APPENDIX B

Black & Veatch, U.S. Market Impact Assessment for LNG Exports at the Bear Head Export Project (February 2015)

U.S. Market Impact Assessment for LNG Exports at the Bear Head Export Project

PREPARED FOR

Bear Head LNG Corporation

FEBRUARY 2015

BLACK & VEATCH
Building a world of difference.

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BLACK & VEATCH STATEMENT

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Glossary of Terms

AIM	Algonquin Incremental Market. Spectra Energy's expansion project on the Algonquin Pipeline System in New England.
Bcf	One billion cubic feet. In the context of LNG, the gas-to-liquid equivalency is approximately 1 Bcf (gas) = 17,200 tonnes (liquid).
Bcf/d	One billion cubic feet per day.
Btu	British thermal unit. A unit of thermal energy in the context of combustion of hydrocarbon fuels, including natural gas. It is defined as the amount of heat energy required to raise the temperature of one pound of water from 60° F to 61° F at a constant pressure of one atmosphere (14.696 psi).
CPP	Clean Power Plan. US Environmental Protection Agency's proposed carbon reduction plan.
EIA	U.S Department of Energy **-** Energy Information Administration.
EMP	Energy Market Perspective. Black & Veatch's subscription-based, bi-annual comprehensive outlook of natural gas and power markets in North America.
GPCM	Gas Pipeline Competition Model. A third-party proprietary model Black & Veatch uses for natural gas market forecasting.
LNG	Liquefied natural gas.
MMcf	One million cubic feet. A common volume unit for (gaseous) natural gas.
MMcf/d	One million cubic feet per day.
MMBtu	One million British Thermal Units. 1 MMBtu = 1 Dekatherm (Dth).
M&NP	Maritimes & Northeast Pipeline
MTPA	One million tonnes per annum. Units of LNG production (by weight) in one year. The liquid-to-gas equivalency is approximately 1MTPA (liquid) = 0.135 Bcf/d (gas flow).
NEB	National Energy Board. The principal energy regulatory agency of Canada.
PNGTS	Portland Natural Gas Transmission System.
SOEP	Sable Offshore Energy Project.
TGP	Tennessee Gas Pipeline.
TQM	Trans Québec and Maritimes Pipeline.
WCSB	Western Canadian Sedimentary Basin.

1.0 Introduction

To support Bear Head LNG Corporation's ("Bear Head Corp.") application to the United States Department of Energy's Office of Fossil Energy, Black & Veatch Corporation ("Black & Veatch") was retained by Bear Head Corp. to provide an independent assessment of the market impact of Bear Head Corp.'s proposed liquefied natural gas ("LNG") export project ("Bear Head Project" or "Project"), to be sited in Point Tupper, Nova Scotia.

Black & Veatch's assessment methodology is built upon our industry expertise in the North American gas and power markets and our experience in fundamental analysis of natural gas supply, demand, and the interconnecting interstate and intrastate pipeline grid. Having served the power industry for nearly a century, Black & Veatch has hands-on experience analyzing key drivers of natural gas demand growth from the power sector such as the relative capital cost of power generation technologies, impact of the proposed Clean Power Plan ("CPP"), nuclear permitting, U.S. Environmental Protection Agency ("EPA") rules, and renewable targets. With oil and gas shale plays emerging as the primary supply source to the U.S. market, we continually monitor their development and undertake in-depth analyses to understand North American natural gas supply potential. In addition, Black & Veatch has conducted numerous analyses in New England related to evaluation of energy infrastructure solutions in the region.

Black & Veatch produces an integrated and comprehensive outlook on North American energy issues in our bi-annual Energy Market Perspective ("EMP") that incorporates our power market expertise with our views on generating fuels such as natural gas and coal. The *Base Case* assumptions and analysis in this report are based on our 2015 EMP and summarize our views on key power and natural gas market fundamental drivers that influence our projections of natural gas supply, demand and prices across North America. Black & Veatch utilized RBAC, Inc.'s GPCM™ model to assess the regional and national market price impact of liquefying and exporting 1.2 billion cubic feet per day ("Bcf/d") of U.S. or Canadian gas supplies at the Bear Head LNG Project from 2019 through 2049.

The *Base Case* incorporates the EPA's proposed CPP as the primary driver for gas demand growth in the power generation sector. It also assumes Spectra Energy's ("Spectra") Algonquin Incremental project to be in service by November 2016 and, with the numerous New England shippers having committed, the currently proposed Kinder Morgan Northeast Energy Direct project and Spectra's Atlantic Bridge and Access Northeast pipeline projects are constructed and in-service as of 2018. As currently stated, the proposed CPP plan has several major building blocks that would support natural gas demand growth because of the plan's emphasis on lower-emitting fossil fuels and the ability of gas-fired generation to mitigate the intermittence of renewable generation. The *Base Case* includes demand associated with LNG exports from various terminals in the U.S and Canada reaching 9.3 Bcf/d by 2020.

Black & Veatch explored three LNG export scenarios to test the impact of exports from the Bear Head LNG Project on prices in the New England market and across the Lower 48. The first scenario is the *With Bear Head Project Exports* scenario which included an additional 1.2 Bcf/d of natural gas demand at the Bear Head LNG Project site on top of the projected demand in the *Base Case*. The second scenario is a *High LNG Exports* scenario, which included, in addition to exports assumed in the *Base Case*, an additional 3.0 Bcf/d of natural gas demand associated with added LNG exports from the U.S. Gulf Coast and Eastern Canada starting in 2019, but no LNG exports from the Bear Head LNG Project. This stress test scenario reflects a fairly aggressive ramp up in LNG exports, but also reflects potential LNG exports levels post-2020. Black & Veatch assumed a 2019 ramp-up to make the various scenarios comparable over the analysis period. The total U.S. and Canadian LNG export-related demand will reach 12.3 Bcf/d by 2020 in this stress-test scenario.

Lastly, a third scenario, the *High LNG Exports with Bear Head Project Exports* scenario, was developed which adds an incremental 1.2 Bcf/d of demand (associated with LNG exports from the Bear Head Project) by 2019 to the *High LNG Exports* scenario.

Black & Veatch's market price assessment examines the market price impact of the Bear Head LNG Project on a regional and national level. For the regional market, Black & Veatch examined prices at Algonquin city-gates and Tennessee Zone 6 Delivered ("Tennessee Zn. 6"), as reference locations to assess the Bear Head Project's price impacts on the New England market. The price impact across a number of other pricing points across the U.S. was also examined, using prices at Henry Hub as a barometer for the national price impact.

Table 1: Scenario Descriptions

SCENARIO	DESCRIPTION
Base Case	Based on Black & Veatch's 2015 Energy Market Perspective, which incorporates our analysis of EPA's proposed Clean Power Plan. It also incorporates Black & Veatch's latest assessment of NGL uplifts to shale gas production costs and their impact on North American unconventional production. Natural gas demand associated with LNG exports from various terminals the U.S and Canada reach 9.3 Bcf/d by 2020 and 11.3 Bcf/d by 2025.
With Bear Head Project Exports	Builds upon the *Base Case* with an additional 1.2 Bcf/d of natural gas demand and pipeline infrastructure associated with LNG exports from the Bear Head Project beginning in 2019
High LNG Exports	Includes an additional 3.0 Bcf/d of natural gas demand associated with LNG exports starting in 2019 incremental to the *Base Case*, designed to stress test the results of the *Base Case*.
High LNG Exports with Bear Head Project Exports	Builds upon the *High LNG Exports* scenario with an additional 1.2 Bcf/d of natural gas demand and pipeline infrastructure associated with LNG exports from the Bear Head Project beginning in 2019, designed to stress test the results of the *With Bear Head Project Exports* case.

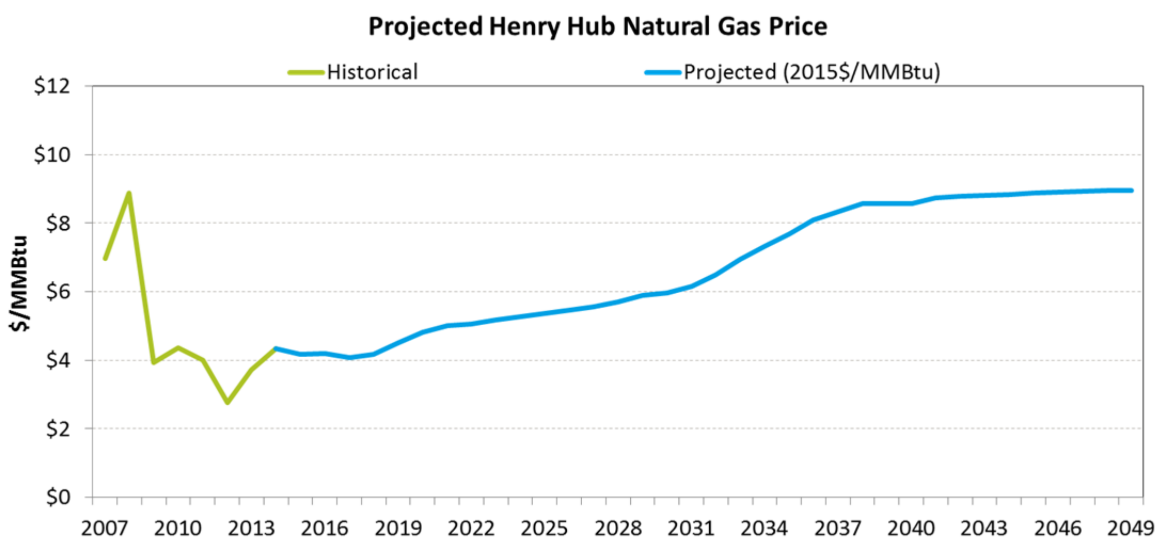
2.0 Executive Summary

Black & Veatch utilized a scenario analysis to assess the potential price impact of 1.2 Bcf/d of related gas demand related to LNG exports from the Bear Head Project. Based on our independent assessment, these proposed export volumes are expected to have a limited price impact both in New England and across the rest of the U.S. during the analysis period when incremental gas pipeline infrastructure into New England is constructed and completed by 2019.

National Price Impact

Black & Veatch's 2015 EMP projects a rising Henry Hub gas price during the analysis period. As seen in Figure 1, Black & Veatch projects that gas prices (in real 2015 dollars) will recover from the 2012 lows and stabilize at $4.50/million British thermal units ("MMBtu") by 2018. Prices then rise more moderately to average $5.57/MMBtu over the first 15 years of the analysis period (2019 through 2033), rising to an average price level of $8.55/MMBtu over the latter half of the analysis period (2034 through 2049). North American demand growth is primarily driven by increased demand for gas-fired electric generation. While some emerging shale producers will continue to benefit from liquids uplifts, continued resource depletion will force producers to drill higher cost wells, as producers' costs are expected to rise over the analysis period. The price trajectory of Henry Hub projected in the *Base Case* is determined by the interplay of all market fundamental factors modeled and cannot be solely, or even mostly, attributed to the level of LNG exports assumed in the *Base Case*.

Figure 1: Projected Base Case Henry Hub Natural Gas Prices



Black & Veatch's *With Bear Head Project Exports* analysis indicates that export volumes from the Bear Head Project would contribute to an estimated $0.04/MMBtu (0.8%) increase in gas prices at the Henry Hub during the first 15 years of operation. The price impact during the remaining 16 years is expected to be an average increase of $0.01/MMBtu (0.1%) over the *Base Case* average price of $8.55/MMBtu. See Table 2.

