Competitive Energy Services

April 5, 2013

Report for - IECG

Assessing Natural Gas Supply for New England for the Winter of 2013-14 and its Impact on Natural Gas and Electricity Prices

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 for New England for the Winter of 2013-14 and its Impact 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. Its contents are strictly confidential and should not be released or shared with anyone who is not a member of the IECG without the prior approval of Competitive Energy Services.

A. Overview and Summary

Competitive Energy Services, LLC ("CES") has been retained by the Industrial Energy Consumer Group ("IECG") to evaluate and assess the status of natural gas supply in New England for the upcoming Winter of 2013-14 (which we define as the months of November 2013 through February 2014, inclusive) and the impact such supply conditions will have on natural gas prices and the price of electric energy during that period.

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. We have used this model to estimate forward natural gas and electric energy prices for the Winter of 2013-14.

Based on what CES currently believes to be the most likely natural gas supply conditions during the Winter of 2013-14 (the Base Case), we estimate the following average monthly prices for natural gas and electric energy:

Base Case - Winter Prices

	Natural Gas $/mmbtu	Electric Energy $/MWh
November	$5.28	$41.35
December	$5.50	$41.92
January	$10.74	$81.64
February	$8.85	$68.36

B. Natural Gas Supply Capacities

New England is served by five (5) interstate natural gas pipelines, as shown on the map in Figure 1 and as described further in Figure 2.[1] 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).

[1] 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.

