NATURAL GAS INFRASTRUCTURE AND ELECTRIC GENERATION: PROPOSED SOLUTIONS FOR NEW ENGLAND

B&V PROJECT NO. 178511

PREPARED FOR

The New England States Committee on Electricity

26 AUGUST 2013

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1.0 Executive Summary

KEY OBSERVATIONS AND ANALYSIS RESULTS

Black & Veatch completed a three-phase study to evaluate sufficiency of gas infrastructure to support electric-power generation in New England for the years 2014-2029

Phase I reviewed published studies on New England's natural gas infrastructure to identify any information gaps leftover from work by other analysts. In Phase I, Black & Veatch concluded that New England's natural gas infrastructure will become increasingly stressed as regional demand for natural gas grows, leading to infrastructure inadequacy at key locations. Phase II developed scenarios for further analysis based on historical gas demand, electric-generation responses and anticipated supply and demand growth for next 15 years. Phase III, as delivered in this report, analyzed alternative scenarios to establish cost-benefit relationships.

In the absence of infrastructure and demand reduction / energy efficiency / non-natural gas-powered distributed generation solutions, New England will experience capacity constraints that will result in high natural gas and electric prices; as noted below, in a Low Demand Scenario, no long-term infrastructure solutions are necessary

Quantitative analyses by Black & Veatch confirmed findings reached previously from review of published reports regarding insufficiency of natural gas infrastructure to support reliable and affordable electric-power generation in New England. Using integrated modeling of natural gas and electric-power markets, separate analyses of a Base Case (most likely outcome from current outlooks), a High Demand Scenario (increased gas use through market and policy drivers) and a Low Demand Scenario (flat or declining gas use across all sectors) provided indications of future price and price-volatility trends in the absence of solutions to infrastructure deficiencies.

Because most natural gas-fired power generation capacity in New England is not supported by firm transportation contracts on natural gas pipelines, the cost of gas-fired power generation is closely tied to wholesale natural gas prices. Therefore, New England's electricity prices across all ISO New England (ISO-NE) zones are highly correlated with regional wholesale natural gas prices that are represented by distribution points known as Algonquin Pipeline City-Gates. Traditionally, gas price movements in New England have been tracked as the "basis" difference between the Algonquin City-Gates price and the national benchmark price defined at the Henry Hub in Louisiana. Black & Veatch adopted the Algonquin City-Gates basis as the principal measurement of price movements in analyses of the Base Case, High Demand Scenario, Low Demand Scenario and for selected short-term and long-term solutions to infrastructure constraints.

In the Base Case, which assumes electric load growth as projected by ISO-NE and 1.2% gas-demand growth annually across all user sectors, the Algonquin City-Gates basis is projected to continue winter peaks averaging $3.00 per million British Thermal Units ("MMBtu") on a monthly timeframe and could exceed $9.00-$10.00/MMBtu on a daily basis through the winter of 2015-2016. Additional capacity provided by the Algonquin Incremental Market

("AIM") pipeline expansion, to be in service in 2016, is expected to moderate the basis for 5-6 years; monthly average basis with AIM in service falls below $2.50/MMBtu (and toward $1.00/MMBtu) and daily volatility is greatly reduced from 2017-2022. Significant basis increases (in the range of $3.00-$4.00/MMBtu) and highly volatile daily pricing during winter months are projected to return in the winter of 2022-2023 as demand grows to outpace natural gas delivery capacity serving the region. Monthly average electricity prices range from $40 to $60 per megawatt-hour ("MWh") when the natural gas market is not constrained but rise to $70 to $80/MWh during the constrained months. Those high and volatile price outcomes are implied even though it was further assumed in the Base Case that renewable portfolio standard ("RPS") targets are fully met and energy-efficiency initiatives are successful.

The High Demand Scenario adopts most of the Base Case assumptions but adds stress to the system by assuming a 1.7% per year growth of gas demand, shortfalls in achieving RPS targets and early retirement (by five years) of nuclear power plants. In the High Demand Scenario, natural gas basis and electricity prices exhibit a pattern similar to the Base Case but with higher gas prices. Specifically, the monthly basis is expected to be $2.00-$4.00/MMBtu higher and daily prices $3.00-$5.00/MMBtu higher than in the Base Case. Likewise, monthly average electricity prices are expected to be $15-$20/MWh higher than in the Base Case. Elevated prices are anticipated even though a further assumption makes the Maritimes & Northeast Pipeline ("M&NP") capable of reverse flow on an economic basis to meet demand growth from Maine and Maritimes Canada.

Both in the Base Case and High Demand Scenario, New England could face significant reliability issues when natural gas-fired power generators are not able to dispatch as a result of the gas pipeline capacity constraints. The interim capacity relief expected from the expanded AIM and reversible M&NP pipelines, along with RPS and energy-efficiency achievements, will be overwhelmed by demand growth on or about the year 2022, and higher-priced supply source from Eastern Canada are introduced.

In the Low Demand Scenario, infrastructure solutions are not needed or justified. The Low Demand Scenario is predicated largely on substantial, ongoing gains in natural gas and energy efficiency, and other demand-side management programs, non-natural gas-powered distributed resources, and RPS, which result in retreat from expanded use of natural gas across all sectors.

Gas-supply requirements driven by episodes of extremely cold weather can be very costly and create significant reliability risks – they aggravate infrastructure deficiencies

Black & Veatch confirmed through analysis that gas demand is highly sensitive to requirements placed on reliable delivery of gas to customers, including any prescriptions for firm deliverability under highly stressful winter weather conditions. To simulate on a broad scale the deliverability requirements faced by local distribution companies ("LDCs"), Black & Veatch structured a design-day scenario to mimic the potential impact of an episode of extremely cold weather in New England. Model analysis of the hypothetical cold event, based on statistically extreme days in winter weather records for New England, indicated that higher natural gas and electricity prices would cost New England consumers an additional $21 million per day compared with the High Demand Scenario and $24 million a day more when compared with the Base Case. Both the Base Case and the High Demand Scenario assumed normal (long-term average) winter weather.

In addition, under the design-day criteria, New England could face a supply deficiency of approximately 500 million cubic feet per day ("MMcf/d") of natural gas in the absence of infrastructure resiliency and capacity/delivery-related solutions, thereby creating serious reliability concerns for the regional electric power supply.

Short-term solutions (2014-2016) provide net benefits to New England customers

Although long-term solutions are required to satisfy needs for gas-fired power reliability through 2029, more immediate relief is available from short-term solutions. Dual-fuel generation (involving fuel oil as the second fuel) and demand response, as well as short-term purchases of liquefied natural gas ("LNG"), could offer sizeable benefits in the near-term, considering that infrastructure constraints are expected to occur throughout New England until AIM commences service in late 2016.[1]

Dual-Fuel and Demand Response together would add 2.3 million MWh of dual-fuel, fuel-oil-fired generation coupled with demand response across New England. LNG Imports would add 300 MMcf/d of gas imports to existing LNG receiving terminals in Saint John, New Brunswick, Canada (Canaport) and Everett, Massachusetts, during the peak winter months of January and February.

Short-term solutions represent an option that could be executed on a year-to-year basis. Under the Base Case, the LNG imports solution provides an average benefit of $96-$138 million per year depending on the contract terms with LNG suppliers while the dual-fuel generation and demand response solution provides a net benefit of $101 million per year. The chart shown below summarizes year-by-year performance of benefits for the short-term solutions.

[1] Dual-fuel, oil-fired generators must comply with increasingly stringent emission standards in order to be permitted, which may influence the extent and duration of some dual-fuel units' ability to contribute to a short-term solution.

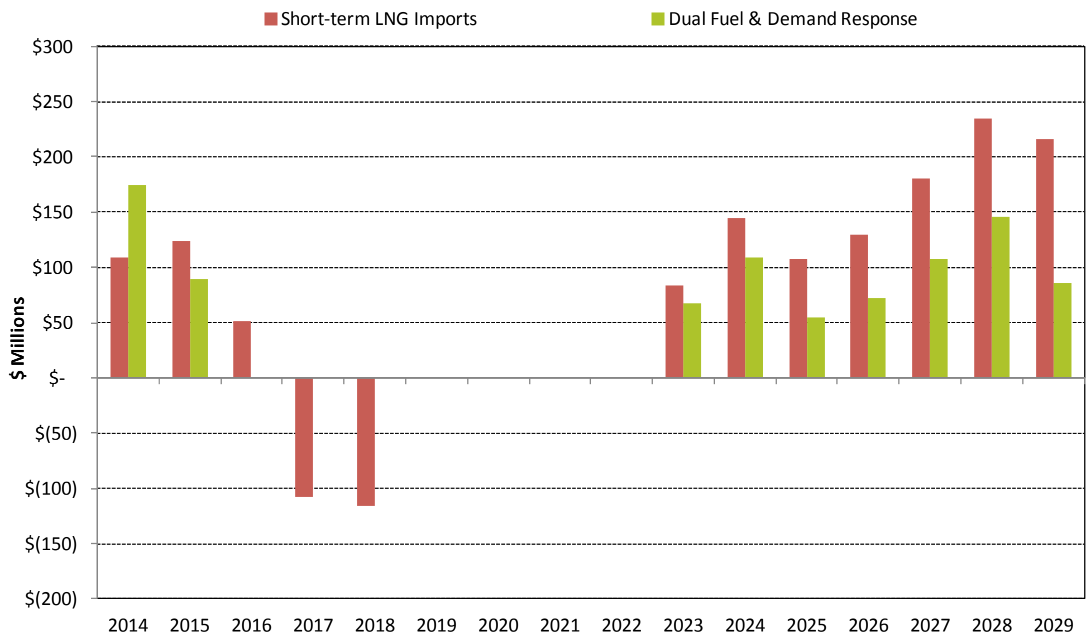

Figure 1 Net Benefits for the Short-Term Solutions

In the absence of greater demand reduction / energy efficiency/ non-natural gas-powered distributed generation solutions, a Cross-Regional Natural Gas Pipeline solution presents higher net benefits to New England consumers than do alternative long-term solutions (2017-2029)

Black & Veatch examined three different long-term solutions for natural gas infrastructure deficiencies, including a major new gas pipeline across New England and two different approaches to importing electricity from eastern Canada. The pipeline solution would address the needs of direct gas users as well as gas-fired generators whereas the imported-electricity options would address deficiencies in electricity supplies and provide relief to gas users as a result of demand reduction from gas-fired generators.

A Cross-Regional Natural Gas Pipeline, with new capacity of 1,200 MMcf/d with a projected in-service date of 2017, would originate at the existing Tennessee Gas Pipeline and Iroquois Pipeline interconnect in Schoharie County, New York, and terminate at Tennessee Gas Pipeline's interconnect with Maritimes & Northeast Pipeline in Middlesex County, Massachusetts. This pipeline is assumed to access gas supplies from existing capacity on the Tennessee and Iroquois pipelines as well as from the proposed Constitution pipeline which is expected to commence service in early 2015. Gas production is expected to come principally from the Marcellus Shale. Black & Veatch estimates that the Cross-Regional Natural Gas Pipeline could be constructed for approximately $1.2 billion. Assuming that 100% of its capacity is contracted, the pipeline could potentially offer a 100% load factor transportation rate of $0.45/MMBtu/day.

An Economic-Based Canadian Energy Imports solution would involve construction of a new electric transmission line capable of importing 1,200 megawatts ("MW") of mainly hydro-electric energy from eastern Canada beginning in 2018. The energy imported by New

England would be based upon the energy needs and price differentials between New England and alternative markets. Black & Veatch estimates a construction cost of $1.1 billion for this new transmission line. Levelized over 20 years, the annual cost of service for this project is estimated to range from $180 to $219 million.

A Firm-Based Canadian Energy Imports solution also would employ a new 1,200-MW electric transmission line from eastern Canada but coupled with energy sales in New England through firm contracts (rather than variable spot markets) that would incent development of additional generation capacity. The construction of power-generation facilities in Hydro Quebec would cost $170 million per year in addition to the previously stated cost of the transmission line.

In the long-term, both the Cross-Regional Natural Gas Pipeline and the Economic-Based Energy Imports solutions offer significant benefits in eliminating market constraints even though they incur near-term losses from capital investments in new infrastructure. However, the benefits offered by the Cross-Regional Natural Gas Pipeline solution are substantial and increase significantly over time. In the Base Case, the Cross-Regional Natural Gas Pipeline offers an average annual net benefit of $118 million per year, almost twice the net benefits contributed by the Firm-Based Canadian Energy Imports solution. In the High Demand Scenario, the Cross-Regional Natural Gas Pipeline can provide an average annual net benefit of $340 million per year compared to the $123 million per year average annual net benefit that could be obtained with the Firm-Based Energy Imports solution. The chart shown below summarizes year-by-year performance of benefits for the long-term solutions under the Base Case.

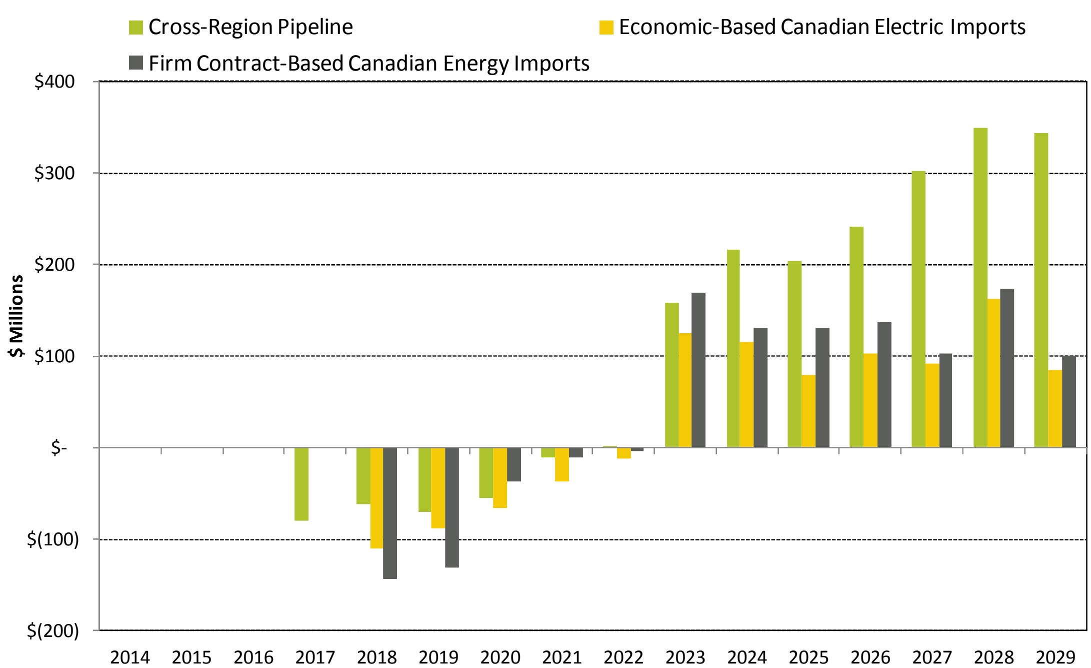

Figure 2 Net Benefits for the Long-Term Solutions

Under the Low Demand Scenario, the AIM project is able to successfully eliminate the short-term infrastructure constraints in New England and regional natural gas and electricity prices remain stable after AIM commences service. This scenario offers New England customers' average cost savings of $411 million per year compared with the Base Case. As no significant infrastructure constraints are observed under the Low Demand Scenario, none of the infrastructure solutions applied in other scenarios yielded a positive net benefit for the analysis period.

For most or all prospective solutions, the majority of the benefits apply to New England electric customers

Black & Veatch separately calculated the benefits to New England natural gas and electric customers as a result of infrastructure additions. For the Base Case, with the Cross-Regional Natural Gas Pipeline solution, $281 Million (95%) of the averaged benefits realized each year can be attributed to electric customers and $14 million (5%) to natural gas end-use customers. These results would follow from the general practice that LDCs typically contract for gas supplies at production basins and have firm pipeline capacity to transport supplies into New England while only limited amounts of gas are purchased at monthly or daily prices near or within New England. On the other hand, a majority of electric generators typically make fuel purchase and dispatch decisions based on regional daily prices and generally purchase gas delivered to a city-gate distribution point.

CONCLUSIONS AND RECOMMENDATIONS

Short-term and long-term solutions are needed to relieve the natural gas market constraints in New England under the Base Case and High Demand Scenario

Black & Veatch recommends that a combination of short-term (2014-2016) and long-term (2017 and later) solutions are necessary to address natural gas infrastructure deficiencies that place future reliability of electric-power generation at risk in New England.

Based on the findings of this report under the Base Case and High Demand Scenario, and assuming the study assumptions reasonably reflect future market conditions, Black & Veatch recommends the construction of a Cross-Regional Natural Gas Pipeline as a long-term solution. Through the construction of incremental pipeline capacity, this project has the potential relieve New England's gas-electric reliability issues through at least 2029.

As for short-term measures, Black & Veatch recommends a strategy that includes immediate deployment of dual-fuel generation, demand response measures and the seasonal purchase of LNG cargoes. Even after long-term solutions are in place, short-term solutions can be deployed to mitigate infrastructure constraints that occur from year-to-year and in specific New England sub-regions as a result of shifting demand loads and changes in area growth rates and weather.

No long-term infrastructure solutions are necessary under the Low Demand Scenario

Black & Veatch recommends that no long-term infrastructure solutions should be implemented should the Low Demand Scenario manifest.

Black & Veatch further recommends that the implementation of short-term solutions at a smaller scale than presented in this report should be considered to mitigate potential infrastructure constraints in the near term.

2.0 Introduction

PURPOSE

This report concludes the final phase of a three-phase study commissioned by the New England States Committee on Electricity ("NESCOE") to assess the adequacy of New England's natural gas infrastructure to serve the region's growing electric generation needs (Figure 3). This report was developed from key findings in the earlier two phases:

- Phase I (December 2012): Black & Veatch concluded from review of available analyses that New England's natural gas infrastructure is not adequate to serve the electric sector, and identified information gaps that should be filled to better inform policymakers.
- Phase II (April 2013): Black & Veatch assessed the natural gas infrastructure adequacy of fourteen New England sub-regions, estimated the duration and magnitude of potential capacity constraints for each sub-region and defined three scenarios for analysis of future supply and infrastructure stresses. Summary-level estimates of costs were presented for a range of potential solutions to supply and infrastructure deficiencies.

This report presents Black & Veatch's findings regarding the cost and benefits of potential infrastructure solutions.

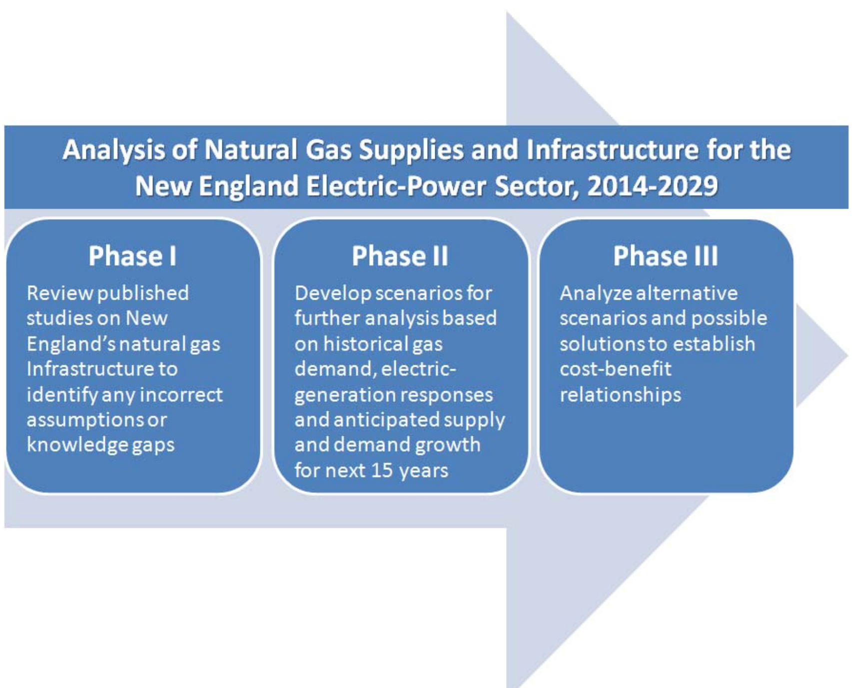

Figure 3 Organization of the Three-Phase Study

The analysis methodology (Section 3.0) and major assumptions (Section 4.0) are explained before results are presented (Sections 5.0, 6.0, 7.0, 8.0, and 9.0). Section 10.0 summarizes conclusions and recommendations.

SCENARIOS FOR EVALUATING ALTERNATIVE OUTCOMES

Black & Veatch found in Phase I that ***New England's natural gas infrastructure will become increasingly stressed as regional demand for natural gas grows, leading to infrastructure inadequacy at key locations***. Therefore, in Phase II scenarios were developed to support quantitative elaboration of future stresses on the supply and infrastructure to deliver natural gas to electric-power generators (Table 1). Phase III presents results of detailed modeling regarding these scenarios.

All scenarios addressed combined effects of the respective drivers in the electric-power and natural gas market segments. The **Base Case** represents Black & Veatch's view of the most likely development scenario given current demand growth, economic and regulatory outlooks. It forms the basis for crafting solutions for the supply and infrastructure deficiencies. For comparison, a **High Demand Scenario** accommodates higher than current demand growth, especially for gas, along with lags in other types of power sources. Lastly, a **Low Demand Scenario** examines overall weak growth in power and gas demand.

Table 1 Key Assumptions in Natural Gas Planning Scenarios

FUNDAMENTAL FACTOR	BASE CASE	HIGH DEMAND SCENARIO	LOW DEMAND SCENARIO
	Electric Power Drivers		
Load Growth	As projected by the 2013 ISO-NE Forecast Report of Capacity, Energy, Loads and Transmission 2013 – 2022 (CELT)	Same as Base Case	Limited demand growth
Energy Efficiency	As projected by the 2013 ISO-NE Forecast Report of Capacity, Energy, Loads and Transmission 2013 – 2022 (CELT)	Energy Efficiency declines slightly from the Base Case, leading to slightly higher load growth	Completely offsets load growth
Renewable Portfolio Standards (RPS)	Each New England state meets 100% of its RPS target	Each New England state meets 75% of its RPS target	Same as Base Case
Environmental Policy	No stricter regulations on hydraulic fracturing; Federal GHG emissions program in 2020	Same as Base Case	Same as Base Case
New England Generation Capacity Changes	Nuclear deactivation occurs between 2032-2035; Later period capacity additions	Nuclear deactivation occurs between 2027-2030	Same as Base Case

FUNDAMENTAL FACTOR	BASE CASE	HIGH DEMAND SCENARIO	LOW DEMAND SCENARIO
Natural Gas Drivers			
Demand Growth	Residential, Commercial and Industrial (R-C-I) demand growth of 1.6% per year	High R-C-I demand growth, at 2.2%, with policy incentives	No demand growth
LNG Exports	Exports from Gulf Coast and West Coast	Additional 4 Bcf/d of export from the Gulf Coast and West Coast	Same as Base Case
Pipeline Infrastructure	Algonquin Incremental Market (AIM) expansion in-service by 2016	AIM in-service by 2016 Maritimes & Northeast Pipeline (M&NP) can reverse flow on an economic basis to meet demand growth from Maine and Maritimes Canada	Same as Base Case
Natural Gas Supply	Marcellus grows at 6% per year; Eastern Canadian production increases sharply in 2014 to >350 MMcf/d and then gradually declines through 2020	Same as Base Case	Same as Base Case
LNG Imports	Everett MA (Distrigas) supplies will sharply decline relative to 2011 but gradually increase starting in 2019 Saint John NB Canada (Canaport) supplies will decline after firm supply contract expires in Oct 2013	Same as Base Case	Same as Base Case

SOLUTIONS FOR INFRASTRUCTURE DEFICIENCIES AND SENSITIVITES

In Phase III, Black & Veatch tested infrastructure solutions associated with each scenario and selective sensitivities related to weather and demand growth. Both short-term and long-term solutions were considered. Some prospective solutions involved increases in natural gas supply while other solutions involved reductions to natural gas demand. An overview of these solutions is presented in Figure 4 and Table 2.

