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March 23, 2012

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***By Email, Facsimile and U.S. Mail***
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Ms. Larine A. Moore
Docket Room Manager
FE-34
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Application of Jordan Cove Energy Project, L.P. for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations, FE Docket No. 12-32-LNG

Dear Ms. Moore:

Please accept for filing the accompanying Application of Jordan Cove Energy Project, L.P. for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations (the "Application") that is being transmitted to you on this date by facsimile and email as indicated above. The Application is accompanied by a photocopy of a check in the amount of $50.00, made payable to the U.S. Department of Treasury, for the filing fee.

On this date, the undersigned is mailing an original and three copies of the Application and the original check for the filing fee.

Please acknowledge receipt of this Application by email to darbyj@dicksteinshapiro.com. Should you have any questions, please do not hesitate to contact me at (202) 420-2745 or. Thank you for your assistance.

Sincerely,

Joan M. Darby

**UNITED STATES OF AMERICA**
**DEPARTMENT OF ENERGY**
**OFFICE OF FOSSIL ENERGY**

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| **In the Matter of:** | ) | |
| | ) | **Docket No. 12-32-LNG** |
| **JORDAN COVE ENERGY PROJECT, L.P.** | ) | |

# APPLICATION FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE AGREEMENT NATIONS

Communications regarding this application should be directed to:


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**UNITED STATES OF AMERICA**
**DEPARTMENT OF ENERGY**
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# APPLICATION FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE AGREEMENT NATIONS

Pursuant to Section 3 of the Natural Gas Act (NGA), 15 U.S.C. § 717b, and Part 590 of the regulations of the Department of Energy (DOE), 10 C.F.R. Part 590, Jordan Cove Energy Project, L.P. (Jordan Cove) requests that the DOE Office of Fossil Energy (DOE/FE) issue an order granting Jordan Cove long-term, multi-contract authorization to export from its proposed terminal to be located on Coos Bay in the State of Oregon up to six million metric tons per annum (mtpa) of liquefied natural gas (LNG), an export volume equivalent to 292 billion cubic feet (Bcf) per year of natural gas. This application requests authorization to export the LNG to any nation with which the United States does not have a Free Trade Agreement (FTA) requiring national treatment for trade in natural gas, which has or in the future develops the capacity to import LNG and with which the trade is not prohibited by United States law or policy (such nations, "non-FTA nations" and this application, the "NFTA Application").[1] Jordan Cove is

[1] By DOE/FE Order No. 3041 issued on December 7, 2011, DOE/FE authorized Jordan Cove to export LNG by vessel up to the equivalent of 438 Bcf per year of natural gas (nine million mtpa of LNG) for a 30-year term to nations with which the United States currently has, or in the future enters into, a FTA requiring national treatment for trade in natural gas and LNG (*Jordan Cove FTA Order*). More than two months after the *Jordan Cove FTA Order* issued, Jordan Cove commenced the pre-filing review process for an application to amend its Federal Energy Regulatory Commission (FERC) authorization to add export facilities (*see* page 4 *infra*). This NFTA Application requests authorization for an export volume of 292 Bcf per year that is consistent with the facility design being proposed in the FERC pre-filing proceeding.

seeking authorization to export for a 25-year term commencing on the earlier of the date of first export or the date seven years from the date the requested authorization is granted.

## I.
## COMMUNICATIONS

Communications regarding this application should be directed to:


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## II.
## APPLICANT

The exact legal name of Jordan Cove is Jordan Cove Energy Project, L.P. Jordan Cove is a Delaware limited partnership authorized to do business in the State of Oregon. Jordan Cove has its principal place of business at 125 Central Avenue, Suite 380, Coos Bay, OR 97420.

The general partner of Jordan Cove is Jordan Cove Energy Project L.L.C., a Delaware limited liability company. Both Jordan Cove and its general partner are owned by the two limited partners in Jordan Cove. The first, Fort Chicago LNG II U.S.L.P., a Delaware limited partnership owns seventy-five percent. It is wholly owned and controlled, through a number of intermediate wholly owned and controlled companies, by Veresen, Inc., a Canadian corporation based in Calgary, Alberta, which, prior to its organization as a corporation, was Fort Chicago Energy Partners L.P., a Canadian limited partnership (although the name of the parent changed, the name of the subsidiary owning Jordan Cove did not). The second, Energy Projects Development L.L.C., a Colorado limited liability company, owns twenty-five percent. It is owned by various private individuals, all of whom are U.S. citizens.

## III.
## <u>REQUESTED AUTHORIZATION</u>

Jordan Cove requests authorization to export by vessel LNG, up to the equivalent of 292 Bcf per year of natural gas, to non-FTA nations.[2] Jordan Cove requests that such authorization commence on the date of first export, with such first export to occur no later than seven years following the grant of the authorization requested by this application, and continue for a term of 25 years. The requested term ties directly to the need for Jordan Cove and its customers to enter into sufficiently long-term contracts both to meet its customers' needs and to finance the construction and operation of its project.

Jordan Cove requests authorization to export from its LNG terminal to be located on the North Spit of Coos Bay in Coos County, Oregon. Jordan Cove's construction and operation of an LNG terminal at this location has already been authorized by FERC as an import facility.[3] Jordan Cove has developed modified plans for the terminal to operate as an export facility. The

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[2] The requested volume in this NFTA Application is not duplicative of the volume authorized in the *Jordan Cove FTA Order*.

[3] *Pacific Connector Gas Pipeline, LP; Jordan Cove Energy Project, L.P.*, 129 FERC ¶61,234 (Dec. 17, 2009) (FERC Order). Rehearing requests of the FERC Order are currently pending before FERC.

terminal facilities already authorized by the FERC Order that will be used for exports include two 160 cubic meter LNG full-containment storage tanks, a single marine berth capable of accommodating LNG vessels up to Q-flex size, and on-site utilities and services. The modified plans include large diameter LNG piping configured for exports and electrically driven liquefaction equipment. On February 29, 2012, Jordan Cove filed a request for FERC's Office of Energy Projects to commence the mandatory National Environmental Policy Act (NEPA) pre-filing review process for an application to amend its FERC authorization to add export facilities, which was docketed in FERC Docket No. PF12-7-000 and approved by letter dated March 6, 2012. FERC Staff will conduct onsite environmental review and Jordan Cove will hold an open meeting on March 27, 2012. Jordan Cove anticipates completing the pre-filing review process and filing its application to amend in October 2012. Provided that FERC authorizes the export facilities by the end of 2013, Jordan Cove would be able to complete construction and commence export service in the fourth quarter of 2017. That service would offer benefits unique to the Jordan Cove terminal, because it is the only currently proposed liquefaction and export project that will provide customers the opportunity (i) to export from the U.S. West Coast and (ii) to export natural gas from Canada and the U.S. Rocky Mountain states.

Jordan Cove requests authorization to export as LNG both natural gas produced domestically in the United States and natural gas produced in Canada and imported into the United States. Jordan Cove's terminal, via the Pacific Connector Gas Pipeline,[4] will be connected to the Northwest United States market hub at Malin, Oregon, providing access to abundant and diverse gas supplies in both countries. At the Malin hub, PCGP will interconnect with Gas Transmission Northwest Pipeline, delivering gas from western Canada and, via its

4 PCGP is a new interstate pipeline natural gas pipeline also certificated by the FERC Order (PCGP, together with the Jordan Cove terminal, the Jordan Cove Project).

Stanfield interconnection with Northwest Pipeline, delivering gas from the U.S. Rockies; Ruby Pipeline, delivering gas from western Wyoming, northwestern Colorado and northern Utah; and, PG&E Redwood Path, serving northern California. Accordingly, unlike any of the other proposed liquefaction and export projects, all of the gas to be exported from Jordan Cove's terminal is likely to be sourced from Canadian and U.S. Rocky Mountain supply basins.

Jordan Cove requests authorization to export pursuant to one or more long-term agreements that do not exceed the term of the requested authorization. Jordan Cove plans commercial arrangements in the form of Liquefaction Tolling Agreements (LTAs), under which an individual customer that holds title to natural gas will have the right to deliver that gas to Jordan Cove's terminal for liquefaction services and to receive LNG in exchange for a processing fee paid to Jordan Cove.[5] Jordan Cove will file, or cause others to file, under seal executed contracts associated with the long-term supply of natural gas to, or the long-term export of LNG from, the Jordan Cove terminal, including LTAs, within 30 days of their execution.[6] Jordan Cove has identified from among at least ten potential interested counterparties the most promising prospective LTA customers. Initial discussions and due diligence activities are already underway and serious negotiations for definitive binding LTAs that will cover all of the ratable liquefaction capacity at the terminal will commence in the near future and are expected to be completed by the end of the year. In short, Jordan Cove has seen significant and serious market interest in the unique commercial opportunities it offers.

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[5] Under the LTA business model, the decision whether to utilize liquefaction capacity will be made by the LTA customer: if the marginal cost of producing or purchasing natural gas, liquefying it, and transporting the resulting LNG to a destination market is higher than another competing source of supply in any month, the LTA customer may forego its nomination rights for that month.

[6] When any such agreement is executed, and the transaction specific information required under 10 CFR 590.202(b) becomes available, Jordan Cove will comply with that provision.

Jordan Cove requests authorization to export on behalf of or as agent for others, as well as on its own behalf. The title holder at the point of export, if not Jordan Cove, may be an LTA customer or a party that purchases LNG from an LTA customer pursuant to a long-term contract. Jordan Cove is prepared to accept conditions on its authorization consistent with the conditions imposed in recent DOE/FE orders, including the *Jordan Cove FTA Order* and the *Sabine NFTA Order*, that have authorized exports on behalf of other title holders.[7] Jordan Cove will include in any LTA (or any other contract made by Jordan Cove for the sale or transfer of LNG exported under its authorization) the requisite contract provision by which the customer commits to: (1) resell or transfer the LNG for delivery only to authorized countries or to purchasers that have agreed to so limit their direct or indirect resale or transfer; (2) cause the provision of a report to Jordan Cove that identifies the country of destination for actual deliveries; and, (3) include in any resale contract conditions to insure that Jordan Cove is made aware of all actual destination countries. Further, when Jordan Cove uses its authorization to export LNG on behalf of or as agent for any other title holder at the point of export, Jordan Cove will register or ensure the registration of such title holder. The registration will include the registrant's acknowledgement and agreement to supply Jordan Cove with all necessary information and copies of contracts, including the registrant's agreement to: (1) comply with the requirements of Jordan Cove's authorization and DOE's regulations; (2) include in any of its contracts the requisite contract provision described above; and, (3) file with DOE/FE under seal within 30 days of their execution (or supply to Jordan Cove for such filing) executed contracts associated with the long-term supply of natural gas to, or the long-term export of LNG from, the Jordan Cove terminal. Hence DOE/FE can be assured that all exporting title holders will be

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7 DOE/FE adopted such conditions in *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 2913, FE Docket No. 10-160-LNG (Feb. 10, 2011).

aware of all DOE/FE requirements applicable to the exports and that DOE/FE will have the necessary information to ensure that authorized exports are permitted and lawful under U.S. laws and policies.

## IV.
## APPLICABLE PUBLIC INTEREST STANDARD

Jordan Cove seeks an order authorizing LNG exports under NGA Section 3(a), which sets forth a statutory directive that DOE/FE "issue such order upon application, unless, after opportunity for hearing, [it] finds that the proposed exportation … will not be consistent with the public interest."[8] In its recent order authorizing LNG exports to non-FTA nations, the *Sabine NFTA Order*,[9] DOE/FE acknowledged its longstanding position that "Section 3(a) creates a rebuttable presumption that a proposed export of natural gas is in the public interest, and DOE must grant such an application unless those who oppose the application overcome that presumption "by mak[ing] an affirmative showing of inconsistency with the public interest."[10] Also in that order, DOE/FE stated that its review is guided by the longstanding principles of the

8 NGA Section 3(a) provides in pertinent part:

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy] authorizing it to do so. The [Secretary] shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest.

15 U.S.C. § 717b(a). The Secretary of Energy's authority (established by the DOE Organization Act transferring jurisdiction from the Federal Power Commission) is delegated to DOE/FE pursuant to Redelegation Order No. 00-002.04E (Apr. 29, 2011).

9 *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961, FE Docket No. 10-111-LNG (May 20, 2011).

10 *Id*. at 28 and n. 38, citing *Phillips Alaska Natural Gas Corporation and Marathon Oil Company*, 2 FE ¶ 70,317 (1999) (*Phillips Order*).

DOE's Policy Guidelines[11] and by the instructions of DOE Delegation Order No. 0204-111[12] and hence "focus[es] on the domestic need for the natural gas proposed to be exported; whether the proposed exports pose a threat to the security of domestic natural gas supplies; and any other issue determined to be appropriate, including whether the arrangement is consistent with DOE's policy of promoting competition in the marketplace by allowing commercial parties to freely negotiate their own trade arrangements."[13]

## V.
## CONSISTENCY WITH THE PUBLIC INTEREST

This NFTA Application is wholly consistent with the public interest standard as articulated and applied by DOE/FE. Indeed, Jordan Cove's export proposal is a market-driven response to the availability of abundant domestic supply and rising international demand for natural gas. Jordan Cove's discussions with customers are taking place in a conspicuously competitive marketplace and will culminate in freely negotiated LTAs with terms and conditions tailored to the needs of each of its individual terminal users. Thus, they will reflect precisely what DOE/FE policy is intended to promote, and issuing the requested authorization would be

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11 Policy Guidelines and Delegation Orders Relating to the Regulation of Imported Natural Gas, 49 Fed. Reg. 6684 (Feb. 22, 1984) (*DOE Policy Guidelines*) ("The federal government's primary responsibility in authorizing [exports] will be to evaluate the need for the gas and whether the [export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market."). In the *Phillips Order* (at 14), DOE/FE held that the *DOE Policy Guidelines* apply to natural gas export applications.

12 DOE Delegation Order No. 0204-111 directs regulation "based on a consideration of the domestic need for the gas to be exported." *See Sabine NFTA Order* at 28-29.

13 *Id.* at 29.

consistent with the goal of the *DOE Policy Guidelines* to "minimiz[e] regulatory impediments to a freely operating market."[14]

The LNG export authorization will serve the public interest in multiple other ways. It will permit exports when competitive and otherwise promote healthy domestic and international natural gas markets. Jordan Cove exports will not pose any threat to the security of domestic natural gas supplies. To the contrary, they will result in significant economic benefits. The demand created by the exports will stimulate increased revenues and jobs in upstream industries, which in turn will benefit the overall U.S. economy. The construction and operation of the Jordan Cove Project will also create jobs and produce revenues to the benefit of the local and regional economies. And, Jordan Cove exports will have positive international trade impacts for the United States. In sum, the Jordan Cove Project's economic benefits advance the Administration's efforts to expand exports, create jobs and otherwise stimulate the beleaguered U.S. economy.

Jordan Cove commissioned independent experts to conduct studies and prepare the following reports that demonstrate these public interest impacts:

- *Jordan Cove LNG Export Project Market Analysis Study*, January 2012 by Navigant Consulting, Inc. (Navigant) analyzing gas supply and demand outlooks and modeling potential price effects of the proposed exports for the North American natural gas market to 2045 (Navigant Study)

- *Whitepaper: Analysis of the EIA Export Report 'Effect of Increased Natural Gas Exports on Domestic Energy Markets' Dated January 19, 2012,* February 2012 by Navigant commenting on the EIA Report[15] (Navigant Whitepaper)

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14 *DOE Policy Guidelines* at 6685; *see* note 11 *supra*.

15 In January 2012, the U.S. Energy Information Administration (EIA) released *Effect of Increased Natural Gas Exports on Domestic Energy Markets* (EIA Report), a case study, prepared at the request of DOE/FE, evaluating the impact of increased natural gas demand reflecting exports of LNG on domestic energy consumption, production and demand under four scenarios. The EIA Report is addressed *infra* at 16-18.

- *An Economic Impact Analysis of the Construction of an LNG Terminal and Natural Gas Pipeline in Oregon*, March 6, 2012 by ECONorthwest examining impacts on the states of Oregon and Washington of the construction of the Jordan Cove Project (Construction Study)
- *An Economic Impact Analysis of Jordan Cove LNG Terminal and Pacific Connector Gas Pipeline Operations*, March 23, 2012 by ECONorthwest examining impacts on the local communities of the operations of the Jordan Cove Project (Operations Study)
- *Upstream Economic Contributions of the Jordan Cove Energy Project*, February 29, 2012 by ECONorthwest quantifying direct and indirect contributions of the Jordan Cove Project to the United States economy (Upstream Contributions Study)
- *Effect of the Jordan Cove Energy Project's LNG Exports on United States Balance of Trade*, March 20, 2012 by ECONorthwest analyzing the impact of the Jordan Cove Project on the nation's balance of trade (Balance of Trade Study)

The approaches and conclusions of these reports are highlighted in the discussion below. Copies of the complete reports are appended to this NFTA Application.

## A. Jordan Cove Exports Will Benefit Natural Gas Markets

### 1. Supply Is More Than Adequate To Serve Projected Domestic Demand and Proposed LNG Exports

By all measures, ample natural gas supplies exist to serve this country's domestic gas needs and the proposed LNG exports by Jordan Cove and other exporters. The Navigant Study (attached as Appendix A) identifies shale gas production growth as the biggest contributor to overall gas supply abundance.[16] The development and continuing improvement of hydraulic fracturing technology have led to increasingly efficient shale gas production and in turn a 28 percent increase in U.S. total gas production from 2005 (49.7 Bcf per day (Bcf/d)) to 2011 (63.6 Bcf/d).[17] Estimates of dry natural gas resources in the United States have likewise grown,

16 Navigant Study at 5.

17 *Id*. at 7-9.

reflecting significantly increased estimates of shale gas resources. As Navigant observes, its own 2008 study estimated U.S. shale gas and total gas reserves at 842 trillion cubic feet (Tcf) and 2247 Tcf, respectively, not far from the EIA's Annual Energy Outlook (AEO) 2011 estimates of 827 Tcf and 2543 Tcf. These reserves constitute sufficient supply at current usage rates for 94 to more than 100 years,[18] well beyond the terms of the proposed export authorizations.

It is important to note that, especially in its initial years, Jordan Cove exports will draw significantly on Canadian as opposed to U.S. natural gas supplies.[19] The Navigant Study 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 Tcf, with total gas in place estimated at 372 Tcf. The other major shale basin in British Columbia, the Montney, has been estimated to contain 65 Tcf of recoverable resources.[20] Other recent estimates of these resources are even higher[21] and, depending upon

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18 *Id*. at 11. In EIA's Annual Energy Outlook (AEO) 2012 Early Release Overview, available at http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf, the AEO 2012 Reference Case estimate of unproven shale gas resources is lowered to 482 Tcf from the AEO 2011 estimate of 827 Tcf. Even so, the lower resource base still constitutes sufficient supply at current usage rates for 91 years. The EIA's downgraded estimate is in any event notably controversial. It appears to be an effort to reconcile EIA figures with those of the United States Geological Survey, but it has spawned discussions among the experts about inconsistency across the various estimates in what resources are included. *See* Reid R. Frazier, *Where did all the shale gas go?*, Allegheny Post, January 28, 2012; available at http://publicsource.org/shared-resources/where-did-all-shale-gas-go; Richard G. Smead, Director, Navigant Consulting, Inc., *The EIA-USGS Gas Resource Revisions – What Do They Mean?*, NGMarket notes, March 2012 at 1-3; available at http://media.navigantconsulting.com/emarketing/Documents/Energy?NG_Notes_Mar12.pdf.. Those discussions continued at a March 19, 2012 conference on the subject at Penn State University. See *New Figures on Shale Gas Optimistic*, Pittsburgh Tribune-Review, March 20, 2012; available at http://www.pittsburghlive.com/x/pittsburghtrib/news/s_787326.html. EIA's final AEO 2012 at this time is in the process of being prepared and in the end may address the most controversial estimates prepared in the original Early Release.

19 *Id*. at 3, 5, 13-14.

20 *Id*. at 13.

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.

Figures for both gas reserves and gas production are likely to continue to rise, again driven by shale gas. Navigant points to the high rate at which new shale resource plays are being identified, noting that "North America is clearly in the early phases of discovery for the resource,"[22] and to the increases in the estimates made by other independent evaluators of gas resources in both the United States and Canada.[23] Navigant states that it "expects this trend towards identifying a larger resource base to continue in the near term in both the U.S. and Canada."[24] Navigant also expects that gas production will continue to grow steadily throughout the Navigant Study's forecast period to 2045.[25] Navigant's Spring 2011 Reference Case[26] projects U.S. dry gas production to grow to 81.6 Bcf/d by 2045 and Navigant allows that "[p]roduction could go higher in response to demand from proposed LNG liquefaction facilities and/or independent increases in the robust supply resource base."[27] Indeed, the growth potential

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21 TransCanada Pipelines Limited, *Mainline Throughput Study* (appendix C1 to the Business and Services Restructuring and Mainline 2012-2013 Tolls Application to National Energy Board of Canada), as revised October 31, 2011, at 77; RBC Capital Markets, *Horn River Basin Shale Gas*, September 27, 2010 at 1, 7 and 27.

22 Navigant Study at 11.

23 *Id*. at 12-13.

24 *Id*. at 13.

25 *Id*. at 5.

26 Navigant bi-annually produces a long-term forecast of monthly natural gas prices, demand and supply for North America. The Navigant Study builds on Navigant's Spring 2011 Reference Case (or Forecast) dated June 2011 and released in July 2011. *Id*. at 1, 30 and 36.

27 Navigant Study at 2. Acknowledging that EIA's shale production forecast between now and 2020 is lower than Navigant's and explaining that EIA's resource forecasts usually lag, Navigant states that it believes its estimates are conservative and reaffirms confidence in them. It also notes that Figure 10 shows that, after 2020, Navigant's and EIA's projected growth rates are "roughly parallel." *Id*. at 17-18.

is enhanced by the fact that the reduced geologic risk and resulting reliability of shale gas discovery and production makes it responsive to demand and by the fact that presence of natural gas liquids (NGLs) in some shale formations creates an added incentive for development.[28]

As to the demand outlook, Navigant projects steady growth, led by electric generation demand, with modest contributions from industrial, residential, commercial and vehicle demand.[29] It also projects that natural gas will remain competitive with oil and other fuels.[30] Navigant concludes that, even as that domestic demand is projected to grow throughout the forecast period to 2045, North American gas resources, especially given the size of the shale gas resources in North America, are wholly adequate to satisfy domestic demand as well as the added demand of LNG exports by Jordan Cove even when other LNG exports are also assumed.[31]

### 2. Effect of Jordan Cove Exports on Natural Gas Prices is Minimal

The Navigant Study develops four scenarios to test the potential effect of Jordan Cove exports on prices. For the first, the Jordan Cove Reference Case, Navigant uses its Spring 2011 Reference Case,[32] extended the term to 2045, and assumes that the Louisiana Sabine Pass and the British Columbia Kitimat LNG export facilities will be operational. The Jordan Cove Export Case adds Jordan Cove exports of 0.9 Bcf/d beginning in 2017. The Aggregate Export Case adds to the Jordan Cove Export Case generic LNG export capacity of 2.0 Bcf/d in the Gulf and 1.0 Bcf/d on the U.S. eastern seaboard, for a total of 6.6 Bcf/d of North American LNG

28 *Id*. at 14-16.

29 *Id*. at 18-20.

30 *Id*. at 20-24.

31 *Id*. at 3, 14, 31 and 37-38.

32 *See* note 26 *supra*.

export capacity.  Finally, the GHG Demand Case further increases demand using figures from Navigant's Spring 2011 Carbon Case Forecast, reflecting a high rate of coal to gas substitution driven by assumed laws and regulations aimed at lowering green house gas (GHG) impacts.[33] Navigant produces price projections for the forecast period under each of the scenarios at three locations:  Henry Hub, the key North American pricing reference point; Sumas, the U.S.-Canadian border point that provides a proxy for prices paid in the population centers of the Pacific Northwest (Seattle and Portland); and, Malin, the California-Oregon border point at which gas volumes will enter PCGP for transport to the Jordan Cove facility.[34]

Prices at each of the three locations in 2025, 2035 and 2045 under each of the four scenarios (all of which that assume Sabine Pass and Kitimat are operational) are presented in Table 1 of the Navigant Study[35] reproduced here:

| Year | Metric | Reference Case | Jordan Cove Export | Aggregate Export | GHG Demand |
|---|---|---|---|---|---|
| 2025 | *Henry Hub* | $5.51 | $5.55 | $5.92 | $6.88 |
| | *Malin* | $5.15 | $5.29 | $5.55 | $6.49 |
| | *Sumas* | $5.28 | $5.26 | $5.53 | $6.46 |
| 2035 | *Henry Hub* | $7.31 | $7.35 | $7.66 | $9.33 |
| | *Malin* | $6.81 | $7.02 | $7.29 | $8.55 |
| | *Sumas* | $6.97 | $6.98 | $7.25 | $8.23 |
| 2045 | *Henry Hub* | $8.28 | $8.30 | $8.55 | $10.31 |
| | *Malin* | $7.57 | $8.11 | $8.39 | $9.72 |
| | *Sumas* | $7.75 | $8.05 | $8.32 | $9.47 |

**Table 1: Sample Output Prices of Selected Locations**

33 *Id*.  at 36.

34 *Id*.  at 30.

35 *Id*. at 4.

Focusing on the Jordan Cove Export Case, Navigant concludes that the effect of Jordan Cove exports is negligible in the national market (prices do not vary by more than 4 cents from those in the Reference Case) and minimal in the Pacific Northwest market (Sumas prices are essentially flat in 2025 and 2035 and are only 3.9% higher in 2045; Malin prices are higher by 2.1, 3.1 and 7.2 percent respectively at each interval).[36] It also points out that Jordan Cove Export Case prices at all three locations are below $8.00 until the end of the forecast period in 2045,[37] a point that can be made with respect to the Aggregate Export Case as well. Comparing the projected prices under the Aggregate Export Case to the Jordan Cove Export Case, the price increases are larger in 2025 (ranging from 4.9% at Malin to 6.7% at Henry Hub) reflecting the concurrent addition of the other assumed LNG export facilities, but these increases moderate as the market recalibrates (at Henry Hub decreasing from 4.3% in 2035 to 3.0% in 2045 and at both Sumas and Malin decreasing from 3.8% in 2035 to 3.4% in 2045).[38] The projected incremental price increases are less moderate in the GHG Demand Case, ranging from 13.6% to 20.6% over the Aggregate Export Case prices at 2025, 2035 and 2045,[39] but, as Navigant notes, these are due to policy-driven growth in demand. More importantly, the price outputs in all scenarios in the Navigant Study would have been lower had Navigant not been as conservative as it was in the modeling assumptions: for resources, no new gas supply basins are assumed; for production, empirical production data that does not reflect the rapid ramp-up in development is used; no

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36 *Id*. at 2.

37 *Id*.

38 *Id*. at 47 (Table 10).

39 *Id*. at 51 (Table 13).

unannounced pipeline and storage infrastructure projects are assumed; and, a high 90 percent load factor for export facilities is assumed.[40]

Shortly after the Navigant Study was delivered to Jordan Cove, the EIA Report, prepared for DOE/FE, was issued.[41] Jordan Cove requested the Navigant Whitepaper (attached as Appendix B), which adds context that is missing from recent media reports and export opponent soundbites on the EIA Report. Observing that the EIA Report analyzes four baseline cases (AEO 2011 Reference; Low Shale Estimated Ultimate Recovery (EUR); High Shale EUR; and, High Economic Growth) in four export scenarios (Low(exports of 6 Bcf/d)/Slow(ramp-up at +1 Bcf/d/yr); Low/Rapid(+3 Bcf/d/yr); High(12 Bcf/d)/Slow; High/Rapid), Navigant explains that the high price outputs garnering attention – in particular, a 54% gas price increase in 2018 – result "from mixing a baseline case and an export scenario [low supply and high exports] that, by their very nature, do not represent a realistic real-world scenario" and points out that the EIA Report effectively acknowledged as much.[42] Moreover, the 54% figure is only a maximum single-year metric out of line with the average price changes that more accurately measure sustained impact.[43]

Navigant suggests that the "least unrealistic baseline case-scenario combination" in the EIA Report is the High Shale EUR baseline case and the low/slow export scenario, which "generates a maximum-year price increase 74% lower than the quoted 54% figure."[44] Still, it tends to overstate price increases for several reasons. First, Navigant states its belief that EIA's

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40 *Id*. at 30, 32 and 33.

41 *See* note 15 *supra*.

42 Navigant Whitepaper at 6.

43 *Id*.

44 *Id*.

low export scenario of 6 Bcf/d is high, observing that the Navigant Study's assumed export level of 5.9 Bcf/d was designed as a "high end figure."[45] Second, even though the High Shale EUR baseline case was intended to be the high supply alternative, it understated production, having been based on the AEO 2011 forecast that "was eclipsed by actual shale production levels in the U.S. in March of 2011, and was about 19% below actual levels at the end of the year."[46] In fact, Navigant points out that AEO projections historically have understated shale gas production, relating that the shale gas production forecast in the AEO 2011 Reference Case, even with its increase of over 70% from the AEO 2010 figure, "was still significantly below the actual 2011 shale gas production forecast levels, by more than 25% for the annual average level and by 35% for the year-end production level."[47] Finally, the fact that the EIA Report studies only exports to be made from Gulf Coast projects, and does not even include an East Coast project, is bound to intensify the price impacts. The Low Shale EUR case should not be relied upon because its much lower forecast than the AEO 2011 Reference Case forecast "is clearly out of line with current developments." [48] And even the High Shale EUR case is problematic as its forecast, while higher than the AEO 2011 Reference Case forecast, was appreciably lower than the conservative forecast in the Navigant Study.[49]

In any event, the EIA Report is not pertinent to the Jordan Cove Project that will export from the U.S. West Coast gas sourced from Canada and the U.S. Rockies, with Canadian

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45 *Id*.

46 *Id*. at 4. The EIA shale gas production forecast is also lower than the conservative one in the Navigant Study. *Id*.

47 *Id*. at 2. Navigant also notes that the AEO 2012 Early Release forecasted level for 2012 was surpassed by the actual 2011 year-end production level. *Id*.

48 *Id*. at 4.

49 *Id*. (Table 4).

gas constituting the more significant portion initially.[50] As observed, it focuses only on exports to be made from Gulf Coast projects, and thus the supply impacts "would be isolated to Gulf supplies."[51] The EIA Report, having been "based on an analysis and scenarios for LNG export and supply that are tied to a wholly distinct region of the country from a supply and infrastructure standpoint,"[52] should have no import for this NFTA Application. The Navigant Study, accounting for exports from the U.S. Pacific, Atlantic and Gulf coasts, as well as from British Columbia in Canada, is the more relevant and accurate measure of the price impacts of Jordan Cove exports.[53]

### 3. LNG Exports Will Strengthen the U.S. Natural Gas Market

LNG exports will enhance the development of a healthy natural gas market – one that achieves a balance of supply and demand. As stated by Navigant, "reliable demand is a key to underpinning reliable supply and a sustainable gas market."[54]

Shale gas compares favorably to conventional gas because the exploration risk is significantly reduced and the production process is significantly more manageable and dependable.[55] For this reason, shale gas production "has the potential to improve the phase

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50 *Id*.

51 *Id*. at 6. Navigant also notes that the EIA Report did not model an East Coast export facility, an assumption that likely would have resulted in lower price projections due to the proximity to the ample supplies from the Marcellus basin. *Id*. at 7 (referencing Navigant's study for the Dominion Cove Point LNG export project).

52 *Id*. at 7.

53 No study shows that exporting LNG from the United States will cause U.S. natural gas prices to follow international oil-linked natural gas prices. Navigant concludes that LNG exports constitute too small a volume to have such an effect. *Id*. at 31-32.

54 *Id*. at 3 and 18; Navigant Whitepaper at 9.

55 Navigant Study at 14-15; Navigant Whitepaper at 9.

alignment between supply and demand, which will in turn tend to lower price volatility,"[56] a welcome prospect in the current market environment of oversupply and low prices. Navigant finds it "increasingly evident that the slow development of new markets for natural gas is the only thing currently restricting even more gas resource development."[57] It also finds that "[t]he vast shale gas resource will support a much larger demand level than has heretofore been seen in North America, and at prices that are less volatile due to its production process characteristics."[58] For these reasons, Navigant concludes that "LNG exports, including those from the Jordan Cove LNG export project, [] should be seen as instrumental in providing the increased demand to spur exploration and development of gas shale assets in North America for the long-term benefit of the country and others."[59] DOE/FE reached a consistent conclusion in the *Sabine NFTA Order*, recognizing that "[o]verall, this will tend to enhance U.S. domestic energy security."[60]

### B. Jordan Cove Exports Will Cause Economic Benefits

#### 1. Construction of the Jordan Cove Project Will Benefit the Regional Economy

The Construction Study (attached as Appendix C) measures the effects on the economies of Oregon and Washington of the construction activity associated with Jordan Cove's LNG terminal and PCGP's natural gas pipeline during the years 2014 through 2017.[61] These two

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56 Navigant Whitepaper at 9.

57 Navigant Study at 20. The importance of developing new markets is underscored by recent reports that the decline in the price of gas in the United States has led producers, including Chesapeake Energy, ConocoPhillips and BG Group, to cut back their gas production. *See* Dan Milmo, *BG cuts back on fracking for shale gas as prices slide*, The Guardian, February 12, 2012; available at http://www.guardian.co.uk/business/2012/feb/09/bg-cuts-back-on-fracking-shale-gas-prices.

58 Navigant Whitepaper at 9-10.

59 *Id*. at 10.

60 *Sabine NFTA Order* at 35.

61 Construction Study at 1.

states are deemed the appropriate economic area for an impact study because they will be the sources of most of the construction labor and a significant portion of the equipment and materials, as well as engineering and related services.[62] The Construction Study expresses all costs and impact value in 2011 dollars.[63]

Working from cost estimates for both the terminal and pipeline facilities, ECONorthwest concludes that, after excluding costs such as real estate payments that are not typically sources of construction output, the remaining direct construction costs of $4.494 billion measure the direct economic impact of the Project.[64] The significance of this figure is put in perspective by the observation that the Project's construction spending will exceed the sum of construction spending on all similar projects in Oregon over the last five years.[65]

Of the $4.494 billion in construction spending, $1.366 billion will be spent in the study area states Oregon and Washington.[66] Using the IMPLAN economic modeling software, the Construction Study measures the successive rounds of impacts generated by the re-spending of that $1.366 billion and concludes that the indirect impact on economic output in Oregon and Washington over the four-year construction period will be approximately $1.17 billion and that the induced output over the same period, arising primarily from household spending by

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62 *Id*. at 5.

63 *Id*. at 1.

64 *Id*. at 2, 6 and 7-8.

65 *Id*. at 8.

66 *Id*. at 8-9 (Table 3). Due to the Project's requirements for specialized equipment and materials not available in Oregon and Washington, $3.128 billion of the $4.494 billion in construction spending will be spent outside the study area states; the economic impacts of that spending are not measured by the Construction Study. *Id*. at 8.

workers,[67] will be $973.5 million.[68] Measuring the net value of, or value added by, construction of the Project, the Construction Study estimates an increase in the regional gross domestic product or GDP of $1.738 billion in total for 2014-2017, averaging $434.6 million a year.[69]

The jobs impact of construction of the Jordan Cove Project will be consequential. On average, the Project will employ 1,768 workers a year, and it will create 1,530 indirect and 1,838 induced jobs a year.[70] Importantly, the labor income from the direct and secondary employment will average $182.6 million and $147.4 million a year, respectively, and total $330 million a year.[71] The total contribution of the Jordan Cove Project to labor income from all associated jobs over the 2014-2017 construction period will exceed $1.3 billion.[72]

### 2. Operation of the Jordan Cove Project Will Benefit the Local Economy

The Jordan Cove Project will continue to produce economic benefits after it achieves commercial operation. The Operations Study (attached as Appendix D) measures the impacts of the operations of Jordan Cove's LNG terminal and PCGP's natural gas pipeline on the economy of Coos County, where nearly all employees will work and reside.[73] These impacts are measured for 2018, chosen as a typical operating year because it is anticipated that by 2018 initial ramp-up and inventory build-up will have been accomplished and operations at the average level of 90

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67 The analysis of downstream impacts excludes spending of wages and salaries of Project employees living outside the study area, and includes only the spending of their *per diems*. *Id*. at 6 and 10.

68 *Id*. at 15.

69 *Id*. at 2 and 16.

70 *Id*. at 2 and 17.

71 *Id*. at 17.

72 *Id*.

73 Operations Study at 1 and 5.

percent of capacity will have been reached.[74] The source of the impacts will be spending by the Project for various payrolls and for contributions (in lieu of property taxes) towards education and urban renewal.[75]

The employment impacts of the Jordan Cove Project in the typical operating year will include 99 direct jobs at the Jordan Cove terminal and the PCGP pipeline, 51 indirect jobs paid by Jordan Cove (Sheriff's deputies, firefighters, tugboat crews and emergency planners), 404 other indirect jobs and 182 induced jobs for a total of 736 total jobs in Coos County.[76] ECONorthwest estimates the average annual compensation for each of the direct, indirect and induced jobs and, on that basis, the Operations Study concludes that the total labor income impact in the typical operating year will be $32.9 million.[77]

ECONorthwest calculates the direct, indirect and induced value added impacts on the Coos County economy of the Project's operations in 2018. The direct GDP impact of Jordan Cove's LNG terminal will be its gross output, measured as the fair market value of the LNG loaded onto ships for export, less the intermediate inputs, measured as the cost of the gas (including its transportation to the terminal) and other non-labor production costs.[78] The direct GDP impact of PCGP will be its gross output, measured as the market value of its shipping services, less the non-labor costs put into those services.[79] The direct GDP impact of the LNG terminal will be $1.29 billion. The portion of the GDP impact of the PCGP attributed to Coos County will be $35 million. The net increase in the GDP of Coos County after the indirect and

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74 *Id*.

75 *Id*. at 6.

76 *Id*. at 13-14.

77 *Id*. at 14.

78 *Id*. at 15-16.

79 *Id*.

induced impacts are included will be $1.36 billion.[80] The Jordan Cove Project is large, and particularly large for Coos County: its projected GDP impact, which is in line with size of the Project, will be of extraordinary importance to Coos County, where the GDP in 2010 was $1.74 billion.[81]

The foregoing impact analysis accounts for the downstream impacts of the contributions by Jordan Cove of $20 million a year for public K-12 education and of $10 million a year for projects of the Bay Area Urban Renewal Association.[82] Consistent with common practice, ECONorthwest does not include the property taxes to be paid by PCGP in the downstream impact analysis, but it does calculate them: PCGP will contribute property taxes of $2.4 million to Coos County and $8.8 million to the three other counties along its route.[83]

### 3. Exports from Jordan Cove Will Foster Upstream Industry Growth and Stimulate the U.S. Economy

The Jordan Cove Project will open new markets for natural gas and meeting that new demand will benefit upstream industries. Using the price and volume forecasts of the Navigant Study, including the forecasted proportion of exports sourced domestically, ECONorthwest calculates the direct economic contributions of four domestic United States industries, the first three being natural gas sectors -- interstate pipeline transportation; extraction; and, exploration and development (E&D) -- and the fourth being state and local government activities (as

80 *Id*. at 16.

81 *Id*.

82 *Id*. at 17; *see also id*. at 9. The Project expects that these contribution amounts will be made annually and indefinitely, although the designated purposes may change in the future. *Id*. at 17.

83 *Id*. at 17-18.

attributable to state gas severance taxes).[84] With the direct impacts thus established for each industry for each year, stated as the value of each industry's economic output over what it would have been without the exports, ECONorthwest then employs the IMPLAN economic modeling software to calculate domestic secondary economic impacts, both indirect and induced.[85] The Upstream Contributions Study (attached as Appendix E) shows that the demand on upstream industries from the Jordan Cove exports will create significant contributions to the U.S. economy averaging $3.9 billion in direct, indirect and induced annual outputs and creating and supporting an annual average of 20,359 new jobs.[86] How these figures were reached is set forth below.

Across the four studied industries, the direct upstream output begins at $268 million in the first year of operation, increases rapidly to $1 billion in the second year, continues to grow through the study period (albeit fluctuating as the domestic versus Canadian supply mix shifts), and reaches $3.3 billion in 2045, with the extraction industry accounting for 81 percent of the total.[87] The domestic network of suppliers to, and the high wages paid in, the extraction industry mean that its large direct upstream output produces greater indirect outputs as it stimulates other industries (increasing from $75 million in 2018 to $1.1 billion in 2045) and greater induced outputs as jobholders receiving wages, landholders receiving royalties and business owners seeing increased patronage all engage in personal spending (increasing from $149.1 million in 2018 to $2.3 billion in 2045).[88] On average, the extraction industry will contribute 5,210 jobs and $1.4 billion in direct output primarily in the Rocky Mountain States of Wyoming, Utah,

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84 Upstream Contributions Study at 4. ECONorthwest's analysis does not quantify upstream benefits in Canada. *Id*.

85 *Id*. at 21-23.

86 *Id*. at 1 and 35.

87 *Id*. at 20.

88 *Id*. at 26.

Colorado and Montana.[89] When the indirect and induced jobs and output are added, the average annual total contribution of the extraction industry will be 16,576 jobs and $3.2 billion in economic output.[90] The same pattern holds for the pipeline and E&D industries, in which the averages will be 158 and 247 direct jobs, 1,461 and 906 total jobs, $107.6 million and $158.8 million in direct output and $305.7 million and $263.8 million in total output, respectively.[91]

In addition to the foregoing impacts in the three natural gas industry sectors, the total impacts comprise impacts in the fourth industry – state government. The U.S. Rocky Mountain states where a portion of the Jordan Cove exports will be produced will collect state gas severance taxes. ECONorthwest measures the impact of these states spending the increased tax revenues, which will average $59.8 million a year, on government services.[92] The job impacts will be substantial because government services are labor intensive, ranging from 175 to 2,713 and averaging 1,416 jobs a year.[93] The total economic output including indirect and induced outputs will average $147.1 million a year, and range up to $281.7 million.[94]

### 4. Jordan Cove Exports Will Provide Trade Benefits

The Jordan Cove proposal advances the Administration's agenda to boost exports.[95] In its Balance of Trade Study (attached as Appendix F), ECONorthwest concludes that the overall impact of the Jordan Cove Project will be a net improvement in the balance of trade for

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89 *Id*. at 1, 26-27.

90 *Id*.

91 *Id*. at 29-30 and 33-34 .

92 *Id*. at 31.

93 *Id*. at 32.

94 *Id*. at 31.

95 *See* National Export Initiative; available at http://export.gov/nei.

the United States.[96] The study acknowledges that the importation of gas from Canada for export from the Jordan Cove terminal will have a negative balance of trade impact, but concludes that it will be offset, not only by the value of the LNG exports, but also by the value of the increased exports of the NGLs that will be a byproduct of the increased domestic gas production.[97] As the proportion of domestic gas used for Jordan Cove LNG exports grows through the study period, the improvement in the balance of trade increases from $2.1 billion in 2020 to $4.9 billion in 2045.[98]

### 5. Jordan Cove Exports Will Provide Additional International Benefits

In the *Sabine NFTA Order*, DOE/FE recognized certain "difficult to quantify" impacts of an authorization to export LNG that "redound to the benefit of the United States."[99] These international impacts are equally applicable to a license for Jordan Cove to export LNG. The positive impacts include: (1) promoting international markets and development of additional resources domestically and internationally; (2) enabling overseas generators to switch from oil or coal to cleaner natural gas with its environmental benefits; (3) assisting countries with limited resources to broaden and diversify their supply base, which will contribute to transparency, efficiency and liquidity of international natural gas markets and encourage liberalized trade and greater diversification of global supplies; and, (4) decoupling international natural gas prices from oil prices, leading to lower natural gas prices.[100]

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[96] Balance of Trade Study at 7.

[97] *Id*. at 1.

[98] *Id*. at 4 and 7.

[99] *Sabine NFTA Order* at 37.

[100] *Id*.

## C. Jordan Cove Exports Will Offer Unique Advantages

The Jordan Cove facility is the only LNG export terminal proposed for the U.S. West Coast. It is thus uniquely positioned among United States terminals, not only to source its natural gas from Canadian and U.S. Rockies supply basins and to serve Asian demand without the longer routes and Panama Canal transits necessary from the Gulf Coast, but also to provide specific advantages (in addition to the economic benefits already detailed) for gas markets in the United States, in the country's two non-contiguous states of Alaska and Hawaii and in Oregon along the route of the new PCGP pipeline.

Given North America's enormous shale gas resources and the Asian demand for its production, there is little doubt that Pacific Northwest LNG export facilities will be built. British Columbia is actively promoting export terminals on the Canadian West Coast. The message from B.C.'s Minister of Energy and Mines, Rich Coleman, is plain: "With the *BC Jobs Plan*, the Province has committed to having our first LNG plant up and running by 2015, with a total of three LNG facilities operating by 2020."[101] The proposed Jordan Cove export terminal represents a fungible substitute for a British Columbia export terminal[102] that will bring distinct advantages to the United States beginning with the economic benefits already set forth of creating U.S. infrastructure and expanding U.S. trade. In addition, building the Jordan Cove terminal and PCGP will draw Canadian gas southwards, creating an additional pathway for

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101 British Columbia Ministry of Energy and Mines, *Liquefied Natural Gas, A Strategy for B.C.'s Newest Industry*, 2011 at page 2; *see also* pages 3 and 4; available at http://www.gov.bc.ca/ener/popt/down/liquefied_natural_gas_strategy.pdf.

102 Existing pipeline infrastructure from the Western Canada supply basins and in the U.S. Northwest to the Malin hub, which will be connected to the Jordan Cove terminal and export markets by the PCGP, may be preferable to the significant pipeline infrastructure that would need to be built through the more difficult terrain between those basins and the coast of British Columbia. Furthermore, the terminus in Oregon is in an area that is an alternative market to the export market for the Canadian gas; the same cannot be said of a terminus on the B.C. coast.

Canadian supplies to the U.S. Pacific Northwest. If in the future U.S. demand grows and the U.S. natural gas price moves higher, Canadian producers will be able to utilize that new pathway to supply the U.S. market. The advantage to the United States will be the dampening effect of these incremental Canadian supplies on upward price pressure.

In addition, the proposed Jordan Cove terminal will provide access to LNG for the isolated markets in Hawaii (where consumers pay the highest price in the U.S. for electricity[103] that is generated using primarily fuel oil and coal) and the Cook Inlet region of Alaska (where there is dwindling deliverability of natural gas). Indeed, Jordan Cove has had ongoing discussions with utilities in both locales that, given their relatively small demand quantities, are looking to "piggy-back" on customers with large enough base-load demand to support the construction of an LNG terminal. More specifically, utilities in these states are looking for a West Coast terminal that would offer gas at prices indexed to a North American basis and be able service the smaller ships appropriate to their demand quantities (which likely would not transit the more significant distances from terminals on the other U.S. coasts). The Jordan Cove Project will be able to serve their needs.

Natural gas customers in Oregon situated along the route of the new PCGP pipeline, particularly those west of the Cascades, stand to benefit from the Jordan Cove Project. Their growth in demand alone would not be sufficient to justify the investment in a pipeline like the PCGP, but they too will be able to "piggy-back" on the LNG terminal customers whose contracts with PCGP will underpin its construction. The incremental capacity available on PCGP will bring additional natural gas supplies to their otherwise isolated market area with concomitant beneficial price effects.

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[103] U.S. Energy Information Administration, State Electricity Profiles; available at http://www.eia.gov/electricity/state.

## VI.
## ENVIRONMENTAL IMPACT

FERC has found that the proposed Jordan Cove LNG import terminal is environmentally acceptable if constructed and operated in accordance with the environmental mitigation measures set forth in the FERC Order. The potential environmental impacts of the terminal as modified to permit exports of LNG will be reviewed by FERC under NEPA when Jordan Cove's application to amend its certificate to authorize liquefaction and export is filed. Jordan Cove requests that DOE/FE issue an order authorizing exports of LNG conditioned upon satisfactory completion of the environmental review process by FERC.

## VII.
## APPENDICES

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|---|---|
| Appendix A: | Navigant Study<br>*Jordan Cove LNG Export Project Market Analysis Study* |
| Appendix B: | Navigant Whitepaper<br>*Whitepaper: Analysis of the EIA Export Report 'Effect of Increased Natural Gas Exports on Domestic Energy Markets' Dated January 19, 2012* |
| Appendix C: | ECONorthwest Construction Study<br>*An Economic Impact Analysis of the Construction of an LNG Terminal and Natural Gas Pipeline in Oregon* |
| Appendix D: | ECONorthwest Operations Study<br>*An Economic Impact Analysis of Jordan Cove LNG Terminal and Pacific Connector Gas Pipeline Operations* |
| Appendix E: | ECONorthwest Upstream Contributions Study<br>*Upstream Economic Contributions of the Jordan Cove Energy Project* |

Appendix F: ECONorthwest Balance of Trade Study
*Effect of the Jordan Cove Energy Project's LNG Exports on United States Balance of Trade*

Appendix G: Verification

Appendix H: Opinion of Counsel

## VIII.
## CONCLUSION

Jordan Cove respectfully requests that DOE/FE find that Jordan Cove's proposed exportation of LNG to non-FTA nations is consistent with the public interest and grant Jordan Cove's request, as more fully described in this application, for long-term, multi-contract authorization to export, on its own behalf and as agent for others, up to the equivalent of 292 Bcf per year (six million mtpa of LNG) for a 25-year term, commencing on the earlier of the date of first export or the date seven years from the date the requested authorization is granted, to any nation that currently has or that develops the capacity to import LNG and with which the United States does not prohibit trade, but with which the United States does not have a FTA. For purposes of this Application, the undersigned certifies that she is a duly authorized representative of Jordan Cove. A verification is attached.