Figure 1

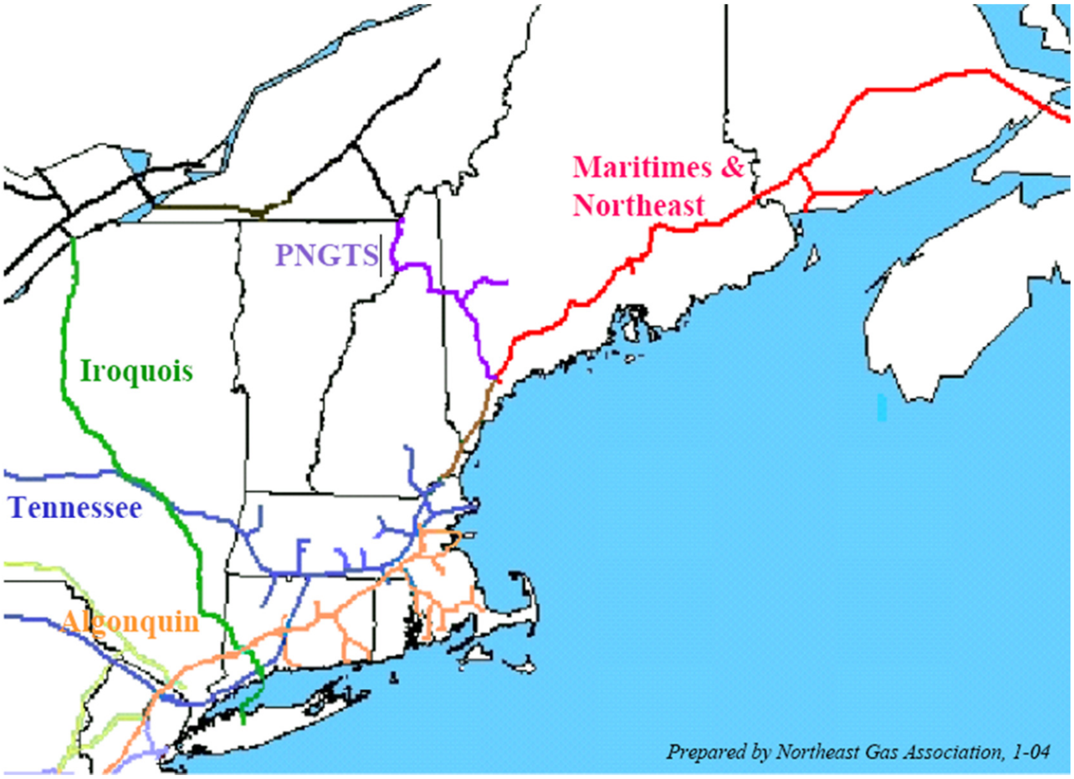


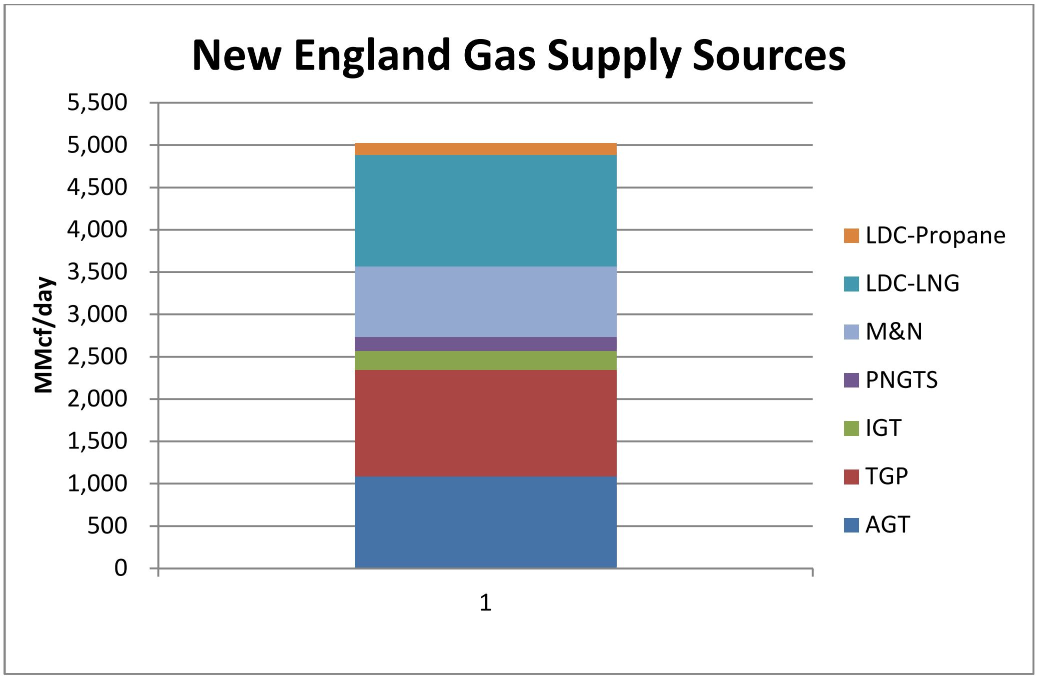
Figure 2

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

In addition, New England is served by three LNG import facilities located within the region – the Northeast Gateway, Neptune and Distrigas. However, only Distrigas has operated with contracted supplies. New England's natural gas utilities ("LDCs") also have more than fifty (50) LNG peaking and propane-air facilities that can be called upon to meet peak natural gas demand. The total LDC LNG peak-shaving capability is estimated to be approximately 1.3 bcf/day[2], while the propane-air capability is about 0.137 bcf/day.[3]

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/day into New England. The region can draw upon almost 1.5 bcf/day of LNG and propane supply to meet peak demands. A further 0.85 bcf/day is available from eastern Canada through the M&NP, which brings natural gas from four potential sources – Sable Island, Deep Panuke, Corridor and LNG in storage at the Canaport facility in Saint John, NB. Total capacity across all sources is a maximum of approximately 5 bcf/day.

Figure 3



C. Natural Gas Demand

For ease of modeling, we have divided natural gas demand in the region into three categories:

---

[2] Of this 1.3 bcf/day capacity, the Distrigas facility in Everett, MA indicates that it has typical send-out capacities of 0.300 bcf/day to the Mystic Generating Station, 0.135 bcf/day injected directly into National Grid's distribution pipeline system, 0.150 bcf/day injected into the AGT, 0.150 bcf/day injected into the TGP and 0.100 bcf/day (or 1 million gallons) via truck/trailer delivery to storage tanks.

[3] These capability figures are drawn from ICF Internal, LLC, "Assessment of new England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs," ISO-NE Planning Advisory Committee, June 21, 2012.

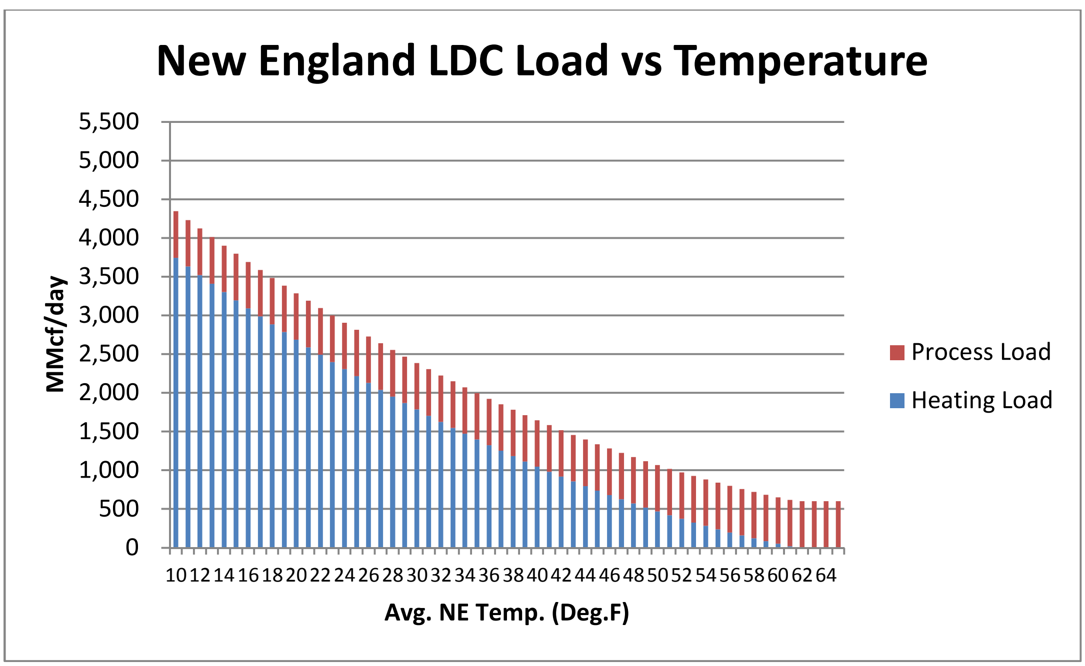
- LDC Demand that is not weather sensitive. This is primarily process load, including industrial and commercial drying.
- LDC Demand that is weather sensitive – We refer to this as "Heating Load"
- Electric Generation Demand

The data on these three end uses is incomplete or proprietary, making it difficult to obtain accurate hourly or even daily natural gas demands. To enable us to develop our Supply and Demand Model, we have made the following assumptions, drawing on the work done by ICF International in the study for ISO-NE referenced earlier:

1. ICF International reports total annual LDC usage for 2013-14 at 434 bcf/year.
2. A rule-of-thumb for LDC systems in the northeast is that peak winter day usage is approximately 1% of total annual usage, or 4.4 bcf/day. Similarly, summer (or non-heating load) usage is only 0.15% of total annual demand or about .6 bcf/day.
3. We defined the summer usage as "process" usage, and assumed it is constant over the course of the year and more importantly, not related to ambient air temperatures.
4. We assumed a non-linear relationship between ambient air temperature and heating load.