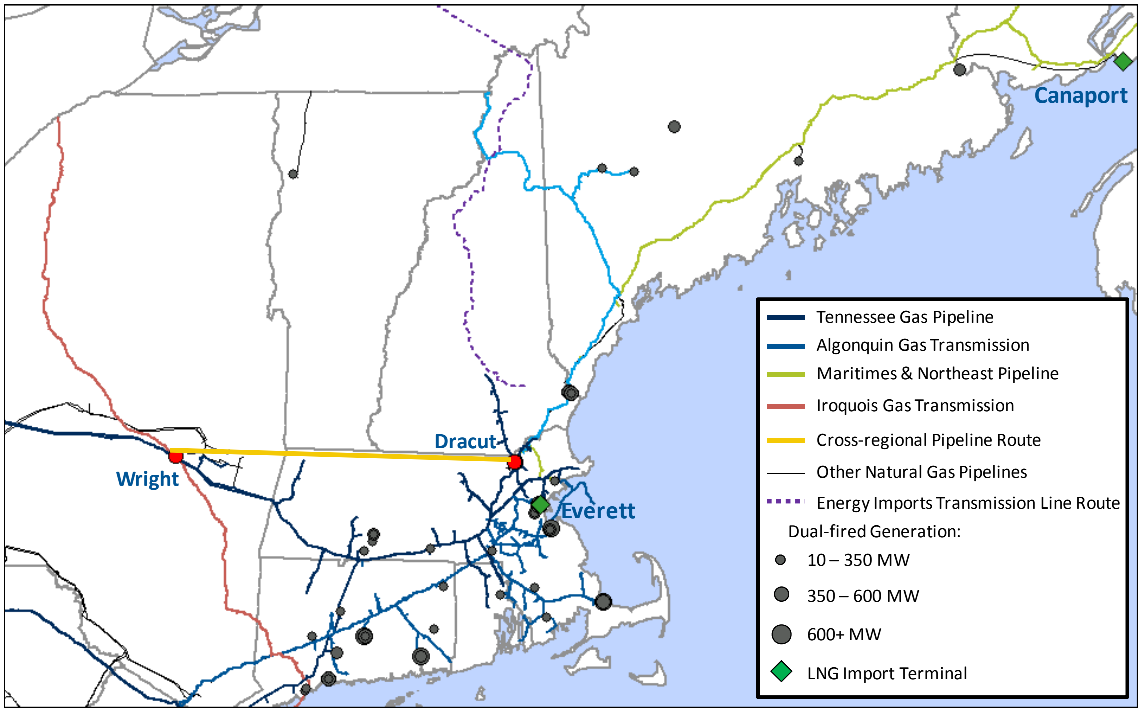

Figure 4 Map of Solutions Evaluated Under All Three Scenarios

Table 2 Solutions Evaluated for Resolving Natural Gas Infrastructure Deficiencies and Sensitivities

	BASE CASE	HIGH DEMAND SCENARIO	LOW DEMAND SCENARIO
Long-Term Solutions	Cross-Regional Natural Gas Pipeline	Cross-Regional Natural Gas Pipeline	LNG Peak Shaving Facilities
	Firm-Based Energy Imports (firm-contracted electricity from eastern Canada)	Firm-Based Energy Imports	Firm-Based Energy Imports
	Economic-Based Energy Imports (market-driven electricity from eastern Canada)		
Short-Term Solutions	LNG Imports	LNG Imports	
	Dual-Fuel Generation and Demand Response		Dual-Fuel Generation and Demand Response
Additional Sensitivities		Design Day	Negative Demand Growth

3.0 Model Approach

OVERVIEW

In Phases I and II, Black & Veatch concluded that, in the absence of infrastructure solutions, natural gas infrastructure constraints are expected to occur across New England for significant periods of time, sometimes exceeding 60 days per year for some sub-regions. These findings are based on reviews of existing literature[2] on this topic and analyses of historical data on pipeline flows and natural gas prices. Phase III analyses were structured to further confirm those findings. Market simulation models were used to understand effects of constraints on natural gas and electricity prices as well as costs and benefits of alternative solutions.

Understanding the economic relationships between the electric and natural gas markets in New England requires application of models that address a large number of factors. The modeling process has to be executed in a fashion that considers supply and demand fundamentals for one commodity will affect fundamentals and price of the other.

INTEGRATED MARKET MODELING

Black & Veatch utilized an Integrated Market Modeling ("IMM") process to generate wholesale market prices for natural gas[3], and wholesale Locational Marginal Price ("LMP") at eleven New England transmission zones. GPCM™ was used to model the natural gas market while PROMOD, was used to model the electric market. Model runs were executed in an iterative fashion to ensure consistent results, as illustrated in Figure 5.

Black & Veatch used this IMM process to estimate the price impact of natural gas infrastructure constraints on natural gas and electric markets. As modeled, natural gas infrastructure constraints result in acute natural gas price increases during winter months, which are then reflected in the assumptions of the electric market model, leading to increased electric prices.

The IMM process involves detailed market projections across the North American energy market to take into account any market activity that could affect New England. For example, high growth in demand across North America could increase the cost of New England supplies or even divert supplies away from New England. A fundamental model that only simulates the New England Energy market would not incorporate such issues.

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[2] In Phase I, Black & Veatch reviewed 35 publicly-available reports: 18 by natural gas companies or gas industry associations; 4 by natural gas suppliers (producers, LNG importers); 4 by electric-power generation companies; 5 by the New England Independent System Operator (ISO-NE); 2 by the Federal Energy Regulatory Commission (FERC); 2 by the National Electric Reliability Corporation (NERC) and the Midcontinent Independent System Operator (MISO).

[3] This report focuses on natural gas prices reported at the Algonquin City-Gates pricing point. This point represents the wholesale price of natural gas delivered by Algonquin Gas Transmission to city-gate distribution points in Connecticut, Massachusetts, and Rhode Island, and is representative of wholesale prices across New England.

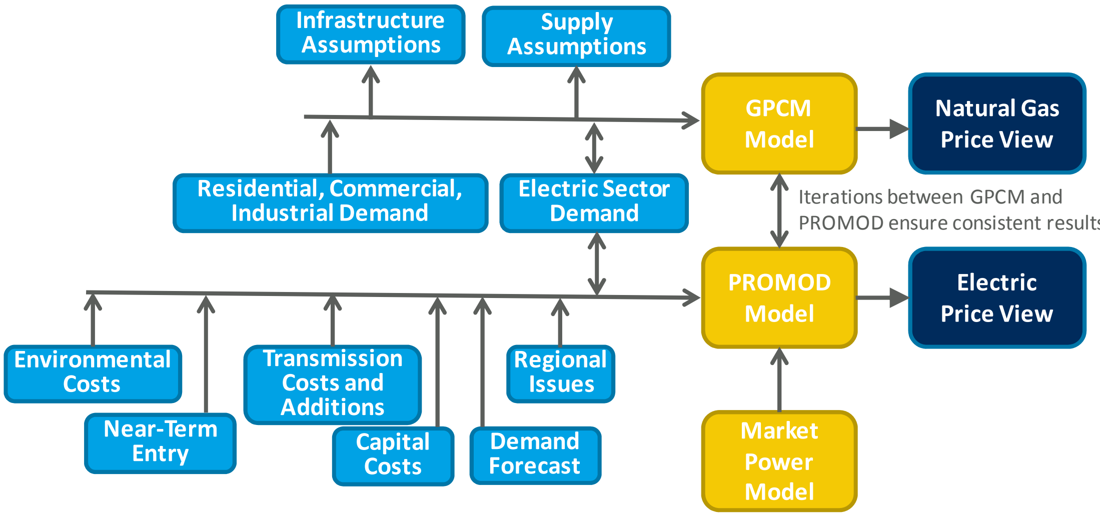

Figure 5 Integrated Market Modeling Process

ESTIMATION OF BENEFITS

The economic benefits offered by each solution were assessed from two perspectives: 1) benefits to natural gas end users and 2) benefits to electric customers. Figure 6 provides an overview of the analytical process used to assess these benefits. Again, the market interrelationships between power-generation economics and the economics of gas as a generation fuel make the estimation of benefits mutually interdependent for gas and power customers.

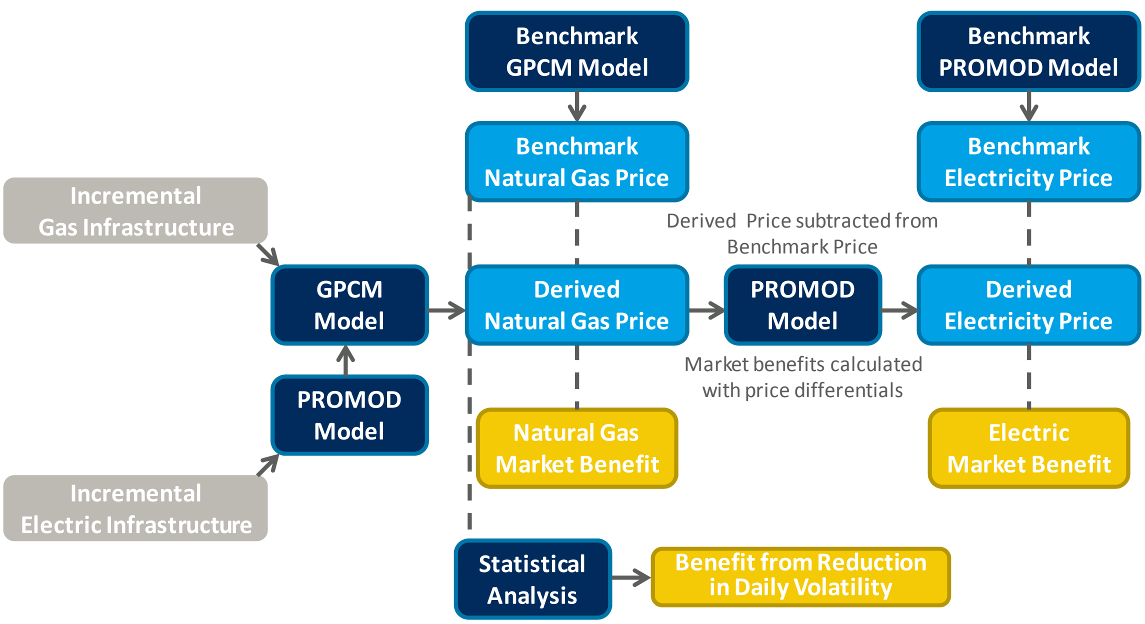

Figure 6 Analytical Process used to Assess Market Benefits

BENEFITS TO NATURAL GAS CUSTOMERS

Benefits to natural gas end-users, including residential, commercial, and industrial customers, are calculated by multiplying anticipated reductions in wholesale natural gas prices by consumption volumes affected by this price reduction. In general, most residential, commercial and industrial customers receive gas from local distribution companies ("LDCs"). LDCs are required to support their ultimate deliverability by contracting firm transportation capacity on natural gas pipelines and long-term supply purchases, so only limited amounts of "swing" supplies are purchased by New England LDCs at the region's prevailing wholesale market price as measured by Black & Veatch in this analysis using Algonquin City-Gates price point.

Given that infrastructure solutions are expected to have an immediate impact on wholesale natural gas prices, only the residential, commercial, and industrial consumption anticipated to be met with "swing" supplies was included in the calculation of benefits. Based on the estimates of Black & Veatch professionals, some of whom have managed LDC supply portfolios, this analysis assumes that 10% of industrial[4] and 3% of both residential and commercial winter demand are purchased as "swing" supplies at wholesale market prices. Under the Base Case, these volumes make up 19 to 25 billion cubic feet ("Bcf") per year.

BENEFITS TO ELECTRIC CUSTOMERS

Because most natural gas-fired power generation capacity in New England is not supported by firm transportation contracts on natural gas pipelines, the cost of gas-fired power generation is closely tied to wholesale natural gas prices. Therefore, New England's electricity prices across all ISO-NE zones are highly correlated with regional wholesale natural gas prices. Figure 7 illustrates the close historical connection between New England's electricity and natural gas wholesale prices at the Algonquin City-Gates, especially during winter months.

[4] This number is expected to vary from state to state. Results presented here in the report were calculated based on 10% of industrial demand. Separately, Black & Veatch calculated the benefits assuming 50% of industrial demand is priced at the regional pricing point, which would have the effect of increasing the benefits to natural gas end customers by less than $1 million per year.

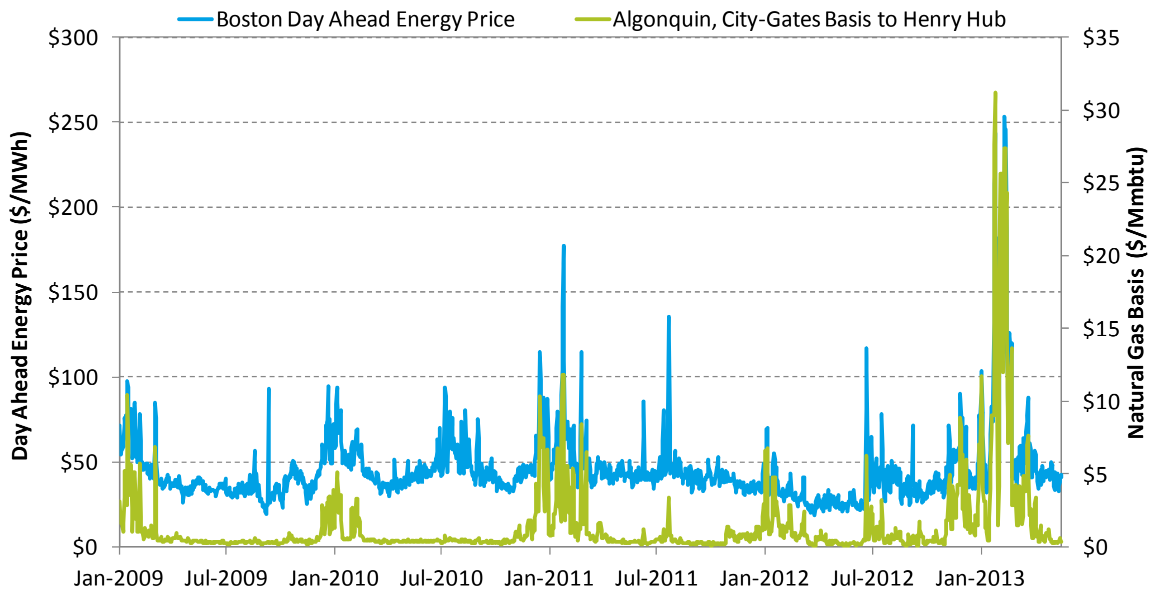

Figure 7 Historical New England Electric and Natural Gas Prices

Source: ISO-NE, Platts

Given that a majority of New England power generators purchase natural gas supplies at wholesale spot prices, Black & Veatch assumed for this study that reductions in electricity prices provided by infrastructure solutions benefit all New England electric customers. Benefits to electric customers are calculated as the reduction in market energy prices in each ISO-NE zone multiplied by total energy consumption in that zone.

BENEFITS FROM REDUCED DAILY GAS PRICE VOLATILITY

In addition to the overall price decreases modeled above, natural gas end-users and electric customers also benefit from reductions in daily natural gas price volatility. Incremental gas infrastructure additions, increased gas supply, or reduced power-sector demand all provide relief from supply constraints and will also reduce daily price volatility. For example, New England winter basis could increase to more than $20/MMBtu in a single day, while increase in summer daily basis never exceeds $1/MMBtu, given the absence of capacity constraints. Because power generators make dispatch decisions based on daily gas prices, daily price volatility for gas has a very significant impact on electric customers.

Because the price estimates were calculated using monthly forecasts[5], the benefits of reduced price volatility were separately calculated using a statistical modeling approach. First, Black & Veatch examined the historical relationship between wholesale daily spot and first-of-month natural gas prices[6] reported at Algonquin City-Gates in order to determine

[5] Forecasts of gas prices made with monthly granularity reflect a limitation of the electric market model, which must utilize a monthly natural gas price forecast to develop electricity price projections.
[6] First-of-month prices usually are indicators of prices paid by gas users seeking to meet baseload requirements on monthly or longer-term contracts.

how often, and by how much, daily spot prices exceed first-of-month prices in peak winter months. That relationship was then used to derive daily price projections using the monthly model output. Reductions in daily volatility provided by infrastructure solutions were then estimated by comparing daily price projections.

4.0 Base Case Assumptions: Most Likely Drivers of Outcomes

NATURAL GAS DEMAND

In the Base Case, Black & Veatch projected New England natural gas demand from the residential, commercial, industrial, and power sectors using the following key assumptions:

1. Normal weather conditions.[7]
2. Demand from residential, commercial and industrial sectors in New England states (except for Connecticut) grows at the average pace of 1.6% per annum.
3. For the state of Connecticut, the goal laid out in the state's Comprehensive Energy Strategy is met, increasing Connecticut's residential and commercial natural gas penetration rate to 50% by 2020.
4. Gross New England electric load grows approximately 1.1% per year as projected in the 2012 Capacity, Energy, Load and Transmission ("CELT") report. Net electric energy load, which incorporates the effect of energy efficiency programs, grows approximately 0.3% per year over the same period. Longer term growth over the study period (2013-2029) shows a growth rate of 0.18% per year incorporating the effect of energy efficiency.
5. Environmental policies and competitive economic pressure trigger significant retirements of coal and oil-fired electric generation.[8]
6. A federal cap-and-trade program on carbon emissions is in effect by 2020, which results in later-period capacity additions that are, separate from renewable resources discussed below, assumed to be exclusively gas-fired.
7. Growth in renewable generation capacity dominates capacity additions in the early years to allow each New England state to meet its Renewable Portfolio Standards ("RPS") goals.

Black & Veatch anticipates moderate growth in New England natural gas demand throughout the analysis period, with growth of 360 million cubic feet per day (MMcf/d) expected from 2014 to 2029 (Figure 8). Overall demand growth is expected to be driven by the residential, commercial, and industrial sectors as a result of economic recovery and market penetration in the residential and commercial sectors. Growth in residential and commercial demand is concentrated in Connecticut, as a result of the state's Comprehensive Energy Strategy.

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[7] Normal weather conditions were defined as monthly-average winter heating-degree days ("HDDs") and monthly-average summer cooling-degree days ("CDDs") for the 20-year period of 1993-2012 as documented for weather stations in Boston MA, Concord VT and Hartford CT.

[8] Nuclear power generators were assumed to remain in service consistent with the terms of their Nuclear Regulatory Commission operating licenses. Notably, the Vermont Yankee station was assumed to remain in service for the entire study period in the Base Case and Low Demand Scenarios.

Growth in electric sector demand for natural gas is driven by increased dispatch of natural gas generation units. However, efficiency gains, demand response programs and renewable resources offset much of the customer load growth in New England, in contrast to the much more robust electric sector demand growth expected throughout the Lower 48 states (Figure 9).

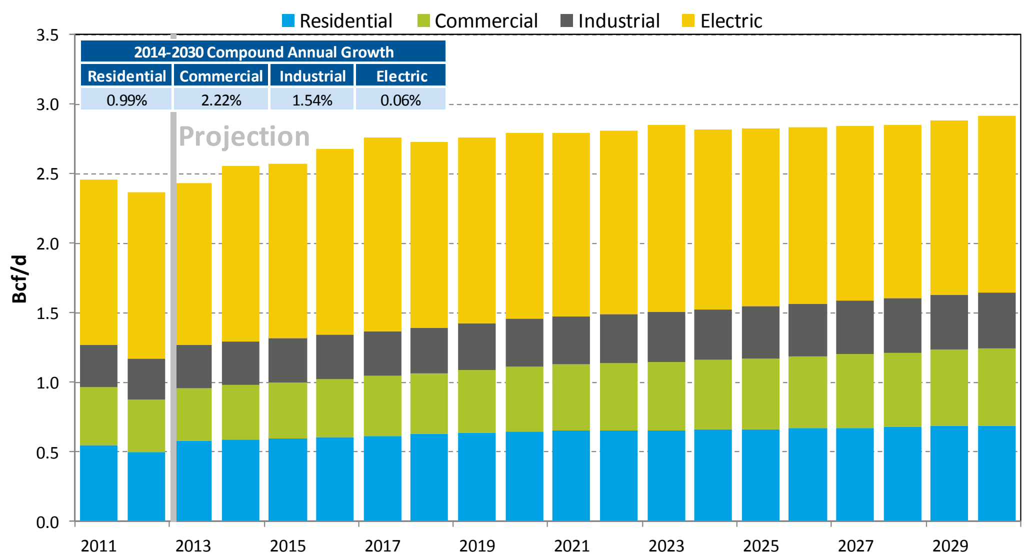

Figure 8 New England Natural Gas Demand: Base Case

Source: Energy Information Administration historical data, Black & Veatch Projection

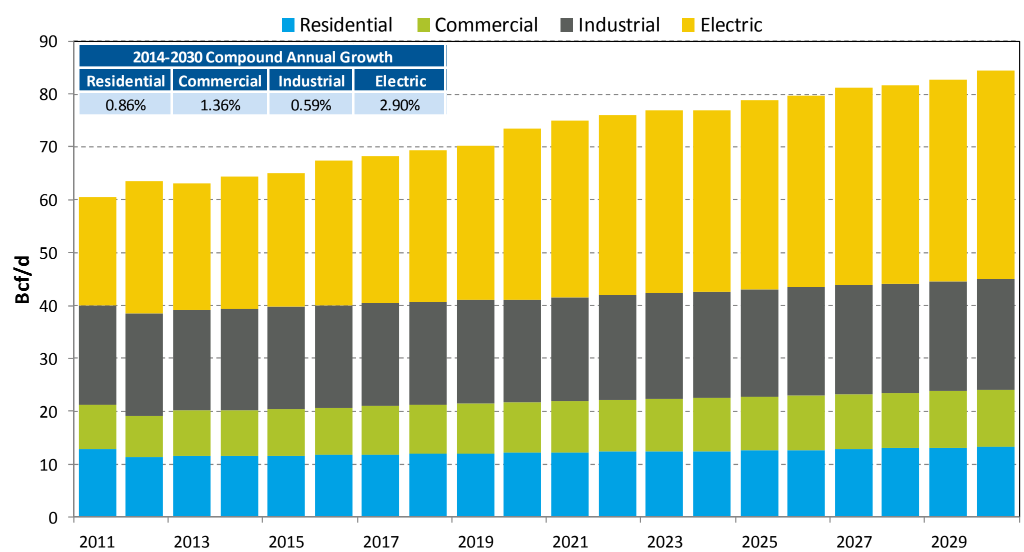

Figure 9 Lower 48 Natural Gas Demand: Base Case

Source: Energy Information Administration historical data, Black & Veatch Projection

NATURAL GAS SUPPLY

New England will primarily rely on Marcellus Shale production for its natural gas supply throughout the analysis period. Marcellus Shale production is expected to grow at an average of 6% per year through the analysis period (Figure 10), driven by Marcellus's status as one of the lowest-cost production basins in North America and by producers' high level of investment currently in the ground. This production, for the most part, will be delivered to New England by Tennessee Gas Pipeline and Algonquin Gas Transmission.

