APPENDIX C

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

New England Market Impact Assessment of 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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In conducting our analysis, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilize in performing the analysis and making these projections follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.

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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.

This summary report is an addendum to Black & Veatch's U.S. Market Impact Assessment of LNG Exports at the Bear Head Project and summarizes the impact of the Bear Head Project on the New England market. This report will review the key assumptions related to the natural gas pipeline infrastructure and the expectation for new incremental pipeline capacity into New England. The *Base Case* incorporates the proposed Clean Power Plan ("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 Energy's ("Spectra") Atlantic Bridge and Access Northeast pipeline projects are constructed and in-service as of 2018.

Black & Veatch's assessment methodology in this report follows the methodology described in the U.S. Market Impact Assessment and utilizes the scenarios listed in Table 1 to assess the New England 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 Project from 2019 through 2049. 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.

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 Natural Gas Liquid ("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* of 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 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 in New England during the analysis period of 2019 through 2049.

A portion of Bear Head Project export volumes are expected to originate at Dracut, Massachusetts, the pipeline interconnect between the Maritimes & Northeast Pipeline ("M&NP") and Tennessee Gas Pipeline, and flow north on the M&NP to a new pipeline lateral to be connected to the Bear Head Project. Black & Veatch has assumed that additional infrastructure on M&NP will be constructed to allow 1.2 Bcf/d of gas supplies to flow south to north to the Project. Upstream of the Dracut Hub, Black & Veatch has assumed that several of the currently proposed pipeline projects, as discussed in Section 4.0, will be constructed and placed into service by 2018. These proposed projects have received interest from local gas distribution companies across New England.

The *With Bear Head Project Exports* price impact to the *Base Case* at Algonquin city-gates is projected to be $0.10/million British thermal units ("MMBtu") (1.8%) over the first 15 years of the Project's operations. The price impact for the remaining 16 years is slightly less, increasing the *Base Case* average price of $8.68/MMBtu by $0.09/MMBtu (1.0%).   The Bear Head 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 2.

Table 2: 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.

The *With Bear Head Project Exports* price impact at the Tennessee Zn. 6 is comparable to the impact at Algonquin city-gates.   In the first half of the analysis period, the *With Bear Head Project Exports* impact averaged $0.10/MMBtu (1.7%). The price impact over the second half of the analysis period is slightly less, increasing the *Base Case* average price of $8.85/MMBtu by $0.07/MMBtu (0.8%). The Bear Head 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 Tennessee Zn. 6 by $0.11/MMBtu (1.9%) from 2019-2033 and $0.08/MMBtu (0.9%) from 2034-2049. See Table 3.

Table 3: Market Price Impact at Tennessee Zn. 6

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.83	5.93	5.96	6.07
	Average Diff. from Base		0.10		0.11
	Percentage Increase		1.7%		1.9%
2034-2049	Average Price ($/MMBtu)	8.85	8.92	8.94	9.03
	Average Diff. from Base		0.07		0.08
	Percentage Increase		0.8%		0.9%

Table reflects prices rounded to the nearest cent.

Further upstream, the Bear Head Project is expected to have a limited impact at key Northeast market prices. At Dominion, South Point ("Dominion South") and Tennessee Zone 4, 300 leg ("TGP Zn. 4 300L"), the average price impact over the first half of the analysis period is $0.03/MMBtu (0.7%) and $0.05/MMBtu (1.1%), respectively. The impact at these two price locations will become more important as more gas supplies originate from the Appalachian shale region.

The Transco Zone 6 ("Transco Zn. 6"), Non-NY and NY, and TETCO M-3 were also examined because they will compete for the same source gas supplies from the producing basins as the Bear Head Project. The recent pipeline expansions from the Marcellus Shale into these markets have reduced basis differentials to Henry Hub and will moderate the seasonal winter basis blowouts. The Northeast market price impact of the Bear Head Project exports, expressed as a percentage of market prices, slowly decreases over the analysis period as Appalachian shale production growth and natural gas prices rise across North America. Key pricing points analyzed in this report can be seen below in Figure 1.

