21.2	$0.3	$25.9	8.5%
Rest of United States	$3.8	$0.5	$5.0	$0.2	$9.4	6.9%
United States	$7.1	$1.5	$26.2	$0.5	$35.3	8.0%
II. Natural Gas Costs of Customers						
Jackson County, MS	$0.0	$0.0	$0.0	$0.0	$0.0	---
Local Mississippi Economic Area	$0.0	$0.0	$0.1	$0.0	$0.1	8.5%
Local Gulf LNG Economic Area	$0.5	$0.1	$2.5	$0.0	$3.1	6.7%
Mississippi	$0.7	$0.3	$5.8	$0.1	$6.9	8.4%
Mississippi and Alabama	$1.2	$0.5	$9.0	$0.1	$10.8	7.6%
Rest of United States	$58.6	$11.5	$198.9	$3.9	$272.8	8.1%
United States	$59.8	$12.0	$207.9	$4.0	$283.6	8.1%
III. Total Operating and Natural Gas Costs						
Jackson County, MS	$2.0	$0.8	$10.2	$0.2	$13.2	5.8%
Local Mississippi Economic Area	$2.6	$0.9	$17.3	$0.2	$21.0	8.7%
Local Gulf LNG Economic Area	$3.4	$1.1	$21.5	$0.3	$26.3	8.2%
Mississippi	$3.7	$1.2	$25.0	$0.3	$30.2	8.6%
Mississippi and Alabama	$4.6	$1.5	$30.2	$0.4	$36.7	8.2%
Rest of United States	$62.3	$12.0	$203.9	$4.0	$282.2	8.0%
United States	$66.9	$13.5	$234.1	$4.4	$318.9	8.1%

Note: Property taxes are not included.

Sources: RIMS II Calculations and Tax Model.

Estimated Property Tax Payments to Jackson County by the Gulf LNG Export Facility

During the Construction phase of the Gulf LNG Export Facility project (the second half of 2012 through the second half of 2018), the facility will pay an estimated average annual amount of $16.0 million in property taxes to Jackson County, MS totaling $104.1 million over the six and a half (6½) year period. During the Operation phase of the Gulf LNG Export Facility beginning in 2019, the facility will pay an estimated $43.5 million in property taxes to Jackson County, MS each year.

Discussion of Other Economic Benefits

The Benefits to the U.S. Natural Gas Sector

The rapid emergence of shale gas has created the possibility of a greater U.S. reliance on natural gas as a clean energy resource and as a means to stimulate a rebound of the U.S. petrochemical industry and energy intensive manufacturing. However, for increased U.S. uses of natural gas to occur, there is a need for a stable U.S. gas market where prices don't fluctuate wildly and natural gas well development proceeds in a consistent and orderly fashion.

Currently, natural gas prices are severely depressed due to a rapid increase in production that has not been matched by a commensurate increase in demand. These depressed gas prices have led to a sharp cutback in the development of new gas wells which, ultimately, could lead to a sharp rebound in natural gas prices. These sharp natural gas price fluctuations will be reduced by the entry of LNG export facilities such as the Gulf LNG Export Project. The ability to expand exports of natural gas as LNG when U.S. natural gas prices drop and to reduce natural gas exports when U.S. natural gas prices rise will work to stabilize U.S. natural gas prices. Such stability will encourage the investment necessary to increase the U.S. use of natural gas to keep pace with expanded U.S. natural gas production. Therefore, LNG export facilities can play an important role in promoting the increased use of natural gas in the United States.

The Positive Effects on the U.S. Trade Balance

The Gulf LNG Export Project is expected to export 1.350 Bcf per day assuming a 90 percent utilization rate. The expected LNG price in Europe is $12 per MMBtu based on the assumption that European natural gas prices are linked to the Brent crude oil price. The netback price at the outlet of the Gulf LNG Export Facility would be $10.35 per MMBtu which equals $12.00 per MMBtu minus the estimated cost of transporting the LNG to Europe ($1.25 per MMBtu) minus the estimated cost of re-gasification in Europe ($0.40 per MMBtu). Therefore, the 1.350 Bcfd of exports would generate annual export revenues of $5,100 million. In 2011, the U.S. trade deficit on current account was $465,926 million.[25] Therefore, the exports of natural gas from the Gulf LNG Export Facility would reduce the U.S. trade deficit on current account by 1.1 percent. This reduction in the U.S. trade deficit provides a sustainable contribution to reducing the U.S. trade deficit.