Black & Veatch also tested the sensitivity of national prices to additional LNG export volumes in excess of those assumed in the *Base Case*. Under the *High LNG Exports* scenario, in which an additional 3.0 Bcf/d of demand associated with Gulf Coast and Eastern Canadian LNG export terminals is assumed beginning in 2019, the price impact of exports from the Bear Head Project (as modeled in the *High LNG Exports with Bear Head LNG* scenario) to Henry Hub is estimated to be $0.05/MMBtu (0.9%) between 2019 and 2033 and $0.02/MMBtu (0.2%) between 2034 and 2049. Under this stress-test scenario, the price impact of the Bear Head Projection Gulf Coast prices remain limited even with fairly aggressive assumptions on LNG export volumes.

Table 2: Market Price Impact at Henry Hub

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.57	5.61	5.70	5.75
	Average Diff. from Base		0.04		0.05
	Percentage Increase		0.8%		0.9%
2034-2049	Average Price ($/MMBtu)	8.55	8.55	8.60	8.61
	Average Diff. from Base		0.01		0.02
	Percentage Increase		0.1%		0.2%

Table reflects prices rounded to the nearest cent.

New England Price Impact

In the *Base Case*, the New England market price as measured at the Algonquin city-gates is projected to reach $4.84/MMBtu by 2019. Similar to Henry Hub, Algonquin city-gates prices rise moderately to average $5.59/MMBtu over the first half of the analysis period (2019-2033), and to an average of $8.68/MMBtu over the second half of the analysis period (2034-2049).

A portion of the Bear Head Project export volumes are expected to originate at Dracut, Massachusetts, the pipeline interconnect between Maritimes & Northeast Pipeline ("M&NP") and Tennessee Gas Pipeline ("TGP"), and will have a higher price impact on the Algonquin city-gates than on Henry Hub. The *Base Case* price impact at Algonquin city-gates is projected to be $0.10/MMBtu (1.8%) over the first 15 years of the Bear Head Project's operations. The price impact for the latter half of the analysis period is slightly less, increasing the *Base Case* average price of $8.68/MMBtu by $0.09/MMBtu (1.0%).

The Bear Head LNG Project is expected to exert a similar, though slightly increased price impact under the *High LNG Exports with Bear Head Project Exports* scenario, raising prices at Algonquin city-gates by $0.13/MMBtu (2.2%) from 2019-2033 and $0.10/MMBtu (1.1%) from 2034-2049. See Table 3.

Table 3: Market Price Impact at Algonquin city-gates

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.69	5.79	5.84	5.96
	Average Diff. from Base		0.10		0.13
	Percentage Increase		1.8%		2.2%
2034-2049	Average Price ($/MMBtu)	8.68	8.77	8.78	8.88
	Average Diff. from Base		0.09		0.10
	Percentage Increase		1.0%		1.1%

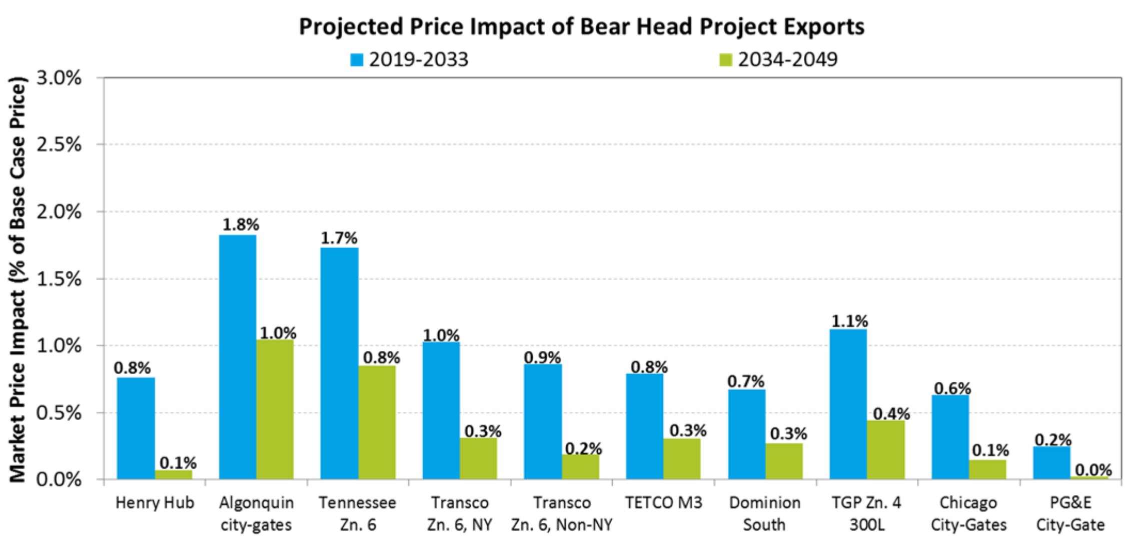
Table reflects prices rounded to the nearest cent.

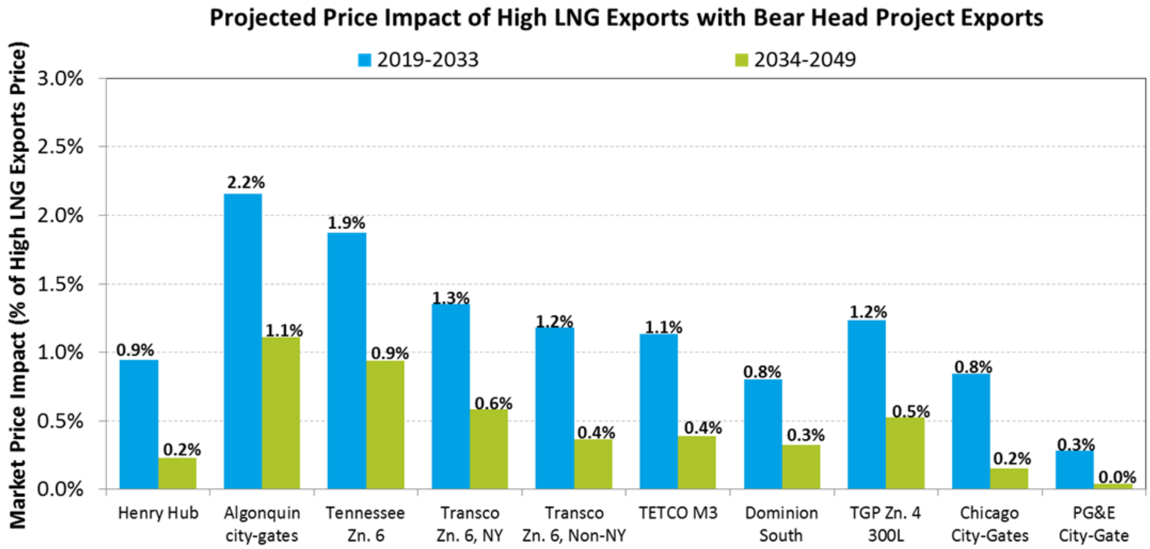
Price Impact across the Broader U.S. Market

Black & Veatch also examined the market price impact of the Bear Head LNG Project at eight additional locations (Tennessee Zn. 6; Transco Zone 6 ("Transco Zn. 6") NY; Transco Zn. 6, Non-NY; TETCO M-3; Dominion, South Point ("Dominion South"); Tennessee Zone 4 300L ("TGP Zn. 4 300L"); Chicago City-Gates; and PG&E City-Gates) and observed a similar range of price impacts, as shown in Figure 2. These trading hubs were selected for their importance to consumers and because they measure the price impact at major markets that source gas supplies from the same producing basins as the Bear Head Project.

The market price impact of the Bear Head Project exports, expressed as a percentage of market prices, slowly decreases over the analysis period as natural gas prices rise across North America. The export terminal has a much lower impact on markets outside of the Northeast, as other alternative low cost supply sources across North America are readily available to serve those markets.

Figure 2: Projected Market Price Impact across Pricing Points





Summary Conclusions

Black & Veatch's assessment demonstrates that the proposed Bear Head LNG Project has a limited impact on natural gas prices across the U.S. when incremental gas pipeline infrastructure in New England is constructed and completed by 2019. Several pipeline projects have been proposed and have received significant shipper interest from local distribution companies and power generators across New England which has led Black & Veatch to include these pipeline projects in the *Base Case*. Incremental gas pipeline infrastructure will reduce the frequency and magnitude of natural gas price spikes and reduce regional price volatility which will benefit New England energy consumers.

The estimated price impact at Henry Hub throughout the analysis period is less than 1% when compared to the *Base Case*. The Bear Head LNG Project is expected to have a higher price impact in the local New England market, with price increases at Algonquin city-gates ranging from 1.8% from 2019-2033 and 1.0% from 2034-2049 when compared to the *Base Case*.

As seen through a comparison of results from the High LNG Exports with Bear Head LNG scenario, exports from the Bear Head LNG Project exert a slightly increased, but not significant, impact on New England prices than observed in the *Base Case* in both absolute and percentage terms.

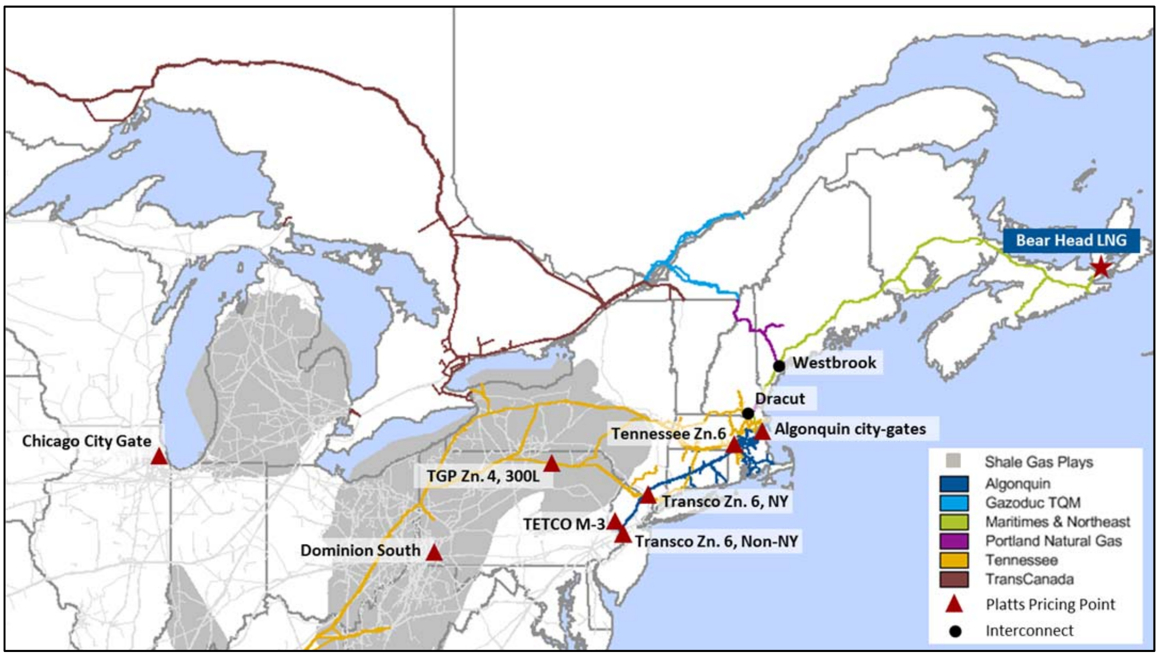
Throughout the analysis period, U.S natural gas supply will continue to outpace demand in the Lower 48 markets. The U.S Northeast market will remain a regional exporter of natural gas with the development of the Marcellus/Utica Shales. The impact of the Bear Head LNG Project on market prices across the U.S. decreases with greater geographic distance from the project. For example, Bear Head LNG exports have a minimal impact on natural gas prices in the U.S. Gulf Coast or Midwest given the robust supply expected to be available from various basins across North America.