Figure 1: Key Pricing Points in New England

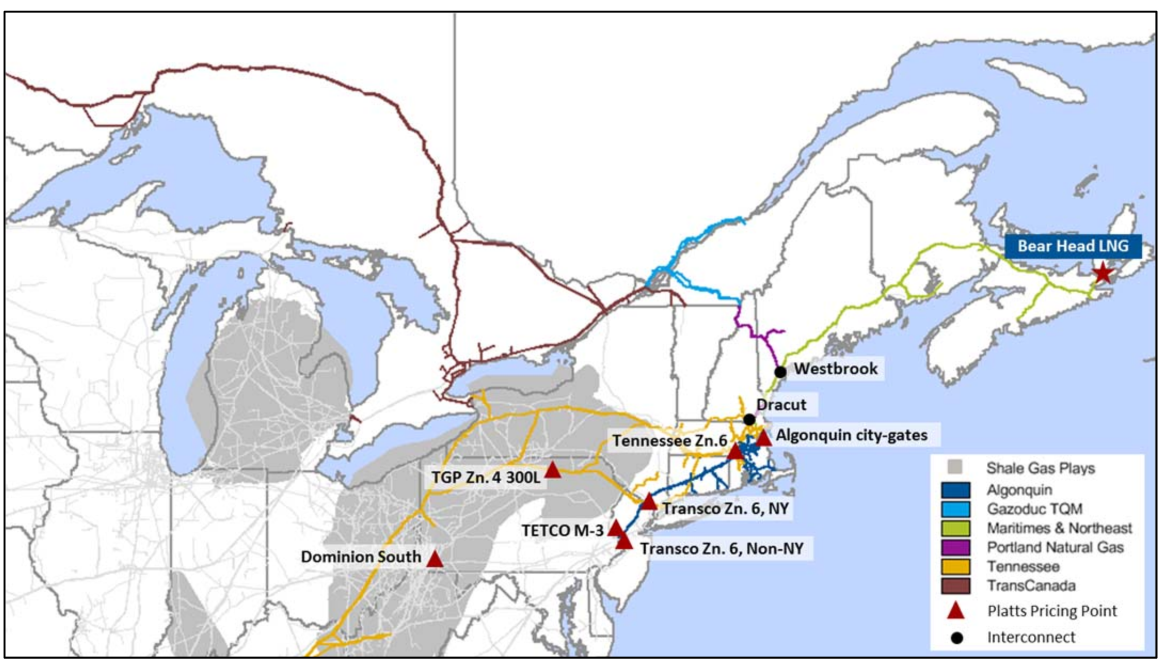
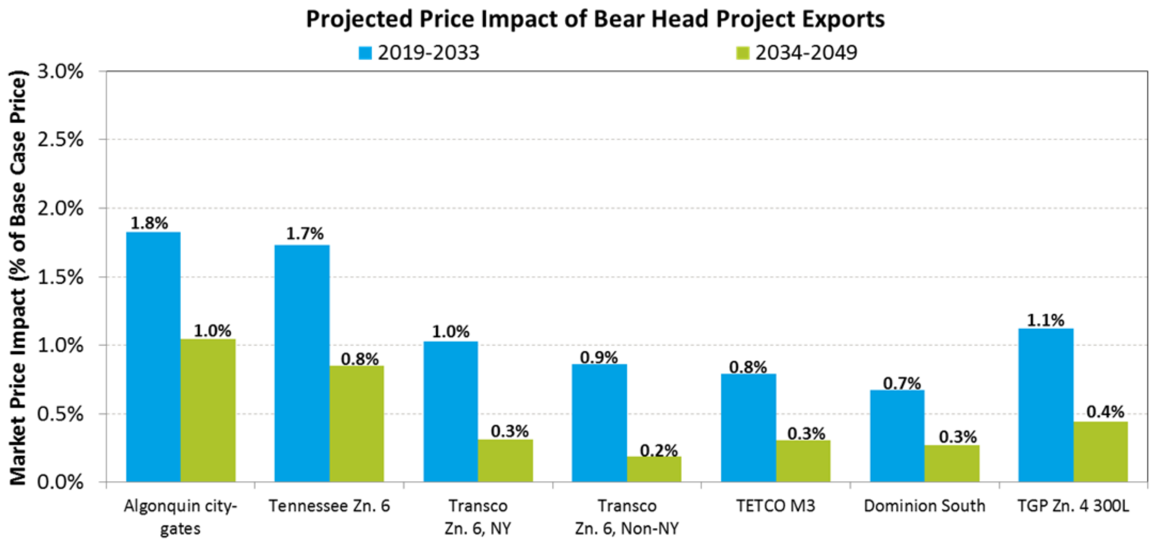
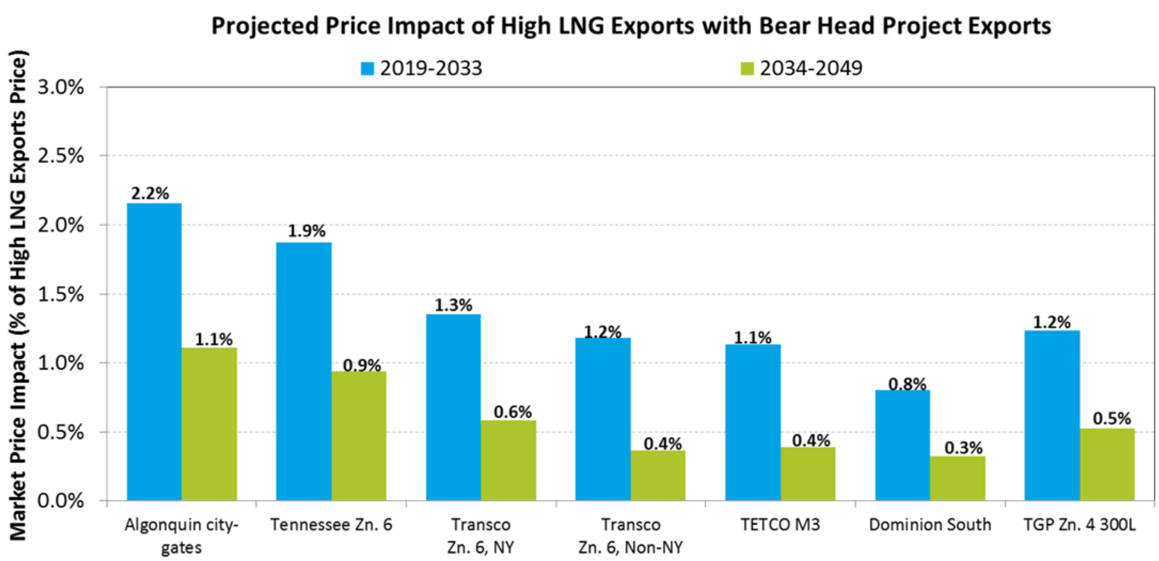