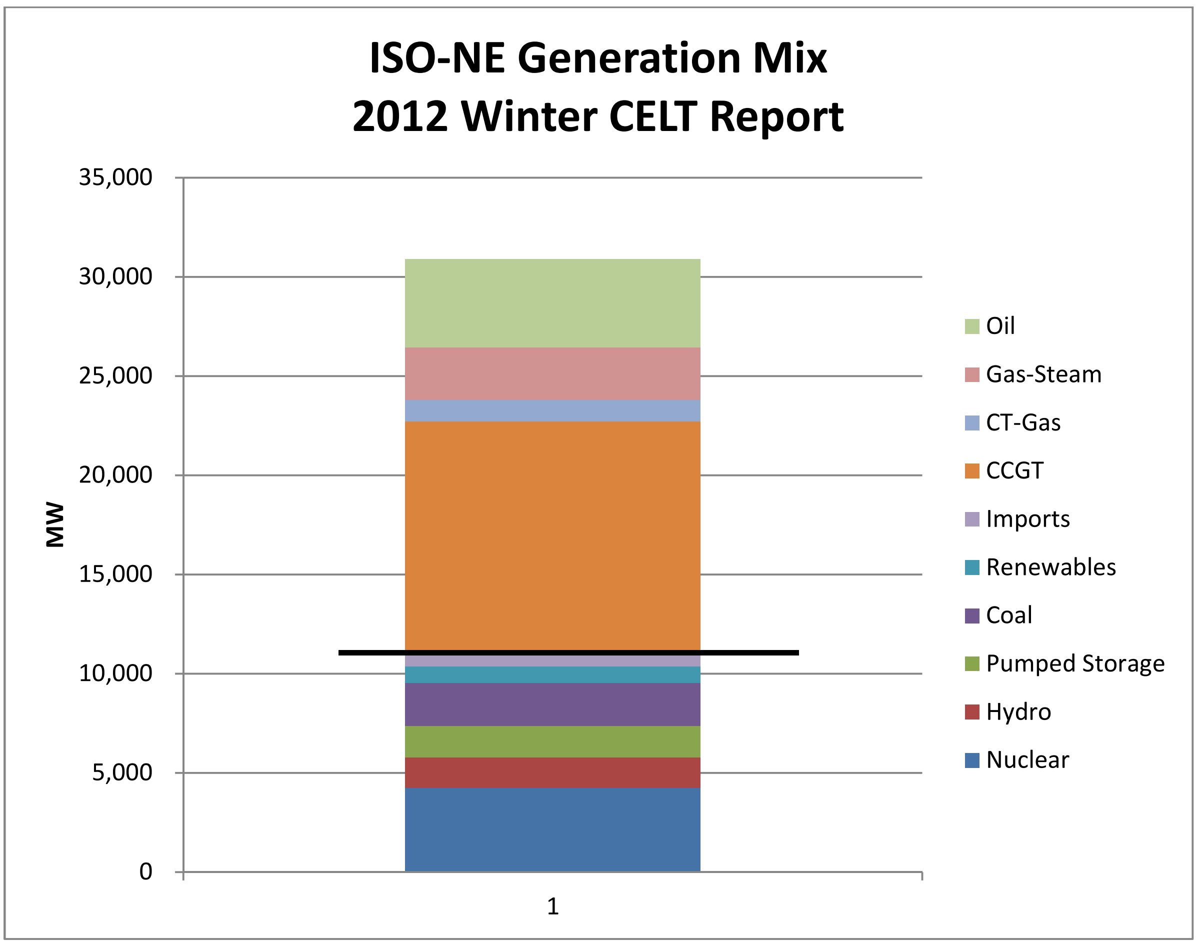
The result of these assumptions is estimated LDC Demand as a function of ambient air temperature as shown below in Figure 4. This curve shows estimated LDC Demand declining with ambient air temperature. We note that temperature is measured as the LDC natural gas usage weighted average temperature in New England. This places the location at approximately the intersection of the borders of Massachusetts, Connecticut and Rhode Island. For modeling purposes, we used the hourly NEMA-Boston temperature as reported by ISO-NE.

Figure 4



We have modeled Electric Generation Demand as a function of hourly electric load in the ISO-NE Control Area, based on certain assumptions about generation mix using the 2012 Winter Capability ratings of generators in New England and actual imports into the New England Control Area. These resources by category and their total capabilities are shown in Figure 5. ISO-NE reports daily kWh produced by fuel type. We have assumed that all nuclear, coal and non-pump storage hydro operate on a flat basis – their hourly load is equal to daily MWh/24 hours. In addition, we modeled pumped storage at its winter capability rating for eight hours each day. Finally, we modeled imports as the actual imports each hour. The sum of these generation sources varies between 10,000 MW and 12,000 MW, and provides a base level of generation resources that can serve load that is not influenced by the availability of natural gas.