Dated: March 23, 2012

Respectfully submitted,

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# APPENDIX A

# NAVIGANT STUDY

# JORDAN COVE LNG EXPORT PROJECT MARKET ANALYSIS STUDY

**Prepared for:**
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NAVIGANT

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## Summary of Assignment

Jordan Cove Energy Project, LP (Jordan Cove or JCEP) is considering the export of liquefied natural gas (LNG) at Coos Bay, Oregon, where it has already received Federal Energy Regulatory Commission (FERC) authority to construct an LNG import facility. In support of this possible export project, JCEP requested Navigant Consulting, Inc. to provide an outlook for the North American 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 electricity, Navigant develops a forecast of the North American natural gas market in the spring and fall of each year. This report for JCEP builds on Navigant's Spring 2011 Reference Case forecast released in July 2011 and Navigant's market expertise and market research. Where appropriate, Navigant's supply forecast has been benchmarked to the latest U.S. Energy Information Administration's 2011 Annual Energy Outlook forecast as well as other supply forecasts that are publicly available.

Navigant developed four scenarios to model realistic circumstances under which JCEP exports may occur. These scenarios were designed to test the potential effect that the JCEP export project may have on prices, given certain assumptions regarding future supply, demand, infrastructure development, and economic activity. These 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:

- Gas drilling trends
- Hydro fracturing – its impact and risk factors
- Infrastructure developments
- The effects and outlook for oil and gas prices
- Gas pricing relative to oil
- Price volatility
- Outlook for economics of gas supply
- Imports (Canada, Mexico, regasification) / exports (LNG, Mexico, Canada)
- Supply balance overview by region
- Frontier gas supply
- Comparative analysis of supply forecasts
- Demand as a factor for gas supply sustainability in a surplus market
- Demand factors affecting gas supply – electric generation (coal, nuclear, renewables, NGVs)

## 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 technological breakthroughs over the last four years.

It is Navigant's assessment that North American gas resources are ample to support the creation and ongoing operation of a domestic LNG export industry through the study period, including JCEP's proposed liquefaction facilities at Coos Bay, Oregon.

It is also Navigant's finding that the effect of the Jordan Cove LNG export project on natural gas commodity prices in the national gas market is negligible. In the local Pacific Northwest market at Sumas, prices remain essentially flat in 2025 and 2035 compared to the Reference Case; in 2045 Sumas prices increase 3.9 percent. At Malin on the California-Oregon border, prices increase by 2.7 percent in 2025, 3.1 percent in 2035 and then by 7.2 percent in 2045.

Importantly, Navigant finds that absolute prices at Henry Hub, Sumas, and Malin in the Jordan Cove Export Case are below $8.00 until 2045 at the very end of our analysis term.

Several facts support Navigant's findings.

- Dry gas production in the U.S. is up 28 percent, from about 49.5 Bcfd to 63.4 Bcfd, from 2004 through the first nine months of 2011.

- Navigant projects U.S. dry gas production alone (excluding Canada) to grow to 81.6 Bcfd by 2045 in its Spring 2011 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 most recent estimate of dry natural gas resources in the United States 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 84.6 Bcfd (30.9 Tcf per year), this represents more than 82 years of supply. (The difference between U.S. demand of 84.6 Bcfd and U.S. supply of 81.6 Bcfd is made up primarily by pipeline imports from Canada, plus a small amount of LNG imports.) Using Navigant's 2008 estimate of 2,247 Tcf for dry natural gas resources, U.S. supplies would last 94 years.

- New shale discoveries have been identified and the productive potential of others has been revised upward with regularity over the past three years. 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. The National Energy Board of Canada recently estimated total gas in place for the Horn River Basin alone to be a minimum of 372 Tcf. The previous estimate of minimum gas in place for the *combined* Horn River Basin, Liard

Basin, and Cordova Embayment was 144 Tcf. Thus the current NEB estimate reflects an increase of 258 percent for the Horn River Basin alone, excluding the other two basins. Navigant expects this trend towards identifying a larger resource base to continue in the near term in both the U.S. and Canada, with natural gas from both countries available for export via the Jordan Cove export project.

- Navigant's modeling shows that the gas feedstock for Jordan Cove will initially be provided mainly from Canadian resources. Over the term of our analysis, Navigant forecasts increasing supply from U.S. sources. GTN is expected to have significant excess pipeline capacity due to gas-on-gas competition with Ruby Pipeline, which was designed to displace Canadian supply from the California market in favor of Rockies supply. Ruby has been operating in such a fashion since commencing operations in July 2011. In 2017, Jordan Cove is supplied 70 percent by Canadian gas and 30 percent by Rockies gas, shifting to 35/65 by 2045. Over the timeframe of the study (2012-2045), Navigant's modeling indicates that the aggregate total feedstock flowing through the Jordan Cove export project will be supplied in roughly equal parts by U.S. and Canadian supplies.

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. That consensus is no longer operative. The situation in North America has reversed from an expectation of domestic supply deficit to an expectation of domestic supply abundance. Prices that were expected to be high and volatile are now expected to be moderate and relatively stable as a result of the technological breakthrough of gas shale development.

The new consensus, which Navigant was instrumental in establishing, 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.

An unappreciated but 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 can help support ongoing supply development and help keep domestic gas prices stable. This is based on the fundamental resource being available – which we believe will be the case.

In all scenarios Navigant prepared for Jordan Cove 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 $158 per barrel, which is equivalent to $27.25 per MMBtu. In the highest gas price scenario modeled, the GHG Demand Case, gas prices only attain $10.30 per MMBtu in the national market at Henry Hub and less than $10.00 per MMBtu in the regional Pacific Northwest market closest to the Jordan Cove export project (see Table 1 below). The price comparison of natural gas to oil is important to the longer term competitiveness of natural gas in North America.

| Year | Metric | Reference Case | Jordan Cove Export | Aggregate Export | GHG Demand |
|---|---|---|---|---|---|
| 2025 | *Henry Hub* | $5.51 | $5.55 | $5.92 | $6.88 |
| | *Malin* | $5.15 | $5.29 | $5.55 | $6.49 |
| | *Sumas* | $5.28 | $5.26 | $5.53 | $6.46 |
| 2035 | *Henry Hub* | $7.31 | $7.35 | $7.66 | $9.33 |
| | *Malin* | $6.81 | $7.02 | $7.29 | $8.55 |
| | *Sumas* | $6.97 | $6.98 | $7.25 | $8.23 |
| 2045 | *Henry Hub* | $8.28 | $8.30 | $8.55 | $10.31 |
| | *Malin* | $7.57 | $8.11 | $8.39 | $9.72 |
| | *Sumas* | $7.75 | $8.05 | $8.32 | $9.47 |

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

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

## Supply Outlook to 2045

Overall 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, but it has been the ramping rates of gas shale production growth that has been the biggest contributor to overall gas supply abundance.

Before the advent of significant shale gas production, natural gas development was susceptible to booms and busts. Investment in both production and usage seesawed on the market's perception of future prices. That perception was driven by uncertainty around the exploration risk associated with finding gas supply to meet demand, both for the short and long terms. The investment cycle for supply was frequently out of phase with demand, due to the uncertainty of the exploration process (and at times the availability of capital to fund such discovery) required for the development of the LNG industry (on the supply side) and for the development of gas fired electric generating facilities and other large users (on the demand side).

To connect supply and demand, pipeline infrastructure was required and 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 help to foster a dynamic of natural gas price volatility. The volatility itself affected 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.

The dependability of shale gas production as a result of its abundance has the potential to improve the phase alignment between supply and demand, which will in turn tend to lower price volatility. The vast size of the shale gas resource will support a much larger demand level than has heretofore been seen in North America at prices that are less volatile.

Navigant expects gas production to continue to grow steadily throughout the forecast period, as shale gas is a relatively new resource in the early stages of development. Our forecast for production, based on our Spring 2011 Reference Case, is shown in ***Figure 1:*** *North American Natural Gas Supply Projection*. Navigant projects that North American-produced supply will be 107.1 Bcfd by the year 2045. By that year, U.S.-produced supply alone is projected to be 81.7 Bcfd, as shown in ***Figure 2:*** *U.S. Natural Gas Supply Projection*.

As we point out in further detail in the report, both Canadian and U.S. gas supply resources are important for the Jordan Cove export project. Over the forecast period, modeling indicates that most of the gas exported at the Jordan Cove export project in the first decade of operation will be Canadian supply. The ongoing continuation of net pipeline imports in aggregate to the large U.S. market over the term of the study period is shown in Figure 2 below. A portion of these Canadian imports will supply the Jordan Cove LNG export project.

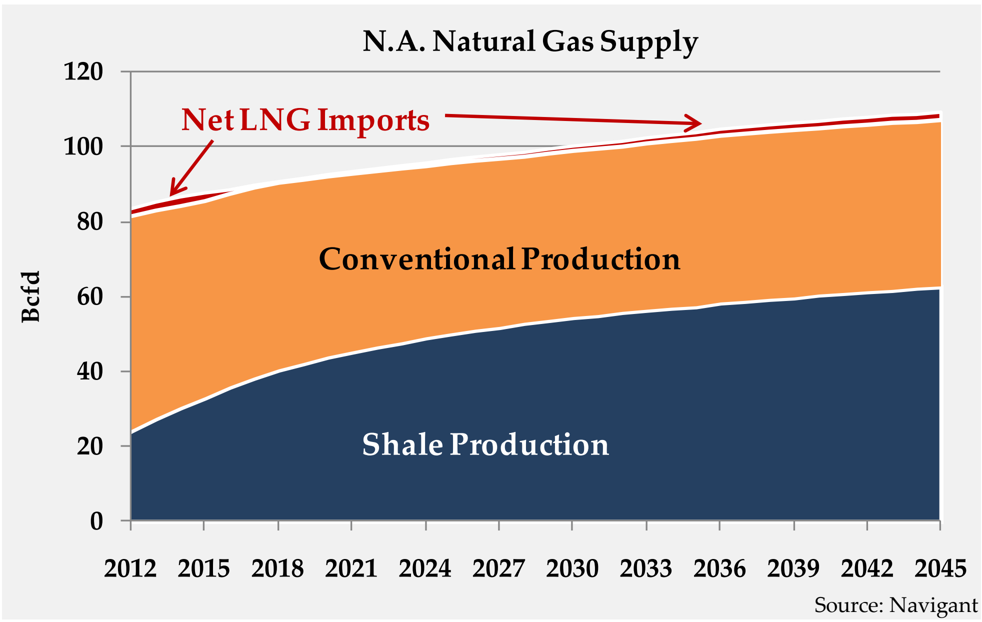


**Figure 1: North American Natural Gas Supply Projection**

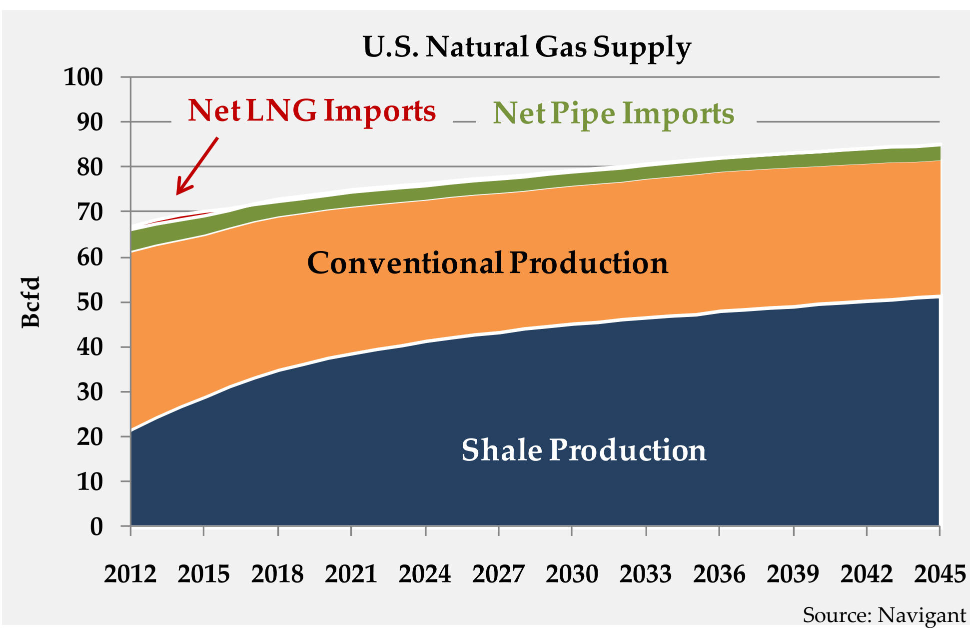


**Figure 2: U.S. Natural Gas Supply Projection**

With this moderated and controlled supply growth, demand and pipeline investment are expected to grow in a measured fashion, with price volatility relatively limited. This will tend to create a healthier and more stable long-term market for natural gas, with the ability for supply and demand to be in much closer balance in aggregate than has been the case in the past.

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 Jordan Cove, neither the Mackenzie Pipeline Project nor the Alaska Pipeline Project has been forecast to be on-stream during the term of our Jordan Cove analysis. We note that the governor and legislature of Alaska recently announced they favor 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.)

## 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, (trace amounts of methane were often detected as drillers penetrated shale on the way to a conventional reservoir), such resources had been uneconomic to recover.

### Improvements in Hydraulic Fracturing and Horizontal Drilling

Natural gas prices increased substantially in the first decade of this century, and culminated in significantly higher prices in 2007-2008, as shown in **Figure 3:** *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 refined and systematized in ways that 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 report,[2] domestic gas production from shale began to overtake imported LNG as the gas supply of choice in North America. The evolution of these cost-effective technologies was the key to unlocking that potential.

[2] 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

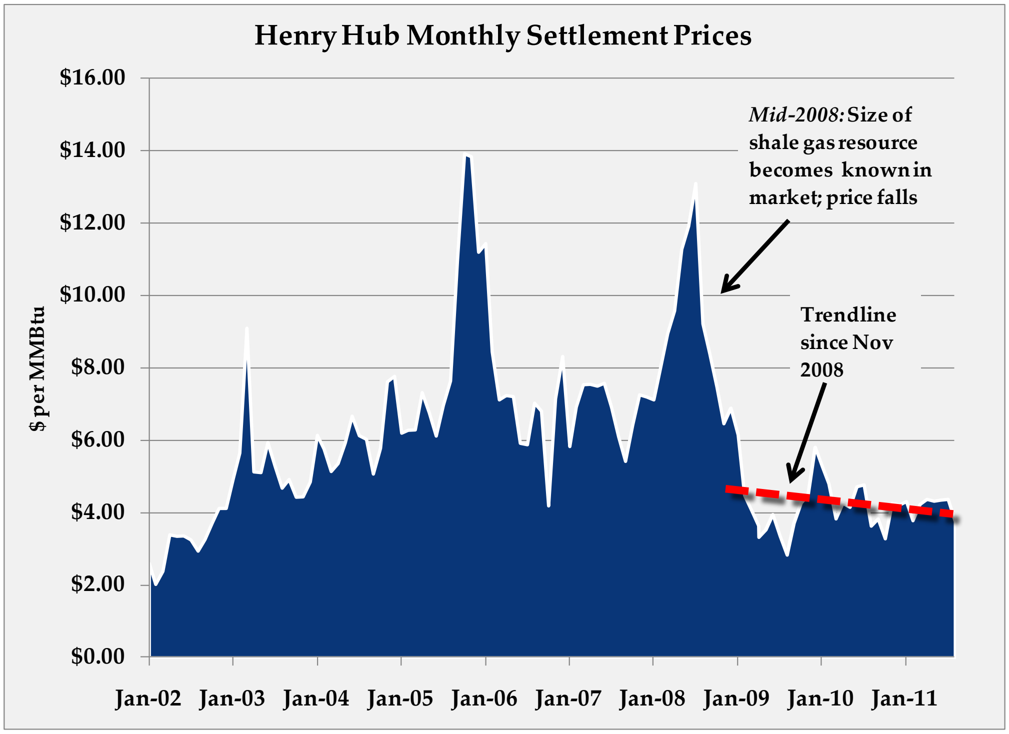


**Figure 3: Henry Hub Price History**

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

Improvements continue in other aspects of hydraulic fracturing technology. Much attention is being focused on water usage and disposal. Several states, including Texas and Wyoming, have passed legislation that requires the contents of chemicals used in the hydraulic fracturing process to be disclosed. The U.S. Environmental Protection Agency is investigating the potential impacts of hydraulic fracturing on drinking water resources. 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.[3] 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.

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[3] "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

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 49.7 Bcfd in August 2005 to about 63.6 Bcfd in August 2011, even as overall rig counts fell from 1,170 to 890. (September was not used for this calculation to discount the production losses from Hurricanes Katrina and Rita in 2005.) This is an increase in gas production of 28 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 and the decrease in vertical (conventional) rig counts. (See **Figure 4:** *U.S. Gas Production and Rig Count History* and ***Figure 5:*** *U.S. Gas Rig Type Shift*.)

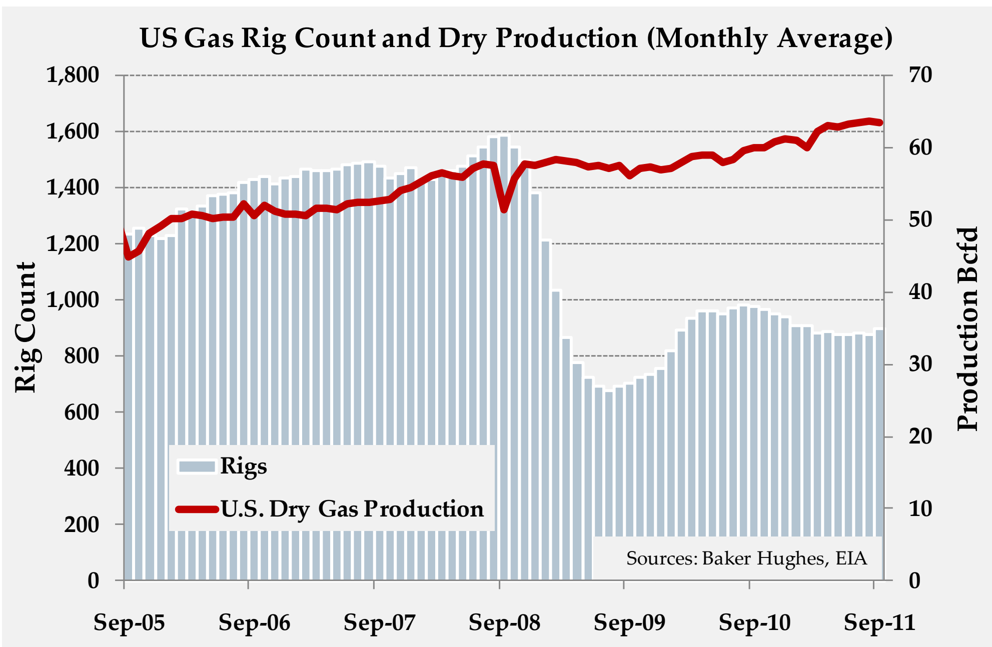


**Figure 4: U.S. Gas Production and Rig Count History**

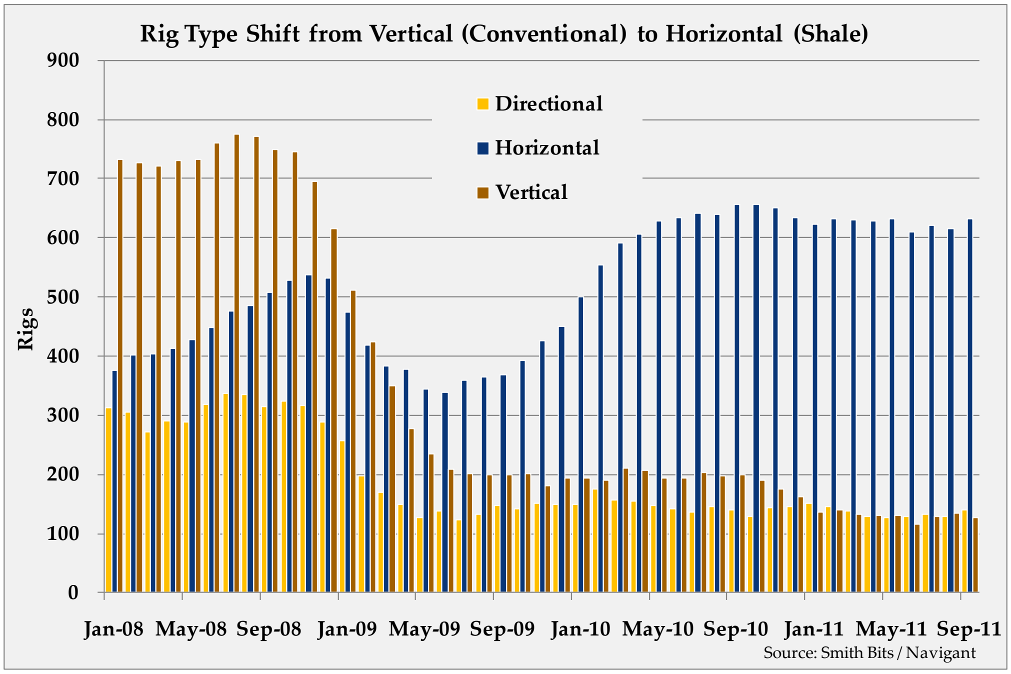


**Figure 5: U.S. Gas Rig Type Shift**

The growth in shale gas production has been prolific, as shown in the graph in **Figure 6:** *Shale Production 2007-2011*. Shale output from eight major basins under development in North America grew from 3.0 Bcfd in the first quarter of 2007 to 20.7 Bcfd in the second quarter of 2011, an increase of more than 580 percent in a little more than four years.

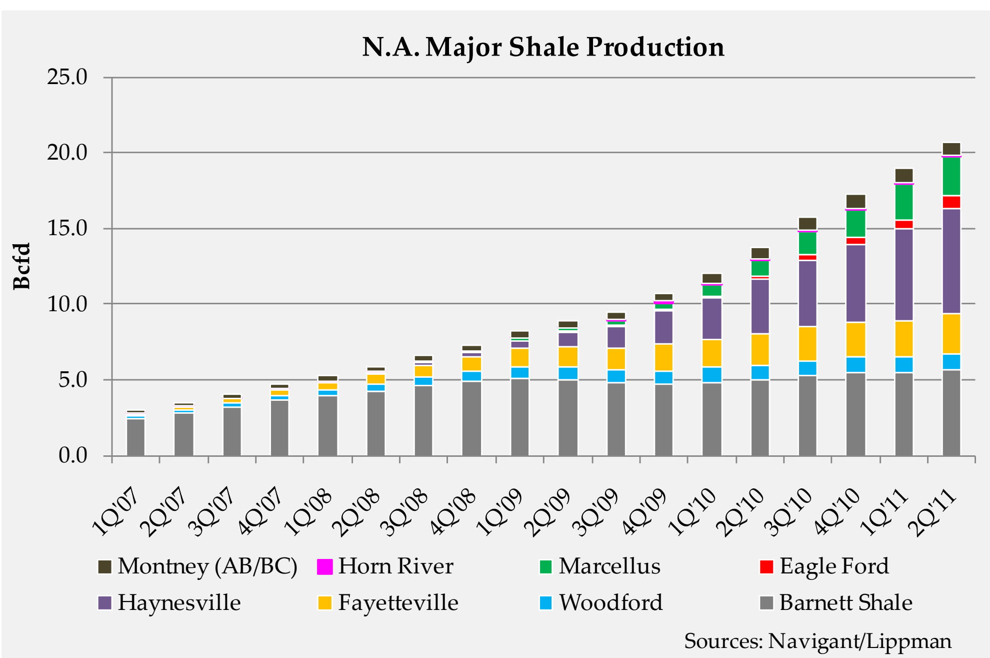


**Figure 6: Shale Production 2007-2011**

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 7:** *EIA Lower-48 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.[4] This is sufficient to satisfy U.S. current annual demand of approximately 24 Tcf per year for 94 years. In its *Annual Energy Outlook 2011*, the EIA's estimate for technically recoverable unproved shale gas resources in the U.S. in its reference case is 827 Tcf not far from Navigant's estimate of 842 Tcf in 2008.[5] The EIA's estimate of *total* dry natural gas resources in the United States is 2,543 Tcf. This is more than 100 years of supply at current usage rates.

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 is clearly in the early phases of discovery for the resource.

[4] *North American Natural Gas Supply Assessment*, by Navigant Consulting for American Clean Skies Foundation, July 4, 2008, available at http://www.cleanskies.org/pdf/navigant-natural-gas-supply-0708.pdf

[5] *Annual Energy Outlook 2011*, EIA, p. 2.

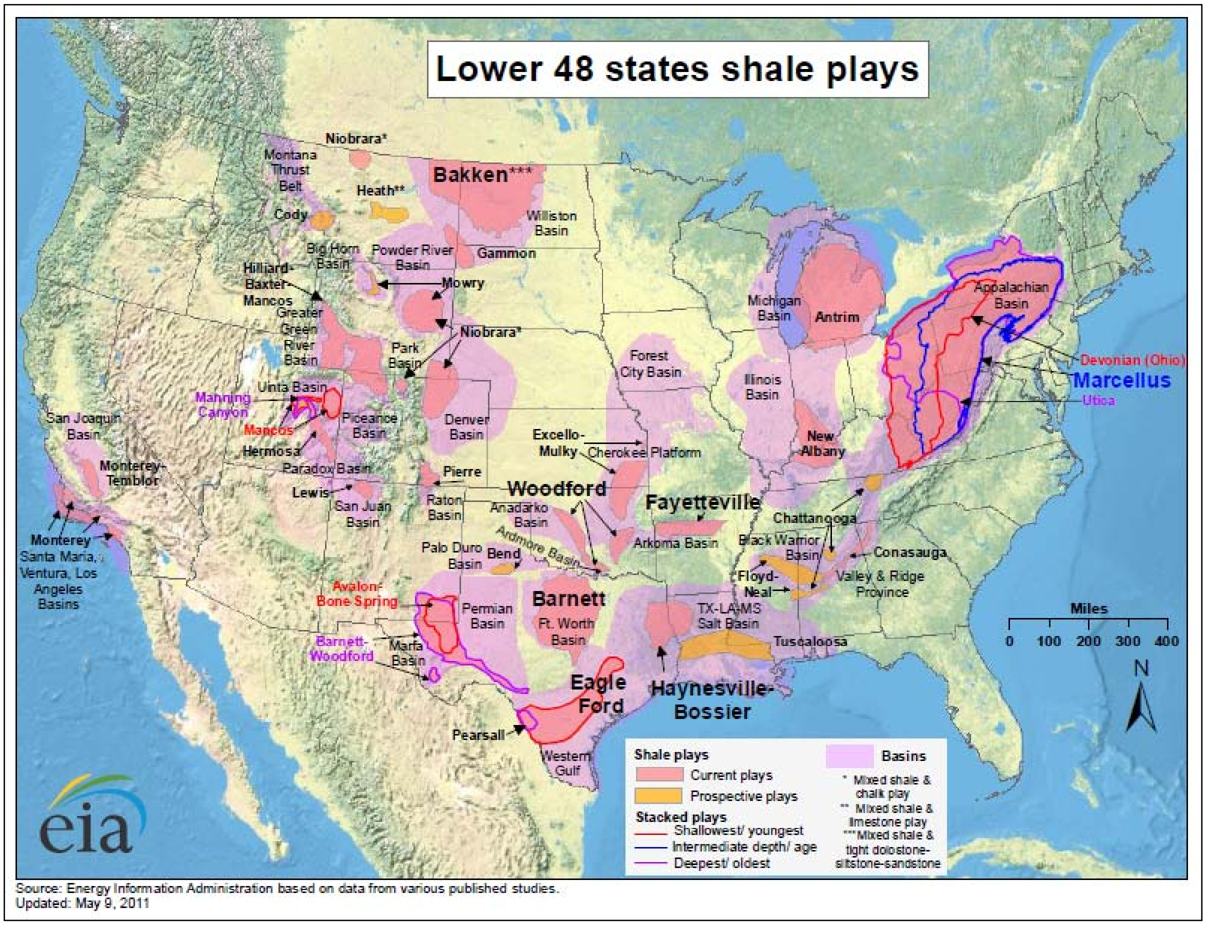


**Figure 7: EIA Lower-48 Shale Play Map (2011)**

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 geology at Penn 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.[6] In 2010, the entire United States used about 24 Tcf per year, or less than five percent of the Marcellus's potential production.[7] Another recent study by Penn State estimates that production from the Marcellus will grow from 327 million cubic feet per day during 2009 to 13.5 billion cubic feet per day by 2020.[8]

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

[7] 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

[8] *The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update,* Penn State University, May 24, 2010, p. 19.

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."[9] In 2009, the Potential Gas Committee of the Colorado School of Mines estimated that the recoverable natural gas resource in North America is 2,170 Tcf, an increase of 89 Tcf over their previous evaluation. This is enough to supply domestic needs at 2010 usage rates (66.1 Bcfd) for 90 years. Of this total, 687 Tcf is shale gas.[10]

Of significant importance to the Jordan Cove export project is the state of the natural gas resource base in Canada which is expected to supply a large portion of the natural gas to be converted to LNG at Jordan Cove.

The British Columbia Ministry of Energy and Mines and the National Energy Board (BCMEM) recently 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.[11] 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. Total gas in place for the Horn River Basin alone was estimated to be a minimum of 372 Tcf. Other estimates for the Horn River have been even higher. RBC Capital Markets estimates that 500 Tcf of gas is in place. At recoverable estimates of 20 to 40 percent, that resource would support 100-200 Tcf of recoverable reserves.[12] In other estimates by the BCMEM, the minimum estimate of gas in place for the *combined* Horn River Basin, Liard Basin, and Cordova Embayment is 144 Tcf.[13] Thus the current NEB estimate reflects an increase of 258 percent for the Horn River Basin alone, excluding the other two basins. Navigant expects this trend towards identifying a larger resource base to continue in the near term in both the U.S. and Canada, with natural gas from both countries available for export via the Jordan Cove export project.

For the other major gas shale basin in B.C., the Montney play has been estimated by the James A Baker III Institute for Public Policy at Rice University to contain 65 Tcf of mean technically recoverable resources.[14] Based upon 2009 gas demand in B.C. (about 386 Bcf) and the estimates of marketable supply for the Horn River and recoverable reserves for the Montney basins, the combined

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[9] 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.

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

[11] *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, pp 18-24.

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

[13] Ibid., p 11.

[14] T*he Rice World Gas Trade Model: A Discussion of Reference Case Results*, Kenneth B. Medlock III, James A Baker III Institute for Public Policy, Rice University, April 19, 2011, p. 20.

resource base for these two BC basins alone would support consumption in B.C. for more than 370 years.[15]

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 2045 as well as the demand added by JCEP's proposed liquefaction facilities at Coos Bay. It has also been our finding that the price impact of such increased demand is marginal as we show in our detailed modeling that is key to our report.

### Character of the Shale Gas Resource

The character of the shale gas resource reinforces its future growth potential. Finding economically producible amounts of conventional gas has historically been expensive due largely to geologic risk. Dry or quickly depleted wells are not uncommon in the conventional gas world. Conventional gas is usually trapped in porous rock formations, typically sandstone, under an impermeable layer of cap rock. It is produced by drilling through the cap into the porous formation, liberating the gas. Despite advances in technology, finding and producing conventional gas still involves a significant degree of 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 economical.

In unconventional shale gas, geologic 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 allows supplies to be produced in concert with market demand requirements and economic circumstances.

Gas in a shale formation is entrained in the rock itself. It does not accumulate in pockets under cap rock. It 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

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

percent of initial production, the expectation is that production will then continue at that lower rate with a very slow decline for many years. The graph below typifies a shale well decline curve. [16]

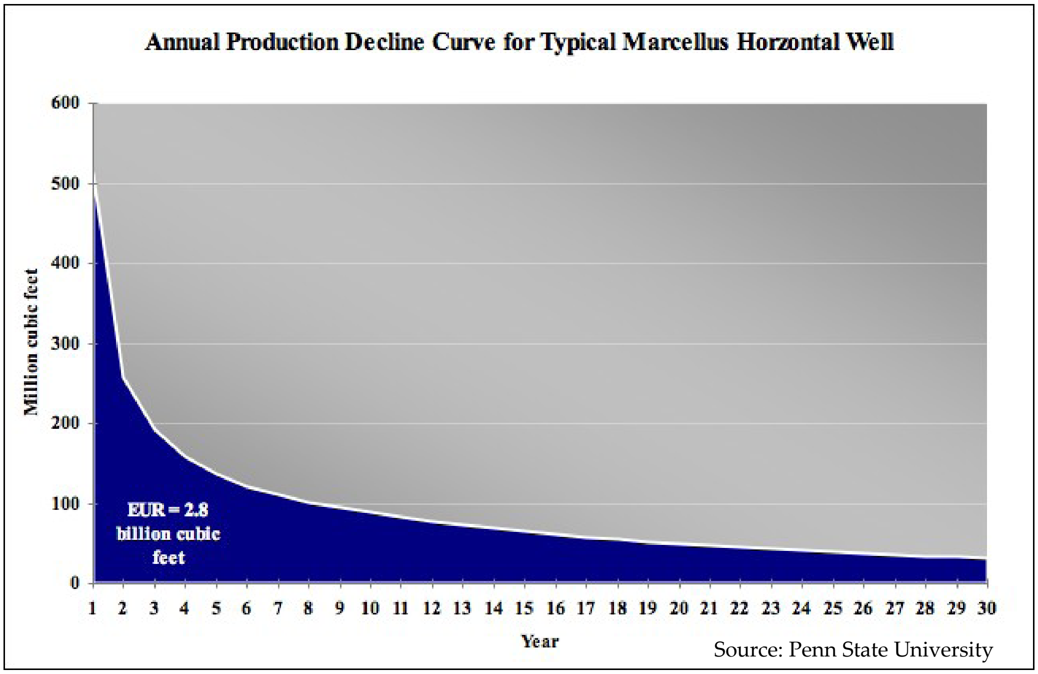


**Figure 8: Shale Gas Well Decline Curve**[17]

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 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. Associated 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, that track crude oil prices. Oil prices can offer a significant premium to natural gas on a per-MMBtu basis, as is currently the case. Oil at $100 per barrel equates to about $17.25 per MMBtu.

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,

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[16] *The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update,* Considine, Watson, and Blumsack, Penn State University, May 24, 2010, p. 16, available at http://www.energyindepth.org/wp-content/uploads/2009/03/PSU-Marcellus-Updated-Economic-Impact.pdf

[17] Typo in title is in the original as published by Penn State.

but economically superior, to the Eagle Ford."[18] The development of estimates for associated gas reserves are in the early stages and run from 2.0 Tcf to 69 Tcf but in any event are very significant in their own right. [19]

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 in addition to shale gas. This has the potential to incent additional gas shale 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 thereby and leverage investments in upstream drilling and completion activities across greater volumes of gas. In some pure gas shale plays, costs have been reported as below $3.00 and even below $2.00 per MMBtu to find and develop. These costs appear to be at the lower end of the spectrum of minimum prices required across the entire gas shale resource. Most shale gas plays appear to be economic in the $4.00 to $6.00 range.

In NGL 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 above, the price of liquids is several multiples higher than the price of natural gas on a per-MMBtu basis. Navigant forecasts NGL and crude oil prices to be higher than natural gas on a per MMBtu basis for the term of the Jordan Cove analysis.

The EIA, in its *International Energy Outlook 2011*, projects worldwide demand for liquid fuels to grow from 85.7 million barrels a day in 2008 to 112.2 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 $125 per barrel by 2035.[20] This is approximately $21.50 per MMBtu and compares to gas prices in 2035 that Navigant forecasts to be $7.31 per MMBtu in the Jordan Cove Reference Case. High oil prices are expected to encourage liquids production which will be accompanied by additional associated gas production.

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[18] Chesapeake Energy, *October 2011 Investor Presentation*, available at http://www.chk.com/Investors/Documents/Latest_IR_Presentation.pdf

[19] http://oilshalegas.com/uticashale.html

[20] *International Energy Outlook 2011*, EIA, p. 25, available at http://www.eia.gov/oiaf/ieo/liquid_fuels.html

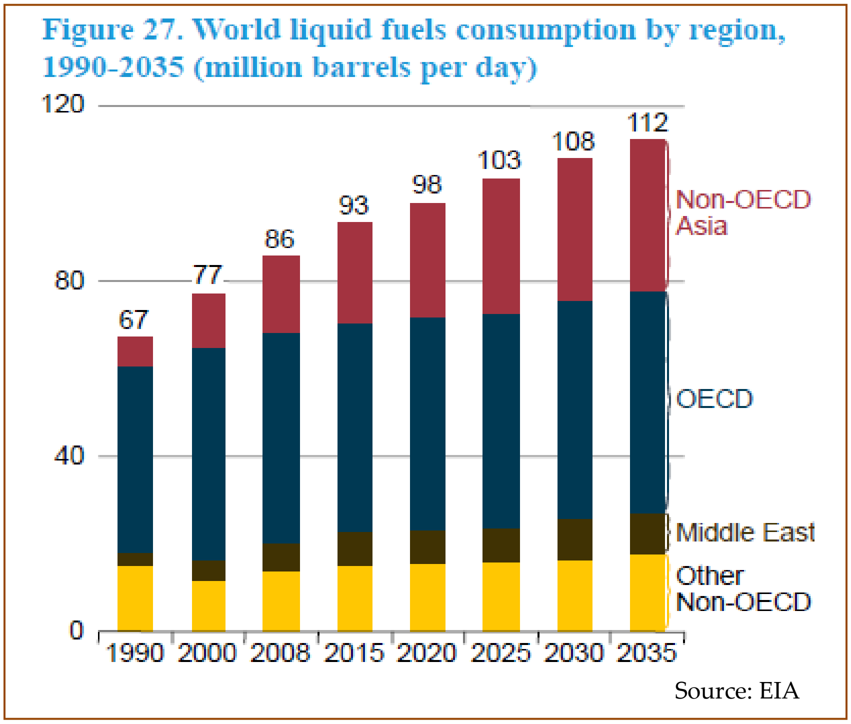


**Figure 9: World Liquids Consumption from EIA International Energy Outlook 2011**

## Comparison of Navigant's Supply Outlook to Other Outlooks

In **Figure 10:** *Supply Outlook Comparison: Navigant and EIA*, Navigant's Spring 2011 shale production forecast calls for more gas to be brought on between now and 2020 than does EIA in its *Annual Energy Outlook 2011*. Navigant is comfortable in its production estimates and believes them to be conservative. After 2020, growth rates between the Navigant and EIA forecasts are roughly parallel. As the graph also shows, both Navigant and EIA increased their post-2020 estimates for shale production this year compared to 2010 by roughly the same amounts.

EIA has historically lagged in the recognition of the size of the shale gas resource in its forecasts. As shown in **Figure** *6: Shale* Production 2007-2011, above, shale production in the U.S. in the second quarter of 2011 is over 20.0 Bcfd. EIA's forecast of 15.0 Bcfd for 2011 therefore has already been eclipsed. The growth in gas production has been so rapid that most forecasters have had difficulty keeping up.

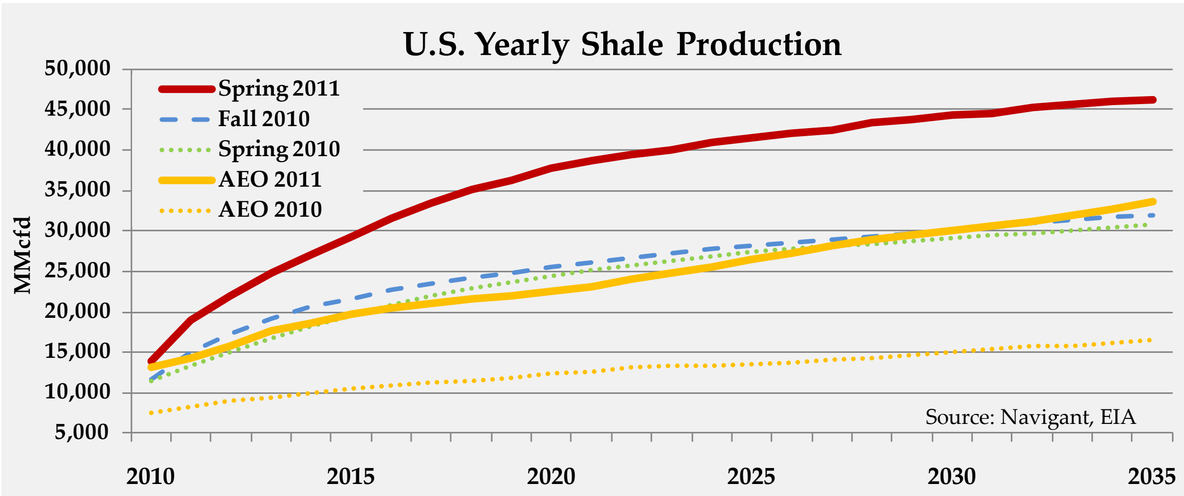


**Figure 10: Supply Outlook Comparison: Navigant and EIA**

| Year | Navigant Spring 2011 | Navigant Fall 2010 | Navigant Spring 2010 | EIA AEO 2011 | EIA AEO 2010 |
|---|---|---|---|---|---|
| 2010 | **13,976** | 11,665 | 11,478 | 13,151 | 7,534 |
| 2015 | **29,276** | 21,659 | 19,586 | 19,726 | 10,548 |
| 2020 | **37,823** | 25,550 | 24,451 | 22,493 | 12,356 |
| 2025 | **41,521** | 28,196 | 27,328 | 26,548 | 13,534 |
| 2030 | **44,250** | 30,049 | 29,155 | 29,973 | 15,068 |
| 2035 | **46,127** | 31,850 | 30,743 | 33,562 | 16,438 |

**Table 2: Supply Outlook Comparison: Navigant and EIA**

## Demand Is Likely to Increase Steadily

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, and demand will not develop unless supply is there to support it. Demand and supply are two parts of the same dynamic.

In Navigant's view, demand is likely to increase over the coming years. Many factors support this outlook.

The chief driver of steadily growing gas demand is the abundance of reliable and economic supply. 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 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.

### Demand by Sector

Navigant projects that the overwhelming majority of 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 4.9 percent through 2015. These expectations are based mainly on expected coal-fired power plant retirements, described later in this report.

Navigant projects industrial demand in the 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.

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

Navigant's sectoral outlook for natural gas demand from its Spring 2011 Reference Case is shown in ***Figure 11:*** *North American Natural Gas Demand Projection*.

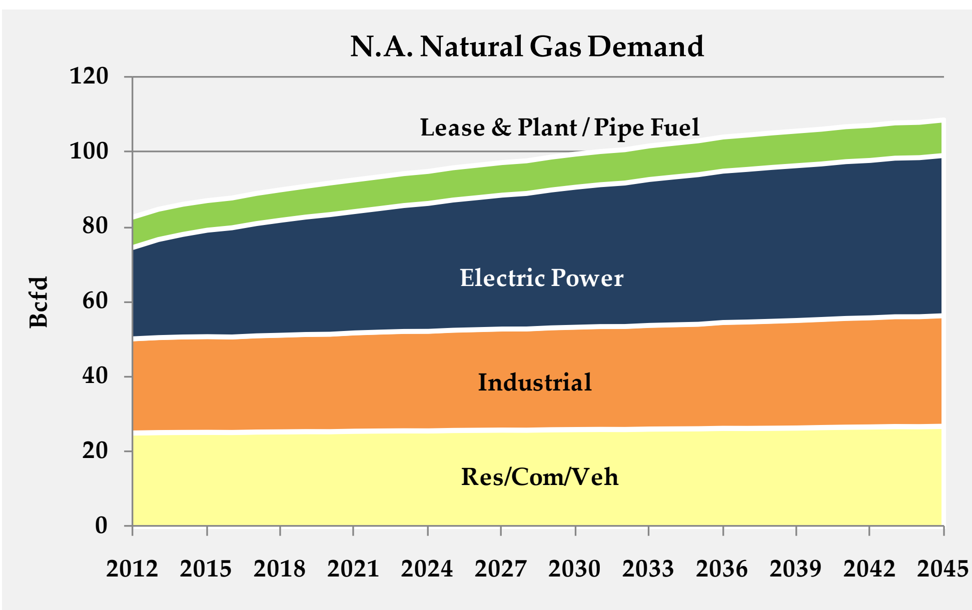


**Figure 11: North American Natural Gas Demand Projection**

As supply abundance creates the potential for an unbalanced market due to relatively slow but steady demand growth, the development of LNG exports can be viewed as a positive development to the long term sustainability of the gas market. Five LNG projects, including JCEP, have received U.S. Department of Energy approval to export natural gas from the U.S. to countries with which the U.S.

has entered Free Trade Agreements (FTA) requiring national treatment for trade in natural gas and LNG. The four projects other than JCEP have also applied for authority to export to non-FTA countries. In May, Cheniere Energy received U.S. Department of Energy approval for the export to non-FTA countries of up to 2.0 Bcfd of LNG from their Sabine Pass terminal. Other applicants whose non-FTA applications are pending are Dominion Cove Point LNG LP, Freeport LNG Development LP, and Lake Charles Exports LLC (with partner BG LNG Services LLC).

LNG export facilities offer the potential for a new baseload market for natural gas and to support ongoing development of the resource. So far, Cheniere is the only U.S. facility in the Lower 48 to have received DOE approval to export domestically-sourced LNG to non-free-trade-agreement countries.

Cheniere's Sabine Pass export facility is not scheduled for start-up until 2016 and will not have market impact in 2011. In fact, none of the announced plans to export U.S.-sourced LNG anticipate start-up before 2016. However, 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. It is becoming increasingly evident that the slow development of new markets for natural gas is the only thing currently restricting even more gas resource development. It is possible that LNG exports may overtake fuel switching from coal plant retirements at some future time 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 JCEP Reference Case from $4.12 per MMBtu in 2012 to $8.28 per MMBtu. 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 12:** *Comparison of Oil and Gas Prices per MMBtu*.

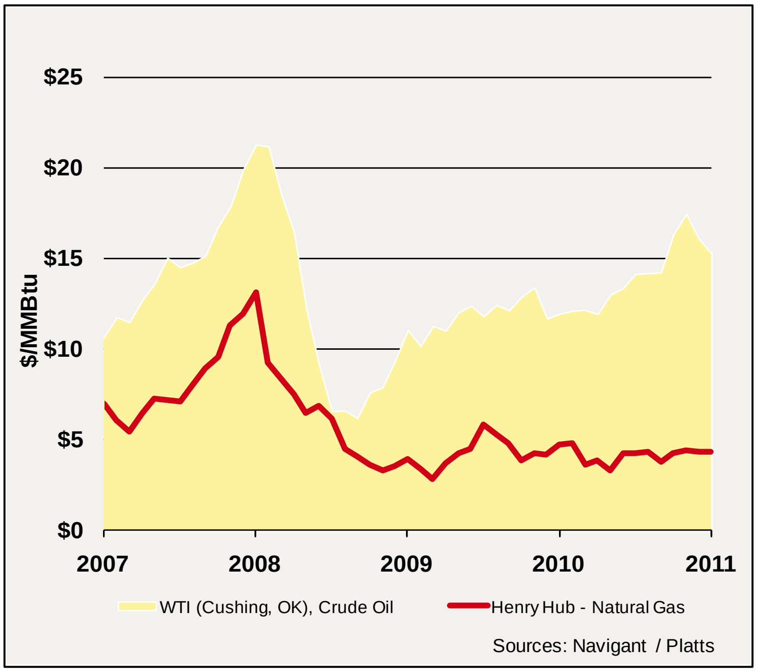


**Figure 12: Comparison of Oil and Gas Prices per MMBtu**

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. The United States imports nearly two-thirds of the oil it consumes.[21] Conventional oil resources in the U.S. have largely 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. It is unlikely that the total oil resource potential in North America has changed recently, 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 tightening environmental regulations, natural gas has been steadily displacing coal as a percentage of megawatt hours generated in the U.S., as shown in ***Figure 13:*** *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 45 percent in 2010. Natural gas, on the other hand, accounted for 14 percent of electric generation in 1997, and grew to 24 percent by 2010.