3.0 Overview of the Proposed Bear Head LNG Project

Bear Head LNG is developing an LNG export terminal in Point Tupper, Nova Scotia. As currently proposed, the project will commence operations in 2019 with an initial liquefaction capacity of up to 8 million tons per annum ("MTPA").

The Bear Head LNG Project's proposed pipeline header will interconnect with the M&NP near Goldboro, Nova Scotia. The Project will have up to 1.2 Bcf/d of pipeline capacity originating from Dracut, MA ("Dracut") to flow north to the Bear Head LNG terminal. For M&NP to flow north, Black & Veatch has assumed additional infrastructure will be constructed to enable up to 1.2 Bcf/d of gas supplies to flow from south to north to the Bear Head LNG pipeline header. At Dracut and Westbrook, ME, the Bear Head Project will be able to access gas supplies on TGP and the Portland Natural Gas Transmission System ("PNGTS"). See Figure 3.

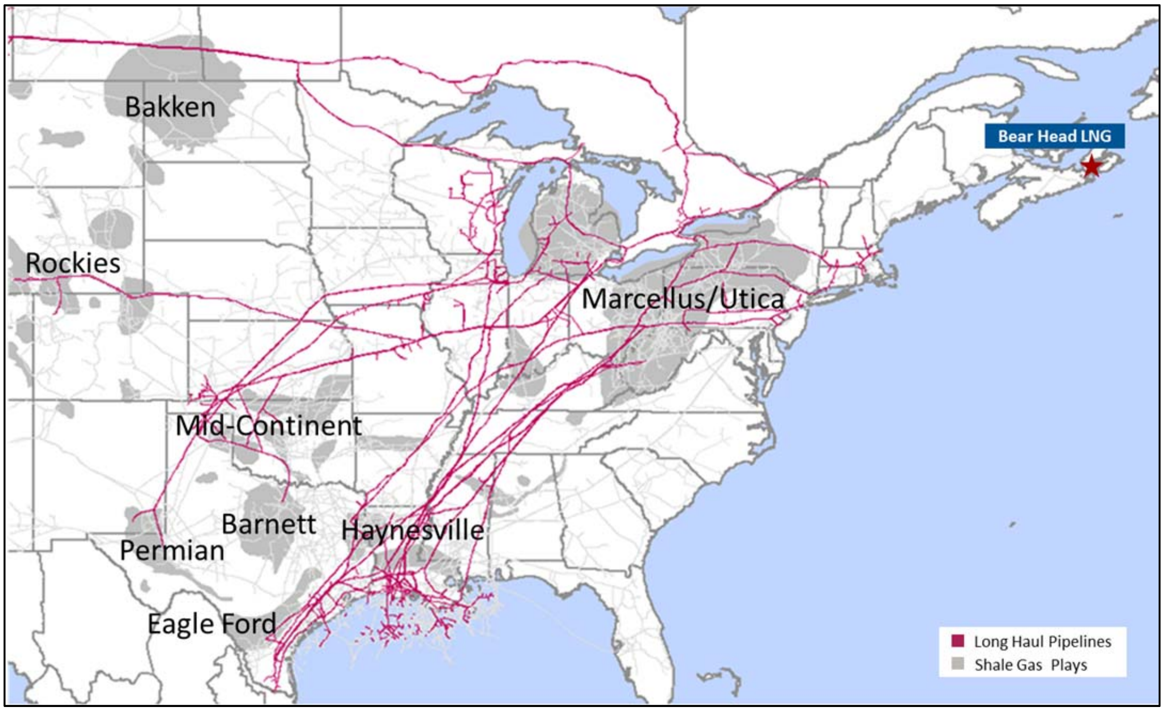
Figure 3: Map of the Bear Head Project



Bear Head LNG is well positioned to access both U.S. and Canadian gas supplies. Potential Canadian supplies include local Eastern Canadian production in Nova Scotia and Newfoundland as well as production sourced in the Western Canadian Sedimentary Basin ("WCSB").

Bear Head LNG has access to numerous U.S.-sourced gas supplies either via interconnects with other interstate pipelines into TGP or directly on the TGP system. In addition to the Appalachian shales, Bear Head LNG could reach back to the major Gulf Coast production basins or production located in the Mid-Continent region. See Figure 4 below. Through TGP and the pipelines with which it connects, the Bear Head Project would be able to access supply basins that comprise of 75% of current total Lower 48 production.

Figure 4: Mid-Continent and Gulf Coast Paths to Bear Head Project



Availability of Underground Storage in Nova Scotia

The Bear Head LNG Project would be able to access an underground storage facility located in Alton, Nova Scotia. Alton Natural Gas Storage, a subsidiary of AltaGas, is currently constructing a natural gas storage complex with three salt caverns and a gas pipeline lateral, and is targeting to commence operations in 2015. Based on its regulatory application, the initial total working gas capacity of the first three caverns will be 3.8 Bcf with maximum withdrawal rate of 0.8 Bcf/d. Alton Gas Storage may develop as many as 10 to 15 caverns at a later date.[1] The pipeline lateral from Alton will interconnect with Maritimes and Northeast Halifax Pipeline. See Figure 5 below.

[1] http://www.novascotia.ca/nse/ea/AltonNaturalGasStorage.asp

Figure 5: Alton Gas Storage Location

Source: AltaGas and B&V Analysis

Overall, additional underground gas storage in Nova Scotia could also help mitigate winter price spikes during the coldest days of the year in New England. Summer storage injections of Nova Scotia, U.S., or other Canadian production and winter storage withdrawals that serve the Maritimes and New England markets will dampen winter seasonal price spreads. The availability of additional winter supplies via Alton Natural Gas Storage's facility will reduce the severity of price spikes and the draw on Northeast supplies. The Bear Head Project's access to storage will allow it to optimize seasonal feed gas supply purchases as well. The Project's customers could purchase additional summer gas supplies when New England and Lower 48 demand is much lower and pipeline capacity to Dracut is more readily available, inject those volumes into storage, and then withdraw them on peak winter days reducing the potential market impact on natural gas prices during the winter months.

Nova Scotia Gas Supply

The availability of Nova Scotia gas supplies, may allow the Bear Head Project to offset U.S and Western Canadian sourced supplies. Currently, there are two local sources of gas supply in Nova Scotia. The Sable Offshore Energy Project ("SOEP") commenced production in 2000, delivering gas supplies to local markets in Nova Scotia and New Brunswick as well as exports to the U.S. via the M&NP pipeline to markets in Maine, New Hampshire and to Dracut. While SOEP supplies have been in steady decline since 2008, the commencement of Deep Panuke production in 2013 has somewhat offset those declines and has increased Eastern Canadian production to its highest levels in the past 10 years.

Additional studies and analysis indicate further potential for development in the region. The Play Fairway Analysis2 ("PFA") and affiliated studies made the model-dependent case for 121 Tcf of natural gas in place ("GIP") in multiple prospective reservoirs in the Nova Scotia offshore region comprising the Scotian Basin. A combination of seismic surveys and exploratory well logs have been used by investigators, including Shell Upstream Americas, to estimate the distribution of gas reservoirs by prospective size. Attention has focused on the Sable sub-basin, underlying the Sable Island area, as possibly the richest gas-prone area and with a prospective resource base of 35 Tcf GIP. A cumulative inventory of exploratory wells drilled over the history of gas assessment of the Scotian Basin, including the PFA, included at least 102 wells with shows of oil, condensate or gas. Among the wells with gas shows, a total of 222 flow tests showed a wide population of flow rates, following approximately a log-normal distribution, which could be interpreted as broadly consistent with the model distribution of prospective gas reservoirs.

Although actual production data has been too few to book significant gas reserves, as would be required to conform to the rules applied by the Canadian Securities Administrators ("CSA"), all geotechnical indications point toward a significant resource base. If referenced to historical experience in developing offshore hydrocarbon resources, it is reasonable to expect that about 10-20% of the GIP will eventually become classified as technically recoverable. Accordingly, upon future development, the Scotian Basin might yield at least 12-24 trillion cubic feet ("Tcf") with about 3-7 Tcf from the Sable sub-basin alone. Based solely on risked-based analysis of only proven discoveries (i.e., reservoirs that have produced gas), which is a more robust analysis than the estimation of GIP, the minimum expected producible gas complement is about 2 Tcf.

Recently, Shell Canada and BP announced plans to develop new deep water blocks off the coast of Nova Scotia. In an agreement in 2011 with the provincial/federal regulatory in Nova Scotia, Shell Canada plans to spend $965 Million on four blocks located about 200 kilometers southwest of Halifax over the nine-year exploration license.[3] See Figure 6. Between 2015 and 2019, Shell Canada plans to drill up to seven exploratory wells. Shell recently announced ConocoPhillips and Suncor Energy as joint venture partners on its exploration program.[4] In 2012, BP was awarded exploration rights for four deepwater blocks 300 kilometers off Halifax after submitting a $1 billion exploration bid. BP began a two-year seismic program to map the four blocks for potential hydrocarbons in May 2014, and will evaluate the seismic data before announcing future plans.[5]

While still in the exploratory phase, if additional offshore Nova Scotia oil and gas resources are produced during the analysis period, the price impact of the Bear Head Project on Henry Hub and New England natural gas prices would be even lower than reported, as less gas exports from the U.S. will be needed to provide feed gas to the terminal. The Bear Head Project will be well positioned to access these incremental Nova Scotia supply sources.

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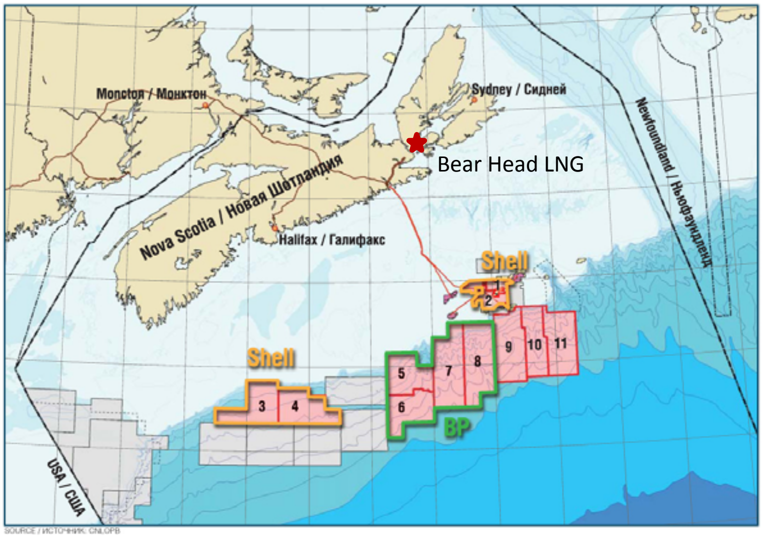
[2] http://energy.novascotia.ca/oil-and-gas/offshore/play-fairway-analysis/analysis
[3] http://www.platts.com/latest-news/oil/calgary/shell-to-drill-seven-wells-offshore-nova-scotia-21917817
[4] http://www.shell.ca/en/aboutshell/media-centre/news-and-media-releases/2014/0609shelburne.html
[5] http://thechronicleherald.ca/business/1236573-bp-wraps-great-seismic-season

Figure 6: Areas of Development in Offshore Nova Scotia



Source: Oil & Gas Euroasia

Western Canadian Sedimentary Basin Supply

There are over 10 major points of entry where WCSB supplies can enter into the U.S. interstate pipeline system, of which 4-6 may potentially be utilized to transport WCSB supplies to either Dracut or Westbrook. Figure 7 shows possible gas receipt points for WCSB gas.