Figure 2: Projected Northeast Market Price Impact – Base Case



In addition to our *Base Case* analysis, Black & Veatch ran stress test scenarios which included higher LNG export volume in the U.S. Gulf Coast and Eastern Canada, in addition to the Bear Head LNG Project export volume. The Northeast price impact is still limited, as shown in Figure 3.

Figure 3: Projected Northeast Market Price Impact – High LNG Exports



Summary Conclusions

Black & Veatch's assessment demonstrates that the proposed Bear Head Project has a limited impact on natural gas prices across the Northeast, 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*. This 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 Algonquin city-gates throughout the analysis period is about 1.4% on average when compared to the *Base Case*. The Bear Head Project is expected to have the a minimal price impact across Northeast market, with price increases at Transco Zn. 6, Non-NY ranging from 0.9% from 2019-2034 and 0.2% from 2035-2049 when compared to the *Base Case*.

As seen through a comparison of results from the *High LNG with Bear Hear Project Exports* scenario stress test, exports from the Bear Head Project result in a slightly increased, but minor, impact on Northeast prices than observed in the *Base Case* in both absolute and percentage terms.

Overall, 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.

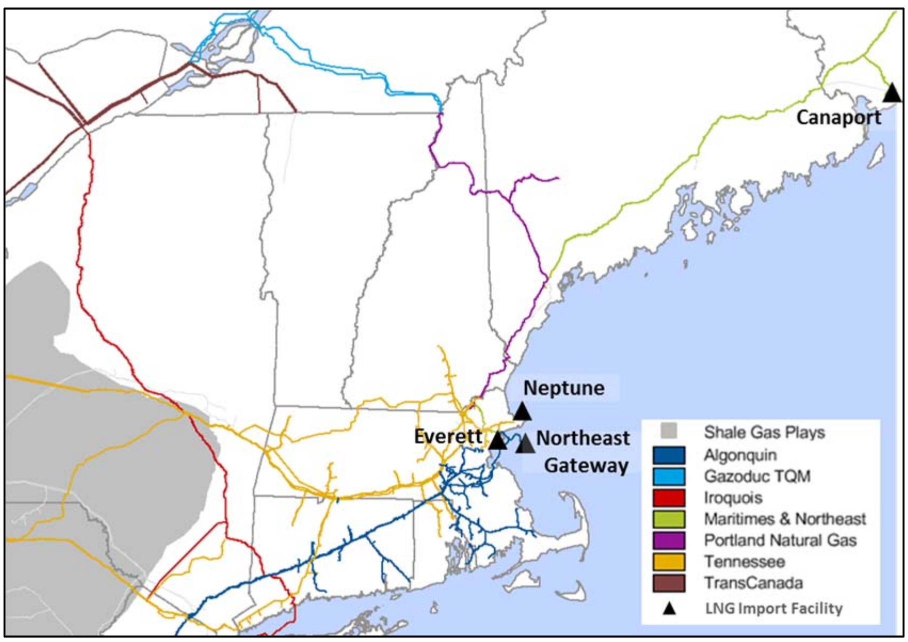
Additional offshore Nova Scotia oil and gas resources are at various exploratory stages of development. Black & Veatch did not incorporate these exploratory gas resources as part of this analysis, but if and when these resources are produced, the Bear Head Project is well positioned to utilize these resources as a potential feed gas alternative to U.S and Western Canadian supply. This could further reduce the price impacts in New England and Lower 48 natural gas prices. The on-going development of storage in Nova Scotia could also dampen regional price spikes, and the impact of the Bear Head Project, while bringing additional benefits to New England energy consumers.