[21] 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

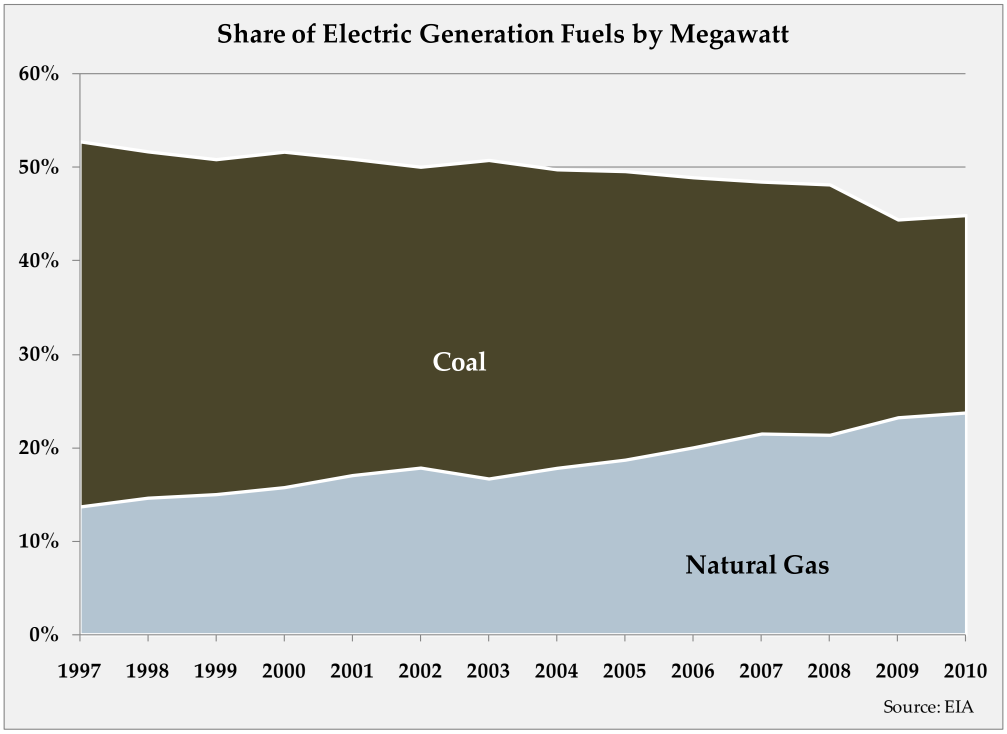


**Figure 13: Coal and Natural Gas as a Percent of Total Megawatt Hours Generated**

Some of the recent displacement of coal by gas as an electric generation fuel is driven by economics. The delivered cost of coal per kilowatt hour of generation has recently averaged slightly 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 July 2011, as shown in **Figure 14:** *Comparison of Electric Generation Fuel Costs*.

Studies by Navigant show 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.

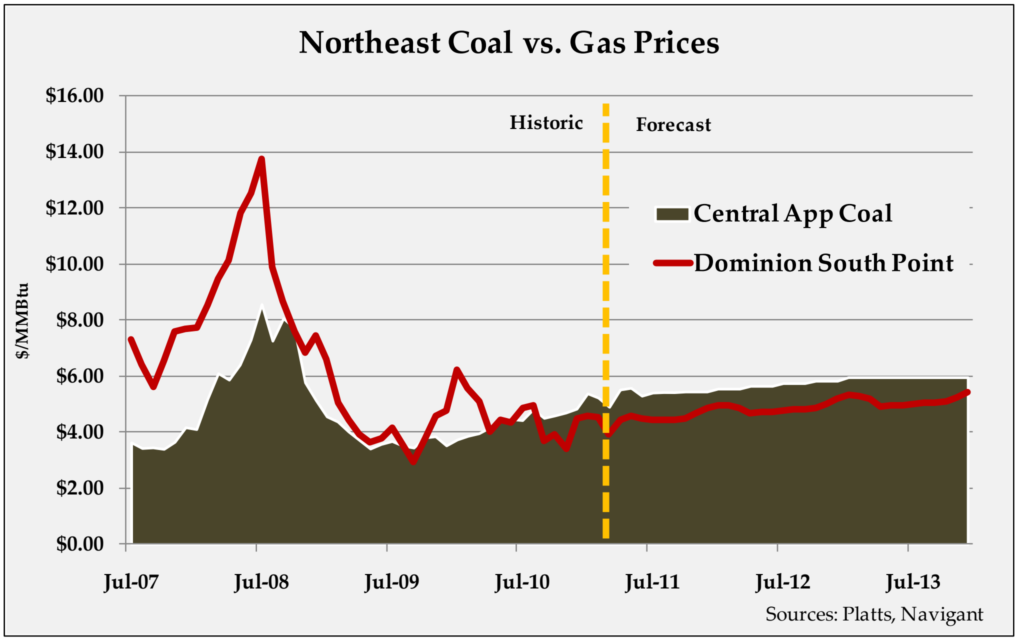


**Figure 14: Comparison of Electric Generation Fuel Costs**

Additional switching may be driven by other factors. Clean coal in the form of carbon capture and sequestration (CCS) has run into further delays, as seen with American Electric Power's July 14 announcement to discontinue its CCS pilot project at its Mountaineer coal-fired power plant in West Virginia.[22]

Coal-fired electric generation is likely to continue to be under pressure from increasingly stringent environmental regulations. According to the news service SNL, the Federal Energy Regulatory Commission recently issued an informal report stating that up to 81 gigawatts[23] of coal- and oil-fired electric generation is "likely" or "very likely" to be retired due to new environmental restrictions, including the Environmental Protection Agency's recently proposed maximum achievable control technology requirement within the proposed Cross-State Air Pollution Rule.[24] CSAPR would institute a stringent national standard on emissions of mercury, arsenic, and other pollutants found in coal and oil, but not in natural gas. While the very large 81 gigawatt estimate is highly fluid and based on assumptions subject to review, it indicates the direction and potential scope of the shift away from fuels with higher emissions burdens than natural gas.

Several major utilities have announced or are actively executing programs to retire coal-fired facilities. For example, Tennessee Valley Authority signed a settlement with the EPA to idle or retire 2,700 megawatts of its 17,000 MW of coal fired capacity (from 18 units) by 2018. Southern Company

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[22] 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.

[23] 1.0 gigawatt equals 1,000 megawatts.

[24] "FERC staff: 81 GW of capacity could be retired due to EPA rules," August 5, 2011, SNL News.

announced that the CSAPR rules would expect to retire 4,000 MW of its 12,000 MW coal-fired fleet, and replace coal and oil with natural gas for another 3,200 MW. American Electric Power states that it will retire almost 6,000 MW of coal-fired generation and refuel 1,070 MW with natural gas in response to the new EPA rules.

The New York Times states that up to 80,000 MW of coal-fired capacity could be supplanted by other fuels or conservation in the U.S. as a result of the new EPA rules.[25] This number is consistent with the FERC number of 81 gigawatts. It represents about eight percent of the U.S.'s electric generating capacity. The EPA's estimate is much lower, 10,000 MW. The rule is still subject to public comment. However, Navigant's view is that the trend toward large-scale coal plant retirements is clear, and that natural gas is the leading replacement fuel choice.

### 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 may result in additional demand for natural gas. Several states have already conducted nuclear power workshops. The eventual impact of the Fukushima disaster on the U.S. nuclear industry is still too early to assess with any precision. However, in the event significant risks are identified, this would likely require the replacement of planned or even existing nuclear generation, with one of the options being gas-fired generation.

Some countries, such as Japan itself and Germany, have already announced plans to reduce their nuclear generation fleet. Germany plans to accelerate the closure of 17 nuclear reactors by 2022. Other countries such as Switzerland and Italy have also indicated signs of retreating from nuclear energy.

On the other hand, France points to the rational cost and carbon emissions advantages of nuclear generation and has reiterated its support for nuclear generation. The UK, Russia, and India have also indicated they are in favor of additional nuclear capacity in their respective countries.

Natural gas is also 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 or support the intermittency of both these forms of renewable electric generation.

Increases in efficiency on the demand side of the gas and electric markets are substitutes for additional fuel supply. Improved energy efficiency is viewed as a positive for the gas market and for the country, and not as competition. As it tends to dampen gas demand in one market segment, it will make the resource base more readily available to serve another.

[25] New York Times, August 12, 2011, p. B3. available at http://www.nytimes.com/2011/08/12/business/energy-environment/new-rules-and-old-plants-may-strain-summer-energy-supplies.html?pagewanted=2&_r=4&ref=energy-environment

## 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 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 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.[26] Many states are considering the mandatory disclosure of hydraulic fracturing chemicals; Wyoming, Texas, and Colorado already require it.

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 8, significant efforts are already underway to improve water management techniques, including reuse in the production of shale gas. As reported in the July 2011 edition of the Journal of Petroleum Technology, flowback water is being treated on site and recycled not merely to comply with regulations but to reduce water acquisition and trucking costs in many places.[27]

Recently, the Natural Gas Subcommittee of the Secretary of Energy Advisory Board (SEAB) in its 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. [28] The SEAB 90-day report also states that "Natural gas is a cornerstone of the U.S. economy… 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."[29]

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.

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[26] http://fracfocus.org/

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

[28] 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

[29] Ibid, pp. 1, 9.

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 for the natural gas industry. Carnegie Mellon University released a study report which states that "[n]atural gas from the Marcellus shale has generally lower life cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability."[30] 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."[31] 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.[32] A recent study conducted by the University of Maryland found that "arguments that shale gas is more polluting than coal are largely unjustified" and that "the greenhouse footprint of shale gas and other unconventional gas resources is about 11% higher than that of conventional gas for electricity generation, and still 56% that of coal." [33]

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 supportive of gas development.

The SEAB has called for independent studies of the life cycle emission from shale gas wells. Navigant views this and any additional study and fact-finding as to the comparative advantages of natural gas to be a positive step forward, and expects the final results to be in line with other studies that have found natural gas to be the cleanest fossil fuel.

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[30] *Life cycle greenhouse gas emissions of Marcellus shale gas*, Jiang, Griffin, Hendrickson, Jaramillo, VanBriesen, and Venkatesh, Carnegie Mellon University, available at http://iopscience.iop.org/1748-9326/6/3/034014/fulltext

[31] *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

[32] *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

[33] *The greenhouse impact of unconventional gas for electricity generation*, Nathan Hultman, Dylan Rebois, Michael Scholten, and Christopher Ramig, October 25, 2011, available at http://iopscience.iop.org/1748-9326/6/4/044008

### Commodity Prices / Reallocation of Drilling Capital

Will the higher price of oil and NGLs 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) 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 September is up from 581 in 2010 to 922 in 2011, or 59 percent.[34]

Despite the shift to oil directed drilling and the fact that gas prices at Henry Hub have declined below the $4.00 per MMBtu area 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 664 to 636,[35] or four percent, dry U.S. gas production has increased from 60.0 Bcfd to 64.0, or 6.7%, over that same period.[36]

Over the last two decades, oil drilling has shifted from the U.S. to more lucrative opportunities elsewhere around the globe. Oil imports comprised 53% of U.S. supply in 2011 through October.[37] Given restrictions put in place on offshore drilling in the wake of Deepwater Horizon, it is believed unlikely, even if those restrictions are lifted, that oil drilling will expand to pre-event levels in the near future. In addition, in oil shale plays such as the Bakken field in North Dakota, large volumes of associated natural gas are being produced which further adds to the availability of natural gas in the country.

As noted earlier in this report, the cost of finding and developing shale gas continues to drop.

Overall, it is Navigant's view that oil drilling will encounter limits in the U.S., due largely to the declining U.S. oil resource base and the prohibition against oil drilling in substantial geographic areas, such as federal parks and certain areas of the outer continental shelf such as California and Florida, and will not cause a drop-off in gas supply.

The fundamental attributes of the natural gas industry including gas shale should allow the market to balance supply and demand. Navigant's Spring 2011 price forecast indicates stability in the $4.00 to $5.00 per MMBtu for the next decade, rising somewhat after 2025 and approaching $8.00 per MMBtu in the late 2030's. At these levels, gas prices will continue to be extremely competitive with oil, which Navigant projects to be two and a half to three times as costly as gas per MMBtu throughout the forecast period.

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[34] Smith Bits.

[35] Smith Bits.

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

[37] EIA, *Weekly U.S. Product Supplied of Petroleum Products* (WRPUPUS2) and *Weekly U.S. Net Imports of Crude Oil* (WCRNTUS2), Navigant calculation.

## Overview of Proposed Energy Operations of Jordan Cove Export Project

The proposed Jordan Cove Energy Project is located at Coos Bay in southern Oregon. JCEP received FERC approval in Docket No. CP07-444 to construct an LNG import facility. FERC also approved the construction of the Pacific Connector Pipeline. JCEP has received authorization from the Department of Energy in Docket No. 11-127-LNG to export LNG from the site to FTA countries. It intends to file applications in 2012 to export to non-FTA countries and to amend its FERC authorization to include authority to construct a dual-use import-export facility.

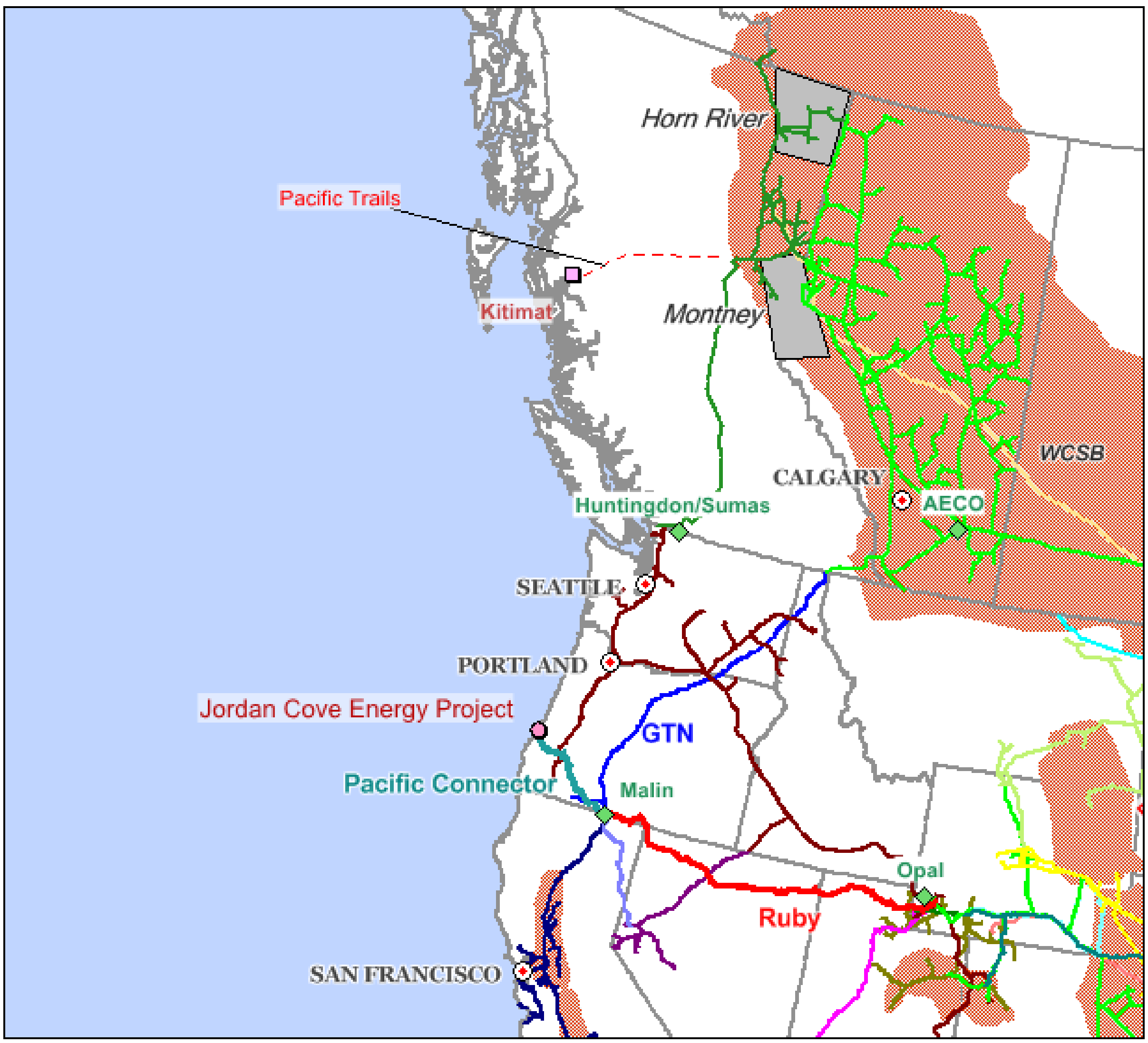


**Figure 15: Jordan Cove Energy Project Location Map**

The Pacific Connector Pipeline, originally intended to carry natural gas derived from imported LNG from Coos Bay to Malin, will transport gas from Malin to the JCEP liquefaction facility Coos Bay. At Malin, Pacific Connector will interconnect with Gas Transmission Northwest Pipeline and Ruby Pipeline. GTN is a 2.2 Bcfd pipeline originally designed to transport Canadian gas to the California border, including gas from the prolific shale resources in eastern British Columbia (Montney and Horn River) as well as conventional gas resources in Alberta. Ruby is a 1.5 Bcfd pipeline that delivers gas to Malin and the California market from the Opal trading hub in Wyoming, which has access to gas supply in the Rocky Mountain basin.

The Pacific Connector Pipeline has an initial capacity of 1.2 Bcfd, more than adequate to carry gas to the proposed 0.9 Bcfd liquefaction facility. Pacific Connector plans to expand to 1.5 Bcfd in 2022. In order to address the Pacific Connector for the present analysis, the Pacific Connector was modeled as a "bullet" line from Malin to Coos Bay. The pipeline may in fact interconnect with Northwest Pipeline, LDCs in Oregon and other systems to meet regional market demand.

Initially, the gas feedstock for Jordan Cove will be provided mainly from Canadian resources. GTN is expected to have significant excess pipeline capacity due to gas-on-gas competition with Ruby Pipeline, which was designed to displace Canadian supply from the California market in favor of Rockies supply. Ruby has been operating in such a fashion since commencing operations in July 2011. Navigant's modeling shows that gas initially exported at Jordan Cove will be 70 percent Canadian gas and 30 percent Rockies gas, shifting to 35/65 by 2045, for an overall ratio across the study period of 50/50.

The Canadian National Energy Board estimates that the Horn River Basin has between 372 Tcf and 529 Tcf of gas in place, with a median value of 448 Tcf. The median estimate of marketable volumes is 78 Tcf. While estimates for the Montney formation are uncertain at this time, Rice University has estimated the Montney mean technically recoverable gas shale resources at 65 Tcf. In addition, significant gas exploration and infrastructure development is taking place in the Montney region. The NEB states in its report ***Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin***: "There are a number of other unconventional natural gas plays in British Columbia … which, if developed, could substantially increase the resources available for Canadian use and export purposes."[38]

[38] NEB, *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, available at http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/hrnrvr/hrnrvrm-eng.html#s3.

## Modeling Overview and Assumptions

Twice a year, Navigant produces a long-term forecast of monthly natural gas prices, demand, and supply for North America. The forecast incorporates Navigant's extensive work on North American unconventional gas supply including the rapidly growing gas shale supply resources. It projects natural gas forward prices and monthly basis differentials at 90 market points, and pipeline flows throughout the entire North American grid. Current projections go through 2035. Navigant's Spring 2011 Forecast (issued in June 2011) forms the basis of the Jordan Cove Export Project analysis. To develop the Reference Case for JCEP, Navigant extended the term to 2045.

Price projections for purposes of this report focus on Henry Hub, which is the underlying physical location of the natural gas NYMEX futures contract and the key North American pricing reference point. Prices at Malin on the California-Oregon border and Sumas at the U.S.-Canadian border are also included in this study to demonstrate the possible effect that JCEP may have on supply and demand on key natural gas markets 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 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 Spring 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 Jordan Cove Reference Case supply projection is that U.S. natural gas supply will grow from 61.4 Bcfd in 2012 to 81.6 Bcfd in 2045, an increase of 33 percent.

As a rule, Navigant's approach towards production capacity is the same for all cases modeled for JCEP. 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 0.7 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 very 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.

An exception is made in the GHG Demand case. In this case, an increase in supply availability across key basins, driven by government policy, is the precipitator of additional demand growth. While no "blanket" additions to supply were made, nor were any new resource plays hypothesized, supply capability was added to certain fields (e.g., the Eagle Ford) as an input assumption.

Reflecting the elasticity of the supply basin to demand signals, the GHG Demand Case supply projection has U.S. natural gas supply growing from 61.2 Bcfd in 2012 to 86.9 Bcfd in 2045, an increase of 42 percent, and 5.3 Bcfd higher in 2045 than in the Jordan Cove Reference case.

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 if economics and policy are supportive.

Gas demand growth in our forecasts is supported 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 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 and 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 the demand for LNG 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. Only the GHG Demand Case includes increased gas demand effects from greenhouse gas reduction legislation.

Navigant has paid particular attention to the concern that exporting LNG from North America will tend to link domestic gas prices to overseas pricing, which has historically been linked to higher-priced oil. In the high-demand GHG Demand Case (detailed below), the annual call on supply is 31.7 trillion cubic feet in 2045. Using the EIA's recent estimate of U.S. technically recoverable reserves of 2,543 Tcf,[39] this would represent only 1.2 percent of total reserves, too small a volume of production to have any appreciable effect upon gas prices in North America.

Navigant furthermore believes it is very unlikely that exports at these levels will increase the need for significant amounts of imported LNG in any of the modeled scenarios. It is more likely that spot LNG cargoes from overseas will land from time to time in the U.S. and accept U.S. domestic pricing when overseas demand is at lower levels, as overseas LNG production capacity is projected to grow, and the U.S. is likely to remain the most liquid market for natural gas in the world, supported by its superior infrastructure (particularly storage) and dependable demand. However, if the modeled imports did not materialize in the future, U.S. supply would be ample to serve both domestic demand and LNG exports.

## 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., Pacific Connector is specifically modeled to support JCEP) 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.

In the case of the GHG Demand scenario, we assumed an expansion of GTN and the western legs of Nova and Foothills Pipeline, by 1.0 Bcfd in 2028. In the absence of such an expansion, the GHG Demand model showed interseasonal instability that would not realistically occur in the market.

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 facing large environmental challenges, absent significant new developments in the marketplace. Likewise, the Alaska Gas Pipeline project is also assumed to be nonoperational over the study period term. In fact, the governor and state legislature of Alaska recently announced they favor a pipeline project from Alaska's North Slope gas resources that delivers to the south coast of the state where it could be

[39] *Shale Gas and the Outlook for U.S. Natural Gas Markets and Global Gas Resources*, presentation of Richard Newell, EIA Administrator to the Organization for Economic Cooperation and Development (OECD), June 21, 2011, p. 13, available at http://www.eia.gov/pressroom/presentations/newell_06212011.pdf

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 Spring 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 may 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 load factors are expected to be lower. The likelihood is that the LNG export facilities will operate initially and perhaps during certain seasonal periods at less than 90 percent of capacity thereby requiring less gas and having an even smaller impact than what is assumed in the analysis.

In order to provide stress scenarios to examine the effect of exporting domestically–sourced LNG, additional LNG export capacity is included in the Aggregate Export and GHG Demand cases. 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 sometime in the 2016-2018 timeframe, as each liquefaction train is assumed to be completed.

| LNG Facility | Export Capacity (Bcfd) | Location | Scenario | | | |
|---|---|---|---|---|---|---|
| | | | *Ref* | *Jordan Cove* | *Aggregate* | *Extreme* |
| Sabine Pass | 2.0 | Cameron Parish, LA | • | • | • | • |
| Kitimat | 0.7 | District of Kitimat-Stikine, BC | • | • | • | • |
| Jordan Cove | 0.9 | Coos Bay, OR | | • | • | • |
| Gulf of Mexico | 2.0 | Texas | | | • | • |
| Mid-Atlanctic | 1.0 | Maryland | | | • | • |
| **Total** | **6.6** | | | | | |

**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 $96 per barrel, in 2010 dollars. In 2045, the price per barrel is $158. For comparison, the EIA's Reference Case projects the price of imported low-sulfur light crude oil to be $94.58 per barrel in 2015 and $124.94 in 2035, in 2009 dollars.

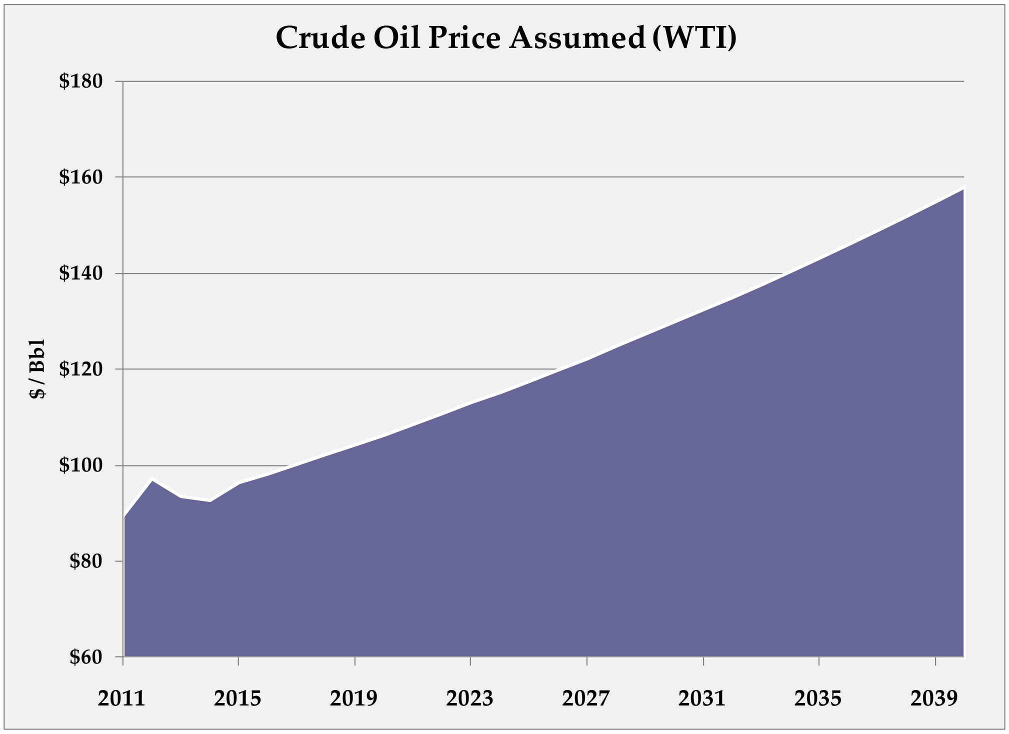


**Figure 16: WTI Price Assumed in Natural Gas Price Forecast**

### Economic Growth

Navigant uses GDP figures from the Congressional Budget Office's Budget and Economic Outlook of January 2011. To extend the outlook beyond the last year, the final year GDP of 2.4 percent is continued to the end of the forecast period.

| 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| 2.7% | 3.1% | 3.1% | 3.5% | 3.8% | 3.0% | 2.5% | 2.4% |

**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, extrapolated to 2045.

### Price Points

Prices for Henry Hub, the location of the North American futures market, are modeled in all outputs. In addition, two other market points are examined. Sumas, Washington, on the British Columbia border, represents the Pacific Northwest market. Malin, Oregon, at the California border, represents the California market.

## Scenario Descriptions

| *Case Name* | *Description* |
|---|---|
| **Jordan Cove Reference Case** | The **Jordan Cove Reference Case** is developed from Navigant's Spring 2011 Forecast of June 2011. The Spring 2011 Forecast incorporates Navigant's extensive work on North American gas shale supply resources. The Spring 2011 Reference Case has been modified to refine the infrastructure assumptions in the Pacific Northwest market based on improved information.<br><br>The Reference Case assumes that two other LNG export facilities in North America will be operational prior to and concurrent with Jordan Cove: 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. |
| **Jordan Cove Export Case** | The **Jordan Cove Export Case** augments the Reference Case with exports from the Jordan Cove export facility of approximately **0.9 Bcfd** beginning January, 2017. No other changes are made. The effects on prices are the specific focus. |
| **Aggregate Export Case** | The **Aggregate Export Case** adds to the Jordan Cove 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 6.6 Bcfd. The effects on prices are the specific focus. |
| **GHG Demand Case** | The **GHG Demand Case** uses the same infrastructure and LNG export assumptions as the Aggregate Export Case, but demand is increased by using figures from the Navigant Spring 2011 *Carbon Case* Forecast. The Carbon Case incorporates the increased gas demand effects of coal-to-gas substitution driven by assumed laws and regulations that favor natural gas's much lower GHG byproducts from combustion compared to coal. The effects on prices are the specific focus. |

## Jordan Cove Reference Case

The **Jordan Cove Reference Case** was derived from Navigant's Spring 2011 Reference Case. Certain refinements to the infrastructure in the Northwest were made, based on more detailed information that was incorporated subsequent to the Navigant Spring 2011 Reference Case. For example, Ruby Pipeline capacity was increased from 1.2 Bcfd to 1.5 Bcfd, based on the actual increase implemented by Ruby in mid-October 2011. In addition, BC Pipeline (formerly Westcoast) was expanded to accommodate increased shale production for the Montney-Horn River area and adjacent shale resources (e.g., Cordoba Embayment).

The 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 is also assumed to come on line in 2015 with exports at 90 percent capacity.

### Supply

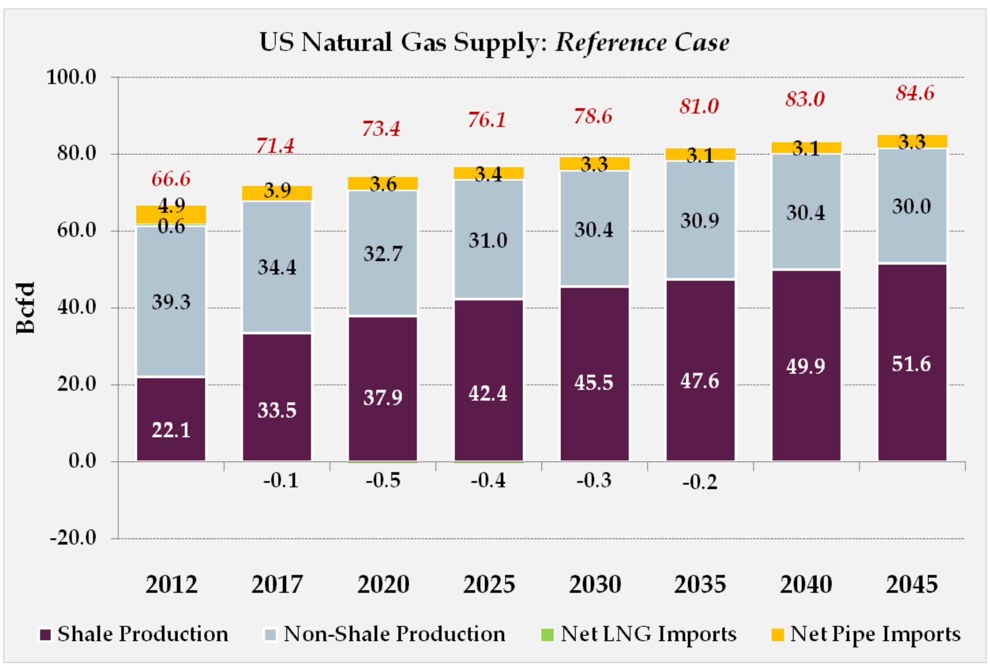


**Figure 17: Reference Case Supply**

Beginning around 2020, net LNG imports to the U.S. are negative, as the U.S. becomes a net exporter of LNG.[40]

## Demand

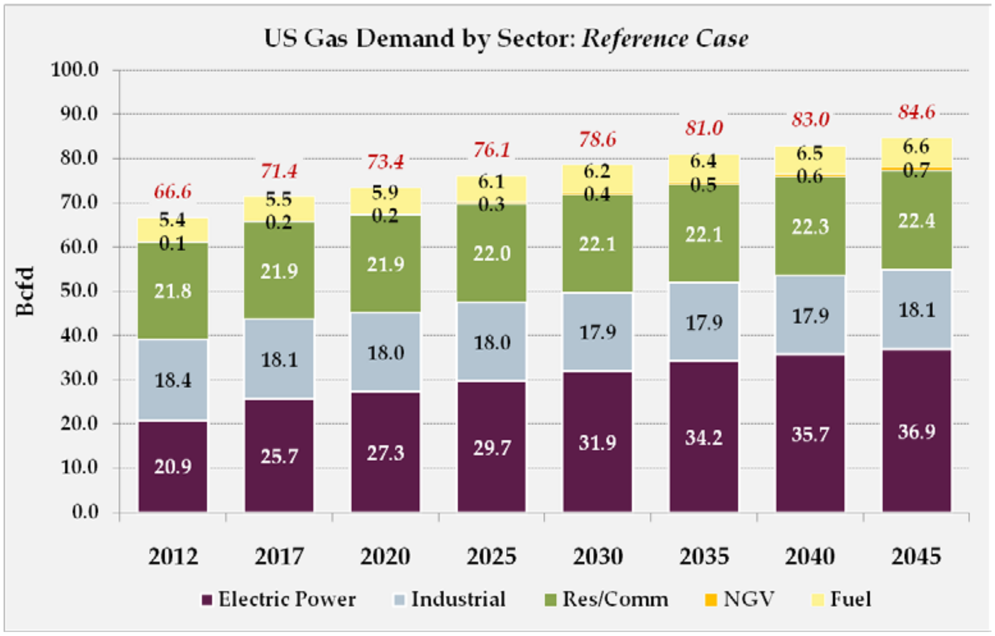


**Figure 18: Reference Case Demand**

Domestic U.S. demand is satisfied across the planning horizon in balance with supply, above.

[40] 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.

### Resultant Gas Prices

Prices at Henry Hub remain below $5.00 per MMBtu through 2020. After 2020, prices rise due to generally increasing marginal costs of additional domestic production. Henry Hub reaches $8.28 per MMBtu in 2045. Prices at Sumas and Malin show a negative basis to Henry Hub throughout the forecast period.

For comparison, the U.S. EIA's Reference Case price forecast for Henry Hub for 2035 (the last year of its forecast) is $7.07 per MMBtu,[41] and Canada's National Energy Board's Henry Hub U.S. dollar denominated price forecast for 2035 is $8.00 per MMBtu.[42] Navigant's Henry Hub price projection for 2035 is $7.31 per MMBtu.

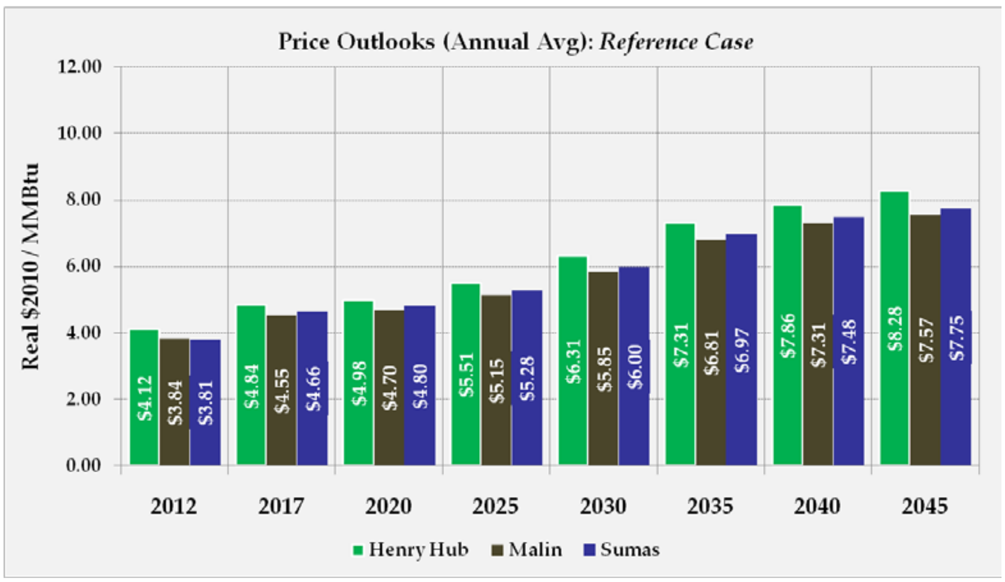


**Figure 19: Reference Case Prices**

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

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

## Jordan Cove Export Case

The **Jordan Cove Export Case** tests the effects of liquefying and exporting 0.9 Bcfd of North American gas from the Jordan Cove Energy Project facility beginning January 2017. All other inputs and assumptions remain the same as in the Jordan Cove Reference Case. Instantaneous daily demand at JCEP is 1.0 Bcfd, if 10% fuel consumption is included. However, on an annual basis, fuel use is offset by a 10% annual maintenance downtime. Therefore, the net average demand of JCEP is 0.9 Bcfd.

The Jordan Cove Export Case also assumes the concurrent commissioning of the Pacific Connector Pipeline from the Malin trading hub to Coos Bay. Pacific Connector is assumed to transport gas delivered to Malin from Canada via Gas Transmission Northwest Pipeline (capacity 2.2 Bcfd) and gas from the Rocky Mountain supply region via Ruby Pipeline (1.5 Bcfd). Pacific Connector was modeled as a "bullet" line, with no interconnections to other pipelines.

### Supply

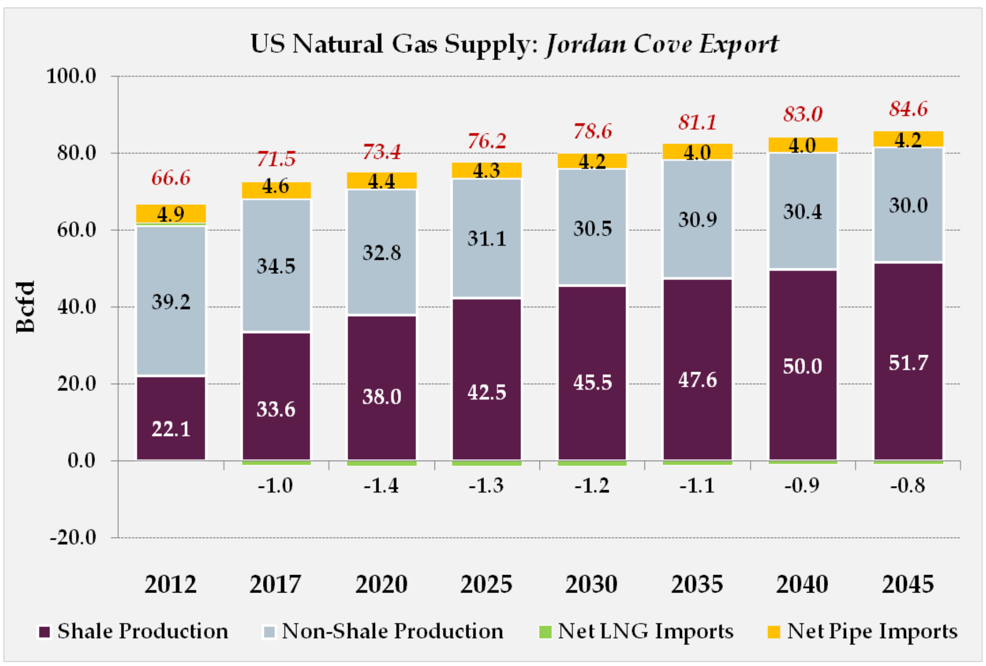


**Figure 20: Jordan Cove Export Case Supply**

The addition of 0.9 Bcfd of LNG exports from Jordan Cove increases pipeline imports from Canada by 0.7 to 0.9 Bcfd, indicating that feedstock comes primarily from increased output from British Columbia shale supplies, either directly or through displacement. Note that Total Supply (above the zero line) remains essentially constant. This is exemplified in 2045, which shows total supply of 84.6, which is the same Total Supply in the Reference Case. Net LNG Exports (below the zero line) reflect the disposition of any increased supply. Net exports decrease as time moves forward, reflecting a small increase in LNG imports in pipeline-constrained parts of North America (e.g., New England and the Canadian Maritimes).

| Year | Metric | Reference Case | Jordan Cove Export | Difference |
|---|---|---|---|---|
| 2025 | *Shale Production* | 42.4 | 42.5 | 0.1 |
| | *Non-shale Production* | 31.0 | 31.1 | 0.1 |
| | *Net LNG Imports* | -0.4 | -1.3 | -0.9 |
| | *Net Pipe Imports* | 3.4 | 4.3 | 0.8 |
| | ***Total Supply*** | **76.1** | **76.2** | **0.1** |
| 2035 | *Shale Production* | 47.6 | 47.6 | 0.1 |
| | *Non-shale Production* | 30.9 | 30.9 | 0.0 |
| | *Net LNG Imports* | -0.2 | -1.1 | -0.9 |
| | *Net Pipe Imports* | 3.1 | 4.0 | 0.9 |
| | ***Total Supply*** | **81.0** | **81.1** | **0.1** |
| 2045 | *Shale Production* | 51.6 | 51.7 | 0.0 |
| | *Non-shale Production* | 30.0 | 30.0 | 0.0 |
| | *Net LNG Imports* | 0.1 | -0.8 | -0.9 |
| | *Net Pipe Imports* | 3.3 | 4.2 | 0.9 |
| | ***Total Supply*** | **84.6** | **84.6** | **0.0** |

**Table 5: Changes in Supply in Jordan Cove Export Case**[43]

[43] "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

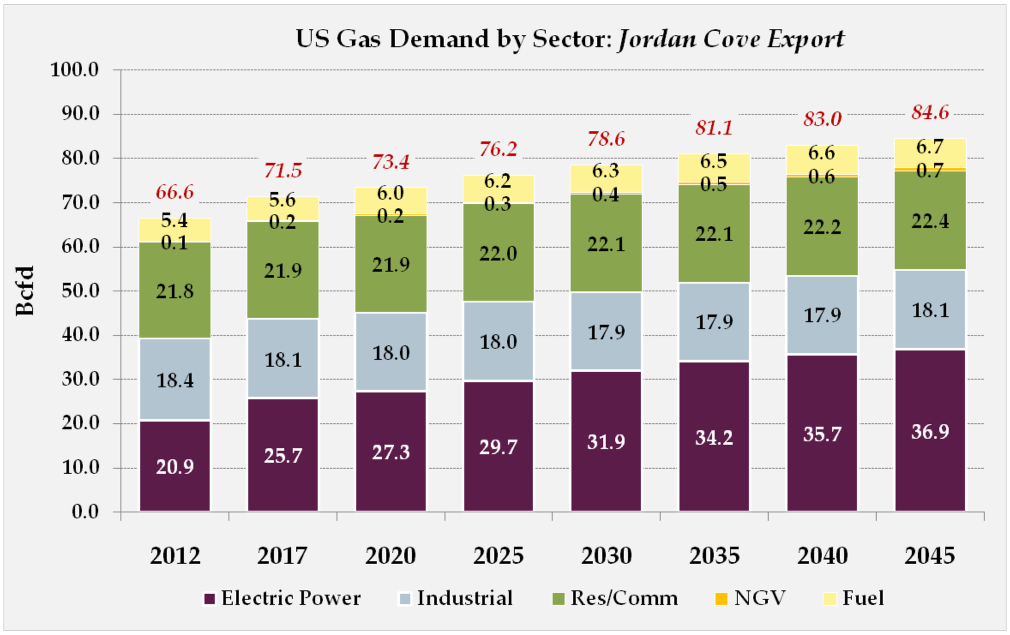


**Figure 21: Jordan Cove Export Case Demand**

LNG exports at Jordan Cove have a negligible effect on the distribution of demand among the major sectors, with very small amounts shaved from each to contribute to an approximate 0.1 Bcfd increase in fuel usage across the U.S.

| Year | Metric | Reference Case | Jordan Cove Export | Difference |
|---|---|---|---|---|
| 2025 | *Electric Power* | 29.7 | 29.7 | 0.0 |
| | *Industrial* | 18.0 | 18.0 | 0.0 |
| | *Res/Comm* | 22.0 | 22.0 | 0.0 |
| | *NGV* | 0.3 | 0.3 | 0.0 |
| | ***Total Consumption*** | **76.1** | **76.2** | **0.1** |
| 2035 | *Electric Power* | 34.2 | 34.2 | 0.0 |
| | *Industrial* | 17.9 | 17.9 | 0.0 |
| | *Res/Comm* | 22.1 | 22.1 | 0.0 |
| | *NGV* | 0.5 | 0.5 | 0.0 |
| | ***Total Consumption*** | **81.0** | **81.1** | **0.1** |
| 2045 | *Electric Power* | 36.9 | 36.9 | 0.0 |
| | *Industrial* | 18.1 | 18.1 | 0.0 |
| | *Res/Comm* | 22.4 | 22.4 | 0.0 |
| | *NGV* | 0.7 | 0.7 | 0.0 |
| | ***Total Consumption*** | **84.6** | **84.6** | **0.0** |

**Table 6: Changes in Demand in Jordan Cove Export Case**

## Resultant Gas Prices

Prices at Henry Hub, Sumas, and Malin in the Jordan Cove Export Case remain below $5.00 per MMBtu through 2020. The maximum incremental price increase at Henry Hub compared to the Reference Case is $0.07 per MMBtu, which occurs in 2020. Incremental price increases at Sumas are between $-0.02 and $0.03 per MMBtu until 2045, when the increment reaches $0.30 per MMBtu. Incremental price increases at Malin are between $0.14 and $0.25 per MMBtu until 2045, when the increment reaches $0.54 per MMBtu. The 2045 Sumas price of $8.09 per MMBtu and the Malin price of $8.11 per MMBtu remain below the Reference Case Henry Hub price of $8.28.

