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Dkt.No. 12-77-LNG

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July 16, 2012

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Mr. John Anderson
Office of Fuels Programs, 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: In the Matter of LNG Development Company, LLC (d/b/a Oregon LNG)
FE Docket No. 12-__-LNG
Application For Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Countries

Dear Mr. Anderson:

Enclosed for filing on behalf of LNG Development Company, LLC (d/b/a Oregon LNG) ("Oregon LNG"), please find an original and three (3) copies of Oregon LNG's application for long-term, multi-contract authorization to engage in exports of up to 9.6 million metric tons per annum of liquefied natural gas ("LNG"), which is the equivalent of approximately 456.25 billion cubic feet per year or 1.3 Bcf per day of natural gas. Oregon LNG is seeking authorization for a 25-year term commencing on the earlier of the date of first export or eight years from the date authorization is issued. Oregon LNG proposes to export LNG from its proposed LNG terminal site in Warrenton, Clatsop County, Oregon, to any country with which the United States does not have a free trade agreement requiring the national treatment for trade in natural gas and LNG that has, or in the future develops, the capacity to import LNG and with which trade is not prohibited by U.S. law or policy.[1]

Should you have any questions about the foregoing, please feel free to contact the undersigned at (212) 318-3009.

Respectfully submitted,

Lisa M. Tonery
Tania S. Perez
Attorneys for
LNG Development Company, LLC (d/b/a Oregon LNG)

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[1] A check in the amount of $50.00 is enclosed as the filing fee stipulated by 10 C.F.R. § 590.207 (2012).

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

In The Matter Of:	)	
	)	
LNG DEVELOPMENT COMPANY, LLC	)	Docket No. 12 - 77 - LNG
(d/b/a OREGON LNG)	)	

RECEIVED
JUL 16 2012

APPLICATION FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE COUNTRIES

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UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

In The Matter Of:	)	
	)	
LNG DEVELOPMENT COMPANY, LLC	)	**Docket No. 12 - ___ - LNG**
(d/b/a OREGON LNG)	)	

APPLICATION FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE COUNTRIES

Pursuant to Section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the Department of Energy's ("DOE") regulations,[2] LNG Development Company, LLC (d/b/a Oregon LNG) ("Oregon LNG") hereby requests that DOE, Office of Fossil Energy ("FE"), grant long-term, multi-contract authorization for Oregon LNG to engage in exports of up to 9.6 million metric tons per annum ("mtpa") of liquefied natural gas ("LNG") (the equivalent of 456.25 billion cubic feet per year ("Bcf/y") or 1.3 Bcf per day ("Bcf/d") of natural gas) for a 25-year period, commencing the earlier of the date of first export or eight years from the date of issuance of the authorization requested herein. Oregon LNG is seeking authorization to export LNG from the proposed Export Project (or "Project") to be located in Warrenton, Oregon to any country with which the United States does not have a free trade agreement ("FTA") requiring the national treatment for trade in natural gas and LNG that has, or in the future develops, the capacity to import LNG and with which trade is not prohibited by U.S. law or policy ("non-FTA Countries").[3]

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1 Natural Gas Act, 15 U.S.C. § 717b (2006).

2 10 C.F.R. Part 590 (2012).

3 Oregon LNG already holds authorization to engage in exports of up to 9.6 mtpa of LNG to any nation that currently has, or develops, the capacity to import LNG and with which the United States currently has, or in the future enters into, an FTA requiring the national treatment for trade in natural gas and LNG ("FTA Countries"). *See LNG Development Company, LLC (d/b/a Oregon LNG), Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas By Vessel from the Proposed LNG Terminal in Warrenton,*

In support of its Application, Oregon LNG states as follows:

I. DESCRIPTION OF THE APPLICANT

The exact legal name of Oregon LNG is LNG Development Company, LLC (d/b/a Oregon LNG). Oregon LNG has its principal place of business in Warrenton, Oregon and is headquartered at 8100 NE Parkway Drive, Suite 165, Vancouver, Washington 98662. Oregon LNG is authorized to do business in the State of Oregon.

II. COMMUNICATIONS AND CORRESPONDENCE

All correspondence and communications concerning this Application, including all service of pleadings and notices, should be directed to the following persons:[4]

Peter Hansen
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Suite 165
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Pursuant to Section 590.103(b) of the DOE regulations,[5] Oregon LNG hereby certifies that the persons listed above and the undersigned are the duly authorized representatives of Oregon LNG.

III. EXECUTIVE SUMMARY

Oregon LNG is herein seeking multi-contract, long-term authorization to export up to 9.6 mtpa of LNG produced from Canadian-sourced supplies of natural gas, and to a lesser extent supplies that may be domestically produced, to those countries which both have, or in the future

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Clatsop County, Oregon to Free Trade Agreement Nations, FE Docket No. 12-48-LNG, DOE/FE Order No. 3100 (May 31, 2012).

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

5 10 C.F.R. § 590.103(b).

develop, the capacity to import LNG and with which trade is not prohibited by U.S. law or policy (*i.e.*, non-FTA Countries). Oregon LNG requests this authorization for a 25-year term commencing the earlier of the date of first export or eight years from the date of issuance of the authorization requested herein.

The Oregon LNG Export Project is proposed to export primarily Canadian-sourced natural gas. The Project will convert Oregon LNG's pending import receiving terminal ("Import Terminal") and pipeline ("Oregon Pipeline") (collectively referred to as the "Import Project") into a bidirectional LNG terminal and pipeline ("Bidirectional Project"). The Oregon Pipeline is being developed by Oregon LNG's affiliate, Oregon Pipeline Company, LLC ("Oregon Pipeline Company"). As described in Sections V and VI below, the Export Project will interconnect with the multi-legged system of Williams Northwest Pipeline Company ("Williams") connecting Pacific Northwest demand centers with British Columbian and Rockies supplies. However, Oregon LNG does not expect that the gas feedstock for the Export Project will be derived to any significant degree from Rockies supply given that the market modeling commissioned by Oregon LNG demonstrates that Canadian supply is the economically preferred resource for the Project.

Unlike the multiple pending applications to export domestically produced LNG to non-FTA Countries, this Application involves a request for authorization to export LNG produced primarily from Canadian natural gas resources. In this regard, this Application is akin to applications for authorization to export previously imported LNG, which DOE/FE has expeditiously granted reasoning that exporting such LNG could not significantly reduce the availability of domestically produced natural gas.[6] The same rationale applies here.

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6 *See, e.g., ConocoPhillips Company, Order Granting Blanket Authorization to Export Previously Imported Liquefied Natural Gas by Vessel*, FE Docket No. 11-109-LNG, DOE/FE Order No. 3038 (November 22, 2011).

Notwithstanding the foregoing, to the extent that DOE is of the opinion that Oregon LNG's proposed exports would nonetheless affect the domestic market because the exports would reduce the volume of natural gas potentially available for domestic consumption on a long-term basis, Oregon LNG submits that empirical data demonstrates that North American natural gas supply is ample, reflecting a large surplus to current demand levels, that are sufficient to support Oregon LNG's proposed exports through the proposed 25-year term. In support of this Application, Oregon LNG commissioned a report by Navigant Consulting, Inc. ("Navigant"),[7] *Oregon LNG Export Project Market Analysis Study*, that further supports that the market for natural gas supplies in North America is vast and liquid. Navigant notes that the British Columbia Ministry of Energy and Mines and the National Energy Board of Canada have recently estimated the marketable gas in place in the Horn River Basin alone to be between 61 and 96 trillion cubic feet ("Tcf"), with total gas in place estimated at 372 Tcf. The other major basin in British Columbia, the Montney, has been estimated to contain 65 Tcf of recoverable resources.[8] Other recent estimates of these resources are even higher and, depending upon which estimate, point to a resource base with a reserve life of 350 to 1,000 years based upon current total demand in British Columbia of one Bcf of gas per day. Moreover, Apache Corp. very recently announced the discovery of a huge shale gas reservoir in the Liard Basin, estimated to contain 48 Tcf of gas.[9]

Oregon LNG submits that the export authorization sought herein is not inconsistent with the public interest. The Oregon LNG Export Project presents numerous benefits to the public,

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7 Navigant is an international consultant to the energy and utility industry.

8 Navigant Consulting, Inc., *Oregon LNG Export Project Market Analysis Study*, at 15 (April 13, 2012) [hereinafter Navigant Report]. The Navigant Report is submitted herewith as Appendix B.

9 *See* Gordon Hamilton, *Apache discovers huge shale gas reservoir in northern B.C.*, THE VANCOUVER SUN, June 19, 2012, http://www.vancouversun.com/business/energy-resources/Apache+discovers+huge+shale+reservoir+northern/6786150/story.html.

including the much needed expansion of market outlets and access for North American natural gas producers at times when neither U.S. nor Canadian gas prices support continued production. Natural gas production in North America has been steadily increasing in recent years, significantly outpacing domestic demand. This supply glut has depressed domestic natural gas prices to historic lows (below $2.00 per million British thermal unit ("MMbtu")) not experienced since 1999.[10] In many instances, the low market prices have resulted in U.S. producers shifting drilling activities to oil-rich formations[11] and even flaring associated natural gas.[12]

The Oregon LNG Export Project will create jobs and increase domestic economic activity and tax revenues, both directly and indirectly. Direct economic benefits to both the Pacific Northwest regional and local economies are quantified in the report Oregon LNG commissioned from *ECONorthwest,* entitled *An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon*. During the construction phase, there will be an average of 10,438 direct, indirect, and induced jobs created through the Export Project. This translates into approximately $847.6 million in wages and benefits to U.S. workers annually.[13] Once operational, the Oregon LNG Export Project will support 643 jobs in Clatsop County and 1,591

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10 *See* U.S. Energy Information Administration ("EIA"), *U.S. Natural Gas Wellhead Price*, http://www.eia.gov/dnav/ng/hist/n9190us3m.htm. Analysts also have expressed concern that burgeoning Canadian gas storage levels may potentially affect U.S. natural gas prices as Canadian producers attempt to move surplus gas across the border to the U.S. *See Canadian Gas Storage Glut Raises Concerns in US*, PLATTS GAS DAILY, June 11, 2012, at 1 and 3.

11 *See Anadarko: Expects More Natural-Gas Production Curtailments*, THE WALL STREET JOURNAL (May 1, 2012), http://online.wsj.com/article/BT-CO-20120430-710310.html.

12 Natural gas production in North Dakota has more than doubled since 2005, largely due to associated natural gas from the growing oil production in the Bakken shale formation. Gas production averaged over 485 million cubic feet per day ("MMcf/d") in September 2011, compared to the 2005 average of about 160 MMcf/d. However, due to insufficient natural gas pipeline capacity and processing facilities in the Bakken shale region, over 35 percent of North Dakota's natural gas production in 2011 has been flared or otherwise not marketed. *See* EIA, *Over one-third of natural gas produced in North Dakota is flared or otherwise not marketed*, November 23, 2011, http://www.eia.gov/todayinenergy/detail.cfm?id=4030.

13 ECONorthwest, An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon, at 16, Table 9 (April 9, 2012) [hereinafter ECONorthwest Report]. The ECONorthwest Report is submitted herewith as Appendix C.

jobs elsewhere in Oregon and Washington, which translates into total annual labor income of $46.5 million and $102.5 million, respectively.[14]

Another direct benefit of the Oregon LNG Export Project will be the expansion of existing pipeline infrastructure in the Pacific Northwest to transport Canadian natural gas across the State of Washington to the Oregon Pipeline interconnection in Woodland, WA. Expansion of the Williams system is required to accommodate the additional transportation volumes to the Project and is estimated to add approximately $700 million in construction revenues and an estimated 1,854 additional direct, indirect and induced construction jobs to the Washington state economy over a three year period.

On a global scale, the Oregon LNG Export Project is uniquely positioned to advance the security interests of the U.S. and its allies through a more proactive role in the international natural gas market. In serving Asian markets, which is the targeted region for the Project, the Export Project will play an important role in furthering America's geopolitical interests in Asia by enhancing the diversity of global natural gas supply in the region and advancing the principles of liberalized global natural gas markets. Moreover, the Project will serve to reinforce the U.S. trade relationship with Canada, which is among the closest and most extensive in the world as reflected in the staggering volume of bilateral trade (the equivalent of $1.4 billion a day in goods).[15] Finally, because of the forecasted long-term LNG price differential between North American and Asian LNG markets, exports from the Project are projected to result in a net improvement to the balance of trade for the United States of up to $4.5 billion for a 25-year period, even after taking into account the cost of gas imports from Canada.

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14 ECONorthwest Report at 18 (Tables 11 and 12).

15 *See* U.S. Department of State, Background: Canada, http://www.state.gov/r/pa/ei/bgn/2089.htm.

IV. AUTHORIZATION REQUESTED

Oregon LNG requests long-term, multi-contract authorization to export up to 9.6 mtpa of Canadian-sourced supplies of natural gas, and to a lesser extent supplies that may be domestically produced, from its Warrenton, Oregon site to any country with which the United States does not have an FTA requiring the national treatment for trade in natural gas and LNG that has, or in the future develops, the capacity to import LNG and with which trade is not prohibited by U.S. law or policy.[16] Oregon LNG requests this authorization for a 25-year term commencing the earlier of the date of first export or eight years from the date of issuance of the authorization requested herein.

Oregon LNG requests authorization to export LNG acting on its own behalf or as agent for others. In the first instance, in exporting on its own behalf, Oregon LNG would hold title to the LNG at the time of export. Oregon LNG would either take title to the gas at a point upstream of the Project or would purchase LNG from a customer of the Oregon LNG Export Project prior to export. In the second instance, in acting as agent, Oregon LNG would not hold title to the gas at the time of export.

Oregon LNG will comply with all DOE/FE requirements for exporters and agents, including the registration requirements set forth in *Freeport LNG Development, L.P.*, DOE/FE Order No. 2913.[17] In this regard, Oregon LNG, when acting as agent, will register with DOE/FE

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[16] In any given year, Oregon LNG expects to export a maximum of 9.6 mtpa of LNG (or the equivalent of 1.3 Bcf/d of natural gas) from the Oregon LNG Export Project. Such export may be to FTA Countries pursuant to the authorization granted in DOE/FE Order No. 3100 or to non-FTA Countries with which trade is not prohibited by U.S. law or policy pursuant to the authorization sought herein. In this regard, 9.6 mtpa is the cumulative volume that will be exported from the Oregon LNG Export Project annually.

[17] *Freeport LNG Development, L.P., Order Granting Long-Term Authorization to Export Liquefied Natural Gas from Freeport LNG Terminal to Free Trade Nations*, FE Docket No. 10-160-LNG, DOE/FE Order No. 2913 (Feb. 10, 2011); *Errata Notice Correcting Footnote 9 in Order 2913 Issued 2/10/2009* (Feb. 17, 2011) [hereinafter, DOE/FE Order No. 2913]. In DOE/FE Order No. 2913, DOE/FE approved a proposal by the applicant 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

each LNG title holder for whom it seeks to export as agent, and will provide DOE/FE with a written statement by the title holder acknowledging and agreeing to (i) comply with all requirements in Oregon LNG's long-term export authorization; and (ii) include those requirements in any subsequent purchase or sale agreement entered into by the title holder. Oregon LNG also will file under seal with DOE/FE any relevant long-term commercial agreements that it enters into with the LNG title holders on whose behalf the exports are performed.

At present, Oregon LNG does not contemplate entering into any long-term gas supply or long-term export contracts in conjunction with the LNG export authorization requested herein. Rather, Oregon LNG will enter into capacity use arrangements with potential Project participants or third-party customers. Accordingly, Oregon LNG is not submitting transaction-specific information (*e.g.*, long-term supply agreements and long-term export agreements) at this time[18] and requests that DOE/FE make a similar finding to that in DOE/FE Order No. 2961 with regard to the transaction-specific information requested in Section 590.202(b) of the DOE regulations.

Finally, Oregon LNG requests that, pursuant to Section 590.402 of the DOE regulations,[19] the Assistant Secretary issue a conditional order authorizing the export of LNG as requested herein, conditioned on completion of the environmental review of the Export Project

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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 DOE/FE any relevant long-term commercial agreements that it reached with the LNG title holders on whose behalf the exports were performed.

18 In the May 20, 2010 order granting Sabine Pass Liquefaction, LLC ("Sabine Pass") long-term export authorization to non-FTA Countries, DOE/FE found that Sabine Pass was not required to submit with its application transaction-specific information pursuant to Section 590.202(b) of the DOE regulations. DOE/FE found that given the state of development for the proposed Sabine Pass export project, it was appropriate for Sabine Pass to submit such transaction-specific information when the contracts reflecting such information are executed. *See Sabine Pass Liquefaction, LLC, Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations*, FE Docket No. 10-111-LNG, DOE/FE Order No. 2961 at 41 (May 20, 2011) [hereinafter DOE/FE Order No. 2961].

19 10 C.F.R. § 590.402.

by the Federal Energy Regulatory Commission ("FERC" or "Commission").[20] DOE routinely issues conditional orders subject to satisfactory environmental review in similar circumstances.[21]

V. DESCRIPTION OF EXPORT PROJECT

The Oregon LNG Export Project is being developed to liquefy primarily Canadian-sourced supplies of natural gas for export to higher priced foreign markets. The Project also will be able to export domestically produced LNG given its access to Rockies supplies through the Williams system. The Oregon LNG Export Project will convert Oregon LNG's pending Import Project into the Bidirectional Project, which will offer both liquefaction and regasification capability. The Oregon Pipeline will be operated as a bidirectional pipeline capable of delivering natural gas to the Export Project for liquefaction and export, and sending out regasified LNG from the Import Terminal. The Import Terminal and Oregon Pipeline are pending before the FERC in Docket Nos. CP09-6-000 and CP09-7-000, respectively.

Oregon LNG and Oregon Pipeline Company requested authorization to commence the Commission's mandatory National Environmental Policy Act ("NEPA")[22] process for the Oregon LNG Export Project on July 3, 2012 in Docket No. PF12-18-000. On July 16, 2012, the Director, Office of Energy Projects, granted the request. Oregon LNG and Oregon Pipeline Company anticipate amending their pending applications with FERC pursuant to Sections 3 and

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[20] In promulgating its regulations setting forth the administrative procedures for the import and export of natural gas, DOE indicated that issuance of a conditional decision is appropriate when the application at issue involves, for example, the importation of LNG into new terminal facilities. In such a case, DOE reviews the application to determine if the proposed importation is in the public interest based on the considerations within DOE's jurisdiction, while, concurrently, FERC must review other aspects of the proposed importation such as siting, construction and operation of the LNG receiving terminal facilities. *See Import and Export of Natural Gas*, 46 Fed. Reg. 44,696, at 44,700 (Sept. 4, 1981).

[21] *See, e.g., Rochester Gas and Electric Corp., Order Amending Conditional Order for the Purpose of Granting Final Long-Term Authorization to Import Natural Gas from Canada*, FE Docket No. 90-05-NG, DOE/FE Order No. 503 (May 16, 1991).

[22] 42 U.S.C. § 4321 (1970).

7 of the NGA, respectively, by the First Quarter of 2013 for authorization to site, construct and operate the Bidirectional Project.

The Export Project will be located in Warrenton, Oregon. LNG carriers ("LNGCs") will arrive at the Project site via the Columbia River Navigation Channel. The Project will be designed to accommodate LNGCs ranging in size from 70,000 m^3 to 266,000 m^3. LNGCs will travel between 10 to 12 knots (11.5 to 13.8 miles per hour) on the Lower Columbia River after clearing the Columbia River Bar until reaching Hammond, Oregon, at the final turn in the river before meeting tug boats to start docking. The Project will be designed with a base-load LNG liquefaction capacity of 9.6 mtpa, which requires approximately 1.3 Bcf/d of pretreated natural gas.[23] Exports from the Oregon LNG Export Project are scheduled to commence in late 2017.

The Project will connect with the Oregon Pipeline, which will extend approximately 86 miles to an interconnect with the Williams system near Woodland, Washington.[24] Through its interconnect with the Oregon Pipeline, which will extend approximately 86 miles to an interconnect with the Williams system near Woodland, Washington, Oregon LNG will have access to various supply basins in Western Canada as well as U.S. Rocky Mountain supply basins.

VI. COMMERCIAL/CONTRACT TERMS AND EXPORT SOURCES

Oregon LNG likely will structure its commercial arrangements in a manner that provides for other entities to hold liquefaction capacity in the Project and bear responsibility for sourcing

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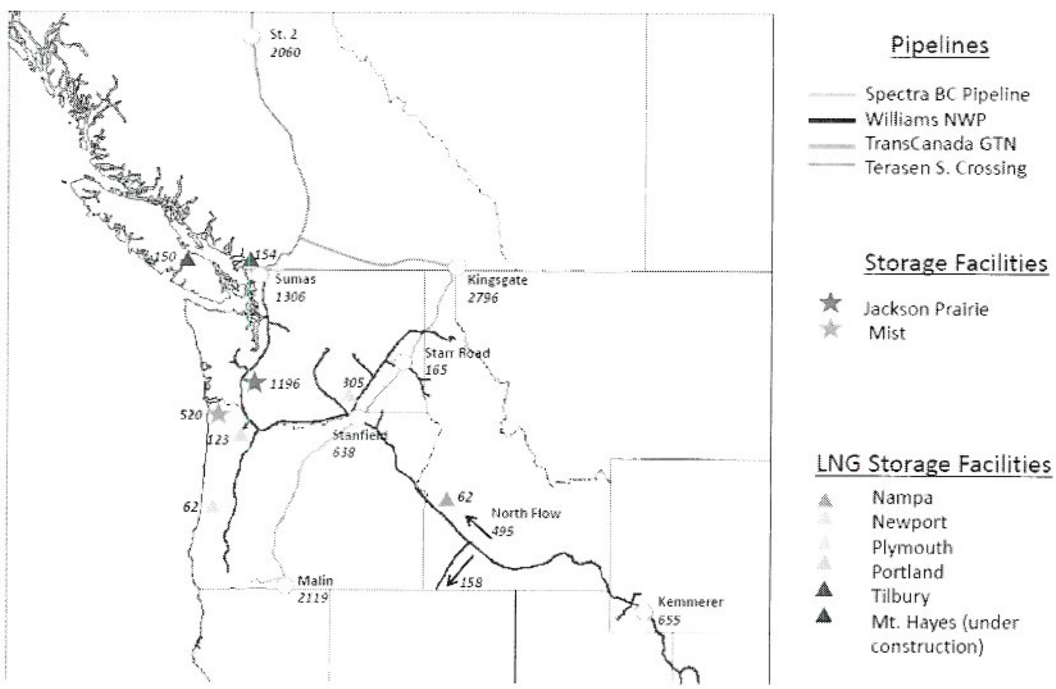
23 The Import Project will have base load capacity for regasification of LNG to send out 0.5 Bcf/d of natural gas.

24 Interconnection with the Williams system will require an expansion of Williams's existing system, including the installation of approximately 96,000 horsepower of compression at five existing compressor stations and the installation of approximately 136 miles of 36-inch diameter pipeline in ten segments along Williams's existing pipeline system between Sumas, Washington and Woodland, Washington ("Washington Expansion Project"). Williams requested authorization to commence the FERC's NEPA prefiling process for the Washington Expansion Project on July 10, 2012 in Docket No. PF12-20-000. On July 16, 2012, the Director, Office of Energy Projects, granted Williams's request.

their own gas supplies. Oregon LNG has not entered into any contractual or other capacity arrangements at this time.

The gas feedstock for the Export Project will be primarily produced from Canadian resources. Oregon LNG contemplates that a portion of the gas for the Project will be sourced through various market hubs in the Pacific Northwest, primarily Sumas. The key pipelines serving the region are shown below, as well as market area storage facilities and LNG peaking plants. In addition, the Williams Ruby Pipeline (not shown) has expanded market reach by adding up to 1.5 Bcf/d of transportation capacity to Malin.

Pacific Northwest Regional Natural Gas Infrastructure



Source: Williams and Northwest Gas Association

The Export Project will interconnect with the Williams system, a multi-legged system linking Pacific Northwest demand centers with British Columbia and Rockies supplies. The Spectra BC Pipeline system, which interconnects with Williams, provides access to the traditional basins in B.C. as well as developing shale basins in the northeastern section of the province. The TransCanada Gas Transmission Northwest ("GTN") was originally designed to transport Canadian gas from Alberta to the California border, but it is expected to have excess pipeline capacity due to gas-on-gas competition from Ruby Pipeline, which was designed to allow Rockies supply to compete with Canadian supply for the California market, and has indeed allowed displacement of Canadian supplies on GTN since commencing operations in July 2011.[25]

VII. APPLICABLE LEGAL STANDARD

Pursuant to Section 3 of the NGA, 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."[26] 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>.[27]

Section 717b(a) thus creates a statutory presumption in favor of approval of this Application which opponents bear the burden of overcoming. Further, in evaluating an export application, 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"),[28] which presume the normal functioning of the

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25 *See New gas pipelines likely to shake up Western winter market, flow patterns, analysts say,* Platts US Natural Gas Winter Outlook (Nov. 17, 2011), http://www.platts.com/NewsFeature/2011/wintergas/index.

26 15 U.S.C. § 717b(a).

27 *Id.* (emphasis added).

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

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.[29] In the past, FE also has considered local interests, international effects and the environment as factors relevant to the public interest determination.[30]

In the context of the instant Application and existing natural gas market conditions, the longstanding principles of minimizing federal control and involvement in natural gas markets articulated in the Policy Guidelines are particularly relevant.[31] The Policy Guidelines emphasize

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29 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 applications. *See Sabine Pass Liquefaction, LLC, supra* note 18, at p. 29.

30 In DOE Opinion and Order No. 2500, which granted ConocoPhillips Alaska Natural Gas Corporation and Marathon Oil Company authorization to export LNG from Alaska, for example, DOE considered the regional need for the gas by reviewing the natural gas supply and demand projections submitted, cited or relied on by the parties in the proceeding and determined that there was a reasonable basis for concluding that local supplies were adequate to support the proposed export as well as to meet local demand requirements during the term of the proposed blanket authorization. *ConocoPhillips Alaska Natural Gas Corp., Order Granting Authorization to Export Liquefied Natural Gas from Alaska*, FE Docket No. 07-02-LNG, DOE/FE Order No. 2500, at 47 (June 3, 2008). In addition, DOE found that (1) local interests would be well served by a grant of the requested authorization because the continued operation of the applicant's liquefaction plant provided significant benefits to the local economy, (2) exportation of LNG would help to improve the United State's balance of payments with Pacific Rim countries during the term of the proposed blanket authorization; and (3) there was no significant environmental impact. *See id.* at 57-58. *See also Cheniere Marketing, Inc., Order Granting Authorization to Export Liquefied Natural Gas*, FE Docket No. 08-77-LNG, DOE/FE Order No. 2651, at 14 (June 8, 2009) (explaining that, consistent with the *Policy Guidelines* and applicable precedent, the DOE considers the potential effects of proposed exports on aspects of the public interest other than domestic need, including international effects and the environment).

31 While the *Policy Guidelines* deal specifically with imports, the principles are applicable to exports as well. *See Phillips Alaska Natural Gas Corp. and Marathon Oil Co., Order Extending Authorization to Export Liquefied Natural Gas from Alaska*, FE Docket No. 96-99-LNG, DOE/FE Order No. 1473, at 14 (Apr. 2, 1999).

free market principles and promote limited government involvement in federal natural gas regulation:

> The market, not government, should determine the price and other contract terms for imported [and exported] gas. U.S. buyers [and sellers] should have full freedom - along with the responsibility - for negotiating the terms of trade arrangements with foreign sellers [and buyers].
>
> The government, while ensuring that the public interest is adequately protected, should not interfere with buyers' and sellers' negotiation of the commercial aspects of import [and export] arrangements. The thrust of this policy is to allow the commercial parties to structure more freely their trade arrangements, tailoring them to the markets served.[32]

The Policy Guidelines also provide some insight into the public interest standard for evaluating potential import and export applications. In this regard, they state that the "policy cornerstone of the public interest standard is competition."[33] Competitive import/export arrangements are therefore an essential element of the public interest and, so long as the sales agreements are set in terms that are consistent with market demands, they should be considered to "largely" meet the public interest standard.[34] The guidelines continue by saying that "[t]his policy approach presumes that buyers and sellers, if allowed to negotiate free of constraining governmental limits, will construct competitive import [and export] agreements that will be responsive to market forces over time."[35] To date, FE orders granting authorization to export natural gas continue to reflect and reinforce the principles laid out in the Policy Guidelines by emphasizing the concepts of free trade and limited government involvement.[36]

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32 *Policy Guidelines*, *supra* note 28, at 6685.

33 *Id.* at 6687.

34 *Id.*

35 *Id.* (with reference to "exports" inserted to reflect DOE policy that "the principles are applicable to exports as well" as enunciated in *Phillips Alaska*, Order No. 1473, at 14).

36 *See, e.g.*, *Sabine Pass Liquefaction, LLC*, *supra* note 18 (referencing DOE's policy of promoting competition in the marketplace by allowing commercial parties to freely negotiate their own trade arrangements); *Phillips Alaska*, *supra* note 31, at 51 (stating that the public interest is generally best served by a free trade policy);

VIII. PUBLIC INTEREST

The Oregon LNG Export Project has been proposed due to the improved outlook for North American natural gas production, owing to drilling productivity gains that have enabled rapid growth in supplies from unconventional, and particularly shale, gas-bearing formations in the United States and Canada. Improvements in drilling and extraction technologies have coincided with rapid diffusion in the natural gas industry's understanding of the unconventional resource base and best practices in drilling and resource development. These changes have rendered obsolete once prominent fears of declining future domestic natural gas production. This has resulted in the Obama Administration showing an increased interest in supporting LNG exports, particularly to non-FTA countries.[37]

The Oregon LNG Export Project presents various benefits to the public, including the much needed expansion of market scope and access for North American natural gas producers at times when neither U.S. nor Canadian gas prices support continued production. The North American supply glut has depressed domestic natural gas prices to historic lows (below $2.00 per MMbtu) not experienced since 1999.[38] Analysts have expressed concern that the Canadian gas storage levels may reach capacity in June 2012, potentially affecting U.S. natural gas prices as Canadian producers attempt to move surplus gas across the border to the U.S.

In many instances, the low market prices have resulted in U.S. producers shifting drilling activities to oil-rich formations[39] and even flaring associated natural gas. For example, natural gas production in North Dakota has more than doubled since 2005, largely due to associated natural gas from the growing oil production in the Bakken shale formation. Gas production

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ConocoPhillips, supra note 30, at 44-45 (stating that DOE's general policy is to minimize federal government involvement and allow commercial parties to freely negotiate their own trade arrangements).

37 *See White House supportive of LNG exports: Zichal,* PLATTS GAS DAILY, June 22, 2012, at 1 and 4.

38 EIA, *supra* note 10; *see* PLATTS, *supra* note 10.

39 *See, Anadarko supra* note 11.

averaged over 485 MMcf/d in September 2011, compared to the 2005 average of about 160 MMcf/d. However, due to insufficient natural gas pipeline capacity and processing facilities in the Bakken shale region, over 35 percent of North Dakota's natural gas production in 2011 was flared or otherwise not marketed.[40]

As discussed below, empirical data and that commissioned by Oregon LNG demonstrate that the current North American natural gas supply is ample, reflecting a large surplus to current demand levels that are clearly sufficient to support Oregon LNG's proposed exports through the proposed 25-year term. In light of the current supply/demand outlook for the U.S. and the fact that this Application involves exporting Canadian natural gas supplies as LNG, Oregon LNG submits that its proposed exports could not significantly reduce the availability of domestically produced natural gas.

A. <u>Analysis of Domestic Need for Gas to be Exported</u>

The Navigant Report, as well as publicly available information, indicate that North America has significant natural gas resources available at prices that are sufficient to meet projected domestic needs and 9.6 mtpa of exports over the 25-year period covered in Oregon LNG's request for export authority.

