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

Prepared for – The Industrial Energy Consumer Group

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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,

[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.

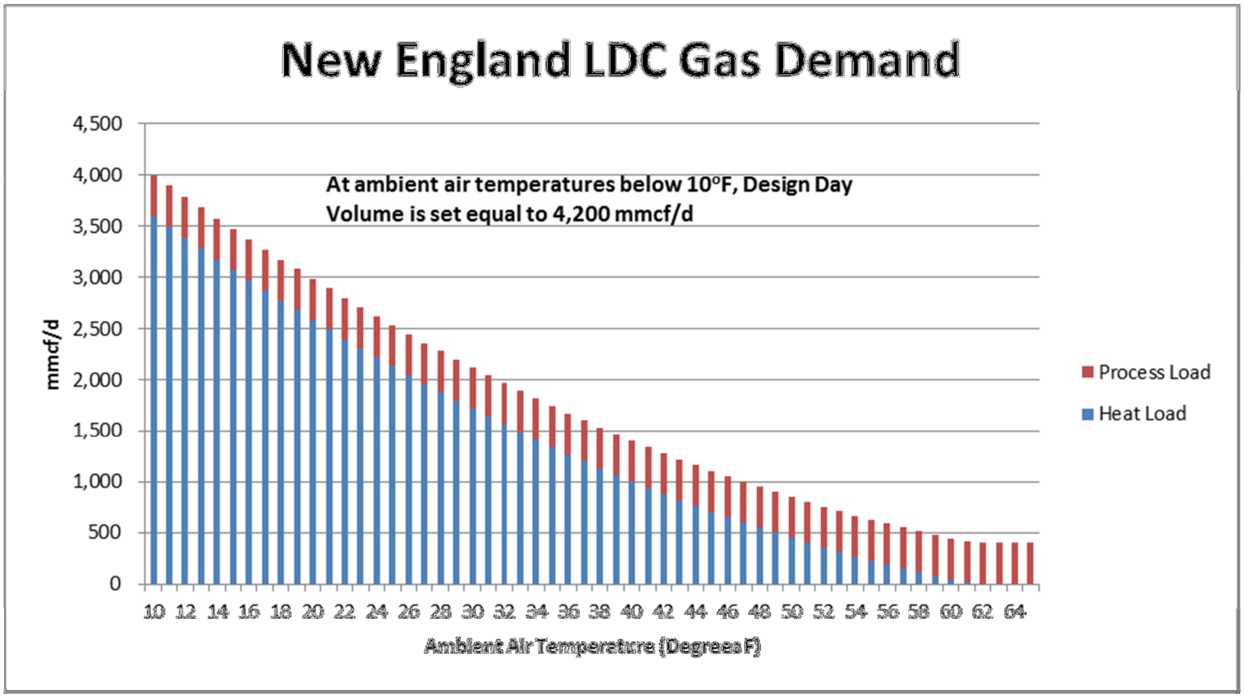
[14] In addition, Sussex Economic Advisors, LLC, who have been retained by the Maine Public Utilities Commission to assist in modeling the price impacts of additional pipeline development in New England, indicated during a telephone conversation that they believed Design Day volumes to be in the 4.2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

