GDF SUEZ

October 10, 2014

Ms. Melanie Kinderdine
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Ms. Kinderdine:

In response to your request for comments designed to inform the Quadrennial Energy Review, GDF SUEZ North America (GSENA) would like to offer the following brief thoughts.

GSENA appreciates the opportunity to offer comments to the U.S. Department of Energy as part of the Quadrennial Energy Review process.

A GSENA subsidiary, Distrigas of Massachusetts LLC (Distrigas) owns and operates the Everett LNG Import Terminal, the longest-operating facility of its kind in the United States. Since receiving our first shipment of LNG in November 1971, we have been a driving force in the adoption of this safe, clean-burning fuel in North America. In the 1970s, the company employed LNG to mitigate New England's regional energy crisis. Today, GSENA continues to build on our reputation for developing innovative, flexible solutions that meet a wide range of energy needs of a growing and diverse customer base. In fact GSENA's parent company is a leading purchaser and supplier of liquefied natural gas (LNG) to the United States and countries around the world, and has a proven history of safety, reliability, and innovation.

GSENA (obviously) has a longstanding interest in and awareness of energy infrastructure issues in New England. Consequently, we wanted to share a few thoughts with you about ongoing discussions in New England and how they may help to inform your efforts to think about energy infrastructure.

The importance of infrastructure to the delivery of energy that improves lives and enables society and the economy to function is beyond dispute. As a company that owns and operates numerous powerplants and other energy facilities across the United States and the world, we, perhaps more than most other market participants, are aware of the challenges faced by those who build and operate such infrastructure.

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President and Chief Executive Officer

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At the same time, it is important to be sensible and make economically prudent decisions. Building infrastructure for the sake of building infrastructure is unwise as a matter of public policy and imprudent as a matter of economic policy and in many cases leads to essentially stranded assets for which either shareholders or consumers (or both) wind up paying, but from which neither group receives any benefit.

Unfortunately, the energy market is faced with the potential for such a situation in New England. Driven by the notion that the market is unable or unwilling to respond to the availability of inexpensive shale-produced natural gas nearby, some in New England have concluded that market intervention by a collection of States is the appropriate response. This approach, which was hatched by the New England States Council on Energy (NESCOE), would result in the selection of one or more pipelines (by the NESCOE States) to deliver natural gas from west of the Hudson River into New England.

GSENA believes there are several problems with this approach. First, it relies on the judgment of those not in the market to make careful, measured, decisions about appropriate responses to market conditions. In our experience, government officials – even those who are excellent stewards of the public resources – have trouble navigating markets in which they are not sophisticated participants. Let us be more specific. Right now, the challenge in New England with respect to energy delivery (to the extent that there is a problem) is that demand for natural gas supply is high (and therefore prices are high) on just a very few days a year. To build a pipeline will require consumers to pay for the fixed cost of the installed infrastructure 365 days a year. That may be (and probably is) an expensive solution to what is a relatively short-term supply problem.

In short, we believe that a new pipeline may not be really supported by demand. The fact that a government organization is prepared to socialize costs suggests that the market – and by that we mean consumers – may not yet be prepared to volunteer to pay for the infrastructure contemplated by NESCOE. That makes sense: as noted above, the asset may not be necessary.

Second, because it socializes costs, such action invariably results in some consumers paying more for energy than they would have otherwise and some consumers paying less for energy than they would have otherwise. As a corollary, depending on which pipeline or pipelines are selected by the NESCOE process, different powerplants and industries will be helped or harmed simply as a result of their geographic domicile.

Third, the practical challenges are substantial. While GSGNA is certain that ISO-NE would very much like to have the security and sense of comfort that a large, new natural gas pipeline would bring, it is both troubling (and novel) that the costs of such a natural gas asset would be spread across a regional electricity consumer tariff. Moreover, there remain important unaddressed questions about who would actually nominate and manage the pipeline capacity in question, what organization would handle the money flow, etc.

Fourth, the NESCOE process, driven by optics and rhetoric, has failed to recognize that there already exists energy delivery options and that those options -- including LNG from the Everett terminal – are present on the eastern side of the congested area in New England. This congestion is part of what drives the short-term price of natural gas supply higher during peak winter periods. In Everett's case, we have the ability to move natural gas supply east to west from nearly the furthest east point on the congested pipelines operating today.

Finally, and perhaps most importantly, the NESCOE process encourages the idea that the market is not responding to appropriate signals. The reality is precisely the reverse. Until NESCOE proposed its out-of-market remedy, the market was moving forward with several different approaches designed to increase the deliverability of gas supply into the New England market. Not surprisingly, once NESCOE stepped in to "help", many of those efforts were set aside, at least temporarily.

In short, the experience in New England suggests that even well-intentioned government action can retard and complicate the development of cost efficient, low impact energy infrastructure and supply solutions. That is an important lesson as we think about how best to build and operate the energy infrastructure we will need in this century.

We have attached a series of letters from GDF SUEZ to NESCOE, as well as a study conducted by ICF. We respectfully request that you incorporate these documents into the record established in this docket. GSENA also wants to note just a very few relevant items from them:

- While the winter of 2013/14 was very cold, New England's weather conditions were not unprecedented. Evidence from this past winter supports the conclusion that New England experiences gas pipeline capacity and supply constraints about 30 days per year, and projected demand growth suggests these constraints will persist at least through the remainder of the decade. Increased utilization of the Everett LNG import terminal for natural gas supply is a relatively low cost way of meeting this short duration constraint.

- This past winter, in-bound existing pipeline capacity was over 90% full on only 42 days and over 95% full on just 10 days. A new, greenfield pipeline would cost about $2 billion, would need to be fully contracted, and would take three or more years to complete. *When annual pipeline costs are allocated over the 30-day period the capacity is needed, the cost per MMBtu of fuel demand served is materially higher than imported LNG.*

- ISO New England's 2013-2014 Winter Reliability program encouraged the use of fuel oil to meet winter fuel needs for electricity generation, but imported LNG would have been cleaner and cost less on a dollar per MMBtu basis. *This past fall, the cost of LNG was about 33% less per MMBtu than what generators spent on fuel oil.* Gas-fired generation units also have a better average heat rate than oil-fired units, yielding additional potential fuel cost savings.

Again, thank you for the opportunity to participate in the Quadrennial Energy Review. Please do not hesitate to contact us if we can be of any assistance.

Sincerely,

Francis J. Katulak
President and Chief Executive Officer

February 10, 2014

Heather Hunt
Executive Director
New England States Committee on Electricity
4 Bellows Road
Westborough, MA 01581

RE: NESCOE Request for "Additional data or analysis in connection with adequacy of increased pipeline capacity"

Dear ~~Ms. Hunt~~: Heather

GDF SUEZ Gas NA LLC (GDF SUEZ) and Distrigas of Massachusetts LLC (Distrigas) appreciate the opportunity to respond to the New England States Committee on Electricity (NESCOE) January 27, 2014 Memorandum to members of the New England Gas-Electric Focus Group, which requested submission of "Additional data or analysis in connection with adequacy of increased pipeline capacity," to better inform NESCOE's request to the New England ISO for tariff assistance in supporting proposed new pipeline infrastructure in New England.

As background, Distrigas owns and operates the Everett LNG Import Terminal, the longest-operating facility of its kind in the United States. Since receiving our first shipment of LNG in November 1971, we have been a driving force in the adoption of this safe, clean-burning fuel in North America. In the 1970s, the company employed LNG to mitigate New England's regional energy crisis. Today, we continue to build on our reputation for developing innovative, flexible solutions that meet a wide range of energy needs of a growing and diverse customer base. Our parent company GDF SUEZ S.A. is a leading purchaser and supplier of liquefied natural gas (LNG) to the United States and countries around the world, and has a proven history of safety, reliability, and innovation.

For more than 40 years, the Everett LNG terminal has been the primary supplier of LNG to a network of 46 utility-owned, above-ground LNG storage tanks (shown on next page) that support New England's peak-shaving natural gas storage needs. Underground natural gas storage in the region is not feasible due to its geological conditions.

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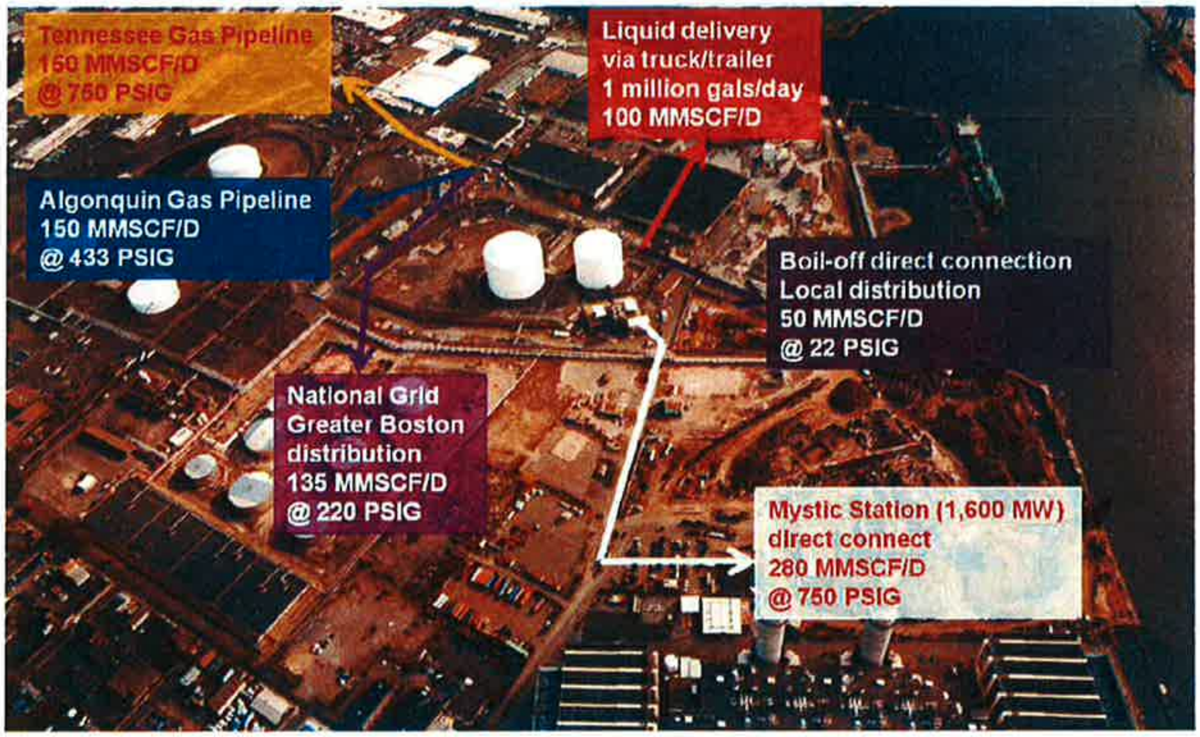
Everett LNG Terminal is Well Connected to Serve NE Gas Demand

The Distrigas facility (shown on next page) is ideally located, connecting with not only two interstate pipeline systems, but also National Grid's distribution system and a neighboring 1,550-megawatt power plant capable of generating enough electricity for about 1.5 million homes. In addition, the Distrigas facility serves nearly all of the gas utilities in New England as well as key power producers. As illustrated below, the Distrigas facility has the available throughput capacity of **435 MMcf/day for power generation and local distribution company customers** of vaporized LNG that can be sent out at multiple pipeline pressures simultaneously, exclusive of the facility's maximum send-out commitment to liquid delivery sales and Mystic Station, for a total sustainable capacity of 715 MMcf/day of vaporized LNG and approximately 100 MMcf/day of LNG loaded on trucks in liquid form.

Everett Can Provide 435 mmcf/day for Power Generation and LDCs



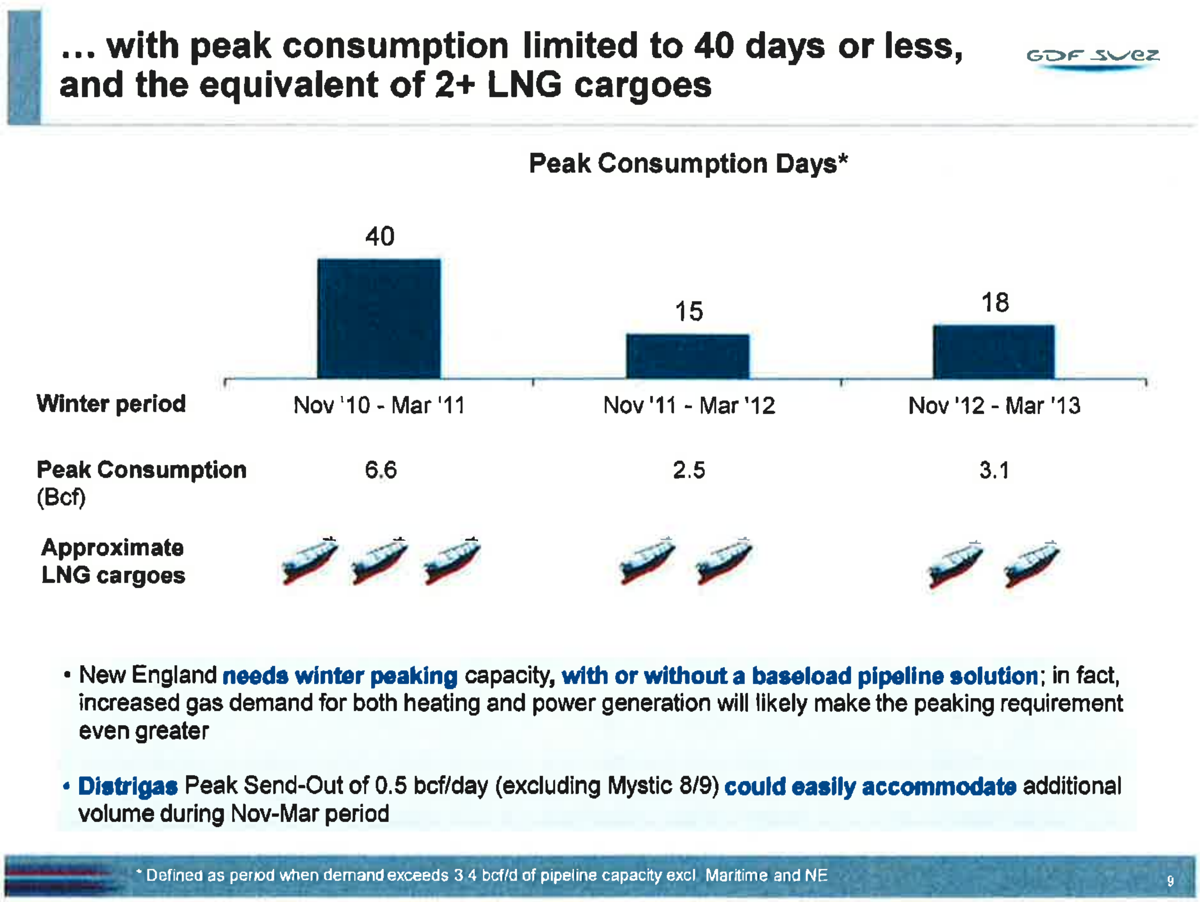
According to the December 2013 statement of the New England Governors, they are, as a group, committed to pursuing an initiative that "diversifies our energy supply portfolio while ensuring that the benefits and costs of transmission and pipeline investments are shared appropriately among the New England States." Distrigas commends the New England Governors, NESCOE, and ISO-NE for elevating the issue of energy infrastructure in our regional dialogue, and we appreciate the fact that a market exists for additional west to east pipeline infrastructure as evidenced by the successful subscription to Spectra's AIM project.

