**Dominion Cove Point LNG, LP**
701 East Cary Street, Richmond, VA 23219

Dominion

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OCT 3 2011

October 3, 2011

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

Re: Dominion Cove Point LNG, LP
FE Docket No. 11-128-LNG
Application for Long-Term Authorization to Export LNG
To Non-Free Trade Agreement Countries

Dear Mr. Anderson:

Dominion Cove Point LNG, LP (DCP) hereby submits for filing, with the U.S. Department of Energy, Office of Fossil Energy (DOE/FE), one original and three copies of its application for long-term authorization to export liquefied natural gas (LNG). DCP is seeking long-term, multi-contract authority to export domestically produced LNG of up to the equivalent of approximately 1 billion cubic feet of natural gas per day or approximately 7.82 million metric tons per annum at its Cove Point LNG Terminal located in Calvert County, Maryland over a twenty-five year period. The requested export authority would permit DCP as an agent for others to export LNG to any country which has or in the future develops the capacity to import LNG via ocean-going carrier with which the United States does not prohibit trade but also does not have a Free Trade Agreement.

As stipulated by 10 C.F.R. § 590.207, a check for the filing fee in the amount of $50.00 is enclosed. Pursuant to 10 C.F.R. § 590.103(b), a certified statement that the signatory is a duly authorized representative is attached in Appendix D.

If you have any questions, please contact Amanda Prestage at 804-771-4416.

Respectfully submitted,

/s/ Matthew R. Bley

Matthew R. Bley
Authorized Representative of
Dominion Cove Point LNG Company, LLC,
The General Partner of Dominion Cove Point LNG, LP
Tel: (804) 771-4399
Fax: (804) 771-4804

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**RECEIVED**
**By Docket Room at 4:32 pm, Oct 04, 2011**

**Dominion Cove Point LNG, LP**
701 East Cary Street, Richmond, VA 23219

Dominion

October 4, 2011

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

Re: Dominion Cove Point LNG, LP
FE Docket No. 11-128-LNG
Application for Long-Term Authorization to Export LNG
To Non-Free Trade Agreement Countries – Resubmitting of Appendices

Dear Mr. Anderson:

On October 3, 2011, Dominion Cove Point LNG, LP (DCP) submitted for filing with the U.S. Department of Energy, Office of Fossil Energy (DOE/FE), its application (Application) for long-term authorization to export liquefied natural gas (LNG) to countries with which the United States does not prohibit trade but also does not have a Free Trade Agreement at its Cove Point LNG Terminal located in Calvert County, Maryland.

DCP hereby requests to withdraw and replace Appendix B (Navigant Price Report) and Appendix C (ICF Economic Benefit Study) of the Application. DCP proposes to withdraw and replace these two appendices to correct minor errors on three pages of Appendix B and one page of Appendix C, so as to ensure that the most accurate and complete information is filed on the record under this docket. This supplemental filing does not affect the Application itself, or Appendices A, D, and E.

For ease of administration, we have enclosed an original and three bound copies of the Application as a whole, including the corrected versions of Appendices B and C. If you have any questions, please contact Amanda Prestage at 804-771-4416.

Respectfully submitted,

*/s/ Matthew R. Bley*

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

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|---|---|---|
| **In the Matter of** | ] | **FE Docket No.** |
| | ] | **11 - 128 - LNG** |
| **DOMINION COVE POINT LNG, LP** | ] | |

# APPLICATION OF DOMINION COVE POINT LNG, LP FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS


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Filed:  October 3, 2011

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

| | | |
|---|---|---|
| **In the Matter of** | ] | **FE Docket No.** |
| | ] | **11 - 128- LNG** |
| **DOMINION COVE POINT LNG, LP** | ] | |

**APPLICATION OF DOMINION COVE POINT LNG, LP FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS**

Pursuant to Section 3 of the Natural Gas Act (NGA) 1/ and Part 590 of the Department of Energy's (DOE) regulations, 2/ Dominion Cove Point LNG, LP (DCP) hereby files this application (Application) with the DOE, Office of Fossil Energy (DOE/FE) for long-term, multi-contract authorization to engage in exports of domestically produced liquefied natural gas (LNG) of up to the equivalent of 1 billion cubic feet of natural gas per day, or approximately 7.82 million metric tons per annum. DCP proposes to export the LNG from its existing LNG terminal ("Cove Point LNG Terminal" or "Terminal") located in Calvert County, Maryland, over a twenty-five year term commencing on the date of the first LNG export or six years from the date that the authorization is issued, whichever is sooner. DCP requests authorization herein to export the LNG to any country that has or in the future develops the capacity to import LNG via ocean-going carrier and with which the United States (U.S.) does not prohibit trade but also does not have a Free Trade Agreement (FTA) requiring the national treatment for trade in natural gas.

1/ 15 U.S.C. § 717 (b).

2/ 10 C.F.R. Part 590 (2011).

DCP is requesting this authorization to act as agent on behalf of other entities who themselves hold title to the LNG, after registering each such entity with DOE/FE.

This Application represents the second part of DCP's two part request for authorization to export domestic natural gas in the form of LNG from its Terminal. On September 1, 2011, DCP filed in FE Docket No. 11-115-LNG its application requesting long-term, multi-contract authorization to export domestically produced LNG to any country (1) with which the United States has, or in the future enters into, an FTA requiring national treatment for trade in natural gas and (2) which has or in the future develops the capacity to import LNG via ocean-going carrier. Through the combination of the two applications, DCP requests authorization to export domestic natural gas as LNG to any country with which trade is not prohibited by U.S. law or policy.

In support of this Application, DCP respectfully shows as follows:

## I. DESCRIPTION OF THE APPLICANT

The exact legal name of DCP is Dominion Cove Point LNG, LP. DCP is a limited partnership organized and existing under the laws of the State of Delaware with its principal place of business at 2100 Cove Point Road, Lusby, Maryland, 20657, and offices at 701 East Cary Street, Richmond, Virginia, 23219. DCP is a subsidiary of Dominion Resources, Inc. ("DRI"), one of the Nation's largest producers and transporters of energy. DRI is a corporation organized and existing under the laws of the Commonwealth of Virginia with its principal place of business at 100 Tredegar Street, Richmond, Virginia, 23219.

DCP owns the Cove Point LNG Terminal, as well as an 88-mile gas pipeline connecting the Terminal to the interstate pipeline grid. The construction and operation of the Cove Point LNG Terminal and pipeline was initially authorized in 1972 as part of a project to import LNG from Algeria and transport natural gas to U.S. markets. 3/ Shipments of LNG to the Terminal began in March 1978, but ceased in December 1980. In 2001, the FERC authorized the reactivation of the Terminal and the construction of new facilities to recommence LNG imports. 4/ In 2006, the FERC authorized the Cove Point Expansion project, which nearly doubled the size of the Terminal, expanded the capacity of the Cove Point pipeline, and provided for new downstream pipeline and storage facilities. 5/ In 2009, FERC authorized DCP to upgrade, modify, and expand its existing off-shore pier at the Terminal to accommodate the docking of larger LNG vessels. 6/

The Cove Point LNG Terminal currently has peak daily send-out capacity of 1.8 billion cubic feet (Bcf) and on-site LNG storage capacity of the equivalent of 14.6 Bcf (or 678,900 cubic meters of LNG). DCP's 88-mile gas pipeline, which has firm transportation capacity of 1.8 Bcf, connects the Terminal to the major Mid-Atlantic gas transmission systems of Transcontinental Gas Pipe Line Company, LLC ("Transco"), Columbia Gas Transmission, LLC ("Columbia") and Dominion Transmission, Inc. ("DTI"). DTI is an interstate gas transmission business unit of DRI.

DCP has experienced a significant decline in the level of LNG imports at the Terminal, especially since mid-2010. The decline in imports has been largely driven by the development of large quantities of shale gas in the U.S., together with the consistent demand for LNG (and higher gas prices) in other countries. In light of the plentiful, inexpensive supplies of domestic

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3/ The Federal Energy Regulatory Commission ("FERC") granted the original certificate for the Cove Point facilities in *Columbia LNG Corp. and Consolidated System LNG Co.*, 47 FPC 1624, *aff'd and modified*, 48 FPC 723 (1972).

4/ *Cove Point LNG LP*, 97 FERC ¶ 61,043, *reh'g*, 97 FERC ¶ 61,276 (2001), *reh'g*, 98 FERC ¶ 61,270 (2002).

5/ *Dominion Cove Point LNG, LP*, 115 FERC ¶ 61,37 (2006), *reh'g*, 118 FERC ¶ 61,007 (2007), *remanded sub nom. Washington Gas Light Co. v. FERC*, 532 F.3d 928 (D.C. Cir. 2008), *order on remand*, 125 FERC ¶ 61,018 (2008), *reh'g*, 126 FERC ¶ 61,036 (2009).

6/ *Dominion Cove Point LNG, LP*, 128 FERC ¶ 61,037, *reh'g*, 129 FERC ¶ 61,137 (2009).

gas in the U.S., LNG cargos have been more profitably delivered to other markets around the world, rather than to the U.S. This market dynamic has led DCP, like certain other existing LNG import terminals, 7/ to plan to export domestic natural gas.

## II. COMMUNICATIONS AND CORRESPONDENCE

The names, titles and mailing addresses of the persons to whom correspondence and communications concerning this Application, including all service of pleadings and notices, are to be addressed are:


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These persons are designated to receive service and should be placed on the official service list for this proceeding.

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7/ See *Sabine Pass Liquefaction, LLC*, FE10-111-LNG, DOE Order No. 2961 (May 20, 2011); *Sabine Pass Liquefaction, LLC*, FE10-85-LNG, DOE Opinion and Order No. 2833 (Sept. 7, 2010); *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, FE10-160-LNG, DOE Opinion and Order No. 2913 (Feb. 10, 2011); *Lake Charles Exports, LLC*, FE11-59-LNG, DOE Opinion and Order 2987 (July 22, 2011).

## III. EXECUTIVE SUMMARY

DCP plans to construct new facilities at its existing Terminal to provide gas liquefaction and LNG export services to customers that will provide their own gas supply. The Cove Point LNG Terminal is well positioned to provide the export customers with access to abundant and diverse domestic gas supply, and particularly well-situated to export gas production from the prolific Marcellus Shale. LNG exports will provide an additional outlet for growing gas supplies, and promote the continued development of the Nation's energy resources.

Following the construction of its liquefaction project, the Cove Point LNG Terminal will be operated as a bi-directional facility. The Terminal then can be used both to export LNG when domestic natural gas prices are low compared to prices elsewhere in the world (as they are now), and to import LNG to supplement domestic supply if supported by market conditions. This flexibility to respond to market conditions comports with DOE policy favoring the trade of natural gas on a market-competitive basis.

In recent years, the American gas market has experienced a tremendous boom, driven by the development of shale gas. North American gas reserves now are more than sufficient to satisfy domestic demand as it grows over time, as well as the export of LNG. The relatively small amount of LNG exports proposed by DCP could not possibly pose any threat to the security of domestic natural gas supply. Moreover, the DCP liquefaction project will result in a host of benefits to the public interest including: supporting the continued development of domestic natural gas and liquid hydrocarbons, the creation of thousands of new jobs, providing a huge economic stimulus, increasing tax revenues, and improving the U.S. balance of trade.

For these reasons, and as fully explained below and in the studies provided in the appendices attached to the Application, authorization of DCP's Application for the export of LNG is "not inconsistent with the public interest." To the contrary, authorization of the Application will advance the public interest significantly. Accordingly, DCP respectfully requests that the DOE/FE authorize the export, as proposed in the Application, by June 1, 2012. Granting the authorization in this time frame will facilitate DCP's contracting with its potential customers, and enable it to place its project in-service by the end of 2016 in response to market needs.

## IV. DESCRIPTION OF PROPOSAL AND REQUESTED AUTHORIZATION

DCP's request for authorization here is part of its plan to develop, own and operate facilities at its existing Terminal to liquefy domestically produced natural gas and to load the resulting LNG onto tankers for export to foreign markets. DCP anticipates placing its liquefaction project in service by the end of 2016. DCP is currently engaged in Preliminary Front End Engineering Design ("Pre-FEED") studies for its liquefaction project. DCP also is in the process of conducting commercial negotiations with potential customers, and has received significant interest in its project. Long-term authorization by DOE/FE to export LNG is required at this time to facilitate the execution of the anticipated long-term agreements with customers.

DCP's liquefaction project will be integrated with some existing facilities at its Terminal. Domestic gas can be delivered to the Terminal through DCP's existing pipeline, which is bi-directional allowing gas to flow both away from and toward the Terminal. In addition, much of the existing facilities at the Terminal will be used as part of the liquefaction project. Existing facilities that may be utilized include the off-shore pier (with two berths), insulated LNG and gas piping from the pier to the on-shore Terminal and within the Terminal facility, the seven LNG storage tanks, on-site power generation, and control systems. In addition, DCP will construct new facilities to liquefy the natural gas delivered to the Terminal through the Cove Point pipeline. The new liquefaction facilities will be located on land already owned by DCP (which encompasses more than 1,000 acres).

DCP requests long-term, multi-contract authorization for the exportation of domestically produced LNG for a term of twenty-five years commencing on the date of the first LNG export or six years from the date that the authorization is issued, whichever is sooner. 8/ DCP proposes to export LNG of up to the equivalent of 1 Bcf of natural gas per day (Bcf/d), or approximately 7.82 million metric tons per annum (mtpa) of LNG. 9/ DCP previously requested, in FE Docket No. 11-115-LNG, similar export authorization limited to any country that has or in the future develops the capacity to import LNG via ocean-going carrier and with which the U.S. has, or in the future enters into, an FTA. By this Application, DCP requests authorization for export to the countries with which the U.S. does not have an FTA but with which trade is not prohibited by U.S. law or policy.

DCP anticipates entering into one or more long-term (likely of twenty years duration) 10/ contractual agreements with customers for natural gas liquefaction and LNG export services on a date that is closer to the start of export operations. These contracts will

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8/ DCP anticipates commencing exports by the end of 2016, but proposes that the requested authorization commence within six years of the date of authorization to allow for some potential delay in that schedule. In its prior order approving LNG exports to non-FTA countries for Sabine Pass, DOE/FE authorized the exports to commence on the earlier of the date of first export or five years from the date of issuance of the authorization. *Sabine Pass*, DOE Order No. 2961. In prior orders approving LNG exports to FTA countries, DOE/FE provided for the authorization to commence on the date of first exports not to exceed ten years (Sabine Pass and Lake Charles) or five years (Freeport) from the date that authorization is issued. *Sabine Pass*, Order No. 2833; *Freeport*, Order No. 2913; *Lake Charles*, Order No. 2987.

9/ Section 590.202(b)(1) of the DOE's regulations requires that applications for export or import authority set forth "the volumes of natural gas involved, expressed either in Mcf or Bcf and their Bcf equivalents." In recent orders authorizing LNG exports, DOE/FE has authorized levels set forth in Bcf of natural gas. *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, Order No. 2913; *Lake Charles,* Order No. 2987 (July 22, 2011). DCP similarly requests authorization for the amount of natural gas of up to 1 Bcf per day. For purposes of LNG measurement, DCP has utilized here a conversion factor of 46.675 Bcf per metric ton of LNG but the actual conversion factor will depend on the composition of the natural gas.

10/ DCP requests export authorization for twenty-five years, even though it anticipates contracts of twenty years duration. The additional length of the export authorization will allow leeway needed because not all contracts will necessarily start on the date that the authorization will begin – *i.e.*, the sooner of (a) six years from authorization or (b) the date of first exports. The request for twenty-five years authorization is intended to ensure that the authorization will remain in place for all initial contracts of twenty years duration, even if they start sometime later.

provide for DCP to provide a service to its customers of liquefying natural gas and loading it onto LNG tankers at the Terminal for export, and may also include rights for the customers to import LNG for vaporization and send-out as regasified LNG into the domestic market, when desired by the customers.

The specific terms of DCP's future contracts with its customers for LNG exports – including, but not limited to, commencement and termination dates, pricing, volumes, and export destinations – will be determined by market conditions and negotiations between the parties. The countries of destination may not be specified in the contracts, so as to allow maximum flexibility to the LNG owner; but, in such instances, the contract will expressly provide that the export destination must be consistent with the export authorizations issued for DCP by DOE/FE and shall be reported on a monthly basis. This approach is consistent with the terms recently approved by DOE/FE for a similar LNG export authorization. 11/

DCP's customers will be responsible for procuring their own gas supplies and holding title to the gas that they will deliver to DCP for liquefaction and the LNG to be exported from the Cove Point LNG Terminal. For this purpose, the customers may enter into long-term gas supply contracts or procure spot supplies in the very large and liquid U.S. gas market. The gas will be delivered to DCP from the interstate pipeline grid and may be sourced from both conventional and non-conventional production. The Cove Point LNG Terminal is ideally located to provide access to a wide range of domestic supply sources.

The Terminal's connection through DCP's own pipeline with the interstate pipeline systems of Transco, Columbia and DTI provide access for DCP's customers to abundant and diverse domestic supplies. These major interstate pipelines connected to DCP are, in turn,

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11/ *Sabine Pass,* Order No. 2961.

interconnected with the pipeline grid, allowing gas to be sourced from a wide variety of regions. The DTI pipeline system, for instance, provides direct access to Appalachian (including Marcellus Shale) supply as well as connections to major pipelines transporting gas from the Gulf of Mexico area, the mid-continent, the Rockies and Canada. DTI also operates the largest underground natural gas storage system in the country, as well as a very liquid trading hub: Dominion South Point.

DCP is especially well positioned to export gas production from the Marcellus Shale, one of the largest shale plays with among the lowest development costs, as well as the very promising Utica Shale – as discussed in Section V.B.1. below. The pipeline industry in the Marcellus area has recently experienced a surge in pipeline expansions as the gas producers look for ways to get their gas to markets. With export authorization, DCP would be able to provide an additional outlet for these growing domestic gas supplies. In addition, LNG exports will increase the opportunities for more robust development of energy resources, not only natural gas but also natural gas liquids (NGL) and oil resources that are also found in the shale formations. These new NGL and oil resources can increase domestic liquids production, improve the balance of trade, benefit the American petrochemical industry, and reduce the need to import oil.

DCP does not intend to hold title to gas delivered to it for liquefaction or the LNG to be exported, and is requesting authorization to act as agent on behalf of its customers that will hold title to the gas and LNG. Consistent with the terms for an LNG terminal operator receiving export authorization in its role as agent for others established by DOE/FE in *Freeport LNG Development, LP*, FE 11-51-LNG, DOE/FE Order No. 2986 (July 19, 2011), DCP will register each LNG title holder for whom DCP seeks to export LNG with DOE/FE. Consistent with that order, the registration will include a written statement by the title holder acknowledging and agreeing to comply with all applicable requirements included in DCP's export authorization and to include those requirements in any subsequent purchase or sale agreement entered into for the exported LNG by that title holder. As DOE/FE has recognized, this registration process is responsive to current LNG markets and provides an expedited process by which companies seeking to export LNG can so do. 12/

DCP also will file under seal with DOE/FE any relevant long-term commercial agreements that it enters into with LNG title holders on whose behalf the exports will be performed, once the agreements are executed. DOE/FE has previously held that the commitment to file contracts once they are executed conforms with the requirement of 10 C.F.R. § 590.202(b) to supply transaction specific information "to the extent practicable." 13/

DCP has not at this time determined the particular facilities to be constructed, or the amount of liquefaction capacity of those facilities because its pre-FEED studies have not been completed. Depending on the outcome of those studies and its negotiations with customers, DCP anticipates constructing one to three liquefaction trains, offering liquefaction capability sufficient to allow the export of the equivalent of up to 1 Bcf/d. Given that DCP has not finalized its facility planning but needs to proceed with obtaining authorization for LNG exports for purposes of customer contracting, DCP requests here authorization to export up to 1 Bcf/d, which is the maximum volume it contemplates exporting at this time.

Once DCP has further developed its plans concerning the facilities to be constructed for its liquefaction project, DCP will request permission to commence the FERC's mandatory pre-filing process under the National Environmental Policy Act (NEPA) and subsequently file an

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12/ *Sabine Pass,* Order No. 2961 at 39-40; *Freeport,* Order No. 2986 at pages 7-8; *see also Freeport,* Order No. 2913 at pages 7-8. Of course, the entities that hold title to the LNG are not required to use the agency rights issued to the terminal and could choose to submit an export application for their own separate authorization. *Id.*

13/ *Yukon Pacific Corp.*, ERA Docket No. 87-68-LNG, Order No. 350 (Nov. 16, 1989); Distrigas Corp., FE95-100-LNG, Order No. 1115 (Nov. 7, 1995); *Sabine Pass*, Order No. 2961 at 41.

application for the necessary FERC authorization for the construction and operation of the facilities to liquefy gas and provide for the exportation of domestically produced LNG from the Cove Point LNG Terminal. The authorization requested here, as a practical matter, will not be actionable until the FERC grants DCP authorization for the needed facilities. DCP does not anticipate receiving FERC authorization within the timeframe during which DOE/FE will act on this Application. Accordingly, consistent with prior orders by DOE/FE, the authorization requested here should be conditioned on DCP's receipt of all necessary FERC authorizations of the facilities needed for the export of LNG. 14/ In this way, the effective level of export authorization will be limited to the amount possible using the facilities approved by FERC and actually constructed, not to exceed 1 Bcf/d.

Following the approval and construction of the liquefaction and export facilities, the Cove Point LNG Terminal will be operated as a bi-directional facility. The Terminal will retain the capability to import LNG and vaporize it into natural gas for delivery into the domestic interstate pipeline network, and add the capability of liquefying natural gas to export as LNG to foreign markets. Thus, the Cove Point LNG Terminal then will be responsive to competitive market forces. When U.S. gas prices are low compared to prices in other countries (as they are now), domestic gas can be exported from the Terminal. In contrast, if prices of LNG in other parts of the world fall below the U.S. prices, DCP's customers may utilize the Terminal to import LNG and supply the regasified natural gas to the domestic market.

14/ *E.g., Sempra LNG Marketing, LLC*, FE10-110-LNG, DOE Opinion and Order No. 2885 at page 6 (Dec. 3, 2010).

## V. CONSISTENCY WITH THE PUBLIC INTEREST

### A. The Applicable Legal Standard

Section 3(a) of the NGA, 15 USC 717b(a), sets forth the following statutory standard for the review of this LNG export Application:

> [N]o person shall export 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 15/] authorizing it to do so. The [Secretary] shall issue such order upon application, unless after opportunity for hearing, [he] finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by [the Secretary's] order grant such application, in whole or in part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate.

Section 3(a) establishes a rebuttal presumption that a proposed export of natural gas is in the public interest, and DOE must grant an export application unless opposing parties (if any) overcome that presumption. 16/ Moreover, DOE/FE has explained that opponents of an export application must make an affirmative showing of inconsistency with the public interest in order to overcome the rebuttable presumption favoring export applications. 17/

In implementing Section 3 of the NGA, the DOE issued policy guidelines explaining the approach that it will employ in evaluating applications for natural gas imports. 18/ DOE/FE has repeatedly reaffirmed the continued applicability of the guidelines and has consistently held that

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15/ The Secretary's authority was established by the DOE Organization Act of 1977, which transferred jurisdiction over gas import and export authorizations from the Federal Power Commission.

16/ *E.g., Sabine Pass* Order No. 2961 at 28; *Conoco Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, FE07-02-LNG, Order No. 2500 at 43 (June 3, 2008); *Phillips Alaska*, FE96-99-LNG, Order No. 1473 at 13 (April 2, 1999).

17/ *Sabine Pass*, Order No. 2961, at 28 & note 38; *ConocoPhillips,* Order No. 2500; *Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, FE96-99-LNG DOE/FE Opinion and Order No. 1473, 2 FE ¶ 70,317 (April 2, 1999); *Panhandle Producers and Royalty Owners Assoc. v. ERA*, 822 F.2d 1105, 1111 (D.C. Cir. 1987).

18/ "New Policy Guidelines and Delegation Orders Relating to the Regulation of Natural Gas," 49 Fed. Reg. 6684-01 (Feb. 22, 1984)(hereinafter the "Policy Guidelines").

they apply equally to export applications (though written to apply to imports). 19/ The Policy Guidelines were "designed to establish natural gas trade on a market-competitive basis and to provide immediate as well as long-term benefits to the American economy from this trade." 20/ The Guidelines provide that:

> The market, not government, should determine the price and other contract terms of imported [or exported] gas. U.S. buyers [sellers] should have full freedom – along with the responsibility – for negotiating the terms of trade arrangements with foreign sellers [buyers]. The federal government's primary responsibility in authorizing imports [exports] should be to evaluate the need for the gas and whether the import 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….
>
> [T]he guidelines establish a regulatory framework for buyers and sellers to negotiate contracts based on traditional competitive and market considerations, with minimal regulatory constraints and conditions. The government, while ensuring that the public interest is adequately protected, should not interfere with buyers' and sellers' negotiation of the commercial aspects of import [export] arrangements. The thrust of this policy is to allow the commercial parties to structure more freely their trade arrangements, tailoring them to the markets served. Thus, with the presumption that commercial parties will develop competitive arrangements, parties opposing an import [export] will bear the burden of demonstrating that the import [export] arrangement is not consistent with the public interest. 21/

The Policy Guidelines further explain:

> The policy cornerstone of the public interest standard [of NGA Section 3] is competition. Competitive import [export] arrangements are an essential element of the public interest, and natural gas imported [exported] under arrangements that provide

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19/ *Yukon Pacific*, Order No. 350; *Phillips Alaska*, Order No. 1479; *ConocoPhillips Alaska*, Order No. 2500, *Sabine Pass*, Order No. 2961.

20/ Policy Guidelines at 6684.

21/ *Id.* at 6685. The parenthetical references to exports are added to reflect the applicability of the Policy Guidelines to exports. *See* note 19, *supra*.

> for the sale of gas in volumes and at prices responsive to market demands largely meets the public interest test....
>
> This policy approach presumes that buyers and sellers, if allowed to negotiate free of constraining governmental limits, will construct competitive import [export] agreements that will be responsive to market forces over time. The specific commercial terms and conditions of a particular arrangement should be negotiated by the parties pursuant to discrete requirements of the buyer's [and seller's] market and not directed by government regulators. 22/

In addition to following the Policy Guidelines, DOE/FE has explained that its review of export applications under its delegated authority focuses on "the domestic need for the gas; 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." 23/

### B. Exports From Cove Point Will Promote the Public Interest

Granting DCP's requested authorization to allow LNG exports will be consistent with, and indeed advance, the public interest. Allowing DCP and its customers to freely negotiate contracts to respond to market conditions and utilize the Cove Point LNG Terminal for exports when warranted by prices will be consistent with the pro-competition focus of the Policy Guidelines. And North American gas reserves are more than adequate to satisfy U.S. demand, even under the most aggressive demand scenarios, including a domestic LNG export industry. The exports proposed by DCP, of only up to 1 Bcf-equivalent per day, could not possibly pose a threat to domestic gas supply security. Indeed, by providing a steady, incremental demand for

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22/ *Id.* at 6687.

23/ *Sabine Pass*, Order No. 2961 at 29. This approach is consistent with DOE Delegation Order No. 0204-111, which previously guided DOE/FE decisions on export applications but is no longer in effect. *Id. See also, e.g., ConocoPhillips Alaska*, Decision No. 2500 at 44-45; *Phillips Alaska*, Order No. 1473 at 13-14.

gas, LNG exports from the Cove Point LNG Terminal will help support ongoing supply development and, thereby, help keep U.S. gas prices stable. Moreover, approval of the requested authorization will promote the public interest in numerous other ways.

To help demonstrate that its liquefaction and LNG export project is consistent with the public interest, DCP commissioned and provides here three studies by independent, expert consultants. The first study, prepared by Navigant Consulting, Inc. ("Navigant") is the "North American Gas Supply Overview and Outlook To 2040," attached as Appendix A ("Navigant Supply Report"). The Navigant Supply Report builds on Navigant's most recent forecast of the North American gas market (its Spring 2011 Reference Case) 24/ to evaluate the adequacy of supply to satisfy domestic demand as well as proposed LNG exports. The Navigant Supply Report also provides benchmark comparisons to other publicly available supply forecasts, including the 2011 Annual Energy Outlook (AEO) issued by the Energy Information Administration (EIA). The second study, also prepared by Navigant, is the "North American Gas System Model to 2040" attached as Appendix B ("Navigant Pricing Report"). The Navigant Pricing Report (which is to be read in conjunction with the Navigant Supply Report) analyzes the possible price effects of proposed LNG exports. The modeling conservatively projects the price effects of DCP's proposed LNG exports under a variety of scenarios and concludes that any possible price increases would be modest. Third, ICF International prepared an "Economic Benefits Study" quantifying the economic benefits associated with the export of LNG by DCP, which is attached as Appendix C.

24/ As part of its internal integrated 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. The Supply Report provided here builds on Navigant's Spring 2011 Reference case forecast and Navigant's ongoing market resource. Navigant Supply Report, "Summary of Assignment."

The benefits of DCP's proposal, as detailed in the Economic Benefits Study, include the following:

- Direct and Indirect Job Creation: At its peak of construction activity, the short-term economic impacts from construction and operation of the DCP liquefaction project have the potential to support between 2,700 and 3,400 "job years" 25/ in Calvert County, Maryland, as well as approximately 1,000 additional jobs in the rest of the State of Maryland. Moreover, the significant inter-linkage between various economic sectors provides the potential to support an additional 3,850 to 4,820 jobs in the rest of the Nation during peak construction. During operations from 2018 through 2040, the economic activity at the Cove Point LNG Terminal is estimated to result in 320 jobs across the Nation. 26/ Moreover, economic activity associated with the long-term upstream supply of natural gas for exports from the Terminal would result in an average of over 18,000 new jobs annually. 27/
- Economic Stimulus From Construction: The DCP liquefaction project has the potential to create significant short-term economic activity in the region and throughout the state during the construction phase. In 2015, the DCP facility will create between $183 and $230 million in "value added" (meaning the contribution to Gross Domestic Product, calculated as the difference between the

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25/ In the Economic Benefits Study, ICF calculates the employment impact in terms of a "job-years", which is defined as the amount of work performed by one full-time individual in one year (typically 2,080 hours). Economic Benefits Study at 1. For ease of presentation, ICF's results in "job-years" are referred to in this Application simply as jobs.

26/ All these employment results are detailed in the Economic Benefits Study at 11, Table 2 "Annual Job-Year Impacts, Facility Construction/Operation (Job-years)."

27/ *See* Economic Benefits Study at 24, Table 7 "U.S. Upstream Natural Gas Sector Annual Job-years Resulting from LNG Exports from Cove Point (Job-years)."

output generated from expenditures and the expenditures for intermediate goods and services) within Calvert County and an additional $80 to $100 million in the rest of Maryland. Annual activities during operations from 2018 through 2040 are expected to generate an additional $22 million in value added annually for Calvert County, Maryland, and over $47 million for the U.S. in total. 28/

- Indirect Economic Stimulus: In aggregate, $44 billion in total value added is projected to result from upstream expenditures of $32 billion needed to supply the LNG exports over the 25-year period. 29/ The top sectors, as a function of total value added, include real estate and equipment rentals; oil and gas support activities; educational, medical, hotel, food, and other services; wholesale and retail trade; and IT, scientific, environmental, and waste management services.
- Promote domestic production of petroleum and liquid hydrocarbons: Incremental production of hydrocarbon liquids from 2016 through 2040 associated with LNG exports by DCP is estimated at 8.5 million barrels per year, with an average projected market value of $1.2 billion per year. 30/ This domestic production of NGLs will help reduce reliance on foreign sources of oil and help U.S. industry, particularly the petrochemical industry.
- Improvement in the U.S. Balance of Trade: LNG exports, along with associated NGL production, will help realign the U.S. balance of trade by a range of $2.8

28/ *See id.* at 16, Table 3 "Annual Value Added Impacts, Facility Construction/Operation (2011$)."

29/ *Id.* at 20. *See also id.* at 26, Table 8 "U.S. Output from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$)" and 28, Table 9 "U.S. Value Added from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$)."

30/ *See id.* at 38, Table 16 "U.S. Volume, Value, and Economic Impact of Incremental Hydrocarbon Liquids Associated with LNG Export from Cove Point."

billion to nearly $7.1 billion per year. 31/ The value of the exports is estimated to reduce the total U.S. trade deficit (compared to the 2010 deficit) by between 0.6 and 1.4 percent. 32/

- Increased Tax and Royalty Revenues: Estimated tax revenues generated as a result of the construction phase of the DCP liquefaction project peak in 2014 with a total of $130-$163 million nationally. 33/ Total U.S. taxes are estimated to increase by nearly $11 million per year from 2018-40, not including income taxes, property taxes, or gross receipt taxes. 34/ In addition, the long-term operation of the Terminal is expected to produce up to $40 million per year of property tax revenues. 35/ In addition, upstream economic activity associated with gas production to support the incremental LNG exports is associated with $25 billion in government royalty and tax revenues to federal, state, and local governments over the 25-year period, with an average of approximately $1 billion in annual revenues. 36/ Another $9.8 billion in royalty income over the 25 years will be provided to landowners in the form of mineral leases. 37/

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31/ *See id.* at 41-42 and Table 19 "Range of Annual Positive Effect of LNG Export from Cove Point on U.S. Balance of Trade."

32/ *Id.* at 2.

33/ *Id.* at 17, Figure 9 "Total Tax Revenue Trends, 2011-2018, Facility Construction/Operation (2011$)."

34/ *Id.* at 19, Table 5 "Tax Impacts, 2011-2018, Facility Construction/Operations (2011$)."

35/ This property tax estimate was internally generated by DCP, and is not based on the Economic Benefits Study.

36/ Economic Benefits Study at 32, Table 11 "U.S. Taxes and Royalties from Upstream Oil and Gas Expenditures and Production Associated with LNG Exports from Cove Point (2011$)."

37/ Economic Benefits Study at 21.

- Environmental Benefits: As the cleanest-burning fossil fuel, natural gas significantly reduces total greenhouse gas emissions when used as a substitute for coal or fuel oil. To the extent that the up to 1 Bcf/d of LNG exported from the Cove Point LNG Terminal is used as substitute for coal and fuel oil in other countries, it will reduce global greenhouse gas emissions significantly over the requested 25-year export term.

### 1. Projected Gas Supplies

The main focus of the DOE/FE's public interest analysis for gas export authorizations has been the projected domestic need for the gas. DOE has historically determined whether there is a domestic need for the gas proposed for export by comparing the total volume of natural gas reserves expected to be available to produce with the expected gas demands during the proposed period of exports. 38/ In light of the dramatic recent successes of domestic gas production, such an analysis clearly demonstrates that the sufficient reserves now exist to satisfy domestic demand as well as the proposed LNG exports.

The most recent estimate by the EIA of dry natural gas reserves in the United States is 2,543 trillion cubic feet ("Tcf"). 39/ This latest EIA reserve estimate compares to EIA's 2005 reserve estimate of about 1,600 Tcf. 40/ The dramatic increase of nearly sixty percent in just six years has been driven by the phenomena of domestic shale gas, resulting from the refinement and improvement in drilling technologies. EIA's 2011 estimate of technically

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38/ *Yukon Pacific*, Order No. 350; *Phillips Alaska*, Order No. 1473; *ConocoPhillips Alaska*, Order No. 2500.

39/ Newell, EIA, *Shale Gas and the Outlook for U.S. Natural Gas Markets and Global Gas Resources*, presentation to the Organization for Economic Cooperation and Development (OECD), June 21, 2011, available at http://www.eia.gov/pressroom/presentations/newell_06212011.pdf. See also US EIA, 2011 AEO, http://www.eia.doe.gov/forecasts/aeo/pdf/0383(2011).pdf

40/ *See* Newell presentation, *supra.* at 13.

recoverable reserves includes 827 Tcf of shale reserves, compared to the 347 Tcf of shale reserves included in its AEO just one year before and the less than 100 Tcf included as recently as 2006. 41/ Similarly, 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), including 687 Tcf of shale gas. 42/

The increase in reserves has mirrored the dramatically increased production levels in recent years, also driven by shale gas. U.S. natural gas production increased from about 50.5 Bcf/d in May 2005 to about 60.9 Bcf/d in May 2011. 43/ Shale gas production from eight major basins under development in North American grew from 3 Bcf/d in the first quarter of 2007 to 16.5 Bcf/d in first quarter of 2011, an increase of more than 525 percent in just over four years. 44/ Total U.S. shale production in the first quarter of 2011 was approximately 18 Bcf/d. 45/

Navigant projects gas production to continue to grow steadily. In its Reference Case, Navigant projects North American produced supply to reach 105 Bcf/d by 2040, with U.S. production of more than 81 Bcf/d. 46/ Navigant expects more than half of the 2040 U.S. production of over 29.5 Tcf to be from shale gas plays. EIA also projects shale gas production to continue to increase strongly through 2035 in its 2011 AEO reference case, growing almost fourfold from 2009 to 2035. EIA's reference case forecasts total domestic natural gas production to grow from 21.0 Tcf in 2009 to 26.3 Tcf in 2035, with shale gas production

41/ *See* Newell presentation, *supra.* at 13, and the 2011, 2010, and 2006 editions of EIA's AEO.

42/ Potential Gas Committee press release, April 27, 2011, http://potentialgas.org/

43/ Navigant Supply Report at 8 & Figure 4.

44/ *Id.* at 9 & Figure 6.

45/ Id. at 15.

46/ *Id.* at 4-5, Figures 1 and 2.

growing to 12.2 Tcf in 2035, amounting to 47 percent of total U.S. production -- compared to its 16-percent share in 2009. 47/

As explained in the Navigant Supply Report (at page 15, Figure 10 & Table 1), EIA has historically been conservative when adding into its projections the latest information about the domestic shale gas resource.  As recently as the 2010 AEO, EIA projected shale production **for 2035** of about 16.5 Bcf/d – less than the actual production this year.  The 2011 AEO now projects shale production in 2035 of about 33.5 Bcf/d (more than twice what it predicted the prior year).  Yet, the current shale production levels (of 18 Bcf/d) have already outpaced the forecast for 2011 in EIA's 2011 AEO of 15 Bcf/d.  In contrast, the Navigant Supply Report forecasts shale production of more than 46 Bcf/d in 2035.  Navigant projects more shale gas to be brought on by 2020 than EIA does in its 2011 AEO; after 2020, the growth rates projected by Navigant and EIA are roughly the same. 48/

One particularly important shale play is the Marcellus Shale formation, which is located in Appalachia near the Cove Point LNG Terminal 49/ and essentially underlies the DTI system which interconnects with the Cove Point pipeline.  Marcellus production has increased from almost nothing in mid-2008 to over 2.5 Bcf per day in June 2011. 50/  Just this run-up in initial Marcellus production dwarfs the amount of LNG that DCP proposes to export.  More significantly, a recent study conducted by Penn State University estimates that Marcellus

47/ US EIA, 2011 AEO, Executive Summary, http://www.eia.doe.gov/forecasts/aeo/pdf/0383(2011).pdf

48/ Navigant Supply Report at 14-15, Figure 10.

49/ *See* Navigant Supply Report at 10-11.

50/ Navigant Supply Study at 30, Figure 16.  *See also The Pennsylvania Marcellus Shale Natural Gas Industry: Status, Economic Impacts and Future Potential*, Penn State University, July 20, 2011, Executive Summary (graphing the increase in Marcellus gas, and NGL production, from Q1 2009 to Q4 2010).

production will grow from 327 MMcf/d during 2009 to 13.5 Bcf/d by 2020. 51/ According to this study, the Marcellus Shale has the potential to be the second largest natural gas field in the world (behind only the South Pars/Asalouyeh field shared between the nations of Iran and Qatar) and its gas, when converted to British Thermal Units (BTUs), could be equivalent to the energy content of 87 billion barrels of oil, enough to meet the demand of the entire world for nearly three years. 52/ Similarly, Dr. Terry Engelder of Penn State has estimated that the Marcellus Shale alone has a 50 percent chance of containing 489 Tcf of recoverable gas. 53/ In 2010, the U.S. consumed about 24 Tcf, or less than 5 percent of the Marcellus potential. 54/ The recent estimate by the U.S. Geological Survey ("USGS") of the "mean undiscovered natural gas resource base" for the Marcellus of 84 Tcf is not (contrary to some press reports) inconsistent with larger reserves estimates by EIA and others: indeed, the USGS estimate seems to be *additive* to the EIA estimate. 55/

Other new shale resource plays are being identified at a high rate. EIA's 2011 map of shale gas plays included several shale plays (including the Niobrara, Heath, Tuscaloosa, Excello-Mulky and Monterey) that were not included on the 2010 version, and enlarged significantly the

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51/ *The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update,* Penn State University, May 24, 2010, page 19.

52/ *Id.*

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

54/ Navigant Supply Report at 11.

55/ *Id.* at 28. *See also* Marcellus Shale Coalition press release, "Myth vs. Fact: USGS/EIA Marcellus Data" (Aug. 30, 2011), available at http://marcelluscoalition.org/2011/08/myth-vs-fact-usgseia-marcellus-data/

areal extent of other plays (notably the Eagle Ford). 56/ As Navigant concludes, "North America is clearly in the early phases of discovery for this resources." 57/

Nevertheless, Navigant's forecast conservatively assumes the addition of no new gas supply basins (shale or otherwise) beyond those already identified. Moreover, Navigant's estimate of the production capacity for each shale play is based on currently available empirical production data. 58/ This approach has the effect of under-estimating the production of shale plays that are now in the early phase of development. A key example of significant importance to the export of LNG from the Cove Point LNG Terminal is the Utica Shale, which is well-situated (very near the DTI system) to provide supply to DCP's customers.

Navigant assumes in its Pricing Study that the Utica Shale will produce only 0.9 Bcf/d in 2040 (from its Canadian portion, with no production at all in the U.S.), while noting that "it is arguable that the Utica Shale could be producing many multiples of that number by that date, given the rapid run-up of development of other liquids-rich shales such as the Eagle Ford." 59/ Public statements by production companies active in developing the Utica support the view that it will be a significant addition to future production. Numerous projects have been announced in recent weeks that reflect burgeoning interest in the development of the Utica Shale. 60/ Chesapeake Energy Corporation ("Chesapeake") has leased 125 million acres of the Utica in

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56/ Navigant Supply Report at 10 & Figure 7.

57/ *Id.* at 10.

58/ Navigant Pricing Report at 7. The Pricing Report does assume the addition of some new supply in the Aggregate Export and Extreme Demand scenarios (described below), but only from existing, quantified reserves.

59/ Navigant Pricing Report at 5 and 8. *See also* "Utica Shale – The Natural Gas Giant Below the Marcellus?", available at http://geology.com/articles/utica-shale/

60/ Navigant Supply Report at 28-29. The report notes, in addition to the Chesapeake announcement, that (1) CONSOL Energy and Hess Corporation have agreed to form a joint venture that will develop nearly 200,000 acres in the Utica Shale and (2) Petroleum Development Corporation has executed agreements to acquire up to 100,000 acres in the wet gas and oil phases of the Utica Shale.

eastern Ohio and has five rigs operating in a liquids-focused effort that is likely to produce natural gas as well; Chesapeake indicates it may have 40 rigs in the Utica by 2014. Chesapeake's CEO recently announced that the Utica Shale could be worth $500 billion, that he expects around ten companies to compete in the play, and that Chesapeake alone plans to drill as many as 12,500 wells in the Utica. 61/ Moreover, an economic impact study recently released by the Ohio Oil & Gas Energy Education Program estimated that by 2015 development of Ohio's Utica formation will create more than 204,000 jobs, increase economic output by over $22 billion, wages by over $12 billion, and local government tax revenues by $240 million. 62/ If these projections are even close to correct, the Utica formation will be another significant source of supply for LNG exports by DCP, which is not included in the Navigant analyses. And providing a market demand for gas to help support development of the Utica Shale will be another benefit of DCP's export project.

### 2. Projected Gas Demand

U.S. gas demand in 2011 was approximately 65.6 Bcf/d. Navigant projects demand to increase steadily in the future, with the overwhelming majority of the growth expected to come from electric generation. 63/ Navigant expects electric generation gas demand to increase at an annual rate of 4.9 percent through 2015, and at an annual rate of 2.1 percent through 2040. In contrast, Navigant projects North American gas industrial demand to grow annually by an

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61/ "McClendon Values Utica Shale at Half a Trillion Dollars, NGI Reports," Sept. 21, 2011, available at http://www.businesswire.com/news/home/20110921006942/en/McClendon-Values-Utica-Shale-Trillion-Dollars-NGI

62/ "Ohio's Natural Gas and Crude Exploration and Production Industry and the Emerging Utica Gas Formation, Economic Impact Study, Ohio Oil & Gas Energy Education Program (Sept. 2011), available at http://www.oogeep.org/downloads/file/Economic%20Impact%20Study/Ohio%20Natural%20Gas%20and%20Crude%20Oil%20Industry%20Economic%20Impact%20Study%20September%202011.pdf

63/ Navigant Supply Report at 15-16.

average rate of 0.5 percent, and residential, commercial and vehicle demand for gas to grow at just 0.2 percent per year.

Navigant's sector-by-sector outlook for gas demand is explained in the Navigant Supply Report at pages 16-17 and illustrated in its Figure 11. In total, Navigant projects U.S. consumption (in its Reference Case) to increase to approximately 30.7 Tcf by 2040, compared to about 24 Tcf this year. Supply and demand are two parts of a single dynamic, with reliable demand a key to underpinning the growth of reliable supply and a sustainable gas market. Navigant concludes that LNG exports from the U.S. have the potential to provide a steady, reliable baseload market that will underpin on-going supply development, and help keep domestic gas prices stable. 64/ In the coming years, LNG exports should provide a new market in the currently oversupplied natural gas market in the U.S., in which the slow development of new markets for natural gas is the only thing currently restricting even more gas resource development. 65/ An example is the current situation with Marcellus supply, where producers are searching for new markets for their gas (as evidenced by the surge in pipeline expansions in the area). With LNG export authorization, DCP would be able to provide an additional outlet for these growing domestic gas supplies, encouraging further development.

Navigant also evaluated the potential concern that exporting LNG from North America will tend to bring overseas LNG pricing, which has historically been linked to higher-priced oil, into the North American gas market. 66/ 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. Given the level of North American gas reserves compared to any

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64/ *Id.* at 3 & 17; Navigant Pricing Report at 9.

65/ Navigant Supply Report at 17.

66/ Navigant Pricing Report at 9.

reasonable expectation of demand (discussed below), Navigant concludes that domestic consumers will not be exposed to overseas LNG prices. Navigant's modeling and market research indicates that it is very unlikely that the projected levels of LNG exports will increase the need for significant amounts of imported LNG. It is more likely that spot LNG cargos from overseas will land from time to time in the U.S. and accept U.S. domestic pricing, as overseas LNG production capacity is projected to grow. DOE/FE itself reached a similar conclusion in its recent *Sabine Pass* order. 67/

### 3. Supply Is More Than Sufficient to Satisfy Demand, Including LNG Exports

EIA's current estimate of reserves of 2,543 Tcf represents more than 100 years of supply at current usage rates of approximately 24 Tcf per year. Even at the 2040 rate of consumption estimated by Navigant of 30.7 Tcf per year, these current reserves represent 83 years of supply. Navigant's "Extreme Demand Case" (which, as discussed below, includes 7.1 Bcf/d of LNG exports, greenhouse gas regulation, and dramatically increased use of natural gas vehicles) projects 2040 demand of 32.7 Tcf. Even this aggressive demand estimate for 2040 would represent just 1.3 percent of EIA's current estimate of reserves, leaving about 77 years of supply to meet demands at that level. This result also assumes very conservatively, and unrealistically, that the amount of reserves will not increase by 2040 over EIA's current estimate.

This showing of the comparative balance between supply reserves and demand, including for the proposed gas exports, convincingly demonstrates that the requested authorization is consistent with the public interest. DOE/FE historically has focused on this issue of the adequacy of reserves compared to expected demand, and authorized exports based

67/ *Sabine Pass*, Order No. 2961 at 34.

on much less robust supply scenarios. 68/ For instance, in 1989, DOE/FE authorized the export of LNG from the North Slope of Alaska of up to 14 mmta in the face of forecasts claiming that proved reserves would be entirely depleted by the end of the next decade, reasoning that new reserves would be added over time. 69/ Just this year, of course, DOE/FE authorized the export of LNG from Sabine Pass based on "substantial evidence showing an existing and projected future supply of domestic natural gas sufficient to simultaneously support the proposed export and domestic natural gas demand both currently and over the 20-year term of the requested authorization." 70/

All available evidence and projections show that current gas reserves are ample to support all expected demand, including LNG exports, at least through 2040. Accordingly, there is no "domestic need" for the gas that DCP proposes to export. And the exports do not pose any possible threat to the security of domestic natural gas supplies. Therefore, the proposed exports are consistent with the public interest.

**4. Any Effect of LNG Exports From DCP On Domestic Prices Would Be Minor**

The Policy Guidelines (as reflected in the quotations in Section V.A above) establish that the federal government's policy is not to manipulate energy prices by approving or disapproving import or export applications. Rather, the Nation's policy is that markets, and not the government, should allocate resources and set prices, and that free trade in natural gas on a market-competitive basis benefits consumers and promotes the public interest.

Although concern about possible price levels appears arguably outside the scope of the Policy Guidelines, DOE/FE evaluated in its recent order authorizing exports from Sabine Pass the

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68/ *See Yukon Pacific*, Order No. 350; *Phillips Alaska*, Order No. 1473.

69/ *Yukon Pacific*, Order No. 350 at 19-22.

70/ *Sabine Pass*, Order No. 2961 at 29.

projected impact of LNG exports on domestic gas prices. In that order, DOE/FE concluded that the export authorization would result in “a modest increase” in domestic gas prices reflecting the increasing marginal costs of additional domestic production for the LNG exports. 71/ This modest projected increase was viewed as not inconsistent with the public interest.

The attached Navigant Pricing Report provides a detailed analysis of the possible effect on prices of LNG exports in general, and from the Cove Point LNG Terminal in particular. The price forecasts build on Navigant’s Spring 2011 Reference Case and the Navigant Supply Report previously described. Thus, the pricing forecasts incorporate Navigant’s approach of conservatively assuming the addition of no new gas supply basins beyond those already identified, and estimating the production capacity for each shale play based only on available empirical production data. As a result, the forecasted price effects likely overstate the impact on prices, since additional new reserves and production will almost certainly be added over time. In addition, Navigant does not introduce any currently unannounced infrastructure projects into its model and limits infrastructure expansion to instances where existing pipelines become constrained, then adding only sufficient capacity to relieve the constraint. 72/ This conservative approach ignores the possibility of major new infrastructure that can restrain possible future price increases by transporting growing supplies to areas of high demand.

The Navigant Pricing Report models four scenarios: (1) a Reference Case, (2) the Cove Point Export Case, (3) the Aggregate Export Case, and (4) the Extreme Demand Case. In all scenarios, Navigant studied price impacts over time through 2040 at Dominion South Point (a major, active trading hub on the DTI system) to focus on the potential price effect on the key

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71/ *Sabine Pass*, Order No. 2961 at 29 & Appendix A.

72/ Navigant Pricing Report at 9-10.

market in the vicinity of the Cove Point LNG Terminal, as well as the Henry Hub (the underlying physical location of the natural gas NYMEX futures contract). Information on the types of supply and sectors of demand over time is detailed for each scenario. All prices in the report (and referenced in this summary of the results) are adjusted for assumed future inflation and shown in constant 2010 dollars.

The Reference Case reflects Navigant's Spring 2011 modeling with steadily increasing demand, as previously described. This case also assumes the operation of two North American LNG export facilities – Sabine Pass in Louisiana and Kitimat in British Columbia – beginning in 2015. The Cove Point Export Case adds 1 Bcf/d of additional LNG exports from the Cove Point LNG Terminal. The Aggregate Export Case adds another 3.4 Bcf/d of LNG exports, to reflect proposals by the Lake Charles LNG facility in Louisiana and the Freeport LNG facility in Texas, with all the capacity assumed to be added between 2017 and mid-2019. Finally, the Extreme Demand Case further increases demand to reflect both increased natural gas vehicle demand (taken from an EIA 2011 AEO scenario) and higher electric generation gas demand resulting from greenhouse gas reduction legislation. Navigant also modeled variations of the Aggregate Export Case and the Extreme Demand Case with no LNG exports from Cove Point, to isolate the possible price impact of approval of this Application.

In its beginning Reference Case, 73/ Navigant projects average annual prices at the Henry Hub to remain below $5.00 per MMBtu through 2020, to remain below $6.00 per MMBtu until 2029, and to reach $8.64 per MMBtu in 2040. These prices reflect assumptions of steadily increasing demand, with consumption rising from about 24 Tcf in 2011 to 30.7 Tcf in 2040. Prices at Dominion South Point are projected to be slightly lower in 2015 than in 2011, then to

73/ See Navigant Pricing Report at 14-16.

rise more slowly than the Henry Hub prices throughout the forecast period, as the abundant Marcellus Shale supply increasingly becomes the dominant supply in the region. The projected Dominion South Point prices reach only $6.01 per MMBtu in 2040, significantly lower than the Henry Hub price. The negative basis at Dominion South Point is expected to develop due to the supply strength and ramping up of Marcellus production resulting in Dominion South Point prices that are increasingly lower over time than Henry Hub prices that are influenced by broader market factors. 74/

These relatively low projected prices (as well as all the prices detailed below) should be contrasted with actual market prices, as well as expectations for the future, just a few years ago. Annual average Henry Hub spot prices per MMBtu, prior to the recent shale gas boom, were $7.91 in 2005, $6.62 in 2006, $6.20 in 2007, and $8.25 in 2008. 75/ Even more dramatically, the EIA as recently as its 2009 AEO reference case projected that prices would be $6.96 in 2010, $7.77 in 2020, and $9.68 in 2030 (adjusted to 2010 dollars for purposes of comparison). 76/ In contrast, Navigant's Cove Point Export Case projects prices in 2030 to be $6.61 – much less than was projected in the 2009 AEO reference case. Even in the Extreme Demand Case, the 2030 prices projected by Navigant are less than EIA's projection in 2009.

