Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II

DRAFT REPORT w/o Appendices
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LIST OF EXHIBITS

Acknowledgements

ICF International would like to thank the staff of ISO New England Inc. for their extensive contributions to this analysis and particularly to Mr. Mark Babula the Project Manager and Mr. Wayne Coste who prepared the IREMM[1] production simulation forecasts used for estimating natural gas consumption by the power sector.

[1] IREMM is the acronym for the Inter-Regional Electric Market Model (IREMM). More information can be found at: www.iremm.com.

Errors and Omissions Statement

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Executive Summary

In 2011 and 2012, ICF International (ICF) conducted a study under the direction of ISO New England, Inc. (ISO-NE) aimed at assessing the adequacy of the natural gas pipeline infrastructure in New England to serve the combined needs of the core natural gas market and the regional electric generation fleet.[2] In the 2011/12 study (referred to hereafter as "Phase I"), ICF quantified New England's natural gas supply capabilities (contracted pipeline capacity, peak shaving capabilities, and LNG import facilities) and projections for growth in peak winter day and summer day gas loads for the region's local distribution companies (LDCs), and compared these values to ISO-NE projections for power sector peak day gas consumption to assess the adequacy of New England gas supplies to meet the growth in peak day gas loads through 2020.

Since the Phase I study, there have been several significant changes in the existing natural gas and electric power systems and projections for future changes that prompted ISO-NE to specify additional cases for gas supply and power sector demand. Additionally, ISO-NE identified the need to extend the power sector gas supply adequacy analysis beyond the peak winter and summer demand day to examine supply adequacy throughout the peak winter demand period (December 1 through February 28). This report provides findings from the new study (referred to hereafter as "Phase II").

While LDCs contract for firm pipeline capacity and arrange for other supplies (such as LNG imports and peak shaving facilities) to meet the projected peak day demands of their firm gas customers, most electric generators rely on interruptible pipeline capacity for their fuel supplies. As in the Phase I study, this analysis assumes that on peak and near-peak demand days, the firmly contracted pipeline capacity is used to meet firm LDC loads, and electric generators must rely on whatever supply capabilities remain.[3] ***Therefore, in the context of this report, a gas supply "deficiency" suggests that the firm shippers are at or near their full contract limits and there is insufficient interruptible pipeline capacity remaining to meet the overall needs of the electric generators. A potential deficit of supplies available to electric generators does not mean that the pipelines serving New England are under-designed or otherwise incapable of meeting their contractual firm shipper obligations; rather it raises a number of questions about how to address potential supply shortages for electric generators.***

For the Phase II study, ICF performed a new review of pipeline contracts based on each pipeline's Index of Shipper data from Q4 2012. The changes between the Phase I and Phase II pipeline capacity assessments are shown in Exhibit ES-1. There were no changes to either the assumed peak shaving or LNG sendout capabilities; therefore the net change in base year (2011/12) maximum winter and supply capabilities was +150 MMcf/d.

[2] Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs, ICF International, ISO New England posting to the Planning Advisory Committee (PAC) on June 15, 2012.
[3] In reality, any spare pipeline capacity during the winter or summer peak load periods could be sought by regional gas LDCs, gas-fired generators, portfolio managers, gas marketers, etc.

Exhibit ES-1. Assessment of New England Natural Gas Pipeline Capacity Contracts, Phase II versus Phase I

Pipeline System and Contracted Capacity (in MMcf/d)	Phase I Assessment of Contracts	Phase II Assessment of Contracts	*Net Change in Phase II*
Algonquin Gas Transmission (AGT)	1,087	1,118	*+31*
Iroquois Gas Transmission (IGT)	220	228	*+8*
Tennessee Gas Pipeline (TGP)	1,261	1,291	*+30*
Portland Natural Gas Transmission (PNGTS)	168	249	*+81*
Maritimes and Northeast Pipeline (M&N)	833	833	-
Total In-Bound Contracted Capacity	**3,569**	**3,719**	***+150***

The size and timing of assumed pipeline expansions into New England was also updated for Phase II, based on ICF's most recent market recognizance of planned projects. ICF currently projects that by November 2016, contracted pipeline capacity into the New England market will increase by a total of 450 MMcf/d, from planned expansions on Algonquin (380 MMcf/d) and Tennessee (70 MMcf/d).

The Phase II cases examine a variety of scenarios for New England gas supply and power sector demand. These scenarios can be group into four categories:

- Phase II Retirement
- Phase II Energy Efficiency
- Phase II Decreased LNG
- Phase II Winter Near-Peak

The first three scenarios (Retirement, Energy Efficiency, and Decreased LNG) use the same analytic approach as in Phase I, but with revised assumptions for generating capacity, energy efficiency, and natural gas supplies. The analysis for the first three scenarios focuses on the winter peak (design) day and summer peak day fuel requirements through 2020, and consisted of five steps:

1) Estimate New England's natural gas supply capabilities (pipeline capacities, LNG import capacities, and peak-shaving facility capabilities.)
2) Estimate New England LDCs' firm gas requirements for a winter peak (design) day and summer peak day.
3) By subtracting (2) from (1), estimate remaining gas supply capabilities to serve electric generation.
4) Project overall power sector gas demands (analysis performed by ISO-NE).
5) By subtracting (4) from (3), calculate the difference between the demand projection and the remaining gas supply capabilities to represent the surplus (or deficit) in gas supplies available for electric generation.

As in Phase I, the Phase II analysis for the Retirement, Energy Efficiency, and Decreased LNG scenarios was repeated for four alternative generation forecasts provided by ISO-NE:

1) **Nominal Gas Demand Forecast**, based on a 50/50 electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 50%.
2) **Reference Gas Demand Forecast**, based on a 90/10 electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 10%. While it is not identical to the gas sector concept of a design day, the 90/10 forecast is closer to the conditions assumed for the gas market on a peak day.
3) **Higher Gas Demand Forecast**, based on the Reference Gas Demand Forecast, where there is a large nuclear or coal-fired power plant outage, combined with high regional natural gas prices.
4) **Maximum Gas Demand Forecast**, based on the Reference Gas Demand Forecast, but where there is a large nuclear or coal-fired power plant outage with low regional natural gas prices.

All of the first three Phase II scenarios still show significant gas supply deficits on peak winter demand days from 2014 through 2020:

- Phase II Retirement gas supply deficits range from about -400,000 Dth (Nominal) to -1,000,000 Dth (Maximum).
    - The Phase II Retirement supply deficits are smaller than the deficits in the Phase I Reference cases due to Phase II's higher assumed base year pipeline capacities and larger assumed pipeline capacity expansion in 2016.
- Phase II Energy Efficiency cases reduced winter peak day electric generator gas consumption by 40,000 Dth (Nominal) to 290,000 Dth (Maximum).
    - However, despite the reduced gas requirements, the gas supply adequacy analysis still shows significant deficits in power sector gas supplies on winter peak days throughout the forecast.
- Phase II Decreased LNG cases reduced peak day gas supplies (and thereby increased supply deficits) by 311,000 Dth in each of the cases examined.

The analytic approach for the Winter Near-Peak was different. Whereas the first three Phase II scenarios focus solely on gas supply and demand on a winter peak day (also referred to as a design day), the Phase II Winter Near-Peak analysis uses load duration analysis to look not just as the peak day, but at supplies and demands throughout the winter. On near-peak winter days, LDC gas loads are still relatively high, but the availability of supplies from LNG terminals and regional peak shaving facilities is reduced, lowering the total gas supplies available. The goal of the Winter Near-Peak analysis was to determine the number of winter days on which there may not be sufficient gas supplies to meet projected consumption for electric generation.

To examine gas supply and demand conditions throughout the 90 days (December 1 through February 28) of winter, ICF developed temperature-based load duration curves to represent the LDC daily gas demand as a function of mean daily temperature, as well as temperature-based gas supply curves for load-following supply sources such as the Distrigas LNG terminal and M&N Pipeline (which is fed in part by the Canaport LNG terminal) and the LDCs' regional peak shaving facilities. To represent a sufficiently wide range of weather conditions, ICF collected historical winter mean daily temperatures for the past 20 years (1993/94 through 2012/13). Using the gas load and gas supply curves along with the historical temperature data, ICF projected the gas supply capability remaining to serve electric generation for each day of winter for each of the 20 historical winter temperature patterns.

Similarly, ISO-NE performed additional analysis on the Phase I Reference, Phase I Repower, and Phase II Retirement cases to quantify the relationship between daily temperatures and gas consumption for electric generation for the winter of 2019/20. ICF then compared the projections for gas supplies remaining to the projected daily power sector consumption to arrive at projection for both the duration of the supply deficit (i.e., the number of days when remaining supplies are less than projected demand) and the total quantity (in Dth) of the daily deficit for each of the 20 historical winter temperature scenarios.

The results indicate median values of between 24 and 34 days for duration of the winter 2019/20 deficit. The duration of the deficit ranges from 0 days (Phase I Reference, assuming the warmest temperature scenario) to 51 days (Phase II Retirement, assuming the coldest temperature scenario). The median quantities of the deficit range from about 6,000,000 Dth to about 10,700,000 Dth. The minimum quantity was 0 Dth (Phase I Reference, assuming the warmest temperature scenario), and the maximum quantity was over 21,900,000 Dth (Phase II Retirement, assuming the coldest temperature scenario).

Exhibit ES-2. Duration of Gas Supply Deficit in Days, Winter 2019/20

Electric Sector Scenario	Duration of Deficit, in Days		
	Median	Minimum	Maximum
Phase I Reference	24	0	42
Phase I Repower	29	1	46
Phase II Retirement	34	5	51

Exhibit ES-3. Size of Gas Supply Deficit in 1,000 Dth, Winter 2019/20

Electric Sector Scenario	Total Winter Deficit (1000 Dth)		
	Median	Minimum	Maximum
Phase I Reference	6,047	0	14,436
Phase I Repower	8,107	66	18,361
Phase II Retirement	10,680	439	21,931

Conclusions and Implications

- Despite the increase in currently contracted capacity on the interstate pipelines and the likelihood of 450 MMcf/d of new capacity being added by the end of 2016, the New England market is likely to remain supply constrained through 2020.
- The updated forecast for capacity retirements (Phase II Retirements) results in very little change in projected gas consumption for electric generation.

- The updated energy efficiency projection (Phase II Energy Efficiency) has a significant impact on projected gas consumption for electric generation.
    - The Phase II Energy Efficiency cases reduced projection winter peak day gas consumption by as much as 550,000 Dth by 2019/20.
    - However, the consumption reductions in the Energy Efficiency cases were not sufficient to eliminate the projected winter peak day supply deficits.
- Future imports of LNG into the region (Phase II Decreased LNG) are likely to be well below the rated capacity of the import terminals.
    - As in the Phase I study, neither Northeast Gateway nor Neptune are projected to receive any future LNG shipments.
    - M&N Pipeline is expected to continue to flow at full capacity on a peak winter day.
        - The ramp-up of Deep Panuke production will increase supplies feeding into M&N through 2014, but Eastern Canadian production is expected to decline from 2015 through 2020.
        - Even with reduced LNG shipments, sendout from the Canaport terminal has been managed so to keep M&N Pipeline full on peak winter days (when New England gas demand and gas prices are highest). However, with fewer LNG shipments coming in, M&N will flow full on fewer winter days in the future.
    - Over the past three years, Distrigas winter sendout has declining on both the peak day and over the entire winter.
        - Based on the 2012/13 sendout pattern, the projected winter peak day sendout from Distrigas is less than 60 percent of its rated capacity.
- The Winter Near-Peak analysis indicates that gas supply deficits may occur not just on peak days, but also on multiple high demand days throughout the winter.
    - Based on projected gas supplies, LDC demands, and electric generator gas demands, there is a high probability that the electric sector will have a gas supply deficit on 24 to 34 day per winter by 2019/20.