In Waddington, NY, the Iroquois Gas Transmission System ("Iroquois") can receive WCSB gas supplies from the TransCanada Pipelines Mainline ("TransCanada") and can move the volumes south to its interconnect with TGP at Wright, NY. On TGP, the gas supplies would traverse from New York through Massachusetts on the TGP 200 Line and deliver to M&NP at Dracut.

In Pittsburg, NH, PNGTS can receive WCSB gas supplies transported across Canada on TransCanada to Trans Québec and Maritimes Pipeline ("TQM") which then delivers the gas to PNGTS which transports volumes south to its interconnect with M&NP near Westbrook, ME.

Other potential entry points for WCSB supplies include Noyes, Minnesota (aka Emerson), where Great Lakes Pipeline ("Great Lakes") and Viking Pipeline receive WCSB supplies from TransCanada. Volumes on Great Lakes can be re-exported at St. Clair, MI to Ontario into Union Gas and back onto the TransCanada network for delivery to Niagara, Waddington or Pittsburg. Similarly, WCSB supplies received at Port of Morgan, MT (aka Monchy) on Northern Border Pipeline can be moved south to Vector Pipeline and re-exported back to Ontario at St. Clair into Union Gas, which can then deliver the gas back to TransCanada for delivery to one of the aforementioned export points.

Figure 7: WCSB Potential Paths to Bear Head Project

Incremental Pipeline Capacity into New England

In an effort to meet the demand for additional pipeline capacity in the New England region, several pipeline expansion projects have been proposed to deliver incremental natural gas supplies into the market to serve both LDC and power generation demand. In aggregate, if all of the proposed pipeline projects are completed, these projects would almost double the current pipeline capacity serving the New England market today. Most of these proposed pipeline projects are scalable in design, and can accommodate additional pipeline shippers, which in turn would increase the contracted billing determinants and reduce the overall cost of the pipeline projects to New England LDCs and power generators.

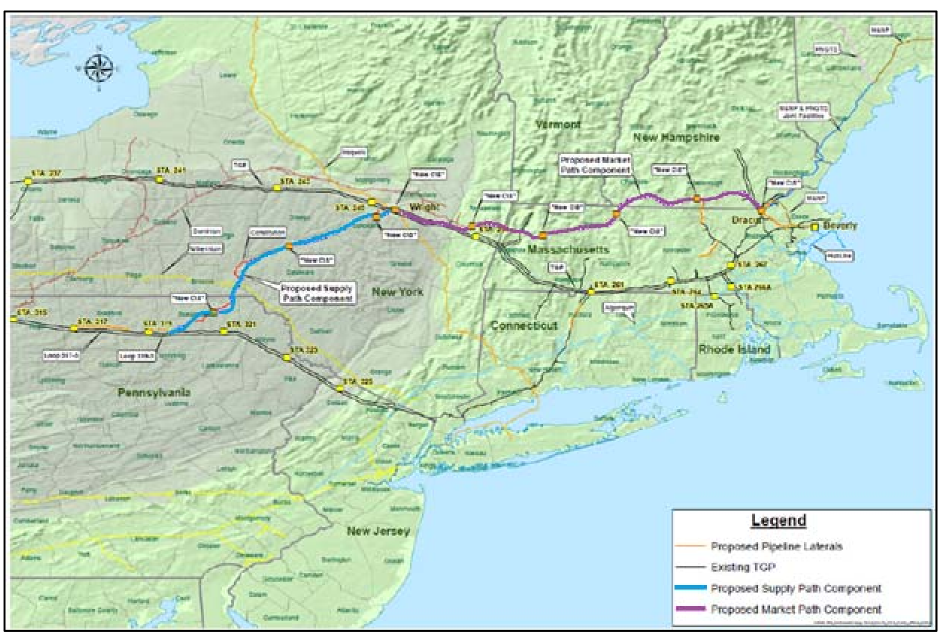
Spectra's Algonquin Incremental Market ("AIM") project is expected to receive its FERC certificate and authorization to begin construction in the spring of 2015. Projected to be in service by November 2016, the AIM expansion project will add an additional 342 million cubic feet per day ("MMcf/d") of capacity from Ramapo, NY to markets in Connecticut, Rhode Island and Massachusetts. The anchor shippers on AIM include UIL Holdings, National Grid, NiSource, and Northeast Utilities. Figure 8 shows the projected project right-of-way.

Figure 8: Spectra AIM Expansion Project Map

Source: Spectra

Kinder Morgan's Northeast Energy Direct will extend from the Marcellus Shale along existing TGP right-of-way across New York and Massachusetts and into Dracut. As depicted in Figure 9 below, the project is currently in the pre-filing process with the Federal Energy Regulatory Commission ('FERC") and it is expected to formally file an application with FERC in the fourth quarter of 2015, with construction beginning in January 2017 to meet the projected in-service date of late 2018. The proposed project is scalable from 0.8 Bcf/d to 2.2 Bcf/d depending on shipper commitments in the region. So far, anchor shippers, including Berkshire Gas Company, Columbia Gas of Massachusetts, Connecticut Natural Gas, Liberty Utilities, National Grid, and Southern Connecticut Gas, have signed binding agreements for a minimum of 0.5 Bcf/d total firm transportation capacity.

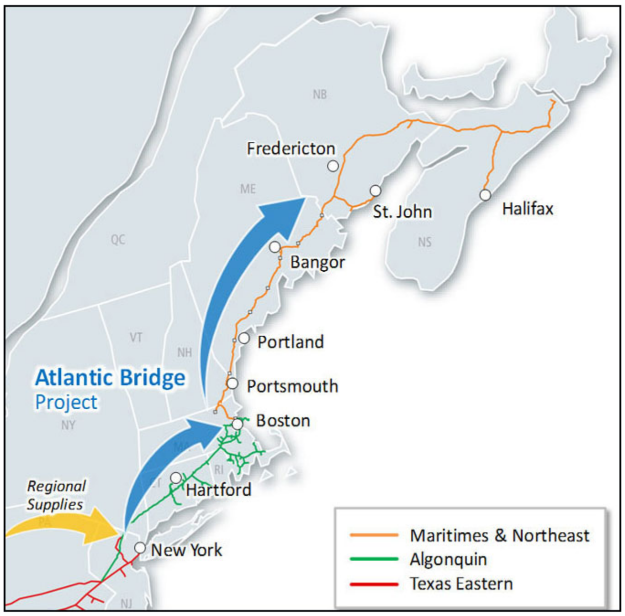
Figure 9: Kinder Morgan Northeast Energy Direct Map



Source: Kinder Morgan

Spectra has proposed two additional pipeline projects that will complement its AIM project. As part of the Atlantic Bridge project, Spectra proposes to expand the Algonquin and M&NP Pipeline to deliver additional supplies to New England and the Maritimes Provinces, as shown in Figure 10 below. The expansion capacity will be at least 100 MMcf/d, but the project can be scaled up to 600 MMcf/d depending on customer commitments. Unitil Corporation has been announced as an anchor shipper on the project. The current projected in-service date is November 2017.

Figure 10: Spectra Atlantic Bridge



Source: Spectra

Spectra's second proposed project, Access Northeast, proposes to add as much as 1 Bcf/d of incremental pipeline capacity into New England by November 2018. The project consists of several 200 MMcf/d expansions of Spectra's existing Algonquin Pipeline and M&NP footprints depending on customer commitments. In a joint ownership venture, Northeast Utilities and Spectra will each own 50 percent of the $3 billion expansion project. As a way to accommodate power generators and their reluctance to hold firm pipeline capacity, Spectra is looking at Multiple Shipper Options where several shippers can share one contract ensuring maximum efficiency of capacity utilization within a single contract.

4.0 Methodology and Base Case Assumptions

Black & Veatch's analysis draws upon those assumptions utilized in the 2015 EMP regarding future natural gas and power infrastructure, pricing, and the outlook on other power fuels. The EMP is an integrated outlook, updated bi-annually, that assesses the direction of the natural gas, power, coal, and emissions markets. The *Base Case* incorporates the EPA's proposed CPP as the primary driver for gas demand growth in the power generation sector, and assumes the currently proposed Kinder Morgan Northeast Energy Direct and Spectra's Atlantic Bridge and Access Northeast projects are all in service by 2018.

Black & Veatch estimated the price impact of the Bear Head Project using RBAC Inc.'s GPCM™ model. The GPCM™ model uses an advanced algorithm to solve for optimal equilibrium price and quantities by balancing demand and supply nodes in the market. As a network model, GPCM™ nodes represent production regions, pipelines, storage facilities, and end-use customer groups.

Supply

Black & Veatch utilizes a basin-by-basin, play-by-play approach to assess the productive capacity, availability and cost of major natural gas supply sources in North America. For the major shale plays that will contribute to the majority of natural gas production growth, Black & Veatch utilizes in-house geoscientists and geologists to assess the resource base, technology trends in drilling and natural gas liquids content. Black & Veatch also monitors trends in finding and development costs, well type curves, estimated ultimate recoveries and tax and policy changes in order to assess the relative production costs across all production areas that will determine the dynamics of production growth based on competitive cost advantages.

Black & Veatch projects that North American natural gas production will grow from 81.6 Bcf/d to 127.7 Bcf/d, at a growth rate of 0.95% per annum from 2014 to 2049, as shown in Figure 11**Error! Reference source not found.**. This projected production is assumed to originate from basins that are currently producing natural gas. Black & Veatch assumed limited production to be sourced from yet-to-be developed sources, such as the Tuscaloosa or Mancos Shale plays. This conservative supply assumption was utilized in each scenario presented in this report.