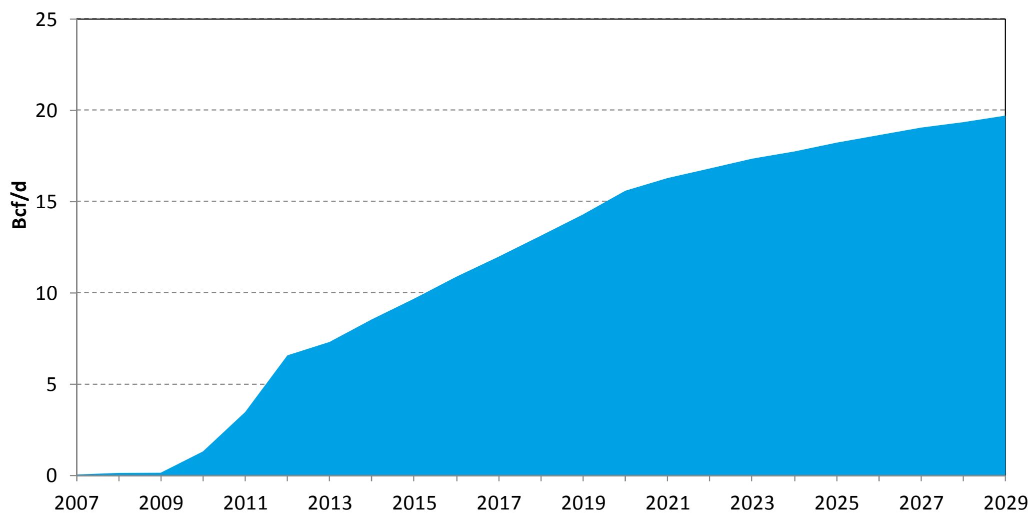

Figure 10 Marcellus Shale Natural Gas Production: Base Case

Source: LCI Energy Insight historical data, Black & Veatch EMP MY2013 Projection

Eastern Canadian production will also be an important supply source delivered to New England by the Maritimes and Northeast Pipeline ("MN&P"). Production from Sable Island Offshore Energy Project ("SOEP") has been in sharp decline and is expected to cease production by 2018.[9] However, total production from eastern Canada is expected to grow in the short term as Deep Panuke begins production in the summer of 2013.[10] Regional production will then exceed 350 MMcf/d by 2014 but quickly decline from loss of SOEP production in 2018 and the steep decline curves faced by Deep Panuke producers (Figure 11). Production is expected to stabilize at 170-200 MMcf/d by 2021 as new supplies from New Brunswick Shale or offshore Newfoundland production come online.

[9] National Energy Board, Canada's Energy Future: Energy Supply and Demand Projections to 2035
[10] Platts Gas Daily, August 5, 2013

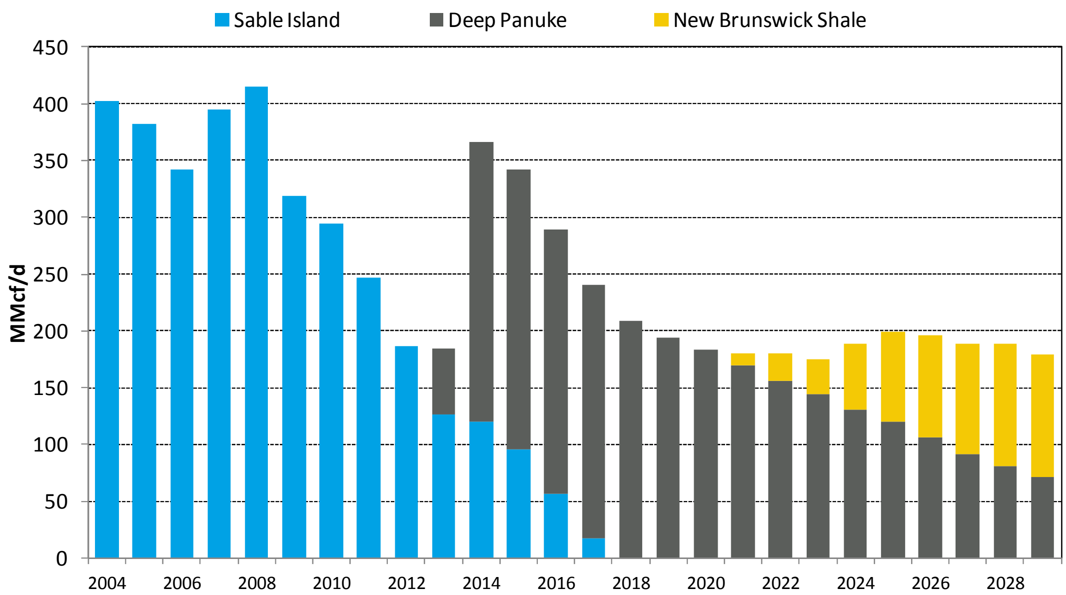

Figure 11 Eastern Canadian Production of Natural Gas

Source: National Energy Board analysis, Black & Veatch projection

LNG imports are expected to serve approximately 350–400 MMcf/d of New England demand during peak winter months (Figure 12). Supplies received at the Canaport LNG terminal (Saint John, New Brunswick) are expected to decline relative to historical norms when a firm supply agreement with Qatar expires in October 2013. Thereafter, imports at the terminal are expected to be driven by opportunistic deliveries based on spot prices. A similar trend is expected to occur at the Distrigas terminal in Everett, Massachusetts. Imports into the Everett terminal are expected to increase slightly by 50 MMcf/d towards the end of the analysis period due to growing New England demand (Figure 13).

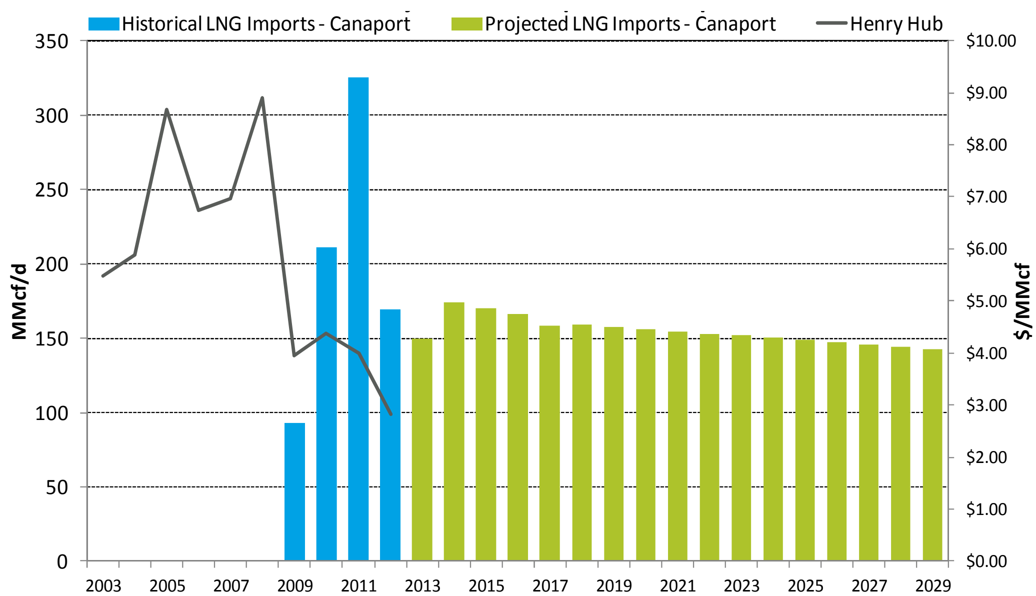

Figure 12 LNG Imports at Canaport LNG Compared with Henry Hub Gas Price

Source: Energy Information Administration historical data, Black & Veatch Projection

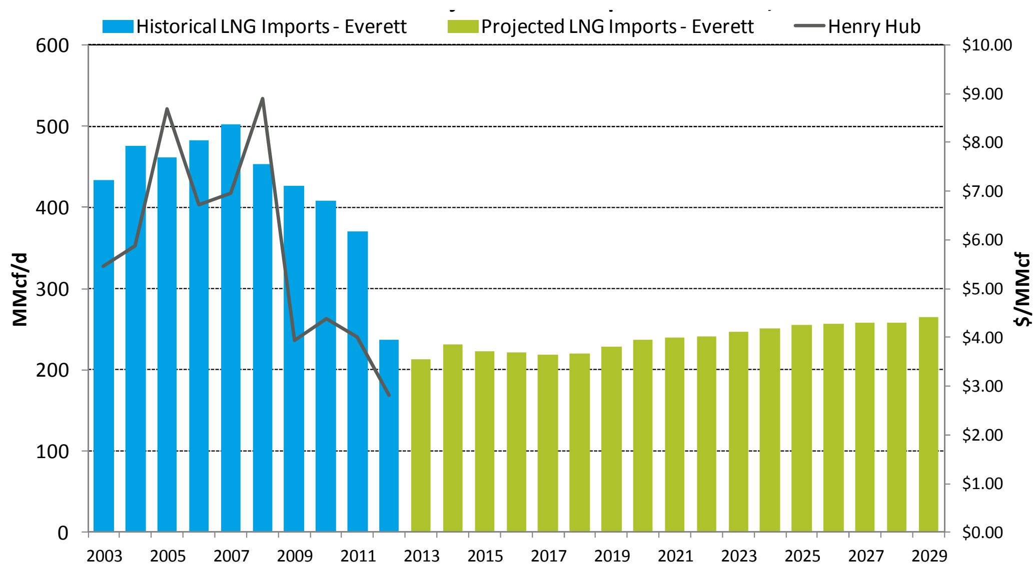

Figure 13 LNG Imports at Everett, MA Compared with Henry Hub Gas Price

Source: Energy Information Administration historical data, Black & Veatch Projection

Robust growth of natural gas production across North America is expected to continue throughout the analysis period. As shown in Figure 14, this growth will be driven by shale production, which mitigates a continued plateau in conventional production. Given that robust production growth, Black & Veatch assumed for the Base Case that New England consumers will not face significant competition for supplies with other major North American demand regions.

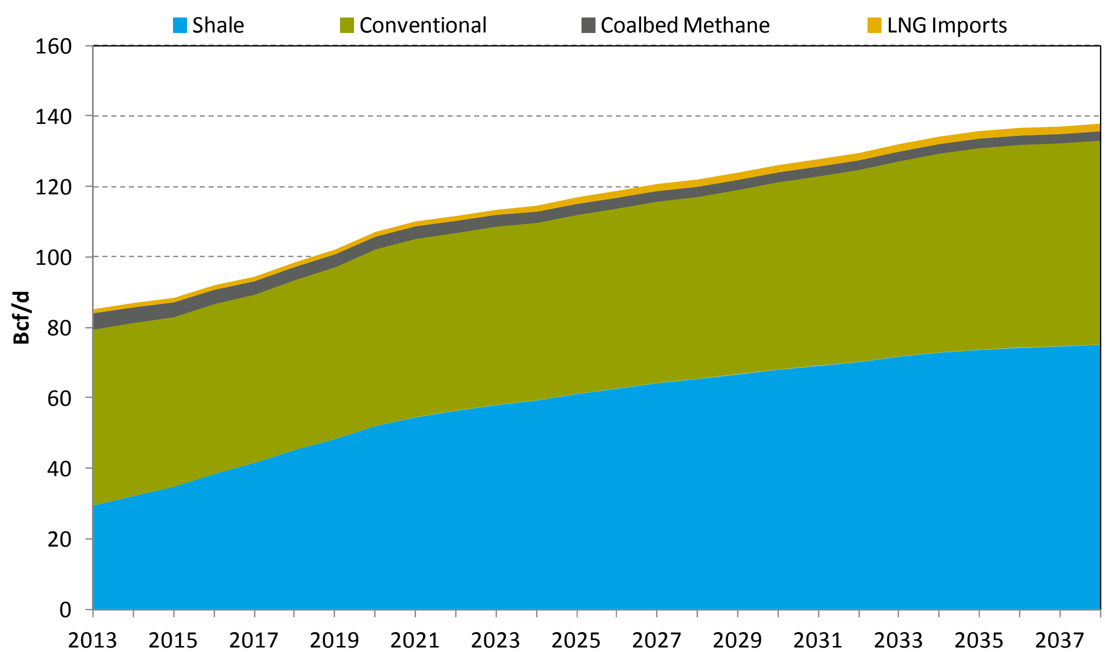

Figure 14 Projected North American Natural Gas Supply

Source: Black & Veatch projection

NATURAL GAS INFRASTRUCTURE ASSUMPTIONS

The Base Case includes all natural gas pipeline capacities currently serving New England as summarized in Table 3.

Table 3 New England Gas Supply Infrastructure and Capacities[11]

Supply Sources	Firm Contracted Capacity Serving New England Demand (Bcf/d)*
Pipeline	
Tennessee Gas Pipeline	1.3
Algonquin Gas Transmission	1.3
Iroquois Gas Transmission	0.2
Maritimes & Northeast Pipeline	0.9
Portland Natural Gas Transmission	0.2
LNG Imports (Firm Supplies)	
Everett LNG	0.7
LNG Import (Non-Firm Supplies)	
Neptune LNG	0.0
Northeast Gateway	0.0
LNG Peak Shaving	1.4
Total	**6.1**

*Firm contracted capacity originating outside of New England

Source: *2012 Quarter 4 FERC Index of Customers*

The Base Case assumes that two natural gas pipeline projects create incremental pipeline capacity to serve New England within the next five years. Approximately 500 MMcf/d of incremental pipeline capacity is assumed to be built in late 2016 through the Algonquin Incremental Market ("AIM") expansion. The AIM project will expand the existing Algonquin Gas Transmission from New Jersey to Massachusetts to carry growing Marcellus Shale production across New England and to the greater Boston area. Figure 15 provides an overview of the AIM project.

[11] In Black & Veatch's modeling analysis, these capacity numbers are maximum capacity available to reach the New England market. The availability of supply on Maritimes will be limited by eastern Canadian production and LNG imports from the Canaport terminal. Similarly, the availability of supply from the Everett terminal is limited by actual LNG import volumes.

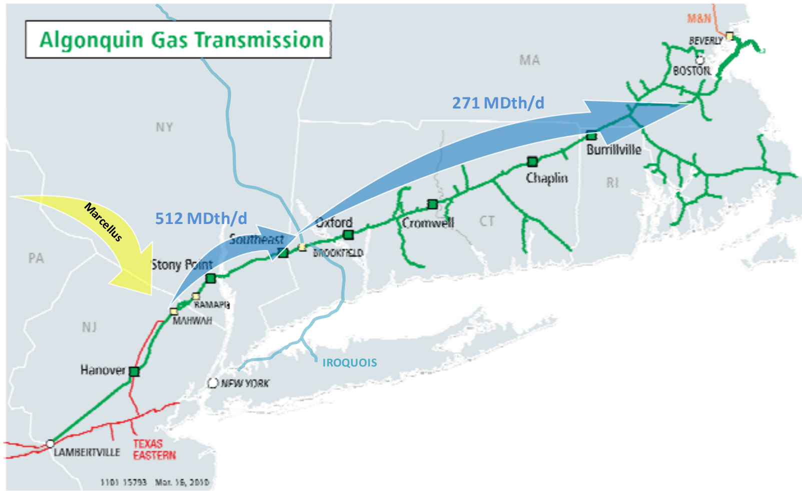

Figure 15 Algonquin Incremental Market Expansion

Source: *Spectra Energy*

The Base Case also assumes that the proposed Constitution Pipeline provides incremental capacity of 650 MMcf/d beginning in 2015 through the construction of a greenfield pipeline that runs from Susquehanna County, Pennsylvania, to Schoharie County, New York. Although the Constitution Pipeline does not provide incremental capacity that directly serves New England, it could unload incremental deliverability from Iroquois Gas Transmission ("Iroquois"), which will in turn be able to deliver additional volumes to Connecticut and New York City via receipts from Wright, as shown in Figure 16.

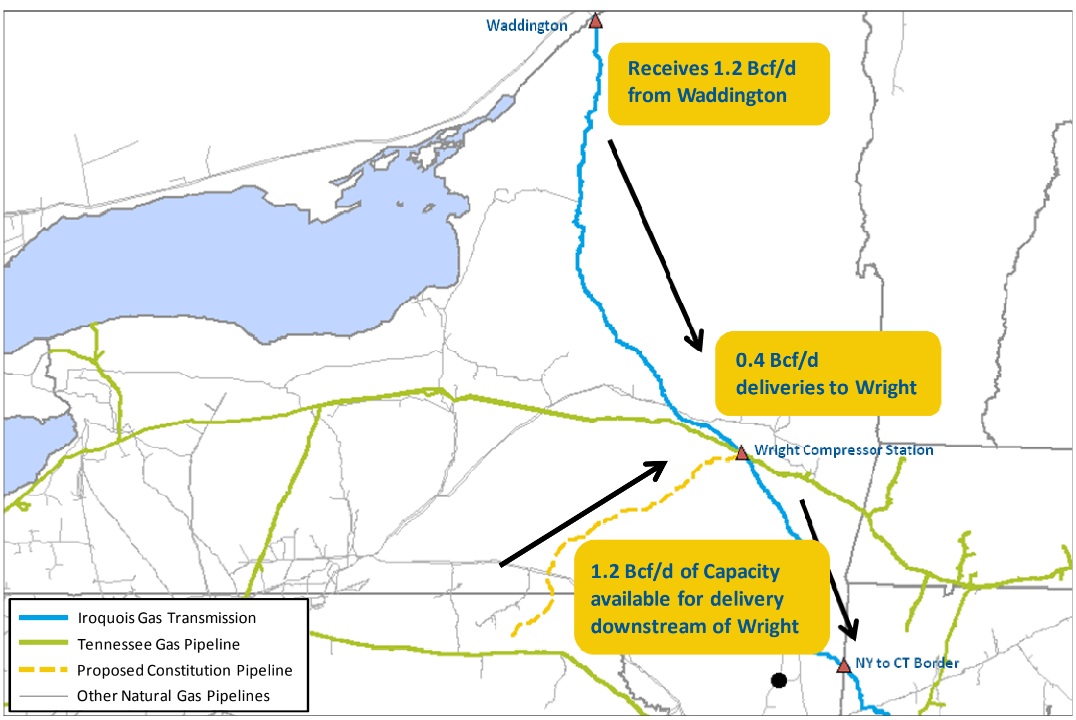

Figure 16 Constitution Pipeline

5.0 Base Case Results: Constraints and Price Impacts

Black & Veatch's Integrated Market Modeling process was applied to the assumptions described in Section 4.0 to develop monthly natural gas and electricity price forecasts. The Base Case price projections were used as benchmarks when quantifying the benefits of proposed solutions.

New England gas prices can be evaluated as a changeable "premium" relative to the Henry Hub benchmark

For the purposes of this discussion, New England natural gas price projections are expressed as ***basis***, that is, as a differential of Algonquin City-Gates prices relative to prices reported at Henry Hub, a Louisiana natural gas pricing point that is considered the bellwether of U.S. natural gas prices. At any given time, a positive basis is essentially a premium paid above the price at Henry Hub whereas a negative basis would represent a discount relative to Henry Hub. Although volatile, especially in winter, New England basis prices, including those at Algonquin City-Gates, traditionally have been strongly positive. Therefore, any model reduction of Algonquin City-Gates basis toward small positive values (lower premium) would indicate more attractive economics for gas end-users.

Premium gas prices will remain high in New England unless infrastructure, supply, and/or demand reduction solutions are introduced

Base Case natural gas price projections indicate that without the introduction of solutions to increase natural gas delivery capacity or moderate natural gas demand, New England will continue to experience significant price increases during winter months.

As seen in Figure 17 and Figure 18, Algonquin City-Gates basis is projected to moderate relative to the extremes experienced in the winter of 2012-2013, but continue to experience winter peaks averaging $3.00/MMBtu on a monthly basis and could exceed $9.00-$10.00/MMBtu on a daily basis through the winter of 2015-2016. Incremental capacity provided by AIM starting in 2016 is expected to moderate basis for 5-6 years; monthly average basis falls below $2.50/MMBtu and daily volatility is greatly reduced from 2017-2022. Significant basis increases and highly volatile daily pricing in winter months are projected to return in the winter of 2022-2023 as demand grows to outpace natural gas delivery capacity serving the region, and higher-cost supply sources from Eastern Canada are introduced.

The significant decline in projected basis relative to historical basis observed in the winter of 2012-2013 is attributable in part to the introduction of Deep Panuke supplies in 2013. Projections also assume normal winter conditions that are more moderate than conditions experienced in the winter of 2012-2013.

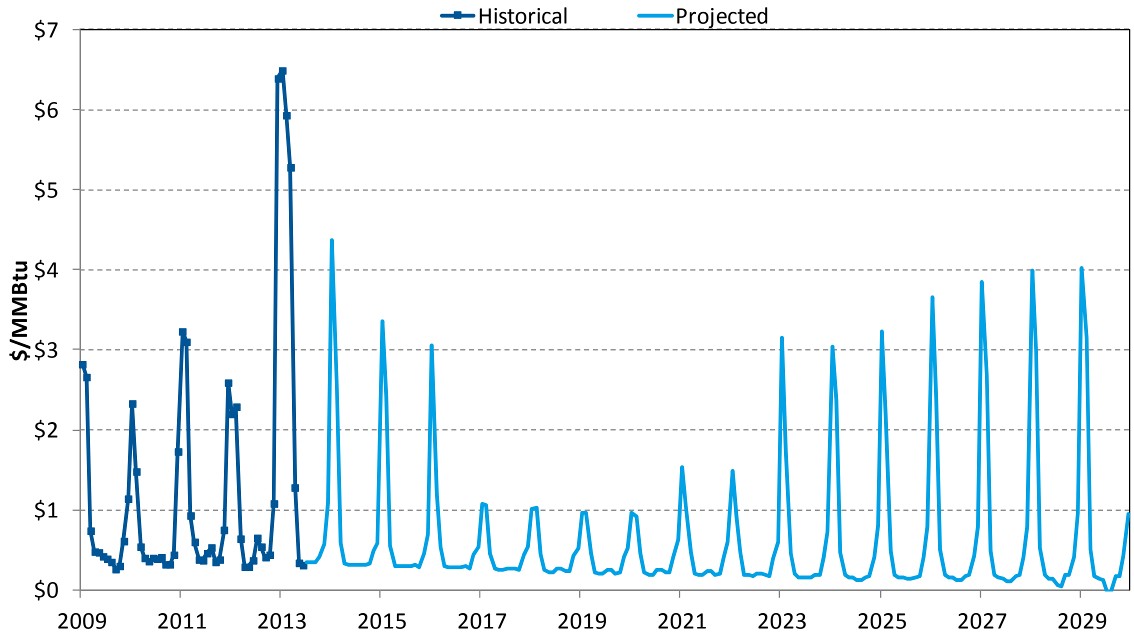

Figure 17 Monthly Algonquin City-Gates Basis to Henry Hub: Base Case Forecast

Source: *Platts historical data, Black & Veatch projection*

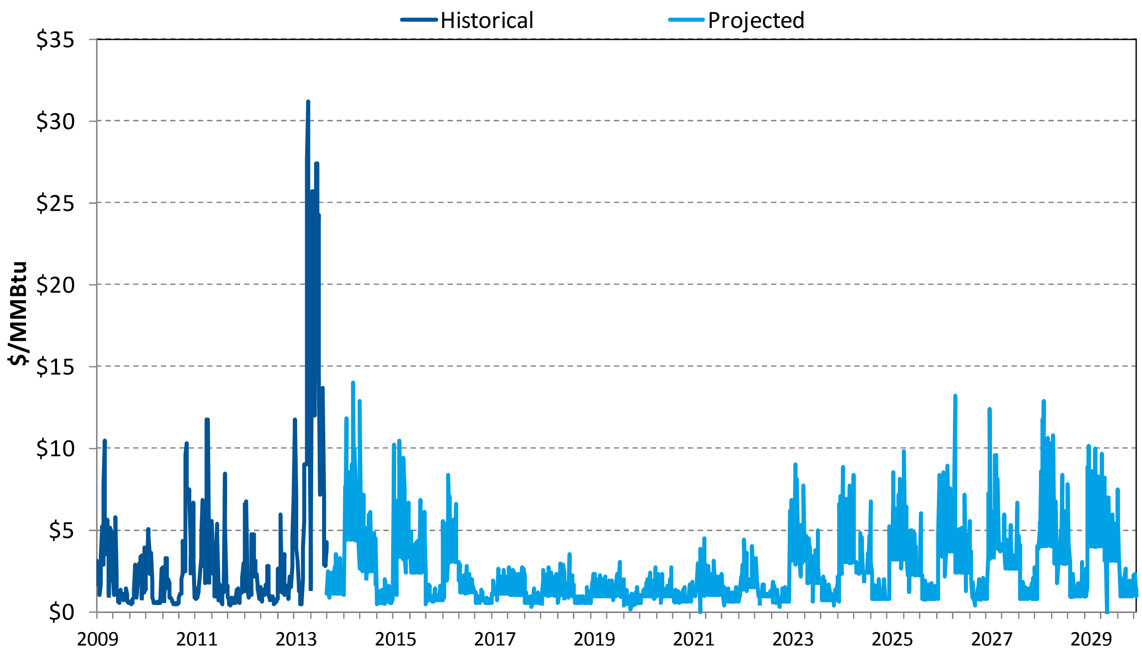

Figure 18 Daily Algonquin City-Gates Basis to Henry Hub: Base Case Forecast

Source: *Platts historical data, Black & Veatch projection*

Electricity prices will remain high in New England in response to high gas prices

New England electricity prices are expected to maintain their tight correlation with natural gas prices and peak in winter months as natural gas pipeline constraints occur. As shown in Figure 19, average electricity prices in peak winter months are expected to grow from $65/MWh in 2014 to $83/MWh in 2029.