1. Introduction

1.1. Purpose of the Report

In 2011 and 2012, ICF International (ICF) conducted a study under the direction of ISO New England, Inc. (ISO-NE) aimed at assessing the adequacy of the natural gas pipeline infrastructure in New England to serve the combined needs of the core natural gas market and the regional electric generation fleet.[4] In the 2011/12 study (referred to hereafter as “Phase I”), ICF quantified New England’s natural gas supply capabilities (contracted pipeline capacity, peak shaving capabilities, and LNG import facilities) and projections for growth in peak day gas loads for the region’s local distribution companies (LDCs), and compared these values to ISO-NE projections for power sector peak day gas consumption to assess the adequacy of New England gas supplies to meet the growth in peak day gas loads.

Since the Phase I study, there have been several significant changes in the existing natural gas and electric power systems and projections for future changes that prompted ISO-NE to specify additional cases for gas supply and power sector demand. Additionally, ISO-NE identified the need to extend the power sector gas supply adequacy analysis beyond the peak winter and summer demand day to examine supply adequacy throughout the peak winter demand period (December 1 through February 28). This report provides findings from the new study (referred to hereafter as “Phase II”).

As in Phase I, the Phase II examines a variety of scenarios for New England gas supply and power sector demand. These scenarios can be group into four categories:

<u>Phase II Retirement</u> – After the Phase I study was conducted and published, the United States Environmental Protection Agency (EPA) changed and revised their U.S. EPA Air and Water Regulations. ISO-NE subsequently revised their “At-Risk” list of retirements, but those units on that list was virtually the same as those in the Phase I analysis.

<u>Phase II Energy Efficiency</u> – The Phase II study also includes an assessment of the impacts of ISO-NE’s Energy Efficiency Forecast 2015-2021 on gas consumption. The new load forecast results from the Phase II Energy Efficiency scenario were applied to the Phase I Reference and Repower projections and the Phase II Retirement projections.

<u>Phase II Decreased LNG</u> – In the Phase I study, the Everett and Canaport LNG import facilities were assumed to be operating at maximum sendout capacity on the peak day. For this portion of the Phase II analysis, ICF developed revised assumptions for LNG terminal sendout, based on each facility’s firm and short-term contracts, and the relationship between recent historical winter sendout and daily temperatures.

<u>Phase II Winter Near-Peak</u> – All Phase I and the other Phase II cases focus solely on gas supply and demand on a winter peak day (also referred to as a design day). The Winter Near-Peak Day scenarios use load duration analysis to look not just as the peak day, but at supplies and demands throughout the winter. On near-peak winter days, LDC gas loads are still relatively high, but the availability of supplies from LNG terminals and regional peak shaving facilities is reduced, lowering the total gas supplies available. To examine gas supply and

[4] Assessment of New England’s Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs, ICF International, ISO New England posting to the Planning Advisory Committee (PAC) on June 15, 2012.

demand conditions on near-peak winter days, ICF developed temperature-based load duration curves to represent the LDC daily gas demand throughout the 90-day peak winter demand period, as well as daily gas supply curves for load-following supply sources such as the Distrigas and Canaport LNG terminals and the LDCs' regional peak shaving facilities.

1.2. Analytic Approach

As in the earlier study, the development of input assumptions for the Phase II analyses was divided between ICF and ISO-NE: ISO-NE provided its projections of power sector gas loads, ICF performed the analysis of New England natural gas supply capabilities and projected LDC gas loads, and ICF compared the projected total gas loads to the projected supply capabilities to assess gas supply adequacy (i.e., gas supplies remaining for electric generators). In total, ISO-NE provided ICF with 42 unique projections for peak day winter and summer power sector gas consumption, based on various combinations of Phase I and Phase II assumptions, and a range of economic dispatch cases.

For the first three groups of scenarios (Retirement, Energy Efficiency, and Decreased LNG), ISO-NE created four gas demand cases, based on a range of projections for peak day electric system dispatch.[5] For each gas demand case, ISO-NE identified the gas-fired[6] generation dispatch and, based on gas-fired unit heat rates, estimated the corresponding daily fuel (gas) requirements. The four economic dispatch cases are:

1. **Nominal Gas Demand Forecast**, based on a 50/50 electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 50%.
2. **Reference Gas Demand Forecast**, based on a 90/10 electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 10%. While it is not identical to the gas sector concept of a design day, the 90/10 forecast is close to the conditions assumed for the gas market on a peak day.
3. **Higher Gas Demand Forecast**, based on the Reference Gas Demand Forecast, where there is a large nuclear or coal-fired power plant outage, combined with high regional natural gas prices.
4. **Maximum Gas Demand Forecast**, based on the Reference Gas Demand Forecast, but where there is a large nuclear or coal-fired power plant outage with low regional natural gas prices.

The Retirement, Energy Efficiency, and Decreased LNG scenarios use the same analytic approach as in Phase I. The analysis focuses on the winter and summer peak day fuel requirements through 2020, and consisted of five steps:

1) Estimate New England's natural gas supply capabilities (pipeline capacities, LNG import capacities, and peak-shaving facility capabilities.)
2) Estimate New England LDCs' firm gas requirements for a peak winter day and peak summer day.
3) By subtracting (2) from (1), estimate remaining gas supply capabilities to serve electric generation.
4) Project overall power sector gas demands.

[5] The Decreased LNG scenario had no direct impact on the ISO-NE's demand forecast, so those cases use the ISO-NE Phase I and Phase II gas demand projections.
[6] Also includes dual fuel units burning natural gas as either a primary or secondary fuel.

5) By subtracting (4) from (3), estimate the difference between the demand projection and the remaining gas supply capabilities.

The Phase II Winter Near-Peak scenario approach was slightly different. For this scenario, ISO-NE developed a series of three gas demand cases that were used to estimate winter near-peak day gas demands in the power sector, and ICF developed winter daily gas supply and load curves to represent the availability of gas to the electric sector throughout the 90 days (December 1 through Feb 28) of winter.

Based on these projections from ISO-NE and varying assumptions for gas supplies, ICF examined a total of 49 distinct cases:

- **Phase II Retirement (4 cases)**
    - Nominal, Reference, Higher, and Maximum Gas Demand
- **Phase II Energy Efficiency (12 cases**)
    - Phase I Reference capacity assumptions
        - Nominal, Reference, Higher, and Maximum Gas Demand
    - Phase I Repowering capacity assumptions
        - Nominal, Reference, Higher, and Maximum Gas Demand
    - Phase II Retirement capacity assumptions
        - Nominal, Reference, Higher, and Maximum Gas Demand
- **Phase II Decreased LNG (24 cases)**
    - Phase I Reference electric load growth assumptions
        - Phase I Reference capacity assumptions
            - Nominal, Reference, Higher, and Maximum Gas Demand
        - Phase I Repowering capacity assumptions
            - Nominal, Reference, Higher, and Maximum Gas Demand
        - Phase II Retirement capacity assumptions
            - Nominal, Reference, Higher, and Maximum Gas Demand
    - Phase II Energy Efficiency electric load growth assumptions
        - Phase I Reference capacity assumptions
            - Nominal, Reference, Higher, and Maximum Gas Demand
        - Phase I Repowering capacity assumptions
            - Nominal, Reference, Higher, and Maximum Gas Demand
        - Phase II Retirement capacity assumptions
            - Nominal, Reference, Higher, and Maximum Gas Demand
- **Phase II Winter Near-Peak (9 cases)**
    - With Maximum LNG sendout
        - Phase I Reference capacity assumptions
        - Phase I Repower capacity assumptions
        - Phase II Retirement capacity assumptions
    - With Decreased LNG sendout
        - Phase I Reference electric load growth assumptions
            - Phase I Reference capacity assumptions
            - Phase I Repower capacity assumptions
            - Phase II Retirement capacity assumptions
        - Phase II Energy Efficiency electric growth load assumptions:
            - Phase I Reference capacity assumptions
            - Phase I Repower capacity assumptions
            - Phase II Retirement capacity assumptions

1.3. Organization of this Report

Because of the large number of cases examined, the main body of the report focuses on a high level comparison of the Phase I and Phase II assumptions and results. Section 2 describes Phase II updates to New England natural gas market assumptions. Sections 3, 4, and 5 summarize the results for the Phase II Retirement, Energy Efficiency, and Decreased LNG cases respectively. Section 6 described the Near-Peak Winter Day and “duration of risk” analysis. Detailed results for each of the individual cases are provided in Appendix A (ISO-NE projections for power sector gas demand) and Appendix B (ICF’s electric sector surplus/deficit calculations).

2. Phase II Updates to New England Natural Gas Market Assumptions

2.1. Natural Gas Supply Capabilities

For the Phase I study, ICF estimated the overall gas supply capability into New England based on a summation of the interstate pipeline capacities into the region (Exhibit 2-1), the firm LNG import capability at Distrigas of Massachusetts, and regional peak shaving capability, as well as anticipated pipeline expansions. The Phase I pipeline capacities were based on an ICF assessment of Index of Shipper (IOS) data for firmly contracted supplies into the region on each system conduced in mid-2011. This deterministic assessment was intended to provide a snapshot of the peak winter day deliverability.

Exhibit 2-1. Map of New England Interstate Pipelines and LNG Terminals

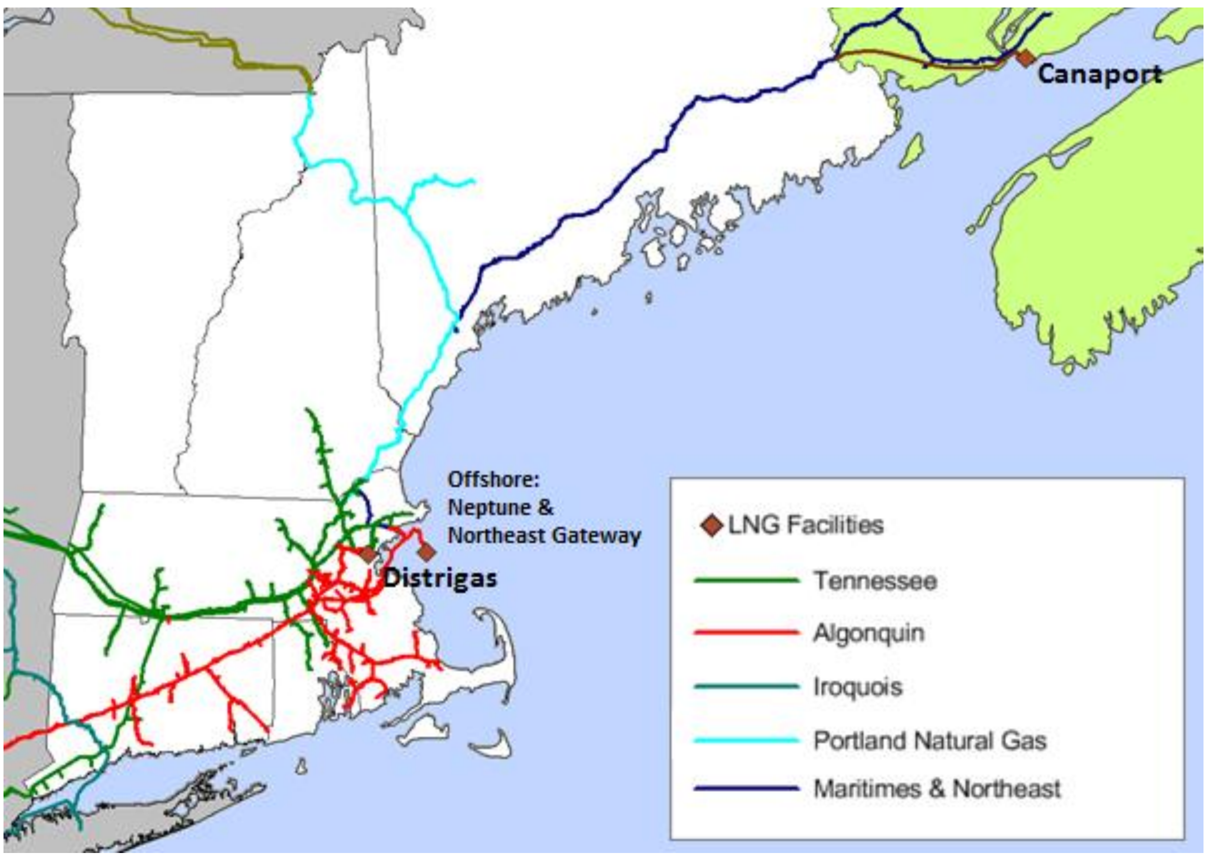


Exhibit 2-2 presents the original Phase I estimate for winter peak day supply capabilities over the forecast period. The estimated supply capability for the winter peak day includes the maximum sendout capability from regional peak shaving facilities and Distrigas, but does not includes capacity from the offshore LNG facilities. The offshore LNG facilities have not received any shipments since 2010, and therefore were not included as potential gas supply sources.