In the Cove Point Export Case, Navigant added 1 Bcf/d of exports from Cove Point to the Reference Case starting in 2016, with no other changes in the model. 77/ This small

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74/ *Id.* at 5.

75/ *Platt's Inside FERC*.

76/ Annual Energy Outlook 2009 with Projections to 2030, Table 13, U.S. Energy Information Administration, available at http://www.eia.gov/oiaf/archive/aeo07/aeoref_tab.html, cited in Navigant Pricing Report at 5-6 & Table 2.

77/ *See* Navigant Pricing Report at 17-20. The primary Cove Point Export Case assumes the Cove Point LNG Terminal is bi-directional, allowing both exports and imports as warranted by market prices and customer decisions. Navigant also modeled an Alternative Case for the Cove Point Export Case, under which Cove Point is assumed to increase in demand -- adding 1 Bcf/d to the 2011 demand of 65.6 Bcf/d and projected 2040 demand of 84 Bcf/d in the Reference Case – results in a small projected increase in prices. In this scenario, Henry Hub prices exceed $6.00 per MMBtu (still a relatively low price compared to recent years prior to the shale boom) for the first time in 2027 – two years earlier than in the Reference Case. Compared to the Reference Case, Henry Hub prices with the Cove Point exports added are projected to be 5.7 percent higher in 2020, 4.1 percent higher in 2030, and 6 percent higher in 2040. For Dominion South Point, the projected prices increases are larger initially but smaller over time, as Marcellus supplies dwarf the exports: 6.2 percent in 2020, 3.6 percent in 2030, and 2.7 percent in 2040. These percentage increases are compared to historically low gas prices.

DCP believes that the projections likely overstate the price effect resulting from LNG exports from the Cove Point LNG Terminal, both at the outset and longer term. To begin with, the new demand is added in a block, upsetting an existing supply/demand balance in the model, resulting in seemingly large price jumps. Yet, in reality unlike economic modeling, given the long lead time associated with an LNG liquefaction project like DCP's, as well as the current ability of shale production to increase if demand is added, producers may plan in advance and add incremental supply to coincide with onset of LNG export operations – minimizing the initial price increase associated with new LNG export demand projected by Navigant. 78/ Producers presumably will have long-term contracts to supply natural gas to DCP's export customers and, therefore, will be obligated to match production to export related demand. More fundamentally, Navigant's conservative assumptions noted above about supply (essentially no

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operate only as an export facility, with no LNG imports at the Terminal. No significant differences in supply, demand or prices resulted from this changed assumption. *Id.*

78/ Navigant itself makes this point in its Pricing Report at 7.

new supply over time) and infrastructure (no unannounced projects added) inherently overstate the price effect, especially in the longer run. Accordingly, the price impacts forecast in the Navigant model should be considered the maximum possible impacts.

Navigant's third scenario, the Aggregate Export Case, assumes that the export projects proposed by Lake Charles LNG facility in Louisiana and the Freeport LNG facility in Texas also are built and added into demand between 2017 and mid-2019. 79/ This scenario makes no judgment about whether any of the proposed facilities will be approved, supported by customers, financed and constructed, but rather conservatively assumes that they all will come on-line. Moreover, Navigant assumes (conservatively for purposes of modeling the price effects) that all the export facilities will operate at 90 percent of capacity – a very high utilization rate since customers likely would not take advantage of contractual rights to export as much as operationally possible at all times. The model projects increases, above the Cove Point Export Case, in Henry Hub prices of 11 percent in 2020, 3.5 percent in 2030 and 5.3 percent in 2040. The projected price effects at Dominion South Point are 9.9 percent in 2020, 6.5 percent in 2030, and 5.6 percent in 2040. The near-term price effect, again, is likely overstated as it reflects the sudden addition, into a model of equalized supply and demand, of significant new demand from North American LNG exports (here, a total of 7.1 Bcf/d) in a very short period of time. Increased production to meet the LNG exports as they come on-line would reduce the near-term (2020) effect. And, again, new supply conservatively omitted from the model would reduce the price effect in later years.

Navigant also modified its Aggregate Export Case to eliminate any LNG exports from Cove Point – to allow a comparison of what portion of the projected price increase is

79/ See Navigant Pricing Report at 21-25.

attributable the LNG export projects other than DCP. 80/ The "Aggregate Export Without Cove Point Case" also may be compared to the "Cove Point Export Case" to compare the scenario of adding to the Reference Case either (a) just Cove Point exports and (b) just the Freeport and Lake Charles projects. The Henry Hub prices are notably lower in all years with Cove Point exports compared to the scenario with the other export projects and not Cove Point; the Dominion South Point price is lower in 2020, but higher in 2030 and 2040, with just Cove Point exports compared to with the other export projects but not Cove Point. These results logically show that exports from DCP affect prices at Dominion South Point more than exports from the Gulf Coast would. Of course, projected Dominion South Point prices are lower than Henry Hub over time as a result of access to the nearby Marcellus Shale, while the Henry Hub prices are more affected by the assumption of three Gulf coast export projects.

For the fourth scenario, Navigant included an Extreme Demand Case showing the highest projected prices, with assumed significant new gas demand as a result of greenhouse gas regulation and dramatically increased natural gas vehicle usage. 81/ In this scenario, U.S. gas demand increases from the 2011 level of 65.6 Bcf/d to 74.5 Bcf/d in 2020, 83.4 Bcf/d in 2030, and 90.1 Bcf/d in 2040. As a result, Henry Hub prices increase by another 5.4 percent in 2020, 17.4 percent by 2030, and 16.2 percent by 2040. The price increases at Dominion South Point are much less pronounced in the later years: increasing by the same 5.4 percent in 2020, but 11.9 percent in 2030, and just 4.8 percent in 2040. Navigant's approach of adding no new, not currently known, supply in this scenario again inflates the results and seems particularly conservative, and unrealistic, in the assumed world of much greater demand for gas.

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80/ *Id.* at 24-25.

81/ *Id.* at 26-30.

Furthermore, the competitive market will determine the level of LNG exports and imports to the U.S. and, thereby, provide a restraining mechanism on domestic gas prices. If domestic prices rise significantly with increased demand, they could exceed prices available around the world. In that event, LNG would once again be imported into the U.S., rather than exported.

Finally, Navigant modified the Extreme Demand scenario to eliminate any LNG exports from Cove Point, in order to isolate the predicted portion of these increased prices that would relate to the exports proposed here. 82/ Compared to the unaltered Extreme Demand scenario, the elimination of Cove Point exports would decrease Henry Hub prices by 5.2 percent in 2020 but by only 1.7 percent in 2040. In other words, while Henry Hub prices are projected to be quite high in 2040 under the Extreme Demand Case assumptions, very little of the price increase would be attributable to LNG exports from Cove Point. This conclusion, of course, is logical, since the 1 Bcf/d of DCP exports would be a very small portion of the assumed increase in demand from 2011 to 2040 of nearly 25 Bcf/d.

In summary, DCP submits that the conclusion from all of the extensive Navigant pricing analysis is that, even with very conservative assumptions, LNG exports from the Cove Point LNG Terminal will have no more than a very modest impact on domestic gas prices. Therefore, any price effect would not render the proposed exports contrary to the public interest.

**5. Benefits of LNG Exports From DCP**

The requested export authorization also is in the public interest because it will benefit the national, regional and local economies and create jobs for Americans. The benefits of the exports are detailed in the ICF Economic Benefits Study (Appendix C) and summarized here. ICF assessed the national and regional impacts of the new DCP facility, quantifying the direct

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82/ *Id.* at 29-30.

and secondary benefits of the project. The Economic Benefits Study discusses the results in the creation of new jobs and the impact on the existing economy (in terms of income, wages, taxes, etc.). The Economic Benefits Study also details the macro-level, national and international implications of the DCP project, including the impact on the U.S. balance of trade and the economic impact of upstream expenditures due to the significant new demand for the gas to be exported. The Economic Benefits Study is premised on a project with inlet capacity of 0.75 Bcf/d, assumed to be operated at a 90 percent of capacity. 83/ To the extent that DCP constructs a larger project – consistent with the requested export authorization for up to 1 Bcf/d – the economic benefits will be even greater. These benefits overwhelm any perceived detriment of modestly increased domestic natural gas prices.

The most basic benefit of the proposed LNG exports will be to encourage and support increased domestic production of natural gas, and NGLs. The DCP liquefaction project would allow domestic natural gas that might otherwise be shut-in as a result of a lack of market demand to be available for sale into the global LNG market. The steady new demand associated with LNG exports can spur the development of new natural gas resources that might not otherwise be developed. In the recent order authorizing LNG exports from Sabine Pass, DOE/FE concluded that it was "persuaded that directionally, natural gas production associated with exports... will result in increased production that could be used for domestic requirements if market conditions warrant such use. Overall, this will tend to enhance U.S. domestic energy security." 84/ Navigant reached the same conclusion, as previously noted.

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83/ Economic Benefits Study at 1, note 1.

84/ *Sabine Pass*, Order No. 2961 at 35.

Moreover, the development of the gas resources for export by DCP will also result in the increased production of NGLs. 85/ In its *Sabine Pass* order, DOE/FE found that the applicant demonstrated that the production of domestic natural gas will yield NGLs which will, in part, offset the need to import oil. 86/ NGLs are used as home heating fuels, refinery blending and agricultural crop drying, and the U.S. petrochemical industry uses ethane in particular as a feedstock in numerous applications. New supplies of NGLs from shale production (including the Marcellus, and Utica) create a new competitive advantage for the industry that presents a tremendous opportunity to strengthen U.S. manufacturing, boost economic output and create jobs. 87/ Indeed, the recent development of shale gas has already lead the U.S. petrochemical industry to announce significant expansions of petrochemical capacity, reversing a decades long decline. 88/ The DCP liquefaction project will further this trend by supporting further shale development, particularly in the Marcellus and Utica Shales. ICF estimates that LNG exports from the Cove Point LNG Terminal will result in the incremental production of approximately 8.5 million barrels of hydrocarbon liquids per year, with a market value of approximately $1.2 billion per year (in real 2011 dollars). 89/

Of particular importance in the current economic climate, the DCP liquefaction project also will result in new jobs for American workers, consistent with the Administration's 2010

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85/ *See* Economic Benefits Study at 38-39.

86/ *Sabine Pass*, Order No. 2961 at 36.

87/ *See* American Chemistry Council (ACC). "Shale Gas and new Petrochemicals Investment: Benefits for the Economy, Jobs, and U.S. Manufacturing." Economics and Statistics, ACC, March 2011, available at http://www.americanchemistry.com/ACC-Shale-Report.

88/ *Id.*

89/ Economic Benefits Study at 38, Table 16 "U.S. Volume, Value, and Economic Impact of Incremental Hydrocarbon Liquids Associated with LNG Export from Cove Point."

National Export Initiative ("NEI"). 90/ The NEI is intended "to improve conditions that directly affect the private sector's ability to export. The NEI will help meet [the] Administration's goal of doubling exports over the next 5 years by working to remove trade barriers abroad, by helping firms -- especially small businesses -- overcome the hurdles to entering new export markets, by assisting with financing, and in general by pursuing a Government-wide approach to export advocacy abroad, among other steps." 91/ In announcing the NEI, President Obama explained:

> Creating jobs in the United States and ensuring a return to sustainable economic growth is the top priority for my Administration. A critical component of stimulating economic growth in the United States is ensuring that U.S. businesses can actively participate in international markets by increasing their exports of goods, services, and agricultural products. Improved export performance will, in turn, create good high-paying jobs. 92/

The President returned to the theme of increasing exports to create jobs in the 2011 State of the Union Address, explaining:

> To help businesses sell more products abroad, we set a goal of doubling our exports by 2014 – because the more we export, the more jobs we create here at home. Already, our exports are up. Recently, we signed agreements with India and China that will support more than 250,000 jobs here in the United States. And last month, we finalized a trade agreement with South Korea that will support at least 70,000 American jobs. This agreement has unprecedented support from business and labor, Democrats and Republicans -- and I ask this Congress to pass it as soon as possible. 93/

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90/ NEI, Executive Order No. 13534, 75 Fed. Reg. 12433 (March 11, 2010).

91/ NEI, Section 1.

92/ *Id.*

93/ President Barack Obama, State of the Union Address (Jan. 25, 2011), transcript available at http://www.whitehouse.gov/the-press-office/2011/01/25/remarks-president-state-union-address

Still more recently, when introducing the American Jobs Act to a Joint Session of Congress, the President explained:

> Now it's time to clear the way for a series of trade agreements that would make it easier for American companies to sell their products in Panama and Colombia and South Korea – while also helping the workers whose jobs have been affected by global competition. If Americans can buy Kias and Hyundais, I want to see folks in South Korea driving Fords and Chevys and Chryslers. I want to see more products sold around the world stamped with the three proud words: "Made in America." That's what we need to get done. 94/

Approval of DCP's LNG export authorization is a concrete step to advance the NEI by making possible the sale of natural gas that is "made in America" around the world, creating American jobs in the process.

In order to export LNG from the Cove Point LNG Terminal, DCP will need to make a significant capital investment with additional annual expenditures to operate the new facility over the life of the exports. ICF concludes that DCP's project has the potential to create significant short-term economic activity in Maryland and the broader region during the construction phase, as well as during operations. ICF estimates that industry output impacts in 2015 will be between $355 million and $443 million in Calvert County, with an additional $130 million to $163 million throughout the rest Maryland. 95/ Furthermore, the DCP project will support the region by creating between $183 million and $230 million in value added (*i.e.*, the difference between the output of long-term expenditures and the expenditures for intermediate goods and services) within Calvert County and an additional $80 million to $100 million in the

94/ President Barack Obama, Address to a Joint Session of Congress (Sept. 08, 2011), transcript available at http://www.whitehouse.gov/the-press-office/2011/09/08/address-president-joint-session-congress

95/ See Economic Benefits Study at 16, Table 4 "Annual Industry Output, Facility Construction/Operation (2011$)."

rest of Maryland. 96/ Annual operations are expected to generate an additional $22 million in value added annually in the local economy from 2018 through 2040. 97/ More generally, ICF calculates $44 billion in industry value added associated with upstream expenditures of $32 billion to support LNG exports over a 25-year term. 98/

The economic value associated with the DCP project, along with the economic activity associated with the natural gas production supporting the LNG exports, will create thousands of new jobs. While many people may have a misperception that natural gas production benefits only major energy companies, the associated economic activity benefits the many smaller companies doing the work and hiring the needed employees.

In its Economic Benefits Study, ICF calculates that the short-term economic impacts from construction and operation of the DCP export project has the potential to support between 2,700 and 3,400 jobs in Calvert County, Maryland at its peak of construction activity (roughly equivalent to 12 percent of the county's total employment). 99/ Moreover, these activities could support over an additional thousand jobs in the rest of the State of Maryland. Furthermore, ICF estimates that thousands of more jobs would be added across the Nation, as the significant inter-linkages between various economic sectors provide a short-run boost to support employment not just in the localized region but across the entire country. 100/ For the period of operations from 2018-2040, ICF estimates that economic activity associated with

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96/ See Economic Benefits Study at 16, Table 3 "Annual Value Added Impacts, Facility Construction/Operation (2011$)."

97/ *Id.*

98/ See *id.* at 28, Table 9 "U.S. Value Added from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$)."

99/ *Id.* at 11, Table 2 "Annual Job-Year Impacts, Facility Construction/Operation (Job-years).".

100/ *Id.*

DCP's liquefaction project will result in the addition of 320 jobs across the Nation. 101/ ICF's study also shows that economic activity associated with the long-term upstream supply of natural gas for the LNG exports proposed by DCP will support an estimated 18,000 jobs annually over the life of the project. 102/

Significant tax revenue also will be generated as a result of the construction phase of the DCP project, and subsequent operations. ICF projects tax revenues for federal, state and local governments will peak in 2014 with a total of $130-163 million. 103/ The state and local taxes, which account for roughly 38 percent of the total tax revenues, include taxes generated in both Maryland and other states, because goods and services purchased in other states are used to supply the direct expenditures in Calvert County. ICF estimates an annual average of increased tax revenue from 2018-2040 for the U.S. as a whole of nearly $11 million. 104/ In addition to the taxes calculated by ICF, DCP estimates that the long-term operation of the Terminal will produce up to $40 million per year of property tax revenues.

In addition, upstream economic activity to support the incremental LNG exports is expected by ICF to lead to over $25 billion in increased government royalty and tax revenues to federal, state, and local governments over the 25-year period, with an average of approximately

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101/ *Id.*

102/ *Id.* at 24, Table 7 "U.S. Upstream Natural Gas Sector Annual Job-years Resulting from LNG Exports from Cove Point (Job-years)."

103/ *Id.* at 17, Figure 9 "Total Tax Revenue Trends, 2011-2018, Facility Construction/Operations (2011$ million)."

104/ *Id.* at 19, Table 5 "Tax Impacts, 2011-2018, Facility Construction/Operations (2011$)"

$1 billion in annual revenues. 105/ In addition, another $9.8 billion in royalty income over 25 years is expected for landowners in the form of mineral leases. 106/

Furthermore, granting DCP's requested export authorization also will help realign the U.S. balance of trade. 107/ The U.S. has experienced large balance of trade deficits for more than decade (although the rise in U.S. exports after the economic crisis somewhat realigned the trade balance). In 2010, the U.S. trade deficit in goods and services was $497.8 billion, up from $374.9 billion in 2009. 108/ More than half of the total trade deficit, over $265 billion, resulted from a negative balance in trade of petroleum products. 109/ Authorizing the export of LNG will help redress this balance, by allowing the U.S. to export some of its abundant natural gas. In a variation on the President's recent remarks: If Americans can buy Hondas and Kias, and fuel them with Middle Eastern oil, folks in Japan and South Korea should be able to burn American natural gas.

In its Economic Benefits Study, ICF calculates that DCP's proposed exports of LNG and associated NGLs can improve the U.S. balance of trade in a range from $2.8 billion to $7.1 billion per year over the 25-year forecast period. 110/ The expected value of the exports is estimated to reduce the U.S. trade deficit by between 0.6 percent and 1.4 percent, based on

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105/ *Id.* at 32, Table 11 "U.S. Taxes and Royalties from Upstream Oil and Gas Expenditures and Production Associated with LNG Exports from Cove Point (2011$ million)."

106/ *Id.*

107/ *Id.* at 41-42.

108/ Bureau of Economic Analysis, U.S. Dept. of Commerce, *U.S. International Trade in Goods and Services* (Feb. 11, 2011), available at http://www.bea.gov/newsreleases/international/trade/2011/pdf/trad1210.pdf at page 3.

109/ *Id.* at page 16.

110/ Economic Benefits Study at 41-42 and Table 19 "Range of Annual Positive Effect of LNG Export from Cove Point on U.S. Balance of Trade."

the 2010 deficit. 111/ In authorizing previous gas export applications, DOE/FE has recognized the positive role that LNG exports can have on the balance of trade with the destination countries. 112/ DOE/FE also acknowledge this benefit (and rejected countervailing arguments) in its recent order approving exports from Sabine Pass. 113/

Authorization of the DCP project also will result in international impacts that will benefit the U.S. in several ways. The following conclusions of DOE/FE when authorizing LNG exports from Sabine Pass order are equally applicable here:

> First, the export of natural gas produced in the United States will help to promote new international markets for natural gas, thereby encouraging the development of additional productive resources in this country (as discussed above) and internationally. Second, augmentation of global natural gas supplies will support efforts by overseas electric power generators to switch away from oil or coal, both more carbon intensive and environmentally damaging than natural gas. Third, an improvement in natural gas supplies internationally will help certain countries that currently have limited sources of natural gas supplies to broaden and diversify their supply base. This will contribute to greater overall transparency, efficiency, and liquidity of international natural gas markets, encouraging a liberalized global natural gas trade and a greater diversification of global natural gas supplies. Fourth, these developments may encourage the decoupling of international natural gas prices from oil prices in some international natural gas markets and may exert downward pressure on natural gas market prices in relation to oil prices in those markets. 114/

The international benefits of increased domestic gas production – which will be fostered by LNG exports – are further explained in the recent report by the James A. Baker III Institute

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111/ *Id.* at 2.

112/ *E.g.*, *ConocoPhillips*, Order No. 2731 at 10; *Freeport*, Order No. 2644 at 12; *Cheniere Marketing, inc.*, FE Docket No. 08-77-LNG, Order No. 2651 at 14 (June 8, 2009).

113/ *Sabine Pass*, Order No. 2961 at 35-36.

114/ *Id.* at 37.

for Public Policy at Rice University. 115/ That report highlights the broad effects that new shale discoveries are having on our Nation's energy security, and explains the added security and stability that increased American natural gas reserves will bring around the world, lessening the many thorny entanglements that our dependence on foreign energy sources brings. The report also details the numerous benefits that shale gas will have on a global scale, from eliminating demand for imports of foreign LNG to the U.S., to reducing the possibility of a natural gas "OPEC," weakening the energy stranglehold held by certain countries, and helping curb America's dependence on Middle East oil.

This section summarizes the many benefits of authorizing LNG exports from the Cove Point LNG Terminal. All of these benefits demonstrate that granting DCP's requested export authorization will not be inconsistent with (indeed, will benefit) the public interest.

## VI. DOE'S CONTINUING DUTY TO PROTECT THE PUBLIC INTEREST

In its recent *Sabine Pass* order, DOE/FE noted that the present and currently projected gas supply and demand conditions may not continue over the duration of a long-term export authorization. 116/ Furthermore, DOE/FE noted its statutory authority, "after opportunity for a hearing and for good cause shown, to make a supplemental order as necessary or appropriate to protest the public interest," as well as "to perform any and all acts and to prescribe, issue, make, amend or rescind such orders, rules, and regulations as it may find necessary or appropriate" to carry out its responsibilities. 117/

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115/ "Shale Gas and U.S. National Security," Medlock, Myers Jaffe, and Hartley, published by the James A. Baker III Institute for Public Policy (July 19, 2011).

116/ *Sabine Pass*, Order No. 2961 at 31-33.

117/ *Id.* at 32-33 & note 45.

DCP recognizes the uncertainty of the future and the agency's statutory authority, but respectfully submits that the prospect of future changes in export authorization may present risks that will undermine the needed investment in LNG export projects. DCP anticipates making a significant capital investment in its liquefaction project, and its customers likely will be making their own billions of dollars of investments in the related gas supply. Moreover, the destination markets will depend on the anticipated LNG supply from the U.S. to meet their future needs. All of these investments will be made in reliance upon an authorization issued by DOE/FE. If terminal developers like DCP, and their customers, cannot rely on an export authorization issued by DOE/FE, the needed investments may not be made. In that event, the great benefits of exports of the Nation's abundant natural gas supplies will be lost.

Accordingly, DCP urges DOE/FE to ensure the sanctity of its export authorizations once issued, so that investments can be made with greater certainty. At a minimum, DOE/FE should clarify the following points concerning any future modifications of the authorization to be issued here. First, in its consideration of any future modification of the authorization, DOE/FE will fully recognize the significant and reasonable reliance of DCP and its customers on its export authorization. Second, any change in the authorization would require a showing that continuation of the existing authorization would be contrary to the public interest (consistent with the statutory standard). Third, a change in the existing authorization will be made only if this showing is proven by clear and convincing evidence, meaning that the threat to the public interest must be highly and substantially more probable to be true than not and DOE/FE must have a firm belief or conviction in the existence of a true threat to the public interest. Finally, the burden of proof will be on an advocate of a change in the authorization (and DOE/FE) to satisfy this showing and justify the change in its previously issued authorization.

DCP respectfully submits that these clarifications likely reflect DOE/FE's intent with respect to possible future modification of its LNG export authorization. Yet, the clarifications are necessary to reassure the parties investing in such projects and allow them to properly assess the risk of a future change in export authorizations. Lack of clarity on this issue (or the appearance of too cavalier an attitude about the possibility of modifying or rescinding export authorizations relied upon by parties) will chill the prospect of beneficial export projects and creation of new American jobs at a time when they are desperately needed.

## VII. ENVIRONMENTAL IMPACT

As previously noted, in order to accommodate the proposed export activities, construction of new facilities at the Cove Point LNG Terminal will be required. The facilities will be designed to minimize or mitigate any environmental or other adverse impacts. Therefore, the proposal does not constitute a major federal action significantly affecting the quality of the human environment, within the meaning of the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321, *et seq*.).

DCP plans to file an application with the FERC for the necessary authorizations for facilities to allow for the liquefaction of domestically produced natural gas and export of LNG from the Cove Point LNG Terminal. An environmental review under NEPA will be completed by FERC prior to granting DCP authorization. The authorization requested here, as a practical matter, will not be actionable until the FERC grants DCP authorization. DCP requests that DOE/FE issue a conditional order authorizing the export of LNG, conditioned on completion of the environmental review by FERC.

## VIII. APPENDICES

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

Appendix A: Navigant Supply Report

Appendix B: Navigant Price Report

Appendix C: ICF Economic Benefits Study

Appendix D: Verification

Appendix E: Opinion of Counsel

## IX. CONCLUSION

Based on the reasons set forth above, DCP respectfully requests that the DOE/FE grant DCP authority for its proposal to engage in long-term, multi-contract exports of LNG that was domestically produced for a term of twenty-five years, commencing on the date of the first LNG export or six years from the date that the authorization is issued whichever is sooner, for the equivalent of up to 1 Bcf of natural gas per day (or approximately to 7.82 million mtpa) to any country which has or in the future develops the capacity to import LNG via ocean-going carrier and with which the U.S. does not prohibit trade but also does not have an FTA requiring the national treatment for trade in natural gas. DCP respectfully requests that the DOE/FE grant such authority as expeditiously as possible, and by no later than June 1, 2012.

Respectfully submitted,

/s/ Matthew R. Bley

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Dated: October 3, 2011

Appendix A

# Navigant Supply Report

NAVIGANT

# NORTH AMERICAN GAS SUPPLY OVERVIEW AND OUTLOOK TO 2040

**Prepared for:**

## Dominion Cove Point LNG, LP

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September 19, 2011

NAVIGANT

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

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## Summary of Assignment

Dominion Cove Point LNG, LP is considering the manufacture and export of liquefied natural gas (LNG) at the site of its LNG import facility at Cove Point, Maryland. In support of this possible project, Dominion requested Navigant Consulting, Inc. to provide a qualitative outlook for the North American natural gas market to 2040, with an emphasis on supply. It also asked Navigant to model the potential price impacts of its export operations.

This ***North American Gas Supply Overview and Outlook to 2040*** responds to supply issues. The companion report ***North American Gas System Model to 2040*** responds to modeling results and implications. These two reports are designed to be read in conjunction with one another.

As part of its internal integrated 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 Dominion builds on Navigant's Spring 2011 Reference Case forecast and Navigant's ongoing market research. Where appropriate, the report benchmarks Navigant's supply forecast 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 reviews 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 available natural gas has become an abundant fuel in North America. In fact, gas supply is surplus to demand.

Before 2008, the general consensus was that domestic gas supplies would be unable to keep pace with growing demand, and that liquefied natural gas (LNG) would have to be imported. That consensus is no longer operative. The situation in North America has reversed from an expectation of domestic supply deficit to an expectation of supply abundance. Prices that were expected to be high and volatile are now expected to be moderate and relatively stable.

The new consensus, which Navigant shares, is that North American gas resources are more than adequate to satisfy domestic demand for the time frame covered by this report, even as demand grows.

It is Navigant's assessment that domestic gas resources are also ample enough to support the creation and ongoing operation of a domestic LNG export industry through the study period to 2040, including the demand added by Dominion's proposed liquefaction facilities at Cove Point.

Several facts support this outlook.

- Dry gas production in the U.S. is up 25 percent, from about 49.5 Bcfd to 62.1 Bcfd, from 2004 through the first seven months of 2011.
- Navigant projects U.S. production to grow to 84 Bcfd in its Reference Case.
- The EIA's most recent estimate of dry natural gas resources in the United States is 2,543 Tcf.[1] This is more than 100 years of supply at current usage rates of approximately 24 Tcf per year. Even at Navigant's projected 2040 rate of consumption of 84 Bcfd (30.7 Tcf per year), this represents 83 years of supply.
- Despite confusion surrounding a recent United States Geological Survey estimate of "undiscovered" reserves in the Marcellus Shale of 84 trillion cubic feet, the Energy Information Agency has not altered its estimate of "undeveloped" Marcellus reserves, which is 410 trillion cubic feet. Based on investigations by Navigant, including direct contact with the personnel involved at the two government agencies, there is a possibility that the two estimates are *additive*. In any case, the EIA has made no changes to its estimate of "undeveloped" Marcellus reserves, reports to the contrary notwithstanding.

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

An unappreciated fact 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.

## Supply Outlook to 2040

Overall supply growth in the U.S. has been remarkable in the past few years. 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 demand grows. The bulk of this change is attributable to 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.

Before the advent of significant unconventional 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 has been driven by uncertainty around the availability of supply to meet demand, both in the short and long terms. The investment cycle for supply was frequently out of phase with demand, due to the uncertainty of the large investment required for exploration or for LNG regasification (on the supply side) and for power plants and other large users (on the demand side).

In between supply and demand are pipelines, another large-scale investment which in individual cases has suffered from underutilization or has become a bottleneck, as a result of the uncoordinated cycles of supply and demand investment.

These factors created a dynamic of price volatility. The volatility itself affected investment decisions, creating a feedback loop of uncertainty.

The dependability of shale gas production has the potential to improve the phase alignment between supply and demand, which will tend to lower price volatility. As long as commodity prices can be sustained at levels that incent drilling and development, yet remain competitive with the price of alternative fuels, the vast size of the shale gas resource will support a much larger demand level than has heretofore been seen in North America.

Navigant expects gas production to continue to grow steadily throughout the forecast period. 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 105 Bcfd by the year 2040. By that year, U.S.-produced supply alone is projected to be a bit more than 81 Bcfd, as shown in ***Figure 2:*** *U.S. Natural Gas Supply Projection*.

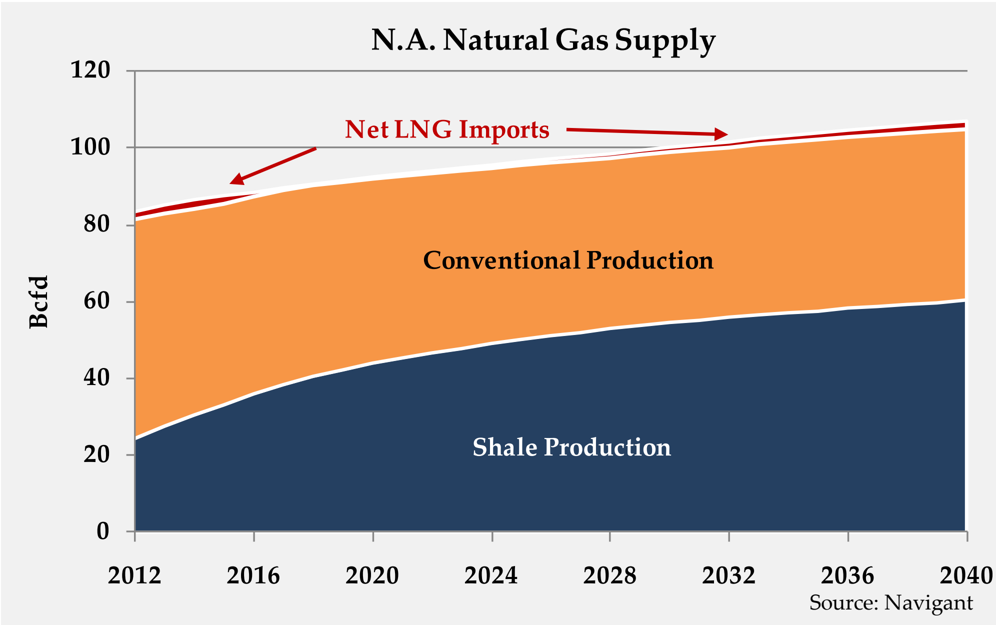


**Figure 1: North American Natural Gas Supply Projection**

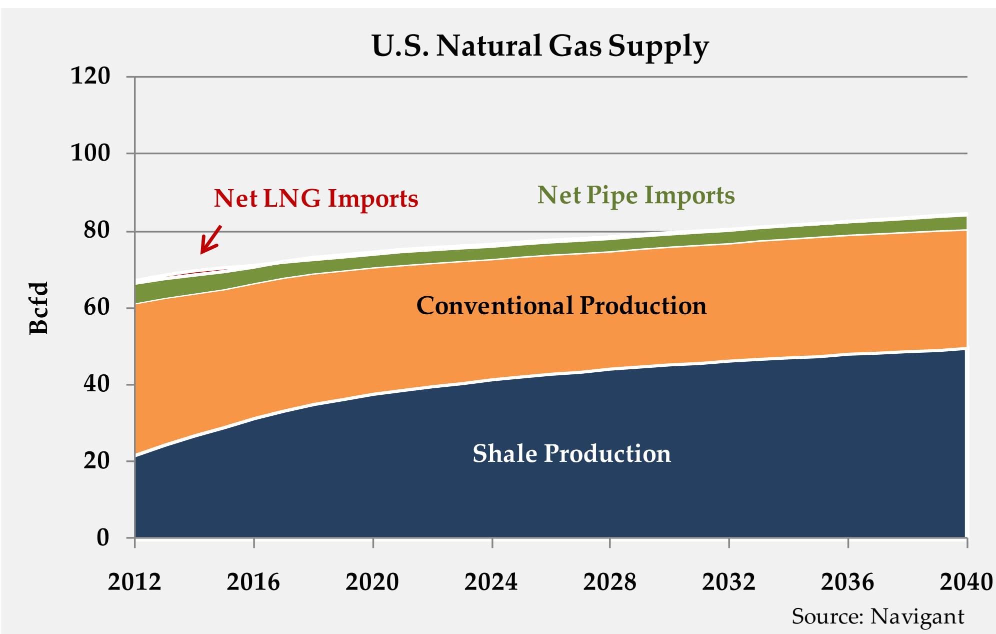


**Figure 2: U.S. Natural Gas Supply Projection**

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 should tend towards creating a healthy, stable, long-term market for natural gas.

This vast majority of production growth is likely to be driven by unconventional gas development, as opposed to conventional gas, which is in decline. Plans to develop frontier gas, such as the Mackenzie Project in Arctic Canada and the Alaska Pipeline Project, are in doubt due to the high cost of those projects relative to unconventional resource development opportunities closer to markets. However, if demand is sufficient, there are scenarios in which these conventional resources may yet play a role in later years.

## 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 were regarded as uneconomic to recover in most instances.

### 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 facilities in the late 1990s and 2000s, which was very conspicuous due to the size of the facilities and to the public approval process required for each. As late as 2008, conventional wisdom held that North American gas production would have to be supplemented increasingly by imported LNG.

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

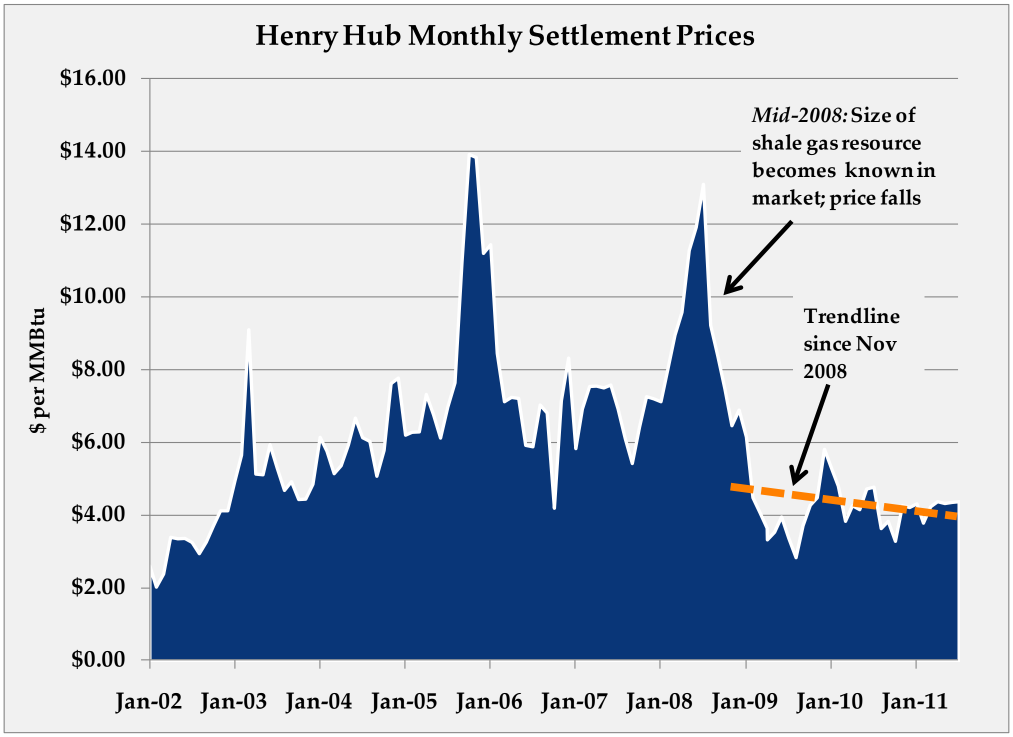


**Figure 3: Henry Hub Price History**

Shale gas production efficiency has since improved. 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 has increased from four to up to 24.

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 costs.[3] Chesapeake Energy is also actively exploring methods of reducing and reusing water.

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

[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

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### Size of the Shale Gas Resource

To illustrate the size of the shale gas resource, its rapid development, and increasing efficiency, consider the following. U.S. natural gas production increased from about 50.5 Bcfd in May 2005 to about 60.9 Bcfd in May 2011, even as overall rig counts fell from 1,170 to 890. This is an increase of 20 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*.)

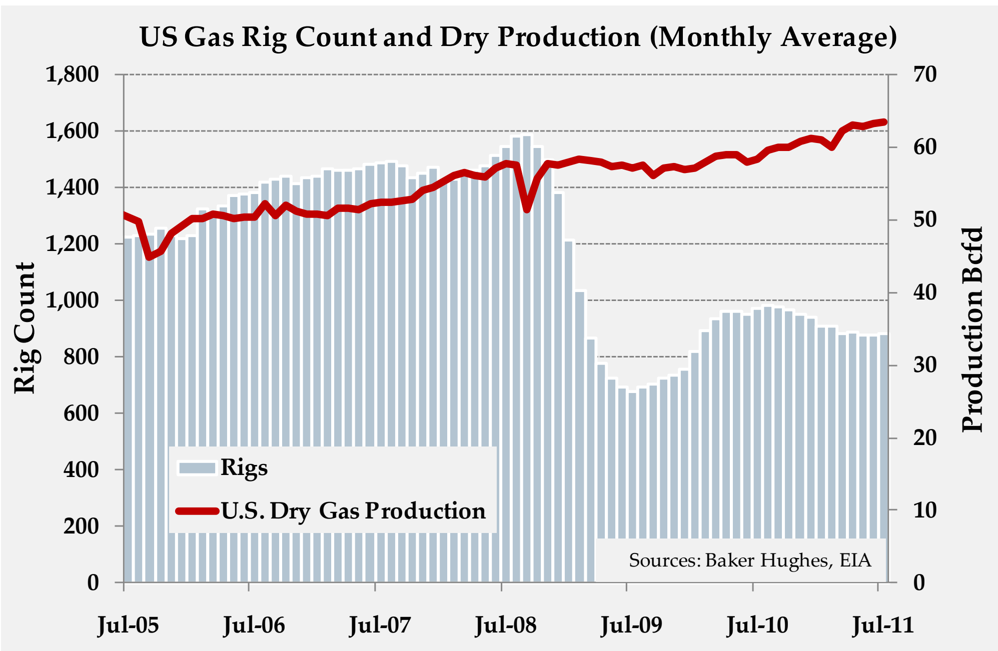


**Figure 4: U.S. Gas Production and Rig Count History**

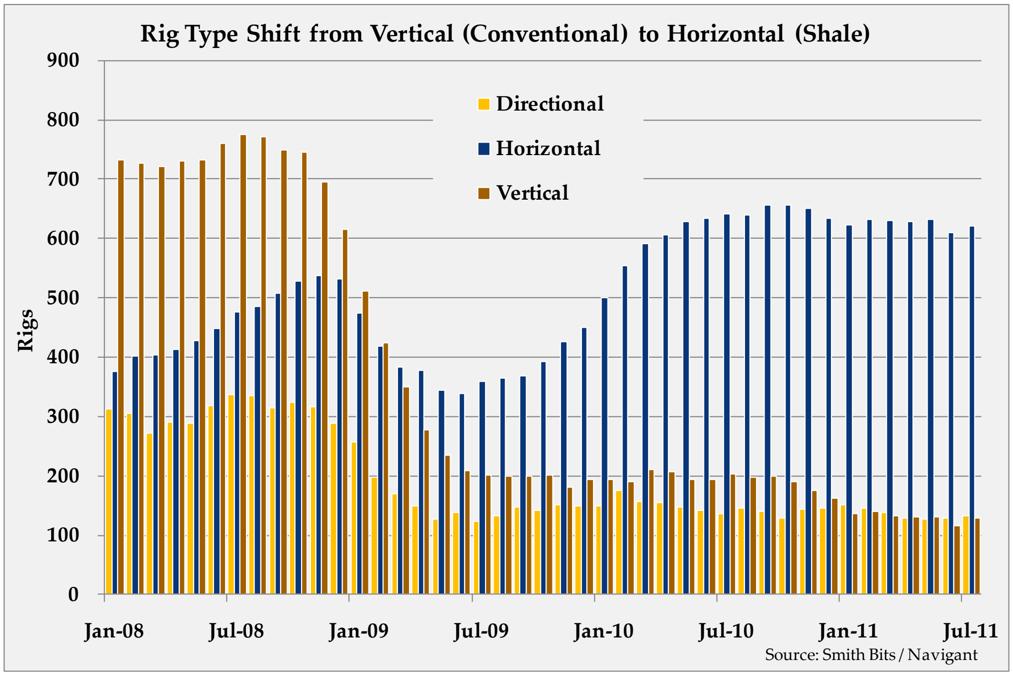


**Figure 5: U.S. Gas Rig Type Shift**

The growth in shale gas production has been phenomenal, 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 16.5 Bcfd in the first quarter of 2011, an increase of almost 525 percent in a little more than four years.

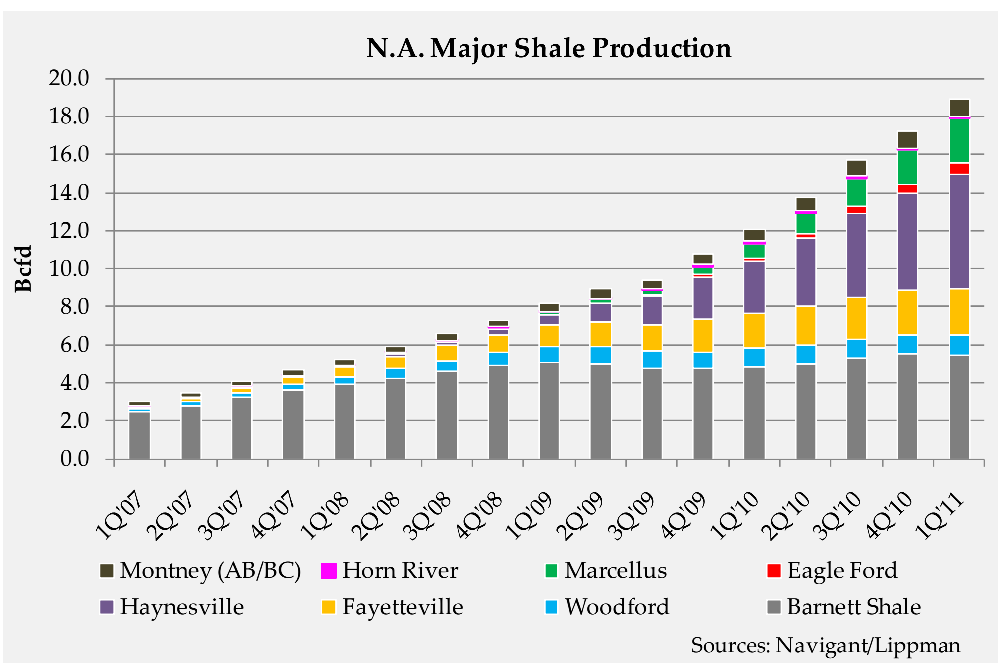


**Figure 6: Shale Production 2007-2011**

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 groundbreaking study on the subject of emerging North American shale gas resources, 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] 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.[5]

New shale resource plays are being identified at a high rate. 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. North America is clearly in the early phases of discovery for this resource.

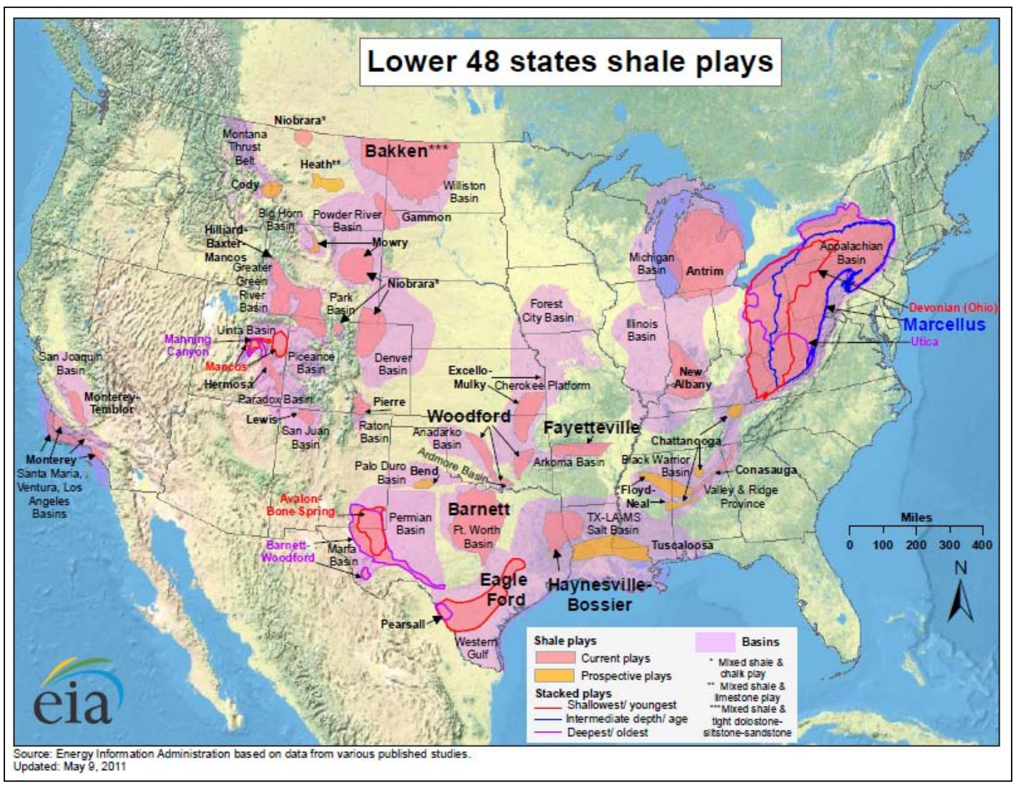


**Figure 7: EIA Lower-48 Shale Play Map (2011)**

The Marcellus Shale formation is a special case. It is in central Appalachia, the market area of the Cove Point facility. The Marcellus was virtually unheard of in 2007. Dr. Terry Engelder, a professor of geology at Penn State University, has estimated that the Marcellus has a 50 percent chance of

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[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.

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] (For a discussion of the recent USGS estimate of the Marcellus resources, see ***The Marcellus Shale and Other Key Supply Basins*** on page 27.)

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]

The British Columbia Ministry of Energy and Mines and the National Energy Board recently estimated the marketable gas in place in the Horn River Basin alone to be between 61 and 96 trillion cubic feet.[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.

As indicated by the above, there is little doubt that the shale gas resource in North America is extremely large. In Navigant's estimation, 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 2040 as well as the demand added by Dominion's proposed liquefaction facilities at Cove Point.

### 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

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[6] Basin Oil & Gas magazine, August 2009, pg 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, page 19.

[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.

risk, with the possibility that a well will be a dry hole or "duster" with no deliverability or production following drilling, and thus no return on investment.

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 throttle 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. Often, 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, and each bore produces 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 exploited, the risk of not finding a producible formation is much lower compared to some types of conventional gas structures.

The horizontal well, once it is properly located in the target formation, is then enabled to produce volumes large enough to be economic through the use of hydraulic fracturing. Water, sand (or some other proppant to keep the fractures open), and a small amount of chemicals are injected at high pressure to fracture the shale so that it releases the gas. As is the case with most shale wells, initial production (IP) rates are high, but drop off steeply within the first two years. However, once a well has declined to 10-20 percent of initial production, the expectation of many scientists in the industry (which has been supported by experience in shale's brief history to date) 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. [12]

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

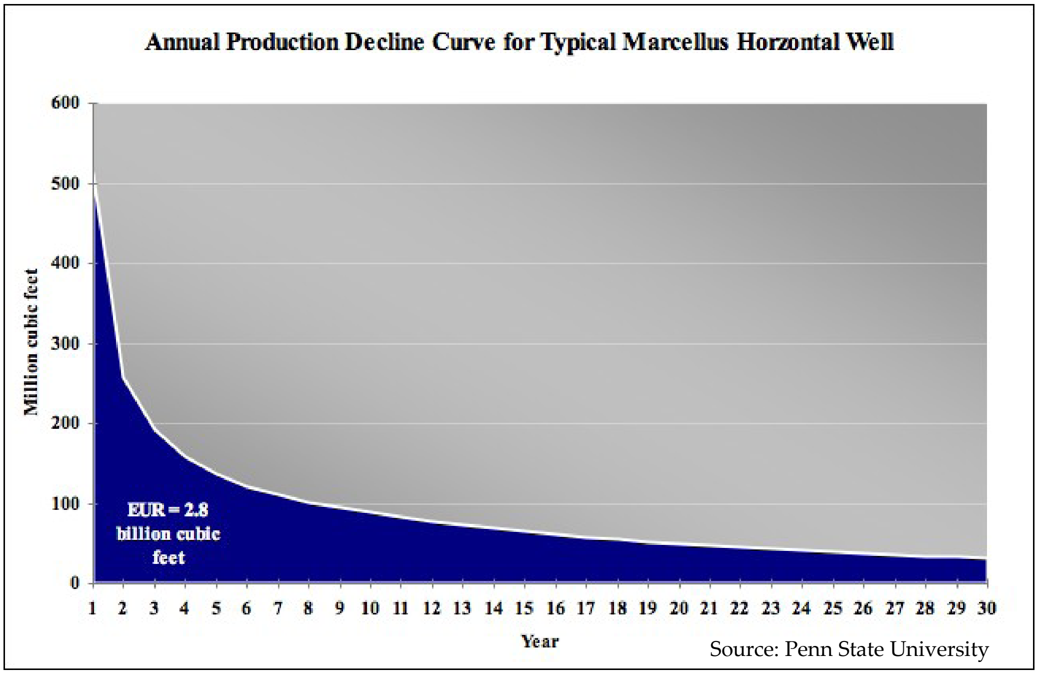


**Figure 8: Shale Gas Well Decline Curve**[13]

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 fractured or drilled 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 is further reinforced by the fact that many shale formations also contain natural gas liquids (NGLs), which strengthens the economic prospects of shale. 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.

Similarly, in April 2011, Encana announced the acquisition of liquids-rich Duvernay Shale acreage in Alberta to exploit natural gas liquids in addition to shale gas. 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, which tend to follow 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.

Much has been made of the per-play economics of shale gas development. While the cost of producing commercial quantities of gas does vary from play to play, and even within a play, the overall trend is that drilling costs are declining as producers gain experience, develop efficiencies such as the ability to develop multiple fracture zones per well, and leverage investments in drilling

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

equipment across greater volumes of gas. In some pure gas shale plays, costs have dropped below $4.00 per MMBtu to produce, and continue to drop. Most shale gas plays are expected 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 thought of as essentially zero, as long as the price of the NGLs and oil 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 expects NGL and crude oil prices to continue to be strong relative to natural gas, based on continued strong demand.

The EIA, in its *International Energy Outlook 2010*, projects worldwide demand for liquid fuels to grow by more than 24 million barrels a 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 also expects oil prices to increase to $130 per barrel by 2035, which will incentivize production.[14] Thus, NGL production will be encouraged in the U.S., along with the production of associated gas.