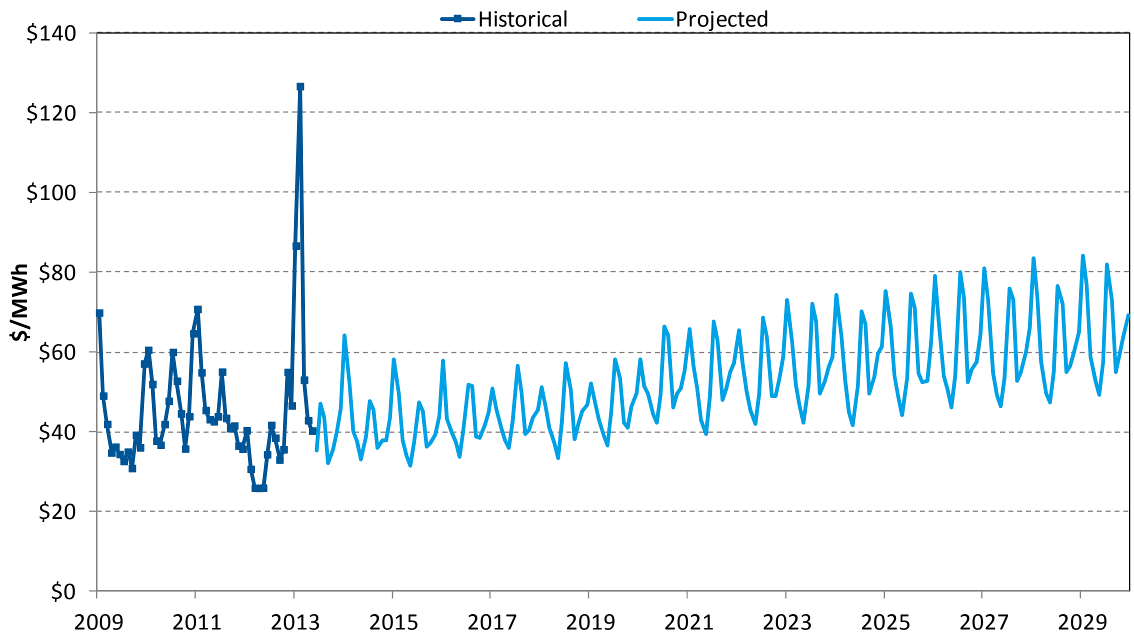

Figure 19 Boston Electric Prices: Base Case Forecast

Source: *Energy Velocity historical data, Black & Veatch projection*

6.0 Long-Term Solutions

Black & Veatch's Base Case modeling analysis indicates that New England will face significant increases in wholesale natural gas and electric prices if solutions are not implemented to alleviate the strain on natural gas infrastructure. Aside from higher gas and electric bills paid by consumers, New England could face significant reliability issues if unresolved natural gas infrastructure constraints prevent gas-fired generators from being dispatched.

Black & Veatch examined three potential long-term solutions to New England's natural gas infrastructure constraints, including one gas pipeline concept and two electric-transmission concepts. Distinctions among the three solutions are as follows:

- **Cross-Regional Natural Gas Pipeline** - A 1.2 Bcf/d natural gas pipeline to provide New England with additional natural gas supplies and reinforce existing natural gas infrastructure.
- **Economic Based Energy Imports** – An electric transmission line capable of importing 1,200 megawatts (MW) of energy from Canada. The amount of energy imported by New England will be based upon the simulated hourly energy needs and price differentials between New England and alternative markets.
- **Firm-Based Energy Imports** – An electric transmission line, similar to the economic based energy imports, that delivers *firm* energy supplies, a constant amount of energy equal to the maximum capacity of the transmission line enabled through the construction of additional generation infrastructure.

Each of the three long-term solutions would require three to five years to develop and construct. Long-term capital investments are expected to provide significant long-term benefits to the region over the analysis period.

CROSS-REGIONAL NATURAL GAS PIPELINE

A natural gas pipeline with a design capacity of 1.2 Bcf/d (1,200 MMcf/d) originating in Upstate New York and terminating in Eastern Massachusetts could potentially relieve constraints during peak winter months and provide the baseload and peak hour flexibility necessary to meet future demand growth.

As shown in Figure 20 , a Cross-Regional Natural Gas Pipeline would originate at Wright, the existing Tennessee Gas Pipeline ("Tennessee") and Iroquois interconnect in Schoharie County, New York, and terminate at Dracut, Tennessee Gas Pipeline's interconnect with M&NP in Middlesex County, Massachusetts. This pipeline is assumed to commence service in the spring of 2017 and access gas supplies from existing capacity on Tennessee and Iroquois. It is also anticipated to access supplies from the proposed Constitution pipeline which is expected to commence service in early 2015.

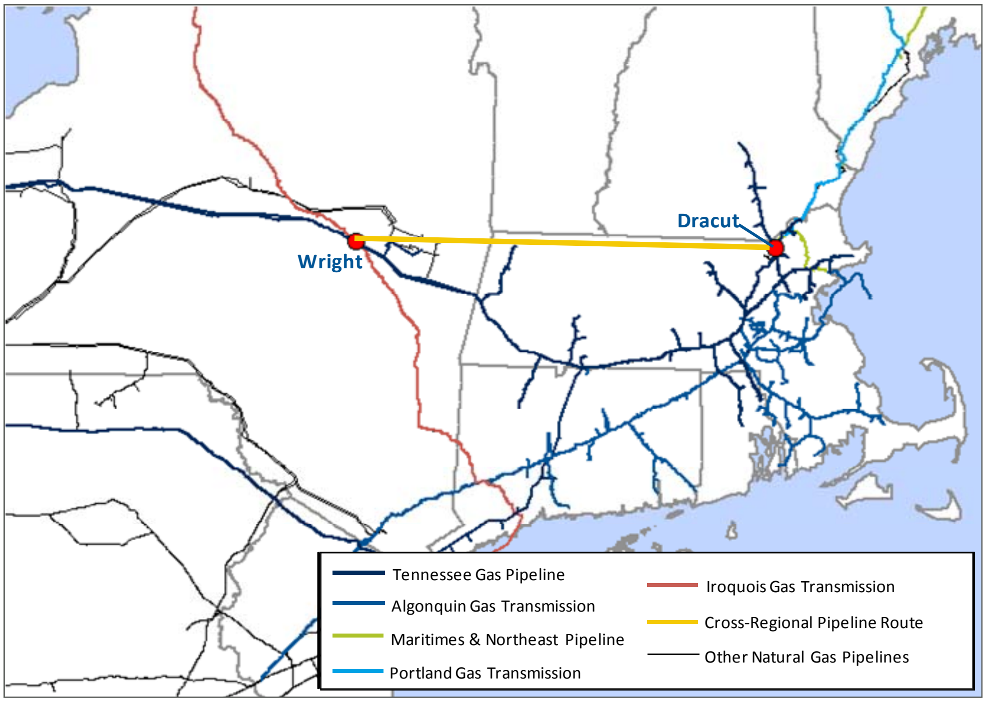

Figure 20 Cross-Regional Natural Gas Pipeline Route

By delivering natural gas to Dracut, the Cross-Regional Natural Gas Pipeline would provide supplies to New Hampshire and Eastern Massachusetts markets via Tennessee. The pipeline can also deliver directly into Maine with the flow reversal of M&NP or indirectly by displacing existing SOEP or Canaport supplies flowing south. The incremental natural gas deliverability created by this pipeline into Eastern Massachusetts could free pipeline capacity on Tennessee and Algonquin to serve demand growth in Connecticut and Rhode Island while alleviating constraints in Eastern Connecticut and Eastern Massachusetts.

Black & Veatch estimates that the Cross-Regional Natural Gas Pipeline could be constructed for approximately $1.2 billion[12]. Assuming that 100% of its capacity is contracted, the pipeline could potentially offer a 100% load factor transportation rate of $0.45/Dth/day[13]. However, it must be noted that the transportation rates offered by this pipeline could greatly exceed this estimate. Even if construction cost overruns are not experienced, lower-than-anticipated capacity subscription could lead to significant increases in the per-unit rate. For example, the per-unit rate would double if the pipeline capacity is only 50% subscribed. The projected rates also could change based on future steel costs, the diameter of the pipeline, the routing and construction delays related to local opposition.

[12] Representative capital costs for greenfield projects in the Northeast U.S. were estimated using Constitution Pipeline's proposed transportation rate of $0.76/dth/day.
[13] Rates were estimated using a capital structure considered to be representative of major interstate pipelines serving New England and levelized over a 20-year period.

ECONOMIC-BASED CANADIAN ENERGY IMPORTS

Black & Veatch also explored the potential cost and benefits of an electric transmission line capable of importing 1,200 MW of hydro-electric energy from Canada to Eastern New England beginning in 2018. The transmission line, originating at the Canada-U.S. border and terminating in New England, would run approximately 180 miles. Black & Veatch has estimated a construction cost of $1.1 billion based on its recent experience in constructing transmission lines in the U.S. Midwest. Levelized over twenty years, the annual cost of service for this project is estimated to range from $180 to $219 million[14].

This sensitivity assumes that energy imports delivered via the transmission line are determined purely by the energy needs and price differentials between New England and alternative markets in the entire Eastern Interconnect. Therefore, when price spreads between ISO-NE and Canada present an arbitrage opportunity, energy will be imported to New England. Figure 21 summarizes these projected imports.

The fact that the Canadian market which is to be the source of the energy is a winter-peaking market may limit the energy imports offered to New England during the winter months when gas infrastructure is most constrained. Imports in peak winter months are expected to be limited, never exceeding 700 megawatt-hour (MWh) in winter throughout the analysis period. In addition, Black & Veatch expects tightening supply-demand fundamentals in the originating Canadian market going forward, leading to a decline in imports to New England over the analysis period.

[14] The cost assumptions are derived based on Black & Veatch's estimates from a $1.1 billion construction cost, levelized over a 20-year period with different rate of returns requirements on capital. Black & Veatch used $219 million in the results reported here as it is close to the annual cost estimates from a recent report on a similar project.

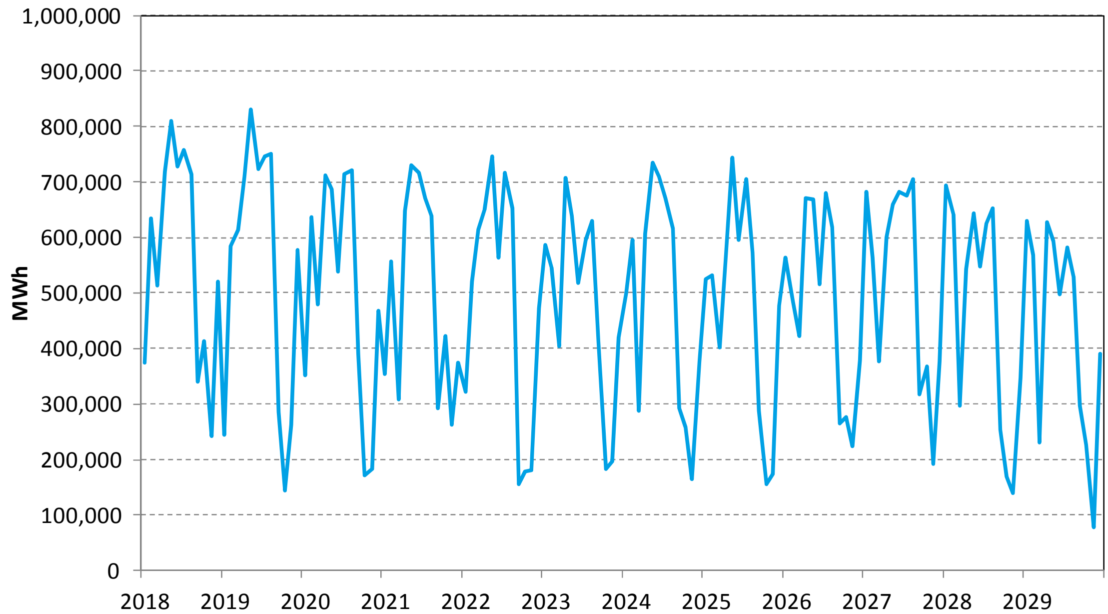

Figure 21 Projected New England Imports of Canadian Hydro Power: Economic-Based Energy Imports
Source: *Black & Veatch projection*

The implementation of this solution is projected to result in both peak and off-peak reduction in New England natural gas demand for power generation relative to the Base Case. During peak winter months, the average reduction is 95 MMcf/d, while the average summer reduction is 118 MMcf/d.

FIRM-BASED CANADIAN ENERGY IMPORTS

Similar to the Economic-Based Energy Imports solution, Black & Veatch explored a Firm-Based Energy Imports solution in which the level of energy imported by the transmission line (Figure 22) described above is guaranteed through a contractual agreement with Hydro Quebec[15]. In addition to the electric transmission line, Black & Veatch assumed the expansion and/or construction of generation facilities (potential dam construction) and a firm contract for 1,200 MW for every hour of the day, 365 days a year starting in 2018. The construction of power-generation facilities in Hydro Quebec would cost $170 million per year[16] in addition to the previously stated cost of the transmission line. This scenario assumes that energy imports delivered via the transmission line will be a lower-priced supply source into the ISO-NE market, and displace the higher-cost sources on the margin.

The Firm-Based Energy Import solution reduces regional gas demand for power generation by 155 MMcf/d, approximately 60% more than the Economic-Based Energy Imports solution.

[15] This assumption does not indicate any preference for any potential alternative sources of hydro-electric energy for this solution.
[16] Black & Veatch estimated construction costs for power generation facilities in Hydro Quebec to range from $800-1,100 million. The $170 million per year represents returns on capital investment, and operating and maintenance costs, levelized over a twenty-year period.

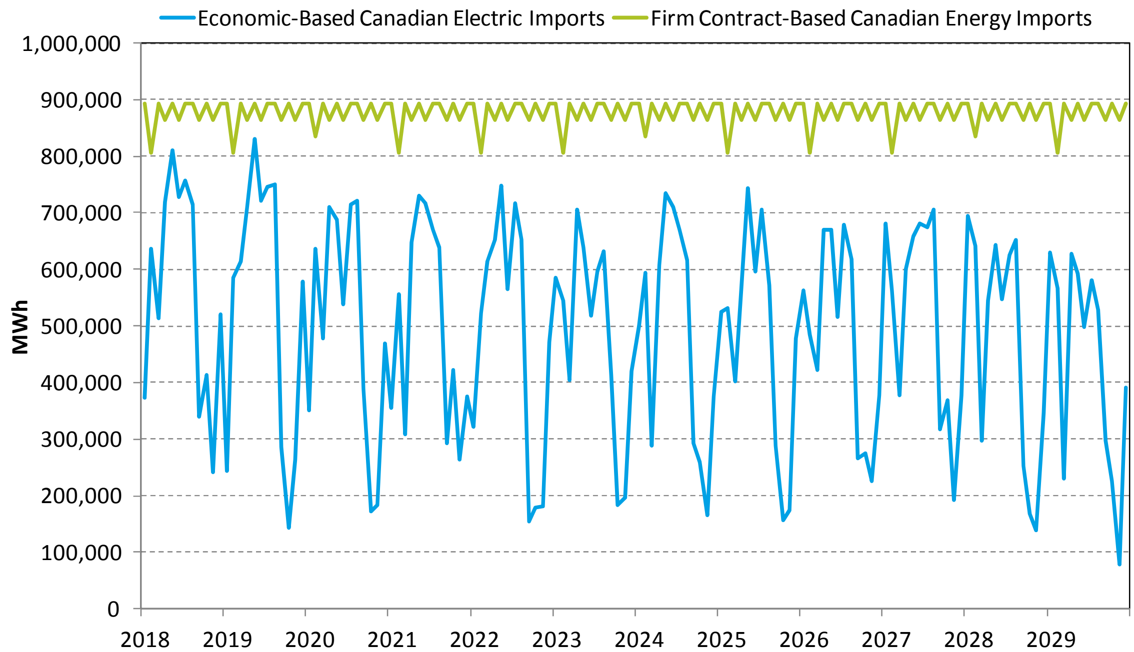

Figure 22 Projected New England Imports of Canadian Hydro Power: Firm Canadian Electric Imports Sensitivity

Source: *Black & Veatch projection*

PRICE IMPACTS

The price impact of each long-term solution is measured by comparing the New England natural gas and electric-power prices in the Base Case with the projected gas and electric prices for each long-term solution. The associated benefits for each proposed solution should be a function of the magnitude and duration of the favorable price impacts.

The Cross-Regional Natural Gas Pipeline has the greatest price impact during the peak winter months

During winter months, natural gas pipelines are highly utilized to serve heating-demand loads across New England, and have limited flexibility to serve interruptible industrial or power generation needs. It is often the last few units of scarce natural gas that are bid up with the consequence of creating large regional price spikes. A Cross-Regional Natural Gas Pipeline will provide additional regional access to low-cost Marcellus Shale supplies while alleviating pipeline constraints on Tennessee, Algonquin, and Maritimes and Northeast and will minimize regional price spikes and price volatility during peak winter months. During peak winter periods, the Cross-Regional Natural Gas Pipeline is expected to reduce average monthly natural gas basis by $1.42/MMBtu over the analysis period. The price impact during the summer months is muted because of the much lower regional gas demand relative to the peak winter months. For the most part, sufficient pipeline capacity exists to serve summer cooling demand loads, which limits pipeline constraints and regional price spikes.

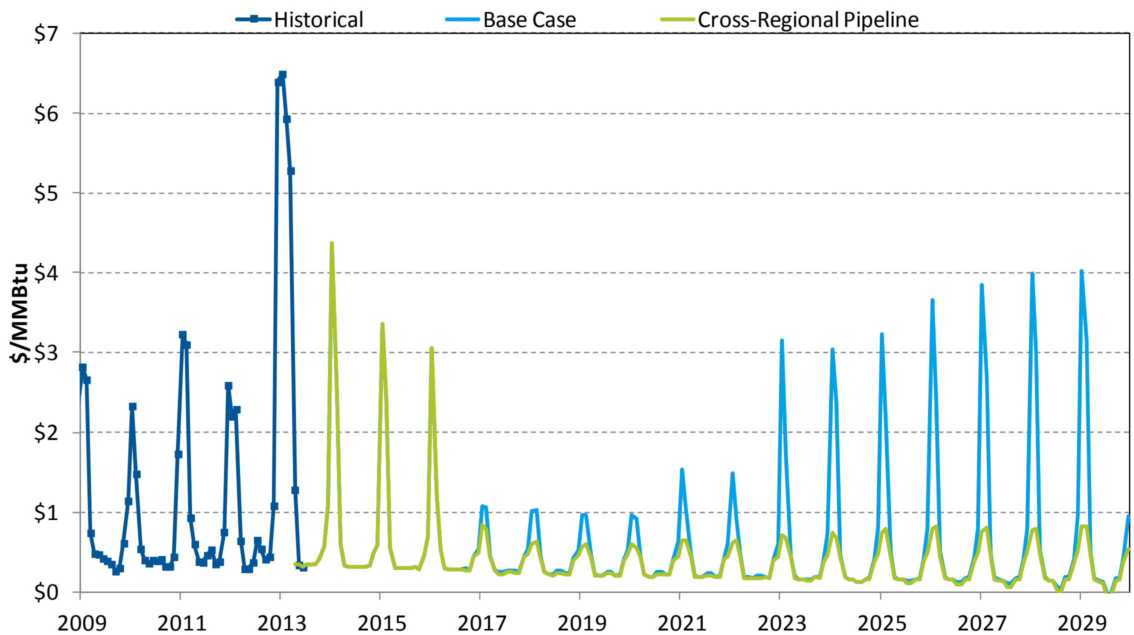

Figure 23 Monthly Algonquin City-Gates Basis to Henry Hub: Base Case vs. Cross-Regional Natural Gas Pipeline

Source: *Platts historical data, Black & Veatch projection*

The natural gas price impact will have a direct impact on the cost of gas-fired power generation and electricity prices across all ISO-NE zones

As shown in Figure 7, natural gas and electricity prices are highly correlated during peak winter months. The Cross-Regional Natural Gas Pipeline is projected to reduce peak winter electricity prices across New England[17]. From 2017-2029, the reduction in regional gas prices translates to a reduction in average monthly electricity prices by $10.88/MWh during peak winter months. During the summer months, the limited impact of the Cross-Regional Natural Gas Pipeline on natural gas prices also translates to a muted impact on electricity prices.

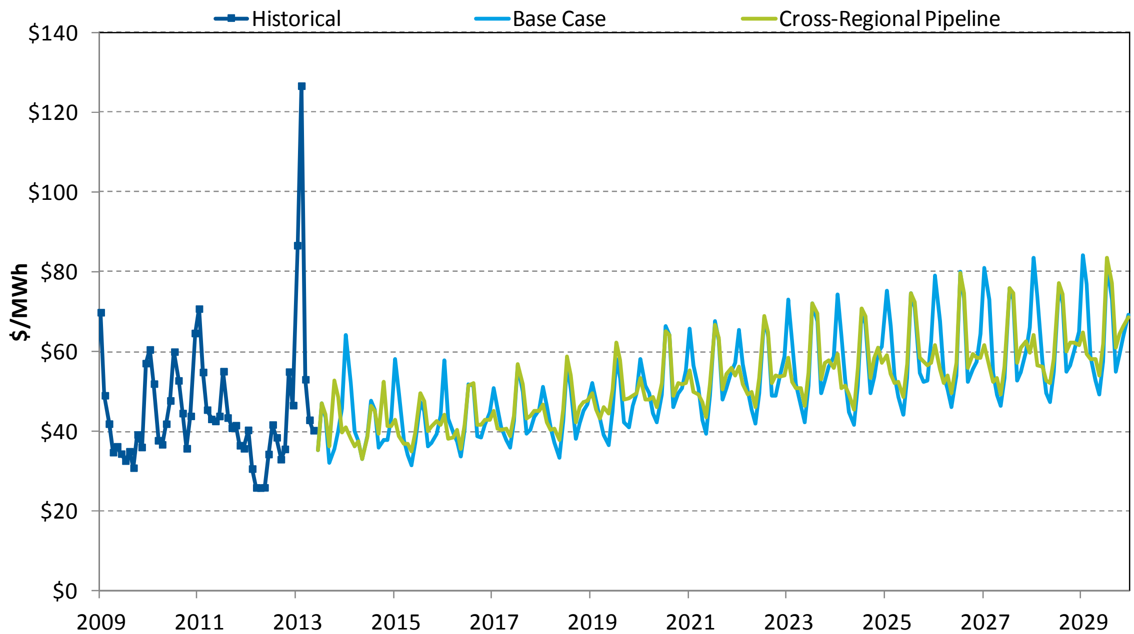

Figure 24 Boston Electric Prices: Base Case vs. Cross-Regional Pipeline Solution
Source: *Energy Velocity historical data, Black & Veatch projection*

Energy imports into New England will reduce natural gas demand during peak winter and summer periods

The reduction in natural gas demand during peak winter months will have the greatest price impact by reducing pipeline constraints or supply shortfalls that drive regional price spikes. On peak winter months, the Economic-Based Energy Imports will reduce average monthly basis by $0.78/MMBtu per day over the 2018-2029 analysis period (Figure 25). A reduction in natural gas demand during the peak summer months has a muted impact because of the lower overall regional demand and limited pipeline constraints in summer months.