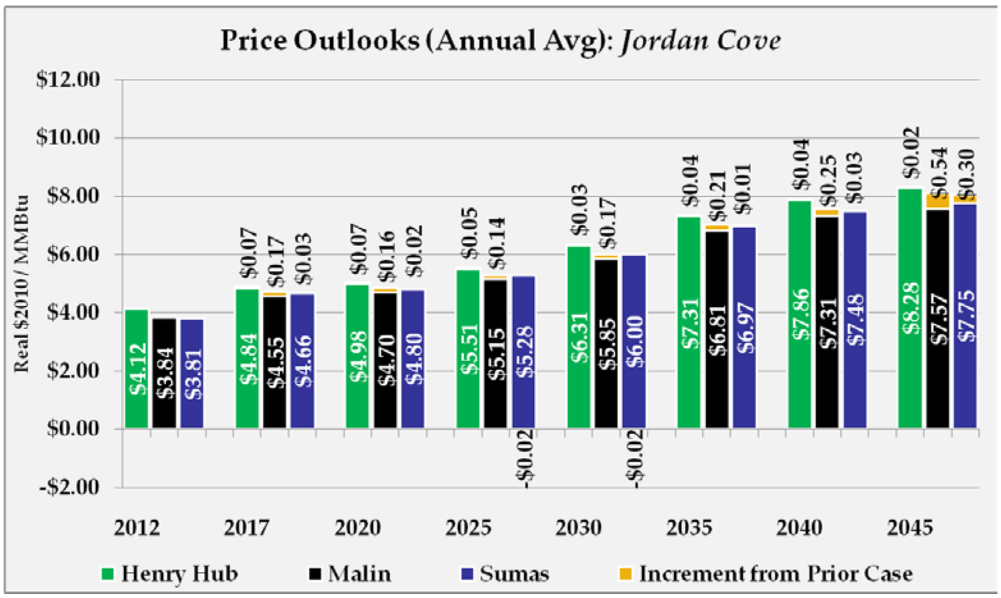


**Figure 22: Jordan Cove Export Case Prices**

| | | A | B | C=A-B | D=A/B-1 |
|---|---|---|---|---|---|
| Year | Metric | Jordan Cove Export | Reference Case | Absolute Difference | Percentage Difference |
| 2025 | Henry Hub | $5.55 | $5.51 | $0.05 | 0.8% |
| | Malin | $5.29 | $5.15 | $0.14 | 2.7% |
| | Sumas | $5.26 | $5.28 | -$0.02 | -0.4% |
| 2035 | Henry Hub | $7.35 | $7.31 | $0.04 | 0.5% |
| | Malin | $7.02 | $6.81 | $0.21 | 3.1% |
| | Sumas | $6.98 | $6.97 | $0.01 | 0.1% |
| 2045 | Henry Hub | $8.30 | $8.28 | $0.02 | 0.2% |
| | Malin | $8.11 | $7.57 | $0.54 | 7.2% |
| | Sumas | $8.05 | $7.75 | $0.30 | 3.9% |

**Table 7: Changes in Jordan Cove Export Case Prices**

## Aggregate Exports Case

The **Aggregate Export Case** builds on the Jordan Cove Export Case. In the **Aggregate Export Case**, other U.S. LNG exports are assumed in addition to Sabine Pass, Kitimat, and JCEP. 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 JCEP, and models these export volumes generically

### Supply

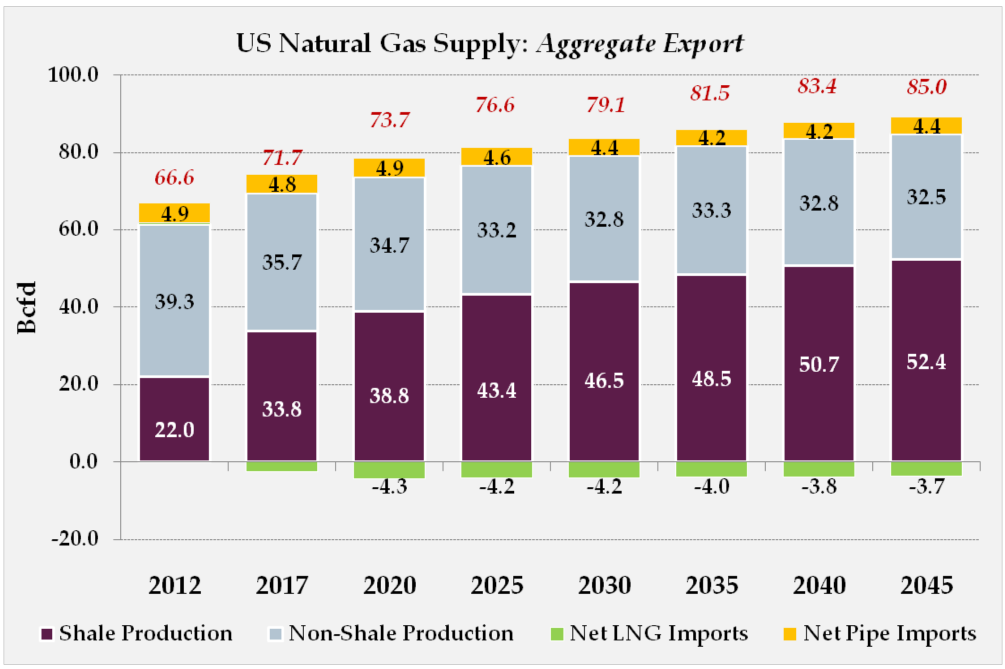


**Figure 23: Aggregate Export Case Supply**

The addition of 3.0 Bcfd of LNG exports in addition to Kitimat, Sabine Pass, and JCEP stimulates supply production in the U.S. In 2020, shale production rises from 33.6 Bcfd in the Jordan Cove Export Case to 34.0 Bcfd. Similarly, non-shale U.S. production rises from 34.5 Bcfd to 35.3 Bcfd. Pipeline imports increase from 4.6 Bcfd in 2020 to 5.0 Bcfd. Total supply increases by about 0.4 Bcfd in 2020.

| Year | Metric | Jordan Cove Export | Aggregate Export | Difference |
|---|---|---|---|---|
| 2025 | *Shale Production* | 42.5 | 43.4 | 1.0 |
| | *Non-shale Production* | 31.1 | 33.2 | 2.1 |
| | *Net LNG Imports* | -1.3 | -4.2 | -2.9 |
| | *Net Pipe Imports* | 4.3 | 4.6 | 0.4 |
| | ***Total Supply*** | **76.2** | **76.6** | **0.4** |
| 2035 | *Shale Production* | 47.6 | 48.5 | 0.9 |
| | *Non-shale Production* | 30.9 | 33.3 | 2.4 |
| | *Net LNG Imports* | -1.1 | -4.0 | -2.9 |
| | *Net Pipe Imports* | 4.0 | 4.2 | 0.2 |
| | ***Total Supply*** | **81.1** | **81.5** | **0.4** |
| 2045 | *Shale Production* | 51.7 | 52.4 | 0.7 |
| | *Non-shale Production* | 30.0 | 32.5 | 2.5 |
| | *Net LNG Imports* | -0.8 | -3.7 | -2.9 |
| | *Net Pipe Imports* | 4.2 | 4.4 | 0.2 |
| | ***Total Supply*** | **84.6** | **85.0** | **0.4** |

**Table 8: Changes in Supply in Aggregate Export Case**[44]

## Demand

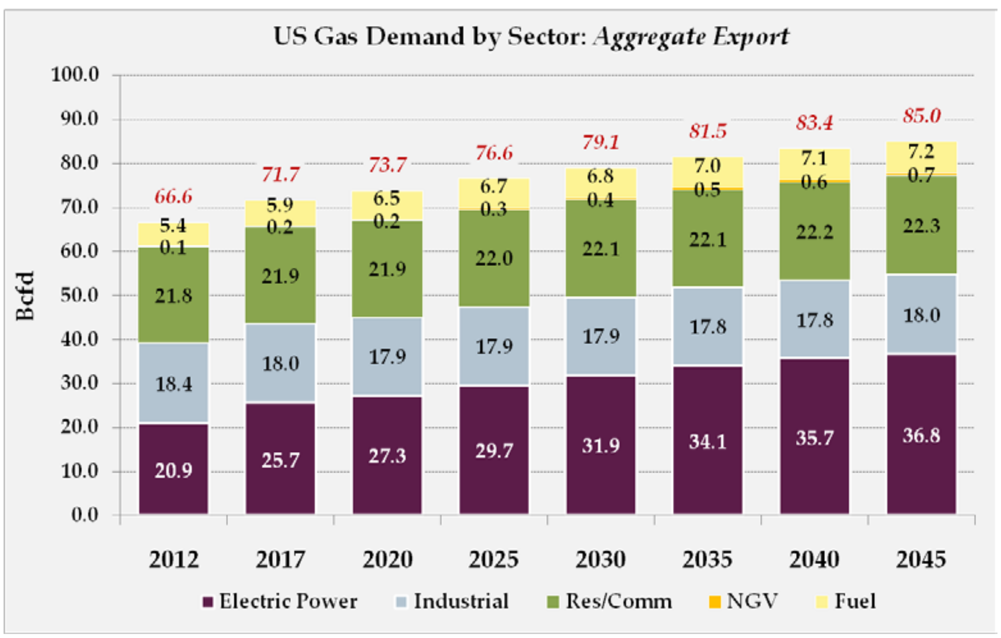


**Figure 24: Aggregate Export Case Demand**

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[44] "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.

Aggregate LNG exports add approximately 0.5 Bcfd increase in fuel usage across the U.S. in the later years of the forecast. Otherwise, the distribution of demand is largely unaffected.

| Year | Metric | Jordan Cove Export | Aggregate Export | Difference |
|---|---|---|---|---|
| 2025 | *Electric Power* | 29.7 | 29.7 | 0.0 |
| | *Industrial* | 18.0 | 17.9 | -0.1 |
| | *Res/Comm* | 22.0 | 22.0 | 0.0 |
| | *NGV* | 0.3 | 0.3 | 0.0 |
| | ***Total Consumption*** | **76.2** | **76.6** | **0.4** |
| 2035 | *Electric Power* | 34.2 | 34.1 | 0.0 |
| | *Industrial* | 17.9 | 17.8 | 0.0 |
| | *Res/Comm* | 22.1 | 22.1 | 0.0 |
| | *NGV* | 0.5 | 0.5 | 0.0 |
| | ***Total Consumption*** | **81.1** | **81.5** | **0.4** |
| 2045 | *Electric Power* | 36.9 | 36.8 | 0.0 |
| | *Industrial* | 18.1 | 18.0 | 0.0 |
| | *Res/Comm* | 22.4 | 22.3 | 0.0 |
| | *NGV* | 0.7 | 0.7 | 0.0 |
| | ***Total Consumption*** | **84.6** | **85.0** | **0.4** |

**Table 9: Changes in Demand in Aggregate Export Case**

### Resultant Gas Prices

Prices at Henry Hub, Sumas, and Malin in the Aggregate Export Case remain below or near $5.00 per MMBtu through 2020 (as they do in the two previous cases). The maximum incremental price increase at Henry Hub compared to the Jordan Cove Export Case is $0.54 per MMBtu, which occurs in 2020, reflecting the step-change impact of the near-concurrent addition of several large export facilities. In later years, the increase is smaller as the steady ramp-up of supply equilibrates to demand. Incremental price increases at Sumas are between $0.17 and $0.41 per MMBtu. Incremental increases in price at Sumas and Malin are less than the incremental increase at Henry Hub. The total price at Sumas and Malin also remains below the Reference Case Henry Hub price for all years.

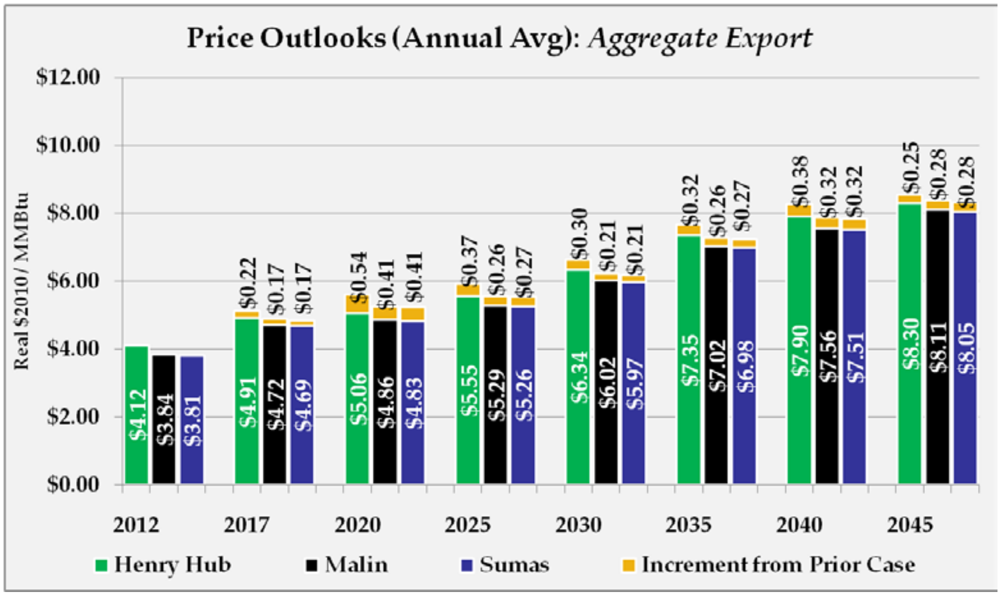


**Figure 25: Aggregate Export Case Prices**

| | | A | B | *C=A-B* | *D=A/B-1* |
|---|---|---|---|---|---|
| **Year** | **Metric** | **Aggregate Export** | **Jordan Cove Export** | *Absolute Difference* | *Percentage Difference* |
| **2025** | *Henry Hub* | **$5.92** | **$5.55** | *$0.37* | *6.7%* |
| | *Malin* | **$5.55** | **$5.29** | *$0.26* | *4.9%* |
| | *Sumas* | **$5.53** | **$5.26** | *$0.27* | *5.1%* |
| **2035** | *Henry Hub* | **$7.66** | **$7.35** | *$0.32* | *4.3%* |
| | *Malin* | **$7.29** | **$7.02** | *$0.26* | *3.8%* |
| | *Sumas* | **$7.25** | **$6.98** | *$0.27* | *3.8%* |
| **2045** | *Henry Hub* | **$8.55** | **$8.30** | *$0.25* | *3.0%* |
| | *Malin* | **$8.39** | **$8.11** | *$0.28* | *3.4%* |
| | *Sumas* | **$8.32** | **$8.05** | *$0.28* | *3.4%* |

**Table 10: Changes in Aggregate Export Case Prices**

## GHG Demand Case

The **GHG Demand Case** builds on the Aggregate Export Case. In the **GHG Demand Case**, U.S. and Canadian policy are assumed to promote the use of natural gas in order to reduce greenhouse gas emissions, notably carbon dioxide. Oil and coal are assumed to be disadvantaged by legislation, regulation, a carbon price, or similar mechanism such that natural gas demand is increased.

In such a scenario, it is almost certain that natural gas infrastructure would experience a concurrent build-out. Navigant's modeling methodology, however, does not attempt to specify particular infrastructure to account for this likely outcome. Some infrastructure was adjusted in a generic fashion to alleviate bottlenecks. An exception was made to accommodate the assumed growth in gas supply and demand in the West, and in particular growth in Canadian shale supply, which otherwise caused unrealistic oscillations in seasonal pricing in the later years of this scenario. Gas Transmission Northwest and the western legs of Nova and Foothills Pipeline were assumed to expand by 1.0 Bcfd in response to policy-driven supply and demand growth, starting in 2028.

We emphasize that our infrastructure methodology is intended to be conservative and that many other such expansions, as well as new pipeline and storage construction, would most certainly take place in such a regulatory environment, to support the increase in gas-fired generation.

### Supply

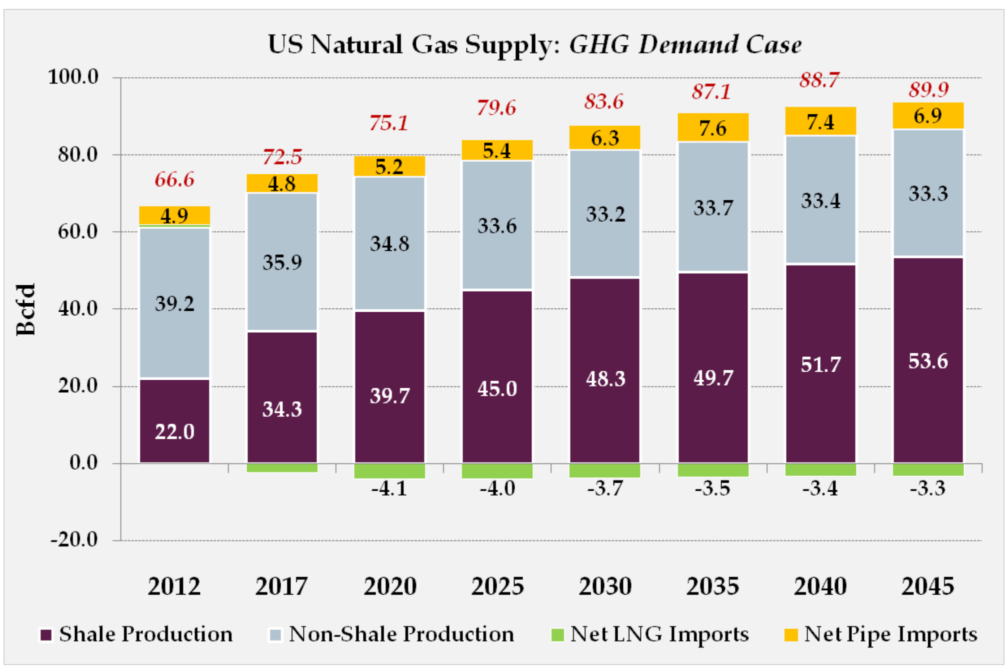


**Figure 26: GHG Demand Case Supply**

In 2025, incremental supply in the GHG Demand Case is 3.0 Bcfd higher than in the Aggregate Export Case. This increment grows to 5.6 Bcfd in 2035, and pulls back slightly to 4.9 Bcfd in 2045.

| Year | Metric | Aggregate Export | GHG Demand | Difference |
|---|---|---|---|---|
| 2025 | *Shale Production* | 43.4 | 45.0 | 1.6 |
| | *Non-shale Production* | 33.2 | 33.6 | 0.4 |
| | *Net LNG Imports* | -4.2 | -4.0 | 0.2 |
| | *Net Pipe Imports* | 4.6 | 5.4 | 0.7 |
| | ***Total Supply*** | **76.6** | **79.6** | **3.0** |
| 2035 | *Shale Production* | 48.5 | 49.7 | 1.2 |
| | *Non-shale Production* | 33.3 | 33.7 | 0.4 |
| | *Net LNG Imports* | -4.0 | -3.5 | 0.5 |
| | *Net Pipe Imports* | 4.2 | 7.6 | 3.4 |
| | ***Total Supply*** | **81.5** | **87.1** | **5.6** |
| 2045 | *Shale Production* | 52.4 | 53.6 | 1.2 |
| | *Non-shale Production* | 32.5 | 33.3 | 0.8 |
| | *Net LNG Imports* | -3.7 | -3.3 | 0.4 |
| | *Net Pipe Imports* | 4.4 | 6.9 | 2.5 |
| | ***Total Supply*** | **85.0** | **89.9** | **4.9** |

**Table 11: Changes in Supply in GHG Demand Case**[45]

[45] "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

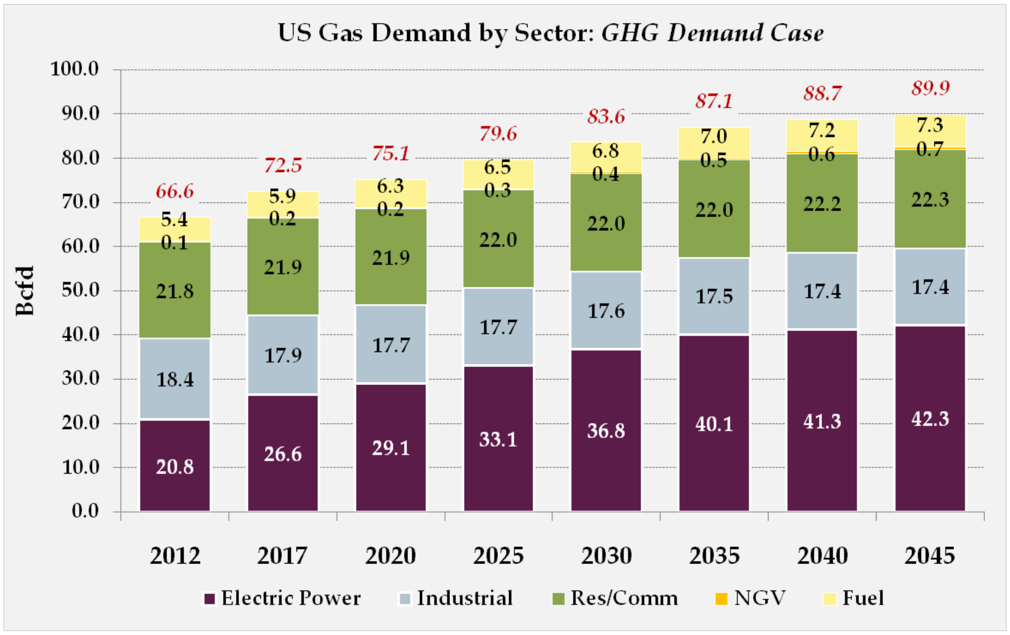


**Figure 27: GHG Demand Case Demand**

U.S. demand increases in the GHG Demand Case by 1.4 Bcfd in 2020, ramping up to an incremental 4.9 Bcfd by 2045. This demand excludes North American production used for LNG exports.

| Year | Metric | Aggregate Export | GHG Demand | Difference |
|---|---|---|---|---|
| 2025 | *Electric Power* | 29.7 | 33.1 | 3.4 |
| | *Industrial* | 17.9 | 17.7 | -0.2 |
| | *Res/Comm* | 22.0 | 22.0 | 0.0 |
| | *NGV* | 0.3 | 0.3 | 0.0 |
| | ***Total Consumption*** | **76.6** | **79.6** | **3.0** |
| 2035 | *Electric Power* | 34.1 | 40.1 | 6.0 |
| | *Industrial* | 17.8 | 17.5 | -0.4 |
| | *Res/Comm* | 22.1 | 22.0 | -0.1 |
| | *NGV* | 0.5 | 0.5 | 0.0 |
| | ***Total Consumption*** | **81.5** | **87.1** | **5.6** |
| 2045 | *Electric Power* | 36.8 | 42.3 | 5.5 |
| | *Industrial* | 18.0 | 17.4 | -0.6 |
| | *Res/Comm* | 22.3 | 22.3 | -0.1 |
| | *NGV* | 0.7 | 0.7 | 0.0 |
| | ***Total Consumption*** | **85.0** | **89.9** | **4.9** |

**Table 12: Changes in Demand in GHG Demand Case**

### Resultant Gas Prices

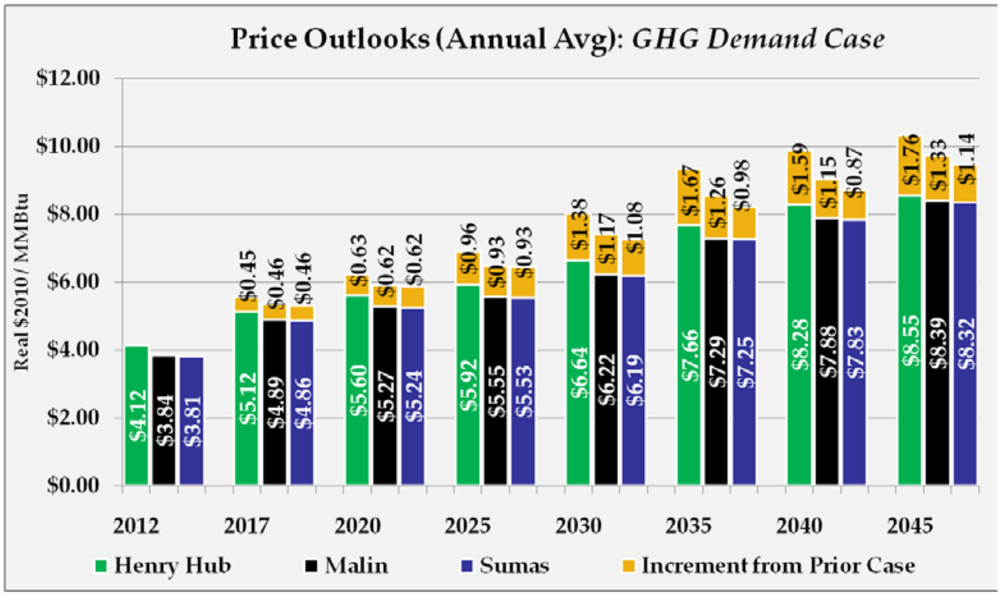


**Figure 28: GHG Demand Case Prices**

| | | A | B | *C=A-B* | *D=A/B-1* |
|---|---|---|---|---|---|
| **Year** | **Metric** | **GHG Demand** | **Aggregate Export** | ***Absolute Difference*** | ***Percentage Difference*** |
| **2025** | *Henry Hub* | **$6.88** | **$5.92** | *$0.96* | *16.2%* |
| | *Malin* | **$6.49** | **$5.55** | *$0.93* | *16.8%* |
| | *Sumas* | **$6.46** | **$5.53** | *$0.93* | *16.9%* |
| **2035** | *Henry Hub* | **$9.33** | **$7.66** | *$1.67* | *21.8%* |
| | *Malin* | **$8.55** | **$7.29** | *$1.26* | *17.3%* |
| | *Sumas* | **$8.23** | **$7.25** | *$0.98* | *13.6%* |
| **2045** | *Henry Hub* | **$10.31** | **$8.55** | *$1.76* | *20.6%* |
| | *Malin* | **$9.72** | **$8.39** | *$1.33* | *15.9%* |
| | *Sumas* | **$9.47** | **$8.32** | *$1.14* | *13.7%* |

**Table 13: Changes in GHG Demand Case Prices**

Policy-driven growth in demand, combined with Navigant's highly conservative modeling methodology of minimizing assumed future infrastructure additions, results in higher natural gas prices (incrementally 10 percent or more) throughout North America, beginning in 2020. By 2045, modeled Henry Hub prices increase by more than 20 percent, compared to the Aggregate Export Case. Resultant incremental price increases at Malin and Sumas are lower than that at Henry Hub. Malin is about 16 percent higher, and Sumas about 14 percent higher.

## 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 |
| JCEP | Jordan Cove Energy Project |
| LNG | Liquefied natural gas |
| Mcf | Thousand cubic feet (approx. 1.0 MMBtu) |
| MMBtu | Million British thermal units |
| MMcf | Million cubic feet |
| MW | Megawatt (one million watts) |
| NEB | National Energy Board (Canada) |
| NETL | National Energy Technology Laboratory |
| NGL | Natural gas liquid |
| NGV | Natural gas vehicle |
| SEAB | Secretary of Energy Advisory Board |
| Tcf | Trillion cubic feet |
| USGS | United States Geological Survey |

# Appendix B: Future Infrastructure in Reference Case

| Storage New and Expansion Projects 2011 and Beyond | | | |
|---|---|---|---|
| **Storage Facility** | **State** | **Date** | **Working Capacity (MMcf)** |
| Blue Sky | CO | Apr-2011 | 4,400 |
| Cadeville | LA | Jun-2012 | 11,500 |
| Central Valley Gas Storage | CA | Jul-2011 | 5,500 |
| Copiah | MS | Apr-2014 | 3,000 |
| East Cheyenne | CO | Jun-2011 | 18,900 |
| Golden Triangle | TX | Apr-2011 | 12,000 |
| Leaf River (Expansion) | MS | Apr-2011 | 16,000 |
| Leaf River (Expansion) | MS | Apr-2013 | 24,000 |
| Leaf River (Expansion) | MS | Apr-2014 | 32,000 |
| Pine Prairie (Expansion) | LA | May-2011 | 26,000 |
| Pine Prairie (Expansion) | LA | May-2013 | 42,000 |
| Pine Prairie (Expansion) | LA | May-2016 | 45,000 |
| Tricor Ten Section Hub | CA | Jan-2012 | 22,400 |
| Western Energy Hub | UT | Apr-2012 | 5,600 |
| Windy Hill | CO | Jul-2011 | 6,000 |
| Windy Hill (Expansion) | CO | Apr-2012 | 12,000 |
| Windy Hill (Expansion) | CO | Apr-2013 | 18,000 |
| Windy Hill (Expansion) | CO | Apr-2014 | 24,000 |
| Windy Hill (Expansion) | CO | Apr-2015 | 32,000 |

| Future Pipelines and Expansions in Spring 2011 Reference Case* | | | | | |
|---|---|---|---|---|---|
| Pipeline | Date | Capacity (MMcfd) | Pipeline | Date | Capacity (MMcfd) |
| Bison Pipeline | Jan-11 | 477 | LNG Manzanillo | Jul-14 | 500 |
| Houston Pipeline (HPL S Tx) | Jan-11 | 400 | Algonquin (Algonquin NJ NY) | Nov-14 | 800 |
| TCO 1278 Line-K Project | Jan-11 | 150 | TETCO NJ/NY Expansion | Nov-14 | 800 |
| Inergy North-South Project | Jan-11 | 325 | IGT NYMarc Connector | Nov-14 | 500 |
| Transco Springville Pipeline | Jan-11 | 450 | CrossTex North Texas (N Texas) | Jan-15 | 750 |
| Florida Gas Phase VIII Exp | Apr-11 | 820 | El Paso (Samalayuca Line) | Jan-15 | 312 |
| Ruby Pipeline | Jul-11 | 1,250 | Enterprise Jonah Gathering | Jan-15 | 600 |
| LNG Golden Pass | Jul-11 | 1,000 | Florida Gas (Mkt Panhandle) | Jan-15 | 500 |
| TGP 300 Line | Jul-11 | 345 | Florida Gas (Zone 3) | Jan-15 | 500 |
| Acadian Pipeline (HH) | Sep-11 | 1,200 | Grasslands Pipeline | Jan-15 | 200 |
| Gulfstream Pipeline | Nov-11 | 35 | NFGS Line N Project | Nov-11<br>Jan-12<br>Nov-11 | 160<br>195<br>350 |
| Algonquin (Algonquin J) | Jan-12 | 400 | Empire Tioga County Extension | Nov-13 | 350 |
| Midcontinent Express Z1 | Jan-12 | 200 | Gulf Crossing | Jan-15 | 1,000 |
| PNGT (N & S of Westbrook) | Jan-12 | 310 | TGT (Fayetteville) | Jan-15 | 150 |
| EQT Sunrise Project | Jan-12 | 313 | Wyoming Interstate (Mainline) | Jan-15 | 225 |
| Millennium Minisink Compr. | Jan-12 | 150 | Questar (Fidlar to KRGT) | Jan-18 | 400 |
| TETCO TEAM 2012 | Jan-12 | 300 | Rockies Express (REX Z1 Wam) | Jan-18 | 332 |
| TGP NE Supply Diversif. | Jan-12 | 250 | White River Hub | Jan-18 | 500 |
| Transco Mid Atl Connect Exp | Jan-12 | 150 | Wyoming Interstate (Kanda Lat) | Jan-18 | 400 |
| Transco Northeast Connector | Jan-12 | 688 | Alliance Pipeline (CAN BC) | Jan-20 | 850 |
| Inergy Marc I Hub Line | Apr-12 | 550 | Kern River (CA/Mainline/NV) | Jan-20 | 500 |
| NW Pipeline (Plymouth ) | Nov-12 | 239 | KM Border Pipeline | Jan-20 | 300 |
| DTI Appalachian Gateway | Nov-12 | 484 | KM Mexico | Jan-20 | 425 |
| DTI Northeast Expansion | Nov-12 | 200 | KM Texas Pipeline (AguaDulce) | Jan-20 | 250 |
| NFGS Northern Access | Nov-12 | 320 | Mojave-Kern Common Facilities | Jan-20 | 200 |
| IGT Wright Transfer Comp. | Nov-12 | 250 | Nova (Gordondale Gr Prairie) | Jan-20 | 4,500 |
| TETCO TEAM 2013 | Jan-13 | 500 | Wyoming Interstate (Mainline) | Jan-20 | 500 |
| NFGS West to East | Jan-13 | 425 | Cypress Pipeline | May-20 | 500 |
| DTI Tioga Area Expansion | Nov-13 | 270 | Nova (Groundbirch) | Jan-22 | 1,344 |
| Florida Gas (Mkt Northern) | Jan-14 | 500 | White River Hub | Jan-23 | 500 |
| Southern Crossing | Jan-14 | 400 | Kern River (Opal to Muddy Ck) | Jan-25 | 440 |
| TGP Northeast Upgrade | Jan-14 | 636 | KM Border Pipeline | Jan-25 | 300 |
| Transco NE Supply Link | Jan-14 | 250 | Transwestern (Topock- Calpine) | Jan-25 | 80 |
| Transco Rockaway Lateral | Jan-14 | 625 | DCP E TX Carthage Gathering | Jan-27 | 250 |
| Enterprise Texas | Jun-14 | 200 | | | |

## Appendix C: Supply Disposition Tables

| U.S. Supply Disposition (Bcfd) – *Navigant Reference Case* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | NET IMPORTS | | | | | |
| Year | Dry Production | Net Pipeline Imports | Net LNG Imports | Total Net Imports | Net Storage | Balancing Item | Consump-tion |
| **2012** | *61.3* | 4.9 | 0.6 | 5.5 | -0.2 | 0.0 | **66.6** |
| **2013** | *62.7* | 4.7 | 0.9 | 5.6 | -0.1 | 0.0 | **68.2** |
| **2014** | *63.8* | 4.5 | 1.1 | 5.6 | -0.1 | 0.0 | **69.3** |
| **2015** | *65.0* | 4.2 | 1.0 | 5.2 | 0.0 | -0.2 | **70.0** |
| **2016** | *66.5* | 3.9 | 0.4 | 4.2 | 0.0 | -0.3 | **70.5** |
| **2017** | *67.9* | 3.9 | -0.1 | 3.7 | 0.0 | -0.3 | **71.4** |
| **2018** | *69.0* | 3.8 | -0.5 | 3.3 | 0.0 | -0.3 | **72.1** |
| **2019** | *69.8* | 3.7 | -0.5 | 3.2 | 0.1 | -0.3 | **72.8** |
| **2020** | *70.6* | 3.6 | -0.5 | 3.1 | 0.0 | -0.3 | **73.4** |
| **2021** | *71.2* | 3.7 | -0.5 | 3.2 | 0.0 | -0.3 | **74.1** |
| **2022** | *71.8* | 3.7 | -0.5 | 3.2 | 0.0 | -0.3 | **74.6** |
| **2023** | *72.3* | 3.6 | -0.5 | 3.1 | 0.1 | -0.3 | **75.1** |
| **2024** | *72.8* | 3.5 | -0.5 | 3.1 | -0.1 | -0.3 | **75.4** |
| **2025** | *73.4* | 3.4 | -0.4 | 3.0 | 0.0 | -0.3 | **76.1** |
| **2026** | *73.9* | 3.5 | -0.4 | 3.0 | 0.0 | -0.3 | **76.6** |
| **2027** | *74.3* | 3.4 | -0.4 | 3.0 | 0.1 | -0.3 | **77.1** |
| **2028** | *74.7* | 3.4 | -0.4 | 3.0 | -0.1 | -0.3 | **77.4** |
| **2029** | *75.4* | 3.4 | -0.4 | 3.0 | 0.0 | -0.3 | **78.1** |
| **2030** | *75.9* | 3.3 | -0.3 | 3.0 | 0.0 | -0.3 | **78.6** |
| **2031** | *76.4* | 3.3 | -0.3 | 3.0 | 0.1 | -0.3 | **79.0** |
| **2032** | *76.8* | 3.2 | -0.3 | 3.0 | -0.1 | -0.3 | **79.3** |
| **2033** | *77.5* | 3.2 | -0.2 | 2.9 | 0.0 | -0.3 | **80.0** |
| **2034** | *77.9* | 3.1 | -0.2 | 2.9 | 0.0 | -0.3 | **80.5** |
| **2035** | *78.4* | 3.1 | -0.2 | 3.0 | 0.0 | -0.3 | **81.0** |
| **2036** | *79.0* | 3.0 | -0.1 | 2.9 | 0.1 | -0.3 | **81.6** |
| **2037** | *79.4* | 3.0 | 0.0 | 2.9 | 0.0 | -0.4 | **81.9** |
| **2038** | *79.7* | 3.0 | 0.0 | 3.0 | 0.0 | -0.4 | **82.3** |
| **2039** | *80.0* | 3.0 | 0.0 | 3.1 | 0.0 | -0.4 | **82.7** |
| **2040** | *80.3* | 3.1 | 0.0 | 3.1 | 0.0 | -0.4 | **83.0** |
| **2041** | *80.6* | 3.1 | 0.1 | 3.2 | 0.0 | -0.4 | **83.4** |
| **2042** | *80.8* | 3.2 | 0.1 | 3.3 | 0.0 | -0.4 | **83.7** |
| **2043** | *81.2* | 3.2 | 0.1 | 3.3 | 0.0 | -0.4 | **84.1** |
| **2044** | *81.3* | 3.2 | 0.1 | 3.3 | 0.0 | -0.4 | **84.2** |
| **2045** | *81.6* | 3.3 | 0.1 | 3.4 | 0.0 | -0.4 | **84.6** |

| U.S. Supply Disposition (Bcfd) – *Jordan Cove Export Case* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | NET IMPORTS | | | | | |
| Year | Dry Production | Net Pipeline Imports | Net LNG Imports | Total Net Imports | Net Storage | Balancing Item | Consump-tion |
| **2012** | *61.3* | 4.9 | 0.6 | 5.5 | -0.2 | 0.0 | **66.6** |
| **2013** | *62.6* | 4.9 | 0.8 | 5.7 | 0.0 | 0.0 | **68.2** |
| **2014** | *63.7* | 4.8 | 0.9 | 5.8 | -0.1 | 0.0 | **69.3** |
| **2015** | *64.7* | 4.6 | 1.0 | 5.5 | 0.0 | -0.2 | **70.1** |
| **2016** | *66.3* | 4.2 | 0.4 | 4.6 | -0.1 | -0.3 | **70.5** |
| **2017** | *68.2* | 4.6 | -1.0 | 3.5 | 0.1 | -0.3 | **71.5** |
| **2018** | *69.3* | 4.5 | -1.4 | 3.1 | 0.0 | -0.3 | **72.1** |
| **2019** | *70.0* | 4.5 | -1.4 | 3.1 | 0.0 | -0.3 | **72.8** |
| **2020** | *70.8* | 4.4 | -1.4 | 3.0 | 0.0 | -0.3 | **73.4** |
| **2021** | *71.4* | 4.5 | -1.4 | 3.1 | 0.0 | -0.3 | **74.2** |
| **2022** | *72.0* | 4.5 | -1.4 | 3.1 | 0.0 | -0.3 | **74.7** |
| **2023** | *72.5* | 4.4 | -1.4 | 3.0 | 0.1 | -0.3 | **75.2** |
| **2024** | *72.9* | 4.3 | -1.4 | 3.0 | -0.1 | -0.3 | **75.5** |
| **2025** | *73.6* | 4.3 | -1.3 | 2.9 | 0.0 | -0.3 | **76.2** |
| **2026** | *74.0* | 4.3 | -1.3 | 3.0 | 0.0 | -0.3 | **76.7** |
| **2027** | *74.4* | 4.3 | -1.3 | 3.0 | 0.1 | -0.3 | **77.2** |
| **2028** | *74.9* | 4.3 | -1.3 | 3.0 | -0.1 | -0.3 | **77.5** |
| **2029** | *75.5* | 4.2 | -1.3 | 3.0 | 0.0 | -0.3 | **78.1** |
| **2030** | *76.0* | 4.2 | -1.2 | 2.9 | 0.0 | -0.3 | **78.6** |
| **2031** | *76.5* | 4.2 | -1.2 | 3.0 | 0.1 | -0.3 | **79.1** |
| **2032** | *76.9* | 4.1 | -1.2 | 2.9 | -0.1 | -0.4 | **79.4** |
| **2033** | *77.6* | 4.0 | -1.1 | 2.9 | 0.0 | -0.4 | **80.1** |
| **2034** | *78.0* | 4.1 | -1.1 | 3.0 | 0.0 | -0.4 | **80.6** |
| **2035** | *78.5* | 4.0 | -1.1 | 3.0 | 0.0 | -0.4 | **81.1** |
| **2036** | *79.1* | 3.9 | -1.0 | 2.9 | 0.0 | -0.4 | **81.7** |
| **2037** | *79.5* | 3.9 | -0.9 | 2.9 | 0.0 | -0.4 | **82.0** |
| **2038** | *79.8* | 3.9 | -0.9 | 3.0 | 0.0 | -0.4 | **82.4** |
| **2039** | *80.1* | 3.9 | -0.9 | 3.1 | 0.0 | -0.4 | **82.7** |
| **2040** | *80.3* | 4.0 | -0.9 | 3.1 | 0.0 | -0.4 | **83.0** |
| **2041** | *80.6* | 4.0 | -0.8 | 3.2 | 0.0 | -0.4 | **83.5** |
| **2042** | *80.9* | 4.1 | -0.8 | 3.3 | 0.0 | -0.4 | **83.7** |
| **2043** | *81.2* | 4.1 | -0.8 | 3.3 | 0.0 | -0.4 | **84.2** |
| **2044** | *81.3* | 4.1 | -0.8 | 3.3 | 0.0 | -0.4 | **84.2** |
| **2045** | *81.7* | 4.2 | -0.8 | 3.4 | 0.0 | -0.4 | **84.6** |

## U.S. Supply Disposition (Bcfd) – *Aggregate Export Case*

| Year | Dry Production | NET IMPORTS | | | Net Storage | Balancing Item | Consump-tion |
|---|---|---|---|---|---|---|---|
| | | Net Pipeline Imports | Net LNG Imports | Total Net Imports | | | |
| **2012** | *61.3* | 4.9 | 0.6 | 5.5 | -0.2 | 0.0 | **66.6** |
| **2013** | *62.6* | 4.9 | 0.8 | 5.7 | 0.0 | 0.0 | **68.2** |
| **2014** | *63.8* | 4.8 | 0.9 | 5.6 | 0.0 | 0.0 | **69.4** |
| **2015** | *65.0* | 4.4 | 0.9 | 5.3 | 0.0 | -0.2 | **70.1** |
| **2016** | *66.8* | 4.1 | 0.3 | 4.4 | -0.3 | -0.3 | **70.6** |
| **2017** | *69.6* | 4.8 | -2.6 | 2.2 | 0.3 | -0.4 | **71.7** |
| **2018** | *71.3* | 4.9 | -3.4 | 1.5 | 0.0 | -0.4 | **72.3** |
| **2019** | *72.4* | 4.9 | -3.9 | 1.0 | 0.0 | -0.4 | **73.1** |
| **2020** | *73.5* | 4.9 | -4.3 | 0.7 | 0.0 | -0.5 | **73.7** |
| **2021** | *74.3* | 5.0 | -4.3 | 0.7 | 0.0 | -0.5 | **74.5** |
| **2022** | *74.9* | 4.9 | -4.3 | 0.7 | 0.0 | -0.5 | **75.1** |
| **2023** | *75.4* | 4.8 | -4.3 | 0.6 | 0.0 | -0.5 | **75.6** |
| **2024** | *76.0* | 4.7 | -4.3 | 0.5 | 0.0 | -0.5 | **75.9** |
| **2025** | *76.7* | 4.6 | -4.2 | 0.4 | 0.0 | -0.5 | **76.6** |
| **2026** | *77.1* | 4.6 | -4.2 | 0.4 | 0.0 | -0.5 | **77.1** |
| **2027** | *77.6* | 4.6 | -4.2 | 0.4 | 0.0 | -0.5 | **77.6** |
| **2028** | *78.0* | 4.6 | -4.2 | 0.4 | 0.0 | -0.5 | **77.9** |
| **2029** | *78.7* | 4.5 | -4.2 | 0.3 | 0.0 | -0.5 | **78.6** |
| **2030** | *79.2* | 4.4 | -4.2 | 0.3 | 0.0 | -0.5 | **79.1** |
| **2031** | *79.7* | 4.4 | -4.2 | 0.3 | 0.1 | -0.5 | **79.5** |
| **2032** | *80.1* | 4.4 | -4.1 | 0.3 | -0.1 | -0.5 | **79.8** |
| **2033** | *80.8* | 4.3 | -4.1 | 0.2 | 0.0 | -0.5 | **80.5** |
| **2034** | *81.3* | 4.3 | -4.0 | 0.2 | 0.0 | -0.5 | **81.0** |
| **2035** | *81.8* | 4.2 | -4.0 | 0.2 | 0.0 | -0.5 | **81.5** |
| **2036** | *82.4* | 4.1 | -3.9 | 0.2 | 0.1 | -0.5 | **82.1** |
| **2037** | *82.7* | 4.1 | -3.9 | 0.2 | 0.0 | -0.5 | **82.4** |
| **2038** | *83.0* | 4.1 | -3.8 | 0.2 | 0.0 | -0.5 | **82.8** |
| **2039** | *83.3* | 4.1 | -3.8 | 0.3 | 0.0 | -0.5 | **83.1** |
| **2040** | *83.5* | 4.2 | -3.8 | 0.4 | 0.0 | -0.5 | **83.4** |
| **2041** | *83.8* | 4.2 | -3.8 | 0.5 | 0.0 | -0.5 | **83.8** |
| **2042** | *84.1* | 4.3 | -3.8 | 0.6 | 0.0 | -0.5 | **84.1** |
| **2043** | *84.4* | 4.4 | -3.7 | 0.6 | 0.0 | -0.5 | **84.5** |
| **2044** | *84.5* | 4.3 | -3.8 | 0.5 | 0.0 | -0.5 | **84.5** |
| **2045** | *84.8* | 4.4 | -3.7 | 0.7 | 0.0 | -0.5 | **85.0** |

| U.S. Supply Disposition (Bcfd) –*GHG Demand Case* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | NET IMPORTS | | | | | |
| Year | Dry Production | Net Pipeline Imports | Net LNG Imports | Total Net Imports | Net Storage | Balancing Item | Consump-tion |
| **2012** | *61.3* | 4.9 | 0.6 | 5.5 | -0.2 | 0.0 | **66.6** |
| **2013** | *62.6* | 4.9 | 0.8 | 5.7 | 0.0 | 0.0 | **68.2** |
| **2014** | *63.8* | 4.8 | 0.9 | 5.6 | 0.0 | 0.0 | **69.4** |
| **2015** | *65.0* | 4.4 | 0.9 | 5.3 | 0.0 | -0.2 | **70.1** |
| **2016** | *66.8* | 4.1 | 0.3 | 4.4 | -0.3 | -0.3 | **70.6** |
| **2017** | *69.6* | 4.8 | -2.6 | 2.2 | 0.3 | -0.4 | **71.7** |
| **2018** | *71.3* | 4.9 | -3.4 | 1.5 | 0.0 | -0.4 | **72.3** |
| **2019** | *72.4* | 4.9 | -3.9 | 1.0 | 0.0 | -0.4 | **73.1** |
| **2020** | *73.5* | 4.9 | -4.3 | 0.7 | 0.0 | -0.5 | **73.7** |
| **2021** | *74.3* | 5.0 | -4.3 | 0.7 | 0.0 | -0.5 | **74.5** |
| **2022** | *74.9* | 4.9 | -4.3 | 0.7 | 0.0 | -0.5 | **75.1** |
| **2023** | *75.4* | 4.8 | -4.3 | 0.6 | 0.0 | -0.5 | **75.6** |
| **2024** | *76.0* | 4.7 | -4.3 | 0.5 | 0.0 | -0.5 | **75.9** |
| **2025** | *76.7* | 4.6 | -4.2 | 0.4 | 0.0 | -0.5 | **76.6** |
| **2026** | *77.1* | 4.6 | -4.2 | 0.4 | 0.0 | -0.5 | **77.1** |
| **2027** | *77.6* | 4.6 | -4.2 | 0.4 | 0.0 | -0.5 | **77.6** |
| **2028** | *78.0* | 4.6 | -4.2 | 0.4 | 0.0 | -0.5 | **77.9** |
| **2029** | *78.7* | 4.5 | -4.2 | 0.3 | 0.0 | -0.5 | **78.6** |
| **2030** | *79.2* | 4.4 | -4.2 | 0.3 | 0.0 | -0.5 | **79.1** |
| **2031** | *79.7* | 4.4 | -4.2 | 0.3 | 0.1 | -0.5 | **79.5** |
| **2032** | *80.1* | 4.4 | -4.1 | 0.3 | -0.1 | -0.5 | **79.8** |
| **2033** | *80.8* | 4.3 | -4.1 | 0.2 | 0.0 | -0.5 | **80.5** |
| **2034** | *81.3* | 4.3 | -4.0 | 0.2 | 0.0 | -0.5 | **81.0** |
| **2035** | *81.8* | 4.2 | -4.0 | 0.2 | 0.0 | -0.5 | **81.5** |
| **2036** | *82.4* | 4.1 | -3.9 | 0.2 | 0.1 | -0.5 | **82.1** |
| **2037** | *82.7* | 4.1 | -3.9 | 0.2 | 0.0 | -0.5 | **82.4** |
| **2038** | *83.0* | 4.1 | -3.8 | 0.2 | 0.0 | -0.5 | **82.8** |
| **2039** | *83.3* | 4.1 | -3.8 | 0.3 | 0.0 | -0.5 | **83.1** |
| **2040** | *83.5* | 4.2 | -3.8 | 0.4 | 0.0 | -0.5 | **83.4** |
| **2041** | *83.8* | 4.2 | -3.8 | 0.5 | 0.0 | -0.5 | **83.8** |
| **2042** | *84.1* | 4.3 | -3.8 | 0.6 | 0.0 | -0.5 | **84.1** |
| **2043** | *84.4* | 4.4 | -3.7 | 0.6 | 0.0 | -0.5 | **84.5** |
| **2044** | *84.5* | 4.3 | -3.8 | 0.5 | 0.0 | -0.5 | **84.5** |
| **2045** | *84.8* | 4.4 | -3.7 | 0.7 | 0.0 | -0.5 | **85.0** |