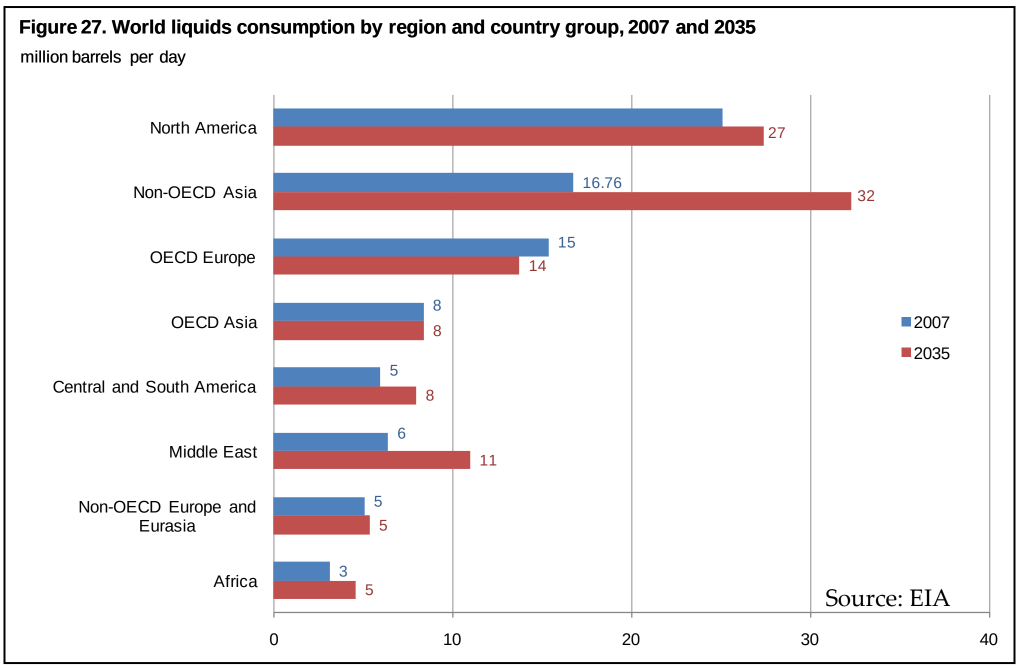


**Figure 9: World Liquids Consumption from *EIA International Energy Outlook 2010***

## 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*. After 2020, the lines of growth are roughly parallel. As the graph also shows, both

[14] *International Energy Outlook 2010*, EIA, p. 23, available at http://www.eia.gov/oiaf/ieo/liquid_fuels.html

Navigant and EIA increased their estimates for shale production this year compared to 2010, by roughly the same amounts post-2020.

EIA has historically lagged in the recognition of the size of the shale gas resource. As shown in **Figure** *6: Shale Production* 2007-2011, above, shale production in the U.S. in the first quarter of 2011 is 18.0 Bcfd, and on its way to the 20.0 Bcfd in our forecast. EIA's forecast of 15.0 Bcfd for 2011 has already been eclipsed.

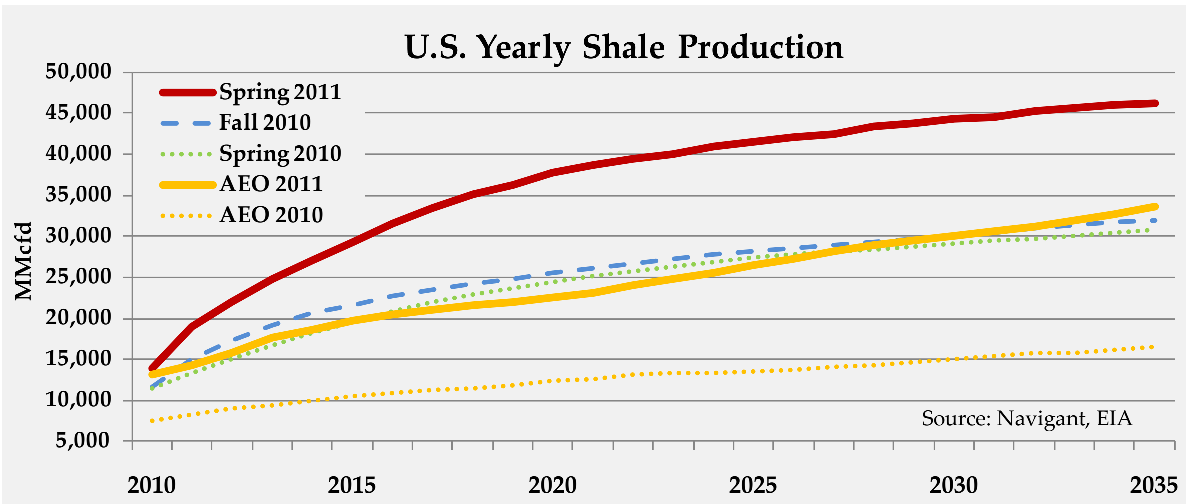


**Figure 10: Supply Outlook Comparison: Navigant and EIA**

| 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 1: Supply Outlook Comparison: Navigant and EIA**

## Demand Is Likely to Increase Steadily

An unappreciated fact is that 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 steadily 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 and pipeline project developers are assured that gas will be available for the indefinite future.

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 will also be supported by the existing pipeline network throughout North America. 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 so widely dispersed around the continent, Navigant does not foresee the need for another long-line pipeline such as the recently built Ruby, which extends from Opal, Wyoming to markets in California, with the possible exception of the Florida market. Florida produces a negligible amount of gas and may be a possible target for a major pipeline. Such a line would likely transport supplies from the prolific Barnett, Haynesville, and Fayetteville shales in Texas, Louisiana, and Arkansas.

### 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 2.1 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.

Industrial demand in the North America is expected 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.

The sectoral outlook for natural gas demand is shown in ***Figure 11:*** *North American Natural Gas Demand Projection*.

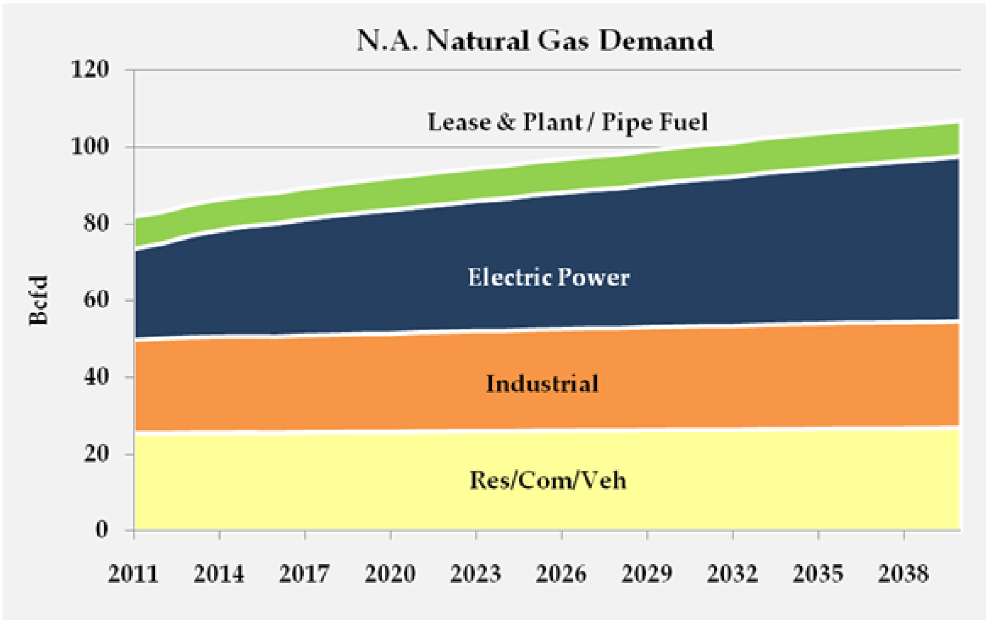


**Figure 11: North American Natural Gas Demand Projection**

Another recent positive development to the sustainability of the long term gas market is the development of LNG exports. As an artifact of gas shale in North America, four LNG developers, including Cove Point, have now applied for approval to export natural gas from the U.S. In May, Cheniere Energy received U.S. Department of Energy approval for the export of up to 2.0 Bcfd of LNG from their Sabine Pass terminal. Taking advantage of the surplus of natural gas supply, Cheniere has plans to construct a new liquefaction terminal on the same site as their existing import facility.

So far, Cheniere is the only U.S. facility in the Lower 48 to have received DOE approval, but other facilities have applied for export authority or are considering it. LNG export facilities offer the potential for a new baseload market for natural gas and to support ongoing development of the resource through market balancing.

Although Cheniere's Sabine Pass export facility is not scheduled for start-up until 2016 and will not have market impact in 2011, 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.

## Competition from Oil and Other Fuels

As Navigant details in the accompanying report ***North American Gas System Model to 2040***, annual average natural gas prices are projected to remain below $6.61 through 2030 in its Cove Point Case. The Cove Point Case includes LNG exports from Cove Point, Kitimat in British Columbia, and Sabine

Pass in Louisiana. On a per-MMBtu basis, this is expected to be well below oil prices and competitive with coal prices.

### 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*.

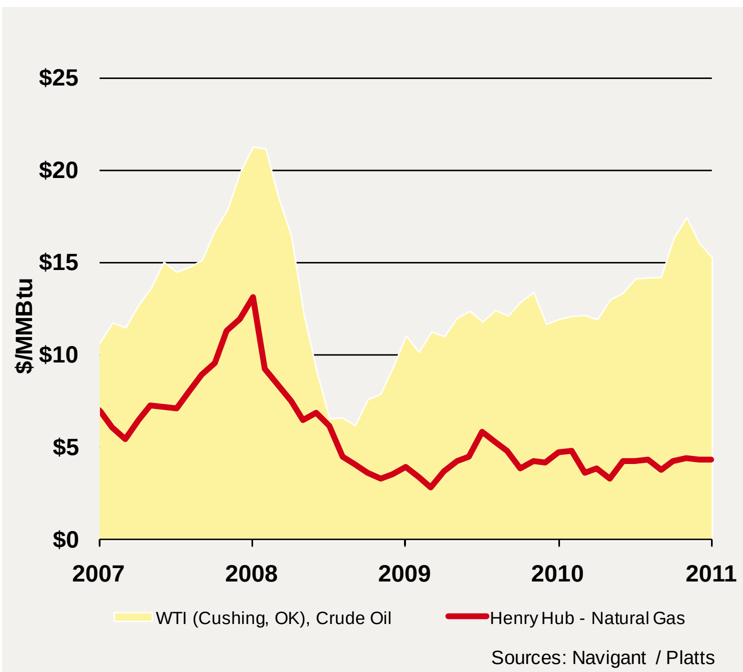


**Figure 12: Comparison of Oil and Gas Prices per MMBtu**

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.[15] 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.

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[15] 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

## 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.

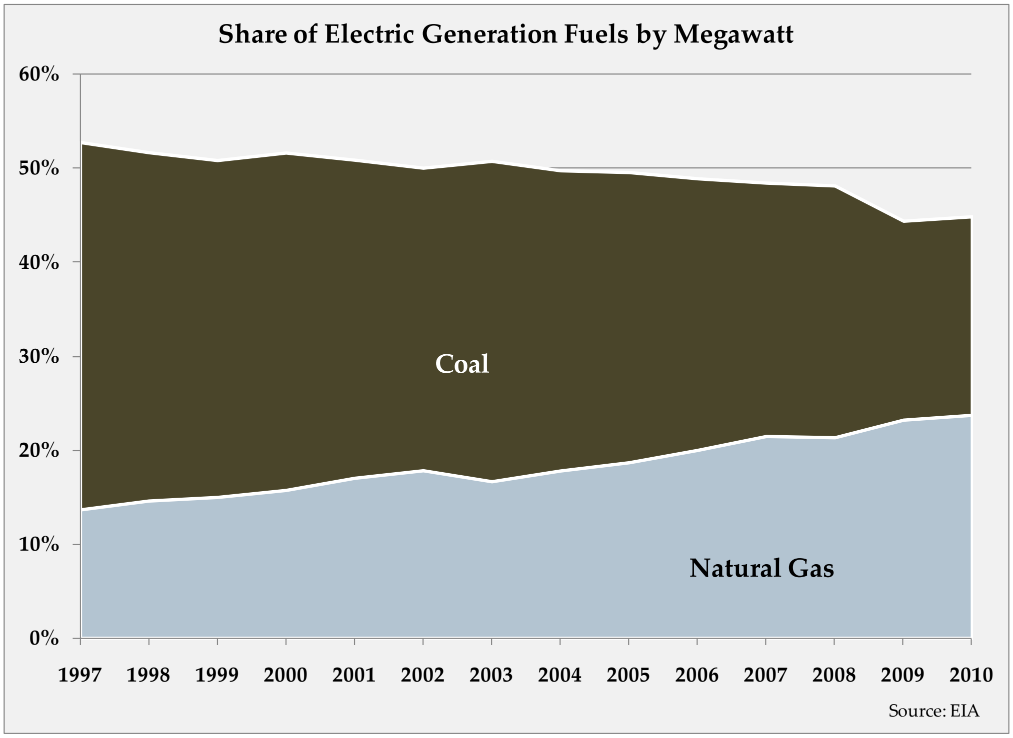


**Figure 13: Coal and Natural Gas as a Percent of Total Megawatt Hours Generated**

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 on commodity price competition, not on any new regulatory or government mandates, based on coal and gas futures prices.

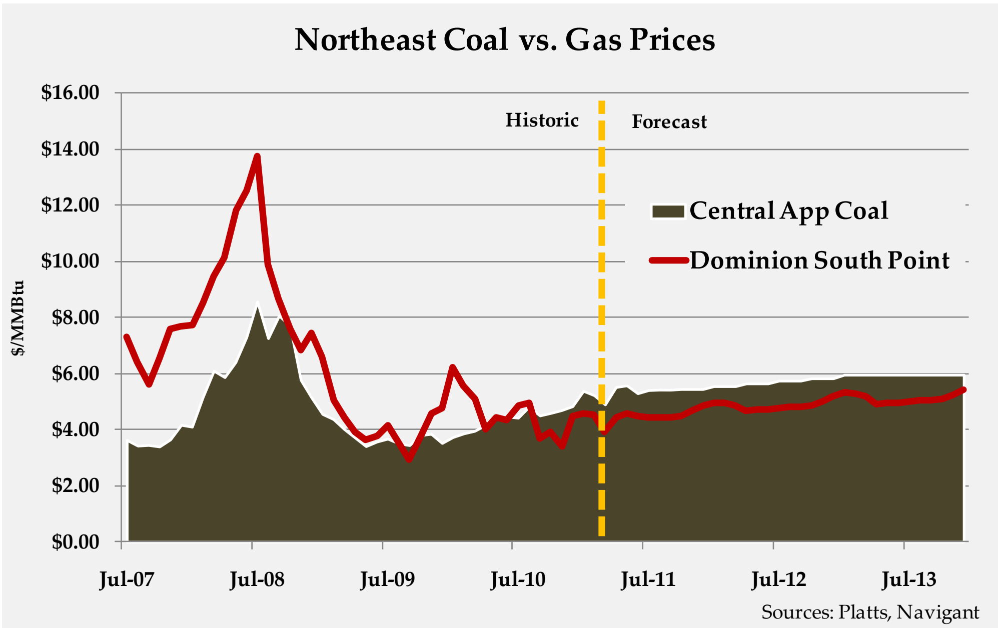


**Figure 14: Comparison of Electric Generation Fuel Costs**

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.[16]

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[17] 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.[18] 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 announced that the CSAPR rules would expect to retire 4,000 MW of its 12,000 MW coal-fired fleet,

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[16] 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.

[17] 1.0 gigawatt equals 1,000 megawatts.

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

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.[19] 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 reductions 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 fuel. Navigant views improved energy efficiency as positive for the gas market, and not as competition. Increased efficiency will tend to dampen demand and volatility and extend the life of the resource.

## Risks to the Supply and Demand Forecasts

While the supply outlook is strong, and Navigant expects production to grow in a synchronized manner with demand, there are risks to the outlook.

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[19] New York Times, August 12, 2011, page 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

## 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 by which almost every well currently producing has been enabled to flow, whether gas or oil, or whether shale or conventional. With shale, it has taken on a much larger scale, and it's happening in regions of the country unaccustomed to such large-scale oil and gas development and production.

The issue is one of execution by the drilling industry, not one of inherent problems in hydraulic fracturing technology or the use of accepted methods. The instances of water well contamination associated with hydraulically fractured wells to date are few and isolated. They have generally been related to failures of the sealing of pipe in the wellbore or to improper wastewater disposal. Technology and methods exist to secure wellbore integrity and to dispose of wastewater properly are improving at a great pace.

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

Dealing with the effects of using and disposing of large volumes of water is manageable by the drilling companies and can be handled using existing technologies and processes. The cost may add to the cost of the well in certain cases (e.g., where water is scarce), but may reduce costs in others. As noted above on page 7, significant efforts are already underway to improve water management techniques, including reuse.

In general, drilling operators are motivated by economics to improve the efficiency of water management. 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 reducing water acquisition and trucking costs in many places, including the Marcellus formation in Pennsylvania, and the Eagle Ford formation in Texas, which is experiencing a severe drought.[21]

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. [22] 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

[20] http://fracfocus.org/
[21] Journal of Petroleum Technology, July 2011, pp. 49-51.
[22] 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

production in reducing existing and potential undesirable impacts can be a cooperative effort among the public, companies in the industry, and regulators."[23]

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.

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 is not seriously impeded. In some regions, such as New York State, where the Marcellus play lies beneath the New York City watershed, opposition to hydraulic fracturing is likely to remain strong despite increased regulation. However, the risk of sustained, organized opposition should be ameliorated by these increasingly stronger regulations and by the economically-driven efforts of the drilling industry.

Despite improving regulations and the diligent efforts of drillers, there is a slight risk that an inappropriate discharge may result in surface water contamination at some future time. Depending on the scale and location of such an event, there could be a regional or nationwide moratorium or other measure, similar to the moratorium placed on deepwater drilling in the Gulf of Mexico after the Deepwater Horizon oil well blowout in 2010. Navigant believes the risks of an accident having an industry-wide effect is very small, and will continue to diminish as regulatory attention and well completion practice and technology improvements increase.

A recent report from a team at Cornell University raised the possibility that shale gas may produce more greenhouse gases than coal, on a full life-cycle basis. That report has since been largely disproven.

For example, 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."[24] The research firm IHS Cambridge Energy Research Associates also 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."[25] 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.[26]

[23] Ibid, pp 1, 9.

[24] *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

[25] *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

[26] *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

The SEAB has called for independent studies of the life cycle emission from shale gas wells. Navigant views this as a positive step, and expects the final results will be in line with the findings of Carnegie Mellon, IHS CERA, and the NETL.

### 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 in 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 price differential for a given heat value. This can be seen in drilling rig numbers. The number of oil rigs operating in the U.S is up from 435 in July 2010 to 796 in July 2011, or 83 percent.[27] This phenomenon could potentially have the effect of reducing gas supply in the future.

Such shifts in drilling generally occur as drilling capital is transferred from a lower-priced commodity to a higher-priced one, in order to reap greater returns on investment. Low gas commodity prices and high oil and NGL prices have recently coincided with the shift in drilling from gas to oil and NGLs.

For the present, gas supply is continuing to increase, despite the fact that gas prices at Henry Hub have declined to the $4.00 per MMBtu area and oil prices have hovered in the $15.00 per MMBtu range (approximately $91.00 per barrel). However, while the overall gas rig count has fallen from 926 to 888[28] or four percent in the past year, horizontal gas rigs have increased from 586 to 625,[29] or seven percent. This indicates shale gas drilling is continuing to grow.

Over the last two decades, oil drilling has shifted from the U.S. to more lucrative opportunities elsewhere around the globe. Oil imports now meet 63% of U.S. oil demand, and the U.S.'s reliance on oil imports is expected to increase to the extent oil demand grows. Given restrictions put in place on offshore drilling in the wake of Deepwater Horizon, it is unlikely, even if those restrictions are lifted, that oil drilling will expand to pre-event levels in the near future, and cannibalize gas rigs to any great degree. In addition, many of the liquids plays contain associated gas, which is produced as a by-product and becomes part of the national gas supply.

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

In addition, Mexico's gas demand from new industrial and electric generating facilities is outstripping in-country supply, making increased gas exports from the U.S. likely. In the EIA's International Energy Outlook 2010, Mexico will account for almost 50 percent of the growth in North America's natural gas consumption through 2035, while the United States will account for about 30 percent, and Canada about 20 percent.[30]

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[27] Smith Bits
[28] Baker Hughes
[29] Smith Bits
[30] EIA IEO 2010, p. 42.

Navigant's view is that the reallocation of drilling capital due to price differentials between natural gas and oil and NGLs needs to be monitored. However, 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. In our view, this makes continued expansion of oil drilling less likely to be a viable long-term competitor to natural gas drilling.

Since shale gas production resembles a manufacturing process, supply production should generally synchronize with demand. Navigant's 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. However, this is still expected 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. (See the accompanying report, ***U.S. Gas Supply Overview and Outlook to 2040***, for more on Navigant's price forecast).

## Review of Regional Issues for Cove Point LNG

Cove Point LNG, on the western shore of Chesapeake Bay in Maryland, is well-situated to take advantage of the newly developing and huge shale gas resources for its proposed export project. Cove Point is near two of the largest gas resources in North America: the Marcellus and the Utica shales. In addition, it is connected directly or indirectly to transmission lines that carry gas from other shale plays to the south (the Fayetteville in Arkansas, the Haynesville in Louisiana, and the Barnett in Texas) that have contributed to the rapid increase in North American reserves and supplies.

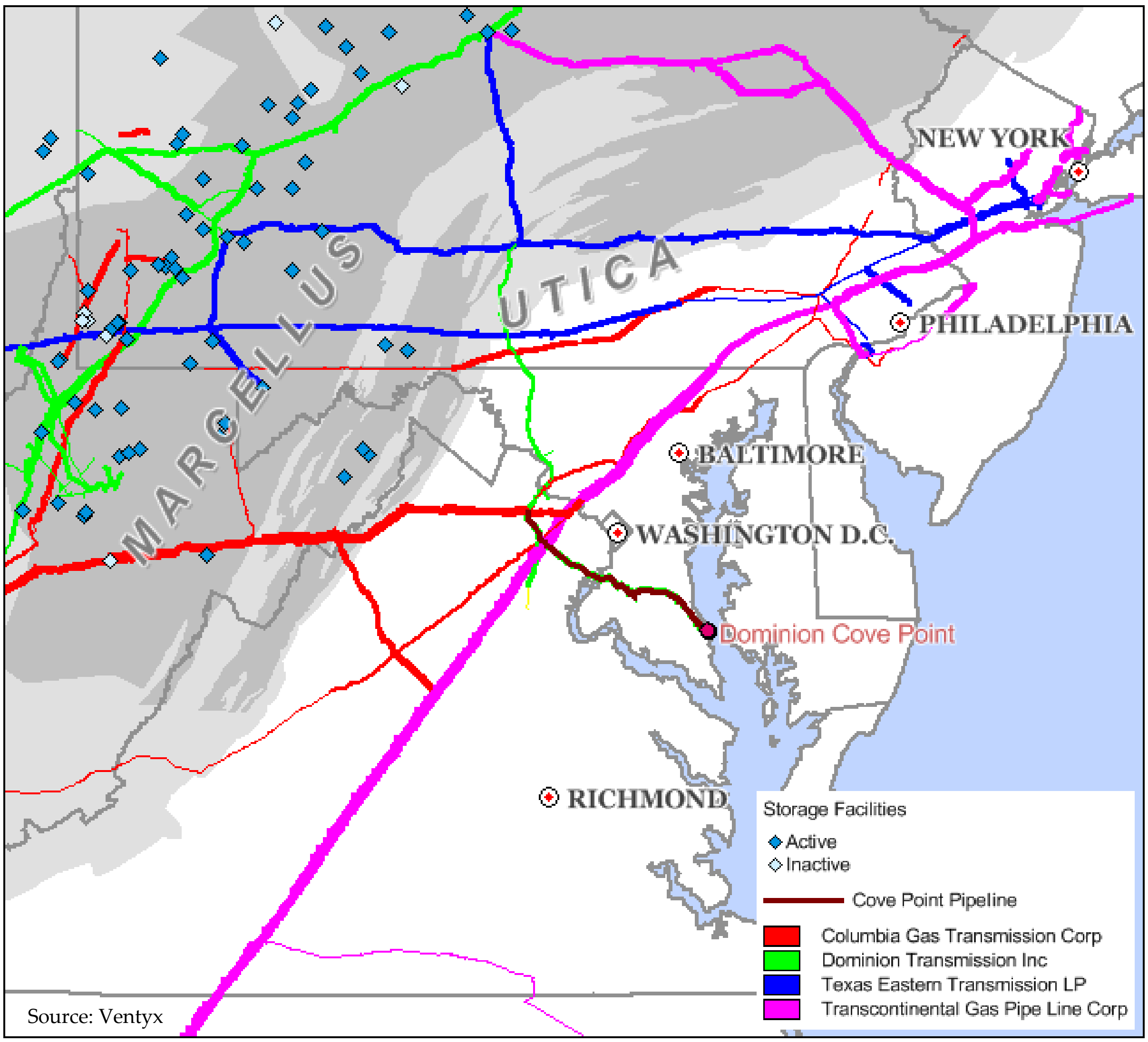


**Figure 15: Dominion Cove Point Location Map**

The original Cove Point LNG import facility was sited because of its proximity to the major mid-Atlantic gas-consuming markets. These markets are now almost certain to be supplied to a great extent by the recently discovered Marcellus shale gas resource, which lies adjacent to and in some cases directly beneath them and, as time goes on, the Utica shale. The Marcellus already produces at much higher volumes than the rated output of Cove Point, as shown in **Figure 16:** *Marcellus Production vs. Cove Point Sendout*, indicating that it has supplanted the LNG import facility as a source of regional supply.

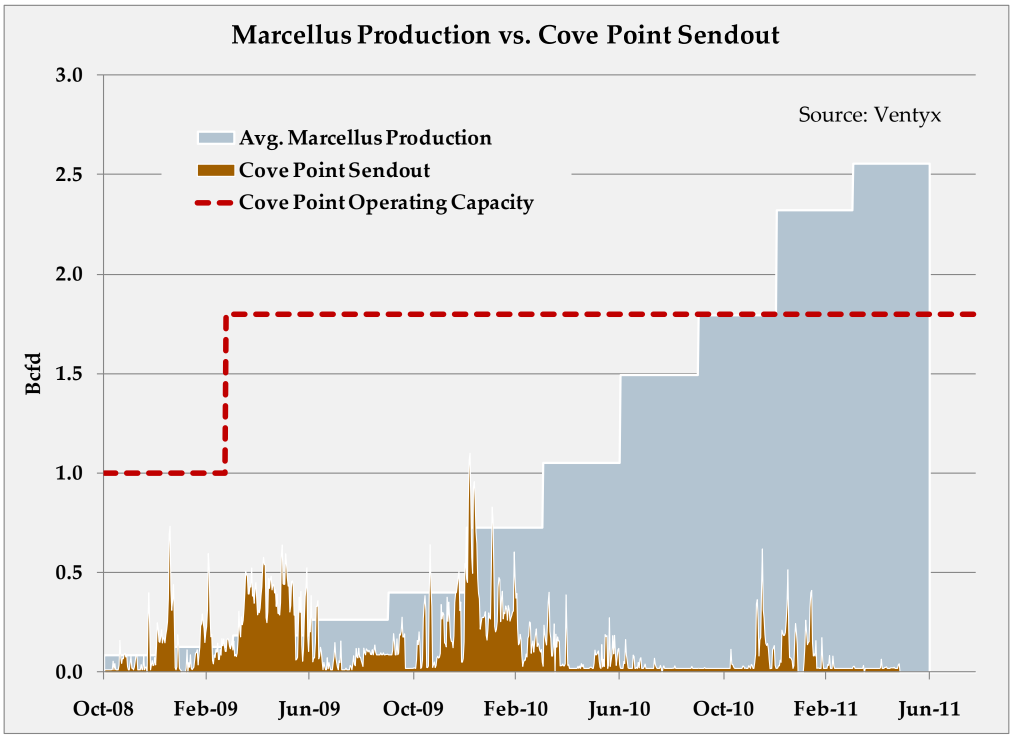


**Figure 16: Marcellus Production vs. Cove Point Sendout**

## The Marcellus Shale and Other Key Supply Basins

### Marcellus Shale

The Marcellus Shale is one of the largest shale resource plays identified in North America to date. The areal extent of the Marcellus is impressive, covering much of New York, Pennsylvania, and West Virginia, and portions of Maryland and Ohio. As noted earlier in this report, the Marcellus has been estimated to have as much as 489 Tcf of recoverable gas. The Marcellus will be a key resource for gas supply for the Cove Point export project. The Marcellus is connected to Cove Point by Dominion Transmission and other pipelines.

The Marcellus is a liquids-rich play, in addition to its prodigious gas resource. This enhances its attraction as a capital investment and makes its rapid development more likely.

The recent announcement by Shell Oil Company that it intends to build a large new petrochemical refinery in the Marcellus region is a testament to the size and expected longevity of the Marcellus resource. The proposed facility could attract up to $16 billion in private investment and create more than 17,000 jobs, according to an Associated Press story from September 3, 2011.[31] One energy consultant in the article was quoted as saying, "If you're building a cracker in the Appalachians you have to be absolutely certain that the supply is there. It's a heck of an endorsement of the Marcellus resource."

In late July 2011, the United States Geological Survey released its most recent estimate of the "mean undiscovered natural gas resource" in the Marcellus. The USGS increased its old estimate by a factor of 44, from 1.9 Tcf to 84.2 Tcf.[32] Some reports in the popular press have interpreted this as a reduction in the federal government's outlook for the Marcellus, since the EIA had just released an estimate of "undeveloped" Marcellus resources of 410.3 Tcf.[33] These reports are mistaken.

Navigant has made direct contact with the responsible personnel at both the USGS and the EIA on this issue. The EIA has confirmed that it has made no official decision to adjust its estimate based on the new USGS number. It acknowledged that there is a difference in nomenclature that may account for some of the confusion. The USGS estimate pertains exclusively to "undiscovered" resources, while the EIA's number pertains to "undeveloped" resources, which are not the same. According to the EIA's website, undeveloped resources do not include "proven reserves, inferred reserves in actively developed areas and undiscovered resources as estimated by the U.S. Geological Survey (USGS)."[34] Clearly, there is the strong possibility that the new USGS estimate is *additive* to the EIA's estimate.

### Utica Shale

The Utica shale is a formation beneath the Marcellus. It has yet to be developed, or even assessed in a conclusive manner. Its areal extent is greater that the Marcellus's, extending into Ohio and southern Ontario as well as beyond the eastern limit of the Marcellus. Early indications are that the Utica contains a significant volume of NGLs, similar to the Marcellus, which is supportive for its eventual development.

In recent weeks, several projects have been announced that reflect burgeoning interest in the development of the Utica shale. Chesapeake Energy has leased 1.25 million net acres of the Utica in eastern Ohio and has five rigs operating in a liquids-focused effort that is likely to produce natural gas as well; Chesapeake indicates it may have 40 rigs in the Utica by 2014. CONSOL Energy and Hess Corporation have agreed to form a joint venture that will develop nearly 200,000 acres in the Utica

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[31] Associated Press, "Pa., W.Va., Ohio vie for huge new Shell gas plant ," September 3, 2011, available http://hosted.ap.org/dynamic/stories/U/US_GAS_DRILLING_REFINERY?SITE=AP&SECTION=HOME&TEMPLATE=DEFAULT&CTIME=2011-09-03-12-16-48

[32] Coleman, et al, *Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011*, USGS, Fact Sheet 2011–3092, available at http://pubs.usgs.gov/fs/2011/3092/

[33] EIA, *Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays*, July 8, 2011, available at http://www.eia.gov/analysis/studies/usshalegas/

[34] Ibid.

shale, also with a focus on liquids that is likely to result in gas production. Petroleum Development Corporation has executed agreements to acquire up to 100,000 acres in the wet gas and oil phases of the Utica shale.

### Barnett, Haynesville, and Fayetteville Shales

The Barnett, Haynesville, and Fayetteville shales were the top shale plays for proved reserves in the EIA's 2009 data release.

The Barnett was the first shale play to be extensively developed. As such, it is considered mature, and has a slow growth profile. It supplies several significant markets through an extensive network of transmission pipelines, and some portion of its gas is transported to the mid-Atlantic. It is an extremely prolific resource.

The Haynesville and Fayetteville plays lie in Louisiana and Arkansas, respectively. These plays are newer than the Barnett and still developing.

In its Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays of July 8, 2011, the EIA estimated the undeveloped technically recoverable shale gas in these resource basins as follows:

| Shale Play | Primary Location | Shale Gas Resource (Tcf) |
|---|---|---|
| Barnett | Texas | 43 |
| Haynesville | Louisiana, Texas | 75 |
| Fayetteville | Arkansas | 32 |
| | **Total** | **150** |

## Infrastructure Issues

The Dominion Cove Point Pipeline has a capacity of 1.8 Bcfd, more than adequate to carry gas to the proposed 1.0 Bcfd liquefaction facility. It has interconnects with Dominion Transmission, Columbia Gas Transmission, and Transcontinental Pipe Line. These interconnects will likely need expansion and/or reconfiguration to reverse the tradition flow direction from Cove Point. However, this is not seen as causing any issues from a supply or demand perspective.

Dominion Transmission, operator of Cove Point, operates one of the largest underground natural gas storage systems in the United States, with links to other major pipelines. Much of this infrastructure is within the boundaries of the Marcellus shale, supporting its ability to deliver feed gas to the proposed liquefaction project.

Appendix B

# Navigant Price Report

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# NORTH AMERICAN GAS SYSTEM MODEL TO 2040

**Prepared for:**

## Dominion Cove Point LNG, LP

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September 19, 2011

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

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## Summary of Assignment

Dominion Cove Point LNG, LP is considering the manufacture and export of liquefied natural gas (LNG) at the site of its LNG import facility at Cove Point, Maryland. In support of this possible project, Dominion requested Navigant Consulting, Inc. to provide modeling and scenario analysis. This ***North American Gas System Model to 2040*** responds to modeling results and implications. The companion report ***North American Gas Supply Overview and Outlook to 2040*** responds to supply matters related to the project.

Navigant's analysis and modeling considered four scenarios:

1. Cove Point Reference Case
2. Cove Point Export Case
3. Aggregate Export Case
4. Extreme Demand Case

In addition, a variant of the Cove Point Export Case was run to test the sensitivity of price to the suppression of Cove Point's ability to import LNG, and operating strictly as an export facility.

This report, ***North American Gas System Model to 2040***, summarizes all of Navigant's findings and discusses methodology used in our modeling and scenario analysis process. It also includes an outline of key input variables included in the forecast.

Navigant's extensive discussion of North America natural gas supply is contained in the companion report, ***North American Gas Supply Overview and Outlook to 2040***.

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## Executive Summary

In Navigant's **Reference Case**, average annual prices at Henry Hub, Louisiana, remain under $6.00 per MMBtu until 2029. Navigant's Reference Case includes two operational export facilities: the 0.7 Bcfd Kitimat LNG in British Columbia and the 2.0 Bcfd Sabine Pass LNG in Louisiana.

In the **Cove Point Export Case**, the addition of 1.0 Bcfd of exports from Cove Point to the Reference Case moves the $6.00 per MMBtu benchmark year up to 2027, a matter of only two years. The difference at Dominion South Point in Pennsylvania, a market point in the Marcellus shale basin near the Cove Point facility, and therefore a measure of the immediate market area effects of Cove Point exports, is only $0.16 per MMBtu in 2040 ($6.17 vs. $6.01, or 2.7%), which indicates the strength of the supply resource in the Marcellus.

In the **Aggregate Export Case**, another 3.4 Bcfd of exports (the total of projected exports from the Lake Charles LNG facility in Louisiana and the Freeport LNG facility in Texas) were assumed in the model in addition to the projected exports at Cove Point. This addition causes prices at Henry Hub to rise somewhat sharply around 2020, as these LNG export facilities come online in large blocks of capacity, while supply continues to ramp up along a smoother line. The price rise at Henry Hub in 2020 is $0.58 per MMBtu ($5.27 vs. $5.85, or 11.0%). By 2030, supply has caught up with this compressed and concentrated creation of demand in the form of LNG exports, and the price difference between the Cove Point and the Aggregate Export cases falls back to $0.23 per MMBtu ($6.61 vs. $6.84, 3.5%). By 2040, the difference has widened somewhat again, to $0.49 per MMBtu (5.3%). The price at Dominion South Point in 2040 rises $0.35 per MMBtu ($6.52 vs. $6.17).

The **Extreme Demand Case** assumes the addition of another 6.7 Bcfd of demand in 2040 to the Aggregate Export Case. Of this, 4.7 Bcfd is natural gas vehicle demand derived from the U.S. Energy Information Administration's aggressive NGV demand from one of its scenarios in the its 2010 Annual Energy Outlook.[1] All in all, the Extreme Demand Case adds 10.1 Bcfd of demand to the Reference Case in 2040. In the Extreme Demand Case, prices at Henry Hub in 2020 are $6.16 per MMBtu, compared to $5.85 per MMBtu in the Aggregate Export Case, an increase of 5.4%. By 2040, the price difference is $1.56 per MMBtu ($11.20 vs $9.64, or 16.2%). Prices at Dominion South Point in 2040 are $6.83, $0.31 per MMBtu higher (4.8%) than in the Aggregate Export Case.

Due to projected supply growth in the Marcellus, prices at Dominion South Point are projected to be slightly lower in 2015 than in 2011, and then rise slowly. From 2015 onward, in all cases, prices at Dominion South Point are projected to move from a slight premium to Henry Hub to an increasing discount. By 2040, in the Extreme Demand Case, Dominion South Point's basis to Henry Hub declines to minus $4.37 per MMBtu. Other cases also show substantial discounts to Henry Hub at Dominion South Point by 2040. It should be noted that the low prices projected at Dominion South Point occur even though the Utica shale, another gas-bearing formation below the Marcellus, was

[1] *2027 Phaseout with Expanded Market Potential.* The EIA's scenario goes to 2035. In that year, NGV demand is 4.7 Bcfd. Navigant extended this number to 2040 through a straight-line extrapolation.

assumed to produce small amounts of gas only from its Canadian portion, and none (zero) from its U.S. portion. This assumption is highly conservative, given recent news about the potential of U.S. production from the Utica.

As a test, Navigant modeled the Aggregate Export Case and the Extreme Demand Case with Cove Point set to zero exports. With this 1.0 Bcfd of load removed, prices were somewhat lower, as would be expected. In the **Aggregate Export Case without Cove Point**, the price at Henry Hub was $0.29 per MMBtu lower in 2020 (5.1%), and $0.18 (1.9%) lower in 2040. In the **Extreme Demand Case without Cove Point**, the price at Henry Hub was $0.31 per MMBtu lower in 2020 (5.2%), declining to $0.19 (1.7%) lower in 2040.

In all cases, natural gas maintains its steep discount to the price of crude oil. In 2040, Navigant forecasts the price of oil to be $158 per barrel, which is equivalent to $27.25 per MMBtu.

| Year | Metric | Reference Case | Cove Point Export | Aggregate Export | Extreme Demand | *Aggregate Export without Cove Point* | *Extreme Demand without Cove Point* |
|---|---|---|---|---|---|---|---|
| 2020 | *Henry Hub* | $4.98 | $5.27 | $5.85 | $6.16 | *$5.56* | *$5.85* |
| | *Dominion South Point* | $4.92 | $5.22 | $5.74 | $6.04 | *$5.42* | *$5.71* |
| 2030 | *Henry Hub* | $6.35 | $6.61 | $6.84 | $8.03 | *$6.63* | *$7.63* |
| | *Dominion South Point* | $5.46 | $5.66 | $6.01 | $6.72 | *$5.60* | *$6.10* |
| 2040 | *Henry Hub* | $8.64 | $9.16 | $9.64 | $11.20 | *$9.46* | *$11.02* |
| | *Dominion South Point* | $6.01 | $6.17 | $6.52 | $6.83 | *$6.05* | *$6.30* |

**Table 1: Sample Output Prices of Selected Locations**[2]

Prices in the Cove Point Reference Case and the Cove Point Exports Case are significantly lower than those projected in the U.S. Energy Information Agency's 2009 *Annual Energy Outlook* Reference Case. This change is due to significant shale gas discoveries. For example, the EIA's 2009 Reference Case called for the 2030 price at Henry Hub to be $9.25 per MMBtu (in 2007 dollars), as shown in the following graph,[3] whereas the Cove Point Export Case calls for the 2030 price at Henry Hub to be $6.61 per MMBtu, or $2.64 lower. Even in the Extreme Demand Case, prices in 2030 are lower than the EIA's 2009 Reference Case prices.

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

[3] *Annual Energy Outlook 2009 with Projections to 2030*, Table 13, U.S. Energy Information Administration, available at http://www.eia.gov/oiaf/archive/aeo09/aeoref_tab.html. Prices in AEO 2009 were in $2007, which Navigant shows in **Table 2:** *EIA 2009 Reference Case Henry Hub Prices for Comparison*. For the sake of a normalized comparison, Navigant also escalated the $2007 prices to $2010 in an adjoining column.

| Year | EIA 2009 Reference Case ($2007) | EIA 2009 Reference Case ($2010) | Cove Point Export | Aggregate Export | Extreme Demand |
|---|---|---|---|---|---|
| 2010 | $6.66 | $6.96 | *N/A* | *N/A* | *N/A* |
| 2020 | $7.43 | $7.77 | $5.27 | $5.85 | $6.16 |
| 2030 | $9.25 | $9.68 | $6.61 | $6.84 | $8.03 |
| 2040 | *N/A* | *N/A* | $9.16 | $9.64 | $11.20 |

**Table 2: EIA 2009 Reference Case Henry Hub Prices for Comparison**

## Basic Modeling 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. For the purposes of developing the Reference Case for Dominion Cove Point LNG, Navigant extended the term to 2040. Navigant's Spring 2011 Forecast (issued in June 2011) forms the basis of the Dominion Cove Point LNG analysis.

Price projections for purposes of this report focus on Henry Hub, which is the underlying physical location of the natural gas NYMEX futures contract. Prices at Dominion South Point in central Pennsylvania is also included in this study to demonstrate the possible effect that Dominion Cove Point may have on supply and demand on a key natural gas market in the vicinity of the Cove Point LNG export facility. All prices are adjusted for future inflation and shown in constant 2010 dollars.

Gas volumes (by state or region), imports and exports (including gas by pipeline and LNG by terminal), storage, and sectoral gas demand are modeled on a monthly basis.

The model takes a mechanistic view of supply, demand, and prices. It does not employ price-smoothing algorithms to represent the market's anticipation of large infrastructure projects, such as pipelines and LNG facilities. Nor does Navigant adjust the model to reflect such market dynamics. Therefore, the introduction of large projects such as the Cove Point LNG export facility can manifest seemingly large jumps in price in the model, depending on the timing, as the demand increase appears to be instantaneous, while supply continues to increase along a steady trajectory. In reality, the market anticipates such events. There is a dynamic feedback mechanism between supply and demand, as well as an anticipatory element in the futures markets, that would rationalize supply, demand, and prices across a much longer time horizon, much of it preceding commissioning. As a result, these discontinuities tend to be minimized in the actual market. In the model, it may take some time for supply to catch up to this instantaneous demand. Price results should be reviewed with this in mind.

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

### Supply

All domestically-sourced supply in Navigant's Reference Case model comes from currently established basins in North America. The forecasts assume the addition of 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. (See the companion report ***North American Gas Supply Overview and Outlook to 2040*** for a more detailed discussion of supply issues.)

Navigant's Reference Case supply projection is that U.S. natural gas supply will grow from 58.5 Bcfd in 2010 to 80.5 Bcfd in 2040, an increase of 37 percent.

As a rule, Navigant's approach towards production capacity is the same for all cases. Estimates of production capacity are based on empirical production data. For example, the Utica Shale, a very large but undeveloped liquids-rich resource co-located with the Marcellus in the market area of Cove Point, is assumed in the model to produce only 0.9 Bcfd in 2040. 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 in the model results in a very small production forecast for the Utica shale.

An exception is made in the Aggregate Export and the Extreme Demand cases. In these cases, it is assumed that an increase in supply availability across key basins is the precipitator of such demand growth. Therefore, supply assumptions are somewhat larger in these scenarios, particularly in the Eagle Ford supply basin. For the Extreme Demand Case, the Alaska Pipeline is able to commence deliveries beginning in 2035, and reaches its full capacity of 4.5 Bcfd in 2040. Nonetheless, supply was added judiciously in locations where increased supply growth appears possible, so this remains a conservative approach. No "blanket" additions to supply were made, nor were any new resource plays hypothesized.

Navigant's Extreme Demand Case supply projection is that U.S. natural gas supply will grow from 58.5 Bcfd in 2010 to 89.7 Bcfd in 2040, an increase of 53 percent.

Navigant's model also assumes that additional supply may come into North America from LNG import projects. Such imports are solved for by the model as a response to demand and the price of gas in North America.

## Demand

Navigant's basic modeling assumption is that natural gas demand will respond dynamically to supply 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.

We recognize the debate about how quickly and to what level the gas resource can be developed. This debate includes risk factors around water availability and disposal and other environmental issues. In Navigant's view, the environmental issues, including water usage and disposal and lifecycle greenhouse gas emissions, favor natural gas over coal. As described in the accompanying report ***North American Gas Supply Overview and Outlook to 2040***, Navigant believes that water issues are likely to be regulated and managed so that the ability to produce gas from North American resources is not impacted.

Gas demand growth in our forecasts is also supported by growth in the deployment of renewable electric generation. Gas, being 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 in any circumstance due to price. Navigant sees oil maintaining its current multiple premium to 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, Navigant's opinion is that gas-fired generation will be the dominant mode of smoothing intermittent electric generation for the foreseeable future.

Navigant's market view is that domestic demand is likely to be supported by the export of LNG from North America. LNG exports represent the potential for a steady, reliable baseload market which will serve to underpin ongoing supply development. Further, the supply is ample. The combination of these two fundamental facts will tend to reduce uncertainty about supply development and as a corollary tend to reduce price volatility. While modeling shows that the U.S. will be a net exporter of LNG, it also shows that LNG imports will also continue to some extent. The largest import point is shown to be Elba Island in Georgia, at 0.5 Bcfd in 2040. The model makes no assumptions about international prices. These imports are responsive to signals embedded in price curves that model domestic U.S. prices only. In any case, LNG imports tend to be minimal over the time horizon of the study.

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 Extreme 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 import overseas pricing, which has historically been linked to higher-priced oil, into the North American gas market. In the high-demand Extreme Demand Case (detailed below), annual call on supply is 32.7 trillion cubic feet in 2040. Using the EIA's recent estimate of U.S. technically recoverable reserves of 2,543 Tcf,[4] this would be 1.3 percent of total reserves, leaving about 77 years of supply to meet domestic demand at that level, including all exports modeled, without exposing the domestic consumer to overseas, oil-linked prices.

Navigant's modeling and market research indicates that it is very unlikely that exports at these levels will increase the need for significant amounts of imported LNG. 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 domestic demand.

## Infrastructure

Navigant's modeling used existing 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

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[4] *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

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. This is a highly conservative assumption. It is likely that some measure of new pipeline will be constructed to support the ongoing development of the gas supply resource and the accompanying demand between 2014 and 2040. But in the absence of specific information, Navigant constrains its infrastructure expansion to those instances where an existing pipeline has become constrained. The remedy consists of adding sufficient capacity to relieve the constraint only.

Some proposed pipeline projects have been excluded from the Reference Case model, most notably the Mackenzie Pipeline in northern Canada, which we believe to be uneconomic and facing significant environmental challenges, absent significant new developments in the marketplace. Likewise, the Alaska Gas Pipeline project is also assumed to be nonoperational in the Reference Case. On the other hand, several large regional pipelines are assumed to be operational by 2015, including Fayetteville Express and Tiger.

In the Aggregate Export and Extreme Demand Cases, the Alaska Gas Pipeline project is assumed to be online in 2035 at a capacity of 4.5 Bcfd, as it is seen as becoming strategically viable in the supply environments within those scenarios. See Appendix A for a list of 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.

### LNG Facilities

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

It is important to note that Navigant's Spring 2011 Forecast includes two LNG export facilities besides Cove Point. 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. 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.

In order to provide stress scenarios to examine the effect of exporting domestically –sourced LNG, two additional LNG export facilities were included in the Aggregate Export and Extreme Demand cases. These facilities were selected based on public announcements of intent, and 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* | *Cove Point* | *Aggregate* | *Extreme* |
| Sabine Pass | 2.0 | Cameron Parish, LA | • | • | • | • |
| Kitimat | 0.7 | District of Kitimat-Stikine, BC | • | • | • | • |
| Cove Point | 1.0 | Calvert County, MD | | • | • | • |
| Freeport | 1.4 | Brazoria County, TX | | | • | • |
| Lake Charles | 2.0 | Lake Charles, LA | | | • | • |
| **Total** | **7.1** | | | | | |

**Table 3: LNG Export Facilities 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 2040, 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 2009 dollars.

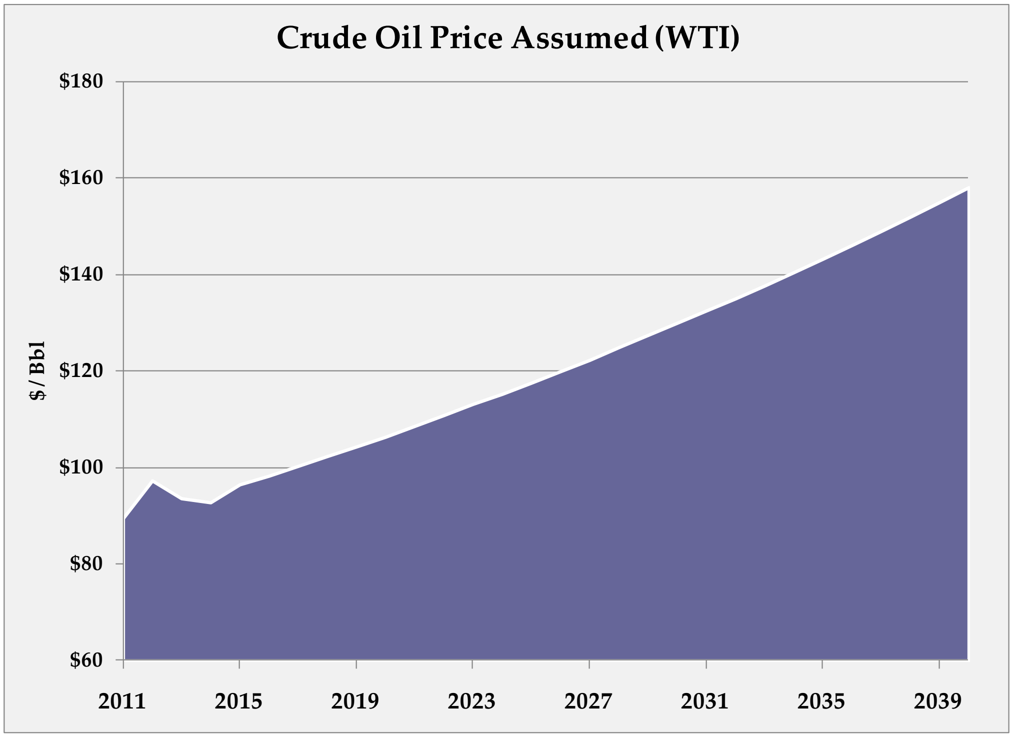


**Figure 1: WTI Price Assumed in Natural Gas Price Forecast**

### Economic Growth

Navigant uses 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 based on EIA projections from its 2011 Annual Energy Outlook. NGV demand is not significant except in the Extreme Demand Case. See **Scenario Descriptions**, below, for a further discussion of NGV demand.

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### Scenario Descriptions

| *Case Name* | *Description* |
|---|---|
| **Reference Case** | The **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 mid-Atlantic market based on late and improved information.<br><br>The Base Case assumes that two other LNG export facilities in North America will be operational prior to and concurrent with Cove Point: 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. |
| **Cove Point Export Case** | The **Cove Point Export Case** augments the Reference Case with exports from the Cove Point export facility of approximately **1.0 Bcfd** beginning late December, 2016. No other changes are made. The effects on prices are the specific focus. |
| **Aggregate Export Case** | The **Aggregate Export Case** adds to the Cove Point Export Case two additional LNG facilities which have applied for export authority. Freeport LNG is modeled to start at 0.4 Bcfd in January 2016. Lake Charles Exports starts at 0.5 Bcfd in January 2017, with three incremental additions of 0.5 Bcfd every six to nine months. These facilities reach their full export capacity in June 2019, with a combined incremental output of roughly 3.4 Bcfd. In total, all North American LNG export facilities modeled in the Aggregate Export Case is approximately 7.1 Bcfd. The effects on prices are the specific focus. |
| **Extreme Demand Case** | The **Extreme Demand Case** uses the same infrastructure and LNG export assumptions as the Aggregate Export Case, but demand is increased substantially in two ways. First, demand from the Navigant Spring 2011 *Carbon Case* Forecast is used which, incorporates the increased gas demand and supply effects of coal-to-gas substitution driven by the ongoing cost-competitiveness of gas with coal, extrapolating recently-observed market trends. Second, the Extreme Demand Case incorporates demand for natural gas as a vehicle fuel from the U.S. EIA's *2027 Phaseout With Expanded Market Potential* from its 2010 Annual Energy Outlook. NGV demand in the Expanded Market scenario, which goes to 2035, is almost ten times higher than in the EIA's 2011 Reference Case. (The "phaseout" refers to the timing of terminating government incentives for NGV development.) Navigant extrapolated the EIA's demand to derive numbers for the 2036-2040 timeframe. The effects on prices are the specific focus. |

## Reference Case Results

The **Cove Point Reference Case** was derived from Navigant's Spring 2011 Reference Case. Certain refinements to the infrastructure in the Northeast were made, based on more detailed information that was incorporated subsequent to the Navigant Spring 2011 Reference Case.

