NEW ENGLAND NATURAL GAS INFRASTRUCTURE AND ELECTRIC GENERATION: CONSTRAINTS AND SOLUTIONS

PREPARED FOR

The New England States Committee on Electricity

APRIL 16, 2013

BLACK & VEATCH
Building a world of difference.

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Black & Veatch Statement

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

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1.0 Executive Summary

Phase II of the study is designed to assess the current state of natural gas infrastructure adequacy in New England and provide summary level estimates of the costs for a range of potential solutions. The natural gas market in New England experienced ever-increasing levels of supply constraints over the course of the past several winters, evidenced by frequent market price spikes. Black & Veatch projects that demand growth for natural gas will be led by the electric sector. New England's natural gas infrastructure is expected to face capacity constraints of increasing severity going forward.

KEY OBSERVATIONS AND FINDINGS

Historical load and price analyses show that the region experienced supply stress, expressed as spot market basis spikes, when load levels approached 75% or more of existing firm contract capacity serving the market. This indicates that the current New England natural gas market balance is very tight, with small shocks to the system causing significant market impacts. Therefore, the 75% utilization factor of firm contracted capacity is identified as the "constraint capacity" threshold facing the region. In the absence of incremental natural gas infrastructure, regional load growth from the electric sector will increase the likelihood of constraints. For the 14 New England sub-regions that Black & Veatch analyzed, 11 will exceed the constraint capacity level by more than 30 days without Spectra's Algonquin Incremental Market Expansion ("AIM"). Even with AIM, nine sub-regions will have load levels exceed the constraint capacity threshold for more than 30 days.

Black & Veatch believes that the following are the most appropriate primary solutions to alleviate the infrastructure constraints: incremental natural gas pipeline capacity, incremental LNG imports, and electric transmission that enables imports from outside the region, particularly to reach the substantial and diverse supply resources north of, and proximate to, New England. Other alternatives considered—additional LNG peak-shaving capacity, dual-fueled generation and demand-side resources—can help to relieve capacity constraints in a meaningful way, at least at a sub-regional level or as part of a blended solution. In Phase III, Black & Veatch and NESCOE will further analyze the combinations of potential solutions to address New England's natural gas infrastructure inadequacy issues associated with electric reliability.

RECOMMENDED SCENARIOS AND SENSITIVITIES

Based on preliminary observations and findings, Black & Veatch recommends three scenarios and several sensitivities to explore the potential severity of infrastructure constraints as well as the benefits brought about by incremental infrastructure: ***a Base Case, a High Demand Scenario, and a Low Demand Scenario.*** The solutions proposed in the sensitivity recommendations are intended to guide the Phase III analysis, with further refinement and customization ensuing as the analysis proceeds. Potential solutions not expressly mentioned may ultimately form part of a blended solution.

2.0 Overview

BACKGROUND

As New England increasingly relies upon natural gas to fuel its electric generation fleet, the adequacy of natural gas infrastructure will be essential to electric system reliability. The New England States Committee on Electricity ("NESCOE") commissioned Black & Veatch to provide an independent multi-phased study to assess the readiness of New England's natural gas infrastructure to serve the region's electric generation needs. Policymakers are interested in understanding the extent of the region's potential natural gas infrastructure inadequacy associated with gas-electric reliability issues and in understanding the costs and benefits of potential solutions.

At the conclusion of Phase I of this study in December 2012, Black & Veatch concluded that New England's natural gas infrastructure will become increasingly stressed from the growth in gas demand from the electric sector. Through a review of more than 30 studies and presentations related to this topic, Black & Veatch found that substantial gaps remain to inform policymakers of the timing, duration, and location of potential natural gas infrastructure constraints. NESCOE commissioned Phase II of this study to further address these gaps.

SCOPE OF STUDY

Phase II of the study is designed to assess the current state of natural gas infrastructure adequacy in New England and provide summary level estimates of the costs for a range of potential solutions. Results of these analyses will inform scenarios and input assumptions for a more targeted and detailed analysis in Phase III. Detailed tasks in Phase II include: (1) analyzing historical gas demand in New England by sector; (2) projecting growth requirements by sector for the next 15 years; (3) summarizing announced pipeline expansion projects and generic infrastructure; (4) identifying potential gas and electric sector solutions for gas adequacy issues; and (5) identifying scenarios and sensitivities for further analysis.

APPROACH

Black & Veatch uses a five-stage framework to assess the adequacy of natural gas capacity and supply for a given power market or region. Broadly stated, our framework involves understanding the adequacy requirements, assessing the adequacy, conceptualizing solutions, comparing the costs and benefits of the solution, and arriving at an optimal solution or a combination of solutions. Phase II of the study undertakes the first three stages of this process and establishes a foundation for the last two stages with regard to analyzing potential solutions.

Figure 1: Black & Veatch Analytical Process

Step 1: HOW IS ADEQUACY DEFINED?

Natural gas infrastructure adequacy for the electric sector can be measured within the context of reliability risk and cost. These parameters are situational and location-specific. A pipeline system serving a region that does not have the physical capacity to meet the last unit of potential gas demand, for example, could be considered adequate when the risk of shortage is within an acceptable range of tolerance that can be managed. On the other hand, a system that meets gas requirements under normal situations may not be adequate if there is no flexibility or if there are no cost-effective alternatives to respond to extreme events that could lead to costly outages.

Our analysis of the New England natural gas market shows that while most sub-regions currently have access to nominally sufficient capacity to serve existing demand, significant and recurring natural gas price volatility observed in recent years indicates that the system is stressed and points to a need for incremental infrastructure solutions going forward.

Step 2: IS THE EXISTING NATURAL GAS SYSTEM ADEQUATE?

To properly assess the adequacy of natural gas infrastructure serving New England, geographic location and physical configuration of demand and infrastructure should be considered. Physical pipeline bottlenecks can inhibit the movement of gas supplies throughout the region. Accordingly, the access to gas supplies varies within the region.

Load requirements must be assessed over a sufficient period of time across various locations. Black & Veatch examined the nature of load requirements during the course of two representative years across 14 New England sub-regions. This detailed assessment provided valuable insights into the potential duration of capacity constraints that underlie our analysis of potential solutions.

Step 3: WHAT ARE THE ALTERNATIVES?

The solutions considered must be tailored to the magnitude and duration of anticipated gas constraints. For example, if the constraints are experienced over multiple days, short duration solutions such as LNG peak shaving facilities or demand-side resources may not provide sustained relief from infrastructure constraints. Instead, new pipeline capacity or other long duration solutions are a better fit.

In addition, in an integrated gas and power market, optimal capacity and infrastructure planning must consider the alternative options available from both electric and natural gas markets. New electric transmission, for instance, can be a solution to gas pipeline constraints.

Step 4: WHAT ARE THE COSTS AND BENEFITS OF ALTERNATIVES?

The optimal solutions will be determined by cost-benefit analyses. The most appropriate approach to estimate the cost and benefits is a systematic fundamental analysis that simultaneously considers the natural gas and the electric market wherein the impact of each alternative solution can be quantified. Black & Veatch performs this analysis using its Integrated Market Modeling process.

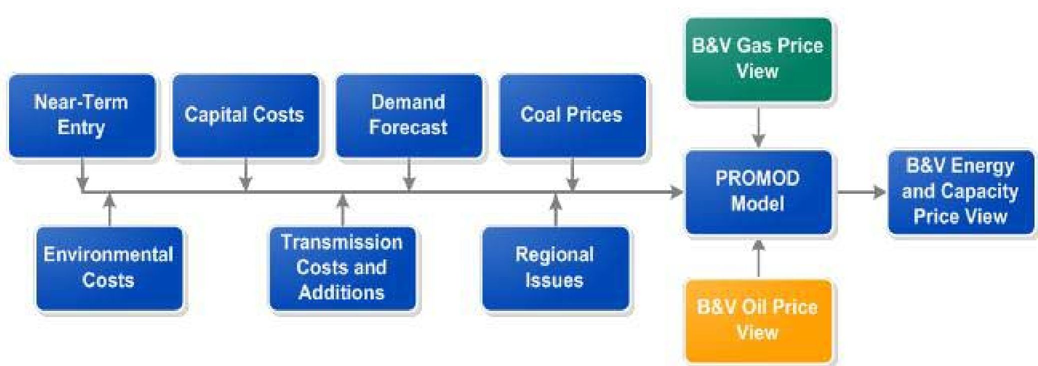
Step 5: WHAT ALTERNATIVES BEST MEET OBJECTIVES?

The alternative(s) that provides the best combination of costs and benefits under a range of scenarios will reflect the optimal solution. It is important to assess and understand how different market conditions, strategic objectives, and implementation feasibility could affect various solutions. The purpose of scenarios is to consider uncertainties and plan for them.

BLACK & VEATCH INTEGRATED MARKET MODELING PROCESS

Black & Veatch utilizes an Integrated Market Modeling process to evaluate the costs and benefits of the natural gas and power alternatives. This process aggregates the expertise of Black & Veatch professionals in areas such as power plant capital costs, environmental and regulatory policy, natural gas resources, and finding and development costs. This data is input into a series of energy market models to project future market conditions, including capacity and energy prices for electricity, fuels prices (natural gas, coal, uranium), production and consumption of electricity, and emissions prices. Black & Veatch utilizes vendor-supplied models such as PROMOD and Market Power for the power market, GPCM™ for the North American gas market, and our proprietary model for the emissions market. This process is executed in an iterative fashion to ensure that the results are consistent across the models.

Figure 2: Black & Veatch Integrated Market Modeling Process



The input of various subject matter experts in conjunction with an iterative modeling process ensures that Black & Veatch's analyses reflect the latest developments of different energy markets and the general equilibrium between them. Black & Veatch proposes to implement this process during the detailed modeling undertaken in Phase III. For Phase II, Black & Veatch projected the demand for natural gas from the electric sector using PROMOD with pre-set assumptions on natural gas and other fuels.

KEY OBSERVATIONS AND FINDINGS

THE NEW ENGLAND MARKET EXPERIENCED INCREASING TIGHTNESS IN NATURAL GAS SUPPLY ACCESS IN RECENT YEARS

The New England natural gas market experienced ever-increasing levels of supply constraints over the course of the past several winters, as evidenced by frequent and abrupt price increases. The most recent winter of 2012-2013 witnessed New England natural gas market basis[1] exceeding $3.00/MMBtu on 78 days and even reaching above $30/MMBtu. The increased level of basis volatility is the market's response to supply tightness.

NATURAL GAS DEMAND IS EXPECTED TO GROW IN NEW ENGLAND, DRIVEN BY THE ELECTRIC SECTOR

Natural gas generation is expected to replace retirements of oil and gas fired capacity triggered by environmental regulation. It is the most economic type of incremental, dispatchable capacity under an emissions control program. Natural gas demand from the residential, commercial, and industrial sectors in New England is expected to grow modestly, at less than 1% per year, through 2028. The state of Connecticut is expected to experience the fastest growth through 2020 from the residential and commercial sectors given Governor Malloy's Comprehensive Energy Strategy.

NEW ENGLAND NEEDS INCREMENTAL CAPACITY IN THE FUTURE

New England's natural gas infrastructure is expected to face capacity constraints of increasing severity going forward. Historical load and price analyses show that the region experienced supply constraints, expressed as spot market basis spikes, when load levels approached 75% or more of existing firm contract capacity serving the market. This indicates that the current New England natural gas market balance is very tight, with small shocks to the system causing significant market impacts. Projected demand growth from the electric sector raises regional natural gas requirements even closer to this threshold level.