1. *North American Natural Gas Supply*

a. Western Canada

The vast majority of the natural gas feedstock for the Export Project would come from resources in Western Canada. The latest data concerning production and reserves from this region show that there will be an abundant supply of natural gas for the Export Project. As indicated in the Navigant Report, the Province of British Columbia has planned an increase in production from 1.2 Tcf per year ("Tcf/y") to over 3.0 Tcf/y in 2020 to supply three new

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40 *See* EIA, *supra* note 12.

proposed LNG export facilities and to accommodate a diversification of its gas markets.[41] Short term historical trends show an increase in production as well. Natural gas production in British Columbia for February 2012 was 122.6 Bcf (4.23 Bcf per day (Bcf/d)), up from 111.5 Bcf (3.98 Bcf/d) in February 2011.[42]

Recoverable natural gas reserves in Western Canada can support the demand from the Export Project. The most recent data indicate that a minimum of 372 Tcf resides in Western Canada's largest natural gas reserve, the Horn River Basin.[43] Including the other two major resources on the Horn River, the Cordova Embayment and the Liard Basin, the total reserves are estimated at 448 Tcf.[44] Estimates of marketable gas from the Horn River range from 90 to 200 Tcf.[45] Recoverable gas estimates from the other major reserve in British Columbia, the Montney play, range from 65 to 221 Tcf.[46] In 2009, British Columbia consumed approximately 386 Bcf of natural gas.[47] Assuming a steady level of demand and the most conservative reserve estimates, the two major gas resources could support British Columbia's demand for over 400 years, even without tapping the tremendous reserves recently discovered in the Liard Basin. Given the intention of British Columbia to increase exports, this results in a more than adequate supply of gas for the Export Project.

b. United States

Domestic production and reserves collectively provide for an abundant domestic supply of natural gas. Domestic gas production has been on an upward trend in recent years allowing

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41 Navigant Report, *supra* note 8, at 14.
42 British Columbia Ministry of Energy, *Monthly Statistics*, http://www.empr.gov.bc.ca/OG/oilandgas/statistics/Pages/MonthlyStatistics.aspx.
43 Navigant Report, *supra* note 8, at 15.
44 *Id.*
45 *Id.*
46 *Id.*
47 *Id.*

the U.S. to transition from a net importer to a net exporter of natural gas.[48] According to EIA, shale gas production in the United States reached 4.87 Tcf in 2010, or 23 percent of U.S. dry gas production.[49] By 2035, the EIA estimates that shale gas will account for 46 percent of total domestic natural gas production.[50]

There have been a number of reports and studies that attempt to identify the total amount of technically recoverable shale gas resources—the volumes of gas retrievable using current technology irrespective of cost—available in the United States. These estimates vary from 482 Tcf[51] of shale gas to 842 Tcf.[52] To put these numbers in context, the United States is projected to consume nearly 25.20 Tcf of gas in 2012,[53] suggesting that the estimates for the shale gas resource alone would be enough to satisfy between approximately 20 and 35 years of U.S. domestic demand.

Available data point to continued growth in domestic production in 2011.[54] EIA estimates U.S. dry gas production totaled 2.00 Tcf (64.6 Bcf/d) in March 2012, a 2.7 Bcf/d increase compared to March 2011 dry production of 1.92 Tcf (61.9 Bcf/d).[55] Increased drilling productivity in certain prolific shale formations, particularly the Marcellus and Haynesville

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48 EIA, Annual Energy Outlook 2012 with Projections to 2035 (June 2012) [hereinafter AEO 2012]. *See* http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

49 EIA, World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States (April 5, 2011), http://www.eia.gov/analysis/studies/worldshalegas/.

50 *Id.* at 1.

51 EIA, Annual Energy Outlook 2012 Early Release, at p. 9 (January 2012) [hereinafter AEO 2012 Early Release], *available at* http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf. In the AEO 2012 Early Release and recently issued AEO 2012, the Reference Case estimate of unproven shale gas resources was lowered to 482 Tcf from the estimate of 827 Tcf in EIA's Annual Energy Outlook 2011 (April 2011), *available at* http://www.eia.gov/forecasts/archive/aeo11/pdf/0383(2011).pdf. This lowered estimate is a matter of considerable controversy and concern expressed by industry and other experts in the Marcellus shale.

52 Navigant Report, *supra* note 8, at 3.

53 AEO 2012, *supra* note 48, at Table 13, *available at* http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=8-AEO2012&table=13-AEO2012&region=0-0&cases=ref2012-d020112c.

54 Lower 48 states wellhead natural gas production increased in the five consecutive months, from December 2009 to May 2010, according to EIA's Form 914 Survey of US natural gas producers. EIA, U.S. Natural Gas Marketed Production, http://205.254.135.7/forecasts/steo/archives/May12.pdf.

55 EIA, U.S. Dry Natural Gas Production, http://www.eia.gov/dnav/ng/hist/n9070us2m.htm.

shales, has enabled domestic production to continue expanding despite a reduction in upstream industry development.

The Potential Gas Committee in April 2011 raised its prior estimates of the U.S. technically recoverable gas resource base by 61 Tcf to 1,898 Tcf at year-end 2010.[56] Including 273 Tcf of established proved domestic natural gas reserves as of year-end 2009, the Potential Gas Committee determined that the United States possesses future available gas supply of 2,170 Tcf,[57] an increase of 89 Tcf over the previous evaluation. This is the highest resource evaluation in the group's 46-year history. Most of the increase arose from the Potential Gas Committee's reevaluation of shale gas plays in the Gulf Coast, Mid-Continent and Rocky Mountain areas.

In its published study, *The Future of Natural Gas* ("MIT Report"), the Massachusetts Institute of Technology estimates that the United States has a mean recoverable resource base of approximately 2,100 Tcf.[58] This estimate includes 650 Tcf of recoverable shale resources, "approximately 400 Tcf [of which] could be economically developed with a gas price at or below $6/MMBtu at the well-head."[59] According to the MIT Report's mean resource estimate, United States gas production will rise by 40 percent between 2005 and 2050.[60]

2. *National Natural Gas Demand*

As evidenced by the plummeting U.S. natural gas price,[61] domestic natural gas demand continues to be outpaced by the available supply. Over the past decade, the U.S. has experienced

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

57 *Id.* at 2.

58 Massachusetts Institute of Technology, The Future of Natural Gas, at 30 (2011) [hereinafter *MIT Report*], *available at* http://web.mit.edu/mitei/research/studies/documents/natural-gas-2011/NaturalGas_Report.pdf.

59 *Id.* at 7.

60 *Id.* at 56.

61 Natural gas spot prices averaged $1.95 per MMBtu at the Henry Hub in April 2012, down $0.23 per MMBtu from the March 2012 average and the lowest average monthly price since March 1999, which also was the last time the Henry Hub price averaged less than $2 per MMBtu. EIA, *Short Term Energy Outlook* (May 8, 2012), http://205.254.135.24/forecasts/steo/report/natgas.cfm.

essentially no growth in demand for natural gas. In AEO 2012, EIA predicts long-term annual gas demand growth of only 0.4 percent, with the domestic market expected to reach 26.63 Tcf (72.9 Bcf/d) in 2035.[62] EIA predicts U.S. natural gas consumption of 25.39 Tcf (69.6 Bcf/d) in 2015, or growth of only 14 percent from the 1998 benchmark (22.24 Tcf).[63] U.S. demand in 2012 of 25.20 Tcf represents a mere 8 percent increase from the 23.33 Tcf consumed in 2000, according to EIA data.[64]

a. *Industrial Sector*

Consumption of natural gas in the U.S. by industrial end-users has steadily declined over the last 15 years, from a peak of 8.51 Tcf (23.3 Bcf/d) in 1997 to 6.7 Tcf (18.4 Bcf/d) in 2011.[65] EIA's recent data in AEO 2012 shows projections of U.S. industrial sector demand totaling 7.0 Tcf (19.2 Bcf/d) in 2035, a 5.53 percent increase in consumption from the 6.65 Tcf (18.2 Bcf/d) consumed in 2008 at the onset of the U.S. economic recession.[66]

b. *Residential and Commercial Sectors*

EIA has documented that gas demand per U.S. residential household has been in decline since the 1990s, down 22 percent on a weather-adjusted basis from 1990 to 2009, due to efficiency gains in heating furnaces, improvements in insulation and building construction codes, 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.[67] EIA is forecasting effectively no growth in future residential sector consumption of natural gas as customer growth is offset by these efficiency gains. U.S. residential natural gas demand is

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62 AEO 2012, *supra* note 48, at Table 13.

63 *Id.* *See also* EIA, *Natural Gas Consumption by End Use* (Dec. 29. 2011), http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

64 *Id.*

65 *Id.*

66 AEO 2012, *supra* note 48, at Table 13. *See also* EIA, *supra* note 63.

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

forecast at 4.64 Tcf (12.7 Bcf/d) in 2035, approximately a 0.2 percent decrease from the 2012 forecast of 5.03 Tcf (13.8 Bcf/d).[68] Commercial sector natural gas use is projected to see modest annual growth of 0.5 percent in the AEO 2012, reaching 3.6 Tcf (9.9 Bcf/d) in 2035 from 3.12 Tcf (8.5 Bcf/d) in 2009.[69]

c. *Electricity Sector*

The electric generating sector has been the only domestic natural gas consuming sector to experience consistent growth in recent years. Natural gas consumption for electricity generation totaled 7.6 Tcf in 2011, a 45.9 percent gain from 5.21 Tcf used in 2000.[70] The outlook for future demand is uncertain however, due primarily to economic headwinds caused by the U.S. recession and increased competition from other sources of electric generation.

EIA in its AEO 2012 Reference Case forecast predicts that U.S. gas demand by the electric power sector will slightly increase to 7.66 Tcf (20.98 Bcf/d) in 2014 from 7.38 Tcf (20.2 Bcf/d) in 2010.[71] Coal remains the dominant fuel for electricity generation in the AEO 2012 Reference Case, but its share declines significantly. In 2010, coal accounted for 45 percent of total U.S. generation; in 2020 and 2035 its projected share of total generation is 39 percent and 38 percent, respectively. Competition from natural gas and renewables is a key factor in the decline. Overall, coal-fired generation in 2035 is 2 percent higher than in 2010 but still 6 percent below the 2007 pre-recession level.[72]

Generation from natural gas grows by 42 percent from 2010 to 2035, and its share of total generation increases from 24 percent in 2010 to 28 percent in 2035. The relatively low cost of natural gas makes the dispatching of existing natural gas plants more competitive with coal

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68 AEO 2012, *supra* note 48, at Table 13.
69 *Id.*
70 *See* EIA, *supra* note 63.
71 AEO 2012, *supra* note 48, at Table 13.
72 *Id.* at 87.

plants and, in combination with relatively low capital costs, makes natural gas the primary choice to fuel new generation capacity. Generation from renewable sources grows by 77 percent in the Reference case, raising its share of total generation from 10 percent in 2010 to 15 percent in 2035.[73] Natural gas use in the electricity sector is projected to grow 0.8 percent annually over the long-term AEO 2012 forecast, to 8.96 Tcf (24.5 Bcf/d) in 2035 from 7.38 Tcf (20.2 Bcf/d) in 2010.[74]

d. *Transportation Sector*

Natural gas consumed for residential and commercial transportation accounts for a small portion of domestic demand. In 2011, 32.85 Bcf of natural gas was used in the U.S. for vehicle fuel, or approximately 0.1 percent of the total U.S. gas market of 23.2 Tcf.[75] Transportation sector energy consumption grows at an average annual rate of 0.1 percent from 2010 to 2035 (from 27.6 quadrillion Btu to 28.6 quadrillion Btu), much slower than the 1.2 percent average from 1975 to 2010.[76]

3. *Oregon LNG Export Project Market Study*

In addition to publicly available information and forecasts, Oregon LNG commissioned the Navigant Report to assess the potential supply, demand and pricing impact on U.S. natural gas markets under three scenarios through 2045, which is the timeframe for Oregon LNG's proposed exports.[77] The first scenario, "OLNG Reference," is based exclusively on Navigant's twice annual long-term forecast. The OLNG Reference case was developed from Navigant's December 2011 forecast, which incorporates numerous data points from across the natural gas

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73 *Id.*
74 AEO 2012, *supra* note 48, at Table 13.
75 EIA, *supra* note 63.
76 AEO 2012, *supra* note 48, at 84.
77 Navigant Report, *supra* note 8.

sector.[78] This case was developed under the assumption that two other North American LNG export facilities would be operational by the time the Oregon LNG Export Project comes on line.[79]

The second scenario, "OLNG Export", expands upon the results in the OLNG Reference case, factoring in the impact of Oregon LNG's estimated exports.[80] The OLNG Export case builds upon the OLNG Reference case by assuming and average of 1.0 Bcf/d of exported natural gas.[81]

The third scenario, "Aggregate Export" expands upon the OLNG Reference case by including the aggregate estimated exports from North America.[82] The total amount of exported gas accounted for in this case comes to approximately 6.8 Bcf/d.[83]

a. *Supply Impact*

Under the three scenarios contemplated in the Navigant Report, little effect would be seen on the supply of natural gas in the U.S. The decline in net imports, in both LNG and pipeline distribution, combined with an increase in unconventional production will yield greater supply throughout the study period until 2045.

The OLNG Reference case projects natural gas supplies growing from 71.9 Bcf/d in 2017 to 83.3 Bcf/d in 2045, a 15.9 percent increase.[84] Under the OLNG Export case, supplies will increase at virtually the same rate, with a total production in 2045 of 83.4 Bcf/d.[85] The slight increase in production between the two scenarios is accounted for by an increase in shale production under the OLNG Export case.

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78 *Id.* at 37
79 *Id.*
80 *Id.* at 40
81 *Id.*
82 *Id.* at 46.
83 *Id.*
84 *Id.* at 37.
85 *Id.* at 40.

Natural gas supply will see a greater increase once other LNG exports are factored in. Under the Aggregate Export case, production will grow from 71.8 Bcf/d in 2017 to 84.4 Bcf/d in 2045, a modest 1.2 percent increase over the OLNG Export case and 1.3 percent increase from the OLNG Reference case.[86] Once more, the difference is accounted for by an increase in unconventional production in the light of a modest decline in LNG imports.

The Export Project in particular, and LNG exports in general, would appear to have a minor positive 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 spur production, yielding net positives across all scenarios.

b. *Demand Impact*

The difference in impact on U.S. demand in the three scenarios is minimal. The Navigant Report shows no change in demand between the OLNG Reference and OLNG Export scenarios for the U.S. Total demand under both scenarios is estimated at 71.9 Bcf/d in 2017 and 83.4 Bcf/d in 2045, the last year projected by the study.[87] Under both scenarios, the largest sector for demand is electric power generation, which is estimated at 25.8 Bcf/d in 2017 and 36.5 Bcf/d in 2045.[88]

A minimal impact on demand is seen under the Aggregate Export case. Under this scenario, demand is actually 0.1 Bcf/d less than under the OLNG Export case in 2017.[89] Only in 2045 do the two cases differ significantly, with the Aggregate Export model showing an increase in demand of 1.0 Bcf/d, represented mostly in the electric power generation sector.[90]

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86 *Id.* at 46.
87 *Id.* at 43.
88 *Id.*
89 *Id.* at 49.
90 *Id.*

These differing scenarios show that the Oregon LNG Export Project will have a statistically insignificant impact on the demand for natural gas in the U.S. market. Between a significant increase in supplies due mostly to unconventional resources, increases in electric power efficiency, and a growing dependence on coal and renewable sources for power generation, the proposed quantities of gas for the Export Project will have a minimal impact on the U.S. market as a whole.

c. *Natural Gas Pricing Impact*

Under the three cases, the price of natural gas in the U.S. shows small variations. The Navigant Report considers the price impact at Henry Hub and Sumas separately. Under the OLNG Export case, the Henry Hub price ($4.47/MMBtu) is estimated to be $0.05 greater than under the Reference Case ($4.42/MMBtu) in 2017, representing a 1.2 percent difference.[91] The Henry Hub price under the Aggregate Export model is $4.66/MMBtu, a 4.2 percent increase over the OLNG Export case price.[92] This results in a 5.43 percent price spread among the cases. In 2045, the Henry Hub price is $8.07/MMBtu under the reference case, $8.22/MMBtu under the OLNG Export case and $8.47 under the Aggregate Export case.[93] This results in a 4.96 percent price spread among the scenarios.

The price differential at Sumas is estimated to follow a similar trend. In 2017, the Sumas price under the Reference Case is estimated at $4.03/MMBtu, the OLNG Export price is estimated at $4.12/MMBtu and the Aggregate Export price is estimated at $4.26/MMBtu for a total price spread among the scenarios of 5.71 percent.[94] In 2045, the estimated price spread at

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91 *Id.* at 45.
92 *Id.* at 50.
93 *Id.* at 45, 50.
94 *Id.*

Sumas increases to 8.49 percent. The price at Sumas remains below the Henry Hub price in all scenarios.

4. *Supply/Demand Balance Demonstrates the Lack of Regional/National Need*

North American supply/demand dynamics, as a whole, show that given the large magnitude of North American natural gas resources, indigenous supplies will be sufficient to meet demand. From a regional perspective, Navigant's results highlight not only the feasibility, but the benefit, of the Oregon LNG Export Project. First, with projections of Canada maintaining its status as a net exporter of natural gas to the U.S., a regional analysis indicates that cross-border flows into the Pacific Northwest consist solely of imports from Canada, confirming the feasibility of sourcing Oregon LNG's exports from burgeoning Western Canadian supplies. In fact, historical data show that natural gas flows from Canada into the U.S. Pacific Northwest have averaged about 340 MMcf/d at Sumas and almost 750 MMcf/d from Kingsgate into Idaho over the last 15 years, on an annual average basis. Second, the situation in Eastern Canada is one where Canada is forecast to be a net importer of U.S. supplies, for the entire forecast term, as a result of burgeoning U.S. gas production from the Marcellus. The benefit to Oregon LNG of this regional supply shift is that Eastern Canadian market imports from the U.S. lessen competitive demand for Western Canadian supplies, ensuring Western Canadian supply availability for the Export Project. The benefit to the Western Canadian producing sector is that the Export Project provides an additional demand that is needed to support Western Canadian natural gas development and further enhancing price stability over the long term. Thus, the ample Canadian and U.S. supply resources are both important for the Export Project. Navigant's forecasts that Western Canadian supplies will be, for the most part, the feedstock for Oregon LNG exports and the ramping up of U.S. resources, particularly from the Marcellus, help enhance the availability of Western Canadian supplies that would otherwise have been delivered to Eastern Canadian and Northeastern U.S. markets.[95]

B. Other Public Interest Considerations

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

Oregon LNG commissioned the ECONorthwest Report to assess the economic impact of the Bidirectional Project in the Pacific Northwest region. According to the report, the Bidirectional Project will significantly stimulate local, regional and national economies in both the construction and operation phases. Job creation, indirect spending and tax revenue will all see positive growth as a result. A majority of the labor, materials and technology to construct and operate the Bidirectional Project will be drawn from Oregon and Washington with a significant portion coming from Clatsop County, Oregon.

a. Construction Impact

The total construction cost for the Bidirectional Project has been estimated at $6.32 billion, $195 million of which is comprised of labor costs.[96] Estimates show pipeline construction will cost $485 million, with $195 million comprising labor costs.[97] The Oregon State Building and Construction Council estimates that 90 percent of the labor force for the LNG terminal facilities may come from Oregon and Washington.[98] The region also may supply 50 percent of the labor force for the construction of the Oregon Pipeline.[99] The estimated time frame for the Bidirectional Project construction is 48 months for the terminal and 36 months for the pipeline.[100]

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95 Navigant Report, *supra* note 8, at 8-9.
96 ECONorthwest Report, *supra* note 13, at 7.
97 *Id.*
98 *Id.* at 8.
99 *Id.*
100 *Id.*

The influx of labor needed to complete the Bidirectional Project will have a major positive impact on the region's economy. In its letter of support, the United Brotherhood of Carpenters and Joiners of America points out that regional unemployment in the construction sector has hovered around 17 percent, which is twice the rate of general unemployment.[101] From 2014 until the anticipated completion date in 2018, the construction phase will create an average of 3,054 direct-employment, new construction jobs for the Bidirectional Project.[102]

The economic impact of a construction project goes well beyond the direct costs of construction. An indirect impact is the result of business-to-business transactions. If the Bidirectional Project requires sheet metal from a local producer, for example, an indirect impact will be felt by the hiring of new workers at the manufacturer. The regional indirect impact of the construction phase of the Bidirectional Project has been estimated at $2.79 billion.[103] The average, indirect employment impact spread over the anticipated 5-year period involving construction efforts has been estimated by EcoNorthwest to be 2,579 jobs.[104]

A substantial stimulus in the form of an induced impact also will follow from the construction phase of the Bidirectional Project. Induced impacts are those that are the result of consumer spending in the region—workers spend their wages in local shops and restaurants. The workers at those businesses spend their wages in the community, and so on. The estimated induced impact for the construction phase of the Bidirectional Project is $2.9 billion.[105] The

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[101] United Brotherhood of Carpenters and Joiners of America, Letter of Support (June 8, 2012). The letter is submitted herewith in Appendix D. Additional letters of support by Ukiah Engineering, Inc., National Construction Alliance II, the Associated General Contractors of America and the Columbia Pacific Building and Construction Trades Council also are included in Appendix D.

[102] ECONorthwest Report, *supra* note 13, at 16 (Table 9).

[103] *Id.* at 15 (Table 7).

[104] *Id.* at 16 (Table 9).

[105] *Id.* at 15 (Table 7).

average, induced employment impact spread over the anticipated 5-year period involving construction efforts has been estimated by EcoNorthwest to 4,805 jobs.[106]

In summary, the total economic impact of the Bidirectional Project in the region over a 5-year period will be $12.1 billion and the total average employment impact spread over the anticipated 5-year period involving construction efforts has been estimated by EcoNorthwest to be 10,438 jobs.[107]

Over the short term, these significant impacts will result in greater tax revenue. The State of Oregon will see a significant increase in income tax revenue during the construction phase of the Bidirectional Project. Oregon levies personal income taxes on all individuals working in the state regardless of their residence. Assuming 2010 income tax rates, the construction phase will generate a total of $219.8 million in additional revenue for the state in its direct impact.[108] The income tax revenue due to direct labor and to indirect and induced labor combined will be $161 million and $58.7 million, respectively, in the construction phase.[109]

b. Operations Impact

The continuing economic impact from the operation of the Bidirectional Project will be significant. Oregon LNG estimates that the Bidirectional Project will cost $285 million per year to operate.[110] The vast majority of the operational expenses will come in the form of electricity costs which will yield indirect and induced impacts to the region.

(1) Output Impact

Oregon LNG estimates its exports to total $6.07 billion in LNG per year, with an

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[106] *Id.* at 16 (Table 9).
[107] *Id.* at 15 (Table 7) and at 16 (Table 9).
[108] *Id.* at 19 (Table 13).
[109] *Id.*
[110] *Id.* at 17 (Table 10).

additional value of $165 million from the Oregon Pipeline.[111] The impact due to indirect and induced output yields an additional $124 million in Clatsop County.[112] The region as a whole will see an impact of approximately $312 million in indirect and induced spending.[113]

(2) Labor Impact

Oregon LNG plans on hiring 149 workers for its operations in Oregon, with an estimate of 129 residing in Clatsop County.[114] Oregon LNG will require the services of numerous contractors and suppliers in the region as well, thus magnifying indirect and induced impacts. In Clatsop County alone, the total value of the indirect and induced labor impact of Oregon LNG's ongoing operations comes to over $32 million.[115] This is the result of an estimated 496 new jobs in the county.[116] With 1,785 people out of work at an unemployment rate of 8.6 percent, these new jobs stand to make a major impact on Clatsop County.[117] Looking beyond Clatsop County to the region, an estimated 1,591 jobs will be created with a valued impact of over $102.5 million.[118]

(3) Tax Impact

The State of Oregon will see a significant increase in income, property and corporate tax revenue from ongoing operations. The annual income tax revenue during the operations phase will be an estimated $809,011 in direct impact and approximately $3.76 billion in indirect and induced impact.[119]

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111 *Id.* at 18.
112 *Id.*
113 *Id.*
114 *Id.* at 17.
115 *Id.* at 18 (Table 11).
116 *Id.*
117 As of May, 2012. U.S. Dept. of Labor, Bureau of Labor Statistics, Labor Force Data by County (May 2012), available at, http://www.bls.gov/lau/laucntycur14.txt.
118 ECONorthwest Report, *supra* note 13, at 18 (Table 12).
119 *Id.* at 19 (Table 13).

As the Bidirectional Project will be subject to property taxes, counties and municipalities in both Oregon and Washington stand to see significant revenue during the operations phase. The LNG terminal, at an assessed value of $4.11 billion, will generate $51.9 million in annual property taxes in Warrenton, Oregon.[120] At an assessed value of $386 million, the pipeline will generate approximately $4.72 million in annual property taxes for counties in Oregon, the vast majority being assessed in Clatsop County.[121] Cowlitz County, Washington will receive approximately $194 million in property taxes from the pipeline.[122]

Both Oregon and Washington will see increased revenues from corporate income taxes as well as business and occupancy taxes. Based on estimated output and income, pipeline and terminal operations will yield $7.96 million in annual corporate income and business and occupancy taxes for Oregon.[123] Washington will see an additional $263,570 in annual business and occupancy tax from operation of the pipeline.[124]

c. Related Infrastructure

Another direct benefit of the Oregon LNG Export Project will be the expansion of existing pipeline infrastructure in the Pacific Northwest to transport Canadian natural gas across the State of Washington to the Project in Warrenton, Oregon (*i.e.*, the Washington Expansion Project). Expansion of the Williams system, which is required to accommodate the transportation of volumes to the Project, will involve the construction of approximately $700 million of pipeline upgrades. These efforts are not included in the ECONorthwest study; however, based on simple comparison and scaling to the Oregon Pipeline, it is reasonable to

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120 *Id.* at 21 (Table 14).
121 *Id.*
122 *Id.*
123 *Id.* at 22 (Table 15).
124 *Id.*

expect that the Washington Expansion Project will result in the creation of an average of 616 direct, 570 indirect, and 669 induced jobs for a total of 1,855 total jobs over a 3-year period.

2. *International Considerations*

U.S. international trade law, general U.S. trade policy and DOE's longstanding policy that the public interest is best served by the principles of free trade all strongly support exportation of LNG as proposed herein. The exportation of LNG will enhance the diversity of global supply and contribute to the security interests of the U.S. and its allies. The Oregon LNG Export Project also will deepen the longstanding trading ties between the U.S. and Canada, reaping economic benefits to both trading partners through job creation, increased economic activity and tax revenues from the Project itself and from associated upstream transportation and exploration and production ("E&P") development. The export of North American LNG from the Project also will have a direct beneficial impact on the U.S. trade deficit.

a. Geopolitical Benefits

A global, 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.[125] The entrance of the United States into the global LNG market as a supplier will significantly diversify the global gas market. Further, the U.S. provides a stable trading partner for Asian utilities and other international customers. This has important security implications

[125] MIT Report, *supra* note 58, at xv ("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 moderate 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.").

because "[t]he U.S., with its unique international security responsibilities, can be constrained in pursuing collective action if its allies are limited by energy security vulnerabilities."[126]

Oregon LNG anticipates that volumes from the Export Project will be destined primarily for Asian markets. The Export Project will, therefore, play an important role in furthering America's geopolitical interests in the region. It will help stabilize supply, meet a growing need, and reduce the burgeoning trade imbalance between the U.S. and Asian markets. Asian countries are diversifying their energy portfolios. The drive to replace nuclear power with safer alternatives will drive demand in Japan and throughout the region. Japan alone imported 3.8 Tcf of natural gas in 2010,[127] well before the tragedy at Fukushima and the resulting move away from nuclear power. Moreover, Japan has agreed to enter into talks with Canada to establish a bilateral free trade agreement in an attempt to secure its natural gas supply.[128] The President has also discussed the possibility of LNG exports with Japan, but no free trade agreement yet exists.[129]

The Export Project will not only help meet this increasing demand, it will help the U.S. enhance its strategic influence over the region. By ceding the market to Canadian, Russian and Middle Eastern exporters, the U.S. risks irrelevancy at a critical juncture in relations with Asia. By providing a stable, liquid energy source to the region, however, the U.S. can strengthen ties with Japan, South Korea and India. U.S. foreign policy has seen a shift toward increased relationships with Asia and any attempt to increase influence and partnership with the region that does not include an integrated energy market misses a vital policy consideration.

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126 *Id.* at 71.

127 EIA, Japan Country Analysis Brief, (June 4, 2012), *available at* http://205.254.135.7/countries/cab.cfm?fips=JA.

128 Takashi Mochizuki, *Japan, Canada to Launch Trade Talks*, Wall St. J., Mar. 25, 2012, *available at* http://online.wsj.com/article/SB10001424052702303404704577302902680560834.html.

129 Rebecca Smith and Mari Iwata, *Japanese Buyers Line Up for U.S. Shale Gas*, Wall St. J., May 24, 2012, *available at* http://online.wsj.com/article/SB10001424052702303505504577406061245167558.html.

b. Benefits to Canada

The Oregon LNG Export Project is uniquely positioned to reinforce the U.S. energy trade relationship with Canada, which is among the closest and most extensive in the world. Canada is the single largest foreign supplier of energy to the United States—providing 20 percent of U.S. oil imports and 18 percent of U.S. natural gas imports. Recognition of the commercial viability of Canada's oil sands in Alberta has raised Canada's proven petroleum reserves to 170 billion barrels, making it the world's second-largest holder of reserves after Saudi Arabia. Canada and the United States operate an integrated electricity grid which meets jointly developed reliability standards and provide all electricity imports of each other. Canada is a major supplier of electricity (mostly clean and renewable hydroelectric power) to New England, New York, the Upper Midwest, the Pacific Northwest and California. Finally, Canadian uranium helps fuel U.S. nuclear power plants.[130]

Development of natural gas resources in Canada will result in tremendous benefits to the Canadian economy at a national scale. Case studies on the economic impact of shale development in the U.S., for example in the Marcellus, demonstrate that natural gas development results in significant national economic activity.[131] In this regard, the Canadian economy will benefit from the Oregon LNG Export Project's role in supporting the E&P chain for natural gas extraction. This indirect stimulus will have far reaching economic impacts due to the wages, taxes and lease payments involved in the natural gas supply chain. In this regard, the Export Project will serve to strengthen U.S. ties to Canada, an important and close neighboring ally.

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[130] *See* U.S. Department of State, *supra* note 15.

[131] *See, e.g., An Emerging Giant: Prospects and Economic Impacts of Developing the Marcellus Shale Natural Gas Play* (Considine et al., 2009); *The Economic Impacts of the Pennsylvania Marcellus Shale Gas Play: An Update* (Considine et al., 2010). These studies estimate how the E&P industry's employment of economic resources to develop unconventional gas fields affects income, employment and tax revenues within the Commonwealth of Pennsylvania.

c. U.S. Balance of Trade

Oregon LNG's exports will result in a net improvement in the balance of trade for the U.S. even after deducting gas imports from Canada. In 2011, the overall U.S. trade deficit increased to approximately $560 billion. Petroleum products alone accounted for $326.1 billion (approximately 58 percent) of that overall deficit.[132] If approved, the export authorization for Oregon LNG is projected to reduce the U.S. trade deficit by $4.5 billion per year over a 25-year period for an estimated total of $112.5 billion of net deficit reduction over the life of the Project.[133]

In addition, approving the export authorization would promote President Obama's stated policy goal of doubling U.S. exports as part of his National Export Initiative and increasing U.S. employment. As part of that initiative, President Obama cited that every $1 billion increase in exports supports more than 6,000 jobs in the United States and also noted that "[i]n a time when millions of Americans are out of work, boosting our exports is a short-term imperative" and doing so is "also critical for our long-term prosperity."[134]

IX. ENVIRONMENTAL IMPACT

The potential environmental impacts of the Oregon LNG Export Project will be reviewed by FERC under NEPA. As noted above, Oregon LNG and Oregon Pipeline Company requested authorization to commence the Commission's mandatory NEPA process for the Oregon LNG Export Project on July 3, 2012 in Docket No. PF12-18-000. On July 16, 2012, the Director,

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132 U.S. Census Bureau, U.S. International Trade in Goods and Services, http://www.census.gov/foreign-trade/Press-Release/2011pr/final_revisions/11final.pdf.

133 This estimated net deficit reduction accounts for the negative impact the import of Canadian origin natural gas into the U.S. will have on the overall U.S. trade deficit. Although there will be some negative impact, it will be more than offset by the value of the subsequent LNG exports. Overall, the projected net positive reduction in the deficit (including the negative impact of the import of Canadian origin natural gas) is approximately $10 per MMBtu with an estimated 450 million MMBtu per year (or $4.5 billion per year).

134 Anna Fitfield, *Obama unveils plans to double exports*, Financial Times (Mar 11, 2010), *available at* http://www.ft.com/cms/s/0/d328bdf6-2d28-11df-9c5b-00144feabdc0.html#axzz1zD1aBsuQ.