The estimate for the summer peak day deliverability does not include the local peak shaving capacity, since these facilities typically do not operate in the summer months. [7]

Exhibit 2-2. Phase I Assumptions for New England Natural Gas Supply Capabilities

Total Projected Pipeline Capacity	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Forward Haul Pipeline Capacity									
Algonquin Gas Transmission (AGT).	1,087	1,087	1,087	1,087	1,287	1,437	1,437	1,437	1,437
Iroquois Gas Transmission System (IGTS).	220	220	220	220	220	220	220	220	220
Tennessee Gas Pipeline (TGP).	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261
Portland Natural Gas Transmission System (PNGTS).	168	168	168	168	168	168	168	168	168
Pipeline Capacity Partly Dependent on LNG Supplies									
Maritimes & Northeast Pipeline (M&N).	833	833	833	833	833	833	833	833	833
Subtotal	**3,570**	**3,570**	**3,570**	**3,570**	**3,770**	**3,920**	**3,920**	**3,920**	**3,920**
Peak Shaving Capacity									
LNG Peakshaving	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319
Propane-Air	137	137	137	137	137	137	137	137	137
Subtotal	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**
Direct LNG Import Capability									
Everett Distrigas Facility	715	715	715	715	715	715	715	715	715
Northeast Gateway	0	0	0	0	0	0	0	0	0
Neptune	0	0	0	0	0	0	0	0	0
Subtotal	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**
Total Assumed Supply Capability Available on a Winter Design Day	**5,741**	**5,741**	**5,741**	**5,741**	**5,941**	**6,091**	**6,091**	**6,091**	**6,091**
Total Assumed Supply Capability Available on a Summer Peak Day (excludes Peak Shaving)	**4,285**	**4,285**	**4,285**	**4,285**	**4,485**	**4,635**	**4,635**	**4,635**	**4,635**

For Phase II, ICF performed a new review of pipeline contracts using data from Q4 2012, and also updated its projection for likely pipeline capacity additions through 2020. The revised Phase II supply capability projections are shown in Exhibit 2-3, and the net change between the Phase I and Phase II assessment are shown in Exhibit 2-4. There were no changes to either the assumed peak shaving or LNG sendout capabilities; therefore the net change in base year (2011/12) maximum winter and supply capabilities was +150 MMcf/d.

[7] Local peak-shaving capability is devoted to serving the economics and reliability of the regional gas LDCs and is almost never used to support merchant power production.

Exhibit 2-3. Phase II Assumptions for New England Natural Gas Supply Capabilities

Total Projected Pipeline Capacity	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Forward Haul Pipeline Capacity									
Algonquin Gas Transmission (AGT).	1,118	1,118	1,118	1,118	1,118	1,568	1,568	1,568	1,568
Iroquois Gas Transmission System (IGTS).	228	228	228	228	228	228	228	228	228
Tennessee Gas Pipeline (TGP).	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,291
Portland Natural Gas Transmission System (PNGTS).	249	249	249	249	249	249	249	249	249
Pipeline Capacity Partly Dependent on LNG Supplies									
Maritimes & Northeast Pipeline (M&N).	833	833	833	833	833	833	833	833	833
Subtotal	**3,719**	**3,719**	**3,719**	**3,719**	**3,719**	**4,169**	**4,169**	**4,169**	**4,169**
Peak Shaving Capacity									
LNG Peakshaving	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319
Propane-Air	137	137	137	137	137	137	137	137	137
Subtotal	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**
Direct LNG Import Capability									
Everett Distrigas Facility	715	715	715	715	715	715	715	715	715
Northeast Gateway	0	0	0	0	0	0	0	0	0
Neptune	0	0	0	0	0	0	0	0	0
Subtotal	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**
Total Assumed Supply Capability Available on a Winter Design Day	**5,890**	**5,890**	**5,890**	**5,890**	**5,890**	**6,340**	**6,340**	**6,340**	**6,340**
Total Assumed Supply Capability Available on a Summer Peak Day (excludes Peak Shaving)	**4,434**	**4,434**	**4,434**	**4,434**	**4,434**	**4,884**	**4,884**	**4,884**	**4,884**

Exhibit 2-4. Assessment of New England Natural Gas Pipeline Capacity Contracts, Phase II versus Phase I

Pipeline System	**Phase I Assessment of Contracts**	**Phase II Assessment of Contracts**	***Net Change in Phase II***
Algonquin Gas Transmission (AGT)	1,087	1,118	*+31*
Iroquois Gas Transmission (IGT)	220	228	*+8*
Tennessee Gas Pipeline (TGP)	1,261	1,291	*+30*
Portland Natural Gas Transmission (PNGTS)	168	249	*+81*
Maritimes and Northeast Pipeline (M&N)	833	833	-
Total In-Bound Contracted Capacity	**3,569**	**3,719**	***+150***

The size and timing of assumed pipeline expansions was also updated for Phase II, based on ICF's most recent market recognizance. The Phase I analysis assumed a phased capacity expansion on the Algonquin system (the Algonquin Incremental Market project, AIM) of 350 MMcf/d between 2015 and 2016. As of October 2013, the response to Algonquin's open season indicates the actual AIM expansion will be sized at approximately 380 MMcf/d. Additionally , Tennessee Gas Pipeline launched an open season in July 2013 for its Connecticut Expansion Project, which would provide an additional 72 MMcf/d from Tennessee's existing interconnect with Iroquois in Wright, New York, to zone 6 delivery points on Tennessee's 200 line, as well as on the 300 line into Connecticut. Therefore, ICF current projects that by the end of 2016, contracted pipeline capacity into the New England market will increase by 450 MMcf/d, most likely on a combination of expansions on the Tennessee and Algonquin system.

While it does not directly provide any additional capacity to the New England market, Spectra's NY-NJ expansion of its Texas Eastern Transmission and Algonquin lines in the New York City metropolitan area may have an indirect impact on the New England market. By providing additional capacity into New York City metropolitan area, the Spectra expansion may displace some of the flow from New England to Long Island on the Iroquois system, thereby allowing for resale of New York-contracted capacity on Iroquois to New England shippers. However, since the Spectra expansion was only just completed in November 2013, the amount of potential displacement of Iroquois flows (and the availability of release capacity to New England shippers) is still unknown. Therefore, the only assumed change to the Iroquois capacity was the nominal 8 MMcf/d increase in contracted capacity indicated by the Index of Shipper data, as shown in Exhibit 2-4 above.

Summary of New England's Natural Gas Supply Capabilities

About two-thirds of the pipeline capacity contracted by New England shippers is on the Tennessee and Algonquin systems. Tennessee contracts are currently at 1,291 MMcf/d, and Algonquin contracts are 1,118 MMcf/d. Iroquois has a total of over 1,500 MMcf/d of capacity, but the majority of this capacity is contracted for New York shippers; New England shippers contract for only 228 MMcf/d of firm capacity on Iroquois.

On PNGTS, New England shippers currently contract for 249 MMcf/d, but the system's physical capacity is greater; on recent peak winter days PNGTS has flowed over 300 MMcf/d. While PNGTS has proposed an expansion (the "Continent to Coast", or C2C, Expansion Project) to offer additional capacity to the New England market, it will likely be a relatively costly option for New England shippers. PNGTS is supplied through the TransCanada Pipeline (TCPL) and TransQuebec systems with gas sourced in western Canada. Declining production and increasing demand in Alberta has reduced flows on TCPL, but there are still localized constraints in the eastern portion of TCPL's system. For the C2C Project to go forward, it would be necessary for TCPL to increase capacity on the eastern portion of their system.

Maritimes and Northeast Pipeline (M&N) has a capacity of 833 MMcf/d, essentially all of which is contracted for by Repsol's gas marketing division. The M&N pipeline is supplied by gas production in Eastern Canada (primarily from offshore fields) and the Canaport LNG import terminal in New Brunswick. While M&N does flow full on peak demand days (when New England gas prices are very high), the annual capacity utilization of the system has been decreasing due to declining Sable Island offshore production, reduced LNG imports to Canaport, and demand growth in Eastern Canada. (Flows on M&N Pipeline are discussed in more detail in Section 5.)

Distrigas (operated by GDF Suez NA) is only terminal in the region currently receiving continuous shipments. DOMAC has a sustainable vaporization capacity of 715 MMcf/d, and can distribute another 100 MMcf/d 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 MMcf/d in 2012, with a peak day sendout of about 440 MMcf/d. 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. (Distrigas LNG imports are discussed in more detail in Section 5.)

The region's 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.

In addition to the pipeline and LNG import terminals, LDCs in New England also operate 45 LNG and 15 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 1,456 MMcf/d and a total storage capacity of about 16 Bcf.[8] 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.

2.2. Projected LDC Firm Demand Forecast

The analysis of Phase II Retirement, Energy Efficiency, and Decreased LNG cases use the same projection for LDC annual and peak day firm demand as were used in the Phase I study. The aggregate projections for LDC firm demand (annual, winter peak day, and summer peak day) is shown below in Exhibit 2-5. Winter peak day demands are based on projected design day loads for each of New England's LDCs. In some cases, the annual and design day load projections were provided to ICF directly by the LDCs at ISO-NE's request for use in the Phase I study; however, most were derived from LDC filings with the New England state public utility / public service commissions.[9]

Exhibit 2-5. Projected LDC Firm Gas Demand

Gas Year	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	***CAGR 2011-2020***
Annual Consumption, Bcf/year	421	425	429	434	439	444	450	456	462	468	1.2%
Winter	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	
Winter Peak Day, Bcf/d	4.252	4.306	4.360	4.414	4.472	4.541	4.612	4.685	4.760	4.839	1.4%
Summer	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	
Summer Peak Day, Bcf/d	0.605	0.611	0.615	0.621	0.627	0.635	0.642	0.651	0.659	0.668	1.1%

CAGR = Cumulative Average Growth Rate. 1 Bcf is equivalent to 1,000,000 MMBtu or 1,000,000 Dth.