3.0 Overview of the New England Natural Gas Market

The New England natural gas market is currently characterized as one of the most constrained gas markets in North America. With steady natural gas demand growth over the past fifteen years, interstate pipeline flows into the New England market have risen during peak winter and summer months to meet the needs of LDCs, power generators and industrial consumers. Unlike the Mid-Atlantic markets, New England does not have any local gas production, or abundant gas storage resources to mitigate seasonal peaking demand.

New England currently relies upon five interstate pipelines (Algonquin Gas Transmission, Iroquois Gas Transmission System, Portland Natural Gas Transmission System, M&NP, and Tennessee Gas Pipeline) and imported liquefied natural gas from the Everett and Canaport LNG terminals to serve its regional gas consumers. See Figure 4. From these five interstate pipelines, New England gas consumers can reach Canadian supply sources in the Western Canadian Sedimentary Basin, or Eastern Canada, and Lower 48 supplies from the Gulf Coast, Mid-Continent, and Appalachian basins.

Figure 4:North American Pipelines that serve the New England Market

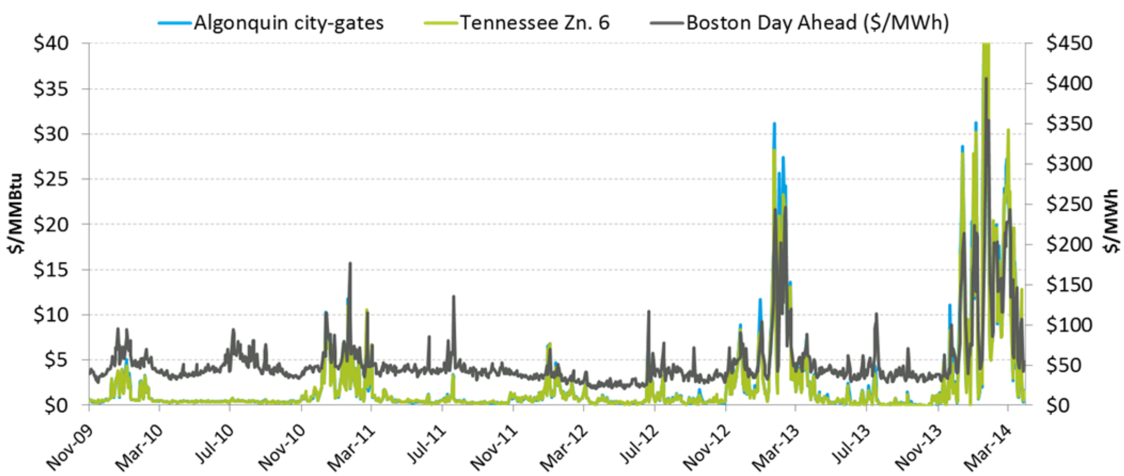


In prior years, LNG imports at the Canaport and Everett LNG terminals have been able to provide additional seasonal supplies, offsetting the need to construct incremental interstate pipeline capacity to import from western supply basins. However, global LNG prices in Europe, South America and Asia have become more lucrative markets for spot LNG cargoes than the New England market and LNG is no longer an abundant supply source in the region. Northeast Gateway and Neptune LNG terminals are also operational import facilities, but in recent years, have not received significant LNG cargoes.

The New England winter price basis reached unprecedented levels during the 2013-2014 winter heating season. Algonquin city-gates and Tennessee Zn. 6 spot prices have spiked over the last several winters, exceeding $40/MMBtu this past year. While most residential and commercial gas consumers that are served by the local distribution companies were for the most part unaffected by the price spikes, New England electric consumers felt the impact on day-ahead electric prices.