Figure 5



We next assumed that all load above that met by this base level of generation is met by natural gas generation, with the lowest heat rate units dispatched first, followed by the second lowest and so forth. Since the actual heat rates of generation units are not public information, we assumed a range of from 6,500 btu/kWh up to 8,500 btu/kWh for the first 10,000 MW of incremental natural gas generation. This additional generation is made up of entirely CCGT units and assumes an unlimited supply of natural gas into the region. As we will discuss later in this Report, if natural gas supplies are limited, oil-fired generation substitutes for some percentage of natural gas generation, either by switching dual-fueled units to oil or by dispatching oil-fired steam units to meet load.

Our assumptions represent a stylized dispatch of generating units and do not take into consideration the dispatch of peaking units to meet short-duration peak loads, scheduled or unscheduled outages of generation units, minimum run-time or ramp-rates for different types of generation or the ability of ISO-NE to call upon demand resources to meet extreme conditions on the grid. Each of these considerations would change our modeling results; however, we believe that on balance these changes would be modest and not impact our general conclusions.

D. Fuel Prices

The last set of assumptions we make is for fuel prices into the ISO-NE Control Area. Four (4) 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 will be $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, drawing natural gas from markets to our south, west and northeast. It corresponds to winter NYMEX prices of approximately $4.25 per mmbtu and a New England Basis differential of $0.75 per mmbtu. As we discuss in the next section, whenever 100% of hourly natural gas demand 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 per mmbtu.

We have assumed that the price for LNG delivered into New England into the Distrigas facility (or either of the other two LNG receiving points) is equal to the world spot price for LNG. We have used $15.00 per mmbtu as this price. We note that published prices range from $8.00 per mmbtu for delivery into Europe to highs of more than $18.00 for deliveries into Japan. These published prices, however, often include forward contracted LNG. Our understanding is that the spot price for incremental LNG deliveries is currently in the $15.00 per mmbtu range. Accordingly, whenever the demand for natural gas is higher than pipeline capacity, we assume that this excess demand is met first by LNG at a price of $15.00 per mmbtu.

Finally, we have assumed that the delivered propane and oil prices into New England are $18.00 and $22.00 per mmbtu, respectively. This oil price is for #2 oil that can be used in dual-fueled CCGT units. 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 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 combined supply of pipeline gas plus LNG (including propane-air) is less than demand, we assume that the incremental demand is met by oil-fired generation with a heat-rate of 10,000 btu/kWh, with an input fuel price of $22.00 per mmbtu.

E. Model Results – Base Case

The supply, demand and pricing assumptions discussed in the prior sections of the Report provide the information to develop estimated natural gas and electric energy prices for each hour, based on specific scenarios regarding pipeline natural gas supply. To see this, we begin with a Base Case under which Deep Panuke and Sable Island are operating to deliver 0.5 bcf/day of natural gas down the M&NP and all other pipelines into New England as well as LNG and propane-air facilities are available to operate at their full capacities. The Base Case assumes that the corrosion problem that have restricted Sable Island send-out this past winter are resolved prior to next winter, as are the rig issues that have delayed development at the Deep Panuke field. Figure 6 shows natural gas demand by hour in descending order from the highest peak loads to the lowest loads. (Note – Demand is measured in MMcf/Hour not in bcf/day.) Natural gas demand is inclusive of LDC demands (both process and heating loads) and electric generation, assuming that 100% of the load above the base level load that can be met by non-fossil generation and imports is met by natural gas generating units.