GDF SUEZ/Distrigas respectfully suggests that, before the New England states endeavor to share the cost of expensive new infrastructure, the region should first consider how to better utilize the billions of dollars in existing infrastructure that can alleviate significant capacity and gas supply shortfalls by flowing natural gas east to west. Indeed, in addition to the Distrigas Terminal, the Repsol Canaport LNG import terminal and the Northeast Gateway and Neptune deep-water port LNG receiving terminals could all be better utilized east of the pipeline bottlenecks and within the most constrained area.

To be sure, the lack of utilization is attributable to the fact that LNG, unlike domestic pipeline natural gas, is a global commodity and can access various global markets. But the global market is always in flux, and just five years ago, as a result of a weak global market and strong domestic US price, there were dozens of LNG import terminal applications filed at FERC. Today, it's just the opposite; there are almost as many export terminal applications pending at the DOE. Nevertheless, there are contractual arrangements that can be negotiated to lessen the gap between current global and domestic market prices.

GDF SUEZ has made several offers to provide short-notice and flexible natural gas services to the New England market over the past two winters. While we have signed a limited number of contracts, potential power generation buyers have lacked appropriate cost recovery mechanisms under existing wholesale electric market design to justify purchase of such services. With appropriate market signals in place and commitments made in advance to facilitate logistics, we are confident that LNG can be economically delivered to the New England market during peak periods.

The chart below illustrates that, particularly during winter peaks, LNG utilization is a flexible and right-sized solution for the region and, regardless of whether additional costly infrastructure projects come online, can accommodate easily additional winter volumes next winter and beyond.



Sending the correct market signals is a critically important aspect of the conversation in New England. To that end, GDF SUEZ/Distrigas appreciates the work of ISO-NE to improve market design, most notably through its Forward Capacity Market Pay for Performance Incentive (FCM-PFP) Proposal currently before the Federal Energy Regulatory Commission (FERC). We believe those proposed market reforms will enhance the prospects for additional peak LNG supply as well as new regional pipeline capacity.

While it will take time to implement those reforms, existing LNG infrastructure can respond to the pressing challenges facing New England much sooner, and very likely much more efficiently. The critical role LNG is playing this winter in New England was recently highlighted in the **U.S. Energy Information Administration's** *In the News* segment of its ***Natural Gas Weekly Update*** publication for the week ending January 22, 2014[1], which noted "Within the United States, the importance of LNG sendout varies greatly by region. It plays a particularly significant role in New England, which utilizes LNG sendout when demand peaks to levels that exceed available capacity to bring gas on pipelines from inland production areas." The *In the News* segment also noted that:

> "The Distrigas LNG terminal in Everett, Massachusetts, accounts for the highest LNG sendout volumes in the United States, accounting for more than half of all sendout last year. Through the first three weeks of 2014, Everett sendout totaled 0.30 Bcf/d, or 7% of total New England consumption. This was a 34% increase over the same dates in 2013, when it accounted for 5% of total New England consumption, but 31% below sendout for these dates in 2010-12, when it accounted for 9% of total New England consumption, according to Bentek data. In recent years, Everett has received a relatively high share of its LNG cargoes contracted on a long-term basis. This has partially mitigated the effect on imports of relatively higher global spot prices."

We thought it might also be helpful to share the data and analysis contained in a report prepared for GDF SUEZ/Distrigas by ICF International this past October. We asked ICF to test the theory that utilizing existing natural gas infrastructure to meet peak winter demand in New England is economically justified.

The report, titled ***Options for Serving New England Natural Gas Demand***, was prepared by ICF International based on assumptions from a variety of sources, including GDF Suez. The report must be considered in its entirety to understand the context, assumptions and conditions on which the conclusions are based. In brief, however, the report concluded the following:

- New England currently experiences a tight supply/demand balance on about 30 days per year, and natural gas demand is projected to grow significantly over the remainder of the decade.

[1] ***"LNG satisfies less U.S. natural gas consumption, although helpful in New England."***

- Compared to 2013 levels, ICF projects that winter peak day gas demand will increase by more than 500 MMcfd by 2015 and more than 1,000 MMcfd by 2020, exacerbating the existing gas supply constraints.

- The projected growth in LDC firm demands justifies some new pipeline capacity. ICF assumes that Algonquin's AIM expansion will add an incremental 450 MMcfd of capacity, but it is not expected until late-2016. Even after the AIM expansion, New England will still need incremental gas supplies on about 30 peak winter days a year by 2020.

- New England gas demand is very seasonal, so there will be sufficient supply capability to meet off-peak loads.

- Given that the duration of the expected supply constraint is approximately 30 days per year, incremental LNG imports at Distrigas appear to be the most cost-effective solution.

GDF SUEZ/Distrigas is pleased to provide a copy of the ICF International report, *"Options for Serving New England Natural Gas Demand,"* as well as the information referenced in EIA's recent Natural Gas Weekly Update and our own data which demonstrate Distrigas' ability to provide 435 mmcf/day of throughput capacity for NE power generators and LDCs in response to NESCOE's request for additional data and analysis. It is unclear whether or not the Governors' request for analysis concerning a range of between 600 mmcf/day and 1000 mmcf/day have fully accounted for the available capacity at Distrigas, Canaport and other existing LNG infrastructure or are instead using as data points the more recent lower sendout volumes which reflect limited firm contracting.

The Distrigas terminal is a unique asset that resides in a unique location; with the right policies and incentives in place, we believe LNG, and more importantly the Distrigas terminal, can be an instrumental part of the solution to New England's near term and long term natural gas supply and capacity constraints. And it's worth noting that as existing infrastructure, the Distrigas terminal can satisfy this need without incremental environmental impact from construction or the sunk cost of infrastructure that goes unutilized all but a few months out of the year.

Thank you for the opportunity to provide our perspective on these important issues for our region.

Sincerely,

Francis J. Katulak
President and Chief Executive Officer

Options for Serving New England Natural Gas Demand

Prepared for

GDF Suez Gas North America

October 22, 2013

Prepared by

ICF International
9300 Lee Highway
Fairfax, VA 22031

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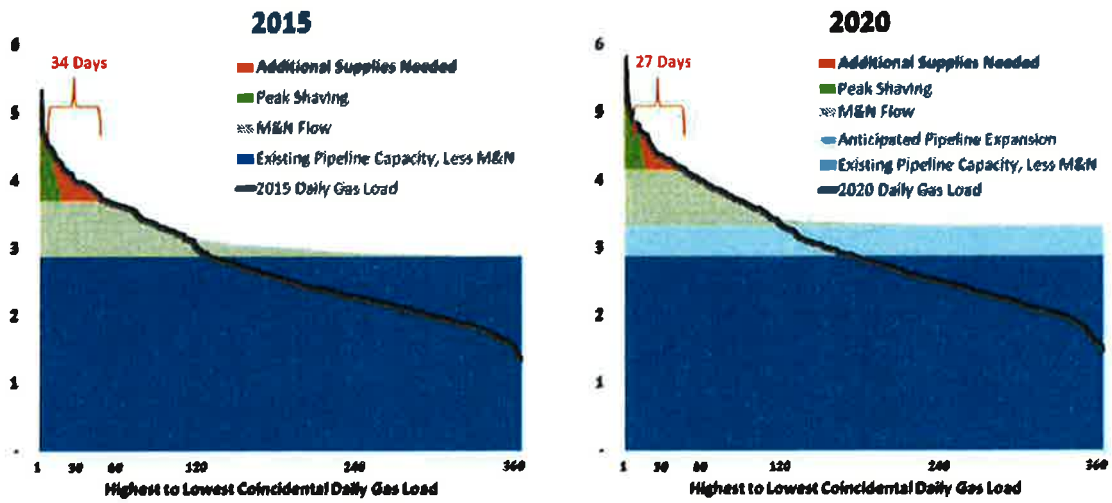
As New England's gas demand continues to increase, it will need new gas supplies on peak demand days. ICF was engaged by GDF Suez Gas North America (GSGNA) to assess the costs of different options for meeting projected gas demand in the New England market. ICF assessed New England's current gas supply capabilities, the projected growth in annual and daily gas loads, and the comparative costs of meeting the need for incremental gas supplies. The projections for annual demand growth, gas prices, and daily loads are based on results from ICF's September 2013 Base Case gas market forecast, developed using ICF's Gas Market Model (GMM) and Daily Gas Load Model (DGLM).

The New England gas market has become increasingly constrained in the winter, as peak winter demand has gradually increased while transport capabilities into the region have not. The power sector has been and will continue to be the biggest source of demand growth, as New England electric generators have become increasingly dependent on natural gas. At the same time, New England's LDCs continue to expand into previously unserved areas and steadily increase their customer counts as residential and commercial customers convert from fuel oil to natural gas furnaces for space heating. ICF projects that New England's peak day demand will increase by about 1 billion cubic feet per day (Bcfd) by 2020.

Currently, New England consumers contract for about 3,700 million cubic feet per day (MMcfd) of interstate pipeline capacity. ICF's Base Case anticipates that about 450 MMcfd of new pipeline capacity will come online by the end of 2016, and Spectra's NY–NJ expansion will free up some capacity on the Iroquois pipeline for New England consumers. Peak shaving facilities operated by New England's LDCs can provide additional supplies on limited number of days each winter, but this still leaves the New England market in need of additional supplies on about 30 days per year between 2015 and 2020 (Figure 1).

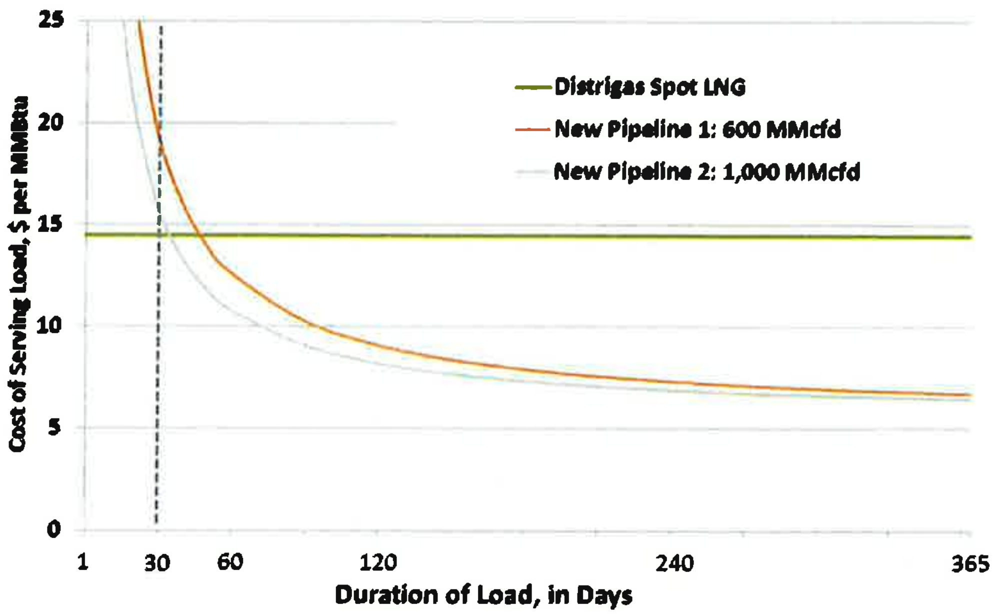
Figure 1. Projected Daily Gas Loads versus Pipeline Capacity and Peak Shaving, in Bcfd



The primary options for meeting **New England's need for** incremental peak day gas supplies are additional pipeline capacity (beyond the incremental 450 MMcfd projected in the ICF Base Case) and LNG imports into Everett. Based on recent historical prices, ICF anticipated that additional spot LNG supplies at Distrigas terminal would cost about $14.50 per million British thermal units (MMBtu). Additional LNG shipments into the Neptune and Northeast Gateway LNG terminals would cost approximately $1 dollar more (around $15.50 per MMBtu) due to the higher charter cost of the specialized tankers required to deliver gas to those buoy-based terminals.

To compare the cost of adding incremental pipeline capacity to the cost of spot LNG deliveries, ICF developed cost duration curves to represent the per-unit cost (in $ per MMBtu) of serving daily loads over the course of a year (Figure 2). While Marcellus-area gas is attractively priced, a new greenfield pipeline to connect New England to the Marcellus Shale would cost about $2 billion. Since the additional capacity would have to be fully contracted to be built but needed only about 30 days per year, the per-unit cost of this option is $16 to $20 per MMBtu, significantly higher than the cost of incremental spot LNG shipments.

Figure 2. Cost per Day of Serving Incremental Gas Load, New Pipeline versus Spot LNG



It is typically more cost effective to increase utilization of an existing asset rather than build new capacity, as the capital cost of existing assets can be treated as a sunk cost and therefore not subject to capital recovery. Given that the duration of the expected supply constraint is approximately 30 days per year, incremental LNG imports at Distrigas appear to be the most cost-effective solution **to meet this portion of New England's gas demand**.

1 Introduction

Over the past 10 years, U.S. natural gas production has surged due to the development of shale gas supplies. Despite the overall increases in domestic production, some markets, like New England, remain supply constrained during peak demand periods. New England has no in-region gas production, so the region depends on interstate pipelines and LNG terminals for all its gas supplies. New England gas demand has been steadily increasing, primarily due to an increase in gas-fired electricity generation, but also due to increases in residential and commercial loads served by the region's LDCs.

On peak demand days in the winter, New England's in-bound pipelines are fully utilized, resulting in price spikes at trading hubs within the region. As recently as January 2013, daily spot prices at the Algonquin Citygate rose to more than $30 per MMBtu, a premium of $25 more than the Henry Hub price. However, during the shoulder and summer months when regional demand is much less than the available in-bound pipeline capacity, New England's basis is far lower. Between April and September 2013, the Algonquin Citygate basis averaged about $0.56; and between July 28 and September 30 there were 11 trading days when the Algonquin price was actually below the Henry Hub price.

As New England gas demand continues to increase, it will need new gas supplies on peak demand days. ICF was engaged by GSGNA to assess the costs of different options for meeting projected gas demand in the New England market. ICF assessed New England's current gas supply capabilities and the projected growth in annual and daily gas loads, and the comparative costs of meeting the need for incremental gas supplies. The projections for annual demand growth, gas prices, and daily loads are based on results from ICF's September 2013 Base Case gas market forecast, developed using ICF's GMM and DGLM. ICF also assessed four different scenarios based on alternate projections for New England power generation gas demand and alternate projections for gas production from eastern Canada (a critical source of incremental supplies for the New England market).

This assessment of the New England gas market is based on the total pool of gas supply resources available to the area and total daily demands within the area. In reality, the ability of individual consumers within New England to receive gas from any one supply source (e.g., a particular pipeline or LNG terminal) is limited by intra-regional infrastructure constraints; however, this "pooled" approach is a reasonable representation of the region's overall supply/demand dynamics.

The remainder of this report is divided into three sections: a discussion of ICF's outlook for the North American gas market, the outlook for New England gas supply and demand, and an assessment of options to meet New England's near- to mid-term (through 2015 and 2020) projected gas supply needs.