In the electric markets, during peak winter periods, gas-fired generation is often the fuel that sets the locational marginal price ("LMP"). New England power generators that do not hold firm pipeline capacity, rely upon interruptible capacity on the interstate pipelines to deliver gas supplies to the generator. As price spikes occur, the cost of that last unit of pipeline capacity and gas supply increases for the power generator, translating to a higher cost to produce each megawatt hour of power. As seen in Figure 5, the Boston day-ahead LMP prices closely follow the gas price basis at Algonquin city-gates and Tennessee Zn. 6 during peak winter periods. The 2013-2014 Winter price blowouts caused New England utilities to increase electric rates in 2015 by 23.6 to 37.0 percent.[1]

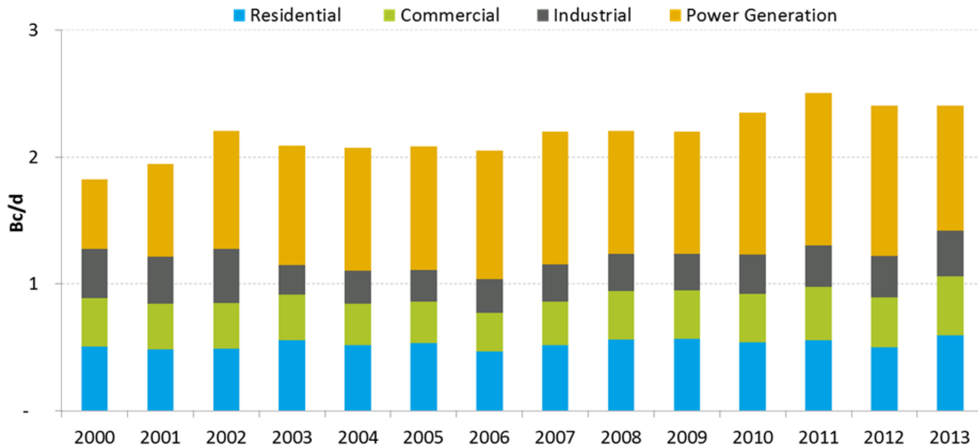
Figure 5: Historical New England Energy Price and Daily Basis (Nov 2009 – March 2014)



The lack of available pipeline capacity for gas-fired generation raises electric reliability concerns for New England as it becomes more reliant on natural gas as a fuel source. As seen in Figure 6, the natural gas demand in New England has grown since 2000 at a CAGR of 2.2% over the period.

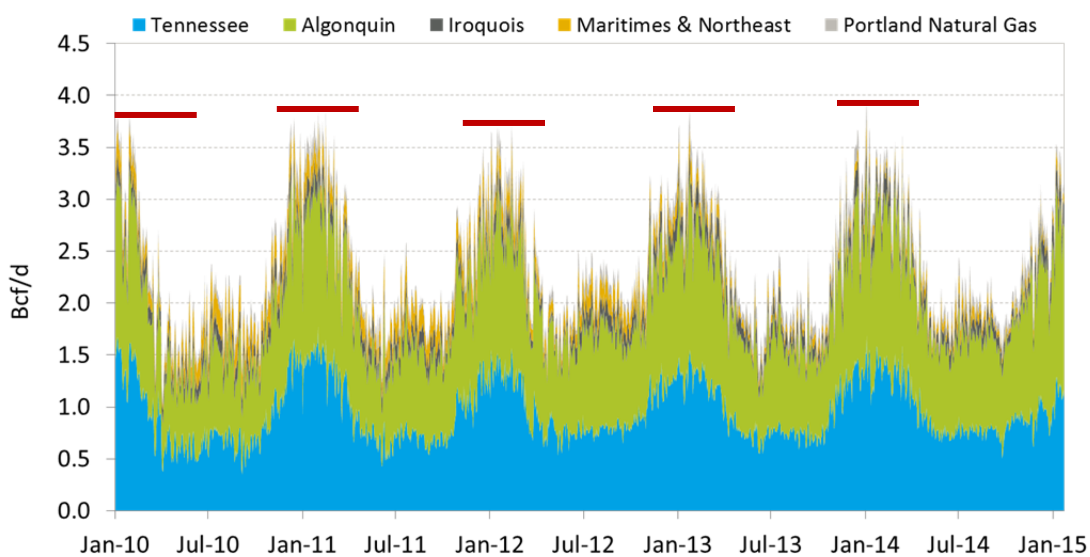
[1] http://instituteforenergyresearch.org/electricity-rate-increases-begin-new-england/

Figure 6: Historical New England Annual Average Demand (2000-2013)



The increase in natural gas demand is further complicated with increased peak day demand. As seen in Figure 7, Black & Veatch used daily interstate pipeline data as a proxy for peak demand, which reached 3.95 Bcf/d during 2013-2014 winter. The growth on peak day demand for LDCs will signal the need to subscribe for incremental pipeline capacity or invest in additional LNG peak shaving facilities.