### Supply

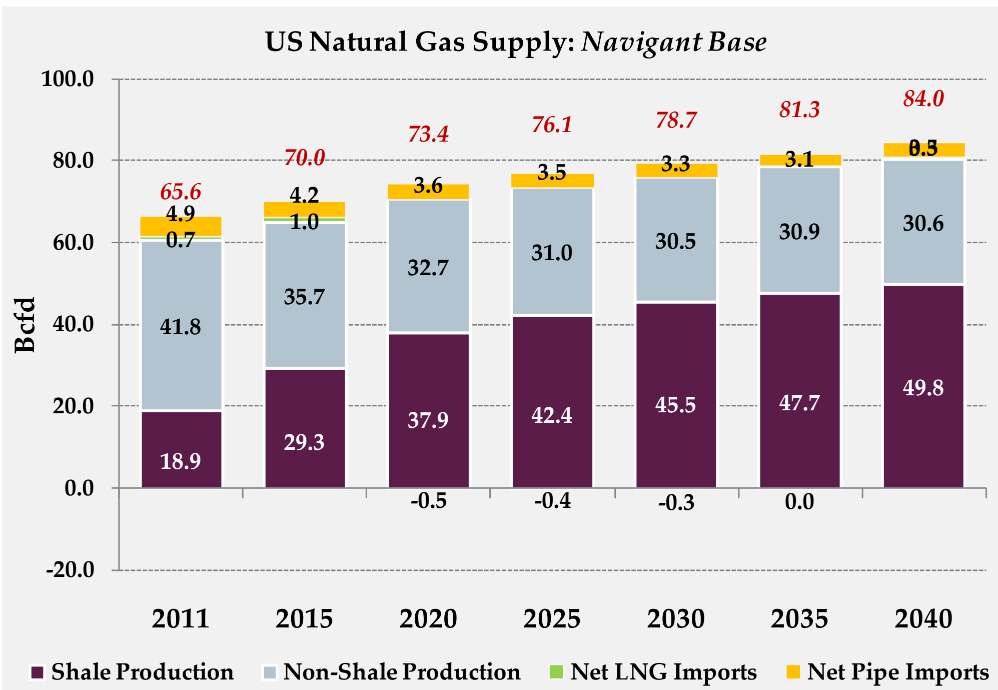


**Figure 2: Reference Case Supply**

Beginning around 2020, net pipeline imports to the U.S. are negative, as gas is exported from the Marcellus shale into Canada. Also in 2020, the U.S. becomes a net exporter of LNG.

## Demand

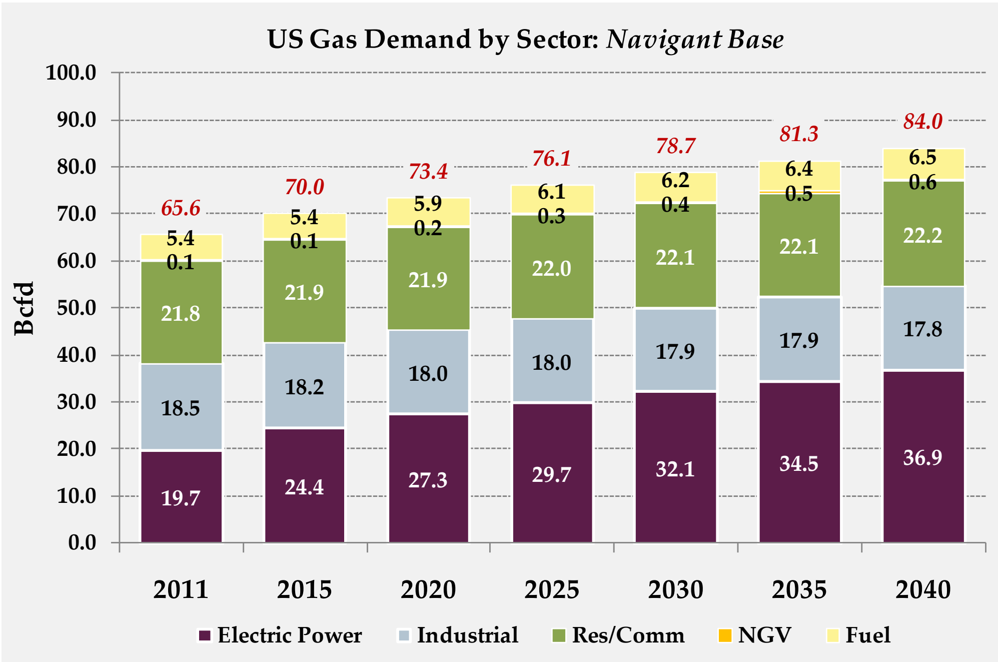


**Figure 3: Reference Case Demand**

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

### Resultant Gas Prices

Prices remain below $5.00 per MMBtu through 2020. After 2020, prices rise due to generally increasing marginal costs of additional domestic production.

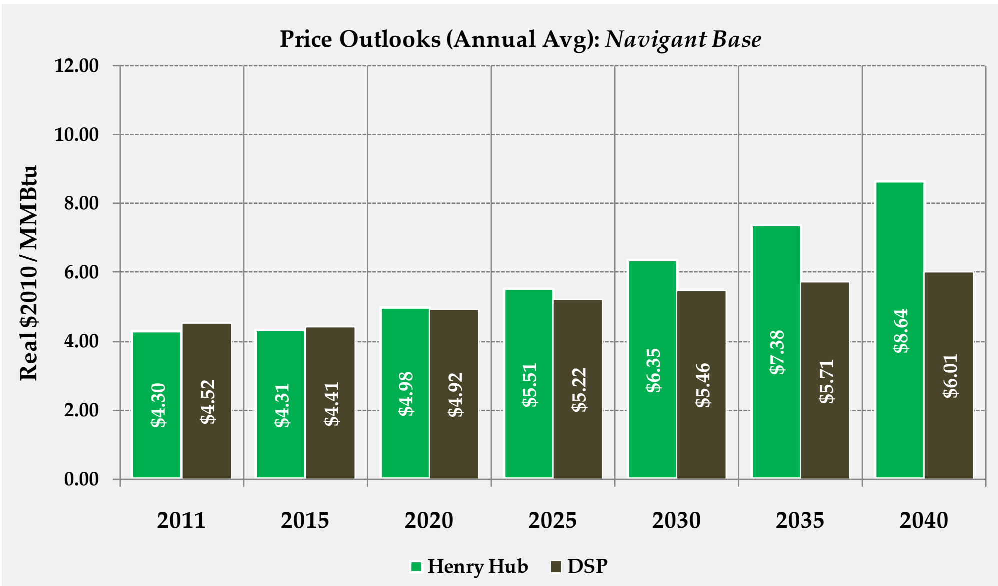


**Figure 4: Reference Case Prices**

Prices at Dominion South Point (in Pennsylvania) climb much more slowly than at Henry Hub throughout the forecast period, as the immediately adjacent Marcellus shale basin increasingly becomes the dominant supply in the mid-Atlantic region.

## Cove Point Export Case Results

The **Cove Point Export Case** tests the effects of liquefying and exporting 1.0 Bcfd of domestically-sourced gas from the Cove Point facility beginning late December 2016. All other inputs and assumptions remain the same as in the Reference Case.

Cove Point was modeled in two modes: with the ability to import, and with such ability suppressed (**Cove Point Export Alternative Case**) so that it functioned exclusively as an export facility. No significant differences in supply, demand, or prices were observed. Price differences are shown in **Table 7:** *Changes in Prices in Cove Point Export Case.*

### Supply

Adding 1.0 Bcfd of exported LNG at Cove Point does not change overall supply from the Reference Case. Net LNG imports back off by 0.9 Bcfd in 2020 (1.4 Bcfd compared to 0.5 Bcfd of exports), and by 0.6 Bcfd in 2040, compared to the Reference Case. This reduction in imports is spread across all import terminals in the U.S. To balance, domestic production increases by 0.9 Bcfd and pipeline imports increase by 0.3 Bcfd, while LNG imports are reduced by 0.3 Bcfd.

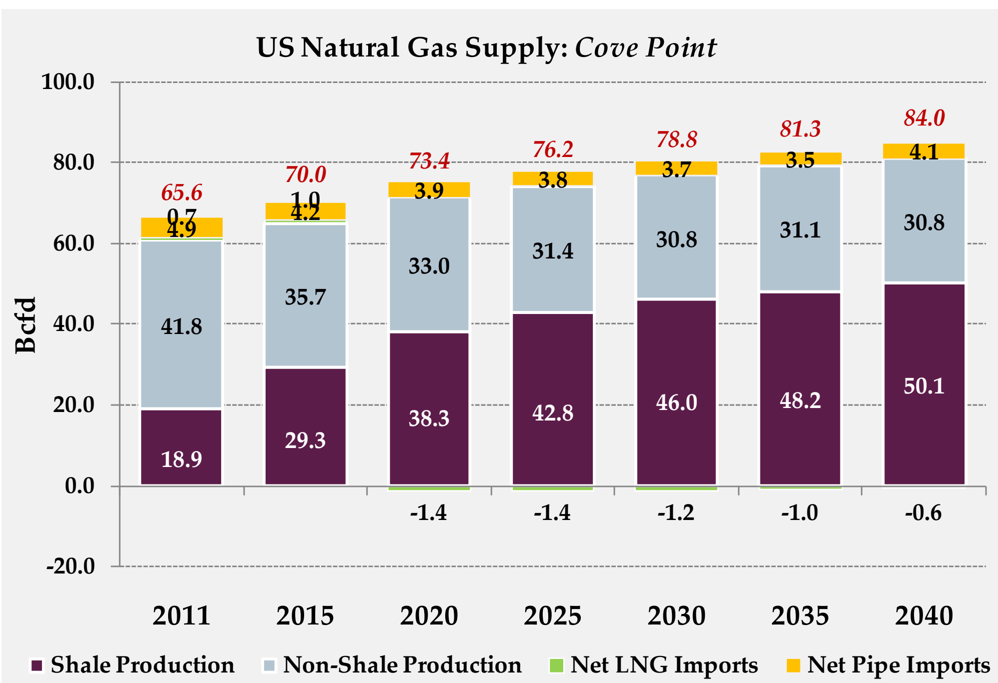


**Figure 5: Cove Point Export Supply**

| Year | Metric | Reference Case | Cove Point Export | Difference |
|---|---|---|---|---|
| 2020 | *Shale Production* | 37.9 | 38.3 | 0.4 |
| | *Non-shale Production* | 32.7 | 33.0 | 0.3 |
| | *Net LNG Imports* | -0.5 | -1.4 | -0.9 |
| | *Net Pipe Imports* | 3.6 | 3.9 | 0.3 |
| | ***Total Supply*** | **73.4** | **73.4** | **0.0** |
| 2030 | *Shale Production* | 45.5 | 46.0 | 0.5 |
| | *Non-shale Production* | 30.5 | 30.8 | 0.3 |
| | *Net LNG Imports* | -0.3 | -1.2 | -0.9 |
| | *Net Pipe Imports* | 3.3 | 3.7 | 0.3 |
| | ***Total Supply*** | **78.7** | **78.8** | **0.1** |
| 2040 | *Shale Production* | 49.8 | 50.1 | 0.3 |
| | *Non-shale Production* | 30.6 | 30.8 | 0.1 |
| | *Net LNG Imports* | 0.3 | -0.6 | -0.9 |
| | *Net Pipe Imports* | 3.5 | 4.1 | 0.5 |
| | ***Total Supply*** | **84.0** | **84.0** | **0.0** |

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

## Demand

Adding 1.0 Bcfd at Cove Point for export does not alter the demand mix appreciably from the Reference Case. Fuel usage increases slightly, reflecting an increase in domestic production and fuel usage at the Cove Point facility.

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

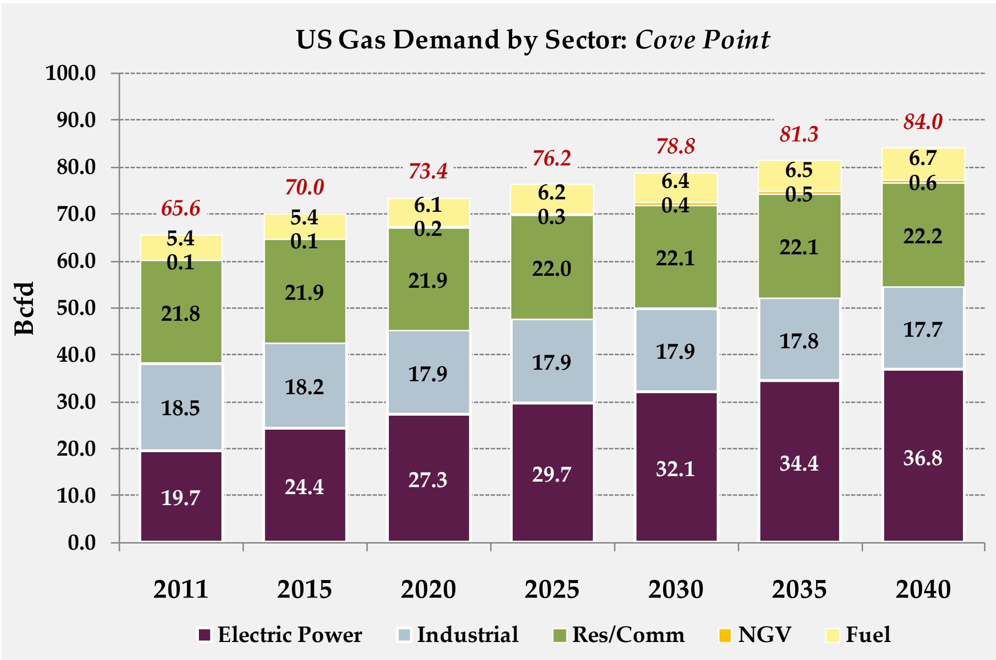


**Figure 6: Cove Point Export Demand**

| Year | Metric | Reference Case | Cove Point Export | Difference |
|---|---|---|---|---|
| 2020 | *Electric Power* | 27.3 | 27.3 | 0.0 |
| | *Industrial* | 18.0 | 17.9 | -0.1 |
| | *Res/Comm* | 21.9 | 21.9 | 0.0 |
| | *NGV* | 0.2 | 0.2 | 0.0 |
| | ***Total Consumption*** | **73.4** | **73.4** | **0.0** |
| 2030 | *Electric Power* | 32.1 | 32.1 | 0.0 |
| | *Industrial* | 17.9 | 17.9 | -0.1 |
| | *Res/Comm* | 22.1 | 22.1 | 0.0 |
| | *NGV* | 0.4 | 0.4 | 0.0 |
| | ***Total Consumption*** | **78.7** | **78.8** | **0.1** |
| 2040 | *Electric Power* | 36.9 | 36.8 | 0.0 |
| | *Industrial* | 17.8 | 17.7 | -0.1 |
| | *Res/Comm* | 22.2 | 22.2 | 0.0 |
| | *NGV* | 0.6 | 0.6 | 0.0 |
| | ***Total Consumption*** | **84.0** | **84.0** | **0.0** |

**Table 6: Changes in Demand in Cove Point Export Case**[6]

[6] "Total consumption" includes pipeline fuel and lease and plant fuel.

## Resultant Gas Prices

Prices at Henry Hub are slightly higher in the **Cove Point Export Case** compared to the Reference Case (by 5.7% in 2020, 4.1% in 2030, and 6.0% in 2040), due to the additional demand created by export of 1.0 Bcfd of LNG. Prices at Dominion South Point also rise slightly compared to the Reference Case, although the increases at Dominion South Point are muted due to strong Marcellus supply.

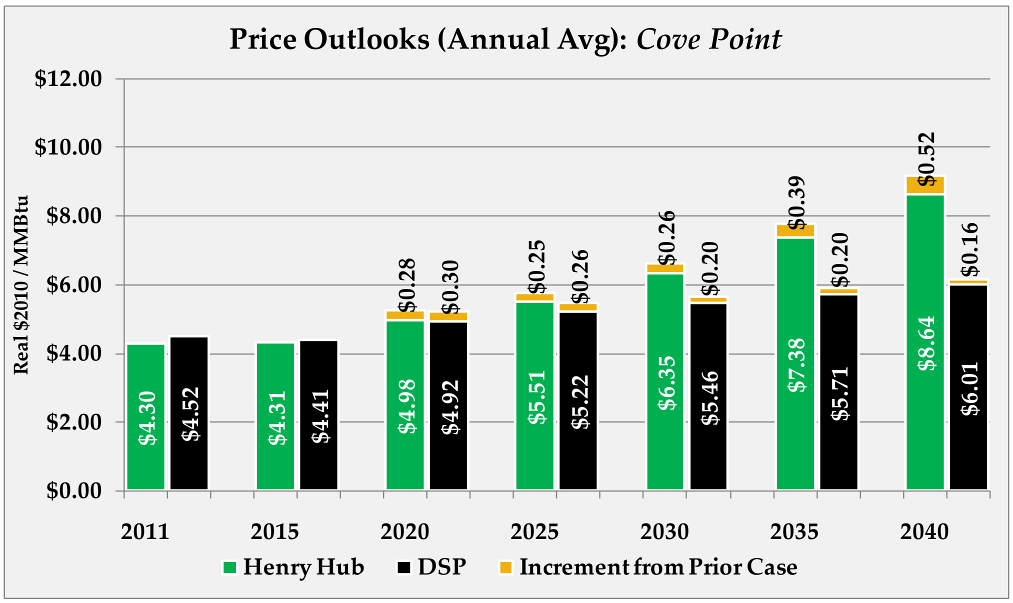


**Figure 7: Cove Point Export Case Prices**

| | | A | B | C=A-B | D=A/B-1 | E | F=A-E | G=A/E-1 |
|---|---|---|---|---|---|---|---|---|
| **Year** | **Metric** | **Cove Point Export** | **Reference Case** | ***Absolute Difference*** | *Percentage Difference* | **Cove Point Alt** | ***Absolute Difference*** | *Percentage Difference* |
| **2020** | *Henry Hub* | **$5.27** | **$4.98** | *$0.28* | *5.7%* | **$5.29** | *-$0.02* | *-0.4%* |
| | *Dominion South Point* | **$5.22** | **$4.92** | *$0.30* | *6.2%* | **$5.24** | *-$0.02* | *-0.4%* |
| **2030** | *Henry Hub* | **$6.61** | **$6.35** | *$0.26* | *4.1%* | **$6.63** | *-$0.02* | *-0.3%* |
| | *Dominion South Point* | **$5.66** | **$5.46** | *$0.20* | *3.6%* | **$5.67** | *-$0.01* | *-0.2%* |
| **2040** | *Henry Hub* | **$9.16** | **$8.64** | *$0.52* | *6.0%* | **$9.22** | *-$0.06* | *-0.7%* |
| | *Dominion South Point* | **$6.17** | **$6.01** | *$0.16* | *2.7%* | **$6.19** | *-$0.02* | *-0.3%* |

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

## Aggregate Export Case Results

The **Aggregate Export Case** adds LNG exports at Freeport LNG in Texas (1.4 Bcfd) and Lake Charles in Louisiana (2.0 Bcfd) to the Cove Point Export Case. In all, the **Aggregate Export Case** contains North American.-based LNG export capacity of 7.1 Bcfd.

All LNG export facilities are modeled at a high 90 percent capacity factor, a conservative assumption. Actual capacity factors are likely to be lower. Additionally, no judgment is made as to which among these facilities may or may not be actually approved, constructed, and operational; they are all simply assumed to be online. This is also a conservative assumption.

A supply pipeline of 0.5 Bcfd from the Marcellus to Transco Zone 5 was input into this model in the year 2030.

### Supply

Total net supply available to the U.S. consuming market in the **Aggregate Export Case** is essentially the same as the total supply in the Reference and Cove Point Export cases. The distribution of supply among sectors changes somewhat. In 2020, net exports of 4.6 Bcfd (compared to 1.4 Bcfd in the Cove Point Case) coincide with an increase of 3.2 Bcfd from the combination of all non-LNG sources of supply (shale production, non-shale production, and net pipe imports).

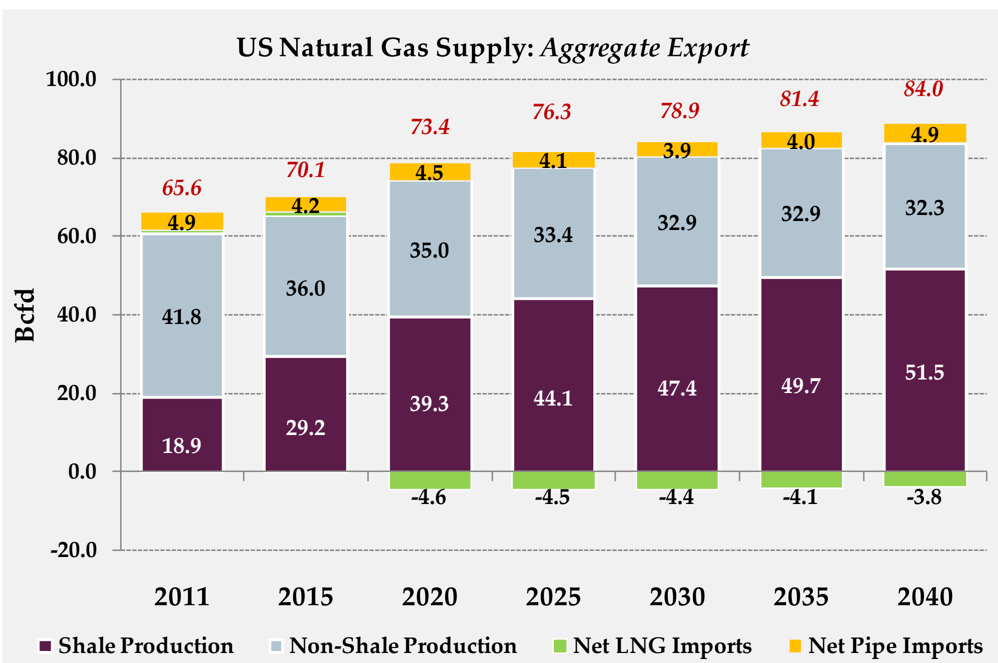


**Figure 8: Aggregate Export Case Supply**

| Year | Metric | Cove Point Export | Aggregate Export | Difference |
|---|---|---|---|---|
| 2020 | *Shale Production* | 38.3 | 39.3 | 1.0 |
| | *Non-shale Production* | 33.0 | 35.0 | 1.9 |
| | *Net LNG Imports* | -1.4 | -4.6 | -3.1 |
| | *Net Pipe Imports* | 3.9 | 4.5 | 0.6 |
| | ***Total Supply*** | **73.4** | **73.4** | **0.0** |
| 2030 | *Shale Production* | 46.0 | 47.4 | 1.4 |
| | *Non-shale Production* | 30.8 | 32.9 | 2.1 |
| | *Net LNG Imports* | -1.2 | -4.4 | -3.2 |
| | *Net Pipe Imports* | 3.7 | 3.9 | 0.2 |
| | ***Total Supply*** | **78.8** | **78.9** | **0.1** |
| 2040 | *Shale Production* | 50.1 | 51.5 | 1.4 |
| | *Non-shale Production* | 30.8 | 32.3 | 1.5 |
| | *Net LNG Imports* | -0.6 | -3.8 | -3.2 |
| | *Net Pipe Imports* | 4.1 | 4.9 | 0.8 |
| | ***Total Supply*** | **84.0** | **84.0** | **0.1** |

**Table 8: Changes in Supply in Aggregate Export Case**

## Demand

The distribution of demand among sectors does not change appreciably from the **Cove Point Export Case**.

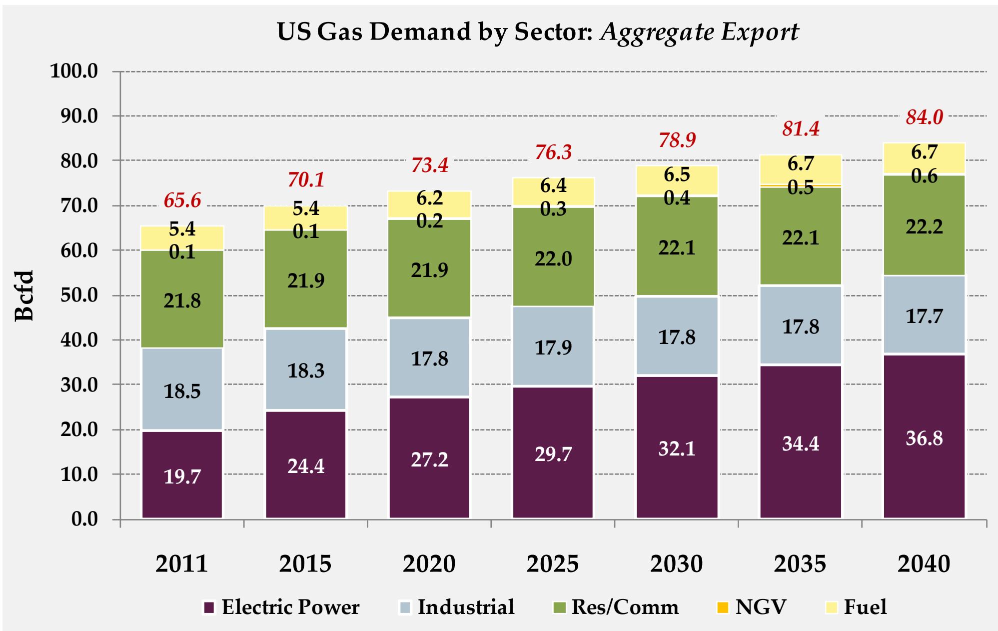


**Figure 9: Aggregate Export Case Demand**

| Year | Metric | Cove Point Export | Aggregate Export | Difference |
|---|---|---|---|---|
| 2020 | *Electric Power* | 27.3 | 27.2 | -0.1 |
| | *Industrial* | 17.9 | 17.8 | -0.1 |
| | *Res/Comm* | 21.9 | 21.9 | 0.0 |
| | *NGV* | 0.2 | 0.2 | 0.0 |
| | ***Total Consumption*** | **73.4** | **73.4** | **0.0** |
| 2030 | *Electric Power* | 32.1 | 32.1 | 0.0 |
| | *Industrial* | 17.9 | 17.8 | 0.0 |
| | *Res/Comm* | 22.1 | 22.1 | 0.0 |
| | *NGV* | 0.4 | 0.4 | 0.0 |
| | ***Total Consumption*** | **78.8** | **78.9** | **0.1** |
| 2040 | *Electric Power* | 36.8 | 36.8 | 0.0 |
| | *Industrial* | 17.7 | 17.7 | 0.0 |
| | *Res/Comm* | 22.2 | 22.2 | 0.0 |
| | *NGV* | 0.6 | 0.6 | 0.0 |
| | ***Total Consumption*** | **84.0** | **84.0** | **0.1** |

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

### Resultant Gas Prices

Prices at Henry Hub rise somewhat sharply, by $0.58 per MMBtu (11.0%), at the 2020 mark in the **Aggregate Export Case**, compared to the Cove Point Export Case. This is due to the compressed time frame in which the additional 3.4 Bcfd of liquefaction capacity comes on line in 2017-2019, while supply grows at a measured pace. The price differential shrinks by 2030 to $0.23 (3.5%), and then widens again to $0.49 (5.3%) by 2040.

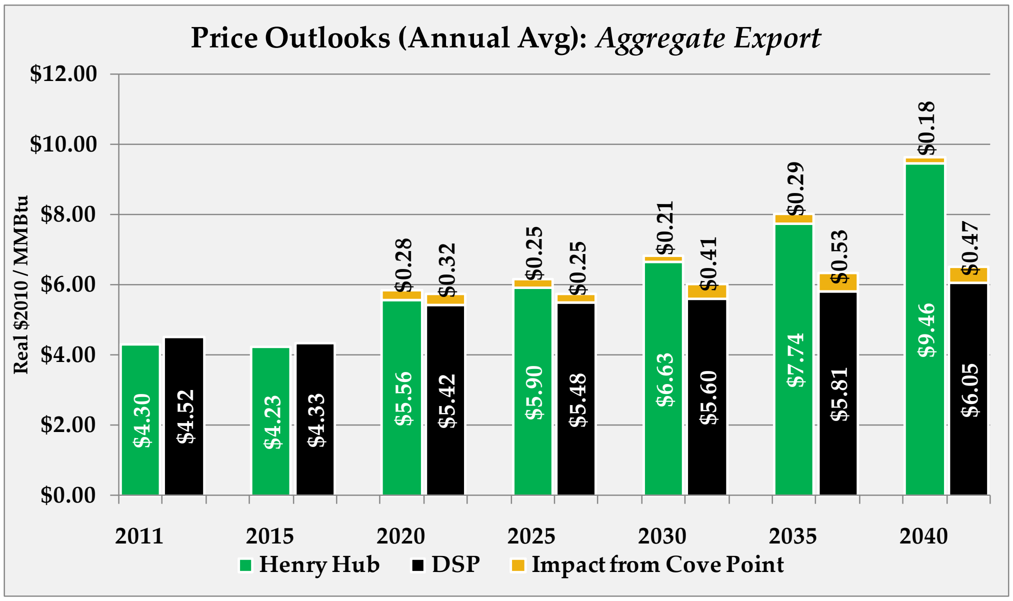


**Figure 10: Aggregate Export Case Prices**

Prices at Dominion South Point remain appreciably lower than Henry Hub, only reaching $6.52 in 2040. As in the previous two scenarios, the strength of Marcellus supplies moderates price increases at Dominion South Point.

Navigant also modeled the **Aggregate Export Case** with Cove Point set to zero exports. With this 1.0 Bcfd of load removed, prices were somewhat lower, as would be expected. In the **Aggregate Export Case without Cove Point,** the price at Henry Hub was $0.29 per MMBtu lower in 2020 (5.1%), declining to $0.18 (1.9%) lower in 2040. The effects can be more completely seen below at **Table 10:** *Changes in Prices in Aggregate Export Case.*

| | | A | B | C=A-B | D=A/B-1 | E | F=A-E | G=A/E-1 |
|---|---|---|---|---|---|---|---|---|
| **Year** | **Metric** | **Aggregate Export** | **Cove Point Export** | ***Absolute Difference*** | ***Percentage Difference*** | **Aggregate Export *without* Cove Point** | ***Absolute Difference*** | ***Percentage Difference*** |
| **2020** | *Henry Hub* | **$5.85** | **$5.27** | *$0.58* | *11.0%* | **$5.56** | *$0.28* | *5.1%* |
| | *Dominion South Point* | **$5.74** | **$5.22** | *$0.51* | *9.9%* | **$5.42** | *$0.32* | *5.8%* |
| **2030** | *Henry Hub* | **$6.84** | **$6.61** | *$0.23* | *3.5%* | **$6.63** | *$0.21* | *3.1%* |
| | *Dominion South Point* | **$6.01** | **$5.66** | *$0.35* | *6.1%* | **$5.60** | *$0.41* | *7.3%* |
| **2040** | *Henry Hub* | **$9.64** | **$9.16** | *$0.49* | *5.3%* | **$9.46** | *$0.18* | *1.9%* |
| | *Dominion South Point* | **$6.52** | **$6.17** | *$0.35* | *5.6%* | **$6.05** | *$0.47* | *7.8%* |

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

## Extreme Demand Case Results

The **Extreme Demand Case** builds on the Aggregate Export Case by adding a significant amount of demand as a stress test.

Navigant's full gas demand is modeled, along with the EIA's very aggressive natural gas vehicle demand from its *2027 Phaseout With Expanded Market Potential* scenario, in the **Extreme Demand Case**.

### Supply

Total net supply available to the U.S. consuming market in the **Extreme Demand Case** is significantly higher than total supply in the Reference, Cove Point Export, and Aggregate Export cases. This increase ranges from 0.2 Bcfd higher in 2015 to 6.0 Bcfd higher in 2040. The 6.0 Bcfd in 2040 is largely from an increase in domestic production of 6.2 Bcfd when compared to the Aggregate Export Case (an increase in net LNG imports of 0.2 Bcfd with a decrease in net pipeline imports of 0.3 Bcfd balance the 6.0 Bcfd of increased total supply).

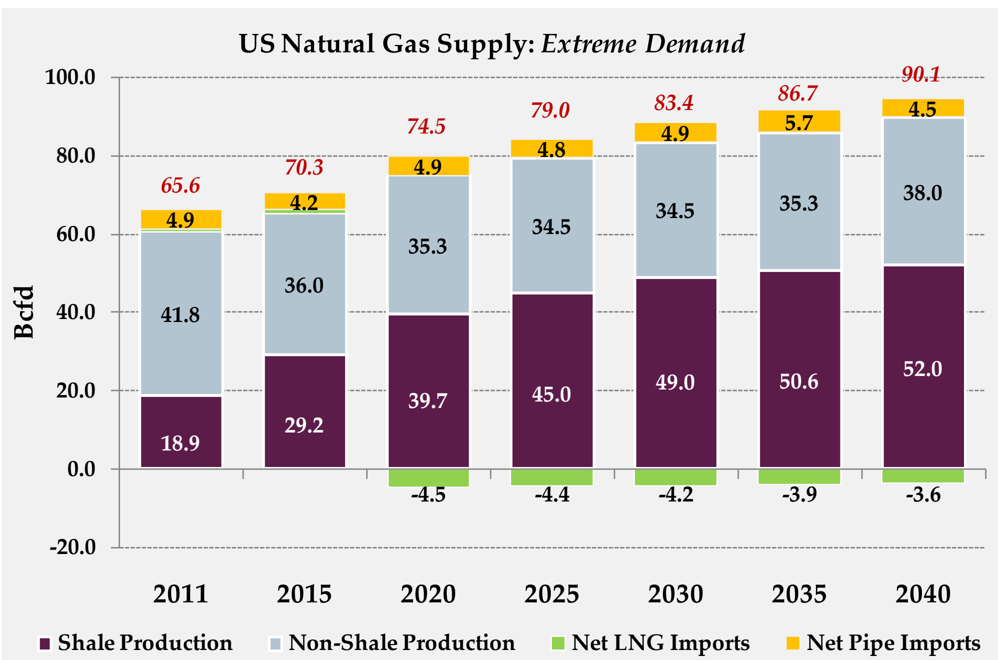


**Figure 11: Extreme Demand Case Supply**

| Year | Metric | Aggregate Export | Extreme Demand | Difference |
|---|---|---|---|---|
| 2020 | *Shale Production* | 39.3 | 39.7 | 0.4 |
| | *Non-shale Production* | 35.0 | 35.3 | 0.3 |
| | *Net LNG Imports* | -4.6 | -4.5 | 0.1 |
| | *Net Pipe Imports* | 4.5 | 4.9 | 0.3 |
| | ***Total Supply*** | **73.4** | **74.5** | **1.1** |
| 2030 | *Shale Production* | 47.4 | 49.0 | 1.7 |
| | *Non-shale Production* | 32.9 | 34.5 | 1.5 |
| | *Net LNG Imports* | -4.4 | -4.2 | 0.3 |
| | *Net Pipe Imports* | 3.9 | 4.9 | 1.0 |
| | ***Total Supply*** | **78.9** | **83.4** | **4.5** |
| 2040 | *Shale Production* | 51.5 | 52.0 | 0.5 |
| | *Non-shale Production* | 32.3 | 38.0 | 5.7 |
| | *Net LNG Imports* | -3.8 | -3.6 | 0.2 |
| | *Net Pipe Imports* | 4.9 | 4.5 | -0.3 |
| | ***Total Supply*** | **84.0** | **90.1** | **6.0** |

**Table 11: Changes in Supply in the Extreme Demand Case**

## Demand

Total U.S. demand is higher in the **Extreme Demand Case** from higher electric generation and NGV demand compared to the Reference, Cove Point Exports, and Aggregate Export cases. In 2020, total demand is 1.1 Bcfd higher from an increase of 0.9 Bcfd in electric power demand and 0.5 Bcfd in NGV demand, and a decrease in industrial demand of 0.1 Bcfd. Total demand increases by 6.0 Bcfd by 2040, with an increase in electric power demand of 2.1 Bcfd and NGV demand of 4.7 Bcfd, and a decrease in industrial demand of 1.2 Bcfd, compared to the other cases.

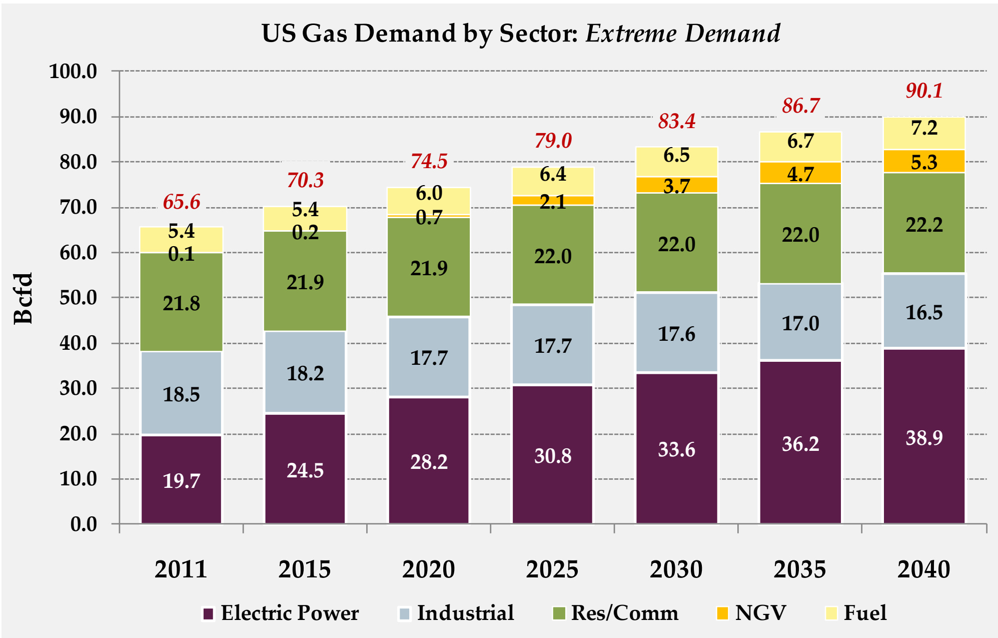


**Figure 12: Extreme Demand Case Demand**

| Year | Metric | Aggregate Export | Extreme Demand | Difference |
|---|---|---|---|---|
| **2020** | *Electric Power* | 27.2 | 28.2 | 0.9 |
| | *Industrial* | 17.8 | 17.7 | -0.1 |
| | *Res/Comm* | 21.9 | 21.9 | 0.0 |
| | *NGV* | 0.2 | 0.7 | 0.5 |
| | ***Total Consumption*** | **73.4** | **74.5** | **1.1** |
| **2030** | *Electric Power* | 32.1 | 33.6 | 1.6 |
| | *Industrial* | 17.8 | 17.6 | -0.2 |
| | *Res/Comm* | 22.1 | 22.0 | -0.1 |
| | *NGV* | 0.4 | 3.7 | 3.3 |
| | ***Total Consumption*** | **78.9** | **83.4** | **4.5** |
| **2040** | *Electric Power* | 36.8 | 38.9 | 2.1 |
| | *Industrial* | 17.7 | 16.5 | -1.2 |
| | *Res/Comm* | 22.2 | 22.2 | 0.0 |
| | *NGV* | 0.6 | 5.3 | 4.7 |
| | ***Total Consumption*** | **84.0** | **90.1** | **6.0** |

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

### Resultant Gas Prices

Prices at Henry Hub rise $0.31 per MMBtu (5.4%), at the 2020 mark in the **Extreme Demand Case**, compared to the Aggregate Export Case. This premium widens over time due to the steadily increasing demand from electric generation and NGV. The price differential reaches $1.19 per MMBtu (17.4%) by 2030 and $1.56 per MMBtu (16.2%) by 2040. Aside from the Alaska pipeline in 2040, no additional pipelines or expansions were added to the model, except for the 0.5 Bcfd of Marcellus supply connected directly to the Transco system carried over from the Aggregate Export Case. A portion of this price increase is thought to be attributable to infrastructure constraints.

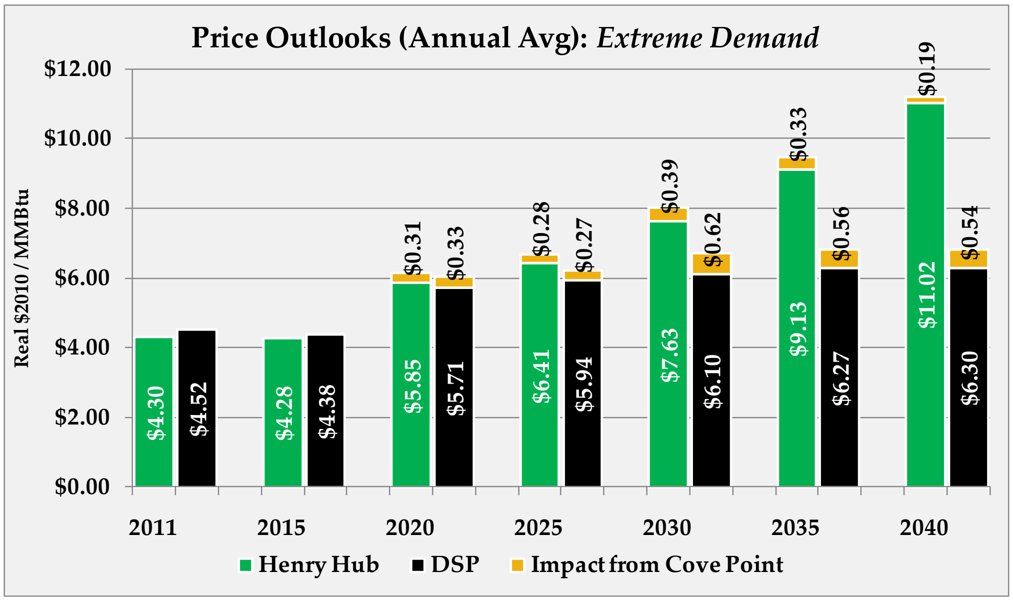


**Figure 13: Extreme Demand Case Prices**

Dominion South Point shows less movement after 2020 compared to Henry Hub in this scenario, showing a $0.71 per MMBtu increase in 2030 and a $0.31 per MMBtu increase in 2040. As in the previous three scenarios, the strength of Marcellus supplies moderates price increases at Dominion South Point.

Navigant also modeled the **Extreme Demand Case** with Cove Point set to zero exports. With this 1.0 Bcfd of load removed, prices were somewhat lower, as would be expected. In the **Extreme Demand Case without Cove Point**, the price at Henry Hub was $0.31 per MMBtu lower in 2020 (5.2%), declining to $0.19 (1.7%) lower in 2040. The effects can be more completely seen below at **Table 13:** *Changes in Prices in Extreme Demand Case*.

| | | A | B | C=A-B | D=A/B-1 | E | F=A-E | G=A/E-1 |
|---|---|---|---|---|---|---|---|---|
| **Year** | **Metric** | **Extreme Demand** | **Aggregate Export** | ***Absolute Difference*** | ***Percentage Difference*** | **Extreme Demand *without* Cove Point** | ***Absolute Difference*** | ***Percentage Difference*** |
| **2020** | *Henry Hub* | **$6.16** | **$5.85** | *$0.31* | *5.4%* | **$5.85** | *$0.31* | *5.2%* |
| | *Dominion South Point* | **$6.04** | **$5.74** | *$0.31* | *5.4%* | **$5.71** | *$0.33* | *5.8%* |
| **2030** | *Henry Hub* | **$8.03** | **$6.84** | *$1.19* | *17.4%* | **$7.63** | *$0.39* | *5.1%* |
| | *Dominion South Point* | **$6.72** | **$6.01** | *$0.71* | *11.9%* | **$6.10** | *$0.62* | *10.1%* |
| **2040** | *Henry Hub* | **$11.20** | **$9.64** | *$1.56* | *16.2%* | **$11.02** | *$0.19* | *1.7%* |
| | *Dominion South Point* | **$6.83** | **$6.52** | *$0.31* | *4.8%* | **$6.30** | *$0.54* | *8.5%* |

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

## Appendix A: 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 | Year | Capacity (MMcfd) | Pipeline | Year | Capacity (MMcfd) |
| Bison Pipeline | Jan-2011 | 477 | Gulf Crossing | Jan-2015 | 1,000 |
| Houston Pipeline Co (HPL S Tx) | Jan-2011 | 400 | Texas Gas Transmission (Fayetteville) | Jan-2015 | 150 |
| Florida Gas Phase VIII Exp | Apr-2011 | 820 | Wyoming Interstate (Mainline) | Jan-2015 | 225 |
| Ruby Pipeline | Jul-2011 | 1,250 | Questar Pipeline (Fidlar to KRGT) | Jan-2018 | 400 |
| LNG Golden Pass | Jul-2011 | 1,000 | Rockies Express (REX Z1 Wam) | Jan-2018 | 332 |
| Acadian Pipeline (HH) | Sep-2011 | 1,200 | White River Hub | Jan-2018 | 500 |
| Gulfstream Pipeline | Nov-2011 | 35 | Wyoming Interstate (Kanda Lat) | Jan-2018 | 400 |
| Algonquin (Algonquin J) | Jan-2012 | 400 | Alliance Pipeline (CAN BC) | Jan-2020 | 850 |
| Midcontinent Express Pipeline (MEP Z1) | Jan-2012 | 200 | Kern River (CA/Mainline/NV) | Jan-2020 | 500 |
| PNGT (N & S of Westbrook) | Jan-2012 | 310 | KM Border Pipeline | Jan-2020 | 300 |
| Northwest Pipeline (Plymouth Sta. / Washougal Sta. / Stanfield) | Nov-2012 | 239 | KM Mexico | Jan-2020 | 425 |
| Florida Gas (Mkt Northern) | Jan-2014 | 500 | KM Texas Pipeline (AguaDulce) | Jan-2020 | 250 |
| Southern Crossing | Jan-2014 | 400 | Mojave (Mojave-Kern Common Facilities) | Jan-2020 | 200 |
| Enterprise Texas (Valero/Teco) (S Tx) | Jun-2014 | 200 | Nova (TCPL Alberta System) (Gordondale Gr Prairie) | Jan-2020 | 4,500 |
| LNG Manzanillo | Jul-2014 | 500 | Wyoming Interstate (Mainline) | Jan-2020 | 500 |
| Algonquin (Algonquin NJ NY) | Nov-2014 | 800 | Cypress Pipeline | May-2020 | 500 |
| CrossTex North Texas (N Texas) | Jan-2015 | 750 | Nova (Groundbirch) | Jan-2022 | 1,344 |
| El Paso (Samalayuca Line) | Jan-2015 | 312 | White River Hub | Jan-2023 | 500 |
| Enterprise Jonah Gathering (Jonah Wy Gath) | Jan-2015 | 600 | Kern River (Kern River Opal to Muddy Ck) | Jan-2025 | 440 |
| Florida Gas (Mkt Panhandle) | Jan-2015 | 500 | KM Border Pipeline | Jan-2025 | 300 |
| Florida Gas (Zone 3) | Jan-2015 | 500 | Transwestern (Topock to Calpine) | Jan-2025 | 80 |
| Grasslands Pipeline | Jan-2015 | 200 | DCP E TX Carthage Gathering | Jan-2027 | 250 |

* Northeast projects identified separately in following table.

| Northeast Pipeline Expansion Projects 2011 and Beyond | In Service Date | Added Capacity (MMcfd) |
|---|---|---|
| TCO 1278 Line-K Project | W 2011 | 150 |
| Empire Tioga County Extension | F 2011<br>F 2013 | 350<br>350 |
| Inergy North-South Project | W 2011 | 325 |
| NFGS Line N Project | F 2011<br>W 2012 | 160<br>195 |
| TGP 300 Line | 2011 | 345 |
| Transco Springville Pipeline | W 2011 | 450 |
| DTI Appalachian Gateway | F 2012 | 484 |
| DTI Northeast Expansion | 2012 | 200 |
| EQT Sunrise Project | W 2012 | 313 |
| Inergy Marc I Hub Line | S 2012 | 550 |
| NFGS Northern Access Project | F 2012 | 320 |
| Millennium Minisink Compression | W 2012 | 150 |
| TETCO TEAM 2012 | W 2012 | 300 |
| TGP Northeast Supply Diversification Project | W 2012 | 250 |
| Transco Mid Atlantic Connector Exp | W 2012 | 150 |
| Transco Northeast Connector | W 2012 | 688 |
| IGT Wright Transfer Compressor 250 - 2012 | 2012 | 250 |
| DTI Tioga Area Expansion | 2013 | 270 |
| TETCO TEAM 2013 | W 2013 | 500 |
| NFGS West to East | W 2013 | 425 |
| TGP Northeast Upgrade | W 2014 | 636 |
| Transco Northeast Supply Link | W 2014 | 250 |
| TETCO NJ/NY Expansion | 2014 | 800 |
| IGT NYMarc Connector | 2014 | 500 |
| Transco Rockaway Delivery Lateral | W 2014 | 625 |

