**New Hampshire Public Utilities Commission**

**IR 15-124**

# PREFERRED SOLUTION TO HIGH NEW ENGLAND WINTER ELECTRIC PRICES

The undersigned is a member of the Science, Technology & Energy Committee of the New Hampshire House of Representatives, but the views expressed in this statement are his own and do not purport to represent the views of the Committee.

1. **Root Cause of High New England Winter Electric Prices.** There is a strong consensus among energy experts that the root cause of recent high winter wholesale and retail electricity prices in New Hampshire and throughout New England is the lack of sufficient interstate natural gas pipeline capacity from the low-cost Marcellus shale region in nearby Pennsylvania into Dracut, the New England pipeline terminus north of Boston. I believe that consensus is entitled to overwhelming weight.

   Natural gas-fired generating plants now produce roughly 50% of New England's electricity, and are "on the margin" for dispatch by ISO-NE during most of the 8760 hours in the year. This means (a) that gas generators typically set the "clearing price" for all electricity sold in the ISO-NE "real-time" market, and (b) that increases or decreases in the wholesale price of electricity in New England are driven largely by increases or decreases in the wholesale price of natural gas at the Dracut hub. Natural gas prices at Dracut are a function of demand and supply. During most of the year, pipeline capacity into New England is sufficient to supply the region's gas-fired generators at low prices reflecting an over-abundance of supply at the well-head in Pennsylvania. Most of these generators cannot justify the premiums they would pay for "firm" gas transportation contracts (i.e. a dedicated share of pipeline capacity), since they can get the gas they need to operate on a "non-firm" basis on all but the 10 or 20 coldest days of the winter, at prices reflecting normal demand.

   But during those 10-20 coldest days of the year, local gas distribution companies, which have paid for firm gas transportation in order to meet home heating demand, claim the bulk of the available gas pipeline capacity. This sharply reduces the "non-firm" or interruptible gas supply available for electric power generation, and causes gas prices to spike for generators who do not have firm gas transportation contracts. If ISO-NE needs those gas generators to run in order to cover retail load, the price of the electric power they produce (and all other power sold at real-time prices while gas is on the margin) will also spike, sometimes to levels several times higher than normal. In extreme cases, these gas generators may simply shut down rather than operate at a loss, forcing ISO-NE to dispatch even more costly coal and oil resources.

2. **Preferred Solution.** The preferred solution is the construction of new interstate gas pipeline capacity into New England—all the way to Dracut—sufficient to eliminate the "basis differential" between natural gas wholesale prices at the Hudson River (e.g., in Tennessee Zone 5) and those at Dracut and throughout New England (Tennessee Zone 6). If this basis differential can be eliminated, or even substantially reduced, through additional supply at Dracut, New England wholesale gas prices during cold peak winter days would come down to levels more closely approximating New York's, and New England wholesale and retail electric prices would follow. New Hampshire residential ratepayers would see significantly lower retail electric rates, and New Hampshire businesses and industrial customers would be at much less of a competitive disadvantage vis-a-vis New York and the mid-Atlantic states.

As compared to the winter of 2012-13 (the four months from December-March), the basis differential in wholesale gas prices between New York and Boston (Dracut) during the four-month winter of 2013-14 cost the New England economy $3.2 billion in added electric bills.

Various industry experts have estimated that it would take an additional 1.2 to 2.4 billion cubic feet (bcf)/day of supply at Dracut to eliminate the basis differential in wholesale gas prices between New York and New England. *See* studies by Black & Veatch (2013), Competitive Energy Services (2014), and ICF International (2015), attached and referred to in Section 8 below. I do not know how much additional pipeline capacity at Dracut would be required to eliminate this basis differential, but I believe the current inquiry in this docket should focus on that question.

The major interstate gas pipeline companies have been slow to build new capacity into New England because FERC policy and regulations require firm gas transportation contracts to support proposed new pipeline capacity. However, gas-fired electric generators are not compensated for the premiums paid for firm transportation, and as noted above, most have no incentive to sign on as anchor tenants. Thus new capacity may depend on additional commitments from local gas distribution companies (LDC's), as is happening now in Connecticut.

Still, there now appear to be at least two serious pipeline development projects that together would bring additional gas supplies in the indicated range to Dracut—the Spectra "Access Northeast" and Kinder Morgan "North East Direct" projects. So new capacity is likely to be built out within the next three to four years, provided individual New England states such as New Hampshire do not delay them by attempting to introduce new regulatory or legal hurdles.

However, because none of these lines is likely to be completed until 2018 at the earliest, the "preferred solution" necessarily requires continuation of ISO-NE's "winter reliability programs" (emphasizing on-site oil storage at "dual-fuel" generating facilities and additional supplies and storage of high-cost LNG) through at least the winter of 2017-18, and perhaps longer. So far, ISO-NE has managed the winter peak program effectively. We have to hope they will continue to be successful.

3. **The Preferred Solution is Regional.** The preferred solution is a regional solution, not merely part of a regional solution. It is not just New Hampshire that needs additional gas pipeline capacity, but all of New England (for which read "Dracut"), with the possible exception of Vermont, which has next to no gas pipeline infrastructure. (For example, the Kinder Morgan proposal closely approximates the hypothetical trans-regional pipeline route recommended to NESCOE, the New England States Committee on Electricity, by their consulting engineers Black & Veatch.) Assuming FERC grants Spectra and/or Kinder Morgan a "certificate of public convenience and necessity" under 15 U.S.C. § 717(c), siting authorities in the separate New England states (in New Hampshire, the Site Evaluation Committee) will each have a role in permitting routes for new or expanded pipelines within their jurisdictions—but because FERC jurisdiction largely pre-empts the field under the Federal Power Act, their authority will largely be limited to influencing the location of routes, rather than approving or blocking one or more particular interstate pipeline projects altogether.

4. **EDC Purchases of Firm Pipeline Capacity.** If by "EDC's" staff means New Hampshire electric distribution companies regulated by the Commission whose retail rates are set by Commission action (Eversource, Unitil, Liberty), it is not clear to me that any New Hampshire EDC's (as distinct from gas LDC's) would need to purchase firm gas pipeline capacity. (Liberty's LDC has proposed to contract with Kinder Morgan for significant additional firm gas transportation capacity.) The "market" has indeed been very sluggish in responding to the obvious need for additional gas pipeline capacity in New England, but it finally seems to be in gear.

5. **LNG is Not a Complete or Long-Term Solution.** I do not believe increased Liquefied Natural Gas supplies or storage facilities at or near Dracut can reliably substitute for new gas pipeline capacity. LNG prices and availability are simply too unpredictable. The appearance of LNG supply ships from the Caribbean in Boston Harbor this past winter may well have helped to hold down winter price spikes for both gas and electricity, as compared to the much higher price spikes in the winter of 2013-14, but it is not something New England can count on going forward. Those fortuitous

and timely shipments appear to have been due to unusually low (and highly volatile) global LNG prices in places as far away—and as little subject to the control of ISO-NE—as Japan and Western Europe. Reliance on more LNG ships in future winters seems to me to be risking regional blackouts.

6. **Energy Efficiency, Renewable Power, Demand Response, and Distributed Generation.** I believe New Hampshire, which badly lags its sister New England states, needs to do everything it reasonably can to promote energy efficiency, transition away from fossil fuels, and decentralize its grid. Achieving these policy goals will require development of a strong Energy Efficiency Resource Standard, the promotion of indigenous renewable energy sources like water, wind, solar, and biomass, support for demand response programs, and incentives for distributed generation. The "negawatt" is by far the least expensive solution to what would otherwise be the need for new power plants.

But ISO-NE projects 1% annual electric load growth in the New England states over the ten-year period 2014-23, and the retirement of up to 4,600 MW (out of some 32,000 MW) of existing electric generating facilities in the next three years alone. Meanwhile, new energy efficiency projects are projected to shave only about 200 MW annually from peak regional load through 2023, and ISO-NE projects that distributed generation (primarily photo-voltaic solar) will increase regional capacity from roughly 500 MW in 2013 to1800 MW in 2023. Proposed wind-powered generation makes up approximately 45% of the new capacity in the ISO-NE interconnection queue, but most experts agree that there is simply no way that any combination of energy efficiency, new renewable energy generating capacity, demand response, and distributed generation can fill a 4,600 MW gap in the next three years—or ten years.

Over time, all these "soft resources" will give us lower and more stable energy prices and cleaner air. They will also help many individual homeowners and businesses with their electric bills in the near term. However, these soft resources will not keep winter New England electric prices down for most residential, commercial, and large industrial users in the near to medium term. For the next ten to twenty years, the most dramatic, reliable, and favorable impact on high winter electric prices in New England will come from significantly increasing the supply of natural gas into Dracut, through the construction of new interstate gas pipeline capacity from the Marcellus shale fields.

Natural gas is indeed a fossil fuel, but it is widely available at historically low prices just 300 miles from Boston, it emits none of the most harmful toxins produced by coal and oil-burning plants ($SO_2$, $NO_x$, and mercury, for example) and only half the $CO_2$ per MWh produced by coal and oil burning plants, and it is much more efficient than the dirtier, more expensive fossil fuels. It is a bridge fuel, needed in the interim to get us to a sustainable future.

7. **Reliability.** Increasing the supply of natural gas into the region will enhance reliability. Of the proposed new generating capacity in development in the ISO-NE interconnection queue, over 50% is natural gas, and most of the rest is wind. But wind is an intermittent resource, providing power when the wind blows hard, but liable to drop when the wind dies. Not all of the proposed wind capacity in the queue will be built, though we should welcome as much of it as can be built, because that will lower prices and increase energy sustainability over time. But we will need quick-ramp "load-following" gas generation resources to balance the use of intermittent resources (i.e., pick up the slack when the wind dies), and fill the gap between our nuclear and hydroelectric baseload generating facilities and our more variable resources like wind and solar. That's reliability.

8. **Supporting Studies.** Attached as Exhibits please find:

   A. Executive Summary of August 26, 2013 Black & Veatch study entitled "Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England", prepared for NESCOE
   B. Februry 17, 2014 Competitive Energy Services study entitled "Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices", prepared for the Industrial Energy Consumer Group
   C. February 18, 2015 ICF International study entitled "Access Northeast Project—Reliability Benefits and Energy Cost Savings to New England", prepared for Eversource Energy and Spectra Energy.

Respectfully submitted,

Howard M Moffett

Rep. Howard Moffett

June 2, 2014

Exhibit A

# 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

BLACK & VEATCH
Building a world of difference.

# 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.

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[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.

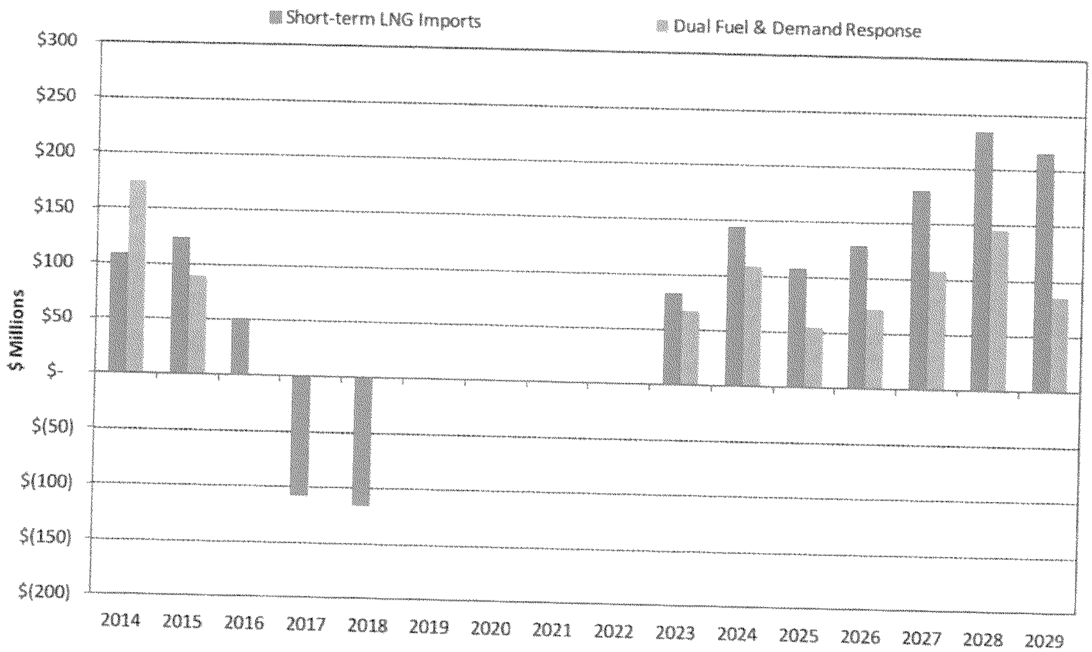



Figure 1 Net Benefits for the Short-Term Solutions

### 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.

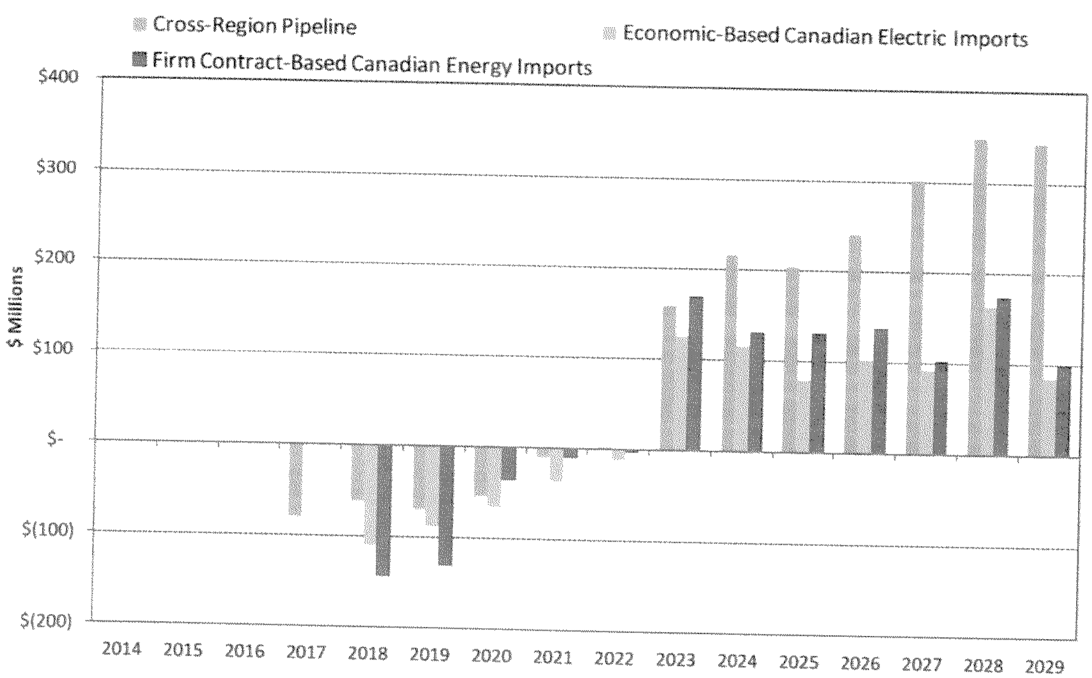
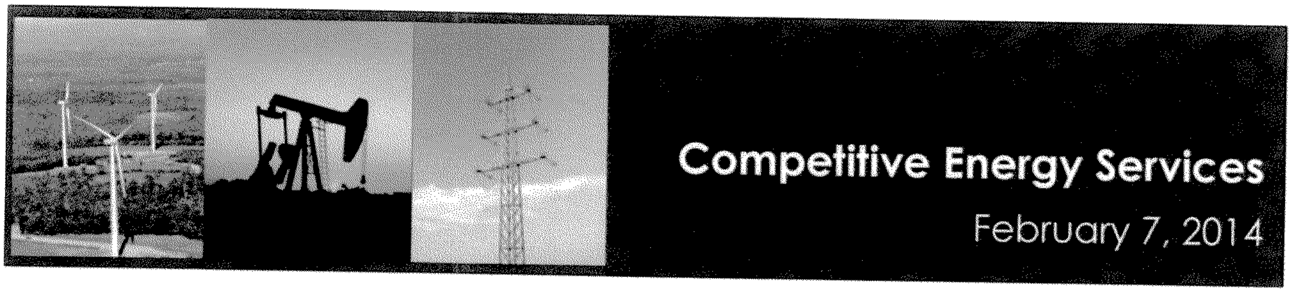



Figure 2 Net Benefits for the Long-Term Solutions

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.

Exhibit B




# Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices

Prepared for – The Industrial Energy Consumer Group

Competitive Energy Services

www.competitive-energy.com | 148 Middle St., Portland, ME 04101 |Phone 207.772.6190
Toll Free 866.408.4591| Fax 866.743.4968

# Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices

*This Report has been prepared for the Industrial Energy Consumer Group and its members by Competitive Energy Services, LLC. Competitive Energy Services is solely responsible for its contents. Competitive Energy Services provides information and projections consistent with standard practices. The analyses contained herein require certain simplifying assumptions regarding New England energy markets; however, it is the opinion of Competitive Energy Services that these assumptions are reasonable, and while subject to refinement, provide a reasonable order of magnitude estimate of prices, costs and savings. This Report, including all of its findings and conclusions, may not be used by anyone without the express consent of Competitive Energy Services. Competitive Energy Services makes no warranty or guarantee regarding the accuracy of any forecasts, estimates or analyses, or that such work products will be accepted by any legal or regulatory body.*

## Overview and Summary

Competitive Energy Services, LLC ("CES") has been retained by the Industrial Energy Consumer Group ("IECG")[1] to evaluate and assess the status of natural gas supply in New England and the impact such supply conditions will have on natural gas prices and the price of electric energy under three scenarios regarding the development of different additional pipeline capacities.

CES has relied on a number of third-party sources for information about pipeline and Liquefied Natural Gas ("LNG") capacities in New England, natural gas usage by non-electric generators (what we refer to as "LDC gas demand") and generation capacity by fuel type in the ISO-NE Control Area. In addition, we have made a number of assumptions about key parameter values and relationships that have enabled us to develop a model of natural gas supply and demand for New England. These are explained in more detail in the Report. We have used this model and actual hourly New England electricity loads, generation dispatch and temperatures in New England during Calendar Year 2013 to estimate the impacts that different gas pipeline expansion options will have on natural gas prices, basis differentials and electricity clearing price in the region.

CES believes it is critical that any modeling of natural gas and electricity markets in the region use an internally consistent hour-by-hour data set to ensure that electricity loads and dispatch conditions

[1] The IECG is an incorporated association formed almost 30 years ago for the purpose of representing Maine industrial energy consumers before regulatory, legislative and congressional bodies on energy-related issues. It is based in Augusta, Maine.

match ambient air temperatures and general weather conditions, since this is the primary driver of LDC demands for natural gas. For this analysis, we have used Calendar Year 2013 data.

We divide our Report into seven sections. The first section provides a brief overview of the studies that have been done over the past two years to assess the pipeline shortage situation in New England. The next three sections each discuss a key component of the energy supply and demand relationship in New England and describe how we have modeled that component with a specific emphasis on how it impacts natural gas usage and prices in the region. Section 5 describes our Base Case assumptions and conditions and presents the results of our modeling under this scenario. Section 6 identifies three different pipeline expansion options that have been discussed for the New England region and presents the results from our model under each of these scenarios. Finally, Section 7 highlights a few key issues that need to be carefully considered, since they will most certainly impact certain assumptions used in the Base Case and have important impacts on energy prices under each of the pipeline development scenarios we have evaluated.

The key results from our study are:

- There has been a fundamental shift in the New England natural gas market since 2012 that is causing price spikes during winter months to be much higher and more frequent than they have previously been. As a result, studies of the natural gas market that were done prior to the winter 2012/2013 or that rely on data prior to that period will understate significantly the financial consequences of inadequate natural gas pipeline capacity into New England.
- 1 bcf/d of additional pipeline capacity into the region, as proposed in the recent Governors' Letter, will provide partial relief to the region from high natural gas and electricity prices but will not eliminate the basis differential between New England and pricing points to our west and south.
- This 1 bcf/d of additional pipeline capacity will reduce the number of hours each winter that New England must rely on expensive Liquefied Natural Gas by over 800 hours, but will still leave the region dependent on LNG for over 200 hours each winter. It is not clear whether two LNG facilities (Canaport in Saint John, New Brunswick and Distrigas in Everett, Massachusetts) can remain in operation at these severely reduced volumes. Were only the Everett facility to remain in business, it would have a monopoly on LNG and its pricing would be constrained only by the price of oil.
- 2 bcf/d of additional pipeline capacity is required to eliminate the natural gas price differential between New England and pricing points to the region's west and south. The additional 1 bcf/d above that proposed in the Governors' Letter will provide the region's electricity consumers $600 million a year in reduced costs beyond the savings they will realize as a result of the 1 bcf/d incremental capacity proposed in the Governors' Letter. This represents a 1 to 3 year payback period on the incremental pipeline investment, depending on the sequencing of the pipeline expansions.
- If there is a new 1,200 MW electric transmission line to Canada constructed and that line is able to import power from Canada into New England during the winter months (when Canada's electric demand is peaking), this power, depending on scheduling of the line and its implementation date, may offset the announced closing of 1,140 MW of coal generation at the Brayton Point plant in Massachusetts. As a result, the new transmission line will not reduce the demand for natural gas in New England during the winter months and therefore will not relieve the current supply constraint. If there is a second or even third line built, these lines may displace a further 2,400 MW of coal and oil units that ISO-NE has repeatedly noted are at risk of

shutting down, and like the first line, will not relieve provide any relief to capacity constraints on natural gas pipelines into New England.

## Section 1: Brief Review of Prior Studies

We are aware of four studies that have been done by various companies over the past two years that have examined the imbalance between natural gas pipeline capacity into New England and natural gas demands in the region. These studies were done by:

- Concentric Energy Advisors, Inc.[2]
- Black & Veatch[3]
- ICF International[4]
- Sussex Economic Advisors, LLC[5]

Each of these studies used different methodologies in their attempts to estimate the economic costs that pipeline capacity constraints and the resulting high basis differentials reflected in New England's price of gas were imposing on New England consumers. None of these studies, however, estimated how much additional pipeline capacity would be required to eliminate the basis differential between New England and price points to our west and south nor whether there is an economically optimal amount of pipeline capacity that should be built in the region.

In later sections of our Report we discuss some of the assumptions and components of the methodologies that were used in these studies. By and large, we have little quarrel with these. We are more concerned, however, by the time period covered by the studies, and in particular, that none of the Concentric Advisors, Black & Veatch or ICF International studies utilized natural gas pricing information for 2013. As we show very clearly in Figure 12 in Section 5 of our Report, there was a fundamental price shift in the natural gas market in New England in 2013 that sent natural gas prices soaring to levels three or more times higher than any prices experienced in the region over the prior 6 years. We believe that this shift was the result of the expiration of below market contracts for imported LNG deliveries into the regasification plants in Everett, Massachusetts (Distrigas or Everett) and Saint John, New Brunswick

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[2] When we refer to Concentric Energy Advisors, we are referring to the report, "New England Cost Savings Associated with Ne Natural Gas Supply and Infrastructure", May 2012, that was prepared by Concentric Energy Advisors for Spectra Energy Corp.