[17] For the graphic presentation of the electricity price impacts of different solutions in this report, Black & Veatch chose Boston as a corresponding electricity price location to Algonquin City-Gates. Black & Veatch selectively graphed the price impacts at other New England electricity zones to confirm that they are similar to Boston's.

When compared to the Economic-Based Energy Imports solution, the Firm-Based Energy Imports solution creates a greater reduction in natural gas demand on peak winter months, which translates to a greater impact on the monthly Algonquin City-Gates basis by \$0.09/MMBtu, averaging \$0.87/MMBtu over the analysis period.

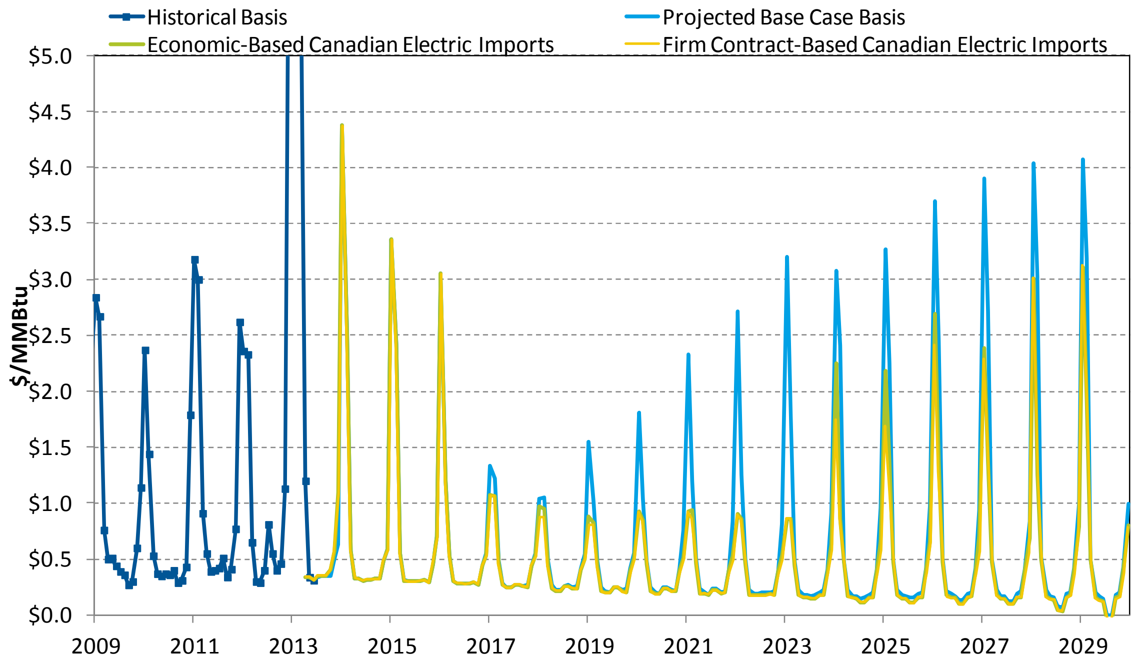

Figure 25 Monthly Algonquin City-Gates Basis to Henry Hub: Base Case vs. Economic- and Firm-Based Energy Imports
Source: *Platts historical data, Black & Veatch projection*

Similar to the Cross-Regional Natural Gas Pipeline solution, both the Economic-Based Energy Imports solution and the Firm-Based Energy Imports solution will lower regional electric prices across ISO-NE. Electric energy imports are expected to modify the regional power plant dispatch by displacing less efficient generation resources and reducing regional gas demand from the power generation sector.

Economic-Based Energy Imports into New England are determined by market conditions, and the economic dispatch of the Eastern Interconnect. Electric imports into New England occur only when market prices between ISO-NE and Hydro Quebec cover the associated costs of electric generation and transmission. On peak winter months, Economic-Based Energy Imports will, on average, reduce electric prices by \$4.20/MWh. During peak summer months, the average electric price reduction is \$0.85/MWh.

Firm-Based Energy Imports, when compared to the Economic-Based Energy Imports, will have a greater impact on electric prices

Firm-Based Energy Imports throughout the year will displace less efficient generation units and reduce natural gas-fired generation during peak winter periods. On peak winter months, the average electric price reduction is \$5.91/MWh, an increased benefit of 40% compared to the Economic-Based Energy Imports solution. During peak summer months, the average electric price reduction is $1.73/MWh, which reflects the impact of additional gas demand reduction and the displacement of higher-cost generation units.

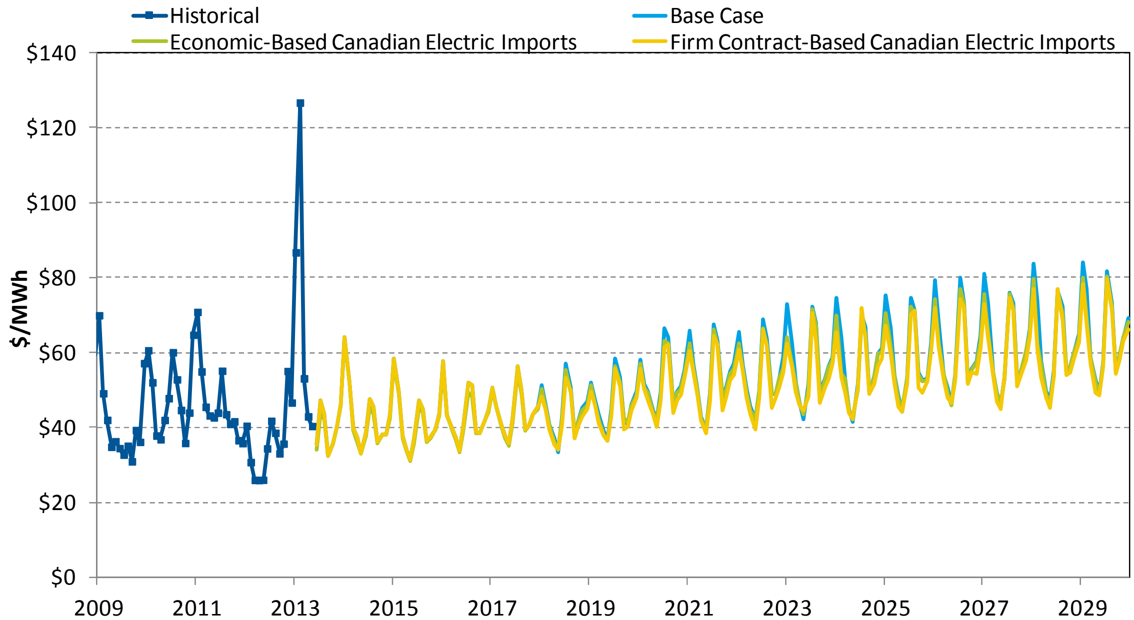

Figure 26 Boston Electric Prices: Base Case vs. Economic- and Firm-Based Energy Imports
Source: *Energy Velocity historical data, Black & Veatch projection*

ECONOMIC BENEFITS

Each long-term solution is expected to offer significant benefits to the New England market under the Base Case, incurring net losses in the near-term but offering significant benefits in the long-term as natural gas and electric prices are projected to rise

New England consumers are expected to benefit from these projects once they are constructed, but these benefits are not expected to exceed costs until 2023 where, in the absence of these solutions, significant increases in natural gas and electric prices are expected.[18] It must be noted that the construction costs of these large-scale infrastructure solutions can vary greatly due to changes in the cost of material and labor as well as construction delays. Further, the relationship between the construction costs and the costs that New England natural gas and electricity customers would ultimately pay depends on a host of market-based and regulatory factors.

These solutions also offer secondary economic benefits beyond the direct benefits to New England's natural gas and electric consumers as modeled in this study. Capital-intensive infrastructure investments will create local jobs to construct and operate these assets, providing income to expand New England's economy. The reduction of energy costs for

[18] This is the timeframe when cumulative demand growth outpaces capacity and new, higher-cost Eastern Canadian supply sources are introduced.

consumers and local businesses will increase savings and spending for other goods and services across the region.

The construction of a Cross-Regional Natural Gas Pipeline presents the least expensive long-term solution that provides the highest net benefit to New England consumers

Sufficient incremental pipeline capacity is expected to directly prevent the pipeline constraints that led to significant increases in natural gas and electric prices. The project's benefits are not limited to the gas market; incremental pipeline capacity is expected to reduce the price of every unit of electricity sold in ISO-NE. As shown in Figure 27, the construction of a Cross-Regional Natural Gas Pipeline is expected to consistently offer annual average benefits to New England electric consumers in excess of $100 million[19].

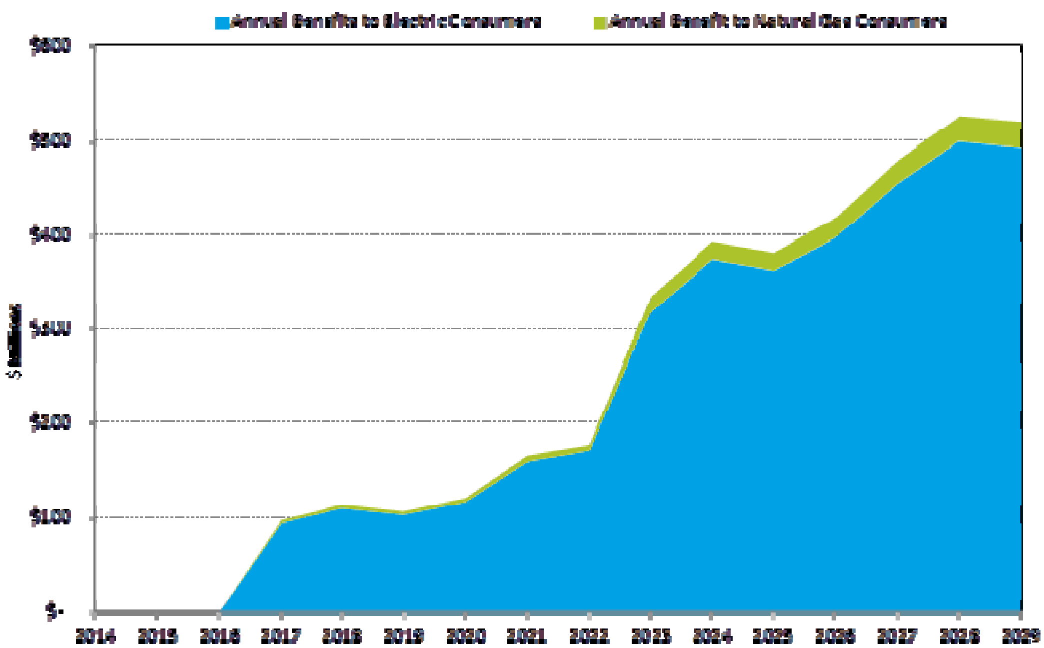

Figure 27 Cross-Regional Natural Gas Pipeline: Long-Term Benefits by Consumer Group

Firm-Based Energy Imports offer a greater net benefit than imports driven by competitive market dispatch

These net benefits are offered despite the fact that construction of generating facilities required for firm contracting requires a total cost nearly 50% greater than the cost of economic-based imports. Firm imports offer greater benefits mainly because they ensure the delivery of electricity when it is most needed in winter months. Guaranteeing electric imports under a firm contract ensures that benefits are consistently delivered to New England's electric consumers and do not fluctuate with changes in market prices or market fundamentals in Hydro Quebec.

[19] Benefits to New England electric customers are the sum of benefits to each New England electricity zone, calculated as each zone's LMP price impacts multiplied by total energy delivered in that zone.

All solutions are expected to show net costs through 2022 and net benefits thereafter

The comparative summary of costs and benefits among the three solutions analyzed is presented in Table 4 and Figure 28. Assuming 3-5-year lead time for construction, commencing in 2014, each of the three long-term solutions can be expected to show a net annual cost in the early years until its capital investment is recovered. The Cross-Regional Natural Gas Pipeline is expected to recover its capital investment fastest but none of the solutions is expected to show a net benefit until the year 2023.

Table 4 Base Case Long-Term Solution Cost Benefit Summary

Total Benefits for Long-Term Infrastructure Solutions (in Million Dollars)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Regional Pipeline	$ 97	$ 114	$ 107	$ 121	$ 165	$ 177	$ 335	$ 392	$ 381	$ 418	$ 478	$ 525	$ 519	$ 3,827	$ 294
Economic-Based Canadian Electric Imports	$ -	$ 109	$ 131	$ 153	$ 182	$ 206	$ 343	$ 334	$ 298	$ 322	$ 311	$ 382	$ 304	$ 3,075	$ 256
Firm Contract-Based Canadian Energy Imports	$ -	$ 255	$ 269	$ 362	$ 388	$ 395	$ 568	$ 530	$ 529	$ 537	$ 501	$ 572	$ 499	$ 5,405	$ 450

Total Costs for Long-Term Infrastructure Solutions (in Million Dollars)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Regional Pipeline	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 2,288	$ 176
Economic-Based Canadian Electric Imports	$ -	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 2,628	$ 219
Firm Contract-Based Canadian Energy Imports	$ -	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 4,668	$ 389

Net Benefits for Long-Term Infrastructure Solutions (in Million Dollars)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Regional Pipeline	$ (79)	$ (62)	$ (69)	$ (55)	$ (11)	$ 1	$ 159	$ 216	$ 205	$ 242	$ 302	$ 349	$ 343	$ 1,539	$ 118
Economic-Based Canadian Electric Imports	$ -	$ (110)	$ (88)	$ (66)	$ (37)	$ (13)	$ 124	$ 115	$ 79	$ 103	$ 92	$ 163	$ 85	$ 447	$ 37
Firm Contract-Based Canadian Energy Imports	$ -	$ (134)	$ (120)	$ (27)	$ (1)	$ 6	$ 179	$ 141	$ 140	$ 148	$ 112	$ 183	$ 110	$ 737	$ 61

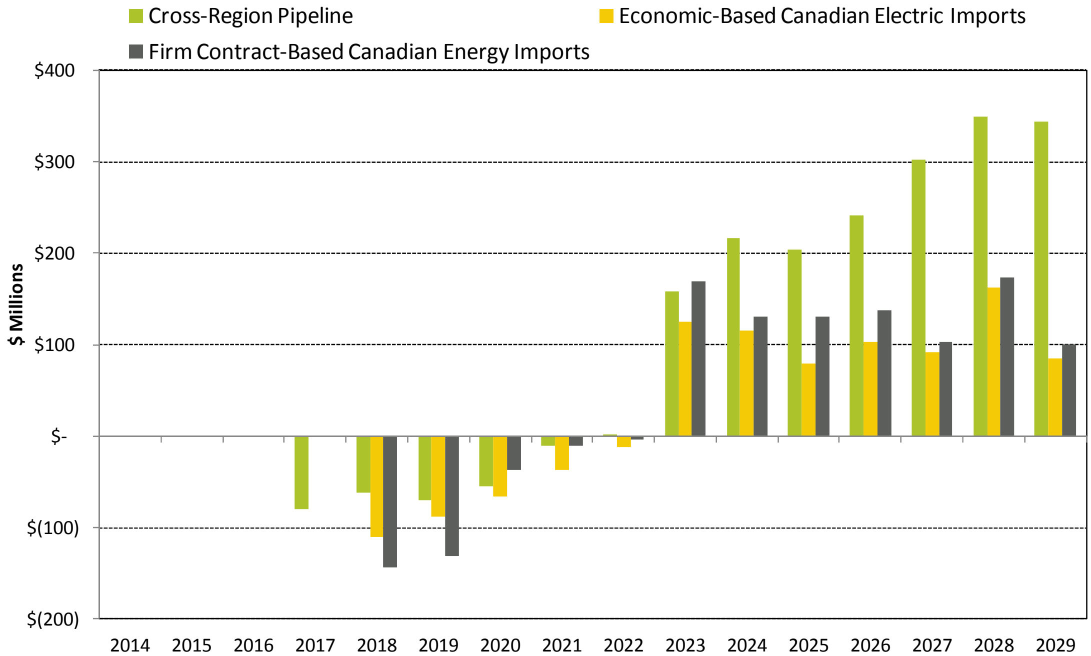

Figure 28 Net Benefits of Long-Term Solutions

7.0 Short-Term Solutions

Black & Veatch examined two potential short-term solutions that could yield net benefits as soon as the winter of 2014. Although they offer net benefits of a lesser magnitude than the long-term solutions discussed above, these short-term solutions could play an important role as part of a portfolio of solutions. Given that long-term solutions will not be in-service until 2017-2018, the short-term solutions explored in this report offer immediate benefits that can alleviate infrastructure constraints in the near term. These solutions can also be implemented on a year-to-year basis in order to serve shifting market needs.

Black & Veatch examined two potential short-term solutions to New England's natural gas infrastructure constraints:

- **LNG Imports** - An additional 300 MMcf/d of LNG imports to existing LNG receiving terminals in Saint John, New Brunswick, Canada ("Canaport") and Everett, Massachusetts, during the peak winter months of January and February.
- **Dual-Fuel and Demand Response** - An additional 2.3 Terawatt hours ("TWh")[20] of dual-fuel, fuel-oil-fired generation coupled with demand response across New England.[21]

First, Black & Veatch assessed the impact of additional LNG imports from the Canaport and Everett terminals. These terminals were chosen because Canaport and Everett have been the primary terminals serving New England during the past several winters as favored by their strategic locations and long-term supply contracts. In addition, both Canaport and Everett have access to storage and interstate pipeline interconnects that can help relieve natural gas infrastructure constraints. Black & Veatch assumes that an additional 4-5 LNG cargoes will reach these receiving terminals and deliver 300 MMcf/d (150 MMcf/d at each terminal) in peak winter months. Delivery into the New England market would be through contracts guaranteeing the provision of 18 Bcf in January and February of each year.

This analysis assumes that incremental LNG imports will be priced at $15/MMBtu in 2014 and steadily increase at around 1.0% annually over the analysis period, consistent with Black & Veatch's projected oil price trajectory. The delivered cost of additional LNG cargoes is expected to be strongly tied to oil-indexed global LNG prices, which are priced significantly higher than current wholesale prices at Algonquin City-Gates. As the growth of LNG liquefaction capacity outpaces global LNG demand, the future oil indexation of global LNG prices may weaken, thus having the effect of reducing global LNG prices for spot cargoes into New England. Black & Veatch did not incorporate the latter assumption for the analysis.

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[20] 1 TWh = 1 million MWh

[21] Dual-fuel, oil-fired generators must comply with increasingly stringent emission standards in order to be permitted, which may influence the extent and duration of some dual-fuel units' ability to contribute to a short-term solution.

Second, Black & Veatch assessed the impact of an additional 2.3 million MWh of fuel-oil-fired generation to be dispatched during peak winter months, regardless of cost. The dispatch of this generation capacity is assumed to decrease natural gas demand by 270 MMcf/d during peak winter months. Currently, the New England power generation fleet has approximately 10,200 MW of dual fuel capacity that can be dispatched into the transmission grid. When natural gas infrastructure constraints occur, these dual-fuel generation facilities can use fuel-oil-fired capacity to provide the necessary generation needed to meet the market demand. Because of high oil prices and environmental restrictions, the impact of dual-fuel generation units to relieve constraints has been limited.

The associated costs of out-of-merit dispatching[22] of fuel-oil-based generation are calculated as the "uplift costs" paid to power generators that would make them financially indifferent between using fuel oil or natural gas to generate electricity. Additional demand response was made available to dispatch into the market, albeit at prices significantly higher than the projected market clearing price.

PRICE IMPACTS

The short-term LNG imports and dual-fuel and demand response solutions have an immediate near-term impact on natural gas and electric prices

Over the first three years of the analysis period, the average peak winter monthly price impact for short-term LNG and dual-fuel and demand response is $1.62/MMBtu and $1.77/MMBtu, respectively (Figure 29). The addition of AIM reduces the effectiveness of these short-term solutions until 2020-2021, when additional natural gas demand growth spurs new pipeline constraints.

Both short-term solutions offer significant near term electric price reductions. Over the first three years of the analysis period, the short-term LNG imports and dual-fuel and demand response solutions will reduce peak winter month average electric prices by $8.13/MWh, and $9.76/MWh, respectively (Figure 30). The short-term LNG import peak winter month average price impact over the last five years of the analysis period is $10.67/MWh, about 7% greater than the dual-fuel and demand response solution.

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[22] Dual-fuel fuel-oil based generation is assumed to be "out of merit" units that will be dispatched during peak winter months. "Out of merit" refers to generation units that are not regularly dispatched through qualified scheduling or clearinghouse operations, primarily due to their offer prices relative to other resources. "Out of merit" units are typically dispatched for reliability-based considerations.

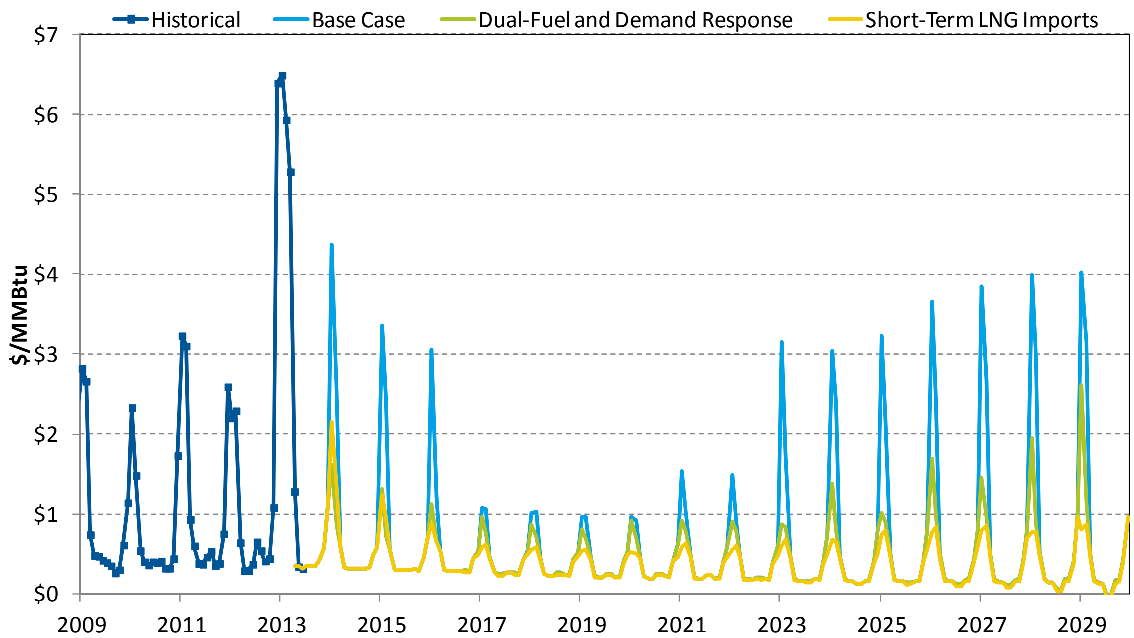

Figure 29 Monthly Algonquin City-Gates Basis to Henry Hub: Base Case vs. Short-Term Solutions
Source: *Platts historical data, Black & Veatch projection*

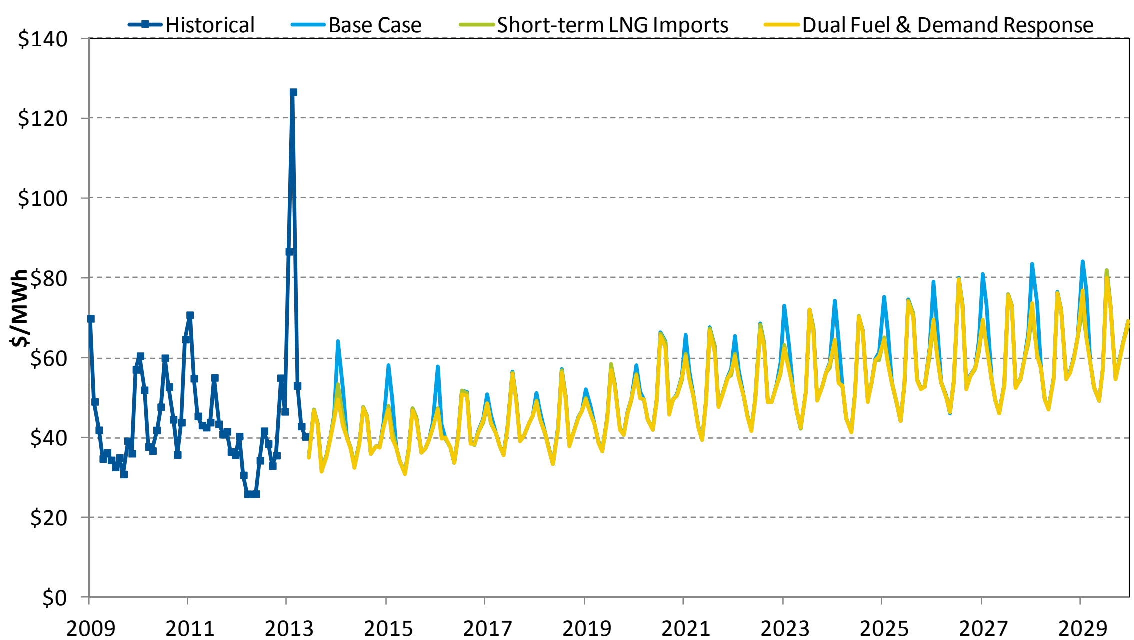

Figure 30 Boston Electric Prices: Base Case vs. Short-Term Solutions
Source: *Energy Velocity historical data, Black & Veatch projection*

BENEFITS

The short-term solutions explored under the Base Case offer significant net benefits with limited long-term capital investments

Dual-fuel generation and demand response can be implemented each year based on market demand and supply expectations. LNG imports can be implemented each year with spot cargoes or over a three-to-five-year period, as seen in supply agreements at terminals in the region.[23]

On average, both short-term solutions offer comparable net benefits.