Figure 7: Daily Interstate Pipeline Deliveries into New England



4.0 Projected Need for Incremental Pipeline Capacity

Over the past few years, New England states' regulators, power generators and regional transmission organizations have begun studying the gas-electric reliability issues and their impacts on electric consumers. Recent studies and analyses like the New England State Committee on Electricity ("NESCOE") and Massachusetts Department of Energy Resources ("DOER") report indicate that incremental pipeline capacity is needed and is a viable long-term solution to the problems facing New England.

NESCOE Observations on New England Natural Gas Infrastructure[2]

NESCOE commissioned a three-phase study to understand the regional infrastructure constraints related to gas-fired power generation in the New England area. The study focused on gas-electric reliability, including the extent and duration of regional congestion related to pipeline capacity. As short-term solutions, NESCOE suggests Spectra's Algonquin Incremental Market ("AIM") pipeline, LNG import terminals and dual-fuel generators will be a sufficient solution to reduce high gas prices. In the long term, NESCOE believes an additional incremental pipeline would offer the most economic net benefit to New England electricity customers, as it would reduce the likelihood of natural gas price spikes across the region, and the corresponding electric price spikes during peak winter months.

Massachusetts DOER Low Gas Demand Study[3]

In January 2015, Synapse Energy Economics released a report commissioned by the Massachusetts DOER detailing the expected gas shortage through 2030. The report focused on potential low demand scenarios that assumed the maximum feasible amount of alternative resources would be available, curtailing gas demand. In some cases additional electric transmission was assumed to displace gas demand in Massachusetts. Across all scenarios, gas shortages in Massachusetts ranged from 0.6 Bcf/d to 0.8 Bcf/d in 2020 and 0.6 Bcf/d to 0.9 Bcf/d in 2030 furthering the need for additional pipeline infrastructure.

Base Case Pipeline Capacity Additions into New England

In an effort to meet the demand for additional pipeline capacity in the region several pipeline expansion projects have been proposed designed to deliver incremental natural gas supplies into the New England market to serve both LDC and power generation demand. The *Base Case* includes Spectra's AIM project, Kinder Morgan's Northeast Energy Direct project, Spectra's Atlantic Bridge and Access Northeast projects. Each project has obtained interest from various stakeholders in the region and offers unique benefits to shippers. 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 that would increase the contracted billing determinants and reduce the overall cost of the pipeline projects to New England LDCs and power generators. Overall,

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[2] http://www.nescoe.com/uploads/Notice_of_Issuance_G-E_Study_Sept_9_2013.pdf
[3] http://synapse-energy.com/sites/default/files/Massachusetts%20Low%20Demand%20Final%20Report.pdf

incremental pipeline capacity additions into New England will reduce the frequency and magnitude of price spikes during the winter, when gas demand levels are at their peak.

Spectra's AIM project is expected to be in service by November 2016, and 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. (*See* FERC Docket No. CP14-96-000). 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

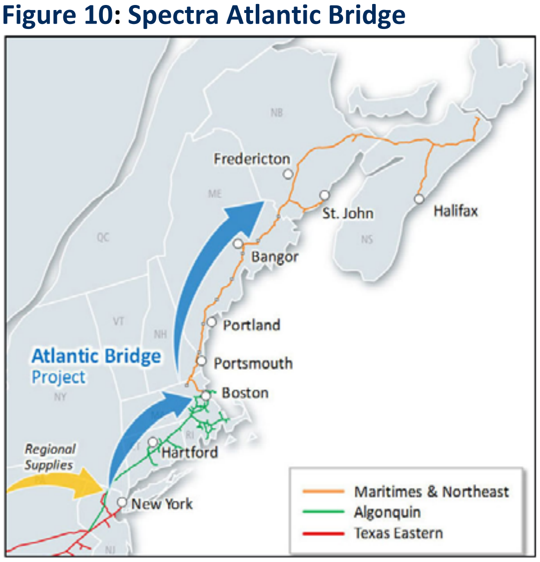
Kinder Morgan's Northeast Energy Direct project will extend from the Marcellus Shale along existing Tennessee Gas Pipeline right-of-way across New York and Massachusetts and into Dracut. As depicted in Figure 9, the project is currently in the pre-filing process with the Federal Energy Regulatory Commission ("FERC") and 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. (*See* FERC Docket No. PF14-22-000) 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 include Berkshire Gas Company, Columbia Gas of Massachusetts, Connecticut Natural Gas, Liberty Utilities, National Grid, and Southern Connecticut Gas, and have signed binding agreements for a combined total of 0.5 Bcf/d of 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 Energy proposes to expand the Algonquin and M&NP to deliver additional supplies to New England and the Maritimes Provinces, as shown in Figure 10. The Atlantic Bridge project is moving forward as a request to commence the pre-filing process was submitted with FERC on January 30, 2015. (*See* FERC Docket No. PF15-12-000). 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