[3] When we refer to Black & Veatch, we are referring to the report, ""Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England," August 26, 2013, prepared by Black & Veatch for the New England States Committee on Electricity (NESCOE).

[4] When we refer to ICF International (or ICF), we are referring to the report "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs, June 21, 2012 (public version) prepared by ICF for the ISO-NE Planning Advisory Committee.

[5] When we refer to Sussex Economic Advisors, LLC (or Sussex), we are referring to the work done by Sussex for the Maine Public Utilities Commission in late 2013 and into 2014.

(Canaport), as well as certain operational requirements of the Canaport facility that have since been eliminated.

By relying on pre-2013 price and market information, these studies are underestimating the winter price for natural gas in New England and therefore the value to New England electricity consumers from relieving the pipeline constraint. For example, the Black & Veatch study projects monthly Algonquin to Henry Hub basis differentials during the current winter period of between $3.00 and $4.00/mmbtu and spot electricity prices less than $60.00.MWh.[6] The actual values have been more close to three times these levels. If the study has significantly underestimated natural gas basis prices in New England under its base case, the study will significantly underestimate the savings to electricity consumers from driving basis prices to zero through the addition of pipeline capacity.

The Concentric Energy Advisors study suffers from the same failing. Concentric utilized daily price premiums or basis between Algonquin and TETCO-M3 over the winters 2008/2009 through 2010/2011, a period during which the average basis differential was less than $0.50/mmbtu.[7] The elimination of so small a basis differential is going to result in very small annual savings to the region's electricity consumers.

The ICF study estimates only the shortfall of capacity based on its assumptions about the demand for natural gas in New England and flows on the region's existing pipelines. Their reference case shows a shortfall of close to 1.4 bcf/d on peak winter days by 2019/20. However, this scenario assumes that north-to-south flows on the Maritimes & Northeast Pipeline are at full capacity (0.833 bcf/d), that the Everett Distrigas facility is injecting gasified LNG into the region's pipelines at its full capacity of 0.715 bcf/d and that Vermont Yankee is generating at full power.[8] If the region is to eliminate imported LNG that is driving basis so high in the winter months, the shortfall balloons to close to 2.5 bcf/d on Design Days and well above 2.0 bcf/d for much of the winter. ICF did not provide any estimates of the cost to New England's electricity consumers of the gas shortfall nor the value to those consumers were the pipeline capacity constraint to be relieved through additional pipeline construction. ICF's primary focus appears to be on whether there would be enough gas for ISO-NE to operate the region's electric grid to meet loads in a reliable manner.

We point out these concerns with prior studies not to be critical of the studies but rather to highlight the fact that the consequences of not relieving the natural gas pipeline capacity constraints in the region have become much higher and accordingly, the value of their relief that much greater.

## Section 2: Derivation of LDC Demand for Natural Gas in New England

The demand for natural gas by local natural gas distribution utilities in the region ("LDCs") must be the starting point for any effort that seeks to understand energy supply and demand conditions in New

[6] See Figures 17 and 19 of the Black & Veatch report at pages 32 and 33.

[7] See pages 37-43 of the Concentric Energy Advisors report.

[8] See pages 32 and 40 of the ICF report.

England.[9] LDC demands, or more accurately the demands for natural gas by the customers LDCs serve, represent "must serve" natural gas loads.[10]

There is general agreement among those who have examined natural gas conditions in New England that total annual LDC demand for natural gas is in the range of 430 bcf. There is also general agreement that this demand is likely to grow over the next decade as a result of new natural gas expansions (e.g., Summit Natural Gas of Maine) and fuel-conversions where natural gas infrastructure already exists to serve customers (e.g., Connecticut's policy to increase residential and commercial natural gas penetration rates by 50% by 2020). There is less agreement, however, regarding the amount by which LDC demands are likely to grow. Concentric Advisors projected average demand growth rates of 0.5% in Design Day volumes for the region through 2020 or an increase of about 0.150 to 0.250 bcf/d.[11] ICF International projected a much higher Design Day average annual growth rate of 1.4% over the same period and an average growth rate of 1.2% for annual LDC demands. This latter growth rate results in an estimated total region-wide demand of 468 bcf by 2020. Finally, Black & Veatch projected average growth in natural gas demand of 1.6% per year New England (except Connecticut), with Connecticut's goal of increasing natural gas penetration by 50% through 2020, resulting in a higher growth rate in that state.[12]

While annual demand for natural gas is important, it is not what is driving capacity shortage situations and very high price spikes in New England. These are the result of peak demands, driven by cold weather and usage levels approaching Design Day demands on LDC systems. There is less agreement among Black & Veatch, Concentric Advisors and ICF about what Design Day demands for the New England region are, as shown below:

Estimated New England LDC Design Day Demands:

| | |
|---|---|
| ICF International | 4.2 bcf/d |
| Concentric Advisors | 3.5 bcf/d |
| Black & Veatch | 3.0 bcf/d |

[9] We note that two Canadian Provinces – New Brunswick and Nova Scotia – are served off the Maritimes & Northeast Pipeline and therefore are interconnected directly to the New England system. We have not included these loads in our modeling. Instead, we have factored them into our assessment by considering only flows on the Maritimes & Northeast Pipeline from the U.S. – Canada border south. These flows are net of all gas usage in the two Maritime Provinces.

[10] We recognize that certain LDC customers may take service under interruptible tariffs that allow LDCs to curtail service during the winter months. Given the very large price spread between natural gas and heating oil prices (including #6 oil) that has emerged over the past four (4) years, the benefits to customers from such interruptible tariffs have fallen so much that customers have found it more economical to move to firm service where that option was available.

[11] We have adopted the convention of reporting natural gas volumes in billions of cubic feet (bcf) rather than mmbtu, since this has been the standard unit of reference when discussing pipeline capacities. For our purposes, we have assumed that 1 bcf = 1,000,000 mmbtu.

[12] Black & Veatch state that they anticipate natural gas demand growth of 0.360 bcf/d from 2014 through 2029, but it is unclear whether this includes growth from electricity generation as well as LDC demand.

Each of these values appears to have been developed using different methodologies and different sources. ICF used as a proxy 1% of total annual volumes to measure Design Day loads; Concentric Advisors based their estimate on the aggregate of the Design Day loads for most of the LDCs in the region gleaned from their Integrated Resource Plans; while Black & Vetch developed its Design Day volumes based on historical records that they indicate show a 2.56 multiplier for Design Day conditions compared to average winter conditions.

Our own work that we performed to specify design capacities for our proposed pipeline system to serve Kennebec Valley Gas Company[13] customers in central Maine resulted in a system-wide Design Day volume equal to approximately 1% of annual projected volumes, leading us to support the ICF estimate.[14] As noted below, we use a Design Day volume equal to 4.2 bcf/d in our modeling.

Knowing total annual gas usage and Design Day demands is a first step but it does not enable one to model how LDC demands impact natural gas prices in New England. For this we need actual hourly natural gas usage. This information is not available, and therefore must be modeled. We used three parameters to develop a relationship between ambient air temperature and LDC natural gas demands:

- Total Annual LDC Demands 440 bcf
- Design Day Demand 4.2 bcf/d
- Process Loads[15] 0.400 bcf/d

The results of our modeling are shown in Figure 1. This graph shows the daily natural gas demands of LDCs at each ambient air temperature between 10°F and 65°F, assuming that temperature held constant for the entire 24 hour day. The graph shows that there is no heating demand at temperatures above 60°F; for all temperatures below 10°F, we used the Design Day demand of 4.2 bcf/d. We then divided each of the daily demands by 24 to obtain an hourly demand that corresponds to an hourly temperature. These results are used in our modeling discussed later in this Report. Using actual hourly temperatures for 2013[16], our model shows a total annual 2013 LDC demand for natural gas 428 bcf,

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[13] Kennebec Valley Gas Company was sold to Summit Natural Gas of Maine, which is building out the distribution pipeline infrastructure to serve customers in Central Maine.

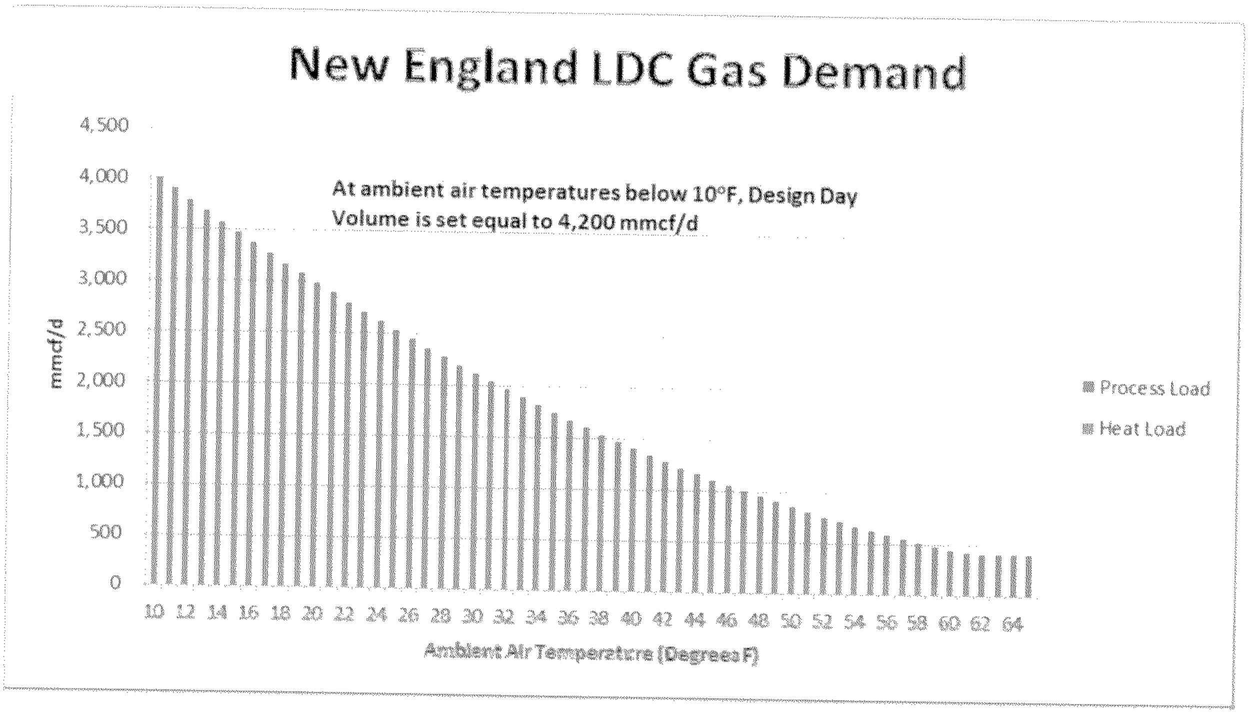
[14] In addition, Sussex Economic Advisors, LLC, who have been retained by the Maine Public Utilities Commission to assist in modeling the price impacts of additional pipeline development in New England, indicated during a telephone conversation that they believed Design Day volumes to be in the 4.2 bcf/d range.

[15] We use process load demand to refer to all natural gas usage that is not ambient temperature or weather sensitive and is therefore is constant over the course of the year.

[16] We have used an electric load weighted temperature for New England as the proxy for ambient air temperature each hour obtained from ISO-NE. Using 65°F as the standard, these temperatures result in total heating degree days (HDD) of 6,270. By comparison, the average HDD values for the period 1971 – 2000 for Connecticut and Massachusetts are approximately 5,850 and 6,200, respectively. http://www.ncdc.noaa.gov/oa/documentlibrary/hcs/hcs.html.

which is in the range of total LDC gas usage that we expect to see when EIA updates its reports to include 2013 figures.

Figure 1: New England LDC Daily Gas Demands as a Function of Temperature




## Section 3: Natural Gas Delivery Capacity into New England

New England is served by five interstate natural gas pipelines, as described in Figure 2.[17] Two of the pipelines bring natural gas into New England from the south (Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (AGT)); one brings natural gas into New England from the west (Iroquois Gas Transmission (IGT)); two bring natural gas into New England from Canada, one from the Maritime Provinces (Maritimes and Northeast Pipeline (M&NP)) the other from the Montreal region (Portland Natural Gas Transmission (PNGTS)).

In addition, New England is served by three LNG import facilities located within the region – the Northeast Gateway, Neptune and Everett, and one outside the region – the Canaport facility in Saint

[17] A sixth pipeline – the Granite State Gas Transmission pipeline – is an interstate pipeline that serves only to distribute natural gas within the region. It has no ability to bring gas from outside of New England into New England. A seventh gas pipeline serves northern Vermont through the Vermont Gas System, which is not interconnected to any other region of New England. The Vermont Gas System is served off the Trans-Quebec-Maritimes (TQM) pipeline. Since the Vermont Gas System's load is so small and isolated, we have not included it in our estimates.

John, New Brunswick. Finally, Concentric Advisors reports that New England's LDCs have more than 50 LNG peaking and propane-air facilities that can be called upon to meet peak natural gas demand, with a total storage of 16 bcf. ICF has estimated that the total LDC LNG peak-shaving send-out capability is approximately 1.3 bcf/d, while the propane-air send-out capability is about 0.137 bcf/d.

Figure 2: Capacities of Existing Pipelines into New England

| Pipeline | | Capacity MMcf/d | Interconnect Pipelines | Gas Sources |
|---|---|---|---|---|
| Algonquin Gas Transmission | AGT | 1,087 | Texas Eastern Pipeline | Gulf of Mexico |
| Iroquois Gas Transmission | IGT | 220 | TransCanada Pipeline | Western Canada |
| Tennessee Gas Pipeline | TGP | 1,261 | Gulf of Mexico, Texas | Gulf of Mexico |
| Portland Natural Gas Transmission | PNGTS | 168 | TQM Pipeline system | Western Canada |
| Maritimes and Northeast Pipeline | M&NP | 833 | None | Sable Island, Deep Panuke fields |

The aggregate supply capabilities are shown in Figure 3. This figure shows that those pipelines that are interconnected to stable supply sources are capable of importing about 2.7 bcf/d into New England, without relying on flows north-to-south on the M&N Pipeline from Canada. The region can draw upon almost 1.5 bcf/d of LNG and propane supply to meet peak demands, however, the LNG component of this resource is limited by available storage and the need to refill storage capacity using trucked LNG out of Everett at approximately 0.100 bcf/d capacity.

A further 0.83 bcf/d is available from eastern Canada through the M&N Pipeline, which brings natural gas from four potential sources – Sable Island, Deep Panuke, Corridor and LNG in storage at the Canaport facility. Total capacity across all sources is a maximum of approximately 5 bcf/d.[18]

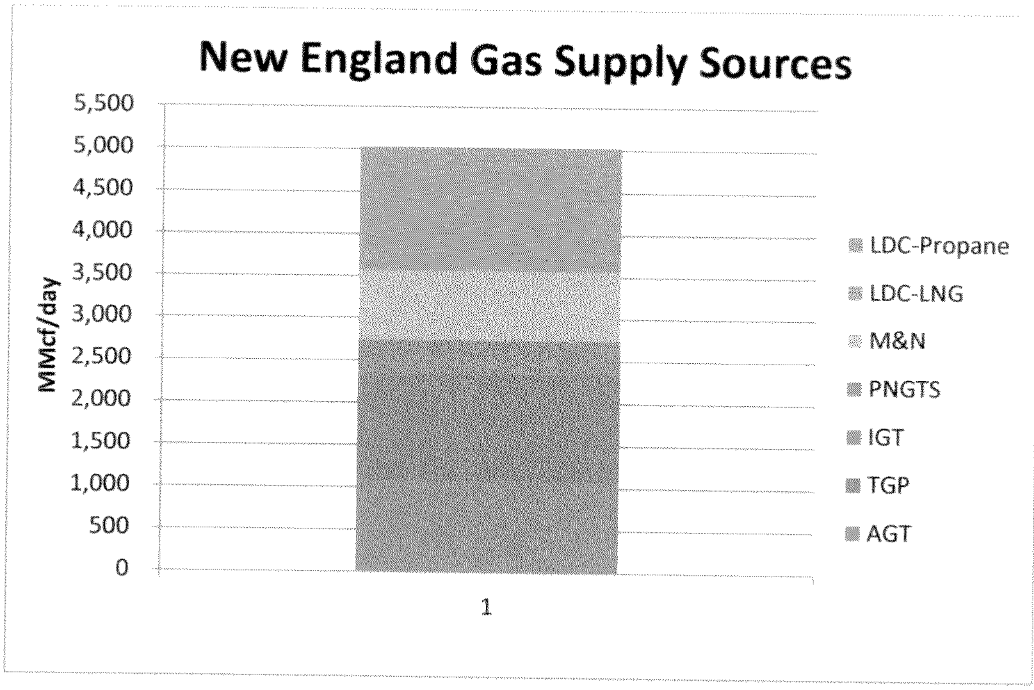
There is general agreement regarding the capacities shown in Figure 3. As we have reviewed other studies of natural gas availabilities in New England, we have seen some differences in three important areas:

- How much Deep Panuke and Sable Island natural gas will be available to flow north-to-south on the M&N Pipeline
- How much LNG will be delivered into Canaport and how much will be available to flow north-to-south on the M&N Pipeline
- Whether there will be adequate LNG in LDC storage facilities to meet their peak demand obligations over a full season

We discuss how we address these issues in Section 5 of our Report.

[18] Please refer to footnote 1 that describes how we have modeled New Brunswick and Nova Scotia LDC and power generation loads served off the M&N Pipeline.

Figure 3: New England Sources of Natural Gas Supply




The combination of natural gas pipelines and LNG supply has served New England well for decades, as it has provided secure supply from pipelines and continental sources of natural gas to meet base level demands plus flexible supply from imported LNG to meet peak demands. Three factors have changed that now make the natural gas delivery system into New England inadequate and too costly:

- Increased and still growing demand for natural gas from the power generation sector
- Reduced send-out capacities and shorter projected useful lives of the Sable Island and Deep Panuke natural gas fields off Nova Scotia
- The widening gap between the price of domestic natural gas and the world price of LNG

The first two of these factors have placed a strain on the region's ability to secure enough natural gas supplies on the coldest days of the winter when heating demands are peaking and electricity demands are relatively high. This has led ISO-NE to implement its recent Winter Reliability Program to ensure that dual-fueled electricity generators in the region maintain enough on-site fuel inventories to be able to displace natural gas used for generation when natural gas supplies are inadequate to meet all natural gas demands in the region.[19]

The third of these two factors has resulted in a skyrocketing of natural gas prices, initially on only the coldest of winter days but more recently on winter days when temperatures are average or only slightly below average. As Figure 3 shows, New England is dependent on LNG to meet its natural gas requirements when daily demand exceeds 3.5 bcf/d with north-to-south flows on the M&N pipeline at capacity and only 3.0 bcf/d with typical non-LNG flows on that pipeline. Given world LNG prices of

[19] We discuss this program further in Section 7 of this Report.

$18/mmbtu during winter months, the need to flow LNG in New England means that natural gas prices get bid up to LNG price levels, and well beyond the $18/mmbtu price on the colder days.

## Section 4: Derivation of the Demand for Natural Gas for Electricity Generation in New England

We have derived hourly demands for natural gas for electricity generation purposes as the output of a dispatch model of the ISO-NE Control Area. The dispatch model is based on actual generation by unit (fuel) type for each day during Calendar Year 2013, as reported by ISO-NE and our assumptions about the generation heat rate of natural gas units that are operating each hour. The results of the model for each hour in 2013 are the MW capacity of each type of unit operating, the amount of natural gas required to power the natural gas or oil units operating and the type and characteristics of the unit that is operating at the margin and therefore setting the clearing price in New England.

We do not pretend that our model is an exact replica of the 2013 hourly dispatch results for New England. Among the reasons why our model will produce results that are different from the actual dispatch include:

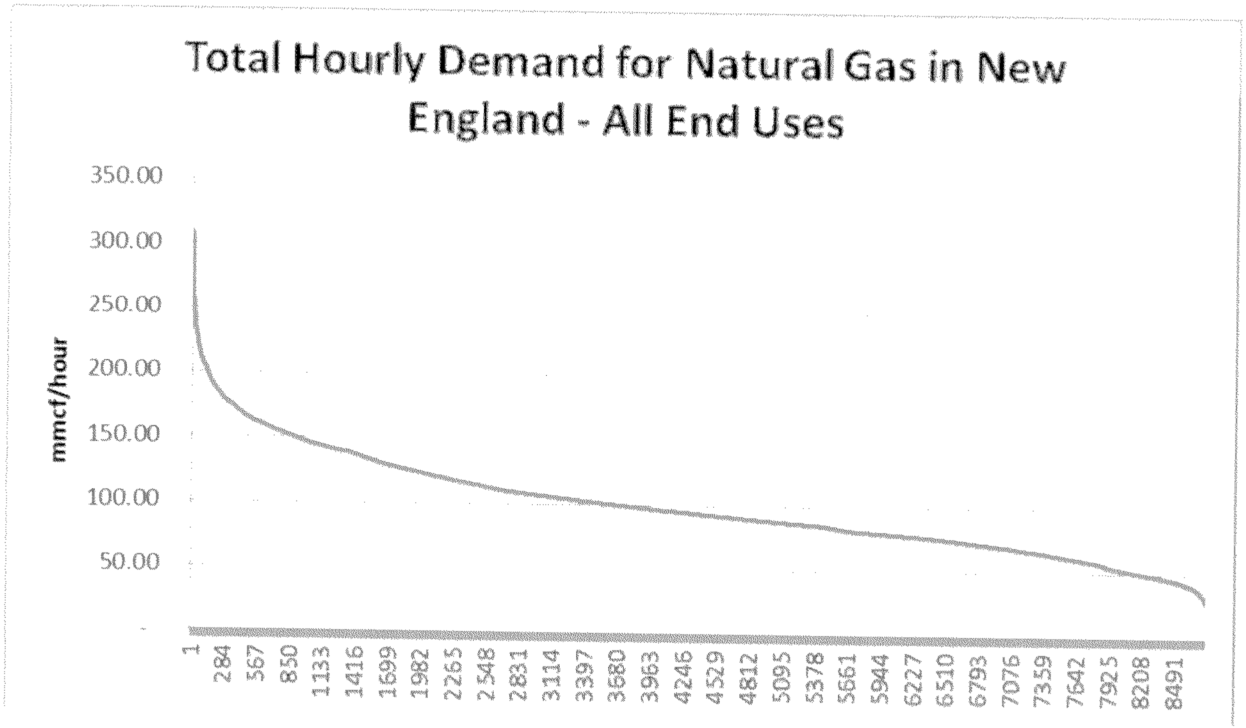
- We do not consider any transmission constraints or must run conditions. We assume that the New England grid is 100% unconstrained during all hours and for all zones in the region.
- We do not consider specific operating parameters that may apply to types of generating resources, such as ramping rates, minimum run times, storage capacity at reservoirs or relative fuel prices.