On a year-to-year basis, LNG imports have a slight advantage over the dual-fuel and demand response solution; however Black & Veatch assumed a three-to-five year supply agreement, similar in length to Qatar Petroleum's contract with Repsol that reduced the average net benefits over the analysis period.

While spot LNG cargoes offer more flexibility, a firm supply agreement could set a fixed or indexed price on the 4-5 additional LNG cargoes, which could potentially reduce the year–to-year volatility in net costs and benefits. In the Base Case, Black & Veatch assumed a five-year supply agreement starting at $15/MMBtu, which is the current contract price for LNG cargoes delivered to Europe and Asia.

Dual-fuel generation and demand response can also provide significant near-term and long-term benefits, especially in sub-regions with the highest level of pipeline constraints

The geographic location of reductions in demand is an important factor in determining the net benefits of this solution. Namely, demand reductions in eastern New England are more effective in lowering regional natural gas and electric prices than reductions in other New England regions. Black & Veatch believes that prioritizing dual-fuel generation capacity would be most effective in sub-regions with the highest level of pipeline constraints including Maine, New Hampshire, Rhode Island, and Eastern Massachusetts.

[23] As shown in Table 5 and Figure 29, the optional nature of deciding whether to pursue either of these solutions on a year-to-year basis affects the associated net benefits. For years in which dual-fuel and demand response are expected to result in negative net benefits, the option not to pursue the solution is reflected. For LNG, an initial five-year supply contract was assumed, which results in two years of negative net benefits after the AIM in-service date of 2016. Excluding the two years of negative benefits would have increased the average annual net benefits to $138 million for the LNG imports solution.

Table 5 Base Case Short-term Solution Cost Benefit Summary

Total Benefits for Short-Term Infrastructure Solutions (in Million Dollars)																	
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Short-term LNG Imports	$ 289	$ 297	$ 227	$ 74	$ 69	$ 67	$ 68	$ 119	$ 106	$ 278	$ 342	$ 307	$ 331	$ 385	$ 441	$425	$3,824	$ 232
Dual Fuel and Demand Response	$ 425	$ 349	$ 274	$ 97	$ 104	$ 104	$ 105	$ 158	$ 141	$ 337	$ 385	$ 325	$ 346	$ 385	$ 440	$365	$4,342	$ 266

Total Costs for Short-Term Infrastructure Solutions (in Million Dollars)																		
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Short-term LNG Imports	$ 180	$ 174	$ 175	$ 182	$ 184	$ 186	$ 189	$ 191	$ 193	$ 195	$ 197	$ 199	$ 202	$ 204	$ 206	$209	$3,066	$ 195
Dual Fuel and Demand Response	$ 250	$ 260	$ 275	$ 265	$ 267	$ 266	$ 275	$ 265	$ 268	$ 269	$ 277	$ 270	$ 275	$ 277	$ 294	$279	$4,333	$ 273

Net Benefits for Long-Term Infrastructure Solutions (in Million Dollars)																		
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Short-term LNG Imports	$ 109	$ 123	$ 52	$ (107)	$ (115)					$ 83	$ 145	$ 108	$ 129	$ 181	$ 234	$216	$1,157	$ 96
Dual Fuel and Demand Response	$ 175	$ 89								$ 68	$ 108	$ 55	$ 72	$ 107	$ 146	$ 86	$ 906	$ 101

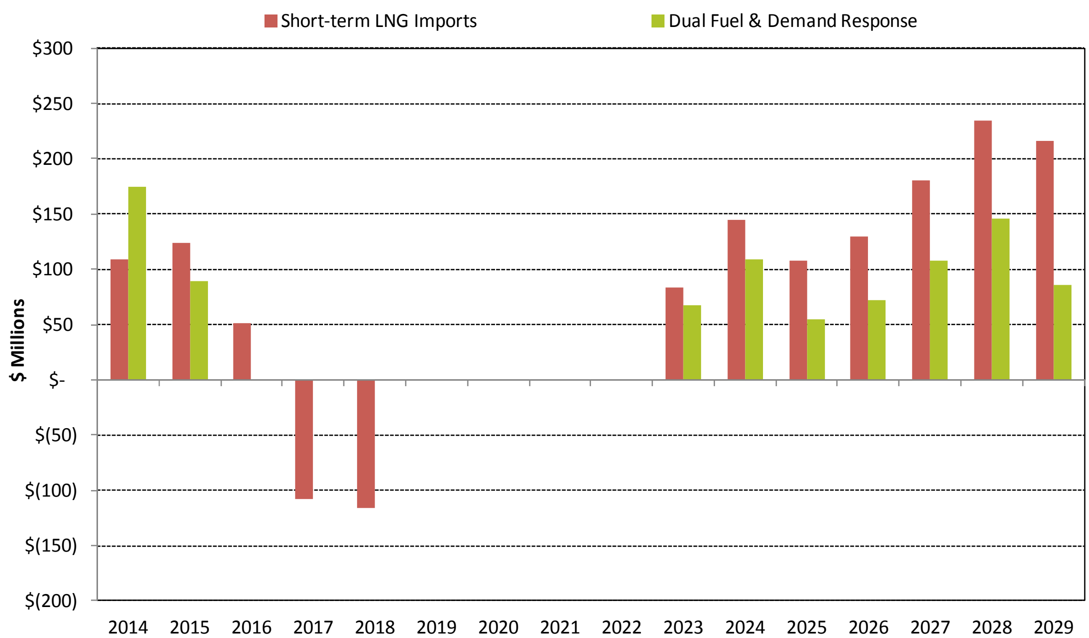

Figure 31 Net Benefits of Short-Term Solutions

8.0 High Demand Scenario

ASSUMPTIONS

Black & Veatch created a High Demand Scenario that assumes, relative to the Base Case, a tighter natural gas demand and supply environment across New England and North America as a whole in order to explore the consequences of increased stress on New England's natural gas infrastructure. In the High Demand Scenario, Black & Veatch assumed:

1. All New England states implement incentives to encourage increased residential and commercial usage of gas similar to Connecticut's Comprehensive Energy Strategy. However, Black & Veatch lowered assumptions for growth in customer penetration in states that already have high rates of penetration. For example, compared to Connecticut's 2.2% per annum growth in residential demand, residential demand in Rhode Island is assumed to grow at 2.0% per annum.
2. New England states are expected to meet 75% of their RPS targets, rather than the 100% assumed in the Base Case. This assumption increases electric-sector demand for natural gas.
3. Lower energy efficiency achievement increases net load growth. The growth rate in energy efficiency was lowered to achieve a 0.20% per year growth rate in electric energy demand over the study period, versus the 0.18% in the more energy-efficient Base Case.
4. Expedited nuclear power plant deactivations increase natural gas demand, due to assumed energy replacement from gas-fired power generators. In the Base Case, three nuclear units (Pilgrim, VT Yankee, and Millstone II) are assumed to be deactivated concurrent with licenses expiring in the 2032-2035 time period. In the High Demand Scenario, the licenses are assumed to expire five years sooner.
5. An additional 4 Bcf/d of LNG (relative to the Base Case) is assumed to be exported from the Gulf Coast and West Coast between 2017 and 2020, reducing the availability of gas supplies from the Gulf Coast and Appalachian shales to meet New England demand.
6. The M&NP can reverse flow to Canada when arbitrage opportunities between prices in New England and Eastern Canada present themselves.

Figure 32 summarizes New England natural gas demand that was assumed in the High Demand Scenario, which exceeds the Base Case projection by 300 MMcf/d by 2029. Electric-sector demand only slightly exceeds Base Case projections until 2027, when the accelerated nuclear license expiration occurs and gas demand rises further.

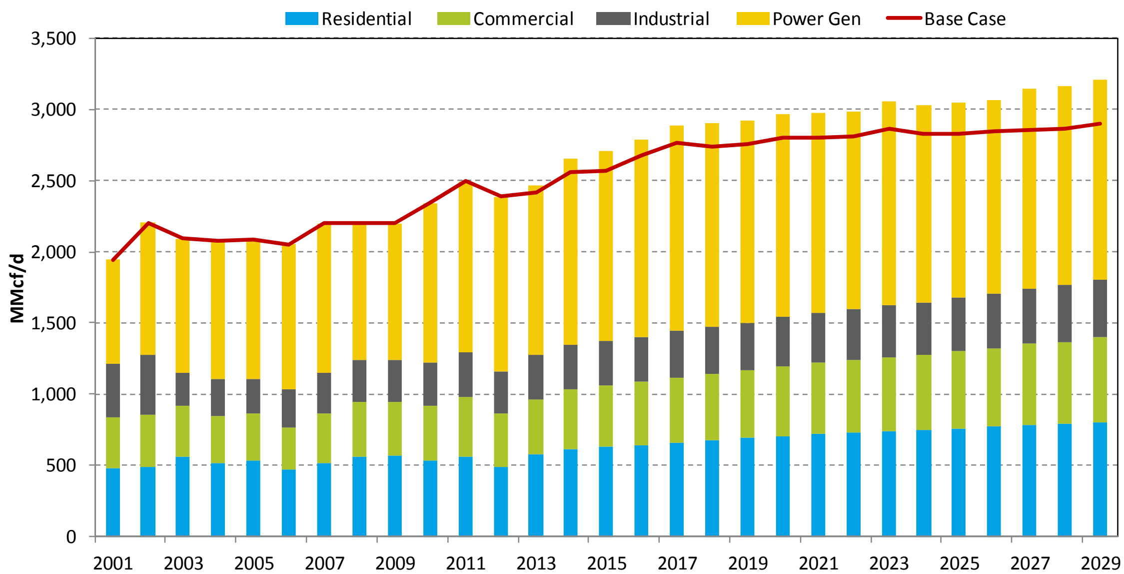

Figure 32 New England Natural Gas Demand: High Demand Scenario

PRICE IMPACTS

New England natural gas basis in the High Demand Scenario, as in the Base Case, is projected to moderate relative to the extremes experienced in the winter of 2012-2013

Similar to the Base Case, this decline results from the assumption of normal weather conditions and growth in Deep Panuke production. However, average monthly projected basis in the High Demand Scenario exceeds the Base Case forecast by $2-$4/MMBtu during peak winter months in 2014-2016 (Figure 33).

Basis is then expected to decrease to levels nearly identical to the Base Case starting in 2017, after AIM begins service, maintaining this level until 2022. This indicates that AIM will be able to provide sufficient capacity to meet the additional demand projected in the High Demand Scenario. The New England market remains free of constraints during this period. Beginning in 2023, however, peak winter monthly basis in the High Demand Scenario is expected to greatly exceed Base Case projections, achieving levels near $8.00/MMBtu (Figure 33). By 2026, peak winter monthly basis is projected to exceed the historical highs reached in the winter of 2012-2013 as pipeline constraints increase in frequency and severity.

In the High Demand Scenario, the monthly average energy price in January is $15-$25/MWh higher than the Base Case and exceeds $100/MWh after 2027

In the non-winter months of the analysis period, when the natural gas market is not constrained, the energy price is very similar to that in the Base Case. However, after 2027, energy prices in each month are slightly higher (Figure 34) due to expedited nuclear license expiration resulting in more natural gas-fired capacity being dispatched.

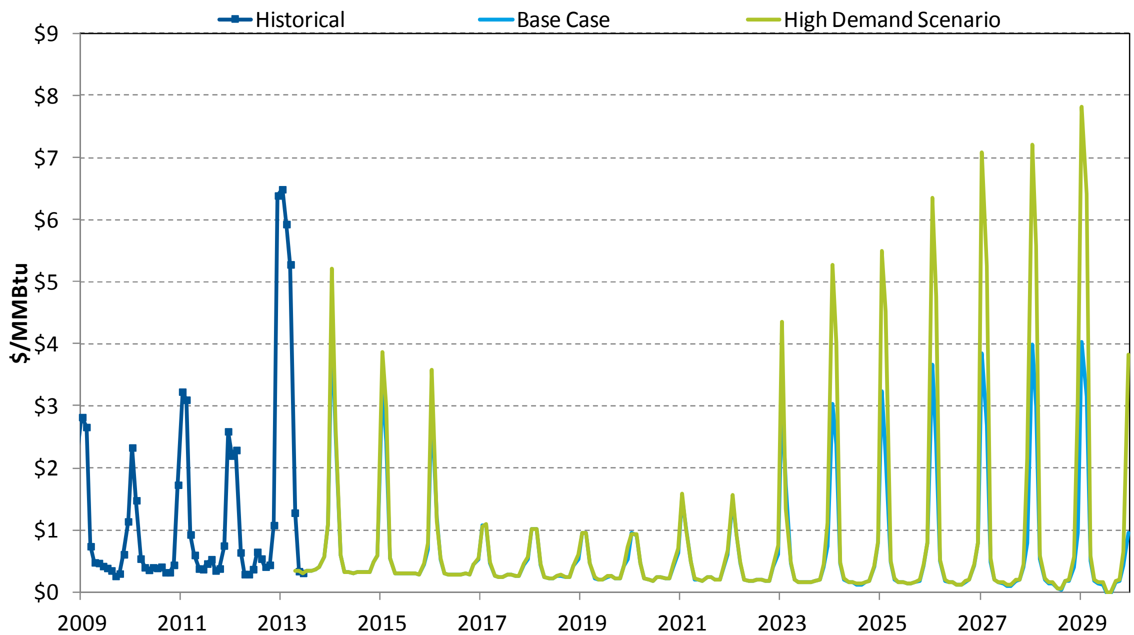

Figure 33 Monthly Algonquin City-Gates Basis to Henry Hub: Base Case vs. High Demand Scenario
Source: Platts historical data, Black & Veatch projection

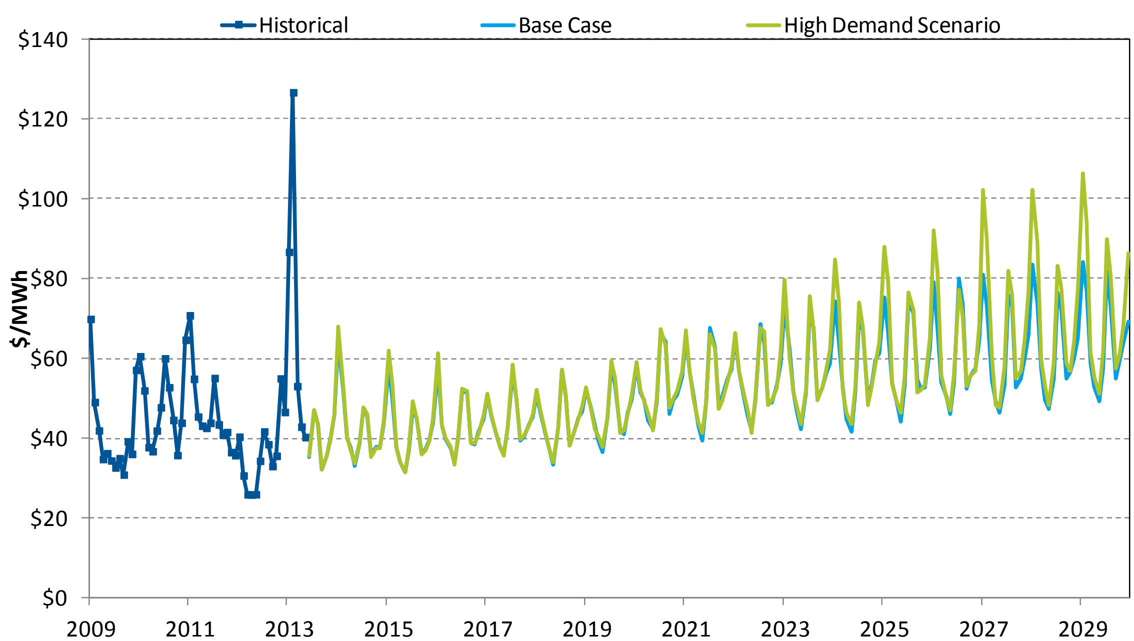

Figure 34 Boston Electric Prices: Base Case vs. High Demand Scenario
Source: *Energy Velocity historical data, Black & Veatch projection*

Black & Veatch calculated the total costs to New England natural gas end-use customers and electric customers as a result of the higher natural gas demand in the High Demand Scenario. Without any infrastructure solutions, higher-than-Base Case demand growth from policy initiatives in the residential, commercial, and industrial sectors combined with the effects of expedited nuclear deactivation will result in higher natural gas and energy prices in New England. On average, during the analysis period, the higher demand will raise costs for New England natural gas customers by $11 million per year and for electric customers by $360 million per year relative to the Base Case.

INFRASTRUCTURE SOLUTIONS

Black & Veatch tested three solutions under the High Demand Scenario: the construction of a cross-regional pipeline, short-term LNG imports, and firm Canadian energy imports (as electricity). The configurations, capacities, and costs associated with these solutions are identical to those used in the Base Case. Figure 35 shows each solution's projected impact on monthly natural gas basis in New England for the High Demand Scenario.

The construction of a cross-regional pipeline offers the incremental pipeline capacity required to alleviate infrastructure constraints and eliminate seasonal increases in basis even when robust demand growth is assumed to occur across New England.

LNG imports offer significant basis reductions in the near term, but these reductions diminish in the later years of the analysis period as robust demand growth causes total demand to reach levels too great for 300 MMcf/d of LNG imports to significantly impact seasonal constraints. For example, monthly Algonquin City-Gates basis exceeds $3.00/MMBtu in 2028 and 2029.

Firm Canadian energy imports could reduce monthly basis by $1.00-$2.00/MMBtu in the initial years of the analysis period, but this reduction diminishes in later years. The limited price reduction indicates that under the High Demand Scenario, 1,200 MW of the firm Canadian energy imports does not reduce the demand in peak winter months by a level that is sufficient to mitigate large seasonal price increases.

As a result of the lower natural gas prices achieved via the cross-regional pipeline or the import of LNG, each of these solutions will reduce power prices by a respective $30/MWh and $25/MWh in peak winter months

Firm Canadian imports are expected to reduce power prices in peak winter months, on average, by approximately $20/MWh (Figure 36). In addition, these imports introduce low-cost hydro-electric energy to the energy supply stack that is projected to lower average power prices by $3-5/MWh in non-winter months, a benefit not achieved through the construction of a cross-regional pipeline or LNG imports.

All three solutions examined under the High Demand Scenario provide greater benefits to New England consumers than observed in the Base Case

Notably, benefits increase by nearly $200 million per year for the construction of a cross-regional pipeline, $140 million per year for short-term LNG imports, and $62 million per year for firm Canadian electric imports, relative to the Base Case. A large portion of these benefits are captured in the latter half of the analysis period. As observed under the Base Case, the construction of a cross-regional pipeline is expected to offer higher benefits for a lower cost than the other solutions explored under the High Demand Scenario (Table 6).

LNG imports are an effective short-term solution, especially in the immediate future before AIM is placed in service.

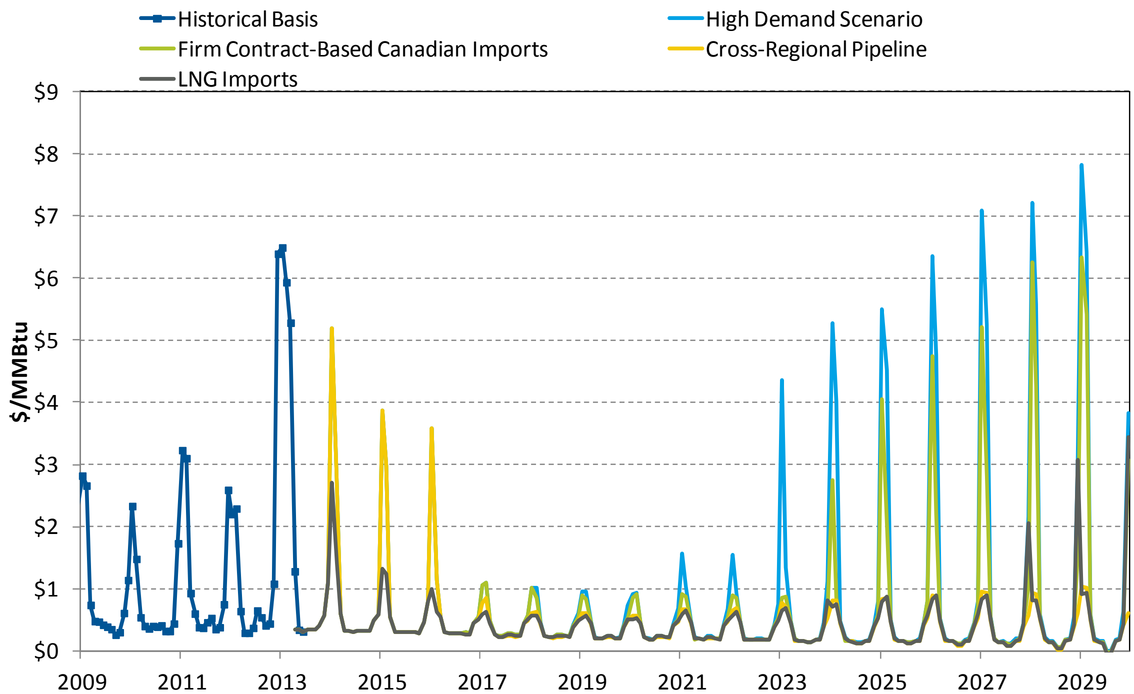

Figure 35 Monthly Algonquin City-Gates Basis to Henry Hub: High Demand Scenario
Source: Platts historical data, Black & Veatch projection

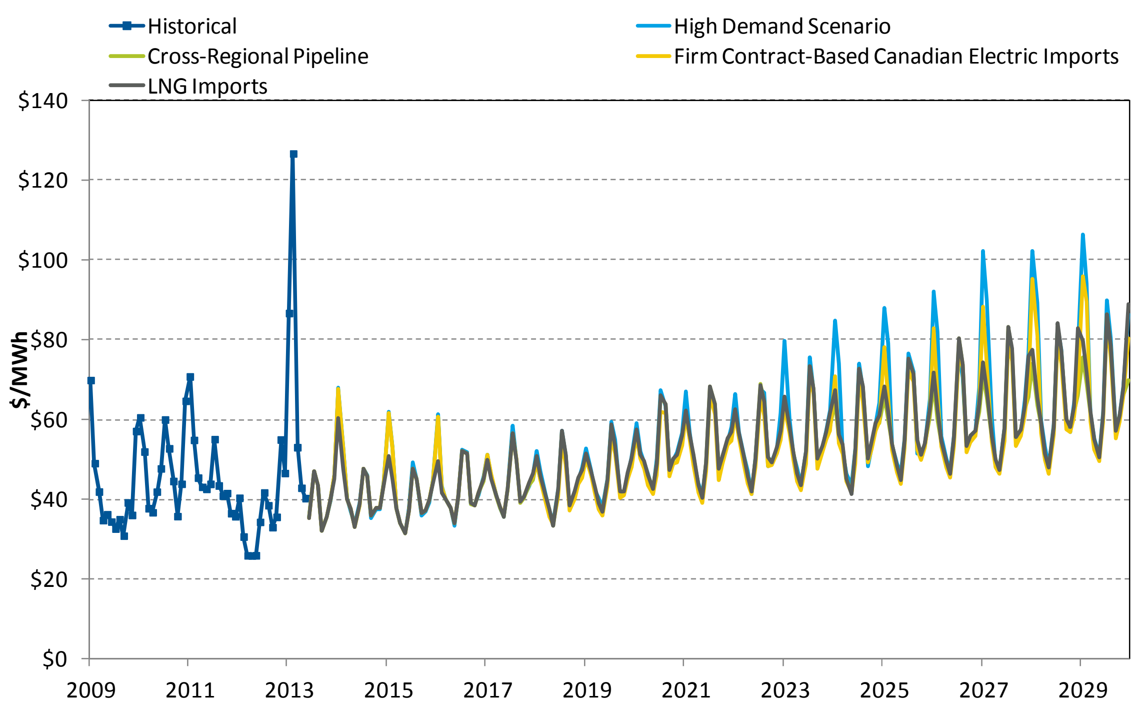

Figure 36 Boston Electric Prices: Base Case vs. High Demand Scenario
Source: *Energy Velocity historical data, Black & Veatch projection*

In the High Demand Scenario, on average, the cross-regional pipeline solution provides total benefits of $28 million per year to natural gas end-use customers and $488 million to electric customers.