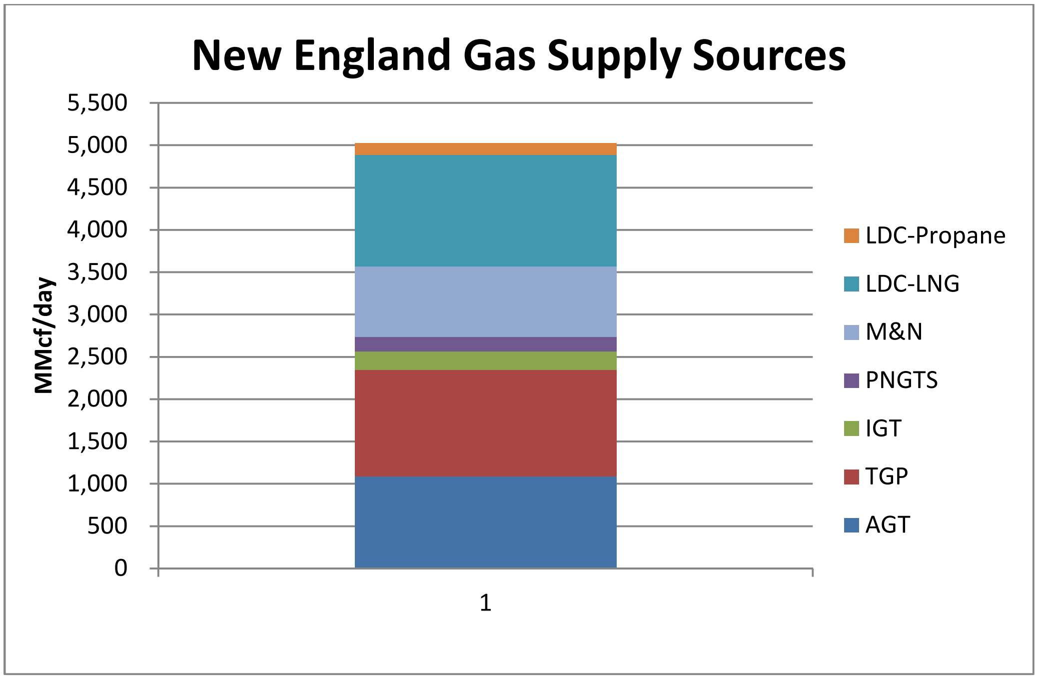
There is general agreement regarding the capacities shown in Figure 3. As we have reviewed other studies of natural gas availabilities in New England, we have seen some differences in three important areas:

- 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.

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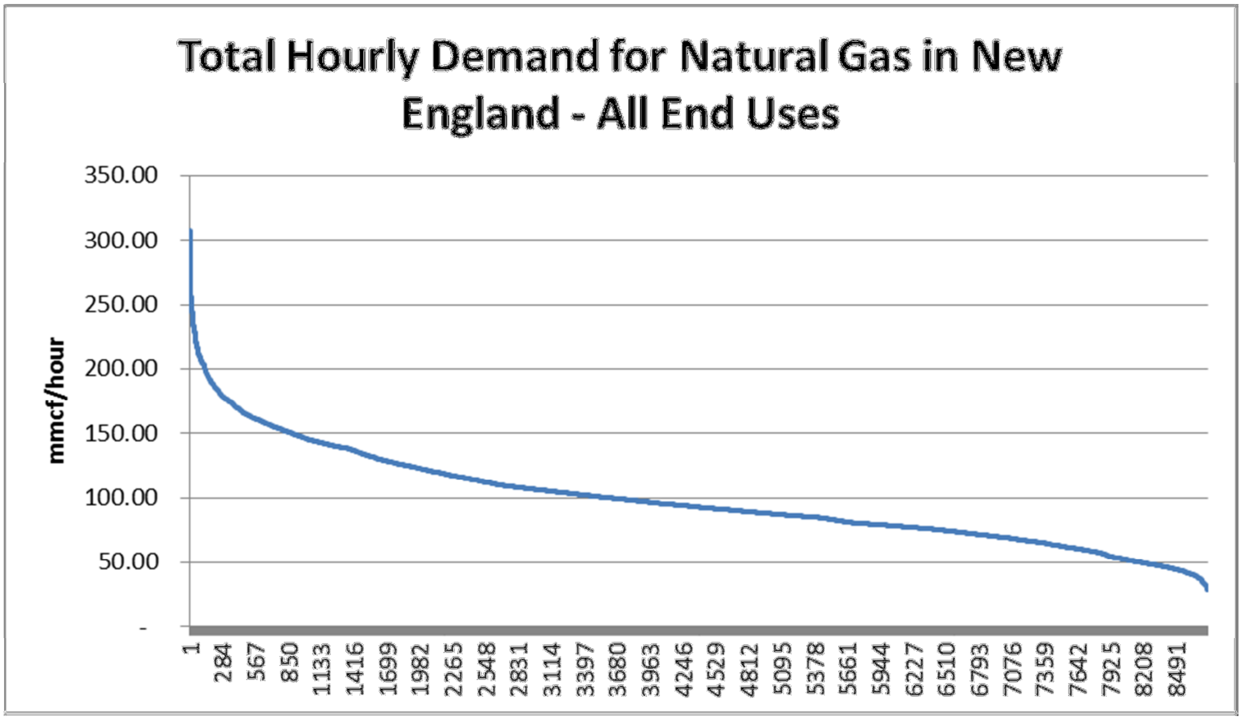
[20] We were able to remove Vermont Yankee, because it is a base load plant, and we are able to determine its outage schedule for refueling from published sources. In contrast, we are not able to determine the actual dispatch for Salem Harbor (unit 3) and Brayton Point and therefore do not know when 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