We did make one change to the 2013 dispatch. We removed the 600 MW Vermont Yankee from the list of resources to reflect its announced closure this year. We did not remove 150 MW of coal at Salem Harbor (unit 3) or 1,140 MW of coal at the Brayton Point plant even though their closures has been announced for 2014 and 2017, respectively. Rather, we discuss the consequences of the closure in the final section of the Report.[20]

The natural gas demand duration curve is shown in Figure 4. This graph shows hourly demands for natural gas – measured in mmcf/hr – for each of the 8,760 hours in 2013, sorted from the highest hourly demands to the lowest hourly demands. It is the sum of the LDC demands and power generation demands and shows very clearly the "peaky" nature of natural gas demands in New England resulting from temperature sensitive heating demands of LDC customers.

[20] We were able to remove Vermont Yankee, because it is a base load plant, and we are able to determine its outage schedule for refueling from published sources. In contrast, we are not able to determine the actual dispatch for Salem Harbor (unit 3) and Brayton Point and therefore do not know when these units ran and at what levels of output they generated during those hours when coal units were generating and in the ISO-NE fuel mix reports.

Figure 4: New England Natural Gas Demands – Load Duration Curve




As a final step, we adjusted the fuel used by natural gas generation to reflect supply and demand conditions for natural gas in the region, based on the various scenarios described in later sections of this Report. This process involved the following decision rules:

- During any hour when the combined demand for natural gas from LDCs and power generation is less than the combined capacities of the region's pipelines, all natural gas generators operating that hour are assumed to pay the same price for pipeline natural gas of $5.00 per mmbtu. This is the assumed price of pipeline natural gas as discussed further in Section 5.
- During any hour when the combined demand for natural gas from LDCs and power generation is greater than the combined capacities of the region's pipelines but less than the combined capabilities of the region's pipelines plus LNG capacities, all natural gas generators operating that hour are assumed to pay the same price for natural gas of $18.00 per mmbtu. This is the assumed price of LNG as discussed further in Section 5.
- During any hour when the combined demand for natural gas LDCs and power generation is greater than the combined capacities of the region's pipelines plus LNG capabilities but less than the combined capabilities of the region's pipelines plus LNG capacities plus propane-air capacities, all natural gas generators operating that hour are assumed to pay the same price for natural gas of $19.00 per mmbtu. This is the assumed price of propane as discussed further in Section 5.
- During any hour when the combined demand for natural gas from LDCs and power generation is greater than the combined capacities of the region's pipelines plus LNG capabilities plus propane-air capacities, all natural gas and oil-fired generators operating are assumed to pay the same price for fuel of $22.00 per mmbtu. This is the assumed price of oil as discussed further in Section 5.

## Section 5: Base Case

Our Base Case is intended to reflect current and longer-term conditions in New England, assuming no additional gas pipeline capacity is developed. A key assumption for this Base Case is that M&N Pipeline flows north-to-south are 0.350 bcf/d. As noted earlier, these flows are natural gas outputs from the Sable Island and Deep Panuke fields in excess of domestic natural gas requirements in New Brunswick and Nova Scotia. This may understate gas flows during the summer months, when heating demands in the two provinces are low, but this is of little consequence for our efforts, since we are focused on the winter period, when gas supplies in New England are tight.

A second set of assumptions that we have made relate to fuel prices in the region. Four fuel prices are critical to our analysis – the price of pipeline natural gas (assuming there are no pipeline constraints), the price of LNG, the price of propane and the price of oil.

We have assumed that the price of pipeline natural gas delivered to the region's natural gas-fired generators at their meters is $5.00 per mmbtu. This assumes that there are no pipeline constraints, and that 100% of gas demand can be met by deliveries over interstate pipelines that draw natural gas from markets to our south, west and/or northeast. This price corresponds roughly to winter NYMEX prices of approximately $4.50 per mmbtu and an unconstrained New England Basis differential of $0.50 per mmbtu. As we noted in the prior section, whenever 100% of hourly natural gas demand from LDCs plus power generation is less than pipeline capacity, we assume that the clearing price at any of the three pricing points in New England – Dracut, TZ6 or Algonquin – is equal to $5.00/mmbtu.

We have assumed that the price for LNG delivered into New England into the Everett and/or Canaport facilities is equal to the world spot price for LNG. We have used $18.00/mmbtu as this price based on reports made available by FERC.[21] We note that published prices range from $10.00 per mmbtu for delivery into Europe to highs of more than $18.00/mmbtu for deliveries into China, Japan and South America during the winter months. These published prices, however, often include forward contracted LNG. Our understanding is that the spot price for incremental LNG deliveries during winter months is currently in the $18.00/mmbtu range. Accordingly, whenever the demand for natural gas from LDCs plus power generation is higher than pipeline capacity, we assume that this excess demand is met first by LNG at a price of $18.00/mmbtu.[22]

Finally, we have assumed that the delivered propane and oil prices into New England are $19.00/mmbtu and $22.00/mmbtu, respectively. This oil price is for #2 oil that can be used in dual-fueled CCGT and simple combustion turbine generating plants. The price of Residual Oil (or #6 oil) that can be burned in oil steam generating units would be lower. However, for our purposes we have assumed that the higher

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[21] A sample of this type of report can be found at http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf.

[22] This price is based on our estimate of the cost of LNG delivered to either the Everett or Canaport facilities and does not reflect any demand-driven mark-ups or opportunistic pricing similar to what we have experienced repeatedly this winter. We will return to this issue in a later section and discuss why this matter is critically important to the region's policymakers as they focus their attentions on how much additional pipeline capacity is required to eliminate basis differentials in the region.

heat rates, inability to cycle to meet load and lower fuel-price of these oil-fired steam plants results in a marginal cost of generation that is roughly comparable to that of a CCGT unit running on #2 oil, given the higher fuel price, lower heat rates and higher O&M costs. Thus, where the total supply of pipeline gas plus LNG (including propane-air) is less than demand for natural gas from LDCs plus power generation, we assume that the incremental demand is met by oil-fired generation with a heat-rate of 10,000 btu/kWh and that the fuel price is $22.00 per mmbtu.

Figure 5 superimposes natural gas supply capacities on the hourly demand duration curve for natural gas shown in Figure 4 under the Base Case capacity specification. Note that all demands and capacities are expressed in mmcf/hr and would need to be multiplied by 24 to obtain bcf/d values. This graph shows that for most of the hours of the year, existing pipeline capacity is more than adequate to meet the combined LDC and power generation natural gas demands in New England. However, for those 1,000 or so hours when it is not adequate, New England must draw upon LNG, and for a few hours, propane or oil and must pay the higher prices for these fuels to meet natural gas demands. Further, since the power generation sector represents "incremental" load in the region, the marginal use of natural gas is to generate electricity. Under ISO-NE's energy market structure, this means that this marginal use sets the energy clearing price for electricity.

Figure 5: Natural Gas Load Duration Curve v. Pipeline Capacity – Base Case

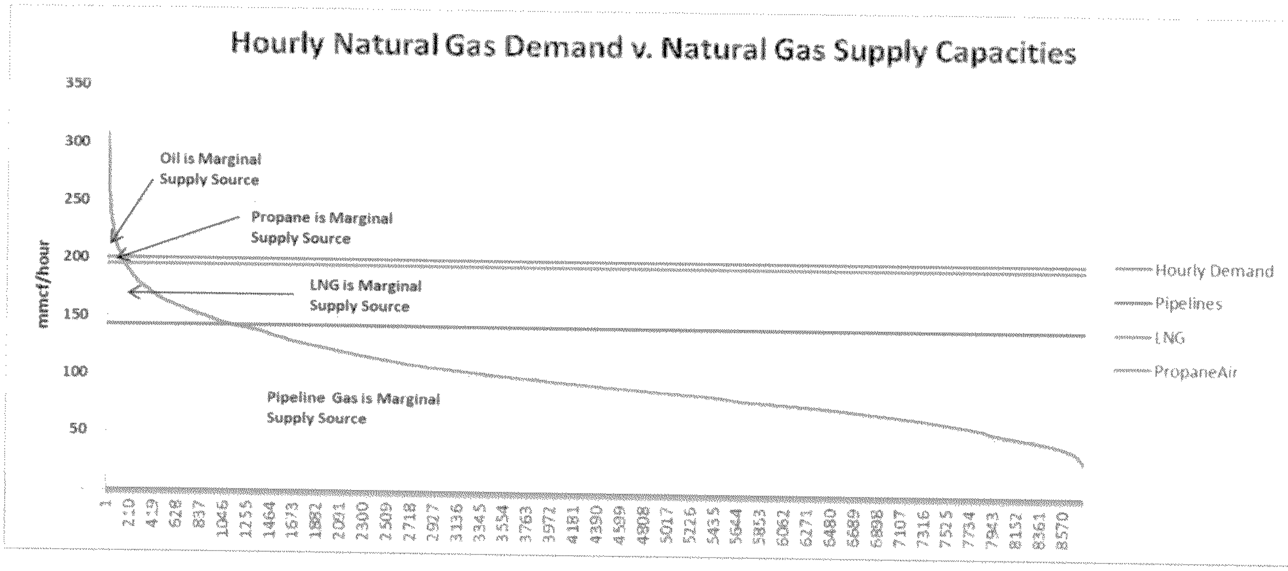
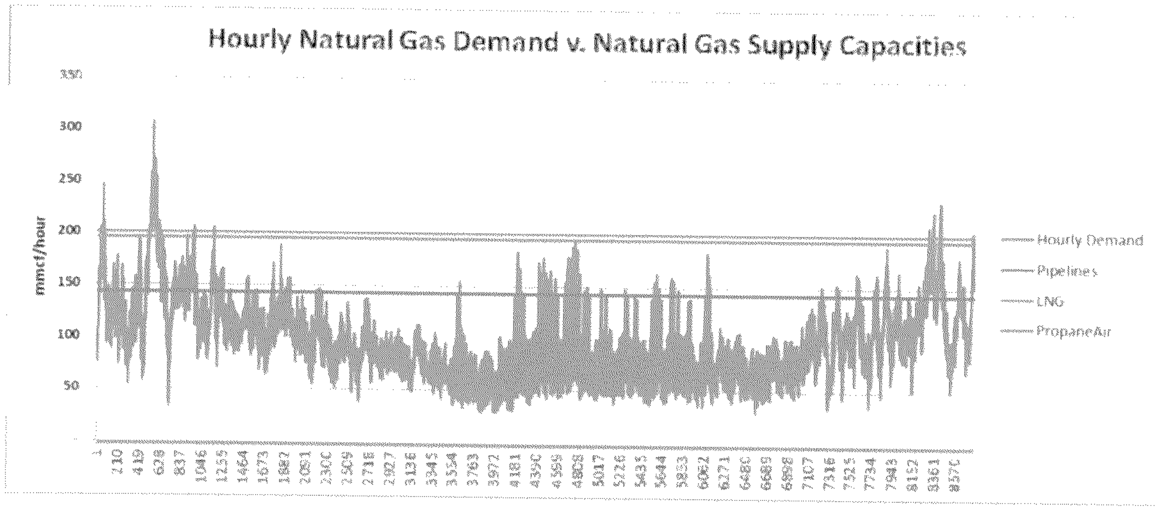



Figure 6 presents the same information as that shown in Figure 5, except that the hourly natural gas demand curve is not sorted from highest to lowest but rather is presented chronologically from January 1, 2013 through December 31, 2013. This graph illustrates very clearly that the issue of natural gas supply availability in New England is largely a winter phenomenon, as it is primarily during the winter months when the combined demand from LDCs and power generation exceeds existing pipeline capacities. While there are high power generation demands during summer peak hours that may push natural gas demands above pipeline capacity as modeled, our model restricts flows north-to-south on the M&N Pipeline to 0.350 bcf/d to allow for winter loads in New Brunswick and Nova Scotia to be served. In the summer these loads are lower, so a much larger portion of Sable Island and Deep Panuke production can flow south into New England. The effect is to increase the pipeline capacity line in Figure 6 – but only for the summer months.

Figure 6: Natural Gas Hourly Demands v. Pipeline Capacity




The key results of our dispatch modeling are as follows:

- Power generation required the use of some amount of LNG to meet electric loads during 1,109 hours of the year. Propane was required during 156 hours; while oil was required during 129 hours.
- LNG was setting the marginal clearing price for energy in the electricity market during 953 hours; propane during 27 hours and oil during 129 hours.
- The total cost of energy during the year was approximately $6.8 billion, with an average clearing price of $53.43 per MWh.

We also computed the average price for natural gas each month and over the year based on the price of the fuel operating at the margin in our dispatch model. These results are shown in the first column in Figure 7. Figure 7 also shows the estimated basis differential each month on the assumption that the zero-basis price for gas into New England from New York State is $5.00/mmbtu, as we have modeled it in our dispatch model. (Recall that the $5.00/mmbtu price represents an estimated price of $4.50/mmbtu at Henry Hub plus a $0.50/mmbtu northeast basis differential.) This calculation yields high basis differentials in the winter months and low (close to zero) basis differentials during the rest of the year,[23] and an average (unweighted) annual basis differential of $1.72/mmbtu.

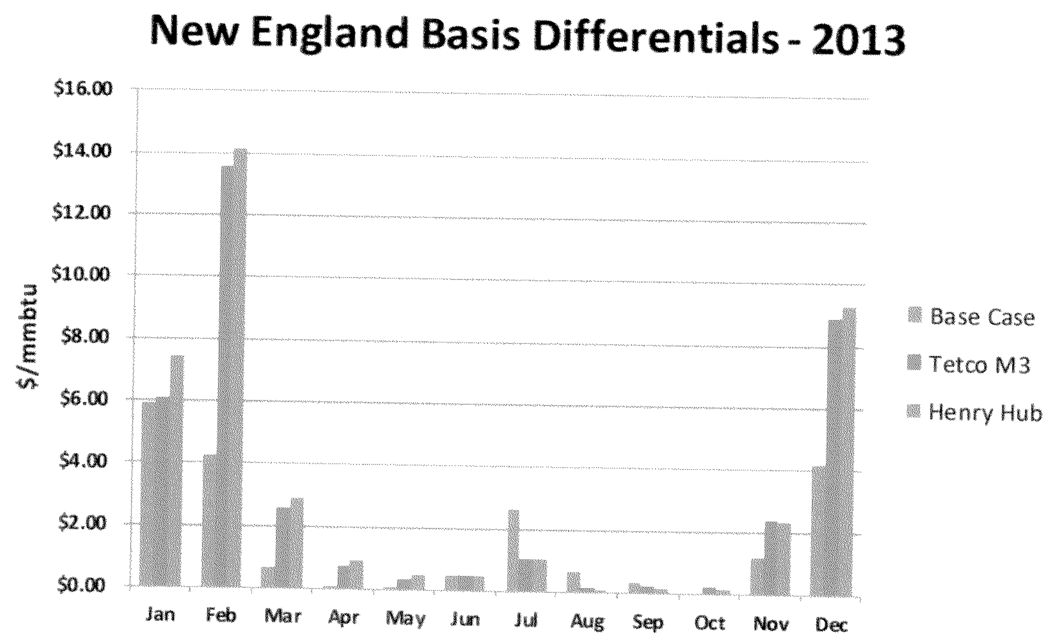
[23] Our model is showing a relatively high basis differential during July. This past July was a relatively hot one with a number of days in the middle of the month pushing total electricity demand to near peak levels. As a result, during July the average electricity clearing price for New England was $57/MWh compared to a much lower $35/MWh in August.

We compared these monthly basis estimates against the actual average monthly basis differentials between the daily price at Algonquin and the average daily prices at TETCO-M3 and Henry Hub for 2013. These are shown in columns 4 and 5 in Figure 7. Our estimated basis differentials are below those actually experienced in New England in 2013. One reason for this is that our modeling does not permit opportunistic pricing of LNG during winter periods when natural gas demands are placing severe strains on the region's natural gas supplies. During these periods, our pricing is constrained to never exceed \$22.00/mmbtu. The consequence of this price ceiling is that our estimates of the value of relieving natural gas pipeline constraints into New England are conservative. If the price of LNG gets bid up higher than the \$22.00/mmbtu price of oil, the clearing price of energy will be higher than in our model and accordingly, the value to relieving the pipeline constraint that must larger. We will discuss this issue further in Section 7 of this Report.

Figure 7: Estimated Natural Gas Prices v. Actual 2013 Basis Values – Base Case

## Estimated Gas Prices - Base Case

| | Average Price for Base Case ($/mmbtu) | Unconstrained Price ($/mmbtu) | Basis Differential for Base Cast ($/mmbtu) | Actual 2013 Values Basis Differential Tetco M3 ($/mmbtu) | Actual 2013 Values Basis Differential Henry Hub ($/mmbtu) |
|---|---|---|---|---|---|
| Jan | $10.91 | $5.00 | $5.91 | $6.12 | $7.44 |
| Feb | $9.25 | $5.00 | $4.25 | $13.59 | $14.16 |
| Mar | $5.70 | $5.00 | $0.70 | $2.61 | $2.89 |
| Apr | $5.07 | $5.00 | $0.07 | $0.74 | $0.91 |
| May | $5.10 | $5.00 | $0.10 | $0.38 | $0.48 |
| Jun | $5.47 | $5.00 | $0.47 | $0.49 | $0.48 |
| Jul | $7.64 | $5.00 | $2.64 | $1.07 | $1.06 |
| Aug | $5.68 | $5.00 | $0.68 | $0.19 | $0.10 |
| Sep | $5.34 | $5.00 | $0.34 | $0.20 | $0.19 |
| Oct | $5.03 | $5.00 | $0.03 | $0.25 | $0.16 |
| Nov | $6.21 | $5.00 | $1.21 | $2.40 | $2.30 |
| Dec | $9.17 | $5.00 | $4.17 | $8.89 | $9.27 |
| Annual | $6.71 | $5.00 | $1.72 | $3.08 | $3.29 |



## Section 6: Scenario Analysis

We have modeled three different pipeline development scenarios that have received attention in the industry over the past year. These are specified in Figure 8. We will refer to these scenarios as "LDC Contracted", "Governors' Letter" and "2 bcf/d Option" as highlighted and defined in the Figure 8. Where capacity project and expansion volumes are know, they are specified as we understand them or as they have been reported. Where there is no specific project, we have noted these as unspecified, but included discussed capacities.

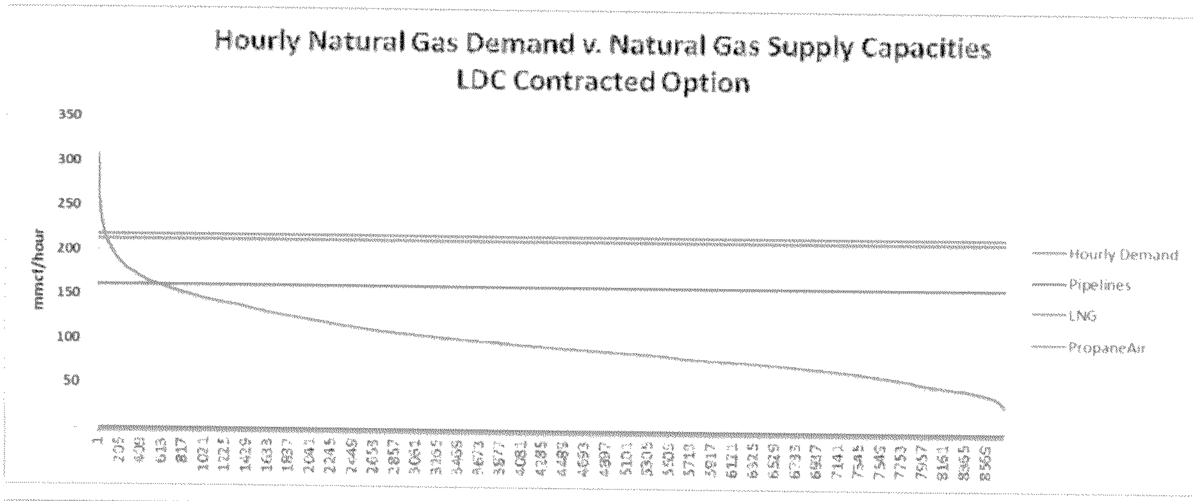
Figure 8: Incremental Pipeline Capacity – Three Scenarios

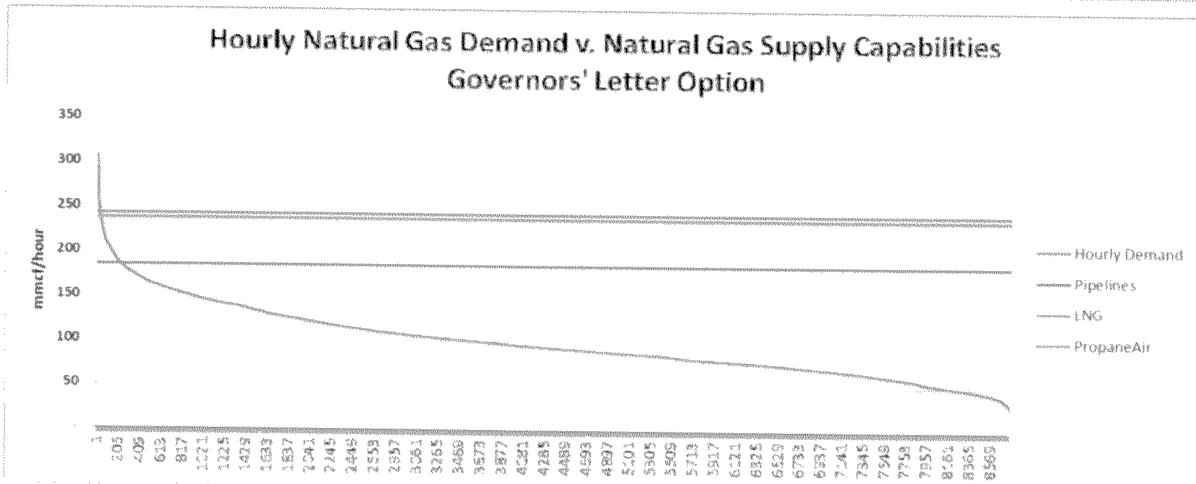
| **Pipeline Development Scenario** | **Incremental New Capacity** | **Cumulative Incremental New Capacity** |
|---|---|---|
| **LDC Contracted** – includes CT expansion at 0.070 bcf/d plus AIM expansion at 0.340 bcf/d | 0.410 bcf/d | 0.410 bcf/d |
| **Governors' Letter** – includes LDC Contracts plus an additional 0.600 bcf/d from unspecified pipeline(s) | 0.600 bcf/d | 1.010 bcf/d |
| **2 bcf/d Option** – includes LDC Contracted plus Kinder Morgan Pipeline at 1.200 bcf/d plus PNGTS expansion at 0.180 bcf/d plus 0.210 bcf/d unspecified pipeline(s) | 0.990 bcf/d | 2.000 bcf/d |

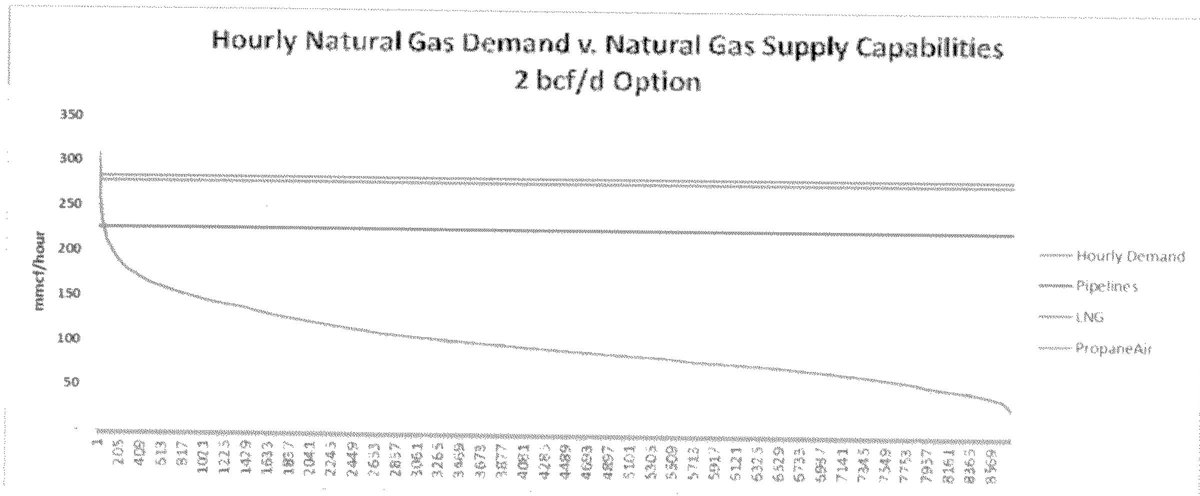
The only thing that changes in our modeling of each scenario is the pipeline capacity – all other variables and parameters are kept at the same values as in our Base Case. Figure 9 shows the same graph as Figure 5 for each scenario. As pipeline capacity increases, the number of hours where New England's power generation sector must rely upon LNG, propane and oil diminishes. This reduces the exposure to higher energy clearing prices, reduces the amount of money electricity customers must pay for energy and lowers the basis differential in the region. A second and important effect which we will return to discuss in more detail in Section 7 of this Report is that increased pipeline capacity reduces or eliminates the possibility of LNG facilities to engage in opportunistic (or even monopoly) pricing.