## Appendix D: Consumption Disposition Tables

| U.S. Natural Gas Consumption by End Use (Bcfd) – *Navigant Reference Case* | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Year** | **Lease & Plant Fuel** | **Pipeline & Distribution Use** | **Res/ Comm** | **Industrial** | **Vehicle Fuel** | **Electric Power** | **Total Consumption** |
| **2012** | 3.2 | 2.1 | 21.8 | 18.4 | 0.1 | 20.9 | **66.6** |
| **2013** | 3.3 | 2.2 | 21.9 | 18.4 | 0.1 | 22.4 | **68.2** |
| **2014** | 3.3 | 2.2 | 21.9 | 18.3 | 0.1 | 23.5 | **69.3** |
| **2015** | 3.3 | 2.1 | 21.9 | 18.2 | 0.1 | 24.4 | **70.0** |
| **2016** | 3.3 | 2.1 | 21.8 | 18.1 | 0.2 | 25.0 | **70.5** |
| **2017** | 3.3 | 2.2 | 21.9 | 18.1 | 0.2 | 25.7 | **71.4** |
| **2018** | 3.3 | 2.2 | 21.9 | 18.1 | 0.2 | 26.3 | **72.1** |
| **2019** | 3.4 | 2.3 | 22.0 | 18.1 | 0.2 | 26.9 | **72.8** |
| **2020** | 3.7 | 2.3 | 21.9 | 18.0 | 0.2 | 27.3 | **73.4** |
| **2021** | 3.7 | 2.3 | 22.0 | 18.1 | 0.2 | 27.9 | **74.1** |
| **2022** | 3.7 | 2.3 | 22.0 | 18.0 | 0.2 | 28.4 | **74.6** |
| **2023** | 3.7 | 2.3 | 22.0 | 18.0 | 0.3 | 28.8 | **75.1** |
| **2024** | 3.7 | 2.3 | 22.0 | 17.9 | 0.3 | 29.2 | **75.4** |
| **2025** | 3.7 | 2.3 | 22.0 | 18.0 | 0.3 | 29.7 | **76.1** |
| **2026** | 3.7 | 2.4 | 22.1 | 18.0 | 0.3 | 30.2 | **76.6** |
| **2027** | 3.7 | 2.4 | 22.1 | 18.0 | 0.4 | 30.6 | **77.1** |
| **2028** | 3.7 | 2.4 | 22.0 | 17.9 | 0.4 | 31.0 | **77.4** |
| **2029** | 3.8 | 2.4 | 22.1 | 17.9 | 0.4 | 31.5 | **78.1** |
| **2030** | 3.8 | 2.4 | 22.1 | 17.9 | 0.4 | 31.9 | **78.6** |
| **2031** | 3.8 | 2.5 | 22.1 | 17.9 | 0.4 | 32.4 | **79.0** |
| **2032** | 3.8 | 2.5 | 22.0 | 17.8 | 0.5 | 32.7 | **79.3** |
| **2033** | 3.8 | 2.5 | 22.1 | 17.9 | 0.5 | 33.3 | **80.0** |
| **2034** | 3.8 | 2.5 | 22.1 | 17.9 | 0.5 | 33.7 | **80.5** |
| **2035** | 3.8 | 2.5 | 22.1 | 17.9 | 0.5 | 34.2 | **81.0** |
| **2036** | 3.9 | 2.6 | 22.2 | 17.9 | 0.5 | 34.6 | **81.6** |
| **2037** | 3.9 | 2.6 | 22.1 | 17.9 | 0.5 | 35.0 | **81.9** |
| **2038** | 3.9 | 2.6 | 22.2 | 17.9 | 0.5 | 35.3 | **82.3** |
| **2039** | 3.9 | 2.6 | 22.2 | 17.9 | 0.6 | 35.5 | **82.7** |
| **2040** | 3.9 | 2.6 | 22.3 | 17.9 | 0.6 | 35.7 | **83.0** |
| **2041** | 3.9 | 2.7 | 22.3 | 18.0 | 0.6 | 36.0 | **83.4** |
| **2042** | 3.9 | 2.7 | 22.3 | 18.0 | 0.6 | 36.2 | **83.7** |
| **2043** | 3.9 | 2.7 | 22.4 | 18.1 | 0.6 | 36.5 | **84.1** |
| **2044** | 3.9 | 2.7 | 22.3 | 18.0 | 0.6 | 36.6 | **84.2** |
| **2045** | 3.9 | 2.7 | 22.4 | 18.1 | 0.7 | 36.9 | **84.6** |

| U.S. Natural Gas Consumption by End Use (Bcfd) – *Jordan Cove Export Case* | | | | | | | |
|---|---|---|---|---|---|---|---|
| Year | Lease & Plant Fuel | Pipeline & Distribu-tion Use | Res/ Comm | Industrial | Vehicle Fuel | Electric Power | Total Consump-tion |
| **2012** | 3.2 | 2.1 | 21.8 | 18.4 | 0.1 | 20.9 | **66.6** |
| **2013** | 3.3 | 2.2 | 21.9 | 18.4 | 0.1 | 22.4 | **68.2** |
| **2014** | 3.3 | 2.2 | 21.9 | 18.3 | 0.1 | 23.5 | **69.3** |
| **2015** | 3.3 | 2.1 | 21.9 | 18.3 | 0.1 | 24.4 | **70.1** |
| **2016** | 3.3 | 2.1 | 21.9 | 18.1 | 0.2 | 25.0 | **70.5** |
| **2017** | 3.3 | 2.3 | 21.9 | 18.1 | 0.2 | 25.7 | **71.5** |
| **2018** | 3.3 | 2.3 | 21.9 | 18.0 | 0.2 | 26.3 | **72.1** |
| **2019** | 3.4 | 2.3 | 22.0 | 18.0 | 0.2 | 26.9 | **72.8** |
| **2020** | 3.7 | 2.3 | 21.9 | 18.0 | 0.2 | 27.3 | **73.4** |
| **2021** | 3.7 | 2.4 | 22.0 | 18.0 | 0.2 | 27.9 | **74.2** |
| **2022** | 3.7 | 2.4 | 22.0 | 18.0 | 0.2 | 28.4 | **74.7** |
| **2023** | 3.7 | 2.4 | 22.0 | 18.0 | 0.3 | 28.8 | **75.2** |
| **2024** | 3.7 | 2.4 | 22.0 | 17.9 | 0.3 | 29.2 | **75.5** |
| **2025** | 3.7 | 2.4 | 22.0 | 18.0 | 0.3 | 29.7 | **76.2** |
| **2026** | 3.7 | 2.5 | 22.0 | 18.0 | 0.3 | 30.2 | **76.7** |
| **2027** | 3.7 | 2.5 | 22.1 | 18.0 | 0.4 | 30.6 | **77.2** |
| **2028** | 3.7 | 2.5 | 22.0 | 17.9 | 0.4 | 31.0 | **77.5** |
| **2029** | 3.8 | 2.5 | 22.1 | 17.9 | 0.4 | 31.5 | **78.1** |
| **2030** | 3.8 | 2.5 | 22.1 | 17.9 | 0.4 | 31.9 | **78.6** |
| **2031** | 3.8 | 2.5 | 22.1 | 17.9 | 0.4 | 32.4 | **79.1** |
| **2032** | 3.8 | 2.6 | 22.0 | 17.8 | 0.5 | 32.7 | **79.4** |
| **2033** | 3.8 | 2.6 | 22.1 | 17.9 | 0.5 | 33.3 | **80.1** |
| **2034** | 3.8 | 2.6 | 22.1 | 17.9 | 0.5 | 33.7 | **80.6** |
| **2035** | 3.8 | 2.6 | 22.1 | 17.9 | 0.5 | 34.2 | **81.1** |
| **2036** | 3.9 | 2.7 | 22.2 | 17.9 | 0.5 | 34.6 | **81.7** |
| **2037** | 3.9 | 2.7 | 22.1 | 17.9 | 0.5 | 34.9 | **82.0** |
| **2038** | 3.9 | 2.7 | 22.1 | 17.9 | 0.5 | 35.3 | **82.4** |
| **2039** | 3.9 | 2.7 | 22.2 | 17.9 | 0.6 | 35.5 | **82.7** |
| **2040** | 3.9 | 2.7 | 22.2 | 17.9 | 0.6 | 35.7 | **83.0** |
| **2041** | 3.9 | 2.7 | 22.3 | 18.0 | 0.6 | 36.0 | **83.5** |
| **2042** | 3.9 | 2.8 | 22.3 | 18.0 | 0.6 | 36.2 | **83.7** |
| **2043** | 3.9 | 2.8 | 22.4 | 18.0 | 0.6 | 36.5 | **84.2** |
| **2044** | 3.9 | 2.8 | 22.3 | 18.0 | 0.6 | 36.6 | **84.2** |
| **2045** | 3.9 | 2.8 | 22.4 | 18.1 | 0.7 | 36.9 | **84.6** |

| 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 | 2.1 | 21.8 | 18.4 | 0.1 | 20.9 | **66.6** |
| **2013** | 3.3 | 2.2 | 21.9 | 18.4 | 0.1 | 22.4 | **68.2** |
| **2014** | 3.3 | 2.2 | 21.9 | 18.3 | 0.1 | 23.5 | **69.4** |
| **2015** | 3.3 | 2.1 | 21.9 | 18.3 | 0.1 | 24.4 | **70.1** |
| **2016** | 3.3 | 2.1 | 21.9 | 18.1 | 0.2 | 25.0 | **70.6** |
| **2017** | 3.4 | 2.5 | 21.9 | 18.0 | 0.2 | 25.7 | **71.7** |
| **2018** | 3.4 | 2.6 | 21.9 | 17.9 | 0.2 | 26.3 | **72.3** |
| **2019** | 3.5 | 2.7 | 21.9 | 17.9 | 0.2 | 26.8 | **73.1** |
| **2020** | 3.8 | 2.7 | 21.9 | 17.9 | 0.2 | 27.3 | **73.7** |
| **2021** | 3.8 | 2.8 | 21.9 | 17.9 | 0.2 | 27.8 | **74.5** |
| **2022** | 3.8 | 2.8 | 22.0 | 17.9 | 0.2 | 28.3 | **75.1** |
| **2023** | 3.8 | 2.8 | 22.0 | 17.9 | 0.3 | 28.8 | **75.6** |
| **2024** | 3.8 | 2.8 | 21.9 | 17.9 | 0.3 | 29.2 | **75.9** |
| **2025** | 3.9 | 2.8 | 22.0 | 17.9 | 0.3 | 29.7 | **76.6** |
| **2026** | 3.9 | 2.8 | 22.0 | 17.9 | 0.3 | 30.1 | **77.1** |
| **2027** | 3.9 | 2.9 | 22.0 | 17.9 | 0.4 | 30.6 | **77.6** |
| **2028** | 3.9 | 2.9 | 22.0 | 17.8 | 0.4 | 31.0 | **77.9** |
| **2029** | 3.9 | 2.9 | 22.1 | 17.9 | 0.4 | 31.5 | **78.6** |
| **2030** | 3.9 | 2.9 | 22.1 | 17.9 | 0.4 | 31.9 | **79.1** |
| **2031** | 3.9 | 2.9 | 22.1 | 17.9 | 0.4 | 32.3 | **79.5** |
| **2032** | 3.9 | 2.9 | 22.0 | 17.8 | 0.5 | 32.7 | **79.8** |
| **2033** | 4.0 | 3.0 | 22.1 | 17.8 | 0.5 | 33.2 | **80.5** |
| **2034** | 4.0 | 3.0 | 22.1 | 17.8 | 0.5 | 33.7 | **81.0** |
| **2035** | 4.0 | 3.0 | 22.1 | 17.8 | 0.5 | 34.1 | **81.5** |
| **2036** | 4.0 | 3.0 | 22.2 | 17.8 | 0.5 | 34.6 | **82.1** |
| **2037** | 4.0 | 3.0 | 22.1 | 17.8 | 0.5 | 34.9 | **82.4** |
| **2038** | 4.0 | 3.0 | 22.1 | 17.8 | 0.5 | 35.2 | **82.8** |
| **2039** | 4.0 | 3.0 | 22.1 | 17.8 | 0.6 | 35.5 | **83.1** |
| **2040** | 4.0 | 3.0 | 22.2 | 17.8 | 0.6 | 35.7 | **83.4** |
| **2041** | 4.0 | 3.1 | 22.3 | 17.9 | 0.6 | 36.0 | **83.8** |
| **2042** | 4.0 | 3.1 | 22.3 | 17.9 | 0.6 | 36.1 | **84.1** |
| **2043** | 4.1 | 3.1 | 22.3 | 18.0 | 0.6 | 36.4 | **84.5** |
| **2044** | 4.1 | 3.1 | 22.3 | 18.0 | 0.6 | 36.5 | **84.5** |
| **2045** | 4.1 | 3.1 | 22.3 | 18.0 | 0.7 | 36.8 | **85.0** |

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**U.S. Natural Gas Consumption by End Use (Bcfd) – *GHG Demand Case***

| Year | Lease & Plant Fuel | Pipeline & Distribu-tion Use | Res/ Comm | Industrial | Vehicle Fuel | Electric Power | Total Consump-tion |
|---|---|---|---|---|---|---|---|
| **2012** | 3.2 | 2.1 | 21.8 | 18.4 | 0.1 | 20.8 | **66.6** |
| **2013** | 3.3 | 2.2 | 21.9 | 18.4 | 0.1 | 22.3 | **68.2** |
| **2014** | 3.3 | 2.2 | 21.9 | 18.3 | 0.1 | 23.5 | **69.3** |
| **2015** | 3.3 | 2.1 | 21.9 | 18.3 | 0.1 | 24.7 | **70.4** |
| **2016** | 3.3 | 2.1 | 21.8 | 18.0 | 0.2 | 25.6 | **71.1** |
| **2017** | 3.4 | 2.5 | 21.9 | 17.9 | 0.2 | 26.6 | **72.5** |
| **2018** | 3.5 | 2.6 | 21.9 | 17.8 | 0.2 | 27.5 | **73.5** |
| **2019** | 3.5 | 2.7 | 21.9 | 17.8 | 0.2 | 28.3 | **74.4** |
| **2020** | 3.5 | 2.8 | 21.9 | 17.7 | 0.2 | 29.1 | **75.1** |
| **2021** | 3.5 | 2.8 | 21.9 | 17.8 | 0.2 | 29.9 | **76.2** |
| **2022** | 3.5 | 2.8 | 21.9 | 17.8 | 0.2 | 30.7 | **77.0** |
| **2023** | 3.5 | 2.9 | 22.0 | 17.7 | 0.3 | 31.5 | **77.9** |
| **2024** | 3.6 | 2.9 | 21.9 | 17.7 | 0.3 | 32.2 | **78.5** |
| **2025** | 3.6 | 2.9 | 22.0 | 17.7 | 0.3 | 33.1 | **79.6** |
| **2026** | 3.6 | 2.9 | 22.0 | 17.7 | 0.3 | 33.9 | **80.4** |
| **2027** | 3.6 | 3.0 | 22.0 | 17.7 | 0.4 | 34.7 | **81.3** |
| **2028** | 3.7 | 3.0 | 21.9 | 17.6 | 0.4 | 35.3 | **81.9** |
| **2029** | 3.7 | 3.0 | 22.0 | 17.6 | 0.4 | 36.1 | **82.8** |
| **2030** | 3.7 | 3.0 | 22.0 | 17.6 | 0.4 | 36.8 | **83.6** |
| **2031** | 3.8 | 3.0 | 22.0 | 17.6 | 0.4 | 37.5 | **84.4** |
| **2032** | 3.8 | 3.0 | 21.9 | 17.5 | 0.5 | 38.1 | **84.9** |
| **2033** | 3.8 | 3.1 | 22.0 | 17.5 | 0.5 | 38.8 | **85.8** |
| **2034** | 3.9 | 3.1 | 22.0 | 17.5 | 0.5 | 39.5 | **86.4** |
| **2035** | 3.9 | 3.1 | 22.0 | 17.5 | 0.5 | 40.1 | **87.1** |
| **2036** | 3.9 | 3.1 | 22.1 | 17.4 | 0.5 | 40.4 | **87.5** |
| **2037** | 4.0 | 3.1 | 22.0 | 17.4 | 0.5 | 40.7 | **87.8** |
| **2038** | 4.0 | 3.1 | 22.1 | 17.4 | 0.5 | 41.0 | **88.1** |
| **2039** | 4.0 | 3.1 | 22.1 | 17.4 | 0.6 | 41.2 | **88.5** |
| **2040** | 4.1 | 3.2 | 22.2 | 17.4 | 0.6 | 41.3 | **88.7** |
| **2041** | 4.1 | 3.2 | 22.2 | 17.5 | 0.6 | 41.6 | **89.2** |
| **2042** | 4.1 | 3.2 | 22.2 | 17.5 | 0.6 | 41.7 | **89.3** |
| **2043** | 4.1 | 3.2 | 22.3 | 17.5 | 0.6 | 42.0 | **89.7** |
| **2044** | 4.1 | 3.2 | 22.2 | 17.4 | 0.6 | 42.0 | **89.5** |
| **2045** | 4.1 | 3.2 | 22.3 | 17.4 | 0.7 | 42.3 | **89.9** |

## Appendix E: Henry Hub Price Forecast Comparison Table

| Henry Hub Price Forecast Comparison (Real$/MMBtu) | | | | |
|---|---|---|---|---|
| Year | *Navigant Base* | *Jordan Cove Export* | *Aggregate Export* | *GHG Demand* |
| **2012** | $4.12 | $4.12 | $4.12 | $4.12 |
| **2013** | $4.53 | $4.52 | $4.52 | $4.52 |
| **2014** | $4.21 | $4.17 | $4.13 | $4.14 |
| **2015** | $4.31 | $4.21 | $4.08 | $4.19 |
| **2016** | $4.68 | $4.59 | $4.45 | $4.82 |
| **2017** | $4.84 | $4.91 | $5.12 | $5.57 |
| **2018** | $4.93 | $5.02 | $5.42 | $5.92 |
| **2019** | $4.92 | $5.01 | $5.50 | $6.07 |
| **2020** | $4.98 | $5.06 | $5.60 | $6.23 |
| **2021** | $5.02 | $5.08 | $5.57 | $6.26 |
| **2022** | $5.10 | $5.15 | $5.59 | $6.34 |
| **2023** | $5.20 | $5.25 | $5.66 | $6.47 |
| **2024** | $5.34 | $5.39 | $5.78 | $6.66 |
| **2025** | $5.51 | $5.55 | $5.92 | $6.88 |
| **2026** | $5.65 | $5.70 | $6.04 | $7.07 |
| **2027** | $5.80 | $5.84 | $6.17 | $7.27 |
| **2028** | $5.96 | $5.99 | $6.31 | $7.51 |
| **2029** | $6.14 | $6.17 | $6.48 | $7.77 |
| **2030** | $6.31 | $6.34 | $6.64 | $8.02 |
| **2031** | $6.47 | $6.50 | $6.79 | $8.18 |
| **2032** | $6.67 | $6.70 | $6.99 | $8.40 |
| **2033** | $6.87 | $6.90 | $7.19 | $8.71 |
| **2034** | $7.07 | $7.10 | $7.40 | $9.02 |
| **2035** | $7.31 | $7.35 | $7.66 | $9.33 |
| **2036** | $7.51 | $7.55 | $7.90 | $9.54 |
| **2037** | $7.62 | $7.66 | $8.00 | $9.62 |
| **2038** | $7.72 | $7.77 | $8.11 | $9.72 |
| **2039** | $7.80 | $7.84 | $8.19 | $9.81 |
| **2040** | $8.28 | $7.90 | $8.28 | $9.87 |
| **2041** | $7.98 | $8.01 | $8.39 | $10.00 |
| **2042** | $8.05 | $8.08 | $8.43 | $10.07 |
| **2043** | $8.17 | $8.19 | $8.50 | $10.21 |
| **2044** | $8.14 | $8.16 | $8.46 | $10.16 |
| **2045** | $8.28 | $8.30 | $8.55 | $10.31 |

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# APPENDIX B

# NAVIGANT WHITEPAPER

NAVIGANT

# WHITEPAPER: ANALYSIS OF THE EIA EXPORT REPORT 'EFFECT OF INCREASED NATURAL GAS EXPORTS ON DOMESTIC ENERGY MARKETS' DATED JANUARY 19, 2012

**Prepared for:**
**Jordan Cove Energy Project, L.P.**

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## EIA Report Overview

On January 19, 2012, the Energy Information Administration (EIA) of the U.S. Department of Energy released a report ("Effect of Increased Natural Gas Exports on Domestic Energy Markets", or "Report") presenting estimated impacts of liquefied natural gas export scenarios on certain aspects of the domestic energy markets. EIA performed the analysis pursuant to a request by the Office of Fossil Energy of the Department of Energy, which is responsible for evaluating applications to export liquefied natural gas. The main findings of the Report included the following:

- Increased natural gas exports lead to increased natural gas prices.
- The source of the gas volumes needed for the increased exports would be about two-thirds from increased natural gas production, with most of the balance provided by decreased natural gas consumption.
- Most of the increased production would be from shale gas sources, and most of the decreased consumption results from coal-for-gas fuel switching in electric generation.

EIA's approach was to start with four "baseline" cases taken from the 2011 Annual Energy Outlook ("AEO2011"), which was released in April 2011; the four baseline cases are the AEO2011 Reference case, and the Low Shale EUR[1], High Shale EUR, and High Economic Growth cases. Against these four baseline cases, EIA performed four alternative export scenarios, as follows:

| Name | Export Level | Ramp-Up |
|---|---|---|
| Low/Slow | 6 Bcfd | +1 Bcfd per year (or 6 years) |
| Low/Rapid | 6 Bcfd | +3 Bcfd per year (or 2 years) |
| High/Slow | 12 Bcfd | +1 Bcfd per year (or 12 years) |
| High/Rapid | 12 Bcfd | +3 Bcfd per year (or 4 years) |

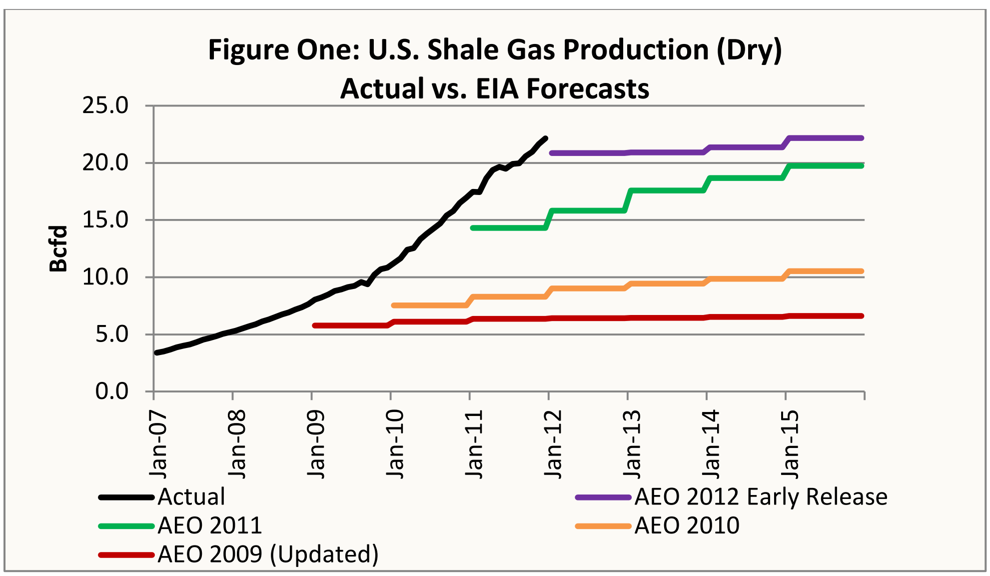
Thus, the Report analyzed 16 different case-scenario combinations, with emphasis on presenting production, consumption, producer revenue and consumer expenditure metrics for the four export scenarios under the Reference case baseline, and also natural gas pricing estimates under all 16 case-scenario combinations. Media reporting has already focused on price impacts estimated under "extreme" market assumptions, i.e. high exports and low supplies, that are by their nature highly unlikely, perhaps "extremely unlikely." The Report also included data tables showing average values of a host of variables over the first and second ten-year periods of the analysis, as well as over the entire twenty-year period of the analysis. Annual data from the analysis is available on the EIA website.[2]

[1] Estimated ultimate recovery.

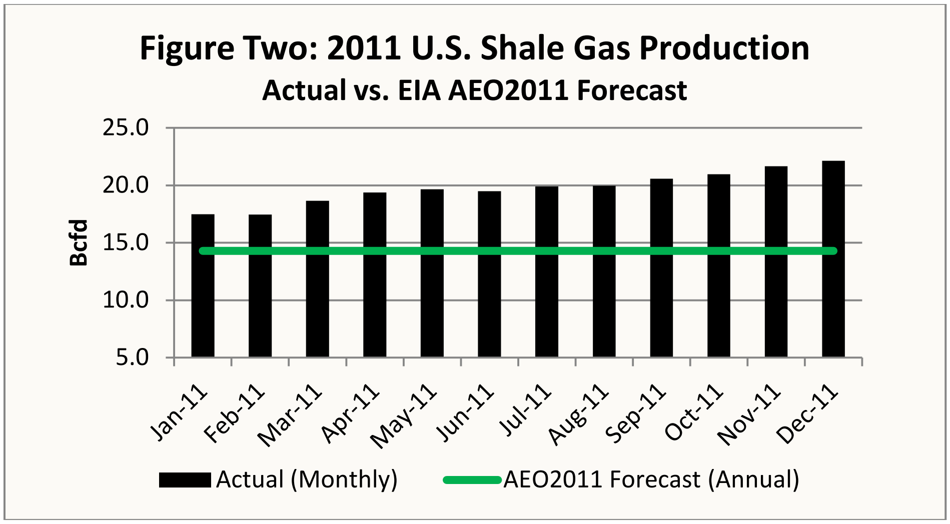
[2] http://www.eia.gov/analysis/requests/fe/

## The Shale Gas Supply Forecasts Used in the Report Are Well Below Existing Levels and Do Not Capture Current Development Trends

As background, it is instructive to note that EIA's Annual Energy Outlook projections historically have systematically understated upcoming shale gas production. As can be seen in Figure One below, the first year of each of the last three shale production forecasts was far surpassed by the actual production for that year (AEO2009, AEO2010, and AEO2011). The speed of development of shale gas resources is so great that many forecasts simply have not caught up with the realities in the field. Even with the very large jump shown for the AEO2011 shale production forecast for 2011, an increase of over 70% from the AEO2010 figure, it was still significantly below actual 2011 shale gas production levels, by more than 25% for the annual average level and by 35% for the year-end production level. The clear trend in the data shows that the same result will occur for AEO2012, where the forecast production level for 2012 was already surpassed by the year-end 2011 production level. Figure Two following shows this surge in more detail.

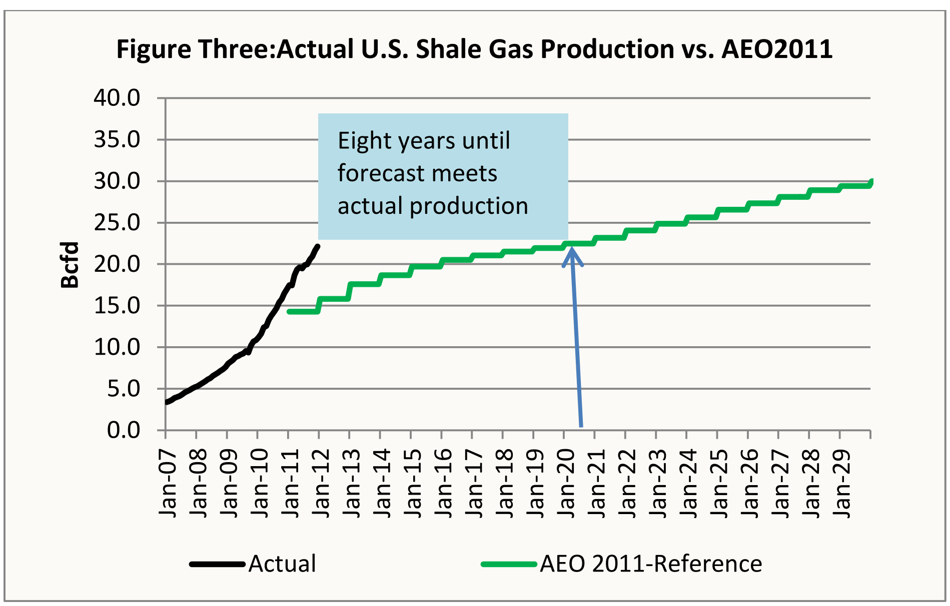



Source: EIA; Lippman/Navigant



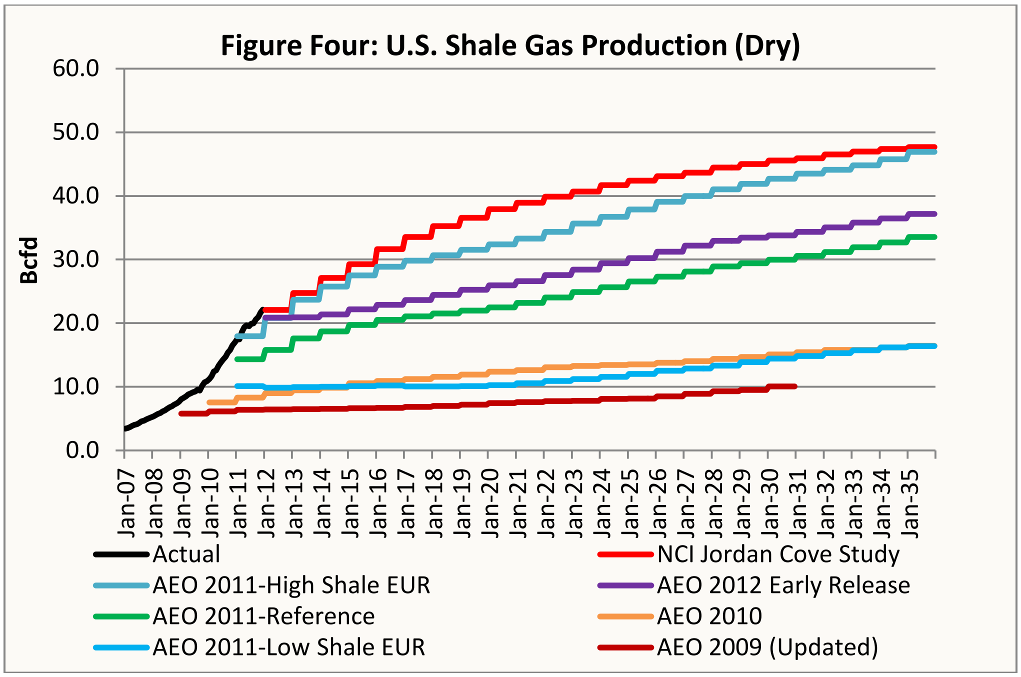

Source: EIA; Lippman/Navigant

The lagging of a forecast behind actual production figures can easily become a long-term issue unless recalibrated. As seen in Figure Three, the AEO2011 Reference case shale gas production forecast that was already eclipsed by a substantial amount by actual production levels in 2011 will be below those current production levels for another eight years; not until 2020 will that Reference case meet today's production levels. While the AEO2012 Early Release Reference case is a step in the right direction (it will match today's production levels in only three more years), the EIA's Report is based on the AEO2011 forecast, and as such appears to assume a significantly underestimated natural gas supply.




Source: EIA; Lippman/Navigant

As noted above, the shale gas production forecasts used in the AEO Reference cases have been low with respect to historical and current production levels. As can be seen following, however, even in the EIA's AEO2011 High Shale EUR case used in the Report, the production forecast appears low. The 2011 forecast production level was eclipsed by actual shale gas production levels in the U.S. in March of 2011, and was about 19% below actual levels at the end of the year.




Source: EIA; Lippman/Navigant

Further, the High Shale case is lower than Navigant's shale gas production forecast used in the market study supporting Jordan Cove's export application, which Navigant believes to be conservative. As outlined in our Jordan Cove Report, Navigant believes its forecast to be conservative as a result of our fundamental basis of projection that requires empirical production data before a resource is included, meaning that forecasts for production from even very large potential plays will be small or zero if the particular play does not have a history of production. This is certainly the case for the Utica Shale, a resource that underlies the prolific Marcellus Shale on the East Coast, but is currently largely undeveloped; while Navigant did not assume any production from the U.S. portion of the Utica Shale in its Jordan Cove Report, it is arguable that it could be producing many multiples of the .5 Bcfd that Navigant estimates for the Canadian portion of the play by the end of the Report's study period.

Given the relationship to both existing production levels and Navigant's forecast, the AEO2011 High Shale EUR forecast can likely be considered low, even as a reference-level case. That conclusion, in turn, helps illuminate the fact that the AEO2011 Low Shale EUR forecast is clearly out of line with current developments, as it already reflects only 50% of actual production, and holds that level for over ten years. Any reliance by the media on the Low Shale case, particularly in combination with a scenario of ultra-high exports, certainly appears misplaced.

Compounding the issue of understated shale production forecasts is the fact that now with the publication of the AEO2012 Early Release, the AEO2011 data underlying the Report is even more dated. Compared to AEO2011, AEO2012 shows a shale gas production forecast increase that averages about 3.5 Bcfd greater than the AEO2011 forecast. This increase in reference case shale gas production beyond that assumed in the Report is actually equivalent to 58% of EIA's assumed low export case incremental volume of 6 Bcfd, or 29% of the assumed high incremental export volume of 12 Bcfd. Using the EIA's updated AEO 2012 forecasts of gas production together with its stated assumptions on export volumes would have led to smaller than the stated price increases.[3]

[3] The understatement of forecast shale volumes due to the dated forecast has an even greater effect on the High Shale EUR case, where the AEO2011 shale production figure for 2025 is 1.42 times that in the Reference case. Using that same factor would give a High Shale EUR increment of 5 Bcfd, based on the 3.5 Bcfd increment in the newly released AEO2012 Reference case. Thus, the effect of the increase in Reference case shale gas production figures on the High Shale EUR figure (i.e. 5 Bcfd) could account for about 83% of EIA's low incremental export volume, or about 42% of the assumed high incremental export volume, in that case.

## Media Coverage is Highlighting the Least Representative Scenarios and Metrics

An article on the Report in Platt's Gas Daily noted a 54% gas price increase in 2018 "under the most extreme export volume and gas market assumptions". The article could have clarified that the "extreme" assumptions, while not mutually exclusive, resulted from mixing a baseline case and an export scenario that, by their very nature, do not represent a realistic real-world scenario, but an extremely unlikely combination of assumptions. The 54% gas price increase is a one-year metric that resulted when the Low Shale EUR baseline case is combined with the high export/rapid ramp-up scenario. The fact that one would not expect higher exports in a low shale case was actually alluded to in the Report by EIA, which stated on page 4 that "for purposes of this study, the scenarios of additional exports posted by DOE/FE in their request do not vary across the different baseline cases that are considered. In reality, given available prices in export markets, lower or higher U.S. natural gas prices would tend to make any given volume of additional exports more or less likely." Thus, beyond the fact that the Low Shale EUR forecast itself is already contradicted by actuality, by being 50% below already existing production levels as discussed in the prior section, the combination of the Low Shale EUR forecast with high exports, resulting in the 54% price increase in a given year, is not a realistic outcome on which to focus attention.

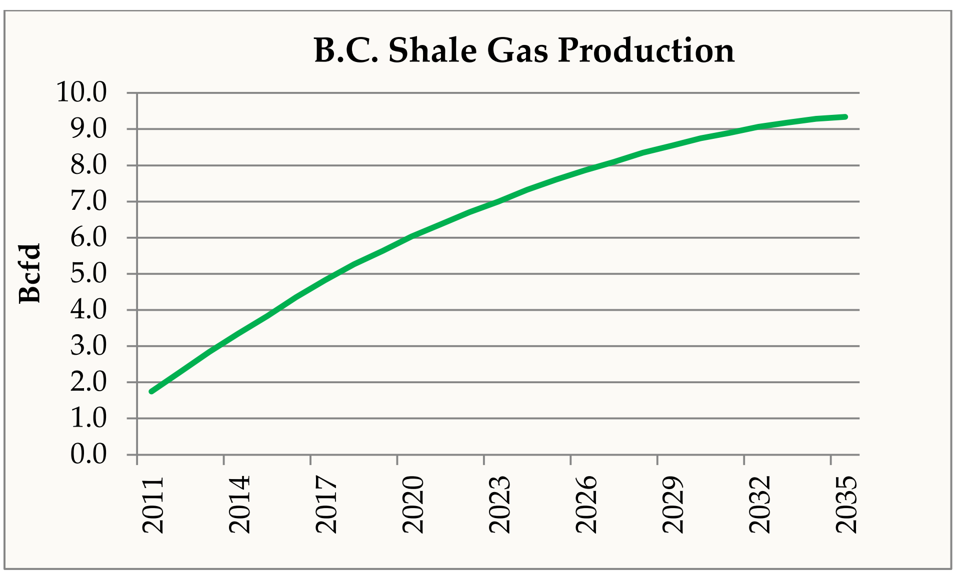
The least unrealistic baseline case-scenario combination from among those offered in the Report would use the High Shale EUR baseline case, which comes closer to a realistic reference case, despite still lagging actual production, as discussed in the prior section. With respect to exports, Navigant's market study supporting Jordan Cove's export application assumes 5.9 Bcfd of U.S. LNG export capacity in the long-term under its "aggregate export" case, designed to be a high end figure comprised of both licensed and generic projects; Navigant thus views the EIA low export case as closer to a reasonable export figure, though still at the high end. In any event, the High Shale baseline together with the low/slow export scenario, while still reflecting assumptions Navigant believes to be low on the production side and high on the export side, generates a maximum-year price increase 74% lower than the quoted 54% figure.

One more point about the media commentary on results concerns the use of maximum, single-year price impacts, as opposed to more generalized measures of sustained impacts, such as changes in price averages over years. As can be seen from the EIA's charts and tables, the average price increases are always a fraction of whatever the maximum-year increase is and illustrated below with respect to the Low Shale EUR scenario.

| Export Scenario | Low Shale EUR Case, Percent Price Change | |
|---|---|---|
| | **Maximum Year** | **Average, 2015 - 2035** |
| Low/Slow | 20% | 9% |
| Low/Rapid | 30% | 11% |
| High/Slow | 29% | 18% |
| High/Rapid | 54% | 20% |

## Canadian Shale Gas Will be a Major Source for Jordan Cove, While the Report Assumes Gulf Coast LNG Export Activity

The location of the Jordan Cove project in the Pacific Northwest is relevant in several ways to an assessment of the Report with respect to Jordan Cove. First, a significant part of the gas feedstock for Jordan Cove will be from Canadian resources, with Navigant's estimates of sourcing being initially 70% from the Western Canadian Sedimentary Basin, shifting down to 35% by 2045, with 50% from the WCSB overall for the full term of the project. As shown below, Navigant estimates future Canadian shale gas supplies from British Columbia will increase from about 4 Bcfd to over 9 Bcfd over the Report's study period - more than adequate to be the primary gas supply source for the Jordan Cove LNG export project. It should also be noted that with the changing dynamics of the U.S. market, stemming from the ample supplies from currently developed and developing U.S. shale plays, the additional demand created by potential LNG exports from the U.S. West Coast is being looked upon increasingly favorably as an important new market for Western Canadian production. U.S. LNG exports would help support gas development in Canada that otherwise could stall or be "stranded" due to the lack of effective access to the US market resulting from less expensive and abundant U.S. domestic gas in other regions.




Source: Navigant

An important aspect of the Report to note is that the Report only focused on LNG exports that would be shipped out of the West South Central Census Division, effectively from LNG export projects in Texas or Louisiana on the Gulf Coast. Due to the strong regional supply and infrastructure in the area, the expectation is that the supply impact of the LNG projects analyzed in the Report would be isolated to Gulf supplies. To the extent Jordan Cove draws on U.S. gas supplies, the supply would in all likelihood be met entirely from supply in the large and growing Rockies supply basin, not from any Gulf area supply. Thus, the Report does not have real pertinence to the Jordan Cove LNG export project because it is based on an analysis and scenarios for LNG export and supply that are tied to a wholly distinct region of the country from a supply and infrastructure standpoint.

It should also be noted that in assuming Gulf Coast exports, the Report specifically did not model any East Coast export facility, the location of which would be suited to the ample supplies coming out of the Marcellus Shale. Had the Report included some assumed LNG export out of the East Coast, the results would likely have yielded lower price impacts due to the size of the Marcellus basin as the most likely supply source for East Coast LNG exports should they develop. This certainly was Navigant's findings in the work done for the Dominion Cove Point LNG export project.

## LNG Exports Will Facilitate a Less Volatile U.S. Gas Market

Certain beneficial attributes of providing for increased gas demand by virtue of LNG exports are not clearly susceptible to quantification, and were not dealt with by the Report. An unappreciated but 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 produced natural gas and then manufactured LNG for export can be an integral part of a healthy natural gas market that achieves a closer balance of supply and demand. In today's market, with a surplus of supply compared to demand, additional baseload LNG export demand offers the ability to sustain the ongoing development of gas supply that fosters a sustainable industry at prices that are more stable and less volatile.

Before the advent of significant shale gas production, the natural gas industry's history reflected periodic periods of 'boom and bust' cycles, partially due to the uncertain nature of the process of exploration and development of natural gas. Driven by uncertainty and risk around the process of exploration process of finding and developing gas supply to meet demand, both for the short and long terms the industry was prone to cycles of over and under supply that often caused prices to rise and fall dramatically. This in itself caused other, second-tier ramifications impacting the investment cycle for supply, causing supply to be frequently out of phase with demand. 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. These factors contribute to natural gas price volatility. The price volatility itself affected 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 shale gas resource has a generally lower-risk profile even when compared to conventional gas supply that reinforces its future growth potential. 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 economical. 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.

The dependability of shale gas production as a result of its abundance as well as its reduced exploration risk has the potential to improve the phase alignment between supply and demand, which will in turn tend to lower price volatility. The vast shale gas resource will support a much larger demand level than has heretofore been seen in North America, and at prices that are less volatile due to its production process characteristics. LNG exports, including those from the Jordan Cove LNG export project, therefore should be seen as instrumental in providing the increased demand to spur exploration and development of shale gas assets in North America for the long-term benefit of this country and others.

# APPENDIX C

# ECONORTHWEST
# CONSTRUCTION STUDY

# An Economic Impact Analysis of the Construction of an LNG Terminal and Natural Gas Pipeline in Oregon

Prepared for the Jordan Cove Energy Project, L.P.

March 6, 2012

ECONorthwest
ECONOMICS • FINANCE • PLANNING

# Introduction

The construction of a liquefied natural gas (LNG) project in southwest Oregon has been proposed, consisting of the following two elements (together, the "Project"):

1. the Jordan Cove Energy Project (JCEP), an LNG terminal in Coos County, Oregon; and,

2. the Pacific Connector Gas Pipeline (PCGP), a 234-mile natural gas pipeline connecting the LNG terminal to the Malin natural gas hub in Klamath County, Oregon.

This report describes the results of an impact analysis that measured the effects of the Project's construction activity on the economies of Oregon and Washington. Specifically, this study focuses on impacts from July 2014 through December 2017 when the Project would be built.

JCEP engaged ECONorthwest for the analysis and provided data. ECONorthwest used that data, labor market data from the U.S. Bureau of Labor Statistics and U.S. Census, and economic models in forecasting the economic impacts attributable to the Project's construction.

Economic impacts include job creation, labor income, economic output, and value added. Other potential effects arising from this construction project, including environmental and social, are not addressed in this study.

All costs and impact values in this report are expressed in 2011 dollars. Hence the report does not speculate how much inflation may occur in labor rates, construction materials, and services.

As is typical of economic impact studies, the analysis for the Project covers the four calendar years 2014 through 2017. The averages reported in this analysis are based on this four-year period. However, plans call for the construction of the JCEP terminal to start July 2014 and end July 2017. Pipeline construction would begin July 2014 and end December 2017.

# Major Findings

This report summarizes the economic impacts in Oregon and Washington associated with the construction of the JCEP LNG terminal facilities and the PCGP natural gas pipeline.

The major findings of this analysis are:

- The total expenditure on the Project would be $5.354 billion of which $4.494 billion would go into the direct construction of the pipeline and terminal facilities. That represents the Project's direct economic output. Through downstream impacts, total economic output in Oregon and Washington would be $6.641 billion as a result.

- In terms of gross domestic product, which is the overall net value added to the economy due to the construction, Oregon and Washington would experience a total increase of $1.738 billion between 2014 and 2017. Of this, $739 million would occur directly at the construction sites while nearly one billion dollars more would result from non-direct effects that would stimulate additional spending and employment in the economy.

- In the average year from 2014 to 2017, Project construction activities would employ 1,768 workers receiving $182.6 million in compensation. The economic stimulus provided by the construction would cause employment and labor earnings to rise elsewhere in the Oregon and Washington economies. The total annual employment impact is estimated to be 5,137 additional jobs earnings $330.0 million in labor income.

# Background

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 Description

JCEP and PCGP received Federal Energy Regulatory Commission (FERC) certification to construct and operate their proposed facilities for imports of LNG. In the import mode, LNG would be unloaded at the JCEP terminal and re-gasified back into natural gas that would be stored at the terminal and then transported by PCGP to markets in the western United States for domestic consumption.

The Project developers are now seeking authorization for the terminal and pipeline to be constructed and operated for exports, with the expectation that, during the foreseeable future, the Project will be exclusively an LNG export facility. Natural gas to be exported is anticipated to originate in the extensive shale gas resources of western Canada and the Rocky Mountain states.  In the export mode, PCGP will transport and deliver natural gas to the terminal, where JCEP will liquefy the gas into LNG, store it, and then load it onto ships for export.

In 2006, ECONorthwest conducted an economic impact study of the Project as an import facility. This current study measures the impacts of the Project solely as an export facility.

The nameplate capacity of the terminal would be six million metric tonnes a year (MMtpy) of LNG exports. Plans call for the terminal to operate at an average capacity factor of 90 percent. At that level, which allows for seasonal variations, routine upkeep, and market fluctuations, the terminal would export nearly 5.4 MMtpy of LNG.

The PGCP would have a nameplate capacity of 1.1 billion cubic feet of natural gas per day (Bcfd). At a 90 percent capacity factor, throughput would average 0.99 Bcfd. As shown on Table 1, about 0.78 Bcfd would be used in exported LNG, 0.05 Bcfd in terminal operations, and 0.16 Bcfd would be used by other consumers between Malin and Jordan Cove and by the pipeline itself.

**Table 1: Project capacity and natural gas use**

| Capacity Measure | Daily | Annual |
|---|---|---|
| *JCEP LNG exports, metric tonnes:* | | |
| Nameplate capacity | 16,438 | 6,000,000 |
| Projected @ 90% of capacity | 14,784 | 5,396,163 |
| *PGCP natural gas throughput, Bcf:* | | |
| Nameplate capacity | 1.10 | 401.50 |
| Projected @ 90% of capacity | 0.99 | 361.35 |
| *Uses of PGCP natural gas throughput, Bcf:* | | |
| Contained in LNG exported | 0.78 | 284.81 |
| Used by the JCEP terminal | 0.05 | 18.73 |
| Used by the PGCP and others | 0.16 | 57.85 |
| Total | 0.99 | 361.39 |

*Source: ECONorthwest analysis of data provided by the JCEP.*

## LNG Terminal

The LNG terminal and an associated power plant would occupy a total of approximately 360 acres located on the lower section of Coos Bay on the North Spit of Coos County, Oregon.

If run at a 90 percent capacity factor for a full year, the terminal would export nearly 5.4 MMtpy of LNG, which requires approximately 90 LNG carrier vessels to call upon the terminal.

Approximately 6.2 percent of the gas delivered to the JCEP terminal would be either consumed as fuel to operate the liquefaction process or be removed from the feed gas stream (trace sulfur compounds, carbon dioxide, nitrogen and water) prior to or during the liquefaction step. Any hydrocarbons recovered that have a higher molecular weight than methane will fuel the power plant.

The JCEP terminal would have two LNG storage tanks, each with a capacity of 160,000 cubic meters. On-site LNG storage capacity is equivalent to approximately eight days of design production.

Additionally, the terminal would generate its own power through the use of multiple natural gas fired combustion turbines operating in combined cycle. Initial estimates have sized the power plant at 350 megawatts (MW) with sufficient redundancy in generation equipment to allow the JCEP facility to be self-sufficient with reserve generation to ensure that the 90% or greater plant availability is maintained. Approximately 10 - 20 MW of excess power is proposed to be available from the facility in order to stabilize the regional power grid.

## Pipeline

The PCGP is a 234 mile, 36” diameter pipeline that will connect the JCEP terminal in Coos County to the natural gas market hub at Malin, Oregon. No significant changes in the design of the PCGP are anticipated to provide for the capability to deliver gas to Coos Bay from Malin in addition to the previously approved design for the delivery of gas from Coos Bay to Malin.

Natural gas will come from sources in Canada and the U.S. Rockies. Canadian gas would be delivered to Malin *via* the existing Gas Transmission Northwest (GTN) pipeline. Natural gas from the Rockies would be delivered to Malin through the newly operational Ruby Pipeline. A single natural gas compressor station at Malin will allow the PCGP to transport 1.1 Bcfd to JCEP terminus in Coos County.

The JCEP would use about 84 percent of the pipeline’s throughput when operating at 90 percent of nameplate capacity.

# Economic Area

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.

Given the Project’s size and complexity, it would draw in resources from throughout Oregon and Washington. This is especially true for labor. In response to previous research inquiries, trade unions notified ECONorthwest that they had sufficient numbers of members skilled in the types of construction needed for the Project and that most would come from Oregon and some from Washington.

Natural gas pipeline construction labor and JCEP project management are more specialized. About half of these workers would come from outside the two-state region.

Besides labor, the two states can supply many of the services and materials needed for construction. Therefore, this study defines the economic area as the states of Oregon and Washington combined.

# Impact Sources

The principal source of impacts would arise directly from construction activity in Coos County as well as nearby Jackson, Douglas, and Klamath counties where portions of the pipeline extend. There would also be some impacts from about $7.7 million of contractor payments for logging, hauling, and clearing timber in the right of way.

Household spending by jobholders residing in Oregon and Washington is another major source of economic impacts. For workers, household spending affects the economy to the degree that they spend their earnings in Oregon and Washington. Impact analysis accounts for earnings used for taxes, savings, or spending outside the two states. Such uses have no impacts on the local economy.

For nonresident Project employees, the analysis counts only those workers' *per diems* as a source of economic impacts in the study area. Spending of their wages and salaries occurs largely outside of the study area of Oregon and Washington; therefore, those downstream impacts are not counted in this analysis, which focuses only on the economic impacts within Oregon and Washington.

The analysis also excludes certain project expenditures that are not typically considered in economic impact studies. These include asset transfers, property and sales taxes, interest during construction, working capital, and purchases from suppliers outside the study area of Oregon and Washington. Examples of asset transfers are land purchases, payments for right of way, and payments for timber.

# Project Construction Costs

Project construction cost estimates used in this analysis were current as of March 2012, but are subject to revisions as detailed designs evolve. The basis for the estimates shown in this report are of a pipeline and an export terminal designed with sufficient pre-investment to readily install import capability in the future.

JCEP Project Manager, Mr. Bob Braddock, provided ECONorthwest with construction cost estimates, adjusted to 2011 dollars, for both the pipeline and LNG terminal. He also forwarded terminal construction labor data from Black & Veatch, the engineering, procurement, and construction firm for the JCEP. ECONorthwest distributed construction cost contingencies across expenditure activities.

As shown in Table 2, the total cost for the Project is $5.354 billion.