Growth rates for annual, winter peak day, and summer peak day are generally similar. Overall consumption grows at approximately 1.2% per year over the forecast period, whereas peak requirements grow slightly higher at approximately 1.4%. Winter peak gas demand is projected

[8] "NGA 2012 Statistical Guide", Northeast Gas Association, 2012.
[9] Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs (Phase I Report), submitted by ICF International to ISO-NE June 2012.

to grow at a slightly faster rate because of increased gas use for space heating, which is highest in winter. Likewise, summer peak day demand grows at a slightly slower rate (1.1% per year) for the same reason.

3. Phase II Retirement Cases

This section of the reports presents the results for ISO-NE's Phase II Retirement case forecasts. As in the Phase I study, ICF compared the projected peak day supply capabilities with ISO-NE's projections of power sector demand and the projected peak day requirements of LDC firm customers on the winter peak and summer peak days, and then calculated the net surplus (+) or deficit (-) in gas supply capability to meet these combined loads.

The detailed results for each of the Phase II Retirement cases are provided in Appendix A; summary comparisons of the results are shown in Exhibit 3-1 (for ISO-NE demand projections) and Exhibit 3-2 (for the power sector supply/deficit calculations) for both the Nominal and Maximum power sector demand cases. The power sector supply deficits in Exhibit 3-2 are shown both in terms on 1,000s of Dth (left-hand Y-axis) and Megawatt equivalent (right-hand Y-axis, based on an assumed heat rate of 10,000 Btu/kWh).

Because the Phase II Retirement cases indicated a supply surplus (no supply constraint) on the summer peak day, this summary discussion focuses only on the winter peak day.

ISO-NE's projection for Phase II Retirement power sector gas demand is very similar to the Phase I Reference for the Maximum demand case; however, in the Nominal demand case, Phase II Retirement demands are higher by about 110,000 Dth (+7%) from 2014 through 2020 (Exhibit 3-1).

In terms of gas supply adequacy, the Phase II Retirement projections for winter peak day still show significant (if slightly smaller) supply deficits throughout the projection period. From 2014 through 2020, Phase II Retirement gas supply deficits range from about -400,000 Dth (Nominal) to -1,000,000 Dth (Maximum). The Phase II Retirement supply deficits are smaller than the deficits in the Phase I Reference cases due to Phase II's higher assumed base year pipeline capacities and larger assumed pipeline capacity expansion in 2016.

Exhibit 3-1. ISO-NE Projected Power Sector Winter Peak Day Gas Demand, Phase II Retirement versus Phase I Reference

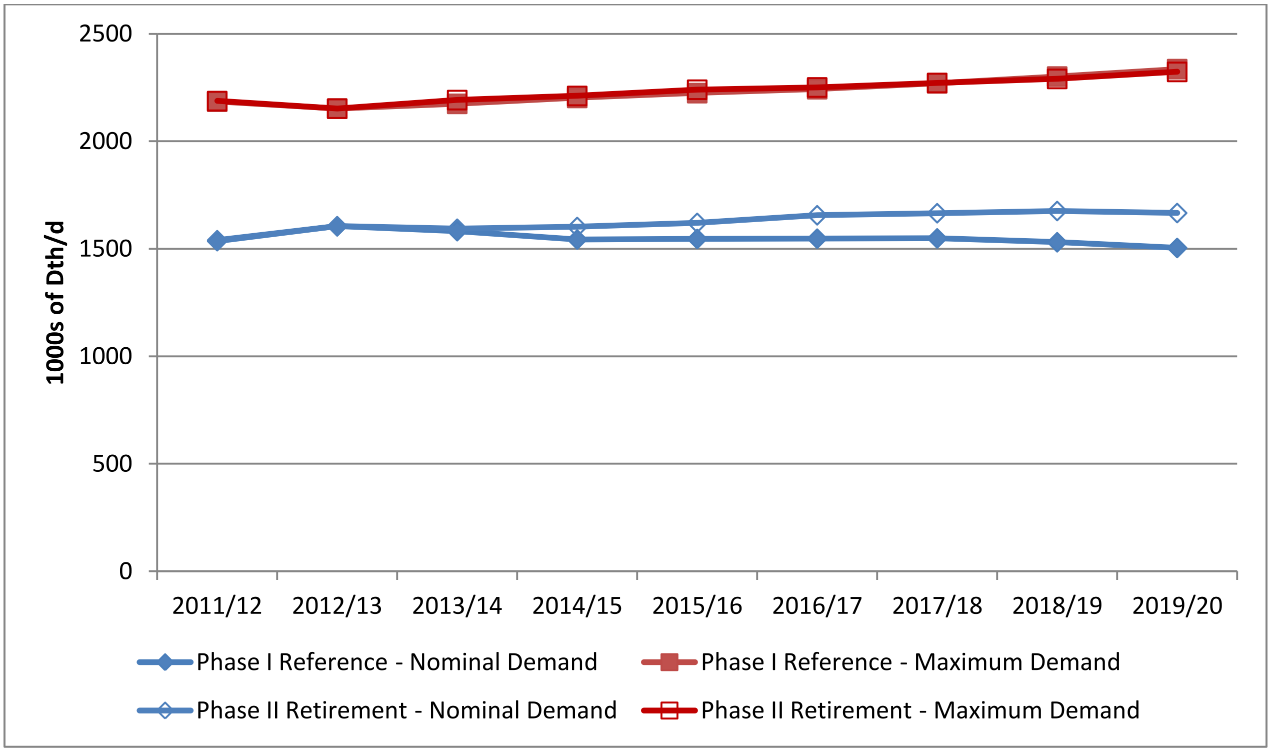
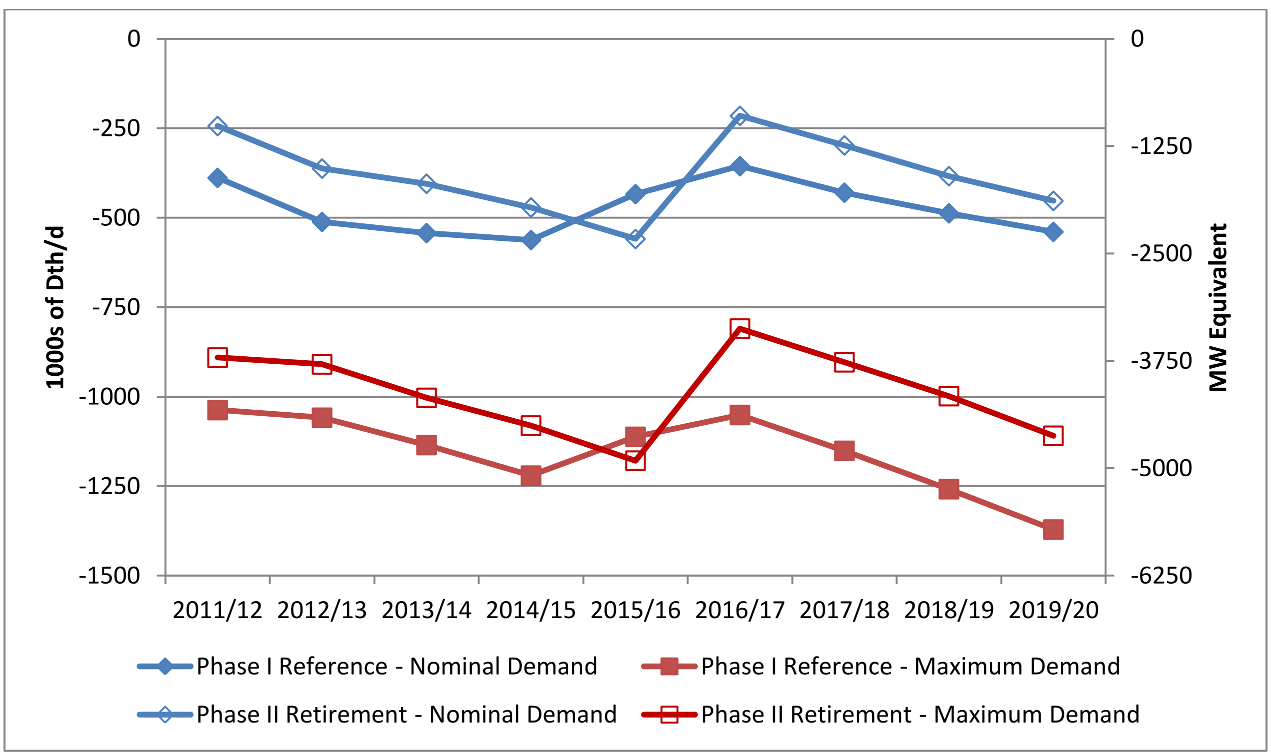


Exhibit 3-2. Power Sector Winter Peak Day Supply Deficits, Phase II Retirement versus Phase I Reference



4. Phase II Energy Efficiency Cases

The Phase II Energy Efficiency scenarios use power sector gas demands based on ISO-NE Energy Efficiency Forecast 2015-2021, which result in lower electric peak load and energy growth and lower power sector gas demands. These scenarios are divided into three groups of cases, based on the capacity assumed for each:

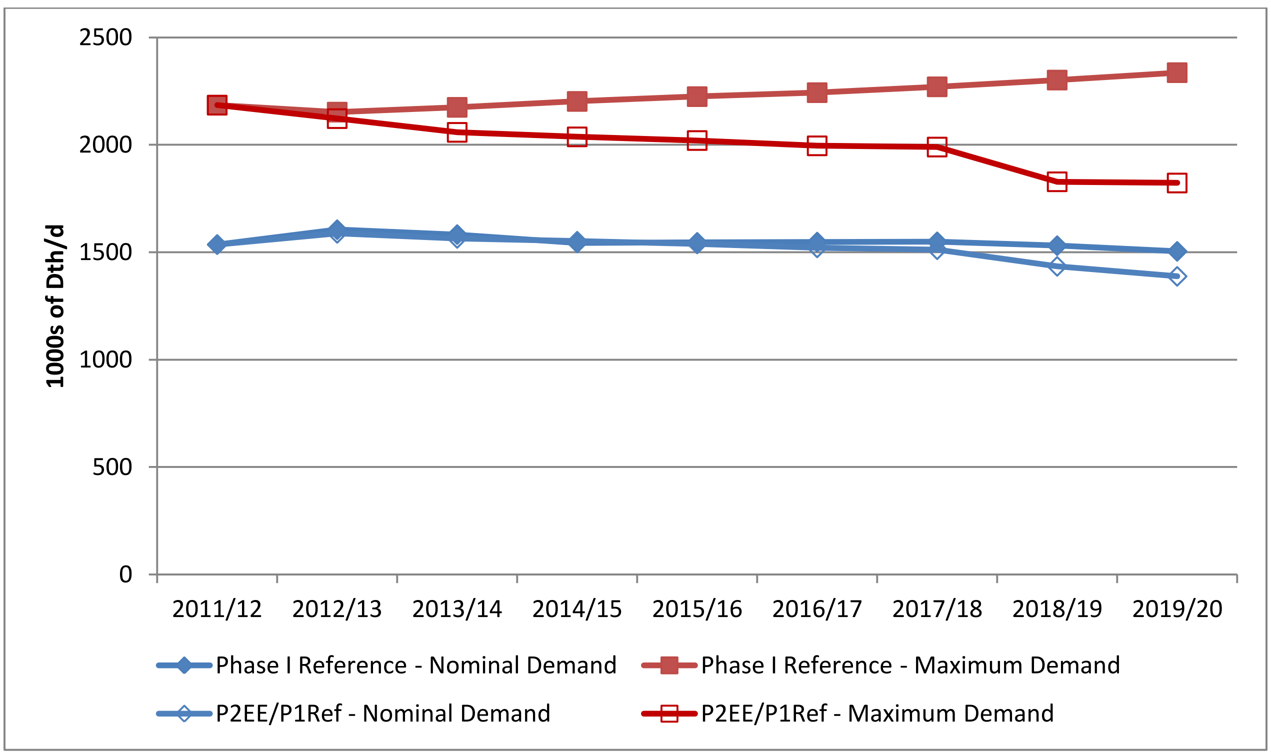
- Phase I Reference capacity assumptions
- Phase I Repowering capacity assumptions
- Phase II Retirement capacity assumptions

The detailed results for each of the Phase II Energy Efficiency cases are provided in Appendix A; summary comparisons of the results to the relevant Phase I cases are provided in the three subsection below. In general, the Phase II Energy Efficiency cases show lower deficits than the Phase I cases due to both the increase in contracted pipeline capacity (150 MMcf/d higher than assumed in Phase I) and the reduced power sector gas demands.