Our analysis does not consider how much the various pipeline options in each of the scenarios costs or how quickly each can be implemented. Costs are clearly an important consideration. At this point we note that the important cost for evaluation purposes is the incremental costs of additional pipeline capacity, which may depend on the specific pipeline selected to meet the incremental 0.600 bcf/d under the Governors' Letter scenario. If this pipeline capacity is phase 1 of the Kinder Morgan line, for example, achieving the incremental 0.600 bcf/d under the 2 bcf/d Option may require adding compression to the phase 1 line and not constructing an entirely new pipeline. If, on the other hand, the 0.600 bcf/d is met by a different option or combination of options, the 2 bcf/d Option would bear the full cost burden of the Kinder Morgan line.

Figure 9: Natural Gas Load Duration Curve v. Pipeline Capacity – Three Expansion Scenarios



We have presented the results of the scenario analysis in Figures 10 and 11. Figure 10 shows the number of hours during the year when LNG, propane and oil must run to meet natural gas demands, the number of hours each fuel is on the margin and as a result the price of that fuel determines the price of energy and the total costs (as well as average per MWh costs) to meet New England's annual electricity usage.

Figure 10: Summary of Scenario Model Results

**Summary of Scenario Analysis**

| Scenario | Pipeline Capacity bcf/d | Hours of Generation by Fuel Type: LNG | Propane | Oil |
|---|---|---|---|---|
| Base Case | 3,086 | 1109 | 156 | 129 |
| LDC Contracted | 3,496 | 596 | 74 | 63 |
| Governors' Letter | 4,096 | 220 | 30 | 24 |
| 2 bcf/d Option | 5,086 | 46 | 4 | 4 |

| Scenario | Hours with Fuel Type on the Margin: LNG | Propane | Oil |
|---|---|---|---|
| Base Case | 953 | 27 | 129 |
| LDC Contracted | 522 | 11 | 63 |
| Governors' Letter | 190 | 6 | 24 |
| 2 bcf/d Option | 42 | 0 | 4 |

| Scenario | Annual Energy Costs ($) | Savings vs. Base Case ($) | Load Weighted Avg. Energy Price ($/MWh) |
|---|---|---|---|
| Base Case | $6,799,918,543 | | $53.43 |
| LDC Contracted | $5,779,346,212 | $1,020,572,331 | $45.41 |
| Governors' Letter | $4,937,899,864 | $1,862,018,679 | $38.80 |
| 2 bcf/d Option | $4,481,671,060 | $2,318,247,482 | $35.22 |

Note that in the Base Case, for example, LNG is called upon for 1,109 hours during the year, but only 953 of those hours it is setting the energy clearing price. For the other 156 hours, propane and oil are at the margin for 27 and 129 hours, respectively.

Figure 10 also shows the incremental savings that are realized with each additional expansion of pipeline capacity under the three scenarios. The addition of the LDC Contracted capacity of 0.410 bcf/d results in savings of $1.0 billion a year for the region's electricity consumers, as it cuts in half the number of hours when pipeline natural gas is not capable of meeting the regions total natural gas requirements. The addition of a further 0.6 bcf/d of capacity as provided for in the Governors' Letter yields an incremental $0.84 billion a year, for a total savings of $1.86 billion a year. At this level of additional capacity, LNG is being called upon for only 220 hours during the year, and the hours when oil is setting the energy clearing price have fallen from 129 in the Base Case to only 24 in this scenario.

The Governors' Letter scenario, however, does not eliminate the basis differential between New England and TETCO-M3, as shown in Figure 11. Figure 11 provides the estimated average monthly prices for natural gas in New England under each of the pipeline scenarios. As the region relies less and less on LNG, propane and oil to meet the combined demands for natural gas of LDCs and power generation, the average price converges to our assumed unconstrained price of $5.00 per mmbtu.[24]

The third scenario evaluated, the 2 bcf/d Option, adds an additional 1 bcf/d pipeline capacity to the 1 bcf/d added under the Governors' Letter scenario, bringing the total increase in pipeline capacity into New England to 2 bcf/d. As shown in Figure 10, the increase of this additional 1 bcf/d of pipeline capacity will provide an incremental $0.45 billion a year in savings for the region's electric consumers, for a total annual savings to electric consumers of $2.3 billion. Figure 11 shows that at this level of additional pipeline capacity, the New England basis differential will fall to essentially zero. There will remain a few hours during the winter when even 2 bcf/d of incremental capacity is not enough to completely free New England from reliance on LNG, propane or oil. These hours, however, will have minimal impacts on the annual average price of natural gas. Further, it will be a much easier task to substitute LNG completely out of the fuel mix by relying on dual-fueled generating units to cover the gap between natural gas pipeline capacity and the combined demands of LDC customers and power generators for natural gas.

[24] Our prices do not include any tariff charges on the new pipeline capacities.

Figure 11: Impact of Additional Pipeline on Gas Prices and Basis

**Estimated Average Monthly Price of Natural Gas**

| | Base Case ($/mmbtu) | LDC Contracted ($/mmbtu) | Scenarios Governors' Letter ($/mmbtu) | 2 bcf/d Option ($/mmbtu) |
|---|---|---|---|---|
| Jan | $10.91 | $9.35 | $7.58 | $5.74 |
| Feb | $9.25 | $6.88 | $5.27 | $5.00 |
| Mar | $5.70 | $5.16 | $5.02 | $5.00 |
| Apr | $5.07 | $5.00 | $5.00 | $5.00 |
| May | $5.10 | $5.00 | $5.00 | $5.00 |
| Jun | $5.47 | $5.23 | $5.00 | $5.00 |
| Jul | $7.64 | $6.24 | $5.14 | $5.00 |
| Aug | $5.68 | $5.02 | $5.00 | $5.00 |
| Sep | $5.34 | $5.18 | $5.00 | $5.00 |
| Oct | $5.03 | $5.00 | $5.00 | $5.00 |
| Nov | $6.21 | $5.29 | $5.02 | $5.00 |
| Dec | $9.17 | $7.62 | $5.98 | $5.09 |
| Annual | $6.71 | $5.91 | $5.34 | $5.07 |

**Estimated Average Basis Differential**

| | Base Case ($/mmbtu) | LDC Contracted ($/mmbtu) | Scenarios Governors' Letter ($/mmbtu) | 2 bcf/d Option ($/mmbtu) |
|---|---|---|---|---|
| Jan | $5.91 | $4.35 | $2.58 | $0.74 |
| Feb | $4.25 | $1.88 | $0.27 | $0.00 |
| Mar | $0.70 | $0.16 | $0.02 | $0.00 |
| Apr | $0.07 | $0.00 | $0.00 | $0.00 |
| May | $0.10 | $0.00 | $0.00 | $0.00 |
| Jun | $0.47 | $0.23 | $0.00 | $0.00 |
| Jul | $2.64 | $1.24 | $0.14 | $0.00 |
| Aug | $0.68 | $0.02 | $0.00 | $0.00 |
| Sep | $0.34 | $0.18 | $0.00 | $0.00 |
| Oct | $0.03 | $0.00 | $0.00 | $0.00 |
| Nov | $1.21 | $0.29 | $0.02 | $0.00 |
| Dec | $4.17 | $2.62 | $0.98 | $0.09 |
| Annual | $1.71 | $0.91 | $0.34 | $0.07 |

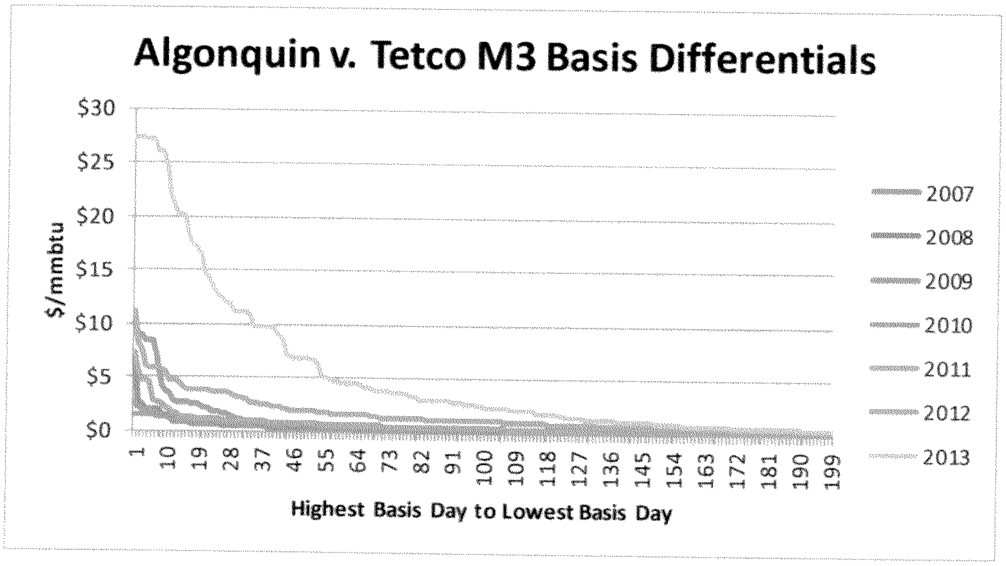
## Section 7 Additional Factors

- **LNG Availability and Price**

The results of our scenario modeling are based on one critical assumption that warrants further discussion and consideration. We have assumed that for each of the pipeline scenarios the region will always have a supply of LNG available to meet its requirements at $18.00/mmbtu. As we are seeing this winter, this price assumption is not likely to hold when natural gas supplies are tight and LNG is required to ensure that all gas demands are met. This price assumption becomes less and less tenable as the need for LNG diminishes with expanding pipeline capacity as we discuss further below.

It is clear that the manner in which LNG is now meeting New England's demand for natural gas has changed in a fundamental way. Figure 12 reproduces a graph from the Concentric Advisors report (see page 32 of that report) but extends the scope through the end of Calendar Year 2013. This graph shows the daily gas price differential between the Algonquin and TETCO-M3 pricing points since the beginning of 2007, sorted each year from the highest to the lowest. This graph illustrates very clearly the fundamental shift that has occurred in basis differential during 2013.

Figure 12: Daily Basis Differentials in New England, 2007 - 2013




| **Premium Level ($/mmbtu)** | **Number of Days During Year with Premium** | | | | | | |
|---|---|---|---|---|---|---|---|
| | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** |
| >$10 | 0 | 0 | 0 | 0 | 0 | 1 | 34 |
| $5 to $10 | 8 | 1 | 0 | 0 | 2 | 9 | 21 |
| $2 to $5 | 14 | 7 | 5 | 0 | 9 | 38 | 59 |
| $1 to $2 | 12 | 16 | 6 | 13 | 12 | 64 | 39 |
| $0 to $1 | 331 | 342 | 354 | 352 | 342 | 254 | 212 |
| Totals | 365 | 366 | 365 | 365 | 365 | 366 | 365 |

The table below the graph in Figure 12 indicates how many days each year the basis differential fell within the ranges shown on the left-most column. Prior to 2013, there had been only one day where the differential was in excess of $10.00/mmbtu and relatively few days when it was above $5.00/mmbtu. This is particularly true for the 2011 – 2013 period, post the development of the Millennium Pipeline project that brought additional gas supplies from the Marcellus region into New York State.

While the graph and accompanying table suggest a fundamental shift has occurred in the New England natural gas market, this shift is not the result of changes in underlying supply and demand conditions in the region. There have been no changes in supply capacities, LDC or power generation demands sufficient enough to cause this shift in basis differential. What have changed, however, are the operations of the two LNG facilities at Canaport and Everett. We understand that many if not all longer term LNG supply contracts for both facilities expired at the end of 2012. This meant that all future deliveries into the facilities are being priced at or very close to world market prices thus driving up the cost of LNG supply. We would expect each of these facilities to seek to pass this higher cost of LNG supply onto their customers, which would drive up the price of natural gas in the region on those days when New England's demand exceeded the supply capacity of the pipelines.[25]

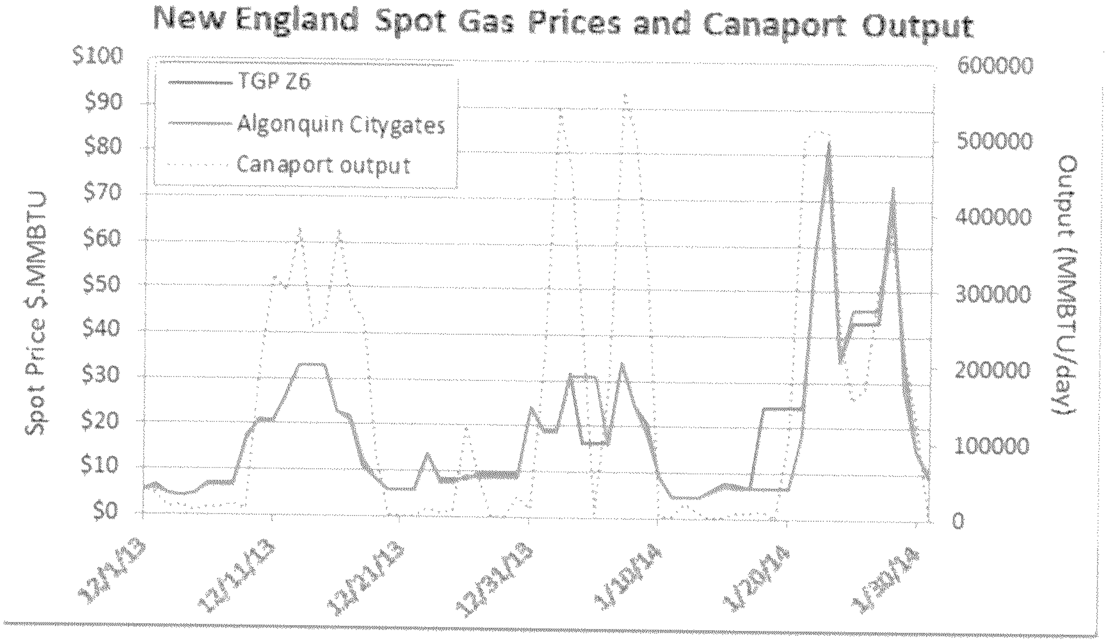
The operations and economic behaviors of Canaport and Everett have become much more critical to the ability of New England to meet its natural gas demands during the winter period, yet the uncertainty of when these facilities will be needed and how much LNG they will be called upon to deliver has made it difficult for them to schedule deliveries. Further, even when they do schedule deliveries, the price of the delivered LNG into the facilities will be at or very near world market prices in the $18/mmbtu range.

As Figure 10 indicates, under the Governors' Letter scenario, LNG will be required for only 220 hours each year. Further, during these 220 hours, we estimate that a total of 4.9 bcf of LNG will be required. Assuming that 100% of this LNG is met by send-out from the Canaport facility and none from the Everett facility, the 4.9 bcf would represent less than 2% of the full capacity send-out of the Canaport facility. We have very serious doubts as to whether the Canaport facility can remain operational at this capacity factor, and certainly not at an LNG price of $18 per mmbtu. If instead Everett meets much of this required LNG supply as we expect it will in light of its location and the fact that it must stay operational to serve the Mystic generating station adjacent to the facility, the Canaport facility may not be called upon at all to operate.

Even in the best of situations for the Canaport facility, where it supplies all of the estimated 4.9 bcf of LNG required, we believe that Canaport will have to sell the LNG it receives at prices well above the delivered price, and further that this margin will have to grow larger as the capacity factor of the facility falls in order for Canaport to cover its costs and remain in operation. Preliminary evidence from December 2013 through January 2014 bears this out. Figure 13 shows the Algonquin and TZ6 spot prices each day and the same day send-out of LNG from the Canaport facility. Assuming that all of the send-out was sold at the spot gas price each day, the average price received by Canaport during December 2013 was $22.50/mmbtu. In January 2014 the average price was $36.45/mmbtu – twice the world market price of $18/mmbtu.

[25] We understand that the Canaport facility operated under a constraint that required it to send-out between 0.050 and 0.100 bcf/d to meet its boil-off requirements or otherwise it would have to flare that amount of gas. Canaport has modified its facility to eliminate this operational requirement. This will reduce gas supply into the region during many hours when Canaport would otherwise have had to inject LNG into the M&N Pipeline. This will put additional pressure on prices on those days.

Figure 13: Canaport Send-out and New England Spot Natural Gas Prices




Were the Canaport facility to close, the region would have to rely fully on the Everett facility to meet its natural gas requirements beyond those that can be met through the expanded pipeline system.[26] This would vest an uncomfortable degree of pricing power with that facility, a power that would be kept in check only through the use of oil as an alternative fuel in the region's generation fleet. This, in turn, would impose its own costs on the region, as we have seen with ISO-NE's Winter Reliability Program this winter. One component of this program is the oil inventory program to ensure that dual-fueled units have available fuel supply to operate on oil when natural gas supplies are limited. ISO-NE estimated the region would require the equivalent of 24.2 million mmbtu of fuel supply.[27] This is equal to 24 bcf of LNG. By comparison, Canaport delivered approximately 3 bcf in December 2013 and 6 bcf in January 2014. The Winter Reliability Program is estimated to cost the region's electricity consumers approximately $75 million, in addition to the over $400 million in fuel costs above the unconstrained natural gas price of $5.00 per mmbtu.

Therefore, the appropriate measure of the value of the additional 1 bcf/d of pipeline capacity under the 2 bcf/d Option is not simply the incremental savings shown in Figure 10. It is that incremental savings of

[26] It is possible that a new small-scale liquefaction facility could be constructed in New England that could liquefy pipeline gas during the periods of low natural gas demand and excess capacity on pipelines into New England for storage at the various LDC LNG storage tanks. We have not estimated what the price of such gas would be per mmbtu.

[27] This is computed as 2.4 million MWhs from oil-fired generation, or 4.2 million barrels of oil as a heat rate of 10,000 btu/kWh and a fuel content of 137,000 btu/gallon.
http://www.iso-ne.com/regulatory/ferc/orders/2013/sep/er13-1851-000_9-16-2013_winter_rel.pdf (page 8).

$0.450 billion **plus** the incremental costs of relying on oil as the fuel when gas demands exceed pipeline capacities under the Governors' Letter scenario. The latter is measured as the difference between the $18/mmbtu used in the model as the LNG price and the price of oil at $22/mmbtu plus the costs of inventorying oil under a program comparable to the Winter Reliability Program. We have estimated the costs of the former to be $0.180 billion and have assumed the latter to be approximately $0.050 billion, based on the $75 million incurred this year. The total savings to New England electricity consumers that can be realized by adding another 1 bcf/d of pipeline capacity under the 2 bcf/d Option scenario is therefore $0.680 billion a year.

We have seen estimates of the cost to construct the Kinder Morgan line in the $1.2 billion range.[28] Even if the 2 bcf/d Option bears the full cost of constructing this line, the simple payback period is two years. If the line is built as part of the Governors' Letter scenario, the incremental cost to add compression to the line to achieve a 1.2 bcf/d throughput will be well below the $1.2 billion construction cost, and the simple payback period could be less than one year. Further, if oil is only partially successful in acting as a check on the price of LNG during those 220 hours noted above, the value of the 2 bcf/d Option will be even greater to New England's electricity consumers.

- **Generating Plant Retirements in New England**

As we noted in Section 4, our Base Case incorporates the shut-down of Vermont Yankee but not the announced closure of the coal units at Salem Harbor (unit 3) and Brayton Point. The capacity of these coal units are approximately 150 MW and 1,140 MW, respectively, and this capacity has been available and running when there is pressure on the region's natural gas supplies. Eliminating these units will increase the power generation demand for natural gas by 0.225 bcf/d assuming that the units are replaced with CCGT units operating at a 7,500 btu/kWh heat rate. This amount of natural gas is more than 20% of the incremental supply under the Governors' Letter scenario.

Additional coal and/or oil unit retirements are a continuing concern for ISO-NE, and to the extent these are replaced by CCGT or simple combustion turbine natural gas units, there will be further pressure on the region's pipeline capacity, even with the additional 1 bcf/d under the Governors' Letter scenario.[29] If we assume that an additional 1,500 MW of these units retire over the next 5 years and are replaced by natural gas units, these 2,700 MW of new natural gas-fired units will add almost 0.500 bcf/d of natural gas demand or 50% of the total new pipeline capacity under the Governors' Letter scenario.[30] This would put the region in a short position roughly similar to that modeled as the LDC Contracted scenario.

It is possible that the retirement of coal and oil units will be offset by Canadian power enabled by new power lines to Canada. This would mitigate the natural gas shortage condition discussed in the above

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[28] See, for example, the Black & Veatch report at page 35.

[29] The results of the recent FCM Auction support ISO-NE's concerns. http://www.iso-ne.com/nwsiss/pr/2014/fca8_initial_results_02052014.pdf

[30] ISO-NE has indicated that over 8,000 MW of coal and oil fired generation are at risk of retiring by 2020. The breakdown is 5,961 MW of oil-fired generation (residual oil units only) and 2,309 MW of coal, inclusive of the Brayton Point plant.

paragraphs; however, these new Canadian imports could not also be counted on to reduce current natural gas demands. They cannot be cited as available to offset unit retirements as well as justification for a more limited pipeline expansion, as this would be double counting.