Figure 6

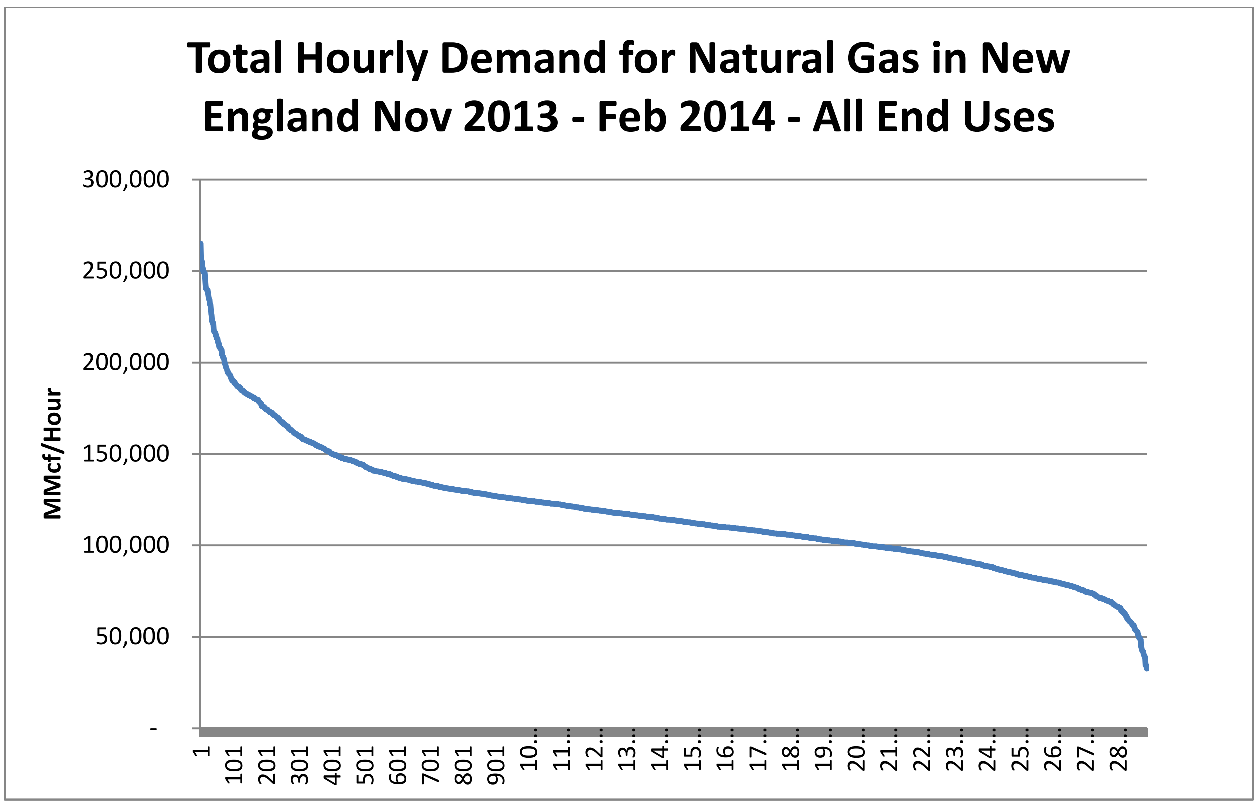
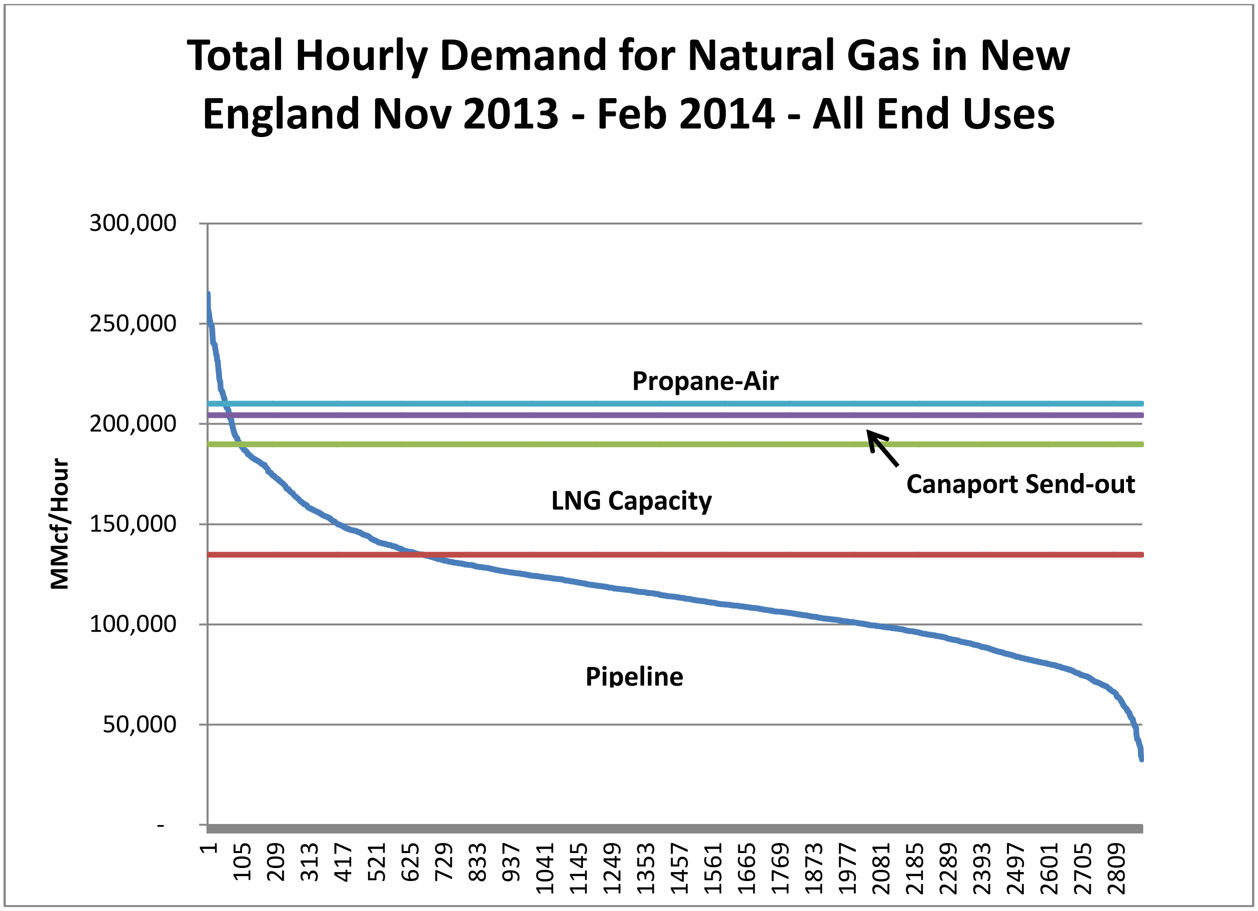