F = Fall W=Winter S=Summer

## Appendix B: Supply Disposition Tables

| U.S. Supply Disposition (Bcfd) – *Navigant Base* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | NET IMPORTS | | | | | |
| Year | Dry Production | Net Pipeline Imports | Net LNG Imports | Total Net Imports | Net Storage | Balancing Item | Consump-tion |
| **2011** | *60.7* | 4.9 | 0.7 | 5.6 | -0.4 | -0.3 | **65.6** |
| **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 | 4.3 | 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* | 3.8 | -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* | 3.5 | -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* | 3.5 | -0.4 | 3.1 | 0.1 | -0.3 | **77.2** |
| **2028** | *74.8* | 3.4 | -0.4 | 3.1 | -0.1 | -0.3 | **77.5** |
| **2029** | *75.5* | 3.4 | -0.3 | 3.1 | 0.0 | -0.3 | **78.2** |
| **2030** | *76.0* | 3.3 | -0.3 | 3.0 | 0.0 | -0.3 | **78.7** |
| **2031** | *76.5* | 3.3 | -0.3 | 3.1 | 0.0 | -0.3 | **79.3** |
| **2032** | *76.9* | 3.3 | -0.2 | 3.1 | -0.1 | -0.3 | **79.6** |
| **2033** | *77.6* | 3.2 | -0.1 | 3.1 | 0.0 | -0.3 | **80.3** |
| **2034** | *78.1* | 3.2 | -0.1 | 3.1 | 0.0 | -0.3 | **80.8** |
| **2035** | *78.6* | 3.1 | 0.0 | 3.1 | 0.0 | -0.3 | **81.3** |
| **2036** | *79.1* | 3.1 | 0.0 | 3.2 | 0.0 | -0.3 | **81.9** |
| **2037** | *79.4* | 3.2 | 0.1 | 3.3 | 0.0 | -0.3 | **82.4** |
| **2038** | *79.8* | 3.3 | 0.2 | 3.4 | 0.0 | -0.4 | **82.9** |
| **2039** | *80.2* | 3.4 | 0.2 | 3.6 | -0.1 | -0.4 | **83.4** |
| **2040** | *80.5* | 3.5 | 0.3 | 3.8 | 0.1 | -0.3 | **84.0** |

| U.S. Supply Disposition (Bcfd) – *Cove Point Exports* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | NET IMPORTS | | | | | |
| Year | Dry Production | Net Pipeline Imports | Net LNG Imports | Total Net Imports | Net Storage | Balancing Item | Consump-tion |
| **2011** | *60.7* | 4.9 | 0.7 | 5.6 | -0.4 | -0.3 | **65.6** |
| **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** | *66.6* | 3.9 | 0.4 | 4.3 | -0.1 | -0.3 | **70.5** |
| **2017** | *68.6* | 4.2 | -1.1 | 3.1 | 0.2 | -0.4 | **71.4** |
| **2018** | *69.8* | 4.1 | -1.4 | 2.7 | 0.0 | -0.4 | **72.1** |
| **2019** | *70.5* | 4.1 | -1.4 | 2.6 | 0.0 | -0.4 | **72.8** |
| **2020** | *71.3* | 3.9 | -1.4 | 2.5 | 0.0 | -0.4 | **73.4** |
| **2021** | *72.0* | 4.1 | -1.4 | 2.6 | 0.0 | -0.4 | **74.2** |
| **2022** | *72.5* | 4.0 | -1.4 | 2.6 | 0.0 | -0.4 | **74.7** |
| **2023** | *73.0* | 3.9 | -1.4 | 2.5 | 0.0 | -0.4 | **75.2** |
| **2024** | *73.5* | 3.9 | -1.4 | 2.5 | -0.1 | -0.4 | **75.5** |
| **2025** | *74.2* | 3.8 | -1.4 | 2.4 | 0.0 | -0.4 | **76.2** |
| **2026** | *74.7* | 3.8 | -1.4 | 2.4 | 0.0 | -0.4 | **76.7** |
| **2027** | *75.1* | 3.8 | -1.3 | 2.5 | 0.1 | -0.4 | **77.2** |
| **2028** | *75.6* | 3.7 | -1.3 | 2.4 | -0.1 | -0.4 | **77.6** |
| **2029** | *76.3* | 3.7 | -1.3 | 2.4 | 0.0 | -0.4 | **78.3** |
| **2030** | *76.8* | 3.7 | -1.2 | 2.4 | 0.0 | -0.4 | **78.8** |
| **2031** | *77.2* | 3.7 | -1.2 | 2.5 | 0.1 | -0.4 | **79.3** |
| **2032** | *77.7* | 3.6 | -1.1 | 2.5 | -0.1 | -0.4 | **79.6** |
| **2033** | *78.4* | 3.5 | -1.1 | 2.5 | 0.0 | -0.4 | **80.4** |
| **2034** | *78.8* | 3.5 | -1.0 | 2.5 | 0.0 | -0.4 | **80.9** |
| **2035** | *79.3* | 3.5 | -1.0 | 2.5 | 0.0 | -0.4 | **81.3** |
| **2036** | *79.7* | 3.5 | -0.9 | 2.6 | 0.0 | -0.4 | **81.9** |
| **2037** | *80.1* | 3.6 | -0.8 | 2.8 | 0.0 | -0.4 | **82.4** |
| **2038** | *80.4* | 3.7 | -0.8 | 3.0 | 0.0 | -0.4 | **82.9** |
| **2039** | *80.7* | 3.9 | -0.7 | 3.2 | -0.1 | -0.4 | **83.4** |
| **2040** | *80.9* | 4.1 | -0.6 | 3.4 | 0.1 | -0.4 | **84.0** |

| U.S. Supply Disposition (Bcfd) – *Aggregate Exports* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | NET IMPORTS | | | | | |
| Year | Dry Production | Net Pipeline Imports | Net LNG Imports | Total Net Imports | Net Storage | Balancing Item | Consump-tion |
| **2011** | *60.7* | 4.9 | 0.7 | 5.6 | -0.4 | -0.3 | **65.6** |
| **2012** | *61.3* | 4.9 | 0.6 | 5.5 | -0.2 | 0.0 | **66.6** |
| **2013** | *62.7* | 4.7 | 0.9 | 5.6 | 0.0 | 0.0 | **68.2** |
| **2014** | *63.9* | 4.4 | 1.0 | 5.5 | 0.0 | 0.0 | **69.3** |
| **2015** | *65.2* | 4.2 | 1.0 | 5.1 | 0.0 | -0.2 | **70.1** |
| **2016** | *67.2* | 3.9 | -0.1 | 3.8 | -0.2 | -0.6 | **70.2** |
| **2017** | *70.0* | 4.4 | -2.5 | 1.9 | 0.2 | -0.7 | **71.3** |
| **2018** | *71.9* | 4.6 | -3.8 | 0.8 | 0.1 | -0.8 | **72.0** |
| **2019** | *73.2* | 4.6 | -4.4 | 0.3 | 0.1 | -0.8 | **72.7** |
| **2020** | *74.3* | 4.5 | -4.6 | -0.1 | 0.0 | -0.8 | **73.4** |
| **2021** | *75.0* | 4.6 | -4.6 | 0.0 | 0.0 | -0.8 | **74.1** |
| **2022** | *75.6* | 4.5 | -4.6 | -0.1 | 0.0 | -0.8 | **74.7** |
| **2023** | *76.2* | 4.4 | -4.6 | -0.2 | 0.1 | -0.8 | **75.2** |
| **2024** | *76.8* | 4.3 | -4.6 | -0.3 | -0.1 | -0.8 | **75.5** |
| **2025** | *77.5* | 4.1 | -4.5 | -0.4 | 0.0 | -0.8 | **76.3** |
| **2026** | *78.0* | 4.1 | -4.5 | -0.4 | 0.0 | -0.9 | **76.8** |
| **2027** | *78.5* | 4.1 | -4.5 | -0.4 | 0.1 | -0.9 | **77.3** |
| **2028** | *79.0* | 4.1 | -4.5 | -0.4 | -0.1 | -0.9 | **77.6** |
| **2029** | *79.7* | 4.0 | -4.5 | -0.5 | 0.0 | -0.9 | **78.3** |
| **2030** | *80.3* | 3.9 | -4.4 | -0.5 | 0.0 | -0.9 | **78.9** |
| **2031** | *80.7* | 3.9 | -4.4 | -0.5 | 0.0 | -0.9 | **79.4** |
| **2032** | *81.1* | 3.9 | -4.3 | -0.4 | -0.1 | -0.9 | **79.7** |
| **2033** | *81.8* | 3.9 | -4.3 | -0.4 | 0.0 | -0.9 | **80.5** |
| **2034** | *82.2* | 3.9 | -4.2 | -0.3 | 0.0 | -0.9 | **81.0** |
| **2035** | *82.5* | 4.0 | -4.1 | -0.2 | 0.0 | -0.9 | **81.4** |
| **2036** | *82.8* | 4.1 | -4.1 | 0.0 | 0.0 | -0.9 | **82.0** |
| **2037** | *83.1* | 4.3 | -4.0 | 0.3 | 0.0 | -0.9 | **82.4** |
| **2038** | *83.4* | 4.5 | -3.9 | 0.5 | 0.0 | -0.9 | **83.0** |
| **2039** | *83.6* | 4.7 | -3.9 | 0.9 | -0.1 | -0.9 | **83.5** |
| **2040** | *83.8* | 4.9 | -3.8 | 1.1 | 0.1 | -0.9 | **84.0** |

| U.S. Supply Disposition (Bcfd) – *Extreme Demand* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | NET IMPORTS | | | | | |
| Year | Dry Production | Net Pipeline Imports | Net LNG Imports | Total Net Imports | Net Storage | Balancing Item | Consump-tion |
| **2011** | *60.7* | 4.9 | 0.7 | 5.6 | -0.4 | -0.3 | **65.6** |
| **2012** | *61.3* | 4.9 | 0.6 | 5.5 | -0.2 | 0.0 | **66.6** |
| **2013** | *62.7* | 4.7 | 0.9 | 5.6 | 0.0 | 0.0 | **68.2** |
| **2014** | *63.9* | 4.5 | 1.1 | 5.5 | -0.1 | 0.0 | **69.4** |
| **2015** | *65.3* | 4.2 | 1.0 | 5.2 | 0.0 | -0.2 | **70.3** |
| **2016** | *67.5* | 4.0 | 0.0 | 3.9 | -0.2 | -0.6 | **70.6** |
| **2017** | *70.4* | 4.6 | -2.5 | 2.1 | 0.2 | -0.8 | **71.9** |
| **2018** | *72.5* | 4.8 | -3.7 | 1.1 | 0.0 | -0.8 | **72.8** |
| **2019** | *74.0* | 4.9 | -4.3 | 0.6 | 0.1 | -0.8 | **73.8** |
| **2020** | *75.0* | 4.9 | -4.5 | 0.4 | 0.0 | -0.8 | **74.5** |
| **2021** | *75.9* | 4.9 | -4.5 | 0.5 | -0.1 | -0.8 | **75.4** |
| **2022** | *76.7* | 4.9 | -4.5 | 0.4 | 0.0 | -0.8 | **76.2** |
| **2023** | *77.5* | 4.9 | -4.5 | 0.4 | 0.1 | -0.8 | **77.1** |
| **2024** | *78.3* | 4.8 | -4.5 | 0.3 | 0.0 | -0.9 | **77.8** |
| **2025** | *79.5* | 4.8 | -4.4 | 0.4 | 0.0 | -0.9 | **79.0** |
| **2026** | *80.5* | 4.9 | -4.4 | 0.5 | 0.0 | -0.9 | **80.1** |
| **2027** | *81.2* | 4.9 | -4.4 | 0.5 | 0.1 | -0.9 | **80.9** |
| **2028** | *81.9* | 4.9 | -4.3 | 0.6 | -0.1 | -0.9 | **81.6** |
| **2029** | *82.7* | 4.9 | -4.2 | 0.7 | 0.0 | -0.9 | **82.6** |
| **2030** | *83.5* | 4.9 | -4.2 | 0.8 | 0.0 | -0.9 | **83.4** |
| **2031** | *84.0* | 5.1 | -4.1 | 1.0 | 0.0 | -0.9 | **84.1** |
| **2032** | *84.3* | 5.2 | -4.0 | 1.2 | -0.1 | -0.9 | **84.5** |
| **2033** | *84.9* | 5.4 | -4.0 | 1.4 | 0.0 | -0.9 | **85.4** |
| **2034** | *85.2* | 5.6 | -4.0 | 1.6 | 0.0 | -0.9 | **86.0** |
| **2035** | *85.9* | 5.7 | -3.9 | 1.7 | -0.1 | -0.9 | **86.7** |
| **2036** | *87.0* | 5.5 | -3.9 | 1.6 | 0.0 | -0.9 | **87.7** |
| **2037** | *88.0* | 5.3 | -3.8 | 1.4 | -0.1 | -0.9 | **88.4** |
| **2038** | *88.9* | 4.7 | -3.8 | 1.0 | 0.0 | -0.9 | **89.0** |
| **2039** | *89.7* | 4.4 | -3.7 | 0.8 | 0.0 | -0.9 | **89.5** |
| **2040** | *89.9* | 4.5 | -3.6 | 0.9 | 0.1 | -0.9 | **90.1** |

## Appendix C: Consumption Disposition Tables

| U.S. Natural Gas Consumption by End Use (Bcfd) – *Navigant Base* | | | | | | | |
|---|---|---|---|---|---|---|---|
| Year | Lease & Plant Fuel | Pipeline & Distribu-tion Use | Res/ Comm | Industrial | Vehicle Fuel | Electric Power | Total Consump-tion |
| **2011** | 3.2 | 2.2 | 21.8 | 18.5 | 0.1 | 19.7 | **65.6** |
| **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 | 30.7 | **77.2** |
| **2028** | 3.7 | 2.4 | 22.0 | 17.9 | 0.4 | 31.1 | **77.5** |
| **2029** | 3.8 | 2.4 | 22.1 | 17.9 | 0.4 | 31.6 | **78.2** |
| **2030** | 3.8 | 2.5 | 22.1 | 17.9 | 0.4 | 32.1 | **78.7** |
| **2031** | 3.8 | 2.5 | 22.1 | 17.9 | 0.4 | 32.6 | **79.3** |
| **2032** | 3.8 | 2.5 | 22.0 | 17.8 | 0.5 | 33.0 | **79.6** |
| **2033** | 3.8 | 2.5 | 22.1 | 17.9 | 0.5 | 33.6 | **80.3** |
| **2034** | 3.8 | 2.5 | 22.1 | 17.9 | 0.5 | 34.0 | **80.8** |
| **2035** | 3.8 | 2.5 | 22.1 | 17.9 | 0.5 | 34.5 | **81.3** |
| **2036** | 3.9 | 2.6 | 22.2 | 17.8 | 0.5 | 35.0 | **81.9** |
| **2037** | 3.9 | 2.6 | 22.1 | 17.8 | 0.5 | 35.4 | **82.4** |
| **2038** | 3.9 | 2.6 | 22.1 | 17.8 | 0.5 | 35.9 | **82.9** |
| **2039** | 3.9 | 2.6 | 22.1 | 17.8 | 0.6 | 36.4 | **83.4** |
| **2040** | 3.9 | 2.6 | 22.2 | 17.8 | 0.6 | 36.9 | **84.0** |

| U.S. Natural Gas Consumption by End Use (Bcfd) – *Cove Point Exports* | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Year** | **Lease & Plant Fuel** | **Pipeline & Distribu-tion Use** | **Res/ Comm** | **Industrial** | **Vehicle Fuel** | **Electric Power** | **Total Consump-tion** |
| **2011** | 3.2 | 2.2 | 21.8 | 18.5 | 0.1 | 19.7 | **65.6** |
| **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 | 2.3 | 21.9 | 18.0 | 0.2 | 25.7 | **71.4** |
| **2018** | 3.4 | 2.4 | 21.9 | 18.0 | 0.2 | 26.3 | **72.1** |
| **2019** | 3.5 | 2.4 | 21.9 | 18.0 | 0.2 | 26.8 | **72.8** |
| **2020** | 3.7 | 2.4 | 21.9 | 17.9 | 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 | 28.3 | **74.7** |
| **2023** | 3.7 | 2.5 | 22.0 | 18.0 | 0.3 | 28.8 | **75.2** |
| **2024** | 3.7 | 2.5 | 21.9 | 17.9 | 0.3 | 29.2 | **75.5** |
| **2025** | 3.7 | 2.5 | 22.0 | 17.9 | 0.3 | 29.7 | **76.2** |
| **2026** | 3.8 | 2.5 | 22.0 | 17.9 | 0.3 | 30.2 | **76.7** |
| **2027** | 3.8 | 2.5 | 22.0 | 17.9 | 0.4 | 30.6 | **77.2** |
| **2028** | 3.8 | 2.5 | 22.0 | 17.8 | 0.4 | 31.0 | **77.6** |
| **2029** | 3.8 | 2.6 | 22.1 | 17.9 | 0.4 | 31.6 | **78.3** |
| **2030** | 3.8 | 2.6 | 22.1 | 17.9 | 0.4 | 32.1 | **78.8** |
| **2031** | 3.8 | 2.6 | 22.1 | 17.8 | 0.4 | 32.5 | **79.3** |
| **2032** | 3.8 | 2.6 | 22.0 | 17.8 | 0.5 | 33.0 | **79.6** |
| **2033** | 3.8 | 2.6 | 22.1 | 17.8 | 0.5 | 33.5 | **80.4** |
| **2034** | 3.9 | 2.7 | 22.1 | 17.8 | 0.5 | 34.0 | **80.9** |
| **2035** | 3.9 | 2.7 | 22.1 | 17.8 | 0.5 | 34.4 | **81.3** |
| **2036** | 3.9 | 2.7 | 22.1 | 17.8 | 0.5 | 34.9 | **81.9** |
| **2037** | 3.9 | 2.7 | 22.1 | 17.7 | 0.5 | 35.4 | **82.4** |
| **2038** | 3.9 | 2.7 | 22.1 | 17.7 | 0.5 | 35.9 | **82.9** |
| **2039** | 3.9 | 2.7 | 22.1 | 17.7 | 0.6 | 36.4 | **83.4** |
| **2040** | 3.9 | 2.8 | 22.2 | 17.7 | 0.6 | 36.8 | **84.0** |

| U.S. Natural Gas Consumption by End Use (Bcfd) – *Aggregate Exports* | | | | | | | |
|---|---|---|---|---|---|---|---|
| Year | Lease & Plant Fuel | Pipeline & Distribu-tion Use | Res/ Comm | Industrial | Vehicle Fuel | Electric Power | Total Consump-tion |
| **2011** | 3.2 | 2.2 | 21.8 | 18.5 | 0.1 | 19.7 | **65.6** |
| **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 | 1.8 | 21.8 | 18.1 | 0.2 | 25.0 | **70.2** |
| **2017** | 3.4 | 2.2 | 21.9 | 18.0 | 0.2 | 25.7 | **71.3** |
| **2018** | 3.4 | 2.3 | 21.9 | 17.9 | 0.2 | 26.2 | **72.0** |
| **2019** | 3.6 | 2.4 | 21.9 | 17.9 | 0.2 | 26.8 | **72.7** |
| **2020** | 3.8 | 2.4 | 21.9 | 17.8 | 0.2 | 27.2 | **73.4** |
| **2021** | 3.8 | 2.5 | 21.9 | 17.9 | 0.2 | 27.8 | **74.1** |
| **2022** | 3.8 | 2.5 | 22.0 | 17.9 | 0.2 | 28.3 | **74.7** |
| **2023** | 3.8 | 2.5 | 22.0 | 17.9 | 0.3 | 28.8 | **75.2** |
| **2024** | 3.9 | 2.5 | 21.9 | 17.8 | 0.3 | 29.2 | **75.5** |
| **2025** | 3.9 | 2.5 | 22.0 | 17.9 | 0.3 | 29.7 | **76.3** |
| **2026** | 3.9 | 2.5 | 22.0 | 17.8 | 0.3 | 30.2 | **76.8** |
| **2027** | 3.9 | 2.6 | 22.0 | 17.8 | 0.4 | 30.6 | **77.3** |
| **2028** | 3.9 | 2.6 | 22.0 | 17.8 | 0.4 | 31.0 | **77.6** |
| **2029** | 3.9 | 2.6 | 22.1 | 17.8 | 0.4 | 31.6 | **78.3** |
| **2030** | 3.9 | 2.6 | 22.1 | 17.8 | 0.4 | 32.1 | **78.9** |
| **2031** | 4.0 | 2.6 | 22.1 | 17.8 | 0.4 | 32.5 | **79.4** |
| **2032** | 4.0 | 2.6 | 22.0 | 17.8 | 0.5 | 32.9 | **79.7** |
| **2033** | 4.0 | 2.6 | 22.1 | 17.8 | 0.5 | 33.5 | **80.5** |
| **2034** | 4.0 | 2.6 | 22.1 | 17.8 | 0.5 | 34.0 | **81.0** |
| **2035** | 4.0 | 2.7 | 22.1 | 17.8 | 0.5 | 34.4 | **81.4** |
| **2036** | 4.0 | 2.7 | 22.1 | 17.7 | 0.5 | 34.9 | **82.0** |
| **2037** | 4.0 | 2.7 | 22.1 | 17.7 | 0.5 | 35.4 | **82.4** |
| **2038** | 4.0 | 2.7 | 22.1 | 17.7 | 0.5 | 35.9 | **83.0** |
| **2039** | 4.0 | 2.7 | 22.1 | 17.7 | 0.6 | 36.4 | **83.5** |
| **2040** | 4.0 | 2.7 | 22.2 | 17.7 | 0.6 | 36.8 | **84.0** |

| U.S. Natural Gas Consumption by End Use (Bcfd) – *Extreme Demand* | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Year** | **Lease & Plant Fuel** | **Pipeline & Distribu-tion Use** | **Res/ Comm** | **Industrial** | **Vehicle Fuel** | **Electric Power** | **Total Consump-tion** |
| **2011** | 3.2 | 2.2 | 21.8 | 18.5 | 0.1 | 19.7 | **65.6** |
| **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 | 0.2 | 23.5 | **69.4** |
| **2015** | 3.3 | 2.1 | 21.9 | 18.2 | 0.2 | 24.5 | **70.3** |
| **2016** | 3.3 | 1.8 | 21.8 | 18.0 | 0.2 | 25.3 | **70.6** |
| **2017** | 3.4 | 2.2 | 21.9 | 17.9 | 0.3 | 26.1 | **71.9** |
| **2018** | 3.5 | 2.3 | 21.9 | 17.8 | 0.4 | 26.9 | **72.8** |
| **2019** | 3.5 | 2.5 | 21.9 | 17.8 | 0.5 | 27.5 | **73.8** |
| **2020** | 3.5 | 2.5 | 21.9 | 17.7 | 0.7 | 28.2 | **74.5** |
| **2021** | 3.5 | 2.5 | 21.9 | 17.8 | 1.0 | 28.7 | **75.4** |
| **2022** | 3.5 | 2.5 | 22.0 | 17.8 | 1.2 | 29.2 | **76.2** |
| **2023** | 3.5 | 2.6 | 22.0 | 17.8 | 1.5 | 29.7 | **77.1** |
| **2024** | 3.6 | 2.6 | 21.9 | 17.7 | 1.8 | 30.2 | **77.8** |
| **2025** | 3.7 | 2.6 | 22.0 | 17.7 | 2.1 | 30.8 | **79.0** |
| **2026** | 3.9 | 2.6 | 22.0 | 17.7 | 2.5 | 31.4 | **80.1** |
| **2027** | 3.8 | 2.7 | 22.0 | 17.7 | 2.8 | 31.9 | **80.9** |
| **2028** | 3.8 | 2.7 | 21.9 | 17.6 | 3.2 | 32.4 | **81.6** |
| **2029** | 3.8 | 2.7 | 22.0 | 17.6 | 3.4 | 33.0 | **82.6** |
| **2030** | 3.8 | 2.7 | 22.0 | 17.6 | 3.7 | 33.6 | **83.4** |
| **2031** | 3.8 | 2.7 | 22.0 | 17.5 | 3.9 | 34.1 | **84.1** |
| **2032** | 3.9 | 2.7 | 21.9 | 17.3 | 4.1 | 34.6 | **84.5** |
| **2033** | 3.9 | 2.8 | 22.0 | 17.2 | 4.3 | 35.1 | **85.4** |
| **2034** | 4.0 | 2.8 | 22.0 | 17.1 | 4.5 | 35.6 | **86.0** |
| **2035** | 3.9 | 2.8 | 22.0 | 17.0 | 4.7 | 36.2 | **86.7** |
| **2036** | 4.0 | 2.9 | 22.1 | 16.9 | 4.9 | 36.9 | **87.7** |
| **2037** | 4.1 | 3.0 | 22.1 | 16.8 | 5.0 | 37.4 | **88.4** |
| **2038** | 4.1 | 3.0 | 22.1 | 16.7 | 5.1 | 37.9 | **89.0** |
| **2039** | 4.1 | 3.1 | 22.1 | 16.6 | 5.2 | 38.4 | **89.5** |
| **2040** | 4.1 | 3.1 | 22.2 | 16.5 | 5.3 | 38.9 | **90.1** |

## Appendix D: Henry Hub Price Forecast Comparison Table

| Henry Hub Price Forecast Comparison (Real$/MMBtu) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Year | *Navigant Base* | *Cove Point Export* | *Aggregate Export* | *Extreme Demand* | *Cove Point Export Alt* | *Aggregate Export without Cove Point* | *Extreme Demand without Cove Point* |
| **2011** | $4.30 | $4.30 | $4.30 | $4.30 | $4.30 | $4.30 | $4.30 |
| **2012** | $4.79 | $4.79 | $4.79 | $4.79 | $4.79 | $4.79 | $4.79 |
| **2013** | $4.76 | $4.76 | $4.76 | $4.76 | $4.76 | $4.76 | $4.76 |
| **2014** | $4.15 | $4.15 | $4.13 | $4.13 | $4.17 | $4.13 | $4.13 |
| **2015** | $4.31 | $4.31 | $4.23 | $4.28 | $4.35 | $4.23 | $4.28 |
| **2016** | $4.67 | $4.72 | $4.69 | $4.79 | $4.75 | $4.65 | $4.75 |
| **2017** | $4.84 | $5.10 | $5.35 | $5.49 | $5.13 | $5.08 | $5.21 |
| **2018** | $4.93 | $5.24 | $5.69 | $5.87 | $5.26 | $5.38 | $5.56 |
| **2019** | $4.92 | $5.22 | $5.80 | $6.04 | $5.25 | $5.50 | $5.72 |
| **2020** | $4.98 | $5.27 | $5.85 | $6.16 | $5.29 | $5.56 | $5.85 |
| **2021** | $5.02 | $5.29 | $5.82 | $6.15 | $5.31 | $5.54 | $5.85 |
| **2022** | $5.10 | $5.35 | $5.84 | $6.20 | $5.37 | $5.58 | $5.92 |
| **2023** | $5.20 | $5.45 | $5.92 | $6.32 | $5.47 | $5.65 | $6.04 |
| **2024** | $5.35 | $5.60 | $6.02 | $6.49 | $5.62 | $5.77 | $6.21 |
| **2025** | $5.51 | $5.76 | $6.15 | $6.69 | $5.78 | $5.90 | $6.41 |
| **2026** | $5.67 | $5.90 | $6.28 | $6.92 | $5.92 | $6.02 | $6.61 |
| **2027** | $5.82 | $6.07 | $6.41 | $7.17 | $6.08 | $6.16 | $6.84 |
| **2028** | $5.98 | $6.22 | $6.55 | $7.46 | $6.25 | $6.30 | $7.08 |
| **2029** | $6.16 | $6.42 | $6.72 | $7.81 | $6.44 | $6.48 | $7.37 |
| **2030** | $6.35 | $6.61 | $6.84 | $8.03 | $6.63 | $6.63 | $7.63 |
| **2031** | $6.51 | $6.77 | $6.98 | $8.23 | $6.80 | $6.77 | $7.84 |
| **2032** | $6.71 | $7.01 | $7.18 | $8.59 | $7.04 | $6.96 | $8.20 |
| **2033** | $6.92 | $7.25 | $7.41 | $8.93 | $7.28 | $7.19 | $8.54 |
| **2034** | $7.13 | $7.48 | $7.66 | $9.25 | $7.52 | $7.42 | $8.87 |
| **2035** | $7.38 | $7.77 | $8.03 | $9.45 | $7.82 | $7.74 | $9.13 |
| **2036** | $7.62 | $8.06 | $8.37 | $9.52 | $8.12 | $8.04 | $9.20 |
| **2037** | $7.86 | $8.34 | $8.66 | $9.69 | $8.40 | $8.35 | $9.43 |
| **2038** | $8.13 | $8.61 | $8.99 | $10.12 | $8.66 | $8.70 | $9.89 |
| **2039** | $8.42 | $8.90 | $9.29 | $10.64 | $8.94 | $9.04 | $10.45 |
| **2040** | $8.64 | $9.16 | $9.64 | $11.20 | $9.22 | $9.46 | $11.02 |

# Appendix E: Summary of Price Impact of Exports per Case

| Impact of Exports on *Henry Hub* Prices: Summary | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Case Description | Domestic Consumption | | Total LNG Exports | | Henry Hub Price ($/MMBtu) | | Price Change ($/MMBtu) | | Price Change (%) | | Identifier | Price Change Calculation |
| | *2020* | *2040* | *2020* | *2040* | *2020* | *2040* | *2020* | *2040* | *2020* | *2040* | | |
| **Reference Case** | 73.4 | 84.0 | 2.7 | 2.7 | $4.98 | $8.64 | *NA* | *NA* | *NA* | *NA* | A | *NA* |
| **Cove Point Export** | 73.4 | 84.0 | 3.7 | 3.7 | $5.27 | $9.16 | $0.28 | $0.52 | 5.7% | 6.0% | B | =B-A |
| **Aggregate Export A** | 73.4 | 84.0 | 7.1 | 7.1 | $5.85 | $9.64 | $0.58 | $0.49 | 11.0% | 5.3% | C | =C-B |
| **Aggregate Export B** | 73.3 | 83.9 | 6.1 | 6.1 | $5.56 | $9.46 | $0.28 | $0.18 | 5.1% | 1.9% | D | =C-D |
| **Extreme Demand A** | 74.5 | 90.1 | 7.1 | 7.1 | $6.16 | $11.20 | $0.31 | $1.56 | 5.4% | 16.2% | E | =E-C |
| **Extreme Demand B** | 74.4 | 90.0 | 6.1 | 6.1 | $5.85 | $11.02 | $0.31 | $0.19 | 5.2% | 1.7% | F | =E-F |

| Impact of Exports on *Dominion South Point* Prices: Summary | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Case Description | Domestic Consumption | | Total LNG Exports | | Dominion South Point Price | | Price Change ($/MMBtu) | | Price Change (%) | | Identifier | Price Change Calculation |
| | *2020* | *2040* | *2020* | *2040* | *2020* | *2040* | *2020* | *2040* | *2020* | *2040* | | |
| **Reference Case** | 73.4 | 84.0 | 2.7 | 2.7 | $4.92 | $6.01 | *NA* | *NA* | *NA* | *NA* | A | *NA* |
| **Cove Point Export** | 73.4 | 84.0 | 3.7 | 3.7 | $5.22 | $6.17 | $0.30 | $0.16 | 6.2% | 2.7% | B | =B-A |
| **Aggregate Export A** | 73.4 | 84.0 | 7.1 | 7.1 | $5.74 | $6.52 | $0.51 | $0.35 | 9.9% | 5.6% | C | =C-B |
| **Aggregate Export B** | 73.3 | 83.9 | 6.1 | 6.1 | $5.42 | $6.05 | $0.32 | $0.47 | 5.8% | 7.8% | D | =C-D |
| **Extreme Demand A** | 74.5 | 90.1 | 7.1 | 7.1 | $6.04 | $6.83 | $0.31 | $0.31 | 5.4% | 4.8% | E | =E-C |
| **Extreme Demand B** | 74.4 | 90.0 | 6.1 | 6.1 | $5.71 | $6.30 | $0.33 | $0.54 | 5.8% | 8.5% | F | =E-F |

| **Case Explanation** | |
|---|---|
| **Reference Case** | Assumes status quo for GHG and other laws and regulations. |
| **Cove Point Export** | Assumes 1.0 Bcfd of LNG exports from the Cove Point Export project, beginning late 2016. |
| **Aggregate Export A** | Assumes three additional export projects come online in 2017-2019, with added exports of 3.4 Bcfd. |
| **Aggregate Export B** | As Aggregate Export A, with the 1.0 Bcfd Cove Point Export project removed. |
| **Extreme Demand A** | Assumes more stringent GHG laws and high natural gas demand from vehicles. |
| **Extreme Demand B** | As Extreme Demand A, with the 1.0 Bcfd Cove Point Export project removed. |

Appendix C

# ICF Economic Benefit Study

# Economic Impact Study of Construction and Operations

## A Report Produced to Support the Dominion Cove Point Application for Export of LNG from Cove Point

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# 1 Executive Summary

Dominion Cove Point is seeking federal approval to construct a facility at its existing terminal to export liquefied natural gas (LNG). This report provides expert analysis on certain economic impacts of this proposal, using the IMPLAN model.[1] Economic analysis includes impacts associated with construction and operations and maintenance (O&M) of the LNG export facility, as well as upstream-related impacts associated with production of the incremental gas volumes required by the facility.[2]

With regard to impact terminology, a "job-year" is defined as the amount of work performed by one full-time individual in one year (typically, 2,080 hours, though work schedules may vary by industry). A job-year is often used synonymously with the term "full-time equivalent" or "FTE." "Value added" for an industry is that portion of output or total sales of that industry that represents its contribution to Gross Domestic Product (GDP). Value added is calculated as the difference between the output generated and the expenditures for intermediate goods and services (Output – Intermediate Purchases = Value Added). All references to "LNG exports" in this report refer to LNG exports from Dominion's liquefaction facility. The key findings of the report are:

**U.S. national impacts**

- Total impacts: Total impacts differ considerably during facility peak construction, facility final construction, and facility operation (upstream impacts are realized during the final construction and operation periods). Thus, total impacts are broken out by the peak construction period (2011-2015), the final construction period (2016-2017), and the facility operations period (2018-2040). Over the peak construction period (2011-2015), annual job-years total 4,200-5,200, annual value added totals $365-$456 million, and tax and government royalties total $76-$95 million annually. During the final construction and upstream ramp-up period (2016-2017), annual job-years total 66,200-67,000, annual GDP value added contributions are estimated at $6.3 billion, and tax and government royalty revenues total $1.5 billion annually. In terms of *post-construction* operations (2018-2040), upstream-related and facility operations lead to 14,600 annual job-years, $1.4 billion in annual GDP value added contributions, and over $962 million in annual tax and government royalty revenues. In *aggregate* terms over the 23-year *post-construction* operating period, upstream and operations impacts will total nearly 337,000 job-years, $33 billion in value added, and $22 billion in tax and government royalty revenues. See **Table 1** for annual rates over the *entire* 30-year construction and operations (including upstream-related) period (2011-2040).

[1] In calculating the economic impacts, ICF assumed average inlet volumes of 0.675 billion cubic feet per day (bcfd), based on a long-run capacity utilization rate of 90 percent of an assumed total plant capacity of 0.750 bcfd. Outlet volumes are assumed at 90 percent of total inlet volumes, or 0.608 bcfd, the difference of which is used for facility fuel consumption.

[2] The upstream employment estimates appearing in this report do not include midstream jobs, which will total approximately 1,446 total jobs related to increased midstream activity associated with LNG exports from Cove Point.

- o <u>Balance of trade impacts</u>: The expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by between 0.6 percent and 1.4 percent (based on the 2010 U.S. balance of trade deficit[3]), with an annual range of $2.8-$7.1 billion over the 25-year forecast period. Values are based on free-on-board (FOB) LNG prices (which exclude transport fuel costs from the U.S. to the market), and include associated liquids production, which will displace foreign oil imports or will be exported in some form.
- o <u>Upstream-related impacts</u>: In terms of upstream-related expenditures to support LNG exports, the project will result in 18,200 job-years annually, $1.76 billion annually in value added GDP contributions, and $988 million in annual government tax and royalties between 2016 and 2040 (the *25-year* LNG facility operating period).
    - Incremental production of hydrocarbon liquids from 2016 through 2040 associated with LNG exports is estimated at 8.5 million barrels per year, with an average market value of $1.2 billion per year.
    - An average of $1.3 billion in upstream capital and O&M expenditures (hereafter referred to as "upstream expenditures") will be required each year to produce natural gas for Dominion's LNG export facility, expenditures which are then funneled through the economy to produce a "multiplier" effect of further economic activity in other sectors. In other words, these findings indicate that every $1 million in upstream expenditures generates a total of $1.4 million in GDP contributions and 14 job-years of work.
    - The upstream expenditures include the following key sectors: oil and gas (O&G) extraction; O&G well drilling; O&G support activities; construction; cement and steel manufacturing; clay, sand, and aggregate mining; water supply and clean-up; and transportation.
- o <u>Facility-related impacts</u>: Overall, construction and operation of the LNG facility is estimated to result in an annual average range of 1,100-1,400 job-years, $115-$134 million in annual valued added GDP contributions, and $25-$29 million in annual government tax revenues from 2011 through 2040.[4]
    - On an annual basis, the project will support 2,600-3,200 job-years during the construction ramp-up phase (2011-2013), 6,700-8,400 job-years during the peak construction phase (2014-2015), an average of 3,200-4,000 job-years during the post-peak construction phase (2016-2017), and 320 job-years over the remaining operating period (2018-2040). These job impacts include the direct jobs in the design, construction, and O&M sectors, as well as jobs in other sectors produced by the "multiplier" effect.
    - Construction of the proposed facility could also generate significant revenues for the public sector. Tax revenues related only to the construction activities peak in 2014, with a total of $130-163 million nationally. The state and local taxes -- at

[3] U.S. 2010 balance of trade deficit totaled $500 billion (seasonally-adjusted). U.S. Census Bureau. "Exhibit 1. U.S. International Trade in Goods and Services." *U.S. International Trade in Goods and Services*. U.S. Census Bureau, 9 June 2011. Web. Sept. 2011. <http://www.census.gov/foreign-trade/Press-Release/2010pr/final_revisions/exh1.pdf>.

[4] The range of design and construction impacts is given, as the analysis examined two potential construction costs, a "low construction cost case" and a "high construction cost case," which assumes a 25% higher construction costs than the Low Case.

$51-$63 million in 2014 -- account for roughly 39 percent of the total tax revenues. The taxes generated at the state and local levels include taxes generated in Maryland, as well as other states, as goods and services purchased in other states are used to supply the project.

**State of Maryland impacts (pertain to LNG facility construction and operation)**

- A significant portion of the national impact discussed above will be felt in Maryland. On an annual basis, the project will support 1,000-1,300 job-years during the construction ramp-up phase (2011-2013), 3,400-4,200 job-years during the peak construction phase (2014-2015), 1,800-2,300 job-years during the post-peak construction phase (2016-2017), and 130 job-years over the remaining operating period (2018-2040) in the State of Maryland. These job impacts include the direct jobs in the design, construction, and O&M sectors, as well as jobs in other sectors produced by the "multiplier" effect.
- The proposed facility has the potential to create significant economic activity in the State of Maryland. At its peak in 2015, it will support the state's Gross State Product (GSP), by adding between $263 million and $328 million in value added (which includes contributions not just from the directly affected sectors, but also other sectors that stand to benefit from the construction phase of the project). Moreover, the facility's design, construction, and operation will contribute an average annual GSP contribution of $56-$65 million between 2011 and 2040 to the Maryland economy.

**Calvert County impacts (pertain to LNG facility construction and operation)**

- A significant portion of the statewide impacts discussed above will be concentrated within the immediate areas surrounding the LNG facility in Calvert County. We estimate that on an annual basis the project will support 500-630 job-years during the construction ramp-up phase (2011-2013), 2,500-3,100 job-years during the peak construction phase (2014-2015), 1,400-1,800 job-years during the post-peak construction phase (2016-2017), and 70 job-years over the remaining operating period (2018-2040) in Calvert County. These job impacts include the direct jobs in the design, construction, and O&M sectors, as well as jobs in other sectors produced by the "multiplier" effect.
- The proposed facility has the potential to create significant economic activity in Calvert County. At its peak in 2015, it will support the county's economy by creating between $183 million and $230 million in value added (which includes contributions not just from the directly affected sectors but other sectors that stand to benefit from the construction phase of the project). Moreover, the facility's design, construction, and operation will generate an average annual value added contribution to the county's economy of $39-44 million between 2011 and 2040.

*Note:* Aside from the value of total exports and associated liquids (crude oil, lease condensate, natural gas plant liquids, and natural gas liquids, or NGLs), which are calculated based on upstream production *and* capital and operating expenditures, all other figures reference the economic impact associated with facility construction, facility O&M, and upstream expenditures *only*, and do not include the economic impact associated with upstream production or the liquefaction process itself, which would increase the full economic impact associated with LNG exports. Gas price data used to calculate export volumes are based on the U.S. Energy Information Agency's 2011 Annual Energy Outlook Reference Case prices.[5] No further analysis of gas price changes over time is included in this report, as it was beyond the scope of the analysis.

[5] U.S. Energy Information Administration (EIA), 2011. "Annual Energy Outlook." EIA: Washington, D.C.: http://www.eia.gov/forecasts/aeo/.

**Table 1: Total Impacts of Cove Point LNG Exports**

| Impact | Geographic Jurisdiction | | |
|---|---|---|---|
| | U.S. National | Maryland | Calvert County |
| **Total (2011-40)** | | | |
| Job-years (No.) | 489,300-497,000 | 16,800-20,300 | 11,200-13,600 |
| Value Added (2011 $MM) | $47,200-$47,700 | $1,700-$2,000 | $1,200-$1,300 |
| Tax/Govt Royalties (2011 $MM) | $25,400-$25,600 | * | * |
| **Annual (2011-40)** | | | |
| Job-years (No.) | 16,300-16,600 | 560-680 | 370-450 |
| Value Added (2011 $MM) | $1,570-$1,590 | $56-$65 | $39-$44 |
| Tax/Govt Royalties (2011 $MM) | $848-$852 | * | * |

*Source: ICF results using the IMPLAN model*

* Embedded in U.S. national figures. State and local taxes include taxes generated in all states, in addition to Maryland, when goods and services are purchased in those states to supply the construction in Calvert County or when the construction-related labor is supplied by workers living in other states. State and local facility-related taxes (all states) total $330-$377 million, while federal facility-related taxes total between $420-$494 million from 2011 and 2040.

*Note 1:* Ranges are based on the difference between current, preliminary low and high facility construction cost estimates detailed below.

*Note 2:* "U.S. National" totals include facility- and upstream-related impacts, while "Maryland" and "Calvert County" totals include only facility-related impacts.

*Note 3:* Taxes are defined in IMPLAN to include the following categories: employee compensation, proprietor income, indirect business tax, household taxes, and corporate taxes. However, with regard to facility operations, other than employment-related taxes of liquefaction plant employees, tax figures do not include income taxes, property taxes, or gross receipt taxes associated with the liquefaction plant over the 25-year operating period.

*Note 4:* Total impacts differ substantially between the peak construction period (2011-2015) and operations period (2016-2040), primarily given the considerable upstream impact on economic activity over the 2016-2040 operations period. Annual rates in the table above, which represent annual figures over the *entire* 30-year period (2011-2040), are significantly different from the 2011-2015 construction and 2016-2040 operations periods. For example, while total job-years between 2011-2015, dedicated to LNG facility peak construction, total 4,200-5,200 job-years annually, the 2016-2017 final construction and upstream ramp-up period are expected to see 66,200-67,000 annual job years, and the 2018-2040 post-construction operating period will see 14,600 annual job-years. In sum, these dramatically different phases (facility construction versus facility operations) together indicate a total of 16,300-16,600 annual job-years over the *entire* 30-year facility construction *and* operations period (2011-2040).

# 2 Introduction

This report was prepared by ICF International (ICF) at the request of Dominion Cove Point to provide expert opinion on certain economic impacts associated with the export of liquefied natural gas (LNG) from Dominion's Cove Point facility. In calculating the economic impacts, ICF assumed average inlet volumes of 0.675 billion cubic feet per day (bcfd), based on a long-run capacity utilization rate of 90 percent of an assumed total plant capacity of 0.750 bcfd. Outlet volumes are assumed at 90 percent of total inlet volumes, or 0.608 bcfd, the difference of which is used for facility fuel consumption.

ICF assessed two specific economic impacts:

1. Regional and national impacts associated with construction and operations and maintenance (O&M) of the LNG facility. This facility-specific economic analysis is based on two facility investment scenarios, given the uncertainties associated with final construction costs:
    - Low Construction Cost Case (Low Case)
    - High Construction Cost Case (High Case) assumes a 25% higher construction costs than Low Case
2. National impacts associated with upstream gas and oil drilling, completion, and production activities to support incremental LNG exports based on the daily volume figures listed above

These impacts were assessed using the IMPLAN model. This report includes a discussion of these results as they relate to the creation of new businesses and the impacts on the existing economy (e.g., income, wages, taxes). The report also explores the macro-level, national, and international implications of the new facility, which includes a discussion on the impact of the new facility on the U.S. balance of trade, as well as a detailed analysis of the economic impacts of the upstream expenditures due to the new demand for the gas to be exported.[6]

[6] All dollar figures listed in 2011 real terms, unless otherwise specified.

# 3 Results of Economic Impact Analysis

## 3.1 Summary of Methodology and Definitions

In addition to proprietary economic analysis, ICF used the Impact Analysis for Planning (IMPLAN) input-output model, based on a social accounting matrix that incorporates all flows within an economy, to assess the aggregate economic impact associated with both the LNG facility construction and O&M and upstream expenditures. The IMPLAN model includes the detailed transactional flow information for hundreds of industries. By tracing purchases between sectors, it is possible to estimate the economic impact of one or more industry's output on related industries. From a change in industry output, IMPLAN generates estimates of the direct, indirect, and induced economic impacts. After identifying the direct expenditure components associated with either the liquefaction plant construction and operation or upstream development and production, the direct expenditure cost components (identified by their associated NAICS[7] codes) are then used as inputs into the IMPLAN model to estimate the total indirect and induced economic impacts of each direct expenditure component. See **Section 6.1** for complete details on the IMPLAN methodology applied in this study.

**Figure 1** outlines the definitions of each impact measure, and **Figure 2** illustrates the relationship among key impact measures.

[7] The North American Industry Classification System (NAICS) is the system used by federal agencies for classification of businesses for data analysis purposes. URL: http://www.census.gov/eos/www/naics/.

**Figure 1: Impact Definitions**

**Classification of Impact Types**

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

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

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

**Definitions of Impact Measures**

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

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

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

**Labor Income** – is part of the value added, and consists of all forms of employment income. Consistent with I/O terminology, IMPLAN defines this as the sum of the employee compensation and proprietor's income.

*Employee Compensation* – represents the total payroll costs (including benefits) of each industry sector.

*Proprietor's Income* – the other component of labor income, consists of payments received by self-employed persons as income. This includes payments received by doctors, lawyers, and other private business owners.

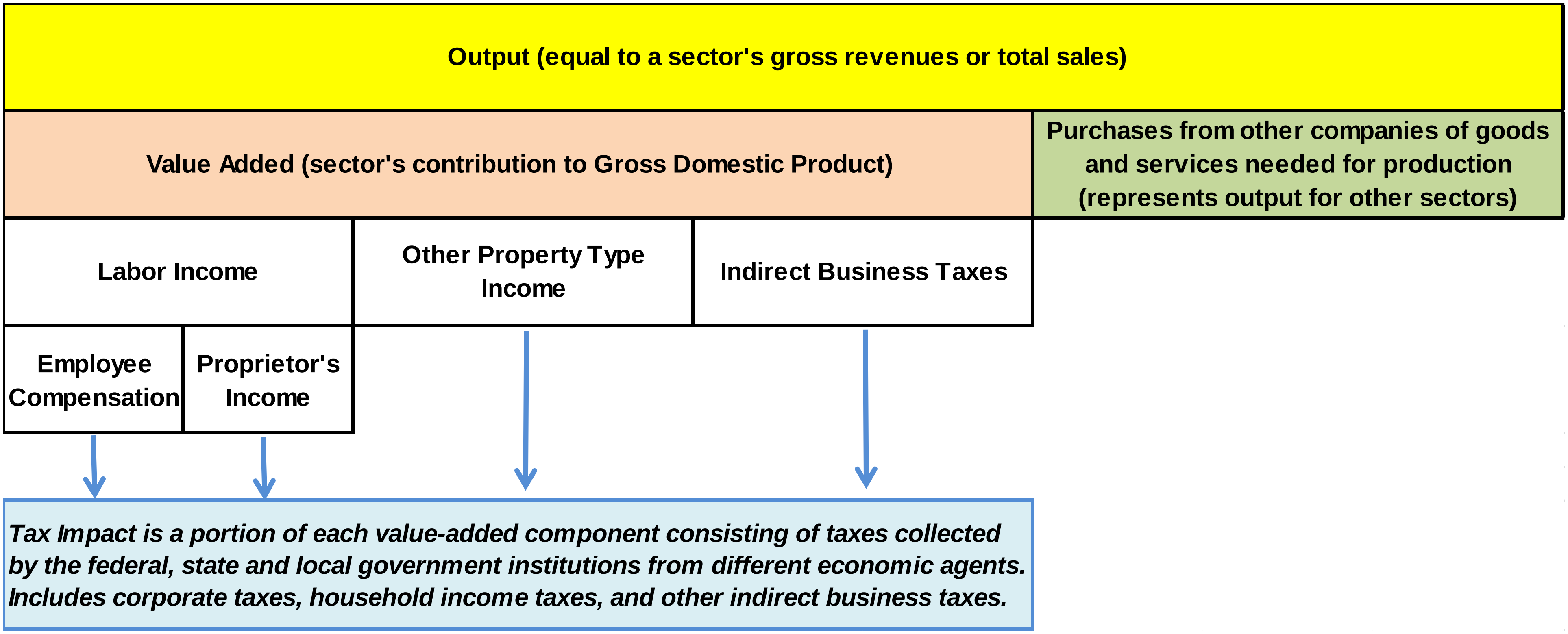
**Other Property Type Income** – another part of value added consisting of payments for rents to individuals on properties, royalties from contracts, and dividends paid by corporations, as well as corporate profits.

**Indirect Business Taxes** – the third and final component of total value added, consists of excise taxes, property taxes, fees, licenses, and sales taxes paid by businesses.

**Tax Impact** – breakdown of taxes collected by the federal, state and local government institutions from different economic agents. This includes corporate taxes, household income taxes, and other indirect business taxes.[8]

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

**Figure 2: Relationship of Key Accounting Concepts for a Given Industry Sector**



## 3.2 Facility Construction and O&M Modeling Results

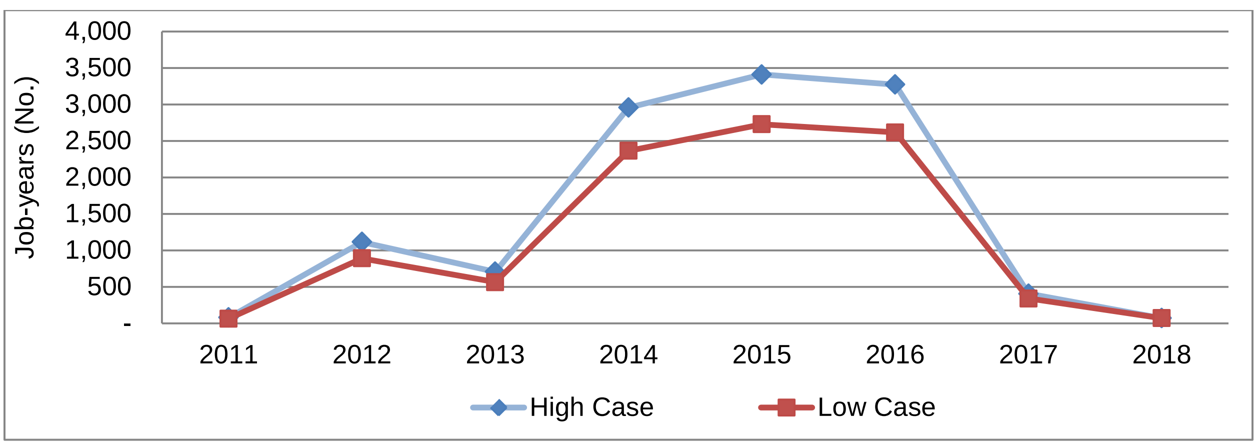
The results of the facility construction and O&M modeling analysis using IMPLAN are presented below. The discussion of results begins with impacts for Calvert County, then the rest of the State of Maryland and finally the residual impacts for the rest of the nation. The upstream impacts are discussed in the next section after the national-level results.

**Employment**

**Figure 3** below presents a summary of the employment results for Calvert County for the Low and High Construction Cost Cases over the construction phase of the project and immediately thereafter. The trend lines mirror those of the input values of annual construction expenditures, with the job impacts peaking in 2015, followed by a decline in 2017 as the construction phase of the project comes to an end. In 2015, the proposed facility is estimated to support between 2,700 and 3,400 annual job-years in Calvert County. These job-years would account for roughly 12 percent of the total employment in the county's baseline employment profile. The job-years generated not only include the direct job-years at the facility, but also the secondary job-years supported in other industries that are expected to be supported by those direct jobs. In regional economic parlance, these secondary job-years are usually referred to as indirect and induced job-years (see **Section 3.1** above for definitions of these terms) that are generated through the "multiplier effect."

The employment results for 2018 are representative of the annual O&M impacts throughout the duration of the facility's operation (2018-2040). Annual O&M activities are expected to support roughly 70 job-years annually in the Calvert County economy.

**Figure 3: Calvert County Employment Impacts 2011 – 2018, Facility Construction/Operation (Job-years)**

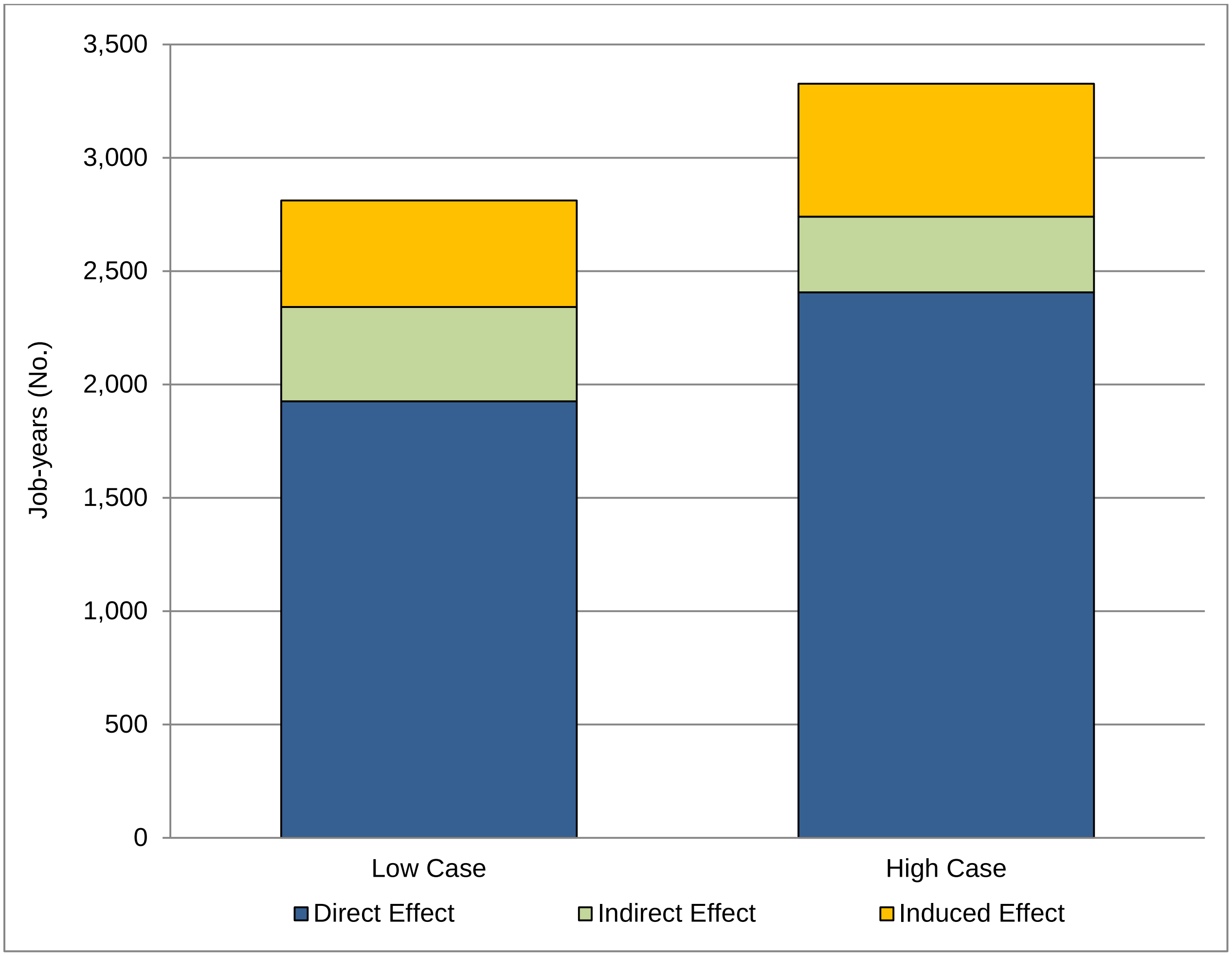



*Source: ICF results using the IMPLAN model*

*Note:* Includes direct, indirect, and induced jobs.