- **Increased Demand for Natural Gas**

As noted in Section 3 of this Report, various studies have estimated that Design Day LDC demand for natural gas will grow over the balance of this decade by between 0.250 bcf/d and 0.400 bcf/d. The low end of this estimated range is roughly equivalent to the combined new pipeline capacities of the CT Expansion project and the proposed expansions on the PNGTS pipeline. At the higher end of the range, the new natural gas demands will offset virtually all of the new pipeline capacity of the LDC Contracted scenario.

The increases referenced in the above paragraph only relate to increases attributable to increased LDC demands. If the proposed transmission lines to Canada are delayed or are never built and the increased demands from the power generating sector are added to those from the LDCs, the combined increase could total as much as 0.900 bcf/d during cold winter days by 2020. This increase would absorb almost all of the increased pipeline capacities under the Governors' Letter scenario, leaving the region pretty much in the same situation it is in today.

- **The Relationship Between Pipelines and Transmission Lines**

The above discussion highlights the relationship between natural gas pipelines and electricity transmission lines. From the important perspective of their abilities to meet energy demands in New England, the two are substitutes. Both have the ability to relieve congestion on the region's current pipeline system and supply New England's winter energy requirements, assuming that natural gas supplies to our south and west are adequate and that there is sufficient electric generation capacity in Canada to import energy over the transmission lines in the winter.

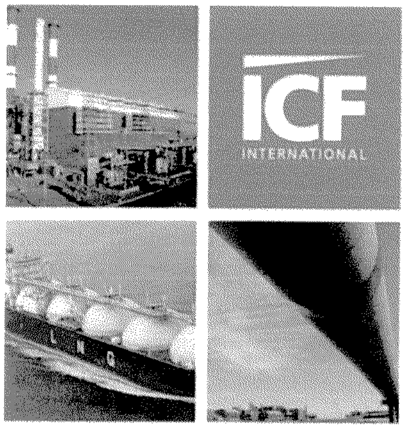
From the perspective of New England's electric consumers, however, the two options are also complementary. Pipeline congestion drives up the price of natural gas in New England and therefore the market price of electricity. Since this market price acts as a bogey against which Hydro Quebec or any other Canadian electricity generator must bid, we can expect bids to be higher in a market characterized by expected gas congestion in the future than one in which there is no natural gas congestion. Put simply, additional pipeline capacity into New England serves to discipline Canadian energy suppliers by reducing their pricing power. Therefore, to be assured of obtaining low prices for any imported Canadian electric energy, New England must move forward with developing additional pipeline capacity into the region as soon as possible and before entering into any electricity purchase agreements with Canadian suppliers.

In either case, whether New England's electricity needs are met from in-region natural gas-fired electric generation or Canadian imports, the costs of this new pipeline capacity will be recovered through either lower prices for in-region natural gas generation enabled by the pipelines or lower prices from Canadian imports enabled by the price pressure brought to bear through the increased pipeline capacity. The additional pipeline capacity is necessary to enable New England electricity consumers to realize the benefits of the natural gas revolution that is benefitting the rest of the country, regardless of whether or not additional transmission lines to Canada are ever developed.

Competitive Energy Services

148 Middle Street, Suite 506
Portland, ME 04101
www.competitive-energy.com

Exhibit C




# Access Northeast Project - Reliability Benefits and Energy Cost Savings to New England

Prepared for

Eversource Energy and Spectra Energy

Prepared by

ICF International
9300 Lee Highway
Fairfax, VA 22031

1331 Lamar
Suite 660
Houston, TX 77010

February 18, 2015

# Disclaimer

This report reflects ICF's opinion and best judgment based upon the information available to it at the time of its preparation.

ICF's opinions are based upon historical relationships and expectations that ICF believes are reasonable. Some of the underlying assumptions, including those detailed explicitly or implicitly in this report, may not materialize because of unanticipated events and circumstances.

ICF's opinions could, and would, vary materially, should any of the above assumptions prove to be inaccurate.

# Introduction

ICF International (ICF) was engaged by Eversource Energy (Eversource) to provide an independent assessment of the potential impacts of the proposed Access Northeast gas infrastructure project (Access Northeast) on New England's natural gas and electric markets. In particular, ICF's analysis focuses on the impact that new infrastructure may have on regional gas and electricity prices, and the associated economic impacts on consumers.

New England has increased its reliance on natural gas-fired electricity generation in recent years. At present, approximately 50 percent of New England's power comes from gas-fired generation; the projected retirements of regional nuclear and coal-fired generating facilities, which will be replaced in large part by new gas-fired generation, will further this trend.

The growth in new gas-fired generation raises important questions about the reliability of gas supplies to meet that demand. Of particular concern is whether the network of gas production, pipelines, and storage capacity serving New England will be adequate to supply power generators under winter peak gas demand conditions.[1] A 2014 ICF study for ISO-NE indicates a need for up to 1.1 Bcf/d of additional gas supply by 2020 to meet projected power plant fuel requirements on a design day.[2] This equates to roughly 5,700 MW of capacity, or up to approximately 30% of the region's gas generation capacity.

Central to the issue is New England's reliance on interruptible gas supplies for much of its power generation fuel supply. Unlike local gas distribution companies (LDCs), who contract for firm pipeline and storage services that assure gas supplies on the coldest of days, most gas-fired generators in New England contract for non-firm pipeline capacity and gas supplies to run their plants. This practice has worked in the past because interruptible pipeline capacity has been widely available during most times of the year. Going forward, natural gas-fired plants will shoulder much of the load presently served by retiring nuclear and coal plants. This means that winter season gas demand for power is growing. Without new gas infrastructure, relatively little pipeline capacity will be available for interruptible services in the winter months, as LDCs continue to utilize their firm capacity to meet heating demands.

The ICF study for ISO-NE indicates that without new firm sources of gas supplies, there is a rising probability of gas supply deficits occurring on a significant number of days throughout the winter[3]. A gas supply deficit[4] is a serious threat to the reliable operation of the New England electric system that, under certain conditions, could result in costly electric system disruptions.

1 Gas utilities typically define peak demand conditions in terms of "design-day" criteria, design day refers to the coldest weather conditions over a given time interval, such as 20 or 30 years.

2 Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II, page 21, Exhibit 4-6.

3 Ibid, page 5.

4 As described in more details later in this report, gas supply deficit is the amount that remaining gas firm supplies to meet power sector demand is less than the projected dispatch needs for gas-fired generation.

In a recent article for IEEE Power & Energy Magazine on conditions during the winter of 2013/14, ISO-NE stated that "subordinate contracts for gas transport were generally not available to power providers."[5] ISO-NE was able to avoid potential brownouts and blackouts during the winter of 2013/14 through the implementation of a number of measures, most notably its "Winter Reliability" program[6].

In response to this emerging need for new firm gas services in New England, Spectra Energy and Eversource have proposed the Access Northeast project to provide scalable deliverability to Power Plant Aggregation Areas (PPAA) to directly serve power plants in order to reach the most efficient power plants on Spectra Energy's Algonquin and Maritimes pipelines. According to the proposal, Access Northeast will provide new Electric Reliability Services (ERS) for firm transportation of natural gas and natural gas supply supported by regional storage facilities for their customers. This proposed service provides greater fuel certainty and performance flexibility for generators through reserved No Notice Transportation with an hourly supply option[7]. For its analysis, ICF has assumed that the project will add 500 MMcf/d pipeline capacity and 6 Bcf of peak supply through storage facilities with a maximum deliverability of 400 MMcf/d, starting in November 2018.

The need for natural gas infrastructure projects that introduce incremental firm natural gas supplies to New England or electric infrastructure projects that reduce the demand for natural gas during peak winter days is well documented. To that end, the New England Governors released a statement in December 2013 committing to support "investments in additional energy efficiency, renewable generation, natural gas pipelines, and electric transmission."[8] In the statement, Governor LePage of Maine expressed that New England's "high energy prices drain family budgets and are a significant barrier to attracting business investment, especially in energy-intensive industries... This energy infrastructure initiative can bring these world-class resources to start powering New England industry and start saving money for families across our states."

It is important to recognize that the economic benefits of new firm gas supplies will accrue to New England stakeholders even when conditions do not result in gas supply deficits or system disruptions. New England's natural gas and electricity grids operate as efficient and transparent markets where energy prices can rise quickly in response to tightening supply conditions. For example, ICF estimates that New England's 2013/2014 electric costs were approximately $3.2 billion higher than the previous winter (December to March), caused largely by Polar Vortex cold weather episodes and the gas market price volatility that cascaded across the East.[9] Grid operators successfully averted gas supply deficits and major system disruptions, but the economic burden on consumers was nonetheless substantial. ICF estimates that if the Access Northeast project had been in operation last year, New England could have saved $2.5

[5] Babula, M. & Petak, K. (2014). The Cold Truth, Managing Gas-Electric Integration: The ISO New England Experience. IEEE Power & Energy Magazine, November/December 2014, pp 20-28.

6 A collaboration between ISO New England and regional stakeholders, this project focused on developing a short-term, interim solution to filling a projected "reliability gap" of megawatt-hours (MWh) of energy that would be needed in the event of colder-than-normal weather during winter 2013/2014. The solutions included demand side response program, and incentives to encourage dual fuel and oil generation capabilities. The 2014/2015 winter reliability program includes a LNG component.

[7] http://www.spectraenergy.com/content/documents/Projects/NewEngland/Access-Northeast-Project-Brochure.pdf

[8] http://nescoe.com/uploads/New_England_Governors_Statement-Energy_12-5-13_final.pdf

[9] As illustrated later in this report, electric prices in New England are strongly correlated to natural gas prices. High and volatile gas prices are quickly communicated to power markets.

billion last winter. The addition of firm gas supplies and transportation infrastructure can mitigate the risk of future energy price shocks, even during normal winters. As presented later in this report, ICF estimates that a project similar to Access Northeast, on average, could lower consumer energy costs by $780 million to $1.2 billion per year during the initial ten-years after it enters service in 2018.

Whether during an extreme year such as 2013/2014 or a normal weather year, ICF's analysis of regional energy price behavior indicate that the potential cost savings from having additional firm gas supplies in New England are well in excess of the annual cost of constructing and operating the infrastructure project.

# Summary of Findings and Conclusions

## New England needs incremental firm natural gas supplies for the electric sector during winter months

In recent years, New England has steadily increased its reliance on natural gas fired generation as coal and nuclear power plants have been retired. As a result, the demand for natural gas from the power sector has increased, with the growth rates being greatest in the winter heating season when traditional heating demand for natural gas is also at its peak. This growing reliance on natural gas is expected to continue during the next few years with the retirement of additional nuclear, coal, and oil-fired capacity (e.g., Vermont Yankee, Brayton Point, and Mount Tom) and the addition of new gas-fired capacity (Footprint Power).

## New England's Reliance on non-firm winter gas supplies poses increasing risks on electricity consumer costs

New England LDCs hold the vast majority of firm capacity rights on pipelines. In contrast, power generators typically rely on interruptible pipeline capacity and the spot natural gas market to procure supply. During peak winter demand periods, pipelines must prioritize gas deliveries first to firm customers, with any remaining capacity allocated to the highest bidders in the market. As evidenced by last winter's record high prices, the resulting competition for scarce interruptible pipeline capacity (particularly during peak demand periods) places upward pressure on spot prices for natural gas. This caused regional wholesale electricity prices to soar, because those prices are set by bids from marginal generators, typically gas-fired units. Last winter, due to the existence of the ISO-NE Winter Reliability program, there were several days where the marginal price was set by oil-fired generation. Had this program not been in place, electric prices would have been even higher.

## Diminishing New England gas supply sources increase consumer exposure to non-firm gas supplies

To supplement gas supplies transported by pipelines from US and Western Canadian fields, New England has historically relied on imports produced from smaller gas fields in offshore Atlantic Canada and liquefied natural gas (LNG) cargoes delivered to regional import terminals. Both of these supply sources have diminished in recent years, which will require New England to replace these sources simply to preserve the supply/demand status quo.

Atlantic Canada gas supplies have principally come from the Sable Offshore Energy Project (SOEP) off the coast of Nova Scotia. SOEP has experienced deep declines in production during the past few years and is expected to cease production completely within 10 years. A new offshore field called Deep Panuke commenced production in Q3 2013, but has had production issues resulting in numerous "shut-ins" of production, and has had higher than expected operating costs. Future gas exploration and production activity around Deep Panuke and other Nova Scotia gas fields is uncertain. Absent material changes in gas exploration and production successes in the Maritimes, New England buyers will need to replace this portion of its fuel supplies.

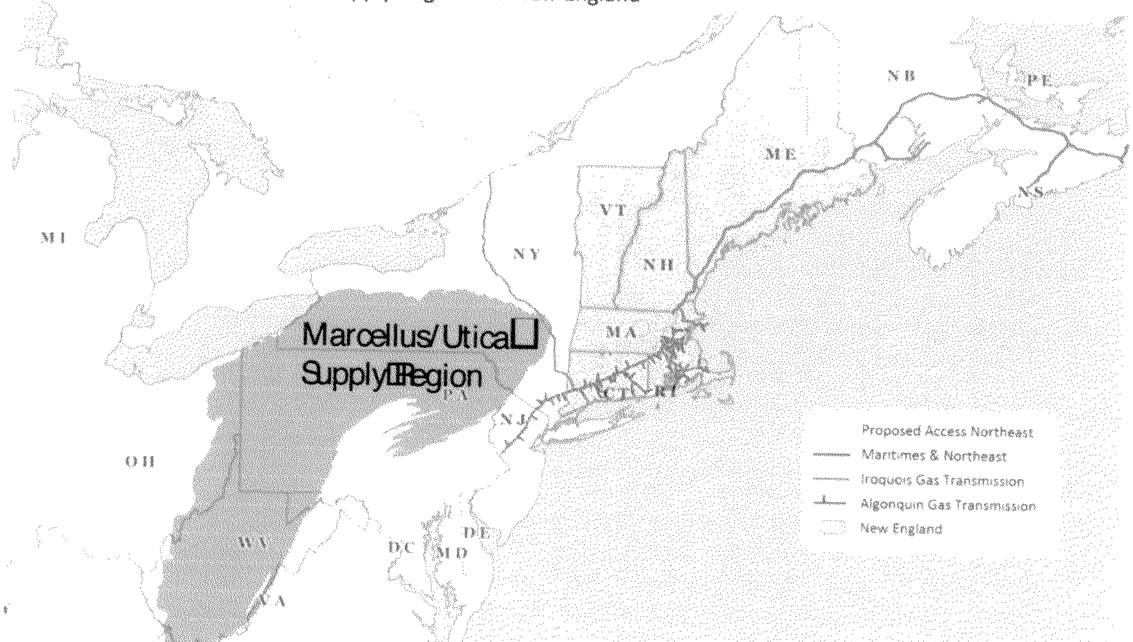
It is important to note that declining gas production in the Canadian Maritimes will likely prompt gas consumers in those provinces to turn to gas imports from New England to meet their heating and power generation needs.[10] This would lead to increased competition for already scarce pipeline capacity and gas supply resources for New England.

New England's access to gas supplies has become further constrained by the reduced frequency of firm cargoes at the regions' LNG import terminals. LNG is a global commodity and importers to New England largely operate without firm contracts to sell to New England buyers, instead preferring to seek the highest prices available wherever that may be. As a result, New England must compete with the rest of the world to have LNG spot cargoes available on peak days. This can result in extremely high gas prices, or no gas at all, depending on the availability of spot cargoes. Even during the 2013-2014 winter, when spot prices spiked to $78/MMBtu, very few spot cargoes were delivered into New England terminals.

## **Expected growth in the Marcellus/Utica production basins provides a reliable and economic supply source to New England and are located very close to the region**

The Appalachian Basin was one of the first US oil and gas producing regions, and ICF expects that the Appalachian Basin's role as supplier will continue to grow as production from the Marcellus/Utica shale region (Exhibit 1) increases from its current output of 17 Bcf/d to a projected 37 Bcf/d by 2035 (as shown by the right axis of Exhibit 2).

Exhibit 1: Marcellus/Utica Shale Supply Region and New England

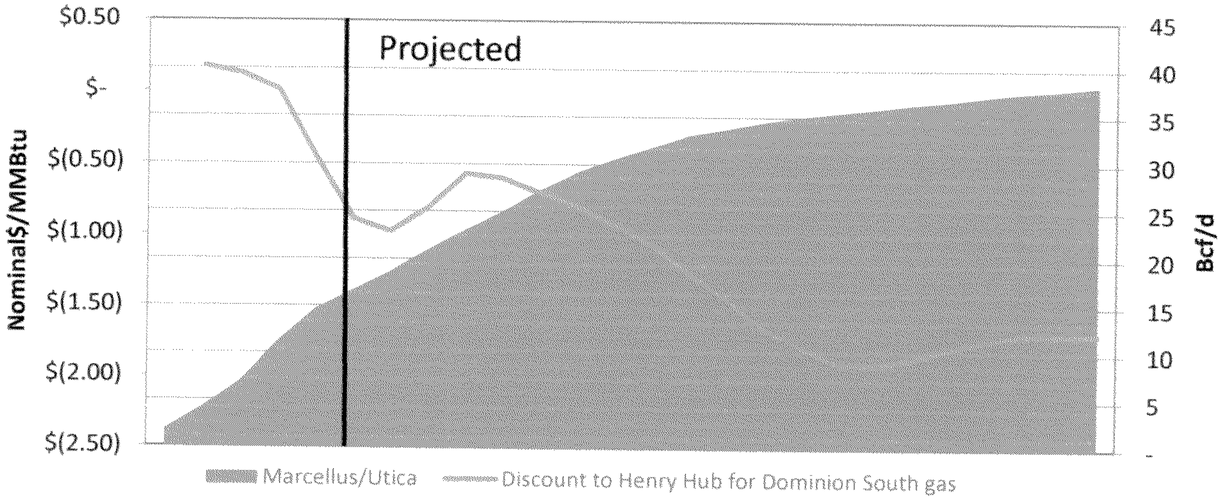



Source: ICF International, Ventyx

[10] See also: "The Future of Natural Gas Supply for Nova Scotia", ICF International, Prepared for Nova Scotia Department of Energy, March 28, 2013.

The dramatic increase in low-cost Appalachian Basin gas production has materially altered the relationship of the basin's gas prices to other trading points across the North American market. As shown on the left axis of Exhibit 2, the price of natural gas in the Appalachian Basin (represented by the Dominion South pricing point) relative to the North American benchmark Henry Hub (Louisiana) price has plummeted nearly $1.50/MMbtu from a premium to a discount of $1.00. ICF projections show that, as a result of declining production costs, the discounted spread will widen further to more than $1.50/MMBtu. At these prices, the Appalachian Basin is among the lowest priced gas supply sources on the continent.

Exhibit 2 - Historical and Projected Marcellus/Utica Production and Dominion South Point to Henry Hub Basis[11]



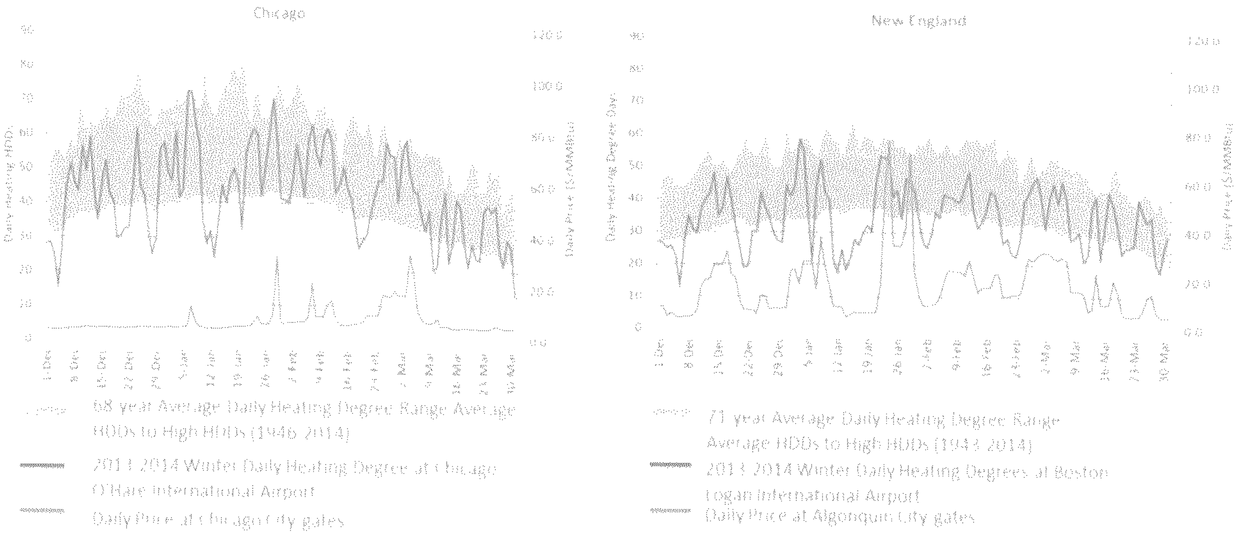

Source: ICF International, SNL

**<u>Lack of gas infrastructure to fuel power generation makes New England consumers especially vulnerable to cold weather situations</u>**

The consequences of New England's growing dependence on non-firm pipeline capacity for gas-fired generation were made clear in the 2013-2014 winter. During the Polar Vortex episodes, power generation and heating demand for natural gas soared in the Midwest, Northeast, and Mid-Atlantic. Exhibit 3 shows the comparable weather and natural gas prices in New England and Midwest during this past winter. The US Midwest region experienced the coldest winter in more than 60 years. This is reflected by the actual daily heating degree days[12] (HDD), represented by the blue line which is repeatedly approaching the top of the blue shaded range representing the past 68 years. On the other hand, New England was only moderately colder than normal with the blue daily HDD line positioned mostly in the middle of the historical range. Natural gas prices in the Midwest, however, were much more stable than those in New England primarily because the Midwest has a multiplicity of supply source options and adequate pipeline capacity on several pipeline systems. This behavior signals the first consequence of New England's winter gas capacity inadequacy - extremely high and volatile natural gas prices.

[11] Basis presented here is Dominion South Point price minus Henry Hub price.
[12] Heating Degree Days is calculated as 65 minus the average temperature of the day.