Figure 7 shows different levels of natural gas supply capacities superimposed on the demand curve in Figure 6. The lowest level is the combined capacity of AGT, TGP, IGT and PNGTS pipelines, which is approximately 2.7 bcf/day, plus the assumed send out capacity on the M&NP of 0.5 bcf/day under the Base Case, for a total Pipeline Capacity of 3.2 bcf/day or 135,000 MMcf/hour. The next tier shown is LNG Capacity, which brings total supply to about 190,000 MMcf/hour. The supply above the green line and below the purple line is Canaport's send-out of approximately 15,000 MMcf/hour.[4] Finally the blue line shows the incremental capacity related to Propane-Air of approximately 6,000 MMcf/hour. The total hourly capacity is shown as 210,000 MMcf/day, which is approximately 5.0 bcf/day. Any demand in excess of 5.0 bcf/day must be met by using oil to generate electricity. As shown in Figure 7, hourly natural gas demand in New England can be met for approximately 75% of the hours between November 1 and February 28 using pipeline gas flows.

Under the Base Case, we assume that the LDCs have not contracted forward for LNG. Therefore, all LNG in New England is purchased at the world spot market price of $15.00 per mmbtu. This assumption establishes three pricing regimes for fuel under this Base Case. For total natural gas demands less than 3.2 bcf/day (the combined volumes on all pipelines into New England), natural gas prices will be equal to $5.00 per mmbtu, as these lower demand levels can be met in their entirety by pipeline natural gas.

Figure 7

[4] This reflects only available capacity on the M&NP under the Base Case assumptions about Sable Island and Deep Panuke send-outs. Under the Base Case, we have assumed, in effect, that no LNG flows from Canaport into New England. This LNG capacity can be viewed as meeting New Brunswick and Nova Scotia gas loads on peak usage days.



Natural gas demands in excess of 3.2 bcf/day but less than 4.85 bcf/day are met first by LNG at a cost of $15.00 per mmbtu. This incremental demand drives up natural gas prices in New England to the world spot market price of LNG of $15.00 per mmbtu. (This represents a Basis differential of $10.00 per mmbtu in addition to the amount by which the $5.00 per mmbtu price exceeds the NYMEX price.) Propane-air facilities are called upon after the LNG capacity is maximized to bring total supply up to 5.0 bcf/day. The price for propane is $18.00 per mmbtu.

Finally, for natural gas demands in excess of 5 bcf/day, oil must be utilized to meet electric loads, since demand is in excess of total natural gas supply. At these very high demand levels, the price of natural gas will increase above the $15.00 per mmbtu level until it reaches the point where supply and demand are in balance. For our purposes, we have assumed that this price averages $30.00 per mmbtu. At these price levels, however, natural gas is no longer the marginal fuel on the electric grid. Oil has taken over this role and will set electric energy prices at the product of the assumed marginal heat rate of 10,000 btu/kWh and the price of oil at $22.00 per kWh or $220 per MWh.

Figure 8 shows the estimated average price for natural gas each month, as well as the number of hours each month where the price corresponds to one of the four (4) pricing regimes – pipeline, LNG, Propane or $30.00 per mmbtu. We have also shown the average NYMEX forward price for each month, as of April 1, 2013. The difference between the average price in the model and the NYMEX spot price is New England Basis. Thus, assuming the Base Case supply scenario on M&NP and weather conditions this upcoming winter that are similar to this past winter, we are estimating that Winter of 2013-14 New England Basis should be in the range shown in Figure 8.