PHYSICAL CONSTRAINTS COULD OCCUR ON MORE THAN 30 DAYS

Black & Veatch's statistical analysis of historical data shows that price spikes could occur regularly when load levels exceed 75% of firm contracted capacity ("constraint capacity").

[1] Basis is the price differential between the price at a given location and Henry Hub, a Louisiana natural gas pricing point that is representative of the US natural gas market

Regional basis spikes have occurred for 10 to 27 days during each of the past three years. In the absence of incremental natural gas infrastructure, electric load growth will increase the likelihood of constraints. As described below in 5 and shown in Figure 11, for the 14 New England sub-regions that Black & Veatch analyzed, 11 will exceed the constraint capacity level on more than 30 days without Spectra's Algonquin Incremental Market Expansion ("AIM"). Even with AIM, nine sub-regions will have load levels exceeding the constraint capacity threshold for more than 30 days.

PHYSICAL CONSTRAINTS ARE EXPECTED TO BE WIDESPREAD ACROSS NEW ENGLAND

Emerging constraints will likely affect most New England states. Projected demand in each of the 14 sub-regions is expected to exceed the threshold levels of existing capacity serving the sub-region. Because a majority of natural gas pipeline supplies enter New England from the west, eastern sub-regions will be more severely impacted as capacity constraints to the west limit the amount of gas available to these sub-regions. It is also important to note that eastern sub-regions will be challenged in achieving gas deliveries at high pressure when constraints occur further west. This is significant, given that natural gas-fired generation capacity requires high-pressure natural gas deliveries. Load growth from the power sector is expected to occur near the terminus of the natural gas pipelines, potentially exacerbating the pressure concerns.

SUPPLY ISSUES COULD EXACERBATE CAPACITY CONSTRAINTS

Throughout this analysis, Black & Veatch uses contracted firm transportation capacity held for natural gas pipeline deliveries to New England as a proxy for supplies available to the region. It must be noted that such a proxy only captures capacity, and not necessarily the natural gas supplies available to serve the region. Capacity serving the region offers little relief to gas-electric reliability concerns if natural gas supplies are not available to be delivered using this capacity. For example, infrastructure inadequacy could be exacerbated if potential supply deficiencies in Eastern Canada and the Everett LNG terminal materialize, leaving some pipeline capacity without access to adequate supplies.

NATURAL GAS PIPELINES, THE LNG IMPORT OPTION, AND ELECTRIC IMPORTS FROM DIVERSE SUPPLY RESOURCES TO THE REGION'S NORTH ARE LIKELY PRIMARY SOLUTIONS TO NEW ENGLAND'S CONSTRAINTS

Black & Veatch reviewed a suite of alternatives that fall under three categories and could potentially address the gas and electric infrastructure constraints facing New England:

1) Fundamental institutional changes to the way natural gas and electric markets operate and interact, such as changing the economic regulatory regime to allow pipeline capacity to be constructed without firm commitments or changing the forward capacity market rules;

2) Solutions to increase natural gas infrastructure and diversify sources of supply; and

3) Solutions to reduce natural gas demand from the electric sector.

Black & Veatch focused on solutions under the last two categories. The nature, timing, and extent of any institutional changes to the electric and natural gas industries are uncertain, beyond the scope of the Phase II analysis, and are being addressed in other forums as potential solutions to address New England's gas-electric reliability issues.

Black & Veatch believes that under the base case assumptions, the following are the most appropriate primary solutions to alleviate the infrastructure constraints: incremental natural gas pipeline capacity, incremental LNG imports, and electric transmission that enables imports from outside the region, particularly to reach the substantial and diverse supply resources north of, and proximate to, New England.

Other alternatives considered—additional LNG peak-shaving capacity, demand-side resources, and dual-fuel generation capacity—can help to relieve capacity constraints in a meaningful way, at least at a sub-regional level or as part of a blended solution. However, each of these options on its own has challenges in providing a sustained solution to the constraints anticipated throughout New England under the base case scenario:

- LNG peak shaving: Given that capacity constraints have the potential to occur on 30 or more days each year going forward, it is not likely that LNG peak shaving alone will offer capacity for a long enough period to successfully alleviate constraints due to the limited refilling flexibility of these facilities.

- Demand-side response: Demand-side response could decrease overall demand and peak demand for natural gas. However, because the natural gas capacity constraints have been observed throughout the region during winter for more than 30 days, there may not be sufficient availability of demand-side resources to single-handedly alleviate the infrastructure adequacy issues facing New England.

- Dual-fuel generation capacity: If implemented as an independent solution, dual-fuel capacity could face economic incentive challenges as the wide disparity between the cost of natural gas and cost of oil-based fuel is expected to persist. It could also face environmental challenges, such as air quality and permitting regulations, which would limit the frequency and duration of alternative fuel generation that can be dispatched to solve the natural gas inadequacy.

Solutions must be tailored, and when appropriate blended, to solve the type of constraints expected to occur. It is very likely that most appropriate solutions could change under different natural gas demand and supply projections. In Phase III, Black & Veatch and NESCOE will further analyze the combinations of potential solutions to address New England's natural gas infrastructure inadequacy issues associated with electric reliability.

SCENARIO AND SENSITIVITY RECOMMENDATIONS

Based on preliminary observations and findings, Black & Veatch recommends three scenarios and several sensitivities to explore the potential severity of infrastructure constraints as well as the benefits brought about by incremental infrastructure solutions. Our recommended scenarios focus on market supply and demand to represent the spectrum of possibilities regarding the market environment going forward. Sensitivities within the defined scenarios explore the impact to the market brought about by proposed infrastructure solutions as well as other market conditions such as unusual weather conditions. The solutions proposed in the sensitivity recommendations are intended to guide Phase III analysis, with further refinement and customization ensuing as the analysis proceeds. Potential solutions not expressly mentioned below may ultimately form part of a blended solution.

Black & Veatch proposes three scenarios – a Base Case Scenario, High Demand Scenario and Low Demand Scenario – to represent the impacts of meaningful variations in major market factors that can occur in driving the needs for natural gas infrastructure in New England.

BASE CASE SCENARIO

The Base Case scenario reflects the most likely assumptions agreed upon by Black & Veatch and NESCOE. In the Base Case, Black & Veatch projects natural gas demand from the residential, commercial, and industrial sectors to grow at less than 1% per year for most states. Electric sector demand for natural gas will be driven by the following assumptions:

1) Load growth is moderate at around 1% per year;
2) Efficiency grows significantly until 2020 and moderates thereafter;
3) Environmental policies and competitive economic pressure trigger significant retirements of coal and oil capacity;
4) A federal cap-and-trade program on carbon emissions is in effect by 2020;
5) Growth in renewable capacity dominates capacity additions in the early years to allow each New England state to meet its Renewable Portfolio Standards ("RPS") goals;
6) Later period capacity additions are exclusively gas-fired.

The Base Case scenario also includes other assumptions:

1) LNG export at Gulf Coast and West Coast;
2) No regulation on natural gas hydraulic fracturing;
3) No stricter control on usage and treatment for water used in hydraulic fracturing;
4) No collapse in the price of the liquids extracted from certain natural gas supply basins; and
5) Projected decline in Eastern Canadian supply.

HIGH DEMAND SCENARIO

Black & Veatch proposes a scenario that assumes a tighter (relative to the Base Case) natural gas demand and supply environment for New England and the US as a whole in order to explore the consequences of increased stress on New England's natural gas infrastructure. Demand growth could be higher than observed in the base case due to the following reasons:

1) New England states implement incentives to encourage increased residential, commercial, and industrial usage of gas;
2) The electric sector experiences a higher level of growth as a result of states not meeting RPS standards and efficiency savings being less than expected;
3) Multiple North American LNG terminals begin exporting natural gas out of North America; and
4) The Maritimes & Northeast Pipeline ("MN&P") is reversed to meet demand growth from Nova Scotia and Maritimes Canada.

All other assumptions will remain the same as in the Base Case. This is a scenario that could potentially increase the level of natural gas infrastructure inadequacy in New England.

LOW DEMAND SCENARIO

This scenario assumes no demand growth for the residential, commercial, and industrial sectors. Load growth from the electric sector will be offset by energy efficiency gains; therefore, limited demand growth from the electric sector could be expected. This scenario is designed to examine the requirements for natural gas infrastructure when the increasing natural gas demand by the electric sector does not materialize.

SENSITIVITES

For each scenario, Black & Veatch recommends a balanced approach of analyzing the two most appropriate electric infrastructure solutions and the two most appropriate natural gas solutions. For the high demand scenario, a colder weather sensitivity will be analyzed to assess natural gas infrastructure adequacy when demand approaches "design day" requirements. For the low demand scenario, a sensitivity will be designed to understand the impact on New England natural gas infrastructure adequacy if strong policy initiatives result in significant efficiency gain and renewable developments to the extent that electric sector demand for natural gas actually contracts.

Table 1 details Black & Veatch's recommended sensitivities as a road map to guide Phase III analyses.

Table 1 : Recommended Sensitivities for Phase III Analysis

Scenario	Sensitivities
Base Case	-No Incremental Solutions Incremental Solutions: -Pipeline Infrastructure -LNG Imports -Demand Response -Dual Fuel Capacity -Canadian Hydro Imports
High Demand Case	-No Incremental Solutions -Design Day Weather Sensitivity Incremental Solutions: -Pipeline Infrastructure -LNG Imports -Canadian Hydro Imports
Low Demand Case	-No Incremental Solutions -Negative Electric Sector Demand Growth Incremental Solutions: -Dual Fuel Capacity -Canadian Hydro Imports -LNG Peak Shaving

3.0 Natural Gas Demand Projections—Residential, Commercial, and Industrial Sectors

Black & Veatch utilized an econometric approach to identify the statistical relationship of residential, commercial, and industrial demand to major drivers of market demand such as population and economic growth, weather, and the relative competitiveness of natural gas with other heating fuels.

Black & Veatch reviewed data from a variety of sources, including the US Energy Information Administration ("EIA"), National Oceanic and Atmospheric Association ("NOAA"), and US Bureau of Economic Analysis ("BEA"), for demand, weather, and economic data.

Black & Veatch analyzed average usage per customer and number of customers for each sector in each state to develop demand projections. The projections assumed 20-year normal weather patterns and historical average usage per customer and customer growth rates. For the state of Connecticut, Black & Veatch's projections of residential and commercial demand reflect Connecticut's final Comprehensive Energy Strategy with increased natural gas consumption throughout the state.

Table 2 shows the growth rate of residential, commercial and industrial demand for each state in New England.

Table 2: Overview of Residential, Commercial, and Industrial Demand for Natural Gas Demand across New England

Compound Annual Growth Rate 2013-2028	Connecticut			Massachusetts			New Hampshire		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Average Customer Usage	-0.76%	-1.02%	2.80%	0.10%	-0.15%	-3.22%	0.32%	4.56%	13.28%
No. of Customers	2.99%	3.16%	-3.10%	0.47%	2.35%	4.00%	1.51%	0.66%	-12.59%
Projected Demand Growth	2.21%	2.11%	-0.30%	0.57%	2.20%	0.78%	1.82%	5.22%	0.69%
2011 Consumption (MMcf/d)	127	126	71	356	211	119	20	25	17
2011 Consumption as % of New England demand for sector	22.48%	30.06%	22.91%	63.06%	50.33%	38.52%	3.57%	6.05%	5.60%

Compound Annual Growth Rate 2013-2028	Rhode Island			Maine			Vermont		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Average Customer Usage	-2.30%	-2.94%	6.45%	1.66%	2.42%	22.40%	-0.07%	-0.76%	1.31%
No. of Customers	3.42%	2.96%	-4.15%	2.52%	1.42%	-13.00%	2.84%	1.81%	-0.55%
Projected Demand Growth	1.12%	0.02%	2.30%	4.18%	3.83%	9.40%	2.78%	1.05%	0.76%
2011 Consumption (MMcf/d)	49	31	21	4	19	73	9	7	8
2011 Consumption as % of New England demand for sector	8.59%	7.41%	6.84%	0.71%	4.48%	23.64%	1.60%	1.67%	2.50%

Data Source: Black & Veatch Analysis

4.0 Natural Gas Demand Projections – Electric Sector

Black & Veatch utilizes PROMOD IV, a fundamental power modeling tool, to project natural gas demand from the power generation sector. Ventyx PROMOD IV is a generator and portfolio modeling system that provides nodal and zonal Locational Marginal Price ("LMP") forecasting and transmission analysis by using algorithms that mimic the decision making process for investments and the dispatch of electric generators.