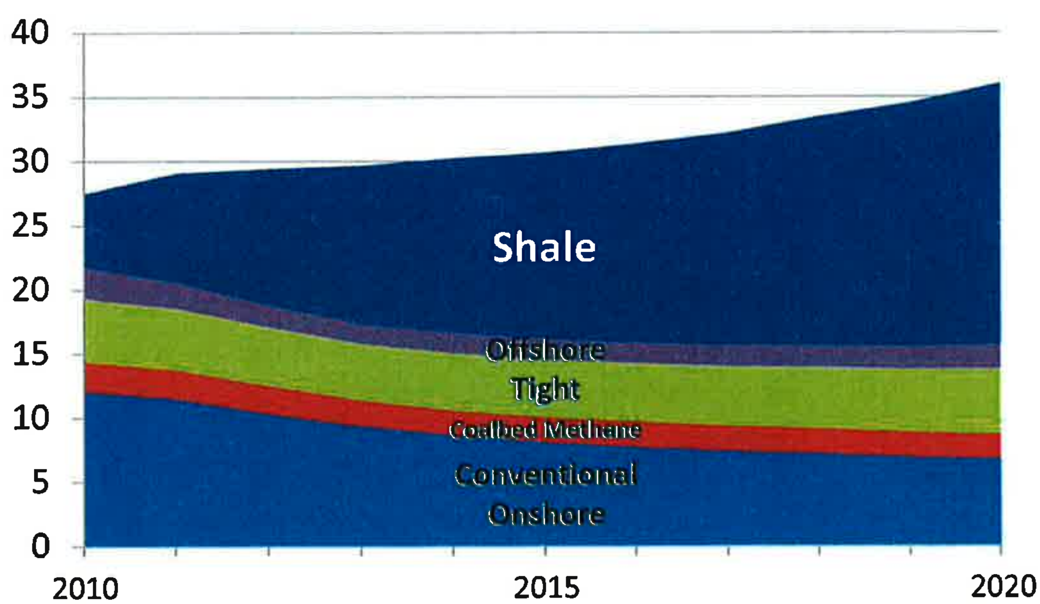
2 Overview of ICF's Outlook for the North American Natural Gas Market

To provide context for the more detailed discussion of the New England gas market (provided in Section 3), this section of the report provides an overview of **ICF's projection for the North** American gas market.

In the past 10 years, the North American natural gas market has undergone dramatic changes. The rise of shale gas production combined with weak economic growth has led to lower and less volatile gas prices. Before the rise of shale, most projections assumed that in the future, the United States would rely on LNG imports to meet a significant portion of its gas demand. Now, it appears that U.S. and Canadian production growth will exceed domestic demand, and there are multiple LNG export terminals under construction or being planned in the United States and Canada, as well as expansion of pipelines exporting gas from the United States to Mexico.

ICF projects that combined U.S. and Canadian gas production will increase by more than 20 percent to 36 trillion cubic feet (Tcf) per year by 2020 (Figure 3). Conventional onshore production is expected to continue declining, but shale gas production is projected to nearly double, reaching more than 20 Tcf per year by 2020. About one-third of the projected growth in shale gas production comes from the Marcellus shale, where production is expected to increase to 5.7 Tcf per year.

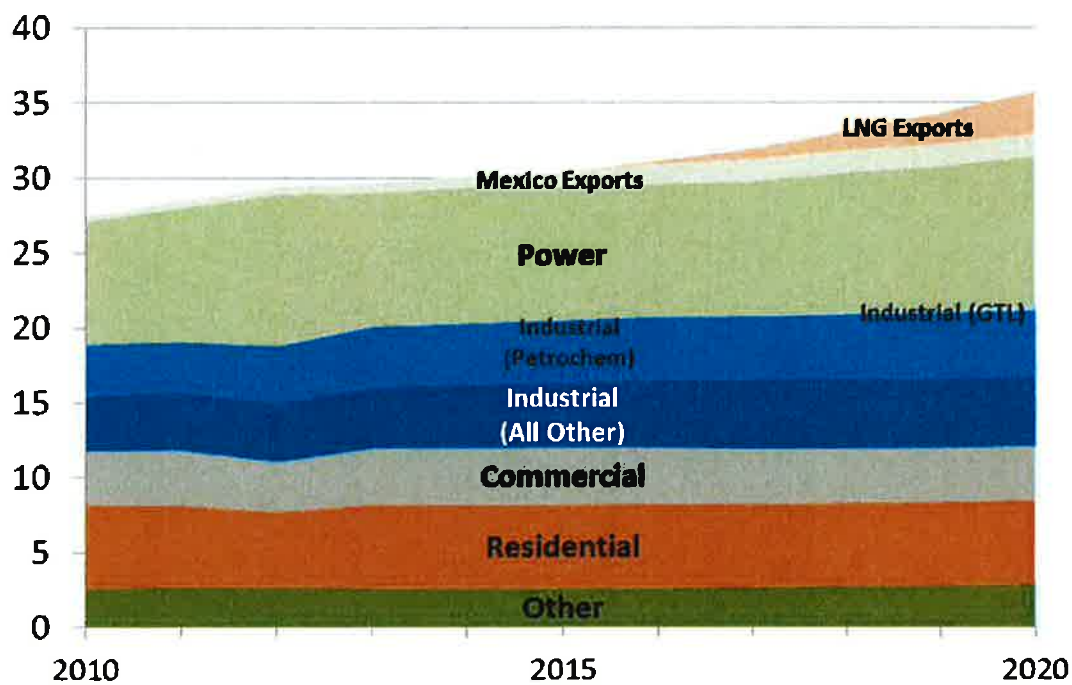
Figure 3. Projected U.S. and Canadian Natural Gas Production, in Tcf per Year



Over the same period, demands for natural gas (both domestic consumption and imports) are expected to increase rapidly (Figure 4). Long-term growth in domestic gas consumption is primarily driven by the power sector. Electric load growth, combined with coal and nuclear plant retirements drive power sector gas consumption up by more than 1 Tcf per year by 2020. Industrial gas consumption is expected to increase rapidly. In the United States, new petrochemical plants are being developed to take advantage of the abundant shale gas resources; in Canada, industrial consumption growth is primarily driven by increased use of natural gas for oil sands development. And toward the end of the decade, Shell and SASOL are planning new gas-to-liquids (GTL) plants, which could create additional demand. By 2020, combined U.S. and Canadian industrial gas consumption is projected to increase by about 1 Tcf per year. While residential and commercial sector gas consumption is expected to increase very little for the United States and Canada as a whole, demands in New England are expected to increase at a higher rate due to continued conversions by space heating customers from oil fuel to natural gas.

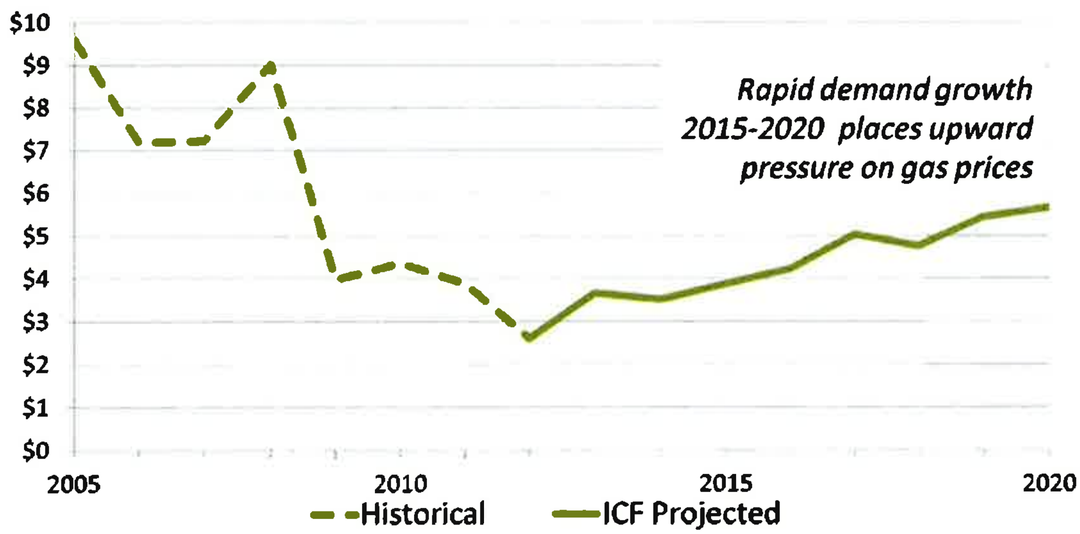
In addition to the domestic consumption growth, both LNG exports and pipeline exports to Mexico are also expected to increase. By 2020, LNG exports from the United States and Canada are expected to reach 2.9 Tcf per year (about 9 Bcfd) and exports to Mexico increase by 1 Tcf per year (about 3 Bcfd).

Figure 4. Projected U.S. and Canadian Natural Gas Demand, in Tcf per Year



While gas prices are expected to remain around $4 per MMBtu through 2014, prices this low are not sustainable in a rapidly growing market. ICF projects Henry Hub gas prices (in 2010$) averaging $4.00 per MMBtu through 2015, then rising to between $5.00 and $6.00 per MMBtu by 2020 (Figure 5).

Figure 5. Annual Average Natural Gas Prices at Henry Hub, in 2010$ per MMBtu



Despite the growth in domestic gas supplies and the relatively low gas price environment, basis differentials to the New England market are expected to remain relatively high (Figure 6 and Figure 7). Before 2013, basis between Henry Hub and the Algonquin Citygate averaged about $1 per MMBtu. Even though winter temperatures during these years were relatively mild (2012 was one of the warmest winters on record), basis during peak months ranged from $2 to $4 per MMBtu. In 2013, winter temperatures were significantly colder, and basis averaged nearly $7 per MMBtu, with basis on peak days spiking to more than $25.

In ICF's Base Case (which assumes forecast weather consistent with the average of the median of the last 20 years), annual basis between Henry Hub and Algonquin is expected to average about $1 per MMBtu, and January basis averages about $3.50 per MMbtu. While there is some dip in basis in 2014 (after Spectra's NY–NJ expansion) and again in 2017 (after the assumed 450 MMcfd of pipeline expansion into the New England market), continued market growth is expected to keep basis values relatively high. In Section 3 we provide additional details on ICF's Base Case projections for New England gas demand and supplies.

Figure 6. Annual Average Basis Henry Hub to Algonquin Citygate, 2010$ per MMBtu

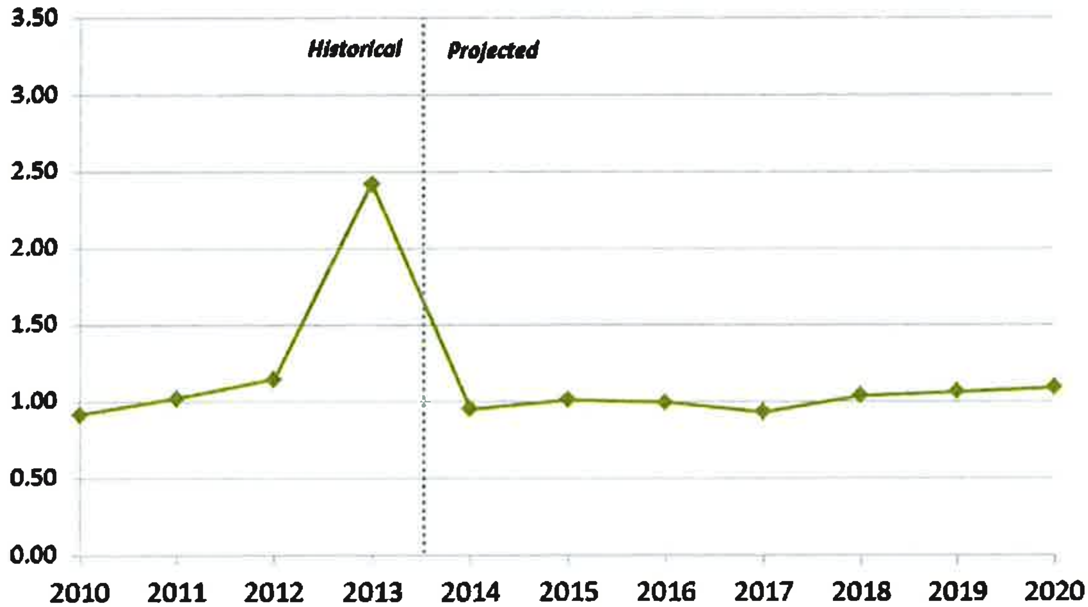
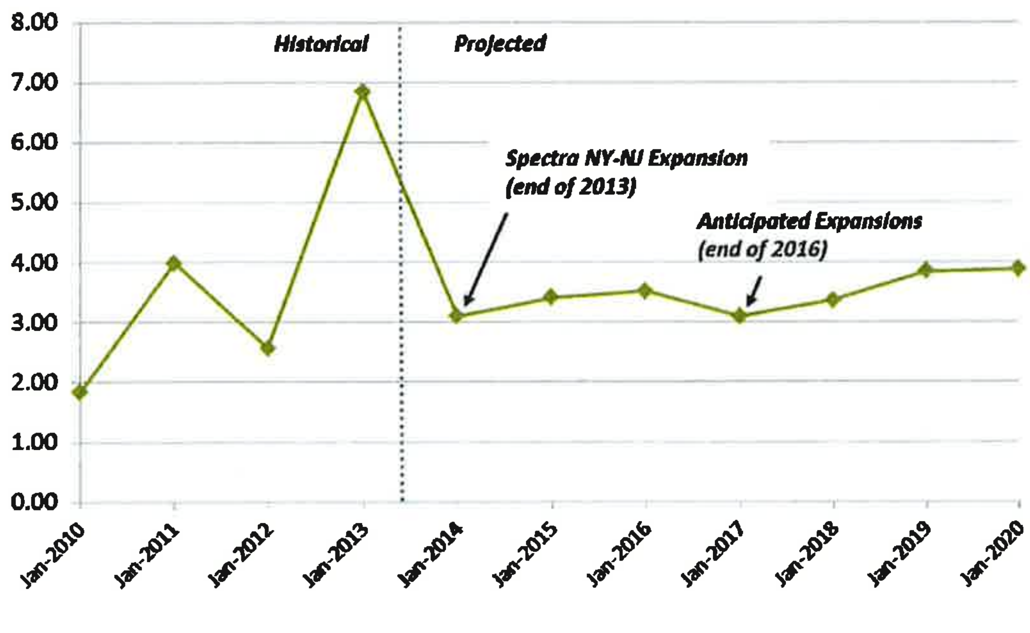


Figure 7. January Average Basis Henry Hub to Algonquin Citygate, 2010$ per MMBtu



3 Outlook for the New England Market

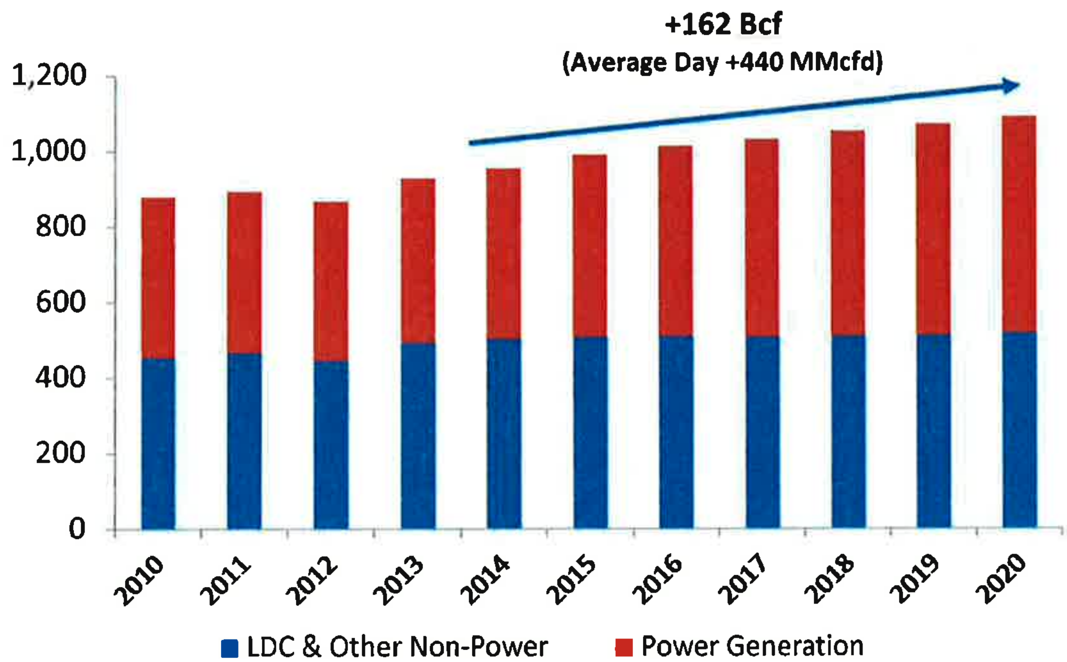
Gas Demand

The New England gas market has become increasing constrained in the winter, as peak winter demand has gradually increased while transport capabilities into the region have not. The power sector has been the biggest source of demand growth, as New England electric generators have become increasingly dependent on natural gas. Between 2004 and 2012, about half **(5,000 MW) of New England's dual**-fuel capable capacity was either mothballed or retired. The recently announced shutdown of Vermont Yankee nuclear power plant in 2014 will further increase gas demand for electricity generation by approximately 110 MMcfd.