Office of Energy Projects, granted the request. Upon completion of the NEPA prefiling process, Oregon LNG will amend its pending application to include the Oregon LNG Export Project. Oregon LNG and Oregon Pipeline Company anticipate filing a formal application with FERC pursuant to Section 3 of the NGA no later than the First Quarter of 2013.

Oregon LNG has requested that the Assistant Secretary issue a conditional order authorizing the export of LNG, conditioned on completion of the environmental review of the Export Project by FERC. Consistent with the NEPA scheme applicable to applications for authorizations under NGA Section 3 delineated by Congress in the Energy Policy Act of 2005 ("EPAct 2005"), Pub. L. No. 109-58, 119 Stat. 594, Oregon LNG expects that FERC shall act as the lead agency, with DOE/FE acting as a cooperating agency, in connection with the Oregon LNG Export Project. Oregon LNG also anticipates that DOE/FE will cooperate with FERC in the development of an Environmental Impact Statement ("EIS") for the Project.[135] Finally, Oregon LNG expects that upon issuance of an EIS by FERC for the Project, DOE/FE will adopt the FERC EIS if DOE/FE concludes that its comments and suggestions have been satisfied.[136] To the extent it reaches such conclusion, DOE/FE may then promptly issue a record of decision pursuant to NEPA, thereby finalizing any conditional order issued on this Application pursuant to Oregon LNG's request herein.

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[135] *See* 10 C.F.R. § 1021.342.

[136] *See* 40 C.F.R. § 1506.3(c) ("A cooperating agency may adopt without recirculating the environmental impact statement of a lead agency when, after an independent review of the statement, the cooperating agency concludes that its comments and suggestions have been satisfied").

X. REPORT CONTACT INFORMATION

The contact with respect to monthly reports to be submitted by Oregon LNG following the receipt of the authorization requested herein is:

Peter Hansen
Oregon LNG
8100 NE Parkway Drive
Suite 165
Vancouver, WA 98662
Telephone: (503) 298-4967
Facsimile: (360) 882-7554
Email: peterh@oregonlng.com

XI. APPENDICES

The following appendices are attached hereto and incorporated by reference herein:

Appendix A:	Opinion of Counsel
Appendix B:	Oregon LNG Export Project Market Analysis Study, prepared by Navigant Consulting, Inc. (April 13, 2012)
Appendix C:	ECONorthwest, An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon (April 9, 2012)
Appendix D:	Letters of Support:
	Christian F. Steinbrecher, President, Ukiah Engineering, Inc. (June 5, 2012)
	Douglas J. McCarron, General President, United Brotherhood of Carpenters and Joiners of America (June 8, 2012)
	Raymond J. Poupore, Executive Vice President, National Construction Alliance II (June 8, 2012)
	Stephen E. Sandherr, Chief Executive Officer, The Associated General Contractors of America (June 12, 2012)
	Jodi Guetzloe Parker, Columbia Pacific Building and Construction Trades Council (June 13, 2012)

XII. CONCLUSION

For the foregoing reasons, Oregon LNG respectfully requests that DOE/FE grant Oregon LNG's request for long-term, multi-contract authorization to export up to 9.6 mtpa of North American LNG (the equivalent of 1.3 Bcf/d of natural gas) from Warrenton, Oregon to any country with which the United States does not have a Free Trade Agreement requiring the national treatment for trade in natural gas and LNG that has the capacity to import LNG and with which trade is not prohibited by U.S. law or policy for a 25-year term commencing the earlier of the date of first export or eight years from the date of issuance of such authorization.

Respectfully submitted,

Lisa Tonery
Tania S. Perez
Attorneys for
LNG Development Company, LLC (d/b/a Oregon LNG)

Fulbright & Jaworski L.L.P.
666 Fifth Avenue
New York, New York 10103
(212) 318-3009

Dated: July 16, 2012

VERIFICATION

State of Washington)

County of Clark)

BEFORE ME, the undersigned authority, on this day personally appeared Peter Hansen, who, having been by me first duly sworn, on oath says that he is the Chief Executive Officer for LNG Development Company, L.P. (d/b/a Oregon LNG) and is duly authorized to make this Verification; that he has read the foregoing instrument and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

Peter Hansen

SWORN TO AND SUBSCRIBED before me on the 13th day of July, 2012.

Name: Kelly M. Mathers

Title: Notary Public

My Commission expires:

1/7/2014

Notary Public
State of Washington
KELLY M MATHERS
My Appointment Expires Jan 7, 2014

Davis Wright Tremaine LLP

Suite 2400
1300 SW Fifth Avenue
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Bill Miller
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July 16, 2012

Office of Fuel Programs
Fossil Energy, U.S. Department of Energy
Docket Room 3F-056, FE50
Forrestal Building
1000 Independence Avenue, S.W.
Washington, D.C. 10585

Re: In the Matter of LNG Development Company, LLC (d/b/a Oregon LNG)
FE Docket No. 12-__-LNG
Application For Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Countries
Opinion of Counsel

Dear Sir or Madam:

We have acted as special counsel to LNG Development Company, LLC ("Oregon LNG"), a Delaware limited liability company. Oregon LNG seeks authorization by filing an application with the office of the Assistant Secretary for Fossil Energy (the "Application") to export liquefied natural gas ("LNG") of up to 9.6 mtpa of LNG for a 25-year term from its proposed LNG terminal site in Warrenton, Clatsop County, Oregon, to any country that currently has or in the future develops the capacity to import LNG and with which trade is not then prohibited by U.S. law or policy and with which the United States does not then have a Free Trade Agreement requiring the national treatment for trade in natural gas and LNG (the "Proposed Exportation"). This opinion of legal counsel is provided to you in accordance with 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 law covered by the opinions expressed herein is limited to the laws of the State of Oregon and the Limited Liability Company Act of the State of Delaware. This opinion of legal counsel is to be interpreted in accordance with customary practice as to the matters addressed, the meaning of the language used and the scope and nature of the work we have performed.

A. Documents and Matters Examined

In connection with this opinion of legal counsel, we have examined originals, or copies certified or otherwise identified to our satisfaction, of such documents, records, certificates and statements of government officials, officers and other representatives of the persons referred to therein, and such other documents as we have deemed relevant or necessary as the basis for the opinions herein expressed, including the following:

A-1 Certificate of Chief Executive Officer, including the following exhibits to the Certificate of Chief Executive Officer: a) Certificate of Formation and b) Amended and Restated Limited Liability Company Agreement (together, the "Organizational Documents").

A-2 Certificate of Good Standing for LNG Development Company, LLC, issued by the Delaware Secretary of State on July 13, 2012.

A-3 Certificate of Authority to Transact Business for LNG Development Company, LLC, issued by the Oregon Secretary of State on July 13, 2012.

B. Assumptions

For purposes of this opinion of legal counsel, we have relied on the following assumptions:

B-1 To the extent the opinions in C-1 and C-2 below require us to interpret the Amended and Restated Limited Liability Company Agreement of LNG Development Company, there exists no law of the State of Delaware other than the Delaware Limited Liability Company Act, which law would differ in any material respect from the laws of the State of Oregon with respect to the existence, enforceability or interpretation of such Amended and Restated Limited Liability Company Agreement.

B-2 Nothing in the minutes of Oregon LNG or in any other limited liability company records of Oregon LNG is inconsistent with the Organizational Documents.

C. Opinions

Based on the foregoing examinations and assumptions and subject to the qualifications and exclusions stated below, we are of the opinion that:

C-1 Oregon LNG is a limited liability company duly formed and validly existing under Delaware law and is duly qualified to do business as a foreign limited liability company in Oregon.

C-2 The Proposed Exportation is within the limited liability company powers of Oregon LNG.

D. Qualifications

The opinions set forth herein are subject to the following qualifications:

D-1 The effect of bankruptcy, insolvency, reorganization, receivership, moratorium, fraudulent transfer and other similar laws affecting the rights and remedies of creditors generally, and the effect of general principles of equity, whether applied by a court of law or equity.

E. Exclusions

We express no opinion as to the following:

E-1 Whether any governmental permits, approvals, authorizations or filings are required in connection with the Proposed Exportation or as to the effect on the Proposed Exportation in the event any such required permits, approvals, authorizations or filings are not made or obtained.

This opinion of legal counsel is delivered as of its date and without any undertaking to advise you of any changes of law or fact that occur after the date of this opinion of legal counsel even though the changes may affect the legal analysis, a legal conclusion or information confirmed in this opinion of legal counsel.

This opinion of legal counsel is rendered only to you and is solely for your benefit in connection with the transaction contemplated by the Loan Documents. This opinion of legal counsel may not be used or relied on for any other purpose or by any other person without our prior written consent.

Respectfully submitted,

Davis Wright Tremaine LLP

NAVIGANT

OREGON LNG EXPORT PROJECT
MARKET ANALYSIS STUDY

Prepared for:
LNG Development Company, LLC (d/b/a/ Oregon LNG)

OregonLNG

Navigant Consulting, Inc.
3100 Zinfandel Drive
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April 13, 2012

Disclaimer: This report was prepared by Navigant Consulting, Inc. for the benefit of LNG Development Company, LLC. This work product involves forecasts of future natural gas demand, supply, and prices. Navigant Consulting, Inc. 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.

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NAVIGANT

Summary of Assignment

LNG Development Company, LLC (Oregon LNG or OLNG) is considering the export of liquefied natural gas (LNG) at Warrenton, Oregon. In support of their export project, OLNG requested Navigant Consulting, Inc. (Navigant) provide an outlook for the U.S. natural gas market to 2045, with an emphasis on supply. It also asked Navigant to model the potential price impacts of its proposed export operations. As part of its integrated internal energy modeling process for natural gas and electric markets, Navigant develops a forecast of the North American natural gas market in the spring and fall of each year. This report for OLNG builds on Navigant's Fall 2011 Reference Case forecast released in December 2011 and Navigant's market and industry expertise and market research.

In order to effectively assess the market impact of the project, Navigant developed three scenarios of realistic circumstances under which OLNG exports may occur. These scenarios were designed to test the potential effect that the OLNG export project may have on natural gas prices, given certain assumptions regarding future supply, demand, infrastructure development, and economic activity. The scenarios are the OLNG Reference Case, the OLNG Export Case, and the Aggregate Export Case. The assumptions are based on market fundamentals and the best professional judgment of Navigant.

As part of our modeling analysis, Navigant reviewed key factors such as:

Supply	Demand	Other
Gas drilling trends	Export outlook	Gas pricing relationship to oil
Import outlook	Electric generation and coal switching	Price volatility
Supply balance by region	Demand as a supply sustainability factor	Gas supply economic outlook
Frontier gas supply		Infrastructure developments
Comparative analysis of supply forecasts		Gas and oil price outlook
Hydraulic fracturing policy outlook		

NAVIGANT

Executive Summary

Domestically produced natural gas has become an abundant fuel in North America. In fact, gas supply is currently surplus to demand. This is due to the advent of economically-producible shale gas as a result of the application of technological breakthroughs over the last four years.

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 gas shale development through technology.

The new consensus, which Navigant was instrumental in establishing with its groundbreaking 2008 study entitled the 'North American Natural Gas Supply Assessment' for the American Clean Skies Foundation, is that North American gas resources are more than adequate to satisfy domestic demand for the time frame covered by this report, even as demand grows.

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 OLNG's proposed liquefaction facilities at Warrenton, Oregon.

In the local Pacific Northwest market at Sumas, the estimated impact of OLNG exports would be an average increase of the commodity cost over the forecast term of 17 cents versus the OLNG Reference Case average price of $5.67 per MMBtu, or 3.1%[1]. Even over just the second half of the forecast period, during which the largest price impacts occur (e.g. 47 cent increase in 2044), the average increase at Sumas is still only 27 cents, or 4.0%.

It is also Navigant's finding that the effect of the OLNG export project on natural gas commodity prices in the national gas market will be minimal. The impacts at Henry Hub are even smaller than those at Sumas, averaging only a five-cent increase over the forecast period. Importantly, Navigant finds that absolute prices at Henry Hub in the OLNG Export Case are below $5.00 until 2025, are below $6.00 until 2032, are below $7.00 until 2032 and are below $8.25 for the entire forecast term to 2045. Prices at Sumas reach these benchmarks several years later. As another point of reference, the OLNG Export Case price forecast at Henry Hub is actually <u>below</u> the EIA's Annual Energy Outlook 2012 Reference Case forecast that includes no LNG exports.

[1] When compared to the average overall residential retail rate, the 17 cents represents an even smaller percentage. For example, under Northwest Natural Gas Company's current residential rate schedule for Oregon, the average rate comes to $11.93 per MMBtu, based on a $6 per month customer charge, and a volumetric charge at $10.88 per MMBtu including gas commodity pass-through at $4.90 per MMBtu (virtually the same as the forecast average price at Sumas), assuming consumption at the utility's average 57 therms per month. The 17 cents would therefore only be 1.4% of the current retail rate for residential gas consumers.

Several facts support Navigant's findings:

- Dry gas production in the U.S. is up over 30 percent since 2005, from about 49.5 Bcfd for 2005 to more than 65 Bcfd by the end of 2011.

- Navigant furthermore projects U.S. dry gas production alone (excluding Canada) to grow a further 24% to 81.0 Bcfd by 2045 in the OLNG Reference 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 AEO 2011 estimate of dry natural gas resources in the U.S. is 2,543 Tcf. This is more than 100 years of supply at current usage rates of approximately 24 Tcf per year. Even at Navigant's projected 2045 rate of consumption of 83.3 Bcfd (30.4 Tcf per year), this represents more than 83 years of supply. (The difference between U.S. demand of 83.3 Bcfd and U.S. supply of 81.0 Bcfd is made up primarily by pipeline imports from Canada, net of a small amount of LNG exports.) Using Navigant's 2008 estimate of 2,247 Tcf for dry natural gas resources, U.S. supplies would last 92 years at 2011 consumption levels.

- 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 at 521 Tcf, 650 Tcf, and 687 Tcf. These estimates are bracketed by Navigant's 2008 estimate (providing a range from a mean of 274 Tcf to a maximum of 842 Tcf) and EIA's most recent estimate at 482 Tcf.[2]

- 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. The areal extent of others, notably the Eagle Ford, has enlarged significantly. As development proceeds and more data is available, plays' productive potential is often revised upward. For example, Dr. Terry Engelder of Penn State 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.

[2] In EIA's Annual Energy Outlook (AEO) 2012 Early Release Overview, 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. 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. At this time, the final AEO 2012 is in the process of being prepared, and in the end may address the most controversial estimates in the Early Release. 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); "New Figures on Shale Gas Optimistic", Pittsburg Tribune-Review, March 20, 2012 (http://www.pittsburghlive.com/x/pittsburghtrib/news/s_787326.html).

- With respect to Canadian shale gas, which is the most important resource for OLNG as we will show, the British Columbia Ministry of Energy and Mines and the National Energy Board of Canada (BCMEM/NEB) estimated in 2011 total gas in place for the Horn River Basin to be a minimum of 372 Tcf. A 2008 published estimate of minimum gas in place for the *combined* Horn River Basin, Liard Basin, and Cordova Embayment, noted in the BCMEM/NEB report, was 144 Tcf. Thus, the current BCMEM/NEB estimate reflects an increase of 158 percent in the minimum estimate for gas in place for the Horn River Basin alone, excluding the other two basins (the estimated mean Horn River gas in place is 448 Tcf, versus the prior estimate of 372 Tcf (not to be confused with the new estimated minimum gas in place for Horn River, which also happens to be 372 Tcf) for all three basins). Navigant expects this trend towards identifying a larger resource base to continue in the near term in both the U.S. and Canada as additional industry activity continues and more data becomes available. Estimates of recoverable shale gas resources for the Horn River Basin were put at 78 Tcf in the BCMEM/NEB Study, and at 90 Tcf by Rice University. Together with an estimated 65 Tcf for the recoverable resources of the other large natural gas play in B.C., the Montney, these two gas plays alone would meet the Province of B.C.'s modest consumption level (2009) of 386 Bcf per year for at least 370 years. Incorporating RBC Capital Markets' more optimistic resource estimate for the Horn River Basin, plus its estimates for the Cordova Embayment shale play near Horn River and for Montney, suggests that there could be between 1,010 and 1,270 years worth of the Province's natural gas consumption in just these three plays.

- Navigant's modeling shows that the gas feedstock for OLNG will come from western Canadian supplies, consistent with OLNG's actual plans for supply contracting. Gas will flow on the Spectra/BC Pipeline (formerly Westcoast) and the TCPL/GTN systems to Williams' Northwest Pipeline. Such flows should be facilitated by expected significant excess pipeline capacity on GTN for the foreseeable future due partially at least to recent gas-on-gas competition by Ruby Pipeline with GTN. Ruby was designed to allow Rockies supply to compete with Canadian supply for the California market, and Ruby has indeed allowed displacement of Canadian supplies on GTN since commencing operations in July 2011.

In all scenarios Navigant prepared for OLNG in this analysis, natural gas maintains its steep discount to the price of crude oil on a heating value equivalent basis. In 2045, Navigant forecasts the price of oil to be $144 per barrel, which is equivalent to $24.83 per MMBtu. Even in the Aggregate Export Case (resulting in the highest modeled gas prices), gas prices only attain $8.51 per MMBtu in the national market at Henry Hub and $8.06 per MMBtu in the regional Pacific Northwest market closest to the OLNG export project, both in 2044 (see ***Table 1: Sample Output Prices of Selected Locations,*** below for a summary of prices in all cases). 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 over time.

Year	Metric	Reference Case	OLNG Export	Aggregate Export
2017	*Henry Hub*	$4.42	$4.47	$4.66
	Sumas	$4.03	$4.12	$4.26
2020	*Henry Hub*	$4.71	$4.78	$4.98
	Sumas	$4.30	$4.45	$4.58
2025	*Henry Hub*	$5.10	$5.06	$5.20
	Sumas	$4.69	$4.71	$4.79
2035	*Henry Hub*	$6.86	$6.88	$7.22
	Sumas	$6.38	$6.56	$6.80
2045	*Henry Hub*	$8.07	$8.22	$8.47
	Sumas	$7.42	$7.80	$8.05

Table 1: Sample Output Prices of Selected Locations[3]

Finally, it should be emphasized that a very important aspect of the North American gas market is that reliable demand is a key to underpinning reliable supply and a sustainable gas market. Demand and supply are two parts of a single dynamic. Domestically manufactured LNG for export can be an integral part of that demand. By providing a steady baseload demand, it helps support ongoing gas supply development, leading to a closer balance of supply and demand and helping to keep domestic gas prices stable. This is all based on the resource being available and abundant as we believe is the case.

[3] In this report, totals may not equal sum of components due to independent rounding.

Supply Outlook to 2045

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, the overall supply-demand balance has the potential to be synchronized for the foreseeable future, 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. It has been the ramping rates of gas shale production growth that has been the biggest contributor to overall gas supply abundance over the last several years.

Before the advent of significant shale gas production, the 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 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. 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 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 OLNG Reference Case, is shown in ***Figure 1: North American Natural Gas Supply Projection***. Navigant projects that North American production will be 106.0 Bcfd by the year 2045 (small amounts of net LNG exports are too small to appear on the chart). By that year, U.S. production alone is projected to be 81.0 Bcfd, as shown in ***Figure 2: U.S. Natural Gas Supply Projection*** (small amounts of LNG imports and then exports are too small to appear on the chart). Canadian production (before any imports or exports) is projected to be 21.1 Bcfd, as shown in ***Figure 3: Canadian Natural Gas Production Projection***.

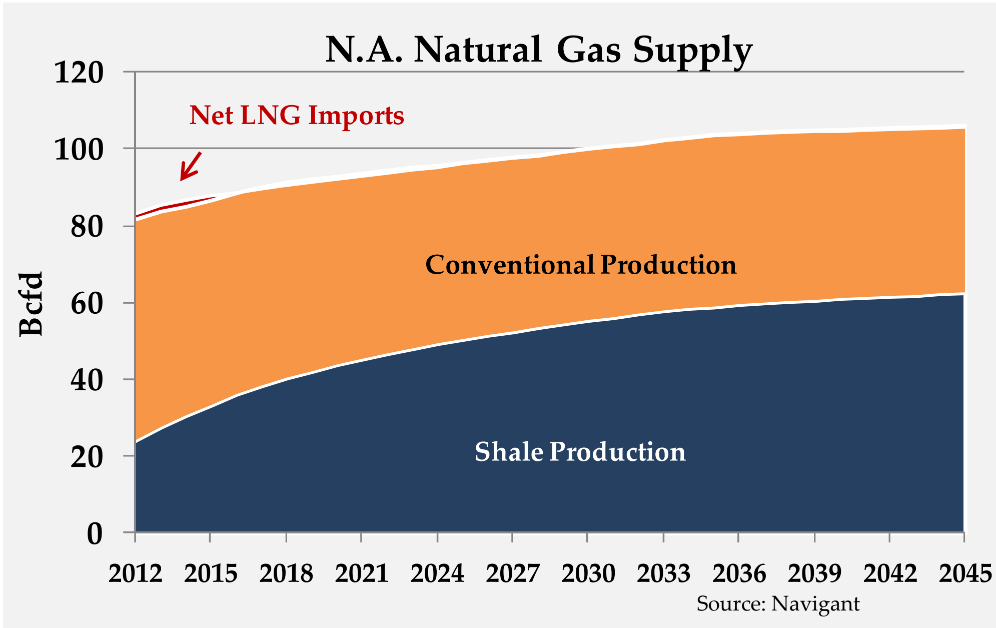

Figure 1: North American Natural Gas Supply Projection

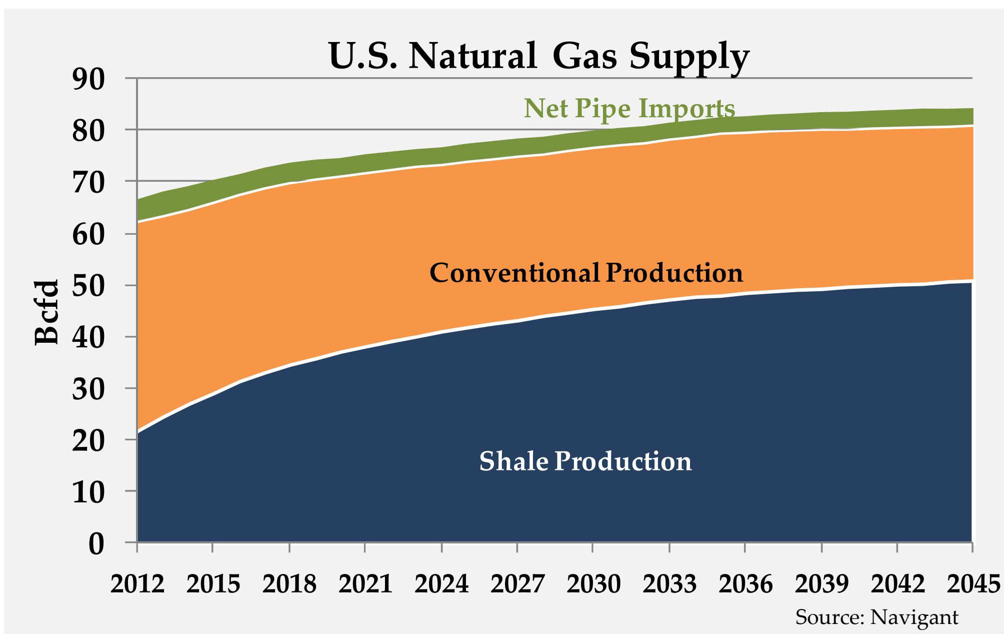

Figure 2: U.S. Natural Gas Supply Projection

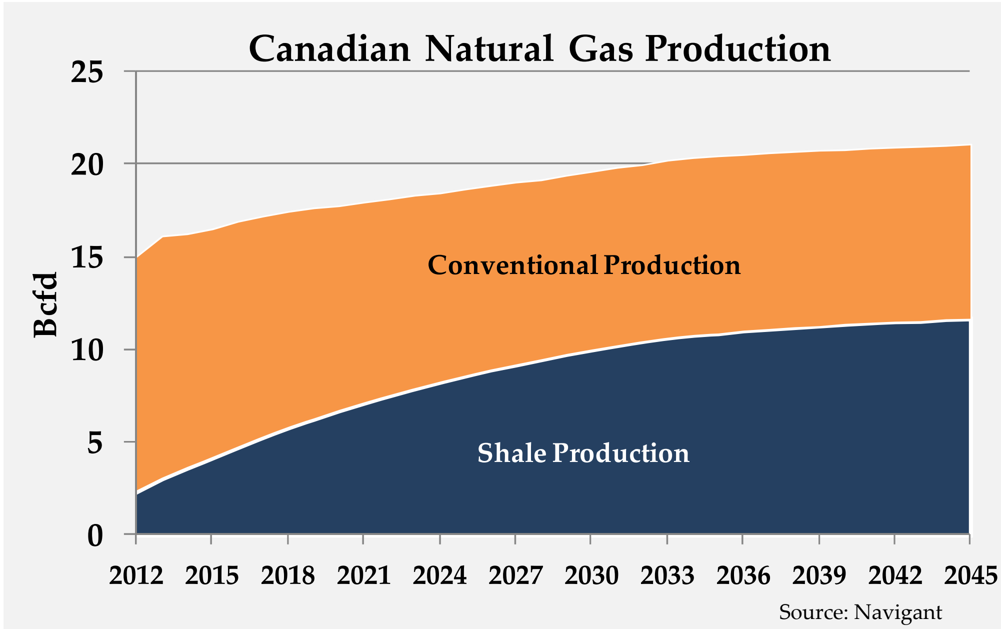

Figure 3: Canadian Natural Gas Production Projection

The majority of production growth is likely to be driven by unconventional gas development, as opposed to conventional gas, which has been in decline. Plans to develop large known deposits of conventional frontier gas, such as the Mackenzie 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 cost of those projects relative to unconventional resource development opportunities closer to markets. In Navigant's modeling for OLNG, neither the Mackenzie Pipeline Project nor the Alaska Pipeline Project is forecast to be on-stream during the term of our analysis. We note that the governor of Alaska recently announced[4] he favors a pipeline project from Alaska's North Slope gas resources that delivers to the south coast of the state where it could be liquefied into LNG instead of connecting to the larger North American grid in Canada. (A portion of the flow would be used to meet the needs of the City of Anchorage). It should be noted, however, that while production from these frontier sources is not being modeled by Navigant in our current forecasts, the sources themselves obviously will continue to exist and represent resources that will be available in the future whenever the economics of supply and demand deem their development feasible.

From a simple supply-demand perspective, as a result of the large magnitude of North American natural gas resources (as subsequently discussed in this report), indigenous supplies will be sufficient to meet U.S. and Canadian demand. From a regional perspective, several interesting results emerge that highlight not only the feasibility but the benefit of the OLNG export project. First, with Canada maintaining its status as a net exporter of natural gas to the U.S. (as projected by the net pipe imports as a portion of U.S. supply in ***Figure 2: U.S. Natural Gas Supply Projection***), a regional analysis indicates that cross-border flows into the Pacific Northwest consist solely of imports from Canada (no exports), confirming the feasibility of sourcing OLNG exports from burgeoning western Canadian supplies. In fact, historical data shows that natural gas flows from Canada into the U.S. Pacific Northwest have averaged about 340 MMcfd at Sumas and almost 750 MMcfd from Kingsgate into

[4] Statements by Governor Sean Parnell on October 27, 2011 at Alaska Oil and Gas Association conference in Anchorage (http://gov.alaska.gov/parnell/multimedia/videos.html).

Idaho over the last 15 years, on an annual average basis. Second, the situation in eastern Canada is one where Canada is forecast to be a net importer of U.S. supplies, for the entire forecast term, as a result of burgeoning U.S. gas production in the Marcellus. The benefit to OLNG of this regional supply shift is that the eastern Canadian market imports from the U.S. lessen competitive demand for western Canadian supplies, ensuring Western Canadian supply availability for OLNG exports. The benefit to the Western Canadian producing sector is that the OLNG export project provides an additional demand that is needed to support western Canadian natural gas development and further enhancing price stability over the long term.

Thus, the ample Canadian and U.S. gas supply resources are both important for the OLNG export project. While modeling indicates that Western Canadian supplies will be the feedstock for OLNG exports, the ramping of U.S. resources, particularly from the Marcellus, helps enhance the availability of Western Canadian supplies that would otherwise have been delivered to Eastern Canadian and U.S. Northeastern markets.

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 shale gas resource, along with the ability to effectively develop the 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 4: Henry Hub Price History***. 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 to be continually improved towards dramatically increased drilling and production efficiencies, reduced costs, and improved the finding and development economics of the industry. In mid-2008, when Navigant released its groundbreaking natural gas report,[5] domestic gas production from shale began to overtake imported LNG as the new gas supply 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.

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[5] 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

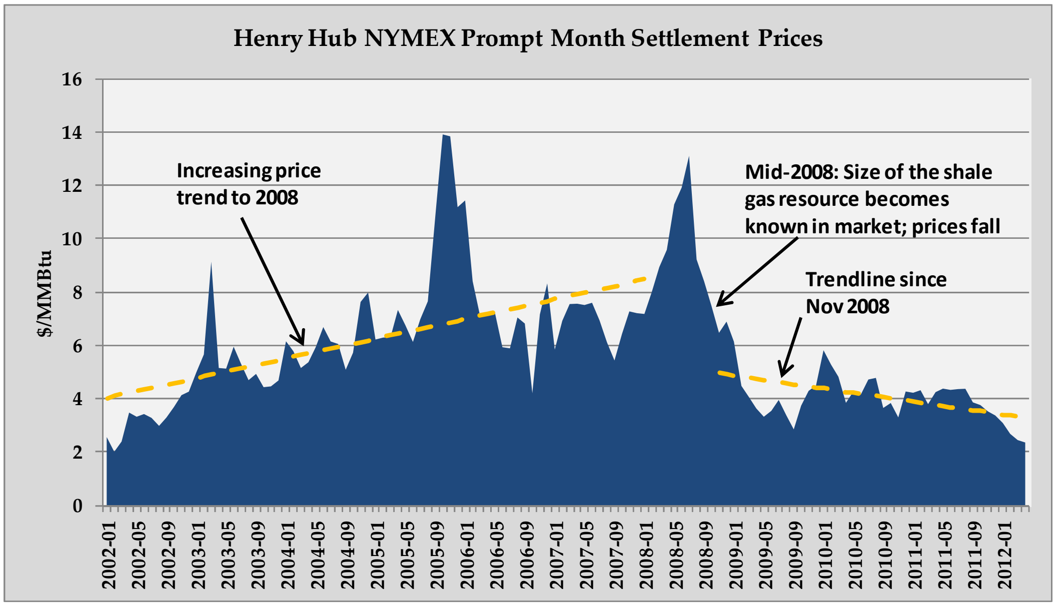

Figure 4: Henry Hub Price History Source: Navigant

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, Mmontana, New Mexico, North Dakota, Pennsylvania, Texas, West Virginia and Wyoming have passed legislation that requires the contents of chemicals used in the hydraulic fracturing process to be disclosed.[6] In addition, the Province of British Columbia is the first province in Canada to require public disclosure of hydraulic fracturing chemical usage, and utilizes a Canadian version of the "Fracfocus" registry website.[7] 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 is pioneering the use of recycled flowback water, and by October 2009 was successfully recycling 100 percent in its core operating area in southwestern Pennsylvania. Range estimates that 60 percent of Marcellus shale operators are recycling some portion of flowback water, noting that such efforts can save significant amounts of money by reducing the need for treatment, trucking, sourcing, and disposal activities.[8] Chesapeake Energy is also actively exploring methods of reducing and reusing water.

These efforts to continue to improve water management will tend to enhance the ability of shale operations to expand.

[6] According to Fracfocus.org website.

[7] Fracfocus.ca

[8] "Range Answers Questions on Hydraulic Fracturing Process ," Range Resources, http://www.rangeresources.com/Media-Center/Featured-Stories/Range-Answers-Questions-on-Hydraulic-Fracturing-Pr.aspx

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 5: EIA North American Shale Play Map (2011)***. 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.[9] 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 mentioned previously, is a matter of some controversy between the EIA, USGS, and other experts), the EIA has maintained its estimate of *total* dry natural gas resources in the U.S. at 2,543 Tcf. This is more than 100 years of supply at current usage rates.