4.1. Phase II Energy Efficiency Cases using Phase I Reference Capacity Assumptions

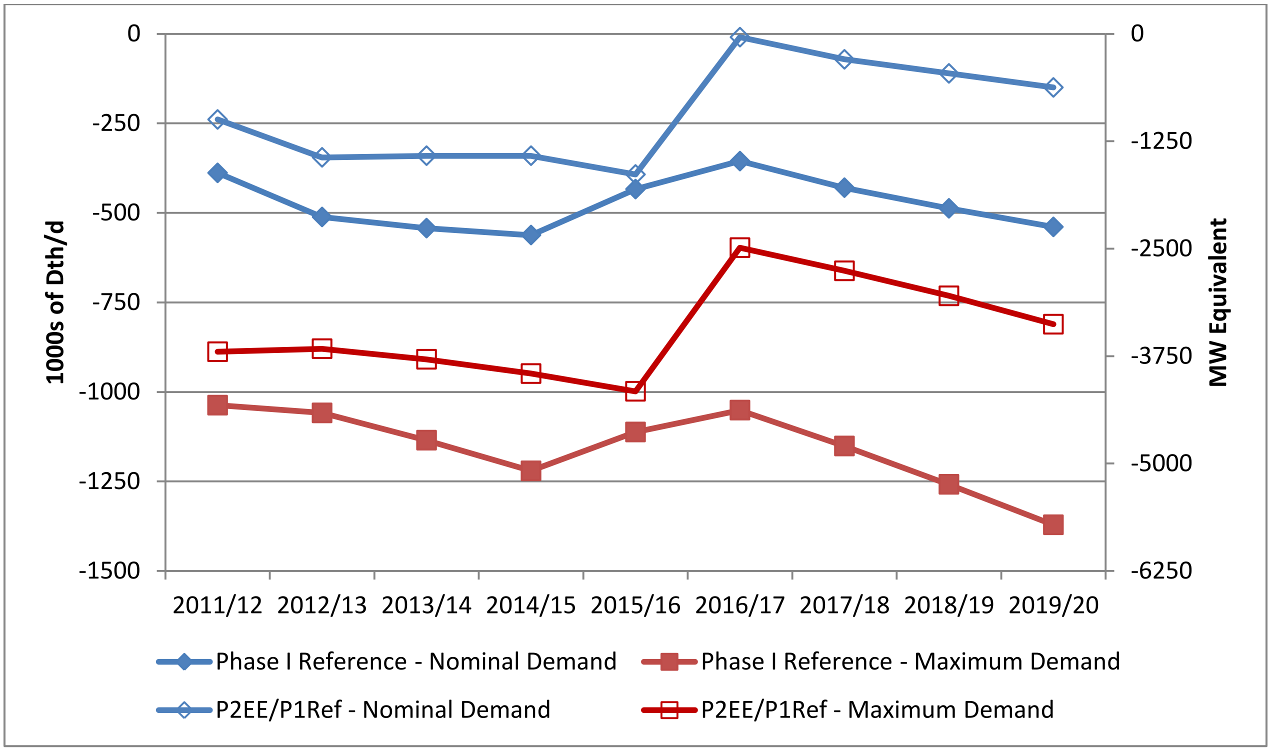
The adoption of the Phase II Energy Efficiency forecast results in a net flat to slightly downward trend in projection power generation gas demand (Exhibit 4-1). Compared to the Phase I Reference case, power sector gas demand between 2014 and 2020 is reduced by an average of 40,000 Dth (Nominal) to 290,000 Dth (Maximum) on the winter peak day.

Exhibit 4-1. ISO-NE Projected Power Sector Winter Peak Day Gas Demand, Phase II Energy Efficiency/Phase I Reference Nominal and Maximum Gas Demands



However, despite the reduced gas requirements, the gas supply adequacy analysis still shows deficits in power sector gas supplies on winter peak days throughout the forecast. Supply deficits in the Phase II Energy Efficiency/Phase I Reference (P2EE/P1Ref) cases range from 200,000 Dth (Nominal) to 800,000 Dth (Maximum); on average, about a 300,000 Dth reduction from the deficits observed in the Phase I Reference cases due to the combination of lower electric sector demand and higher assumed pipeline capacity for Phase II (Exhibit 4-2).

Exhibit 4-2. Power Sector Winter Peak Day Supply Deficits, Phase II Energy Efficiency/Phase I Reference Nominal and Maximum Gas Demands



4.2. Phase II Energy Efficiency Cases using Phase I Repowering Capacity Assumptions

Using the capacity assumptions from the Phase I Repowering case, the adoption of the Phase II Energy Efficiency forecast results in a net flat to slightly downward trend in projection power generation gas demand (Exhibit 4-1). Compared to the Phase I Repowering case, average sector gas demand between 2014 and 2020 is reduced by 80,000 Dth (Maximum) to 190,000 Dth (Nominal) on the peak winter day.

The gas supply adequacy analysis still shows winter peak day supply deficits throughout all the cases in this scenario (Exhibit 4-4). The projected supply deficits in the Phase II Energy Efficiency/Phase I Repower cases range from about 250,000 Dth (Nominal) to 700,000 Dth (Maximum); on average, about a 300,000 Dth reduction from the deficits observed in the Phase I Repower cases.

Exhibit 4-3. ISO-NE Projected Power Sector Winter Peak Day Gas Demand, Phase II Energy Efficiency/Phase I Repower Nominal and Maximum Gas Demands

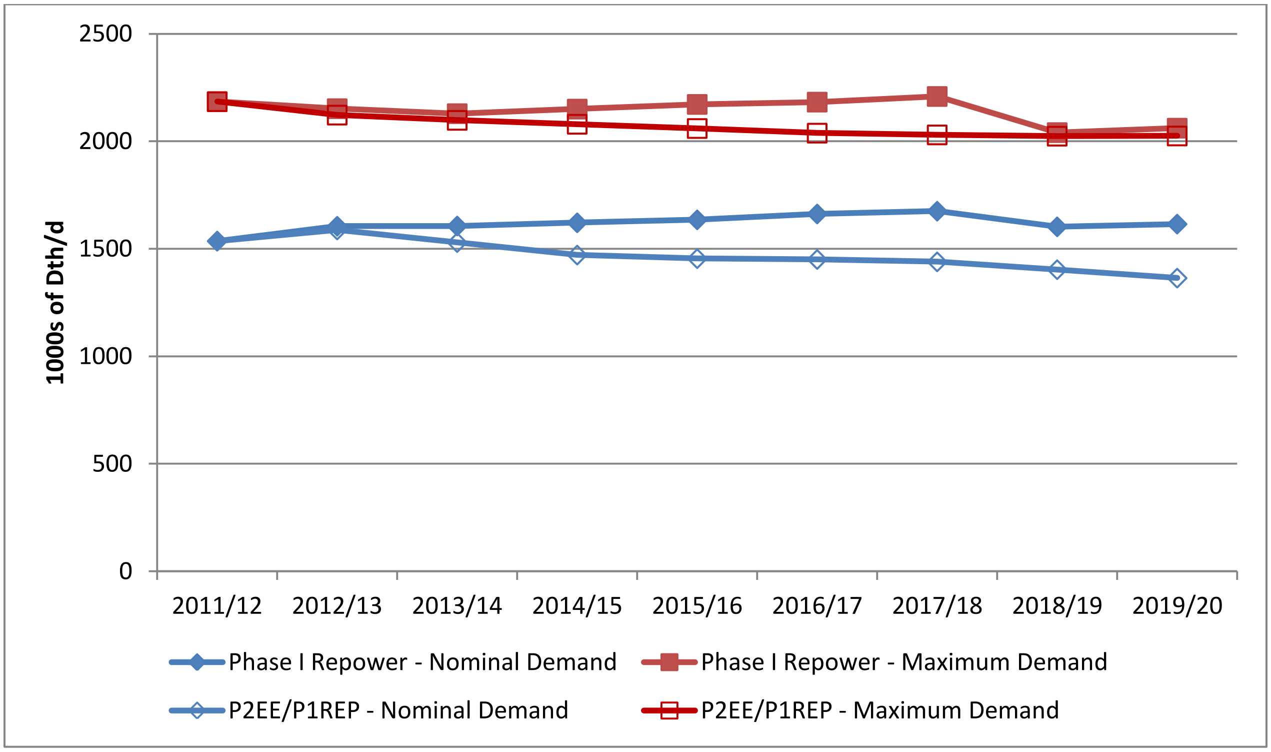
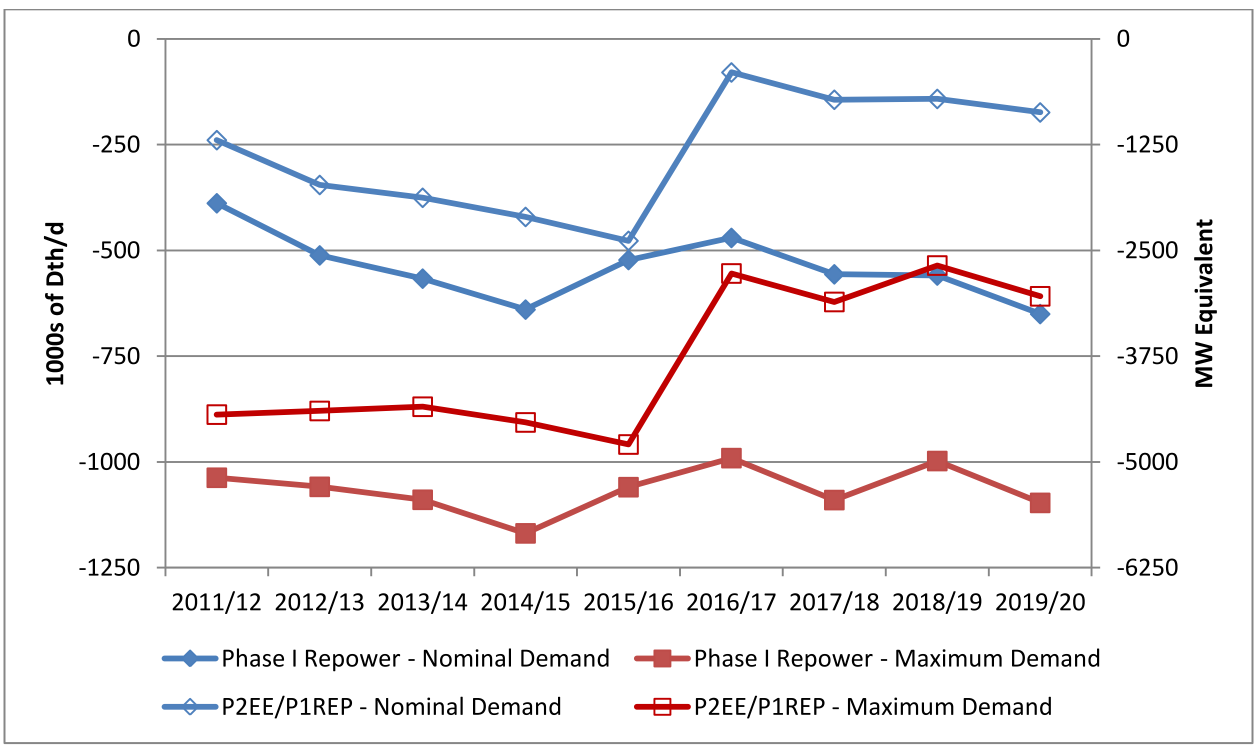