For each hour of the forecast period, the model utilizes the most cost effective way to dispatch generation and meet load. The resulting energy price reflects the cost of the most expensive generation that is required to meet electric demand. The model optimizes the dispatch decision while incorporating load and transmission developments in the future ("perfect foresight"). Any out-of-merit commitment and dispatch performed to maintain reliability of the system will not be reflected in the simulated dispatch.

This simulation process is repeated for each hour of the simulation period, while at the same time capturing the chronological constraints and limitations of each generation asset.

The results from this analysis are influenced by Black & Veatch's assumptions regarding major drivers of the electric market such as load growth, energy efficiency, environmental policies, renewable resource developments and technology costs.

LOAD GROWTH AND ENERGY EFFICIENCY

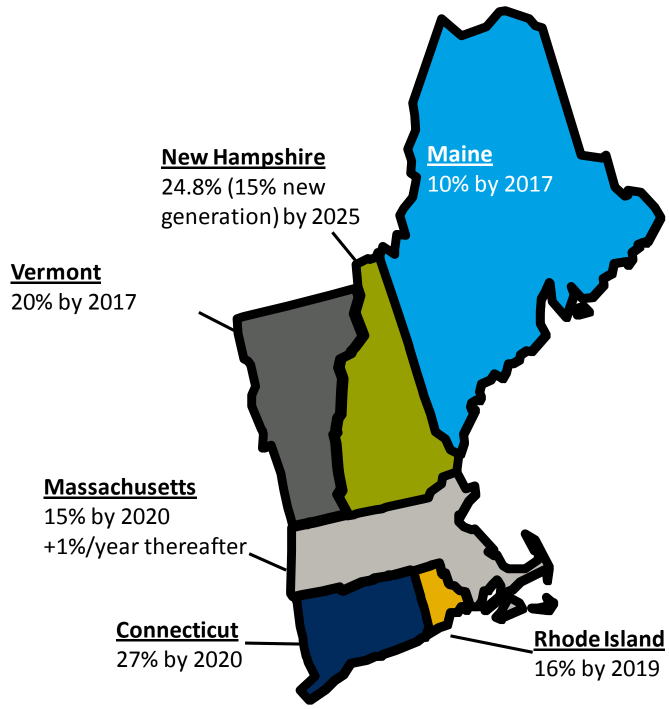
Black & Veatch utilized load growth and energy efficiency projections from the most recent ISO New England ("ISO-NE") Capacity, Energy, Load and Transmission ("CELT") forecasts. The CELT load forecast horizon runs from 2012 through 2021/2022 with a projected overall annual growth rate of 0.9% (gross of energy efficiency). Black & Veatch extended the CELT load forecast to 2028 assuming that this growth rate is sustained from 2022 through 2028. Energy efficiency forecasts were extended beyond the CELT forecast period by using the forecast's average annual growth rate between 2016 and 2022. As in the ISO-NE 2012 Regional System Plan ("RSP"), the net energy load forecast is estimated after subtracting the impact of passive demand resources and energy efficiency.

RENEWABLE RESOURCES

Black & Veatch modeled the RPS goals for each state in the U.S. and assumed that states with mandatory RPS requirements will reach 100% of their target on time while states with voluntary RPS goals will meet 75% of their target. In light of Vermont's Sustainably Priced Energy Development Program, 100% of the renewable resource goals for the state of Vermont are assumed to be met. To avoid double counting Vermont's Renewable Energy Credits ("RECs") that are sold to Massachusetts and Connecticut, an equivalent amount of renewable MWs are deducted from the Massachusetts and Connecticut renewable capacity additions.

Figure 3 shows a map with RPS requirements and goals of New England states.

Figure 3: Renewable Portfolio Standards by State



Data Source: Energy Velocity, Dsrieusa.org

Renewable resources are not economically dispatched into the market within PROMOD. Rather, renewable resources such as solar or wind and necessary transmission infrastructure are assumed to come online and be dispatched to meet the RPS schedule.

ENVIRONMENTAL AND EMISSION POLICIES

Environmental and emissions policies drive plant operators' decision to build, retire, or retrofit in order to be in compliance with the defined policies. Even though an assumed federal emissions control program, described below, that attaches a price to CO_2 emissions may not accelerate gas demand until 2020, numerous other laws are compelling generators to adopt gas technologies in the near-term. In fact, many of these laws will take effect before new gas infrastructure can be placed into service. This suggests that current gas constraints could become more frequent. The policies described below reflect assumptions made in Black & Veatch's proposed Base Case Scenario.

Mercury & Air Toxics Standards ("MATS")- Black & Veatch assumed a 2016 start date based on the final rule allowing one to two year extensions from the April 2015 compliance deadline. This standard is designed to place strict limits on hazardous air pollutant emissions from coal and oil-fired power generation units, with specific applicability to mercury, particulate matter, and hydrogen chloride or sulfur dioxide emissions.

Cooling Water Intake "316b" – Black & Veatch assumed a June 2013 start date. This rule requires intakes at power plants and industrial sources withdrawing 2 million gallons per day or more of water to have best technology available ("BTA") for minimizing the environmental impacts to aquatic species from impingement and entrainment. Options for upgrading intake design to BTA may include a combination of finer mesh screens with fish buckets, low pressure spray wash, and dedicated fish return lines screens; reduced velocity; or conversion to a closed cycle cooling system.

Greenhouse Gas Regulation- Black & Veatch assumes the implementation of a national CO_2 cap-and-trade program in 2020. The program covers electric generation, transportation, and other fossil fuel used by the residential, commercial, and industrial sectors. The price of greenhouse gas emission allowances is expected to grow from $22 to $57 per short ton in 2012 dollars from 2020 to 2037.

RETIREMENTS

Based on known and anticipated environmental regulatory requirements, generating unit data, knowledge of the air quality control ("AQC") systems, and other treatment systems currently installed, Black & Veatch screens fossil fuel-fired generation units based on several key criteria. These criteria include the location of fossil fuel-fired units in the U.S., existing AQC equipment, age of AQC equipment, size of the unit, and pertinent operating parameters. Applicability of individual air quality regulatory programs is assessed based on technology, fuel, geographic location, and ongoing state implementation plan developments.

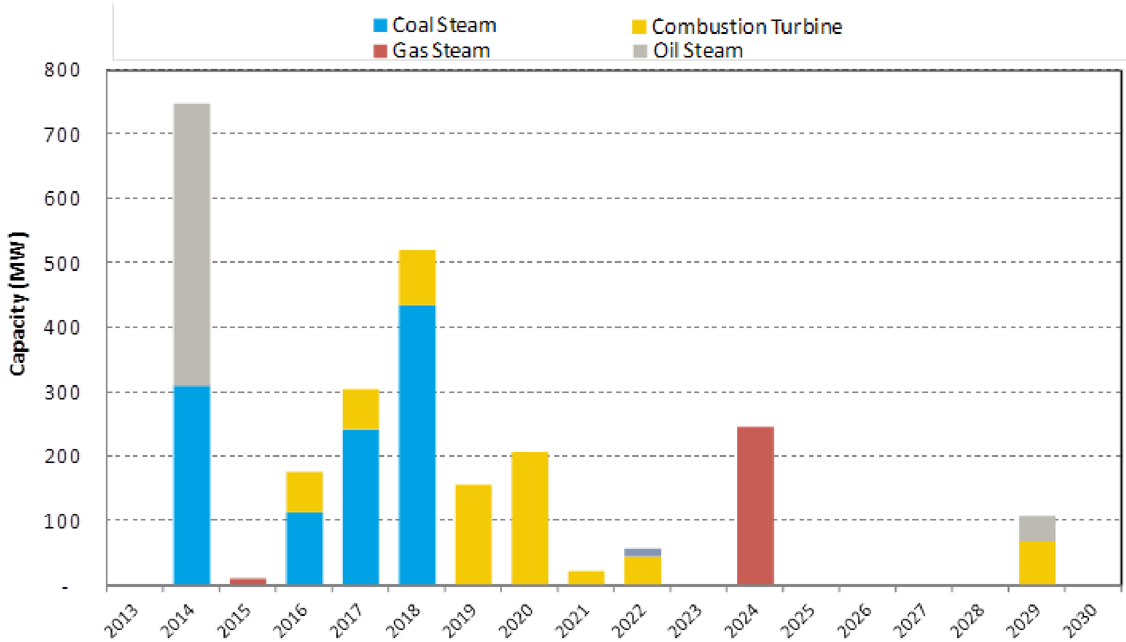
Black & Veatch applies a five-stage approach to determine coal unit retirements for the analysis period. Retrofit and related economic analysis is based upon publicly available information on each plant and industry average cost for retrofits. Oil and old natural gas units are retired according to public announcements or age.

Figure 4: Stages of Coal Unit Retirement

Stage 1	Stage 2	Stage 3	Stage 4	Stage 5
• Announced retirements	• Retirements of uneconomical units	• Assessment of units (on an individual unit basis), that would need different emission control equipment to be installed in order to be compliant	• Retirement of old units	• Retirement of units that are unable to recover cost of retrofits

Figure 5 shows retirement capacity by type in New England assumed in Black & Veatch's Base Case Scenario. The retirement capacity was reviewed by NESCOE.

Figure 5: Assumed ISO-NE Capacity Retirements



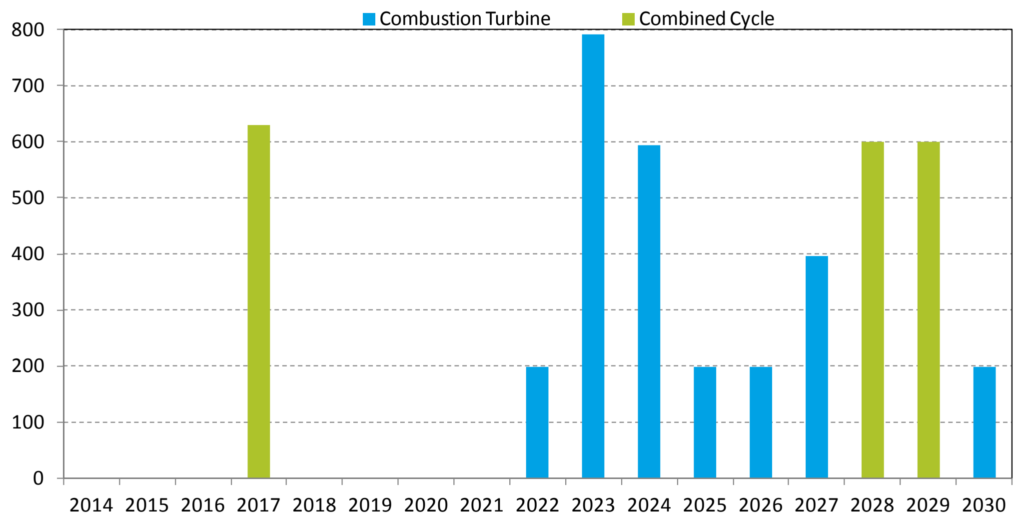
Data Source: Black & Veatch Analysis

CAPACITY ADDITIONS AND COSTS

Black & Veatch utilizes a purely economic approach to forecast electric generation capacity additions. In addition to installation costs and operation costs, Black & Veatch also incorporates the cost of environmental compliance that must be considered when selecting different technologies.