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

Figure 5: 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 potential 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 proved reserves estimate of 273 Tcf; the 2,170 Tcf supply estimate represents an increase of 89 Tcf over their previous evaluation. This is

[9] *North American Natural Gas Supply Assessment*, note 3, supra.

enough to supply domestic needs at 2011 usage rates for 89 years. Of the potential gas resource, 687 Tcf, or 36%, is shale gas.[10] In the final version of its recently published study ***The Future of Natural Gas***, the Massachusetts Institute of Technology stated that "The current 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 gas price at or below $6/MMBtu at the well-head."[11]

New shale resource plays are being identified at a high rate. 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 percent chance of containing 489 Tcf of recoverable gas, following his 2008 estimate at 50 Tcf. [12] Such upward revisions have become the norm as development proceeds in a play and additional data becomes available. 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 2010, the entire U.S. used about 24 Tcf per year, or less than five percent of Dr. Engelder's estimate of the Marcellus's potential production.[13]

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 50.1 Bcfd in February 2006 to about 64.6 Bcfd in February 2012, even as overall rig counts fell from about 1320 to 725. This is an increase in gas production of 29 percent 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 6: U.S. Gas Production and Rig Count History*** and ***Figure 7: U.S. Gas Rig Type Shift***.)

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

[11] 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/documents/natural-gas-2011/NaturalGas_Full_Report.pdf.

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

[13] 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

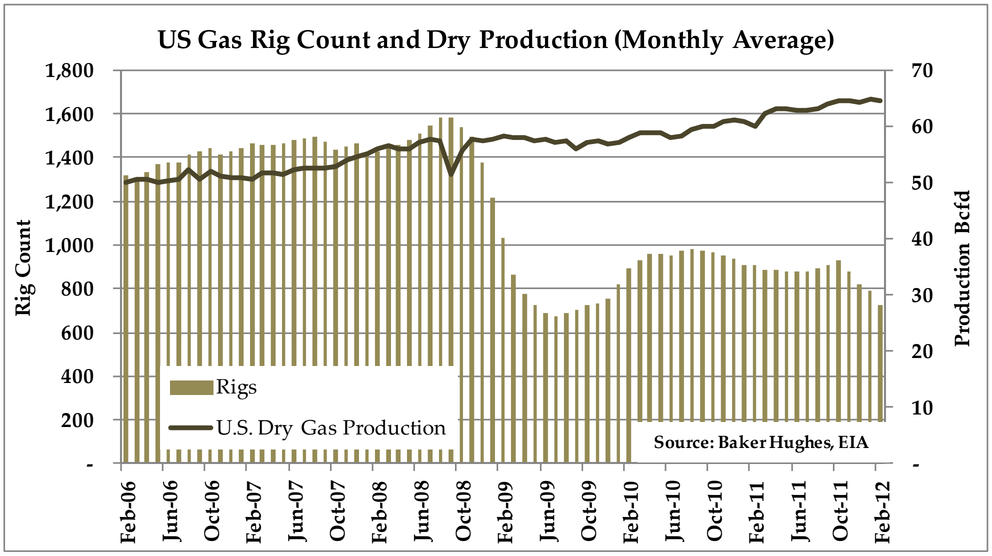

Figure 6: U.S. Gas Production and Rig Count History

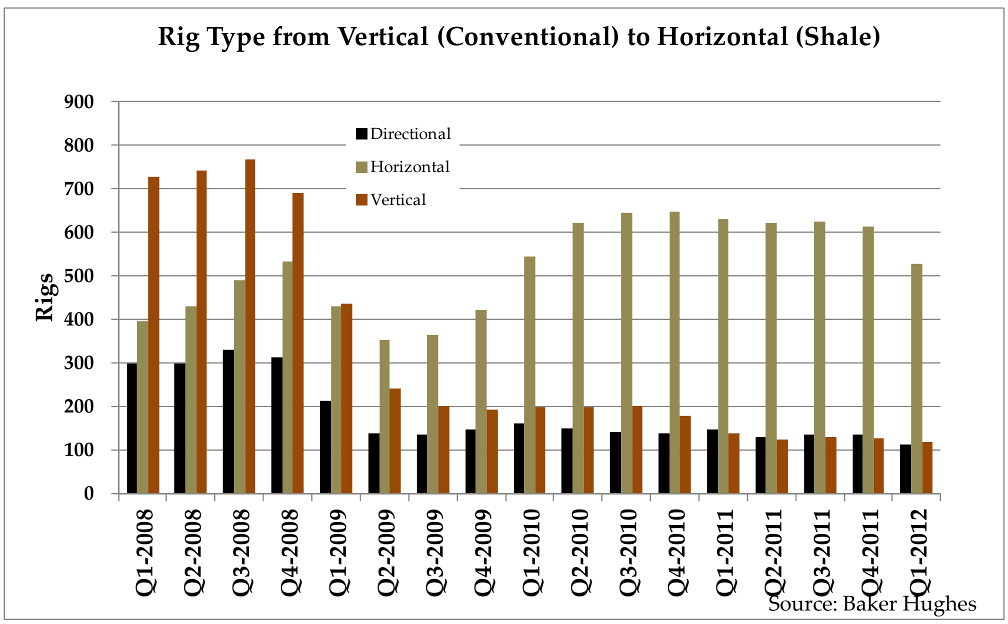

Figure 7: U.S. Gas Rig Type Shift

The growth in shale gas production has been prolific, as shown in the graph in ***Figure 8: U.S. Shale Production (Dry) 2007-2011***. Total shale gas output, on a dry basis, from the six major basins under development in the U.S. plus "other shale" grew from 3.5 Bcfd in January 2007 to 23.4 Bcfd in January 2012, an increase of more than 550 percent in five years. As can also be seen in ***Figure 8: U.S. Shale Production (Dry) 2007-2011*** each new shale play shows strong ramp-up, reflective of shale gas being a relatively new resource in the early stages of development. An example of expectations for such increasing production trends are two recent studies by Pennsylvania State University; the first, from 2010, estimates that production from the Marcellus could grow from 500 million cubic feet per day at the end of 2009 to 13.5 billion cubic feet per day by 2020[14], and then the second, from 2011, estimates that Marcellus production could increase from 2 Bcfd in 2010 to 17.5 Bcfd in 2020.[15]

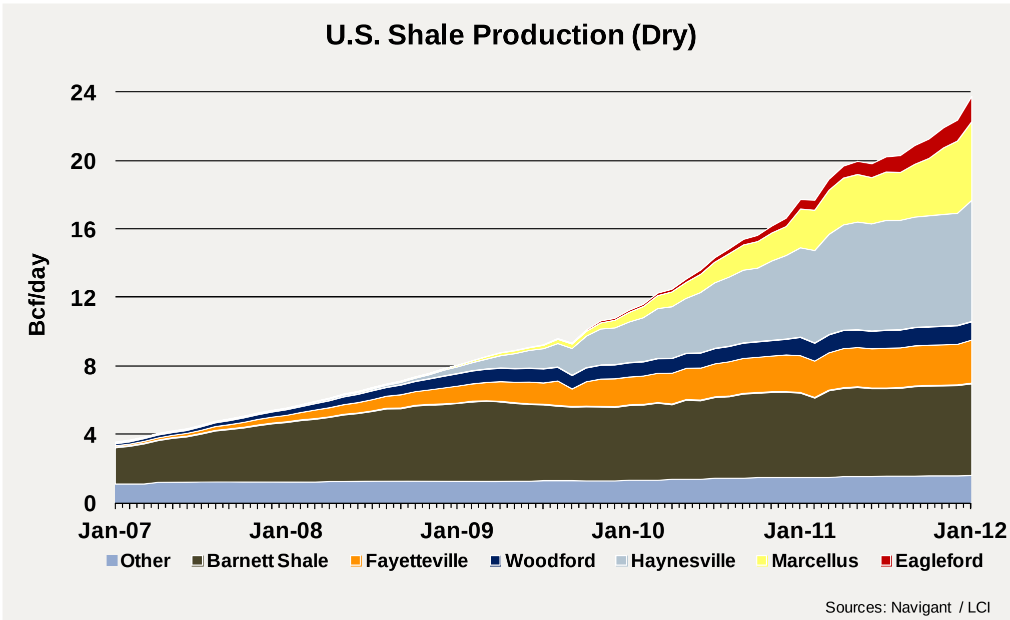

Figure 8: U.S. Shale Production (Dry) 2007-2011

Western Canada

Of significant importance to the OLNG export project is the state of the natural gas resource base in Canada, which is expected to supply the natural gas to be liquefied at OLNG.

Before outlining the specifics of the Western Canadian natural gas resource base, it is important 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/year to over 3 Tcf/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.

With these natural gas and LNG strategies, the province is clearly planning for a massive increase for its natural gas industry, from upstream production through midstream transportation and processing. In fact, very significantly capitalized joint ventures to develop the regional natural gas resources have already formed, often involving the pairing of major Canadian gas producers with Asian companies or countries that will ultimately be destinations for Canadian LNG exports.[16] This

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[14] *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.

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

[16] E.g. Encana Corporation and Mitsubishi Corporation joint venture to develop 409,000 acres in the Cutbank Ridge resource play of the Montney formation, with Mitsubishi to contribute C$2.9 billion for a 40 percent share,

activity, together with the proactive involvement of the provincial government, is a good indicator of the likely ultimate development of the resources. Together with the historical integration of Canadian supplies into the U.S. Pacific Northwest market, as discussed earlier, the anticipated development activity in B.C. bodes well for the commercial operations of OLNG.

The British Columbia Ministry of Energy and Mines and the National Energy Board (BCMEM/NEB) recently estimated total gas in place for the Horn River Basin alone to be a minimum of 372 Tcf.[17] This estimate excludes the Montney natural gas play further to the south, resources in the territories to the north such as the Liard Basin and the Cordova Embayment, conventional gas, and any as-yet-to-be-discovered resources. A prior published estimate from 2008 of the minimum gas in place for the *combined* Horn River Basin, Liard Basin, and Cordova Embayment, noted in the BCMEM/NEB report, was 144 Tcf.[18] Thus, the current BCMEM/NEB estimate reflects an increase of 158 percent in the minimum estimate for gas in place for the Horn River Basin, even when the other two basins were included in the 2008 published estimate; the estimated mean gas in place for Horn River is 448 Tcf, versus the earlier estimate of 372 Tcf (not to be confused with the new estimated minimum for Horn River gas in place) for all three basins. Navigant expects this trend towards identifying a larger resource base to continue in the near term in both the U.S. and Canada.

BCMEM/NEB estimated the marketable gas in place in the Horn River Basin alone to be between 61 and 96 trillion cubic feet, with a mean expectation of 78 Tcf.[19] Other estimates for the Horn River have been even higher; RBC Capital Markets estimates that 500 Tcf of gas is in place, with recoverable estimates of 20 to 40 percent, supporting estimates of 100-200 Tcf of recoverable resources.[20] The James A Baker III Institute for Public Policy at Rice University estimated Horn River recoverable shale gas resource at 90 Tcf.[21] The other major gas play B.C., the Montney play, has been estimated by Rice University to contain 65 Tcf of mean technically recoverable resources[22] and by RBC to contain up to 221 Tcf of recoverable resources. Based upon 2009 annual gas demand in B.C. (about 386 Bcf) and the more conservative estimates of marketable supply for the Horn River and technically recoverable resources for the Montney basins, the combined resource base for these two B.C. basins alone would support consumption in B.C. for more than 370 years (or more than 180 years of combined B.C. and OLNG demand), and should clearly be an available and sufficient resource for OLNG.[23] Incorporating RBC Capital Markets' more optimistic resource estimate for the Horn River Basin, plus its estimates for the Cordova Embayment shale play near Horn River (at 70 Tcf) and for

as announced on February 17, 2012; Progress Energy Resources Corp. and Petronas (Malaysia) joint venture to develop 150,000 acres in the Montney formation, with Petronas to contribute about C$1 billion for a 50% interest, as announced on June 2, 2011

[17] *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. 9.

[18] Id. at p 11.

[19] Id at p. 17.

[20] RBC Capital Markets Equity Research, Horn River Shale Gas – Awakening the Northern Giant, September 27 2010, p. 5.

[21] *The 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.

[22] Ibid.

[23] National Energy Board, *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, Appendix 2, Table A2.3, available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/nrgyftr-eng.html#s7; Navigant calculations

Montney resources, suggests that there could be between 1,010 and 1,270 years worth of the Province's natural gas consumption in these three plays.

As with U.S. shale production, Canadian shale production likewise shows a trend of steeply increasing production levels as shown in ***Figure 9: Canadian Shale Production (Dry)***, albeit for only the two plays with available data, the Montney and the Horn River. Navigant expects the general trend to continue, with Canadian shale production forecast to increase to more than 11.6 Bcfd by 2045, more than a seven-fold increase from Q3, 2011 (last available data).

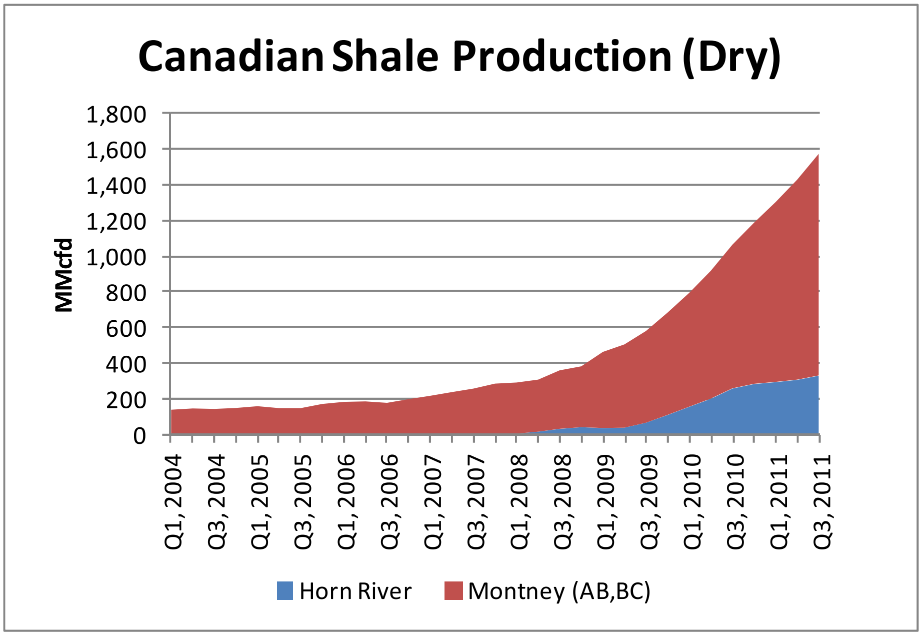

Figure 9: Canadian Shale Production (Dry)

With respect to natural gas resources in Alberta, several data points serve to highlight the strong natural gas supply position of the Western Canada region. First, the estimated remaining conventional recoverable gas resource in Alberta was recently estimated at 78 Tcf, in the BCMEM/NEB report.[24] In addition, the following significant unconventional gas-in-place estimates have been made: 500 Tcf for coal-bed methane[25], 530 Tcf for Deep Basin tight gas[26], and 100 Tcf for the Colorado shale formation in the WCSB[27].

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 OLNG's proposed liquefaction facilities at Warrenton. It has also been our finding

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[24] See note 17, supra, at p.13, Table 2.4B.

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

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

[27] See "An Overview of Canada's Natural Gas Resources", Canadian Society for Unconventional Gas, May 2010, Figure 16.

that the price impact of such increased demand is marginal as we show following in our detailed modeling.

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 still 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. Since the shale formations can be dozens or even hundreds of miles long and often several hundred feet thick and, in many cases, are in existing gas fields wherein the shale was penetrated regularly but not able to be produced economically from vertically drilled wells, 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. Water, sand (or some other proppant to keep the fractures open), and a small amount of chemicals are injected at high pressure to fracture the shale so that it releases the gas. 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 percent of initial production, recent history has shown that production will then continue from that lower rate with a very slow subsequent decline.

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 $100 per barrel equates to about $17.25 per MMBtu, compared to gas prices that are currently $2.50 per MMBtu or even lower.

For example, several energy companies including Enbridge, Enterprise Products Partners, Buckeye Partners, Kinder Morgan, and Dominion have recently announced plans to build or enhance NGL gathering and transmission systems in the Marcellus shale formation. The Eagle Ford formation in Texas is being developed as an NGL play as much as a natural gas play. Recently, discoveries in the Utica formation in eastern Ohio have led Chesapeake Energy to state that it is "likely most analogous, but economically superior, to the Eagle Ford."[28] For the Utica, which is in its earliest stages of development with limited data, the resource estimates already run from 2.0 Tcf to 69 Tcf.[29]

Similarly, in April 2011, the Canadian natural gas producing company Encana announced the acquisition of liquids-rich Duvernay Shale acreage in Alberta to exploit natural gas liquids, which again would lead to additional natural gas production in Alberta.

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, costs have been reported as below $3.00 and even below $2.00 per MMBtu to find and develop recently. 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.[30]

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 OLNG 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, 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 $145 per barrel by 2035.[31] This is approximately $24.94 per MMBtu and compares to gas prices in 2045 that Navigant forecasts to be $6.86 per MMBtu in the OLNG Reference 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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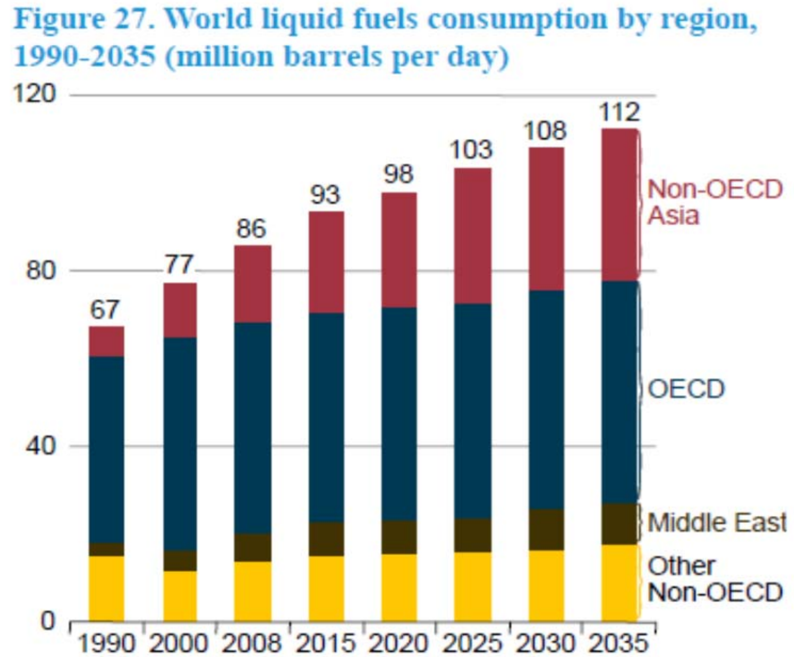
[28] Chesapeake Energy, *October 2011 Investor Presentation*, available at http://www.chk.com/Investors/Documents/Latest_IR_Presentation.pdf
[29] http://oilshalegas.com/uticashale.html
[30] See Progress Energy, Presentation to National Bank Financial Markets Energy Conference, February 14, 2012, slide 12, citing Morgan Stanley analysis.
[31] *International Energy Outlook 2011*, EIA, p. 25, available at http://www.eia.gov/oiaf/ieo/liquid_fuels.html



Source: EIA

Figure 10: World Liquids Consumption from EIA International Energy Outlook 2011

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

In ***Figure 11: Supply Outlook Comparison: Navigant and EIA,*** the OLNG Reference 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*. 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 further increased its shale production forecast in its 2012-vintage outlook. Despite this additional increase, EIA's forecast trails the Navigant forecast because of the difference in the pre-2020 period.

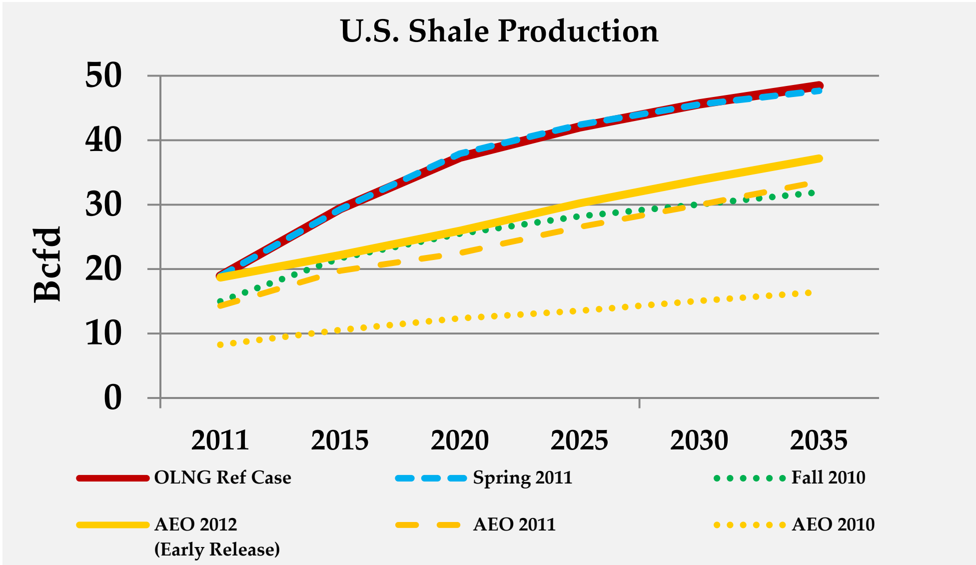


Figure 11: Supply Outlook Comparison: Navigant and EIA

Year	OLNG	Navigant		EIA		
	OLNG Ref Case	Spring 2011	Fall 2010	AEO 2012 (Early Release)	AEO 2011	AEO 2010
2011	18.9	18.9	15.0	18.7	14.3	8.3
2015	29.4	29.3	21.7	22.2	19.7	10.5
2020	37.4	37.9	25.5	25.9	22.5	12.4
2025	42.1	42.4	28.2	30.2	26.5	13.5
2030	45.6	45.5	30.0	33.8	30.0	15.1
2035	48.4	47.7	31.9	37.2	33.6	16.4

Table 2: Supply Outlook Comparison: Navigant and EIA

EIA has historically lagged in the recognition of the size of the shale gas resource in its forecasts. As previously shown in ***Figure 8: U.S. Shale Production (Dry) 2007-2011***, dry shale production in the U.S. at the beginning of 2011, before the release of AEO 2011, was already 17.8 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. The growth in gas production has been so rapid that many forecasters have had difficulty keeping up with the ramping gas shale resource.

Demand Is Likely to Increase Steadily if Undramatically

Reliable demand is a key to underpinning reliable supply and a sustainable gas market. Supply is unlikely to be developed unless demand is there to absorb it; however, demand 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 is behind 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 is expected to grow at an annual rate of 1.8 percent through the study period, with a higher rate of 5.2 percent through 2015. 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 the large amounts of expected new renewable generation.

Navigant projects industrial demand in North America to grow annually by an average 0.5 percent, 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, including recent issues related to the Keystone XL pipeline project and inherent environmental factors tied to the project, Navigant believes that increased oil sands development will occur, requiring increased consumption of natural gas in the process.

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

Navigant's sectoral outlook for natural gas demand growth from its OLNG Reference Case is shown in ***Figure 12: North American Natural Gas Demand Projection***.

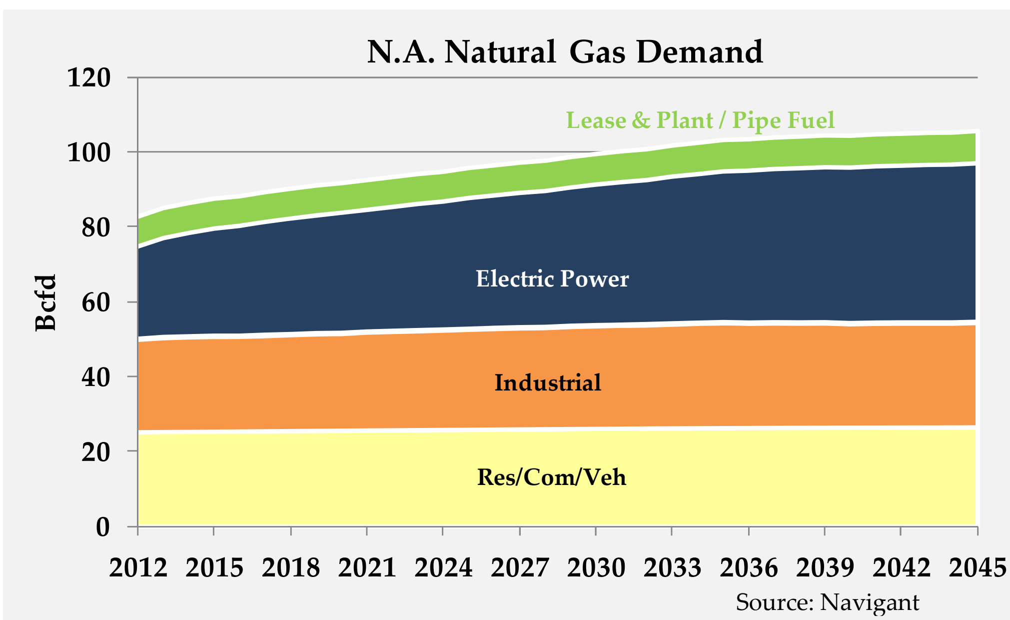


Figure 12: North American Natural Gas Demand Projection

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. Low price volatility, like supply growth, is supportive of long-life end-use infrastructure development and pipeline and mid-stream processing projects.

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. Since shale resources are widely dispersed around the continent, the need for significant long-line pipeline capacity such as the recently built Ruby Pipeline, which extends from Opal, Wyoming to markets in California, is likely not required with the possible exception of the Florida market and possibly some expansions in the Northeast.

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 none of the six major projects that have applied for approval to export U.S.-sourced LNG anticipate start-up before 2016, over the mid and long term, emerging LNG exports should provide a new market in the currently oversupplied natural gas market in the U.S., and may even overtake fuel switching from coal plant retirements as a primary mechanism for balancing oversupply conditions in the gas market.

Competition from Oil and Other Fuels

Annual average natural gas prices are projected to increase slowly in the OLNG Reference Case from \$3.87 per MMBtu in 2012 to \$8.07 per MMBtu in 2045. 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 motor fuel and lubricant. 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 the chart at ***Figure 13: Comparison of Oil and Gas Prices per MMBtu***.

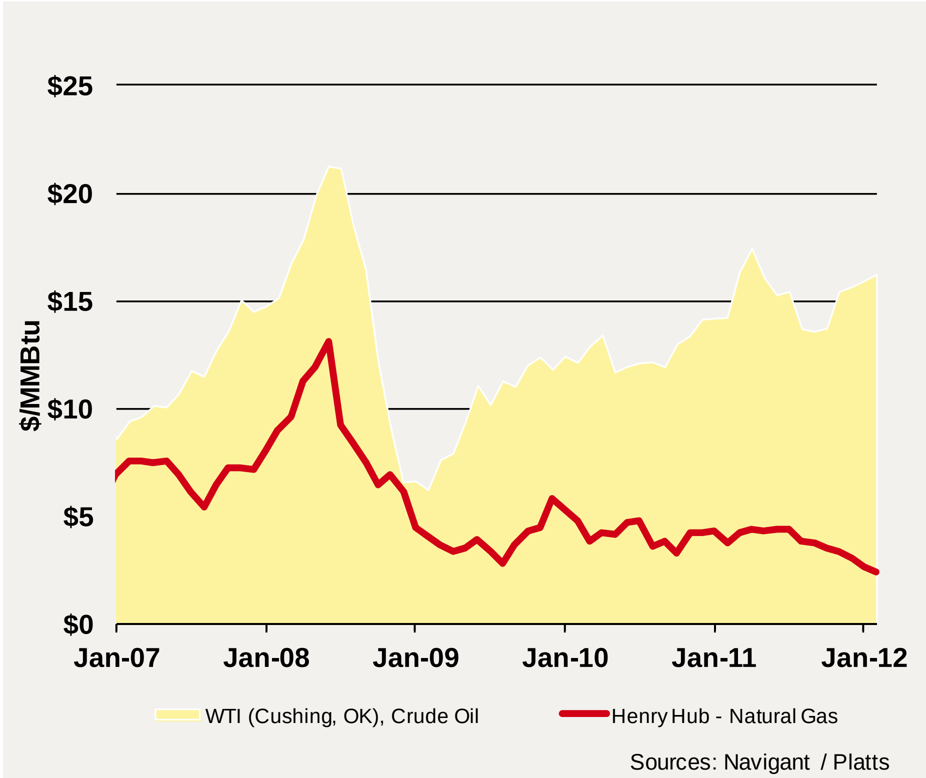


Figure 13: Comparison of Oil and Gas Prices per MMBtu

In any case, the price of oil is likely to continue to be at a significant premium to gas. Gas is domestically plentiful, relative to demand. 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.[32] Conventional oil resources in the U.S. have largely already been identified. Over the last two decades, the motivation to drill for oil in the U.S. has shifted to opportunities around the globe with better returns. While there is recent positive news regarding oil production in the U.S., it is unlikely that the total oil resource potential in North America will allow the current voracious demand for oil in the U.S. to be met without 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.

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 14: Coal and Natural Gas as a Percent of Total Megawatt Hours Generated***. While coal accounted for 53 percent of annual electric generation in 1997, it accounted for only 42 percent in 2011. Natural gas, on the other hand, accounted for 14 percent of electric generation in 1997, and grew to 25 percent by 2011.

[32] 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

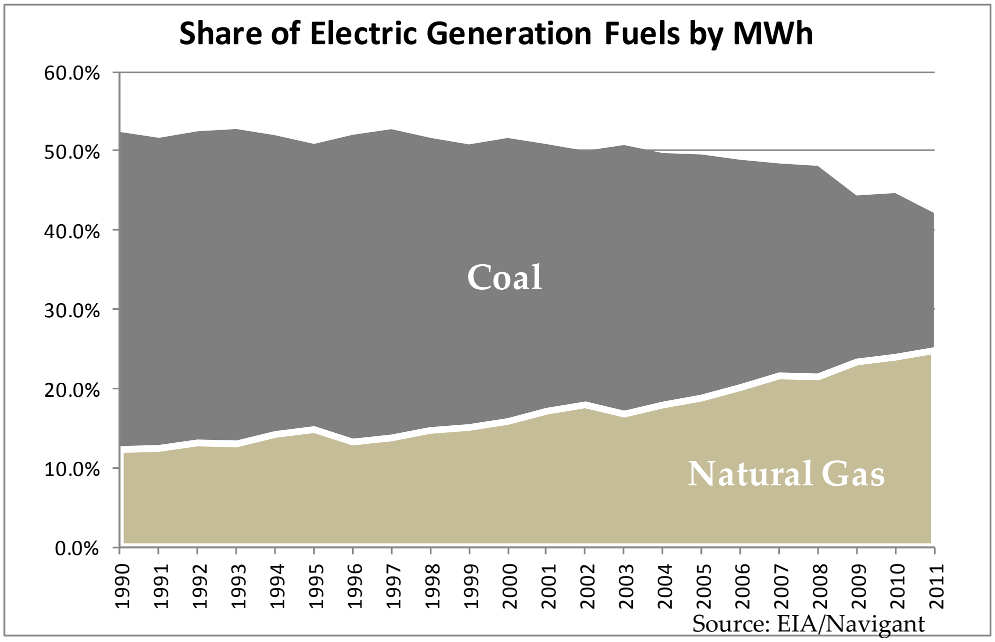
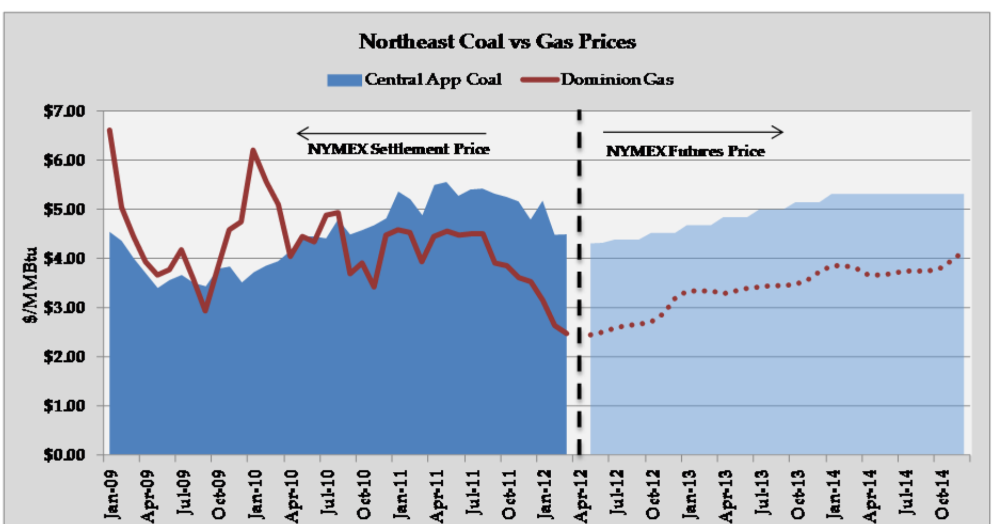


Figure 14: Coal and Natural Gas as a Percent of Total Megawatt Hours Generated

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 March 2012, as shown in ***Figure 15: Comparison of Electric Generation Fuel Costs***, where gas maintains a $1.50 to $2.00 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 that have been delayed.