LDCs have expanded into previously unserved areas and have steadily increased their customer counts as residential and commercial customers convert from fuel oil to natural gas furnaces for space heating. Relatively mild winter weather over the past decade has obscured the rate of market growth; three of the last five years have been much warmer than normal, and the winter of 2011–2012 was the warmest on record. In fact, New England has not experienced **very cold "design day" winter conditions the past 10 years.** When the weather did turn relatively cold in January–February 2013, spot gas prices at the Algonquin Citygate soared past $30 per MMBtu, even as other Northeast price points remained relatively stable around $4 per MMBtu, indicative of the regional supply constraints.

ICF's Base Case projects that total New England annual natural gas demand will increase by more than 160 billion cubic feet (Bcf) by 2020 (Figure 8). The majority of the increase in annual demand is expected to come from the power sector, which increases by 140 Bcf; the remainder of the increase is from LDC demand (residential and commercial) and a small amount of industrial demand. **ICF's projections for annual gas demand assume "normal" weather, based** on the median of the past 20 year.

Figure 8. New England Annual Natural Gas Demand, in Bcf per Year



While the growth in LDC demand is modest on an annual basis, the impact on peak day demand is much greater, since the majority of LDC load is for space heating. Growth in daily load due to increased power sector gas demand is spread more evenly throughout the year, as much of the increase in gas-fired generation is for based load use, such as the replacement of generation from the Vermont Yankee plant. Also, about 6 gigawatts (GW) of the gas-capable units in the region have the ability to switch to fuel oil, which helps limit power sector gas consumption on peak winter days.[1] Figure 9 shows ICF's projection for total daily gas loads. By 2020, peak day demand is projected to increase by about 1 Bcfd.

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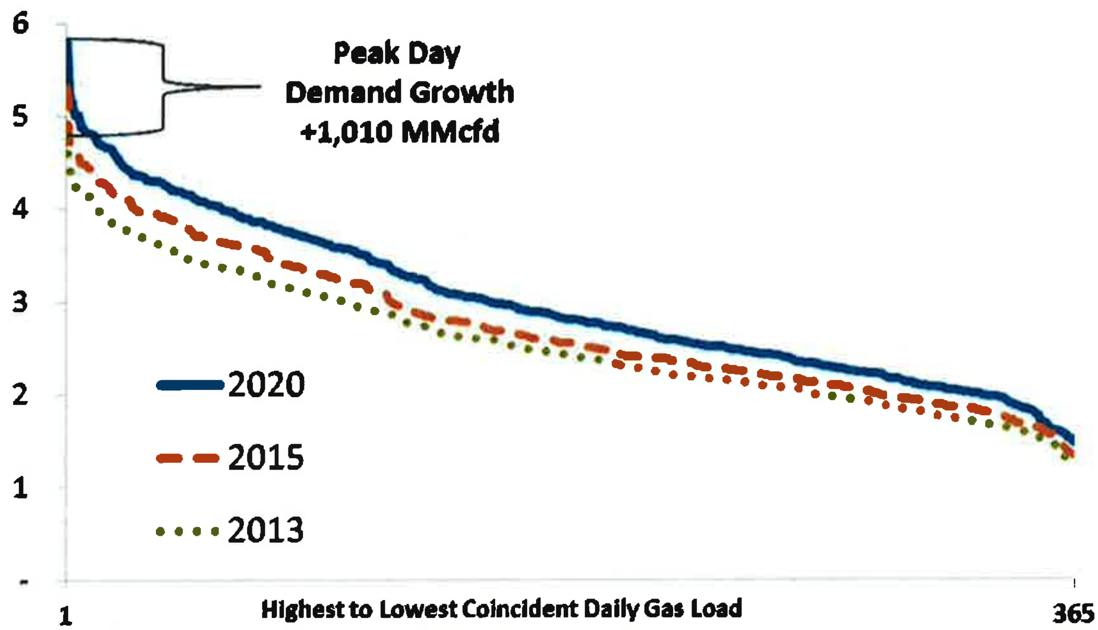
[1] "CELT Report: 2013–2022 Forecast Report of Capacity, Energy, Loads, and Transmission," ISO New England, May 2013.

Figure 9. Projected New England Daily Natural Gas Demand, in Bcfd



ICF also examined two alternate projections for New England power sector demand, based on potential change in the region's capacity mix. In the higher demand scenario, ICF projects there could be an additional 0.16 to 0.17 Bcfd of incremental demand growth if New England's coal or nuclear capacity were reduced by another 1,000 MW. In the lower demand scenario, if 1,000 MW of coal capacity retirement anticipated in the ICF Base Case did not occur, then demand growth would be reduced by about 0.1 Bcfd.

<u>New England Pipeline Capacity</u>

New England has no in-region gas production, so it depends on deliveries via pipeline and LNG terminals for all its gas supplies. There are five interstate pipelines that supply the New England market—Tennessee Gas Pipeline, Algonquin Gas Transmission, Iroquois Gas Transmission, Portland Natural Gas Transmission System (PNGTS), and Maritimes and Northeast Pipeline (M&N) (Figure 10). Based on ICF's analysis of Index of Customer data for each of these pipelines, a total of approximately 3,700 MMcfd of pipeline capacity is contracted for by consumers in New England (Table 1).[2] The vast majority of the firmly contracted pipeline

[2] ICF's analysis of the Index of Customers data was performed in the fourth quarter of 2012.

capacity is held by the region's LDCs; less than 8 percent of the firm pipeline capacity is held directly by electric generators in New England.[3]

Figure 10. Map of New England Interstate Pipelines and LNG Terminals

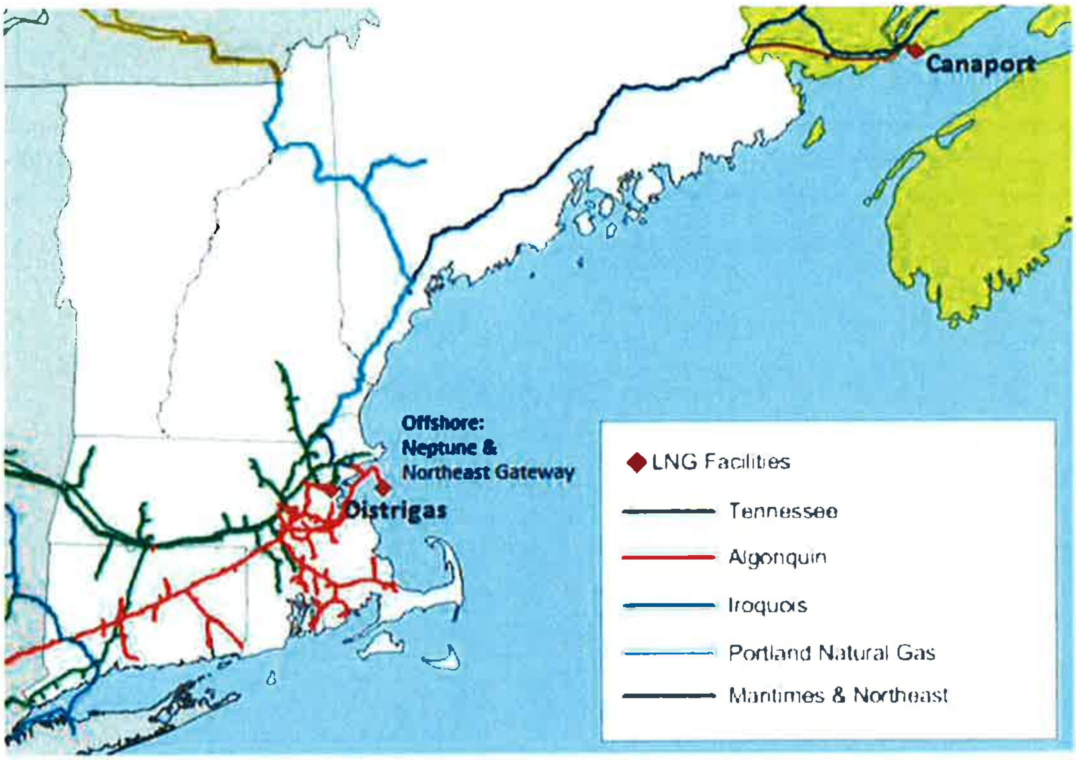


Table 1. Firm Pipeline Capacity Held by New England Shippers, in MMcfd

Tennessee	Algonquin	Iroquois	PNGTS	M&N	Total
1,290	1,120	230	250	830	**3,720**

About two-thirds of the capacity contracted by New England shippers is on the Tennessee and Algonquin systems. Iroquois has a total of more than 1,500 MMcfd of firm contracts, but the majority of this capacity is contracted for by shippers further downstream in New York. New England shippers contract for only about 230 MMcfd of firm capacity on Iroquois.

[3] ICF analysis of the Index of Customers data indicates about 280 MMcfd of firm capacity is directly held by New England electric generators; however, generators may contract for additional firm capacity through marketers.

On PNGTS, New England shippers contract for approximately 250 MMcfd, but the system's physical capacity is greater; on peak winter days PNGTS has flowed more than 300 MMcfd. While PNGTS has proposed an expansion to offer additional capacity to the New England market, it will likely be increasingly difficult to get gas supplies to the system. Declining production and increasing demand in Alberta has reduced flows on the TransCanada and TransQuebec systems, which supplies PNGTS.

M&N has a capacity of 830 MMcfd, essentially all of which is contracted for by Repsol's gas marketing division. While M&N does flow full on peak demand days (when New England prices are very high), the annual capacity utilization of the system has been declining due to declining Sable Island offshore production, reduced LNG imports to Canaport, and demand growth in eastern Canada.

Potential Pipeline Expansions

Several pipeline systems have proposed expanding capacity into New England. In July 2013, Tennessee Gas Pipeline launched an open season for its Connecticut Expansion Project, which would provide an additional 72 MMcfd from Tennessee's existing interconnect with Iroquois Gas Transmission in Wright, New York, to zone 6 delivery points on Tennessee's 200 and 300 lines in Connecticut through upgrades and modifications to its existing system in New York, Massachusetts, and Connecticut. The Algonquin Incremental Market (AIM) expansion project was proposed to add as much as 450 MMcfd of capacity by the end of 2016. As of late September 2013, the response to Algonquin's open season indicates the expansion would be sized at less than 400 MMcfd. ICF projects that by the end of 2016, contracted pipeline capacity into the New England market will increase by 450 MMcfd, most likely on some combination of expansions on the Tennessee and Algonquin system.

Spectra's NY–NJ expansion of its Texas Eastern Transmission and Algonquin lines in the New York City metropolitan area is due online in November 2013. While these expansions do not directly provide any additional capacity into the New England market, they may make additional capacity available to New England shippers by displacing flows from New England to Long Island on the Iroquois system.

New England LNG Terminals

The Distrigas LNG terminal in Everett, MA (operated by GDF Suez NA) is the only terminal in the region currently receiving shipments. Distrigas has a sustainable vaporization capacity of 715 MMcfd and can distribute another 100 MMcfd via truck; it has two storage tanks with a combined capacity of 3.4 Bcf. The combined sendout from Distrigas to interstate pipelines (Tennessee and Algonquin) and Mystic Generating Station averaged about 215 MMcfd in 2012, with a peak day sendout of about 440 MMcfd. Distrigas also delivers additional volumes directly to the local LDC system (National Grid/Boston Gas) and via truck to LNG peak shaving facilities across New England.

Two other offshore LNG terminals, Neptune and Northeast Gateway, have not received any shipments since 2010. The offshore terminals can only receive deliveries from specialized tankers with on-board regasification and buoy-docking systems. Also, since the offshore terminals have no LNG storage capacity, they are only able to send out gas when a LNG tanker is docked at one of their buoys.

New England Peak Shaving Facilities

In addition to the pipeline and LNG import terminals, LDCs in New England also operate about 45 LNG and propane-air peak shaving facilities. The peak shaving facilities are used by the LDCs to maintain system reliability and help meet firm customer demand during the 10 to 15 peak demand days of winter. The peak shaving facilities have a total send-out capability of about 1,450 MMcfd and a total storage capacity of about 16 Bcf.[4] **Some of the facilities are "full-cycle" LNG peak shaving (i.e., they can liquefy pipeline** gas to refill the storage tanks), but the majority are supplied by truck shipments from the Distrigas facility.

Upstream Gas Supplies and Supply Scenarios

The closest major production area to New England is the Marcellus Shale; the Marcellus shale is centered in Pennsylvania but also stretches across portions of West Virginia, Ohio, and New York. Producers began drilling in the Marcellus Shale just six years ago, but production has already reached 9 Bcfd. Marcellus shale gas has become a major new source of gas supply for the entire northeast, including the New England market, displacing flows from traditional supply sources such as the Gulf Coast and western Canada. Despite the increase in Marcellus production, the availability of pipeline capacity into New England limits the availability of these supplies to the market, particularly on peak demand day. There have been pipeline system expansions and reconfigurations within the Marcellus play area, but no new pipeline capacity built directly into the New England market since the last M&N system expansion in 2009.

New England also receives gas from eastern Canada via the M&N pipeline. Gas production in eastern Canada has been declining and that has reduced supplies available on M&N. Most eastern Canada production comes from the Sable Island offshore field and the new Deep Panuke offshore field, which began production in August 2013. Production from Deep Panuke may improve average annual M&N flows in the near-term, but there have been a number of problems in the field since the start of production. There are also on-shore shale gas resources in New Brunswick, but producers have not announced any plans to develop them.