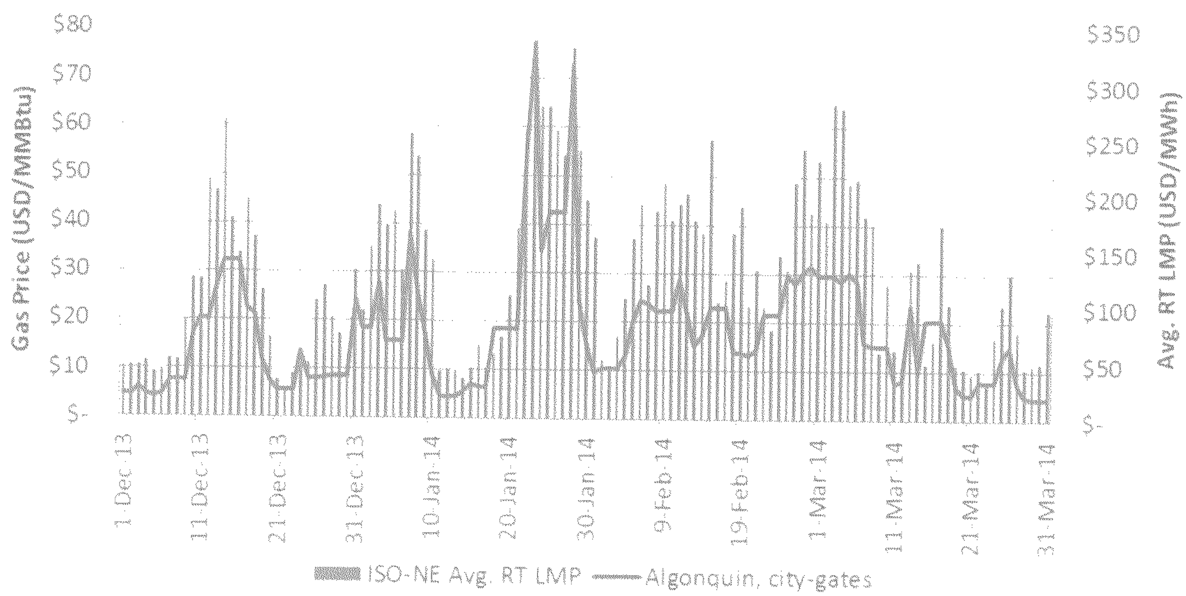
Exhibit 3: Winter 2013-2014 Natural Gas Spot Price Comparison




Source: ICF International, SNL, NOAA

Exhibit 4 shows the second and potentially more damaging consequence of the natural gas capacity inadequacy. In New England, power prices are closely correlated with natural gas prices, so electric prices last winter also reached unprecedented levels as a result of the natural gas price spikes. This tight correlation between gas and electric prices is expected to continue with the increasing dependency of the power grid on natural gas supply and delivery infrastructure.

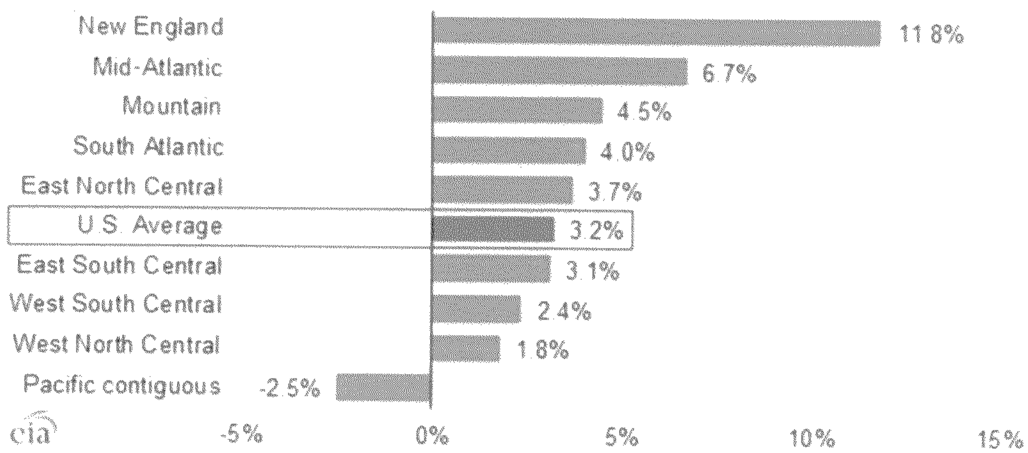
Exhibit 4: Comparison of New England Gas and Wholesale Power Prices




Source: ICF International, SNL

As a result, this extreme sensitivity to weather events may become very costly for New England's electricity consumers if left unaddressed. For December 2013 through March 2014, New England paid an estimated $6.8 billion for wholesale power, $3.2 billion above the prior year's level. New England residential electric customers experienced the highest single-year growth rate in the country.

Exhibit 5: Percent Change in Average Residential Electricity Prices, First Half 2014 versus First Half 2013




Source: Energy Information Administration http://www.eia.gov/todayinenergy/detail.cfm?id=17791

In addition, almost all New England utilities have had a drastic increase in residential retail rates for the first half of 2015, with increases ranging from 7 to 100 percent, as shown in Exhibit 6.

Exhibit 6: Average Residential Electricity Rates – Energy Only

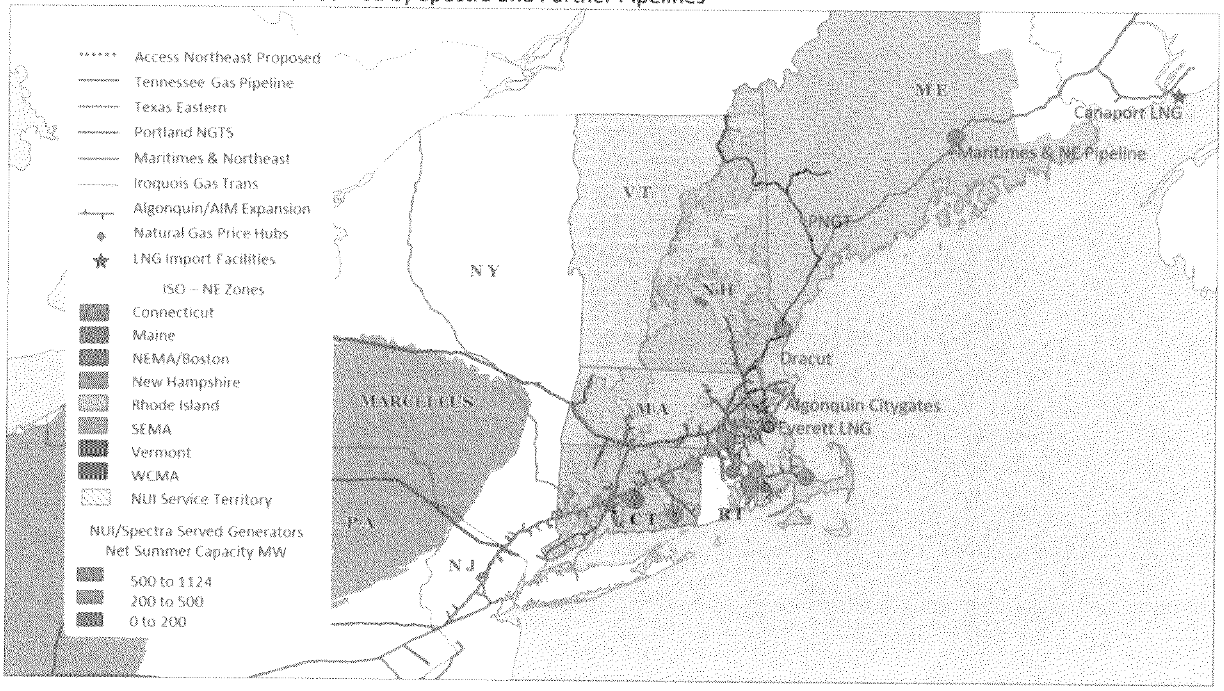
| Residential Rates | Energy Rate (c/kWh) | | % Change | Current Period |
|---|---|---|---|---|
| | Prior Rate | Current Rate | | |
| Connecticut | | | | |
| CL&P | 10.0 | 12.5 | 25% | Jan '15 – Jun '15 |
| United Illuminating | 8.7 | 13.3 | 53% | Jan '15 – Jun '15 |
| Massachusetts | | | | |
| NSTAR | 9.4 | 15.0 | 60% | Jan '15 – Jun '15 |
| WMECO | 8.8 | 14.0 | 58% | Jan '15 – Jun '15 |
| National Grid | 8.3 | 16.2 | 96% | Nov '14 – Apr '15 |
| Fitchburg | 8.5 | 14.1 | 66% | Dec '15- May '15 |
| New Hampshire | | | | |
| PSNH | 9.9 | 10.6 | 7% | Jan '15 – Dec '15 |
| Unitil | 8.4 | 15.5 | 85% | Dec '14 – May '15 |
| Liberty | 7.7 | 15.5 | 100% | Nov '14- Apr '15 |
| NH Elec Coop | 9.0 | 11.6 | 29% | Oct '14 - Apr '15 |

Source: Eversource Energy

**Access Northeast will enhance New England's grid reliability, complement the ISO-NE's market improvements to incentivize generation availability, and support the region's renewable energy goals**

To maintain electric system reliability and potentially prevent spikes in wholesale electricity prices, New England's gas-fired electric generators will need access to firm, reliable and economic natural gas supplies, particularly during the winter months. Access Northeast is designed to supply a significant amount of new pipeline capacity to both existing power plants and proposed facilities and will provide access to domestically sourced peaking LNG supply during winter periods.[13] This design will optimize the use of natural gas infrastructure by providing year-round access to more natural gas and, when demand for gas is low (typically, Spring, Summer and Fall) storing this domestic gas in regional LNG facilities to be used by electric generation during the Winter. Exhibit 7 shows that the proposed project can potentially serve 6,900 MW, or nearly 70 percent of the region's existing natural gas fired power generation capacity interconnected to the pipeline system and operating without backup fuel capability.[14] By providing secure fuel supplies to these generators, Access Northeast could improve electric reliability across the grid.

Exhibit 7: Gas Fired Generation Served by Spectra and Partner Pipelines




Source: Ventyx

The ISO-NE has developed a market enhancement that is intended to improve generation availability in order to mitigate the adverse consequences of reliability shortage events. This program is known as "Pay for Performance" (or Performance Incentives "PI") and is planned to be implemented by ISO-NE on June 2018. Once the program is in place, severe penalties ($2,000 increasing to $5,455 /Mwh over time) will be levied on generation that is not available to run at its credited generation capacity level during a

[13]http://www.spectraenergy.com/content/documents/Projects/NewEngland/Access-Northeast-Project-Brochure.pdf
[14] Data from Spectra Energy, which includes capacity served by ALQ, MN&P and Iroquois.

generation resource shortage. As ICF has pointed out, currently there could be insufficient firm fuel for as much as 5,700 MW of generation, which means that during winter shortage events the existing gas fired generation units could incur severe penalties if they are not able to dispatch. The infrastructure solution provided by Access Northeast and the Electric Reliability gas supply service, is capable of providing fuel for up to 5,000 MW and can provide this fuel to follow the hourly gas load variations of power plants. Access Northeast will, therefore, help ISO-NE meet its system reliability mandate and help generation avoid the PI shortage penalties.

In addition, New England states have ambitious goals for deployment of renewable generation. Due to the intermittent nature of wind and solar generation, additional quick response gas-fired generation is needed as renewables' share of total generation increases. Once again, the Access Northeast will provide services that are designed specifically to follow the hourly gas load variations of power plants as electric load and gas fired generation dispatch fluctuates during the day. Access Northeast is also well positioned to provide fuel supplies to insure that generators have a fuel supply when renewable resources are not generating due to the intermittent and unpredictable nature of the resources.

**New England could have saved $2.5 billion in wholesale electric costs had a project like Access Northeast been in operation during the 2013 – 2014 winter**

In addition to enhancing the area's electric reliability, additional firm supplies created by a project like Access Northeast will significantly reduce regional gas and electricity prices, especially during winter months when lack of gas supply during peak days has led to high and volatile gas prices. ICF estimates that a project like Access Northeast could have eliminated gas and electric price spikes on 49 days during this past winter and saved $2.5 billion in wholesale energy costs for New England's electric consumers.

ICF has analyzed historical flow and price data for the "Polar Vortex winter" of 2013 - 2014 to illustrate the potential impacts that a project like Access Northeast could have had during the winter of 2013-2014. Daily load factors on pipelines serving New England from New York, namely Tennessee Gas Pipeline (Tennessee) and Algonquin, averaged 89 percent from December 2013 to March 2014, and load factors on price spike days frequently exceeded 95 percent. An additional 500 MMcf/d of capacity, such as is proposed by Access Northeast, could have reduced the average load factor to 75%. Additionally, the pipeline load factors on peak winter days could have been further reduced with Access Northeast's proposed capability to use strategically located LNG injection points on the Spectra pipeline systems, as illustrated in Exhibit 8. When pipeline load factor is at or below 75% of capacity, New England natural gas price spikes and associated electric price spikes are much less likely to occur[15].

Exhibit 8: Hypothetical Load Factor Reduction with Access Northeast

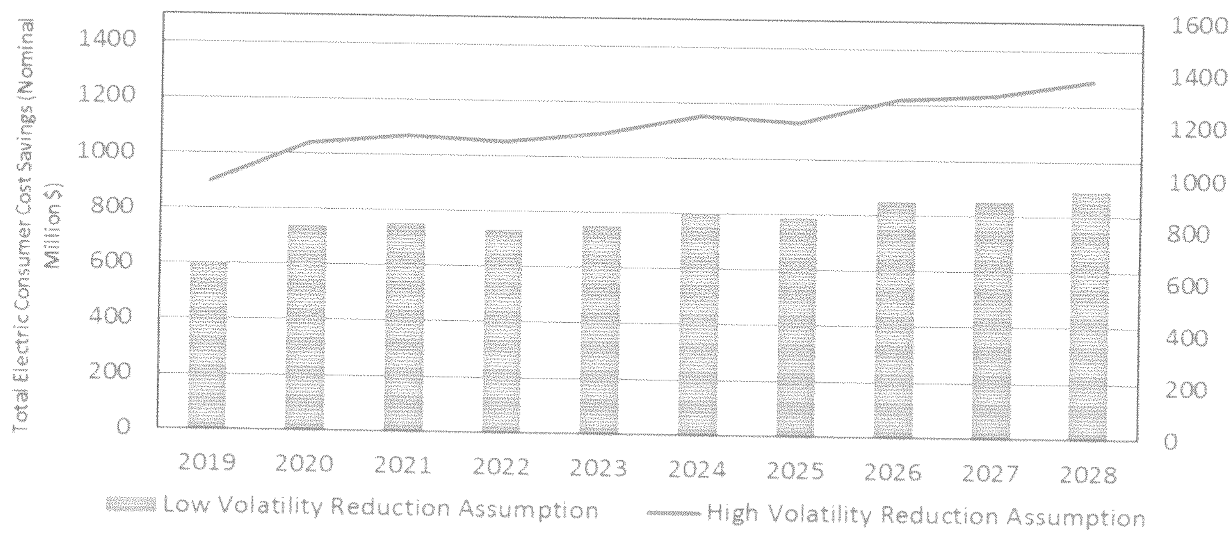
| January 23, 2014 | | | | | | |
|---|---|---|---|---|---|---|
| Actual | | | Hypothetical with Access Northeast | | | |
| Flows MMcf/d | Capacity MMcf/d | Load Factor % | Capacity MMcf/d | Storage Dispatch MMcf/d | Reduced Flows MMcf/d | Load Factor % |
| 2479 | 2761 | 90% | 3261 | 83 | 2396 | 73% |

[15] Historical data analysis indicates that New England prices tend to spike up when pipeline load factors exceed 75% of existing infrastructure capacity, which is consistent with the conclusions of the NESCOE study.

## A project like Access Northeast generates $780 million to $1.2 billion savings for New England Electric consumers under normal weather conditions

ICF estimates that, on average, a project like Access Northeast could save New England electric consumers $780 million to $1.2 billion per year over its first ten years of operation (2019 – 2028). Reduced wholesale energy prices resulting from reduced gas prices lower the cost of every MWh of energy consumed in the region, so all electric consumers will benefit from this cost reduction. It is critical to note, however, the price correlation between natural gas and power can only be realized if power plants have access to natural gas supply, which is a primary benefit that Access Northeast provides. Exhibit 9 shows that annual electric cost savings resulting with Access Northeast rises from $600 million to $1.4 billion over time.

Exhibit 9: New England Electric Consumer Cost Savings




Source: ICF International

The extreme price volatility of natural gas in winter was partly driven by generators' lack of firm access to fuel. The volatile market price for gas on a daily basis results from the scarcity pricing effect where generation buyers were faced with little to no market liquidity (a "seller's market"). ICF's volatility analysis is intended to capture the asymmetric nature of the "gas for power" market in New England - prices can go very high, but tend to decline only modestly. ICF's estimates of volatility reduction are conservative, by assuming that a project like Access Northeast results in "reduction" and not "elimination" of volatility, which could have resulted in larger economic benefits such as the $2.5 billion estimated for the 2013-2014 winter.

In addition to the projected savings to consumers, an infrastructure project like Access Northeast will improve market liquidity by providing the infrastructure needed to ensure firm gas access for power generation and, therefore, create a more balanced and efficient "gas for power" market. The Access Northeast infrastructure will "de-bottleneck" the gas supply market for generation much like a transmission line removes market price separation along a constrained electric interface.

The annualized cost of the Access Northeast project assessed in this analysis is approximately $400 million a year.[16] ICF estimates that the project would potentially produce net savings of $380 million to $800 million a year to New England's electric consumers. This estimate assumes that the project is constructed following the funding mechanism that the electric distribution companies proposed to NESCOE[17]. Under such a mechanism, New England's electric consumers would bear the full cost of the electric portion of the project, so those costs are netted out of the total savings that ICF has estimated. However, the cost savings to consumers would be greater if projected revenues for pipeline reservation charges paid by electric generators were to be credited back to the consumers (as is proposed). ICF also estimates that the majority of the $2.4 billion investment required for the project could be recovered from the cost savings realized from a single winter like 2013/14.

**Access Northeast's cost savings increase by more than 25% if extreme winter weather conditions occur along with a nuclear plant outage**

ICF has assessed the benefits of Access Northeast under a "1-in-20 year" design winter and also assuming that 1,000 MWs of base load units are not available during the 2018-2019 winter (this is also a condition evaluated by ISO-NE and carries a high risk to electric reliability without new gas infrastructure). This results in more dramatic natural gas and wholesale electricity price reductions. ICF estimates that during the five-month winter period from November 2018 through March 2019, cost savings to the area's electric customers would be approximately $1.1 billion dollars, 25 percent higher than the high volatility reduction under normal weather conditions.

**Access Northeast promotes greater reliability and mitigates the risks of costly electric grid disruption**

The cost savings estimated by ICF in preparing this study and report focus solely on the benefits that additional infrastructure have on fuel supply costs and, in turn, the cost of producing electricity. Another and potentially much greater financial benefit is gained by avoiding potential direct and indirect economic consequences from disruptions to electric grid services. Although beyond the scope of this study, other sources have shown that disruptions to electric services can be multiples of the billions of dollars in fuel cost savings we identify.

[16] ICF estimated the levelized cost for the power generation solution based on a $2.4 billion capital investment requirement.

[17] http://www.nescoe.com/uploads/GasforElectricReliabilityGraphic_April2014.pdf

# Study Background

## The ISO-NE Perspective

Over the past decade, the New England power market has experienced a rapid shift towards gas-fired generation, which has created challenges for ISO-NE regarding electric system reliability. Although the region has expanded pipeline infrastructure as demand from gas LDCs customers has grown, there has been no equivalent investment to ensure that gas is available for power plants as New England's reliance on gas-fired generation has increased significantly. Generators' lack of firm pipeline capacity contracts has been identified as a key risk by ISO-NE. Under the pipeline regulatory system imposed by FERC, interstate gas pipelines only build new or increased pipeline capacity if shippers are willing to commit to long-term firm contracts for the capacity rights. Without long-term firm contracts, pipeline capacity will not be added into New England.

LDCs contract for firm pipeline capacity based on potential peak day demand of their firm service customers under extreme winter weather conditions, referred to as a "design day" and buy their gas supplies under a portfolio of supply contracts and delivery points in the gas production areas served by their pipeline transport providers. Electrical generators in vertically integrated power markets (primarily in the Midwest, southern states, and some western states) will make long-term pipeline contracts because they are usually permitted to pass the costs of the capacity contracts through to their electric customers. However, in ISO/RTO markets like New England, generators are unwilling to take the risk of entering in long-term contracts absent any certainty that they will be able to recover those costs. As a result, most gas-fired generators in New England have made no long term commitment and rely on non-firm, interruptible capacity (IT) services and spot market purchases of natural gas supplies.

During the summer months, New England LDC loads are low and IT services are readily available. However, in the winter months (and particularly on cold winter days when firm LDC demand is highest), IT services become scarce, leading to sharp increases in regional spot gas prices and concerns about meeting minimum fuel requirements needed to avoid electric system disruptions. The 2013/14 Winter Reliability program encouraged oil and dual-fuel generation to stockpile oil reserves though out-of-market payments. With FERC approval, ISO-NE has implemented a similar Winter Reliability program for the winter of 2014/15. However, in its order approving the new 2014/15 program, FERC stated, "we expect ISO-NE to abide by its commitment to develop a long-term, market-based solution to address winter reliability issues."[18]

As part of its effort to look for long-term solutions, ISO-NE has engaged ICF for three separate studies since 2011 to evaluate the availability of gas supplies to New England electric generators during peak winter demand periods through 2020. The three ICF studies are:

1) Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs ("Phase I"), analysis completed June 2012[19]

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[18] http://www.ferc.gov/CalendarFiles/20140909165718-ER14-2407-000.pdf

[19] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public_slides.pdf

2) Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II ("Phase II"), analysis completed December 2013[20]
3) Winter 2013/14 Benchmark and Revised Projections for New England Natural Gas Supplies and Demand ("Winter Benchmark"), analysis completed April 2014[21]

A similar analytic approach was used in the Phase I and Phase II studies. First, ICF evaluated the total gas supplies available to New England consumers (from firmly contracted interstate pipeline capacity, send out from LNG import terminals, and LDC-operated peak-shaving facilities) on a peak winter day. Next, ICF projected the aggregated design day firm load for the New England LDCs, based on data provided by the LDCs for use in the study and LDC filings with their state public service commissions. To arrive at gas supplies remaining for New England's electric generators on a peak winter day, ICF subtracted the LDC firm design day load from the total regional gas supplies. Separately, ISO-NE modeled multiple scenarios for gas generation fuel requirements, based on various combinations of gas prices, projected electric load, availability of non-gas generation, and other variables. The ISO-NE projections for generator gas demand were compared to the remaining supply; where projected demand is greater than the remaining supply, this is referred to as a gas supply deficit. The Phase II study concluded that by the winter of 2019-2020, gas supply deficit would range from 250 to 1,100 MMcf/d under the Phase II Retirements scenarios, which did not include ISO-NE's revised projections for electric load reductions due to energy efficiency.[22] However, even in cases including new energy efficiency projections that reduce electric load growth and gas demand, the Phase II still projected gas supply deficits of from 200 to 800 MMcf/d.[23]

For the most recent Winter Benchmark study, ISO-NE asked ICF to examine gas system performance during the winter of 2013/14 (particularly during the January 2014 polar vortex events), and based on this new data, revise its Phase II projections for New England natural gas supplies, firm LDC demand, and gas supplies remaining for electric generators. ICF collected data on daily pipeline flows throughout the winter, and the Northeast Gas Association (NGA) provided send out data from their member LDCs for four of the peak demand days in January. ISO-NE provided a total of nine new gas demand projections, based on its dispatch analysis using results from the latest Forward Capacity Auction (FCA 8), and various combinations of gas prices, load assumptions, and nuclear outages.