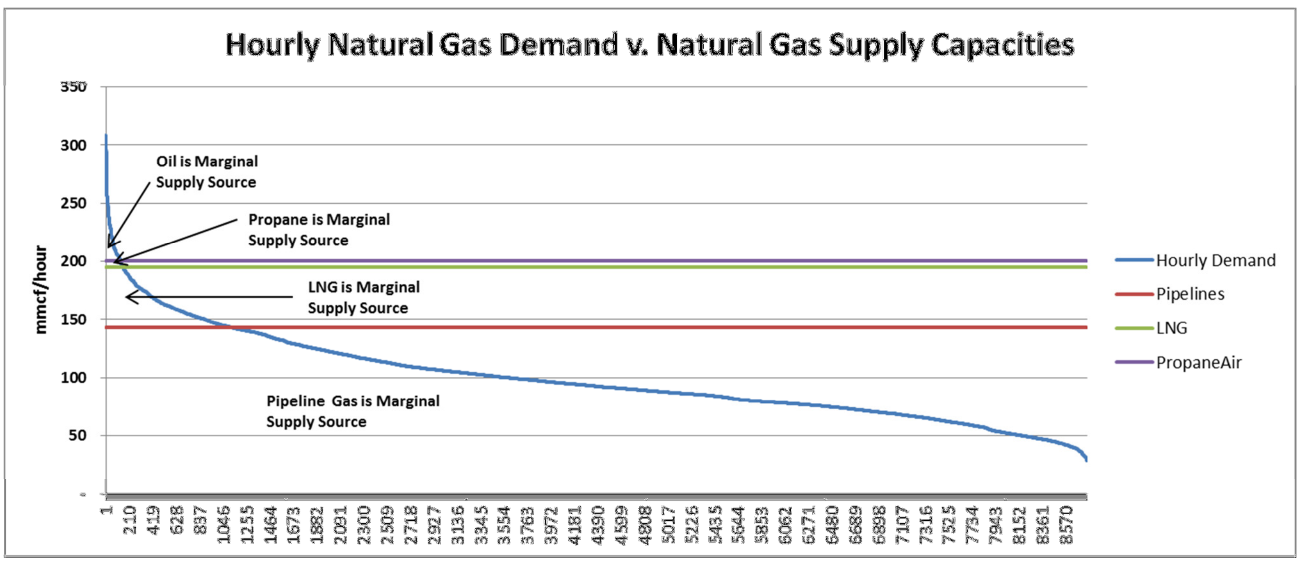
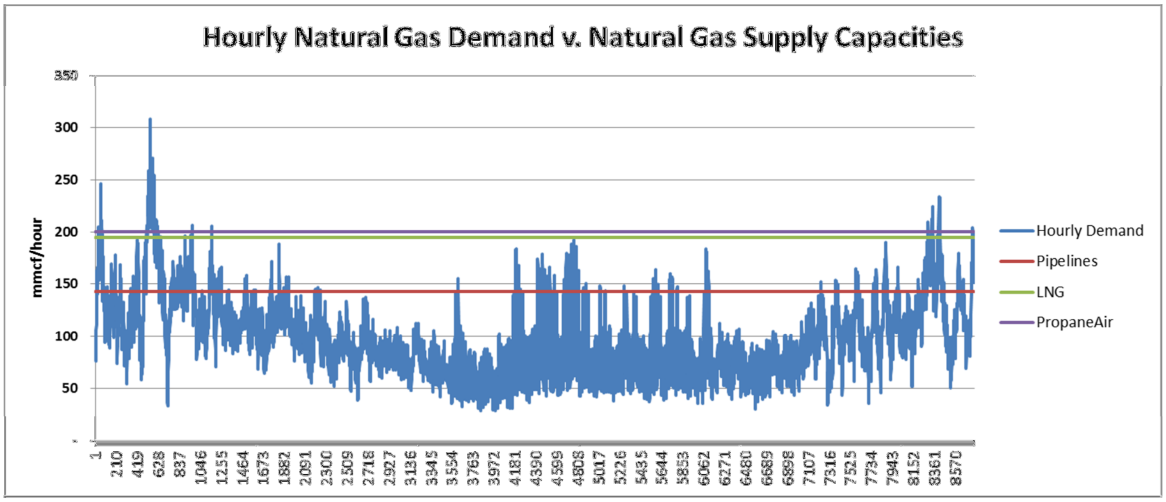