### Table 2: Project construction costs and direct impacts by activity and element, millions of 2011 dollars

| Expenditure | Total Project Cost | Direct Construction Impacts | JCEP Portion | PCGP Portion |
|---|---|---|---|---|
| Marine facilities | $146 | $146 | $146 | - |
| LNG tank systems | 380 | 380 | 380 | - |
| Liquefaction plant | 1,331 | 1,331 | 1,331 | - |
| Power plant | 420 | 420 | 420 | - |
| Pipeline construction | 1,333 | 1,333 | - | $1,333 |
| Pipeline right of way timber | 45 | - | - | - |
| Pipeline easement & damage payments | 17 | - | - | - |
| Right of way payments | 10 | - | - | - |
| Road, utility infrastructure | 7 | 7 | 7 | - |
| Marine, safety infrastructure | 46 | 46 | 46 | - |
| Taxes | 9 | - | - | - |
| Land for the JCEP | 100 | - | - | - |
| JP project & const. management | 25 | 25 | 25 | - |
| JCEP pre-opening expenses | 17 | 17 | 17 | - |
| Development phase contingencies | 66 | 66 | 66 | - |
| JCEP escalation & contingency | 573 | 573 | 573 | - |
| PCGP escalation & contingency | 150 | 150 | - | 150 |
| Interest during JCEP construction | 680 | - | - | - |
| **Total Expenditures** | $5,354 | $4,494 | $3,011 | $1,483 |

*Sources: ECONorthwest analysis of data provided by Bob Braddock, Vice President – Project Manager of the JCEP, memos dated 12/19/11, 12/27/11, and 1/3/12.*
*Note: Not included are pipeline pre-development expenses, interest, and land purchase costs.*

For the purposes of measuring the economic impacts of construction, certain expenditures are excluded. As noted on Table 2, land purchased for the terminal and other real estate payments (a $100 million asset transfer), capitalized interest ($680 million), and several other items are not counted. Although they are Project costs, they are not sources of construction output. Therefore, the value of construction that would be put in place totals $4.494 billion.

The $4.494 billion is the direct output of construction. About $3.011 billion of the direct construction would be attributable to the JCEP terminal and related facilities. The pipeline accounts for the remaining $1.483 billion of construction spending.

At $4.494 billion in direct construction costs, the value of the proposed Project is very large, exceeding that of construction spending on all similar projects in Oregon over the last five years. From 2007 through 2011, $4.435 billion was spent constructing power plants, natural gas pipelines, communication utilities, transmission infrastructure, and manufacturing buildings in the entire state.[1]

The analysis measured the downstream economic effects of these direct construction impacts on the study area.

Constructing both the JCEP and PCGP would require specialized equipment and materials that are only available from suppliers outside the study area. As Table 3 illustrates, of the $4.494 billion in total construction spending, $1.366 billion would be spent in Oregon and Washington. Much of the $1.366 billion would be re-spent within the study area, generating successive rounds of secondary impacts. This would continue until the money eventually exits the economy through savings, taxes, and purchases made outside of the two states.

[1] Spending on new, additions, and alterations on utility infrastructure and manufacturing buildings as reported by McGraw-Hill Construction Research & Analytics for the years 2007 through 2011, in emails to R. Whelan (ECONorthwest) from Shawn LaRoche, Economic Analyst, McGraw Hill. The most recent data received on February 20, 2012.

**Table 3: Project expenditures by geography[2] and category, in millions of 2011$**

| Project Component | Oregon and Washington | Elsewhere | Total |
|---|---|---|---|
| JCEP | | | |
| Employee compensation | $364 | $48 | $412 |
| Materials | $134 | $315 | $449 |
| Equipment | $20 | $573 | $594 |
| All other expenditures | $499 | $1,058 | $1,557 |
| PCGP | | | |
| Employee compensation | $130 | $188 | $318 |
| All other expenditures | $219 | $946 | $1,165 |
| **Total** | **$1,366** | **$3,128** | **$4,494** |

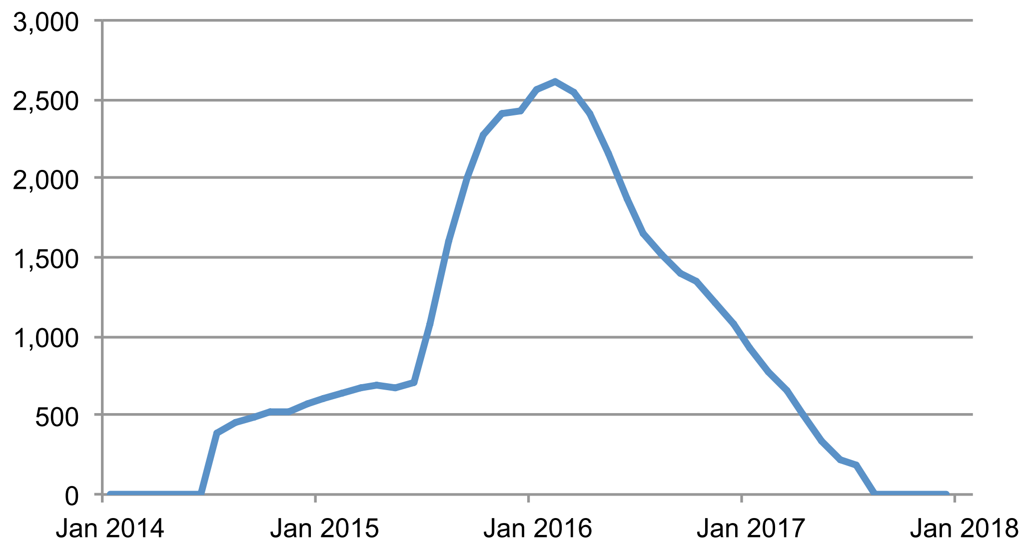
*Sources: ECONorthwest analysis of data provided by Bob Braddock, Vice President – Project Manager of the JCEP, memos dated 12/19/11, 12/27/11, and 1/3/12; IMPLAN.*

# Construction Schedule

Black & Veatch provided workforce estimates for the LNG facility's construction period from July 2014 to July 2017. The prime contractor for the Project would obtain its workers through direct hiring and subcontractors. In addition there would be construction and project management employees. These and an adjustment for construction contingencies were added to the totals shown on Figure 1.

[2] Labor payrolls will be made in Oregon for work performed in the state during construction. The portion shown as being "elsewhere" on Table 3 is compensation to employees that reside outside of the two-state study area.

**Figure 1: JCEP workers on site per month**




*Source: JCEP manpower forecast by Black & Veatch received by ECONorthwest from JCEP in an email dated December 19, 2011. Employment adjusted by ECONorthwest to reflect current project specifications, cost estimates, and contingencies.*

Employment peaks in February 2016 at 2,612 workers, but averages 931 over the four-year period.[3] JCEP alone will require about 7.7 million total worker-hours of employment. Approximately half of JCEP's management staff is expected to come from outside the study area.

The construction of the JCEP facilities will require highly skilled tradespeople, including electricians, pipefitters, metalworkers, and cement masons. The Project will use union labor, drawing on the available workforce in Oregon and Washington.

For the PCGP, ECONorthwest estimated, based on pipeline construction worker compensation rates, that pipeline construction would employ an average of 837 workers over four years. Construction labor will cost about $318 million.[4]

Workers living in Oregon and Washington are expected to comprise half the PCGP workforce and earn a combined $130.2 million. Workers from outside the study area would earn higher wages because of their more specialized skill level. For those itinerant employees their contribution to the study area economy would come solely from their *per diems*, which PCGP projects will total $40.7 million.

For the entire Project (terminal and pipeline), direct employment will average 1,768 jobs a year over four years. Total direct labor income would be $730 million.

[3] The construction estimates provided by JCEP assume 2,080 working hours per year.

[4] Average compensation calculated based on median wages for pipefitters in Oregon, reported by the U.S. Bureau of Labor Statistics 2010 Occupational Employment Statistics.

# Economic Impacts

The enormity of the Project is such that it would necessarily attract construction labor and rely on suppliers from throughout the study area. Currently, there is ample slack in the construction sector, which has seen its employment drop in Oregon and Washington by more than 103,000 jobs since 2007.[5]

Project spending and employment from within Oregon and Washington will cause direct economic impacts that would filter down through the economy causing additional hiring, spending, and other economic activities.

ECONorthwest analyzed construction planning and forecast data provided by the Project's development team. Spending and payroll impacts that would occur outside the borders of Oregon and Washington were excluded.

## Economic Impact Analysis

This impact analysis measures the annual effects of the Project for each of the four construction years from 2014 to 2017. As the initial direct impacts of $4.494 billion, apportioned over the years based on construction schedules, spread to other parts of the economy, subsequent *secondary* impacts occur. These are estimated using an economic impact model of Oregon and Washington. This model counts all the effects of labor and spending at the construction project, as those direct effects filter down through an economy *via* local spending by the Project, its subcontractors, local suppliers, and affected employees.

### Economic Impact Model

ECONorthwest estimated the impact of construction for the Project 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 Project, rather than relying on industry averages, which encompass all forms of heavy construction work.

[5] Change calculated by subtracting 2011 total employment in construction in Oregon and Washington from 2007 reported by the U.S. Bureau of Labor Statistics in its Current Employment Statistics database available at http://www.bls.gov/ces/.

The Project's development team provided spending and payroll estimates by year and location. ECONorthwest excluded from any downstream effects Project expenditures expected from vendors outside of the Northwest, as these have no significant economic impacts on the study area. ECONorthwest also excluded from having secondary impacts all but the *per diem* spending that would arise from Project construction employees who come from outside of Oregon and Washington.

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

The IMPLAN model divides the economy into 440 sectors including government, households, farms, and various industries. For each sector IMPLAN allocates spending and employment impacts between the local and non-local economies.[6] The IMPLAN data, derived from U.S. Census and other government sources, approximates how, from where, and on what products and services various local industries spend money. IMPLAN also estimates the employment effects by industry.

ECONorthwest replaced the default estimates of IMPLAN with actual spending and payroll budget data for the Project. When fed into IMPLAN, the impacts of the Project's construction spending and employment, as they flow through the modeled economies of Oregon and Washington, are 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 Project construction sites), the amounts diminish due to the effects of savings, taxes, or other activities that happen outside the local economy. 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*.

[6] IMPLAN production function and regional purchase coefficient data were used.

## 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 the Project construction sites and offices that oversee construction activity.
- **Indirect impacts:** An indirect impact is one that occurs because of business-to-business transactions. Thus, when JCEP buys steel from a wholesaler in Eugene, Oregon, that purchase causes an indirect impact in the form of higher output, employment, and business income for the steel service center. That would also represent a first round of indirect impacts. An example of a second round would be if the service center buys the steel it sells to the terminal from a mill in Portland, Oregon. That too is a business-to-business transaction causing an indirect impact. Spending by the Project from a supplier outside the study area shows up as a direct impact, but not as an indirect impact.
- **Induced impacts:** An induced impact is one caused by household spending. For example, a pipeline welder working on the PGCP who spends his wages on groceries from a store in Roseburg, Oregon causes a first round of induced impacts. If store employees or its owner earn more money because of the increased business coming from the pipeline's construction, their increased household spending causes a second round of induced impacts. Because induced impacts originate from household spending, they often are called "consumption-driven" effects. Induced impacts of workers living in the study area are greater than those based elsewhere (itinerant workers). Resident workers spend most of their wages and benefits in the study area. Itinerant worker induced impacts are limited to what their *per diems* cause.

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 on the construction project. An annual average is work for twelve months. Therefore, seven months of work by a steamfitter on the LNG terminal plus five months of work by a pipeline welder counts 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, benefits (*i.e.,* health insurance, vacation pay, retirement), and employer paid payroll taxes. In this study, payrolls of the general contractors and trades at the construction sites are counted as being direct impacts.
- **Proprietor income:** Earnings of self-employed workers and farmers in the local economy. This includes owner-operator businesses.
- **Labor income:** The sum of employee compensation and proprietors' income.
- **Output:** For construction projects, output is the cost of building and completing structures. This includes the cost of equipment, engineering, project management, and other expenses of assembling physical structures. Land and financing are not part of construction output. Direct output is the value of construction put in place even though many components and services used in the building process may be non-local.
- **Value added:** For construction projects, value added is the most useful overall impact measure because it estimates the net contribution of a project to a local economy. Value added, when calculated for an entire country or region, is known as the gross domestic product or "GDP." This is a common measure of the size of an economy.[7] GDP is the market value of all the goods and services produced by labor and property located in the study area (for this analysis, Oregon and Washington).

[7] The U.S. Bureau of Economic Analysis calculates national and local area GDP data. Some analysts reserve the term GDP for national data and call county-level results the gross regional product or GRP.

# Results

The economic impact analysis yields estimates of the total effects on the economy of Oregon and Washington that would result throughout the four years of construction on the JCEP and the PGCP.

## Economic Output Impacts

The direct output of the Project represents the gross value of construction work each year on the pipeline and LNG terminal facilities. ECONorthwest was provided monthly spending data for the pipeline and construction site labor by the JCEP. JCEP spending on goods and services, including contingencies, was allocated in proportion to the monthly labor schedule.

Total direct output, shown on Table 4 as a four-year period total, equals $4.494 billion. This was also reported on Table 2 as the portion of total Project expenditures that constitute direct construction impacts.

**Table 4: Project construction impacts on economic output in Oregon and Washington, 2014 – 2017, millions of 2011 $**

| Level of Impact on Economic Output | 2014 | 2015 | 2016 | 2017 | Four-Year Period Total | Annual Average |
|---|---|---|---|---|---|---|
| Direct | $271.8 | $1,283.7 | $1,776.0 | $1,162.1 | $4,493.6 | $1,123.4 |
| Indirect | 90.2 | 412.5 | 465.3 | 206.0 | 1,173.9 | 293.5 |
| Induced | 55.7 | 276.4 | 403.5 | 237.9 | 973.5 | 243.4 |
| Total Output | $417.6 | $1,972.6 | $2,644.8 | $1,606.0 | $6,641.1 | $1,660.3 |

*Source: ECONorthwest impact analysis of JCEP and PGCP construction spending, March 2012.*

Besides the value of the construction put in place, output would also result from Project spending on goods and services and the spending of employee households. These cause indirect and induced impacts, respectively. In total, the combined gross economic output in the study area would be $6.641 billion.

The net impact of the Project on the GDP of the study area would be less than total output largely because most of the construction inputs would come from sources outside the study area. To account for this, value added was calculated.

# Value Added (GDP) Impacts

Value added or GDP is output minus intermediate purchases of goods and services. Intermediate goods and services are the outputs of other industries. By subtracting the values of intermediates from the output of the construction project, the remainder is the amount that the Project's construction work adds to the economy.

In the first year, 2014, the GDP of Oregon and Washington combined would be $85.0 million higher due to the Project’s construction. As the pace of construction accelerates, the impact on GDP rises, peaking at $702.6 million in 2016.

**Table 5: Project construction impacts on the GDP of Oregon and Washington, 2014 – 2017, millions of 2011 $**

| Level of Impact on Value Added | 2014 | 2015 | 2016 | 2017 | Four-Year Period Total | Annual Average |
|---|---|---|---|---|---|---|
| Direct | $26.8 | $149.4 | $292.1 | $271.0 | $739.4 | $184.8 |
| Indirect | 27.9 | 130.5 | 177.5 | 104.1 | 440.0 | 110.0 |
| Induced | 30.3 | 152.4 | 233.0 | 143.3 | 559.1 | 139.8 |
| Total Value Added | $85.0 | $432.3 | $702.6 | $518.5 | $1,738.4 | $434.6 |

*Source: ECONorthwest impact analysis of JCEP and PGCP construction spending, March 2012.*

Construction has a direct impact on the GDP of Oregon and Washington of $739.4 million over the four-year period. Indirect effects contribute another $440.0 million to total GDP and the induced impacts, caused by higher incomes of jobholders and small business owners, add another $559.1 million. The total impact on the study area economy is $1.738 billion in additional GDP.

# Labor Impacts

Labor impacts are reported as labor income and jobs. Income includes overtime and benefits, which in the construction trades are substantial. Jobs are measured as a combination of the number of payroll employees and self-employed people engaged in work for twelve months. They include both the employees of the prime contractor and all subcontractors working at the construction site. While it can be part-time work, for construction employment in this study, direct jobs were measured as full-time, 2,080 hours per year.

### Table 6: Project construction impacts on labor income and full-year equivalent jobs in Oregon and Washington, 2014 – 2017

| Type/Level of Impact | 2014 | 2015 | 2016 | 2017 | Four-Year Period Total | Annual Average |
|---|---|---|---|---|---|---|
| *Labor income, including benefits (million 2011 $):* | | | | | | |
| Direct | $26.1 | $145.8 | $288.0 | $270.5 | $730.4 | $182.6 |
| Indirect | 17.4 | 81.8 | 114.6 | 68.9 | 282.7 | 70.7 |
| Induced | 16.8 | 84.2 | 127.7 | 78.2 | 306.9 | 76.7 |
| Total Labor Income | $60.3 | $311.8 | $530.3 | $417.6 | $1,320.0 | $330.0 |
| *Jobs (full-year equivalents):* | | | | | | |
| Direct | 246 | 1,315 | 2,701 | 2,812 | 7,073 | 1,768 |
| Indirect | 400 | 1,857 | 2,425 | 1,438 | 6,120 | 1,530 |
| Induced | 395 | 1,991 | 3,070 | 1,897 | 7,353 | 1,838 |
| Total Jobs | 1,040 | 5,163 | 8,196 | 6,146 | 20,546 | 5,137 |

*Source: ECONorthwest impact analysis of JCEP and PGCP construction spending, March 2012.*

Direct labor income between 2014 and 2017 would total about $730.4 million. Including indirect and induced impacts, total labor income throughout Oregon and Washington would be $1.320 billion higher because of the construction.

The construction of the Project would employ the full-year equivalent of 1,768 workers a year directly. As a result of the construction, there would be another 1,530 and 1,838 jobs a year, indirect and induced, respectively, throughout the study area. The increase in total employment in Oregon and Washington would range from 1,040 in 2014 and peak at 8,196 in 2016. On average, the states would experience 5,137 more jobs per year between 2014 and 2017 and labor income would be $330 million higher.

# APPENDIX D

# ECONORTHWEST OPERATIONS STUDY

# An Economic Impact Analysis of Jordan Cove LNG Terminal and Pacific Gas Connector Pipeline Operations

Prepared for the Jordan Cove Energy Project, L.P.

March 23, 2012

ECONorthwest
ECONOMICS • FINANCE • PLANNING

Section I

# Introduction

A liquefied natural gas (LNG) terminal and natural gas pipeline project may be built in Coos County, Oregon (the Project). The total cost to construct and start operations, beginning in December 2017, is in excess of $5.3 billion. Jordan Cove Energy Project, L.P. (JCEP), the developer of the LNG terminal, engaged ECONorthwest to determine the economic impacts of operations for a typical operating year.

This study summarizes the findings of the operations economic impact analysis. It quantifies the impacts of the terminal and pipeline on the economy of Coos County for a typical operating year. All values in this study are reported in 2011 dollars and, therefore, do not include predictions of inflation.

The typical operating year analyzed was 2018. This year was chosen because the developers anticipate that it would be the first full year of normal operations when the terminal and pipeline would be working at a long-run average of 90 percent capacity.

In 2018, the Project operation will perform and consist of the following:

1. The JCEP LNG terminal capable of exporting natural gas. Marine facilities at the terminal would be able to load approximately 90 full LNG carriers a year.

2. The terminal would have a liquefaction plant consisting of two units that would treat incoming pipeline gas, removing $CO_2$, water vapor, and hydrocarbons heavier than methane. Four trains, with a combined nameplate capacity of 6.0 million metric tons per year (MMtpy) will liquefy the methane into LNG. Operating at 90 percent of capacity over a year, the terminal would deliver 5.4 MMtpy of LNG for export.

3. Two LNG storage tanks, each with a capacity of 160,000 cubic meters. This capacity is equivalent to approximately eight days of design production.

4. A 350 megawatt (MW) combined cycle power plant that would provide power to the terminal. It will consume the equivalent of about 18.7 billion cubic feet (Bcf) of natural gas a year including the heavier hydrocarbons recovered from liquefaction when operating at 90 percent. The power plant may have some excess power for sale beyond the terminal. This analysis does not count the value of excess power that may be sold.

5. The Pacific Connector Gas Pipeline (PCGP), a 234-mile natural gas pipeline connecting the terminal to the Malin hub in Klamath County, Oregon. It would be able to deliver 1.1 billion cubic feet a day (Bcfd). When operating at 90 percent of capacity, the terminal would use 0.83 Bcfd, thus leaving 0.158 Bcfd available for other consumers.

JCEP provided ECONorthwest with operating data, including employment, payrolls, expenditures, and volumes. ECONorthwest used that data and economic models in forecasting the economic impacts attributable to the Project's operations. Navigant Consulting, Inc. provided energy price forecasts used in this analysis. Their research is summarized in *Jordan Cove LNG Export Project Market Analysis Study*, a related report prepared for JCEP and dated January 2012 (the Navigant Study). The price impact on Coos County consumers of natural gas was included in this analysis.

Economic impacts include job creation, labor income, economic value added, and local government revenues arising from operations and natural gas price effects in 2018. Other potential effects, including environmental, recreational, and social, are not addressed in this study.

# Major Findings

This analysis finds that in Coos County and in each year that the Project operates:

- GDP would be about $1.36 billion higher.

- The Project would create 99 jobs at an average wage of $81,921. It would also support another 637 jobs elsewhere in the county.

- PCGP would contribute about $2.4 million in property taxes (plus another $8.8 million in property taxes to counties other than Coos County).

- JCEP would contribute $30 million annually, in lieu of property taxes, towards education and urban renewal.

Section II

# Background

LNG facilities benefit local economies through goods and services spending, taxes, and well-compensated, skilled labor needed in overseeing operations. Economic impact studies measure these benefits as annual effects on employment, income, government, and value added. To do so, researchers begin by clearly defining the business, the time period being studied, the economic area over which the effects are being measured, and the sources of impacts being included or excluded.

## Project Description

JCEP and PCGP received Federal Energy Regulatory Commission (FERC) certification to construct and operate their proposed facilities for imports of LNG. In import mode, LNG would be unloaded at the JCEP terminal and re-gasified back into natural gas that would be stored at the terminal and then transported by PCGP to markets in the western United States for domestic consumption.

The Project developers are now seeking authorization for the terminal and pipeline to be constructed and operated for exports, with the expectation that, during the foreseeable future, the Project will be exclusively an LNG export facility. In the export mode, PCGP will transport and deliver natural gas to the terminal, where JCEP will liquefy the natural gas into LNG, store it, and then load it onto ships for export. Neither PCGP nor JCEP intend to own the natural gas. PCGP would charge fees to the shipper-owners of the gas to deliver it to the terminal. The terminal would operate as a contract manufacturer, charging fees to the owners of the natural gas for liquefaction, storage, and delivery onto ships. Natural gas to be exported is anticipated to originate in the extensive shale gas resources of western Canada and the Rocky Mountain states.

Although the terminal may in the future add the capacity to import LNG, this analysis measures the impacts of the Project's operations solely as an export facility.

### LNG Terminal

The LNG terminal, and an associated power plant, would occupy approximately 360 acres located on the lower section of Coos Bay on the North Spit of Coos County, Oregon along Jordan Cove Road.

LNG terminal and LNG liquefaction facilities typically operate at high load factors. The JCEP terminal would have a design capacity of 6.0 MMtpy of LNG (based upon 365 days of operation per year). Allowing for maintenance and market fluctuations, the Project plans for a 90 percent on-stream factor. At that level, the annual LNG quantity of 5.4 MMtpy would require about 90 LNG ships a year to call upon the terminal. The quantities exported in 2018 would equal about 1.3 percent of recent annual U.S. natural gas production.[1]

Approximately 6.2 percent of the gas delivered to the JCEP terminal would be either consumed as fuel to operate the liquefaction process or be removed from the feed gas stream (trace sulfur compounds, carbon dioxide, nitrogen and water) prior to or during the liquefaction step. Any hydrocarbons recovered, which have a higher molecular weight than methane, will fuel the power plant.

For all its needs and when operating at 90 percent of capacity, the JCEP will need about 0.83 Bcfd of natural gas from the PCGP, about 0.78 Bcfd for the gas contained in the LNG exports and 0.05 Bcfd for the gas used by the terminal.

The terminal will generate its own power through the use of multiple natural gas fired combustion turbines operating in combined cycle. Initial estimates have sized the power plant at 350 MW with redundancy in generation equipment to allow the JCEP facility to be self-sufficient with reserve generation to ensure that the 90 percent or greater plant availability is maintained.

Approximately 10 to 20 MW of excess power is proposed to be available from the power plant in order to stabilize the regional power grid, although the value of this output is not included in this analysis.

This analysis assumes construction of the JCEP terminal begins in July 2014 and concludes 42 months later, in December 2017 when operations begin. The first full-year of service is 2018. This analysis measures the economic impacts of operations for that year.

## Pipeline

The PCGP will extend 234 miles. This 36" diameter pipeline will connect the JCEP terminal in Coos County to the natural gas market hub at Malin, Oregon. No significant changes in the previously approved design for shipping liquefied imported gas from Coos Bay to Malin are anticipated to provide for delivery of gas to Coos Bay from Malin for export as LNG.

Natural gas will come from Canada and the U.S. Rockies. Canadian gas would be delivered to Malin *via* the existing Gas Transmission Northwest (GTN) pipeline. Natural gas from the Rockies would be delivered to Malin through the newly operational Ruby Pipeline. A single natural gas compressor station at Malin will allow the PCGP to transport 1.1 Bcfd to the JCEP terminus in Coos County.

[1] Based on 2010 marketed production of 22,402,141 MMcf, as reported by the U.S. Energy Information Administration. Natural Gas Monthly. January 30, 2012.

The owners of natural gas shipped through the PGCP will pay the pipeline for transmission. Those payments are revenues for the pipeline.

For the purposes of estimating total Project impacts on the economy of Coos County, the analysis does factor in the change in natural gas pricing on in-county consumption, which is based upon data from the local utility, Northwest Natural.

# Time Period

Economic impact studies measure the effects of a project on the economy over a selected time period. Usually it is for a single year or, if there are significant fluctuations in the volume of output over time, several years are analyzed serially.

For the Project, output would vary little over time because LNG is storable and consumed by electric utilities, which have predictable needs. Also, large-scale LNG facilities are capital intensive.[2] Maintaining a high capacity factor is expected. Therefore, the analysis was done for a single time period chosen for its likelihood of being a typical operating year.

Jordan Cove informed ECONorthwest that it expects to operate fully in 2018. Allowing for routine maintenance, equipment repairs, and fluctuations in shipments, LNG terminals run at high levels of their rated capacities. JCEP anticipates operating in a normal year at an average capacity factor of 90 percent.

The 90 percent rate would be reached after the initial ramp-up and inventory build-up in December 2017. The economic impact analysis covers the first typical operating year, which is 2018. The impacts from operations in 2018 would recur in future years.

# Economic Area

The economic area for an impact study is one that encompasses where the bulk of the operations occur and where labor predominantly comes from. For this Project the appropriate economic area is Coos County, Oregon. Nearly all employees for the JCEP and the PCGP would work in Coos County. According to the U. S. Census, 96.6 percent of all workers in Coos County also reside in that county.[3] This is a consequence of its geography, with businesses and housing concentrated in the cities around Coos Bay, but isolated by extensive forestlands from the populous Interstate-5 corridor running north-south through western Oregon.

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[2] Many natural gas utilities and pipeline companies operate small LNG liquefaction and storage facilities. They provide back-up storage so that customers are adequately served when local natural gas demand spikes unexpectedly. Four such plants operate in Oregon and Washington. Their LNG unit costs are higher, and volumes considerably less, than the proposed LNG terminal.

[3] U.S. Census 3-year average 2008 – 2010 American Community Survey for Coos County.

## Impact Sources

The principal sources of impacts come from the spending by the operators of the pipeline and terminal facilities. Spending by the Project for its operations in 2018 at businesses in Coos County constitutes the first round of impacts. Another source of first round impacts is the spending done in Coos County by Project and Project-related employee households.

The impact of Project and other associated employees on the county economy varies according to where they reside. Commuters spend less locally than employees who also reside in the county do. Resident employees are a major source of induced economic impacts.

For commuting workers coming from outside the county, their initial impact on the Coos County economy is limited to what they spend locally. This analysis assumes $4,800 a year per employee, which is $20 per working day.

There are significant sources of impacts unique to the Project that the analysis specifically includes. These are activities that JCEP will pay for or are explicit economic consequences of the Project in 2018. Included are ancillary government operations that are related to the Project and for which JCEP's operator would pay (*e.g.,* security, fire safety, and emergency planning). These unique impact sources are:

- Vessel services for LNG carriers making calls to the Port.
- Three working tugboats and twelve crewmembers based in Coos County.
- Payroll and operating expenses for the North Spit Industrial Fire Station.
- Effect of higher natural gas prices on Coos County consumers.
- Payroll and operating expenses for the Coos County Sheriff's Marine LNG Division.
- Payroll covering four emergency planners working for state and local government.
- $20 million in annual funding for local public K-12 education *via* a trust.
- $10 million in annual funding for urban renewal *via* JCEP's location within the Bay Area Enterprise Zone.

## Not Considered as Impact Sources

There are several types of transactions and effects that are excluded from this economic impact analysis. They are:

- Any purchases of goods or services outside of Coos County by Project operators, their suppliers, or employees.
- Asset transfers (*e.g.*, land and right-of-way purchases) that are not normally counted in economic impact studies.
- Interest and other financial charges.

- Downstream impacts from property taxes paid by the pipeline.
- Sale of electric power from the power plant into the local electric grid (excluded due to its uncertainty).

## Project Operating Costs

PCGP will transport natural gas and JCEP will liquefy it for export as LNG. Operating expenses of the Project would total almost $65.3 million in 2018, its first full-year of operation, as shown on Table 1. Similar levels of spending would be repeated in future years. The value of the natural gas used at the terminal is not an operating expense on Table 1 because neither the pipeline nor the terminal, which would provide transportation and liquefaction as contracted services, would buy natural gas.

### Table 1: 2018 Project operating expenses by activity, 2011 $

| Project component | Expense category - excluding natural gas | Total amount | Percent spent or paid in Coos County |
|---|---|---|---|
| JCEP | Major replacement parts | $10,000,000 | 0% |
| | Payroll and benefits | 7,503,390 | 100% |
| | Insurance | 7,500,000 | 0% |
| | Other consumables | 500,000 | 100% |
| | Catalysts, lubricants, and chemicals | 450,000 | 50% |
| | Miscellaneous expenses | 250,000 | 100% |
| | Government worker payrolls and benefits | 3,066,782 | 100% |
| | Other government worker expenses | 500,306 | 79% |
| | Tugboat payrolls and benefits | 527,580 | 100% |
| | Contributions to local K-12 education | 20,000,000 | 100% |
| | Contributions to Bay Area Urban Renewal Association | 10,000,000 | 100% |
| PCGP | Payroll and benefits | 606,770 | 100% |
| | Non-labor operating expenses* | 1,960,085 | 32% |
| | Property taxes | 2,429,775 | 100% |
| **Total Project Spending** | | **$65,294,688** | **71%** |

*Source: ECONorthwest analysis of data provided by Bob Braddock, Vice President – Project Manager of the JCEP, memos dated 12/19/11 and 12/27/11. Government and tugboat worker wages were obtained from publically available databases including Worksource Oregon.*

** Some operating costs include the engaging of contractors that, in turn, will hire employees.*

According to JCEP's estimates, the terminal facilities would employ 94 full-time workers. These employees would earn a combined $7.5 million in wages and benefits annually, an average of nearly $80,000 per person. In addition, the Project would pay the salaries of 52 other workers, including tug crews and county workers, at an average annual compensation of $70,800 per person.

As stated previously, 96.6 percent of workers in Coos County also reside in Coos County. Therefore, the model assumes that three JCEP employees and two other JCEP-supported workers would live outside Coos County, and the downstream effects of their earnings are less, as most of their household spending would occur in the other counties where they reside.

According to PCGP, five full-time employees would work for the pipeline. This analysis assumes that all five employees would live in Coos County and attributed their jobs and earnings to that county.

The pipeline transportation industry has so few employees in Oregon that useable payroll data are unavailable. Therefore, this analysis relied on the national average compensation estimate for 2011 of $124,995.

# Economic Impacts

Project operations in 2018 result in direct employment, payroll, and purchases that affect Coos County. In addition, spending and payroll in Coos County by vessel service firms and local government operations dependent on the Project for funding also result in economic impacts. As these impacts filter down through the local economy, additional jobs, payroll, and economic value added would occur in Coos County during the year.

ECONorthwest analyzed operations forecast data. Spending beyond county borders and certain other items noted on pages 6-7 were excluded. ECONorthwest used an economic model of the Coos County economy to quantify all of the local economic impacts in 2018.

## Economic Impact Analysis

In 2018, the combined PGCP and JCEP would have a direct payroll of $8.1 million, 99 employees, and expenditures of $65.3 million.

In addition, in lieu of property taxes, JCEP will pay $20 million to K-12 schools, $10 million to the Bay Area Urban Renewal Association, and about $3.6 million for ancillary government operations. These are first round secondary impacts. Subsequent *secondary* impacts are estimated using an economic impact model of Coos County as the effects of the Project's operations filter down through the County's economy.

### Economic Impact Model

ECONorthwest estimated the impacts from operations 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 Project, rather than relying solely on U.S. Census derived industry averages that economic impact models normally start with.

The combination of Project-specific data, flexibility in application, and an open access philosophy make IMPLAN the appropriate modeling framework for this analysis. IMPLAN is a widely used economic modeling system and is accepted in the U.S. court system and in regulatory settings.[4]

[4] University of Wisconsin Center for Cooperatives and the Department of Agricultural and Applied Economics at the University of Wisconsin — Madison at http://reic.uwcc.wisc.edu/implan/

The U.S. Forest Service, in cooperation with FEMA and the Department of the Interior, developed IMPLAN as a product of the Rural Development Act of 1972. 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, 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

The IMPLAN model divides the economy into 440 industry sectors, as well as government, and households. For each sector IMPLAN allocates spending and employment impacts between the local and non-local economies.[5] The IMPLAN data, derived from U.S. Census and other government sources, approximates how, from where, and on what products and services various local industries spend money. IMPLAN also estimates the employment effects by industry.

Where data were available, ECONorthwest replaced the default estimates of IMPLAN with 2018 spending and payroll estimates from the Project. When fed into IMPLAN, the impacts of the Project's spending and employment, as they flow through the modeled Coos County economy, are 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 the Project), the amounts diminish due to the effects of savings, taxes, or other activities that happen outside the local economy. 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 Project. Economists call this the *multiplier effect*.

## 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:** Employment and spending in conducting pipeline and LNG terminal operations.

[5] IMPLAN production function and regional purchase coefficient data were used.

- **Indirect impacts:** An indirect impact is one that occurs because of business-to-business transactions. Thus, when a JCEP buys plumbing services from a contractor in Coos Bay, that purchase causes an indirect impact in the form of higher employment and business income for the plumbing firm. That would also represent a first round of indirect impacts. An example of a second round would be if the plumber buys solder from a hardware store in North Bend (Coos County). That too is a business-to-business transaction causing an indirect impact.

- **Induced impacts:** An induced impact is one caused by household spending. For example, an engineer working for the terminal spends some of his pay on groceries at a store in North Bend. That is a first round of induced impacts. If the store's employees or owner earn more money because of the increased business coming from the terminal's engineer, that increased income results in even more local household spending causing a second round of induced impacts. Because induced impacts originate from household spending, they often are called "consumption-driven" effects.

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.* These impacts happen largely in places away from the primary sources, but still inside Coos County.

The usefulness 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 jobs, both for workers on payroll and the self-employed, for either full- or part-time work done in Coos County during 2018. An annual average is work for twelve months. Therefore, nine months of work by a schoolteacher paid through the $20 million grant by JCEP, plus three months of work by a contractor maintaining land on which the pipeline lies would 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, benefits (*i.e.,* health insurance, vacation pay, retirement), and employer paid payroll taxes.

- **Proprietor income:** Earnings of self-employed workers and farmers in the local economy. This includes owner-operator businesses.

- **Labor income:** The sum of employee compensation and proprietors' income.

- **Value added:** The measure of how much a project contributes on a net basis to a local economy. In the context of this analysis, value added is the sum of PGCP transmission revenues and the increased market value the terminal affords to natural gas by converting it into LNG, minus Project spending on goods and services. From another perspective, value added is the net contribution of the Project's labor and capital in Coos County. Value added is also known as the gross domestic product or "GDP" — a common measure of the size of an economy.[6]

By operating the Project, upstream producers, transporters, and developers of natural gas would experience positive impacts because the Project opens up new markets for them. The value added to the national economy by these upstream industries may, in some years, exceed that of the PGCP and JCEP operators. A separate analysis was produced describing these substantial upstream impacts.

[6] The U.S. Bureau of Economic Analysis calculates national and local area GDP data. Some analysts reserve the term GDP for national data and call county-level results the gross regional product or GRP.

# Results

Using jobs, taxation, and spending data for the Project and IMPLAN, ECONorthwest determined the total impacts of the Project's operations in 2018 on Coos County's economy.

## Employment Impacts on Coos County

The Project will pay for 152 workers in Oregon (151 in Coos County). Of these, 99 would be direct hires of the terminal and pipeline operators, and the remainder would be indirect hires for ancillary needs such as security, fire safety, planning, and handling incoming vessels.

Typical of large, capital-intensive energy projects, worker compensation rates for jobs covered by the Project would be high and employees would overwhelmingly reside in the county where they work. Thus, there would be substantial secondary impacts on the local economy through the spending of employee households and other households whose incomes would improve as a result. Payments by the JCEP for local education and urban renewal would also result in significant secondary job impacts.

In total, the IMPLAN analysis shows that 736 jobs would result in Coos County in years, like 2018, when the Project operates at 90 percent of capacity. This is shown on Table 2.

**Table 2: Impact on employment in Coos County by the Project, 2018**

| Job function/type | Jobs |
|---|---|
| Direct jobs: | |
| JCEP operations | 76 |
| JCEP finance & administration | 14 |
| JCEP safety, security, & environmental | 4 |
| PCGP employees | 5 |
| Direct jobs | 99 |
| Indirect jobs paid for by the JCEP: | |
| Sheriffs' deputies | 20 |
| Firefighters | 16 |
| Tugboat crews | 12 |
| Emergency planners* | 3 |
| Indirect jobs paid by JCEP | 51 |
| Other indirect jobs in Coos County | 404 |
| Induced job impacts in Coos County | 182 |
| **Total jobs impact on Coos County** | **736** |

*Source: ECONorthwest analysis of data provided by Bob Braddock, Vice President – Project Manager of the JCEP, memo dated 12/27/11; IMPLAN.*
**Excludes one Project-funded emergency planner working at the state level.*

The analysis estimates that the average direct employee of the Project would earn nearly $82,000 a year in wages and benefits. Indirect impacts, which include those at ancillary government services as well as K-12 education paid for by the JCEP, total 455 jobs at an average annual compensation of $42,572. Induced impacts, which tend to be concentrated in food service and retailing, would account for 182 jobs at an annual rate of $29,691 in wages and benefits. Overall, the Project would support 736 jobs in Coos County at an average annual compensation rate of $44,679.

**Table 3: Impact on Coos County labor income and compensation rates in 2011 $ by the Project, 2018**

| Type of Impact | Jobs | Labor Income | Compensation per Job |
|---|---|---|---|
| Direct | 99 | $8,110,160 | $81,921 |
| Indirect | 455 | 19,372,223 | 42,572 |
| Induced | 182 | 5,403,686 | 29,691 |
| Total | 736 | $32,886,070 | $44,679 |

*Source: ECONorthwest.*

# Value Added Impacts on Coos County

The U.S. Census Bureau classifies LNG terminals as manufacturers of industrial gas. Gross output for manufacturers is measured as the fair market value of the things they produce. Therefore, the gross output of the JCEP is the fair market value of the LNG loaded onto ships for export.[7]

Pipelines, on the other hand, are considered a transportation industry. The output of transportation sectors is measured as the market value of the services they provide. Consequently, the gross output of the PCGP is the market value of shipping natural gas.

According to the U.S. Bureau of Economic Analysis, value added (GDP) is defined as "the difference between an industry's gross output (sales or receipts plus other operating income and inventory change) and its intermediate inputs (goods and services that are purchased for use in production)."[8]

Intermediate inputs to the Project include the fair market value of the natural gas used by the terminal as well as goods and services, such as replacement parts and other consumables necessary for production.

For integrated systems that span multiple counties, the unitary valuation method is often used to apportion the system's value among its component counties. This method is commonly used in the valuation of railroads, telecommunications networks, natural gas pipelines, and other large systems. In this case, because the PCGP spans four counties, it is conservative to apply this method when considering its GDP instead of attributing its full value to a single county. Pipeline miles were used to allocate the value added (GDP) of the PCGP to each county for this portion of the analysis. As a result, 19.7% of the PCGP's GDP was allocated to Coos County.

In 2018, the analysis finds that the operations of the PGCP and the JCEP businesses in Coos County would generate about $1.29 billion and $35 million, respectively, in GDP to the local economy directly. The indirect and induced value added impacts would be about $24.1 and $11.0 million, respectively. A breakdown of the GDP calculations by Project component is shown in Table 4.

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[7] It should be noted that JCEP would not own LNG, but rather liquefy natural gas that is owned by other companies. As a result, the revenues of the terminal would be the value of the liquefaction services. The owners of the LNG would receive additional revenues.

[8] U.S. Bureau of Economic Analysis. Concepts and Methods of the U.S. National Income and Product Accounts. October 2009. Accessed on March 22, 2012 at http://www.bea.gov/national/pdf/NIPAhandbookch1-4.pdf

**Table 4: 2018 Value added impacts of the Project on the Coos County economy, 2011 $**

| | |
|---|---|
| **LNG Terminal** | |
| LNG export quantity (MMBtu) | 294,777,833 |
| Times unit price of LNG ($/MMBtu) | $ 10.07 |
| Equals LNG terminal output | $ 2,967,297,339 |
| Less cost of gas used by terminal (Malin value) | (1,501,108,488) |
| Less gas transportation cost from Malin | (149,340,588) |
| Less other terminal non-labor inputs | (22,794,668) |
| Equals the direct GDP of the terminal | $ 1,294,053,594 |
| **Pipeline** | |
| Natural gas throughput (MMBtu) | 370,383,750 |
| Times unit transport charge ($/MMBtu) | $0.48 |
| Equals pipeline output | $ 177,784,200 |
| Less cost of pipeline non-labor inputs | (1,960,085) |
| Equals the direct GDP of the pipeline in Oregon | $ 175,824,115 |
| Times portion of pipeline in Coos County | 19.7% |
| Equals the direct GDP of the pipeline in Coos County | $ 34,563,715 |
| **Total GDP impact of the Project on Coos County** | |
| Direct terminal GDP | $ 1,294,053,594 |
| Direct pipeline GDP | 34,563,715 |
| Indirect GDP Impacts | 24,073,632 |
| Induced GDP Impacts | 10,954,111 |
| Total GDP Impact | $ 1,363,645,052 |

*Source: ECONorthwest.*

In total, assuming the Project operates at 90 percent of its nameplate capacity, the County's economy would experience a net increase of approximately $1.36 billion in its gross domestic product during 2018. This is a substantial addition, as the GDP of Coos County in 2010 was approximately $1.74 billion.[9]

The magnitude of the Project's operating impact while large is nonetheless reasonable given its size relative to the local economy. Total Project construction and pre-opening costs exceed $5.3 billion. In comparison, the fiscal year 2010-11 assessed value of all industrial and commercial properties in Coos County was $682 million.[10]

[9] According to 2010 U.S. industry data from IMPLAN.

[10] Oregon Department of Revenue. Oregon Property Tax Annual Statistics. Fiscal year 2010-11. Accessed on March 1, 2012 at http://www.oregon.gov/DOR/STATS/303-405-11-toc.shtml

# Tax Impacts

The county's economy will benefit from taxes and other payments arising from the Project each year. As previously noted, JCEP will make annual contributions through Coos County's Bay Area Enterprise Zone in lieu of property taxes. These contributions will consist of $20 million a year in funding for education, and $10 million for urban renewal. The Project expects to make these contributions indefinitely, although the funds may eventually be repurposed. Because these amounts are directly targeted for specific government purposes, the impact analysis does account for their downstream impacts. For example, the $20 million for K-12 schools indirectly increases K-12 spending and employment.

The pipeline will pay property taxes based primarily on the number of miles in each county. Common practice is for impact models not to count downstream impacts of general property taxes because it is assumed that the amounts displace property taxes paid by others and do not indirectly cause increases in government spending. However, because the increased tax revenues from PCGP would be significant for Coos County and the other counties along the pipeline route, an analysis was completed to estimate property taxes that would be paid by the PGCP.

The PCGP spans four counties: Coos, Douglas, Jackson, and Klamath. Assessed value was provided by the Project, and distributed by the number of pipeline miles in each county. A list of all jurisdictions and their tax rates in each county was obtained to determine an average tax rate, using assessed value to determine the weighted average.

This approach is an approximation, as specific taxing district data for each segment of the pipeline were unavailable. Thus, county averages were used which may overestimate the tax rates, since cities have higher tax rates and have a disproportionate amount of assessed value relative to their areas.

The methodology was modified slightly for Klamath County, as the county was unable to provide comparable detail in time for this analysis. Klamath County provided a list of taxing districts and their permanent tax rates. It was used to create tax rates for hypothetical tax code areas and assemble totals from likely constituent parts.

### Table 5: Annual Property Tax Impacts by County

| County | Pipeline Miles | Assessed Value | Tax Rate* | Property Taxes |
|---|---|---|---|---|
| Coos | 46 | $186,752,137 | $12.89 | $2,408,058 |
| Douglas | 63 | 255,769,231 | 11.57 | 2,959,096 |
| Jackson | 54 | 219,230,769 | 14.06 | 3,082,537 |
| Klamath | 71 | 288,247,863 | 9.20 | 2,652,284 |
| Total | 234 | $950,000,000 | | $11,101,975 |

*Source: ECONorthwest.*
** Tax rate in dollars per thousand dollars of assessed value.*

Once the rates were determined, property taxes were calculated by first grouping the tax rates for districts with similar purposes. Then, totals by district type were determined based on the type of tax rate: permanent rates, general obligation bonds (GO), and local option levies.

It is worth noting that local option levies are temporary in nature, and general obligation bonds are levy-based, as opposed to rate-based, which means that the pipeline would not increase tax collections for jurisdictions with GO bonds, but would effectively reduce the GO bond tax rate levied on all property owners within the jurisdiction.

**Table 6: Annual Property Tax Impacts by Tax District and Category**

| | Permanent | GO Bonds | Local Options | Total |
|---|---|---|---|---|
| *General Government* | | | | |
| Counties | $1,457,238 | $0 | $129,705 | $1,586,943 |
| Cities | 1,828,964 | 20,282 | 88,593 | 1,937,839 |
| Fire Districts | 796,360 | 17,640 | 15,379 | 829,379 |
| Parks & Recreation | 400,660 | 1,027 | - | 401,687 |
| Library Districts | 277,365 | - | - | 277,365 |
| Health Districts | 134,488 | - | - | 134,488 |
| Other Districts | 444,991 | 818 | 512 | 446,321 |
| *Education* | | | | |
| School Districts | 4,329,342 | 51,110 | 602,109 | 4,982,561 |
| Community Colleges | 481,966 | - | 23,425 | 505,391 |
| Total | $10,151,374 | $90,877 | $859,723 | $11,101,974 |

*Source: ECONorthwest.*

## Price Effects

Navigant Consulting, Inc. forecast price effects in its January 2012 report, *Jordan Cove LNG Export Project Market Analysis Study*, concluding that in 2018 that the price of natural gas in Malin would be higher because of the Project. ECONorthwest calculated the marginal increase in natural gas costs incurred in Coos County as a result of the Project.

According to Northwest Natural, the only Oregon public utility now providing natural gas to Coos County, about 1,300 customers in the county used a combined 354,045 million British thermal units (MMBtu) in 2011.[11] To estimate utility gas consumption in 2018, the analysis assumes demand would rise with population. The Oregon Office of Economic Analysis forecast shows the population of the county rising at an annual rate of about 0.14 percent between 2010 and 2020.[12] By applying this growth rate to natural gas consumption, demand in 2018 is estimated to be 357,492 MMBtu.

[11] Melissa Moore of NW Natural supplied this information to ECONorthwest via email on February 7, 2012.

[12] *State and County Population Forecasts and Components of Change, 2000 to 2040*. Oregon Office of Economic Analysis, 2004. Retrieved from http://www.oea.das.state.or.us/DAS/OEA/demographic.shtml February 27, 2012.

Navigant forecasts a price increase effect due to the Project in 2018 of 17.2 cents per MMBtu in 2018 at the gas hub in Malin, Oregon. Assuming this price change does not affect consumers' behavior and the utility passes the entire difference onto consumers in 2018, the corresponding increase in natural gas costs would be $61,447 countywide. That equals an increase of roughly $46.75 per customer each year. This price effect is included in the impact results reported in Table 4.

# APPENDIX E

# ECONORTHWEST
# UPSTREAM CONTRIBUTIONS STUDY

# Up-Stream Economic Contributions of the Jordan Cove Energy Project

Prepared for the Jordan Cove Energy Project, L.P.