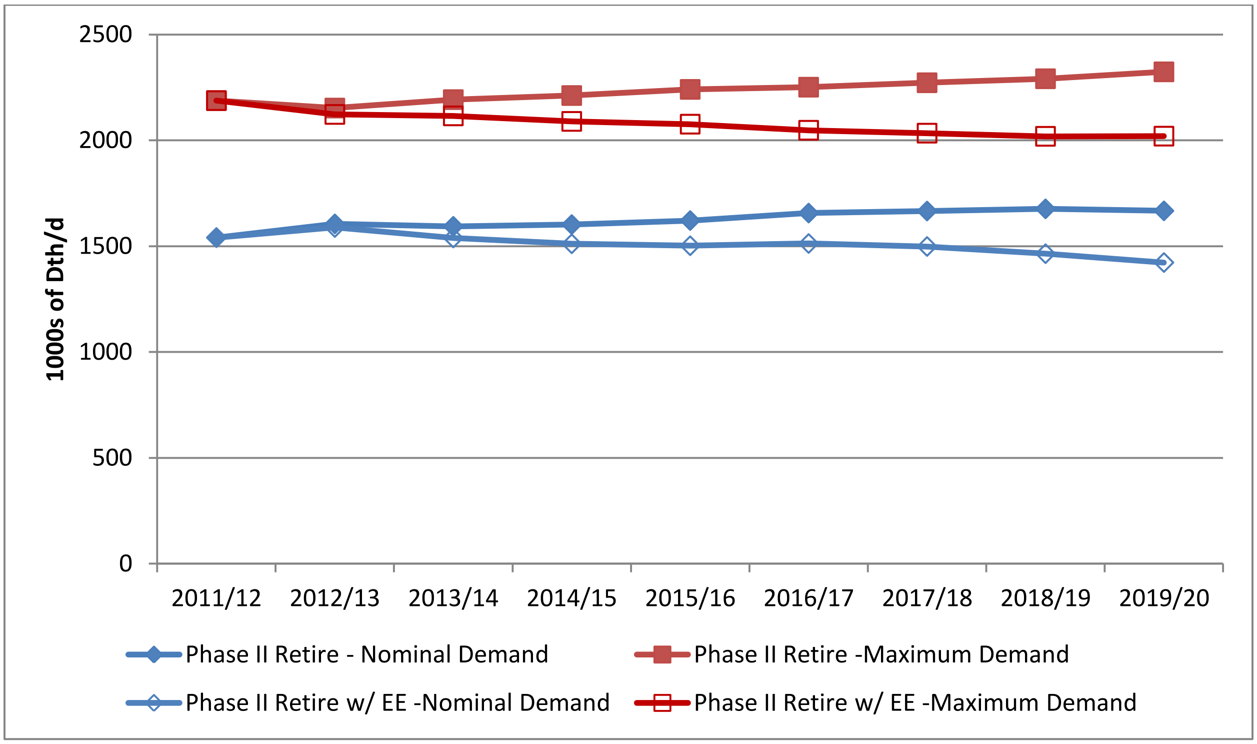
Exhibit 4-4. Power Sector Winter Peak Day Supply Deficits, Phase II Energy Efficiency/Phase I Repower Nominal and Maximum Gas Demands



4.3. Phase II Energy Efficiency Cases using Phase II Retirement Capacity Assumptions

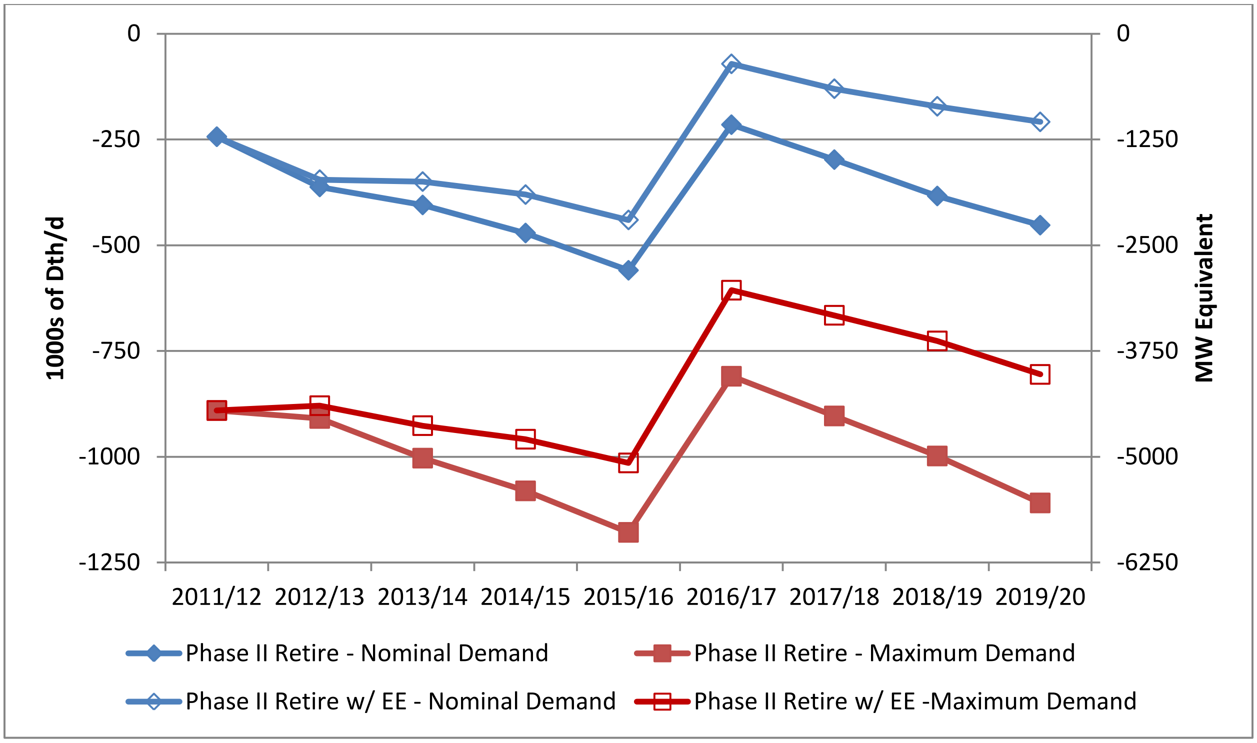
The next set of cases uses capacity assumptions from the Phase II Retirement case combined with the Phase II Energy Efficiency forecast. These cases result in a net flat to slightly downward trend in projection power generation gas demand (Exhibit 4-5). Compared to the Phase II Retirement case without Energy Efficiency, average sector gas demand between 2014 and 2020 is reduced by 150,000 Dth (Nominal) to 190,000 Dth (Maximum) on the peak winter day.

Exhibit 4-5. ISO-NE Projected Power Sector Winter Peak Day Gas Demand, Phase II Energy Efficiency/Phase II Retirement versus Phase II Retirement Nominal and Maximum Gas Demands



Even with the reduced power sector gas demand, the gas supply adequacy analysis still shows winter peak day supply deficits throughout all the cases in this scenario (Exhibit 4-6). The projected supply deficits in the Phase II Energy Efficiency/Phase I Repower cases range from about 250,000 Dth (Nominal) to 800,000 Dth (Maximum); on average, about a 200,000 Dth reduction from the deficits observed in the Phase II Retirement cases that did not include Energy Efficiency.

Exhibit 4-6. Power Sector Winter Peak Day Supply Deficits, Phase II Energy Efficiency/Phase II Retirement versus Phase II Retirement Nominal and Maximum Gas Demands



5. Phase II Decreased LNG Cases

Each of the cases described in Section 3 and Section 4 examined alternate scenarios for power sector natural gas consumption on the peak day with fixed assumptions for gas supplies. In this section, we examine the impact of an alternate (decreased) projection for regional LNG imports on the availability of gas supplies to the power sector on a winter design day.[10] These "Decreased LNG" cases apply the same power sector gas demand assumptions used in the Phase II Retirement and Phase II Energy Efficiency cases, but with lower levels of LNG imports to determine the subsequent impact on potential peak day gas supply deficits.

Section 5.5.1 reviews the recent historical operations of the New England LNG terminals and changes in their supply contracts, and historical gas supplies delivered via the M&N Pipeline. Section 5.5.2 describes ICF's projections for peak day supplies Distrigas and M&N Pipeline throughout the forecast period. Section 5.5.3 provides a summary of the impacts on gas supplies available to the power sector for the Phase I Reference and Phase II Energy Efficiency cases, respectively.

5.1. Historic Activity for Distrigas and M&N Pipeline

[10] Cases examining variations in LNG supplies throughout the 90 days of winter are discussed in Section 6.

As described in Section 2.2.1, there are three LNG import terminals located within New England: Distrigas, Neptune, and Northeast Gateway. Canaport is located outside the region, but is an important gas supply source for the New England market, particularly on peak winter days.

Assumptions for Offshore LNG Terminals

Neptune (operated by GDF Suez Gas North America) and Northeast Gateway (operated by Excelerate Energy) are both offshore buoy terminals that can only receive LNG shipments from specialized tankers with on-board regasification systems. Neither of the two offshore terminals has received any shipments since 2010. In June 2013, the U.S. Maritime Administration approved Neptune LNG's request for a temporary five-year suspension of its deepwater port license.[11] In January 2013 article in the Boston Globe, Excelerate's chief operating officer was quoted as saying the Northeast Gateway terminal remains "in a state of readiness." However, despite several weeks of sustained high gas prices in New England during January and February 2013, no shipments were received at Northeast Gateway.

Distrigas LNG Imports and Winter Sendout

The Distrigas facility, located on the Mystic River in Boston Harbor, has been operating continuously since 1971, longer than any other import terminal in the U.S. Owned and operated by Distrigas of Massachusetts (DOMAC), a subsidiary of GDF Suez North America, the terminal currently supplies up to 20 percent of New England's annual natural gas demand. Imports to Distrigas come primarily from Trinidad and Tobago, with some additional shipments from Yemen. Distrigas is also the sole source of gas supply for Mystic power plant's combined cycle units 8 and 9, with supplies procured under long-term contract through 2027. About 20 percent of the LNG received at Distrigas goes directly in to National Grid's Greater Boston-area distribution system, and another 10 percent is delivered via trucks to satellite LNG peak shaving facilities throughout New England. The remaining LNG is regasified and delivered via a dedicated pipeline to the Mystic Generating Station or into either the Tennessee or Algonquin pipeline systems.