Figure 6 presents the same information as that shown in Figure 5, except that the hourly natural gas demand curve is not sorted from highest to lowest but rather is presented chronologically from January 1, 2013 through December 31, 2013. This graph illustrates very clearly that the issue of natural 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.

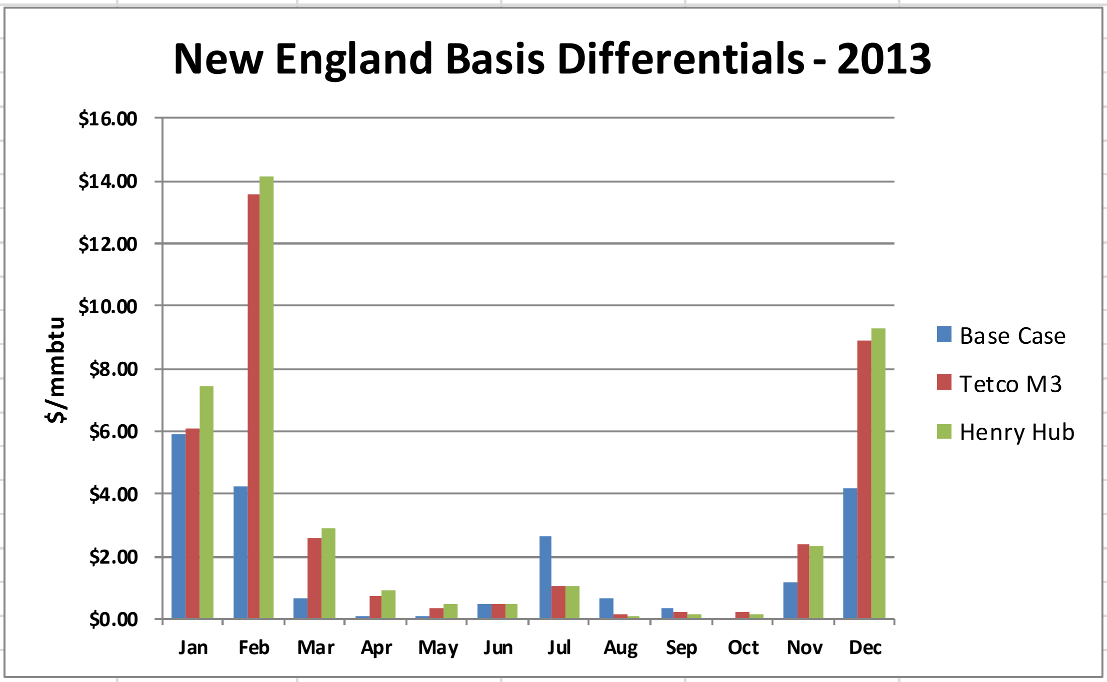
We also computed the average price for natural gas each month and over the year based on the price of the fuel operating at the margin in our dispatch model. These results are shown in the first column in Figure 7. Figure 7 also shows the estimated basis differential each month on the assumption that 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					
				Actual 2013 Values	
	Average Price for Base Case ($/mmbtu)	Unconstrained Price ($/mmbtu)	Basis Differential for Base Cast ($/mmbtu)	Basis Differential Tetco M3 ($/mmbtu)	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.