Figure 11: Historical and Projected North American Production

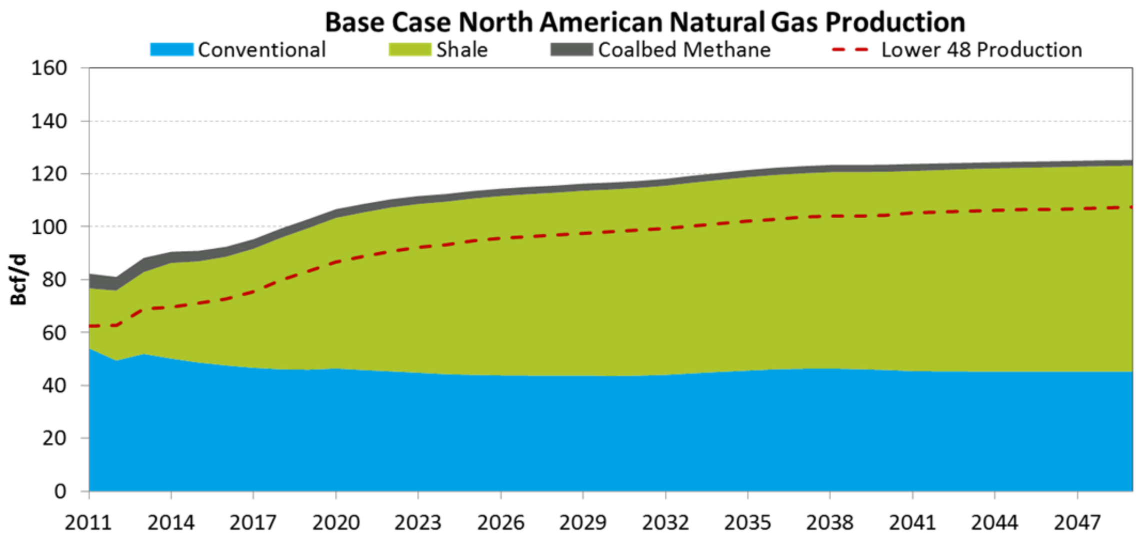
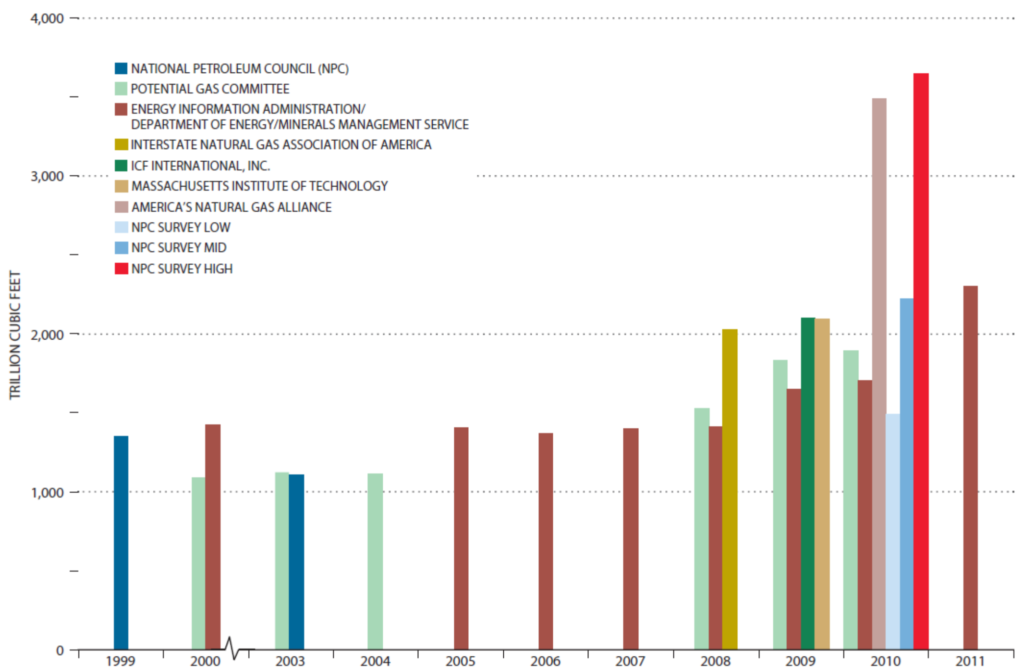


Figure 12: Evolution of U.S. Technically Recoverable Natural Gas Resource Estimates

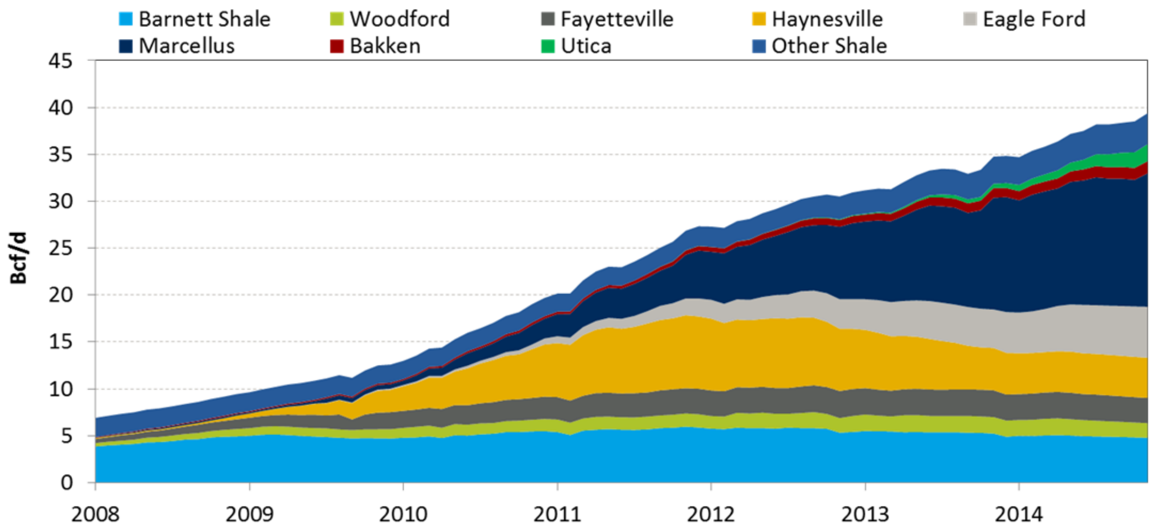


Source: National Petroleum Council. Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources (September 2011)

Rapid technological advances in horizontal drilling and hydraulic fracturing expanded the economically recoverable gas resource base that had hitherto been only technically recoverable. As new land positions were established and resources were tested, the resulting influx of shale gas reserves has dramatically increased the supply base of the North American market. Figure 12 shows that the technically recoverable natural gas resource estimates have grown substantially since 2007.

As seen in Figure 12, estimates of natural gas producible from shale plays in the U.S. have steadily increased as exploration and production work has matured. Actual U.S. production of natural gas from shales (Figure 13) increased more than five times from January 2008 to 2014, from approximately 6 Bcf/d to more than 40 Bcf/d. At Dracut, the Bear Head Project can reasonably expect to make supply arrangements from a majority of the current major shale basins in the U.S. and Canada.

Figure 13: Major Shale Production by Basin



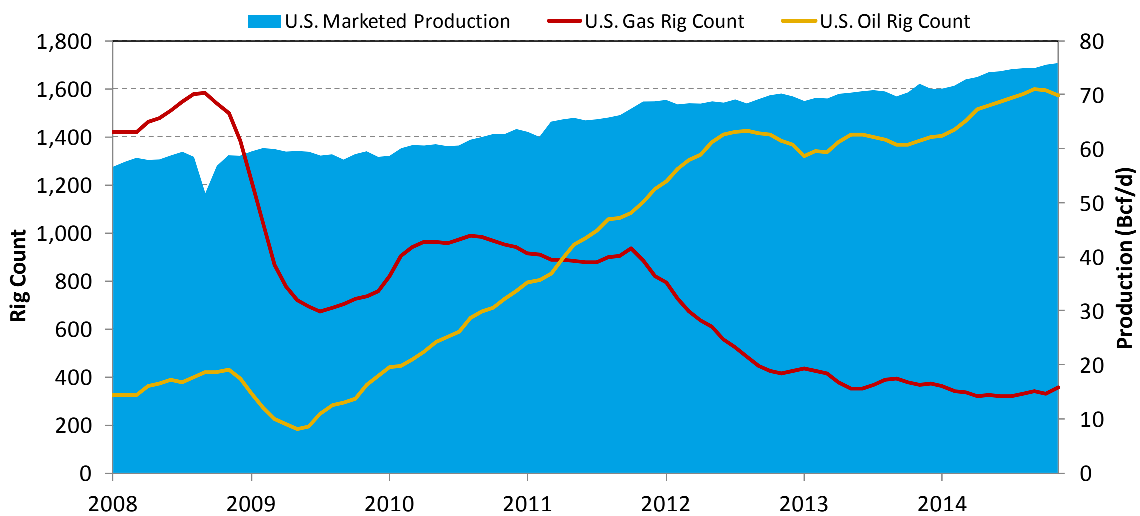
Source: LCI Energy Insight

The recent growth in shale gas production is primarily attributable to two types of plays: (a) dry gas plays that are economical to produce, mainly by close proximity to major demand centers; (b) oil or wet gas plays (rich in natural gas liquids) that have gas associated with high-value liquids. As shown in Figure 14, natural gas rig counts have been in steep decline, while oil rig counts have continued to grow. Following the steep decline of global oil prices during late 2014 and early 2015, oil drilling activity has begun to decline while gas drilling activity has remained flat. Indeed, gas production from the market-proximate gas plays, Marcellus Shale and Haynesville Shale, has remained steady and volumetrically more significant than production of associated gas from wet plays. Black & Veatch expects WTI oil prices to remain in the $45 - $55/bbl for the next 18-24 months and then begin to gradually increase up to a level of about $85/bbl by 2020. Gas prices at the Henry Hub are expected to remain in the $3.50 - $5.00/MMBtu range throughout the end of this decade.

The production/technology growth story in the U.S. has not been limited to shale opportunities. In the Permian Basin, producers are going back into previously drilled wells and using horizontal drilling to enhance oil and gas extraction. According to the EIA, from 2007 to 2010, the Permian Basin had flat oil production, averaging nearly 900,000 barrels per day. In January 2015, Permian oil production reached its highest level to date exceeding 1.8 million barrels per day. From January 2007 to January 2015, the Permian Basin added 1.6 Bcf/d of natural gas production, exceeding 6.2 Bcf/d in January 2015, representing a 36% increase over the period. By 2020, many expect the Permian Basin to have the highest production rate of tight oil in the U.S. A similar situation can be examined in the Texas

Panhandle in the Granite Wash play where horizontal drilling has extended the life of these mature reservoirs, where associated gas is producing over 1 Bcf/d. Associated gas already makes up nearly one-third of the new growth in U.S. natural gas supply; and tight oil with associated gas is expected to continue to draw more attention from producers than dry gas plays. Black & Veatch believes that reduced production of associated gas from oil plays will not occur until mid to late 2015 and will be temporary as oil prices begin to recover before the end of the year.

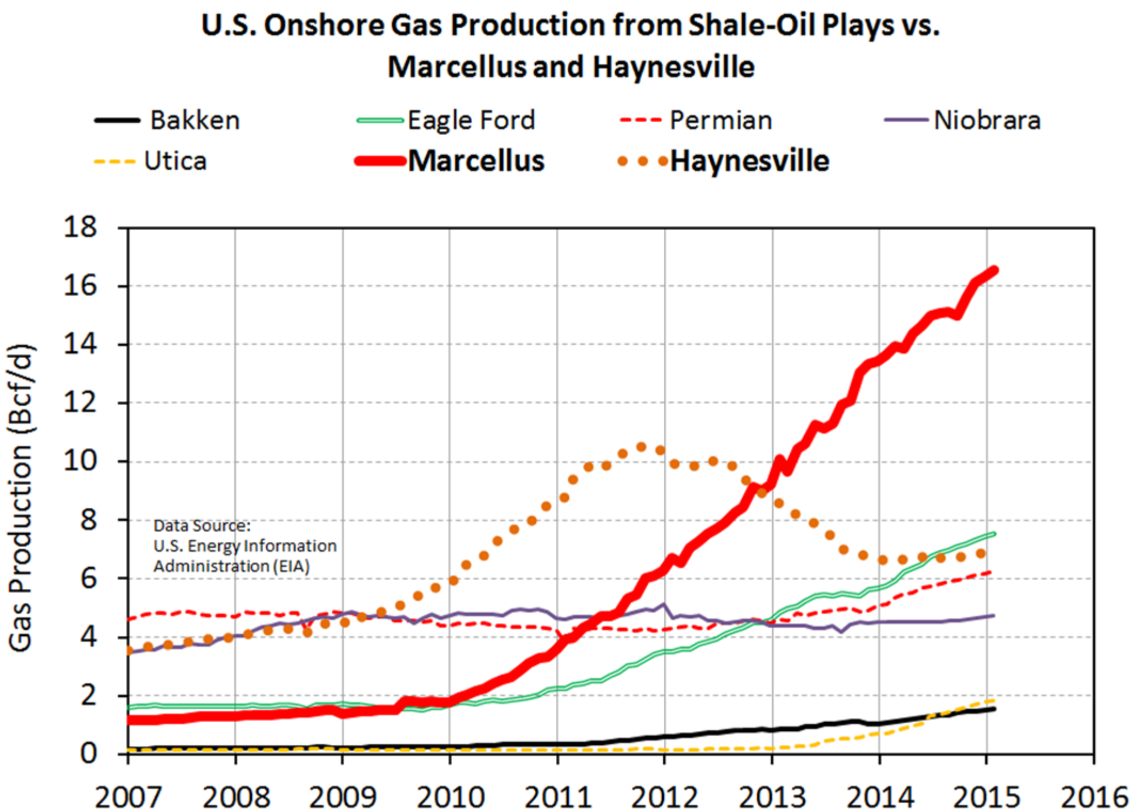
Figure 14: U.S. Natural Gas Rig Count vs. Marketed Production



Source: LCI Energy Insight

The proposed Bear Head Project is located in Nova Scotia with proximate access to U.S. production from the Marcellus Shale and Utica Shale, both of which have experienced a production boom along with other North American shale basins in recent years. Although some other shale gas plays have witnessed declining development activity as natural gas prices have remained depressed since 2011, Marcellus gas production has maintained robust growth and the Utica growth has only just begun, as shown in Figure 15.