**Figure 4** below shows the breakdown of these total job-years into direct, indirect, and induced job-years in Calvert County for peak year, 2015.

**Figure 4: Calvert County Direct, Indirect and Induced Job-years, 2015, Facility Construction/Operation (Job-years)**




*Source: ICF results using the IMPLAN model*

As **Figure 4** shows, over 70 percent of the total job-years (i.e.,1,925-2,400 job-years in 2015, the blue shaded bar) are expected to be supported directly in sectors that will provide the inputs needed for construction and operation of the facility, including non-residential construction, as well as architectural, engineering, and other technical services.

An additional 800-1,000 job-years are expected in sectors in which the indirect and induced impacts occur (refer to **Section 3.1** for definitions). Among the sectors with indirect job-years are employment services, automotive repair, real estate establishments, services to buildings and dwelling, commercial and industrial machinery, and equipment rental and leasing. Among the sectors with induced job-years are traditional retail and service sectors such as restaurants, physician consultations, private hospitals, real estate establishments, and food and beverage retail.

Not all of the inputs required for the proposed Cove Point Export Facility can be satisfied locally, and thus, economic impacts will also be felt in the rest of Maryland and the nation as a whole. **Table 2** presents the annual employment impacts for each geographic region.

**Table 2: Annual Job-Year Impacts, Facility Construction/Operation (Job-years)**

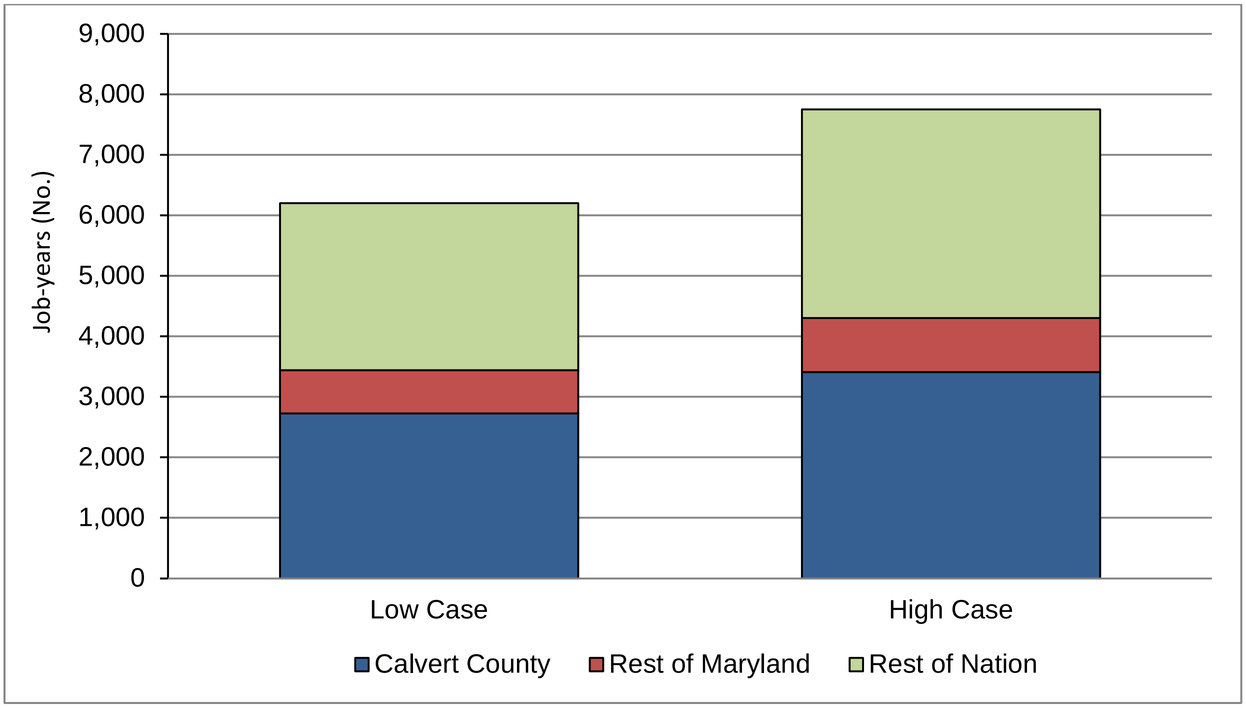
| Year | Calvert County | | Rest of Maryland | | Rest of Nation | | U.S. Total | |
|---|---|---|---|---|---|---|---|---|
| | Low Case | High Case | Low Case | High Case | Low Case | High Case | Low Case | High Case |
| 2011 | 60 | 80 | 70 | 90 | 70 | 80 | 200 | 250 |
| 2012 | 890 | 1,110 | 1,000 | 1,240 | 910 | 1,140 | 2,800 | 3,490 |
| 2013 | 560 | 710 | 640 | 810 | 3,460 | 4,320 | 4,660 | 5,840 |
| 2014 | 2,360 | 2,960 | 1,020 | 1,280 | 3,850 | 4,820 | 7,230 | 9,060 |
| 2015 | 2,730 | 3,410 | 710 | 890 | 2,760 | 3,450 | 6,200 | 7,750 |
| 2016 | 2,620 | 3,270 | 680 | 853 | 2,280 | 2,850 | 5,580 | 6,973 |
| 2017 | 340 | 410 | 150 | 180 | 440 | 510 | 930 | 1,100 |
| 2018-40 (yearly) | 70 | 70 | 60 | 60 | 190 | 190 | 320 | 320 |

*Source: ICF results using the IMPLAN model*

*Note:* The table above and related discussion present state and national results for the rest of Maryland and the rest of the nation so that job-years can be added across geographies without double-counting.

**Figure 5** presents the total (i.e., direct, indirect, and induced) employment impacts from the proposed facility in the peak year (2015), for each region – Calvert County, the rest of Maryland, and the rest of the nation. Spending in Calvert County has the potential to support job-years throughout the state and country. According to our modeling, roughly 55 percent of the total employment impacts (i.e., 3,440-4,300 job-years in 2015) are likely to be in the State of Maryland, while the remaining 45 percent will be in the rest of the U.S. Calvert County will have 44 percent of the jobs in Maryland, with the remaining 56 percent spread across other counties in Maryland.

**Figure 5: Employment Impacts by Geography, 2015, Facility Construction/Operation (Job-years)**



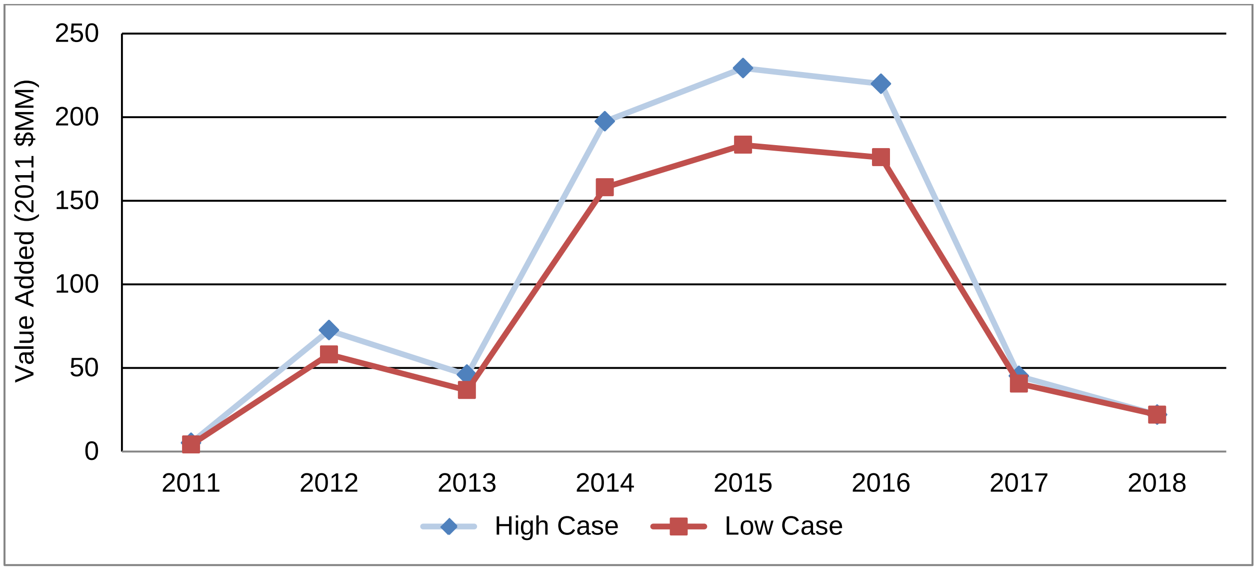

*Source: ICF results using the IMPLAN model*

### Value Added and Industry Output

The trends in value added and output are consistent with the employment trends discussed above, with value added and output peaking in 2015 and declining after 2016 as the construction phase ends. Value added is commonly referred to as individual contributions of different sectors in total Gross Domestic Product (GDP). Industry output refers to the entire value of industry sales and is equal to value added plus purchases of goods and services from other sectors. For full definitions, refer to **Section 3.1**.

**Figure 6** below presents a summary of the value added results for Calvert County for the Low and High Construction Cost Cases over the construction phase of the project and immediately thereafter. In 2015, the proposed facility is expected to contribute an additional $183 to $230 million in valued added at the county-level. These value added contributions include all direct, indirect, and induced impacts from the construction phase of the project. Annual O&M activities are expected to generate an additional $22 million in value added annually in the local economy from 2018 through 2040.

**Figure 6: Calvert County Value Added Impacts 2011 – 2018, Facility Construction/Operation (2011$ million)**

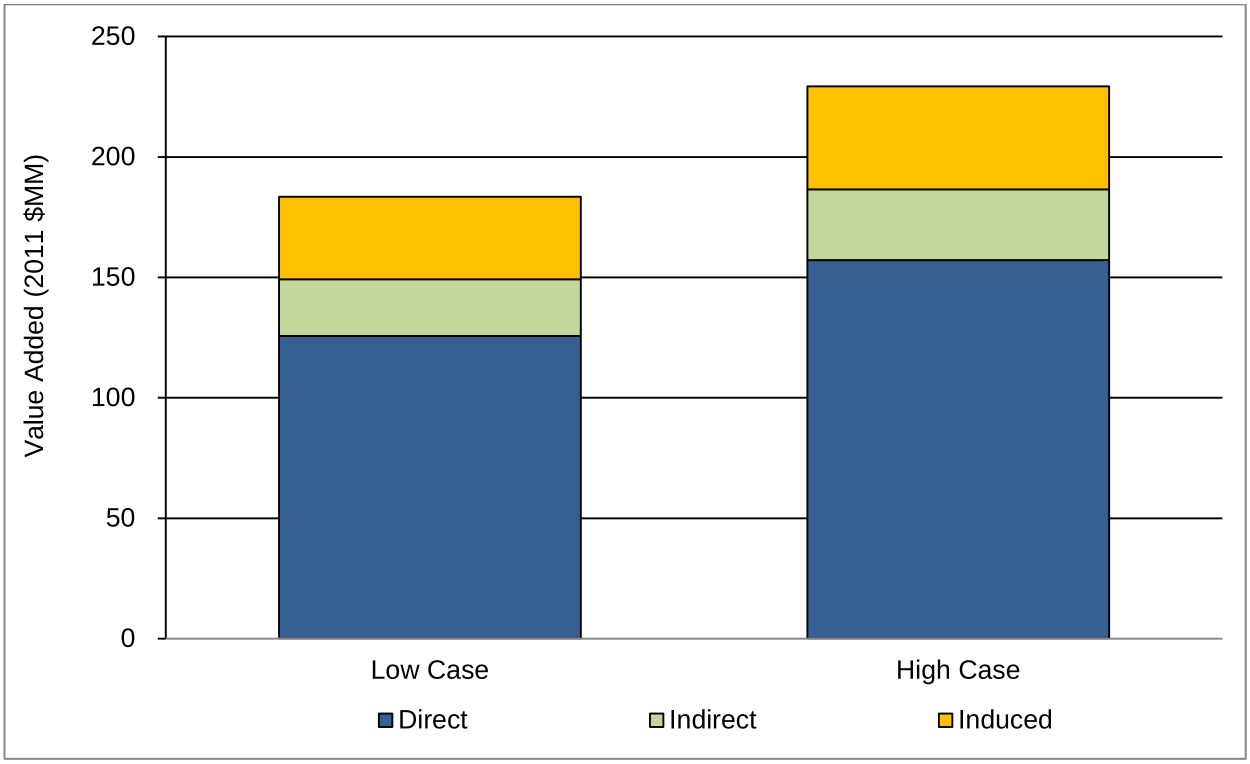



*Source: ICF results using the IMPLAN model*

*Note:* Figure includes direct, indirect, and induced effects.

**Figure 7** below shows the breakdown of the total value added into direct, indirect, and induced industry activity in Calvert County for the peak year 2015.

**Figure 7: Direct, Indirect and Induced Value Added in Calvert County, 2015, Facility Construction/Operation (2011$ million)**



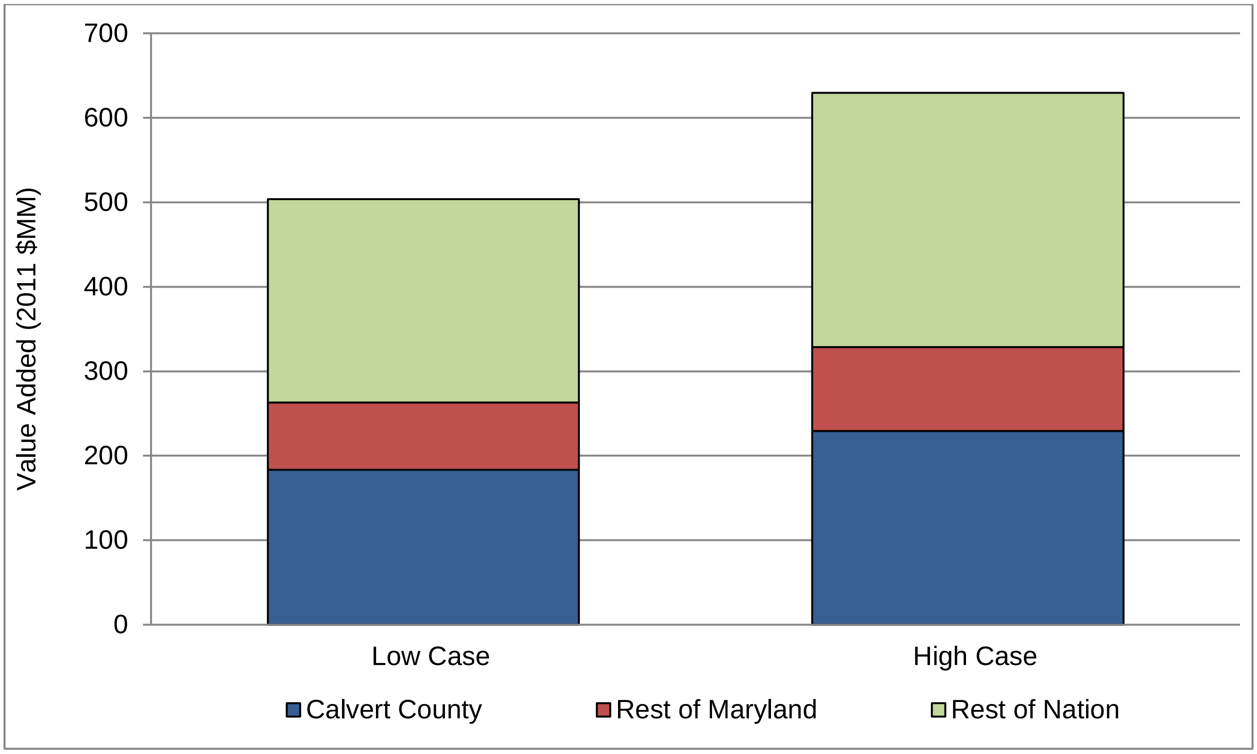

*Source: ICF results using the IMPLAN model*

As **Figure 7** shows, almost 70 percent of the total value added contributions (i.e., roughly $126-$157 million in 2015, the blue shaded bar) is expected to be generated in sectors that will provide the inputs needed for construction and operation of the facility, including non-residential construction, as well as architectural, engineering and other technical services. These are referred to as the direct impacts.

The remainder of the value added will be from the indirect and induced impacts (refer to **Section 3.1** for definitions). Among the sectors with indirect industry spending are commercial and industrial machinery and equipment rental and leasing; real estate establishments; wholesale trade businesses; automotive repair and maintenance; employment services; and electric power generation, transmission, and distribution. Among the sectors with induced impacts are traditional retail and service sectors such as rental properties, physician consultations, private hospitals, and food and beverage retail.

Not all the inputs required for the proposed Cove Point Export Facility can be satisfied locally, and thus, economic impacts will be felt in the rest of Maryland, as well as the rest of the nation. **Figure 8** presents the total value added contribution to the economy generated from the proposed facility in 2015 and illustrates the geographic distribution of the impacts. As was the case with the employment estimates discussed above, slightly more than half of the GDP impacts (i.e., roughly $263-$329 million in 2015) are likely to impact the State of Maryland, in the form of contributions to the Gross State Product (GSP). Of this amount, Calvert County accounts for $183-$230 million, with the remaining $80- $100 million benefiting rest of the state. Finally, slightly less than 50 percent of the total valued added contributions from the proposed facility will be in states outside of Maryland, which translates to roughly $241-$301 million annually.

**Figure 8: Value Added Impacts by Geography, 2015, Facility Construction/Operation (2011$ million)**




*Source: ICF results using the IMPLAN model*

*Note:* The tables, figures, and discussion in this section present state and national results for the rest of Maryland and the rest of the nation, so that value added and industry output can be added across geographies without double-counting.

**Table 3** below provides detailed results for annual value added resulting from the proposed facility for all the regions.

**Table 3: Annual Value Added Impacts, Facility Construction/Operation (2011$)**

| Year | Calvert County | | Rest of Maryland | | Rest of Nation | | U.S. Total | |
|---|---|---|---|---|---|---|---|---|
| | Low | High | Low | High | Low | High | Low | High |
| 2011 | 4,140,183 | 5,175,229 | 7,304,282 | 9,130,352 | 4,956,577 | 6,195,723 | 16,401,042 | 20,501,304 |
| 2012 | 57,998,388 | 72,482,490 | 102,323,156 | 127,919,437 | 69,434,965 | 86,793705 | 229,756,509 | 287,195,632 |
| 2013 | 36,711,306 | 45,889,133 | 66,507,495 | 83,134,366 | 345,670,273 | 432,087,875 | 448,889,074 | 561,111,374 |
| 2014 | 158,001,978 | 197,502,472 | 109,612,988 | 137,016,232 | 356,235,690 | 445,294,634 | 623,850,656 | 779,813,338 |
| 2015 | 183,447,399 | 229,309,248 | 79,621,384 | 99,526,738 | 240,561,873 | 300,702,317 | 503,630,656 | 629,538,303 |
| 2016 | 175,946,220 | 219,932,775 | 76,339,583 | 95,424,489 | 192,273,751 | 240,342,172 | 444,559,554 | 555,699,436 |
| 2017 | 40,642,218 | 45,113,515 | 12,946,106 | 15,407,587 | 43,774,252 | 48,992,625 | 97,362,756 | 109,513,727 |
| 2018-40 (yearly) | 21,985,791 | 21,985,791 | 2,995,115 | 2,995,115 | 22,124,642 | 22,124,642 | 47,105,548 | 47,105,548 |

*Source: ICF results using the IMPLAN model*

**Table 4** below provides detailed results for annual industry output resulting from the proposed facility. Industry output differs from value added, because it is a measure of all industry sales which includes expenditures paid out to suppliers. Again, it is important to note that due to industry linkages, the economic benefit of the project will be felt at the local, state, and national level.

**Table 4: Annual Industry Output Impacts, Facility Construction/Operation (2011$)**

| Year | Calvert County | | Rest of Maryland | | Rest of Nation | | U.S. Total | |
|---|---|---|---|---|---|---|---|---|
| | Low | High | Low | High | Low | High | Low | High |
| 2011 | 7,183,657 | 8,979,572 | 11,346,992 | 14,183,739 | 9,935,280 | 12,419,103 | 28,465,929 | 35,582,414 |
| 2012 | 100,633,367 | 125,766,819 | 158,956,073 | 198,719,984 | 139,179,899 | 173,974,866 | 398,769,339 | 498,461,669 |
| 2013 | 63,698,019 | 79,622,524 | 104,311,558 | 130,389,442 | 744,216,677 | 930,270,907 | 912,226,254 | 1,140,282,873 |
| 2014 | 299,660,772 | 374,575,965 | 174,686,042 | 218,357,547 | 771,837,761 | 964,797,234 | 1,246,184,575 | 1,557,730,746 |
| 2015 | 354,990,889 | 443,738,612 | 129,986,742 | 162,483,434 | 529,097,948 | 661,372,390 | 1,014,075,579 | 1,267,594,436 |
| 2016 | 340,464,765 | 425,580,956 | 124,672,901 | 155,841,147 | 424,116,013 | 530,144,981 | 889,253,679 | 1,111,567,084 |
| 2017 | 88,842,970 | 97,444,416 | 28,569,207 | 32,785,086 | 90,012,658 | 101,810,306 | 207,424,835 | 232,039,808 |
| 2018-40 (yearly) | 52,592,303 | 52,592,303 | 11,308,987 | 11,308,987 | 41,370,789 | 41,370,789 | 105,272,079 | 105,272,079 |

*Source: ICF results using the IMPLAN model*

In 2015, industry output impacts at the county level are estimated to be between $355 million and $444 million, adding the equivalent of roughly 12 percent of the total industry activity in the region. According to our modeling output, annual county O&M expenditures are expected to generate an additional $53 million in economic output in the local economy from 2018 to 2040.

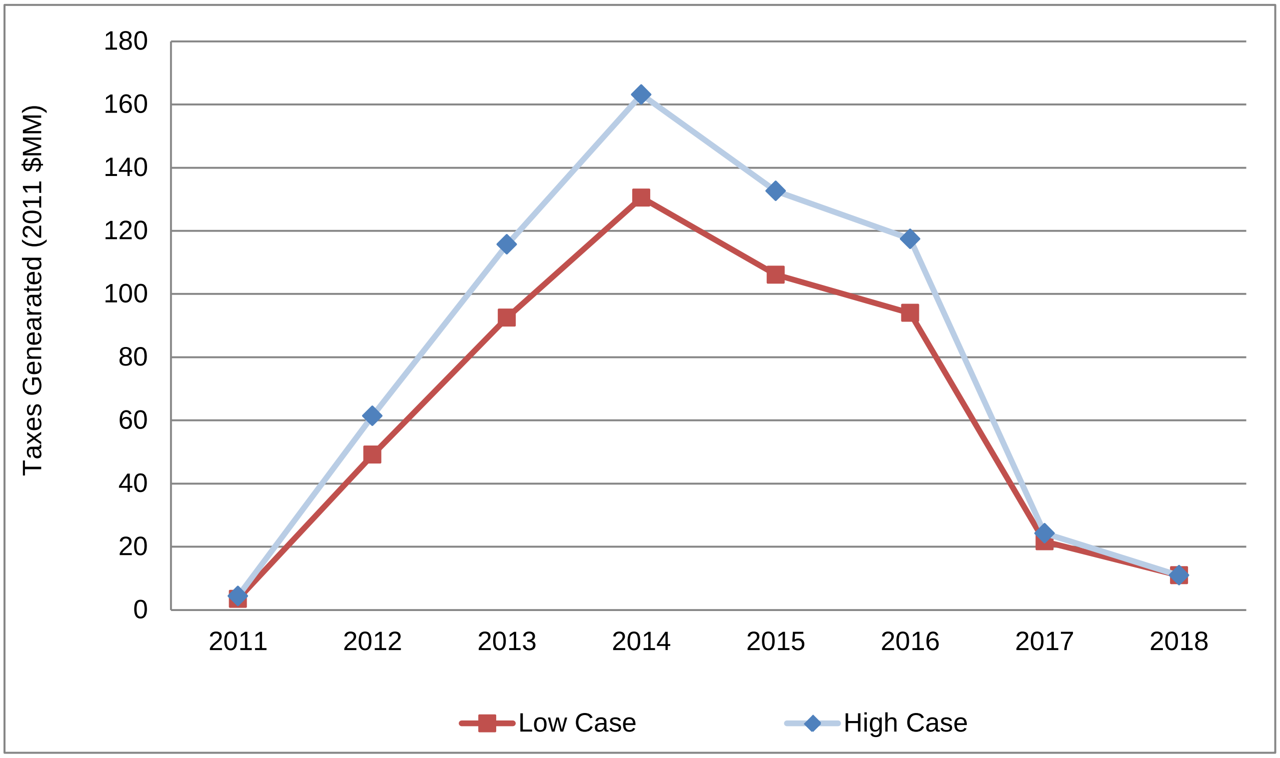
In 2015, almost 75 percent of the total industry output (i.e., roughly $355-$444 million) generated is expected to be in sectors that will provide the direct inputs needed for construction and operation of the facility, including the non-residential construction, as well as architectural, engineering, and other technical services sectors.

Additional industry activity is expected to occur in sectors with indirect and induced impacts. Among the sectors that benefit from the indirect industry activity are architectural, engineering, and other technical services, commercial and industrial machinery, equipment rental and leasing, real estate establishments, and wholesale trade. Among the sectors benefitting from the induced industry activity are more traditional retail and service sectors, such as rental properties, physician consultations, real estate establishments, private hospitals, and food and beverage retail.

**Tax Impacts**

**Figure 9** below shows the trends in total tax revenue over the study timeframe. Tax revenues peak in 2014, with a total of $130 million nationally under the Low Construction Cost Case and about $163 million nationally under the High Construction Cost Case that year.

**Figure 9: Total Tax Revenue Trends, 2011-2018, Facility Construction/Operation (2011$ million)**

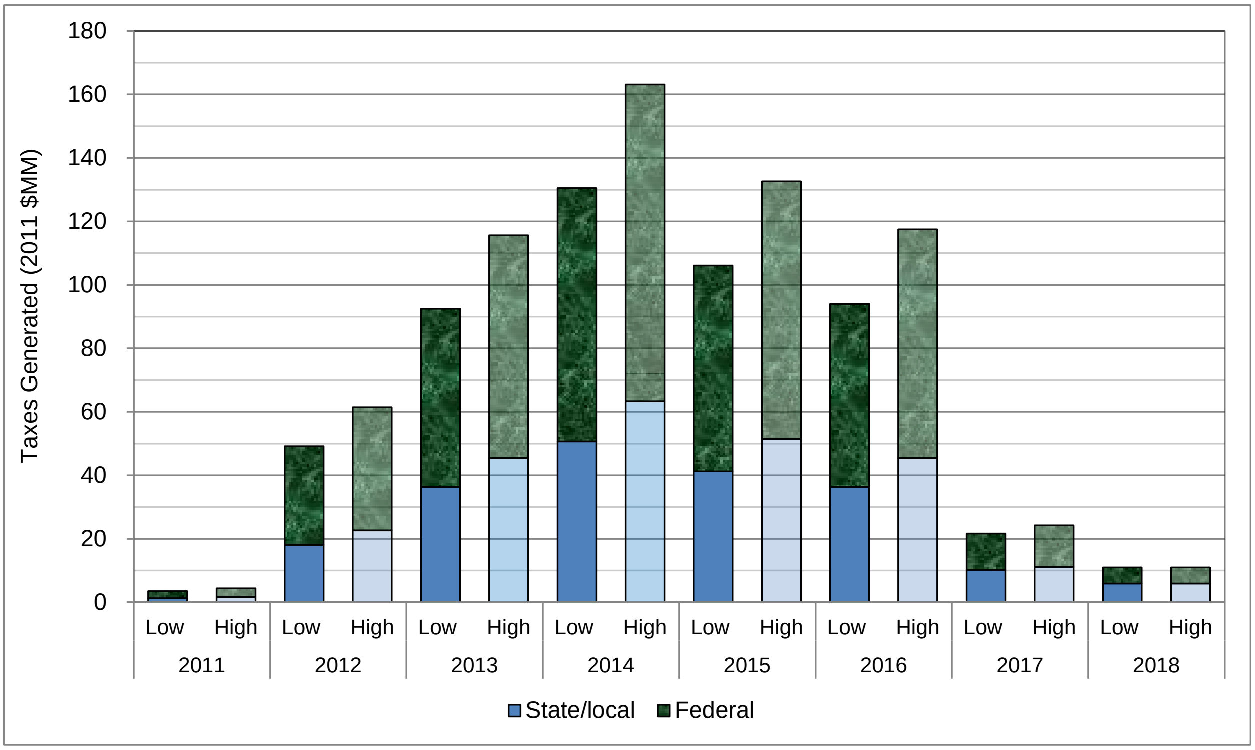



*Source: ICF results using the IMPLAN model*

*Note:* Taxes are defined in IMPLAN to include the following categories: employee compensation, proprietor income, indirect business tax, household taxes, and corporate taxes. However, with regard to facility operations, other than employment-related taxes of liquefaction plant employees, tax figures do not include income taxes, property taxes, or gross receipt taxes associated with the liquefaction plant over the 25-year operating period.

**Figure 10** and **Table 5** below present the detailed tax revenue implications for the state, local, and federal taxes generated by the proposed facility for each year over the study timeframe. The state and local taxes, which account for roughly 39 percent of the total tax revenues (i.e., $130-$163 million in 2014 under the Low and High Construction Cost Cases), include taxes generated in all states, in addition to Maryland, when goods and services are purchased in those states to supply the construction in Calvert County or when the construction-related labor is supplied by workers living in other states. The remaining 61 percent of total tax revenues is generated at the federal level.

**Figure 10: Tax Impacts, 2011-2018, Facility Construction/Operations (2011$ million)**




*Source: ICF results using the IMPLAN model*

*Note:* Taxes are defined in IMPLAN to include the following categories: employee compensation, proprietor income, indirect business tax, household taxes, and corporate taxes. However, with regard to facility operations, other than employment-related taxes of liquefaction plant employees, tax figures do not include income taxes, property taxes, or gross receipt taxes associated with the liquefaction plant over the 25-year operating period.

**Table 5: Tax Impacts, 2011-2018, Facility Construction/Operation (2011$)**

| Year | Case | State and Local | Federal | Total U.S. Taxes |
|---|---|---|---|---|
| **2011** | Low Case | $ 1,292,156 | $ 2,215,726 | $ 3,507,882 |
| | High Case | $ 1,615,195 | $ 2,769,655 | $ 4,384,850 |
| **2012** | Low Case | $ 18,101,365 | $ 31,039,317 | $ 49,140,682 |
| | High Case | $ 22,626,707 | $ 38,799,143 | $ 61,425,850 |
| **2013** | Low Case | $ 36,354,310 | $ 56,183,269 | $ 92,537,579 |
| | High Case | $ 45,442,890 | $ 70,229,091 | $ 115,671,981 |
| **2014** | Low Case | $ 50,660,825 | $ 79,837,207 | $ 130,498,032 |
| | High Case | $ 63,326,033 | $ 99,796,509 | $ 163,122,542 |
| **2015** | Low Case | $ 41,193,642 | $ 64,886,175 | $ 106,079,817 |
| | High Case | $ 51,492,053 | $ 81,107,715 | $ 132,599,768 |
| **2016** | Low Case | $ 36,366,632 | $ 57,602,689 | $ 93,969,321 |
| | High Case | $ 45,458,289 | $ 72,003,361 | $ 117,461,650 |
| **2017** | Low Case | $ 10,157,326 | $ 11,539,058 | $ 21,696,384 |
| | High Case | $ 11,168,150 | $ 13,115,207 | $ 24,283,357 |
| **2018-40 (yearly)** | Low Case | $ 5,906,823 | $ 5,057,069 | $ 10,963,892 |
| | High Case | $ 5,906,823 | $ 5,057,069 | $ 10,963,892 |

*Source: ICF results using the IMPLAN model*

*Note:* Taxes are defined in IMPLAN to include the following categories: employee compensation, proprietor income, indirect business tax, household taxes, and corporate taxes. However, with regard to facility operations, other than employment-related taxes of liquefaction plant employees, tax figures do not include income taxes, property taxes, or gross receipt taxes associated with the liquefaction plant over the 25-year operating period.

## 3.3 Upstream-related Modeling Results

As with the analysis of the economic impacts of constructing and operating the export facility, ICF used the IMPLAN model to estimate the economic impacts from the capital and operating expenditures needed to supply up to 750 million cubic feet per day (MMcfd) of natural gas to a liquefaction plant at Cove Point. Using the expenditure breakdown of typical gas wells (see **Section 6.3** for full discussion), ICF allocated the required capital and operating expenditures among industry sectors to estimate the annual direct output by sector going into the IMPLAN model (see **Table 6** and **Figure 11**). Expenditures of one dollar by the oil and gas industry in goods and services from industry "X" represent an incremental one dollar of output from industry "X".

In aggregate, $32 billion in upstream capital and O&M expenditures ("upstream expenditures") lead to total value added GDP contributions of $44 billion and over 455,000 job-years over the 25-year period. In other words, every $1 million in upstream expenditures generates an additional $1.4 million in GDP contributions and 14 job-year additions.

Direct economic impacts and job-years are those within the oil and gas industry and its supporting industries that result from capital and operating expenditures by oil and gas producers. **Table 7** and **Figure 12** illustrate the upstream employment impact of LNG exports between 2016 and 2040 (reported in job-years), while **Table 8** through **Table 11** and **Figure 13** through **Figure 16** include economic impacts such as output, value added, labor income, and government royalty and tax revenues, broken out by direct, indirect, and induced impact. While output, value added, and labor income are based upon upstream O&G expenditures, tax and government royalty figures also include severance taxes and royalties associated with production of oil and gas, required for delivery to the LNG facility.

The key sectors in which the upstream expenditures will be made are oil and gas (O&G) extraction; gas and oil well drilling; O&G support activities; construction; cement and steel manufacturing; clay, sand and aggregate mining; water supply and clean-up; and transportation. Such direct activity contributes $13 billion to the GDP and nearly 122,000 in direct job-years over the 25-year operating period. These findings indicate that every $1 million in upstream expenditures means an additional $400,000 directly to GDP and 3.8 job-year additions.

Upstream expenditures not only affect sectors in which the upstream expenditures are directly made, but also create a "multiplier" effect, as upstream spending flows through secondary and tertiary economic activity. Secondary (or indirect) industries provide upstream development support services (e.g., iron ore mining for steel manufacturing, and tools and transport equipment manufacturing), while tertiary (or induced) economic activity is generated through the consumer spending of direct and indirect workers (e.g., real estate purchases and retail revenues generated in local communities from employees in O&G and support sectors).

The results indicate a multiplier of 1.9, meaning that for every $1 million in upstream expenditures, another $1.9 million in indirect and induced economic activity is created through the multiplier effect. The model calculated the indirect and induced economic impact of direct industry expenditures based on the sector expenditures described in **Section 6.3**. In terms of job-years and value creation, indirect and induced job-years total nearly 333,000, while indirect and induced economic activity contributes $30 billion to GDP over the 25-year period. Every $1 million in upstream expenditures, through the multiplier effect, generates another $970,000 in indirect and induced GDP contributions and 10 indirect and induced jobs.

In addition, upstream economic activity to support incremental LNG exports will to lead to $25 billion in government royalty and tax revenues to federal, state, and local governments over the 25-year period, with an average of $1 billion in annual revenues. Another $9.8 billion (over 25 years) in royalty income goes to landowners or other holders of mineral rights. These tax and government royalty figures are associated with the oil and gas expenditures and production needed to maintain requisite gas deliveries to the LNG facility, plus associated liquids produced along with the gas.

**Table 12** through **Table 15** include economic impact and employment data for 2025, a representative year over the 25-year period, broken out by sector to show the relative impact on each industry.

The significant increase in upstream job-years during 2016 and 2017 is associated with the ramp-up in expenditures required to support the incremental increase in natural gas production for LNG exports. While significant expenditures are required initially, as a large number of wells must be drilled to support the project, expenditures after this ramp-up are needed only to replace annual production levels.

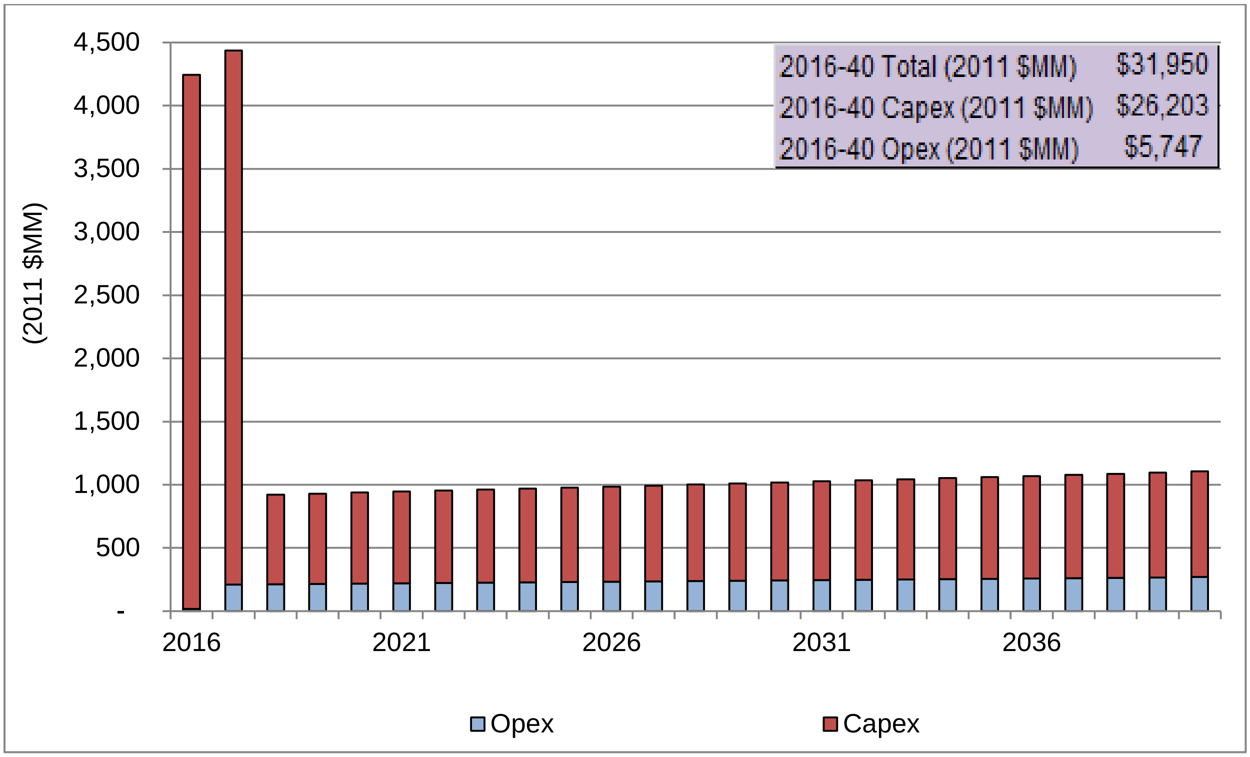
**Table 6: Total U.S. Upstream Natural Gas Sector Expenditures Required to Supply up to 750 MMcfd of Natural Gas for LNG Exports from Cove Point**

| Year | LNG Export Case | | |
|---|---|---|---|
| | O&M Share (%) | Capital Share (%)* | Total Expenditures (2011 $MM) |
| 2016 | 0% | 100% | $4,245 |
| 2017 | 5% | 95% | $4,437 |
| 2018 | 23% | 77% | $922 |
| 2019 | 23% | 77% | $930 |
| 2020 | 23% | 77% | $938 |
| 2021 | 23% | 77% | $946 |
| 2022 | 23% | 77% | $954 |
| 2023 | 23% | 77% | $962 |
| 2024 | 23% | 77% | $970 |
| 2025 | 23% | 77% | $977 |
| 2026 | 24% | 76% | $985 |
| 2027 | 24% | 76% | $993 |
| 2028 | 24% | 76% | $1,002 |
| 2029 | 24% | 76% | $1,010 |
| 2030 | 24% | 76% | $1,019 |
| 2031 | 24% | 76% | $1,027 |
| 2032 | 24% | 76% | $1,036 |
| 2033 | 24% | 76% | $1,044 |
| 2034 | 24% | 76% | $1,053 |
| 2035 | 24% | 76% | $1,061 |
| 2036 | 24% | 76% | $1,070 |
| 2037 | 24% | 76% | $1,078 |
| 2038 | 24% | 76% | $1,087 |
| 2039 | 24% | 76% | $1,096 |
| 2040 | 24% | 76% | $1,105 |
| **Total** | | | **$31,950** |

*Source: ICF*

** Capital expenditures averaged over 2016 and 2017.*

**Figure 11: U.S. Upstream Natural Gas Sector Expenditures Required to Supply up to 750 MMcfd of Natural Gas for LNG Exports from Cove Point (2011$ million)**




*Source: ICF*

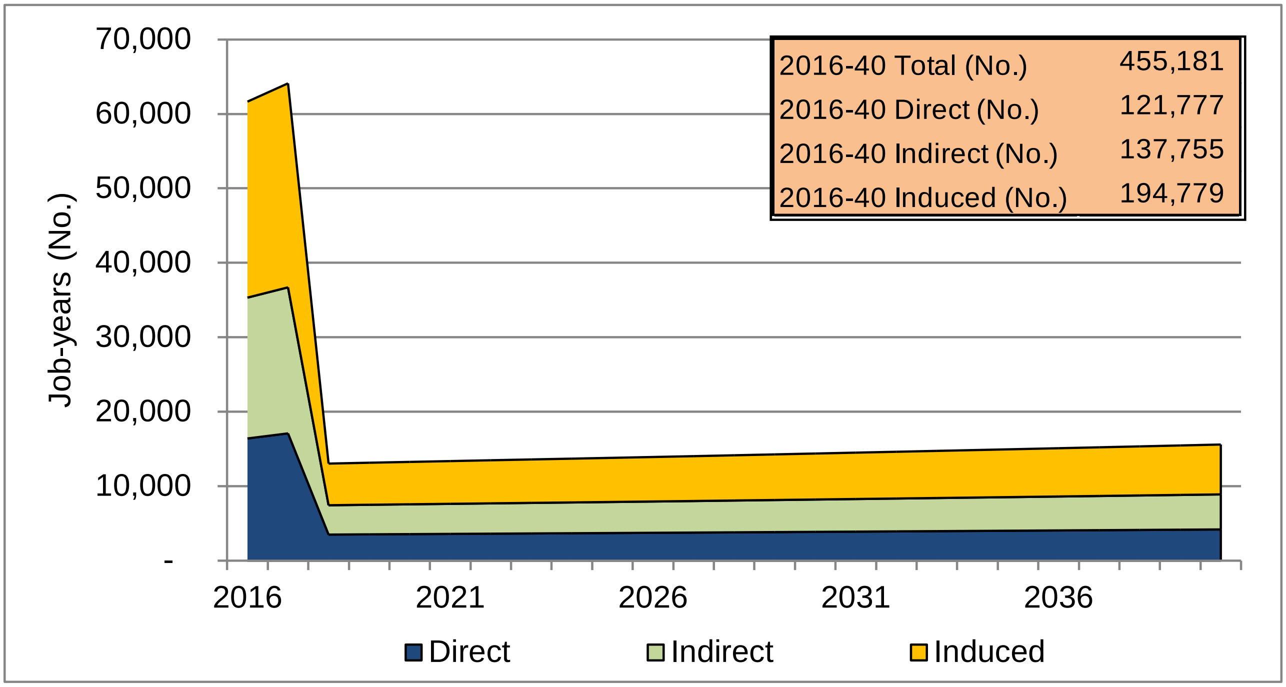
*Note:* Capital expenditures averaged over 2016 and 2017.

**Table 7: U.S. Upstream Natural Gas Sector Annual Job-years Resulting from LNG Exports from Cove Point (Job-years)**

| Year | Job-years (No.) | | | |
|---|---|---|---|---|
| | Direct | Indirect | Induced | Total |
| 2016 | 16,410 | 18,915 | 26,319 | 61,743 |
| 2017 | 17,093 | 19,613 | 27,396 | 64,209 |
| 2018 | 3,501 | 3,939 | 5,595 | 13,061 |
| 2019 | 3,532 | 3,973 | 5,645 | 13,176 |
| 2020 | 3,561 | 4,006 | 5,692 | 13,286 |
| 2021 | 3,591 | 4,039 | 5,739 | 13,396 |
| 2022 | 3,621 | 4,072 | 5,787 | 13,507 |
| 2023 | 3,651 | 4,105 | 5,834 | 13,618 |
| 2024 | 3,679 | 4,138 | 5,880 | 13,725 |
| 2025 | 3,709 | 4,171 | 5,928 | 13,835 |
| 2026 | 3,739 | 4,204 | 5,976 | 13,947 |
| 2027 | 3,769 | 4,238 | 6,024 | 14,059 |
| 2028 | 3,801 | 4,273 | 6,074 | 14,177 |
| 2029 | 3,833 | 4,309 | 6,126 | 14,296 |
| 2030 | 3,865 | 4,344 | 6,176 | 14,415 |
| 2031 | 3,897 | 4,380 | 6,227 | 14,533 |
| 2032 | 3,929 | 4,415 | 6,278 | 14,651 |
| 2033 | 3,961 | 4,451 | 6,329 | 14,770 |
| 2034 | 3,992 | 4,486 | 6,379 | 14,888 |
| 2035 | 4,024 | 4,522 | 6,430 | 15,006 |
| 2036 | 4,057 | 4,558 | 6,483 | 15,128 |
| 2037 | 4,090 | 4,595 | 6,535 | 15,251 |
| 2038 | 4,123 | 4,632 | 6,589 | 15,375 |
| 2039 | 4,157 | 4,669 | 6,642 | 15,500 |
| 2040 | 4,191 | 4,707 | 6,696 | 15,626 |
| **Total** | **121,777** | **137,755** | **194,779** | **455,181** |

*Source: ICF results using the IMPLAN model*

**Figure 12: U.S. Job-years Supported by Upstream O&G Expenditures Associated with LNG Exports from Cove Point (Job-years)**




Source: ICF results using the IMPLAN model

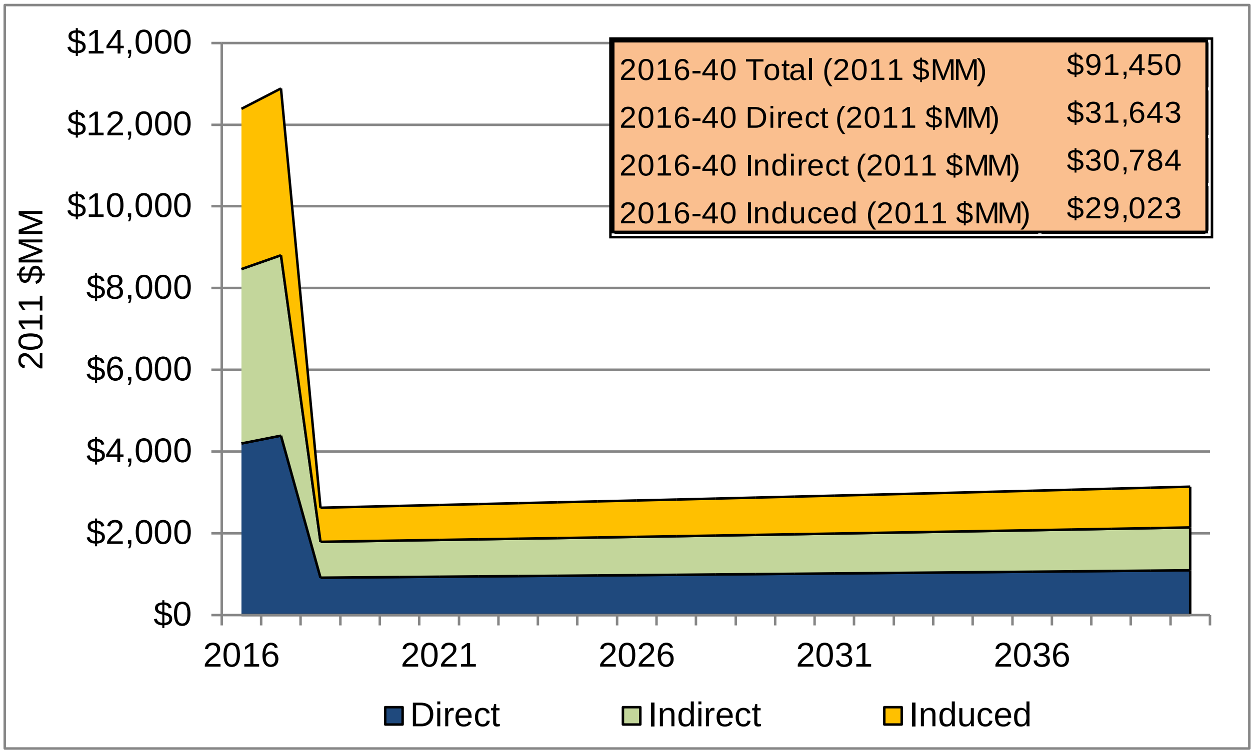
*Note:* "Total Job-years" includes direct, indirect, and induced job-years supported by upstream O&G expenditures associated with LNG exports.