The cases ISO-NE deemed to be most relevant in the Winter Benchmark study were those using "extreme" (~$23/MMBtu) gas prices, since these cases are most representative of spot prices observed in New England when gas supplies are constrained and oil-fired units frequently become the marginal supply.

[20] While the Phase II study was complete in 2013 and a draft report was issued in December 2013, the final version of the report was posted on ISO-NE on November 20, 2014; see: http://www.iso-ne.com/static-assets/documents/2014/11/final_icf_phii_gas_study_report_with_appendices_112014.pdf

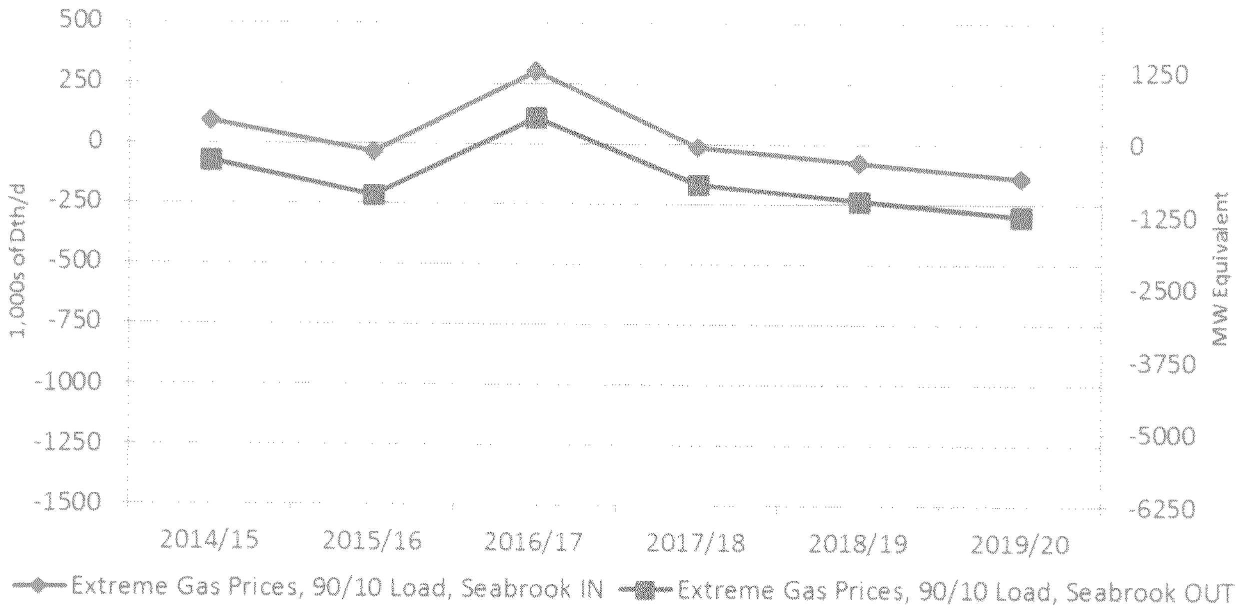
[21] http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/apr292014/a3_icf_benchmarking_study.pdf

[22] Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near Term Electric Generation Needs: Phase II, ICF International (2014), page 21, Exhibit 4-6.

[23] Ibid.

Exhibit 10 shows the projected gas deficits for peak winter days through the winter of 2019/20; points below 0 on the y-axis represent supply deficits.[24]

Exhibit 10: Power Sector Winter Peak Day Supply Deficits




Source: ISO-NE Planning Advisory Committee presentation, April 29, 2014

Even assuming extreme gas prices and heavy reliance on older more expensive oil-fired generation, the electric system is still expected to have a gas deficit of between 140 and 300 MMcf/d (equivalent to 600 and 1,300 MW) by the winter of 2019/20, meaning electric system reliability will remain at risk without additional gas supplies into the region. As shown in the Phase II study, the supply gap is expected to be much larger if gas prices are less extreme. Gas supply to ISO-NE generation would need to provide an additional 1.1 Bcf/day in order to fuel as much as 5,700 MW of generation and allow for cost efficient and reliable operations.

With extreme gas prices at $23/MMBtu and above many oil units are in merit, which reduces gas-fired generation, producing a "lower" deficit for natural gas fired generation capacity. However, while the ISO-NE dispatch analysis assumes oil supplies are available, experience from the winter of 2013/14 indicates that this might not be the case. Generators had stockpiled oil prior to winter (due to the ISO-NE Winter Reliability program requirements), but by February of 2014 most generators were down to two days of oil supplies. In a filing with FERC, ISO-NE stated that during this winter2013/14:

> "Those [oil-fired generating stations] that tried to replenish their inventory reported difficulties in both procuring and transporting oil. Oil was unavailable given the increased demand from both the heating and power sectors and reduced supply following years of reduced demand. Even when oil was available, barges to transport the oil were in short supply due to high demand all along the East Coast. When they were

[24] The deficit reduction in the winter of 2016/17 is due to the planned Algonquin AIM and Tennessee Connecticut pipeline expansions in November 2016; these were the only pipeline capacity expansions assumed in the Winter Benchmark analysis.

available, barges had difficulties with frozen and shallow water conditions. Trucks were also limited, and commercial drivers' license requirements restricted hours per day of work (although the license requirement was loosened in Massachusetts at the ISO's request)."[25]

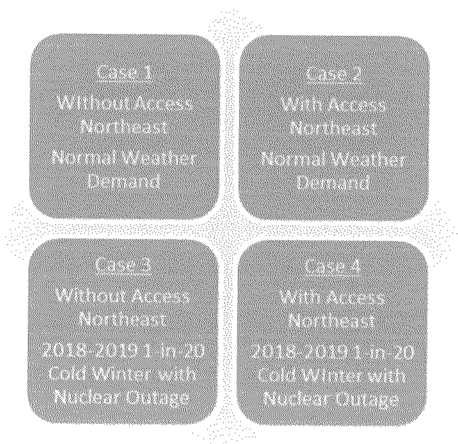
While ISO-NE's Winter Reliability program encourages less reliance on gas-fired generation, the resulting increase in dependence on oil-fired generation can also present reliability risks, demonstrated by the difficulties replenishing oil supplies this past winter. Additionally, the increased dependence on oil-fired generation can result in high electricity rates to customers (such as those experienced during winter 2013/14) as summarized earlier in this report. Consistent with the design of the Access Northeast project, firm pipeline capacity, from both more firm transport from stable gas sources west of New England and access to supplemental LNG supplies from strategically located facilities in New England, will provide enhanced power supply reliability.

## Purpose of This Study

The purpose of this study is to assess the impact to electric system reliability and estimate the potential cost savings to New England electric consumers from the proposed Access Northeast project.

ICF's analyses focused on four model runs – one scenario assuming the average normal weather conditions from 2019 through 2028 with and without Access Northeast, and a second scenario assuming a 2018-2019 cold winter season with a large nuclear outage, as shown in Exhibit 11. ICF also provides qualitative assessments on the proposed project's potential non-economic benefits, including enhancing the electric system reliability and supporting renewable generation.

Exhibit 11 : ICF Analysis Overview




ICF's analyses and findings draw from years of experience consulting on North American natural gas and electric markets, and the proprietary software tools and data bases developed for that purpose. For this analysis, ICF utilized a suite of analytical tools –Gas Market Modeling (GMM©), ICF's Integrated Planning

[25] ISO-NE ISO New England Inc., Docket No. ER14-2407-000 Winter 2014-15 Reliability Program (Part 1 of 2) http://www.iso-ne.com/regulatory/ferc/filings/2014/jul/er14-2407-000_win_rel_pro_7-11-2014.pdf

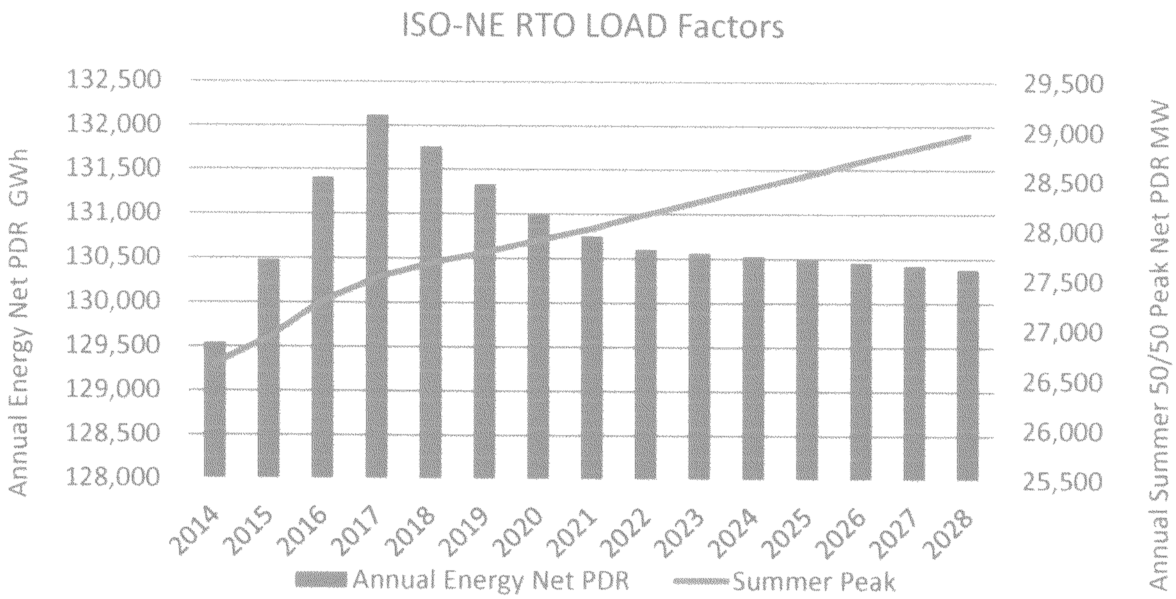
Model (IPM®), and GE's Multi Area Production Simulation (MAPS) –through an iterative and integrated process.

## Analytic Assumptions

### Electric Load Growth

For electric load growth in New England, ICF utilizes the 2014 ISO-NE CELT report's net of Passive Demand Response ("PDR") energy load forecast extrapolated through 2028. The projection assumes that New England's annual net energy load grows through 2017 and declines until 2023 and remains flat afterwards as seen in Exhibit 12. This load growth projection reflects significant amount of energy efficiency gains over time to offset the load growth resulted from population growth and economic developments.

Exhibit 12: ISO-NE RTO LOAD Factors




Source: ICF International

### Capacity Retirements and Builds

In the analysis, ICF assumes that approximately 2,800 MW of coal, oil, and nuclear generation capacity in ISO – NE is retired by 2018 as shown in Exhibit 13.

Exhibit 13 – ISO – NE Firm Retirements

| Plant Name | Capacity Type - Sub Type | Retirement Date | Capacity Modeled(MW) |
|---|---|---|---|
| Vermont Yankee | Nuclear - Nuclear | 01-Oct-14 | 604 |
| SALEM HARBOR | Coal, Oil/Gas Steam | 30-May-14 | 581 |
| Bridgeport Station | Oil/Gas Steam - Heavy Oil | 01-Jan-17 | 130 |
| Brayton PT | Oil/Gas Steam - Heavy Oil, Combustion Turbine, Coal | 31-May-17 | 1500 |

Source: ICF International

For this analysis, ICF assumes that the Footprint Power facility (700 MW rating) comes online in January 2017. In addition, a 500 MW of combined cycle facility is assumed to be constructed in 2023 to replace retired capacities.

## Renewables

ICF assumes all renewable portfolio standards ("RPS") in the New England states are met according to the proposed timeline. For Massachusetts, the RPS requires 22 percent of energy from renewable resources by 2020 and an additional 1 percent each year thereafter. Connecticut, 27 percent by 2020; New Hampshire, 24.8 percent by 2025; Rhode Island, 16 percent by 2020 and Maine, 30 percent by 2020. ICF assumes 800 MW of wind will be built through 2028. 1,500 MW of solar and approximately 150 MW of landfill and biomass capacity will also be added to serve ISO-NE.

## Environmental Regulations

For this analysis, ICF assumes that federal maximum achievable control technology (MACT) standards, consistent with those set by the Environmental Protection Agency (EPA) in its final mercury and air toxics standards (MATS) released on December 21, 2011, will be in place. ICF also assumes that the EPA will not have an alternative to current the Clean Air Interstate Rule (CAIR) regulations, and that CAIR remains in place through 2017. In 2018, ICF assumed standards tighten to the Cross State Air Pollution Rule (CSAPR) Phase II requirements. Furthermore, ICF considers a national $CO_2$ cap and trade program starting in 2020 at $1/ton and increasing to $16.6/ton by 2028. However, on the regional level, the analysis assumes the existing $CO_2$ market for Northeastern and Mid-Atlantic states[26] under the Regional Greenhouse Gas Initiative ("RGGI") program remains in place[27] and is gradually integrated into the federal program.

ICF's $CO_2$ forecast reflects a probability weighted assessment of several alternative GHG mitigation policies. Exhibit 14 shows the RGGI $CO_2$ expected allowance prices in New England increases from $5.2/Ton to $16.6/Ton by 2028.

[26] Includes MD, CT, DE, ME, MA, NH, RI, VT, and NY.

[27] RGGI $CO_2$ program is assumed to be subsumed by National $CO_2$ program by 2026. Inflation used beyond 2013 is 2.1% annually. Therefore the values presented here beyond 2025 are actually national $CO_2$ numbers.

Exhibit 14: Carbon Pricing Assumptions

| Year | RGGI: $CO_2$ Expected Allowance Prices (Nom$/Ton) |
|---|---|
| 2014 | 5.2 |
| 2015 | 6.3 |
| 2016 | 7.5 |
| 2017 | 8.9 |
| 2018 | 9.1 |
| 2019 | 9.3 |
| 2020 | 11.4 |
| 2021 | 11.6 |
| 2022 | 11.8 |
| 2023 | 12.1 |
| 2024 | 12.3 |
| 2025 | 12.6 |
| 2026 | 13.3 |
| 2027 | 14.9 |
| 2028 | 16.6 |

Source: ICF International

# Impact on System Reliability

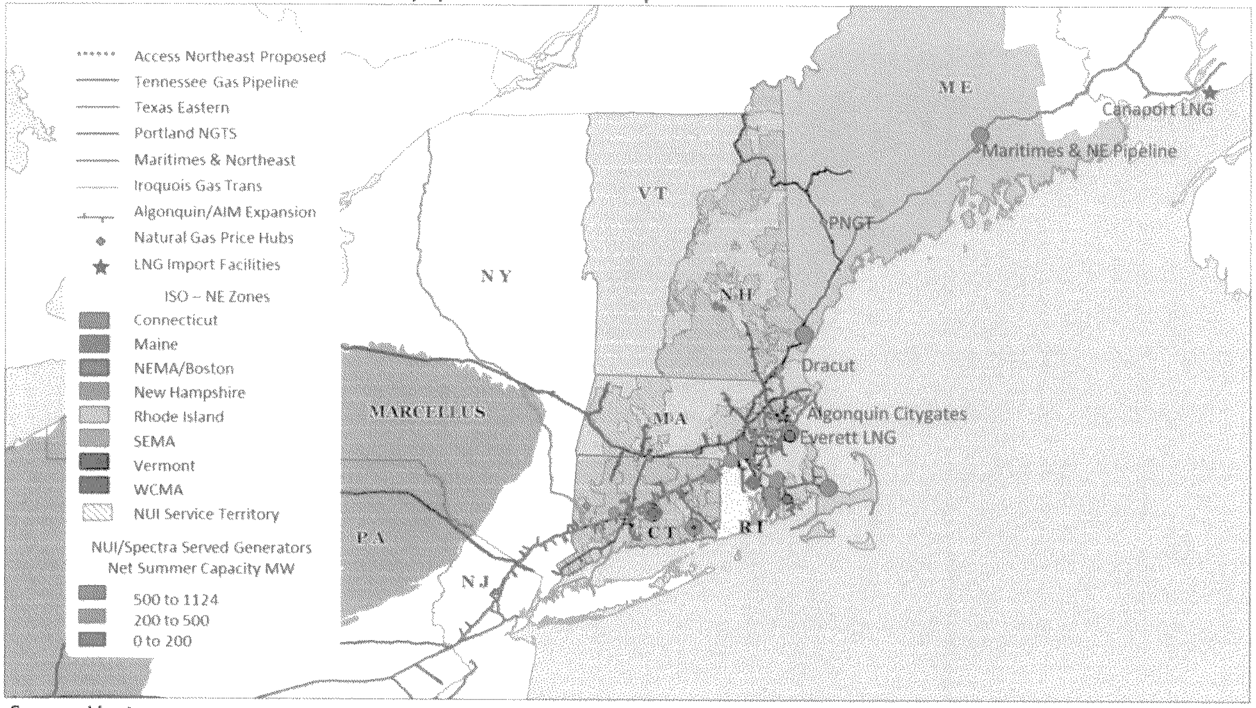
Access Northeast will increase ISO-NE's electric system reliability by directly providing firm natural gas fuel for gas fired power generators. As discussed earlier, the most recent ISO-NE study performed by ICF last year identified that potential capacity needs for the region range from 250 MMCf/d to 1.1 Bcf/d for peak winter days under different assumptions.

The Mass DOER study, recently completed by Synapse Energy, analyzed a suite of scenarios and concluded that in order to balance supply and demand for natural gas in Massachusetts in 2020, there is a hypothetical natural gas capacity need of 25 billion Btu per peak hour to 33 billion Btu per peak hour (0.6 Bcf per day to 0.8 Bcf per day).[28] The estimated need for pipeline capacity exists even under the low demand scenario with the assumption of a new transmission project that imports 2,400 MW of Canadian hydroelectric power into Massachusetts. The low demand scenario is based on the assumption that Massachusetts implements all of the alternative resources deemed technically and economically feasible and practically achievable.

To maintain electric system reliability and potentially prevent spikes in wholesale electricity prices, New England's gas-fired electric generators will need access to firm, reliable and economic natural gas supplies, particularly during the winter months. Access Northeast is designed to supply a significant amount of new pipeline capacity to both existing power plants and proposed facilities and will provide access to domestically sourced peaking LNG supply during winter periods. This design will optimize the use of existing natural gas infrastructure by providing year round access to more natural gas and, when demand for gas is low (typically, Spring, Summer and Fall) storing this domestic gas in regional LNG facilities to be used by electric generation during the Winter. Exhibit 15 shows that the proposed project can potentially serve 6,900 MW, or nearly 70 percent of the region's existing natural gas fired power generation capacity interconnected to the pipeline system and operating without backup fuel capability[29]. By providing secure fuel supplies to these generators, Access Northeast could significantly improve electric reliability across the grid.

[28] Massachusetts Low Demand Analysis, slide 28, http://synapse-energy.com/project/massachusettslow-demand-analysis.
[29] Including connections with ALQ, MN&P and Iroquois.

Exhibit 15: Gas Fired Generation Served by Spectra and Partner Pipelines




Source: Ventyx

The ISO-NE has developed a market enhancement that is intended to improve generation availability in order to mitigate the adverse consequences of reliability shortage events. This program is known as "Pay for Performance" (or Performance Incentives "PI") and is planned to be implemented by ISO-NE on June 2018. Once the program is in place, severe penalties ($2,000 increasing to $5,455 /Mwh over time) will be levied on generation that is not available to run at its credited generation capacity level during a generation resource shortage. As ICF has pointed out, currently there could be insufficient firm fuel for as much as 5,700 MW of generation, which means that during winter shortage events the existing gas fired generation units could incur severe penalties if they are not able to dispatch. The infrastructure solution provided by Access Northeast and the Electric Reliability gas supply service, is capable of providing fuel for up to 5,000 MW and can provide this fuel to follow the hourly gas load variations of power plants. Access Northeast will, therefore, help ISO-NE meet its system reliability mandate and help generation avoid the PI shortage penalties.

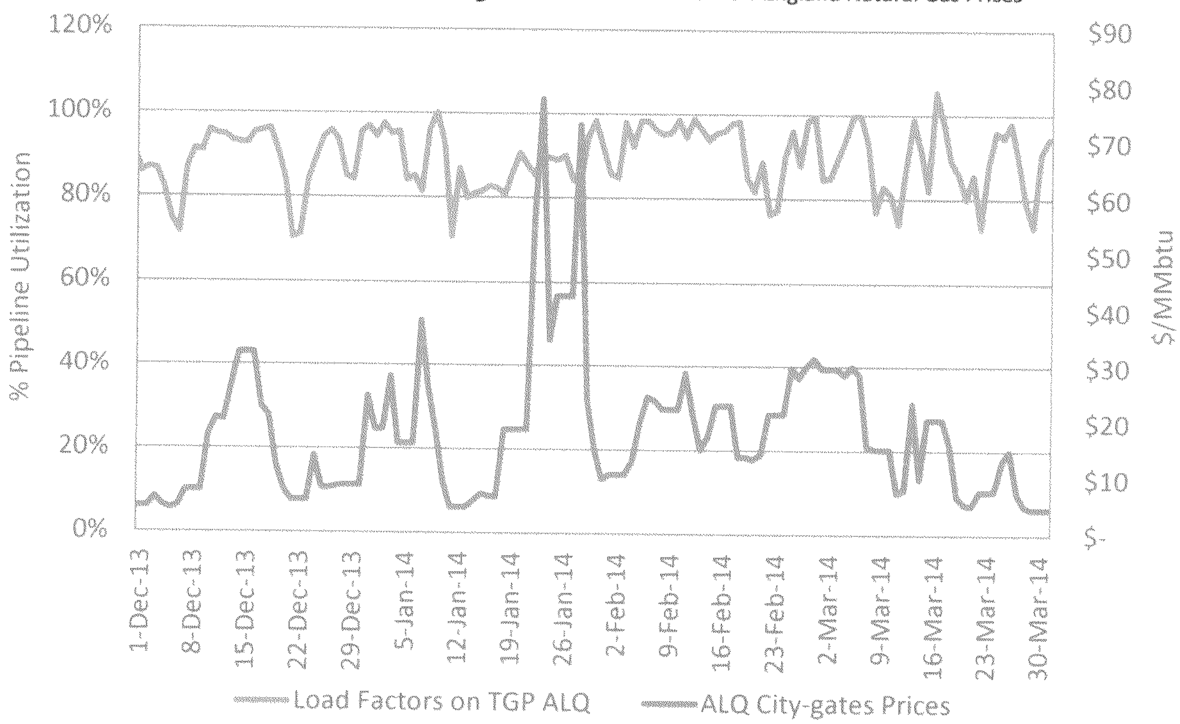
In addition, New England states have ambitious goals for deployment of renewable generation. Due to the intermittent nature of wind and solar generation, additional quick response gas-fired generation is needed as renewables' share of total generation increases. Once again, the Access Northeast will provide services that are designed specifically to follow the hourly gas load variations of power plants as electric load and gas fired generation dispatch fluctuates during the day. Access Northeast is also well positioned to provide fuel supplies to insure that generators have a fuel supply when renewable resources are not generating due to the intermittent and unpredictable nature of the resources.