The M&N pipeline also transports supplies from New Brunswick's Canaport LNG terminal. Repsol, which owns both Canaport and the M&N pipeline, sold the majority of its LNG assets, including interest in the gas liquefaction facility in Trinidad and Tobago, which have provided **most of Canaport's supplies. Canaport's current LNG supply contracts** with Shell will allow it to **continue operations, but at only a small fraction of its nominal capacity; Repsol's current**

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[4] **"NGA 2012 Statistical Guide", Northeast Gas Association, 2012.**

contract with Shell equates to about 5 Bcf per year. Utilization of both M&N and Canaport have been on the decline; in the past year, M&N only flowed full on a limited number of peak winter days, supported by sendout from Canaport.

ICF projects that eastern Canadian production will increase to approximately 0.5 Bcfd in the near-term, due to the startup of Deep Panuke production. After 2014, total production from eastern Canada (primarily Sable Island and Deep Panuke offshore fields, plus a small amount of additional onshore production) is expected to resume its decline, and reach about 0.18 Bcfd by 2020. Canaport is currently operating **as a "swing supply" for the New England market,** increasing sendout up to the available remaining capacity on M&N during peak demand periods when gas prices are very high, and sending out minimal volumes during the rest of the year; it is expected to continue operating this way through the projection.

ICF also examined two alternate supply scenarios for eastern Canadian gas production. In the higher supply scenario, eastern Canada production peaks at 0.51 Bcfd in 2014 and is maintained at 0.44 Bcfd through 2020. The lower supply scenario assumes Deep Panuke production is less than in the Base Case; eastern Canada production peaks at only 0.33 Bcfd in 2014 and declines to less than 0.1 Bcfd by 2020.

<u>Conclusions from Demand and Supply Outlook</u>

ICF's Base Case projection indicates that the New England market is likely to remain supply constrained during peak winter demand periods through 2020. Figure 11 and Figure 12 show **ICF's projected daily gas loads for New England in 2015 and 2020**, respectively, versus projected pipeline and peak shaving resources.

In summer and shoulder months, space heating gas use is minimal and LDC loads average about 80 percent lower than on a peak winter day. As a result, much of the pipeline capacity held by LDCs is available to other consumers (mostly electric generators) in the shoulder and summer months. On the 15 highest demand days, regional peak shaving facilities supplement the pipeline supplies to help meet loads. However, because the storage capacity of these facilities is limited, they cannot be relied on to provide additional supplies for extended periods. As indicated by the orange area in Figure 12, between the days when pipeline supplies and peak shaving facilities can meet daily loads is a period of approximately 30 peak demand days when additional gas supplies are needed. Even after expected expansion increases pipeline capacity by 450 MMcfd, the projected growth in daily load indicates that by 2020 there will still be about 30 days per year during which the New England market will need additional gas supplies beyond the expected pipeline and peak shaving capabilities (Figure 12).

In Section 4, we compare the cost of two options for meeting the need for additional gas capacity—additional pipeline capacity and LNG imports into Distrigas.

Figure 11. Daily Gas Load in 2015 versus Pipeline Capacity and Peak Shaving, in Bcfd

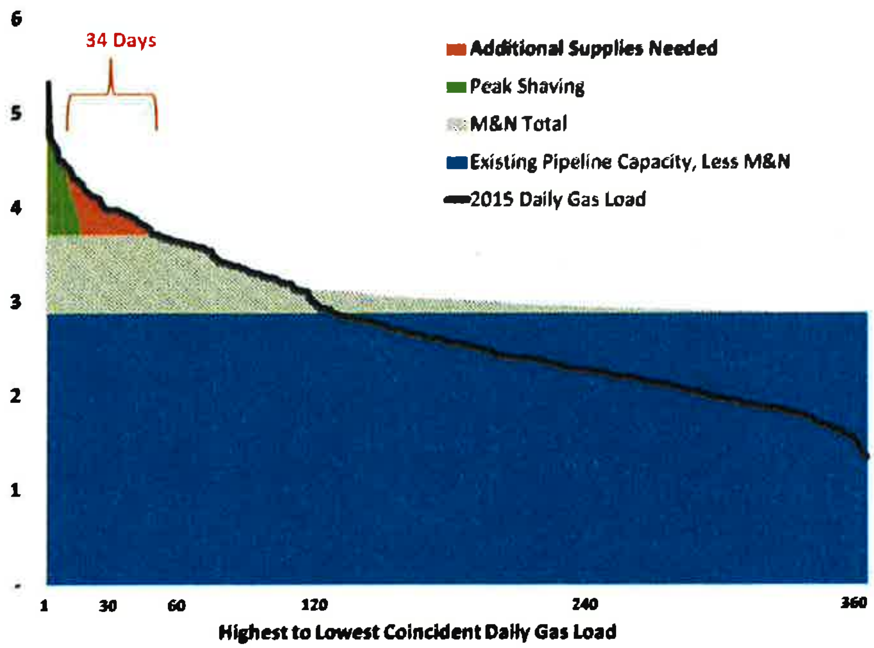
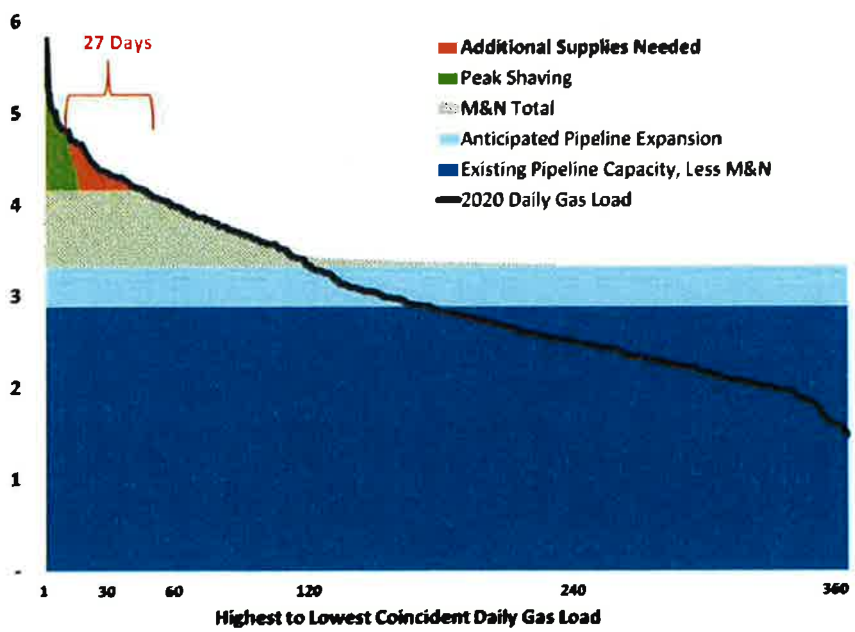


Figure 12. Daily Gas Load in 2020 versus Pipeline Capacity and Peak Shaving, in Bcfd



4 Cost of Supply Options to Meet New England's Near- to Mid-term Needs

Section 3 identifies additional pipeline capacity (beyond the incremental 450 MMcfd projected in the ICF Base Case) and LNG imports into Everett as the primary options to meet the need for incremental peak day gas supplies.

Based on recent historical prices, ICF anticipated that additional spot LNG supplies at Distrigas terminal would cost about $14.50 per MMBtu; this estimate is based on a landed cost for the LNG of $14.25 and an additional terminal fee of $0.25. The Distrigas terminal fee is relatively low since it only covers marginal operating costs and does not include any capital recovery. Additional LNG shipments into the Neptune and Northeast Gateway LNG terminals would cost approximately $1 dollar more (around $15.50 per MMBtu) due to the higher charter cost of the specialized tankers required to deliver gas to those buoy-based terminals.

ICF also assessed the option of adding additional oil backup/fuel switching capability (beyond the approximately 6 GW of switchable capacity currently in-place) as a means of reducing incremental gas demand growth, and thereby lessening the need for additional gas supplies. Assuming the price of crude oil is $95 per barrel (similar to recent historical prices), this equates to a distillate fuel oil price of more than $20 per MMBtu, significantly higher than the fuel cost of incremental spot LNG. In addition to the higher cost per MMBtu, adding new oil switching capability would require new oil storage tanks and other modifications at power plants which would further increase the cost. Since oil switching would be more costly than incremental spot LNG supplies, we concentrated the cost comparison analysis on the pipeline option.

To compare the costs of adding incremental pipeline capacity to the cost of spot LNG deliveries, ICF first assessed the cost of building a new pipeline to New England from the Marcellus Shale. Based on a recent survey of pipeline construction costs, ICF estimates the cost of building a new "greenfield" pipeline to New England would be approximately $200,000 per inch-mile.[5] Right-of-way and construction costs in New England are significantly higher than the national average.

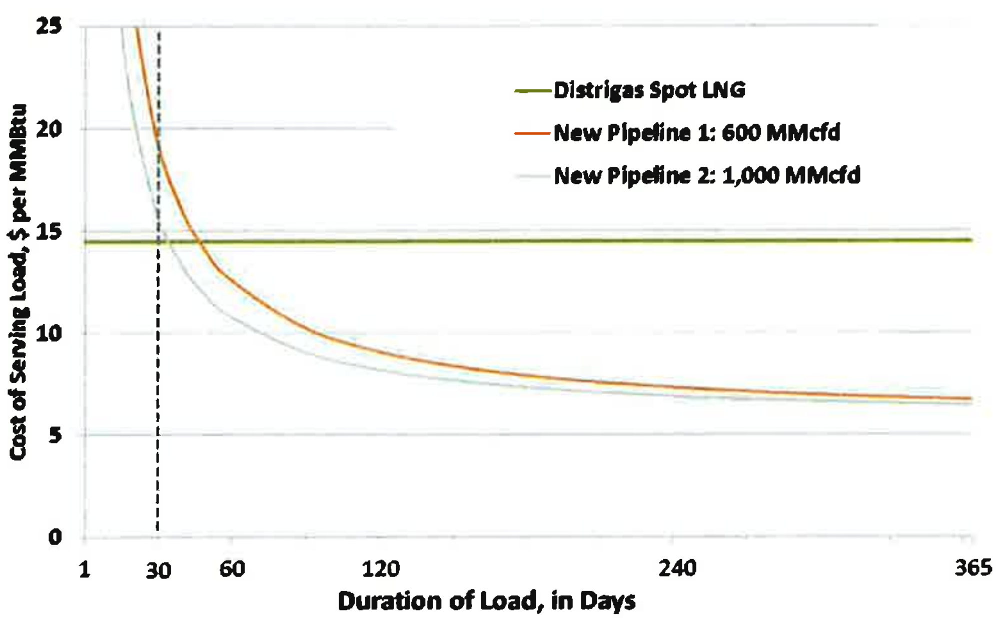
To connect to a liquid trading point within the Marcellus play area would require a pipeline length of about 300 miles. Given economies of scale, the new pipeline's capacity would be between 600 MMcfd (30-inch diameter) and 1,000 MMcfd (36-inch diameter); this range of capacity is similar to proposals for new pipeline capacity to serve New England. Given these potential diameters and the mileage required to connect to Marcellus supplies, the total pipeline costs would be between $1.8 billion (for a 600 MMcfd pipeline) and $2.2 billion (for a 1,000 MMcfd pipeline).

[5] Annual Pipeline Economics Report. Oil & Gas Journal, September 2, 2013.

A new pipeline would have to be fully contracted to be built. This means that shippers on this **hypothetical pipeline would have to contract for the pipeline's full capacity throughout the year** before the Federal Energy Regulatory Commission could approve it. Assuming a capital recovery factor of 14 percent, the annual capital charge would be between $260 and $360 per thousand cubic feet (Mcf) of capacity; fuel charges would add $0.05 per Mcf (assuming fuel use of 1 percent and a gas price of $5 per MMBtu), and other variable operations and maintenance (O&M) costs would add an additional $0.01 per MMBtu.

To create the cost duration curve, the annual capital charge is divided by the number of days the pipeline is used, and added to the variable costs and projected cost of gas (around $5 per MMBtu) to arrive at cost of service curves based on the number of days of load being served. Figure 13 shows the per-unit cost of the service as a function of the number of days the capacity is needed (e.g., the more days over which the load is spread, the lower the per-unit cost). Since the incremental capacity is only needed for about 30 days per year, the effective per-unit cost of the pipeline-delivered supply would be between $16 and $20 per MMBtu, significantly higher than the cost of incremental spot LNG shipments.

Figure 13. Cost Duration Curves: Cost per Day of Serving Incremental Gas Load



Conclusions and Implications from the Cost Duration Analysis

The existing interstate pipelines serving New England are already fully utilized during peak **demand periods, as are the LDC's peak shaving facilities.** It appears likely that about 450 MMcfd of new pipeline capacity will be added by the end of 2016 to meet LDC incremental demand growth, but even with that additional capacity ICF projects that the New England market will still need additional gas supplies about 30 days per year.

While the proposed incremental expansion of the Algonquin system appears to be moving forward, the new capacity is not likely to be available until late 2016 or early 2017. Even after that expansion, continued market growth will likely result in continued supply constraints on peak winter days.

A new greenfield pipeline from the Marcellus Shale to New England would cost between $1.8 and $2.2 billion; since the incremental supplies are only needed on a limited number of days, the effective cost would be $16 to $20 per MMBtu. Supplies from additional spot LNG shipments are expected to available for between $14 and $15 per MMBtu; **Distrigas' variable operating** costs (exclusive of the LNG itself) are only about $0.25 per MMBtu, so this adds very little to the anticipated cost.

It is typically more cost effective to increase utilization of an existing asset rather than build new capacity, as the capital cost of existing assets can be treated as sunk cost and therefore not subject to capital recovery. Given that the duration of the expected supply constraint is approximately 30 days per year, incremental LNG imports at Distrigas appear to be the most cost-effective solution **to meet this portion of New England's gas demand**.

5 Summary of Conclusions

- New England currently has a very tight supply/demand balance on about 30 days per year, and demand is projected to grow significantly over the remainder of the decade.
  - Compared to 2013 levels, ICF projects that winter peak day demand will increase by more than 500 MMcfd by 2015 and more than 1,000 MMcfd by 2020, exacerbating the existing gas supply constraints.
  - The projected growth in LDC firm demands justifies some new pipeline capacity. **ICF assumes that Algonquin's AIM expansion will add an incremental 450 MMcfd** of capacity, but it is not expected until late-2016. Even after the AIM expansion, New England will still need incremental gas supplies on about 30 peak winter days a year by 2020.

    - New England gas demand is very seasonal, so there will be sufficient supply capability to meet off-peak loads.

- Given that the duration of the expected supply constraint is approximately 30 days per year, incremental LNG imports at Distrigas appear to be the most cost-effective solution.

    - Based on current Atlantic Basin LNG prices, the landed price of LNG at Distrigas is likely to be less than $15 per MMBtu; terminal fees add only about $0.25 per MMBtu. In recent years, Distrigas has been operating well below its rated capacity.

    - While Marcellus-area gas is attractively priced, a new pipeline to connect New England to the Marcellus Shale would cost about $2 billion. Since the additional capacity would have to be fully contracted but needed only about 30 days per year, the per-unit cost of this option is relatively high at $16 to $20 per MMBtu.

- New production from Deep Panuke will increase supplies into the M&N Pipeline, but LNG imports at Canaport would still be needed to fill the pipeline; importing LNG at Distrigas would be a lower cost option.

    - The landed price of spot LNG cargos at Canaport would about the same as at Distrigas, but New England shippers also have to pay the transportation costs on M&N.