Figure 6 shows incremental capacity additions to the New England region. Combined cycle units are added to major load centers and combustion turbine units are added across the region to meet reserve margins. The Footprint project,[2] which recently cleared in the forward capacity market, will be included in the model as an announced addition.

Figure 6: Assumed ISO-NE Capacity Additions



Data Source: Black & Veatch Analysis

[2] Footprint Power Salem Harbor Development LP proposes to construct and operate a 630 megawatt natural gas-fired, quick-start combined-cycle generating facility at the Salem Harbor power station site in Salem, Massachusetts. The Salem Harbor station site is within the import-constraint Northeast Massachusetts / Boston forward capacity market zone.

5.0 Regional Load Curves

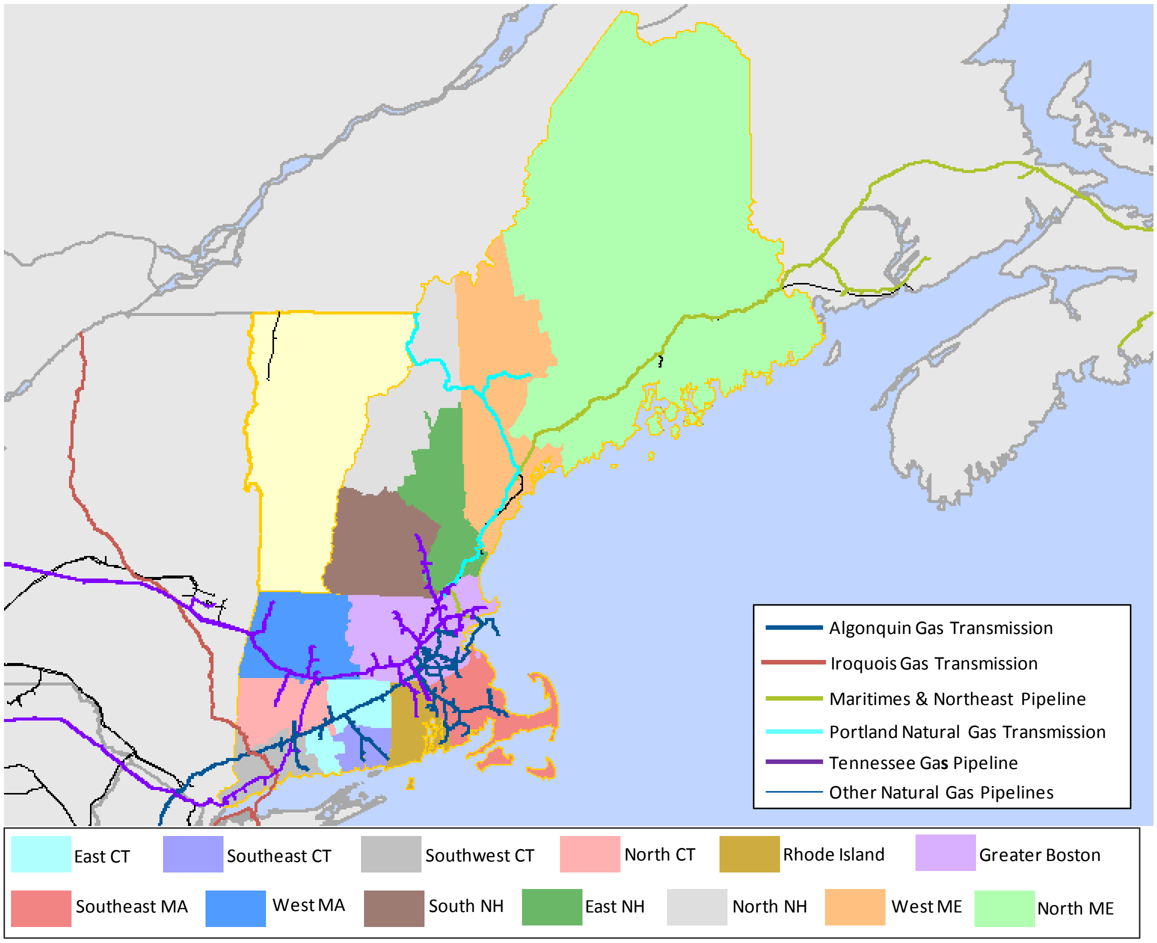
DAILY LOAD CURVES

Projected demand growth is a static measure of natural gas infrastructure adequacy and only illustrates the average need for natural gas in a region over time. Fluctuations of gas requirements over a period of time, such as in a month, a season, or a year, provide a more dynamic picture of infrastructure needs. Black & Veatch identified in our Phase I review that no study has provided a dynamic profile of natural gas demand growth. In Phase II, we undertook an analysis to convert the static projection into a visual "load shape" over a year. The "load shape" of a region provides a summary of the range of demand experienced as well as how often various levels of demand were experienced over a period of time.

Black & Veatch also identified in Phase I that none of the reviewed studies considered the intra-regional constraints and the unique characteristics of New England's natural gas and electric infrastructure. In Phase II, our analysis disaggregated the New England market into 14 sub-regions to reflect the intra-regional physical pipeline access to natural gas supply and the pipeline constraints that exist today.[3] The map in Figure 7 shows these sub-regions. Black & Veatch considers Vermont gas demand in the aggregate. However, given its relatively low demand in relation to New England as a whole, no separate load duration and constraint assessment was performed for the state of Vermont.

[3] Each sub-region was developed at an aggregated county level and takes into account the service territory boundaries of local distribution companies.

Figure 7 Map of New England Sub-Regions

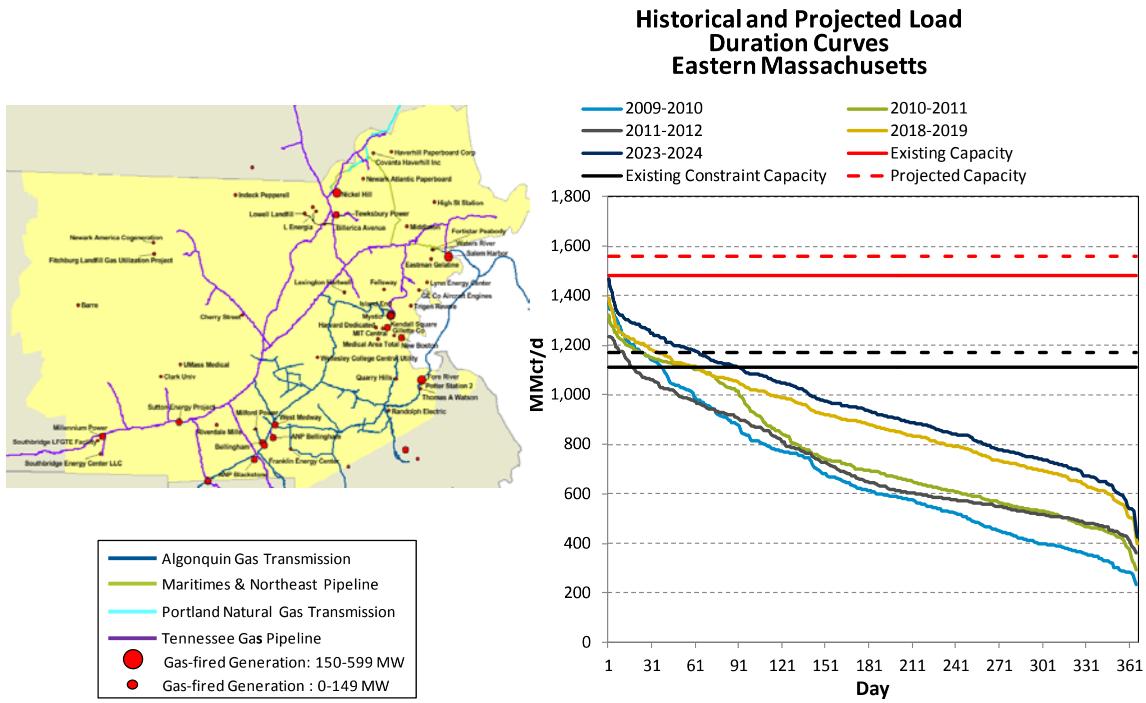


Data Source: Energy Velocity

Black & Veatch used daily historical Electronic Bulletin Board ("EBB") data from interstate pipelines to create each sub-region's daily load duration curve. For each sub-region, Black & Veatch reviewed the daily natural gas load duration curves for the past three years[4] to understand the impacts of weather and load growth.

[4] Black & Veatch uses data over a gas year, from April to next March, to construct the load duration curves.

Figure 8 Eastern Massachusetts Sub-Region Map and Load Duration Curve



Data Source: Energy Velocity, Black & Veatch Analysis

To estimate the gas delivery capacity for each sub-region, Black & Veatch assessed the physical capacity on existing natural gas pipelines as well as the current firm contracted capacity to delivery points serving the sub-region. As part of the Base Case, NESCOE requested that the incremental pipeline capacity from Spectra's AIM expansion project be included, which Spectra indicates will be placed into service in November 2016.

Our review of the past three years' daily load curves for each sub-region[5] identified only limited occurrences when load requirements are higher than the contracted capacity and existing peak shaving capacities. An important caveat to this finding is that existing and proposed firm contracted capacity is only a theoretical proxy for natural gas availability. For example, the send-out capacity of 700 MMcf/d from the Everett LNG terminal and 800 MMcf/d from the Maritimes & Northeast Pipeline are assumed to be fully available year-round. In reality, the limited availability of LNG cargos to the U.S. market and declining production from East Canada may hamper the supply of natural gas that could utilize the available capacity.

HOURLY LOAD CURVES

With natural gas demand growth almost exclusively driven by the electric sector, hourly variation of power load could exacerbate the gas infrastructure adequacy issues during

[5] The detailed appendix included with this report contains the daily load curves for each sub-region.

summer periods of peak electric demand. Black & Veatch constructed hourly load duration curves for select sub-regions that have the largest proportion of gas-fired generation load.

Based on daily load duration curves, Black & Veatch utilized the simplifying assumptions that residential, commercial, and industrial customers draw upon their capacity on a fully ratable basis (i.e. an equal amount on each hour of the day). Power generators, on the other hand, nominate for gas deliveries to meet their hourly fuel burn requirements derived though Black & Veatch's aforementioned power market analysis using PROMOD.