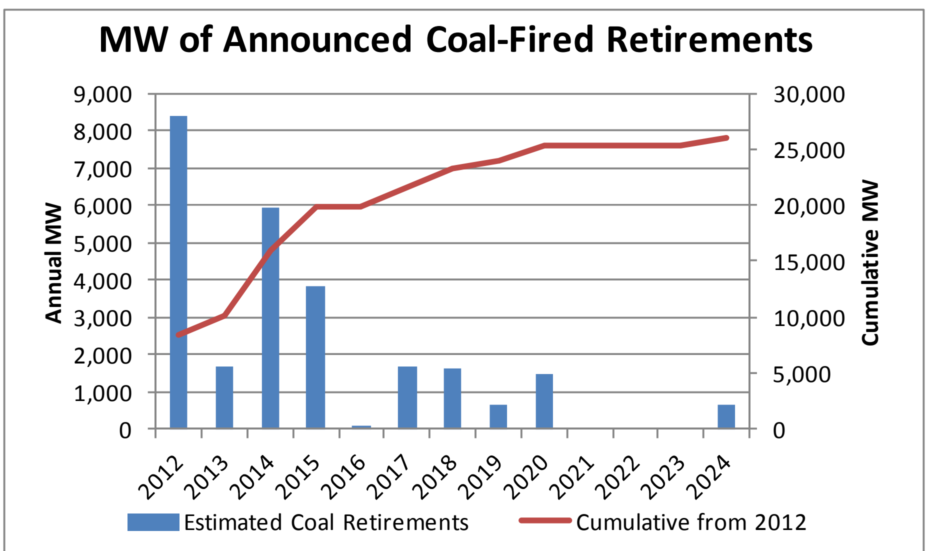
Source: Platts/Navigant

Figure 15: 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.[33]

Coal-fired electric generation is likely to continue to be under pressure from increasingly stringent environmental regulations. The EPA's Cross-State Air Pollution Rule (CSAPR) requires the reduction of power plant emissions of SO_2 and NO_x that contribute to ozone and/or fine particulate pollution in other states. EPA estimates that implementation of its final rule in the eastern half of the country will lower emissions in that area by 2014, compared to 2005 levels, by 73% for SO_2 and by 54% for NO_x.[34] 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.

Companies have responded to the economic and regulatory pressures impacting coal-fired generation by retiring coal-fired generation units. ***Figure 16: Trajectory of Announced Coal-Fired Generation Retirements***, below, shows the planned retirements of the 26,000 MW of additional, currently announced coal-fired retirements.[35] As can be seen, the great bulk of these announced retirements will have occurred prior to 2017, when the OLNG export facility begins to come on-line. Consequently, most of the coal-to-gas switching due to announced retirements will have already occurred, and the additional demand represented by LNG exports should provide a welcome boost to help maintain a sustainable gas market.



Source: Ventyx/Navigant

Figure 16: Trajectory of Announced Coal-Fired Generation Retirements

[33] 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.

[34] EPA finalized the CSAPR on July 6, 2011; the U.S. Court of Appeal for the D.C. Circuit issued a stay of implementation on December 30, 2011, with a hearing set for April 13, 2012

[35] Based on data from Ventyx Energy Velocity.

Nuclear, Renewables, and Efficiency

The disaster at the Fukushima nuclear generating facility in Japan 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 the form of LNG. Several states have already conducted nuclear power workshops to assess the possible complications of a similar disaster in this country.[36] 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 in the US Pacific Northwest region, natural gas looks to be critical to wind industry development. It is too early to estimate the eventual demand created by the renewable industry and specifically in the US Pacific Northwest region, with any assurance, although even the most optimistic forecasts are for incremental gas demand to the renewable sector to be modest for at least the mid-term.

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.[37] 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 10, significant efforts are already underway to improve water

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

[37] See note 6, supra.

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.[38]

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. [39] 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."[40] 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.[41]

Navigant expects hydraulic fracturing to be subject to continuing scrutiny and increasing disclosure requirements. This should mitigate environmental risks and concerns so that shale resource development in North America will 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. The risk of sustained, organized opposition to gas shale development should however be ameliorated by increasingly close collaboration between the interests of the producers and the interests of the community at large.

The area of greenhouse gas emissions is another potential risk. The research firm IHS Cambridge Energy Research Associates released a 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."[42] The National Energy Technology Laboratory stated in May 2011 that natural gas baseload power generation has a life cycle global warming potential that is 54 percent lower than coal baseload generation. NETL included shale gas in its analysis.[43] 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, but still 56% that of coal." [44]

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

[39] 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

[40] Ibid, pp. 1, 9.

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

[42] *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

[43] *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

[44] *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

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.

Commodity Prices / Reallocation of Drilling Capital

Will the higher price of oil and NGLs result in a shift of drilling resources from gas, and cause a drop-off in gas supply? Within the drilling industry, there is currently a shift from gas to natural gas liquids (NGLs, such as ethane and propane, which are typically priced based on oil prices) and oil, 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 February is up from 812 in 2011 to 1,167 in 2012, or 44 percent.[45]

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 638 to 484,[46] or 24 percent, dry U.S. gas production has increased from 60.0 Bcfd to 64.6, or 7.7%, over that same period.[47] 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 OLNG Reference Case price forecast indicates a gradual increase from $4.00 to $6.00 per MMBtu over the next 20 years, reaching $8.00 per MMBtu only in the last year of the forecast. At these levels, gas prices will continue to be extremely competitive with oil, which Navigant projects may be four to five times as costly as gas per MMBtu throughout the forecast period.

[45] Smith Bits.

[46] Smith Bits.

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

Overview of Proposed Energy Operations of OLNG Export Project

The proposed Oregon LNG export project is located at Warrenton in northern Oregon. OLNG applied for FERC approval in Docket Nos. CP09-6-000 and CP09-7-000 to construct an LNG import facility and associated natural gas pipeline ("Oregon Pipeline"), respectively. OLNG intends to file applications in 2012 to export to FTA and non-FTA countries and to amend its FERC application to include authority to construct an LNG export facility.

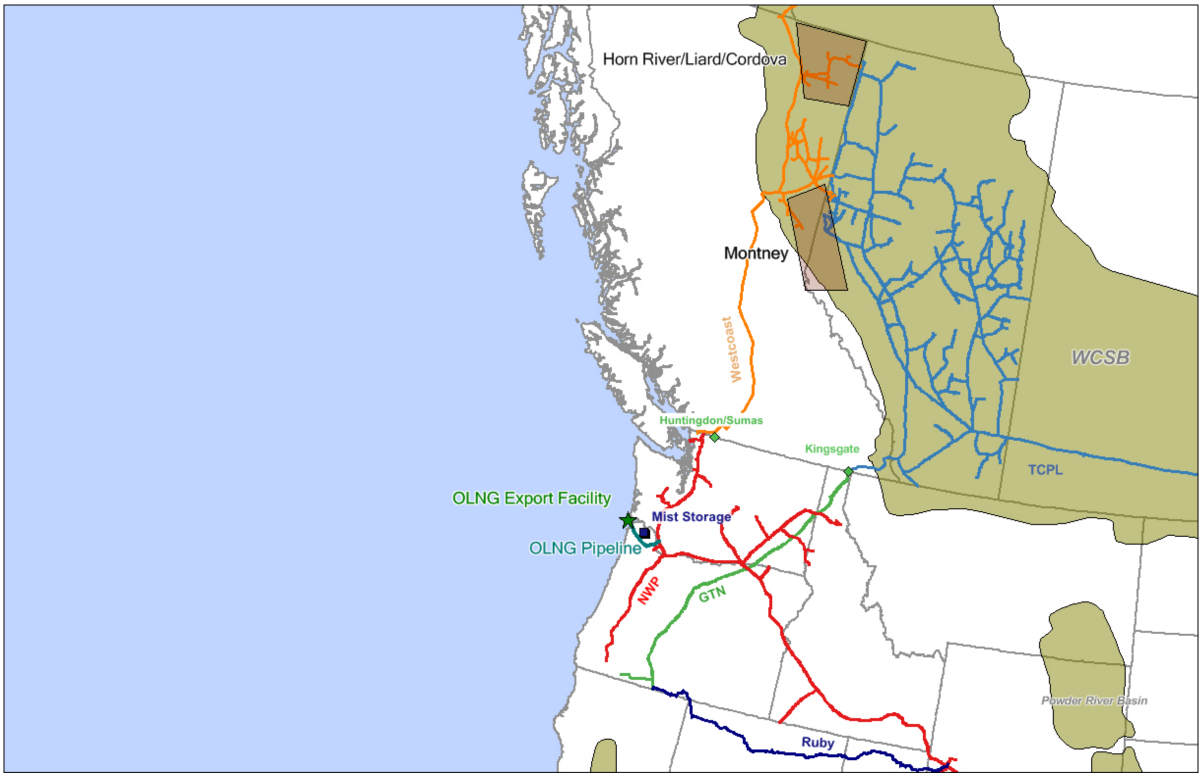

Figure 17: Oregon LNG Location Map

The OLNG export facility will consist of two liquefaction trains sized to handle 550 MMcfd of feedstock each. The trains are tentatively planned for phase-in of operations starting June 2017, with operation of both trains, at a total capacity of 1.1 Bcfd, planned for June 2019.

The Oregon Pipeline was originally intended as a 121-mile, 36-inch diameter pipeline to carry natural gas derived from imported LNG from Warrenton to an interconnect with the Williams Northwest Pipeline at the Molalla Gate Station south of Portland, Oregon. As amended, the proposed Oregon Pipeline will transport gas from a new interconnection location with the Northwest Pipeline to the OLNG liquefaction facility at Warrenton. OLNG anticipates that the Oregon Pipeline will travel generally eastward from Warrenton to an interconnection with Northwest Pipeline in the vicinity of Deer Island, Oregon, downstream on the Columbia River from Portland. It has an expected on-line date of June 2017.

The Oregon Pipeline has an assumed capacity of 1.5 Bcfd, more than adequate to carry gas to the proposed 1.1 Bcfd liquefaction facility; in fact, the addition of the Oregon Pipeline and its various interconnections will potentially enhance regional supply diversity and flexibility, for example by improving operational ties between the 16 Bcf Mist storage facility near Portland and the Northwest Pipeline and local demand. Further, the Oregon Pipeline could provide supply opportunities to potential new gas loads, such as electric generating facilities to serve growing regional needs. The highly seasonal and highly peaking nature of Pacific Northwest natural gas demand, resulting from cold weather events, means that average day demand is generally well below pipeline capacities that are designed for peak day demand. Not only could the construction of the OLNG export facility and the Oregon Pipeline lead to better utilization of other pipelines (and likely lower tolls due to such improved utilization), but the presence of the new facilities and their additional volumes of gas flow should help the region address peak demands more effectively.

The gas feedstock for OLNG will be provided from Canadian resources; Navigant's modeling results confirm that OLNG's planned Canadian feedstock supply is actually the economically preferred source for the facility, comprising 100% of optimal gas supply for the entire forecast period. Gas will arrive from Western Canada at the Oregon Pipeline interconnection with Northwest Pipeline, having travelled either down the Spectra/BC Pipeline system to the Northwest Pipeline at Sumas, or off the TCPL/GTN system from Alberta to the Northwest Pipeline at Stanfield, Oregon. The Northwest Pipeline is a multi-legged system connecting Pacific Northwest demand centers with British Columbian and Rockies supplies. The Spectra/BC Pipeline system provides access to the traditional basins in B.C. as well as developing shale basins in the northeastern section of the province. GTN was originally designed to transport Canadian gas from Alberta to the California border, but is expected to have excess pipeline capacity due to gas-on-gas competition from Ruby Pipeline, which was designed to allow Rockies supply to compete with Canadian supply for the California market, and has indeed allowed displacement of Canadian supplies on GTN since commencing operations in July 2011.

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 Fall 2011 Forecast (issued in December 2011) was the starting point of the OLNG Export Project analysis. To develop the OLNG Reference Case, Navigant made a minor modification to the pipeline infrastructure in BC that supplies the Kitimat LNG export facility, based on the latest available information.

Price projections for purposes of this report focus on both Henry Hub, which is the underlying physical location of the natural gas NYMEX futures contract and the key North American pricing reference point, and Sumas at the U.S.-Canadian border, to demonstrate the possible effect that OLNG may have on the natural gas market in the vicinity of the export facility. All prices are adjusted for future inflation and are shown in constant 2010 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 OLNG Reference Case model comes from currently established basins in North America. The forecasts assume no new gas supply basins beyond those already identified as of Fall 2011. 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 OLNG Reference Case supply projection is that U.S. domestically-produced natural gas supply will grow from 62.4 Bcfd in 2012 to 81.0 Bcfd in 2045, an increase of 30 percent.

As a rule, Navigant's approach towards production capacity is the same for all cases modeled for OLNG. 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 2.5 Bcfd in 2045. It is arguable that the Utica Shale could be producing many 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 from existing LNG import projects. The model solves for such imports as a response to demand and the price of gas in North America.

Demand

Navigant's basic modeling assumption is that 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 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.

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 volumes that are most likely 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 likely to be built. 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 post-2014, except as it directly supports the modeled export projects (e.g., Oregon Pipeline is specifically modeled to support OLNG) or has been announced. This is a highly conservative assumption. It is likely that some measure of new pipeline capacity will be constructed to support the ongoing development of the gas supply resource and the accompanying demand between 2014 and 2045. 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 relieve the constraint only.

Some proposed pipeline projects have been excluded from the Reference Case model, most notably the Mackenzie Pipeline in northern Canada, which we believe to be uneconomic and faces large environmental challenges. Likewise, the Alaska Gas Pipeline project is also assumed to be nonoperational over the study period term. In fact, the governor of Alaska recently announced he favors a pipeline project from Alaska's North Slope gas resources that delivers to the south coast of the state where it could be liquefied into LNG instead of connecting to the larger North American grid in Canada. (The project would also serve the needs of the City of Anchorage.) On the other hand, several large regional pipelines are assumed to be operational by 2015, including Fayetteville Express and Tiger.

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 Fall 2011, 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 highly 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 Reference Case includes two specific LNG export facilities. 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 begins operations at a capacity of approximately 0.7 Bcfd in October 2015. These export facilities are assumed to be operating at a 90 percent load factor year-round in all scenarios. This is a conservative assumption, since 90 percent is what is operationally possible, and actual annual load factors are likely to be lower. The likelihood is that the LNG export facilities will operate initially and perhaps during certain seasonal periods at less than 90 percent of capacity, thereby requiring less gas and thus resulting in an even smaller impact than what is assumed in the analysis.

The OLNG Export Case adds the OLNG export facility to the two facilities already included in the OLNG Reference Case. The assumptions for the OLNG export facility are for two 550 MMcfd liquefaction trains, coming on-line in phases, in June 2017 and in June 2019.

In order to provide stress scenarios to examine the effect of exporting more domestically–sourced LNG, additional LNG export capacity is included in the Aggregate Export 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 2017-2020 timeframe, as each liquefaction train is assumed to be completed.

LNG Facility	Export Capacity (Bcfd)	Location	Ref Case	OLNG Export	Agg. Export
Sabine Pass	2.0	Cameron Parish, LA	•	•	•
Kitimat	0.7	District of Kitimat-Stikine, BC	•	•	•
Oregon LNG	1.1	Warrenton, OR		•	•
Gulf Coast	2.0	Texas			•
Northeast	1.0	Maryland			•
Total	**6.8**				

Table 3: 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 minimize LNG imports in light of the modeled export activity. This assumes that a reduction in exports is likely to occur if U.S. prices at any time attract overseas LNG before significant imports occur, 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 at the Everett, Northeast Gateway, and Neptune facilities in Boston Harbor and Massachusetts Bay much as they do today.

Other Assumptions

Oil Prices

The chart below 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 $88 per barrel, in 2010 dollars. In 2045, the price per barrel is $144. For comparison, the EIA's Reference Case projects the price of imported low-sulfur light crude oil to be $116.55 per barrel in 2015 and $144.56 in 2035, in 2010 dollars.

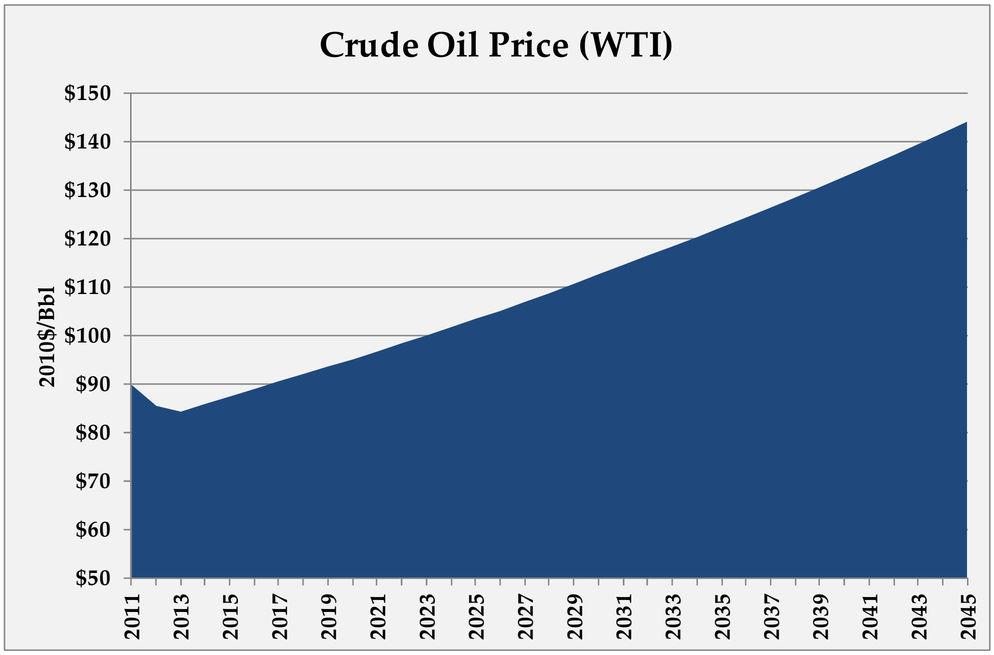

Figure 18: WTI Price Assumed in Natural Gas Price Forecast

Economic Growth

Navigant uses GDP figures from the Congressional Budget Office's Budget and Economic Outlook of January 2011, updated August 2011. To extend the outlook beyond the last year, the final year GDP of 2.3 percent is continued to the end of the forecast period.

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2.40%	2.60%	1.70%	4.40%	5.00%	3.20%	2.80%	2.50%	2.50%	2.30%	2.30%

Table 4: 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 2011 Annual Energy Outlook.

Price Points

Prices for Henry Hub, the location of the North American futures market, are modeled in all outputs. In addition, the market point at. Sumas, Washington, on the British Columbia border, represents the Pacific Northwest market.

Scenario Descriptions

Case Name	*Description*
OLNG Reference Case	The **OLNG Reference Case** is developed from Navigant's Fall 2011 Forecast of December 2011. The Fall 2011 Forecast incorporates Navigant's extensive work on North American gas shale supply resources. The Fall 2011 Reference Case has been changed with a minor modification to the pipeline infrastructure in BC that supplies the Kitimat LNG export facility based on the latest available information. The OLNG Reference Case assumes that two other LNG export facilities in North America will be operational prior to and concurrent with OLNG: Sabine Pass in Louisiana and Kitimat in British Columbia. Sabine Pass is modeled as exporting 0.5 Bcfd of gas in LNG form beginning in May 2015, ramping up to 2.0 Bcfd by October 2017. Kitimat is modeled as exporting 0.7 Bcfd beginning in October 2015.
OLNG Export Case	The **OLNG Export Case** augments the Reference Case with exports from the OLNG export facility of approximately **1.0 Bcfd (annual average)** beginning June 2017. In addition, there were some adjustments to the B.C. shale production outlook and regional infrastructure. The effects on prices are the specific focus.
Aggregate Export Case	The **Aggregate Export Case** adds to the OLNG Export Case additional LNG export capacity. In the Gulf of Mexico, 2.0 Bcfd of generic LNG export capacity is assumed. On the U.S. eastern seaboard, 1.0 Bcfd of generic export capacity is assumed. In total, all North American LNG export facilities modeled in the Aggregate Export Case when all export facilities are fully online is approximately 6.8 Bcfd. In addition, there was some adjustment to Gulf area production outlooks. The effects on prices are the specific focus.

OLNG Reference Case

The **OLNG Reference Case** was derived from Navigant's Fall 2011 Reference Case. Certain refinements to the infrastructure in British Columbia were made, based on more detailed information that was incorporated subsequent to the Navigant Fall 2011 Reference Case. For example, BC Pipeline was expanded to accommodate increased shale production for the Montney-Horn River area and adjacent shale resources (e.g., Cordoba Embayment) and to supply Kitimat LNG exports.

The OLNG Reference Case includes two LNG liquefaction and export facilities as active. Sabine Pass LNG in Louisiana, the only liquefaction facility to receive DOE authority to export LNG to both FTA and non-FTA countries, is specifically modeled, with a capacity of 2.0 Bcfd. It is assumed to come online in 2015 at 25 percent capacity. Exports ramp up to 90 percent capacity 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 also assumed to come on line in 2015 with exports at 90 percent capacity.

Supply

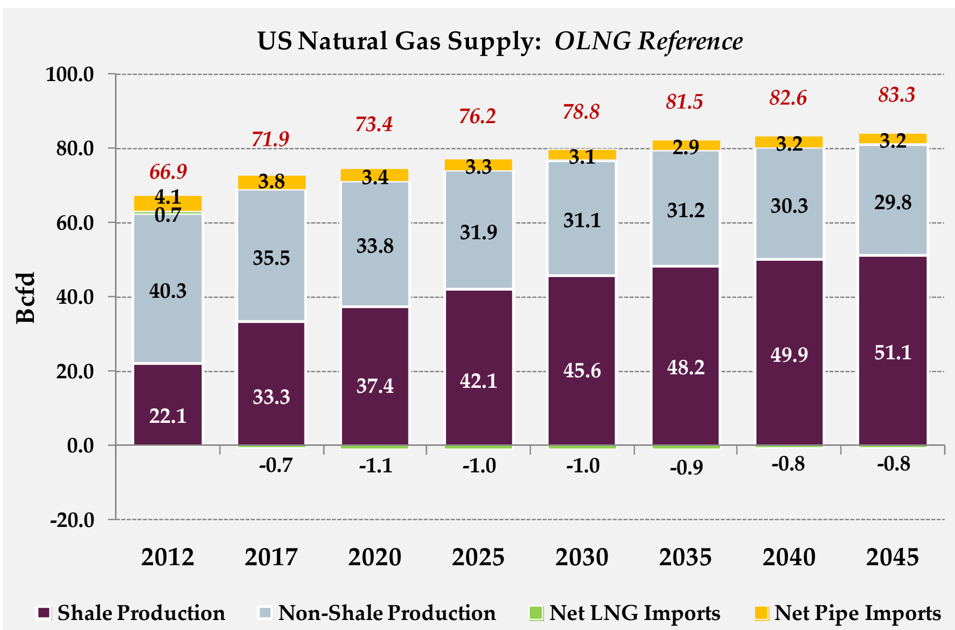

Figure 19: OLNG Reference Case Supply

As shown in ***Figure 19: OLNG Reference Case Supply***, above, beginning around 2017, net LNG imports to the U.S. are negative, as the U.S. becomes a net exporter of LNG.[48]

[48] 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

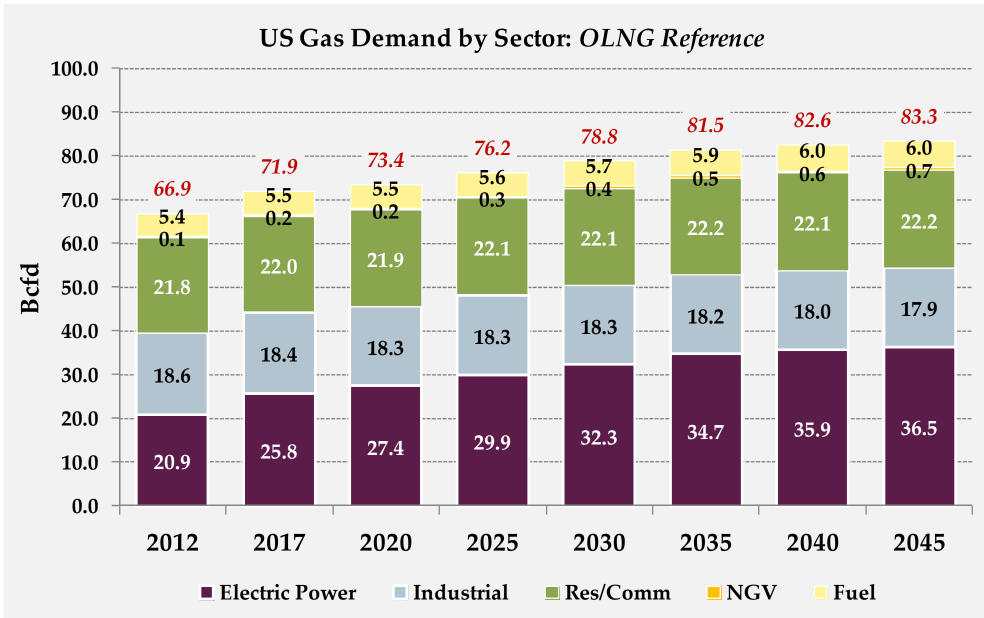

Figure 20: OLNG Reference Case Demand

As shown in ***Figure 20: OLNG Reference Case Demand***, above, domestic U.S. demand is satisfied across the planning horizon in balance with supply, depicted ***in Figure 19: OLNG Reference Case Supply***, on the previous page.

Resultant Gas Prices

As shown in ***Figure 21: OLNG Reference Case Prices***, 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 $6.86 per MMBtu in 2035, and $8.07 per MMBtu in 2045. Prices at Sumas show a negative basis to Henry Hub 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 $7.23 per MMBtu,[49] and Canada's National Energy Board's Henry Hub U.S. dollar denominated price forecast for 2035 is $8.00 per MMBtu.[50]

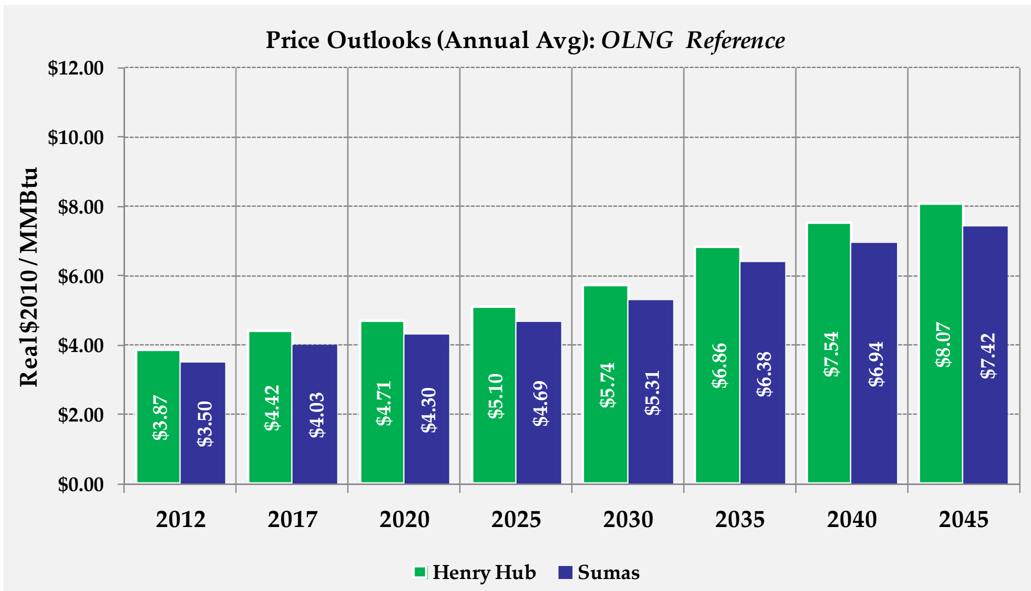

Figure 21: OLNG Reference Case Prices

[49] EIA Annual energy Outlook 2011, interactive table Natural Gas Supply, Disposition, and Prices, Reference Case.

[50] National Energy Board, ***Canada's Energy Future: Energy Supply and Demand Projections to 2035***, Reference Case, p. viii.

OLNG Export Case

The **OLNG Export Case** tests the effects of liquefying and exporting 1.0 Bcfd of North American gas from the OLNG export facility beginning June 2017, versus the OLNG Reference Case[51]. Instantaneous daily demand at OLNG is 1.1 Bcfd.[52] On an annual basis, the net average demand of OLNG is 1.0 Bcfd due to a 10% annual maintenance downtime.

The OLNG Export Case also assumes the concurrent commissioning of the Oregon Pipeline from its interconnection with Northwest Pipeline to Warrenton. Oregon Pipeline is assumed to transport gas delivered from Canada via either the Spectra/BC Pipeline or the TCPL/GTN systems.

Supply

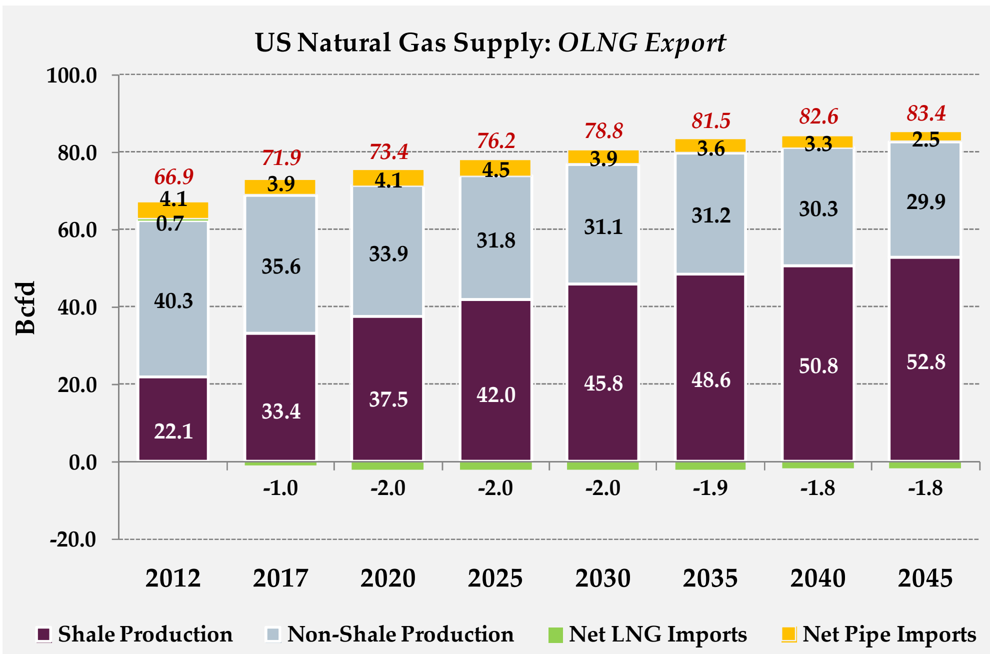

Figure 22: OLNG Export Case Supply

As can be seen in both ***Figure 22: OLNG Export Case Supply***, above, and ***Figure 19: OLNG Reference Case Supply***, as well as shown in ***Table 5: Changes in U.S. Supply in OLNG Export Case***, net pipe imports are generally declining in both the OLNG Reference and Export Cases.

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[51] While it is possible that some other LNG export facility could export the 1.0 Bcfd incremental quantity assumed in the OLNG Export Case in the absence of OLNG, the purpose of this analysis is to review the impact of OLNG as the specific assumed facility.

[52] There is also a small amount of plant feed gas consumption, equal to an extra 0.25%.