**Table 8: U.S. Output from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$)**

| Year | Output (2011$) | | | | Output Dollars per Job-Year (2011$) | | | |
|---|---|---|---|---|---|---|---|---|
| | Direct | Indirect | Induced | Total | Direct | Indirect | Induced | Total |
| 2016 | $4,197,702,898 | $4,267,621,850 | $3,921,523,649 | $12,386,847,636 | $255,795 | $225,615 | $149,001 | $200,619 |
| 2017 | $4,389,083,192 | $4,415,048,323 | $4,081,990,174 | $12,886,120,932 | $256,776 | $225,103 | $149,001 | $200,689 |
| 2018 | $913,799,373 | $877,723,002 | $833,740,421 | $2,625,262,672 | $261,008 | $222,841 | $149,003 | $200,994 |
| 2019 | $921,931,099 | $885,356,514 | $841,090,855 | $2,648,378,344 | $261,026 | $222,831 | $149,003 | $200,995 |
| 2020 | $929,692,135 | $892,642,499 | $848,106,390 | $2,670,440,898 | $261,043 | $222,822 | $149,003 | $200,996 |
| 2021 | $937,483,806 | $899,957,206 | $855,149,602 | $2,692,590,487 | $261,060 | $222,812 | $149,003 | $200,998 |
| 2022 | $945,352,066 | $907,343,715 | $862,262,009 | $2,714,957,663 | $261,077 | $222,803 | $149,003 | $200,999 |
| 2023 | $953,159,055 | $914,672,782 | $869,319,060 | $2,737,150,769 | $261,093 | $222,794 | $149,003 | $201,000 |
| 2024 | $960,733,213 | $921,783,567 | $876,165,762 | $2,758,682,413 | $261,109 | $222,786 | $149,003 | $201,001 |
| 2025 | $968,549,393 | $929,121,250 | $883,231,116 | $2,780,901,629 | $261,125 | $222,777 | $149,003 | $201,002 |
| 2026 | $976,454,415 | $936,542,225 | $890,376,736 | $2,803,373,246 | $261,140 | $222,769 | $149,003 | $201,003 |
| 2027 | $984,411,519 | $944,012,027 | $897,569,408 | $2,825,992,821 | $261,156 | $222,760 | $149,003 | $201,004 |
| 2028 | $992,760,757 | $951,849,460 | $905,116,353 | $2,849,726,438 | $261,172 | $222,751 | $149,003 | $201,006 |
| 2029 | $1,001,186,585 | $959,758,697 | $912,732,493 | $2,873,677,641 | $261,188 | $222,743 | $149,003 | $201,007 |
| 2030 | $1,009,563,396 | $967,621,980 | $920,304,348 | $2,897,489,589 | $261,204 | $222,734 | $149,003 | $201,008 |
| 2031 | $1,017,949,397 | $975,493,879 | $927,884,506 | $2,921,327,647 | $261,219 | $222,726 | $149,003 | $201,009 |
| 2032 | $1,026,289,445 | $983,322,696 | $935,423,149 | $2,945,035,153 | $261,235 | $222,717 | $149,003 | $201,010 |
| 2033 | $1,034,693,828 | $991,211,828 | $943,019,914 | $2,968,925,432 | $261,250 | $222,709 | $149,003 | $201,011 |
| 2034 | $1,043,021,621 | $999,029,157 | $950,547,485 | $2,992,598,124 | $261,264 | $222,701 | $149,003 | $201,012 |
| 2035 | $1,051,422,940 | $1,006,915,417 | $958,141,482 | $3,016,479,700 | $261,279 | $222,693 | $149,003 | $201,013 |
| 2036 | $1,060,036,055 | $1,015,000,238 | $965,926,825 | $3,040,962,978 | $261,293 | $222,685 | $149,003 | $201,014 |
| 2037 | $1,068,728,074 | $1,023,159,033 | $973,783,455 | $3,065,670,420 | $261,308 | $222,677 | $149,003 | $201,015 |
| 2038 | $1,077,499,743 | $1,031,392,501 | $981,712,043 | $3,090,604,145 | $261,322 | $222,669 | $149,003 | $201,017 |
| 2039 | $1,086,351,814 | $1,039,701,347 | $989,713,271 | $3,115,766,288 | $261,337 | $222,661 | $149,003 | $201,018 |
| 2040 | $1,095,285,046 | $1,048,086,282 | $997,787,823 | $3,141,159,006 | $261,351 | $222,654 | $149,003 | $201,019 |
| **Total** | **$31,643,140,865** | **$30,784,367,478** | **$29,022,618,330** | **$91,450,122,071** | **Avg: $259,844** | **Avg: $223,472** | **Avg: $149,003** | **Avg: $200,909** |

Source: ICF results using the IMPLAN model

**Figure 13: U.S. Output from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$ million)**



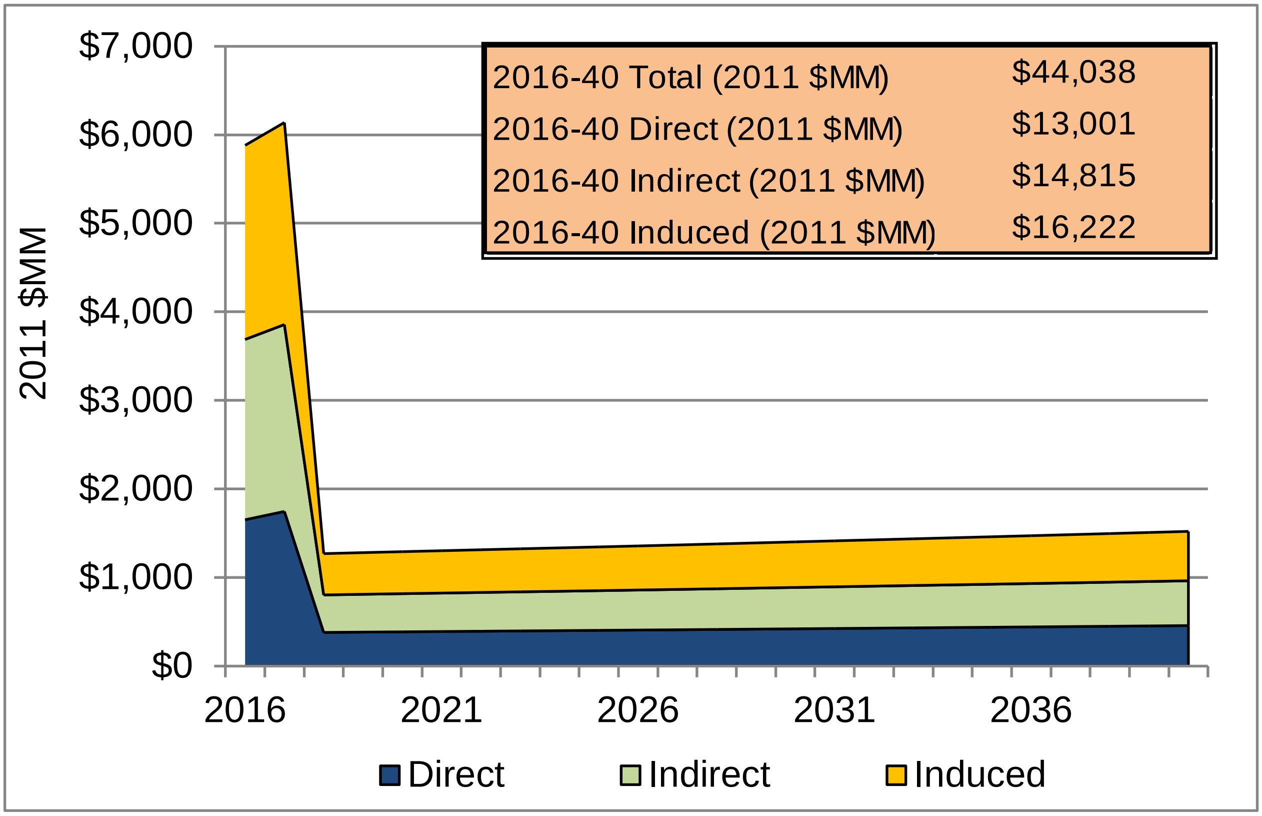

Source: ICF results using the IMPLAN model

**Table 9: U.S. Value Added from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$)**

| Year | Value Added (2011$) | | | | Value Added Dollars per Job-Year (2011$) | | | |
|---|---|---|---|---|---|---|---|---|
| | Direct | Indirect | Induced | Total | Direct | Indirect | Induced | Total |
| 2016 | $1,652,195,434 | $2,036,196,946 | $2,191,794,489 | $5,880,187,081 | $100,680 | $107,647 | $83,278 | $95,236 |
| 2017 | $1,746,092,533 | $2,110,869,859 | $2,281,526,100 | $6,138,488,704 | $102,152 | $107,624 | $83,280 | $95,601 |
| 2018 | $379,874,738 | $423,498,836 | $466,037,754 | $1,269,411,365 | $108,503 | $107,520 | $83,289 | $97,188 |
| 2019 | $383,324,967 | $427,199,216 | $470,146,615 | $1,280,670,834 | $108,531 | $107,520 | $83,289 | $97,195 |
| 2020 | $386,617,737 | $430,731,086 | $474,068,268 | $1,291,417,127 | $108,556 | $107,519 | $83,289 | $97,201 |
| 2021 | $389,923,521 | $434,276,882 | $478,005,392 | $1,302,205,831 | $108,582 | $107,519 | $83,289 | $97,208 |
| 2022 | $393,261,836 | $437,857,494 | $481,981,196 | $1,313,100,563 | $108,607 | $107,518 | $83,289 | $97,214 |
| 2023 | $396,574,126 | $441,410,253 | $485,926,056 | $1,323,910,472 | $108,631 | $107,518 | $83,289 | $97,220 |
| 2024 | $399,787,516 | $444,857,171 | $489,753,331 | $1,334,398,056 | $108,655 | $107,518 | $83,289 | $97,226 |
| 2025 | $403,103,710 | $448,414,108 | $493,702,833 | $1,345,220,689 | $108,678 | $107,517 | $83,289 | $97,232 |
| 2026 | $406,457,641 | $452,011,432 | $497,697,203 | $1,356,166,314 | $108,702 | $107,517 | $83,289 | $97,238 |
| 2027 | $409,833,695 | $455,632,431 | $501,717,875 | $1,367,184,039 | $108,725 | $107,516 | $83,289 | $97,244 |
| 2028 | $413,376,318 | $459,431,689 | $505,936,584 | $1,378,744,630 | $108,750 | $107,516 | $83,289 | $97,250 |
| 2029 | $416,951,473 | $463,265,764 | $510,193,973 | $1,390,411,248 | $108,774 | $107,516 | $83,289 | $97,256 |
| 2030 | $420,505,807 | $467,077,556 | $514,426,607 | $1,402,010,009 | $108,797 | $107,515 | $83,289 | $97,262 |
| 2031 | $424,064,045 | $470,893,526 | $518,663,883 | $1,413,621,493 | $108,820 | $107,515 | $83,289 | $97,268 |
| 2032 | $427,602,764 | $474,688,606 | $522,877,951 | $1,425,169,359 | $108,843 | $107,514 | $83,289 | $97,273 |
| 2033 | $431,168,809 | $478,512,931 | $527,124,510 | $1,436,806,290 | $108,866 | $107,514 | $83,289 | $97,279 |
| 2034 | $434,702,323 | $482,302,441 | $531,332,389 | $1,448,337,192 | $108,888 | $107,514 | $83,289 | $97,285 |
| 2035 | $438,267,067 | $486,125,374 | $535,577,400 | $1,459,969,882 | $108,909 | $107,513 | $83,289 | $97,290 |
| 2036 | $441,921,777 | $490,044,586 | $539,929,374 | $1,471,895,777 | $108,931 | $107,513 | $83,289 | $97,296 |
| 2037 | $445,610,003 | $493,999,667 | $544,321,196 | $1,483,930,907 | $108,953 | $107,513 | $83,289 | $97,301 |
| 2038 | $449,332,062 | $497,990,956 | $548,753,243 | $1,496,076,302 | $108,975 | $107,512 | $83,289 | $97,307 |
| 2039 | $453,088,273 | $502,018,794 | $553,225,895 | $1,508,333,004 | $108,997 | $107,512 | $83,289 | $97,312 |
| 2040 | $456,878,960 | $506,083,527 | $557,739,535 | $1,520,702,063 | $109,018 | $107,511 | $83,289 | $97,317 |
| **Total** | **$13,000,517,136** | **$14,815,391,132** | **$16,222,459,651** | **$44,038,369,229** | **Avg: $106,756** | **Avg: $107,549** | **Avg: $83,286** | **Avg: $96,749** |

Source: ICF results using the IMPLAN model

**Figure 14: U.S. Value Added from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$ million)**



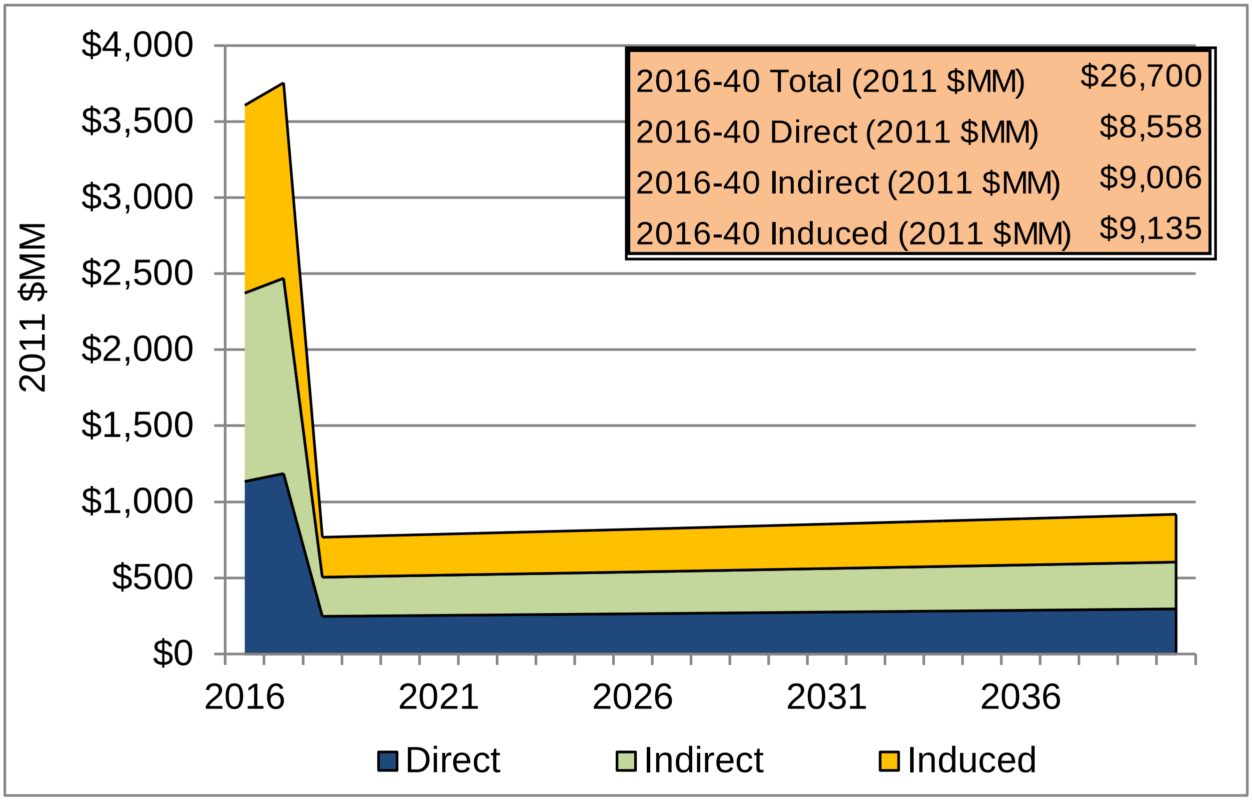

Source: ICF results using the IMPLAN model

**Table 10: U.S. Labor Income from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$)**

| Year | Labor Income (2011$) | | | | Labor Income Dollars per Job-Year (2011$) | | | |
|---|---|---|---|---|---|---|---|---|
| | Direct | Indirect | Induced | Total | Direct | Indirect | Induced | Total |
| 2016 | $1,133,927,225 | $1,238,399,849 | $1,234,293,795 | $3,606,620,614 | $69,098 | $65,470 | $46,898 | $58,413 |
| 2017 | $1,185,973,699 | $1,283,667,423 | $1,284,819,278 | $3,754,460,130 | $69,383 | $65,448 | $46,899 | $58,472 |
| 2018 | $247,224,590 | $257,407,868 | $262,439,114 | $767,071,512 | $70,615 | $65,352 | $46,902 | $58,728 |
| 2019 | $249,425,905 | $259,656,423 | $264,752,906 | $773,835,175 | $70,620 | $65,352 | $46,902 | $58,729 |
| 2020 | $251,526,869 | $261,802,583 | $266,961,278 | $780,290,669 | $70,625 | $65,351 | $46,902 | $58,730 |
| 2021 | $253,636,126 | $263,957,206 | $269,178,361 | $786,771,632 | $70,630 | $65,351 | $46,902 | $58,731 |
| 2022 | $255,766,117 | $266,132,985 | $271,417,226 | $793,316,267 | $70,635 | $65,350 | $46,902 | $58,732 |
| 2023 | $257,879,521 | $268,291,839 | $273,638,666 | $799,809,964 | $70,639 | $65,350 | $46,902 | $58,733 |
| 2024 | $259,929,894 | $270,386,379 | $275,793,892 | $806,110,101 | $70,644 | $65,350 | $46,902 | $58,734 |
| 2025 | $262,045,786 | $272,547,771 | $278,017,945 | $812,611,439 | $70,649 | $65,349 | $46,902 | $58,735 |
| 2026 | $264,185,729 | $274,733,705 | $280,267,265 | $819,186,635 | $70,653 | $65,349 | $46,902 | $58,736 |
| 2027 | $266,339,771 | $276,934,024 | $282,531,396 | $825,805,128 | $70,658 | $65,349 | $46,902 | $58,737 |
| 2028 | $268,599,971 | $279,242,662 | $284,907,047 | $832,749,615 | $70,662 | $65,348 | $46,902 | $58,738 |
| 2029 | $270,880,904 | $281,572,456 | $287,304,479 | $839,757,774 | $70,667 | $65,348 | $46,902 | $58,739 |
| 2030 | $273,148,568 | $283,888,710 | $289,687,971 | $846,725,183 | $70,672 | $65,347 | $46,902 | $58,740 |
| 2031 | $275,418,720 | $286,207,503 | $292,074,076 | $853,700,233 | $70,676 | $65,347 | $46,902 | $58,741 |
| 2032 | $277,676,432 | $288,513,603 | $294,447,113 | $860,637,080 | $70,681 | $65,347 | $46,902 | $58,742 |
| 2033 | $279,951,560 | $290,837,473 | $296,838,446 | $867,627,411 | $70,685 | $65,346 | $46,902 | $58,743 |
| 2034 | $282,205,954 | $293,140,187 | $299,207,998 | $874,554,071 | $70,689 | $65,346 | $46,902 | $58,744 |
| 2035 | $284,480,252 | $295,463,211 | $301,598,460 | $881,541,855 | $70,693 | $65,346 | $46,902 | $58,745 |
| 2036 | $286,811,887 | $297,844,739 | $304,049,154 | $888,705,711 | $70,698 | $65,345 | $46,902 | $58,745 |
| 2037 | $289,164,883 | $300,248,062 | $306,522,288 | $895,935,164 | $70,702 | $65,345 | $46,902 | $58,746 |
| 2038 | $291,539,442 | $302,673,387 | $309,018,074 | $903,230,832 | $70,706 | $65,345 | $46,903 | $58,747 |
| 2039 | $293,935,766 | $305,120,921 | $311,536,725 | $910,593,341 | $70,710 | $65,344 | $46,903 | $58,748 |
| 2040 | $296,354,062 | $307,590,874 | $314,078,458 | $918,023,321 | $70,714 | $65,344 | $46,903 | $58,749 |
| **Total** | **$8,558,029,633** | **$9,006,261,844** | **$9,135,381,412** | **$26,699,670,857** | **Avg: $70,276** | **Avg: $65,379** | **Avg: $46,901** | **Avg: $58,657** |

Source: ICF results using the IMPLAN model

**Figure 15: U.S. Labor Income from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$ million)**




*Source: ICF results using the IMPLAN model*

**Table 11: U.S. Taxes and Royalties from Upstream Oil and Gas Expenditures and Production Associated with LNG Exports from Cove Point (2011$ million)**

| Year | Royalties* | Royalties to Federal and State Government | Severance Tax** | Other State Taxes | Federal Taxes | Total Taxes and *Government* Royalties |
|---|---|---|---|---|---|---|
| 2016 | $30 | $5 | $10 | $494 | $614 | **$1,122** |
| 2017 | $384 | $58 | $127 | $570 | $949 | **$1,703** |
| 2018 | $377 | $57 | $125 | $138 | $306 | **$626** |
| 2019 | $383 | $57 | $127 | $136 | $288 | **$609** |
| 2020 | $394 | $59 | $131 | $135 | $278 | **$603** |
| 2021 | $406 | $61 | $135 | $135 | $269 | **$599** |
| 2022 | $416 | $62 | $138 | $133 | $257 | **$591** |
| 2023 | $428 | $64 | $142 | $133 | $248 | **$587** |
| 2024 | $441 | $66 | $146 | $158 | $398 | **$769** |
| 2025 | $452 | $68 | $150 | $184 | $546 | **$947** |
| 2026 | $462 | $69 | $153 | $187 | $559 | **$968** |
| 2027 | $472 | $71 | $156 | $190 | $572 | **$989** |
| 2028 | $479 | $72 | $159 | $192 | $582 | **$1,005** |
| 2029 | $485 | $73 | $161 | $194 | $590 | **$1,017** |
| 2030 | $491 | $74 | $163 | $196 | $598 | **$1,031** |
| 2031 | $499 | $75 | $165 | $199 | $609 | **$1,048** |
| 2032 | $509 | $76 | $169 | $202 | $622 | **$1,069** |
| 2033 | $519 | $78 | $172 | $205 | $635 | **$1,090** |
| 2034 | $529 | $79 | $175 | $208 | $649 | **$1,112** |
| 2035 | $542 | $81 | $180 | $212 | $667 | **$1,140** |
| 2036 | $553 | $83 | $183 | $215 | $682 | **$1,164** |
| 2037 | $564 | $85 | $187 | $219 | $698 | **$1,188** |
| 2038 | $575 | $86 | $191 | $222 | $713 | **$1,212** |
| 2039 | $587 | $88 | $194 | $226 | $729 | **$1,237** |
| 2040 | $598 | $90 | $198 | $229 | $745 | **$1,262** |
| **Total** | **$11,579** | **$1,737** | **$3,836** | **$5,311** | **$13,804** | **$24,688** |

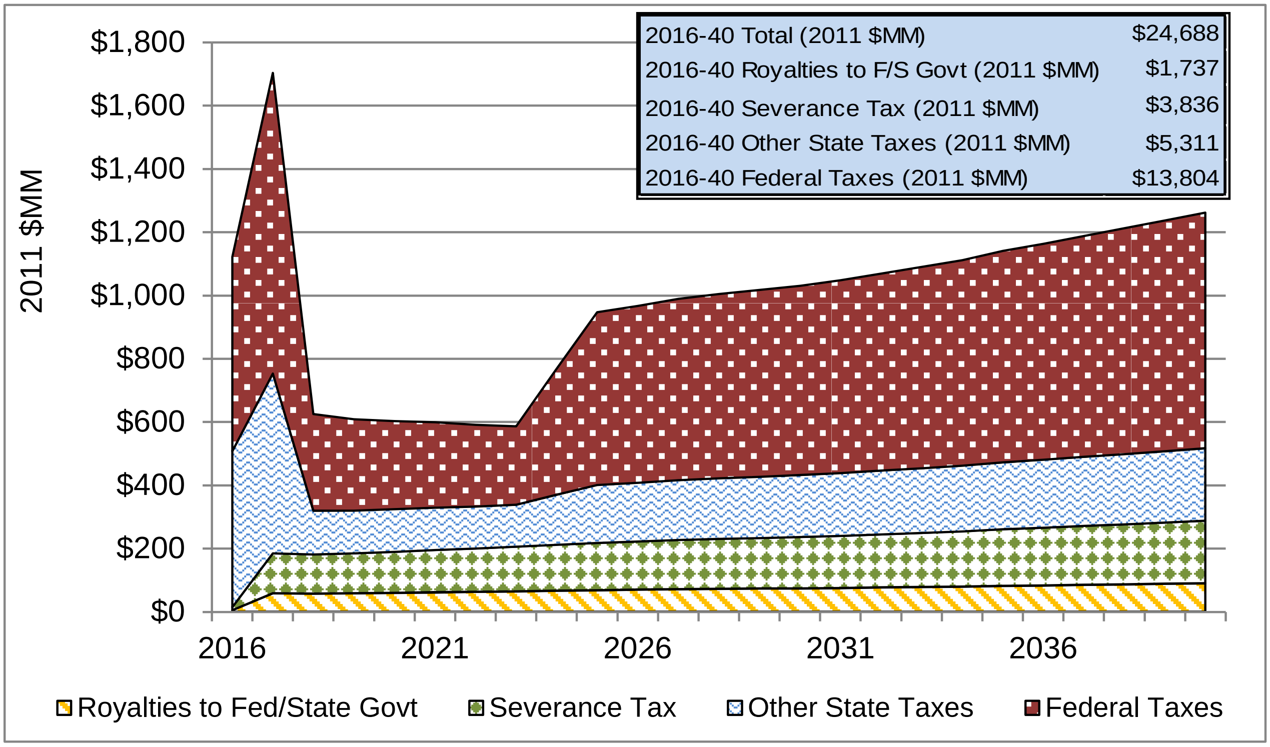
*Source: ICF results using the IMPLAN model and IPAA studies from 2009-10, 2008-09, 2007-08, and 2006-07*

* Assumes average royalty rate of 16%, of which 15% is assumed to go to the federal and state governments. Most of the royalties (75% to 85%) are paid to private citizens and are not considered government revenue.

** Assumes rate of 5.3%, based on average rate reported in IPAA 2009-10, 2008-09, 2007-08, and 2006-07 "Oil and Gas Producing Industry in Your State."

Note: "Other State Taxes" and "Federal Taxes" are based on the IMPLAN model, and include property and income taxes from oil and gas exploration and production (E&P), taxes generated by E&P sector suppliers, and all related employee taxes.

**Figure 16: U.S. Taxes and Royalties from Upstream Oil and Gas Expenditures and Production Associated with LNG Exports from Cove Point (2011$ million)**




*Source: ICF results using the IMPLAN model and IPAA studies from 2009-10, 2008-09, 2007-08, and 2006-07*

*Note:* "Other State Taxes" and "Federal Taxes" are based on the IMPLAN model, and include property and income taxes from oil and gas exploration and production (E&P), taxes generated by E&P sector suppliers, and all related employee taxes.

The following tables illustrate the per-year economic impact disaggregated for the example year of 2025.

**Table 12: U.S. Job-years from Upstream O&G Expenditures Associated with LNG Exports from Cove Point for 2025 (Job-years)**

| NAICS | IMPLAN | Sector | Job-years (No.) | | | |
|---|---|---|---|---|---|---|
| | | | Direct | Indirect | Induced | Total |
| 111-115 | 1-19 | Agriculture and forestry | - | 39 | 117 | *157* |
| 211 | 20 | Oil and gas extraction | 245 | 42 | 14 | *302* |
| 212 | 26 | Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying | 252 | 9 | 1 | *262* |
| 212 | 21, 30, etc. | Other mining and support | - | 37 | 4 | *43* |
| 213 | 28 | Drilling oil and gas wells | 119 | - | - | *119* |
| 213 | 29 | Support activities for oil and gas operations | 1,296 | 290 | 7 | *1,593* |
| 221 | 31 | Electric power generation, transmission, and distribution | 7 | 25 | 17 | *49* |
| 221 | 32 | Natural gas distribution | 1 | 10 | 4 | *16* |
| 221 | 33 | Water, sewage and other systems | 76 | 0 | 2 | *79* |
| 23 | 34-40 | Construction, maintenance and repair | 230 | 89 | 56 | *374* |
| 31-33 | 41-114 | Manufacturing: food, textiles, paper products | - | 55 | 139 | *192* |
| 31-33 | 115-120 | Manufacturing: petroleum and petrochemicals | 1 | 15 | 3 | *20* |
| 31-33 | 121 | Manufacturing: industrial gases | 9 | 5 | 0 | *14* |
| 31-33 | 122-159 | Manufacturing: chemicals, rubber, glass | 37 | 62 | 41 | *144* |
| 31-33 | 160-169 | Manufacturing: cement, concrete, lime, non-metal minerals | 22 | 22 | 3 | *47* |
| 31-33 | 170-171 | Manufacturing: iron, steel and products | 159 | 74 | 2 | *234* |
| 31-33 | 172-181 | Manufacturing: non-ferrous metals and products | - | 21 | 3 | *25* |
| 31-33 | 182-318 | Manufacturing: tools, machinery, equipment, electronics, vehicles, airplanes | 131 | 291 | 86 | *528* |
| 42, 44, 45 | 319-331 | Wholesale and retail trade | 12 | 328 | 1,128 | *1,468* |
| 48 | 335 | Truck transportation | 509 | 156 | 60 | *725* |
| 48 | 332, 340, etc. | Non-truck transportation, warehousing | 75 | 205 | 116 | *397* |
| 51 | 341-353 | Publishing, telecommunications, information services | 3 | 95 | 120 | *217* |
| 52 | 354-359 | Monetary, investment services, insurance | 39 | 271 | 411 | *722* |
| 53 | 360-366 | Real estate, equipment rentals | 14 | 227 | 354 | *596* |
| 54-56 | 367-368 | Legal and accounting services | - | 180 | 118 | *298* |
| 54-56 | 369-370 | Architectural, engineering, design services | 22 | 275 | 33 | *329* |
| 54-56 | 371-390 | IT, management, scientific, environmental, waste management services | 98 | 932 | 530 | *1,562* |
| 61-62, 71-72, 81 | 391-426 | Educational, medical, hotel, food, miscellaneous services | 332 | 345 | 2,476 | *3,154* |
| 491, N/a | 427-440 | Postal, governmental services | 18 | 72 | 82 | *172* |
| **Total** | | | **3,709** | **4,171** | **5,928** | ***13,835*** |

*Source: ICF results using the IMPLAN model*

**Table 13: U.S. Output from Upstream O&G Expenditures Associated with LNG Exports from Cove Point for 2025 (2011$)**

| NAICS | IMPLAN | Sector | Output (2011$) | | | |
|---|---|---|---|---|---|---|
| | | | Direct | Indirect | Induced | Total |
| 111-115 | 1-19 | Agriculture and forestry | $0 | $4,339,680 | $12,404,208 | $16,743,884 |
| 211 | 20 | Oil and gas extraction | $129,243,326 | $22,414,750 | $7,578,254 | $159,236,330 |
| 212 | 26 | Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying | $38,363,852 | $1,396,825 | $98,135 | $39,858,811 |
| 212 | 21, 30, etc. | Other mining and support | $0 | $16,176,809 | $1,715,444 | $17,892,262 |
| 213 | 28 | Drilling oil and gas wells | $125,089,171 | $0 | $0 | $125,089,171 |
| 213 | 29 | Support activities for oil and gas operations | $288,483,774 | $64,690,292 | $1,413,620 | $354,587,684 |
| 221 | 31 | Electric power generation, transmission, and distribution | $4,704,838 | $16,187,537 | $11,258,846 | $32,151,221 |
| 221 | 32 | Natural gas distribution | $2,993,222 | $17,229,063 | $7,377,989 | $27,600,273 |
| 221 | 33 | Water, sewage and other systems | $16,108,067 | $122,498 | $471,117 | $16,701,684 |
| 23 | 34-40 | Construction, maintenance and repair | $29,260,144 | $10,026,498 | $6,541,951 | $45,828,585 |
| 31-33 | 41-114 | Manufacturing: food, textiles, paper products | $0 | $18,108,292 | $58,662,362 | $76,770,652 |
| 31-33 | 115-120 | Manufacturing: petroleum and petrochemicals | $8,510,964 | $72,487,545 | $25,244,862 | $106,243,379 |
| 31-33 | 121 | Manufacturing: industrial gases | $11,019,792 | $5,556,005 | $580,643 | $17,156,440 |
| 31-33 | 122-159 | Manufacturing: chemicals, rubber, glass | $20,373,460 | $34,478,962 | $30,851,168 | $85,703,547 |
| 31-33 | 160-169 | Manufacturing: cement, concrete, lime, non-metal minerals | $12,207,283 | $9,458,306 | $1,151,400 | $22,816,978 |
| 31-33 | 170-171 | Manufacturing: iron, steel and products | $92,907,963 | $64,420,835 | $1,633,929 | $158,962,735 |
| 31-33 | 172-181 | Manufacturing: non-ferrous metals and products | $0 | $8,842,576 | $2,099,305 | $10,941,874 |
| 31-33 | 182-318 | Manufacturing: tools, machinery, equipment, electronics, vehicles, airplanes | $36,611,244 | $89,816,999 | $34,456,084 | $160,884,264 |
| 42, 44, 45 | 319-331 | Wholesale and retail trade | $2,359,130 | $54,421,850 | $93,421,983 | $150,202,953 |
| 48 | 335 | Truck transportation | $71,670,022 | $21,927,966 | $8,468,522 | $102,066,509 |
| 48 | 332, 340, etc. | Non-truck transportation, warehousing | $22,188,020 | $31,072,227 | $16,856,375 | $70,116,617 |
| 51 | 341-353 | Publishing, telecommunications, information services | $1,295,457 | $31,772,806 | $38,808,633 | $71,876,881 |
| 52 | 354-359 | Monetary, investment services, insurance | $14,120,160 | $57,311,308 | $102,818,766 | $174,250,239 |
| 53 | 360-366 | Real estate, equipment rentals | $4,583,182 | $63,273,653 | $125,713,779 | $193,570,614 |
| 54-56 | 367-368 | Legal and accounting services | $0 | $26,033,720 | $18,027,138 | $44,060,856 |
| 54-56 | 369-370 | Architectural, engineering, design services | $2,993,222 | $36,914,758 | $4,369,018 | $44,276,997 |
| 54-56 | 371-390 | IT, management, scientific, environmental, waste management services | $16,041,293 | $111,042,526 | $54,790,655 | $181,874,484 |
| 61-62, 71-72, 81 | 391-426 | Educational, medical, hotel, food, miscellaneous services | $16,157,393 | $26,409,532 | $199,755,343 | $242,322,263 |
| 491, N/a | 427-440 | Postal, governmental services | $1,264,412 | $13,187,437 | $16,661,588 | $31,113,442 |
| **Total** | | | **$968,549,393** | **$929,121,250** | **$883,231,116** | **$2,780,901,629** |

*Source: ICF results using the IMPLAN model*

**Table 14: U.S. Value Added from Upstream O&G Expenditures Associated with LNG Exports from Cove Point for 2025 (2011$)**

| NAICS | IMPLAN | Sector | Value Added (2011$) | | | |
|---|---|---|---|---|---|---|
| | | | Direct | Indirect | Induced | Total |
| 111-115 | 1-19 | Agriculture and forestry | $0 | $1,676,644 | $4,724,802 | $6,401,454 |
| 211 | 20 | Oil and gas extraction | $68,260,479 | $11,838,459 | $4,002,493 | $84,101,424 |
| 212 | 26 | Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying | $20,827,502 | $758,331 | $53,277 | $21,639,109 |
| 212 | 21, 30, etc. | Other mining and support | $0 | $6,685,477 | $970,724 | $7,656,201 |
| 213 | 28 | Drilling oil and gas wells | $47,663,366 | $0 | $0 | $47,663,366 |
| 213 | 29 | Support activities for oil and gas operations | $112,115,920 | $25,141,137 | $549,387 | $137,806,444 |
| 221 | 31 | Electric power generation, transmission, and distribution | $3,423,377 | $11,778,516 | $8,192,260 | $23,394,146 |
| 221 | 32 | Natural gas distribution | $1,013,969 | $5,836,427 | $2,499,328 | $9,349,722 |
| 221 | 33 | Water, sewage and other systems | $11,248,819 | $85,550 | $329,000 | $11,663,368 |
| 23 | 34-40 | Construction, maintenance and repair | $13,518,345 | $5,213,605 | $3,367,151 | $22,099,111 |
| 31-33 | 41-114 | Manufacturing: food, textiles, paper products | $0 | $5,285,028 | $14,357,604 | $19,642,644 |
| 31-33 | 115-120 | Manufacturing: petroleum and petrochemicals | $1,505,785 | $14,915,109 | $4,596,994 | $21,017,873 |
| 31-33 | 121 | Manufacturing: industrial gases | $2,810,687 | $1,417,101 | $148,100 | $4,375,881 |
| 31-33 | 122-159 | Manufacturing: chemicals, rubber, glass | $4,783,378 | $8,199,185 | $8,473,836 | $21,456,401 |
| 31-33 | 160-169 | Manufacturing: cement, concrete, lime, non-metal minerals | $4,586,131 | $3,626,513 | $412,443 | $8,625,087 |
| 31-33 | 170-171 | Manufacturing: iron, steel and products | $20,511,811 | $14,380,706 | $364,750 | $35,257,283 |
| 31-33 | 172-181 | Manufacturing: non-ferrous metals and products | $0 | $2,491,705 | $502,905 | $2,994,610 |
| 31-33 | 182-318 | Manufacturing: tools, machinery, equipment, electronics, vehicles, airplanes | $13,031,848 | $33,823,860 | $12,692,233 | $59,547,957 |
| 42, 44, 45 | 319-331 | Wholesale and retail trade | $1,668,078 | $39,073,410 | $74,914,609 | $115,656,096 |
| 48 | 335 | Truck transportation | $32,487,743 | $9,939,861 | $3,838,748 | $46,266,355 |
| 48 | 332, 340, etc. | Non-truck transportation, warehousing | $9,791,467 | $17,192,566 | $8,957,488 | $35,941,543 |
| 51 | 341-353 | Publishing, telecommunications, information services | $741,052 | $17,330,173 | $21,052,036 | $39,123,257 |
| 52 | 354-359 | Monetary, investment services, insurance | $8,672,066 | $34,959,850 | $59,296,662 | $102,928,574 |
| 53 | 360-366 | Real estate, equipment rentals | $2,402,149 | $44,478,018 | $91,424,778 | $138,304,958 |
| 54-56 | 367-368 | Legal and accounting services | $0 | $19,305,172 | $13,567,900 | $32,873,079 |
| 54-56 | 369-370 | Architectural, engineering, design services | $1,783,399 | $22,175,661 | $2,660,348 | $26,619,404 |
| 54-56 | 371-390 | IT, management, scientific, environmental, waste management services | $9,800,199 | $70,210,513 | $34,427,130 | $114,437,838 |
| 61-62, 71-72, 81 | 391-426 | Educational, medical, hotel, food, miscellaneous services | $9,225,947 | $15,409,274 | $112,533,038 | $137,168,248 |
| 491, N/a | 427-440 | Postal, governmental services | $1,230,192 | $5,186,257 | $4,792,809 | $11,209,257 |
| **Total** | | | **$403,103,710** | **$448,414,108** | **$493,702,833** | **$1,345,220,689** |

*Source: ICF results using the IMPLAN model*

**Table 15: U.S. Labor Income from Upstream O&G Expenditures Associated with LNG Exports from Cove Point for 2025 (2011$)**

| NAICS | IMPLAN | Sector | Labor Income (2011$) | | | |
|---|---|---|---|---|---|---|
| | | | Direct | Indirect | Induced | Total |
| 111-115 | 1-19 | Agriculture and forestry | $0 | $1,345,441 | $3,448,121 | $4,793,550 |
| 211 | 20 | Oil and gas extraction | $29,640,181 | $5,140,513 | $1,737,965 | $36,518,666 |
| 212 | 26 | Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying | $14,146,175 | $515,061 | $36,182 | $14,697,425 |
| 212 | 21, 30, etc. | Other mining and support | $0 | $2,822,531 | $409,880 | $3,232,412 |
| 213 | 28 | Drilling oil and gas wells | $11,174,945 | $0 | $0 | $11,174,945 |
| 213 | 29 | Support activities for oil and gas operations | $105,508,524 | $23,659,486 | $517,010 | $129,685,012 |
| 221 | 31 | Electric power generation, transmission, and distribution | $990,576 | $3,408,179 | $2,370,478 | $6,769,232 |
| 221 | 32 | Natural gas distribution | $236,809 | $1,363,077 | $583,710 | $2,183,595 |
| 221 | 33 | Water, sewage and other systems | $5,916,469 | $44,997 | $173,042 | $6,134,507 |
| 23 | 34-40 | Construction, maintenance and repair | $11,857,841 | $4,407,465 | $2,780,855 | $19,046,160 |
| 31-33 | 41-114 | Manufacturing: food, textiles, paper products | $0 | $3,506,043 | $7,712,173 | $11,218,181 |
| 31-33 | 115-120 | Manufacturing: petroleum and petrochemicals | $264,661 | $3,324,614 | $866,844 | $4,456,128 |
| 31-33 | 121 | Manufacturing: industrial gases | $1,205,221 | $607,652 | $63,501 | $1,876,374 |
| 31-33 | 122-159 | Manufacturing: chemicals, rubber, glass | $3,525,132 | $5,149,757 | $4,177,342 | $12,852,259 |
| 31-33 | 160-169 | Manufacturing: cement, concrete, lime, non-metal minerals | $1,919,234 | $1,670,419 | $252,269 | $3,841,906 |
| 31-33 | 170-171 | Manufacturing: iron, steel and products | $12,082,357 | $6,481,084 | $164,206 | $18,727,647 |
| 31-33 | 172-181 | Manufacturing: non-ferrous metals and products | $0 | $1,517,078 | $289,205 | $1,806,293 |
| 31-33 | 182-318 | Manufacturing: tools, machinery, equipment, electronics, vehicles, airplanes | $9,709,672 | $20,970,158 | $7,339,062 | $38,018,866 |
| 42, 44, 45 | 319-331 | Wholesale and retail trade | $969,041 | $22,880,513 | $45,113,428 | $68,962,960 |
| 48 | 335 | Truck transportation | $25,277,749 | $7,733,914 | $2,986,819 | $35,998,473 |
| 48 | 332, 340, etc. | Non-truck transportation, warehousing | $6,477,070 | $11,939,244 | $6,302,036 | $24,718,352 |
| 51 | 341-353 | Publishing, telecommunications, information services | $235,317 | $9,163,464 | $10,834,021 | $20,232,801 |
| 52 | 354-359 | Monetary, investment services, insurance | $3,249,797 | $20,291,269 | $31,320,518 | $54,861,584 |
| 53 | 360-366 | Real estate, equipment rentals | $1,233,470 | $6,920,597 | $6,513,680 | $14,667,748 |
| 54-56 | 367-368 | Legal and accounting services | $0 | $12,317,345 | $8,380,018 | $20,697,366 |
| 54-56 | 369-370 | Architectural, engineering, design services | $1,688,252 | $20,512,274 | $2,366,870 | $24,567,395 |
| 54-56 | 371-390 | IT, management, scientific, environmental, waste management services | $6,897,443 | $57,163,949 | $27,722,414 | $91,783,793 |
| 61-62, 71-72, 81 | 391-426 | Educational, medical, hotel, food, miscellaneous services | $6,756,951 | $11,825,126 | $97,256,837 | $115,838,916 |
| 491, N/a | 427-440 | Postal, governmental services | $1,082,903 | $5,866,523 | $6,299,459 | $13,248,892 |
| **Total** | | | **$262,045,786** | **$272,547,771** | **$278,017,945** | **$812,611,439** |

*Source: ICF results using the IMPLAN model*

# 4 Economic Impact of Additional Hydrocarbon Liquids

Liquids in the form of crude oil, lease condensate, ethane, propane, butanes, and pentanes plus[9] would be produced along with the dry gas to supply feedstock and fuel for liquefaction plants. Estimates of the average annual incremental volumes for these liquids associated with the LNG exports from Cove Point are shown in **Table 16**. The ratio of liquids per unit of dry natural gas is estimated at approximately 20 bbl/MMcf for crude plus condensate, and 36 bbl/MMcf for the natural gas liquids. These ratios are taken from the ICF resource base analysis as represented by the U.S. long-run natural gas supply curve. The ratios represent relatively dry “marginal resources” as other resources with higher liquids ratios are often down on the low-cost part of dry gas supply curve as defined by “oil-derived” pricing.[10] The average annual incremental production of hydrocarbon liquids from 2016 through 2040 is estimated at 8.5 million barrels per year supported by LNG exports. The average market value of these liquids totals $1.2 billion per year (real 2011 dollars).

**Table 16: U.S. Volume, Value, and Economic Impact of Incremental Hydrocarbon Liquids Associated with LNG Export from Cove Point**

| Case | Incremental Gas (bcf/y) | Incremental Oil & Lease Condensate (mmb/y) | Incremental NGLs (mmb/y) | All Incremental Liquids (mmb/y) | Value of All Liquids (billion 2011$/y) | Incremental Ethane Only (mmb/y) | Petrochem Jobs Associated with Incremental Ethane |
|---|---|---|---|---|---|---|---|
| LNG Exports | 237 | 4.8 | 8.5 | 13.3 | 1.2 | 4.5 | 800 |

*Source: ICF; employment impacts based on ACC analysis*

Earlier this year the American Chemistry Council (ACC) produced a report entitled “Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs, and U.S. Manufacturing” to estimate the petrochemical value and petrochemical jobs that can be supported by the extra natural gas liquids (NGLs) that might be expected from increased gas production in the U.S.[11]

The ACC report examined a hypothetical 25 percent increase in ethane supply (392 x 25% = 98 million barrels per year) and concluded that those increased ethane volumes would be used to make ethylene and associated petrochemicals in the U.S., and that use would generate:

- $16.2 billion in one-time capital investment by the chemical industry to build new petrochemical and derivatives capacity.
- 17,000 new permanent jobs in the U.S. chemical industry.

[9] The term “pentanes plus” means pentanes (five carbon atoms per molecule) and hydrocarbon molecules with six or more carbon atoms. Ethane, propane, butanes, and pentanes plus are collectively referred to as “natural gas plant liquids” since they are removed from wet gas at a natural gas processing plants.

[10] The term “oil-derived” pricing for natural gas means that the net present value of any liquids is deducted from costs before the resource cost (minimum acceptable selling price) of the dry natural gas is computed. When large volumes of liquids are produced along with dry gas, the resource cost of the dry natural gas can be zero or negative.

[11] American Chemistry Council (ACC). “Shale Gas and new Petrochemicals Investment: Benefits for the Economy, Jobs, and U.S. Manufacturing.” Economics and Statistics, ACC, March 2011. URL: http://www.americanchemistry.com/ACC-Shale-Report.

- $32.8 billion increase in annual U.S. chemical production.

Although the ACC's report was directed at general increases in natural gas production (not specifically for LNG exports), its conclusions can be applied to the export scenario examined here. Proportioning the ACC job impact to the amount on incremental ethane in the LNG export scenario yields the chemical industry job impact values shown in **Table 16**. Using analysis conducted by the American Chemistry Council (ACC), the domestic employment increases associated with increased petrochemical use of the incremental ethane alone (about 34 percent of liquids by barrel volume) would total 800 jobs.

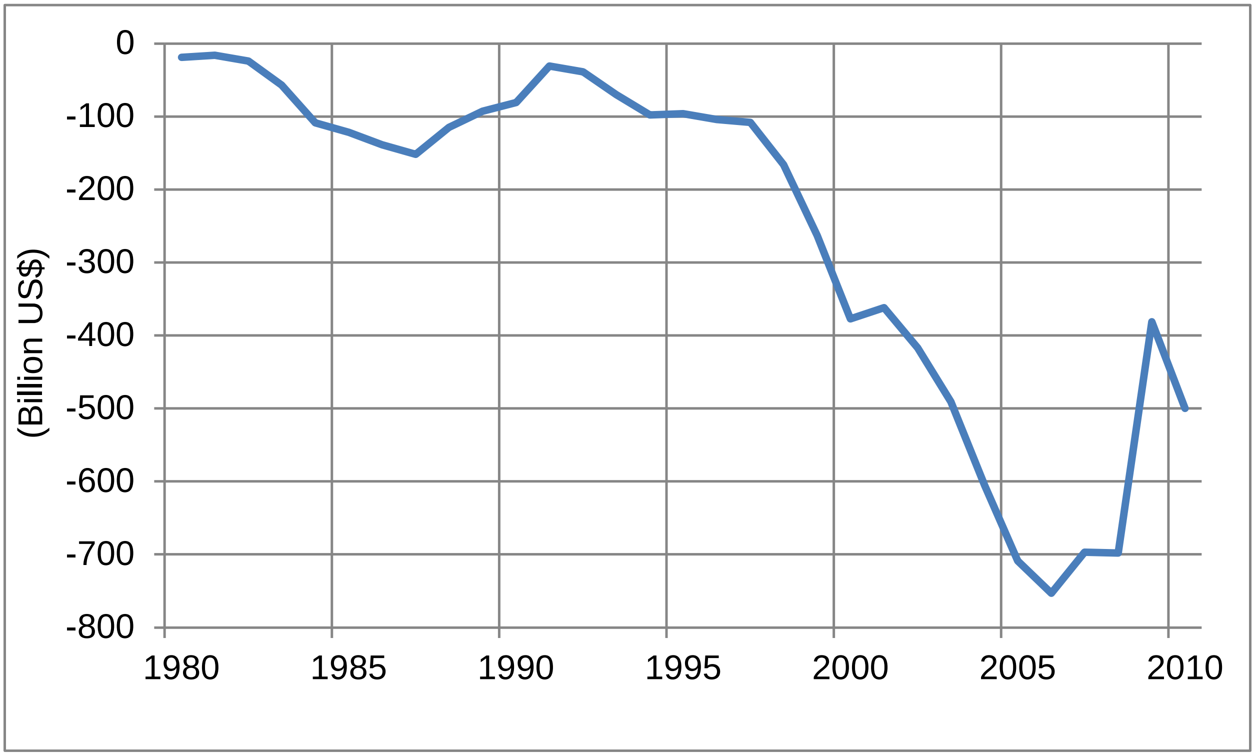
There will also be economic impacts from the incremental production of non-ethane liquids. The incremental amounts of crude oil and lease condensate would reduce the need for imported oil and petroleum products, and help the U.S. balance of trade. The incremental non-ethane gas plant liquids (propane, butane, and pentanes plus) would be used as petrochemical or refinery feedstock or could be exported. Such uses would support even more U.S. jobs and further improve U.S. balance of trade.

# 5 Balance of Trade Associated with LNG Exports

The U.S. has long been a champion of free markets, arguing that free trade agreements are imperative for economic growth. LNG exports would help reduce the U.S. balance of trade (BoT) deficit, in addition to stimulating the domestic economy and employment.

As shown in **Figure 17**, the U.S. has experienced large balance of trade deficits for more than a decade.[12] The existence of these deficits increases the need for borrowing and adds to the total amount of U.S. debt to foreign nations. The rise in U.S. exports apparent after the 2008 economic crisis, spurred by a weak dollar and continued growth in the developing world, has somewhat reduced the U.S. trade balance deficit.

**Figure 17: U.S. Trade Balance**




*Source: U.S. Census Bureau Foreign Trade Division*

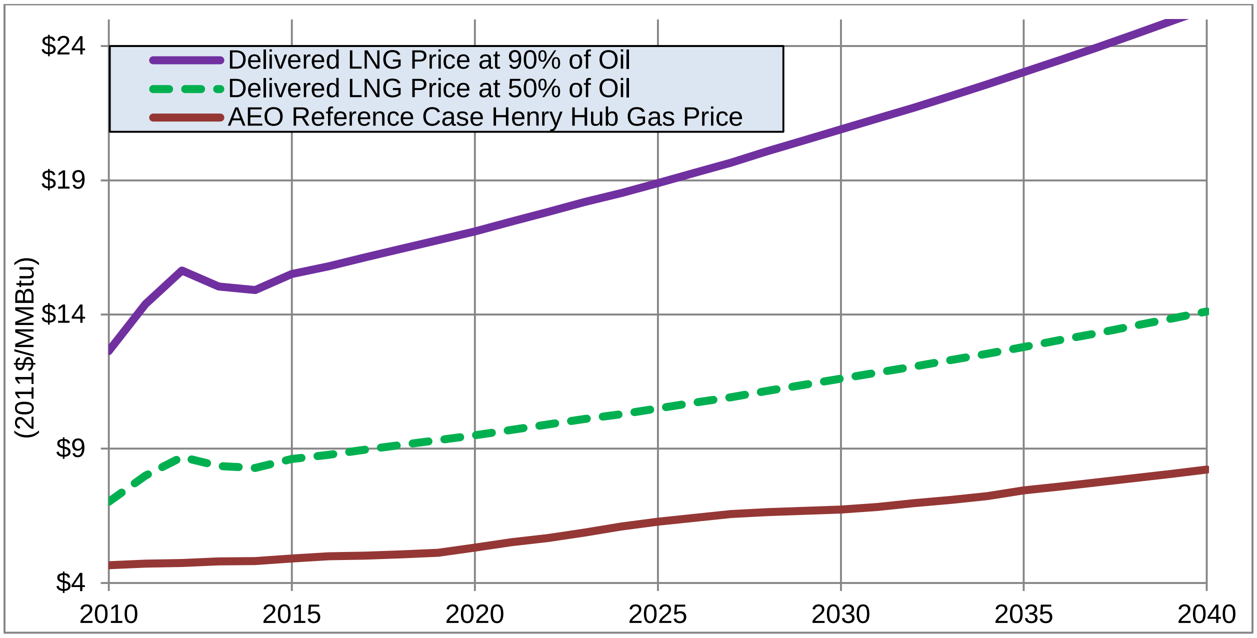
[12] The temporary improvement in 2009 was a result of the overall economic contraction in consumer spending in the U.S.

In **Figure 19** below, the solid lines indicate the export value of LNG plus associated liquids, assuming liquids substitute for imports or are exported as fuel/feedstock or as petrochemical products. The dotted lines below include LNG only in export calculations. The “high” figures below are based on a combination of market deliveries in close proximity to the U.S. with low shipping costs plus high delivered LNG prices (based on a 90% oil-indexed price). The “low” figures are comprised of far market deliveries (such as to Asia) with high shipping costs plus low delivered LNG prices (based on a 50% oil-indexed price).

Commodity exports, such as LNG, can further improve the U.S. Balance of Trade, as seen in **Figure 19**, with an annual range of $2.8-$7.1 billion. The range in **Figure 19** is represented by the solid green (minimum) and solid red (maximum) lines. While the dotted green line indicates minimum LNG-only values, gas extraction typically involves associated liquids production, as well; thus, minimum LNG values should include at least some associated liquids. Figures exclude LNG as ship fuel to calculate free-on-board (FOB) LNG export delivery volumes (net of transportation fuel costs).

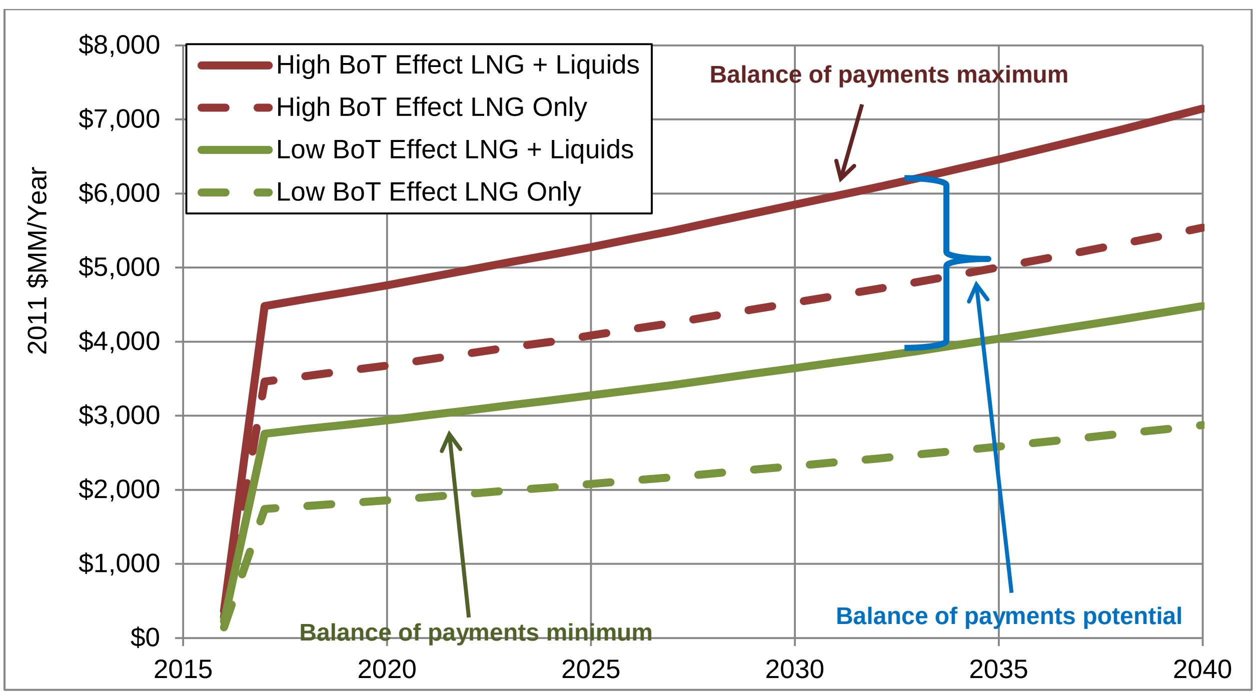
See **Figure 18** for a comparison between the oil-indexed prices cited above and Henry Hub AEO rates over the 25-year period.