GDF SUEZ

May 30, 2014

Heather Hunt
Executive Director
New England States Committee on Electricity
4 Bellows Road
Westborough, MA 01581

RE: NESCOE Request for Comments on Governors' Infrastructure Initiative

Dear Ms. Hunt:

GDF SUEZ Gas NA LLC (GDF SUEZ) and Distrigas of Massachusetts LLC (Distrigas) appreciate the opportunity to respond to the New England States Committee on Electricity (NESCOE) April 30, 2014 Memorandum to NEPOOL and members of the New England Gas-Electric Focus Group, which invited comment on the "Governors' Infrastructure Initiative – Approach to Increasing Natural Gas Infrastructure."

Our company further appreciates NESCOE and staffs from each of the New England Governors' offices meeting with a number of stakeholders, including us, on this important issue. Respectfully, and consistent with all of our public comments to date, as well as the substance of our stakeholder meeting with NESCOE and States' staff, we continue to believe that the proposal to increase pipeline infrastructure is premature and perhaps misinformed when existing supply and delivery infrastructure is not being fully utilized. We find the expansion proposal puzzling given that existing infrastructure east of the pipeline constraint points would, if better utilized, greatly enhance natural gas and electricity delivery reliability and do so in a manner that would be economically beneficial and less disruptive to the region.

In this regard, we note again that the Distrigas regasification facility has the capacity to produce **435 MMcf per day of natural gas for power generation and/or local distribution company customers** that can be sent out at multiple pipeline pressures simultaneously, in addition to the facility's maximum send-out commitment to liquid delivery sales and the Mystic Power Plant. This means the Distrigas facility can provide a total sustainable delivery capacity of 715 MMcf per day of vaporized LNG and an additional capacity of approximately 100 MMcf per day of LNG loaded on trucks in liquid form.

It is also worth noting that, while the April 30 memo repeatedly comments that the competitive market has not satisfied the region's need in regard to natural gas delivery infrastructure, in fact multiple competitive market solutions, from new rules around generator performance incentives and strong FCM auction signals, to a number of pipeline expansion and transmission project

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open seasons, are all presently being actively discussed in multiple venues within the region and at the Federal Energy Regulatory Commission (FERC). Undoubtedly, the potential for a mandated solution will stultify the development of those competitive solutions as market participants will hold back on taking affirmative action until it is clear where the state proposal will end up, thus creating a self-fulfilling prophecy of the market not resolving the problem.

Given our continuing view that the region would be best served for reliability and economic purposes by first utilizing existing natural gas infrastructure before investing in new increments of natural gas pipeline, we asked ICF International to update the report they prepared in October 2013, titled, "***Options for Serving New England Natural Gas Demand.***" The update[1] includes an analysis of the experience of this past winter. Some of the report's conclusions include:

- While the winter of 2013/14 was very cold, New England's weather conditions were not unprecedented.
    - Evidence from this past winter supports the conclusion that New England experiences gas pipeline constraints about 30 days per year, and projected demand growth suggests these constraints will persist at least through the remainder of the decade.
- This past winter, in-bound pipeline capacity was over 90% full on 42 days and over 95% full on 10 days.
- Increased utilization of the Everett LNG import terminal is a relatively low cost way of meeting this short duration constraint.
    - A new, greenfield pipeline would cost about $2 billion, would need to be fully contracted, and would take three or more years to complete.
    - When annual pipeline costs are allocated over the 30-day period the capacity is needed, the cost per MMBtu of fuel demand served is higher than imported LNG.
- ISO New England's Winter Reliability program encouraged the use of fuel oil to meet winter fuel needs, but imported LNG would have cost less on a dollar per MMBtu basis.
    - This past fall, the cost of LNG was about 33% less per MMBtu than what generators spent on fuel oil.
    - Gas-fired units also have a better average heat rate than oil-fired units, yielding additional potential fuel cost savings.

GDF SUEZ/Distrigas is pleased to provide a copy of the updated ICF International report, "***New England Natural Gas Supply and Demand: Post-Winter Review,***" as an attachment to this letter.

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[1] The updated report titled, "***New England Natural Gas Supply and Demand: Post-Winter Review***," was prepared by ICF International based on assumptions from a variety of sources, including GDF Suez. The report must be considered in its entirety to understand the context, assumptions and conditions on which the conclusions are based.

With respect to the Incremental Gas for Electric Reliability (IGER) concept specifically, there is limited detail upon which to offer constructive guidance at this point. However, given this and the competing proposal offered by the EDCs, what is imminently clear is that under either approach, the strongest possible safeguards must be put in place to prevent even the appearance of conflicts of interest both in the selection and administration of duty on the part of both the contract entity and capacity manager. This is especially true if the prerequisite qualifications for the capacity manager and contract entity end up being as described in NESCOE's April 30 memo. While deep natural gas management experience is an obvious plus, if that experience was gained in the northeast market, it could be a disadvantage as well. While creditworthiness and strength of balance sheet are important attributes for a contract entity, it would be naïve to think that a current market participant could play that role and be agnostic to their own financial interests with respect to the administration of the program. Consequently, it would be helpful to stakeholders in the region to better understand NESCOE's view of how IGER or any proposal would be positioned to overcome the numerous legal, regulatory, legislative, and marketplace challenges that would have to be cleared in order for the proposal to be implementable.

Given the foregoing, GDF SUEZ is troubled by a number of potential intended and unintended consequences of the IGER concept and the EDC proposal. Fundamentally, we oppose using the ISO electricity tariff to subsidize construction of new natural gas pipeline as there is a basic disconnect between the purpose of the tariff and this intended application. Among other concerns, the proposal would require that the region socialize and subsidize the cost of substantially more natural gas pipeline than truly needed and consequently undermine the value of the firmness provided by other resources currently in the market. The concept leads to an outcome that explicitly picks winners and losers in many different respects. As structured, it ignores any other potential natural gas reliability solution to the states' concerns. For instance, newly constructed in-region natural gas liquefaction and storage can't compete on a level playing field under this structure – there is no mechanism to participate. Moreover, unless every pipeline project currently proposed gets some level of subscription, it is conceivable that those natural gas fired power plants along a pipeline with no incremental expansion will be unable to receive the same level of benefit envisioned by the program as those plants located along expanded pipeline systems. What is the market implication? How do the states intend to fairly adjudicate the appropriation of additional capacity through the capacity manager?

We appreciate NESCOE's work in getting this concept out to stakeholders and subjecting in to vigorous debate. We look forward to contributing to the discussion and thank you for the opportunity to provide our perspective on these important issues for our region.

Sincerely,

Francis J. Katulak
President and Chief Executive Officer

New England Natural Gas Supply and Demand: Post-Winter Review

Prepared for

GDF SUEZ Gas North America

May 29, 2014

Prepared by

ICF International
9300 Lee Highway
Fairfax, VA 22031

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TABLE OF CONTENTS

1 Introduction

In October 2013, GDF SUEZ Gas North America (GSGNA) engaged ICF to perform an assessment of alternate solutions to providing incremental natural gas supplies to the New England market.

In the 2013 study, ICF provided its assessments of New England's gas supply capabilities, and the projected growth in annual and daily gas loads. Based on that comparison, ICF estimated that New England will need additional gas supplies on about 30 peak winter days per year through 2020. ICF also compared the costs of meeting the need for incremental gas supplies on 30 days from new pipeline versus incremental imports of liquefied natural gas (LNG). ICF concluded that LNG imports to Distrigas appear to be a more cost-effective solution for meeting the region's gas supply needs, given the limited number of days when gas supplies are expected to be constrained.

Following the winter of 2013/14, GSGNA asked ICF to assess how the gas market reacted during the extreme weather events, as well as past and future drivers of gas demand growth in New England. ICF was also asked to compare the cost of fuel oil purchased by generators under ISO New England's (ISO-NE) Winter Reliability Program to imported LNG, as another means to meet a portion of the region's peak seasonal fuel demand.

2 Winter of 2013/14 Market Conditions

While the winter of 2013/14 was unusual in the extent and severity of cold weather across most of the eastern United States, it was not the coldest on record. This winter ranked as the 34th coldest winter in the past 119 years, and the coldest since 2009/10. The average temperature for the contiguous U.S. during the winter season (December 2013-February 2014) was 31.3°F, 1.0°F below the 20th century average.[1]

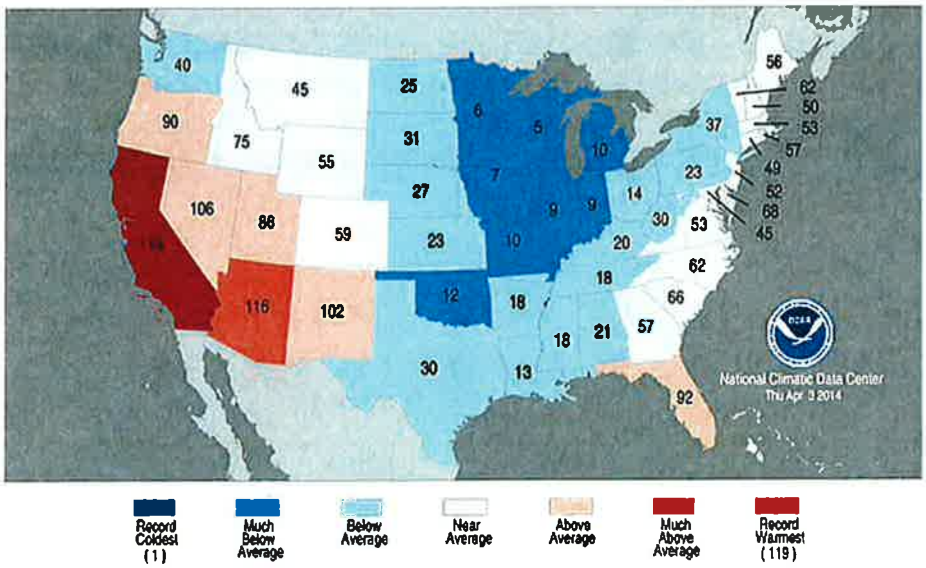
This winter was in sharp contrast to the previous two winters, and most winters of the past two decades, when temperatures were predominately warmer than the 20th century average. Below-average temperatures dominated east of the Rockies, with the coldest conditions occurring across the Midwest. Seven Midwestern states were much colder than average and had a top 10 cold winter season, though no state experienced record cold (Figure 1). Numerous cold Arctic air outbreaks impacted both the Midwest and Northeast during the winter season, particularly in January and February.

In the New England states, this winter's average temperature ranked near the middle of the 119 years of recorded temperatures, ranging from 49th to 62nd (Figure 1). Compared to the past 20 years, the range of daily temperatures New England experienced was near the low but not unprecedented. Between November 1 and March 31, New England temperatures averaged

[1] National Climate Data Center, http://www.ncdc.noaa.gov/sotc/national/2014/2/

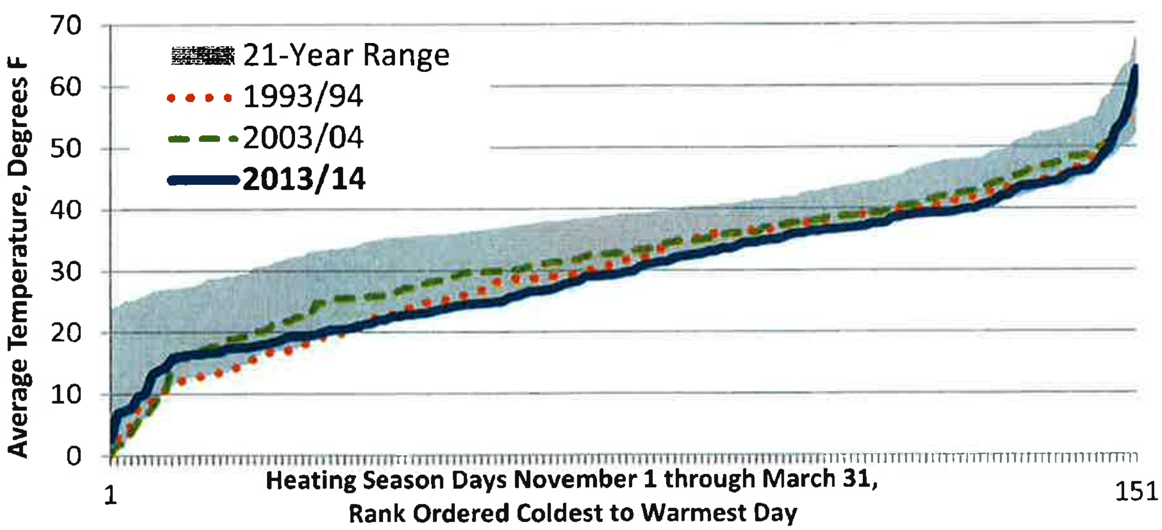
about 30° F; on the coldest day (January 3), temperatures averaged less than 3° F. Over the prior 20 years, New England has experienced two winters with similar "cold snaps". The winters of 1993/94 and 2003/04 both had 7 or more days with average temperatures below 10° F, and coldest days at or near 0° F (Figure 2).

Figure 1. State-wide Temperature Ranks, December 2013-February 2014 (Ranking based on years 1895-2014)



Source: National Climate Data Center

Figure 2. New England November-March Daily Temperatures, 1993/94 through 2013/14[2]



Source: ICF International, derived from NOAA data

[2] Population weighted average of mean daily temperatures from 6 weather stations across New England.

There have been no changes to New England's in-bound natural gas pipeline capacity since ICF's 2013 study for GDF SUEZ. New England shippers currently have firm contracts for about 3.7 billion cubic feet per day (Bcfd) of capacity on five pipeline systems (Figure 3). Planned expansions on the Algonquin and Tennessee systems will add slightly over 400 million cubic feet per day (MMcfd) of additional pipeline capacity into New England in November 2016.

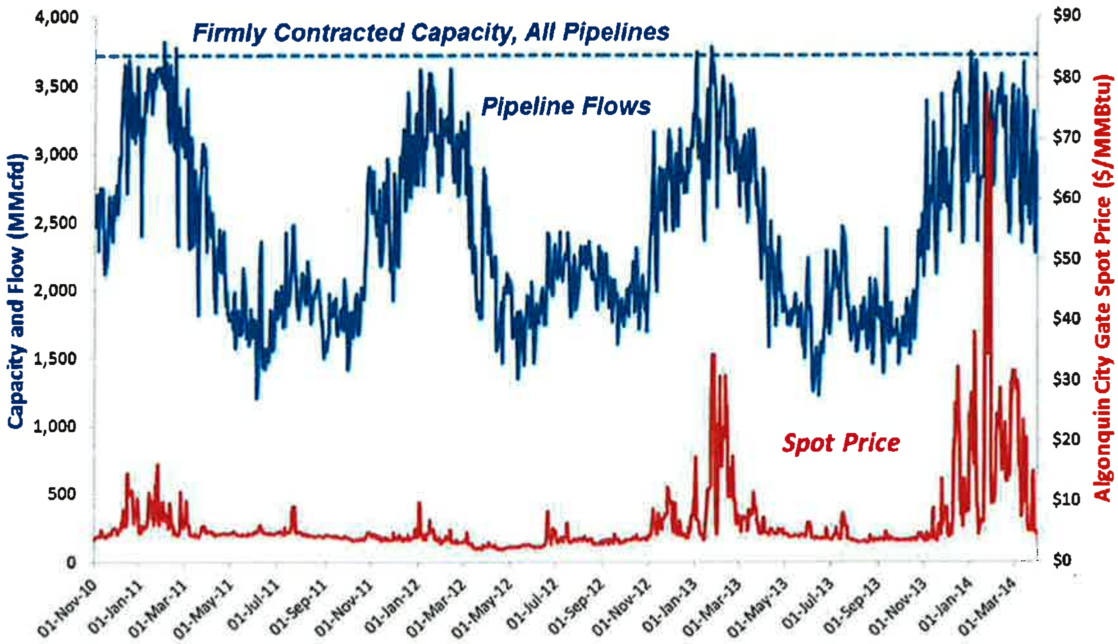
Figure 3. Firmly Contracted Pipeline Capacity into New England, MMcfd[3]

Pipeline System	Current Contracts	With 2016 Expansions[4]
Tennessee Gas Pipeline	1,290	1,362 (+72)
Algonquin Gas Transmission	1,120	1,462 (+342)
Iroquois Gas Transmission	230	230
Portland Natural Gas Transmission System	250	250
Maritimes and Northeast (M&N)	830	830
Total Firmly Contracted Capacity	**3,720**	**4,134 (+414)**

While the physical capability of the pipelines entering New England is somewhat greater that the firmly contracted capacity, contracted and interruptible deliveries to upstream shippers on cold winter days effectively limit total deliveries to New England shippers to firmly contracted volumes. This pattern of pipeline constraints on winter peak day pipeline deliveries can be seen in the daily in-bound flows and regional spot prices over the past 4 years, as shown in Figure 4.