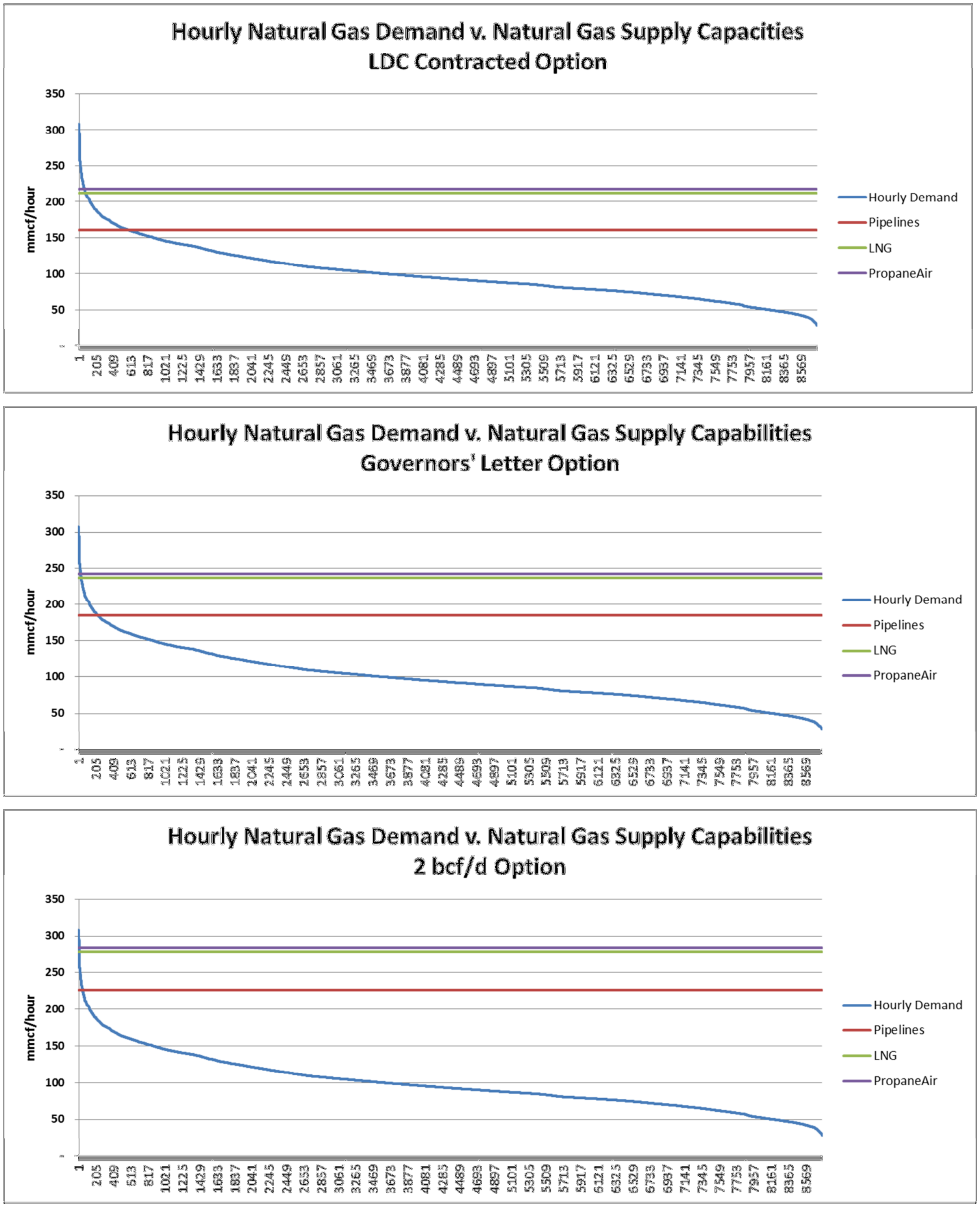
Figure 8: Incremental Pipeline Capacity – Three Scenarios

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				
	Pipeline Capacity	Hours of Generation by Fuel Type		
Scenario	bcf/d	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
		Hours with Fuel Type on the Margin		
Scenario		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
		Annual Energy Costs	Savings vs. Base Case	Load Weighted Avg. Energy Price
Scenario		($)	($)	($/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 ($/mmbtu)	Scenarios LDC Contracted ($/mmbtu)	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 ($/mmbtu)	Scenarios LDC Contracted ($/mmbtu)	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