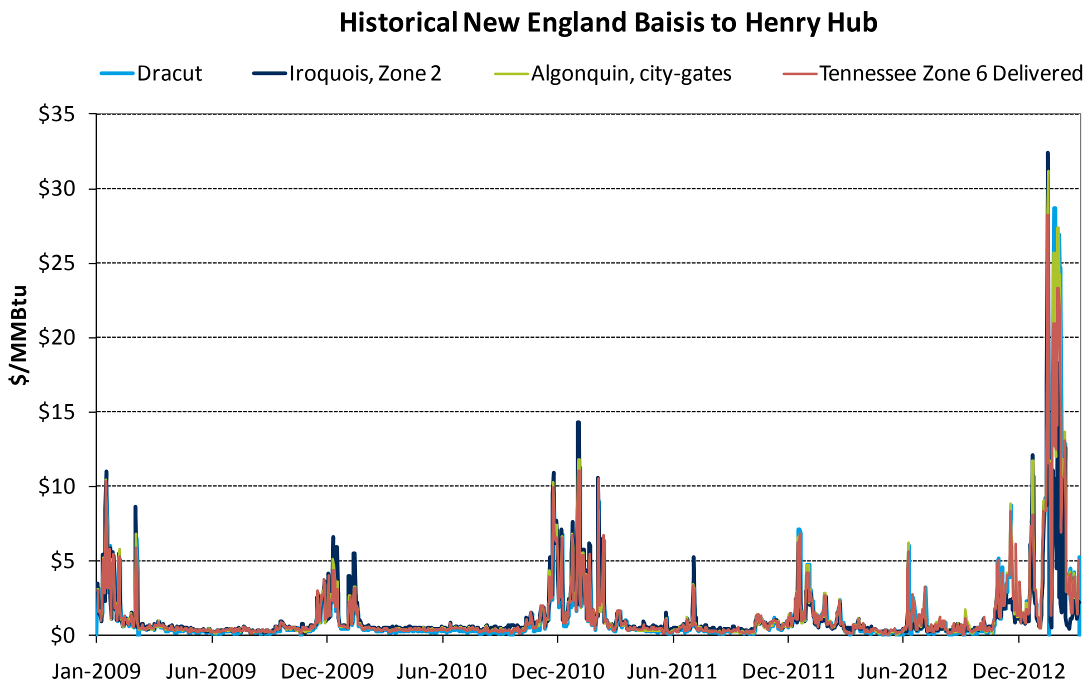
Our review of hourly load curves indicates that the hourly load variations do not increase the number of occurrences when total load requirements exceed contract capacity. Limited residential and commercial demand during the summer season when the region experiences the greatest hourly variations allows for some additional pipeline flexibility to serve gas-fired power generation. Peak winter remains the most constrained period for the natural gas infrastructure in New England given that winter-peaking residential and commercial demand comprises a large share of total natural gas demand in the region.

BASIS VOLATILITY AND CONSTRAINT ASSESSMENT

The New England market has experienced significantly higher levels of natural gas price volatility than other parts of the U.S. in recent years. In order to understand the regional price volatility, we look at a measure comparing the regional price to a baseline price in Louisiana (i.e., basis). Basis is the difference between the price at a given location and the price at Henry Hub, a location in Louisiana considered representative of the general U.S. market. Figure 9 shows the natural gas spot basis in New England at Algonquin city-gates, Tennessee Zone 6, and Dracut.

Natural gas price spikes increase the cost of fuel and thereby impact the price of electricity. The increasing frequency of basis spikes signals an increasingly tight supply dynamic across New England. Note that our review of the historical daily and hourly load duration curves for sub-regions only identified limited occurrences of total load requirements exceeding the existing pipeline contract capacity at certain sub-regions.

Figure 9: Historical New England Basis to Henry Hub

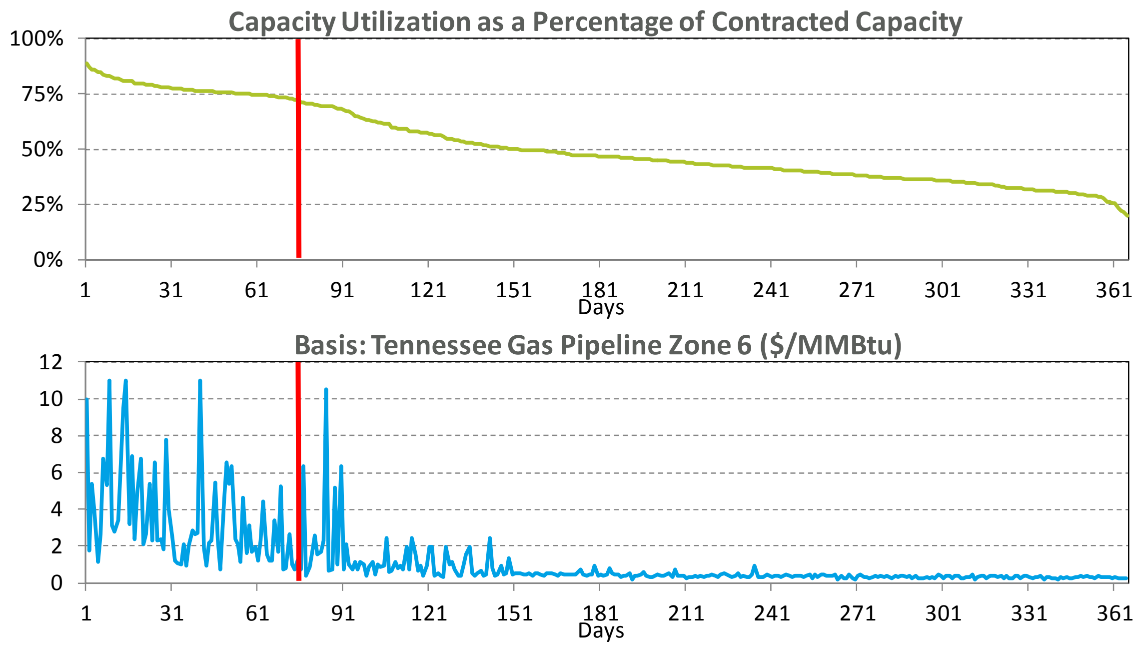


Data Source: Platts, Black & Veatch Analysis

This apparent disconnect between basis spikes and available capacity on the pipeline shows that the existing contract capacity is only a partial measure of natural gas infrastructure adequacy. Closer analysis needs to look at the relationship between pipeline utilization factors and basis spikes.

As shown in Figure 10, when total deliveries in East Massachusetts approach 75% of existing contract capacity serving the sub-region, regional gas price basis (measured at the Tennessee Gas Pipeline Zone 6 pricing point) spikes up. To reflect these dynamics that are characteristic of the New England market, Black & Veatch constructed an “Existing Constraint Capacity” threshold, which is 75% of existing contracted capacity. The red line in Figure 10, illustrates this “Existing Constraint Capacity” threshold, highlighting the relationship between gas pipeline capacity utilization and basis. Review of utilization factor and basis spikes for other sub-regions lead to similar observations.

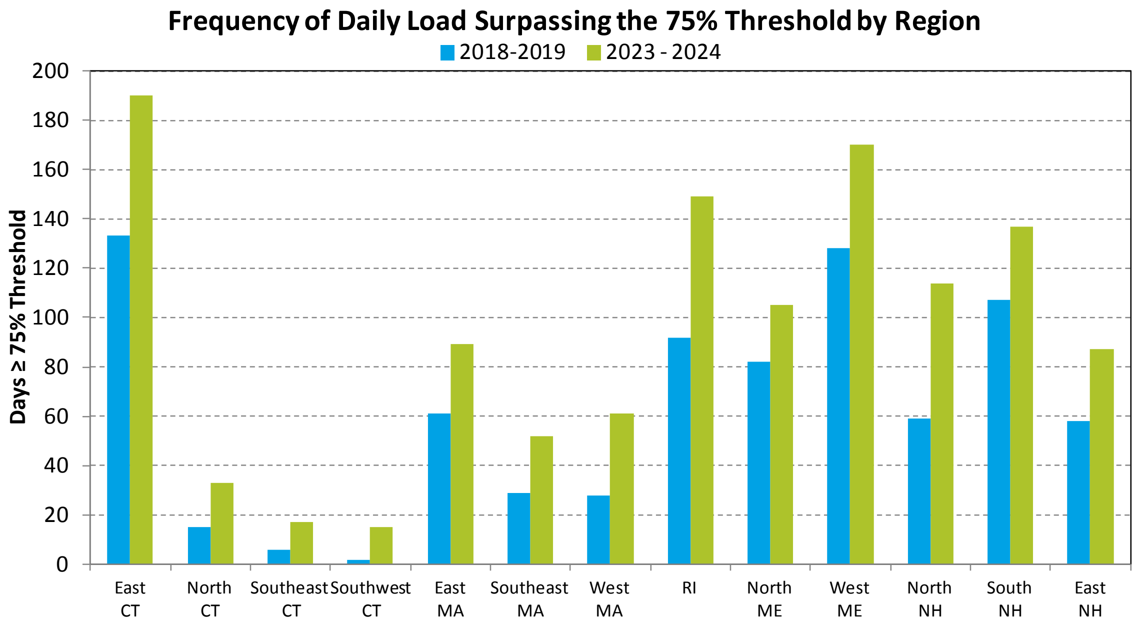
Figure 10: Capacity Utilization vs. Basis: Eastern Massachusetts, 2010-2011 Gas Year



Data Source: Black & Veatch Analysis

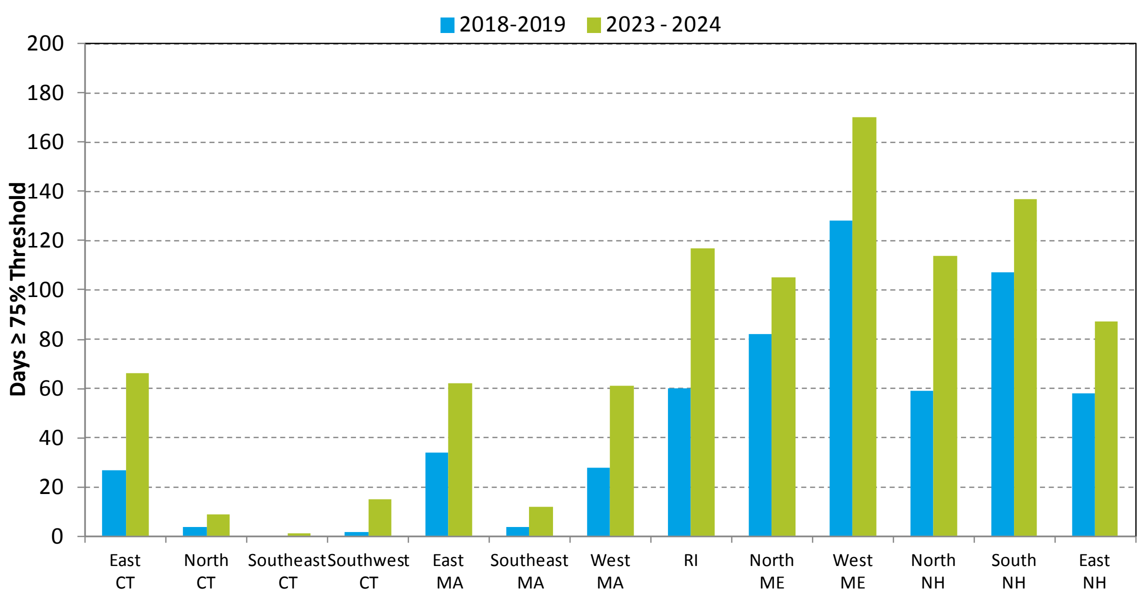
We applied this "Existing Constraint Capacity" threshold to each load duration curve to realistically assess the expected constraints facing each sub-region. Figure 11 illustrates the number of days each sub-region in New England is expected to experience load higher than the existing constraint capacity threshold, as a proxy for the occurrence of future capacity constraints. Figure 12 illustrates the same information with AIM included in the Existing Constraint Capacity threshold. Figure 12 shows that AIM's incremental capacity significantly reduces the number of constraint days in the Connecticut, Massachusetts, and Rhode Island sub-regions.