**Figure 18: Comparison of Domestic Natural Gas Price Projections versus Assumed Range of Delivered LNG Prices (2011$/MMBtu)**




*Source: ICF estimates based on AEO Reference Case prices*

**Figure 19: Range of Annual Positive Effect of LNG Exports from Cove Point on U.S. Balance of Trade**




*Source: ICF estimate based on AEO Reference Case prices*

# 6 IMPLAN Methodology

## 6.1 IMPLAN Description

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

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

After identifying the direct expenditure components associated with upstream development (detailed in **Section 6.3**), the direct expenditure cost components (identified by their associated NAICS code) are then used as inputs into the IMPLAN model to estimate the total indirect and induced economic impacts of each direct cost component.

**Direct, indirect, and induced economic impact**

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

**Use of IMPLAN Modeling**

The IMPLAN model includes detailed flow information for hundreds of industries. By tracing purchases between sectors, it is possible to estimate the economic impact of an industry's output (i.e., the goods and services purchased by the upstream oil and gas sector) to impacts on related industries. From a change in industry spending, IMPLAN can generate estimates of the direct, indirect, and induced economic impacts. The goal of IMPLAN is to evaluate the economic and employment impact of any given industry.

The IMPLAN modeling framework consists of two components–the descriptive model and the predictive model. The descriptive model defines the specified modeling region (the U.S.), and includes accounting tables that trace the "flow of dollars from purchasers to producers within the region."[13] The model also includes the trade flows that describe the movement of goods and

[13] IMPLAN Pro Version 2.0 User Guide.

services, both within and outside the modeling region (i.e., national exports and imports with the outside world). In addition, the model includes the Social Accounting Matrices (SAM) that traces the flow of money between institutions, such as transfer payments from governments to businesses and households, and taxes paid by households and businesses to governments.

The predictive model consists of a set of "local-level multipliers" that can then be used to analyze the changes in final demand and their ripple effects throughout the domestic economy. These multipliers are thus coefficients that "describe the response of the [domestic] economy to a stimulus (a change in demand or production)."[14]

Details of ICF Economic Analysis Approach Using IMPLAN

Because there are several iterations, as each industry purchases inputs from other industries, which in turn purchase inputs from other industries-an input/output model is the appropriate approach to portray the total economic impact. IMPLAN is considered a static model because the impacts calculated for any scenario estimate the indirect and induced impacts *for that year*. For projects that span more than one year, such as this, the impacts can be assessed annually, with job impacts reported in annual job-years. The baseline data used (i.e., multipliers) are for a snapshot/historical year and hence projected results are an approximation of future impacts and are usually considered reasonable approximations.

IMPLAN measurement metrics

In addition to viewing the economic impact through the direct, indirect, and induced lenses, IMPLAN further breaks out economic impact by industry output, value added, job-years supported, labor income and tax revenues. Each component illustrates an essential function, and will differ by type of power facility. For example the construction and operation of a nuclear facility will both require more labor than a similarly-sized gas-fired power plant. The three main types of impact results that can be obtained from IMPLAN–changes in output, employment, and total value added–can be further broken down into several components (discussed earlier in **Figure 1**) and include:

1. Labor Income
    a. Employee Compensation
    b. Proprietor's Income
2. Other Property Type Income
3. Indirect Business Taxes
4. Tax Impact

[14] *Ibid.*

## 6.2 Facility Construction and O&M Impact Modeling Approach

ICF used the regional economic model IMPLAN to estimate the economic impacts of the proposed Cove Point Export Facility on the local (i.e., Calvert County), state, and national economies. We used IMPLAN to estimate the direct, indirect, and induced employment and industry activity generated by the construction and operation and maintenance (O&M) associated with the proposed facility, as well as the longer term impacts on the upstream natural gas sector discussed in this study.

### IMPLAN Modeling Inputs

First, ICF used the construction and operational (O&M) inputs provided by Dominion to prepare the modeling inputs by identifying the industry sectors that correspond to the construction and O&M expenditure data. ICF was provided with cost estimates for each year of construction and a typical year of operation. Separate costs streams were provided for Dominion-related expenses and third-party EPC contractor expenses. Dominion costs included project management; environmental and regulatory permitting; legal fees; hazard reviews and associated risk mitigation methods; security, construction inspection; etc. EPC contractor costs included construction and technical services labor as well as capital costs for materials and equipment. ICF then allocated these annual expenditures to the relevant IMPLAN industry sector codes. **Table 20** below lists the IMPLAN sectors used by ICF.

**Table 17: IMPLAN Sectors used for Modeling Facility Construction and Operation**

| IMPLAN Sector Description | Cost Description |
|---|---|
| Architectural- engineering- and related technical services | Dominion and EPC technical labor costs |
| Construction of other new nonresidential structures | Construction labor costs |
| Turbine and turbine generator set units manufacturing | Equipment costs |
| Air and gas compressor manufacturing | Equipment costs |
| Power boiler and heat exchanger manufacturing | Equipment costs |
| Steel product manufacturing from purchased steel | Material costs |
| Natural gas distribution | Dominion Operation costs |

The cost allocations were informed by the NETL/DOE report and were approved by Dominion.[15] ICF analyzed two scenarios, the Low Construction Cost Case and the High Construction Cost Case for the investments required for construction and operation of the Cove Point facility. Both construction cost cases used the same industry allocation shown above (though at different shares).

Next, ICF ran the IMPLAN model for each scenario (High and Low Construction Cost Cases) annually from 2011 through 2018 at the county (i.e., Calvert), state (i.e., MD) and national

[15] DOE/NETL, Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2, November 2010.

levels. Modeling years 2011 through 2016 included only construction costs, modeling year 2017 included both construction and operation costs, and modeling year 2018 represented a typical year of operation in which only O&M costs were modeled. Thus, the results for 2018 can be assumed to carry over for the rest of the life of the facility.

The results from this modeling analysis are reported as the total (direct, indirect, and induced) impacts generated by the proposed Cove Point Export Facility on changes to employment, output, and tax revenue. These are further explained below:

- **Employment** – represents the jobs created by industry, based on the output per worker and output impacts for each industry.
- **Output** – represents the value of an industry's total output increase due to the modeled scenario (in millions of constant dollars).
- **Tax Impact** – breakdown of taxes collected by the federal, state and local government institutions from different economic agents. This includes corporate taxes, household income taxes, and other indirect business taxes.[16]

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

## 6.3 Upstream-related Impact Modeling Approach

### IMPLAN Sectoral Detail

The latest version of IMPLAN provides data on hundreds of industry sectors, along with several institutional sectors such as households by income category and various government sectors (federal, state, and local). These industry sectors are based on the North American Industry Classification System (NAICS). The highly detailed sector plan could be an advantage in any input-output modeling framework. A more detailed breakdown of the sector impacts allows the user to analyze impacts specific to individual sectors of interest. Moreover, because IMPLAN also allows the user to implement different sector aggregation schemes with ease (before running the model), starting with the most disaggregated sector plan gives the user the flexibility to choose the right level of detail in the results.

### IMPLAN Employment Numbers and Allocation among Segments

Employment statistics were estimated for the natural gas industry and associated industries (which supply the primary industries with goods and services). This step included reviewing prior studies that we and others have done to obtain the most logical and consistent approaches to identifying and allocating jobs.

The main source of employment data for the U.S. can be found in the publications of the Bureau of Labor Statistics. **Table 18** shows the two main U.S. data sources that are available. Data are updated annually. Estimates of current data are released each month with a one- to two-month time lag, depending on the details.

**Table 18: Main Employment Data Sources from the Bureau of Labor Statistics**

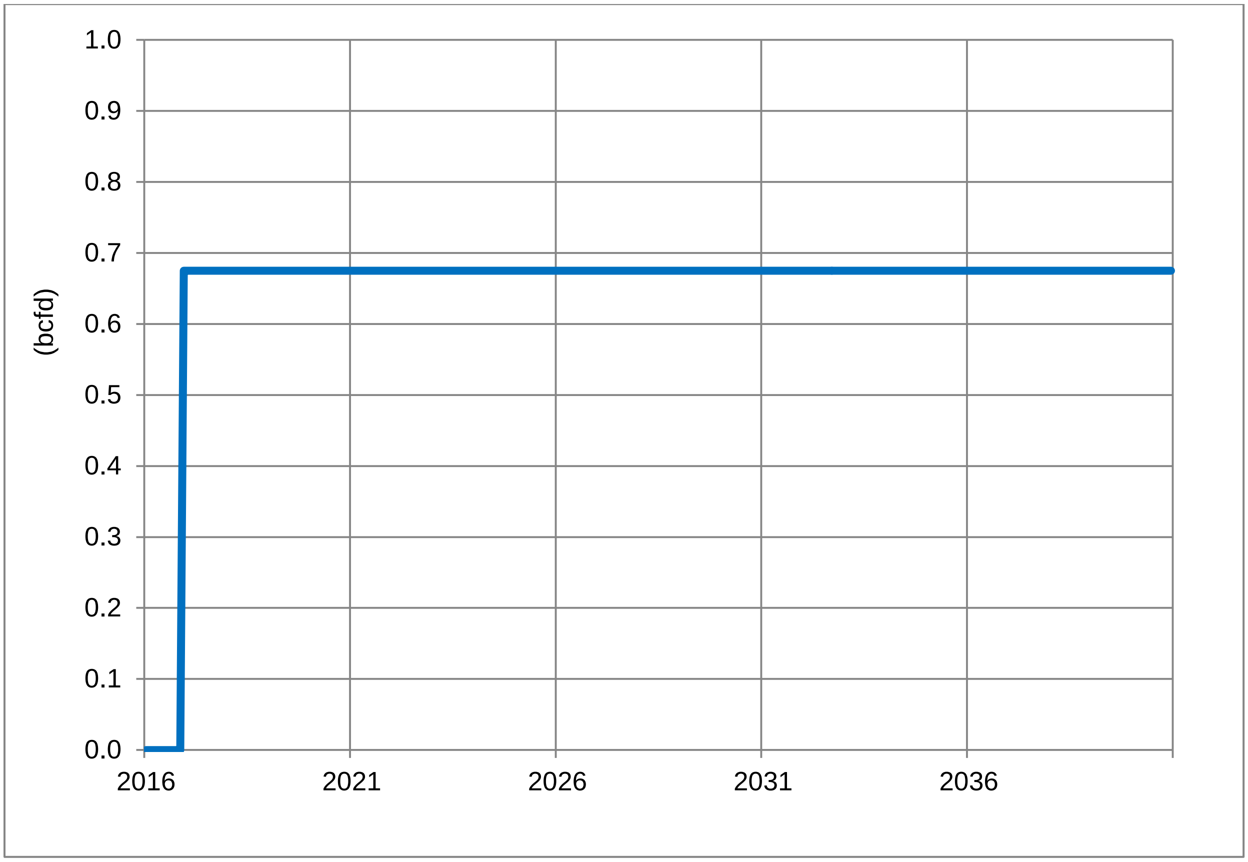
| | |
|---|---|
| Occupational Employment Statistics | Provides employment level and wage estimates for over 800 occupations for the nation as a whole, individual states, and metropolitan areas; national occupational estimates for specific industries are available. |
| Current Population Survey | A monthly survey of about 50,000 households conducted by the U.S. Census Bureau, which provides data on labor force and employment, including union membership and a variety of demographic indicators. The sample is scientifically selected to represent the civilian non-institutional population. |

### Description of Production Case

ICF assumes an inlet capacity of 0.750 billion cubic feet per day (bcfd) and outlet capacity of 90 percent of inlet capacity, or 0.675 bcfd, the difference of which is assumed for facility fuel consumption. For the LNG export economic analysis, ICF assumes capacity utilization of 90 percent starting December 2016, which is maintained over the 25-year period. Thus, inlet volumes are assumed at 0.675 bcfd and outlet volumes of 0.608 bcfd.

See **Table 19** for year-on-year capacity utilization and export volumes by scenario through the forecast period, and **Figure 20** for a visual representation.

**Figure 20: LNG Export Case Scenario (Inlet Volumes)**




*Source: Dominion Cove Point*

### Table 19: LNG Export Scenario

| Year | LNG Exports | | |
|---|---|---|---|
| | Inlet Volume (bcfd)** | Outlet Volume† (bcfd) | Capacity Utilization Rate (%) |
| 2016* | 0.056 | 0.051 | 90% |
| 2017 | 0.675 | 0.608 | 90% |
| 2018 | 0.675 | 0.608 | 90% |
| 2019 | 0.675 | 0.608 | 90% |
| 2020 | 0.675 | 0.608 | 90% |
| 2021 | 0.675 | 0.608 | 90% |
| 2022 | 0.675 | 0.608 | 90% |
| 2023 | 0.675 | 0.608 | 90% |
| 2024 | 0.675 | 0.608 | 90% |
| 2025 | 0.675 | 0.608 | 90% |
| 2026 | 0.675 | 0.608 | 90% |
| 2027 | 0.675 | 0.608 | 90% |
| 2028 | 0.675 | 0.608 | 90% |
| 2029 | 0.675 | 0.608 | 90% |
| 2030 | 0.675 | 0.608 | 90% |
| 2031 | 0.675 | 0.608 | 90% |
| 2032 | 0.675 | 0.608 | 90% |
| 2033 | 0.675 | 0.608 | 90% |
| 2034 | 0.675 | 0.608 | 90% |
| 2035 | 0.675 | 0.608 | 90% |
| 2036 | 0.675 | 0.608 | 90% |
| 2037 | 0.675 | 0.608 | 90% |
| 2038 | 0.675 | 0.608 | 90% |
| 2039 | 0.675 | 0.608 | 90% |
| 2040 | 0.675 | 0.608 | 90% |

*Source: ICF estimates based on Dominion projections*

* December 2016 production only

** 90% capacity utilization assumed

† Also known as throughput

*Note:* Total capacity of 0.750 bcfd assumed in the LNG export scenario, with 0.675 bcfd outlet capacity assumed (with 10% shrinkage assumed for plant fueling).

**Oil and Natural Gas Price Forecasts**

ICF assumes international oil prices based on the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2011 to 2035, and extrapolated oil prices through 2040, based on the annual average AEO price growth rates from 2030 to 2035.

**Table 20** includes annual oil price estimates through 2040. Domestic natural gas price forecasts are based on the AEO estimates through 2035, and extrapolated natural gas prices through 2040, based on the annual average AEO price growth rates from 2030 to 2035. **Table 19** includes Henry Hub spot prices through 2040, in real terms.

High and low scenarios will be made for the international delivered selling price of LNG as a function of the oil price forecasts (assuming deliveries to buyers in Latin America, Asia, or Europe). The price estimate is calculated by taking the oil price for any given year in real dollars per barrel and dividing the figure by 5.8 to convert dollars per barrel measurements to dollars per million British thermal units (MMBtu). That figure is then multiplied by either 50 percent or 90 percent, for a low-end or high-end price estimate for delivered LNG prices, respectively. See **Table 19** for year-on-year estimates through 2040.

**Table 20: U.S. Oil and Natural Gas Pricing Scenarios and Assumed Range of Delivered LNG Prices**

| Year | WTI (2011$/barrel) | AEO Henry Hub NG Price (2011$/MMBtu) | Low International LNG Price (2011$/MMBtu)* | High International LNG Price (2011$/MMBtu)† |
|---|---|---|---|---|
| 2011 | $92.72 | $4.72 | $7.99 | $14.39 |
| 2012 | $100.81 | $4.74 | $8.69 | $15.64 |
| 2013 | $96.99 | $4.80 | $8.36 | $15.05 |
| 2014 | $96.12 | $4.81 | $8.29 | $14.92 |
| 2015 | $99.97 | $4.91 | $8.62 | $15.51 |
| 2016 | $101.83 | $4.99 | $8.78 | $15.80 |
| 2017 | $103.93 | $5.01 | $8.96 | $16.13 |
| 2018 | $106.05 | $5.06 | $9.14 | $16.46 |
| 2019 | $108.10 | $5.13 | $9.32 | $16.77 |
| 2020 | $110.19 | $5.32 | $9.50 | $17.10 |
| 2021 | $112.52 | $5.52 | $9.70 | $17.46 |
| 2022 | $114.85 | $5.68 | $9.90 | $17.82 |
| 2023 | $117.26 | $5.88 | $10.11 | $18.20 |
| 2024 | $119.40 | $6.11 | $10.29 | $18.53 |
| 2025 | $121.80 | $6.29 | $10.50 | $18.90 |
| 2026 | $124.27 | $6.42 | $10.71 | $19.28 |
| 2027 | $126.70 | $6.57 | $10.92 | $19.66 |
| 2028 | $129.43 | $6.64 | $11.16 | $20.08 |
| 2029 | $132.05 | $6.69 | $11.38 | $20.49 |
| 2030 | $134.67 | $6.74 | $11.61 | $20.90 |
| 2031 | $137.30 | $6.83 | $11.84 | $21.30 |
| 2032 | $139.89 | $6.97 | $12.06 | $21.71 |
| 2033 | $142.65 | $7.10 | $12.30 | $22.14 |
| 2034 | $145.52 | $7.23 | $12.54 | $22.58 |
| 2035 | $148.41 | $7.44 | $12.79 | $23.03 |
| 2036 | $151.37 | $7.59 | $13.05 | $23.49 |
| 2037 | $154.37 | $7.75 | $13.31 | $23.95 |
| 2038 | $157.44 | $7.90 | $13.57 | $24.43 |
| 2039 | $160.57 | $8.06 | $13.84 | $24.92 |
| 2040 | $163.77 | $8.22 | $14.12 | $25.41 |

*Source: ICF estimates based on AEO Reference Case oil and natural gas forecasts*

* 50% of oil price (assumes conversion of 5.8 MMBtu/bbl)

† 90% of oil price (assumes conversion of 5.8 MMBtu/bbl)

## Upstream Sector Impact Analysis

To determine which sectors are directly impacted by expenditures on natural gas well drilling, completion and production, ICF analyzed the per-well expenditures of three wells located in the Marcellus shale region, the Horn River, and the Montney shale formation.[17,18] The assessment allotted each associated sector (e.g., oil and gas extraction, drilling oil and gas wells, construction, steel product manufacturing) a relevant proportion of each expenditure item (e.g., surface casing). As each sector (associated with a unique North American Industrial Classification System, NAICS) often appears in multiple expenditure line items (e.g., the cement sector appears in both "Surface Cementing" and "Intermediate Cementing" expenditure line items), each sector expenditures were then totaled to indicate the percentage of expenditures going to each relevant sector.

**Table 21** includes all expenditure line items found in the two PSAC well expenditure analyses, while **Table 22** includes all relevant sectors. The economic impact totals include both those related to drilling and completing wells and constructing associated roads and facilities, plus the jobs associated with the ongoing operation and maintenance of the wells and associated facilities. The allocations were also adjusted to account for some investment in onshore non-shale and offshore wells.

## Midstream Sector Impact Analysis

While analysis of midstream sector impact (associated with the incremental natural gas volumes required by the LNG export facility) was beyond the scope of this study, inclusion of such impacts would undoubtedly increase every national-level economic impact indicator.

To illustrate, the direct upstream employment estimates appearing in this report do not include midstream jobs. According to the Bureau of Labor Statistics, the gas processing (NAICS 211112) and natural gas pipeline (NAICS 4862) sectors directly employed approximately 32,291 people nationally in 2009 when U.S. dry marketed gas production was 56.4 bcfd per EIA. Using a simple scaling factor, this would imply that an increase of 0.675 bcfd in production due to Cove Point LNG exports would add roughly 387 direct jobs to the midstream sector. Applying a factor of 3.74 for total jobs versus direct upstream jobs, as computed in this report, results in an estimate of 1,446 total jobs related to increased midstream activity associated with LNG exports from Cove Point.

## ICF Assessment of North America Oil and Gas Resources

For over 25 years, ICF has used various databases and models to evaluate conventional and unconventional North American gas resources and their economics. These models contain a full characterization of reserve appreciation, new conventional fields, and unconventional gas and oil. Undiscovered conventional fields are evaluated by drilling depth, water depth, and field size class. Most recently, ICF has completed extensive analyses of North America unconventional resources using a GIS-based analysis system. Proprietary models were developed to work with GIS data on a 6 by 6 square-mile unit basis to estimate unrisked and

[17] Hefley, William E, et al. "The Economic Impact of the Value Chain of a Marcellus Shale Well." University of Pittsburgh: Pitt Business, August 2011.

[18] Petroleum Services Association of Canada (PSAC), 2009. "PSAC 2009 Well Cost Study – Upcoming Summer Costs."

risked gas-in-place, recoverable resources, estimated ultimate recovery (EUR) per well and wellhead, and Henry Hub resource costs at a specified rate of return. The resource assessment component is based upon mapped parameters of depth, thickness, organic content, and thermal maturity, and assumptions about porosity, pressure gradient, and other information. The unit of analysis for gas in place and recoverable resources is a 6 by 6 mile grid block. Gas-in-place is determined for free gas and adsorbed gas and well recovery is modeled using a reservoir simulator. Well recovery is estimated as a function of well spacing.

ICF has estimated the investment cost, operating cost and resource cost of the remaining U.S. natural gas resources using discounted cash flow (DCF) analysis at various levels of granularity, depending upon the category of resource. For undiscovered conventional fields (new fields), the analysis is done by field size class and depth interval, while for unconventional plays, DCF analysis is generally done on each 36-square-mile unit of play area. The wellhead resource cost is the total required wellhead price in dollars per MMBtu needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes, and income taxes.

Wellhead economics are based upon discounted cash flow analysis of all costs including drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, which are based upon cost per stage and number of stages. Per-foot drilling costs were based upon analysis of industry and published data. The API Joint Association of Drilling Costs and Petroleum Services Association of Canada (PSAC) are sources of drilling and completion cost data, and the EIA is a source for operating and equipment costs.[19,20,21] Lateral length, number of fracturing stages, and cost per fracturing stage assumptions were based upon investor slides and other sources.

From these resource assessments and economic analyses, ICF produced reports on U.S. oil and gas resource endowment and future activity levels for the American Petroleum Institute (API)[22], the National Petroleum Council natural gas studies[23], the INGAA Foundation[24] and America's Natural Gas Alliance. We have also produced midstream infrastructure assessments for the NPC and the INGAA Foundation, among other clients. ICF recently completed a study for the INGAA Foundation and other sponsors to support the ongoing NPC study by projecting oil and gas resource development and infrastructure needs for the U.S. over the next 25

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[19] American Petroleum Institute, various years, "Joint Association Survey of Drilling Costs," API, Washington, DC.

[20] Petroleum Services Assn. of Canada, 2009, "2009 Well Cost Study." http://www.psac.ca/.

[21] U.S. Energy Information Administration, 2011, "Oil and Gas Lease Equipment and Operating Costs," http://www.eia.gov/petroleum/reports.cfm.

[22] ICF, "Strengthening Our Economy: The Untapped US Oil and Gas Resources," prepared for API, December 2008. http://www.api.org/aboutoilgas/upload/Access_Study_Final_Report_12_8_08.pdf.

[23] National Petroleum Council (NPC), 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy." NPC. Washington, D.C. http://www.npc.org/. Also available at: http://www.fossil.energy.gov/programs/oilgas/publications/npc/03gasstudy/NG_Vol1_9-25.pdf.

[24] INGAA Foundation, 2008, "Availability, Economics, and Production Potential of North American Unconventional Gas Supplies," prepared by ICF for Interstate Natural Gas Association of America, Washington, D.C. http://www.ingaa.org/cms/31/7306/7628/7833.aspx.

years.[25] The study included play level analysis of past and future drilling activity, EUR per well, and production for both gas and oil plays.

Using these various databases, models and reports, ICF has evaluated the amount of upstream capital and operating and maintenance expenditures that would be required to develop the gas resources for LNG exports over the 2016 to 2040 period. Costs include the drilling and completion of gas and oil wells and operating costs over the forecast period, and encompass the costs associated with crude oil lease condensate, and gas plant liquids that will be produced with the dry gas. For the purposes of the IMPLAN analysis, the costs are further broken out into the industrial sectors from which the oil and gas industry would be purchasing goods and services.

**LNG Value Estimation**

The value of the LNG to be exported will depend on prevailing future prices of natural gas in the Atlantic and Pacific markets to which the LNG could be shipped and the contractual terms of the sale. For the purposes of estimating balance of payment effects we have assumed a range of possible LNG ex-ship (that is, delivered to import terminal) prices. The upper end of the range is 90 percent of the crude oil price on Btu basis, a level relative to crude which is slightly above oil-indexed pricing formulas of recent LNG contracts in Pacific markets. The lower end of the range is assumed to 50 percent of crude oil price on Btu basis. The lower end of the range is consistent with a scenario in which the upstream technology changes that have made natural gas abundant in North America are successfully spread widely around the world, depressing the value of natural relative to crude oil compared to what it has been for LNG contracts in recent years. For both ends of the range, the Reference Case AEO oil prices are assumed to be the base on which the 90%/50% factor is applied to obtain the ex-ship LNG prices.

The relevant price for balance of trade impacts for the U.S. is the free on board (FOB) price, which can be computed as the ex-ship prices minus the shipping costs. This is the case because the LNG tankers are likely to be built and operated by non-U.S. companies and will not contributed for U.S. export revenues. The high end of the FOB prices comes from pairing the highest ex-ship prices (90% of oil) with the shortest shipping distance (to Northern Europe). This produces FOB prices of $15.15 to $24.77 per MMBtu from 2016 to 2040. The low end of the FOB prices range comes from combining the lowest ex-ship prices (50% of oil) with the longest shipping distance (to Asian markets). This produces FOB prices of $7.72 to $13.06 per MMBtu from 2016 to 2040.

[25] INGAA Foundation, 2011, "North American Midstream Infrastructure Through 2035 – A Secure Energy Future, INGAA, Washington, D.C. http://www.ingaa.org/Foundation/Studies/14904/14889.aspx.

**Table 21: Expenditure Line Items**

| Drilling-related | Completion-related |
|---|---|
| Well license/application | Prod. Casing & access. |
| Surface lease & survey | Cementing - production |
| Preparation & roads | Tubing & access. |
| Cleanup | Wellhead equip |
| Rig move | Remedial cementing |
| Day work | Service rig |
| Directional costs | Logging (cement bond log) |
| Boiler | Slickline/wireline (other) |
| Bits | Perforating |
| Fuel & power | Stimulation (frac/acid) |
| Water | Testing/pressure surveys |
| Mud & chemicals | Gas/liquid analysis |
| Crew travel | Transportation |
| Camp & sustenance | Equipment rentals |
| Coring & analysis | Downhole tools (intangibles) |
| DST & analysis | Completion fluids |
| Logging | Snubbing |
| Surface casing & access. | Nitrogen |
| Cementing - surface | Inspection/safety |
| Intermediate casing & access. | Wellsite supervision |
| Cementing - intermediate | Other completion services (in-house engineering) |
| Equipment rentals | Misc. costs (in-house engineering completions) |
| Transportation & hauling | Overhead (in-house engineering completions) |
| Supervision & consulting | |
| In-house engineering (drilling) | |
| Equipment inspection | |
| Well insurance | |
| Safety | |
| Environmental services | |
| Misc. costs | |
| Overhead | |
| Abandonment cost | |

*Source: Petroleum Services Association of Canada (PSAC)*

**Table 22: Sectors Relevant to Direct Oil and Gas Expenditures**

| IMPLAN | NAICS | IMPLAN Sector |
|---|---|---|
| 20 | 211 | Oil and gas extraction |
| 26 | 21232 | Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying |
| 28 | 213111 | Drilling oil and gas wells |
| 29 | 213112 | Support activities for oil and gas operations |
| 31 | 2211 | Electric power generation, transmission, and distribution |
| 32 | 2212 | Natural gas distribution |
| 33 | 2213 | Water, sewage and other systems |
| 36 | 23* | Construction of other new nonresidential structures |
| 39 | 23* | Maintenance and repair construction of nonresidential structures |
| 115 | 32411 | Petroleum refineries |
| 121 | 32512 | Industrial gas manufacturing |
| 141 | 32592, 32599 | All other chemical product and preparation manufacturing |
| 160 | 32731 | Cement manufacturing |
| 171 | 33121, 33122 | Steel product manufacturing from purchased steel |
| 195 | 33271 | Machine shops |
| 202 | 332997-9 | Other fabricated metal manufacturing |
| 226 | 333911, 333913 | Pump and pumping equipment manufacturing |
| 227 | 333912 | Air and gas compressor manufacturing |
| 230 | 333992, 333997, 333999 | Other general purpose machinery manufacturing |
| 251 | 334513 | Industrial process variable instruments manufacturing |
| 252 | 334514 | Totalizing fluid meters and counting devices manufacturing |
| 256 | 334518-9 | Watch, clock, and other measuring and controlling device manufacturing |
| 282 | 336214 | Travel trailer and camper manufacturing |
| 290 | 336611 | Ship building and repairing |
| 319 | 42 | Wholesale trade |
| 332 | 481 | Air transportation |
| 333 | 482 | Rail transportation |
| 334 | 483 | Water transportation |
| 335 | 484 | Truck transportation |
| 336 | 485 | Transit and ground passenger transportation |
| 337 | 486 | Pipeline transportation |
| 351 | 517 | Telecommunications |
| 357 | 5241 | Insurance carriers |
| 365 | 5324 | Commercial and industrial machinery and equipment rental and leasing |
| 369 | 5413 | Architectural, engineering, and related services |
| 374 | 54161, 5613* | Management, scientific, and technical consulting services |
| 375 | 54162, 54169 | Environmental and other technical consulting services |
| 380 | 54191, 54193, 54199 | All other miscellaneous professional, scientific, and technical services |
| 390 | 562 | Waste management and remediation services |
| 394 | 6211-3 | Offices of physicians, dentists, and other health practitioners |

| IMPLAN (cont.) | NAICS | IMPLAN Sector |
|---|---|---|
| 396 | 6214-5, 6219 | Medical and diagnostic labs and outpatient and other ambulatory care services |
| 411 | 72111-2 | Hotels and motels, including casino hotels |
| 413 | 722 | Food services and drinking places |
| 426 | 814 | Private households |
| 437 | N/A | Employment and payroll for SL Government Non-Education |

*Source: IMPLAN*

# 7 Conclusion

Based on extensive economic analysis, ICF concludes that LNG exports are associated with significant economic impacts on the U.S. national economy, as well as that of local communities near Cove Point.

The total value added (GDP contribution) over the life of the project (2011-2040) for the analyzed sectors totals $47 billion and $48 billion, respectively, for the low and high construction/O&M cases. The total respective job-years for the life of the project total 489,000 and 497,000. The total respective tax and royalty revenues to local, state, and federal governments (relating to both facility construction and O&M and upstream impacts) is estimated at $25 billion and $26 billion for the low and high facility construction/O&M cases between 2011 and 2040, respectively. These findings together indicate the clear advantages associated with LNG exports to both local communities near Cove Point, as well as the U.S. economy at large.

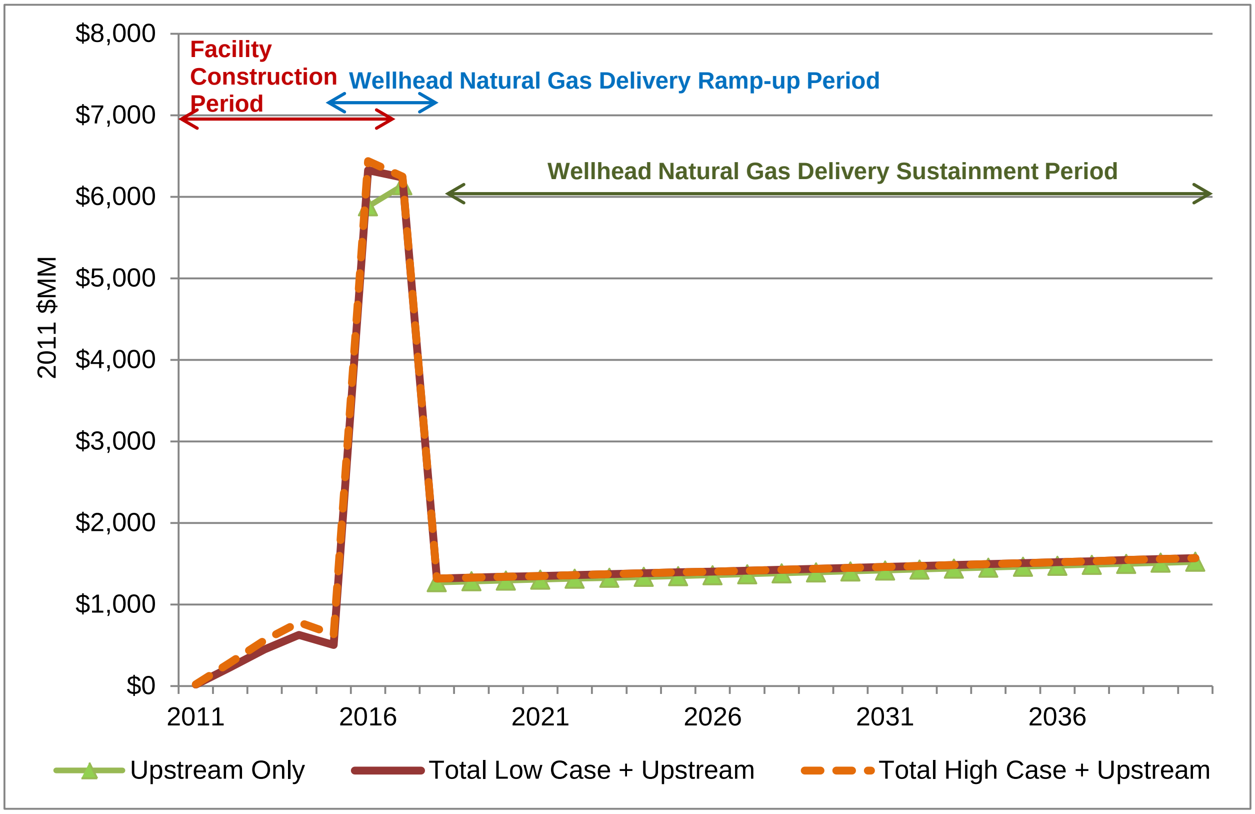
The following tables and figures show the aggregate impacts of facility construction, facility O&M, and upstream-related activity, in terms of value added, job-years, and government royalty and taxes.

**Table 23: Total Value Added from Facility Construction/O&M and Upstream Oil and Gas Expenditures Associated with LNG Exports from Cove Point (2011$ million)**

| Year | Construction and O&M Value Added (2011 $MM) | | Upstream-related Value Added (2011 $MM) | Total Value Added (2011 $MM) | |
|---|---|---|---|---|---|
| | Total Low Case | Total High Case | | Total Low Case | Total High Case |
| 2011 | $16 | $21 | - | **$16** | **$21** |
| 2012 | $230 | $287 | - | **$230** | **$287** |
| 2013 | $449 | $561 | - | **$449** | **$561** |
| 2014 | $624 | $780 | - | **$624** | **$780** |
| 2015 | $504 | $630 | - | **$504** | **$630** |
| 2016 | $445 | $556 | $5,880 | **$6,325** | **$6,436** |
| 2017 | $97 | $110 | $6,138 | **$6,236** | **$6,248** |
| 2018 | $47 | $47 | $1,269 | **$1,317** | **$1,317** |
| 2019 | $47 | $47 | $1,281 | **$1,328** | **$1,328** |
| 2020 | $47 | $47 | $1,291 | **$1,339** | **$1,339** |
| 2021 | $47 | $47 | $1,302 | **$1,349** | **$1,349** |
| 2022 | $47 | $47 | $1,313 | **$1,360** | **$1,360** |
| 2023 | $47 | $47 | $1,324 | **$1,371** | **$1,371** |
| 2024 | $47 | $47 | $1,334 | **$1,382** | **$1,382** |
| 2025 | $47 | $47 | $1,345 | **$1,392** | **$1,392** |
| 2026 | $47 | $47 | $1,356 | **$1,403** | **$1,403** |
| 2027 | $47 | $47 | $1,367 | **$1,414** | **$1,414** |
| 2028 | $47 | $47 | $1,379 | **$1,426** | **$1,426** |
| 2029 | $47 | $47 | $1,390 | **$1,438** | **$1,438** |
| 2030 | $47 | $47 | $1,402 | **$1,449** | **$1,449** |
| 2031 | $47 | $47 | $1,414 | **$1,461** | **$1,461** |
| 2032 | $47 | $47 | $1,425 | **$1,472** | **$1,472** |
| 2033 | $47 | $47 | $1,437 | **$1,484** | **$1,484** |
| 2034 | $47 | $47 | $1,448 | **$1,495** | **$1,495** |
| 2035 | $47 | $47 | $1,460 | **$1,507** | **$1,507** |
| 2036 | $47 | $47 | $1,472 | **$1,519** | **$1,519** |
| 2037 | $47 | $47 | $1,484 | **$1,531** | **$1,531** |
| 2038 | $47 | $47 | $1,496 | **$1,543** | **$1,543** |
| 2039 | $47 | $47 | $1,508 | **$1,555** | **$1,555** |
| 2040 | $47 | $47 | $1,521 | **$1,568** | **$1,568** |
| **Total** | **$3,446** | **$4,026** | **$44,038** | **$47,487** | **$48,066** |

*Source: ICF results using the IMPLAN model*

**Figure 21: Value Added from Facility Construction/O&M and Upstream Oil and Gas Expenditures Associated with LNG Exports from Cove Point (2011$ million)**



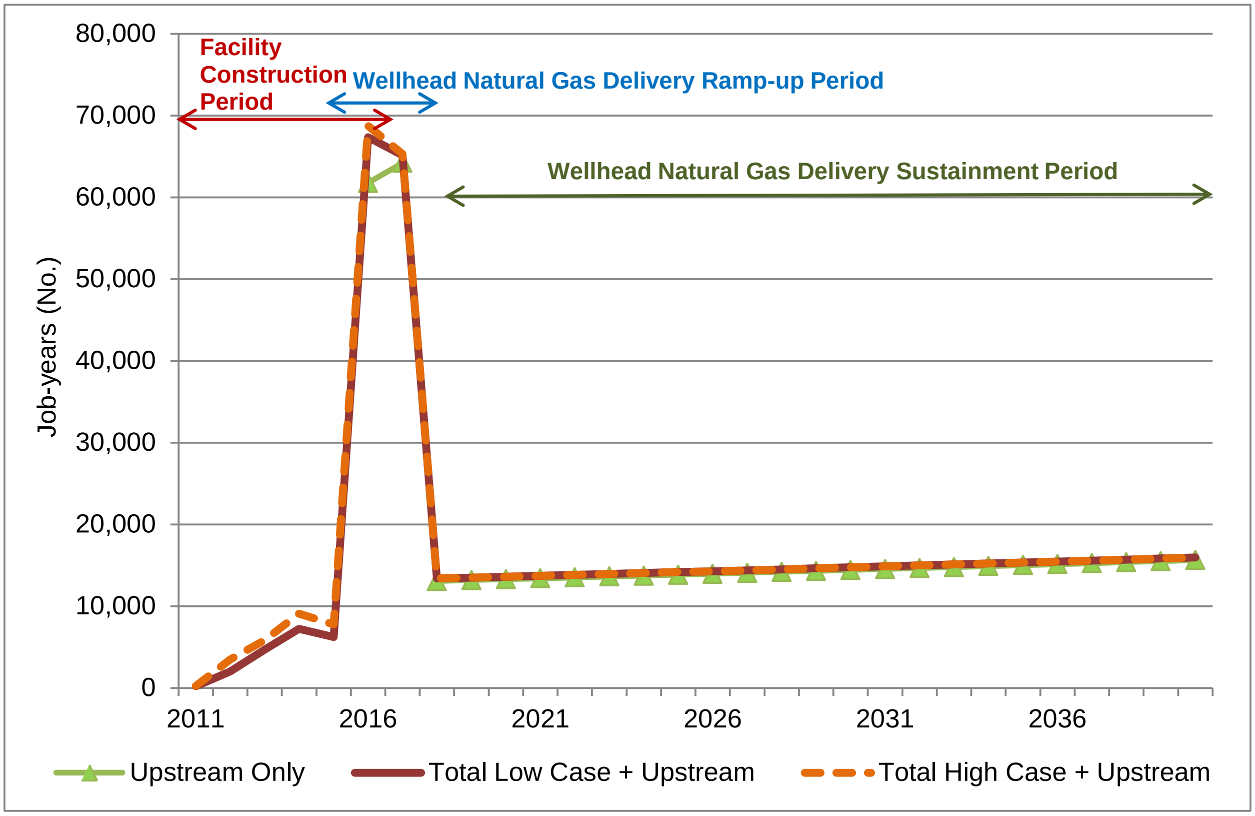

*Source: ICF results using the IMPLAN model*

**Table 24: Job-Years (Facility Construction and O&M and Upstream Expenditure Impact, 2011-40) Associated with LNG Exports from Cove Point (Job-years)**

| Year | Construction and O&M Job-years (No.) | | Upstream-related Job-years (No.) | Total Job-years (No.) | |
|---|---|---|---|---|---|
| | Total Low Case | Total High Case | | Total Low Case | Total High Case |
| 2011 | 200 | 250 | - | 200 | 250 |
| 2012 | 2,800 | 3,490 | - | 2,800 | 3,490 |
| 2013 | 4,660 | 5,840 | - | 4,660 | 5,840 |
| 2014 | 7,230 | 9,060 | - | 7,230 | 9,060 |
| 2015 | 6,200 | 7,750 | - | 6,200 | 7,750 |
| 2016 | 5,580 | 6,973 | 61,743 | 67,323 | 68,716 |
| 2017 | 930 | 1,100 | 64,209 | 65,139 | 65,309 |
| 2018 | 320 | 320 | 13,061 | 13,381 | 13,381 |
| 2019 | 320 | 320 | 13,176 | 13,496 | 13,496 |
| 2020 | 320 | 320 | 13,286 | 13,606 | 13,606 |
| 2021 | 320 | 320 | 13,396 | 13,716 | 13,716 |
| 2022 | 320 | 320 | 13,507 | 13,827 | 13,827 |
| 2023 | 320 | 320 | 13,618 | 13,938 | 13,938 |
| 2024 | 320 | 320 | 13,725 | 14,045 | 14,045 |
| 2025 | 320 | 320 | 13,835 | 14,155 | 14,155 |
| 2026 | 320 | 320 | 13,947 | 14,267 | 14,267 |
| 2027 | 320 | 320 | 14,059 | 14,379 | 14,379 |
| 2028 | 320 | 320 | 14,177 | 14,497 | 14,497 |
| 2029 | 320 | 320 | 14,296 | 14,616 | 14,616 |
| 2030 | 320 | 320 | 14,415 | 14,735 | 14,735 |
| 2031 | 320 | 320 | 14,533 | 14,853 | 14,853 |
| 2032 | 320 | 320 | 14,651 | 14,971 | 14,971 |
| 2033 | 320 | 320 | 14,770 | 15,090 | 15,090 |
| 2034 | 320 | 320 | 14,888 | 15,208 | 15,208 |
| 2035 | 320 | 320 | 15,006 | 15,326 | 15,326 |
| 2036 | 320 | 320 | 15,128 | 15,448 | 15,448 |
| 2037 | 320 | 320 | 15,251 | 15,571 | 15,571 |
| 2038 | 320 | 320 | 15,375 | 15,695 | 15,695 |
| 2039 | 320 | 320 | 15,500 | 15,820 | 15,820 |
| 2040 | 320 | 320 | 15,626 | 15,946 | 15,946 |
| **Total** | **34,160** | **41,823** | **455,181** | **489,341** | **497,004** |

*Source: ICF results using the IMPLAN model*

**Figure 22: Job-Years (Facility Construction and O&M and Upstream Expenditure Impact, 2011-40) Associated with LNG Exports from Cove Point (Job-years)**




*Source: ICF results using the IMPLAN model*

**Table 25: Taxes and Royalties from Facility Construction/O&M and Upstream Oil and Gas Expenditures and Production Associated with LNG Exports from Cove Point (2011$ million)**

| Year | Construction and O&M Taxes (2011 $MM) | | Upstream-related (2011 $MM) | | Total Government Tax/Royalty Impact (2011 $MM) | |
|---|---|---|---|---|---|---|
| | Total Low Case | Total High Case | Total Royalties* | Taxes and Govt Royalties | Total Low Case | Total High Case |
| 2011 | $4 | $4 | - | - | **$4** | **$4** |
| 2012 | $49 | $61 | - | - | **$49** | **$61** |
| 2013 | $93 | $116 | - | - | **$93** | **$116** |
| 2014 | $130 | $163 | - | - | **$130** | **$163** |
| 2015 | $106 | $133 | - | - | **$106** | **$133** |
| 2016 | $94 | $117 | $30 | $1,122 | **$1,216** | **$1,239** |
| 2017 | $22 | $24 | $384 | $1,703 | **$1,725** | **$1,727** |
| 2018 | $11 | $11 | $377 | $626 | **$637** | **$637** |
| 2019 | $11 | $11 | $383 | $609 | **$620** | **$620** |
| 2020 | $11 | $11 | $394 | $603 | **$614** | **$614** |
| 2021 | $11 | $11 | $406 | $599 | **$610** | **$610** |
| 2022 | $11 | $11 | $416 | $591 | **$602** | **$602** |
| 2023 | $11 | $11 | $428 | $587 | **$598** | **$598** |
| 2024 | $11 | $11 | $441 | $769 | **$780** | **$780** |
| 2025 | $11 | $11 | $452 | $947 | **$958** | **$958** |
| 2026 | $11 | $11 | $462 | $968 | **$979** | **$979** |
| 2027 | $11 | $11 | $472 | $989 | **$1,000** | **$1,000** |
| 2028 | $11 | $11 | $479 | $1,005 | **$1,016** | **$1,016** |
| 2029 | $11 | $11 | $485 | $1,017 | **$1,028** | **$1,028** |
| 2030 | $11 | $11 | $491 | $1,031 | **$1,042** | **$1,042** |
| 2031 | $11 | $11 | $499 | $1,048 | **$1,059** | **$1,059** |
| 2032 | $11 | $11 | $509 | $1,069 | **$1,080** | **$1,080** |
| 2033 | $11 | $11 | $519 | $1,090 | **$1,101** | **$1,101** |
| 2034 | $11 | $11 | $529 | $1,112 | **$1,123** | **$1,123** |
| 2035 | $11 | $11 | $542 | $1,140 | **$1,151** | **$1,151** |
| 2036 | $11 | $11 | $553 | $1,164 | **$1,175** | **$1,175** |
| 2037 | $11 | $11 | $564 | $1,188 | **$1,199** | **$1,199** |
| 2038 | $11 | $11 | $575 | $1,212 | **$1,223** | **$1,223** |
| 2039 | $11 | $11 | $587 | $1,237 | **$1,248** | **$1,248** |
| 2040 | $11 | $11 | $598 | $1,262 | **$1,273** | **$1,273** |
| **Total** | **$750** | **$871** | **$11,579** | **$24,688** | **$25,438** | **$25,559** |

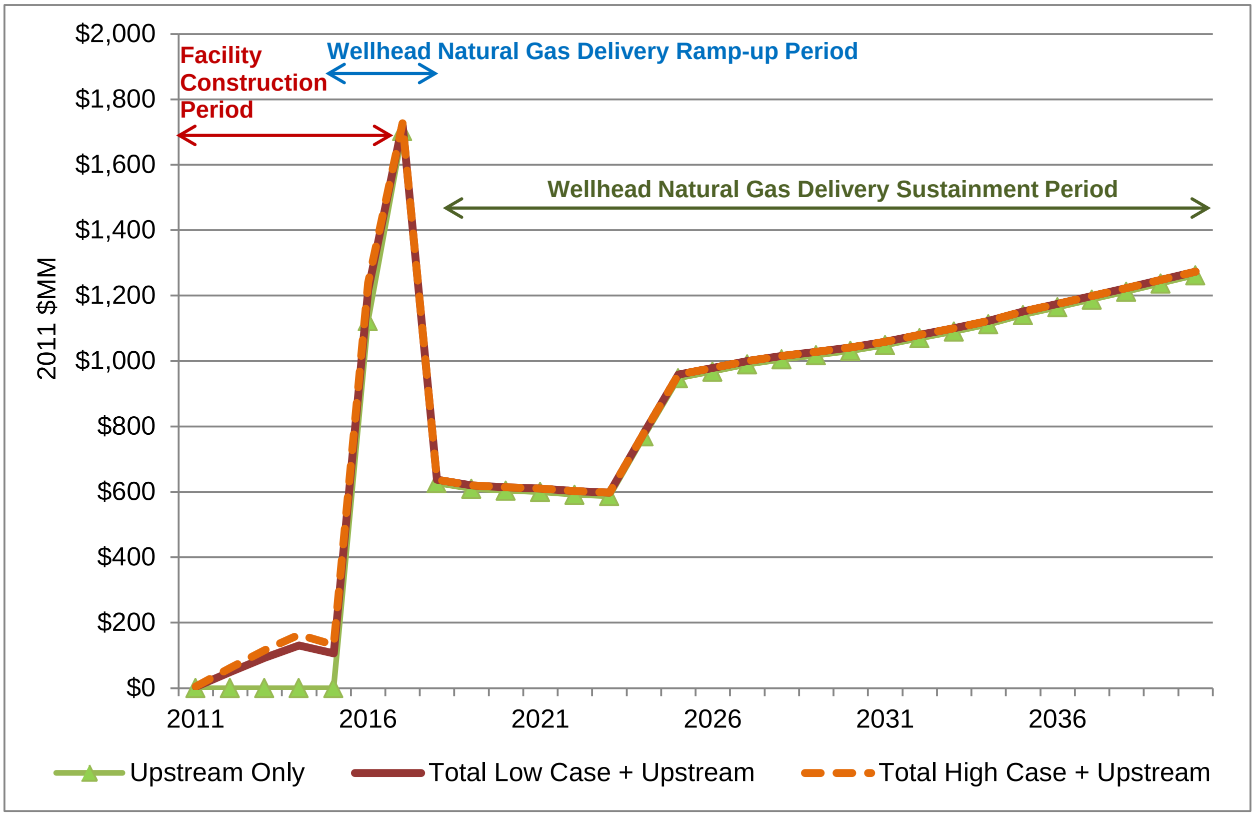
*Source: ICF results using the IMPLAN model and IPAA studies from 2009-10, 2008-09, 2007-08, and 2006-07 (in the case of royalties and severance tax calculations)*

* Assumes average royalty rate of 16%, of which 15% is assumed to go to the federal and state governments. Most of the royalties (75% to 85%) are paid to private citizens and are not considered government revenue.

*Note on facility construction and O&M:* Taxes are defined in IMPLAN to include the following categories: employee compensation, proprietor income, indirect business tax, household taxes, and corporate taxes. However, with regard to facility operations, other than employment-related taxes of liquefaction plant employees, tax figures do not include income taxes, property taxes, or gross receipt taxes associated with the liquefaction plant over the 25-year operating period.

*Note on upstream-related taxes*: "Other State Taxes" and "Federal Taxes" are based on the IMPLAN model, and include property and income taxes from oil and gas exploration and production (E&P), taxes generated by E&P sector suppliers, and all related employee taxes.

**Figure 23: Taxes and Royalties from Facility Construction/O&M and Upstream Oil and Gas Expenditures and Production Associated with LNG Exports from Cove Point (2011$ million)**




*Source: ICF results using the IMPLAN model and IPAA studies from 2009-10, 2008-09, 2007-08, and 2006-07 (in the case of royalties and severance tax calculations)*

*Note on facility construction and O&M:* Taxes are defined in IMPLAN to include the following categories: employee compensation, proprietor income, indirect business tax, household taxes, and corporate taxes. However, with regard to facility operations, other than employment-related taxes of liquefaction plant employees, tax figures do not include income taxes, property taxes, or gross receipt taxes associated with the liquefaction plant over the 25-year operating period.

*Note on upstream-related taxes*: "Other State Taxes" and "Federal Taxes" are based on the IMPLAN model, and include property and income taxes from oil and gas exploration and production (E&P), taxes generated by E&P sector suppliers, and all related employee taxes.

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Appendix D

# Verification

STATE OF VIRGINIA )

) SS:

CITY OF RICHMOND )

Matthew R. Bley, being first duly sworn on his oath deposes and says: that he is Manager, Gas Transmission Certificates, Authorized Representative of Dominion Cove Point LNG Company, LLC, the General Partner of Dominion Cove Point LNG, LP.; that he is duly authorized to make this Verification; that he has read the foregoing submittal and is familiar with the contests thereof; that all the statements and matters contained therein are true and correct to the best of his information, knowledge and belief; and that he is authorized to execute and file the same with the U.S. Department of Energy.

M. Bley

Matthew R. Bley
Manager, Gas Transmission Certificates

Sworn to and subscribed before me this 29th day of September, 2011.

HOLLY SCOTT NOTARY PUBLIC REG. #362000 MY COMMISSION EXPIRES 02/29/2012 COMMONWEALTH OF VIRGINIA

Holly Scott

Notary Public
In and For said City

My Commission Expires: February 29, 2012

Appendix E

## OPINION OF COUNSEL

**Opinion of Counsel**

This opinion is submitted pursuant to 10 C.F.R. 590.202(c) of the Department of Energy administrative procedures. The undersigned is counsel to Dominion Cove Point LNG, LP.

I have reviewed the corporate documents and it is my opinion that the proposed export of domestically produced natural gas is within the company's corporate powers.

Respectfully submitted.

Dennis R. Lane
Deputy General Counsel