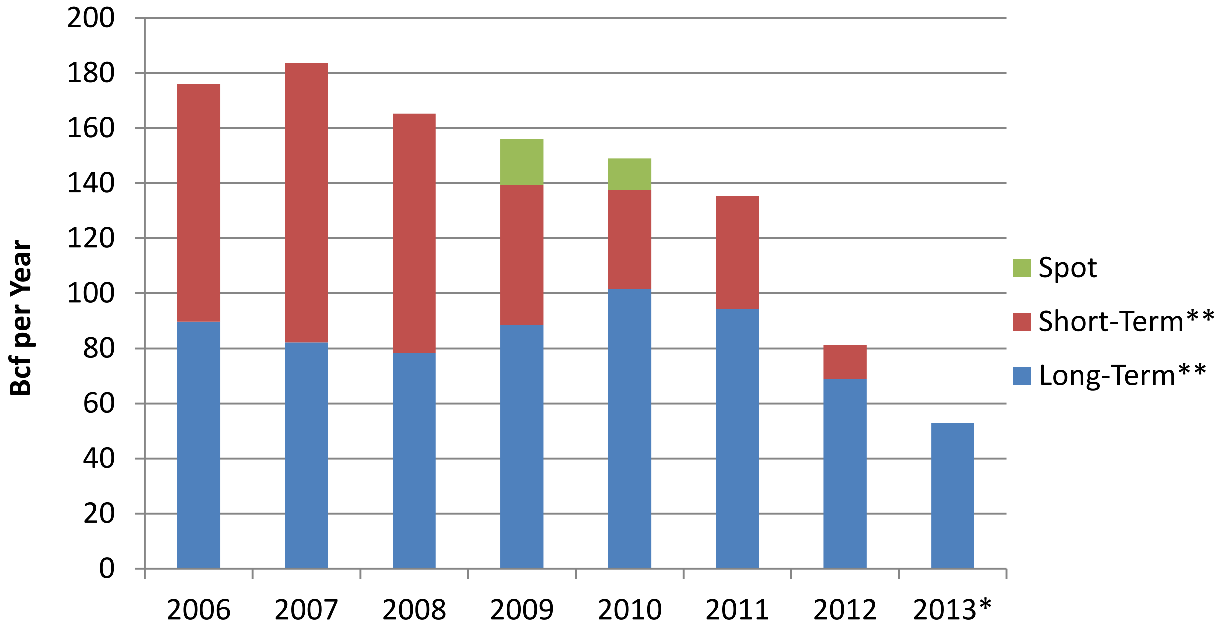
From 2006 through 2011, Distrigas received over 60 shipments per year. However, as natural gas prices in the U.S. declined, the number of shipments received at Distrigas has fallen. In 2012, Distrigas received only 81 Bcf, due to declines in both long-term and short-term contract shipments (Exhibit 5-1). As of September (latest data available), only 59 Bcf of LNG shipments have been received at Distrigas in 2013. Given the long-term contract shipments expected in the fourth quarter, the total for long-term contract shipments in 2013 is likely to be similar to 2012 (about 70 Bcf), but it appears unlikely there will be any short-term contract or spot cargo shipments received at Distrigas in 2013.

The winter sendout from the Distrigas facility is correlated to daily mean temperatures; as temperatures decline, sendout increases. However, as LNG imports have declined, so has the daily winter sendout. Exhibit 5-2 show the change in daily sendout from Distrigas over the past 4 years, with points representing actual daily sendout during each winter (December 1 through February 28), and lines representing the fit trend for each winter period. During the winter of 2010/11, daily sendout from Distrigas average about 420 MMcf/d and peaked at 620 MMcf/d.

[11] Federal Docket for Neptune LNG (Docket Number: USCG-2005-22611); Response Letter from U.S. DOT/MARAD dated June 22, 2013 (http://www.regulations.gov/#!documentDetail;D=USCG-2005-22611-0481).

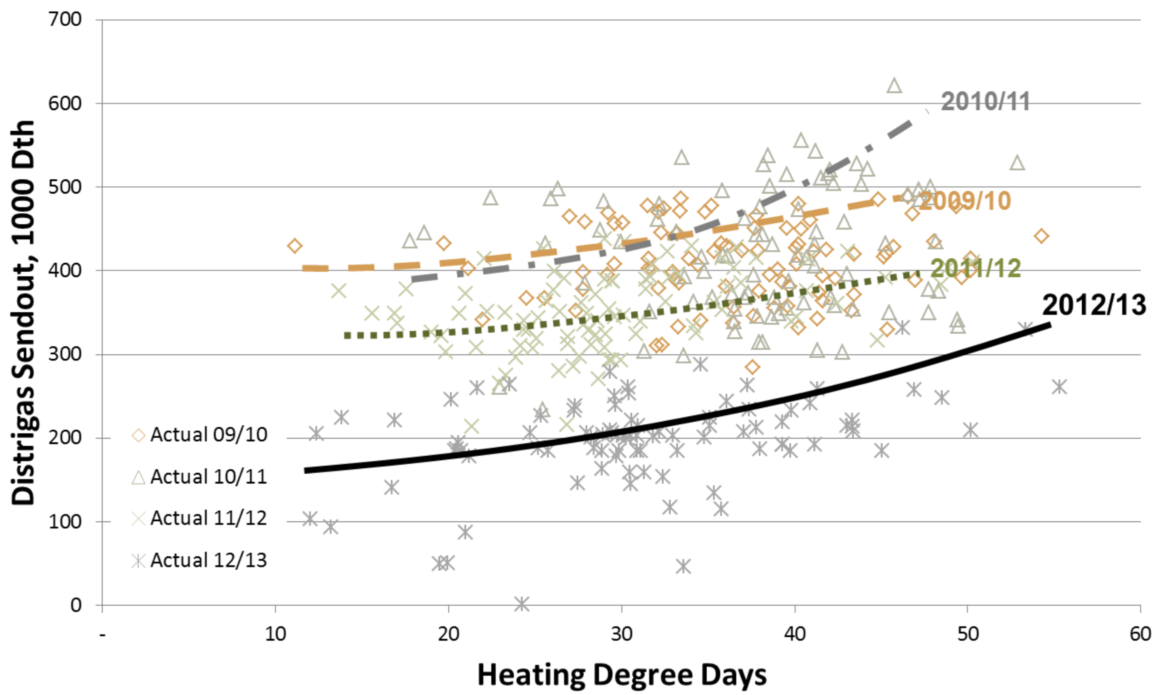
By the winter of 2012/13, average daily sendout had declined to 200 MMcf/d and the peak sendout was only 330 MMcf/d.

Exhibit 5-1. Distrigas Terminal LNG Annual Import Volumes, Bcf per Year



Source: U.S. DOE, Office of Oil and Gas Global Security and Supply
* 2013 data through September
** U.S. DOE defines Long-Term contract shipments as those with contract terms of 2 years or more, and Short-Term contract shipments as those with contract terms of less than 2 years.

Exhibit 5-2. Distrigas Historical Daily Winter Sendout versus Heating Degree Days



Canaport LNG and Flows on M&N Pipeline

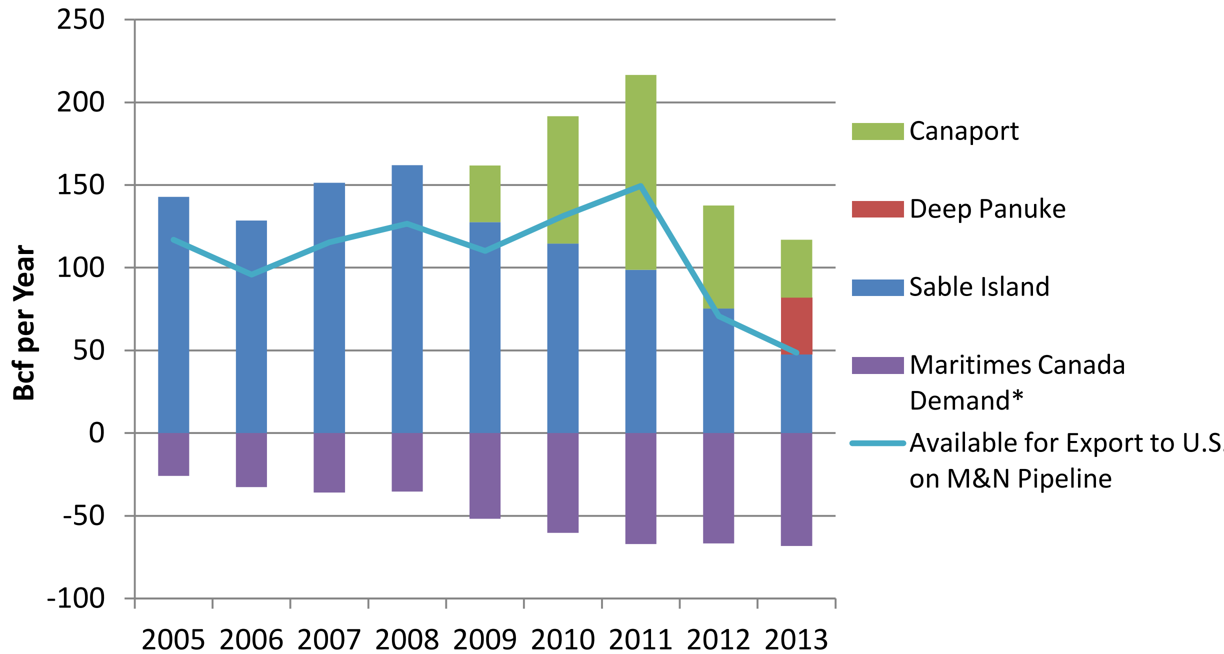
The flow of gas on the M&N Pipeline into the U.S. is a function of three factors: Eastern Canadian gas production, gas consumption in Maritimes Canada, and sendout from the Canaport LNG terminal.

The M&N Pipeline was originally constructed to bring Sable Island offshore gas production to markets in Eastern Canada and New England. However, Sable Island production was less than originally anticipated, and production has been declining over the past 5 years (Exhibit 5-3). A new offshore field, Deep Panuke, has been under development for over four years. After numerous delays, Deep Panuke production began in October 2013. At its peak, Deep Panuke is expected to produce about 300 MMcf/d (equivalent to 110 Bcf per year), but then production is expected to decline due to basin maturation through the remainder of the decade.

The onshore areas of Nova Scotia and New Brunswick also have some conventional and unconventional gas resources. Currently, there is a small amount (about 10 MMcf/d) of conventional gas production in McCully Field in New Brunswick. Several exploration and production (E&P) companies have done exploratory drilling in New Brunswick's Frederick Brooks shale, but there is currently no commercial shale gas production in Eastern Canada. In April 2012, the Nova Scotia provincial government implemented a moratorium on the use of hydraulic fracturing (i.e., "fracking") through the summer of 2014, pending additional studies of the potential impacts.[12] Currently, ICF is not projecting any commercial development of Eastern Canadian shale gas or other onshore resources within the next ten years.

[12] http://metronews.ca/news/halifax/106301/fracking-on-hold-for-two-years-in-nova-scotia/

Exhibit 5-3. Eastern Canadian Historical Supply, Demand, and Exports on M&N Pipeline



* All demands, including residential, commercial, industrial, power generation, lease, plant, and pipeline fuel use.