Year	Metric	Reference Case	OLNG Export	Difference
2017	*Shale Production*	33.3	33.4	0.1
	Non-shale Production	35.5	35.6	0.1
	Net LNG Imports	-0.7	-1.0	-0.3
	Net Pipe Imports	3.8	3.9	0.1
	Total Supply	**71.9**	**71.9**	**0.0**
2020	*Shale Production*	37.4	37.5	0.1
	Non-shale Production	33.8	33.9	0.1
	Net LNG Imports	-1.1	-2.0	-1.0
	Net Pipe Imports	3.4	4.1	0.8
	Total Supply	**73.4**	**73.4**	**0.0**
2025	*Shale Production*	42.1	42.0	-0.1
	Non-shale Production	31.9	31.8	-0.1
	Net LNG Imports	-1.0	-2.0	-1.0
	Net Pipe Imports	3.3	4.5	1.2
	Total Supply	**76.2**	**76.2**	**0.0**
2035	*Shale Production*	48.2	48.6	0.4
	Non-shale Production	31.2	31.2	0.0
	Net LNG Imports	-0.9	-1.9	-1.0
	Net Pipe Imports	2.9	3.6	0.6
	Total Supply	**81.5**	**81.5**	**0.0**
2045	*Shale Production*	51.1	52.8	1.7
	Non-shale Production	29.8	29.9	0.0
	Net LNG Imports	-0.8	-1.8	-1.0
	Net Pipe Imports	3.2	2.5	-0.6
	Total Supply	**83.3**	**83.4**	**0.1**

Table 5: Changes in U.S. Supply in OLNG Export Case[53]

[53] "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

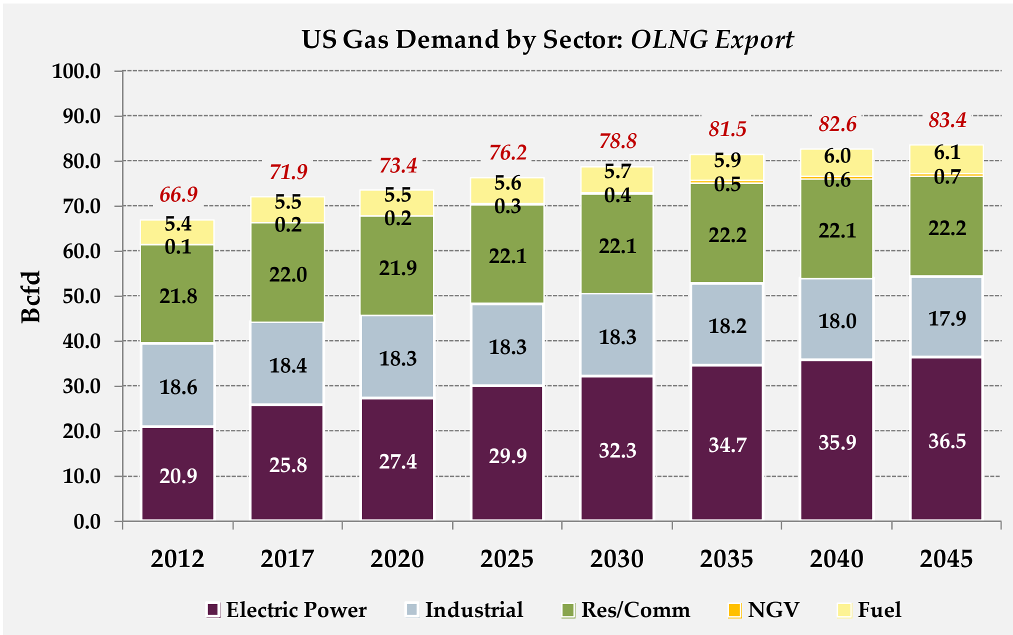

Figure 23: OLNG Export Case Demand

As can be seen by comparing ***Figure 23: OLNG Export Case Demand*** to ***Figure 20: OLNG Reference Case Demand***, LNG exports at OLNG in essence have no effect on the distribution of demand among the major sectors, as can also be seen in ***Table 6: Changes in U.S. Demand in OLNG Export Case***, below, where there is no difference between the OLNG Reference Case and the OLNG Export Case.

Year	Metric	Reference Case	OLNG Export	Difference
2017	*Electric Power*	25.8	25.8	0.0
	Industrial	18.4	18.4	0.0
	Res/Comm	22.0	22.0	0.0
	NGV	0.2	0.2	0.0
	Total Consumption	**71.9**	**71.9**	**0.0**
2020	*Electric Power*	27.4	27.4	0.0
	Industrial	18.3	18.3	0.0
	Res/Comm	21.9	21.9	0.0
	NGV	0.2	0.2	0.0
	Total Consumption	**73.4**	**73.4**	**0.0**
2025	*Electric Power*	29.9	29.9	0.0
	Industrial	18.3	18.3	0.0
	Res/Comm	22.1	22.1	0.0
	NGV	0.3	0.3	0.0
	Total Consumption	**76.2**	**76.2**	**0.0**
2035	*Electric Power*	34.7	34.7	0.0
	Industrial	18.2	18.2	0.0
	Res/Comm	22.2	22.2	0.0
	NGV	0.5	0.5	0.0
	Total Consumption	**81.5**	**81.5**	**0.0**
2045	*Electric Power*	36.5	36.5	0.0
	Industrial	17.9	17.9	0.0
	Res/Comm	22.2	22.2	0.0
	NGV	0.7	0.7	0.0
	Total Consumption	**83.3**	**83.4**	**0.1**

Table 6: Changes in U.S. Demand in OLNG Export Case[54]

Resultant Gas Prices

Prices at Henry Hub and Sumas in the OLNG Export Case remain below $5.00 per MMBtu through 2024. The maximum incremental price increase at Henry Hub compared to the Reference Case is $0.25 per MMBtu, which occurs in 2044. Incremental price increases at Sumas are less than $0.20 per MMBtu until 2038, when they begin to climb toward their maximum level of $0.47 per MMBtu in 2044. The average price increase at Sumas over the forecast term is 17 cents per MMBtu versus the OLNG Reference Case average price of $5.67 per MMBtu, or 3.1%. When compared to the average overall residential retail rate, the 17 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, the wholesale gas cost currently represents about 41% of what a consumer in Oregon pays for natural gas, so the 17cents actually

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

translates to only 1.4% of an average total cost of $11.93 per MMBtu[55]. The 2045 Sumas price of $7.80 per MMBtu in the OLNG Export Case remains below the OLNG Reference Case Henry Hub price of $8.07. ***Figure 24: OLNG Export Case Prices*** and ***Table 7: Changes in OLNG Export Case Prices***, below, summarize these impacts.

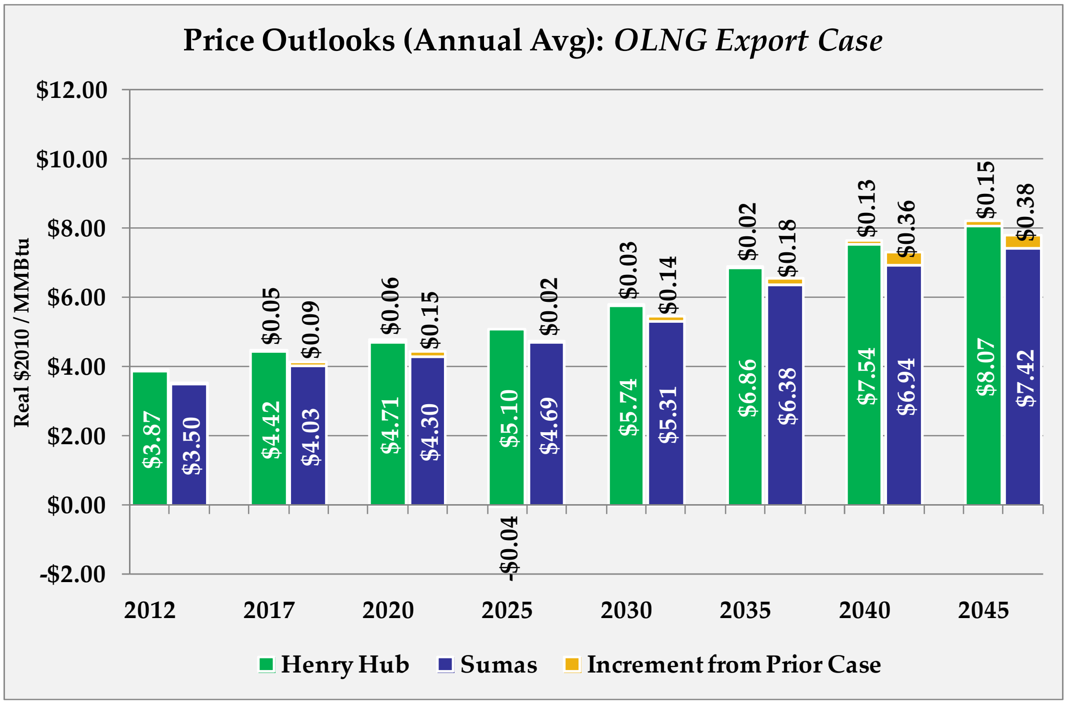

Figure 24: OLNG Export Case Prices

[55] Under Northwest Natural Gas Company's current residential rate schedule for Oregon, the average rate comes to $11.93 per MMBtu, based on a $6 per month customer charge, and a volumetric charge at $10.88 per MMBtu including gas commodity pass-through at $4.90 per MMBtu (virtually the same as the forecast average price at Sumas), assuming consumption at the utility's average 57 therms per month. The 17 cents would therefore only be 1.7% of the current retail rate for residential gas consumers.

		A	B	C=A-B	D=A/B-1
Year	**Metric**	**OLNG Export**	**Reference Case**	***Absolute Difference***	***Percentage Difference***
2017	*Henry Hub*	**$4.47**	**$4.42**	*$0.05*	*1.2%*
	Sumas	**$4.12**	**$4.03**	*$0.09*	*2.2%*
2020	*Henry Hub*	**$4.78**	**$4.71**	*$0.06*	*1.4%*
	Sumas	**$4.45**	**$4.30**	*$0.15*	*3.6%*
2025	*Henry Hub*	**$5.06**	**$5.10**	*-$0.04*	*-0.7%*
	Sumas	**$4.71**	**$4.69**	*$0.02*	*0.5%*
2035	*Henry Hub*	**$6.88**	**$6.86**	*$0.02*	*0.4%*
	Sumas	**$6.56**	**$6.38**	*$0.18*	*2.9%*
2045	*Henry Hub*	**$8.22**	**$8.07**	*$0.15*	*1.9%*
	Sumas	**$7.80**	**$7.42**	*$0.38*	*5.1%*

Table 7: Changes in OLNG Export Case Prices

Aggregate Exports Case

The **Aggregate Export Case** builds on the OLNG Export Case. In the **Aggregate Export Case**, other U.S. LNG exports are assumed in addition to Sabine Pass, Kitimat, and OLNG. This includes an additional 2.0 Bcfd of LNG liquefaction and export capacity in the Gulf of Mexico and 1.0 Bcfd on the U.S. East Coast. 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 OLNG, and models these export volumes generically.

Supply

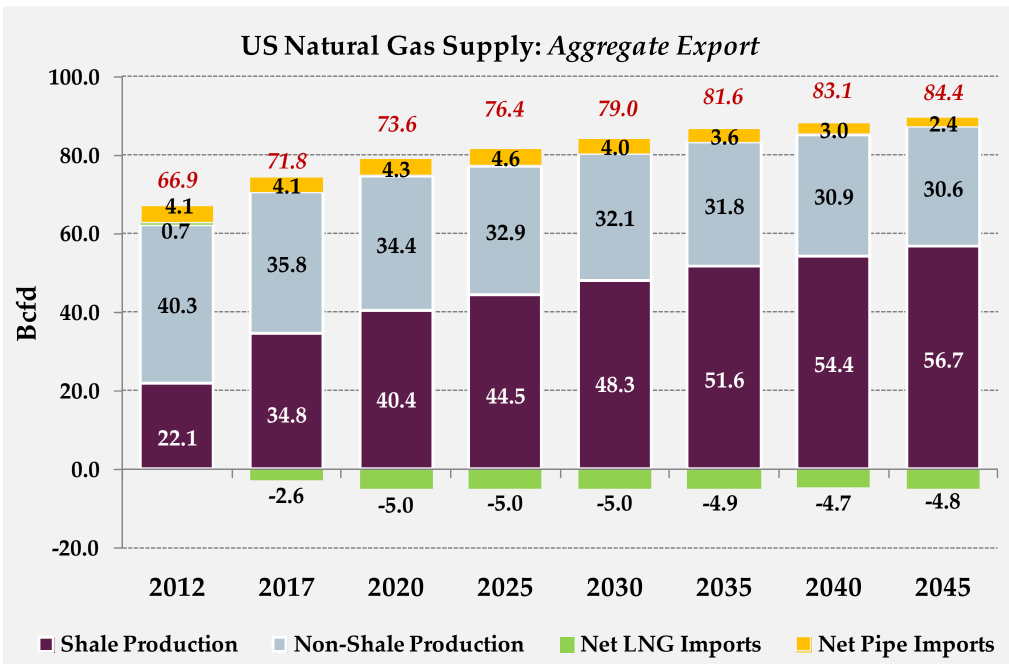

Figure 25: Aggregate Export Case Supply

The addition of 3.0 Bcfd of LNG exports in addition to Kitimat, Sabine Pass, and OLNG stimulates supply production in the U.S. For example, in 2020, shale production rises from 37.5 Bcfd in the OLNG Export Case to 40.4 Bcfd. Similarly, non-shale U.S. production rises from 33.9 Bcfd to 34.4 Bcfd, for a total increase in dry production of about 3.5 Bcfd. Pipeline imports increase from 4.1 Bcfd in 2020 to 4.3 Bcfd. Total supply, after exports (after changes in storage and a balancing component) increases by about 0.2 Bcfd in 2020. These impacts can be seen by comparing ***Figure 25: Aggregate Export Case Supply***, above, to ***Figure 22: OLNG Export Case Supply***, and are summarized in ***Table 8: Changes in U.S. Supply in Aggregate Export Case***, below.

Year	Metric	OLNG Export	Aggregate Export	Difference
2017	*Shale Production*	33.4	34.8	1.5
	Non-shale Production	35.6	35.8	0.2
	Net LNG Imports	-1.0	-2.6	-1.6
	Net Pipe Imports	3.9	4.1	0.2
	Total Supply	**71.9**	**71.8**	**-0.1**
2020	*Shale Production*	37.5	40.4	2.9
	Non-shale Production	33.9	34.4	0.6
	Net LNG Imports	-2.0	-5.0	-3.0
	Net Pipe Imports	4.1	4.3	0.2
	Total Supply	**73.4**	**73.6**	**0.2**
2025	*Shale Production*	42.0	44.5	2.5
	Non-shale Production	31.8	32.9	1.1
	Net LNG Imports	-2.0	-5.0	-3.0
	Net Pipe Imports	4.5	4.6	0.1
	Total Supply	**76.2**	**76.4**	**0.2**
2035	*Shale Production*	48.6	51.6	3.0
	Non-shale Production	31.2	31.8	0.5
	Net LNG Imports	-1.9	-4.9	-3.0
	Net Pipe Imports	3.6	3.6	0.1
	Total Supply	**81.5**	**81.6**	**0.2**
2045	*Shale Production*	52.8	56.7	3.9
	Non-shale Production	29.9	30.6	0.7
	Net LNG Imports	-1.8	-4.8	-3.0
	Net Pipe Imports	2.5	2.4	-0.1
	Total Supply	**83.4**	**84.4**	**1.0**

Table 8: Changes in U.S. Supply in Aggregate Export Case[56]

[56] "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

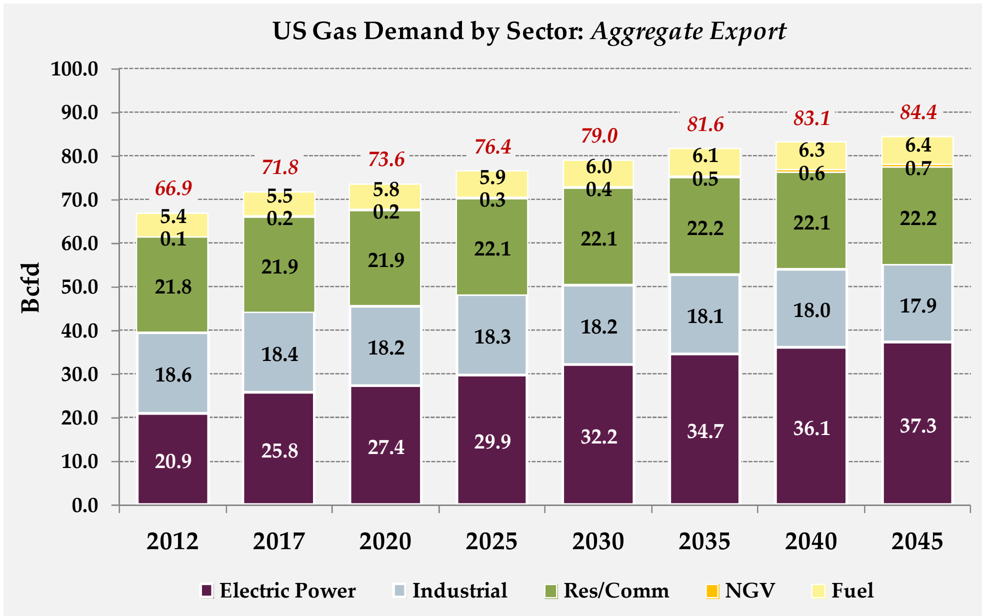

Figure 26: Aggregate Export Case Demand

Aggregate LNG exports add approximately 0.3 Bcfd increase in fuel usage across the U.S. in the later years of the forecast. Otherwise, the distribution of demand is largely unaffected. These impacts can be seen by comparing ***Figure 26: Aggregate Export Case Demand***, above, to ***Figure 23: OLNG Export Case Demand***, and are summarized in ***Table 9: Changes in U.S. Demand in Aggregate Export Case***, below.

Year	Metric	OLNG Export	Aggregate Export	Difference
2017	*Electric Power*	25.8	25.8	0.0
	Industrial	18.4	18.4	0.0
	Res/Comm	22.0	21.9	0.0
	NGV	0.2	0.2	0.0
	Total Consumption	**71.9**	**71.8**	**-0.1**
2020	*Electric Power*	27.4	27.4	0.0
	Industrial	18.3	18.2	0.0
	Res/Comm	21.9	21.9	0.0
	NGV	0.2	0.2	0.0
	Total Consumption	**73.4**	**73.6**	**0.2**
2025	*Electric Power*	29.9	29.9	0.0
	Industrial	18.3	18.3	0.0
	Res/Comm	22.1	22.1	0.0
	NGV	0.3	0.3	0.0
	Total Consumption	**76.2**	**76.4**	**0.2**
2035	*Electric Power*	34.7	34.7	0.0
	Industrial	18.2	18.1	-0.1
	Res/Comm	22.2	22.2	0.0
	NGV	0.5	0.5	0.0
	Total Consumption	**81.5**	**81.6**	**0.2**
2045	*Electric Power*	36.5	37.3	0.8
	Industrial	17.9	17.9	-0.1
	Res/Comm	22.2	22.2	0.0
	NGV	0.7	0.7	0.0
	Total Consumption	**83.4**	**84.4**	**1.0**

Table 9: Changes in U.S. Demand in Aggregate Export Case[57]

Resultant Gas Prices

Prices at Henry Hub and Sumas in the Aggregate Export Case remain below or near $5.00 per MMBtu through 2023 and 2027, respectively. Incremental price increases at Sumas (compared to the OLNG Export Case) are between $0.07 and $0.34 per MMBtu, and average about $0.17. Incremental increases in price at Sumas are less than the incremental increases at Henry Hub, which average about $0.23. The forecast prices at Sumas also remain below the Reference Case Henry Hub prices through 2040. ***Figure 27: Aggregate Export Case Prices*** and ***Table 10: Changes in Aggregate Export Case Prices***, below, summarize these impacts.

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

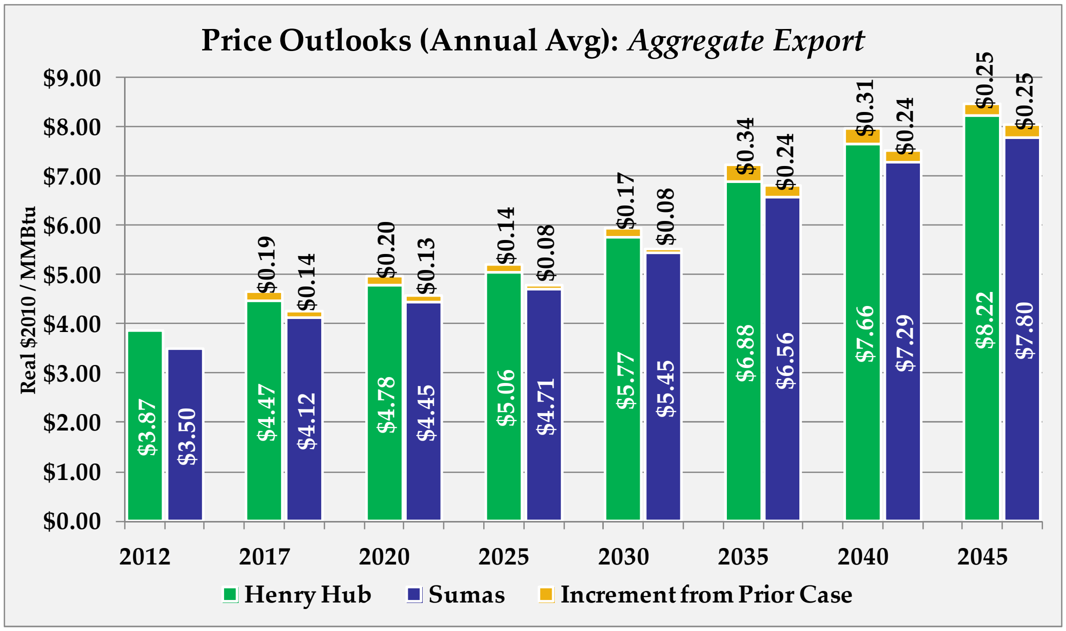

Figure 27: Aggregate Export Case Prices

		A	B	*C=A-B*	*D=A/B-1*
Year	**Metric**	**Aggregate Export**	**OLNG Export**	*Absolute Difference*	*Percentage Difference*
2017	*Henry Hub*	**$4.66**	**$4.47**	*$0.19*	*4.2%*
	Sumas	**$4.26**	**$4.12**	*$0.14*	*3.4%*
2020	*Henry Hub*	**$4.98**	**$4.78**	*$0.20*	*4.1%*
	Sumas	**$4.58**	**$4.45**	*$0.13*	*2.9%*
2025	*Henry Hub*	**$5.20**	**$5.06**	*$0.14*	*2.7%*
	Sumas	**$4.79**	**$4.71**	*$0.08*	*1.7%*
2035	*Henry Hub*	**$7.22**	**$6.88**	*$0.34*	*5.0%*
	Sumas	**$6.80**	**$6.56**	*$0.24*	*3.6%*
2045	*Henry Hub*	**$8.47**	**$8.22**	*$0.25*	*3.1%*
	Sumas	**$8.05**	**$7.80**	*$0.25*	*3.2%*

Table 10: Changes in Aggregate Export Case Prices

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
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
OLNG	Oregon LNG
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)
Cadeville	LA	Jun-12	11,500
Copiah	MS	Apr-14	3,000
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
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)	Jan-12	400	Gulf Crossing	Jan-15	1,000
Midcontinent Express Z1	Jan-12	200	Texas Gas (Fayetteville)	Jan-15	150
PNGT (N & S of Westbrook)	Jan-12	310	Wyoming Interstate (ML)	Jan-15	225
Transco Z5	Jan-12	150	Westcoast (ML)	Oct-15	781
Transco Z6 (PA)	Jan-12	500	Westcoast (Ft St John ML)	Oct-15	438
Transco Z6 (PA)	Apr-12	300	Westcoast (Pine River/St2)	Oct-15	281
Stagecoach Hub (N & S Lat)	Jul-12	50	Westcoast (St2 to PNG)	Oct-15	1,500
Transco Z6 (PA)	Jul-12	300	Questar (Fidlar to KRGT)	Jan-18	400
Transco Z6 (PA)	Oct-12	300	Rockies Express (REX Z1 Wam)	Jan-18	332
Alliance Pipeline BC	Nov-12	300	White River Hub	Jan-18	500
Equitrans WV-PA Line	Nov-12	313	Wyoming Interstate (Kanda Lat)	Jan-18	400
Millennium Phase I	Nov-12	150	Kern River (CA/Mainline/NV)	Jan-20	500
NWP (Plymouth)	Nov-12	239	Kern River (Opal to Muddy Ck)	Jan-20	440
NWP (Stanfield)	Nov-12	239	KM Border Pipeline	Jan-20	300
NWP (Washougal)	Nov-12	239	KM Mexico	Jan-20	425
Tenn Z5 NJ	Nov-12	350	KM Texas Pipeline (AguaDulce)	Jan-20	250
Tenn Z5 NY	Nov-12	250	Mojave-Kern Common Facilities	Jan-20	200
Texas Eastern (M3)	Nov-12	190	Nova (Gordondale/Prairie ML)	Jan-20	4,500
Transco Z6 (PA)	Jan-13	200	Tenn Z0 Rio Bravo	Jan-20	315
Empire (Millennium/Tioga)	Sep-13	350	Tenn Z6 East MA	Jan-20	285
Empire (Chippewa/ML)	Sep-13	175	Tenn Z6 West MA	Jan-20	306
Alliance Pipeline (CAN BC)	Nov-13	300	Wyoming Interstate (ML)	Jan-20	500
NFGS (Leidy Hub/ML)	Nov-13	425	Cypress Pipeline	May-20	500
Tenn Z4	Nov-13	636	El Paso Natural Gas (Arizona S)	Jan-22	350
Tenn Z5 NY	Nov-13	350	Nova (TCPL BC Groundbirch)	Jan-22	1,344
TETCO TEAM 2013	Nov-13	500	White River Hub	Jan-23	500
Transco Z6 (Leidy to NYC)	Nov-13	250	Florida Gas (Panhandle)	Jan-25	247
Florida Gas (Mkt Northern)	Jan-14	500	KM Border Pipeline	Jan-25	300
Southern Crossing	Jan-14	400	PEMEX – SW	Jan-25	300
Enterprise Tex (Valero/Teco)	Jun-14	200	SoCal Northern Zone	Jan-25	250
LNG Manzanillo Header	Jul-14	500	Transwestern (Top. to Calpine)	Jan-25	80
Algonquin (NJ NY)	Nov-14	799	DCP E TX Carthage Gathering	Jan-27	250
Tenn Z5 NJ	Nov-14	636	Florida Gas (Panhandle/Z3)	Jan-30	430
CrossTex North Texas	Jan-15	750	Florida Gas (Z2)	Jan-30	460
El Paso (Samalayuca)	Jan-15	312	Kern River (CA/ML/NV)	Jan-30	500
Enterprise Jonah Gath (WY)	Jan-15	600	Kern River (Opal to Muddy Ck)	Jan-30	500
Florida Gas (Panhandle/Z3)	Jan-15	500			

NAVIGANT

Appendix C: Supply Disposition Tables

U.S. Supply Disposition (Bcfd) – *Oregon LNG Reference Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	*62.4*	4.1	0.7	4.8	-0.3	0.0	**66.9**
2013	*63.4*	4.6	0.7	5.3	-0.1	0.0	**68.6**
2014	*64.6*	4.4	0.8	5.2	0.0	0.0	**69.8**
2015	*66.1*	4.2	0.4	4.6	0.0	0.0	**70.7**
2016	*67.6*	3.8	-0.2	3.6	0.0	0.0	**71.1**
2017	*68.8*	3.8	-0.7	3.1	0.0	0.0	**71.9**
2018	*69.8*	3.7	-1.1	2.7	0.0	0.0	**72.5**
2019	*70.5*	3.6	-1.1	2.5	0.0	0.0	**73.1**
2020	*71.1*	3.4	-1.1	2.3	0.0	0.0	**73.4**
2021	*71.8*	3.4	-1.0	2.4	0.0	0.0	**74.1**
2022	*72.4*	3.3	-1.0	2.3	0.0	0.0	**74.7**
2023	*73.0*	3.2	-1.0	2.2	0.0	0.0	**75.2**
2024	*73.3*	3.2	-1.0	2.2	0.0	0.0	**75.5**
2025	*74.0*	3.3	-1.0	2.3	0.0	0.0	**76.2**
2026	*74.4*	3.3	-1.0	2.3	0.0	0.0	**76.7**
2027	*75.0*	3.3	-1.0	2.3	0.0	0.0	**77.2**
2028	*75.4*	3.2	-1.0	2.2	0.0	0.0	**77.5**
2029	*76.1*	3.2	-1.0	2.2	0.0	0.0	**78.3**
2030	*76.7*	3.1	-1.0	2.1	0.0	0.0	**78.8**
2031	*77.2*	3.1	-1.0	2.2	0.0	0.0	**79.3**
2032	*77.6*	3.1	-1.0	2.1	0.0	0.0	**79.6**
2033	*78.3*	3.0	-0.9	2.1	0.0	0.0	**80.4**
2034	*78.8*	3.0	-0.9	2.1	0.0	0.0	**80.9**
2035	*79.4*	2.9	-0.9	2.0	0.0	0.0	**81.5**
2036	*79.6*	3.0	-0.9	2.1	0.0	0.0	**81.6**
2037	*79.9*	3.0	-0.9	2.1	0.0	0.0	**82.0**
2038	*80.1*	3.1	-0.8	2.2	0.0	0.0	**82.2**
2039	*80.2*	3.1	-0.8	2.3	0.1	0.0	**82.5**
2040	*80.2*	3.2	-0.8	2.4	0.0	0.0	**82.6**
2041	*80.4*	3.2	-0.8	2.4	0.0	0.0	**82.8**
2042	*80.5*	3.3	-0.8	2.5	0.0	0.0	**83.0**
2043	*80.7*	3.4	-0.8	2.6	0.0	0.0	**83.2**
2044	*80.8*	3.3	-0.8	2.5	0.0	0.0	**83.2**
2045	*81.0*	3.2	-0.8	2.4	0.0	0.0	**83.3**

U.S. Supply Disposition (Bcfd) – *Oregon LNG Export Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	*62.4*	4.1	0.7	4.8	-0.3	0.0	**66.9**
2013	*63.4*	4.6	0.7	5.3	-0.1	0.0	**68.6**
2014	*64.6*	4.4	0.8	5.2	0.0	0.0	**69.8**
2015	*66.1*	4.2	0.4	4.6	0.0	0.0	**70.7**
2016	*67.6*	3.8	-0.2	3.6	0.0	0.0	**71.1**
2017	*69.0*	3.9	-1.0	2.9	0.1	0.0	**71.9**
2018	*70.0*	4.1	-1.6	2.5	0.0	0.0	**72.5**
2019	*70.7*	4.2	-1.9	2.4	0.0	0.0	**73.0**
2020	*71.3*	4.1	-2.0	2.1	0.0	0.0	**73.4**
2021	*71.9*	4.4	-2.0	2.3	0.0	-0.1	**74.1**
2022	*72.3*	4.5	-2.0	2.5	0.0	-0.1	**74.7**
2023	*72.8*	4.5	-2.0	2.5	0.0	-0.1	**75.2**
2024	*73.1*	4.5	-2.0	2.4	0.0	0.0	**75.5**
2025	*73.8*	4.5	-2.0	2.5	0.0	-0.1	**76.2**
2026	*74.4*	4.4	-2.0	2.4	0.0	-0.1	**76.7**
2027	*75.0*	4.3	-2.0	2.3	0.0	-0.1	**77.2**
2028	*75.4*	4.2	-2.0	2.2	0.0	0.0	**77.5**
2029	*76.2*	4.1	-2.0	2.1	0.0	-0.1	**78.3**
2030	*76.9*	3.9	-2.0	2.0	0.0	-0.1	**78.8**
2031	*77.4*	3.9	-2.0	1.9	0.0	-0.1	**79.3**
2032	*77.8*	3.8	-2.0	1.8	0.0	0.0	**79.6**
2033	*78.6*	3.7	-1.9	1.8	0.0	-0.1	**80.3**
2034	*79.2*	3.7	-1.9	1.8	0.0	-0.1	**80.9**
2035	*79.8*	3.6	-1.9	1.7	0.0	-0.1	**81.5**
2036	*80.0*	3.7	-1.9	1.8	0.0	0.0	**81.7**
2037	*80.4*	3.6	-1.9	1.7	0.0	-0.1	**82.0**
2038	*80.7*	3.5	-1.8	1.6	0.0	0.0	**82.3**
2039	*81.0*	3.4	-1.8	1.6	0.0	0.0	**82.6**
2040	*81.1*	3.3	-1.8	1.5	0.0	0.0	**82.6**
2041	*81.5*	3.2	-1.8	1.4	0.0	0.0	**82.8**
2042	*81.8*	3.0	-1.8	1.2	0.0	0.0	**83.0**
2043	*82.1*	3.0	-1.8	1.2	0.0	0.0	**83.2**
2044	*82.3*	2.8	-1.8	0.9	0.0	0.0	**83.2**
2045	*82.7*	2.5	-1.8	0.7	0.0	0.0	**83.4**