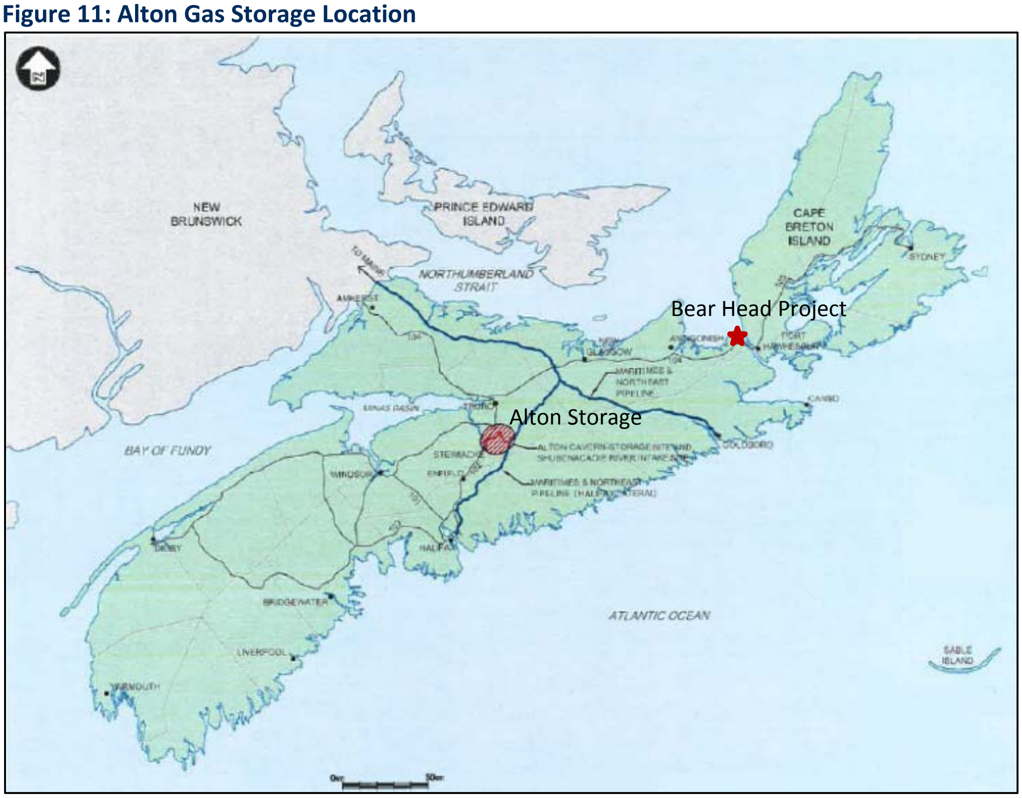
Source: Spectra

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 has not yet submitted a request with FERC for approval of pre-filing review but would consist 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.

Availability of Underground Storage in Nova Scotia

In addition to the proposed incremental pipeline capacity, the Bear Head Project would be able to access to 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 capacity of the first three caverns could have a total working gas capacity of 3.8 Bcf and may develop as many as 10 to 15 caverns at a later date. The pipeline lateral from Alton will interconnect with Maritimes and Northeast Halifax Pipeline. See Figure 11 below.