Figure 15: Natural Gas Production from U.S. Shale Oil Plays and Key Shale Gas Plays



Prospective Gas Resources in Eastern Canada

Gas supplies from U.S. shale plays, especially the Marcellus Shale and Utica Shale, are emphasized because their resource bases are large, their production growth remains strong and their proximity to the Bear Head Project site is attractive. Additional gas supplies from eastern Canada, with even closer proximity to the Bear Head Project site, could become available in the future.

Based on the Play Fairway Analysis (PFA) which began in 2008 under sponsorship of the Nova Scotia Department of Energy, unproven resources in the Nova Scotia offshore are estimated to be 8 billion barrels of oil and 120 Tcf of gas. The estimates are based on occurrence of known or suspected petroleum reservoir rocks and geologic analogy with more extensive knowledge about the offshore area near Halifax. The PFA identified six zones across the Scotian Shelf and the Scotian Basin that have been, or could become, open to lease bids by petroleum exploration companies. Encana Corporation has produced gas from the Deep Panuke field on the Scotian Shelf since 2013. Based solely on risked-based analysis of only proven discoveries, the minimum expected producible gas complement in the Scotian Basin is about 2 Tcf.

Sable Island occurs within Zone 3, which is estimated to contain 35 Tcf of gas in place (but with the portion technically recoverable not yet established). Lease parcels for exploration in Zone 3, commonly referenced as the Sable sub-basin, were awarded to Shell Canada in 2011 and to BP in 2012. Over the next two to three years, Shell Canada and BP will need to assess the seismic analysis and exploratory well data to determine how they will meet the exploratory agreements with Nova Scotia.

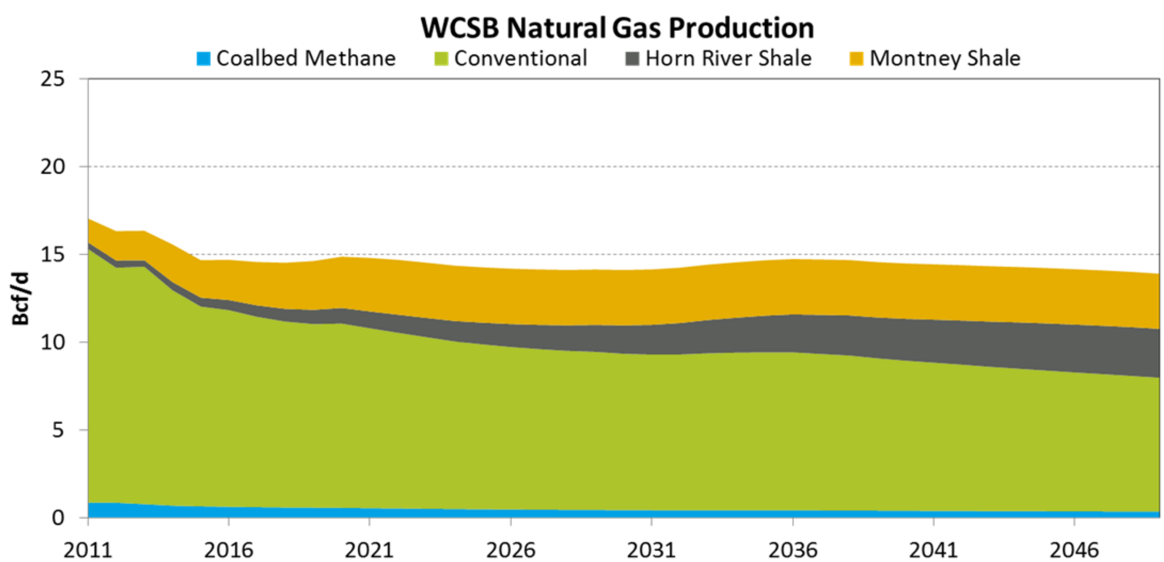
The Utica Shale extends into Quebec and the Canadian portion of the recoverable resource base has been estimated as 31 Tcf (ARI, Inc. on behalf of EIA). The Horton Bluff Shale underlies Nova Scotia and the Frederick Brook Shale underlies New Brunswick. ARI, Inc. (on behalf of EIA) estimated recoverable resources of 2 Tcf for the Horton Bluff Shale. Geologic investigation of the Frederick Brook Shale is largely incomplete although early exploration work led by Southwestern Energy, Inc. suggested that about 67 Tcf of gas in place (but with the fraction recoverable not yet determined).

None of the aforementioned onshore plays currently are in production. Indeed the recent trend in eastern Canada has been for moratoria on onshore shale gas development projects based, in part, on local objections to hydraulic fracturing. Nonetheless, the prospective gas resource base in eastern Canada is significant and might become a further advantage to the Bear Head Project in the future.

Gas Resources in Western Canada

Figure 16 presents historical and projected natural gas production in the WCSB. Production from unconventional shale and conventional production sources are projected to slowly decline from 15.5 Bcf/d in 2014 to 13.9 Bcf/d by 2049. Recent shale gas developments have slowed the pace of decline in the WCSB and are expected to offset, in part, expected production declines in conventional and coalbed methane plays.

Figure 16: Historical and Projected WCSB Production

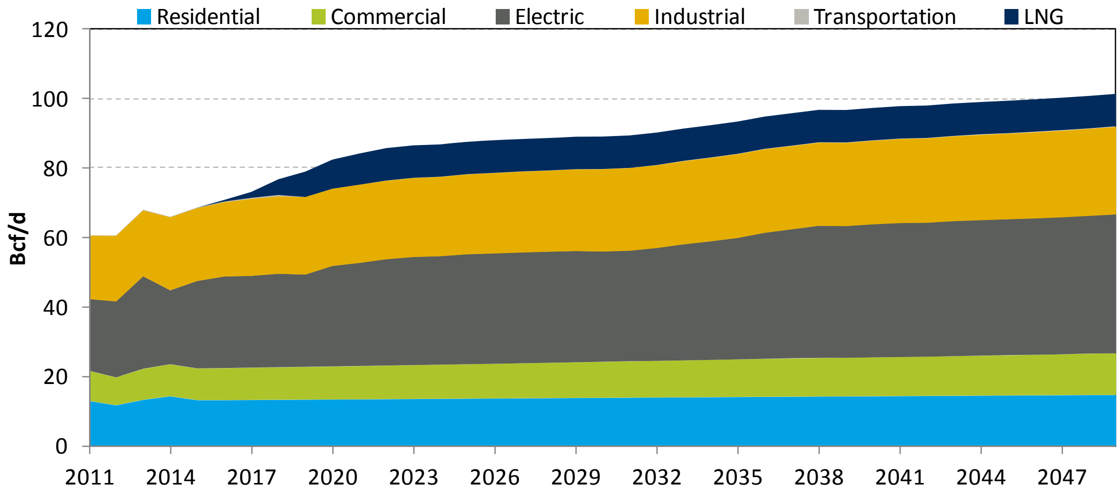


Further delays in the development of British Columbia LNG export facilities could potentially re-direct Horn River and Montney Shale production to other Canadian and Lower 48 markets. Multiple large LNG export projects in British Columbia have announced delays in development, changes in ownership, and rising pipeline infrastructure costs to monetize WCSB production. If such delays continue to hinder LNG exports in British Columbia, producers in the Horn River and Montney could choose to monetize their production by selling their gas into other Canadian or U.S. markets which would further dampen the U.S. price impacts of the Bear Head Project.

Demand

Black & Veatch expects demand for natural gas in the Lower 48 to grow from 70 Bcf/d to 96 Bcf/d over the forecast period from 2014 through 2049, an average growth rate of 0.9% per annum. This growth is largely driven by the increased demand for natural gas-fired power generation.

Figure 17: Historical and Projected Lower 48 Demand for Natural Gas



Power generation is expected to be the main driver of demand growth in the North American natural gas market. In June 2014, the U.S. Environmental Protection Agency (EPA) proposed the Clean Power Plan, with the overall objective to achieve a cumulative, nationwide reduction of GHG emissions of 30 percent below 2005 emission levels by 2030.

Based on the major building blocks of the Clean Power Plan, Black & Veatch believes that natural gas-fired generation is positioned to play a critical role in lowering emission levels as well as mitigating renewable capacity intermittency. Black & Veatch projections indicate that the share of natural gas in providing energy for the U.S. is expected to increase by 30% between 2015 and 2039.

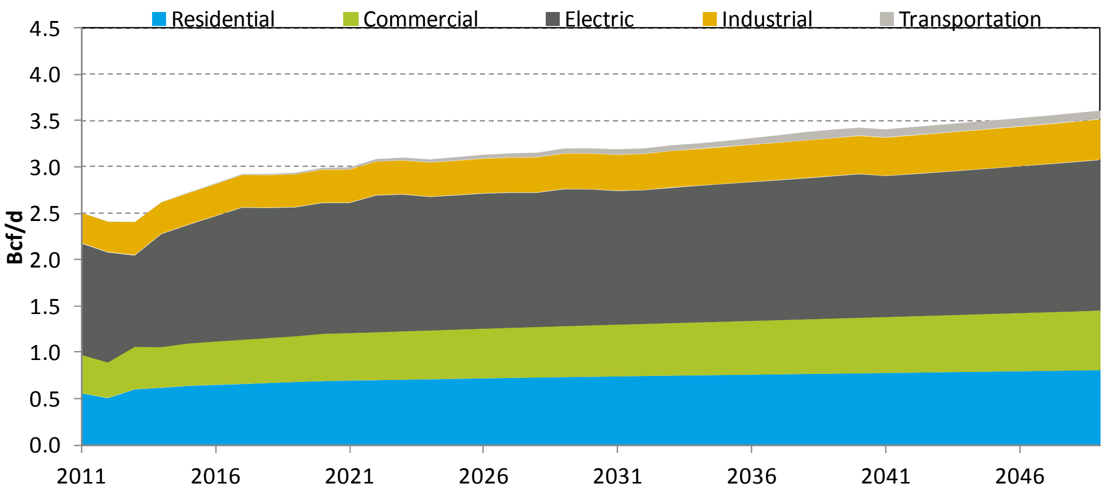
Overall, Black & Veatch anticipates a slight recovery of industrial demand from the past few years as the economy continues to recover from the 2008-2010 recession. As U.S. natural gas prices remains relatively inexpensive compared to alternative fuels and relative to other regions in the world, industrial demand is expected to experience moderate growth over the long term. Residential and commercial demand is expected to remain flat as demand growth due to population and economic growth are offset by energy efficiency gains.