U.S. Supply Disposition (Bcfd) – *Aggregate Export Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	*62.4*	*4.1*	*0.7*	*4.8*	*-0.3*	*0.0*	**66.9**
2013	*63.4*	*4.6*	*0.7*	*5.3*	*-0.1*	*0.0*	**68.6**
2014	*64.6*	*4.4*	*0.8*	*5.2*	*0.0*	*0.0*	**69.8**
2015	*66.1*	*4.2*	*0.4*	*4.6*	*0.0*	*0.0*	**70.7**
2016	*67.6*	3.8	-0.2	3.6	-0.1	0.0	**71.1**
2017	*70.6*	4.1	-2.6	1.4	0.2	-0.4	**71.8**
2018	*72.4*	4.2	-3.7	0.5	0.0	-0.5	**72.5**
2019	*73.7*	4.4	-4.5	-0.1	0.0	-0.5	**73.1**
2020	*74.8*	4.3	-5.0	-0.7	0.0	-0.5	**73.6**
2021	*75.4*	4.5	-5.0	-0.6	0.0	-0.5	**74.3**
2022	*75.8*	4.6	-5.0	-0.4	0.0	-0.5	**74.9**
2023	*76.3*	4.6	-5.0	-0.4	0.0	-0.5	**75.4**
2024	*76.6*	4.6	-5.0	-0.5	0.0	-0.5	**75.7**
2025	*77.4*	4.6	-5.0	-0.4	0.0	-0.5	**76.4**
2026	*77.9*	4.5	-5.0	-0.5	0.0	-0.5	**76.9**
2027	*78.5*	4.4	-5.0	-0.6	0.0	-0.5	**77.4**
2028	*78.9*	4.3	-5.0	-0.7	0.0	-0.5	**77.8**
2029	*79.8*	4.2	-5.0	-0.8	0.0	-0.5	**78.5**
2030	*80.4*	4.0	-5.0	-0.9	0.0	-0.5	**79.0**
2031	*81.0*	4.0	-5.0	-1.0	0.0	-0.5	**79.5**
2032	*81.3*	3.9	-4.9	-1.0	0.0	-0.5	**79.8**
2033	*82.1*	3.8	-4.9	-1.1	0.0	-0.5	**80.5**
2034	*82.6*	3.8	-4.9	-1.1	0.0	-0.5	**81.0**
2035	*83.3*	3.6	-4.9	-1.3	0.0	-0.5	**81.6**
2036	*83.6*	3.6	-4.8	-1.2	0.0	-0.5	**81.8**
2037	*84.1*	3.4	-4.8	-1.4	0.0	-0.5	**82.3**
2038	*84.6*	3.3	-4.7	-1.5	0.0	-0.5	**82.6**
2039	*85.0*	3.1	-4.7	-1.6	0.0	-0.5	**83.0**
2040	*85.3*	3.0	-4.7	-1.7	-0.1	-0.5	**83.1**
2041	*85.9*	2.8	-4.8	-2.0	0.0	-0.5	**83.4**
2042	*86.2*	2.7	-4.8	-2.0	0.0	-0.5	**83.7**
2043	*86.6*	2.7	-4.8	-2.1	0.0	-0.5	**84.0**
2044	*86.9*	2.5	-4.8	-2.2	0.0	-0.5	**84.1**
2045	*87.3*	2.4	-4.8	-2.4	0.0	-0.5	**84.4**

Appendix D: Consumption Disposition Tables

U.S. Natural Gas Consumption by End Use (Bcfd) – *Oregon LNG Reference Case*							
Year	Lease & Plant Fuel	Pipeline & Distribution Use	Res/ Comm	Industrial	Vehicle Fuel	Electric Power	Total Consumption
2012	3.2	2.2	21.8	18.6	0.1	20.9	**66.9**
2013	3.2	2.2	21.9	18.7	0.1	22.5	**68.6**
2014	3.2	2.3	21.9	18.6	0.1	23.6	**69.8**
2015	3.3	2.3	21.9	18.6	0.1	24.5	**70.7**
2016	3.2	2.3	21.9	18.4	0.2	25.2	**71.1**
2017	3.2	2.3	22.0	18.4	0.2	25.8	**71.9**
2018	3.2	2.3	22.0	18.4	0.2	26.4	**72.5**
2019	3.2	2.4	22.0	18.4	0.2	27.0	**73.1**
2020	3.2	2.3	21.9	18.3	0.2	27.4	**73.4**
2021	3.2	2.4	22.0	18.3	0.2	28.0	**74.1**
2022	3.2	2.4	22.0	18.3	0.2	28.5	**74.7**
2023	3.2	2.4	22.0	18.3	0.3	28.9	**75.2**
2024	3.2	2.4	22.0	18.3	0.3	29.4	**75.5**
2025	3.2	2.4	22.1	18.3	0.3	29.9	**76.2**
2026	3.2	2.4	22.1	18.3	0.3	30.4	**76.7**
2027	3.2	2.4	22.1	18.3	0.4	30.8	**77.2**
2028	3.2	2.4	22.0	18.2	0.4	31.2	**77.5**
2029	3.3	2.4	22.1	18.3	0.4	31.8	**78.3**
2030	3.3	2.4	22.1	18.3	0.4	32.3	**78.8**
2031	3.3	2.5	22.1	18.2	0.4	32.7	**79.3**
2032	3.3	2.5	22.1	18.2	0.5	33.1	**79.6**
2033	3.3	2.5	22.1	18.2	0.5	33.7	**80.4**
2034	3.3	2.5	22.2	18.2	0.5	34.2	**80.9**
2035	3.3	2.5	22.2	18.2	0.5	34.7	**81.5**
2036	3.4	2.5	22.1	18.1	0.5	35.0	**81.6**
2037	3.4	2.5	22.1	18.1	0.5	35.3	**82.0**
2038	3.4	2.6	22.2	18.1	0.5	35.5	**82.2**
2039	3.4	2.6	22.2	18.1	0.6	35.7	**82.5**
2040	3.4	2.6	22.1	18.0	0.6	35.9	**82.6**
2041	3.4	2.6	22.2	18.0	0.6	36.0	**82.8**
2042	3.4	2.6	22.2	18.0	0.6	36.1	**83.0**
2043	3.4	2.6	22.2	18.1	0.6	36.3	**83.2**
2044	3.4	2.6	22.2	18.0	0.6	36.4	**83.2**
2045	3.4	2.6	22.2	17.9	0.7	36.5	**83.3**

U.S. Natural Gas Consumption by End Use (Bcfd) – *Oregon LNG Export Case*							
Year	Lease & Plant Fuel	Pipeline & Distribu-tion Use	Res/ Comm	Industrial	Vehicle Fuel	Electric Power	Total Consump-tion
2012	3.2	2.2	21.8	18.6	0.1	20.9	**66.9**
2013	3.2	2.2	21.9	18.7	0.1	22.5	**68.6**
2014	3.2	2.3	21.9	18.6	0.1	23.6	**69.8**
2015	3.3	2.3	21.9	18.6	0.1	24.5	**70.7**
2016	3.2	2.3	21.9	18.4	0.2	25.2	**71.1**
2017	3.2	2.3	22.0	18.4	0.2	25.8	**71.9**
2018	3.2	2.3	22.0	18.4	0.2	26.4	**72.5**
2019	3.2	2.3	22.0	18.3	0.2	27.0	**73.0**
2020	3.2	2.3	21.9	18.3	0.2	27.4	**73.4**
2021	3.2	2.4	22.0	18.3	0.2	28.0	**74.1**
2022	3.2	2.4	22.0	18.3	0.2	28.5	**74.7**
2023	3.2	2.4	22.0	18.3	0.3	28.9	**75.2**
2024	3.2	2.4	22.0	18.3	0.3	29.4	**75.5**
2025	3.2	2.4	22.1	18.3	0.3	29.9	**76.2**
2026	3.2	2.4	22.1	18.3	0.3	30.4	**76.7**
2027	3.2	2.4	22.1	18.3	0.4	30.8	**77.2**
2028	3.2	2.4	22.0	18.2	0.4	31.2	**77.5**
2029	3.3	2.4	22.1	18.3	0.4	31.8	**78.3**
2030	3.3	2.4	22.1	18.3	0.4	32.3	**78.8**
2031	3.3	2.5	22.1	18.2	0.4	32.7	**79.3**
2032	3.3	2.5	22.1	18.2	0.5	33.1	**79.6**
2033	3.3	2.5	22.1	18.2	0.5	33.7	**80.3**
2034	3.3	2.5	22.2	18.2	0.5	34.2	**80.9**
2035	3.4	2.5	22.2	18.2	0.5	34.7	**81.5**
2036	3.4	2.5	22.1	18.1	0.5	35.1	**81.7**
2037	3.4	2.6	22.1	18.1	0.5	35.3	**82.0**
2038	3.4	2.6	22.2	18.1	0.5	35.5	**82.3**
2039	3.4	2.6	22.2	18.1	0.6	35.7	**82.6**
2040	3.4	2.6	22.1	18.0	0.6	35.9	**82.6**
2041	3.4	2.6	22.2	18.0	0.6	36.0	**82.8**
2042	3.4	2.6	22.2	18.0	0.6	36.1	**83.0**
2043	3.4	2.6	22.2	18.0	0.6	36.2	**83.2**
2044	3.5	2.6	22.2	18.0	0.6	36.3	**83.2**
2045	3.5	2.6	22.2	17.9	0.7	36.5	**83.4**

U.S. Natural Gas Consumption by End Use (Bcfd) – *Aggregate Export Case*							
Year	**Lease & Plant Fuel**	**Pipeline & Distribu-tion Use**	**Res/ Comm**	**Industrial**	**Vehicle Fuel**	**Electric Power**	**Total Consump-tion**
2012	3.2	2.2	21.8	18.6	0.1	20.9	**66.9**
2013	3.2	2.2	21.9	18.7	0.1	22.5	**68.6**
2014	3.2	2.3	21.9	18.6	0.1	23.6	**69.8**
2015	3.3	2.3	21.9	18.6	0.1	24.5	**70.7**
2016	3.2	2.3	21.9	18.4	0.2	25.1	**71.1**
2017	3.3	2.3	21.9	18.4	0.2	25.8	**71.8**
2018	3.3	2.3	21.9	18.3	0.2	26.4	**72.5**
2019	3.3	2.4	22.0	18.3	0.2	26.9	**73.1**
2020	3.3	2.5	21.9	18.2	0.2	27.4	**73.6**
2021	3.3	2.5	22.0	18.3	0.2	28.0	**74.3**
2022	3.3	2.5	22.0	18.3	0.2	28.4	**74.9**
2023	3.3	2.5	22.0	18.3	0.3	28.9	**75.4**
2024	3.3	2.5	22.0	18.3	0.3	29.3	**75.7**
2025	3.3	2.5	22.1	18.3	0.3	29.9	**76.4**
2026	3.4	2.5	22.1	18.3	0.3	30.3	**76.9**
2027	3.4	2.5	22.1	18.3	0.4	30.8	**77.4**
2028	3.4	2.5	22.0	18.2	0.4	31.2	**77.8**
2029	3.4	2.6	22.1	18.2	0.4	31.8	**78.5**
2030	3.4	2.6	22.1	18.2	0.4	32.2	**79.0**
2031	3.4	2.6	22.1	18.2	0.4	32.7	**79.5**
2032	3.4	2.6	22.1	18.1	0.5	33.1	**79.8**
2033	3.5	2.6	22.1	18.2	0.5	33.7	**80.5**
2034	3.5	2.6	22.1	18.1	0.5	34.1	**81.0**
2035	3.5	2.6	22.2	18.1	0.5	34.7	**81.6**
2036	3.5	2.6	22.1	18.0	0.5	35.0	**81.8**
2037	3.5	2.7	22.1	18.0	0.5	35.4	**82.3**
2038	3.6	2.7	22.1	18.0	0.5	35.7	**82.6**
2039	3.6	2.7	22.2	18.0	0.6	35.9	**83.0**
2040	3.6	2.7	22.1	18.0	0.6	36.1	**83.1**
2041	3.6	2.7	22.2	18.0	0.6	36.4	**83.4**
2042	3.6	2.7	22.2	18.0	0.6	36.6	**83.7**
2043	3.6	2.7	22.2	18.0	0.6	36.8	**84.0**
2044	3.6	2.7	22.2	17.9	0.6	37.0	**84.1**
2045	3.7	2.8	22.2	17.9	0.7	37.3	**84.4**

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APPENDIX E: PRICE FORECAST COMPARISON TABLES

Prepared for:
LNG Development Company, LLC (d/b/a/ Oregon LNG)

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April 2012

Appendix E: Price Forecast Comparison Tables

Henry Hub Price Forecast Comparison (Real$/MMBtu)			
Year	*Reference Case*	*Oregon LNG Export*	*Aggregate Export*
2012	$3.87	$3.87	$3.87
2013	$4.26	$4.26	$4.26
2014	$4.06	$4.06	$4.06
2015	$4.01	$4.01	$4.01
2016	$4.22	$4.22	$4.25
2017	$4.42	$4.47	$4.66
2018	$4.58	$4.62	$4.80
2019	$4.66	$4.72	$4.90
2020	$4.71	$4.78	$4.98
2021	$4.77	$4.80	$4.96
2022	$4.85	$4.81	$4.97
2023	$4.95	$4.89	$5.02
2024	$5.01	$4.95	$5.11
2025	$5.10	$5.06	$5.20
2026	$5.19	$5.17	$5.32
2027	$5.32	$5.31	$5.45
2028	$5.42	$5.43	$5.58
2029	$5.59	$5.61	$5.75
2030	$5.74	$5.77	$5.94
2031	$5.93	$5.95	$6.14
2032	$6.11	$6.15	$6.38
2033	$6.38	$6.42	$6.72
2034	$6.64	$6.69	$7.05
2035	$6.86	$6.88	$7.22
2036	$7.01	$6.94	$7.26
2037	$7.25	$7.23	$7.53
2038	$7.41	$7.43	$7.72
2039	$7.54	$7.62	$7.92
2040	$7.54	$7.66	$7.97
2041	$7.71	$7.89	$8.21
2042	$7.82	$8.00	$8.31
2043	$7.90	$8.07	$8.43
2044	$7.99	$8.24	$8.51
2045	$8.07	$8.22	$8.47

NAVIGANT

Sumas Price Forecast Comparison (Real$/MMBtu)			
Year	*Reference Case*	*Oregon LNG Export*	*Aggregate Export*
2012	$3.50	$3.50	$3.50
2013	$3.79	$3.79	$3.79
2014	$3.61	$3.61	$3.61
2015	$3.60	$3.60	$3.60
2016	$3.86	$3.86	$3.88
2017	$4.03	$4.12	$4.26
2018	$4.17	$4.25	$4.38
2019	$4.25	$4.37	$4.49
2020	$4.30	$4.45	$4.58
2021	$4.36	$4.47	$4.56
2022	$4.44	$4.45	$4.54
2023	$4.53	$4.51	$4.58
2024	$4.60	$4.59	$4.68
2025	$4.69	$4.71	$4.79
2026	$4.77	$4.82	$4.91
2027	$4.89	$4.97	$5.04
2028	$4.98	$5.08	$5.16
2029	$5.14	$5.26	$5.33
2030	$5.31	$5.45	$5.53
2031	$5.48	$5.63	$5.73
2032	$5.66	$5.83	$5.97
2033	$5.90	$6.08	$6.29
2034	$6.16	$6.35	$6.61
2035	$6.38	$6.56	$6.80
2036	$6.52	$6.57	$6.83
2037	$6.73	$6.86	$7.10
2038	$6.86	$7.07	$7.30
2039	$6.96	$7.26	$7.50
2040	$6.94	$7.29	$7.53
2041	$7.09	$7.50	$7.76
2042	$7.19	$7.60	$7.88
2043	$7.24	$7.68	$8.02
2044	$7.34	$7.81	$8.06
2045	$7.42	$7.80	$8.05

An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon

April 9, 2012

ECONorthwest
ECONOMICS • FINANCE • PLANNING

Introduction

This report summarizes an economic impact analysis of a proposed natural gas project in Northwest Oregon and Southwest Washington. LNG Development Company, LLC (d/b/a Oregon LNG) and Oregon Pipeline Company, LLC plan to build and operate liquefied natural gas ("LNG") exporting/receiving terminal and natural gas pipeline (collectively, the "Oregon LNG" project). ECONorthwest was retained by Oregon LNG to determine the economic impacts from the construction and a typical year of full operations of the project.

The Oregon LNG Project

Oregon LNG can operate as either an importer or exporter of natural gas, depending on market conditions. As an importer, the terminal would receive LNG from oceangoing vessels, gasify the LNG into natural gas, and send the natural gas through the Oregon Pipeline onto interstate pipelines. The gas would eventually be consumed by end-users mostly in the United States.

As an exporter, natural gas originating from domestic and Canadian wells would be shipped through interstate pipelines into the Oregon Pipeline, and then delivered to the LNG Terminal. There the natural gas would be cooled down into liquefied natural gas and loaded onto oceangoing vessels for export.

Given current market conditions and the abundance of developable natural gas reserves in western Canada and the United States, Oregon LNG anticipates that it would operate primarily as an exporter. This analysis is based upon that model.

The LNG Terminal would consist of equipment to support ship berthing for LNG loading and offloading, two containment LNG storage tanks, equipment to vaporize imported LNG, equipment to liquefy the natural gas for export, equipment to treat the natural gas prior to liquefaction, and a variety of administrative and support facilities. The LNG Terminal is proposed on the East Skipanon Peninsula ("ESP") in the City of Warrenton, Oregon at river mile eleven ("RM 11") along the Columbia River.

Natural gas will flow to and from the terminal *via* an 86-mile long pipeline, which will interconnect with downstream pipelines and markets. The 36-inch-outside-diameter pipeline, buried approximately five-feet underground, will extend from the LNG Terminal to the proposed point of interconnection with the interstate natural gas pipeline system of Williams Northwest Pipeline Company in the vicinity of the City of Woodland, Washington.

The pipeline also includes an electrically driven gas compressor station at approximately pipeline milepost 81 on the south bank of the Columbia River in Columbia County, Oregon. The aboveground compressor station ensures the desired pressure is available for liquefaction.

Major Findings

This report summarizes the economic impacts of both the construction and operations of the Oregon LNG facilities. For the construction phase, impacts were measured for the combined economies of Oregon and Washington, as the majority of the workers and many of the goods and services used would come from these two states. The analysis of construction shows:

- The finished value of the pipeline, terminal, and plant would be about $6.32 billion. Construction would support another $5.76 billion in output between 2014 and 2018.

- In the average year there would be 2,608 workers from Oregon and Washington earning $429.4 million in wages and benefits. This would vary from 1,550 to 3,313 depending upon the year.

Once fully operational, Oregon LNG would employ workers in Clatsop County. Through its payroll spending, and purchases of goods and services, Oregon LNG is forecast to have the following major impacts on the Clatsop County economy in 2019:

- Direct output of $6.23 billion, and total output of $6.36 billion.

- Direct labor income of $14.4 million, and $32.1 million in labor income elsewhere in the economy.

- 147 jobs at Oregon LNG and 496 jobs elsewhere in the county.

Employee shopping and commuting patterns, as well as the broad array of suppliers outside of the immediate county, will cause economic impacts to migrate beyond Clatsop County. When measured for all of Oregon, and in the two nearby southwest Washington counties of Cowlitz and Pacific, the economic impacts of Oregon LNG operations would be as follows in 2019:

- Total output of $6.55 billion.

- Direct labor income of $14.7 million, and $87.9 million in labor income elsewhere in the economy.

- A total of 1,591 jobs in other business sectors.

Section II

Scope of Analysis

Economic impact studies measure the annual effects of projects on employment, income, and other economic metrics. Researchers begin by defining the project, the economic area over which the effects are being measured, and the sources of impacts being included or excluded.

Project Dimensions

Terminal and plant construction is anticipated to begin in the third quarter of 2014 and continue for 48 months. The first phase would be complete in the third quarter of 2017 and the full build-out is expected complete and operational by the end of 2018.

Terminal and plant construction costs are $5.83 billion. The analysis assumes costs are distributed evenly by month over the entire 48-month construction period. Thus, the impact study assumes that one-eighth of the construction work would occur in the first and last years, 2014 and 2018, and one-fourth in the years 2015, 2016, and 2017. All of the construction put-in-place will occur in Warrenton in Clatsop County, Oregon.

Construction of the 86-mile pipeline will begin in the third quarter of 2014 and completed in 36-months. The pipeline would extend through five counties. In Oregon, 41 miles would be in Clatsop County, 38 miles in Columbia, three miles in Tillamook, and less than one mile in Washington County. Four miles of the pipeline would be in Cowlitz County, Washington. The cost of the pipeline would be $508.7 million.

Construction costs exclude asset transfers, such as land and right-of-way purchases, and financing. Such items, although they are project costs, they are not sources of construction output and are typically excluded from economic impact studies.

The nameplate capacity of the terminal is 9.47 million metric tonnes a year (MMtpy) of LNG. However, due to routine maintenance, the analysis assumes the facility would operate at a 95 percent capacity factor. Therefore, the long-term sustainable output for the Terminal would be 9.0 MMtpy.

Similarly, at full build-out, the Pipeline would operate at about a 95 percent level. The nameplate capacity is 1.3 billion cubic feet (Bcf) a day. At 95 percent of capacity, it would deliver about 1,242 million cubic feet (MMcf) a day to the Terminal. This level is assumed in the analysis for the year 2019. The analysis assumes there are no other users of natural gas along the Pipeline. The Pipeline would use an electric compressor located at milepost 81 along with a gas pretreatment facility.

A summary of the values, volumes, and energy contents of the facilities in 2019 are shown in Table 1.

Table 1: Project capacity, natural gas use, and output in 2019

Capacity Measure	Daily	Annual
LNG exports, metric tonnes:		
Nameplate capacity	25,954	9,470,000
Projected 95% of capacity	24,656	9,000,000
Gas throughput to terminal (MMcf):		
For use in LNG	1,236	451,269
For use at terminal	6	2,190
Total natural gas throughput	1,242	453,459
LNG exports at 95% of capacity:		
Metric tonnes	24,656	9,000,000
Cubic meters	57,919	21,141,649
MMBtu	1,248,717	455,781,690
Vessels*	less than one	124
Value of LNG output, fob Warrenton (2012 $):		
LNG export price $/MMBtu	$13.32	$13.32
LNG exports (MMBtu)	1,248,717	455,781,690
Value of LNG terminal output	$16,629,181	$6,069,651,210
Value of Oregon Pipeline output (2012 $):		
Pipeline tariff ($/MMBtu)	$0.36	$0.36
Pipeline throughput (MMBtu)	1,254,777	457,993,590
Value of pipeline output	$451,720	$164,877,692

** Vessels are assumed to each carry 170,000 cubic meters of LNG.*
Source: ECONorthwest analysis of data provided by Oregon LNG.

The energy content of natural gas and LNG varies from one project to the next. For this analysis, based on estimates from Oregon LNG, a cubic foot of natural gas at the Terminal will contain 1,010 British thermal units (Btu). A metric tonne of LNG from the Terminal would contain about 50.6 million Btu (MMBtu) of energy and fill about 2.35 cubic meters. The average held per oceangoing vessel from the Terminal would be 170,000 cubic meters.

When operating at 95 percent of capacity in 2019, the Terminal would need 1,242 million cubic feet (MMcf) of natural gas a day, of which all but 6 MMcf would be contained in the LNG for export.

The daily LNG output would contain 1,248,717 MMBtu and be worth, loaded onto a vessel for export from Warrenton, over $16.6 million. Annual exports would be in excess of six billion dollars.

Although this analysis forecasts operations as an LNG export facility, the Terminal would be designed to import LNG as well. The maximum import capacity of the Terminal is 0.5 Bcf/day.

To deliver the gas to the terminal, the Oregon Pipeline would need throughput of 1,254,777 MMBtu a day. The value of the pipeline output (transportation charge) per day is $451,720. Annually, Pipeline output is estimated at $165 million.

Scope of the Impact Study

This analysis forecast the economic impacts of construction for each year individually from 2014 through 2018. The economic impact analysis of operations is based on projections for 2019, which is the first full year after build out year.

All monetary values in this report are expressed in 2012 dollars. Therefore, the economic impacts do not include forecasts of general inflation.

Economic Study Area - Construction

The appropriate area for an impact study is one that encompasses where the direct construction activities occur and where workers, supplies, and services used in that construction predominantly come from. For the construction impact analysis of Oregon LNG, the economic study area is Oregon and Washington states.

Given the Project's size and complexity, it would draw in resources from throughout Oregon and Washington. For the Terminal there is an abundance of available skilled craft labor in the Portland Metropolitan Area, which is within a 90-minute commuting range of Warrenton. A greater amount of skilled labor can be drawn from the Seattle-Tacoma Metropolitan Area, which is two to three hours from Warrenton.

Natural gas pipeline construction labor is more specialized. Typically, workers skilled in gas pipeline welding are drawn from outside the region. The analysis assumes that half of these workers would come from states other than Oregon and Washington.

Besides labor, the two states can supply many of the services and materials needed for construction. For example, natural gas pipeline is manufactured in Portland, as is steel plate, pumps, and other heavy equipment. Thus, this study defines the economic area for construction impacts as the states of Oregon and Washington combined.

Economic Study Area - Operations

This analysis measured the economic impacts of operations for two different study areas.

The principal economic study area for operations would be Clatsop County because it is the location of the LNG Terminal and where the majority of employees would live. According to recent census data, 92 percent of all workers in Clatsop County also reside in Clatsop County.[1]

The second study area is larger. It includes all of Oregon, including the two adjacent Washington State counties of Pacific and Cowlitz (where the Pipeline ends). This larger area encompasses most of the suppliers of goods and services used by the Terminal and Pipeline. It is where all workers would probably reside. According to the Census, residents of the Portland Metropolitan Area, and Cowlitz and Pacific counties hold over six percent of the jobs in Clatsop County.

[1] 2000 U.S. Census worker flow data http://www.census.gov/hhes/commuting/ accessed March 26, 2012.

Construction Costs of the Project

CH2M HILL provided detailed construction cost estimates to ECONorthwest. These costs included construction of the pipeline, LNG plant, and marine terminal. ECONorthwest allocated construction cost contingencies *pro rata* among cost categories. Costs were also distributed *pro rata* to each calendar month of the construction period.

As shown in Table 2, the expected cost of the marine terminal and process plant is $5.83 billion, while the pipeline is $485 million. Overall, the Project would cost $6.39 billion.

Table 2: Project construction costs by element and component, millions of 2012 dollars

Project Element / Component	Labor Costs	Materials & Equipment	Other Costs	Total
Marine Terminal & Process Plant				
Berthing Facility & Tugboats	$27	$85	$4	$116
Trestle and Pier	8	13	2	23
Intake Structure	0	0	0	1
Site Grading, Foundations, & Water / Wastewater	308	298	20	626
Bi-directional Terminal	727	2,413	110	3,250
Substation	1	22	0	23
Power Transmission Line	26	49	0	75
Contractors' Overhead & Profit	198	518	24	740
Engineering, Construction Management, Survey, etc.	971	3	0	974
Total	**$2,266**	**$3,402**	**$160**	**$5,828**
Pipeline				
Oregon Pipeline Construction (85-miles of 36" pipe)	$98	$150	$26	$274
Horizontal Directional Drilling Under the Columbia River	2	4	0	6
Compressor Station	12	40	1	53
Gas Treatment at Compressor Station	2	27	0	29
Contractors' Overhead & Profit	21	41	1	63
Engineering, Construction Management, Survey, etc.	59	0	0	59
Total	**$195**	**$261**	**$28**	**$485**
Freight Costs				$26
Performance Bonds				48
Total Project Costs				**$6,386**
Less Right-of-Way costs				(22)
Less Performance Bonds				(48)
Total Costs Counted in Output				**$6,317**

Sources: Construction estimate provided by Mark Bricker, Vice-President of CH2M HILL, by email to ECONorthwest dated March 15, 2012.

Note: Costs include 25% construction contingency. Totals may not add due to rounding.

Not all construction expenditures have economic impacts. Some costs, such as performance bonds, were not included in the economic impact model because they do not affect the finished value of the Project.

ECONorthwest worked with the Oregon LNG development team to understand procurement expectations for various labor, materials, and equipment. Many of these needs could be supplied from businesses within Oregon and Washington. For instance, the Oregon State Building and Construction Trades Council estimates that Oregon and Washington union members could provide about 90 percent of the labor needed for LNG plant and terminal construction. For the pipeline, 50 percent of construction labor is assumed to come from outside the study area.

These assumptions reflect the best estimates available. Ultimate procurement decisions and supplier capacity may affect these assumptions.

Table 3: Project labor requirements by element and component

Project Element / Component	Total Worker Hours
Marine Terminal & Process Plant	
Berthing Facility & Tugboats	704,442
Trestle and Pier	208,719
Intake Structure	8,390
Site Grading, Foundations, & Water / Wastewater	8,038,306
Bi-directional Terminal	18,988,019
Substation	22,950
Power Transmission Line	685,352
Total	**28,656,177**
Pipeline	
Oregon Pipeline Construction (85-miles of 36" pipe)	2,279,225
Horizontal Directional Drilling Under the Columbia River	47,677
Compressor Station	283,643
Gas Treatment at Compressor Station	46,926
Total	**2,657,472**
Project Total	**31,313,648**

Sources: Construction estimate provided by Mark Bricker, Vice-President of CH2M HILL, by email to ECONorthwest dated March 15, 2012.
Note: Worker hours reflect 25% increase for construction contingencies.

Construction Timeline

Construction of the Project would begin in the second half of 2014 and become fully operational by the end of 2018. Construction of the terminal and LNG plant would take 48 months, while the pipeline would take 36 months. The pipeline would be operational by the second half of 2017. Project spending in each year is shown in Table 4.

Table 4: Project construction costs by element and year, millions of 2012 dollars

Year	Terminal & Plant	Pipeline	Total
2014	$729	$81	$809
2015	1,457	162	1,619
2016	1,457	162	1,619
2017	1,457	81	1,538
2018	729	-	729
Total	$5,828	$485	$6,313
Average	$1,166	$97	$1,263

Sources: ECONorthwest analysis of data provided by CH2M HILL. Averages are for five years.

The Project's EPC contractor would directly hire individuals and subcontractors. Both types of workers are considered direct jobs of the Project in this analysis. The number of workers on site each year is shown in Table 5. The Project will directly employ an average of 3,011 workers in each of the five construction years. These workers would consist of highly skilled tradespeople, including pipefitters, metalworkers, cement masons, and electricians.

Table 5: Project construction workers by element, year, and place of residence

Year	Terminal & Plant	Pipeline	Total
Oregon & Washington Residents			
2014	1,550	106	1,656
2015	3,100	213	3,313
2016	3,100	213	3,313
2017	3,100	106	3,206
2018	1,550	-	1,550
Average	2,480	128	2,608
All Workers			
2014	1,722	213	1,935
2015	3,444	426	3,870
2016	3,444	426	3,870
2017	3,444	213	3,657
2018	1,722	-	1,722
Average	2,755	256	3,011

Sources: ECONorthwest analysis of data provided by CH2M HILL. Averages are for five years.

Construction worker wages are shown in Table 6. Those building the terminal and LNG plant will earn an average of about $165,000 per year in wages and benefits. Those working on the pipeline will earn about $152,000 yearly. Spending by employees from outside the study area is assumed to be $50 per working day.

Table 6: Project construction workers wages by element, year, and place of residence, in millions of 2012 $

Year	Terminal & Plant	Pipeline	Total
Oregon & Washington Residents			
2014	$256	$16	$272
2015	512	32	545
2016	512	32	545
2017	512	16	529
2018	256	-	256
Total	$2,050	$97	$2,147
All Workers			
2014	$285	$32	$317
2015	569	65	634
2016	569	65	634
2017	569	32	602
2018	285	-	285
Total	$2,278	$195	$2,472

Sources: ECONorthwest analysis of data provided by CH2M HILL.