[3] Current contracts based on ICF's assessment of each pipeline's reported firm capacity contracts with receipt points outside of New England and delivery points within New England.
[4] Expansion capacities based on announce capacities for the Algonquin Incremental Market (AIM) project and the Tennessee Gas Connecticut Expansion project, both due online in November 2016.

Figure 4. New England In-bound Pipeline Capacity, Daily Flows, and Daily Spot Gas Price



Sources: Pipeline bulletin board data (flow), SNL (Algonquin spot prices)

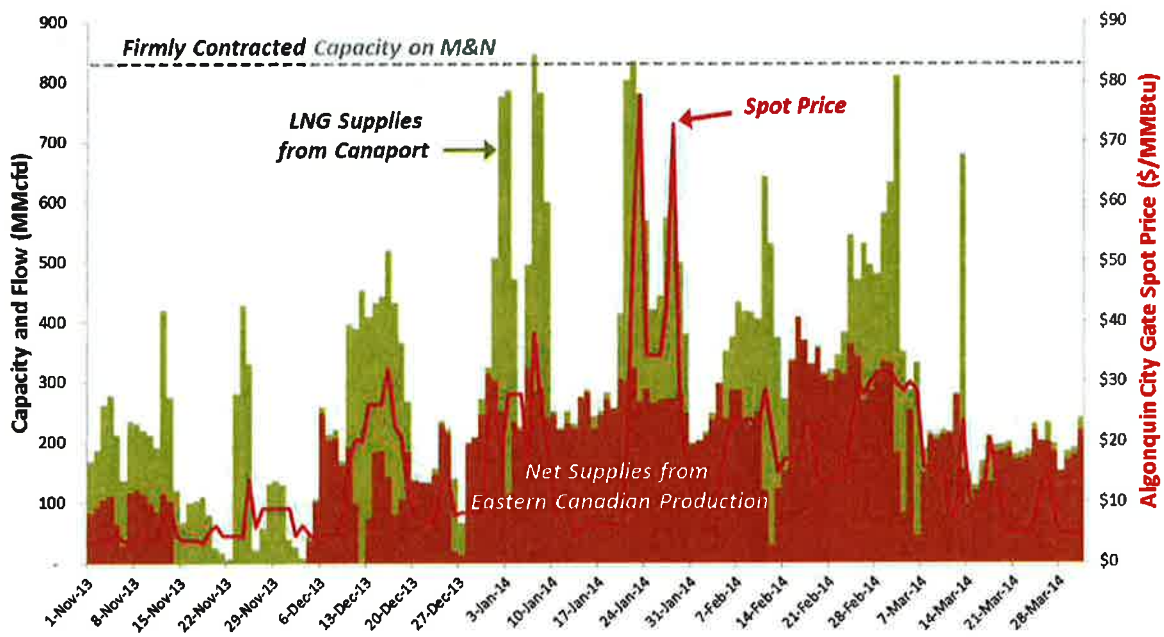
During this past winter, pipeline utilization (the ratio of total in-bound flows to firm pipeline capacity) was above 90% on 42 days, and above 95% on 10 days. As the pipelines approached their limits, the price of remaining spot supplies increased. As a result, spot prices spiked to over $70/MMBtu on two days, and averaged over $23/MMBtu for the entire month of January.

One of the five pipelines serving New England is the Maritimes and Northeast (M&N) Pipeline. Firmly contracted capacity on M&N is slightly over 0.8 Bcfd, representing about 22% of the region's total in-bound pipeline capacity. M&N relies on gas supplies from eastern Canada's two offshore platforms, Sable Island and Deep Panuke, as well as LNG from the Canaport import terminal in New Brunswick. Production from the Deep Panuke platform began in August 2013. Deep Panuke has a nominal capability of 300 MMcfd, but output from this platform was interrupted several times during the winter. Projection from the Sable Island, which has a nominal capacity of as much as 500 MMcfd, has been declining in recent years, averaging less than 200 MMcfd.

Canaport LNG is jointly owned by Irving Oil (25%) and Repsol (75%), and is connected to M&N via the Brunswick Pipeline. Due to the rapid growth of Marcellus shale gas production, shoulder and summer month gas prices in New England and eastern Canada have been far below Atlantic basin LNG prices. As a result, the overall utilization of the facility has been very low. In February 2013, Repsol reached an agreement to sell its LNG supply contracts and ship charters to Shell. As part of the deal, Shell will continue to supply the Canaport terminal with approximately 1 million tons (approximately 48 Bcf) of LNG per year over the next ten years.

While Canaport currently provides little if any gas supplies to Northeast markets during the shoulder and summer months, it was an important supply source this past winter. Over the 90 days from December 1, 2013 through February 28, 2014, supplies from Canaport LNG made up over 40% of the total flows to the U.S. on M&N Pipeline (Figure 5). On several days when output from the eastern Canadian offshore fields was not available, Canaport LNG was the sole source of M&N gas supplies to the U.S.

Figure 5. Maritimes and Northeast Pipeline Capacity and Flows



Sources: Pipeline bulletin board data (flow), SNL (Algonquin spot prices)

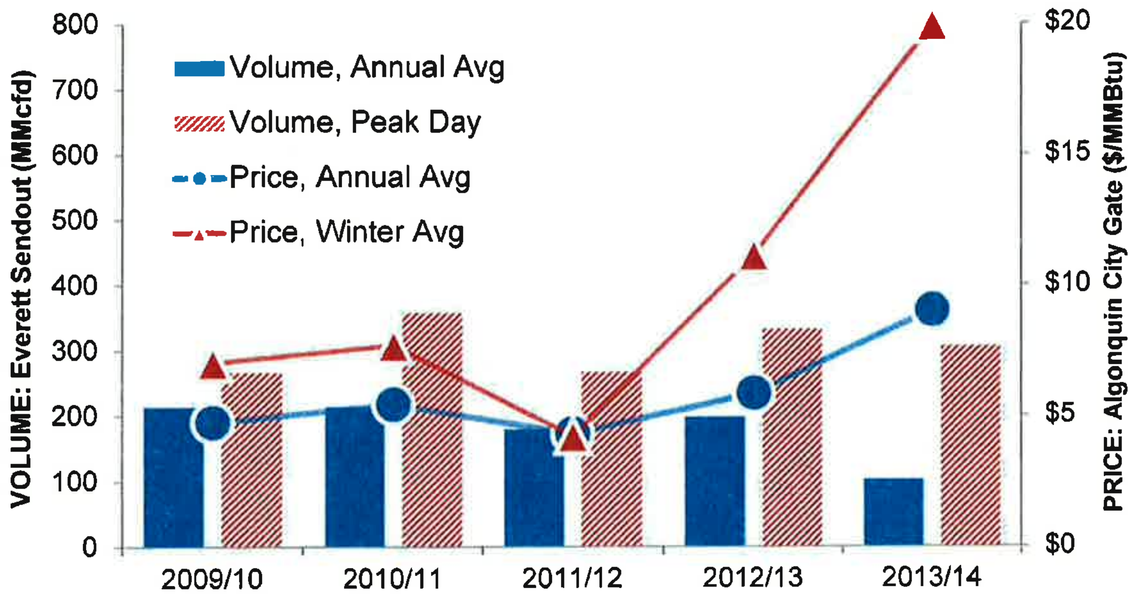
The Distrigas LNG terminal in Everett, MA (operated by GDF SUEZ NA) is the region's only other source of natural gas supplies currently in use.[5] The Everett facility has a total storage capacity of 3.4 Bcf and a sustained vaporization capacity of 715 MMcfd. Everett can deliver up to 300 MMcfd to Algonquin and Tennessee pipelines (150 MMcfd each), in addition to direct connections to the Mystic Generating Station and National Grid/Boston Gas. Everett also provides up to 100 MMcf per day of trucked shipments of LNG to 46 satellite peak shaving facilities operated by the local distribution companies (LDCs). The LDCs rely on these facilities to meet up to 30% of their peak day loads. However, the peak shaving facilities do not represent a separate supply source into the region; they are merely a way of redistributing LNG supplies received at Everett.

Over the past 5 years, New England natural gas prices have been relatively low compared to LNG prices, leading to a decline in imports to the Everett terminal (Figure 6). Since 2010, daily spot gas prices at the Algonquin City Gate during the shoulder and summer months (March through October) have averaged only about $4.50 per MMBtu, compared to Atlantic Basin LNG

[5] New England's two offshore LNG terminals, Neptune and Northeast Gateway, have not received any shipments since 2010.

prices of $14 to $15 per MMBtu. Over that same period, sendout from the Everett LNG has declined from over 200 MMcf to only 100 MMcfd.

Figure 6. Everett LNG Sendout and New England Spot Prices



Sources: LNG sendout based scheduled deliveries from Everett to Algonquin and Tennessee pipelines and estimate deliveries to Mystic units 7 and 8; Algonquin daily spot prices provided by SNL

While gas prices have been low in shoulder and summer months, New England gas prices often rise well above global LNG prices during the winter. 2011/12 was an exception, as gas prices remained lower due to record warm winter weather. However, during the winter of 2012/13, spot prices were over $15 per MMBtu on 17 days and averaged $12 per MMBtu. This past winter, prices were above $15 per MMBtu on 36 days and averaged nearly $20 per MMBtu, well above global LNG prices.

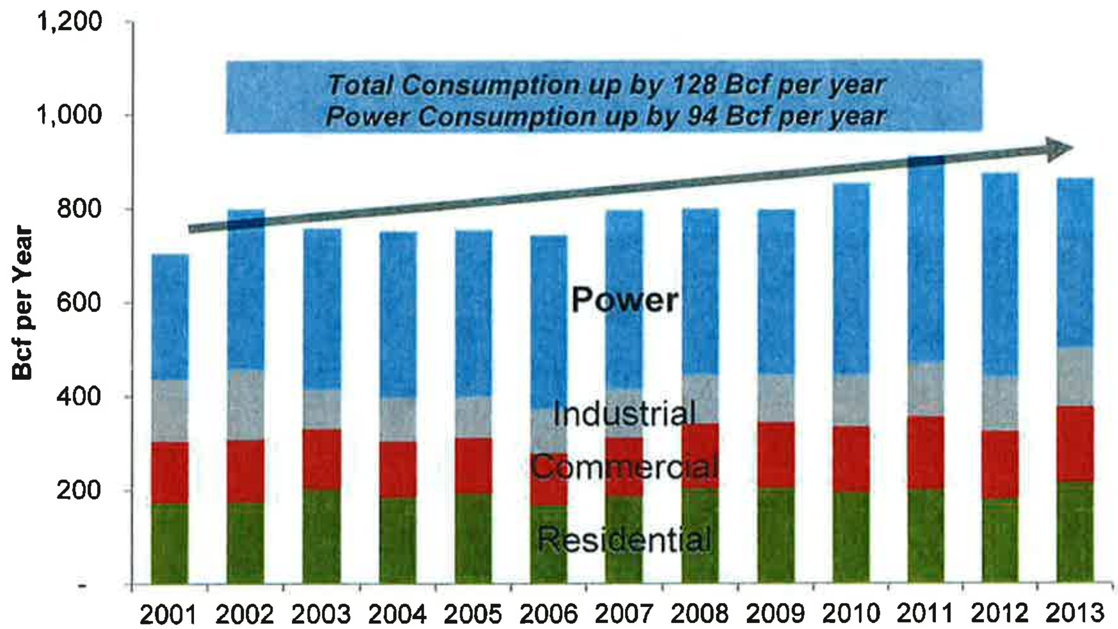
During these periods of supply constraints, additional LNG imports could have eased regional supply constraints and reduced gas prices in New England. However, under the current market system, electric generators have no way to recover costs for this service. As a result, generators continue to rely on interruptible pipeline capacity, and are exposed to potential gas supply shortages and high prices during peak demand periods.

3 New England Natural Gas Demand Growth

When adjusted for fluctuations in weather, New England natural gas consumption has increased by about 130 Bcf per year since 2001 (Figure 7). Over this same time period, the total number of residential and commercial (R/C) gas customers has grown from 2.3 million to 2.6 million, an increase of 12%.[6] However, increases in end-use efficiency have reduced per-customer consumption, offsetting some of the impacts of customer growth. As a result, over the same time period R/C gas consumption has increased by only 9 percent (about 40 Bcf per year). Industrial gas demand has rebounded somewhat since the recession, but is still down versus 2001 levels. Currently, industrial gas consumption in New England averages less than 120 Bcf per year, as output from energy-intensive industries in New England (e.g., paper and chemicals) have all declined from 2001 levels.

Most of the growth in New England gas consumption since 2001 has come from the power sector, which has increased by about 94 Bcf per year. Currently, the power sector accounts for just under half of the region's total annual gas consumption, and over 40% of New England's total electric generating capacity is fueled by gas.