February 29, 2012

ECONorthwest
ECONOMICS • FINANCE • PLANNING

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# Introduction

The Jordan Cove Energy Project (JCEP) and the Pacific Connector Gas Pipeline (PCGP), collectively the "Project," will export liquefied natural gas (LNG) starting in 2018. This analysis describes the economic contributions of the Project's suppliers, known as up-stream project impacts, to the United States from 2018 through 2045.

The Project developers would build an LNG terminal facility in Coos County, Oregon capable of exporting natural gas, as well as a 234-mile natural gas pipeline connecting the terminal to the Malin Hub in Klamath County, Oregon where interstate gas transmission pipelines meet. Although the terminal may in the future add the capacity to import LNG, this analysis assumes only exports.

The Project opens up new markets for natural gas, benefitting domestic up-stream industries that produce and transport natural gas. To meet the Project's demand, these industries would hire more workers, increase output, and purchase more goods and services. These transactions would, in turn, stimulate further economic activity in the U.S. ECONorthwest conducted an economic contribution analysis that quantifies those impacts for the years 2018 through 2045.

Navigant Consulting, Inc., calculated price and volume forecasts used in this analysis. Their research is summarized in a related report, *Jordan Cove LNG Export Project Market Analysis Study*, dated January 2012. Navigant provided ECONorthwest with individual year-by-year data from their research; these data appear in this report starting on Page 4.

## Major Findings of This Analysis

This analysis finds that up-stream industries would contribute an average of $3.9 billion per year in economic output (2010 dollars) and 20,359 jobs per year as the result of LNG exports.

Four major sectors would experience direct benefits as part of the JCEP supply chain for LNG exports. The natural gas production sector would be the largest beneficiary, but state & local government, pipelines, and exploration companies would also generate higher revenues. Key up-stream impacts include:

- An annual average of $1.4 billion in output and 5,210 jobs directly by natural gas producers in Wyoming, Utah, Colorado, and Montana. Nationally, the effect of this activity would add $3.2 billion to total economic output and 16,576 jobs per year.

- $158.8 million per year in additional exploration and drilling activities, which would directly support 247 additional jobs. Including secondary impacts, the up-stream impacts from the natural gas producing sector would support an average of $263.8 million in output and 906 jobs each year.

- $59.8 million per year from severance taxes on natural gas production for LNG exports, which would support state and local government services. And, through further impacts migrating throughout the national economy, $147 million per year in economic output and 1,416 jobs.

- $107.6 million in annual economic output from domestic natural gas transmission pipelines that would deliver gas for the JCEP. As impacts propagate through the U.S. economy, this activity would support an average of $305.7 million in total output and 1,461 jobs each year.

# Background

## Project Description

Table 1 summarizes the output and natural gas up-stream impacts of the Project, on average, over the entire 2018 to 2045 period. Plans call for the terminal and pipeline to operate at an average capacity factor of 90 percent. At that level, about 5.4 million metric tonnes of LNG containing approximately 284.8 billion cubic feet (“Bcf”) of natural gas would be exported each year. In addition, the terminal itself would consume an average of 18.7 Bcf per year for powering its own operations. The PGCP is also expected to carry about 57.8 Bcf per year of natural gas for consumers other than the terminal. Annually, an average of 361.4 Bcf would be sent into the PGCP at Malin, which is 90 percent of its rated capacity.

**Table 1: Project output and up-stream need for natural gas, daily and annual averages, 2018 - 2045**

| Measure | Per Day | Annually |
|---|---|---|
| LNG exports (metric tonnes) | 14,784 | 5,396,163 |
| **Natural gas volumes (Bcf):** | | |
| Contained in LNG exports | 0.78 | 284.8 |
| Used by terminal | 0.05 | 18.7 |
| Used by other consumers | 0.16 | 57.8 |
| Total sent into the PGCP | 0.99 | 361.4 |
| Used by Project | 0.83 | 303.5 |
| **Sources of natural gas for the Project:** | | |
| Domestic wells | 0.45 | 165.2 |
| Canadian imports | 0.42 | 153.5 |
| Domestic/imported need | 0.87 | 318.7 |
| ***Less losses in:*** | | |
| Domestic processing | (0.02) | (6.5) |
| Pipeline use to Malin | (0.02) | (8.7) |
| Total used by the Project | 0.83 | 303.5 |

*Source: ECONorthwest calculations based on data from the JCEP.*

The JCEP would use a mix of domestic and Canadian gas. Navigant Consulting forecast annual quantities by source for 2018 through 2045; this forecast is used in ECONorthwest’s up-stream impact analysis. The ratios of Canadian to domestic gas that would be used by the Project for the terminal and running the pipeline vary considerably by year.

Overall, the Project would need 165.2 Bcf from domestic wells and 153.5 Bcf in Canadian imports in the average year. Some of that gas would be consumed during processing and transporting to Malin. These processing and transporting volumes are shown as losses of 6.5 and 8.7 Bcf per year, respectively, on Table 1. Thus, the Project would use a total of 303.5 Bcf per year.

Losses occur because natural gas is consumed, and byproducts removed, in the processing, transmission, and liquefaction steps leading to the export of LNG. Before delivery into pipelines, the natural gas withdrawn from the earth is cleaned and processed. Processing removes most of the heaviest hydrocarbons and a significant portion of the non-methane gaseous hydrocarbons such as propane and ethane from the raw natural gas. Transmission pipelines that deliver gas to Malin operate with compressors; many run on natural gas. In Coos County, the terminal would use natural gas to power its operations. As a result of these processing and transmission losses, the annual volume of natural gas required by up-stream sources (318.7 Bcf) would necessarily exceed the quantity exported (284.8 Bcf).

## Up-Stream Industries

Up-stream industry output is only considered if the activity occurs inside the United States, as the focus of this analysis is on impacts on the U.S. economy. Using Navigant's annual forecasts of domestic and Canadian gas supplies to the Project and price forecasts at various points throughout the supply chain, ECONorthwest determined the economic impacts of domestic up-stream industries affected by the LNG exports at Jordan Cove. Those industries are:

- Interstate natural gas pipeline transportation.
- Natural gas extraction, including processing and royalties.
- Natural gas exploration and drilling.
- State and local government activities attributable to state-level natural gas severance tax.

The analysis considers only those activities occurring in the United States up to the point of delivery into the PCGP at Malin, Oregon. Thus, the up-stream impact of imported Canadian gas is limited to the value of pipeline transport from the Canadian border to Malin resulting from JCEP exports. The Project would have up-stream impacts on the Canadian economy, but these impacts are not considered in this analysis.

# Natural Gas Forecast

The following describes output forecasts of domestic up-stream industries. The up-stream impact analysis is complicated by the removal and use of gas, which is extracted from wells as it moves to the terminal for export as LNG. Annual fluctuations in the proportions of domestic and Canadian gas also affect the analysis. ECONorthwest considered both factors in its forecasts.

# Measures

For ease of presentation, many quantities in this report are expressed in daily values, which is a common industry practice. LNG is shown in terms of metric tonnes per day (mtpd); natural gas volumes are in MMcfd. Jordan Cove informed ECONorthwest that one metric tonne of its LNG would contain 52,780 cubic feet of natural gas.

Heat content is in million British thermal units per day (MMBtu/day).

All monetary values in this report are expressed in 2010 dollars. These values exclude the effects of general inflation over time. Natural gas prices are expressed in terms of 2010 dollars per million British thermal units (2010$/MMBtu).

Navigant concluded that the Project would obtain the domestic portion of its natural gas from the Rocky Mountain region. The region consists of five states and is known by the U.S. Energy Information Administration (EIA) as the Petroleum Administration for Defense District 4 (PADD IV). The five states in the region are Colorado, Idaho, Montana, Utah and Wyoming. Idaho does not produce natural gas. This report uses EIA data on PADD IV natural gas production for the four producing states to estimate energy output.

In natural gas fields, where gas is withdrawn from wells, raw gas is processed prior to delivery into pipelines for transport. Water, sulfur compounds, non-hydrocarbon gases, and impurities are removed. Wells, processing plants, and other systems in production also consume some raw gas, leaving gas that can be marketed. This is called wellhead gas and is also known as marketable gas.

Wellhead gas is primarily methane, but may also contain heavier gaseous hydrocarbons (ethane, propane, and butane) that have higher heat contents. In PADD IV, the heat content of wellhead gas averaged 1,086 Btu per cubic foot in 2009.[1] Gaseous, non-methane, hydrocarbons are compressible into liquids at room temperature and can be sold as natural gas liquids (NGLs). The mix of hydrocarbons and the heating value of NGLs vary by field and, over time, even for the same field.

This analysis uses the EIA estimate of PADD IV average heating value of wellhead natural gas, which was 1,086 Btu per cubic foot in its calculations of domestic gas field production. However, with the extraction of NGLs, some heat content is removed. Pipeline natural gas, also known as dry gas, averages 1,025[2] British thermal units (Btu) when measured at 60° F and standard atmospheric pressure. Actual heating values vary. This analysis used 1,025 Btu for pipeline gas, including the gas delivered to the JCEP terminal, and 1,086 Btu for domestically produced wellhead gas.

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[1] Calculated by ECONorthwest from state-level data on the heat content and wellhead production volume from natural gas production as reported in EIA State Energy Data 2009 tables P1 and P2.

[2] EIA Natural Gas Annual 2010, table B2, 2009 national dry gas production heat content.

Natural gas processing plants remove much, but not all, of these non-methane hydrocarbons from gas before it is delivered to interstate pipelines. Because the price of NGLs is linked to the price of crude petroleum, there is typically an incentive to remove the NGLs from the wellhead gas stream prior to delivery into the interstate pipeline system. Like crude oil, NGLs are measured in 42-gallon barrels (Bbl). The production of NGLs is a major value component of the up-stream economic output arising from LNG export demand.

## Energy content and volumes, 2009

The EIA PADD IV data for the year 2009 was the most current database available for this analysis. Table 2 summarizes the quantities and energy contained in wellhead natural gas production from the Rocky Mountains. Note that, due to the removal of NGLs between the wellhead and the pipeline, the energy content of wellhead gas is higher than that of pipeline gas.

**Table 2: PADD IV natural gas wellhead production volumes, heat content, and energy density. NGL production in Bbl, 2009**

| Output | MMcf | Trillion Btu | Btu/cf | Bbl |
|---|---|---|---|---|
| Natural gas to: | | | | |
| NGL production | 171,745 | 442 | 2,573 | - |
| Pipelines | 4,205,060 | 4,310 | 1,025 | - |
| Statistical adjustment | - | 3 | - | - |
| Wellhead gas production | 4,376,805 | 4,755 | 1,086 | - |
| Natural gas liquids | | | | 120,222,000 |

*Sources: Data for the year 2009 from EIA Natural Gas Annual 2010 tables 33, 54, 72, and 78; EIA State Energy Data 2009 tables P1 and P2; EIA Natural Gas Annual 2009 table 7.*
*Statistical adjustment made by ECONorthwest to resolve minor (0.06 percent) discrepancy in the EIA data.*

The production of pipeline natural gas in this region results in the co-production of NGLs, as reflected in the table. The removal of these NGLs creates a valuable byproduct while also reducing the Btu density of the natural gas to levels that are suitable for pipeline transport, and downstream commercial and residential use. NGLs from PADD IV in 2009 were composed of heavier hydrocarbons totaling 442 trillion Btu. With production of 120,222,000 Bbl, the average energy content of NGLs from this region was approximately 3.7 MMBtu per barrel.

For many uses, NGLs and crude oil are substitutes. The energy content of a barrel of crude oil is about 5.8 MMBtu; therefore, NGLs from PADD IV had about 63.4 percent of the energy content of crude oil. As a substitute for crude oil in refineries, the price of NGLs would also be about 63.4 percent of the price of crude oil. This analysis uses this price ratio in conjunction with Navigant's forecast of the domestic price of crude oil to estimate the value of incremental NGL production created by the export of LNG.

This analysis conservatively assumes that all incremental natural gas output for the JCEP would come from natural gas wells. In 2010, about 21.5 percent of all the natural gas extracted in the United States actually came from crude oil wells.[3] By excluding crude oil wells, the analysis does not count possible increases in crude oil production as up-stream economic impacts.

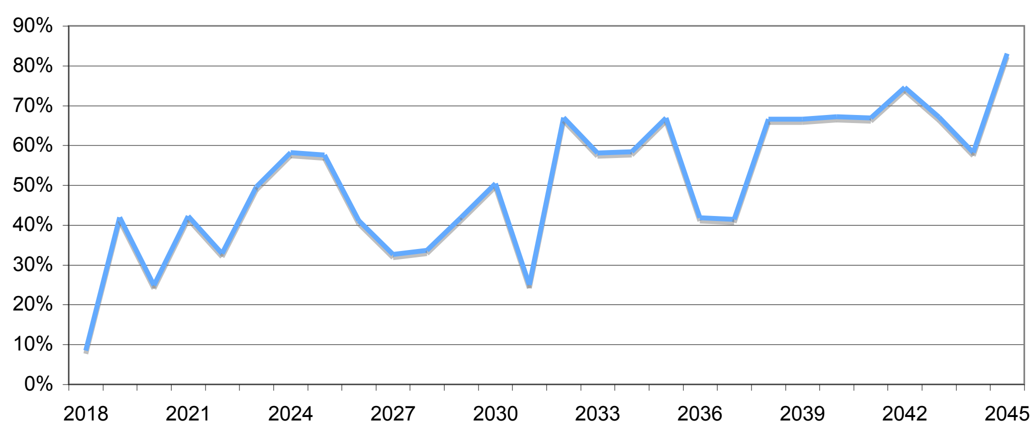
# Daily Natural Gas Volumes Through the Project

The Project would demand goods and services from up-stream industries. Before calculating the increased output of those industries, the analysis first must determine the throughput and sources of natural gas at the Project's pipeline and terminal facilities.

## Domestic natural gas content of LNG exports

The Project is expected to start production in December 2017 and operate at 90 percent capacity in 2018 and all years going forward. Navigant's energy model (Figure 1) forecasts the expected supply of domestic natural gas to JCEP. The proportion of domestic gas to Canadian gas is projected to rise from 8 percent in 2018 to 83 percent in 2045. Navigant attributes supply fluctuations to planned pipeline expansions and other developments in British Columbia, Canada, and the Rockies.[4]

**Figure 1: Proportion of natural gas arriving at the JCEP from domestic sources, 2018 - 2045, Navigant Consulting**




*Source: January 12, 2012 email to ECONorthwest from Mr. Gordon Pickering of Navigant Consulting.*

[3] Annual Energy Review 2010. U.S. Energy Information Administration. Page 195.

[4] Email from Rebecca Honeyfield of Navigant to Carsten Jensen of ECONorthwest. January 31, 2012.

## Mix of domestic and Canadian gas in LNG exports

ECONorthwest calculated the quantities of domestic and Canadian natural gas contained in LNG exports (Table 3). Quantities of natural gas are expressed in millions of cubic feet per day. As previously shown in Table 1, the Project and its up-stream industries would also require additional gas from domestic and Canadian sources to meet transportation, processing, and terminal needs.

**Table 3: Domestic and Canadian natural gas content of daily LNG exports from the JCEP**

| | | Natural Gas in LNG Exports (MMcfd) | | |
|---|---|---|---|---|
| Year | LNG Exports (mtpd) | Domestic Content | Canadian Content | Total |
| 2018 | 14,784 | 66.3 | 714.0 | 780.3 |
| 2019 | 14,784 | 327.1 | 453.2 | 780.3 |
| 2020 | 14,784 | 194.0 | 586.3 | 780.3 |
| 2021 | 14,784 | 329.2 | 451.1 | 780.3 |
| 2022 | 14,784 | 256.5 | 523.8 | 780.3 |
| 2023 | 14,784 | 386.9 | 393.4 | 780.3 |
| 2024 | 14,784 | 454.1 | 326.2 | 780.3 |
| 2025 | 14,784 | 448.9 | 331.4 | 780.3 |
| 2026 | 14,784 | 320.7 | 459.6 | 780.3 |
| 2027 | 14,784 | 254.4 | 525.9 | 780.3 |
| 2028 | 14,784 | 262.2 | 518.1 | 780.3 |
| 2029 | 14,784 | 327.1 | 453.2 | 780.3 |
| 2030 | 14,784 | 393.4 | 386.9 | 780.3 |
| 2031 | 14,784 | 194.5 | 585.8 | 780.3 |
| 2032 | 14,784 | 522.3 | 258.0 | 780.3 |
| 2033 | 14,784 | 453.2 | 327.1 | 780.3 |
| 2034 | 14,784 | 455.4 | 324.9 | 780.3 |
| 2035 | 14,784 | 521.6 | 258.7 | 780.3 |
| 2036 | 14,784 | 326.2 | 454.1 | 780.3 |
| 2037 | 14,784 | 322.8 | 457.5 | 780.3 |
| 2038 | 14,784 | 519.5 | 260.8 | 780.3 |
| 2039 | 14,784 | 519.5 | 260.8 | 780.3 |
| 2040 | 14,784 | 524.5 | 255.8 | 780.3 |
| 2041 | 14,784 | 521.6 | 258.7 | 780.3 |
| 2042 | 14,784 | 581.5 | 198.8 | 780.3 |
| 2043 | 14,784 | 523.8 | 256.5 | 780.3 |
| 2044 | 14,784 | 454.1 | 326.2 | 780.3 |
| 2045 | 14,784 | 647.8 | 132.5 | 780.3 |
| Average | 14,784 | 396.8 | 383.5 | 780.3 |

*Sources: ECONorthwest analysis of data provided by Navigant Consulting.*

## Daily natural gas deliveries to the JCEP terminal

The terminal would require 831.6 MMcf of pipeline gas delivered from Malin each day (the equivalent of 303.5 Bcf/year set forth in Table 1). Of that, 51.3 MMcf would be consumed by the Project itself, primarily for power production, leaving the remaining 780.3 MMcfd for export as LNG. Table 4 shows that, based on Navigant's price forecast, the Project would take deliveries worth $4.1 million a day in 2018 from the Malin Hub. Delivery values would rise to over $6.9 million a day in 2045.

**Table 4: Daily volumes, 2010$ prices, and values of natural gas from the Malin Hub needed by the JCEP, 2018 - 2045**

| | Natural Gas Volume (MMcfd) | | | JCEP Gas BTUs and Values at Malin | | |
|---|---|---|---|---|---|---|
| Year | Contained in LNG | Used by Project | Delivered from Malin | MMBtus/day from Malin | Price 2010$ per MMBtus | Total Value, 2010 $ per day |
| 2018 | 780.3 | 51.3 | 831.6 | 852,401 | $4.82 | $4,112,626 |
| 2019 | 780.3 | 51.3 | 831.6 | 852,401 | 4.82 | 4,109,439 |
| 2020 | 780.3 | 51.3 | 831.6 | 852,401 | 4.86 | 4,141,654 |
| 2021 | 780.3 | 51.3 | 831.6 | 852,401 | 4.90 | 4,178,406 |
| 2022 | 780.3 | 51.3 | 831.6 | 852,401 | 4.95 | 4,217,575 |
| 2023 | 780.3 | 51.3 | 831.6 | 852,401 | 5.04 | 4,298,781 |
| 2024 | 780.3 | 51.3 | 831.6 | 852,401 | 5.15 | 4,393,900 |
| 2025 | 780.3 | 51.3 | 831.6 | 852,401 | 5.29 | 4,509,885 |
| 2026 | 780.3 | 51.3 | 831.6 | 852,401 | 5.41 | 4,615,371 |
| 2027 | 780.3 | 51.3 | 831.6 | 852,401 | 5.55 | 4,727,512 |
| 2028 | 780.3 | 51.3 | 831.6 | 852,401 | 5.68 | 4,845,770 |
| 2029 | 780.3 | 51.3 | 831.6 | 852,401 | 5.85 | 4,986,763 |
| 2030 | 780.3 | 51.3 | 831.6 | 852,401 | 6.02 | 5,127,845 |
| 2031 | 780.3 | 51.3 | 831.6 | 852,401 | 6.17 | 5,260,074 |
| 2032 | 780.3 | 51.3 | 831.6 | 852,401 | 6.37 | 5,428,349 |
| 2033 | 780.3 | 51.3 | 831.6 | 852,401 | 6.58 | 5,606,419 |
| 2034 | 780.3 | 51.3 | 831.6 | 852,401 | 6.78 | 5,776,931 |
| 2035 | 780.3 | 51.3 | 831.6 | 852,401 | 7.02 | 5,987,097 |
| 2036 | 780.3 | 51.3 | 831.6 | 852,401 | 7.21 | 6,145,923 |
| 2037 | 780.3 | 51.3 | 831.6 | 852,401 | 7.32 | 6,240,764 |
| 2038 | 780.3 | 51.3 | 831.6 | 852,401 | 7.43 | 6,330,123 |
| 2039 | 780.3 | 51.3 | 831.6 | 852,401 | 7.50 | 6,393,405 |
| 2040 | 780.3 | 51.3 | 831.6 | 852,401 | 7.56 | 6,445,659 |
| 2041 | 780.3 | 51.3 | 831.6 | 852,401 | 7.66 | 6,531,233 |
| 2042 | 780.3 | 51.3 | 831.6 | 852,401 | 7.75 | 6,605,315 |
| 2043 | 780.3 | 51.3 | 831.6 | 852,401 | 7.90 | 6,731,290 |
| 2044 | 780.3 | 51.3 | 831.6 | 852,401 | 7.92 | 6,750,568 |
| 2045 | 780.3 | 51.3 | 831.6 | 852,401 | 8.11 | 6,911,870 |
| Average | 780.3 | 51.3 | 831.6 | 852,401 | $6.34 | $5,407,520 |

*Source: ECONorthwest analysis of data provided by Navigant Consulting using its Jordan Cove Export Case. Data presented is corrected for rounding errors and assumes energy content of 1,025 Btu per cubic foot.*

# Daily Domestic Up-Stream Industry Output

Up-stream impacts are the economic contributions created by the steps needed to supply natural gas to the JCEP terminal. The analysis counts output from natural gas transported from U.S. wells. Output of Canadian gas is counted only after it has crossed the Canadian border and during its transit to Malin.

The analysis excludes gas carried for local consumption, about 162,349 MMBtu a day, from the measurement of up-stream impacts. This output is not counted predicated on the assumption that other sources would meet local demand if the Project were not built. Thus, only the increased up-stream output needed for producing LNG for export from Jordan Cove is included in the impact analysis.

## Increased Domestic Natural Gas Output

LNG exports would affect the oil and gas extraction sector by increasing the production of both gas delivered to pipelines and NGLs. The sum of the two components equals industry output.

### Increased domestic wellhead production

JCEP demand for natural gas at Malin creates the need to increase up-stream production (Table 1). As shown in Table 5, required wellhead production rises not only to supply additional natural gas at Malin, but also to transport this gas through interstate pipelines as fuel, and provide the heavier hydrocarbons that are extracted as NGLs during processing. To supply an average of 422.8 MMcfd from domestic sources to Malin, wellhead production must average 452.7 MMcfd. Based on Navigant's price forecast, domestic wellhead output would average \$3,051,068 a day, from 2018 to 2045.

**Table 5: Calculation of daily domestic wellhead natural gas production resulting from JCEP, 2018 - 2045**

| | Domestic Natural Gas Volume (MMcfd) | | | | Wellhead Production | |
|---|---|---|---|---|---|---|
| Year | Delivered to Malin | Used by Pipelines | Used in NGLs | Wellhead Production | Price per MMBtus* | Value 2010$ per Day** |
| 2018 | 70.6 | 2.0 | 3.0 | 75.6 | $4.60 | $377,813 |
| 2019 | 348.6 | 10.0 | 14.6 | 373.2 | 4.59 | 1,860,488 |
| 2020 | 206.8 | 5.9 | 8.7 | 221.4 | 4.65 | 1,118,490 |
| 2021 | 350.9 | 10.0 | 14.7 | 375.6 | 4.68 | 1,907,123 |
| 2022 | 273.4 | 7.8 | 11.5 | 292.7 | 4.72 | 1,499,533 |
| 2023 | 412.4 | 11.8 | 17.3 | 441.5 | 4.80 | 2,300,441 |
| 2024 | 484.0 | 13.8 | 20.3 | 518.1 | 4.92 | 2,767,935 |
| 2025 | 478.5 | 13.7 | 20.1 | 512.2 | 5.04 | 2,804,408 |
| 2026 | 341.8 | 9.8 | 14.4 | 365.9 | 5.15 | 2,047,063 |
| 2027 | 271.1 | 7.8 | 11.4 | 290.3 | 5.27 | 1,661,349 |
| 2028 | 279.5 | 8.0 | 11.7 | 299.2 | 5.41 | 1,756,255 |
| 2029 | 348.6 | 10.0 | 14.6 | 373.2 | 5.55 | 2,250,443 |
| 2030 | 419.2 | 12.0 | 17.6 | 448.8 | 5.70 | 2,778,671 |
| 2031 | 207.3 | 5.9 | 8.7 | 222.0 | 5.84 | 1,407,403 |
| 2032 | 556.7 | 15.9 | 23.4 | 596.0 | 6.03 | 3,903,206 |
| 2033 | 483.0 | 13.8 | 20.3 | 517.1 | 6.21 | 3,488,981 |
| 2034 | 485.3 | 13.9 | 20.4 | 519.6 | 6.40 | 3,609,035 |
| 2035 | 555.9 | 15.9 | 23.4 | 595.2 | 6.63 | 4,282,261 |
| 2036 | 347.6 | 9.9 | 14.6 | 372.2 | 6.80 | 2,746,233 |
| 2037 | 344.0 | 9.8 | 14.5 | 368.3 | 6.89 | 2,756,297 |
| 2038 | 553.6 | 15.8 | 23.3 | 592.7 | 6.98 | 4,494,355 |
| 2039 | 553.6 | 15.8 | 23.3 | 592.7 | 7.05 | 4,535,085 |
| 2040 | 559.0 | 16.0 | 23.5 | 598.4 | 7.09 | 4,608,526 |
| 2041 | 555.9 | 15.9 | 23.4 | 595.2 | 7.17 | 4,633,495 |
| 2042 | 619.7 | 17.7 | 26.0 | 663.5 | 7.21 | 5,194,782 |
| 2043 | 558.2 | 16.0 | 23.5 | 597.6 | 7.28 | 4,726,519 |
| 2044 | 484.0 | 13.8 | 20.3 | 518.1 | 7.23 | 4,065,471 |
| 2045 | 690.3 | 19.7 | 29.0 | 739.1 | 7.29 | 5,848,258 |
| Average | 422.8 | 12.1 | 17.8 | 452.7 | $6.21 | $3,051,068 |

*Sources: ECONorthwest analysis of data provided by Navigant Consulting using its Jordan Cove Export Case.*
** Navigant forecast of wellhead gas from the Rocky Mountain basins.*
*** Value is based on a wellhead heat content of 1,086 Btu/cf.*

## Increased domestic NGLs production

Data from the EIA reveal that, for every thousand cubic feet of dry natural gas sent out on interstate transmission pipelines from PADD IV in 2009, there were 0.0286 Bbl of NGLs produced at gas processing plants in the Rocky Mountain basins.

The value of NGL output is based on the energy content of the product. Because NGLs are a direct substitute for crude oil, NGL output is included in the EIA's accounting of national crude oil field production.[5] Refineries pay for NGLs based on the heat content per barrel relative to crude oil. The average heat content of NGLs in PADD IV is about 63.4 percent that of the national pricing standard for crude oil; West Texas intermediate (WTI).

[5] Annual Energy Review 2010. Page 135.

Using Navigant's WTI price forecast, ECONorthwest calculated the domestic daily production of NGLs resulting from meeting the Project's demand for gas (Table 6).

**Table 6: Calculation of daily natural gas liquids output caused by JCEP LNG exports, 2018 - 2045**

| Year | NGL output Bbl a day* | NGLs Price 2010$/Bbl | Value 2010$ per Day |
|---|---|---|---|
| 2018 | 2,077 | $64.77 | $134,526 |
| 2019 | 10,251 | 66.08 | 677,379 |
| 2020 | 6,081 | 67.39 | 409,749 |
| 2021 | 10,318 | 68.70 | 708,833 |
| 2022 | 8,040 | 70.01 | 562,869 |
| 2023 | 12,127 | 71.32 | 864,877 |
| 2024 | 14,232 | 72.63 | 1,033,643 |
| 2025 | 14,070 | 73.94 | 1,040,305 |
| 2026 | 10,050 | 75.25 | 756,237 |
| 2027 | 7,973 | 76.56 | 610,392 |
| 2028 | 8,219 | 77.86 | 639,949 |
| 2029 | 10,251 | 79.17 | 811,642 |
| 2030 | 12,328 | 80.48 | 992,238 |
| 2031 | 6,097 | 81.79 | 498,712 |
| 2032 | 16,371 | 83.10 | 1,360,457 |
| 2033 | 14,204 | 84.41 | 1,199,045 |
| 2034 | 14,271 | 85.72 | 1,223,389 |
| 2035 | 16,348 | 87.03 | 1,422,856 |
| 2036 | 10,223 | 88.34 | 903,151 |
| 2037 | 10,117 | 89.65 | 907,035 |
| 2038 | 16,281 | 90.96 | 1,480,995 |
| 2039 | 16,281 | 92.27 | 1,502,314 |
| 2040 | 16,437 | 93.58 | 1,538,239 |
| 2041 | 16,348 | 94.89 | 1,551,327 |
| 2042 | 18,224 | 96.20 | 1,753,211 |
| 2043 | 16,415 | 97.51 | 1,600,681 |
| 2044 | 14,232 | 98.82 | 1,406,445 |
| 2045 | 20,302 | 100.13 | 2,032,795 |
| Average | 12,435 | $85.08 | $1,057,975 |

*Sources: ECONorthwest analysis of data provided by Navigant Consulting.*
** Based on EIA PADD IV production statistics (2009), for every 1,000 cubic feet of pipeline gas, approximately 0.0286 barrels of NGLs were produced.*

## Net increase in natural gas extraction industry output

The oil & gas extraction industry, which includes gas wells and NGL processing plants, would experience a significant increase in up-stream activity from the Project. The economic output of the extraction industry equals the values of higher wellhead and NGLs production minus the value of the portion of wellhead gas contained in the NGLs sold.[6] As shown on Table 7, the oil & gas extraction industry would experience an average increase in output of $3,825,324 a day between 2018 and 2045 directly attributable to the demand created by the Project.

[6] Subtracting the portion of wellhead gas contained in the NGLs sold removes double counting. The value of wellhead natural gas contained in NGLs is the price of wellhead gas ($ per MMBtu) times the number of Btus contained in the natural gas used in NGLs.

**Table 7: Increase of daily output of the domestic oil & gas extraction industry due to Jordan Cove LNG exports, 2018 - 2045**

| | Daily Value of Output 2010$ | | | |
|---|---|---|---|---|
| Year | Wellhead Production | Value of NGL Output | Less Wellhead value in NGLs | Net Natural Gas Extraction Output |
| 2018 | $377,813 | $134,526 | ($35,133) | $477,206 |
| 2019 | 1,860,488 | 677,379 | (173,007) | 2,364,860 |
| 2020 | 1,118,490 | 409,749 | (104,009) | 1,424,230 |
| 2021 | 1,907,123 | 708,833 | (177,344) | 2,438,612 |
| 2022 | 1,499,533 | 562,869 | (139,442) | 1,922,960 |
| 2023 | 2,300,441 | 864,877 | (213,918) | 2,951,400 |
| 2024 | 2,767,935 | 1,033,643 | (257,391) | 3,544,187 |
| 2025 | 2,804,408 | 1,040,305 | (260,782) | 3,583,930 |
| 2026 | 2,047,063 | 756,237 | (190,357) | 2,612,943 |
| 2027 | 1,661,349 | 610,392 | (154,489) | 2,117,251 |
| 2028 | 1,756,255 | 639,949 | (163,314) | 2,232,889 |
| 2029 | 2,250,443 | 811,642 | (209,269) | 2,852,816 |
| 2030 | 2,778,671 | 992,238 | (258,389) | 3,512,520 |
| 2031 | 1,407,403 | 498,712 | (130,875) | 1,775,240 |
| 2032 | 3,903,206 | 1,360,457 | (362,960) | 4,900,704 |
| 2033 | 3,488,981 | 1,199,045 | (324,441) | 4,363,584 |
| 2034 | 3,609,035 | 1,223,389 | (335,605) | 4,496,820 |
| 2035 | 4,282,261 | 1,422,856 | (398,208) | 5,306,909 |
| 2036 | 2,746,233 | 903,151 | (255,373) | 3,394,012 |
| 2037 | 2,756,297 | 907,035 | (256,309) | 3,407,024 |
| 2038 | 4,494,355 | 1,480,995 | (417,931) | 5,557,419 |
| 2039 | 4,535,085 | 1,502,314 | (421,718) | 5,615,680 |
| 2040 | 4,608,526 | 1,538,239 | (428,548) | 5,718,217 |
| 2041 | 4,633,495 | 1,551,327 | (430,869) | 5,753,953 |
| 2042 | 5,194,782 | 1,753,211 | (483,064) | 6,464,930 |
| 2043 | 4,726,519 | 1,600,681 | (439,520) | 5,887,681 |
| 2044 | 4,065,471 | 1,406,445 | (378,049) | 5,093,868 |
| 2045 | 5,848,258 | 2,032,795 | (543,830) | 7,337,223 |
| Average | $3,051,068 | $1,057,975 | ($283,719) | $3,825,324 |

*Sources: ECONorthwest analysis of data provided by Navigant Consulting.*

## Increase in state and local government output

Higher production in PADD IV would result in higher severance tax receipts in Wyoming, Montana, Utah, and Colorado. ECONorthwest estimated the average tax rate by weighing tax rates in the four states[7] against 2009 natural gas production, as reported by EIA.[8] To calculate the taxes associated with the Project, ECONorthwest multiplied the calculated average tax rate, 5.36 percent, by the forecast increase in domestic output (Table 8).[9] State and local governments spend severance taxes on schools, healthcare, and many other public services. Those taxes would average $163,660 a day from 2018 through 2045.

**Table 8: Daily increase in state severance taxes arising because of Jordan Cove LNG exports, 2018 - 2045**

| Year | State Severance Tax (2010$/day) |
|---|---|
| 2018 | $20,266 |
| 2019 | 99,797 |
| 2020 | 59,996 |
| 2021 | 102,299 |
| 2022 | 80,435 |
| 2023 | 123,396 |
| 2024 | 148,473 |
| 2025 | 150,429 |
| 2026 | 109,805 |
| 2027 | 89,115 |
| 2028 | 94,206 |
| 2029 | 120,714 |
| 2030 | 149,049 |
| 2031 | 75,493 |
| 2032 | 209,369 |
| 2033 | 187,150 |
| 2034 | 193,590 |
| 2035 | 229,702 |
| 2036 | 147,309 |
| 2037 | 147,849 |
| 2038 | 241,078 |
| 2039 | 243,263 |
| 2040 | 247,203 |
| 2041 | 248,542 |
| 2042 | 278,649 |
| 2043 | 253,532 |
| 2044 | 218,073 |
| 2045 | 313,702 |
| Average | $163,660 |

*Sources: ECONorthwest, Navigant Consulting, EIA, and the Allegheny Conference on Community Development.*

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[7] *A summary of Severance Taxes on the Natural Gas Industry.* Allegheny Conference on Community Development. Benchmarking Pennsylvania. February 2009.

[8] *Natural Gas Annual 2010*. Energy Information Administration, U.S. Department of Energy

[9] Actual severance tax rates vary based on conditions, size of producer, various and often complex tax rules, and are subject to change.

## Increase in U.S. transmission pipeline output

Gas delivered at Malin to the PCGP would originate from natural gas production areas in Canada and the Rocky Mountains *via* interstate pipelines. These upstream pipelines are compensated for transporting gas. That compensation determines the gas pipeline industry's economic output and is an up-stream impact of the Project's LNG exports.

Navigant Consulting did not include pipeline tariff rate forecasts. In the absence of posted tariff forecasts, ECONorthwest used Navigant's forecast prices for Malin and the Project's two sources of gas, the Canadian border at Kingsgate and the Rocky Mountain basins. ECONorthwest estimated the output of pipeline transmission on a per MMBtu basis by calculating the price differences between Malin, and the Rocky Mountain Basins and Kingsgate.

With these pipeline transmission calculations, ECONorthwest determined the JCEP's effect on daily interstate pipeline output. The analysis shows that domestic interstate pipeline output would increase by an average of $294,643 per day to accommodate the JCEP demand.

### Table 9: Calculation of daily domestic natural gas pipeline industry output resulting from JCEP, 2018 – 2045, 2010$

| | Canadian Natural Gas Imports | | | | Domestic Natural Gas | | | | Total |
|---|---|---|---|---|---|---|---|---|---|
| Year | Volume at Malin MMcfd | Energy Content MMBtus | Kingsgate - Malin Differential $2010/ MMBtus | Pipeline Output, Canadian Gas 2010$/day | Volume at Malin MMcfd | Energy Content MMBtus | Rockies - Malin Differential $2010/ MMBtus | Pipeline Output, Domestic Gas 2010$/day | Daily Pipeline Output |
| 2018 | 761.0 | 780,005 | $0.22 | $168,236 | 70.6 | 72,396 | $0.22 | $16,140 | $184,376 |
| 2019 | 483.0 | 495,092 | 0.22 | 111,233 | 348.6 | 357,308 | 0.23 | 82,034 | 193,266 |
| 2020 | 624.8 | 640,465 | 0.22 | 141,895 | 206.8 | 211,936 | 0.21 | 43,486 | 185,381 |
| 2021 | 480.7 | 492,758 | 0.23 | 113,432 | 350.9 | 359,643 | 0.23 | 81,265 | 194,697 |
| 2022 | 558.2 | 572,159 | 0.24 | 137,377 | 273.4 | 280,242 | 0.23 | 64,331 | 201,708 |
| 2023 | 419.2 | 429,703 | 0.25 | 107,929 | 412.4 | 422,698 | 0.24 | 103,226 | 211,155 |
| 2024 | 347.6 | 356,331 | 0.23 | 82,850 | 484.0 | 496,069 | 0.23 | 116,376 | 199,225 |
| 2025 | 353.1 | 361,978 | 0.25 | 90,784 | 478.5 | 490,422 | 0.25 | 121,836 | 212,620 |
| 2026 | 489.9 | 502,099 | 0.26 | 130,139 | 341.8 | 350,301 | 0.26 | 91,651 | 221,790 |
| 2027 | 560.5 | 574,494 | 0.27 | 154,626 | 271.1 | 277,906 | 0.27 | 76,342 | 230,968 |
| 2028 | 552.1 | 565,938 | 0.27 | 154,443 | 279.5 | 286,462 | 0.28 | 79,852 | 234,295 |
| 2029 | 483.0 | 495,093 | 0.28 | 138,963 | 348.6 | 357,308 | 0.30 | 105,929 | 244,892 |
| 2030 | 412.4 | 422,697 | 0.29 | 121,669 | 419.2 | 429,703 | 0.31 | 134,797 | 256,466 |
| 2031 | 624.3 | 639,884 | 0.29 | 188,388 | 207.3 | 212,516 | 0.33 | 70,386 | 258,774 |
| 2032 | 274.9 | 281,805 | 0.30 | 84,282 | 556.7 | 570,596 | 0.34 | 191,929 | 276,210 |
| 2033 | 348.6 | 357,307 | 0.30 | 108,465 | 483.0 | 495,094 | 0.36 | 179,797 | 288,261 |
| 2034 | 346.3 | 354,972 | 0.31 | 110,713 | 485.3 | 497,428 | 0.38 | 188,792 | 299,504 |
| 2035 | 275.7 | 282,576 | 0.32 | 90,137 | 555.9 | 569,825 | 0.40 | 226,295 | 316,432 |
| 2036 | 484.0 | 496,069 | 0.33 | 161,491 | 347.6 | 356,332 | 0.41 | 147,603 | 309,094 |
| 2037 | 487.6 | 499,765 | 0.33 | 164,287 | 344.0 | 352,636 | 0.43 | 151,317 | 315,604 |
| 2038 | 278.0 | 284,912 | 0.33 | 93,736 | 553.6 | 567,489 | 0.44 | 251,236 | 344,972 |
| 2039 | 278.0 | 284,914 | 0.33 | 95,339 | 553.6 | 567,487 | 0.45 | 257,436 | 352,775 |
| 2040 | 272.7 | 279,476 | 0.34 | 94,819 | 559.0 | 572,925 | 0.47 | 268,586 | 363,405 |
| 2041 | 275.7 | 282,576 | 0.34 | 96,959 | 555.9 | 569,825 | 0.49 | 280,333 | 377,292 |
| 2042 | 211.9 | 217,188 | 0.35 | 76,173 | 619.7 | 635,213 | 0.54 | 341,612 | 417,785 |
| 2043 | 273.4 | 280,241 | 0.36 | 100,769 | 558.2 | 572,159 | 0.61 | 350,475 | 451,245 |
| 2044 | 347.6 | 356,334 | 0.36 | 129,381 | 484.0 | 496,067 | 0.69 | 343,709 | 473,090 |
| 2045 | 141.3 | 144,792 | 0.37 | 53,859 | 690.3 | 707,609 | 0.82 | 580,869 | 634,729 |
| Average | 408.8 | 418,987 | $0.28 | $117,942 | 422.8 | 433,414 | $0.41 | $176,701 | $294,643 |

*Sources: ECONorthwest analysis using prices provided by Navigant Consulting. Data presented is corrected for rounding errors.*

## Increase in U.S. gas exploration and drilling

According to Economic Census,[10] PADD IV exploration and development drilling for oil & gas equals approximately 11.4 percent of annual shipments from wells. Producers continually replace depleted wells with production from new wells. Using the 11.4 percent annual replacement rate, ECONorthwest estimated the increase in daily output by the oil & gas drilling and exploration industry that would result from the Project. The increase in output from this upstream activity would average $434,781 per day in the forecast period, although the actual value would vary from year-to-year in accordance with the Navigant forecast of fluctuating domestic natural gas use at the JCEP.

[10] http://www.census.gov/econ/census07/ data for NAICS 211 and 213111.

**Table 10: Increase in daily domestic natural gas exploration output because of the JCEP, 2018 – 2045, 2010$**

| Year | O&G Drilling & Exploration (2010$/day) |
|---|---|
| 2018 | $54,239 |
| 2019 | 268,787 |
| 2020 | 161,876 |
| 2021 | 277,169 |
| 2022 | 218,561 |
| 2023 | 335,452 |
| 2024 | 402,828 |
| 2025 | 407,345 |
| 2026 | 296,984 |
| 2027 | 240,644 |
| 2028 | 253,787 |
| 2029 | 324,247 |
| 2030 | 399,228 |
| 2031 | 201,771 |
| 2032 | 557,007 |
| 2033 | 495,959 |
| 2034 | 511,103 |
| 2035 | 603,176 |
| 2036 | 385,759 |
| 2037 | 387,238 |
| 2038 | 631,649 |
| 2039 | 638,271 |
| 2040 | 649,925 |
| 2041 | 653,987 |
| 2042 | 734,795 |
| 2043 | 669,186 |
| 2044 | 578,962 |
| 2045 | 833,939 |
| Average | $434,781 |

*Sources: ECONorthwest analysis using Navigant and 2007 Economic Census data. Data presented is corrected for rounding errors.*

# Increases in Domestic Annual Up-Stream Output

Economic impact analysis measures the annual effects of changes in industry output. The results presented in this report have, though Table 10 followed the industry norm of expressing production or throughput on a per day basis. ECONorthwest has converted these daily production quantities into annual 2010$ values and used the resultant values to calculate annual economic impacts.

In the Project's first full-year of operation, up-stream industries in the United States would experience nearly $269 million in additional output. This quickly increases to more than $1.0 billion in the second year of operation, and then fluctuates as the supply mix shifts from year-to-year between the U.S. and Canada. Over time, more domestic gas would be produced for making LNG at the JCEP, so economic output up-stream would eventually rise above $3.3 billion. The annual average would be $1,723,378,474 of up-stream, domestic output. Of the affected industries, oil & gas extraction would benefit the most, accounting for 81 percent of total output.

**Table 11: Increase in direct annual economic output at up-stream industries in the United Stated because of LNG exports from Jordan Cove, 2018 – 2045, 2010$**

| Year | Oil & Gas Extraction | Oil & Gas Drilling | State & Local Government* | Transmission Pipelines** | Total Up-Stream Output |
|---|---|---|---|---|---|
| 2018 | $174,180,235 | $19,797,092 | $7,397,085 | $67,297,361 | $268,671,773 |
| 2019 | 863,173,865 | 98,107,184 | 36,425,920 | 70,542,187 | 1,068,249,155 |
| 2020 | 521,268,130 | 59,246,637 | 21,958,568 | 67,849,287 | 670,322,622 |
| 2021 | 890,093,562 | 101,166,841 | 37,338,979 | 71,064,331 | 1,099,663,713 |
| 2022 | 701,880,297 | 79,774,773 | 29,358,893 | 73,623,589 | 884,637,552 |
| 2023 | 1,077,260,864 | 122,440,025 | 45,039,622 | 77,071,443 | 1,321,811,953 |
| 2024 | 1,297,172,467 | 147,434,883 | 54,341,021 | 72,916,426 | 1,571,864,797 |
| 2025 | 1,308,134,416 | 148,680,803 | 54,906,640 | 77,606,368 | 1,589,328,228 |
| 2026 | 953,724,034 | 108,398,995 | 40,078,811 | 80,953,439 | 1,183,155,279 |
| 2027 | 772,796,781 | 87,835,046 | 32,527,041 | 84,303,377 | 977,462,245 |
| 2028 | 817,237,531 | 92,886,122 | 34,479,386 | 85,751,963 | 1,030,355,001 |
| 2029 | 1,041,277,706 | 118,350,228 | 44,060,737 | 89,385,648 | 1,293,074,319 |
| 2030 | 1,282,069,669 | 145,718,319 | 54,402,745 | 93,610,103 | 1,575,800,836 |
| 2031 | 647,962,772 | 73,646,580 | 27,555,108 | 94,452,585 | 843,617,045 |
| 2032 | 1,793,657,550 | 203,864,712 | 76,629,045 | 101,092,889 | 2,175,244,195 |
| 2033 | 1,592,708,333 | 181,025,093 | 68,309,687 | 105,215,364 | 1,947,258,477 |
| 2034 | 1,641,339,206 | 186,552,413 | 70,660,196 | 109,319,098 | 2,007,870,912 |
| 2035 | 1,937,021,805 | 220,159,300 | 83,841,081 | 115,497,636 | 2,356,519,823 |
| 2036 | 1,242,208,245 | 141,187,723 | 53,914,967 | 113,128,312 | 1,550,439,247 |
| 2037 | 1,243,563,687 | 141,341,781 | 53,964,705 | 115,195,439 | 1,554,065,613 |
| 2038 | 2,028,458,113 | 230,551,829 | 87,993,601 | 125,914,894 | 2,472,918,437 |
| 2039 | 2,049,723,352 | 232,968,807 | 88,791,037 | 128,762,930 | 2,500,246,127 |
| 2040 | 2,092,867,286 | 237,872,489 | 90,476,116 | 133,006,384 | 2,554,222,275 |
| 2041 | 2,100,192,898 | 238,705,108 | 90,717,786 | 137,711,472 | 2,567,327,264 |
| 2042 | 2,359,699,315 | 268,200,259 | 101,707,046 | 152,491,704 | 2,882,098,325 |
| 2043 | 2,149,003,425 | 244,252,847 | 92,539,067 | 164,704,318 | 2,650,499,657 |
| 2044 | 1,864,355,526 | 211,900,149 | 79,814,691 | 173,150,904 | 2,329,221,270 |
| 2045 | 2,678,086,229 | 304,387,689 | 114,501,257 | 231,675,955 | 3,328,651,131 |
| Average | $1,397,182,761 | $158,801,919 | $59,776,101 | $107,617,693 | $1,723,378,474 |

* *State severance taxes.*
*** This excludes output of the Pacific Connector Gas Pipeline, which is part of the Project and, therefore, not an up-stream business.*
*Source: ECONorthwest.*

# Section III Economic Contributions

Supplying natural gas for export entails an extensive network of transmission pipelines, gas production wells, gas gathering and processing facilities, and drilling and exploration activities. All activities involve the deployment of skilled, often well-compensated workers and the purchasing of supplies and services. These activities create economic impacts that filter down through the national economy, causing additional hiring and other positive economic impacts.

ECONorthwest estimated the up-stream impacts that would occur within the borders of the United States as a result of the JCEP. ECONorthwest used those estimates, in conjunction with a national economic impact model, to determine total gross up-stream economic impacts from the Project.

## Economic Impact Analysis

Economic impact analysis measures the annual effects of increased natural gas production and the associated activities of pipeline transmission, gas processing, and oil & gas exploration on the U.S. economy for each year from 2018 to 2045 that would result from the JCEP LNG exports. ECONorthwest estimated the subsequent *secondary* impacts using a national economic impact model that counts all the effects of labor and spending by up-stream sectors as they filter through the U.S. economy.

This analysis does not account for the impacts of any price effects on households and businesses in the U.S. as a result of JCEP LNG exports.