25 http://www.bea.gov/iTable/iTable.cfm?ReqID=6&step=1.

Appendices

Appendix A
List of the RIMS II Model's 62 Industry Codes

Aggregate industry code and title		RIMS II detailed industry codes
Agriculture, forestry, fishing, and hunting		
1	Crop and animal production	1111C0-112300
2	Forestry, fishing, and related activities	113A00-115000
Mining		
3	Oil and gas extraction	211000
4	Mining, except oil and gas	212100-212390
5	Support activities for mining	213111-21311A
Utilities*		
6	Utilities*	2211A0-221300
Construction		
7	Construction	230000
Manufacturing		
8	Wood product manufacturing	321100-321999
9	Nonmetallic mineral product manufacturing	32711A-327999
10	Primary metal manufacturing	331110-331520
11	Fabricated metal product manufacturing	33211A-33299C
12	Machinery manufacturing	333111-33399B
13	Computer and electronic product manufacturing	334111-334613
14	Electrical equipment and appliance manufacturing	335110-335999
15	Motor vehicle, body, trailer, and parts manufacturing	336111-336300
16	Other transportation equipment manufacturing	336411-336999
17	Furniture and related product manufacturing	337110-337920
18	Miscellaneous manufacturing	33911A-339994
19	Food, beverage, and tobacco product manufacturing	311111-3122A0
20	Textile and textile product mills	313100-314990
21	Apparel, leather, and allied product manufacturing	315100-316900
22	Paper manufacturing	322110-322299
23	Printing and related support activities	323110-323120
24	Petroleum and coal products manufacturing	324110-324199
25	Chemical manufacturing	325110-3259A0
26	Plastics and rubber products manufacturing	326110-326290
Wholesale trade		
27	Wholesale trade	420000
Retail trade		
28	Retail trade	4A0000
Transportation and warehousing*		
29	Air transportation	481000
30	Rail transportation	482000
31	Water transportation	483000
32	Truck transportation	484000
33	Transit and ground passenger transportation*	485A00
34	Pipeline transportation	486000

Appendix A
List of the RIMS II Model's 62 Industry Codes

Aggregate industry code and title		RIMS II detailed industry codes
35	Other transportation and support activities*	48A000-492000, 491000
36	Warehousing and storage	493000
Information		
37	Publishing industries, except Internet	511110-511200
38	Motion picture and sound recording industries	512100-512200
39	Broadcasting, except Internet	515100-515200
40	Telecommunications	517000
41	Internet and other information services	51A000
Finance and insurance		
42	Federal Reserve banks, credit intermediation and related services	52A000-522A00
43	Securities, commodity contracts, investments	523000
44	Insurance carriers and related activities	524100-524200
45	Funds, trusts, and other financial vehicles	525000
Real estate and rental and leasing		
46	Real estate	531000, S00800
47	Rental and leasing services and lessors of intangible assets	532100-533000
Professional, scientific, and technical services		
48	Professional, scientific, and technical services	541100-5419A0
Management of companies and enterprises		
49	Management of companies and enterprises	550000
Administrative and waste management services		
50	Administrative and support services	561100-561900
51	Waste management and remediation services	562000
Educational services		
52	Educational services	611100-611B00
Health care and social assistance		
53	Ambulatory health care services	621A00-621600
54	Hospitals	622000
55	Nursing and residential care facilities	623000
56	Social assistance	624A00-624400
Arts, entertainment, and recreation		
57	Performing arts, spectator sports, museums, zoos, and parks	711100-712000
58	Amusements, gambling, and recreation	713A00-713950
Accommodation and food services		
59	Accommodation	7211A0-721A00
60	Food services and drinking places	722000
Other services*		

Appendix A
List of the RIMS II Model's 62 Industry Codes

Aggregate industry code and title		RIMS II detailed industry codes
61	Other services*	8111A0-813B00, S00A00
Households		
62	Households	H00000

* Includes Federal Government enterprises.