Figure 11: Number of Days Greater than or Equal to 75% Capacity by Sub-Region



Data Source: Black & Veatch Analysis

Figure 12: Number of Days Greater than or Equal to 75% Capacity by Sub-Region with Spectra's AIM Project



Data Source: Black & Veatch Analysis

COMPARABLE MARKET REVIEW

As a comparison to the New England natural gas market, Black & Veatch reviewed the natural gas market dynamics in Florida. Similar to New England, Florida is located at the terminus of a pipeline transportation system and has no access to storage and supply capacity inside the region.

Our review showed that the Florida market experienced a similar level of capacity constraints during the period of 2007 through 2009, with frequent basis spikes arising when delivery approached 70% of firm capacity serving the state. The constraint condition was improved significantly when an incremental 820 MMcf/d Florida Gas Transmission ("FGT") pipeline capacity was placed in service in 2011.

6.0 Potential Natural Gas Infrastructure Solutions

Black & Veatch has reviewed a number of long-term solutions proposed by various stakeholders to solve potential natural gas adequacy issues facing New England. One category involves institutional changes to either the natural gas or the electric industry. Examples include 1) Revisions to the pricing and construction requirements of incremental natural gas pipeline capacity; 2) ISO-NE changing pricing policy and rules to compensate generators for holding firm pipeline capacity or alternative fuel availability; and 3) ISO-NE assuming jurisdiction over both the region's electric and natural gas networks. These proposals imply significant policy issues and could require complex regulatory and/or legislative action. As the nature, timing, and extent of any institutional changes to the electric and natural gas industries are uncertain, are beyond the scope of the Phase II analysis, and are being addressed in other forums, institutional changes as potential solutions are not considered here to address New England's gas electric reliability issues.

A second category includes long-term natural gas infrastructure solutions, including utilizing LDC storage, peak shaving facilities, and existing offshore LNG storage capacity through out of market purchases; or enhancing pipeline deliverability at constraint points or building new pipeline capacities into the region.

The third category includes electric market solutions that would decrease natural gas demand, such as demand response, dual-fueled generation capacity or incremental transmission projects.

In sections 6 and 7, Black & Veatch discusses the applicability of both the gas and electric market solutions to relieve the seemingly extensive and wide spread potential natural gas constraints identified in Section 5.

PIPELINE INFRASTRUCTURE

Black & Veatch estimated the cost of constructing incremental natural gas pipeline infrastructure to serve New England as a potential means of alleviating gas constraint issues in the region. Construction costs were estimated for several proposed expansions on existing pipelines that will utilize existing rights-of-way by looping,[6] lift-and-replace,[7] or greenfield construction.[8]

Per unit cost of capacity for these potential solutions is an important input to be incorporated in Phase III modeling for the cost-benefit estimate. Per unit cost of capacity is derived from the estimated construction cost using the cost-of-service approach that the natural gas industry uses for capacity pricing.

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[6] Looping describes a pipeline construction method in which additional pipeline segments are added to an existing pipeline right-of-way (adjacent to existing pipelines in that right-of-way) to increase capacity along that right-of –way.

[7] Lift-and-replace describes a pipeline construction method in which pipeline segments are added to an existing right-of -way and existing segments are extracted, or "lifted", and replaced.

[8] Greenfield projects describe pipeline construction that does not utilize an existing right-of-way.

Black & Veatch reviewed four potential projects: Tennessee Gas Pipeline's proposed Northeast Expansion of its 200 Line and Tennessee Gas Pipeline's Connecticut Expansion projects are two announced projects that would be constructed using looping; Spectra's proposed AIM expansion would be constructed using lift-and-replace methods; and Tennessee Gas Pipeline's conceptual Bullet line would be constructed as a greenfield project. Black & Veatch's assessment of constraints presented in this report assumes that the AIM project is placed into service in November 2016.

To benchmark for the capital cost of pipeline construction using looping, Black & Veatch analyzed the costs of Tennessee Gas Pipeline's 300 Line project that was placed in service in November 2012. Costs from this project were considered a reasonable proxy for future looping projects in New England, given its recent completion and geographic proximity to New England.

The costs of the AIM expansion were independently derived by Black & Veatch and verbally confirmed through discussions with the project sponsor as approximately $1 billion dollars. Capital cost estimates for proposed greenfield projects were derived using Constitution Pipeline's proposed capacity rate of $0.76/Dth as reported by project sponsors. Black & Veatch estimated that the total construction costs for the Constitution pipeline will range from $730 million to $1 billion.

Using these proxies, Black & Veatch estimated that the total construction costs of proposed projects are as follows:[9]

Table 3: Capital Cost Estimates for Pipeline Projects

Construction Type	Project	Capacity (Dth/day)	Estimated Cost (millions)
Looped	Tennessee Gas Pipeline Northeast Expansion 200 Line Looping	500,000 to 1,000,000	$508 to $653
	Tennessee Gas Pipeline Connecticut Expansion[1]	72,100	$47 to $60
Lift and Replace	Algonquin Incremental Market Expansion	400,000	$861 to $1,017
Greenfield	Constitution Pipeline	650,000	$729 to $971
	Tennessee Gas Pipeline Northeast Expansion Bullet Line	1,200,000	$900 to $1,200

[1]Pipeline construction cost only. Excludes estimated cost of Thompsonville Lateral.

Data Source: Black & Veatch Analysis

LNG PEAK SHAVING

An LNG peak shaving facility could provide short-term supply to LDCs and power plants, typically for a few days, when natural gas pipeline capacity is not available. Currently, the 15 Bcf of peak shaving capacity serving New England is owned and operated by LDCs to

[9] It must be noted that each of these projects could entail unique considerations that affect the actual cost of construction. Therefore, the costs of recently completed projects cannot predict the construction costs of proposed projects with absolute certainty. With the exception of AIM, Black & Veatch did not verify the accuracy of its cost estimates with sponsors of these projects.

meet the high winter load from cold weather. Black & Veatch estimated that the construction costs of a 1.0 to 1.1 Bcf LNG peak shaving facility with a peak delivery capacity of 60,000 MMBtu/d would range from $110 to $130 million, based on the experience of Black & Veatch's Energy Division in constructing LNG liquefaction and storage tank capacity in North America.

The extremely slow liquefaction cycle of these peak shaving facilities makes it difficult to refill the storage after initial withdrawal. A typical peak shaving facility takes more than 150 days to fill for a 10-day withdrawal cycle. Therefore, it may not be an effective solution to relieve potential natural gas infrastructure constraints that are expected to occur more frequently.

LNG IMPORTS

Purchasing and storing LNG may serve to alleviate the type of capacity constraints observed in the New England market either as an independent solution or in tandem with other infrastructure solutions. Existing LNG terminals and infrastructure off the New England coast and in Canada require limited new construction to integrate this supply source into the New England market. In addition, as the largest natural gas demand centers and natural gas generators are located in eastern New England, injecting supply from the east is desirable as a high pressure supply source to generators.

It must be noted that the cost of LNG supplies could be high if this option is implemented, given that LNG prices are currently indexed to global oil prices and could exceed $15/MMBtu. Such an oil-indexed price would carry a premium to supplies produced in North America, especially when the premium required to attract supply to the New England market in winter is considered. To obtain firm commitment from LNG suppliers for a limited number of cargos, the New England market must offer a comparable market price plus a premium to in order to call upon the supply on short notice.

In order to mitigate this supply cost premium, it may be prudent to invest in additional storage capacity at an LNG terminal to enable purchases of spot supply during summer when supply is more available and the spot LNG price is relatively low. The capital cost of storage tank construction must be balanced with the cost savings derived from the supply cost differential of procuring supplies in the summer rather than winter.

7.0 Potential Power Side Solutions–Demand Response and Dual-Fuel Capacity

Electric sector solutions are designed to relieve natural gas infrastructure constraints by reducing natural gas demand. The effectiveness of these solutions will be largely dependent on the level of demand reduction that could be achieved through implementing these solutions. Black & Veatch's analysis shows that since the New England natural gas market is already experiencing frequent and widespread natural gas constraint issues, as reflected in the natural gas basis spikes, the electric market solutions need to be able to reduce the requirement for gas-fueled generation significantly during the winter peak time. Accordingly, our analysis focused on demand response and natural gas generators dispatching dual-fuel capacity below. We excluded the potential option of building generation capacity in a less constrained area within New England and transmitting energy to the constrained area. Because new economic generation capacity would likely be gas-fired, such a strategy would move the constraints to this location, making this solution ineffective. However, given New England's proximity to significant and diverse resources to the north, electric energy imports from Canada are examined as a solution to be studied in Phase III.

DEMAND RESPONSE

ISO-NE is currently in a state of transition with respect to its Demand Response ("DR") program. The "transitional" program from emergency to economic dispatch in the energy market was instituted in 2012 to act as a bridge until a new DR program is implemented in 2017 to comply with FERC Order 745. ISO-NE has provided a review of the available capacity and energy generation from demand response resources under the previous DR programs.

As shown below in Table 4, there are approximately 1,700 MW of demand resources (both active and passive) that fall under various categories in ISO-NE's forward capacity market.

Table 4: Capacity Supply Obligation by Demand - Resource Type (MW), 2010 and 2011

	Active Demand Resources			Passive Demand Resources			
	Real-Time Demand Response Resource	Real-Time Emergency Generation Resource	Total Active Demand Resources	On-Peak Demand Resource	Seasonal Peak Demand Resource	Total Passive Demand Resources	Total All Demand Resources
2010 Year End	669	522	1191	406	118	524	1716
2011 Year End	649	436	1085	617	259	876	1960

Data Source: ISO-NE

The revenue stream for demand response (Active Demand Resources in Table 3) consists of capacity payments as compensation for readiness to serve and energy payments, which are determined by Real-Time locational marginal pricing.

Table 5 shows the payments for years 2010 and 2011. In those years, about 93% of the revenue came from the capacity payments and only 7% of the revenue came from energy payments. These numbers suggest that demand response has primarily participated in the New England markets as capacity resources, which were historically dispatched only during emergency conditions.