Figure 11: Alton Gas Storage Location



Source: AltaGas

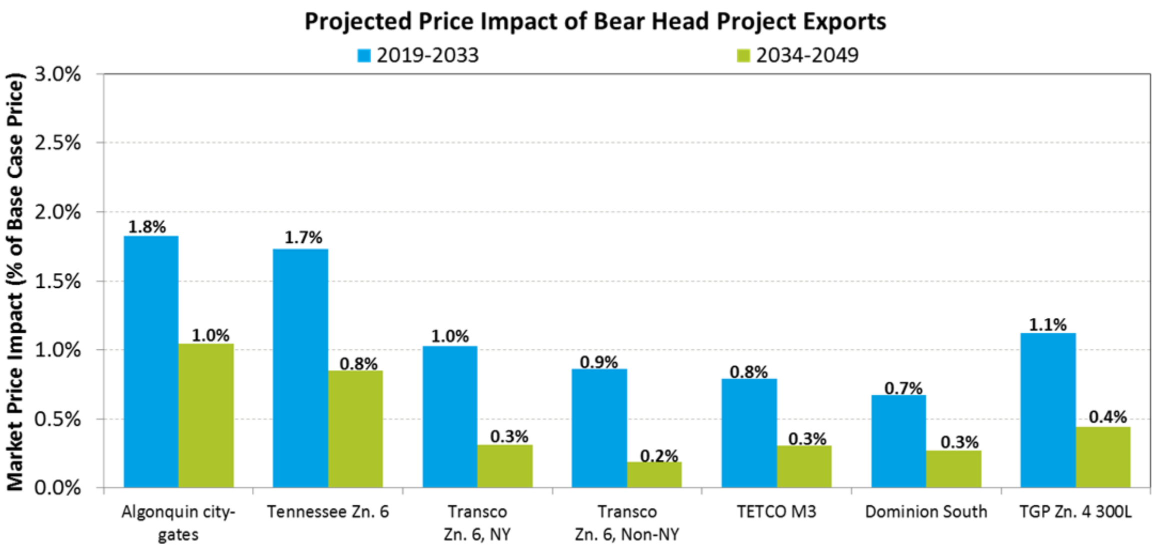
Overall, additional underground gas storage in Nova Scotia could also help mitigate winter price spikes during the coldest days of the year in New England. Summer storage injections of Nova Scotia, U.S., or other Canadian production and winter storage withdrawals will dampen winter seasonal price spreads in the M&NP and New England markets. The availability of additional winter supplies 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. The Project could purchase additional summer feed gas supplies when New England and Lower 48 demand is much lower and pipeline capacity to Dracut is more readily available, to inject into storage and then withdraw them on peak winter days, reducing the potential market impact on natural gas prices.

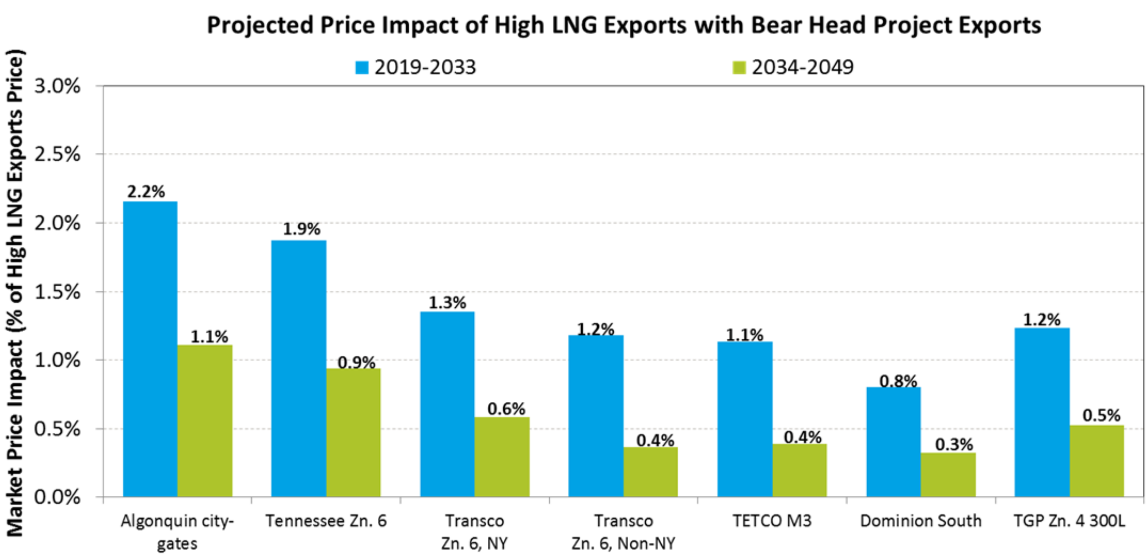
5.0 Northeast Market Price Impacts

Black & Veatch's independent assessment examined the Northeast U.S. 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 directly in New England or regionally in the Northeast during the analysis period, as shown in Figure 12.

The projected market price impact of the Bear Head Project is expected to be higher in New England and smaller across the other Northeast pricing points further from the Bear Head Project, as shown in Figure 12.

Figure 12: Projected Market Price Impact across Pricing Points





At Dominion South, the market price impact is muted because of 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 $0.02/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 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 because of 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 Bear Head 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-M3 represent gas delivered to the Northeast markets that stem from Northern Virginia to New Jersey. The Bear Head Project's price impact at these locations is slightly greater than at upstream points like Dominion South because of 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.