Appendix B

Development/Support Task Expenditures and Construction Tasks Expenditures on the Gulf LNG Facility by 6-Month Period and by Year (Millions of Dollars)

Period	Development/ Support Tasks Expenditures	Annual Share of Total (%)	Construction Tasks Expenditures	Annual Share of Total (%)	Total Construction Effort Expenditures	Annual Share of Total (%)
2nd Half 2012	$1.4		$0.0		$1.4	
2012	$1.4	0.1%	$0.0	0.0%	$1.4	0.0%
1st Half 2013	$27.0		$0.0		$27.0	
2nd Half 2013	$27.0		$0.0		$27.0	
2013	$54.0	5.0%	$0.0	0.0%	$54.0	0.8%
1st Half 2014	$31.0		$0.0		$31.0	
2nd Half 2014	$84.4		$510.5		$594.9	
2014	$115.4	10.7%	$510.5	8.6%	$625.9	8.9%
1st Half 2015	$109.2		$1,106.7		$1,215.9	
2nd Half 2015	$132.9		$1,103.0		$1,236.0	
2015	$242.1	22.4%	$2,209.8	37.4%	$2,451.9	35.1%
1st Half 2016	$114.3		$896.3		$1,010.5	
2nd Half 2016	$127.2		$808.8		$936.0	
2016	$241.5	22.3%	$1,705.0	28.8%	$1,946.5	27.8%
1st Half 2017	$173.2		$573.8		$747.0	
2nd Half 2017	$121.2		$252.2		$373.4	
2017	$294.4	27.2%	$826.0	14.0%	$1,120.4	16.0%
1st Half 2018	$64.8		$330.8		$395.6	
2nd Half 2018	$67.0		$330.8		$397.8	
2018	$131.8	12.2%	$661.5	11.2%	$793.4	11.3%
Total	$1,080.6	100.0%	$5,912.8	100.0%	$6,993.4	100.0%

Source: Gulf LNG.

APPENDIX C

VERIFICATION

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY/OFFICE OF FOSSIL ENERGY

VERIFICATION

Patricia S. Francis, first being sworn, states that she is Assistant General Counsel for Gulf LNG Liquefaction Company, LLC; that she is authorized to execute this Verification; that she has read the foregoing filing and is familiar with the contents thereof; and that all of the statements of fact therein contained are true and correct to the best of her knowledge and belief.

Patricia S. Francis

Patricia S. Francis

On behalf of
Gulf LNG Liquefaction Company, LLC

STATE OF ALABAMA)
)
COUNTY OF JEFFERSON)

Subscribed and sworn to before me on this 31st day of August 2012, by Patricia S. Francis, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Regina H LaMaster

NOTARY PUBLIC SIGNATURE

REGINA H. LaMASTER
Notary Public, Alabama State At Large
My Commission Expires Jan. 27, 2013

NOTARY PUBLIC SEAL

REGINA H. LaMASTER NOTARY PUBLIC ALABAMA STATE AT LARGE

APPENDIX D

OPINION OF COUNSEL

Gulf LNG Liquefaction Company, LLC
a Kinder Morgan, GE company

August 31, 2012

Mr. John Anderson
Office of Fossil Energy
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

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

Dear Mr. Anderson,

This opinion is submitted pursuant to the requirements of Section 590.202(c) of the U.S. Department of Energy's regulations, 10 C.F.R. § 590.202(c) (2011). The undersigned is counsel to Gulf LNG Liquefaction Company, LLC. I have reviewed the corporate documents of Gulf LNG Liquefaction Company, LLC and it is my opinion that the proposed long-term export of liquefied natural gas, as described in the above-referenced application, is within the limited liability company powers of Gulf LNG Liquefaction Company, LLC.

Respectfully submitted,

Patricia S. Francis
Asst. General Counsel