Table 6 High Demand Scenario Cost-Benefit Summary

Total Benefits for Infrastructure Solutions (in Millions of Dollars)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Region Pipeline	$ -	$ -	$ -	$ 94	$ 113	$ 127	$ 122	$ 79	$ 177	$ 407	$ 687	$ 719	$ 740	$1,050	$1,096	$1,300	$ 6,712	$ 516
LNG Imports	$ 301	$ 349	$ 250	$ 67	$ 69	$ 59	$ 69	$ 121	$ 103	$ 310	$ 589	$ 630	$ 683	$ 849	$ 837	$ 875	$ 6,159	$ 433
Firm Contract Based Canadian Energy Imports	$ -	$ -	$ -	$ -	$ 264	$ 270	$ 333	$ 296	$ 385	$ 621	$ 763	$ 623	$ 557	$ 781	$ 613	$ 634	$ 6,139	$ 512

Total Costs for Infrastructure Solutions (in Millions of Dollars)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Region Pipeline	$ -	$ -	$ -	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 2,288	$ 176
LNG Imports	$ 180	$ 174	$ 175	$ 182	$ 184	$ 186	$ 189	$ 191	$ 193	$ 195	$ 197	$ 199	$ 202	$ 204	$ 206	$ 209	$ 3,066	$ 196
Firm Contract Based Canadian Energy Imports	$ -	$ -	$ -	$ -	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 4,668	$ 389

Net Benefits for Infrastructure Solutions (in Millions of Dollars)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Region Pipeline	$ -	$ -	$ -	$ (82)	$ (63)	$ (49)	$ (54)	$ (97)	$ 1	$ 231	$ 511	$ 543	$ 564	$ 874	$ 920	$1,124	$ 4,424	$ 340
LNG Imports	$ 121	$ 175	$ 75	$(115)	$(115)	$ -	$ -	$ -	$ -	$ 115	$ 392	$ 430	$ 482	$ 645	$ 630	$ 666	$ 3,093	$ 236
Firm Contract Based Canadian Energy Imports	$ -	$ -	$ -	$ -	$(125)	$(119)	$ (56)	$ (93)	$ (4)	$ 232	$ 374	$ 234	$ 168	$ 392	$ 224	$ 245	$ 1,471	$ 123

DESIGN DAY SENSITIVITY

Black & Veatch constructed a design-day[24] sensitivity to assess the additional costs that New England natural gas and electric consumers might risk from an extreme cold event that could theoretically occur for an entire month throughout the study period. Black & Veatch analyzed the historical weather data and identified that January 9, 2004 through January 16, 2004 are the coldest seven days New England experienced since 1983, with an average temperature of 10.6 degrees Fahrenheit over the seven day period.

Black & Veatch analyzed the residential and commercial demand sensitivity to temperature in December, January, and February using data from 1989, the first year for which historical monthly residential and commercial data are publically available from the Energy Information Agency ("EIA"). The strongest correlation between natural gas demand and weather was observed in data from 2008 to 2013. Using the 2008 to 2013 weather and demand relationship, Black & Veatch adjusted the forecasted residential and commercial demand to reflect design-day conditions.

Black & Veatch developed this sensitivity by hypothetically assuming that the entire month of January would be as cold as its coldest seven days in the post-1983 historical records. The demand adjustment was based on the calculation that had January 2004 been as cold as its coldest seven days, New England residential and commercial consumption for this month would have been 2.56 times the 2004 annual average. Thus, the 2.56 multiplier was

[24] Design day refers to the coldest day in a 20 or 30 year time period. LDCs typically plan for sufficient supply to meet their load requirements under the design-day condition. In this analysis, the design day condition refers to the maximum daily HDD value for coldest consecutive 7-day period over the past 30 years, which included multiple days of design-day or near-design-day conditions.

applied to the baseline High Demand Scenario forecast to construct January residential and commercial demand with design-day weather conditions for every year through the analysis period.

Figure 37 shows that design-day demand increases from 4,000 MMcf/d to over 5,000 MMcf/d, exceeding all available capacity (including AIM) in 2027. However, historically, the New England market has been constrained when deliveries approach 75% of available capacity. As a result, a deficiency in deliverable capacity of over 500 MMcf/d is expected to develop under a design-day condition.

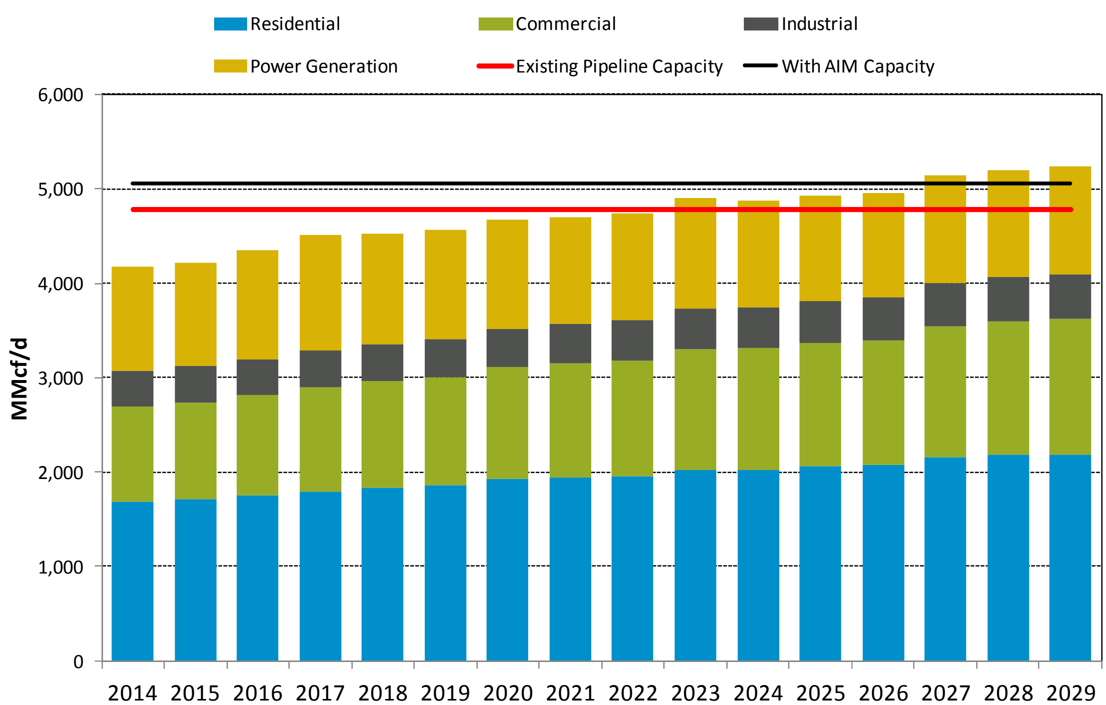

Figure 37 Projected January Design-Day Demand

The 500 MMcf/d constraint will be embodied in the market as extremely high and volatile natural gas prices. The monthly basis at Algonquin City-Gates is projected to rise above $10/MMBtu, exceeding historical highs experienced in the winter of 2012-2013, and daily prices will spike up to $35/MMBtu, as shown in Figure 38.

Natural gas price spikes attributable to design-day weather conditions will have a significant impact on electric prices. Similar to Figure 39, the projected monthly average electric prices are expected to approach $120/MWh under design-day conditions defined for natural gas.

As January basis and electricity prices spike to unprecedented levels under design-day conditions, the associated incremental cost to New England customers will rise significantly

The cost associated with a design-day condition is the incremental cost that New England natural gas and electric customers pay in January under the hypothetical design-day condition relative to the Base Case and High Demand Scenario where the weather conditions in January are normal. As shown in Table 7, under design-day conditions, New England natural gas end customers and electric customers will pay on average $21 million more per day relative to normal weather conditions under the High Demand Scenario in January and $24 million more per day under the Base Case.

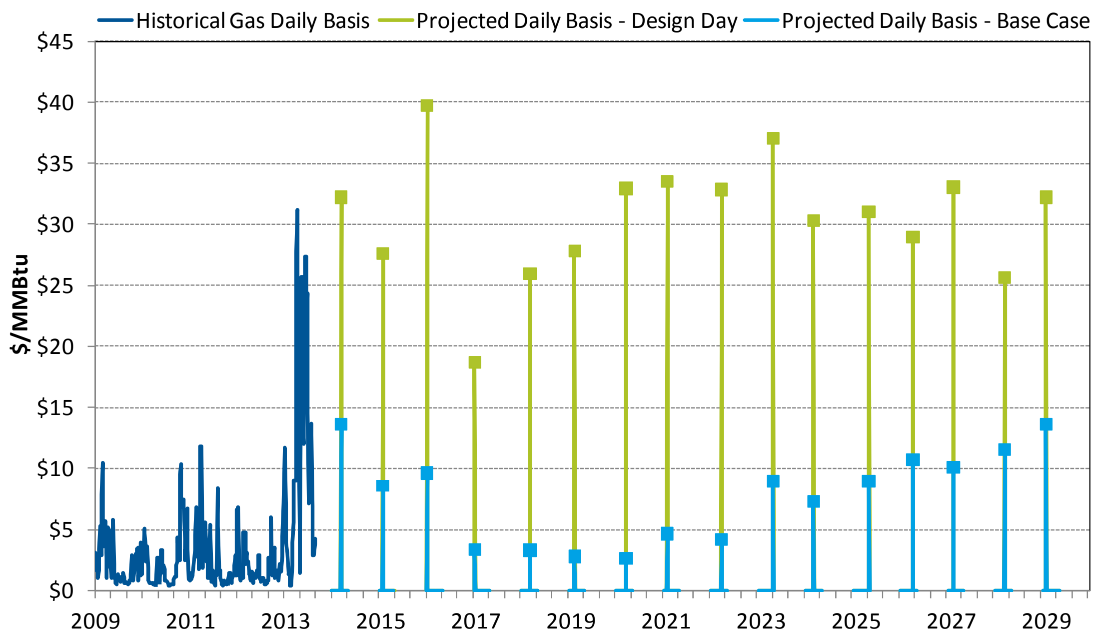

Figure 38 Daily Algonquin City-Gates Basis to Henry Hub: Base Case vs. Design Day
Source: *Platts historical data, Black & Veatch projection*

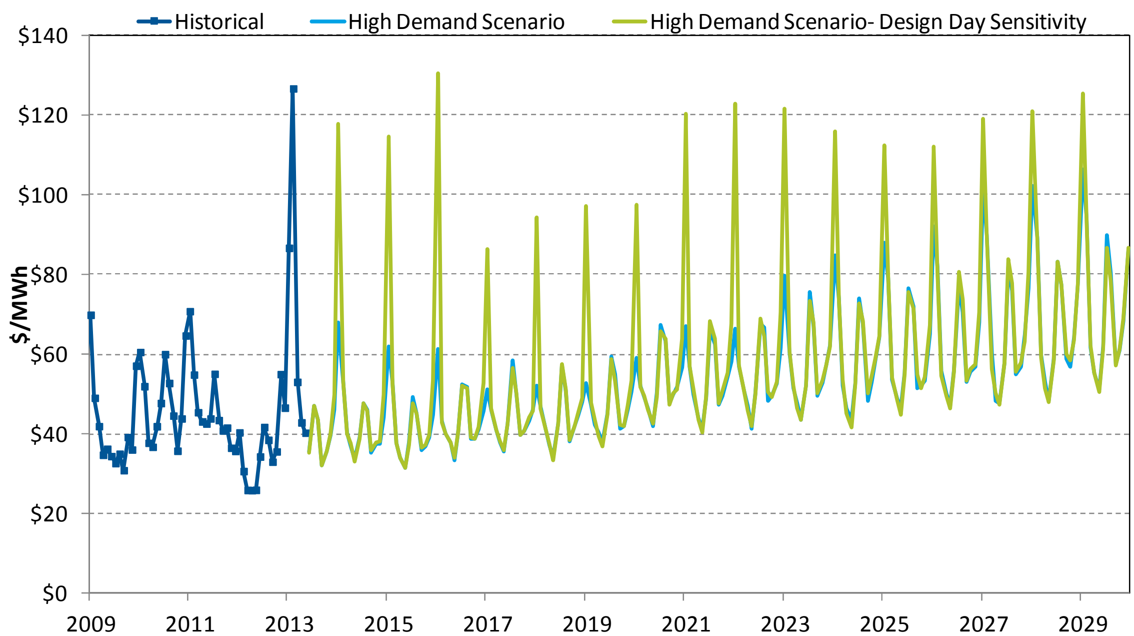

Figure 39 Boston Electric Prices: Base Case vs. High Demand Design Day Scenario
Source: *Energy Velocity historical data, Black & Veatch projection*

Table 7 January Design Day Weather Cost Summary

Total Costs (in Millions of Dollars/Per Day)																		
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Design Day over High Demand Scenario	$ (26)	$ (28)	$ (35)	$ (19)	$ (23)	$ (25)	$ (22)	$ (28)	$ (30)	$ (23)	$ (17)	$ (14)	$ (11)	$ (9)	$ (10)	$ (11)	$ (333)	$ (21)
Design Day over Base Case Scenario	$ (27)	$ (29)	$ (36)	$ (19)	$ (23)	$ (25)	$ (22)	$ (28)	$ (30)	$ (25)	$ (22)	$ (20)	$ (18)	$ (20)	$ (20)	$ (22)	$ (386)	$ (24)

9.0 Low Demand Scenario

ASSUMPTIONS

This scenario assumes no growth in natural gas demand in the residential, commercial, and industrial sectors. This demand trajectory could be attributed to the continued decline in per-customer usage, reflective of energy efficiency that offsets increases in the number of customers. Successful implementation of distributed renewable resources, such as solar thermal and geothermal, could also contribute to a future with flat demand growth as these technologies serve customers that otherwise would have used natural gas.

The net electric load is assumed to remain flat in the Low Demand Scenario as gains in energy efficiency offset customer load growth. Figure 40 shows that New England natural gas demand in 2014 is 100 MMcf/d lower in the Low Demand Scenario than in the Base Case; the difference grows to 400 MMcf/d by 2029.

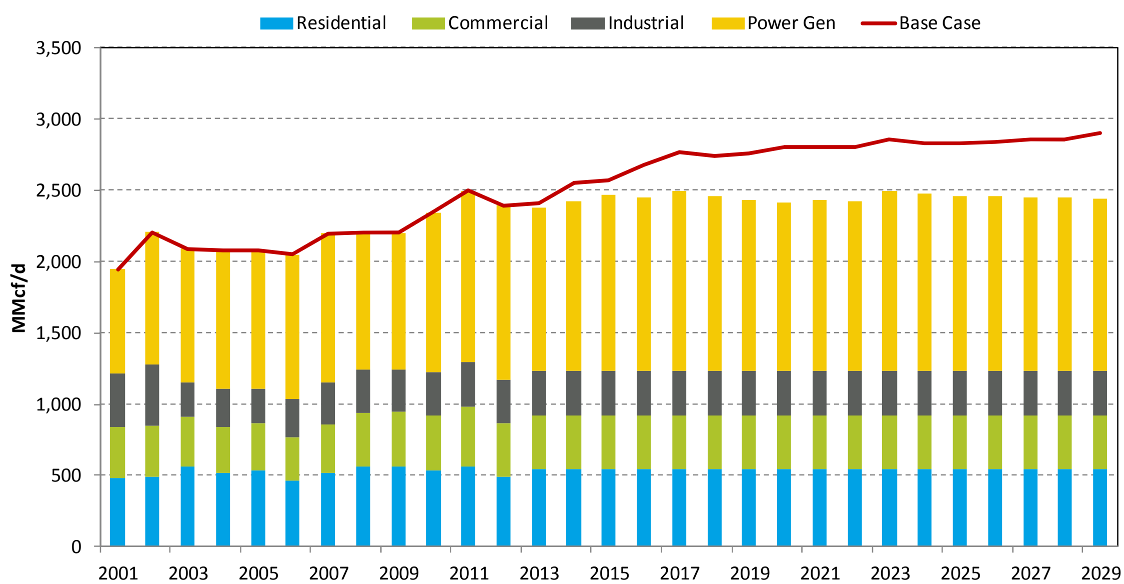

Figure 40 New England Natural Gas Demand: Low Demand Scenario

PRICE IMPACTS

Under the Low Demand Scenario, monthly natural gas basis in New England is expected to decline from $2.00/MMBtu in 2014 to $1.00/MMBtu in 2016 during the peak winter months

The Low Demand Scenario shows an average monthly basis decrease of more than $2.00/MMBtu relative to the Base Case. After AIM is placed in service, monthly basis will remain below $1.00/MMBtu throughout the analysis period. Daily gas prices are also expected to have low volatility and remain stable. This basis trend indicates that under the Low Demand Scenario AIM will eliminate most regional constraints (Figure 41).

As a result, the monthly average electricity prices in the New England electricity zones are projected to be $15-20/MWh lower than in the Base Case, and, for most of the analysis period, to stay below $70/MWh (Figure 42).

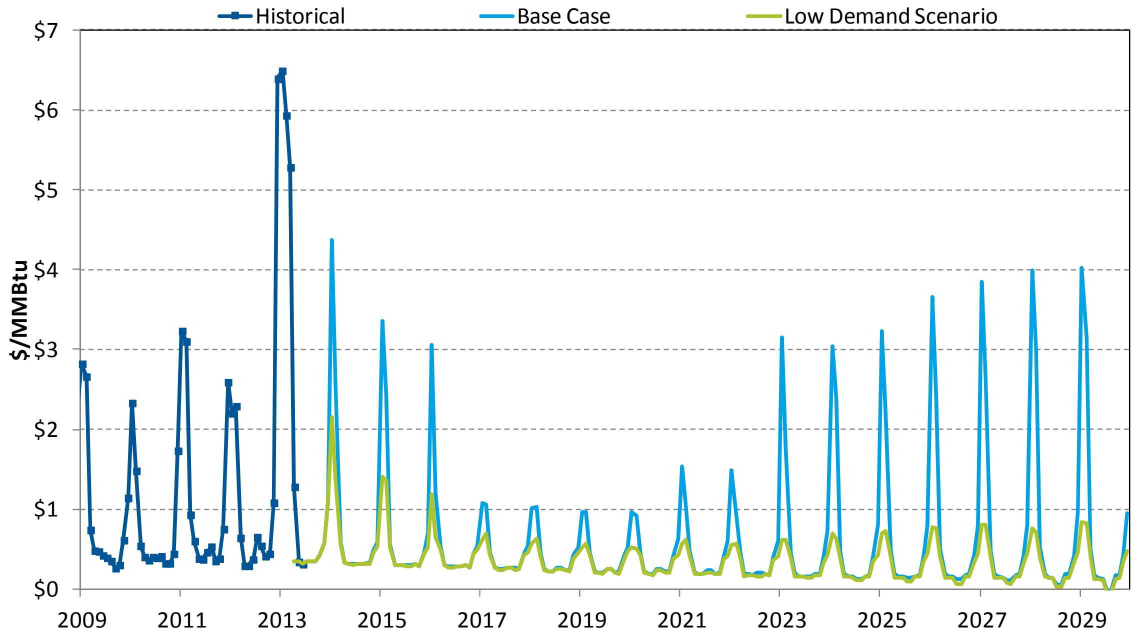

Figure 41 Monthly Algonquin City-Gates Basis to Henry Hub: Low Demand Scenario
Source: *Platts historical data, Black & Veatch projection*

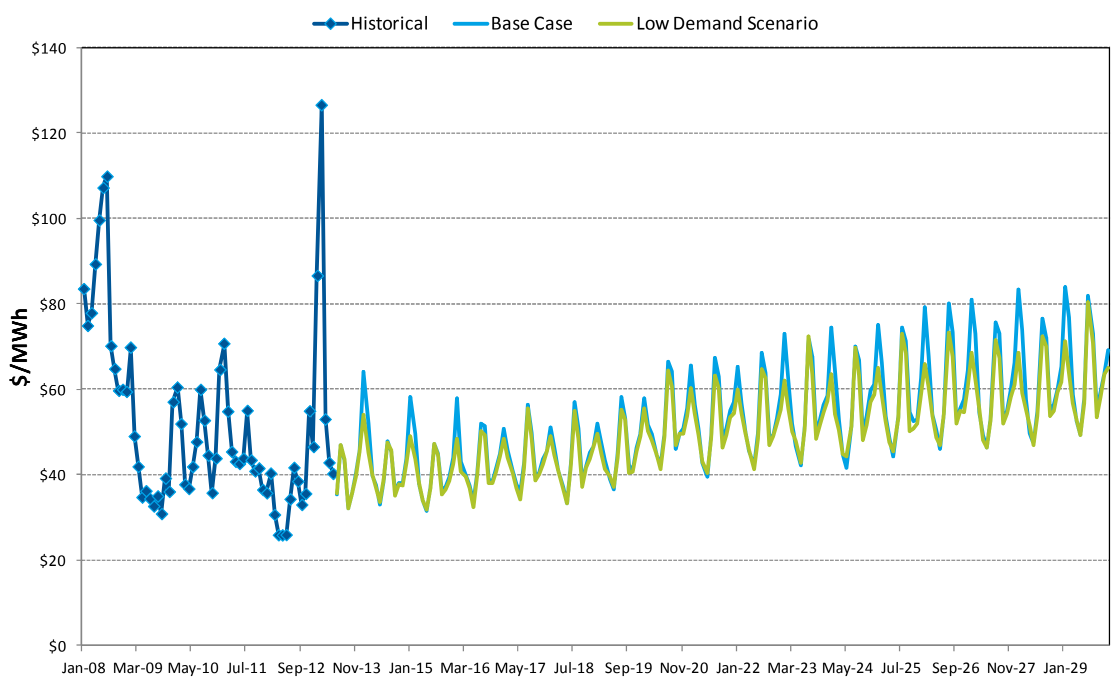

Figure 42 Historical and Projected Boston Electric Prices
Source: *ISO-NE historical data, Black & Veatch projection*

Black & Veatch also calculated the associated cost reduction for natural gas and electric customers under the Low Demand Scenario compared to the Base Case. These hypothetical savings can be used to approximate benefits of implementing energy efficiency and other demand-side management programs or of encouraging greater penetration of renewable thermal heating applications and non-natural gas-powered distributed generation that help to create a flat natural gas demand trajectory.[25] Compared to the Base Case, under the Low Demand Scenario natural gas and electric customers in New England, on average, pay $411 million per year less.