Economic Impacts

An economic impact analysis measures the effects of a project on the economy of a set geographic area for a single year. Those effects may have lingering benefits causing economic growth in future years, but in the type of analysis done for this report, only the more immediate impacts felt in one year are measured.

For this report, seven different economic impact analyses were run. For the Project's construction, there were five impact studies or one for each year of construction from 2014 through 2018. Operations are analyzed for just 2019, but their impacts were measured for two different geographic areas (also known as study areas or local economies). The first operations analysis considered the impacts of the Project on Clatsop County. The second analysis counts the economic impacts of operations in 2019 on the economies of the state of Oregon plus Cowlitz and Pacific counties in Washington.

An impact analysis measures the effects of a project that occur directly in the economy (employment at the construction site, spending by the pipeline operator, and purchases of equipment by the terminal, for example). These direct impacts cause further spending and employment elsewhere in the economy resulting in subsequent *secondary* impacts. The tool used to estimate what the total impacts would be is an economic impact model.

Economic Impact Model

ECONorthwest estimated the impacts of Oregon LNG using the economic modeling software IMPLAN (Impact Analysis for Planning). IMPLAN calculates economic impacts in a transparent manner using well-known and robust data sources for its calculations. This transparency allows for the inclusion of data specific to the Oregon LNG, rather than relying on industry averages, which are poor substitutes for describing something as specialized as an LNG terminal.

Oregon LNG provided spending and payroll estimates for both the construction of their project and a post build-out operating year. ECONorthwest excluded Project spending from vendors based outside of the study areas, as these would have no significant downstream impacts on the local economy.

Similarly, the effects of employee wage and salary spending by workers who do not permanently live in the study area have no downstream effects. The exception is any *per diem* spending from pipeline and terminal construction workers. That does cause secondary economic impacts on the local economy.

IMPLAN was developed as a product of the Rural Development Act of 1972 by the U.S. Forest Service in cooperation with FEMA and the Department of the Interior. It is economic modeling software that creates regional input-output models based on county-level data. The Forest Service made IMPLAN widely available. The relationship among university-based researchers, USDA extension specialists, and the Forest Service became bilateral. Researchers and specialists questioned data and assumptions, made suggestions, and recommended changes.

To accommodate this feedback, the U.S. Forest Service privatized IMPLAN and it is now operated by the Minnesota IMPLAN Group ("MIG"). In addition to updating and improving the databases and software, MIG holds regular training sessions, biannual user conferences, and maintains a collection of hundreds of papers that have used IMPLAN.

Industry Data

IMPLAN divides the economy into 440 sectors including government, farms, and various industries. For each sector, IMPLAN allocates spending and employment impacts between the local and non-local economies.[2] The IMPLAN data comes from the U.S. Economic Census, U.S. Bureau of Labor Statistics, IRS, and other government statistical sources.

From this data, IMPLAN approximates how, from where, and on what products and services various local industries spend money. It also estimates paid employees, wages, and benefits. For self-employed jobholders, IMPLAN estimates the number of proprietors and their average incomes.

ECONorthwest replaced the default estimates of IMPLAN with actual spending and payroll budget data from Oregon LNG covering the construction and operations phases of the Project. In doing so the models reflect more accurately what would happen in the economy should the terminal and pipeline be built.

When fed into IMPLAN, the total impacts of the Project's spending and employment, as they flow through the modeled subject area economies, were determined. IMPLAN calculates the total impact by sector, according to the supply lines linking the various economic sectors in the economy.

With each additional transaction away from the source impact (*i.e.*, the initial level of expenditures at construction sites and at Oregon LNG operations), the amounts diminish due to the effects of savings, taxes, and purchases and employment from outside the study area. For what stays local, for each round of spending and the employment it provides, more is added to the initial impact. In the end, the total regional economic impacts exceed the initial impact from the Project. Economists call this the *multiplier effect*.

[2] IMPLAN production function and regional purchase coefficient data were used when Project specific data was not available.

Impact Levels

Transactions (and employment) occur at three different levels depending on how removed they are from the initial source. For this analysis those levels are:

- **Direct impacts:** Those that happen at the initial source, which in this analysis are at the terminal and pipeline construction sites in 2014 through 2018, or at their operations in 2019.
- **Indirect impacts:** An indirect impact is one that occurs because of business-to-business transactions. Thus, when Oregon LNG buys natural gas pipeline from a manufacturer in Portland, Oregon, that purchase causes an indirect impact in the form of higher output, employment, and business income. That would also represent a first round of indirect impacts. An example of a second round would be if the manufacturer buys steel plate needed to make the pipe from a steel mill in North Portland. That too is a business-to-business transaction causing an indirect impact. The value of welding equipment bought for the Project adds to the value of the direct impact of construction, but if that equipment comes in from a company in Texas, the value has no indirect impact because Texas is outside the study area.
- **Induced impacts:** An induced impact is one caused by household spending. For example, a supervisor at the LNG terminal who spends her some of her salary at a restaurant in Astoria, Oregon causes a first round of induced impacts. If the waiter at the restaurant earns more money because of her visit, his increased earnings cause him to spend more money locally, for example at a grocery store in Warrenton. That is a second round of induced impact. Because induced impacts originate from household spending, they often are called "consumption-driven" effects. Induced impacts also come from non-local construction workers (itinerant workers) that spend their *per diems* locally.

Direct impacts are sometimes referred to as *primary* impacts because they start where the primary sources of economic activities occur. Induced and indirect together are called *secondary impacts,* and they happen largely away from the primary sources.

The value of IMPLAN is that it can estimate all of the eventual secondary impacts, well beyond the first and second rounds.

Types of Impacts

Impacts are reported using economic measures, such as jobs and income that, while not additive, do provide alternative perspectives for expressing the size of economic effects. The measurements used in this report are:

- **Jobs:** The annual average number of employees, both payroll and self-employed, for either full- or part-time work. An annual average is work for twelve months. Therefore, seven months of work by a steamfitter building the LNG terminal plus five months of work by a pipeline welder together count as one job for one year even though two different people in two different occupations were employed for part of the year.
- **Employee compensation:** Payroll cost of employers. It is the sum of wages, salaries, overtime, benefits (*i.e.*, health insurance, vacation pay, retirement), and employer paid payroll taxes.
- **Proprietor income:** Earnings of self-employed workers and farmers. This includes owner-operator businesses.
- **Labor income:** The sum of employee compensation and proprietors' income.
- **Output:** Output is the market value of whatever is produced. For construction projects, it is the cost of building and completing structures excluding land (since land is not something that is produced) and financing costs. Output of a natural gas pipeline is the value of transporting gas or what a pipeline company under normal market conditions would charge for delivering gas. Output for an LNG terminal is the market value of the LNG loaded onto ships for export. If the terminal is importing LNG, then the output is the value of the natural gas it ships out of the terminal into the pipeline.

Results

The following economic impact analyses measure the effects of Oregon LNG. The first estimates the economic impacts of construction over five years. The second measures economic impacts of operating the pipeline, terminal, and LNG plant.

Construction Impacts

The direct output of constructing Oregon LNG is the gross, put-in-place value of the pipeline, terminal, and LNG plant. Total direct output, shown on Table 7, is $6.34 billion. The direct output of each individual Project element was previously reported in Table 2.

In addition, indirect output would also result from spending on goods and services. Induced output would come from employees spending income earned from the Project. Together, the total gross economic output in Oregon and Washington between 2014 and 2018 is $12.1 billion, or $2.4 billion per year.

Table 7: Construction output impacts in Oregon and Washington, 2014 – 2018, millions of 2012 $

	Direct	Indirect	Induced	Total
Terminal & Plant	$5,828	$2,546	$2,785	$11,160
Pipeline	485	235	172	891
Freight	26	10	16	52
Total	$6,338	$2,791	$2,972	$12,102
Output by year:				
2014	$812	$359	$379	$1,550
2015	1,625	717	757	3,100
2016	1,625	717	757	3,100
2017	1,544	678	729	2,951
2018	732	320	350	1,401

Source: ECONorthwest impact analysis of construction spending.

The direct labor income of construction is the payroll cost of Oregon LNG workers. These values were provided in construction cost estimates, except for freight workers, whose wages were calculated using average transportation wages in the region. Table 8 reports all labor income impacts by year and type.

Direct labor income would equal about $2.47 billion. Another $1.77 billion in labor income would come *via* indirect and induced impacts. Construction would contribute $4.24 billion in labor income for the combined economies of Oregon and Washington over five years.

Table 8: Construction labor income impacts in Oregon and Washington, 2014 – 2018, millions of 2012 $

	Direct	Indirect	Induced	Total
Terminal & Plant	$2,266	$710	$922	$3,898
Pipeline	195	68	57	320
Freight	12	4	5	21
Total	$2,472	$782	$984	$4,238
Labor income by year:				
2014	$317	$101	$125	$543
2015	634	201	251	1,086
2016	634	201	251	1,086
2017	602	190	241	1,033
2018	285	89	116	490

Source: ECONorthwest impact analysis of construction spending.

Construction jobs include both employees of the prime contractor as well as subcontractors. Direct jobs were calculated using a full-time worker capacity of 2,080 hours per year.

Construction would directly employ the full-year equivalent of 3,054 workers a year. Another 2,579 indirect and 4,805 induced jobs throughout the study area would be supported by Oregon LNG’s construction. These secondary jobs include some part-time and seasonal workers. Total yearly employment in Oregon and Washington would range from 6,042 to 13,369.

Table 9: Construction jobs impacts in Oregon and Washington, 2014 – 2018, annual averages

	Direct	Indirect	Induced	Total
Terminal & Plant	2,755	2,327	4,502	9,584
Pipeline	256	237	278	771
Freight	43	15	25	84
Total	3,054	2,579	4,805	10,438
Jobs by year:				
2014	1,962	1,661	3,061	6,684
2015	3,924	3,322	6,123	13,369
2016	3,924	3,322	6,123	13,369
2017	3,711	3,125	5,891	12,726
2018	1,749	1,464	2,830	6,042
Average	3,054	2,579	4,805	10,438

Source: ECONorthwest impact analysis of construction spending.

Operations Impacts

CH2M HILL provided estimates for annual operating expenses of the terminal and plant. Spending pattern data from IMPLAN was used to estimate pipeline operating expenses.

Each year, Oregon LNG expects to spend about $285 million to operate the terminal, plant, and pipeline. These are shown in Table 10. More than 80 percent of all operating expenses are for the electric power needed to operate the LNG plant. These expenditures are important because they drive the impact analysis and yield secondary impacts.

Table 10: Annual operating expenditures, 2012 $

Terminal & Plant	
Direct Labor	$13,946,000
Electricity	222,687,000
Consumable Materials	20,000,000
Vessel Services	9,697,000
Contract Services	6,782,000
Contract Maintenance	5,000,000
Annual Overhauls	5,000,000
Subtotal	$283,112,000
Pipeline	
Direct Labor	$360,000
Services	697,000
Fuels / Energy	697,000
Equipment and Materials	344,000
Subtotal	$2,098,000
Project Total	**$285,210,000**

Source: CH2M HILL; IMPLAN.

Oregon LNG anticipates hiring 149 workers in Oregon. The terminal and plant would require 145 workers, while the pipeline would require 4. Employees usually reside in the same county where they work. Based on commuting data from the U.S. Census, about 129 of Oregon LNG's permanent workforce would live in Clatsop County, while the remaining 20 would reside in the other nearby counties.[3]

The average wage for Oregon LNG's employees would be high. This would lead to many additional impacts in the local and regional economy.

The terminal, plant, and pipeline would all rely on services provided by contractors, such as security and maintenance. These workers and their earnings are counted as indirect impacts. Provisions, piloting services, and other purchases by LNG vessels are also considered indirect impacts.

[3] 2000 U.S. Census worker flow data. For those working in Clatsop County, about 92% reside in other counties. The above calculations reflect pipeline employees who work in other counties.

Oregon LNG would export $6.07 billion worth of LNG per year, requiring $165 million in output by the Oregon Pipeline. This direct spending would lead to another $124 million in output in the county each year.

This would support 643 jobs in total, including 147 directly by Oregon LNG and 437 elsewhere. It would generate $14.4 million in direct labor income, and another $25.0 million and $7.0 million in indirect and induced labor income, respectively.

Table 11: Project operations impacts in Clatsop County, 2019, thousands of 2012 $

	Direct	Indirect	Induced	Total
Output				
Terminal & Plant	$6,069,651	$101,172	$22,335	$6,193,158
Pipeline	164,878	526	103	165,506
Total	$6,234,529	$101,698	$22,437	$6,358,664
Labor Income				
Terminal & Plant	$14,126	$24,870	$6,982	$45,977
Pipeline	311	170	32	513
Total	$14,437	$25,040	$7,014	$46,491
Jobs				
Terminal & Plant	145	260	229	634
Pipeline	2	6	1	9
Total	147	266	230	643

Source: ECONorthwest impact analysis of construction spending.

Expanding the study area beyond Clatsop County causes the impacts to increase. Oregon LNG's impacts would be greater, although its direct output would not change. Each year, it would support total output of $6.55 billion throughout Oregon and Southwest Washington. This would create $102.5 million in labor income, supporting 1,591 jobs.

Table 12: Project operations impacts in Oregon and Southwest Washington, 2019, thousands of 2012 $

	Direct	Indirect	Induced	Total
Output				
Terminal & Plant	$6,069,651	$238,881	$72,190	$6,380,722
Pipeline	164,878	1,099	732	166,709
Total	$6,234,529	$239,980	$72,922	$6,547,431
Labor Income				
Terminal & Plant	$14,305	$62,701	$24,504	$101,510
Pipeline	360	421	248	1,029
Total	$14,665	$63,122	$24,752	$102,540
Jobs				
Terminal & Plant	145	772	654	1,570
Pipeline	4	10	7	20
Total	149	782	660	1,591

Source: ECONorthwest impact analysis of construction spending.

Oregon Personal Income Taxes

Oregon taxes the earnings of people working in the state regardless of their residency. ECONorthwest estimated Oregon personal income tax receipts for all work performed in Oregon due to the construction and operations of Oregon LNG, either from direct, or indirect and induced labor.

The estimates are based on the state tax table of actual 2010 full-year resident returns reported by the Oregon Department of Revenue. By using this table, the analysis accounts for wage rates, and the many complex deductions and credits that affect what workers ultimately pay the state.

Household characteristics that affect total income taxes beyond the earnings of individuals working at or at jobs linked back to Oregon LNG are not counted. So the total impact of Oregon LNG on actual state income tax receipts would be higher than what is presented in Table 13.

Table 13: Net Oregon Personal Income Taxes from Labor Income due to Oregon LNG, 2012 $

Labor sources and years	Net increase in Oregon state personal income taxes paid			
	Direct labor	Indirect labor	Induced labor	Total
Construction, 2014	$20,643,570	$3,344,892	$4,168,903	$28,157,365
Construction, 2015	41,287,139	6,689,785	8,337,807	56,314,731
Construction, 2016	41,287,139	6,689,785	8,337,807	56,314,731
Construction, 2017	39,263,457	6,311,118	8,022,216	53,596,791
Construction, 2018	18,619,887	2,966,226	3,853,313	25,439,426
Total from construction	$161,101,192	$26,001,806	$32,720,045	$219,823,043
Operations, 2019 (reoccur annually)	809,011	$2,698,533	$1,058,190	$4,565,733

Source: ECONorthwest analysis.

For example, a household of a person moving to Oregon to work for the LNG terminal likely has other sources of taxable income. In 2010, the typical Oregon middle-income household earned over 25 percent of their adjusted gross income from sources other than wages. Workers at the terminal are apt to have other taxable income, besides their Oregon LNG wages, as well. In addition, many workers live in households with working spouses and others with taxable income. Thus, jobs due to Oregon LNG will increase other taxable personal income sources to migrate or develop in the state.

The analysis makes adjustments for work occurring outside of Oregon. It is assumed that 90 percent of the secondary labor income resulting from operations would occur in Oregon. Adjustments were made to account for the portion of project construction work done outside Oregon (about 4.65 percent) and the share of secondary impacts out of state (30 percent).

By applying 2010 tax data to just the labor income identified as being directly or secondarily the result of Oregon LNG operations, the analysis finds that the state would receive nearly $4.6 million a year in personal income taxes each year the project operates at its intended rate. Being a capital-intensive business, direct labor income, and therefore income tax receipts, would be only about $0.8 million a year. Most of the tax revenue from operations will come from indirect labor. That is due to the many jobs in marine transportation, public schools, and government services dependent on Oregon LNG.

During the construction phase, total Oregon personal income receipts from 2014 to 2018 would be $219.8 million. Such taxes would come primarily from direct employment ($161.1 million) because of the large numbers of highly compensated construction workers on the jobsites. Indirect labor tax receipts are comparatively less as most of the equipment and construction materials used in building the project would come from outside Oregon.

Corporate Property and Business Taxes

The terminal and pipeline are subject to property taxes. ECONorthwest estimated these using the current property tax rates and applied them to the taxable assessed values, which are assumed to equal the hard construction costs. The assessed value changes over time as physical plant depreciates. Based on a conversation ECONorthwest had with Mr. Michael Olson, principal appraisal analyst of the Oregon Department of Revenue, purchases of replacement plant materials and equipment tends to be offset by this depreciation and hard construction costs are a reasonable estimate of assessed value. Actual property taxes levied, however, will depend on tax rates, limits, and laws at the time.

Based on the data available, the pipeline would be subject to $4,911,851 in property taxes, of which $194,074 would be levied in Cowlitz County, Washington. In Oregon, property taxes on the pipeline would be over $4.7 million a year. The LNG terminal has a substantially higher assessed value and its property is entirely in Oregon. At the current Warrenton property tax rate of $12.62 per thousand, its property taxes would be in excess of $51.9 million a year.

Table 14: Annual Property Taxes from Oregon LNG, 2012 $

Location	Gas Pipeline Miles	Assessed Value ($)	Tax Rate Per Thousand $	Property Tax Imposed ($)
Pipeline:				
Clatsop, OR	41	$184,019,761	$12.26	$2,256,425
Columbia, OR	38	170,554,900	13.54	2,308,929
Tillamook, OR	3	13,464,861	11.11	149,601
Washington, OR	-	170,011	16.60	2,823
Cowlitz, WA	4	17,953,147	10.81	194,074
Total Pipeline	86	$386,162,680	$12.72	$4,911,851
LNG Terminal:				
Warrenton OR		$4,113,988,307	$12.62	$51,918,532
Project Total		$4,500,150,987		$56,830,384

Source: ECONorthwest analysis.

Estimating corporate income taxes for the pipeline was done by applying the share of output in each state and applying it to the most recently reported actual taxes paid by the transportation and warehousing sector, of which pipelines are a major component, as a percent of output. For Oregon, the most recent corporate tax data are for 2009. Applying the rates for that year to the projected output of the Oregon portion of the pipeline yields an estimated income tax of $483,255 per year (in 2012 $). On the Washington side, the business and occupancy tax rate is 1.8 percent, thus the tax due would be $263,570 a year.

Table 15: Annual Corporate Income and Business & Occupancy Taxes from the Operations of Oregon LNG in a Typical Year, 2012 $

Business/Location	State Corp. Tax
In Oregon:	
Pipeline operations	$483,255
LNG terminal	7,479,943
State of Oregon	$7,963,198
In Washington:	
Pipeline operations	$263,570
Washington B&O tax	$263,570
Total state taxes	$8,226,768

Source: ECONorthwest analysis.

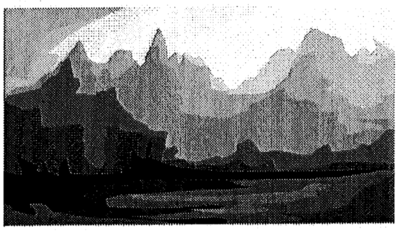
Estimating Oregon corporate income tax for the terminal is challenging because it depends on business operations, which can vary from one year to the next. Rather than speculate, ECONorthwest chose to estimate the tax based on the statewide average manufacturing corporate state income tax as a percent of output and applying it to the forecast output of the LNG terminal. This yields an estimated income tax of nearly $7.5 million. The actual rate in any one year could be substantially higher, especially in cases where the terminal liquefies natural gas as a service provider for another Oregon company, or less if Oregon LNG takes financial possession of all the natural gas it processes and then exports it entirely overseas.

The construction project, with a total cost to open in excess of $6.3 billion, is extremely large by Northwest standards. For comparison, according to McGraw Hill Construction, in the five years 2007 to 2011, the total value of construction for all utilities, power plants, and manufacturing buildings in Oregon was $4.4 billion. Thus, the construction activity engendered by Oregon LNG will produce considerable corporate taxable income in the state. Based on industry averages for construction, from data from the Oregon Department of Revenue, ECONorthwest estimates that over the entire period of building, the Oregon LNG project will produce nearly $4.4 million in state corporate income taxes and about $220,000 in taxes for the State of Washington.

Table 16: Total State Income and B&O Taxes Paid During Construction of the Oregon LNG Project, 2012 $

Construction/Location	State Corp. Tax
In Oregon:	
Pipeline	$344,229
LNG Terminal	4,034,388
Total Oregon Tax	$4,378,618
In Washington:	
Pipeline const. in WA	$220,758
Washington B&O tax	$220,758
Total state taxes	$4,599,376

Source: ECONorthwest analysis.



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Project Managers - Construction Managers - Construction Engineers - Civil Engineers

June 5, 2012

Mr. John A. Andersen
Manager, Natural Gas Regulatory Activities
US Department of Energy
Office of Fossil Energy
Office of Natural Gas Regulatory Activities
PO Box 44375
Washington, D.C. 20026-4375

Subject: Oregon LNG

Dear Mr. Andersen,

Oregon LNG has proposed a $6 billion project for the North Oregon coast to export Canadian gas. This project is an important project for Oregon. Oregon is still feeling the effects of the last recession, particularly on the North Oregon Coast. Unemployment is still endemic and the economic drivers which had previously buoyed economic recoveries in Oregon are no longer available. The previous economy was based on natural resource extraction and must be replaced by new economic opportunities which take advantage of Oregon's location as well as its skilled blue-collar work force.

Oregon LNG is such a project. As the President-Elect of the Oregon Section of the American Society of Civil Engineers I have had the opportunity to travel throughout Oregon and meet many Oregonians and engineers. The message that I get is consistent in that economic opportunities are limited. It is clear that from the construction and engineering perspective the capacity that exists in Oregon is well in excess of the demand. Oregon has traditionally benefited from export to the Far East and this project would build on that existing infrastructure. Given the potential demand for natural gas overseas this facility would also help ease the U.S.'s balance of trade deficit.

This project will put thousands of people to work and add millions of dollars to the local economies. This is particularly relevant at this point in time as the Secure Schools Funding Act has expired and a substantial funding source for many Oregon Coast counties is no longer available. As a result public services have been significantly curtailed in many of the affected counties. This project will help provide replacement funding from a private project.

I would like to lend my voice to those who urge that this project be moved forward as quickly as possible and put Oregonians back to work.

Very truly yours,

Christian F. Steinbrecher, P.E.
President

UNITED BROTHERHOOD OF CARPENTERS AND JOINERS OF AMERICA

Douglas J. McCarron
General President

June 8, 2012

Mr. John A. Anderson
Manager, Natural Gas Regulatory Activities
US Department of Energy
Office of Fossil Energy
Office of Natural Gas Regulatory Activities
P. O. Box 44375
Washington, D.C. 20026-4375

Dear Mr. Anderson:

I write to support the application of the Oregon LNG project in Warrenton, Oregon to be permitted to export LNG to non FTA countries. On behalf of the United Brotherhood of Carpenters, who along with the employees of the Building Trades and other construction trades comprise tens of thousands of employees in Oregon and Washington States, I write to signal our strong support for the project and for DOE approval of this export application.

This project will bring desperately needed jobs to the Northwest. An estimated average of 2,700 skilled workers will help build the more than $6 billion dollar project over a period of five years. Unemployment in the construction industry hovers officially around 17% in this region, twice the general rate of unemployment. Unofficial estimates suggest that number could be as much as double that rate. This $6 billion spent directly on this project will lead to more than $6 billion in additional economic activity in the region. Combined, this investment during the construction period will provide a great boost to the broader economy.

When the Oregon LNG project is complete and operational, it will pump tens of millions of dollars annually into local, state and federal tax coffers, helping with current budget deficits and funding critical governmental functions.

101 Constitution Avenue, N.W. Washington, D.C. 20001 Phone: (202) 546-6206 Fax: (202) 543-5724

Finally, the sale of exports from this project will bring in billions of dollars annually, helping in a significant way to offset our current trade deficit, particularly with Asia. Since the gas will be sourced from western Canada, and is already destined to be exported to Asia (either from Oregon, or Canada), this project should have little or no impact on domestic pricing of natural gas.

I urge you to approve the application in a timely fashion and enable thousands of skilled workers to get back to work and contributing to the economic livelihood of their communities.

Sincerely,

Douglas J. McCarron

Douglas J. McCarron
GENERAL PRESIDENT

DJM/jb

NCA II
www.ncabuild.org
Raymond J. Poupore
Executive Vice President

UNITED BROTHERHOOD of CARPENTERS & JOINERS of AMERICA
Douglas J. McCarron
General President

INTERNATIONAL UNION of OPERATING ENGINEERS
James T. Callahan
General President

NATIONAL CONSTRUCTION ALLIANCE II

HEADQUARTERS: 1634 Eye Street NW, Suite 805 • Washington, DC 20006 • 202-239-4779

June 8, 2012

Mr. John A. Anderson
Manager, Natural Gas Regulatory Activities
US Department of Energy
Office of Fossil Energy
Office of Natural Gas Regulatory Activities
P. O. Box 44375
Washington DC 20026-4375

Dear Mr. Anderson:

The National Construction Alliance II supports Oregon LNG's application to export liquefied natural gas (LNG) to non-Free Trade Act countries.

The National Construction Alliance II (NCA II) – a partnership between two of the nation's leading construction unions, the International Union of Operating Engineers and the United Brotherhood of Carpenters of Joiners of America – represents nearly one-million workers across the United States and Canada, many of whom build the nation's energy infrastructure.

Oregon LNG offers a major economic opportunity to the Pacific Northwest and the nation. The facility proposes to import stranded gas from British Columbia and Alberta, liquefy it in Oregon, and then ship it to Asia. The project will deliver a valuable backup supply to the Pacific Northwest, moderating, to some degree, local demand spikes in natural-gas markets and providing important emergency backup capacity to the region in the event of a supply shock. The project will generate substantial tax revenue for the states of Oregon and Washington, as well as local governments. It will put nearly $12 billion into the local and regional economy, and when operational, it will make a significant dent in our trade deficit with Asia. Most important to the National Construction Alliance II is the project's job-creation potential.

The construction unemployment rate is the highest of any sector of the economy; it is currently 14.2%. In some labor markets around the country, including in part of the Pacific Northwest, the unemployment rate is much higher. Massive industrial projects like Oregon LNG represent game-changing potential for thousands of unemployed Carpenters, Operating Engineers, and other construction workers. This Oregon-based project stands to provide nearly 3,000 skilled workers extended employment over a roughly five-year period, and is expected to deliver approximately 10-million worker-hours to construction craftworkers.

Because this gas is already destined for export to Asia, either from Kitimat, British Columbia, or Oregon, exporting LNG to Asia from this project will not have any additional impact on consumer prices in the United States. Navigant Consulting estimated that the effect on wholesale prices in the Pacific Northwest at the Sumas Hub on the British Columbia/Washington border would be modest, likely amounting to just a few cents per month for the average residential consumer. With the region's natural-gas network connected to Canada, the impact on wholesale prices will occur at the Sumas Hub even if the Department of Energy denies the Oregon LNG application. In this way, LNG export licenses in this region represent a different set of policy choices than other LNG export proposals pending before the Department of Energy.

LNG represents a significant global environmental improvement, displacing higher-emitting electricity generation in Japan and elsewhere. Utilities are scrambling to replace nuclear-based generation in Japan, and this gas will likely displace heavy fuel oil and crude oil, consumption of which has skyrocketed since the crisis at the Fukushima nuclear facility.

On behalf of the nearly one-million members of the Carpenters and Operating Engineers, I urge you to approve Oregon LNG's license to export LNG to non-Free Trade Act countries.

Thank you for your consideration.

Sincerely,

Raymond J. Poupore
Executive Vice President

STEPHEN E. SANDHERR, Chief Executive Officer

AGC of America
THE ASSOCIATED GENERAL CONTRACTORS OF AMERICA
Quality People. Quality Projects.

June 12, 2012

Mr. John A. Anderson
Manager, Natural Gas Regulatory Activities
US Department of Energy
Office of Fossil Energy
Office of Natural Gas Regulatory Activities
P. O. Box 44375
Washington DC 20026-4375

Dear Mr. Anderson:

As Chief Executive Officer of the Associated General Contractors of America (AGC) I write in support of Oregon LNG's application to export Liquid Natural Gas. AGC of America counts more than 30,000 construction and construction-related companies nationwide as members.

The U.S. construction industry is struggling economically. The national problem is worse in the Pacific Northwest. Many companies throughout Oregon and Washington are challenged to find projects to bid on. Construction employment in Washington State in April totaled 139,700, a decrease of 71,600 (34%) from the state's peak in June 2007 and Oregon employment in April totaled 70,100, a decrease of 35,300 (33%) from the state's peak. Both states have lost more than the national average of 28%. We believe strongly that Oregon LNG's project will create construction job opportunities in the short-term and good paying energy jobs in the long-term.

This project is estimated to include $6 billion in direct spending in the Northwest for the next 4 to 5 years. AGC estimates that, a $1 billion investment in nonresidential construction supports or creates 28,500 jobs. More than half of the gain is spread throughout the entire economy, as workers and owners in the construction and supplier industries spend their added income on a wide range of goods and services. The boost this project will provide will be critical at a time in which federal and state spending on infrastructure is at a near standstill, and private construction has not been able to pick up the slack. The direct spending and indirect impact will be a welcomed investment to local communities, workers and their families.

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We believe there are credible studies that indicate that the export of gas from the Northwest will have little impact on consumer price of gas in the region. We also understand that this specific project will be importing much of its natural gas from Canada and transporting it via pipelines to Warrenton where it will be liquefied and shipped to export markets across Asia. Since this gas is already destined for export to Asia – either from Canada or the US -- there should be little if any additional impact on the price of gas to consumers in North America if the facility is located in Oregon, rather than Canada.

In conclusion, we urge you to approve Oregon LNG's application for export. We believe the benefits to the construction industry and economy will be significant.

Sincerely,

Stephen Sandherr

Columbia Pacific Building and Construction Trades Council

June 13, 2012

Mr. John A. Anderson
Manager, Natural Gas Regulatory Activities
US Department of Energy - Office of Fossil Energy
PO Box 44375
Washington, D.C. 20026-4375

Dear Mr. Anderson:

With our nation's unemployment rate remaining stubbornly above 8%, it is imperative that we seize opportunities to create and sustain family wage jobs. Today I write you on behalf of The Columbia Pacific Building & Construction Trades Council (CPBCTC) in support of an important project that will help do just that. We strongly support the proposal by Oregon LNG and Oregon Pipeline Company to build a liquefied natural gas (LNG) export facility in Warrenton, Oregon. This project provides an opportunity to create thousands of jobs here in the Northwest through building and operating an export facility that will export primarily Canadian gas from British Columbia through the Port in Warrenton. CPBCTC has signed a Memorandum of Understanding that ensures hundreds of family wage jobs will go to our members in Oregon and Washington. Our well trained and highly skilled members represent multiple crafts that produce the highest standards of workmanship. It is estimated that over 2600 jobs a year will be created in the first five years of this project. The recession has been especially hard here in the Northwest and approximately 33 percent of our members are currently waiting to get back to work building critical infrastructure like this.

We believe it is important to allow this project to export natural gas to non-FTA countries as it will create American jobs, reduce the use of more carbon rich fossil fuels by these countries, and further strengthen our relationship with our Canadian neighbors.

With the discovery of significant deposits of natural gas in our own country, Canada must now find other markets for their excess supplies of gas. Creating jobs for our own citizens, while helping Canada meet its objectives, is truly a win-win opportunity. It is clear they will find a way to export it from their own shores if we miss this opportunity for cooperation.

We ask that you give quick approval to this application and give our members an opportunity to once again provide for their families while building infrastructure that will prove valuable to the United States.

Sincerely,

JG Parker

Jodi Guetzloe Parker

JGP:cmc
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