Table 5: Total Payments to Demand-Response Resources, 2010 and 2011

	Capacity Payments	% of Total	DALRP Payments	% of Total	RTPR Payments	% of Total	Total Payments
2010	$134,456,420	93.9%	$7,763,220	5.4%	$942,307	0.7%	$143,161,947
2011	$97,591,566	93.5%	$6,296,955	6.0%	$455,462	0.4%	$104,343,983

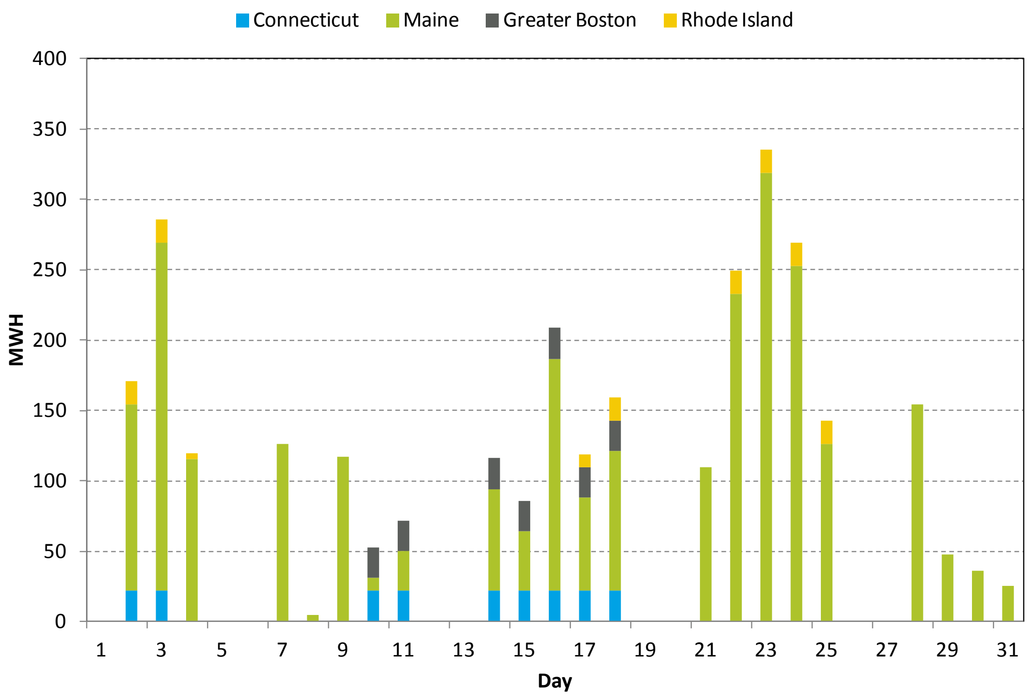
Data Source: ISO-NE, Black & Veatch Analysis

The approximately 1,100 MW of active demand resources in the capacity market represents only 3.5% of total ISO-NE capacity.[10] The energy it generates in real time is also insignificant as a share of regional generation, as evidenced by the low historical load-response program payments. Based on previous levels of participation, Black & Veatch does not expect demand response to bring about the level of demand reductions required to provide significant and sustained relief to gas adequacy issues in the region.

[10] Also, recent forward capacity market auction results indicate the attrition of demand response capacity in New England.

As a snapshot reflecting the transition program that has been in place since 2012, Black & Veatch plotted in Figure 13 the cleared price responsive demand in day-ahead market for January 2013.

Figure 13: Cleared Demand Response Day-Ahead Market in January 2013



Data Source: ISO-NE, Black & Veatch Analysis

For the week ending January 26, 2013, when New England experienced the five coldest consecutive days since the week of January 19, 2009 and natural gas basis in New England exceeded $15/MMBtu, only 1,107 MWh of demand response resources were dispatched to the market. Overall, demand response resources continue to be a relatively modest resource that is currently not offered on a large enough scale to significantly relieve natural gas infrastructure constraints. The level of natural gas constraints projected for the year 2023-2024 represents approximately the equivalent of 4,000 MW of capacity dispatched for 10 hours every day for more than 20 days throughout the region, which could be a challenging requirement to meet primarily using demand response resources. Thus, demand response may be considered as a complement to other potential solutions in Phase III.

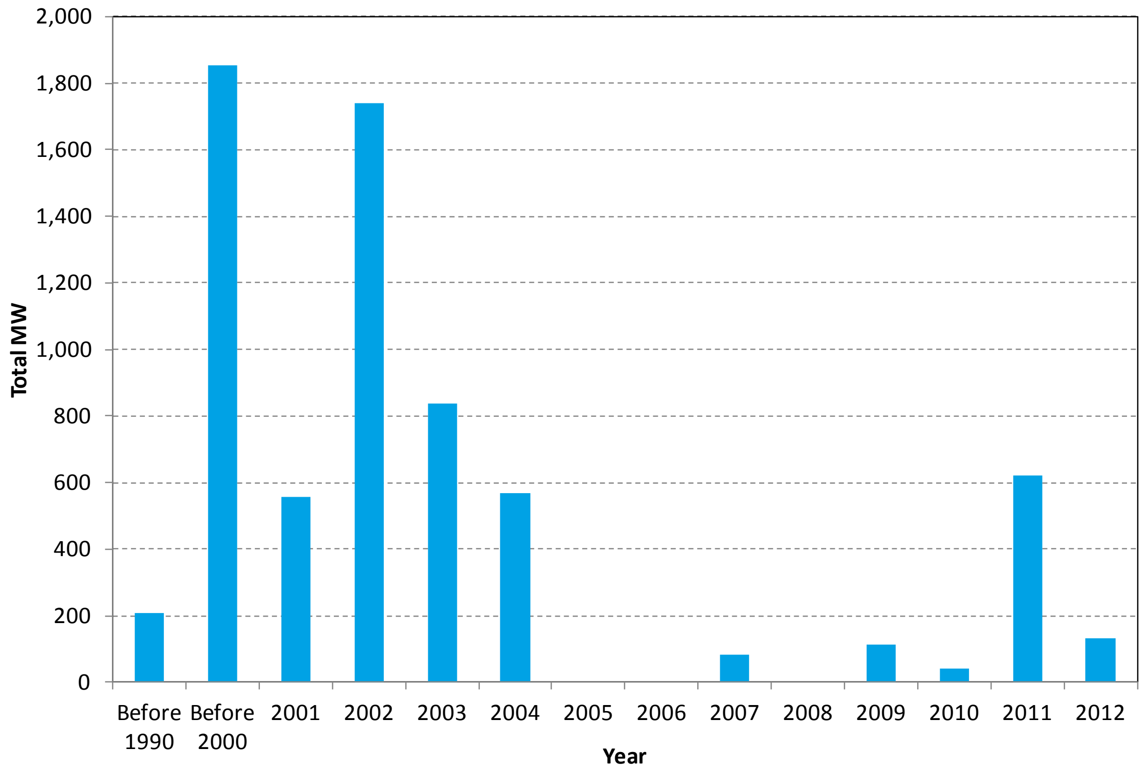
DUAL–FUEL GENERATION CAPACITY

Generators with dual-fuel capability could continue to provide energy during emergency situations when natural gas supply is not available or too expensive to dispatch. Operators of dual-fuel generation capacity have been facing financial challenges over the last several years. The cost divergence between natural gas and oil-based fuel makes the dispatch of the alternative fuel out of economic merit most of the time, and at present, capacity market payments may not provide adequate financial incentives to hold alternative fuel and maintain dual-fuel capability. One indication of the financial challenges faced by dual-fuel generation is that oil-fired generation has decreased from 9.1% to 0.5% of total New England generation in the last 10 years.

Another challenge that could potentially limit the effectiveness of dual-fuel capacity is the environmental restrictions that exist to limit the length of time that generators can run on oil. Many of these generators have restrictions on their air permits that restrict the number of days they may burn oil in a given year.

However, ISO-NE currently contains a large amount of dual-fuel generation capacity. As illustrated in Figure 14, most generators with dual-fuel capability were built in the 1990s and early 2000s and are not expected to retire in the near future. Compared to new infrastructure, incremental capital costs associated with these units are relatively low, with the ongoing operating costs and maintaining a constant supply of oil, which could range from $1 million to $2 million a year for a unit with 250 MW capacity.

Figure 14: Age of ISO-NE's Dual-Fuel Capacity



Data Source: Ventyx, Black & Veatch Analysis

Given the significant level of existing dual-fuel capacity available to serve New England, it is likely that this capacity could provide at least a partial solution to gas-electric reliability issues facing the region, if proper incentives are put into place. Primarily, compensation offered for dispatching these units could be altered to ensure that they are financially rewarded when dispatching to the market at cost levels higher than the equivalent natural gas units. Furthermore, environmental restrictions placed on these units could be altered to accommodate more frequent dispatch.

8.0 Key Observations and Conclusions

THE NEW ENGLAND MARKET EXPERIENCED INCREASING TIGHTNESS IN NATURAL GAS SUPPLY ACCESS IN RECENT YEARS

The New England natural gas market experienced ever-increasing levels of supply constraints over the course of the past several winters, as evidenced by frequent and abrupt price increases. The most recent winter of 2012-2013 witnessed New England natural gas market basis[11] exceeding $3.00/MMBtu on 78 days and even reaching above $30/MMBtu. The increased level of basis volatility is the market's response to supply tightness.

NATURAL GAS DEMAND IS EXPECTED TO GROW IN NEW ENGLAND, DRIVEN BY THE ELECTRIC SECTOR

Natural gas generation is expected to replace retirements of oil and gas fired capacity triggered by environmental regulation. It is the most economic type of incremental, dispatchable capacity under an emissions control program. Natural gas demand from the residential, commercial, and industrial sectors in New England is expected to grow modestly, at less than 1% per year, through 2028. The state of Connecticut is expected to experience the fastest growth through 2020 from the residential and commercial sectors given Governor Malloy's Comprehensive Energy Strategy.

NEW ENGLAND NEEDS INCREMENTAL CAPACITY IN THE FUTURE

New England's natural gas infrastructure is expected to face capacity constraints of increasing severity going forward. Historical load and price analyses show that the region experienced supply constraints, expressed as spot market basis spikes, when load levels approached 75% or more of existing firm contract capacity serving the market. This indicates that the current New England natural gas market balance is very tight, with small shocks to the system causing significant market impacts. Projected demand growth from the electric sector raises regional natural gas requirements even closer to this threshold level.

PHYSICAL CONSTRAINTS COULD OCCUR ON MORE THAN 30 DAYS

Black & Veatch's statistical analysis of historical data shows that price spikes could occur regularly when load levels exceed 75% of firm contracted capacity ("constraint capacity"). Regional basis spikes have occurred for 10 to 27 days during each of the past three years. In the absence of incremental natural gas infrastructure, electric load growth will increase the likelihood of constraints. As described in Section 5 and shown in Figure 11, for the 14 New England sub-regions that Black & Veatch analyzed, 11 will exceed the constraint capacity level on more than 30 days without Spectra's AIM project. Even with AIM, nine sub-

[11] Basis is the price differential between the price at a given location and Henry Hub, a Louisiana natural gas pricing point that is representative of the US natural gas market

regions will have load levels exceed the constraint capacity threshold for more than 30 days.

PHYSICAL CONSTRAINTS ARE EXPECTED TO BE WIDESPREAD ACROSS NEW ENGLAND

Emerging constraints will likely affect most New England states. Projected demand in each of the 14 sub-regions is expected to exceed the threshold levels of existing capacity serving the sub-region. Because a majority of natural gas pipeline supplies enter New England from the west, eastern sub-regions will be more severely impacted as capacity constraints to the west limit the amount of gas available to these sub-regions. It is also important to note that eastern sub-regions will be challenged in achieving gas deliveries at high pressure when constraints occur further west. This is significant, given that natural gas-fired generation capacity requires high-pressure natural gas deliveries. Load growth from the power sector is expected to occur near the terminus of the natural gas pipelines, potentially exacerbating the pressure concerns.

SUPPLY ISSUES COULD EXACERBATE CAPACITY CONSTRAINTS

Throughout this analysis, Black & Veatch uses contracted firm transportation capacity held for natural gas pipeline deliveries to New England as a proxy for supplies available to the region. It must be noted that such a proxy only captures capacity, and not necessarily the natural gas supplies available to serve the region. Capacity serving the region offers little relief to gas-electric reliability concerns if natural gas supplies are not available to be delivered using this capacity. For example, infrastructure inadequacy could be exacerbated if potential supply deficiencies in Eastern Canada and the Everett LNG terminal materialize, leaving some pipeline capacity without access to adequate supplies.