### Economic Impact Model

ECONorthwest estimated up-stream impacts 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 up-stream sectors affected by the LNG exports from Jordan Cove. IMPLAN is a widely used economic impact modeling system accepted by the U.S. court system and in regulatory settings.[11]

[11] University of Wisconsin Center for Cooperatives and the Department of Agricultural and Applied Economics at the University of Wisconsin — Madison at http://reic.uwcc.wisc.edu/implan/

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

The IMPLAN model divides the economy into 440 industry sectors, as well as government, and households. For each sector, IMPLAN allocates spending and employment impacts between the local and non-local economies.[12] The IMPLAN data, derived from U.S. Census and other government sources, approximates how, from where, and on what products and services various local industries spend money. IMPLAN also estimates the employment effects by industry.

ECONorthwest estimated the output of up-stream sectors (pipelines, oil & gas production, oil & gas services) for each year of the forecast (Sections I and II). ECONorthwest then used these results as inputs to the IMPLAN model. The IMPLAN model was then used to calculate the total impact of up-stream activities within the national economy.

With each additional transaction away from the source impact (*e.g.*, the initial level of expenditures at an upstream natural gas producer), the amounts diminish due to the effects of savings, taxes, or other activities that happen outside the national economy. For what stays in the country, for each round of spending and the employment it provides, more impacts result. In the end, the total national economic impacts exceed the initial impact from up-stream activities. Economists call this the *multiplier effect*.

Impacts that occur in Canada are excluded from the analysis. The output (revenues) received by U.S. pipeline moving Canadian gas to Malin is a domestic up-stream impact. The value of the gas, as it crosses the border into the United States, is not an economic impact.

[12] IMPLAN production function and regional purchase coefficient data were used.

## 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** Direct impacts occur at various domestic up-stream sources, but only to the extent that those sources benefit because of the demands placed on them by the LNG exports from Jordan Cove.
- **Indirect impacts** An indirect impact is one that occurs because of business-to-business transactions. For example, when an exploration and development company working on a gas field in Utah to supply JCEP demand buys steel from a wholesaler in Salt Lake City, that purchase causes an indirect impact in the form of higher output, employment, and business income for the wholesaler. That would also represent a first round of indirect impacts resulting from the Project. An example of a second round impact would be if the wholesaler buys the steel it sells to the exploration company from a mill in Portland, Oregon. That too is a business-to-business transaction that causes an indirect impact.
- **Induced impacts** An induced impact is one caused by household spending. For example, a welder working on a gas gathering system at a gas field in Utah who spends some of his salary on groceries from a store in Provo, Utah causes a first round of induced impacts. If store employees (or its owner) earn more money because of the increased business coming from the gas field that exists to supply JCEP, their increased household spending causes a second round of induced impacts that may be attributed to the Project. Because induced impacts originate from household spending, they often are called "consumption-driven" effects.

Direct impacts are sometimes referred to as *primary* impacts because they start where the primary sources of economic activities occur. Induced and indirect impacts are together 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 jobs, both of payroll employees and the self-employed, for both full- or part-time work done inside the United States during a year.
- **Employee compensation** Payroll cost of employers. It is the sum of wages, salaries, benefits (*i.e.,* health insurance, vacation pay, retirement), and employer-paid payroll taxes.
- **Proprietor income** Earnings of self-employed workers and farmers in the local economy. This figure includes owner-operator businesses.
- **Labor income** The sum of employee compensation and proprietors' income.
- **Output** The value of a year's worth of production. For pipelines, it is the value of shipping natural gas. For service sectors, including restaurants, it is approximately the same as their sales. For gas production, it is the fair market value of their production (this includes the value of natural gas liquids that are a necessary byproduct of dry pipeline gas that would eventually be exported as LNG from Jordan Cove).

# Contributions to Output and Jobs by Industry

The IMPLAN analysis calculated the contributions to total economic output and jobs in the United States for each of the four up-stream industries. The basis for this calculation is each industry's direct output; shown on Table 11. Using IMPLAN, ECONorthwest determined the contributions to output and jobs in other sectors of the U.S. economy *via* direct and induced impacts resulting from JCEP LNG exports.

## Oil & Gas Extraction Industry

The largest contributor of up-stream output would be the oil & gas extraction industry, which stands to benefit substantially from increased demand for natural gas, and, secondarily, NGL production. More than four out of every five dollars of increased U.S. economic output caused by up-stream industries would originate from the extraction industry.

The sector has a deep, domestic network of suppliers and pays high wages, thus, its indirect and induced impacts are great. For example, JCEP LNG exports would require nearly $1.4 billion per year in direct output from natural gas producers from 2018 to 2045 (Table 11).

That direct production, as illustrated in Table 12, would stimulate an average of $602.0 million a year additional indirect output from other industries in the U.S. that are part of the supply chain.

Induced output, caused by increased personal spending by jobholders, landholders (receive royalties), and business owners, would rise nearly $1.1 billion per year. This impact is especially large because the industry pays high wages. In 2010, the average wage was $145,684 per employee.[13]

Thus, the $1.4 billion in in direct output by the natural gas extraction industry would ultimately result in nearly $3.2 billion in total output in the U.S. economy in the average year from 2018 to 2045. Creating that output would require thousands of American workers.

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[13] U.S. Bureau of Labor Statistics. Quarterly Census of Employment and Wages for the oil and gas extraction industry, NAICS 211, as reported on February 16, 2012 http://www.bls.gov/cew/ .

**Table 12: Total contribution to U.S. economic output by the oil & gas extraction industry because of Jordan Cove LNG exports, 2018 – 2045, millions of 2010$**

| Year | Direct Output | Indirect Output | Induced Output | Total Output |
|---|---|---|---|---|
| 2018 | $174.2 | $75.0 | $149.1 | $398.3 |
| 2019 | 863.2 | 371.9 | 738.6 | 1,973.7 |
| 2020 | 521.3 | 224.6 | 446.1 | 1,191.9 |
| 2021 | 890.1 | 383.5 | 761.7 | 2,035.3 |
| 2022 | 701.9 | 302.4 | 600.6 | 1,604.9 |
| 2023 | 1,077.3 | 464.1 | 921.8 | 2,463.3 |
| 2024 | 1,297.2 | 558.9 | 1,110.0 | 2,966.1 |
| 2025 | 1,308.1 | 563.6 | 1,119.4 | 2,991.2 |
| 2026 | 953.7 | 410.9 | 816.1 | 2,180.8 |
| 2027 | 772.8 | 333.0 | 661.3 | 1,767.1 |
| 2028 | 817.2 | 352.1 | 699.3 | 1,868.7 |
| 2029 | 1,041.3 | 448.6 | 891.1 | 2,381.0 |
| 2030 | 1,282.1 | 552.4 | 1,097.1 | 2,931.6 |
| 2031 | 648.0 | 279.2 | 554.5 | 1,481.6 |
| 2032 | 1,793.7 | 772.8 | 1,534.9 | 4,101.4 |
| 2033 | 1,592.7 | 686.2 | 1,362.9 | 3,641.9 |
| 2034 | 1,641.3 | 707.2 | 1,404.6 | 3,753.1 |
| 2035 | 1,937.0 | 834.6 | 1,657.6 | 4,429.2 |
| 2036 | 1,242.2 | 535.2 | 1,063.0 | 2,840.4 |
| 2037 | 1,243.6 | 535.8 | 1,064.2 | 2,843.5 |
| 2038 | 2,028.5 | 874.0 | 1,735.8 | 4,638.2 |
| 2039 | 2,049.7 | 883.1 | 1,754.0 | 4,686.9 |
| 2040 | 2,092.9 | 901.7 | 1,790.9 | 4,785.5 |
| 2041 | 2,100.2 | 904.9 | 1,797.2 | 4,802.3 |
| 2042 | 2,359.7 | 1,016.7 | 2,019.3 | 5,395.7 |
| 2043 | 2,149.0 | 925.9 | 1,839.0 | 4,913.9 |
| 2044 | 1,864.4 | 803.3 | 1,595.4 | 4,263.0 |
| 2045 | 2,678.1 | 1,153.9 | 2,291.7 | 6,123.7 |
| Average | $1,397.2 | $602.0 | $1,195.6 | $3,194.8 |

*Source: ECONorthwest.*

U.S. employment that would arise from higher domestic natural gas production for JCEP exports is shown on Table 13. In the first year of terminal operations, employment traced back to gas production for JCEP exports would total 2,066 jobs. The contribution to jobs would rise rapidly as a higher proportion of domestic gas is used. After six years, 15,389 jobs would be attributable to the sector. This figure would rise above 30,000 in 2045. In the average annual forecast, 16,576 full-year jobs would result from effects of the JCEP on domestic gas production.

**Table 13: Total contribution to U.S. employment caused by the up-stream impacts on the oil & gas extraction industry from Jordan Cove LNG exports, 2018 – 2045, jobs**

| Year | Direct Jobs | Indirect Jobs | Induced Jobs | Total Jobs |
|---|---|---|---|---|
| 2018 | 649 | 348 | 1,069 | 2,066 |
| 2019 | 3,219 | 1,724 | 5,298 | 10,241 |
| 2020 | 1,944 | 1,041 | 3,200 | 6,184 |
| 2021 | 3,319 | 1,777 | 5,464 | 10,560 |
| 2022 | 2,617 | 1,402 | 4,308 | 8,327 |
| 2023 | 4,017 | 2,151 | 6,612 | 12,780 |
| 2024 | 4,837 | 2,590 | 7,962 | 15,389 |
| 2025 | 4,878 | 2,612 | 8,030 | 15,519 |
| 2026 | 3,556 | 1,904 | 5,854 | 11,315 |
| 2027 | 2,882 | 1,543 | 4,744 | 9,168 |
| 2028 | 3,047 | 1,632 | 5,016 | 9,696 |
| 2029 | 3,883 | 2,079 | 6,392 | 12,353 |
| 2030 | 4,781 | 2,560 | 7,870 | 15,210 |
| 2031 | 2,416 | 1,294 | 3,977 | 7,687 |
| 2032 | 6,688 | 3,582 | 11,010 | 21,280 |
| 2033 | 5,939 | 3,180 | 9,776 | 18,896 |
| 2034 | 6,120 | 3,277 | 10,075 | 19,472 |
| 2035 | 7,223 | 3,868 | 11,890 | 22,980 |
| 2036 | 4,632 | 2,480 | 7,625 | 14,737 |
| 2037 | 4,637 | 2,483 | 7,633 | 14,753 |
| 2038 | 7,564 | 4,050 | 12,451 | 24,065 |
| 2039 | 7,643 | 4,093 | 12,582 | 24,317 |
| 2040 | 7,804 | 4,179 | 12,846 | 24,829 |
| 2041 | 7,831 | 4,194 | 12,891 | 24,916 |
| 2042 | 8,799 | 4,712 | 14,484 | 27,995 |
| 2043 | 8,013 | 4,291 | 13,191 | 25,495 |
| 2044 | 6,952 | 3,723 | 11,444 | 22,118 |
| 2045 | 9,986 | 5,348 | 16,439 | 31,772 |
| Average | 5,210 | 2,790 | 8,576 | 16,576 |

*Source: ECONorthwest.*

# Oil & Gas Exploration and Drilling Industry

The exploration and drilling industry supports natural gas extraction by replacing reserves as they are depleted by production. This critical up-stream sector is smaller than the production industry but, like it, pays high wages to workers; the average worker earned $83,058 a year in 2010.[14] The sector employs many well-paid workers directly, supporting roles from land agents and petrophysicists to engineers and welders. That income flow leads to strong induced impacts on other parts of the U.S. economy.

Table 14 lists the contributions to U.S. economic output from the exploration and drilling sector caused by the JCEP exports each year. In the average forecast year, the sector contribution to direct output[15] would be $158.8 million $44.7 million in indirect output and $60.3 million in induced output. Total output that could be traced back to JCEP, both directly and indirectly, would average $263.8 million per year.

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[14] U.S. Bureau of Labor Statistics. Quarterly Census of Employment and Wages for the oil and gas drilling industry (NAICS 213111) as reported on February 16, 2012 http://www.bls.gov/cew/ .

[15] ECONorthwest distributed the direct output equal to 11.37 percent of natural gas production: 24 percent to NAICS 213111 (drilling) and 76 percent to 213112 (support services to oil & gas), as these encompass overall natural gas exploration and drilling activities. The proportions are based on the ratio of shipments for each NAICS code in PADD IV, as reported in the 2007 Economic Census available at http://www.census.gov/econ/census07/ from the U.S. Census website. By using these ratios, the forecast economic impacts are less than if the ratio of total shipments of both NAICS codes (29.2 percent) was used to estimate total output of the sector. Given the low exploration risk of unconventional natural gas in PADD IV, this more conservative method was deemed appropriate.

**Table 14: Total contribution to U.S. economic output by the oil & gas exploration and drilling industry because of JCEP exports, 2018 – 2045, millions of 2010$**

| Year | Direct Output | Indirect Output | Induced Output | Total Output |
|---|---|---|---|---|
| 2018 | $19.8 | $5.5 | $7.5 | $32.8 |
| 2019 | 98.1 | 27.3 | 36.7 | 162.1 |
| 2020 | 59.2 | 16.4 | 22.1 | 97.8 |
| 2021 | 101.2 | 27.9 | 37.7 | 166.8 |
| 2022 | 79.8 | 22.0 | 29.6 | 131.3 |
| 2023 | 122.4 | 33.7 | 45.4 | 201.6 |
| 2024 | 147.4 | 40.7 | 54.8 | 242.9 |
| 2025 | 148.7 | 41.1 | 55.4 | 245.1 |
| 2026 | 108.4 | 30.0 | 40.4 | 178.8 |
| 2027 | 87.8 | 24.3 | 32.8 | 145.0 |
| 2028 | 92.9 | 25.8 | 34.8 | 153.5 |
| 2029 | 118.4 | 33.0 | 44.4 | 195.8 |
| 2030 | 145.7 | 40.7 | 54.9 | 241.3 |
| 2031 | 73.6 | 20.6 | 27.8 | 122.1 |
| 2032 | 203.9 | 57.3 | 77.3 | 338.5 |
| 2033 | 181.0 | 51.1 | 68.9 | 301.0 |
| 2034 | 186.6 | 52.9 | 71.3 | 310.7 |
| 2035 | 220.2 | 62.7 | 84.6 | 367.4 |
| 2036 | 141.2 | 40.3 | 54.4 | 235.9 |
| 2037 | 141.3 | 40.4 | 54.4 | 236.1 |
| 2038 | 230.6 | 65.8 | 88.7 | 385.1 |
| 2039 | 233.0 | 66.4 | 89.5 | 388.9 |
| 2040 | 237.9 | 67.7 | 91.2 | 396.8 |
| 2041 | 238.7 | 67.9 | 91.5 | 398.1 |
| 2042 | 268.2 | 76.1 | 102.6 | 446.9 |
| 2043 | 244.3 | 69.2 | 93.3 | 406.8 |
| 2044 | 211.9 | 59.7 | 80.5 | 352.1 |
| 2045 | 304.4 | 85.7 | 115.5 | 505.5 |
| Average | $158.8 | $44.7 | $60.3 | $263.8 |

*Source: ECONorthwest.*

The job impacts on the whole economy from exploration and drilling are particularly strong because of the high wage rates of both the industry and many of its suppliers. Each direct job in exploration and development because of LNG exports leads to the creation of 3.7 new jobs nationwide. The total job contribution would rise from 112 jobs in 2018 to 1,735 in 2045. On average, 906 jobs per year would be attributable to the stimulative effects of JCEP exports on the exploration and drilling sector.

**Table 15: Total contribution to U.S. employment caused by the up-stream impacts on oil & gas exploration and drilling from JCEP exports, 2018 – 2045, jobs**

| Year | Direct Jobs | Indirect Jobs | Induced Jobs | Total Jobs |
|---|---|---|---|---|
| 2018 | 31 | 28 | 53 | 112 |
| 2019 | 150 | 139 | 262 | 552 |
| 2020 | 91 | 84 | 158 | 333 |
| 2021 | 154 | 143 | 269 | 566 |
| 2022 | 121 | 112 | 211 | 445 |
| 2023 | 186 | 172 | 324 | 683 |
| 2024 | 224 | 208 | 391 | 824 |
| 2025 | 227 | 210 | 395 | 832 |
| 2026 | 166 | 153 | 288 | 607 |
| 2027 | 134 | 125 | 234 | 493 |
| 2028 | 142 | 132 | 248 | 523 |
| 2029 | 182 | 169 | 317 | 668 |
| 2030 | 225 | 208 | 391 | 824 |
| 2031 | 114 | 106 | 198 | 418 |
| 2032 | 317 | 293 | 551 | 1,161 |
| 2033 | 282 | 262 | 491 | 1,035 |
| 2034 | 292 | 271 | 508 | 1,071 |
| 2035 | 346 | 321 | 603 | 1,271 |
| 2036 | 223 | 206 | 388 | 817 |
| 2037 | 223 | 207 | 388 | 818 |
| 2038 | 364 | 337 | 633 | 1,334 |
| 2039 | 367 | 340 | 639 | 1,346 |
| 2040 | 374 | 346 | 651 | 1,371 |
| 2041 | 375 | 347 | 653 | 1,375 |
| 2042 | 420 | 389 | 732 | 1,541 |
| 2043 | 382 | 354 | 666 | 1,402 |
| 2044 | 330 | 306 | 574 | 1,210 |
| 2045 | 473 | 438 | 824 | 1,735 |
| Average | 247 | 229 | 430 | 906 |

*Source: ECONorthwest.*

## State & Local Government

Colorado, Montana, Utah, and Wyoming, collectively, would collect an average of $59.8 million per year in severance tax on gas produced for JCEP between 2018 and 2045. The analysis assumes these taxes would go to state and local government services, with about 30 percent earmarked for education.[16]

**Table 16: Total contribution to U.S. economic output by severance tax spending on state & local government services resulting from Jordan Cove LNG exports, 2018 – 2045, millions of 2010$**

| Year | Direct Output | Indirect Output | Induced Output | Total Output |
|---|---|---|---|---|
| 2018 | $7.4 | $1.1 | $9.7 | $18.2 |
| 2019 | 36.4 | 5.2 | 48.0 | 89.6 |
| 2020 | 22.0 | 3.2 | 28.9 | 54.0 |
| 2021 | 37.3 | 5.4 | 49.2 | 91.9 |
| 2022 | 29.4 | 4.2 | 38.7 | 72.2 |
| 2023 | 45.0 | 6.5 | 59.3 | 110.8 |
| 2024 | 54.3 | 7.8 | 71.5 | 133.7 |
| 2025 | 54.9 | 7.9 | 72.3 | 135.1 |
| 2026 | 40.1 | 5.8 | 52.8 | 98.6 |
| 2027 | 32.5 | 4.7 | 42.8 | 80.0 |
| 2028 | 34.5 | 5.0 | 45.4 | 84.8 |
| 2029 | 44.1 | 6.3 | 58.0 | 108.4 |
| 2030 | 54.4 | 7.8 | 71.6 | 133.8 |
| 2031 | 27.6 | 4.0 | 36.3 | 67.8 |
| 2032 | 76.6 | 11.0 | 100.9 | 188.5 |
| 2033 | 68.3 | 9.8 | 89.9 | 168.1 |
| 2034 | 70.7 | 10.2 | 93.0 | 173.8 |
| 2035 | 83.8 | 12.0 | 110.4 | 206.3 |
| 2036 | 53.9 | 7.7 | 71.0 | 132.6 |
| 2037 | 54.0 | 7.8 | 71.0 | 132.8 |
| 2038 | 88.0 | 12.6 | 115.8 | 216.5 |
| 2039 | 88.8 | 12.8 | 116.9 | 218.4 |
| 2040 | 90.5 | 13.0 | 119.1 | 222.6 |
| 2041 | 90.7 | 13.0 | 119.4 | 223.2 |
| 2042 | 101.7 | 14.6 | 133.9 | 250.2 |
| 2043 | 92.5 | 13.3 | 121.8 | 227.7 |
| 2044 | 79.8 | 11.5 | 105.1 | 196.4 |
| 2045 | 114.5 | 16.4 | 150.7 | 281.7 |
| Average | $59.8 | $8.6 | $78.7 | $147.1 |

*Source: ECONorthwest.*

[16] 30 percent is weighted for the 2010 natural gas output by Utah, Montana, Wyoming, and Colorado. The source of state expenditures is: State & Local Government Finance Data Query System. The Urban Institute-Brookings Institution Tax Policy Center. Data from U.S. Census Bureau, Annual Survey of State and Local Government Finances, Government Finances, Volume 4, and Census of Governments. Date of Access: (03-Feb-12 02:55 PM)

As shown in Table 17, the contribution of severance taxes to total national economic output would range from $18.2 million in 2018 to $281.7 million in 2045.

Government services, because of their concentration in education and healthcare, are labor intensive. Thus, total job impacts would be substantial. They expected range is from 175 to 2,713 jobs a year, for an average 1,416 jobs annually, as shown on Table 17.

**Table 17: Total contribution to U.S. employment caused by state and local government services spending supported by state severance taxes resulting from JCEP exports, 2018 – 2045, jobs**

| Year | Direct Jobs | Indirect Jobs | Induced Jobs | Total Jobs |
|---|---|---|---|---|
| 2018 | 100 | 6 | 69 | 175 |
| 2019 | 492 | 30 | 341 | 863 |
| 2020 | 296 | 18 | 206 | 520 |
| 2021 | 504 | 31 | 350 | 885 |
| 2022 | 396 | 24 | 275 | 696 |
| 2023 | 608 | 37 | 422 | 1,067 |
| 2024 | 734 | 45 | 509 | 1,288 |
| 2025 | 741 | 45 | 515 | 1,301 |
| 2026 | 541 | 33 | 376 | 950 |
| 2027 | 439 | 27 | 305 | 771 |
| 2028 | 466 | 28 | 323 | 817 |
| 2029 | 595 | 36 | 413 | 1,044 |
| 2030 | 735 | 45 | 510 | 1,289 |
| 2031 | 372 | 23 | 258 | 653 |
| 2032 | 1,035 | 63 | 718 | 1,816 |
| 2033 | 922 | 56 | 640 | 1,619 |
| 2034 | 954 | 58 | 662 | 1,674 |
| 2035 | 1,132 | 69 | 786 | 1,987 |
| 2036 | 728 | 44 | 505 | 1,278 |
| 2037 | 729 | 44 | 506 | 1,279 |
| 2038 | 1,188 | 72 | 825 | 2,085 |
| 2039 | 1,199 | 73 | 832 | 2,104 |
| 2040 | 1,222 | 74 | 848 | 2,144 |
| 2041 | 1,225 | 74 | 850 | 2,150 |
| 2042 | 1,373 | 83 | 953 | 2,410 |
| 2043 | 1,249 | 76 | 867 | 2,193 |
| 2044 | 1,078 | 65 | 748 | 1,891 |
| 2045 | 1,546 | 94 | 1,073 | 2,713 |
| Average | 807 | 49 | 560 | 1,416 |

*Source: ECONorthwest.*

## Natural Gas Transmission Pipeline Sector

Direct output from natural gas transmission pipelines transporting gas for the JCEP would average $107.6 million annually (Table 19). Through spending by the pipeline companies, employees, contractors, and property holders receiving compensation, total output in the United States would increase by $305.7 million a year. Pipelines are heavy users of contractors, such as pilots; landscaping firms; regulatory consultants; and self-employed professional service workers. The money spent on these services is not counted as a direct impact, which explains the relatively high contribution of induced and indirect output to the total.

**Table 18: Total contribution to U.S. economic output by up-stream impacts on natural gas pipeline throughput resulting from JCEP exports, 2018 – 2045, millions of 2010$**

| Year | Direct Output | Indirect Output | Induced Output | Total Output |
|---|---|---|---|---|
| 2018 | $67.3 | $48.6 | $75.3 | $191.2 |
| 2019 | 70.5 | 50.9 | 78.9 | 200.4 |
| 2020 | 67.8 | 49.0 | 75.9 | 192.7 |
| 2021 | 71.1 | 51.3 | 79.5 | 201.9 |
| 2022 | 73.6 | 53.1 | 82.4 | 209.1 |
| 2023 | 77.1 | 55.6 | 86.2 | 218.9 |
| 2024 | 72.9 | 52.6 | 81.6 | 207.1 |
| 2025 | 77.6 | 56.0 | 86.8 | 220.4 |
| 2026 | 81.0 | 58.4 | 90.6 | 230.0 |
| 2027 | 84.3 | 60.9 | 94.3 | 239.5 |
| 2028 | 85.8 | 61.9 | 95.9 | 243.6 |
| 2029 | 89.4 | 64.5 | 100.0 | 253.9 |
| 2030 | 93.6 | 67.6 | 104.7 | 265.9 |
| 2031 | 94.5 | 68.2 | 105.7 | 268.3 |
| 2032 | 101.1 | 73.0 | 113.1 | 287.2 |
| 2033 | 105.2 | 76.0 | 117.7 | 298.9 |
| 2034 | 109.3 | 78.9 | 122.3 | 310.5 |
| 2035 | 115.5 | 83.4 | 129.2 | 328.1 |
| 2036 | 113.1 | 81.7 | 126.5 | 321.3 |
| 2037 | 115.2 | 83.2 | 128.9 | 327.2 |
| 2038 | 125.9 | 90.9 | 140.9 | 357.7 |
| 2039 | 128.8 | 93.0 | 144.0 | 365.8 |
| 2040 | 133.0 | 96.0 | 148.8 | 377.8 |
| 2041 | 137.7 | 99.4 | 154.0 | 391.2 |
| 2042 | 152.5 | 110.1 | 170.6 | 433.2 |
| 2043 | 164.7 | 118.9 | 184.2 | 467.8 |
| 2044 | 173.2 | 125.0 | 193.7 | 491.8 |
| 2045 | 231.7 | 167.2 | 259.2 | 658.1 |
| Average | $107.6 | $77.7 | $120.4 | $305.7 |

*Source: ECONorthwest.*

The reliance on contractors and high wage-earning employees results in above-average indirect and induced job impacts, according to IMPLAN data. This trend is reflected in the forecast, which attributes an average of 1,461 total jobs per year to this sector, only 158 of which are direct employees working for pipeline companies.

**Table 19: Total contribution to U.S. employment caused by natural gas throughput on transmission pipelines that supply the JCEP for LNG exports, 2018 – 2045, jobs**

| Year | Direct Jobs | Indirect Jobs | Induced Jobs | Total Jobs |
|---|---|---|---|---|
| 2018 | 99 | 274 | 541 | 914 |
| 2019 | 104 | 287 | 567 | 958 |
| 2020 | 100 | 276 | 546 | 921 |
| 2021 | 104 | 289 | 572 | 965 |
| 2022 | 108 | 299 | 592 | 1,000 |
| 2023 | 113 | 313 | 620 | 1,046 |
| 2024 | 107 | 297 | 586 | 990 |
| 2025 | 114 | 316 | 624 | 1,054 |
| 2026 | 119 | 329 | 651 | 1,099 |
| 2027 | 124 | 343 | 678 | 1,145 |
| 2028 | 126 | 349 | 690 | 1,164 |
| 2029 | 131 | 363 | 719 | 1,214 |
| 2030 | 137 | 381 | 753 | 1,271 |
| 2031 | 139 | 384 | 760 | 1,282 |
| 2032 | 148 | 411 | 813 | 1,373 |
| 2033 | 154 | 428 | 846 | 1,429 |
| 2034 | 160 | 445 | 879 | 1,484 |
| 2035 | 170 | 470 | 929 | 1,568 |
| 2036 | 166 | 460 | 910 | 1,536 |
| 2037 | 169 | 468 | 927 | 1,564 |
| 2038 | 185 | 512 | 1,013 | 1,710 |
| 2039 | 189 | 524 | 1,036 | 1,748 |
| 2040 | 195 | 541 | 1,070 | 1,806 |
| 2041 | 202 | 560 | 1,108 | 1,870 |
| 2042 | 224 | 620 | 1,227 | 2,071 |
| 2043 | 242 | 670 | 1,325 | 2,236 |
| 2044 | 254 | 704 | 1,393 | 2,351 |
| 2045 | 340 | 942 | 1,863 | 3,146 |
| Average | 158 | 438 | 866 | 1,461 |

*Source: ECONorthwest.*

# Total Contribution by Up-Stream Industries

Table 20 summarizes the total contributions of up-stream industries on the U.S economy that would result from the Project. Initially, the contribution to total U.S. economic output would be $640.4 million, but would rise rapidly as more domestic gas is used by the JCEP. After five year the effect on output would approach $3.0 billion. By 2035 it would exceed $5.3 billion. Over the entire period, 2018 to 2045, the annual effect on U.S. economic output by up-stream industries would average over $3.9 billion per year.

**Table 20: Total contribution to U.S. employment caused by natural gas throughput on transmission pipelines that supply Jordan Cove LNG exports, 2018 – 2045, jobs**

| | Output (Million 2010 $) | | | | Jobs | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Direct | Indirect | Induced | Total | Direct | Indirect | Induced | Total |
| 2018 | $268.7 | $130.2 | $241.5 | $640.4 | 879 | 656 | 1,733 | 3,268 |
| 2019 | 1,068.2 | 455.3 | 902.3 | 2,425.8 | 3,964 | 2,180 | 6,469 | 12,613 |
| 2020 | 670.3 | 293.2 | 573.0 | 1,536.5 | 2,430 | 1,419 | 4,109 | 7,959 |
| 2021 | 1,099.7 | 468.1 | 928.0 | 2,495.8 | 4,082 | 2,240 | 6,654 | 12,975 |
| 2022 | 884.6 | 381.7 | 751.2 | 2,017.6 | 3,243 | 1,837 | 5,387 | 10,467 |
| 2023 | 1,321.8 | 559.9 | 1,112.8 | 2,994.5 | 4,924 | 2,674 | 7,979 | 15,577 |
| 2024 | 1,571.9 | 660.0 | 1,318.0 | 3,549.8 | 5,902 | 3,139 | 9,449 | 18,491 |
| 2025 | 1,589.3 | 668.6 | 1,333.9 | 3,591.8 | 5,960 | 3,183 | 9,564 | 18,706 |
| 2026 | 1,183.2 | 505.1 | 999.9 | 2,688.1 | 4,382 | 2,420 | 7,169 | 13,971 |
| 2027 | 977.5 | 422.8 | 831.2 | 2,231.5 | 3,579 | 2,037 | 5,961 | 11,577 |
| 2028 | 1,030.4 | 444.8 | 875.4 | 2,350.5 | 3,781 | 2,141 | 6,277 | 12,199 |
| 2029 | 1,293.1 | 552.5 | 1,093.5 | 2,939.0 | 4,791 | 2,648 | 7,841 | 15,279 |
| 2030 | 1,575.8 | 668.5 | 1,328.3 | 3,572.6 | 5,877 | 3,194 | 9,524 | 18,595 |
| 2031 | 843.6 | 371.9 | 724.2 | 1,939.8 | 3,041 | 1,806 | 5,194 | 10,040 |
| 2032 | 2,175.2 | 914.1 | 1,826.2 | 4,915.5 | 8,188 | 4,349 | 13,093 | 25,629 |
| 2033 | 1,947.3 | 823.1 | 1,639.5 | 4,409.8 | 7,298 | 3,926 | 11,754 | 22,978 |
| 2034 | 2,007.9 | 849.1 | 1,691.1 | 4,548.1 | 7,527 | 4,050 | 12,125 | 23,702 |
| 2035 | 2,356.5 | 992.7 | 1,981.7 | 5,331.0 | 8,871 | 4,727 | 14,208 | 27,806 |
| 2036 | 1,550.4 | 665.0 | 1,314.9 | 3,530.3 | 5,749 | 3,191 | 9,428 | 18,368 |
| 2037 | 1,554.1 | 667.1 | 1,318.5 | 3,539.6 | 5,758 | 3,202 | 9,454 | 18,414 |
| 2038 | 2,472.9 | 1,043.3 | 2,081.3 | 5,597.5 | 9,300 | 4,972 | 14,922 | 29,193 |
| 2039 | 2,500.2 | 1,055.3 | 2,104.5 | 5,660.0 | 9,398 | 5,029 | 15,088 | 29,515 |
| 2040 | 2,554.2 | 1,078.4 | 2,150.1 | 5,782.7 | 9,594 | 5,141 | 15,415 | 30,150 |
| 2041 | 2,567.3 | 1,085.2 | 2,162.2 | 5,814.7 | 9,633 | 5,175 | 15,502 | 30,310 |
| 2042 | 2,882.1 | 1,217.5 | 2,426.3 | 6,525.9 | 10,816 | 5,805 | 17,396 | 34,017 |
| 2043 | 2,650.5 | 1,127.3 | 2,238.4 | 6,016.2 | 9,887 | 5,391 | 16,049 | 31,327 |
| 2044 | 2,329.2 | 999.4 | 1,974.7 | 5,303.3 | 8,613 | 4,798 | 14,159 | 27,570 |
| 2045 | 3,328.7 | 1,423.2 | 2,817.1 | 7,569.0 | 12,345 | 6,822 | 20,199 | 39,366 |
| Average | $1,723.4 | $733.0 | $1,455.0 | $3,911.3 | 6,422 | 3,505 | 10,432 | 20,359 |

*Source: ECONorthwest. This table summarizes the impacts reported from Table 12 to Table 19.*

Jobs in the U.S. economy linked to JCEP's up-stream suppliers would exceed 3,200 in the first year and rise to 15,577 five years later, averaging a contribution of 20,359 jobs per year for the U.S. economy for the entire forecast period.

# APPENDIX F

# ECONORTHWEST BALANCE OF TRADE STUDY

# Effect of the Jordan Cove Energy Project's LNG Exports on United States Balance of Trade 2018 - 2045

Prepared for the Jordan Cove Energy Project, L.P.

March 20, 2012

ECONorthwest
ECONOMICS • FINANCE • PLANNING

Section I

# Introduction

The Jordan Cove Energy Project ("JCEP") expects to export domestic natural gas in the form of liquefied natural gas (LNG) from its terminal in Coos County, Oregon. These exports would also increase gas field byproduct output. The combination of these two effects would improve the U.S. balance of trade.

The balance of trade is the difference in the values of exports from the United States and imports into the country. Improving the balance of trade (*i.e.,* exporting more and/or importing less) raises national income and stimulates employment.[1]

In 2010, President Obama stated a policy goal of doubling U.S. exports as part of his National Export Initiative. Citing that every $1 billion increase in exports supports more than 6,000 jobs in the United States, the President 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."[2]

ECONorthwest analyzed the trade impacts of the JCEP for the years 2018 through 2045 under the assumption the terminal would only export LNG (it has the ability to import as well). This report summarizes the findings of that analysis.

The JCEP will receive natural gas from Canada, as well as from domestic gas fields in the Rocky Mountain basins. The value of the Canadian gas imports has a negative impact of the U.S. balance of trade. However, this is offset by the value of LNG exports from Coos County, as well as an increase in exports of natural gas liquids (NGLs), a byproduct of domestic natural gas output.

This analysis shows that the impacts vary by year as prices and the domestic-import mix of natural gas purchases change.

This analysis relies on the price and volume forecasts from a report from Navigant Consulting, Inc., entitled "Jordan Cove LNG Export Project Market Analysis Study" dated January 2012. Navigant gave ECONorthwest annual forecast data from the analysis done for their study.

The analysis in this report takes into consideration the following:

- The Navigant forecast starts with 2017. The terminal is scheduled to open in December 2017. This analysis begins with 2018, which is the first full-year of production.
- In estimating NGLs production, the consumption of natural gas used in pipeline transmission is included, as well as the natural gas used for exports.

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[1] McTeer, Bob. "The impact of foreign trade on the economy." *The New York Times* 10 Dec. 2008.

[2] Fifield, Anna. "Obama unveils plans to double exports." *Financial Times* 11 Mar. 2010.

- Since the U.S. is currently a net exporter of NGLs, the increased value of NGLs extracted from domestic well production due to JCEP exports adds to the current trade surplus for NGLs.

The considerations account for the anticipated timing of the JCEP, and its ultimate impacts on natural gas imports and production.

# Current U.S. Trade

Basic economic theory states that two entities (whether they be individuals, groups, or our nation states) can potentially increase their wellbeing by trading with each other, so long as they each have a comparative advantage in the good they are trading away. Embracing an open economic system of trade is a major foundational basis for strong economic growth. As a proponent of free trade, the U.S. has aggressively sought out trade agreements with other nations.

Over the past 30 years, the U.S. has experienced a trade deficit, meaning it had a negative balance of trade. The value of imports was greater than the value of exports. This can be a result of many factors, some of which are:

- The high relative value of the U.S. dollar compared to other international currencies
- The relative cost advantage other nations have in producing final goods
- Higher demand for final goods produced outside the U.S.

Figure 1 displays the U.S. trade deficit from January 1992 to December 2011. The deficit was initially $2 billion a month, but has widened considerably. In December 2011 the monthly trade deficit was a seasonally adjusted $48.8 billion. For the year, the U.S. trade deficit was approximately $558 billion. All else being equal, exporting LNG from Jordan Cove, and possibly from projects in other parts of the U.S., would reduce the trade deficit.

### Figure 1: Trade Balance: Goods and Services, U.S. Balance of Payments, Monthly Seasonally Adjusted Millions of Dollars, January 1992 – December 2011


*Source: U.S. Department of Commerce: Census Bureau.*

## Section II Data Analysis

Calculating the effect Jordan Cove would have on the U.S. trade balance requires ascertaining the value of domestic and imported gas needed to facilitate the exports, as well as the FOB value of LNG exported each year. This section summarizes how these values were determined.

## Natural Gas Production Sources

The Jordan Cove Energy Project will use natural gas from domestic and Canadian sources. Initially, the majority of the natural gas is expected to be Canadian, with a moderate proportion coming from domestic sources.

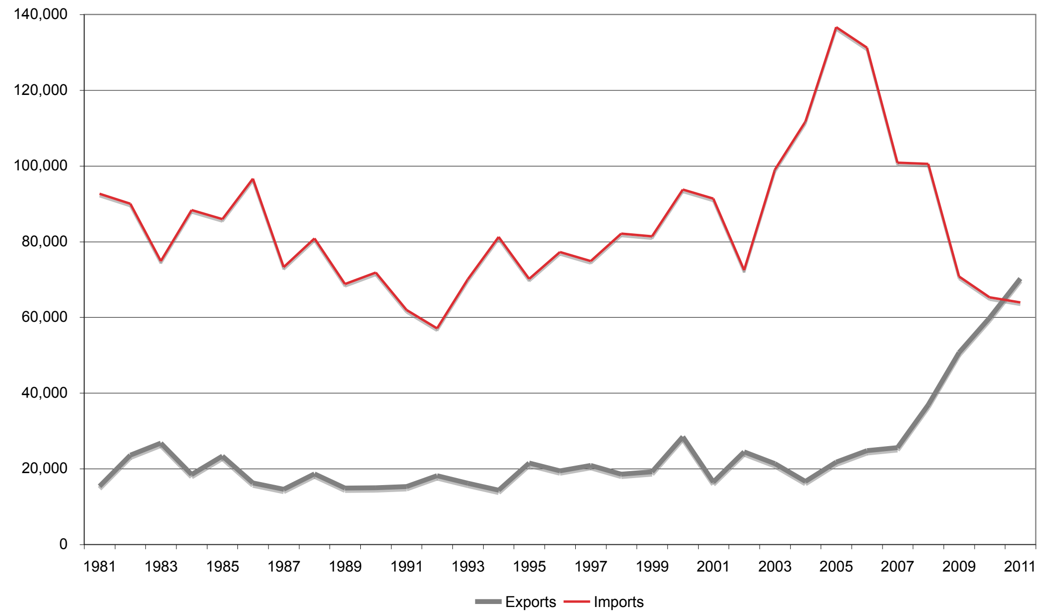
Navigant concludes that the JCEP will obtain its domestic natural gas from the Rocky Mountain region. The U.S. Energy Information Administration ("EIA") includes five states in the region, which it calls the Petroleum Administration for Defense District Four ("PADD IV.") The five states are Colorado, Idaho, Montana, Utah and Wyoming albeit Idaho currently produces no natural gas.

In the future, the mix of natural gas used for the JCEP is expected to shift to a majority of PADD IV relative to Canadian Gas. This shift in demand will improve the U.S. trade balance.

Natural gas liquids are necessary by-products of natural gas production in much of PADD IV. NGLs are extracted from the wellhead before transporting natural gas through the gas pipelines. These NGLs (*i.e.* butane, ethane, propane, *etc*.) are then brought to market, either domestically or abroad.

Since domestic supply of natural gas is increasing through the forecast horizon, the supply of NGLs will increase as well. Historically, the U.S. has been a net importer of NGLs, but has recently changed to a net exporter. Figure 2 illustrates the volumes of NGL imports and exports since 1981.

**Figure 2: Total U.S. Imports and Exports of NGLs, Thousands of Barrels, 1981 - 2011**




*Source: Energy Information Administration. U.S. international trade in natural gas and refinery gas liquids.*

## Value of domestic NGL output

Future NGL output is assumed to be a function of the total volume of marketable gas. In PADD IV, for a well to supply 1,000 cubic feet of pipeline gas, approximately 1,041 cubic feet of marketable gas must be produced. The difference, 41 cubic feet, is separated as NGLs. In liquid form, it is approximately 1.2 gallons (or 0.0286 barrels) of NGL.[3]

Thus, to compute future production of NGLs and their effects on the balance of payments for trade, 1.2 gallons for every 1,000 cubic feet of domestic pipeline gas needed by the JCEP is the total quantity of NGLs produced. As the production of NGLs increases, the excess NGL volumes will be exported abroad.

The price of NGL output is based on the energy content of the product. Because NGLs are a direct substitute for crude oil, NGL output is included in the EIA's accounting of national crude oil field production.[4] Refineries pay for NGLs based on the heat content per barrel relative to crude oil.

[3] Calculated by ECONorthwest from PADD IV state-level data on the heat content and marketable production volume from natural gas production as reported in EIA State Energy Data 2009, Tables P1 and P2.

[4] U.S. Energy Information Administration, Annual Energy Review 2010, October 19, 2011. Page 135.

The average heat content of NGLs in PADD IV is about 63.4 percent that of the national pricing standard for crude oil; West Texas intermediate (WTI). The heat content of a barrel of NGL produced in PADD IV in 2009 averaged about 3.68 million British thermal units (MMBtu). The average content of WTI was 5.80 MMBtu.

Using Navigant's WTI price forecast, ECONorthwest calculated the value of domestic daily production of NGLs resulting from meeting the demand for gas by the JCEP.

## Value of Canadian natural gas imports

Navigant expects that the JCEP would get its Canadian natural gas from the Gas Transmission Northwest Pipeline that originates in Kingsgate, British Columbia. That pipeline carries natural gas to hub in Malin, Oregon, from which the Pacific Connector Gas Pipeline would deliver Canadian and domestic natural gas to the JCEP.

Kingsgate is a hub just north of the Washington state-Canadian border. Navigant provided its volume and price forecast of natural gas imports entering the United States from Kingsgate because of the LNG exports from the JCEP. ECONorthwest used the Navigant data to forecast the value of increased natural gas imports due to the JCEP.

## Value of LNG exports from Coos County

ECONorthwest estimated the FOB value of LNG exports from the JCEP based on the average price of recent U.S. LNG exports adjusted for Navigant's forecast for WTI. Data from the U.S. Census Bureau show the average price of LNG exports from the United States for the most recent twelve-month period (ending October 2011) was $9.16 per MMBtu.[5]

The average price of WTI over the same period was $93.01 a barrel. LNG export prices, for the years 2018 to 2045, were forecast by adjusting the recent price of LNG exports proportionately to Navigant's WTI price forecasts. The value of exports was calculated by multiplying the forecast LNG price by the average quantity of about 295 trillion Btu a year.

[5] Source: https://www.usatradeonline.gov/

# Results

Jordan Cove's LNG exports, as well as the increase in domestic NGLs, will result in a net improvement in the balance of trade for the United States — even after deducting higher gas imports from Canada.

Table 1 shows the change in the U.S. trade balance due to the JCEP exports for each five-year mark from 2020 (two years after the start of operations) through 2045. As the relative price of LNG and NGLs increases during the forecast period, and the quantity of imported gas decreases, the trade balance improves. By 2045, the JCEP will improve the U.S. balance of trade by $4.9 billion per year.

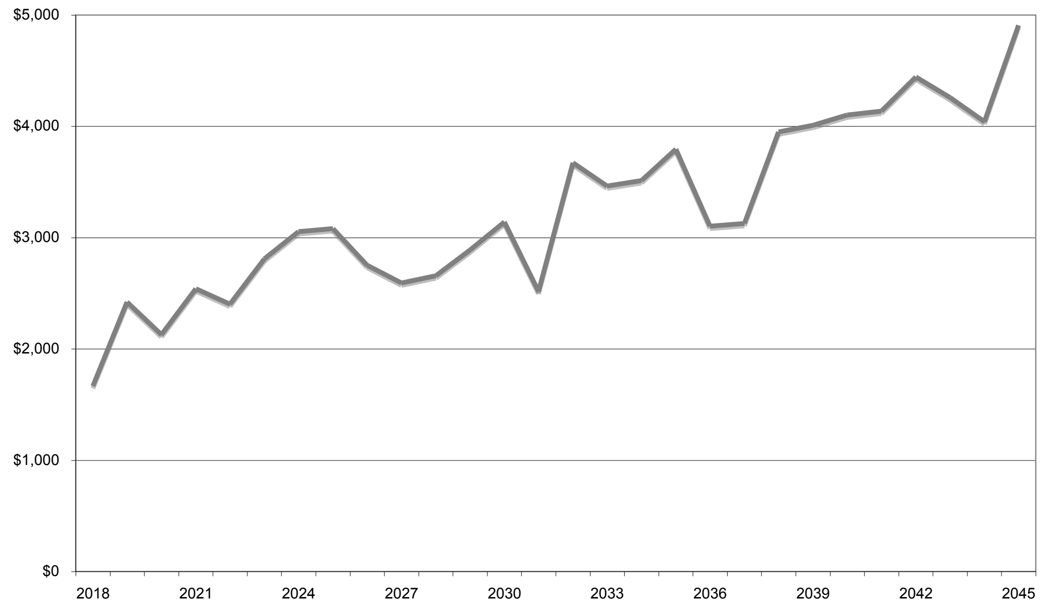
**Table 1: Impact of JCEP LNG Exports on the U.S. Balance of Trade, Millions of 2010 $ per Year, 2020 – 2045**

| Year | LNG Exports | NGL Exports | (Less) Canadian Gas Imports | Change in the Balance of Trade |
|---|---|---|---|---|
| 2020 | $3,096 | $150 | ($1,118) | $2,128 |
| 2025 | 3,387 | 380 | (685) | 3,082 |
| 2030 | 3,687 | 362 | (909) | 3,141 |
| 2035 | 3,987 | 519 | (711) | 3,795 |
| 2040 | 4,299 | 563 | (760) | 4,102 |
| 2045 | 4,587 | 742 | (421) | 4,909 |

*Source: ECONorthwest calculations.*

Figure 3 is an illustration of the improvement in the U.S. balance of trade that would arise from the exportation of approximately 295 trillion Btu of LNG a year from the JCEP in each forecast year from 2018 to 2045.

**Figure 3: Improvement in the U.S. Trade Balance Because of JCEP LNG Exports, 2018 – 2045, Millions 2010 $**



# APPENDIX G

# VERIFICATION

# VERIFICATION

DISTRICT OF COLUMBIA

I, Joan M. Darby, being duly sworn on oath, hereby affirm that: I am a duly authorized representative of Jordan Cove Energy Project, L.P.; I am familiar with the contents of the Jordan Cove's Application for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations; and, the matters set forth in the Application are true and correct to the best of my knowledge, information and belief.

Joan M Darby

Joan M. Darby

Sworn to and subscribed before me,
a Notary Public in and for the
District of Columbia on
this 23rd day of March, 2012

Marina M. Lauziere

Notary Public

MARINA M. LAUZIERE
NOTARY PUBLIC DISTRICT OF COLUMBIA
MY COMMISSION EXPIRES APRIL 30, 2013

# APPENDIX H

# OPINION OF COUNSEL

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March 23, 2012

Ms. John A. Anderson
Manager, Natural Gas Regulatory Activities
Office of Natural Gas & Petroleum
Import & Export Activities
Office of Fossil Energy
U.S. Department of Energy
1000 Independence Avenue SW
Washington, D.C. 20585

Re: Jordan Cove Energy Project, L.P.
Application for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations

Dear Mr. Anderson:

This opinion is furnished to you pursuant to Section 590.202(c) of the Department of Energy Regulations, 10 C.F.R. §590.202(c) and the Application of Jordan Cove Energy Project, L.P. ("Jordan Cove") for Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations. We are counsel to Jordan Cove, a limited partnership organized under the laws of the State of Delaware, in connection with the referenced Application. We have reviewed and relied upon the limited partnership formation documents of Jordan Cove and information provided to us by Jordan Cove. Based on the foregoing, and for the purposes of the Application to the Office of Fossil Energy, we are of the opinion that the proposed exports as described in the Application are within the limited partnership powers of Jordan Cove.

Very truly yours,

*/s/ Dickstein Shapiro LLP*