# Hypothetical Impact of Project on Winter 2013/2014

ICF has analyzed historical flow and price data to illustrate the potential impacts that a project like Access Northeast could have had during the "polar vortex winter" of 2013-2014.

As shown in Exhibit 16, daily load factors on pipelines serving New England from New York - namely Tennessee Gas Pipeline (Tennessee) and Algonquin - averaged 89 percent from December 2013 to March 2014, and load factors on price spike days frequently exceeded 95 percent.

Exhibit 16: Daily Load Factors on TGP and ALQ during winter 2013-2014 and New England Natural Gas Prices




Source: ICF International, LCI

An additional 500 MMcf/d of capacity, such as is by Access Northeast analyzed in this study, could have reduced the load factors by increasing available capacity. Additionally, the dispatch of Access Northeast's proposed LNG capabilities on peak winter days could have further reduced pipeline load factors. Exhibit 17 shows the actual load factor and the hypothetically reduced load factors for introducing the Access Northeast project. Based on the assumption that the gas price spikes and associated electric price spikes would be eliminated when pipeline load factors are at or below 75 percent[30], ICF estimates that a project like Access Northeast could have eliminated gas and electric price spikes on 49 days from December 2013 through March 2014, saving $2.5 billion in wholesale energy costs for New England's electric consumers.

[30] Historical data analysis indicates that New England prices tend to spike up when pipeline load factors exceed 75% of existing infrastructure capacity, which is consistent with findings of the NESCOE study.

Exhibit 17: Actual Pipeline Load Factors and Hypothetical Reduced Load Factors with Access Northeast


Source: ICF International

The estimated cost savings were extraordinary for winter 2013-2014, because the polar vortex conditions have impacted a very large US geographic area (including the Northeast, Southeast, and Mid-west simultaneously) that drove up the demand for natural gas throughout the natural gas transportation systems.

# Cost Savings – Normal Weather Scenario

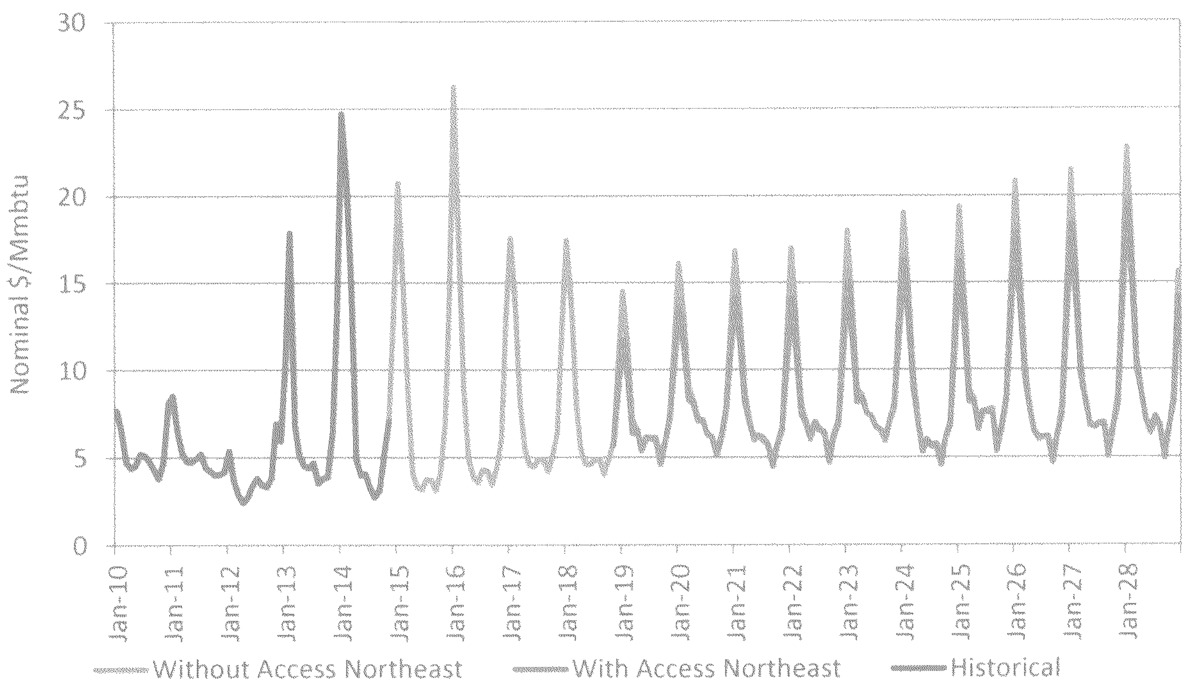
ICF estimates the economic impact of Access Northeast by running GMM and IPM models under normal weather conditions with and without Access Northeast and compares the difference between natural gas prices and electricity prices. The price reduction is used to calculate the market impact and potential cost savings to New England's electric consumers before estimating savings from reduced price volatility. The project's impact on natural gas price volatility and subsequent reduction to the electric price spikes are then estimated separately utilizing a statistical approach.

## Natural Gas Price Impact (excluding volatility)

Exhibit 18 shows that without Access Northeast, under normal weather conditions, ICF projects gas prices in New England will briefly exceed the level reached in last winter. Incremental capacity expansions (such as AIM, Tennessee's Connecticut Expansion, Spectra's Atlantic Bridge, and other projects to meet LDCs' load growth) will lower the price down to $15/MMBtu. It then steadily increase over time and exceed $20/MMBtu by January 2026 when more gas is needed for generation and supply from East Canada is no longer available. Access Northeast reduces January price by $2.80 – 3.20/MMBtu for the entire study period.

Even before taking the impact of volatility into consideration, ICF projects that Access Northeast will significantly reduce natural gas prices during peak winter months. On average, peak winter month prices will be approximately $3/MMBtu lower with Access Northeast.

Exhibit 18: New England Natural Gas Price Forecast (excluding volatility reduction benefits)

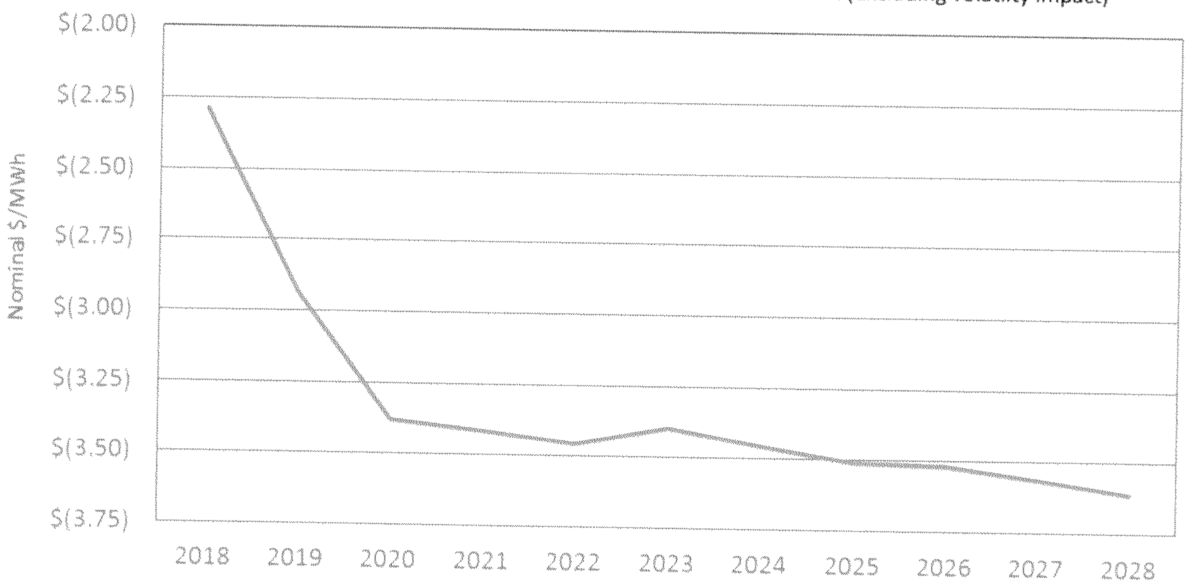



Source: ICF International, SNL

## Electric Price Impact (excluding volatility)

Access Northeast is designed to provide firm gas supply to the gas fired power plants that are connected to the Spectra pipelines. The Spectra pipelines are already directly and indirectly connected to 70 percent of the gas fired generation plants that serve New England. Further, Spectra pipelines serve twice the number of efficient gas fired power plants than the other pipelines combined. Because Access Northeast along with interconnecting pipelines and regional storage assets will provide firm service to gas fired generators (even during severe winter conditions), the reduction in natural gas prices resulting from Access Northeast will result in a reduction of electricity prices. Exhibit 19 shows the energy price with Access Northeast minus the energy price without Access Northeast. Access Northeast reduces the New England annual average wholesale power price by $2.25/MWh to $3.50/MWh between 2019 and 2028, with substantial reduction as high as $15/MWh during peak winter periods.

Exhibit 19: New England Annual Average Electric Price Reductions with Access Northeast (excluding volatiity impact)




Source: ICF International

## Consumer Cost Savings

ICF estimates the potential cost savings to New England's electric consumers from reductions in average price levels and in natural gas and electric price volatility.

### Cost Savings to Electric Consumers from Average Price Reduction

Analysis results presented above show that Access Northeast may reduce New England's wholesale energy price by lowering the regional natural gas price and the fuel costs for gas fired power generation. ICF assumes that for this analysis that reductions in wholesale electricity prices provided by infrastructure solutions benefit all New England electric consumers. Annual cost savings to electric consumers are calculated as the reduction in New England's wholesale energy prices multiplied by ISO-NE annual net energy load.

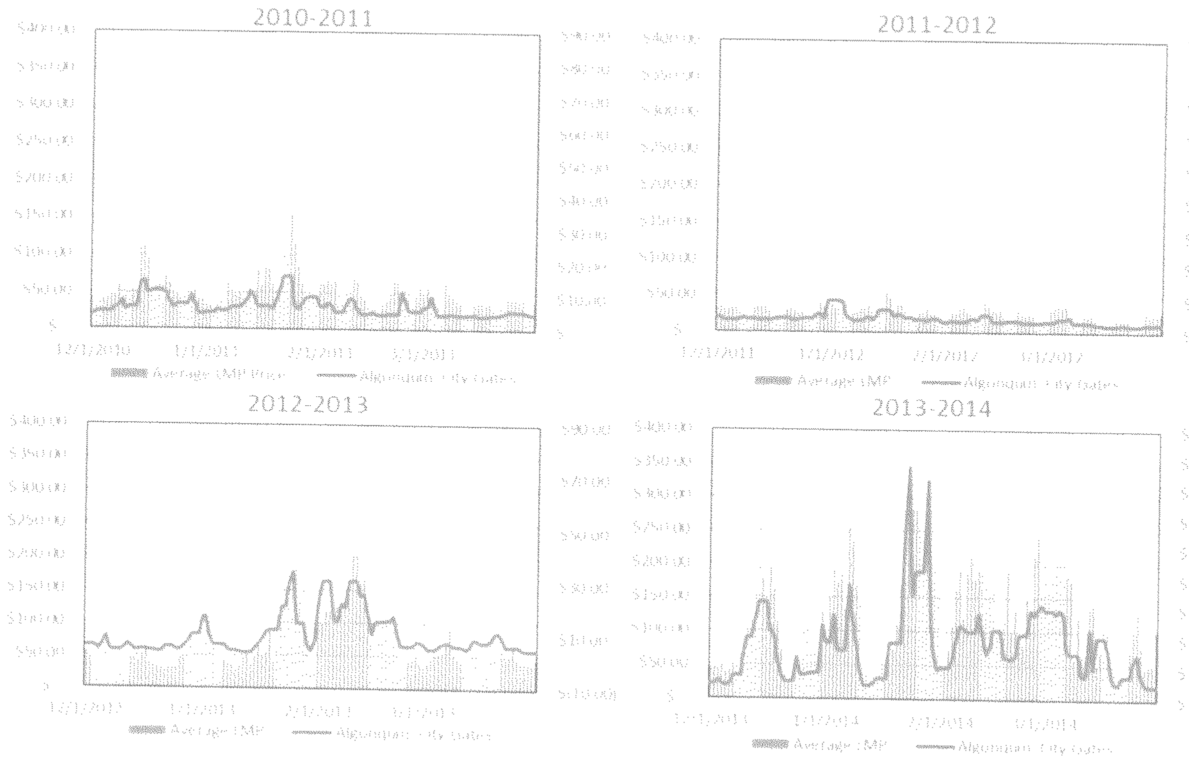
## Benefits from Reduced Daily Gas Price Volatility

In addition to the overall price decreases that ICF derived using the GMM and IPM models, there are additional cost savings to natural gas and electric consumers due to reductions in daily natural gas and power price volatility.

For the purpose of this analysis, ICF assumes that Access Northeast will introduce 500 MMcf/d incremental gas supply capacity into New England year-round, and an additional 6 Bcf of winter supply (400 MMcf/d of send out from the LNG storage). Both serve to relieve the winter constraints recently experienced in New England. In addition to reducing monthly average prices captured by ICF's GMM modeling analysis, the volatility of prices, i.e., the frequency and magnitude of price spikes, may be reduced. As New England's power generators dispatch their gas generation based on daily fuel prices, reduction in natural gas price volatility may result in further reduction in natural gas prices.

For this study, ICF uses the frequency and magnitude of extraordinary price spikes as a proxy to measure the impact of volatility reductions. Exhibit 20 presents daily ALQ price and ISO-NE daily LMPs for the past four winters.

Exhibit 20: New England Power and Gas Price Correlation




Source: ICF International, SNL, ISO-NE

ICF estimates a range of the volatility reduction impacts by assuming two volatility reduction levels:

- Low Volatility Reduction Assumption - Frequency and size of price spikes were reduced by half from a moderate volatility market, similar to that experienced in the 2010-2011 or 2012-2013 winter;

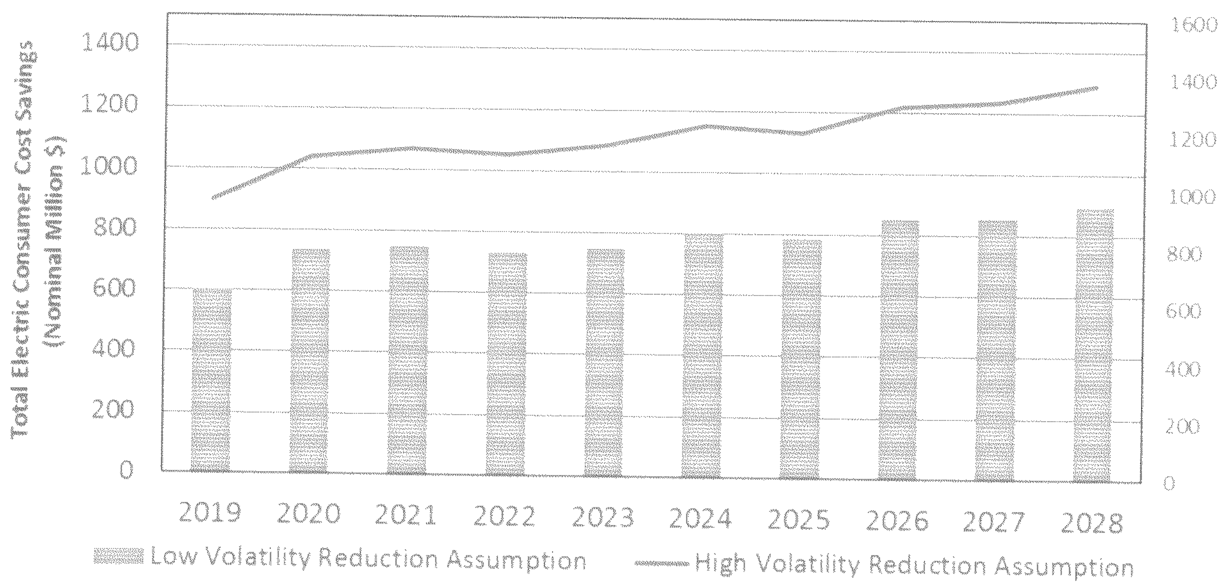
- High Volatility Reduction Assumption - Frequency and size of price spikes were reduced by half from a high volatility market, similar to that experienced in the 2013-2014 winter.

Both assumptions reflect a conservative scenario that a project like Access Northeast will result in "reduction" and not "elimination" of volatility. ICF estimates that additional eight percent reduction in natural gas prices for December and March using the low volatility assumption and 20 percent further price reduction using the high volatility assumption, which translate into an additional $330 million and $750 million a year of cost savings to electric consumers.

## Total Estimated Impact to Consumers

With Access Northeast reducing prices of natural gas and thus reducing the price of wholesale power for New England consumers, Exhibit 21 shows that a project like Access Northeast could generate $600 million to $1.4 billion a year to New England electric consumers. The annual average cost savings to consumers for the 10-year period is $780 million to $1.2 billion for the low and high volatility assumption scenarios, respectively.

Exhibit 21: New England Electric Consumer Cost Savings




Source: ICF International

# Cost Savings – Cold Weather and Nuclear Outage Scenario

ICF assessed the impact of Access Northeast by assuming that the winter of 2018-2019 is a "1-in-20 year design" winter and also experiences a large nuclear outage event. On the electric market, ICF also used the 90-10[31] scenario from ISO-NE's CELT report that has a significantly different peak energy load profile than under the normal weather conditions.

## Weather and RCI Demand Assumptions

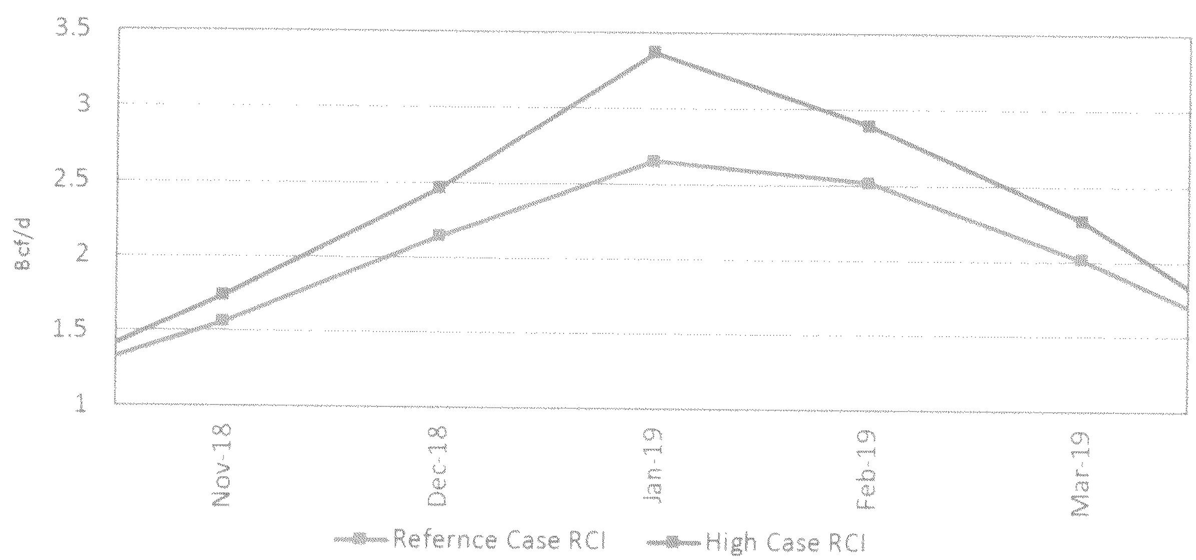
ICF utilized the design winter weather data provided by Eversource, to calibrate the design winter conditions in New England. Exhibit 22 shows that the design winter is, on average, 20 percent colder than normal winter conditions. Exhibit 23 shows that residential and commercial demand for the five winter months is 20 percent higher than under normal weather conditions.

Exhibit 22: Weather Assumptions

| | Normal HDDs | 1-20 Design HDDs | Design Winter Colder % |
|---|---|---|---|
| November | 708 | 812 | 15% |
| December | 1036 | 1188 | 15% |
| January | 1222 | 1522 | 25% |
| February | 1052 | 1207 | 15% |
| March | 916 | 1051 | 15% |

Source: Eversource, ICF International

Exhibit 23: RCI Demand Comparison - High Winter Case vs. Reference Winter Case




Source: ICF International

[31] The 90/10 scenario refers to ISO-NE's electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 10%. Therefore, a high electric load demand is estimated.

## Price Impact and Cost Savings

Under the cold weather and nuclear outage scenario, Access Northeast is expected to have a more significant impact on natural gas and electric market. Exhibit 24 shows that on average (before taking volatility into consideration), natural gas price could be reduced by 23 percent and electric prices be reduced by 12 percent.

Exhibit 24: Colder than Normal Winter Scenario Power and Gas Price Results with and without Access Northeast (Excluding Volatility Impact)

| | Natural Gas Prices ($/MMBtu) | | | Power Prices ($/MWh) | | |
|---|---|---|---|---|---|---|
| | With Access Northeast | Without Access Northeast | Delta | With Access Northeast | Without Access Northeast | Delta |
| Nov-18 | $4.95 | $ 5.45 | 10% | $40.80 | $43.57 | 7% |
| Dec-18 | $10.83 | $12.79 | 18% | $52.31 | $56.96 | 9% |
| Jan-19 | $20.95 | $ 31.73 | 51% | $81.19 | $98.65 | 22% |
| Feb-19 | $12.07 | $14.87 | 23% | $60.99 | $68.93 | 13% |
| Mar-19 | $6.44 | $7.38 | 15% | $53.67 | $58.05 | 8% |

Source: ICF International

Under the cold weather and nuclear outage scenario, ICF assumes that Access Northeast could reduce the volatility by a level consistent with the high volatility reduction assumption. In total, Access Northeast could generate approximately $1.1 billion cost savings to electric consumers in the five winter month period, 25 percent higher than under normal winter conditions. The average cost savings of the ten-year period, if assuming the 1-in-20 weather scenario and high volatility reduction, is approximately $1.4 billion a year.

# Cost / Benefits of Access Northeast

The portion of Access Northeast that will serve electric generation in New England, assumed in ICF's analysis is estimated to cost $2.4 billion. Assuming this translates into a $400 million annual cost, after taking into account the return on the capital investment and O&M costs annually to operate the capacity, the estimated benefits of Access Northeast to New England exceed its costs in all scenarios.

Exhibit 25: Annual Access Northeast Cost and Benefits Summary

| | Total Benefits | Net Benefits |
|---|---|---|
| Base Case Normal Weather | $0.8 - $1.2 billion | $0.4 - $0.8 billion |
| 1-in-20 Weather | $1.4 billion | $1.0 billion |
| 2013/2014 Extreme Winter | $2.5 billion | $2.1 billion |

Source: ICF International

The net benefits to New England, ranging from $0.4 billion to $2.1 billion, assumes that New England's electric consumers bear the full cost of the electric portion of the project, so those costs are netted out of the total savings that ICF has estimated. However, the cost savings to consumers would be greater if projected revenues for pipeline reservation charges paid by electric generators were to be credited back to the consumers as is proposed. We also estimate that the majority of the $2.4 billion investment required for the project could be recovered from the cost savings in a single extreme winter similar to 2013/14.

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