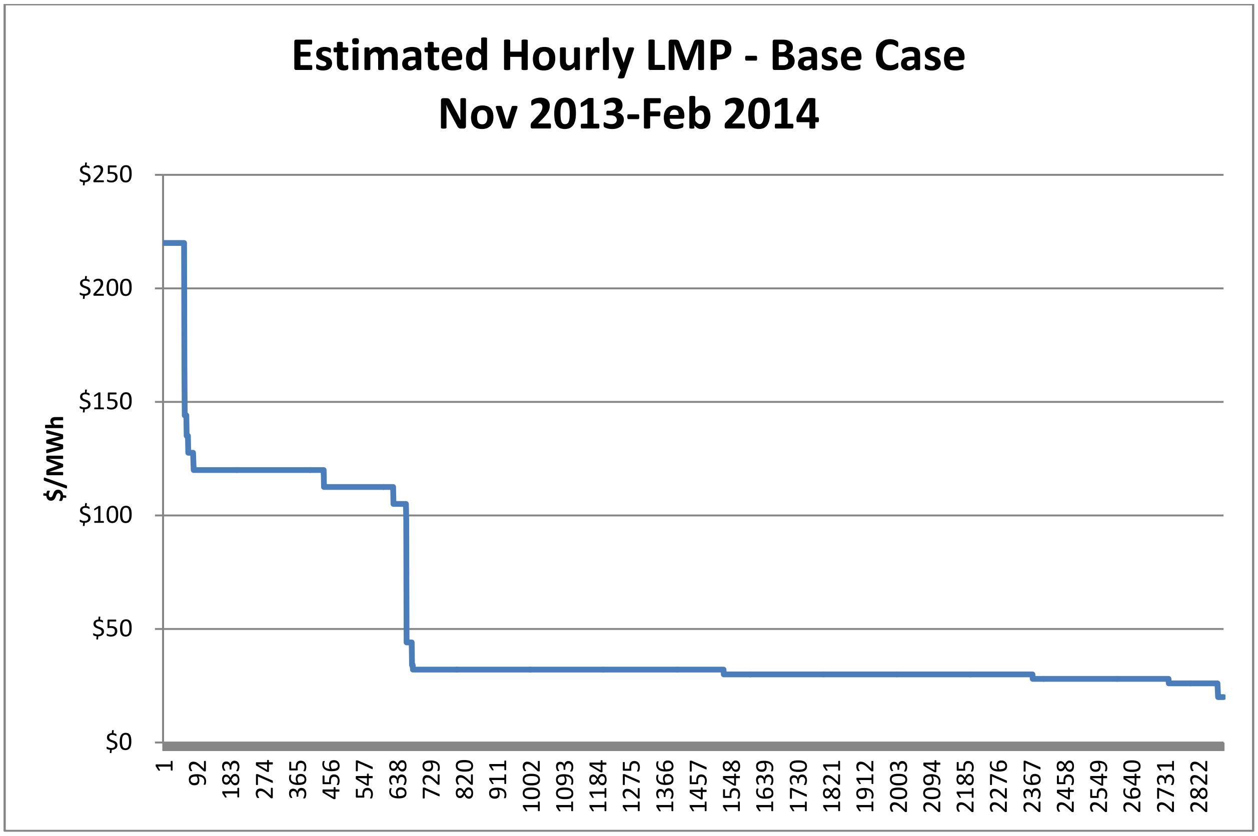
Figure 8

Base Case - Natural Gas Price Regimes

	Average $/mmbtu	Pipeline (Hrs)	LNG (Hrs)	Propane (Hrs)	Oil (Hrs)	NYMEX Forward $/mmbtu	Implied Basis $/mmbtu
November	5.28	689	26	1	0	4.16	1.12
December	5.50	701	39	0	0	4.31	1.19
January	10.74	416	268	10	57	4.40	6.34
February	8.85	407	261	0	0	4.39	4.46
Total	6.41	2,092	552	13	55		

The computed spot electric energy prices for each hour for this Base Case are shown in Figure 9. The four price regimes discussed above show very clearly on the curve. (The relatively few hours where prices are between $130 and $150 per MWh are those hours during which fuel is injected from the propane-air facilities are at the margin.) The hour-to-hour variabilities for all but the oil price regime reflect variations in marginal heat rates for different ISO-NE load levels.

Figure 9



The curve in Figure 9 results in average computed spot electric energy prices for each month under the Base Case of:

$41.35 for November 2013

$41.92 for December 2013

$81.64 for January 2014

$68.36 for February 2014

These prices are for energy only on a 24x7 basis.

F. Model Results – Sensitivities

We have defined a few other scenarios to assess the sensitivity of natural gas and electric energy prices to different natural gas supply conditions in New England. These scenarios are discussed below. All changes are all in relation to the Base Case; the scenarios are not cumulative.

1. *2012 Maritimes Flows* – this scenario assumes that production from the Deep Panuke and Sable Island fields in the Winter of 2013-14 is comparable to production this past winter. For our purposes, we have assumed average flows of 100 MMcf/day from these two fields. Any incremental flows on the pipeline are gasified LNG delivered out of Canaport.

2. *Low Maritimes Flows* - this scenario assumes that production from the Deep Panuke and Sable Island fields increases to 300 MMcf/day. As with the 2012 Maritimes Flow Scenario, any incremental flows on the pipeline are gasified LNG delivered out of Canaport.

3. *AIM Completed* – this scenario assumes that the Algonquin Incremental project is completed, increasing capacity on the AGT by 250 MMcf/day. (This project is not slated for completion until 2015 at the earliest.)

4. *High Maritimes* – this scenario assumes full flow of non-LNG gas down the M&NP line from new shale-gas sources in New Brunswick. This increases the flow on the pipeline to 850 MMcf/day.

5. *High Supply* – this scenario combines scenarios 3 and 4 and provides an optimistic view of natural gas pipeline supply conditions into New England.

6. *LDC LNG Contracts* – this scenario assumes that the LDCs have forward contracted for LNG supply at the pipeline price of $5.00 per mmbtu.

In all of these scenarios and in the Base Case, we have assumed temperatures for the Winter 2013-14 that are the same as those experienced during this past winter from November 1, 2012 through February 28, 2013. We note that this past winter has been an average one, relative to the past few winters, though warmer than the 100 year average. Since LDC natural gas demand for Heating Load represents such a large component of overall natural gas demand in New England, especially on colder days, our results are highly sensitive to actual ambient air temperatures. Should next winter have fewer severely cold days, there will be correspondingly fewer days when electric load will need to be met using oil-fired generation and therefore prices will be lower than those shown in Figure 11. On the other hand, should this upcoming winter have more colder days and higher heating degree days, overall, prices will be higher than those we are forecasting in this Report.