Figure 7. Historical New England Gas Consumption by Sector



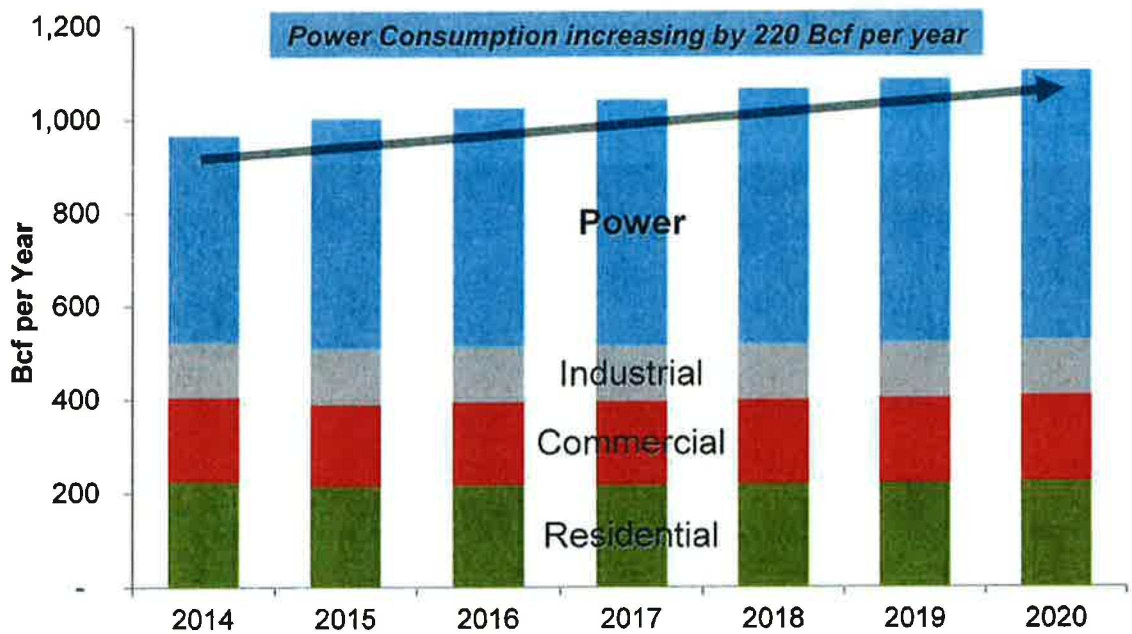
Source: EIA

Future gas demand growth in the region will continue to be driven primarily by the power sector. ICF currently projects that annual New England power generation gas consumption will increase by 220 Bcf through 2020, accounting for 90% of the region's total projected gas demand growth (Figure 7). As in the past, incremental electric load growth is likely to be met by increases in gas-fired generation. Additionally, pending retirements of coal, oil, and nuclear capacity will increase New England's dependency on gas-fired generation. Based on ISO New England's most recent Forward Capacity Auction (FCA8), retirements of Salem Harbor Units 3 and 4 and Vermont Yankee will remove 1,201 MW of non-gas capacity from the market by the winter of 2015/16. Assuming the full output of these units is replaced with gas-fired capacity, these

[6] Based on residential and commercial customer counts reported in EIA Form 176.

retirements could increase peak power generation gas demand by 0.23 Bcfd. By the winter of 2017/18, addition retirements of Brayton Point units (another 1,535 MW) could increase peak gas demand by another 0.32 Bcfd (0.55 Bcfd total).[7]

Figure 8. Projected New England Natural Gas Consumption



Source: ICF International Q2 2014 Natural Gas Strategic Outlook; assumes normal weather

[7] Estimates for incremental peak gas demand from non-gas unit retirements are based on replacing all the potential MWh of generation from this capacity with gas-fired generation at the fleet average heat rate of 8.2 MMBtu/MWh.

Figure 9. Capacity Exiting the New England Wholesale Electric Market, 2014-17

Plant and Unit Number	Primary Fuel	Year Retiring	Capacity (MW)
Salem Harbor 3	Coal	2014	150
Salem Harbor 4	Oil	2014	431
Vermont Yankee	Nuclear	2014	620
Brayton Point 1	Coal	2017	244
Brayton Point 2	Coal	2017	244
Brayton Point 3	Coal	2017	612
Brayton Point 4	Oil	2017	435
Total Retirements			**2,736**

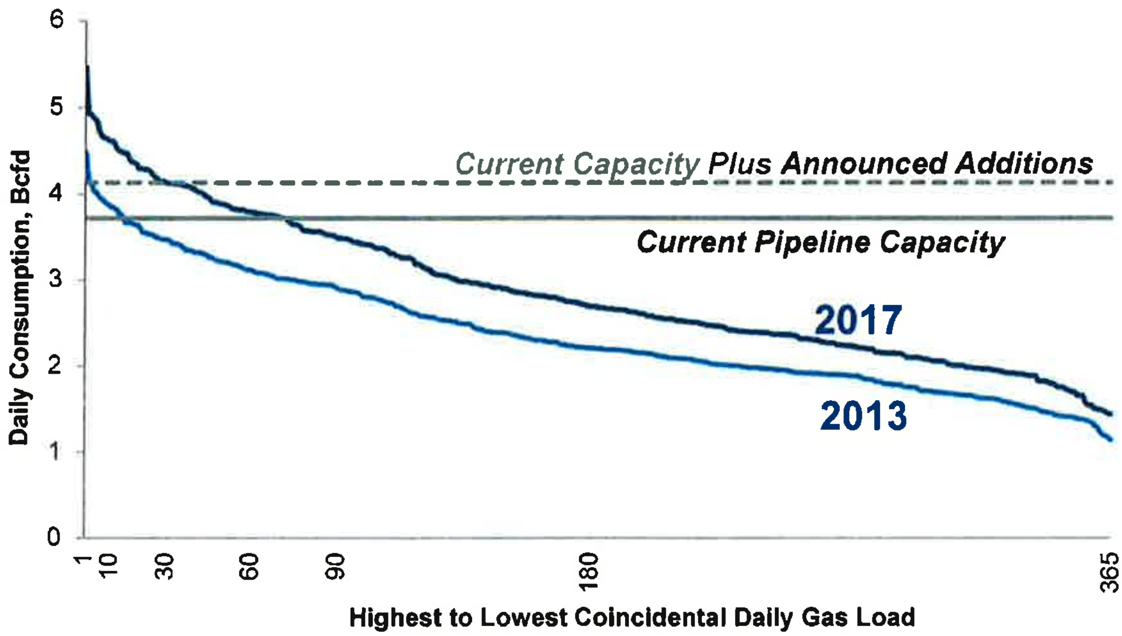
Source: Based on ISO New England Forward Capacity Auction (FC8)

Given expected demand growth, ICF projects that winter peak day loads will reach 5.5 Bcfd by 2017, an increase of almost 1 Bcfd over the 2013 peak (Figure 10). This projection for peak day load is based on 20-year average temperatures; colder-than-normal weather (similar to what was experienced this past winter) would yield a peak day load projection that is about 20% higher than a typical peak winter day. A significant portion of New England's peak day gas load is met by peak-shaving facilities. These facilities are owned and operated by regional LDCs, which use them to insure reliable service to their firm customers. As such, these peak shaving resources are not available to serve customers that rely on interruptible gas service, including the majority of gas-fired electric generators.

As discussed above, planned expansions of the Algonquin and Tennessee systems will provide over 400 MMcfd of new pipeline capacity into the region by the winter of 2016/17, but this will not be available in time to meet the incremental gas demand created by the 1,201 MW of non-gas generation retirements scheduled to occur before 2016. And even after the new pipeline capacity is built, it will not necessarily be available to interruptible shippers (i.e., the gas-fired generators) on cold winter days, since the LDCs hold the firm rights and will use this capacity to meet their customers' demand. As a result, it is likely that New England's total daily gas load will exceed in-bound pipeline capacity on about 30 days per year.

Upstream supply issues on M&N Pipeline may also exacerbate New England's gas supply constraints. Production from the Sable Island offshore platform has been steadily declining, Canaport's firm LNG supply contracts are limited, and gas consumption in eastern Canada is increasing. Based on these conditions, M&N Pipeline (which represents over 20% of the region's in-bound firm capacity) is unlikely to flow full on more than a few days per winter.

Figure 10. New England Daily Natural Gas Consumption, 2013 and 2017



Source: ICF estimate for 2013; 2017 projection assuming 20-year average temperatures

4 ISO New England's Winter Reliability Program and the Cost of Fuel Oil

In 2013, ISO-NE instituted its Winter Reliability program to address electric system reliability concerns arising from constraints on the interstate pipeline system into New England, increased reliance on natural gas-fired generation, and generating resource performance during periods of stressed system conditions.[8] As a short-term means to reduce these risks, ISO-NE offered to procure up to 2.4 million MWh of energy this winter from a combination of oil-fired generators, dual-fuel generators, and demand response assets. In exchange for their commitment to maintain oil inventories needed to provide power when called upon, the selected oil-fired and dual-fuel generators receive monthly payments regardless of whether they were actually dispatched. These payments reduced the financial risk to the generators holding oil inventories that might not be used. ISO-NE ultimately accepted bids from 20 participants for 1.95 million MWh of energy (83% of the original target). While the program included demand response, only one demand response bid was accepted, amounting to less than 1% of the total program MWh. LNG inventories at Everett and Canaport were not included in the Winter Reliability program.

The Winter Reliability program required that generators have the fuel oil in inventory by December 1, 2013. Data from the U.S. Energy Information Administration (EIA) indicates that the delivered cost of fuel oil to electric generators in New England averaged about $22 per

[8] ISO-NE's FERC filings related to the Winter Reliability program: http://www.iso-ne.com/key_projects/win_relblty_sol/iso_ne_filings/

MMBtu from September to November 2013, the period when oil for the program would most likely have been purchased.[9] Assuming an oil fleet average heat rate of 12 MMBtu/MWh[10], ICF estimates the total amount of fuel oil purchased for the program was approximately 23.3 trillion Btu at a total cost of over $500 million.

In its 2013 study for GDF SUEZ, ICF assumed that the cost of incremental LNG delivery to Everett would be $14.50 per MMBtu; global landed LNG prices in November 2013 appear to support this assumption (Figure 11). Given the reported cost of fuel oil, LNG would have cost about 33% less, a potential savings of about $175 million based on ICF's estimate of fuel oil expenditures related to the Winter Reliability program. Shifting from oil-fired to gas-fired generation could also yield additional fuel cost savings, as New England's gas-fired units have a significantly better average heat rate than the oil-fired units.

Figure 11. Estimated Landed Prices for LNG in November 2013, Dollars per MMBtu

Source: FERC Natural Gas Market Overview, October 2013

As discussed above, evidence from this past winter supports the conclusion that New England is likely to need additional fuel supplies about 30 days per year, during the peak winter demand period. In its 2013 study for GDF SUEZ, ICF compared the cost of serving this relatively short duration load with either new ("greenfield") pipeline capacity or incremental LNG imports. In March 2014, ICF completed a study of gas, oil and natural gas liquids midstream infrastructure

[9] EIA Electric Power Monthly, Table 4.11.A. Average Cost of Petroleum Liquids Delivered for Electricity Generation.
[10] The oil-burning fleet average heat rate is based on data from EIA-923 Monthly Generation and Fuel Consumption Time Series.

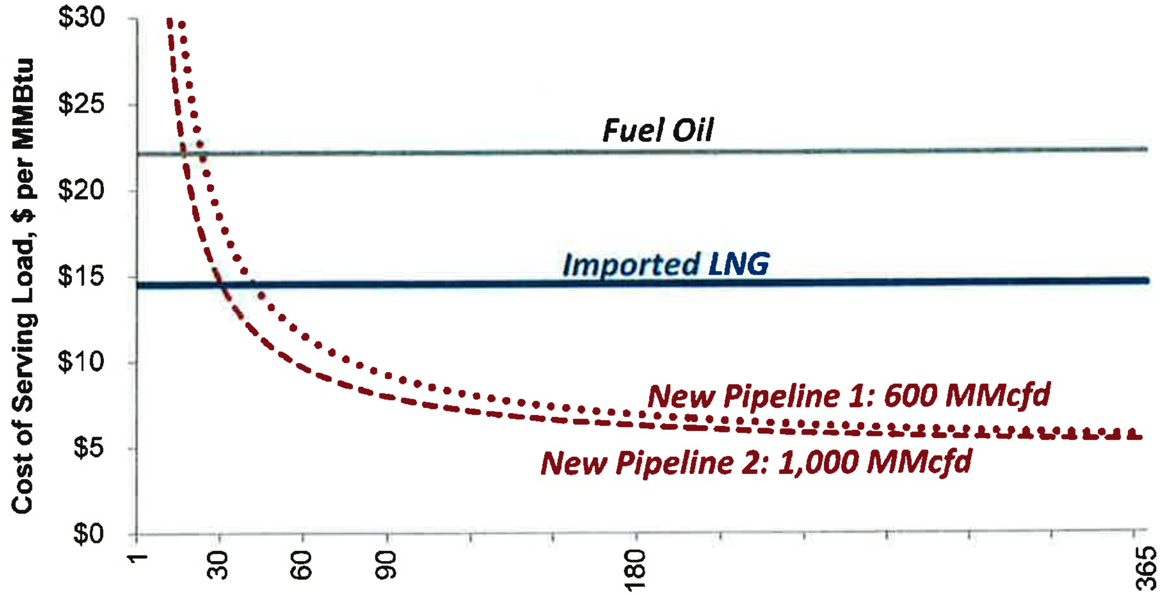
requirements for the INGAA Foundation.[11] For that study, ICF collected extensive data on recent natural gas pipeline projects and compiled new regional cost estimates for pipeline construction. Based on new data collected during the INGAA study, ICF currently estimates that a greenfield pipeline from the Marcellus Shale (the most likely source of incremental domestic gas supplies) to New England would cost between $1.7 billion (for a 600 MMcfd pipeline) to $2.1 billion (for a 1,000 MMcfd pipeline).

Using these new cost estimates, ICF created revised "cost duration curves" to illustrate the cost of pipeline service (in dollars per MMBtu) versus the number of days the capacity is needed (Figure 12). The cost duration curves for the two new pipeline options are derived by dividing the annual capital charge ($310 to $425 per Mcf annually, assuming a capital recovery factor of 14.6%) by the number of days the pipeline is needed, and then adding the variable costs, including the cost of gas supplies (assumed to be $4.50 per MMBtu). Since the incremental capacity is only needed for about 30 days per year, the effective per-unit cost of the pipeline-delivered supply would be between $15 and $19 per MMBtu.

For comparison, Figure 12 also shows the costs of fuel oil at $22 per MMBtu (consistent with last fall's delivered price, and also with the current world crude oil price of over $100 per barrel) and the assumed cost of incremental LNG imports at $14.50 per MMBtu. This illustrates the point that LNG imports are a more cost-effective option to serve incremental fuel demand with a duration of 30 days or less per year. As was pointed out in ICF's 2013 report for GDF SUEZ, it is typically more cost effective to increase the utilization of an existing asset rather than build new capacity, as the capital cost of existing assets can be treated as sunk cost and therefore not subject to capital recovery.

[11] "North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance," INGAA Foundation Report prepared by ICF International, March 2014.

Figure 12. Cost Duration Curves: Cost per Day to Serve Incremental Fuel Demand, Dollars per MMBtu



Source: ICF International

5 Summary of Conclusions

- While the winter of 2013/14 was very cold, New England's weather conditions were not unprecedented.
  - During the prior 20 years New England experienced two other very cold winters, so it is prudent to plan for similar events in the future.
  - Evidence from this past winter supports the conclusion that New England experiences gas pipeline constraints about 30 days per year, and projected demand growth suggests these constraints will persist at least through the remainder of the decade.
- This past winter, in-bound pipeline capacity was over 90% full on 42 days and over 95% full on 10 days.
  - Planned pipeline expansions will increase gas supplies into the region, but gas demand will also continue to increase.
  - Pending retirements of coal, oil, and nuclear generating capacity could create up to 0.23 Bcfd of additional peak demand within the next two years (prior to the AIM expansion), and up to 0.55 Bcfd by the winter of 2017/18.
- Increased utilization of the Everett LNG import terminal is a relatively low cost way of meeting this short duration constraint, and one of the few options available over the next two to three years.

    - A new, greenfield pipeline would cost about $2 billion, would need to be fully contracted, and would take at three years to complete.
    - When annual pipeline costs are allocated over the 30-day period the capacity is needed, the cost per MMBtu of fuel demand served is higher than imported LNG.
- ISO New England's Winter Reliability program encouraged the use of fuel oil to meet winter fuel needs, but imported LNG would have cost less on a dollar per MMBtu basis.
    - This past fall, the cost of LNG was about 33% less per MMBtu than what generators spent on fuel oil.
    - Gas-fired units also have a better average heat rate than oil-fired units, yielding additional potential fuel cost savings.
    - Pending retirements of some oil-fired capacity will limit the ability to switch to oil in the future.