New England Demand

Figure 18 shows historical and projected demand for natural gas in New England. Compared to other U.S. regions, New England is expected to experience moderate demand growth in the residential and commercial sectors in part due to state conversions programs like the one in Connecticut. Connecticut plans to increase natural gas market share from

31% to 50% by 2020, and add 250,000 residential customers. Demand from the residential sector is expected to grow at 0.79% per year while demand from the commercial sector is expected to grow at a rate of 1.1% per year. The announced retirement of the Vermont Yankee nuclear facility and Salem Harbor Power Station have recently increased the region's dependency on natural gas for power generation. The potential impact of the Clean Power Plan is expected to increase gas demand in the electric sector at 0.82% per year, and spur the associated pipeline infrastructure investment. Demand from the industrial sector is projected to grow at 0.7% per year due to increased oil to gas conversions during the analysis period.

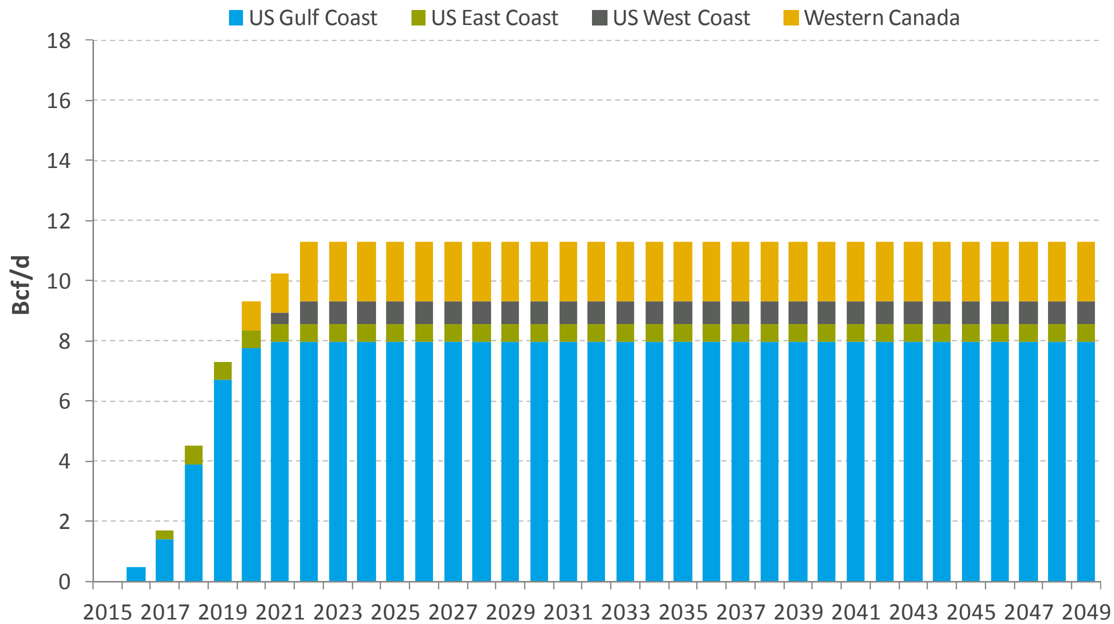
Figure 18: Historical and Projected New England Demand for Natural Gas



LNG EXPORTS

The phenomenal growth in shale gas production has transformed the U.S. natural gas market from an import market to a source of future exports. Black & Veatch included multiple U.S export terminals located in the Gulf Coast, West Coast, and East Coast, as well as a terminal in British Columbia in its *Base Case* assumptions. Figure 19 represents Black & Veatch's *Base Case* LNG export assumptions by region. In the Lower 48, Black & Veatch's *Base Case* assumptions include the following FERC approved U.S export terminals: Sabine Pass, Cameron, Freeport, Cove Point, and Corpus Christi. Jordan Cove is expected to receive its FERC approval in the summer of 2015, and was also included in the *Base Case*. In Western Canada, Black & Veatch assumed one of the NEB-approved terminals would be placed into service with a gas demand of approximately 2 Bcf/d by 2020. In terms of LNG export volumes from the Lower 48, Black & Veatch's *Base Case* is comparable to EIA AEO 2014 Reference Case. Black & Veatch's *Base Case* is projecting higher LNG exports by 2019, 7.3 Bcf/d as compared to EIA AEO 2014 Reference Case projection of 4.8 Bcf/d, but both projections reach comparable levels by 2028 at 9.3 and 9.6 Bcf/d, respectively.

Figure 19: Projected Natural Gas Demand for LNG Exports By Region – Base Case



PIPELINE INFRASTRUCTURE

Black & Veatch included all existing North American natural gas pipeline infrastructure in its projection as well as proposed interstate pipeline projects that are under construction, have held a successful binding open season, or have obtained regulatory approvals. Beyond the timeline of currently announced pipeline expansions, Black & Veatch also included some generic pipeline expansions from various supply basins to demand centers to meet growing demand and to allow gas supply access to additional markets over the analysis period that had limited impacts to the conclusions of this report.

In New England, Black & Veatch has included in its *Base Case* Kinder Morgan's Northeast Energy Direct project, as well as Spectra's Atlantic Bridge and Access Northeast projects. All three projects are at various stages of development and serve a growing market in need of incremental pipeline capacity. Several recent market analysis studies conducted by the New England State Committee on Electricity ("NESCOE") and the State of Massachusetts strongly supports the conclusion that additional pipeline infrastructure will be needed to serve New England. With numerous New England shippers committing to these various projects, Black & Veatch believes that these three projects can potentially be completed by 2018.

Appendix A includes the major announced pipeline projects that Black & Veatch incorporated in the *Base Case*.

5.0 Scenario Assumptions

Black & Veatch created three scenarios in addition to the *Base Case* in order to examine the potential impact of the Bear Head LNG Project on natural gas prices across the U.S.

WITH BEAR HEAD LNG PROJECT EXPORTS SCENARIO

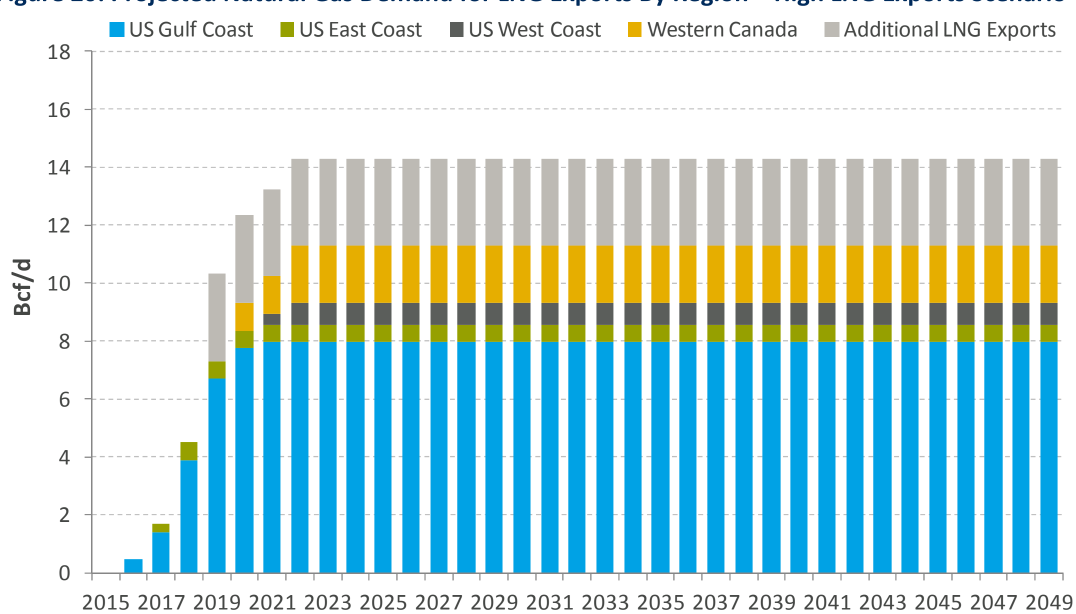
In the *With Bear Head Project Exports* scenario, an additional 1.2 Bcf/d of natural gas demand is created by LNG exports from the Bear Head Project by 2019. As part of this scenario, Black & Veatch assumed additional pipeline capacity on M&NP will be constructed by 2019, originating at Dracut to flow 1.2 Bcf/d north to the Project.

HIGH LNG EXPORTS SCENARIO

In the High LNG Exports scenario, Black & Veatch further added 3.0 Bcf/d of natural gas demand to *Base Case* assumptions for LNG exports from the Gulf Coast and Eastern Canada. This scenario tests the cumulative market price impact of additional LNG exports (relative to the *Base Case*) on regional and national market prices during the analysis period. In this scenario, total U.S. and Canadian export volumes will reach 12.3 Bcf/d by 2020, similar to the 12 Bcf/d scenario requested by the Department of Energy's Office of Fossil Energy (DOE/FE) in its May 2014 request of EIA to update its 2012 analysis on LNG exports.

Starting in 2019, Black & Veatch assumed three additional export terminals would be constructed in the Gulf Coast and Eastern Canada. In the Gulf Coast, Black & Veatch assumed two 1.2 Bcf/d terminals, one located on Lake Charles, Louisiana, and the other in Brownsville, Texas. In Eastern Canada, Black & Veatch assumed one 0.6 Bcf/d terminal located in Nova Scotia.

Figure 20: Projected Natural Gas Demand for LNG Exports By Region – High LNG Exports Scenario