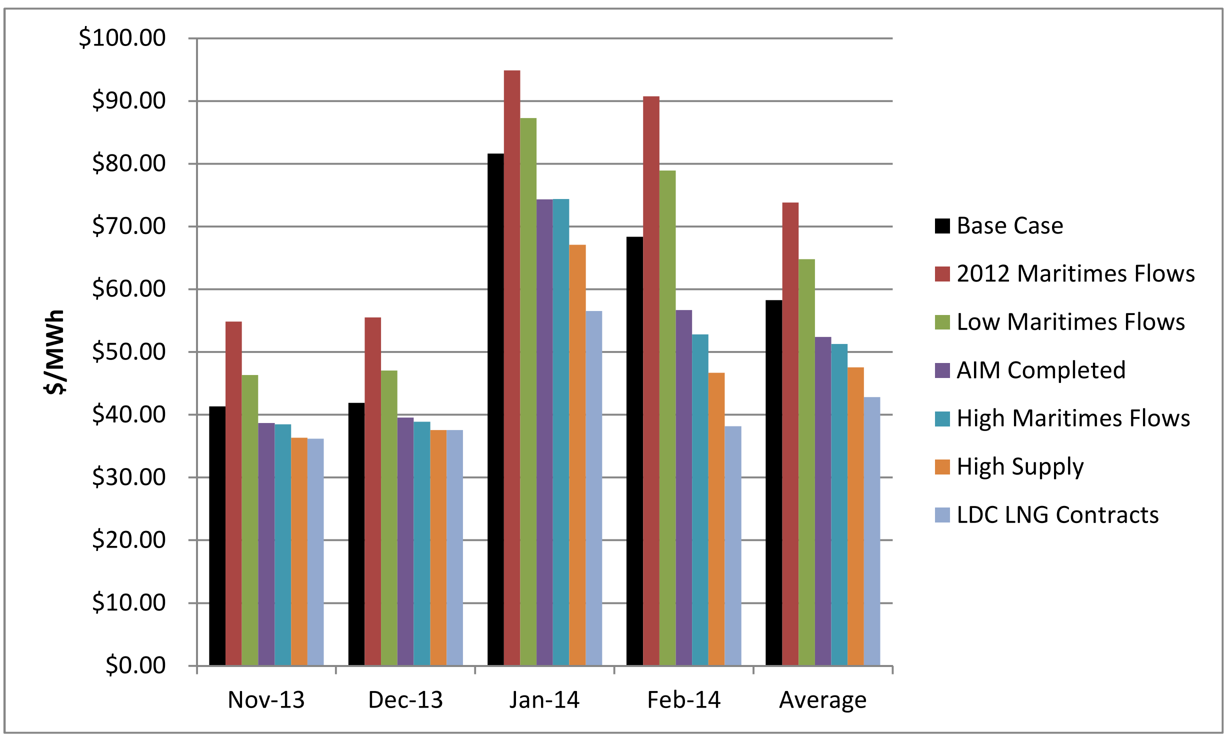
The computed average prices for natural gas and for electric energy each month under each of the above scenarios is shown in Figure 11. The prices and the bar graph confirm expectations that scenarios that tighten natural gas supply availability in New England result in higher electric energy prices, especially during the colder months of January and February when LDC gas demands are highest.

On interesting result relates to the scenario under which LDCs have forward contracted for LNG supply at pipeline gas supply prices. The pricing under this scenario illustrates how sensitive winter gas and electricity prices are to the price of LNG. At lower LNG prices, electric energy prices during January and February are significantly lower than the Base Case. This may be an important reason why the natural gas supply constraint had much less impact on electric energy prices. If the LDCs and Canaport had multi-year contracts that carried them through 2011, the price and availability of LNG would have reflected these contracts and had a moderating impact on natural gas prices during those years. With the expiration of such contracts, we are seeing much higher prices and much more volatility.

Figure 11

Average Monthly Electric Energy Prices - Various Supply Scenarios

Scenario	Nov-13 $/MWh	Dec-13 $/MWh	Jan-14 $/MWh	Feb-14 $/MWh	Average $/MWh
Base Case	$41.35	$41.92	$81.64	$68.36	$58.29
2012 Maritimes Flows	$54.85	$55.51	$94.88	$90.73	$73.81
Low Maritimes Flows	$46.32	$47.07	$87.26	$78.92	$64.78
AIM Completed	$38.69	$39.53	$74.31	$56.69	$52.38
High Maritimes Flows	$38.47	$38.91	$74.37	$52.79	$51.28
High Supply	$36.36	$37.55	$67.07	$46.67	$47.57
LDC LNG Contracts	$36.20	$37.55	$56.53	$38.20	$42.82



Another interesting result is the consequence of incremental expansions of the flow capacities of existing pipelines into New England. The AIM Completed Scenario shows that small incremental increases in pipeline natural gas supplies into New England will have a relatively small impact on natural gas and electric energy prices. The slice of natural gas demand met by LNG capacity during the winter is very large and a significant contributor to high prices. The LDC

LNG Contract case discussed above demonstrates clearly the impact that constraining the price of natural gas to the price of unrestricted pipeline gas by contract has on New England electricity pricing. On the other hand, when incremental increases in capacity like the AIM Project are combined with large increases in pipeline gas flowing down the M&NP from potential shale gas wells in New Brunswick under the High Supply Scenario, the price impacts are more favorable. However, even in this situation LNG is the marginal fuel during many hours, resulting in Basis pricing in January considerably higher than in neighboring New York and therefore higher average spot electricity prices.[5]

[5] In all of the scenarios, we have held electricity imports into the ISO-NE Control Area constant. In fact, with new shale gas finds in New Brunswick, we may see additional imports of electricity south from the Maritimes into New England, should the M&NP reach its capacity. Similarly, imports could increase from New York.