INFRASTRUCTURE SOLUTIONS

Black & Veatch tested three solutions under the Low Demand Scenario: LNG peak shaving facilities, Firm-Based Energy Imports (as electricity from eastern Canada), and dual-fuel generation and demand response. The assumptions associated with the Canadian energy imports and dual-fuel generation and demand response solutions are the same as previously described. The costs associated with the firm Canadian energy imports are the same as in the Base Case. However, the costs of the dual-fuel generation are expected to be different under this scenario given that the costs should reflect real-time "uplift costs" – the amount of costs that generators incur by dispatching "out-of-merit" energy into the market that are not fully recovered by receiving energy market prices.

LNG peak-shaving facilities are designed to provide natural gas supplies during peak winter days for a very short period of time. Black & Veatch assumed two peak-shaving facilities, 1.1 Bcf each; one in Eastern Massachusetts and one in Rhode Island, where the analysis showed that pipeline capacity constraints exist for more than 10 days each year. Each facility can deliver 60 MMcf/d of natural gas for 18 days[26]. Black & Veatch estimated that each facility will cost $120 million to construct[27]. Total capital costs for the proposed facilities are $240 million. Using an assumed capital structure of 47% debt and 53% equity, a 7.8% required rate of return on the debt and 14% return on equity, the same as for the Cross-Regional Natural Gas Pipeline cost structure assumption, Black & Veatch determined that the LNG peak shaving solution costs $31 million per year.

As shown in Table 8, the benefits associated with all three solutions are much lower in the Low Demand Scenario than in the Base Case. As stated before, the AIM project eliminates the natural gas infrastructure constraints in New England. No solutions to increase supply or reduce demand are absolutely necessary after AIM is put in service because of the limited regional natural gas demand growth. The benefits associated with the Canadian energy import solution were 54% lower relative to the Base Case. Dual-fuel generation benefits are

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[25] The costs associated with programs and measures that could achieve the extent of assumed demand reduction in the Low Demand Scenario are not known. Further analysis would be required to estimate such costs for comparison with customer savings and/or infrastructure solutions.

[26] The peak-shaving facilities are assumed to have a liquefaction rate of 8.6 MMcf/day and a vaporization rate of 60 MMcf/day, implying a 130-day filling period for an 18-day dispatch.

[27] The cost estimates for LNG peak-shaving facilities are based on Black & Veatch's Energy division experience in building these facilities across North America.

20% of the Base Case levels. LNG peak shaving facilities yield benefits of only $8 million per year.

After considering the costs associated with each infrastructure solution, no tested solution yielded a positive net benefit. Therefore, under the Low Demand Scenario, the existing natural gas infrastructure in New England is sufficient to support both the natural gas and electric demand after AIM is placed into service and no further solutions are economically necessary.

Table 8 Low Demand Cost Benefit Summary

Total Benefits for Infrastructure Solutions (in Millions of Dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
LNG Peak Shaving	$ -	$ -	$ -	$ 1	$ 0	$ 2	$ 10	$ 12	$ 6	$ 3	$ 10	$ 14	$ 12	$ 17	$ 13	$ 9	$ 108	$ 8
Dual-Fuel & Demand Response	$ 135	$ 130	$ 78	$ 43	$ 43	$ 35	$ 53	$ 58	$ 46	$ 44	$ 61	$ 63	$ 57	$ 75	$ 27	$ 65	$ 1,013	$ 52
Firm Contract-Based Canadian Energy Imports	$ -	$ -	$ -	$ -	$ 197	$ 219	$ 284	$ 193	$ 241	$ 268	$ 238	$ 268	$ 199	$ 200	$ 204	$ 249	$ 2,760	$ 230

Total Costs for Infrastructure Solutions (in Millions of Dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
LNG Peak Shaving	$ -	$ -	$ -	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 403	$ 31
Dual-Fuel & Demand Response	$ 254	$ 267	$ 278	$ 269	$ 270	$ 269	$ 280	$ 270	$ 273	$ 274	$ 282	$ 277	$ 283	$ 288	$ 304	$ 296	$ 4,434	$ 280
Firm Contract-Based Canadian Energy Imports	$ -	$ -	$ -	$ -	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 4,668	$ 389

Net Benefits for Infrastructure Solutions (in Millions of Dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
LNG Peak Shaving	$ -	$ -	$ -	$ (30)	$ (31)	$ (29)	$ (21)	$ (19)	$ (25)	$ (28)	$ (21)	$ (17)	$ (19)	$ (14)	$ (18)	$ (22)	$ (295)	$ (23)
Dual-Fuel & Demand Response	$(119)	$(137)	$(200)	$(226)	$(227)	$(234)	$(226)	$(212)	$(227)	$(230)	$(221)	$(214)	$(227)	$(213)	$(277)	$(231)	$(3,421)	$ (228)
Firm Contract-Based Canadian Energy Imports	$ -	$ -	$ -	$ -	$(192)	$(170)	$(105)	$(196)	$(148)	$(121)	$(151)	$(121)	$(190)	$(189)	$(185)	$(140)	$(1,908)	$ (159)

NEGATIVE DEMAND GROWTH SENSITIVITY

Black & Veatch examined a sensitivity that assumed natural gas demand would decline as a result of even greater penetration of electric and gas energy efficiency and demand-side management programs, thermal heating applications, non-natural gas-powered distributed electric generation and increased renewable policy goals.[28] In the residential, commercial, and industrial sectors, Black & Veatch assumed a 1% decline in natural gas demand by 2020 and a 2% decline by 2030, and that efficiency gains would to reduce net electric loads by 1% in 2020 and 2% by 2030.

The Negative Demand Growth Sensitivity reduces total New England demand by less than 50 MMcf/day, compared to the Low Demand Scenario, with the greatest reductions observed in January and July (Figure 43).

As the demand is not significantly lower for the Negative Demand Growth Sensitivity, the resulting natural gas and electricity prices are not much different from those observed in the Low Demand Scenario. When compared with the Low Demand Scenario, the Negative

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[28] The costs associated with programs and measures that could achieve the extent of assumed demand reduction in the Negative Demand Growth Sensitivity are not known. Further analysis would be required to estimate such costs for comparison with customer savings.

Demand Growth Sensitivity, on average, only reduces Algonquin City-Gates basis by $0.03/MMBtu during the month of January (Figure 44).

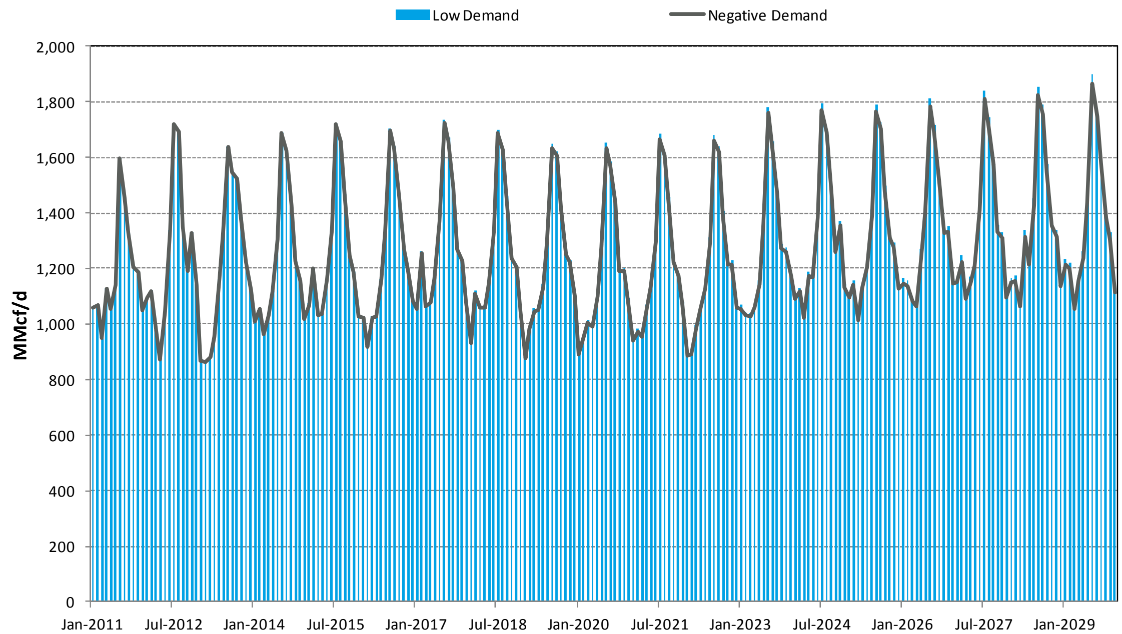

Figure 43 New England Gas Demand for Power Generation: Scenario Comparison

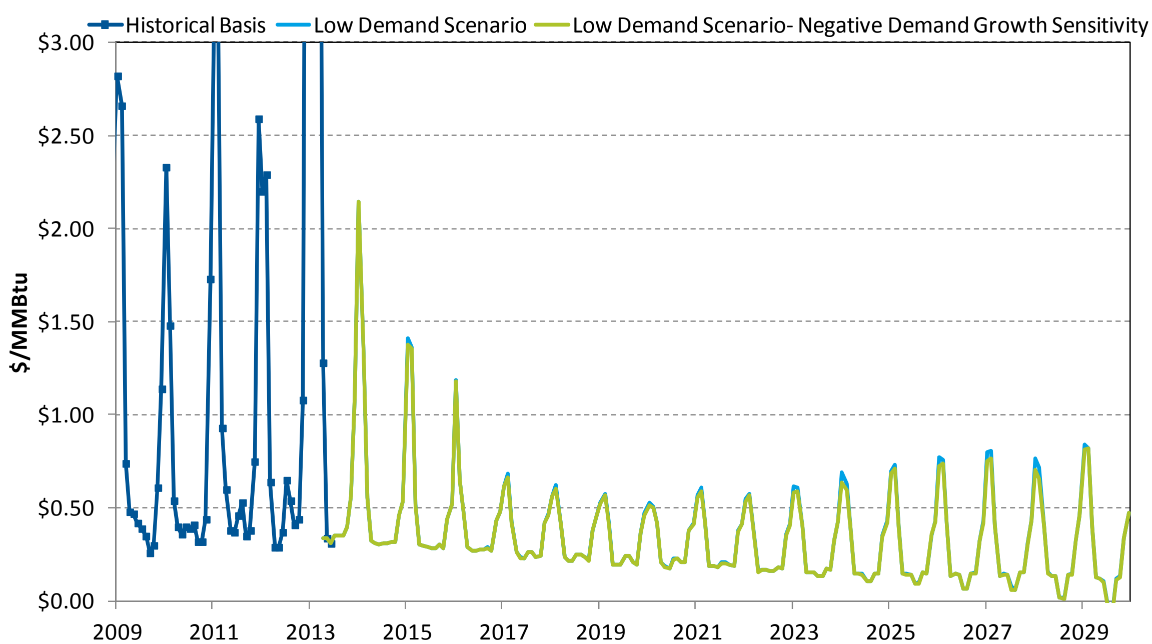

Figure 44 Monthly Algonquin City-Gates Basis: Low Demand Scenario vs. Negative Demand Scenario
Source: *Platts historical data, Black & Veatch projection*

As shown in Figure 45, the Negative Demand Growth Sensitivity has a slightly more noticeable impact on electricity prices. The net reduction in monthly average electricity price of $1.00/MWh compared to the Low Demand Scenario is a result of the lower level of net electric load as well as the lower natural gas price.

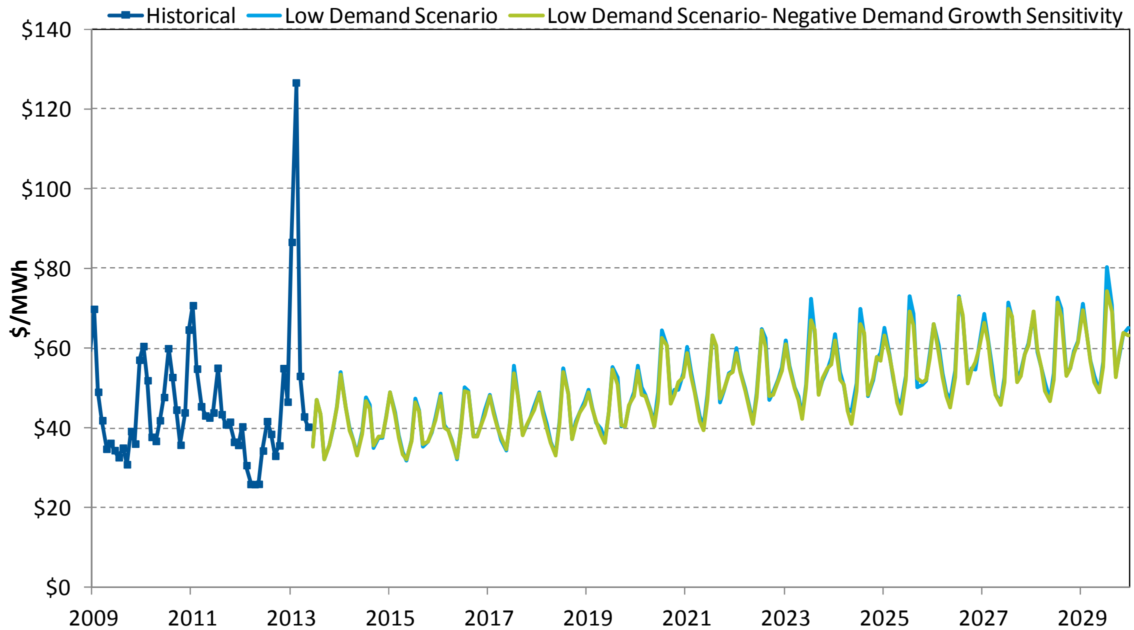

Figure 45 Boston Electric Prices: Low Demand vs. Negative Demand Growth Scenario
Source: *Energy Velocity historical data, Black & Veatch projection*

Black & Veatch estimated that the Negative Demand Growth Sensitivity saves New England customers annually on average $90 million compared to the Low Demand Scenario and $497 million compared to the Base Case (Table 9). These savings could reflect the collective benefits of the successful implementation of natural gas and electricity energy efficiency and demand-side management programs, thermal appliances, and non-natural gas-powered distributed generation that cause the demand for natural gas and the net electric load to decline in the long-term.[29]

Table 9 Total Benefits of the Negative Demand Growth Scenario

Total Benefits for Infrastructure Solutions (in Millions of Dollars)																		
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Negative Demand Growth over Low Demand Scenario	$ 68	$ 58	$ 55	$ 42	$ 59	$ 77	$ 101	$ 47	$ 82	$ 124	$ 132	$ 132	$ 75	$ 112	$ 88	$ 179	$ 1,433	$ 90
Negative Demand Growth over Base Case Scenario	$ 401	$ 380	$ 386	$ 226	$ 246	$ 274	$ 336	$ 381	$ 391	$ 565	$ 664	$ 654	$ 714	$ 757	$ 778	$ 808	$ 7,959	$ 497

[29] The costs associated with programs and measures that could achieve the extent of assumed demand reduction in the Negative Demand Growth Sensitivity are not known. Further analysis would be required to estimate such costs for comparison with customer savings.

10.0 Conclusions and Recommendations

OBSERVATIONS AND CONCLUSIONS

Black & Veatch's Phase III analysis confirmed the conclusions reached in Phase I and Phase II of this study. Under the Base Case and High Demand Scenario assumptions, in the absence of infrastructure or other solutions to increase supply or reduce demand, New England will experience significant natural gas infrastructure constraints. The constraints could dramatically increase wholesale natural gas and electricity prices throughout the region, and potentially threaten the integrity and reliability of the regional electric grid. Black & Veatch's main conclusions and observations are summarized below.

In the absence of infrastructure and demand reduction / energy efficiency / non-natural gas-powered distributed generation solutions, New England will experience capacity constraints that will result in high natural gas and electric prices; as noted below, in a Low Demand Scenario, no long-term infrastructure solutions are necessary

The presence of natural gas infrastructure constraints is reflected in the projected regional natural gas and electric prices from Black & Veatch's fundamental modeling analysis. Under the Base Case, Algonquin City-Gates basis is projected to continue to experience winter peaks averaging $3.00/MMBtu on a monthly basis and could exceed $9.00-$10.00/MMBtu on a daily basis through the winter of 2015-2016. Incremental capacity provided by AIM starting in 2016 is expected to moderate the basis for 5-6 years; monthly average basis with AIM in service falls below $2.50/MMBtu and daily volatility is greatly reduced from 2017-2022. Significant basis increases and highly volatile daily pricing in winter months are projected to return in the winter of 2022-2023 as demand grows to outpace natural gas delivery capacity serving the region and declines in Eastern Canadian production requires introduction of new higher-cost supply sources. Monthly average electricity prices range from $40 to $60/MWh when the natural gas market is not constrained, but rise to $70 to $80/MWh during the constrained months.

In the High Demand Scenario, natural gas basis and electricity prices exhibit a pattern similar to the Base Case, but with higher gas prices. Specifically, the monthly basis is expected to be $2.00-$4.00/MMBtu higher and daily prices $3.00-$5.00/MMBtu higher than in the Base Case. Likewise, monthly average electricity prices are expected to be $15-$20/MWh higher than in the Base Case.

Aside from higher gas and electric bills paid by consumers, New England could face significant reliability issues when natural gas-fired power generators are not able to dispatch as a result of the gas pipeline capacity constraints.

Short-term solutions provide net benefits to New England customers

Short-term solutions such as dual-fuel generation and demand response, as well as short-term LNG purchases, could offer considerable benefits in the near-term, considering that infrastructure constraints are expected to occur throughout New England until AIM commences service in late 2016. Short-term solutions represent an option that could be executed on a year-to-year basis. Under the Base Case, the LNG imports solution provides an average benefit of $96-$138 million per year depending on the contract terms with LNG suppliers while the dual-fuel generation and demand response solution provides a net benefit of $101 million per year.[30]

In the absence of greater demand reduction / energy efficiency / non-natural gas-powered distributed generation solutions, a Cross-Regional Natural Gas Pipeline solution presents higher net benefits to New England consumers than do alternative long-term solutions

In the long-term, both the Cross-Regional Natural Gas Pipeline and Firm-Based Energy Imports (electricity imported from eastern Canada as driven by market differentials) solutions offer significant benefits in eliminating market constraints even though they incur near-term losses. The benefits offered by the Cross-Regional Natural Gas Pipeline solution increases significantly over time. In the Base Case, the Cross-Regional Natural Gas Pipeline offers a net benefit of $118 million per year, almost twice the level of net benefits contributed by the Firm Canadian Energy import solution. In the High Demand Scenario, the Cross-Regional Natural Gas Pipeline can provide a net benefit of $340 million per year compared to the $123 million per year benefit that could be obtained with the Firm-Based Electric Imports solution.

Majority of the benefits apply to New England electric customers

Black & Veatch separately calculated the benefits to New England natural gas and electric customers as a result of infrastructure additions. For the Base Case, with the Cross-Regional Natural Gas Pipeline solution, on average, $281 Million (95%) total benefits can be attributed to electric customers while $14 million (5%) to natural gas end-use customers per year. These results would follow from the general practice that LDCs typically contract for gas supplies at production basins and have firm pipeline capacity to transport supplies into New England while only limited amounts of gas are purchased at monthly or daily prices within New England. On the other hand, a majority of electric generators typically make fuel purchase and dispatch decisions based on regional daily prices and generally purchase gas delivered to a city-gate distribution point.

For all the analyzed solutions under the Base Case and High Demand Scenario, the majority of the benefits come from savings to New England electric customers.

In the absence of infrastructure solutions, gas-supply requirements driven by episodes of extremely cold weather can be very costly and create significant reliability risks

Black & Veatch structured a design-day scenario to mimic the potential impact of annually recurring, sustained extreme winter cold events in New England. As a result of these hypothetical cold events, higher natural gas and electricity prices will cost New England consumers an additional $21 million per day in January compared with the normal weather scenario adopted for the High Demand Scenario and $24 million a day more when compared to the Base Case which also assumed normal weather.

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[30] Dual-fuel, oil-fired generators must comply with increasingly stringent emission standards in order to be permitted, which may influence the extent and duration of some dual-fuel units' ability to contribute to a short-term solution.

In addition, under the design-day criteria, New England could face a supply deficiency of approximately 500 MMcf/d of natural gas in the absence of infrastructure solutions, thereby creating serious reliability concerns for the regional electric power supply.

Limited natural gas infrastructure constraints are observed under the Low Demand Scenario

The Low Demand Scenario assumes that successful implementation of natural gas and electric efficiency and other demand-side management programs, the penetration of renewable thermal applications, increased use of non-natural gas-powered distributed generation, or increased renewable policy goals which result in no growth in natural gas demand. Under this scenario, the AIM project is able to successfully eliminate the short-term infrastructure constraints in New England and regional natural gas and electricity prices remain stable after AIM commences service. This scenario offers New England customers a total cost savings of $411 million a year compared with the Base Case.[31]

A Negative Demand Growth Sensitivity, which assumes the efficiency programs and penetration of alternative energy, actually reduces future natural gas demand, showed very similar results to the Low Demand Scenario. New England customers' total cost savings increase to $497 million a year compared to the Base Case under this assumption.

No solutions under the Low Demand Scenario yield positive net benefits

Black & Veatch tested three infrastructure and supply solutions under the Low Demand Scenario: LNG Peak shaving; dual-fuel generation and demand response; Firm-Based Energy Imports. As no significant infrastructure constraints are observed under the Low Demand Scenario, the benefits generated by these solutions are considerably smaller than in the Base Case and no solution yielded a positive net benefit for the analysis period.

RECOMMENDATIONS

Short-term and long-term solutions are needed to relieve the natural gas market constraints in New England under the Base Case and High Demand Scenario

If the market dynamics assumed in the Base Case and High Demand Scenario of this analysis materialize, solutions to New England's natural gas infrastructure constraints must come in the form of large-scale infrastructure improvements as well as strategies that can be deployed on short notice and adapt to the changing needs of the region.

Black & Veatch's analysis indicates that the construction of a Cross-Regional Natural Gas Pipeline provides the greatest net benefits of the large-scale infrastructure improvements considered in this study. Through the construction of incremental pipeline capacity, this project could relieve New England's gas-electric infrastructure adequacy issues for the long-term. Based on the findings of this report under the Base Case and High Demand Scenarios,

[31] The costs associated with programs and measures that could achieve the extent of assumed demand reduction in the Low Demand Scenario are not known. Further analysis would be required to estimate such costs for comparison with customer savings and/or infrastructure solutions.

and assuming these assumptions reflect future market conditions, Black & Veatch recommends the construction of a Cross-Regional Natural Gas Pipeline as a long-term solution.

In addition to long-term solutions, strategies that can be quickly deployed will play a vital role in alleviating infrastructure constraints. Black & Veatch recommends that dual-fuel generation, demand response measures, and the seasonal purchase of LNG cargoes be deployed immediately. Considering that the long-term solutions considered in this study cannot be placed into service before 2017-2018, short-term solutions can offer relief before long-term infrastructure solutions are constructed. Furthermore, they can be deployed to address infrastructure constrains that occur from year-to-year and in specific geographic regions. For example, dual-fuel, fuel-oil-fired generation capacity can address acute infrastructure constraints facing Eastern New England.

No Long-term Infrastructure Solutions are needed under the Low Demand Scenario

The solutions explored in this report will offer negligible benefits under in a market environment where energy efficiency programs and robust growth in renewable generation capacity prevent further growth in natural gas demand within the New England market. If policymakers believe that the future of the market envisioned in the Low Demand Scenario will be a reality, Black & Veatch recommends that these solutions not be implemented.