NATURAL GAS PIPELINES, THE LNG IMPORT OPTION, AND ELECTRIC IMPORTS FROM DIVERSE SUPPLY RESOURCES TO THE REGION'S NORTH ARE LIKELY PRIMARY SOLUTIONS TO NEW ENGLAND'S CONSTRAINTS

Black & Veatch reviewed a suite of alternatives that fall under three categories and could potentially address the gas and electric infrastructure constraints facing New England:

1) Fundamental institutional changes to the way natural gas and electric markets operate and interact, such as changing the economic regulatory regime to allow pipeline capacity to be constructed without firm commitments or changing the forward capacity market rules;

2) Solutions to increase natural gas infrastructure and diversify sources of supply; and

3) Solutions to reduce natural gas demand from the electric sector.

Black & Veatch focused on solutions under the last two categories. The nature, timing, and extent of any institutional changes to the electric and natural gas industries are uncertain, beyond the scope of the Phase II analysis, and are being addressed in other forums as potential solutions to address New England's gas-electric reliability issues.

Black & Veatch believes that under the base case assumptions, the following are the most appropriate primary solutions to alleviate the infrastructure constraints: incremental natural gas pipeline capacity, incremental LNG imports, and electric transmission that enables imports from outside the region, particularly to reach the substantial and diverse supply resources north of, and proximate to, New England.

Other alternatives considered—additional LNG peak-shaving capacity, demand-side resources, and dual-fuel generation capacity—can help to relieve capacity constraints in a meaningful way, at least at a sub-regional level or as part of a blended solution. However, each of these options on its own has challenges in providing a sustained solution to the constraints anticipated throughout New England under the base case scenario:

- LNG peak shaving: Given that capacity constraints have the potential to occur on 30 or more days each year going forward, it is not likely that LNG peak shaving alone will offer capacity for a long enough period to successfully alleviate constraints due to the limited refilling flexibility of these facilities.

- Demand-side response: Demand-side response could decrease overall demand and peak demand for natural gas. However, because the natural gas capacity constraints have been observed throughout the region during winter for more than 30 days, there may not be sufficient availability of demand-side resources to single-handedly alleviate the infrastructure adequacy issues facing New England.

- Dual-fuel generation capacity: If implemented as an independent solution, dual-fuel capacity could face economic incentive challenges as the wide disparity between the cost of natural gas and cost of oil-based fuel is expected to persist. It could also face environmental challenges, such as air quality and permitting regulations, which would limit the frequency and duration of alternative fuel generation that can be dispatched to solve the natural gas inadequacy.

Solutions must be tailored, and when appropriate blended, to solve the type of constraints expected to occur. It is very likely that most appropriate solutions could change under different natural gas demand and supply projections. In Phase III, Black & Veatch and NESCOE will further analyze the combinations of potential solutions to address New England's natural gas infrastructure inadequacy issues associated with electric reliability.

9.0 Scenario and Sensitivity Recommendations

Based on preliminary observations and findings, Black & Veatch recommends three scenarios and several sensitivities to explore the potential severity of infrastructure constraints as well as the benefits brought about by incremental infrastructure solutions. Our recommended scenarios focus on market supply and demand to represent the spectrum of possibilities regarding the market environment going forward. Sensitivities within the defined scenarios explore the impact to the market brought about by proposed infrastructure solutions as well as other market conditions such as unusual weather conditions. The solutions proposed in the sensitivity recommendations are intended to guide Phase III analysis, with further refinement and customization ensuing as the analysis proceeds. Potential solutions not expressly mentioned below may ultimately form part of a blended solution.

Black & Veatch proposes three scenarios – a Base Case Scenario, High Demand Scenario and Low Demand Scenario – to represent the impacts of meaningful variations in major market factors that can occur in driving the needs for natural gas infrastructure in New England.

For each scenario, Black & Veatch recommends a balanced approach of analyzing two most appropriate electric infrastructure solutions and two most appropriate natural gas solutions. For the high demand scenario, a colder weather sensitivity will be analyzed to assess natural gas infrastructure adequacy when demand approaches "design day" requirements. For the low demand scenario, a sensitivity will be designed to understand the impact on New England natural gas infrastructure adequacy if strong policy initiatives result in significant efficiency gain and renewable developments to the extent that electric sector demand for natural gas actually contracts.

BASE CASE SCENARIO

The Base Case scenario reflects the most likely assumptions agreed upon by Black & Veatch and NESCOE. In the Base Case, Black & Veatch projects natural gas demand from the residential, commercial, and industrial sectors to grow at less than 1% per year for most states. Electric sector demand for natural gas will be driven by the following assumptions:

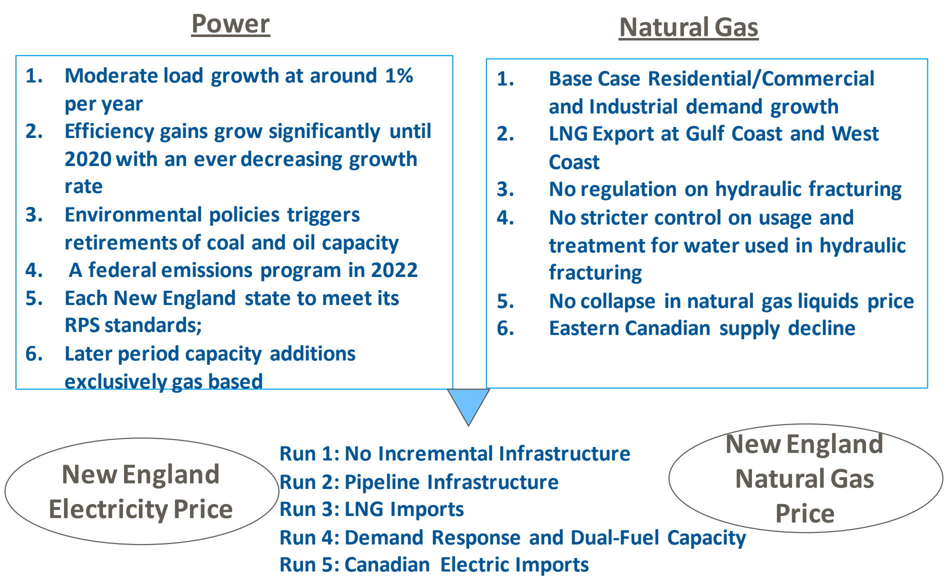
1) Load growth is moderate at around 1% per year;
2) Efficiency grows significantly until 2020 and moderates thereafter;
3) Environmental policies and competitive economic pressure trigger significant retirements of coal and oil capacity;
4) A federal cap-and-trade program on carbon emissions is in effect by 2020;
5) Growth in renewable capacity dominates capacity additions in the early years to allow each New England state to meet its Renewable Portfolio Standards ("RPS") goals;
6) Later period capacity additions are exclusively gas-fired.

The Base Case scenario also includes other assumptions:

7) LNG export at Gulf Coast and West Coast;
8) No regulation on natural gas hydraulic fracturing;
9) No stricter control on usage and treatment for water used in hydraulic fracturing;
10) No collapse in the price of the liquids extracted from certain natural gas supply basins; and

Projected decline in Eastern Canadian supply.

Figure 15: Base Case Assumptions



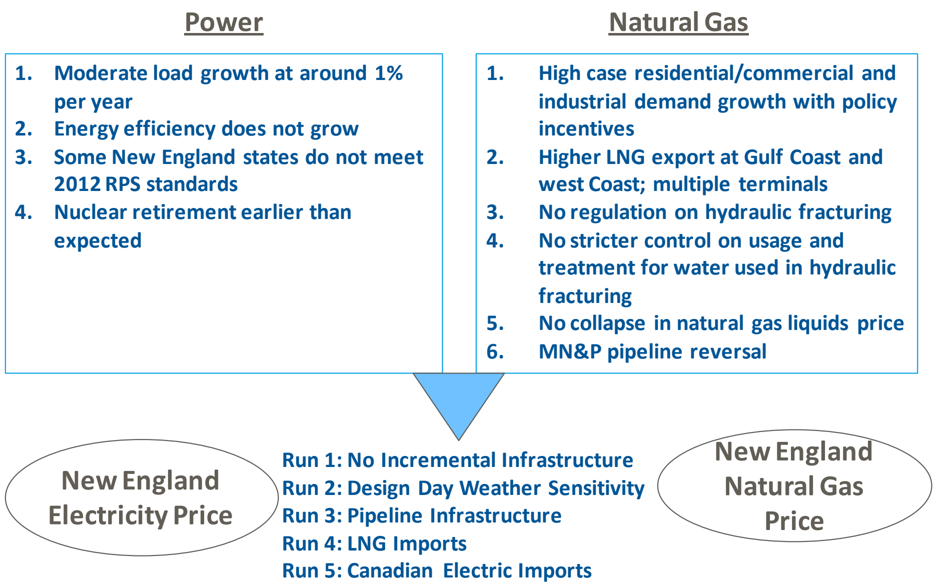
HIGH DEMAND SCENARIO

Black & Veatch proposes a scenario that assumes a tighter (relative to the Base Case) natural gas demand and supply environment for New England and the US as a whole in order to explore the consequences of increased stress on New England's natural gas infrastructure. Demand growth could be higher than observed in the base case due to the following reasons:

1) New England states implement incentives to encourage increased residential, commercial, and industrial usage of gas;
2) The electric sector experiences a higher level of growth as a result of states not meeting RPS standards and efficiency savings being less than expected;
3) Multiple North American LNG terminals begin exporting natural gas out of North America; and
4) The Maritimes & Northeast Pipeline ("MN&P") is reversed to meet demand growth from Nova Scotia and Maritimes Canada.

All other assumptions will remain the same as in the Base Case. This is a scenario that could potentially increase the level of natural gas infrastructure inadequacy in New England.

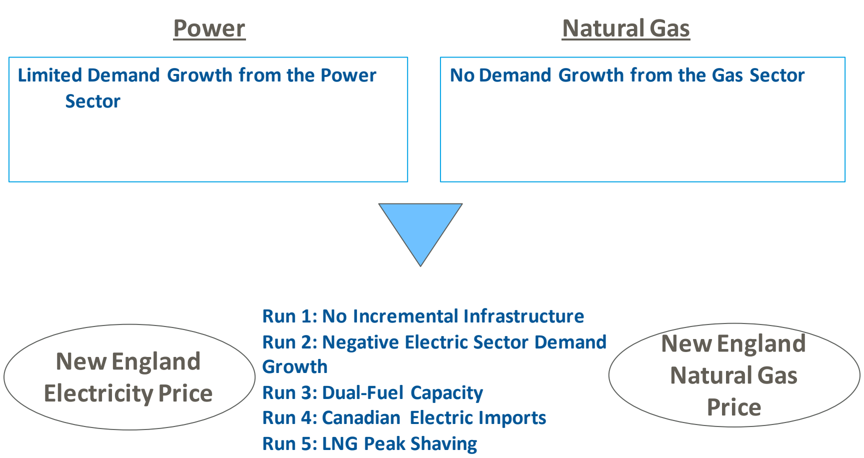
Figure 16: High Demand Scenario Assumptions



LOW DEMAND SCENARIO

This scenario assumes no demand growth for the residential, commercial, and industrial sectors. Load growth from the electric sector will be offset by energy efficiency gains; therefore, limited demand growth from the electric sector could be expected. This scenario is designed to examine the requirements for natural gas infrastructure when the increasing natural gas demand by the electric sector does not materialize.

Figure 17: Low Demand Scenario Assumptions



In Phase III, the costs and benefits of the recommended scenarios and sensitivities will be evaluated to inform public policymakers' consideration of potential solutions. The Phase III report will provide recommendations on infrastructure and/or other opportunities that may help to provide electricity at the lowest possible price over the long term, consistent with maintaining reliable electric service and environmental quality, identifying the overall value to electric customers, and evaluated associated costs and risks.