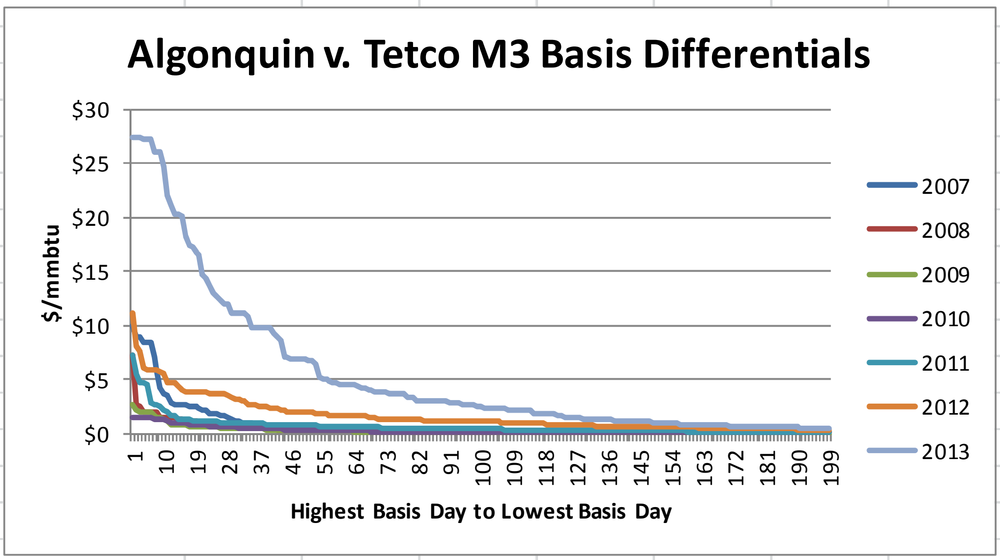
Section 7 Additional Factors

- **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	Number of Days During Year with Premium						
($/mmbtu)	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]

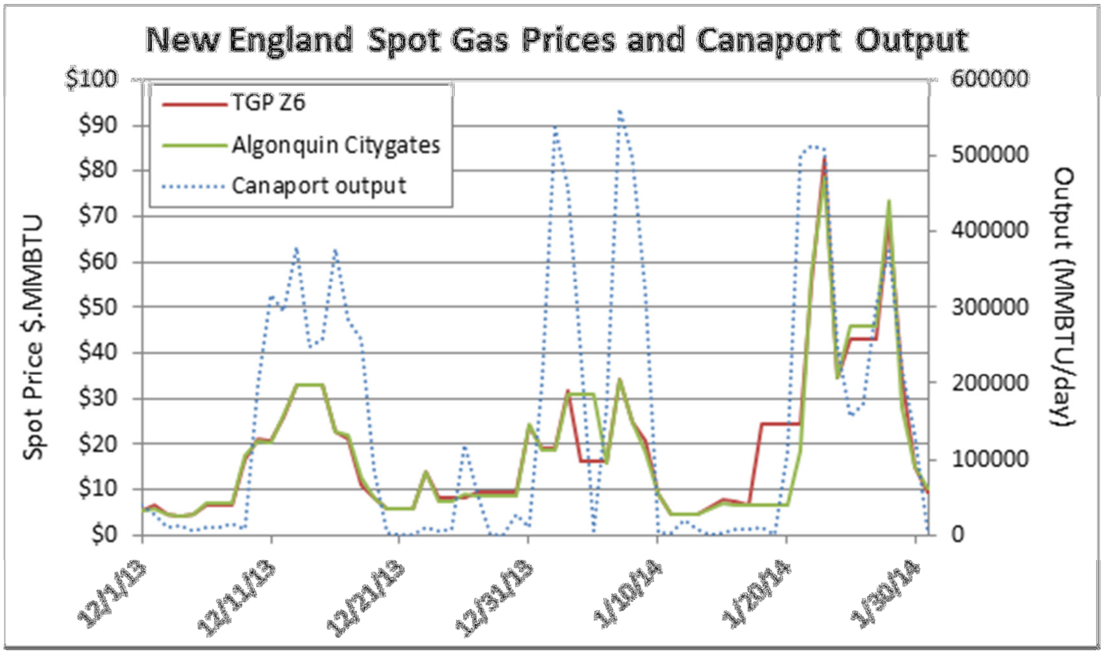
The operations and economic behaviors of Canaport and Everett have become much more critical to the ability of New England to meet its natural gas demands during the winter period, yet the uncertainty of when these facilities will be needed and how much LNG they will be called upon to deliver has made 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

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[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.

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