HIGH LNG EXPORTS WITH BEAR HEAD Project SCENARIO

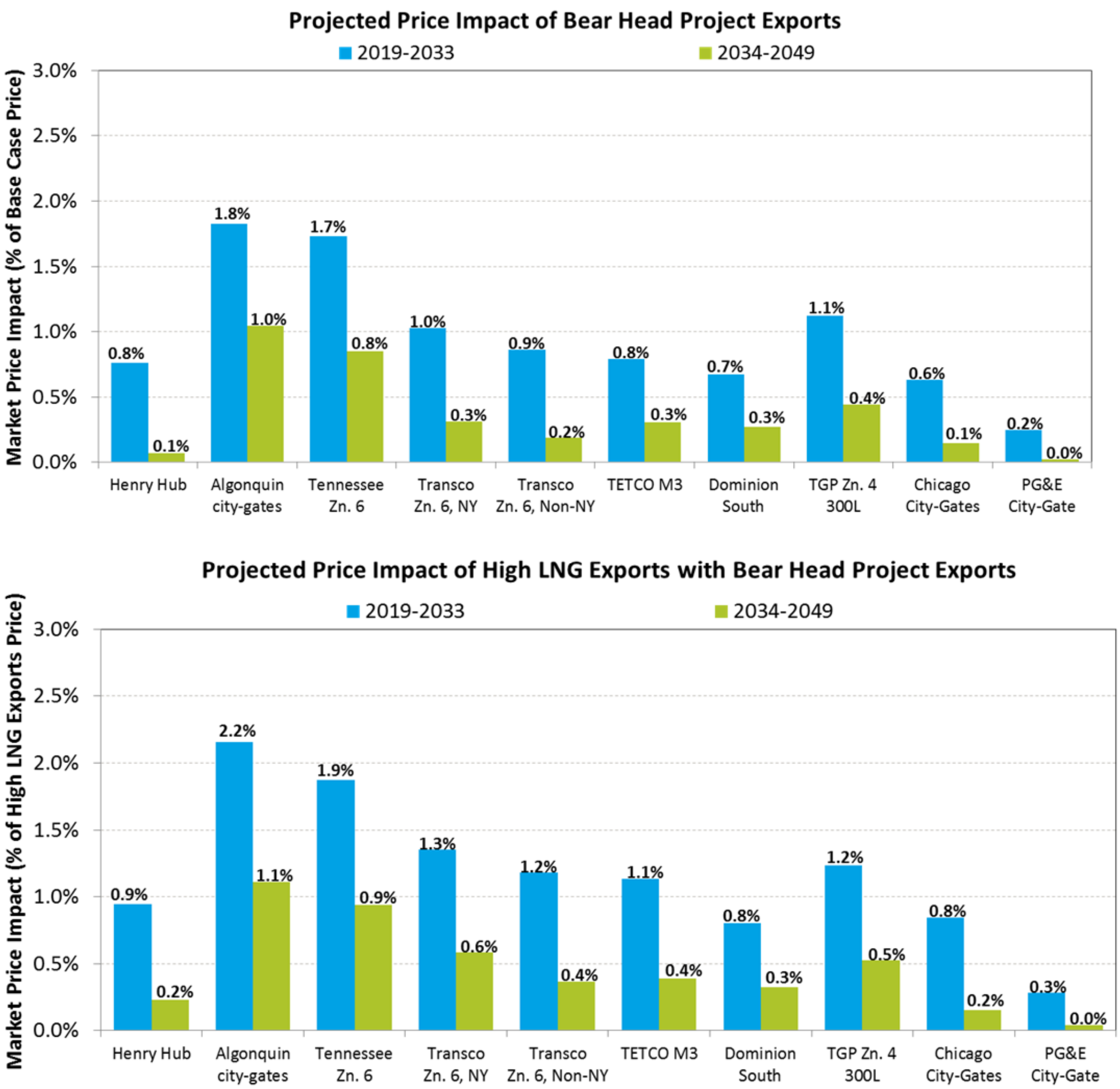
In the *High LNG Exports With Bear Head Project Exports* scenario, an additional 1.2 Bcf/d of natural gas demand is created by LNG exports from the Bear Head Project by 2019. Similar to the *With Bear Head Project Exports* scenario, Black & Veatch assumed pipeline capacity on M&NP will be constructed by 2019, originating at Dracut to flow 1.2 Bcf/d north to the Project. This scenario stress tests the regional and national market price impact of additional Eastern Canadian exports (on top of the High LNG Export Case), which already includes an Eastern Canada LNG export project, during the analysis period.

6.0 National and Regional Price Impacts

Black & Veatch's independent assessment examined the market price impacts of the proposed Bear Head Project. Across various scenarios, we found that the proposed export volumes should have limited impact on the price levels for natural gas either regionally in New England or nationally at Henry Hub during the analysis period, as shown in Figure 21.

The projected market price impact of the Bear Head Project is expected to be similar across the pricing points closest to the Bear Head Project. The impact estimated at more remote pricing points tends to be smaller in both the *Base Case* and *High LNG Exports* scenario, as shown in Figure 21.

Figure 21: Projected Market Price Impact across Pricing Points



At Dominion South, the market price impact is muted due to the continued growth of the Marcellus/Utica Shale production, which is assumed to reach 23 Bcf/d by 2019 and 32.2 Bcf/d by 2049. Black & Veatch expects Marcellus/Utica production to continue to serve market demand in the Northeast, Midwest, and Southeast U.S. The market price impact of the Bear Head Project at Dominion South is projected to be $0.03/MMBtu (0.7%) over the first 15 years of the analysis period and $0.02/MMBtu (0.3%) for the final 16 years the analysis period when compared to the *Base Case*. A similar price impact is observed when compared to the *High LNG Exports with Bear Head Project Exports* scenario, leading to an increase of $0.04/MMBtu (0.8%) from 2019-2034 that diminishes to $0.04/MMBtu (0.3%) from 2035-2049. See Table 4.

Table 4: Market Price Impact at Dominion South

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	4.93	4.96	4.98	5.02
	Average Diff. from Base		0.03		0.04
	Percentage Increase		0.7%		0.8%
2034-2049	Average Price ($/MMBtu)	7.59	7.61	7.61	7.64
	Average Diff. from Base		0.02		0.02
	Percentage Increase		0.3%		0.3%

Table reflects prices rounded to the nearest cent.

The Bear Head Project's market price impact at TGP Zn. 4, 300L is similar to what is observed at Dominion South. As one of the market prices in the Northeast Marcellus Shale, the price impact is muted in part due to continued production growth. This pricing point's proximity to Mid-Atlantic premium markets and the potential supply point for recently proposed pipeline expansions to New England makes it a key market price indicator for the Project. See Table 5.

Table 5: Market Price Impact at TGP Zn. 4 300L

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	4.88	4.93	4.95	5.02
	Average Diff. from Base		0.05		0.06
	Percentage Increase		1.1%		1.2%
2034-2049	Average Price ($/MMBtu)	7.81	7.85	7.87	7.91
	Average Diff. from Base		0.03		0.04
	Percentage Increase		0.4%		0.5%

Table reflects prices rounded to the nearest cent.

The market price impact of the Bear Head Project at the Transco Zn. 6, NY is projected to be $0.06/MMBtu (1.0%) for the first 15 years of the analysis period and $ 0.03/MMBtu (0.3%) for the remaining 15 years of the analysis period compared to the *Base Case*. A similar price impact is observed when compared to the *High LNG Exports with Bear Head Project Exports* scenario, leading to an increase of $0.08/MMBtu (1.3%) from 2019-2034 and $0.05/MMBtu (0.6%) from 2034-2049. See Table 6.

Table 6: Market Price Impact at Transco Zn. 6, NY

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.97	6.03	6.06	6.14
	Average Diff. from Base		0.06		0.08
	Percentage Increase		1.0%		1.3%
2034-2049	Average Price ($/MMBtu)	9.29	9.32	9.36	9.41
	Average Diff. from Base		0.03		0.05
	Percentage Increase		0.3%		0.6%

Table reflects prices rounded to the nearest cent.

Both Transco Zn. 6, Non-NY and TETCO M-3 represent gas delivered to the Northeast markets that stem from Northern Virginia to New Jersey. The Bear Head Project price impact at these locations is slightly greater than at upstream points like Dominion South due to the large gas consuming loads along the Mid-Atlantic coast. See Table 7 and Table 8.

Table 7: Market Price Impact at Transco Zn. 6, Non-NY

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.91	5.96	6.00	6.07
	Average Diff. from Base		0.05		0.07
	Percentage Increase		0.9%		1.2%
2034-2049	Average Price ($/MMBtu)	9.25	9.26	9.29	9.32
	Average Diff. from Base		0.02		0.03
	Percentage Increase		0.2%		0.4%

Table reflects prices rounded to the nearest cent.

Table 8: Market Price Impact at TETCO M-3

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.84	5.88	5.94	6.00
	Average Diff. from Base		0.04		0.07
	Percentage Increase		0.8%		1.1%
2034-2049	Average Price ($/MMBtu)	9.13	9.16	9.17	9.20
	Average Diff. from Base		0.03		0.03
	Percentage Increase		0.3%		0.4%

Table reflects prices rounded to the nearest cent.

Given the projection for ample North American natural gas production, Black & Veatch's assessment indicates that exports from the Bear Head Project will lead to minimal price increases of approximately 1% to nearby New England and Northeast markets.

An even lesser price impact is expected in major downstream markets with potential price impacts at Henry Hub ranging from $0.04/MMBtu (0.8%) to $0.01/MMBtu (0.1%) over the analysis period of the *Base Case*. See Table 9.

Table 9: Market Price Impact at Henry Hub

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.57	5.61	5.70	5.75
	Average Diff. from Base		0.04		0.05
	Percentage Increase		0.8%		0.9%
2034-2049	Average Price ($/MMBtu)	8.55	8.55	8.60	8.61
	Average Diff. from Base		0.01		0.02
	Percentage Increase		0.1%		0.2%

Table reflects prices rounded to the nearest cent.

The Bear Head Project has limited price impacts in the Chicago and PG&E city-gate markets. These markets have numerous supply and pipeline alternatives that will help mitigate the additional LNG exports from the Project. See Table 10 and Table 11.

Table 10: Market Price Impact at Chicago City-Gates

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.65	5.69	5.72	5.77
	Average Diff. from Base		0.03		0.05
	Percentage Increase		0.6%		0.8%
2034-2049	Average Price ($/MMBtu)	8.83	8.84	8.84	8.85
	Average Diff. from Base		0.01		0.01
	Percentage Increase		0.1%		0.2%

Table reflects prices rounded to the nearest cent.

Table 11: Market Price Impact at PG&E City-Gate

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	6.26	6.27	6.28	6.29
	Average Diff. from Base		0.01		0.02
	Percentage Increase		0.2%		0.3%
2034-2049	Average Price ($/MMBtu)	9.54	9.54	9.54	9.55
	Average Diff. from Base		0.00		0.00
	Percentage Increase		0.0%		0.0%

Table reflects prices rounded to the nearest cent.

Appendix A – Major Natural Gas Pipeline Expansions

PIPELINE	IN-SERVICE DATE	CAPACITY
Constitution Pipeline	Apr-2015	650 MMcf/d
Spectra Atlantic Bridge	Mid-2018	600 MMcf/d
Spectra Access Northeast	Nov-2018	1,000 MMcf/d
Kinder Morgan Northeast Energy Direct	Nov-2018	1,500-2,200 MMcf/d
Tennessee Connecticut Express Expansion	Nov -2016	72
Tennessee Southwest Louisiana Supply	2018	900 MMcf/d
Tennessee Broad Run	2015-2017	790 MMcf/d
NGPL Gulf Coast Market Expansion	2016-2017	450 MMcf/d
NGPL Chicago Market Expansion	2016-2017	450 MMcf/d
Transco Leidy Southeast	Late 2015	525 MMcf/d
Transco Gulf Trace	2017	1,200 MMcf/d
Transco Dalton Expansion	2017	450 MMcf/d
Transco Atlantic Sunrise	2017-2018	1,700 MMcf/d
Transco VA Southside Expansion	Sept 2015	250
NiSource Leach Xpress	2017	1,500 MMcf/d
Columbia Gulf Cameron Access	2017	800 MMcf/d
NiSource Mountaineer XPress	2018-2019	750-1,500 MMcf/d
Texas Gas Ohio-Louisiana Access	Late 2016	626 MMcf/d

PIPELINE	IN-SERVICE DATE	CAPACITY
Spectra Sabal Trail	2017	800-1,000 MMcf/d
Spectra Gulf Markets	2016-2017	650 MMcf/d
Iroquois South to North Project	Late 2017	650 MMcf/d
Iroquois Wright Interconnect Project	Spring 2016	650 MMcf/d
Nexus Pipeline	Late 2015-Early 2016	1,000 MMcf/d
NGPL Gulf Coast Markets Expansion	Late 2016	750 MMCf/d
Rockies Express East to West	Late 2015-Early 2016	950 MMcf/d
Texas Eastern Access South	Late 2017	320
Texas Eastern OPEN	Mid - 2015	550
Texas Eastern Uniontown to Gas City	Jul-2017	425