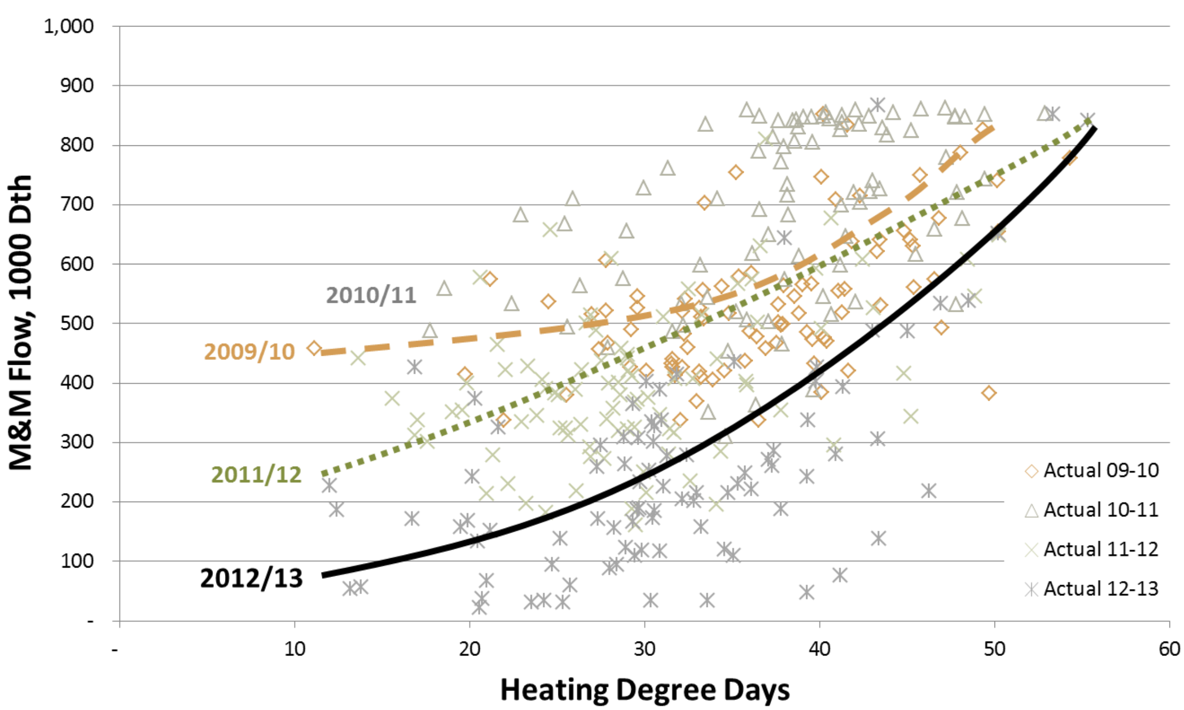
While Eastern Canadian gas production has been declining, gas consumption in Nova Scotia and New Brunswick has been growing. The Maritimes Canadian gas market is dominated by three end users: Nova Scotia Power's Tufts Cove generating station, Emera's Bayside power plant, and Irving Oil's refinery in Saint John, which also has a gas-fired cogeneration power plant on site. There are also two LDCs in Maritimes Canada, Enbridge in New Brunswick and Heritage in Nova Scotia. Enbridge serves primarily commercial, residential, and small industrial users Saint John, Fredericton and Moncton. Heritage has a similar load profile, serving primarily the Halifax/Dartmouth metropolitan area. In addition, there are a number of direct industrial gas customers served off of the Canadian portion of the M&N pipeline, including several pulp and paper mills. In 2012, Eastern Canada's total gas consumption (which includes all end uses, pipeline fuel, lease, and plant gas use) was about 66 Bcf in 2012. The LDCs accounted for just over 10 Bcf, or about one-sixth of the total consumption. ICF projects relatively modest growth in Maritimes Canadian gas demand, with total consumption reaching about 76 Bcf per year by 2020.

In 2001, Irving Oil applied to the Canadian government for a permit to add the capability to receive shipment of LNG at its Canaport deep-water crude receiving terminal. The permit was granted in April 2004, and Irving Oil entered into a partnership with Repsol S.A. to develop what is now called Canaport LNG. Canaport LNG is jointly owned by Irving Oil (25 percent) and Repsol (75 percent). The facility was commissioned in 2008 and received its first shipment of LNG in June 2009. The construction of Canaport LNG was coincident with construction of the Brunswick Pipeline, which connects the terminal to M&N pipeline at the U.S./Canada border.

LNG supplies for Canaport were originally contracted by Repsol. However, 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, there is little if any call on Canaport to provide gas supplies outside of winter peak days, and 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 (48 Bcf) over the next ten years. In their press release discussing the deal, Repsol said that, "The [Canaport terminal] is not included in the sale process as the low gas prices currently seen in the US market do not allow the asset's medium and long term potential to be adequately valued."[13]

Since 2009, the Canaport terminal has acted primarily as a "swing" supply of gas for the Eastern Canadian and New England markets, increasing its sendout on cold winter days (when gas prices are highest), and reducing sendout when regional demand (and gas prices) are low. Exhibit 5-4 shows the change in daily flows over on M&N Pipeline over the past 4 years, with points representing actual daily flows during each winter (December 1 through February 28), and lines representing the fit trend for each winter period. During the winter of 2010/11, daily flows on M&N averaged over 630 MMcf/d, and flows were at or slightly above M&N's contracted capacity of 833 MMcf/d on 25 days. During the winter of 2012/13, average daily sendout had declined to about 250 MMcf/d, and the pipeline reached full capacity on only 3 days.

Exhibit 5-4. Historical Daily Flows on M&N Pipeline to the U.S.



5.2. Assumed Peak Day Supplies from Distrigas and M&N Pipeline in the Decreased LNG Cases

For the Decreased LNG cases, design day sendout from Distrigas LNG was based on a regression fit of the winter 2012/13 observed sendout versus heating degree days, shown

[13] Repsol press release dated February 26, 2013.

above in Exhibit 5-2. The regression fit was based on data for the combined Distrigas sendout (total deliveries to Tennessee, Algonquin, and the Mystic Generating Station) and heating degree day (HDD) values (65 minus the mean daily temperature, in degrees Fahrenheit). The fit equation is:

$$\text{Projected Distrigas Design Day Sendout in MMcf/d} = \min(a + (HDD^2 * c)\,, Maximum\ Daily\ Sendout)$$

Where:
a (intercept) = 150 MMcf/d
c (HDD^2 coefficient) = 0.06
HDD = 65
Maximum Daily Sendout = 715 MMcf/d

The intercept value was based on the typical winter sendout to the Mystic Generating Station alone, which averages about 150 MMcf/d. The assumed design day temperature is 0 degrees Fahrenheit , so design day HDD is equal to 65. The Maximum Daily Sendout defines the upper bound on sendout, based Distrigas's reported maximum sustained sendout of 715 MMcf/d; however, because the value of $a + (HDD^2 * c)$ is less than 715 when HDD = 65, this is not a binding constraint. Based on this regression fit of the 2012/13 sendout pattern, ICF projects Distrigas sendout on a design day would be just over 400 MMcf/d; this same assumed sendout is used for all the of the Decreased LNG cases.

For design day flows on M&N Pipeline, ICF used the same functional form for the regression analysis of daily M&N flows version heating degree days as was used for the Distrigas fit:

$$\text{Projected M\&}N\ Pipeline\ Design\ Day\ Flow\ in\ MMcfd = \min(a + (HDD^2 * c)\,, Maximum\ Daily\ Flow)$$

Where:
a (intercept) = 31 to 384 MMcf/d, depending on the year
c (HDD^2 coefficient) = 0.40
HDD = 65
Maximum Daily Flow = 833 MMcf/d

The projected intercept value is based on projected Eastern Canada gas production and demand, and therefore changes over time. The assumed design day temperature is 0 degrees Fahrenheit , so design day HDD is equal to 65. The Maximum Daily Flow is 833 MMcf/d, based on M&N Pipeline's contracted capacity; since the value of $a + (HDD * c^2)$ is greater than 833 MMcf/d when HDD = 65, this is a binding constraint. Therefore, the projected design day flows on M&N pipeline are 833 MMcf/d through 2020; this is the same as was assumed for the other Phase I and Phase II cases.

The same regression fits of Distrigas sendout and M&N Pipeline flows are used for the Winter Near-Peak analysis, discussed in Section 6.

5.3. Decreased LNG Case: Summary Results

The Decreased LNG cases use the same Phase II assumptions for pipeline capacities (other than M&N) and peak shaving gas supplies as described in Section 2.2.1. Since the alternate projection for M&N Pipeline flows on a design day is the same as the pipeline's contracted capacity of 833 MMcf/d, the only difference in the Decreased LNG cases design day gas supplies is the reduction in the assumed Distrigas sendout (Exhibit 5-5).

Exhibit 5-5. Winter Design Day Gas Supply Assumptions for Decreased LNG Case

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Base Phase II Assumption for Total Winter Design Day Supply Capability (Distrigas Sendout at Full Capacity)	5,890	5,890	5,890	5,890	5,890	6,340	6,340	6,340	6,340
Decreased LNG Assumption for Total Winter Design Day Supply Capability (Distrigas Sendout Less than Full Capacity)	5,579	5,579	5,579	5,579	5,579	6,029	6,029	6,029	6,029
Total Reduction in Supplies (Base minus Reduced)	**311**	**311**	**311**	**311**	**311**	**311**	**311**	**311**	**311**

The Decreased LNG gas supply assumptions shown in Exhibit 5-5 were applied to a total of six cases, using both Phase I and Phase II power sector gas demands:

- Phase I Reference electric load growth assumptions
  - Phase I Reference capacity assumptions
  - Phase I Repowering capacity assumptions
  - Phase II Retirement capacity assumptions
- Phase II Energy Efficiency electric load growth assumptions
  - Phase I Reference capacity assumptions
  - Phase I Repowering capacity assumptions
  - Phase II Retirement capacity assumptions

Detailed results for each of these cases are shown in Appendix B; the result for each case was to increase the peak day gas supply deficit by 311,000 Dth (i.e., the same as the reduction in LNG supplies).

6. Phase II Winter Near-Peak and Duration of Risk Analysis

The cases summarized above in Sections 3, 4, and 5 used the same methodology as the Phase I analysis, and focused on gas supplies, demands, and potential shortfalls in power sector gas supplies on a winter peak (design) day. While it is important to examine winter design day conditions, there is also the potential for a shortfall in gas supplies on “near-peak” winter days; that is, a winter day that is relatively cold, but not as cold as a design day. To determine the availability of gas supplies to electric generators on winter near-peak days, ICF performed a regression analyses to derive relationships between mean daily temperatures and daily LDC demands, Distrigas sendout, pipeline flows on the M&N system, and peak shaving storage sendout. As with the design day analyses, gas supplies on the interstate pipelines (other than M&N pipeline) were assumed to be equal to the firmly contracted capacities shown in Exhibit 2-3.

The analyses on Distrigas sendout and M&N Pipeline flows was described above in Section 5.1. Section 6.6.2 describes how the projections for LDC daily firm demand were developed. Section 6.6.4 describes the methodology for projecting peak shaving sendout.

6.1. Mean Daily Temperature Data

Heating degree days for New England were based on mean daily temperature data from the 13 weather stations shown in Exhibit 6-1. The weather stations were selected based on the continuity of the historical data (i.e., few or no missing days of temperature data) and for their geographic diversity. From these data, ICF calculated population-weighted daily temperatures for New England from 1993/94 through 2012/13. In addition to being used from the regression analysis of LDC demand (discussed below), the historic data are used to represent the potential range of LDC firm demand New England could experience in the 10-year forecast horizon.

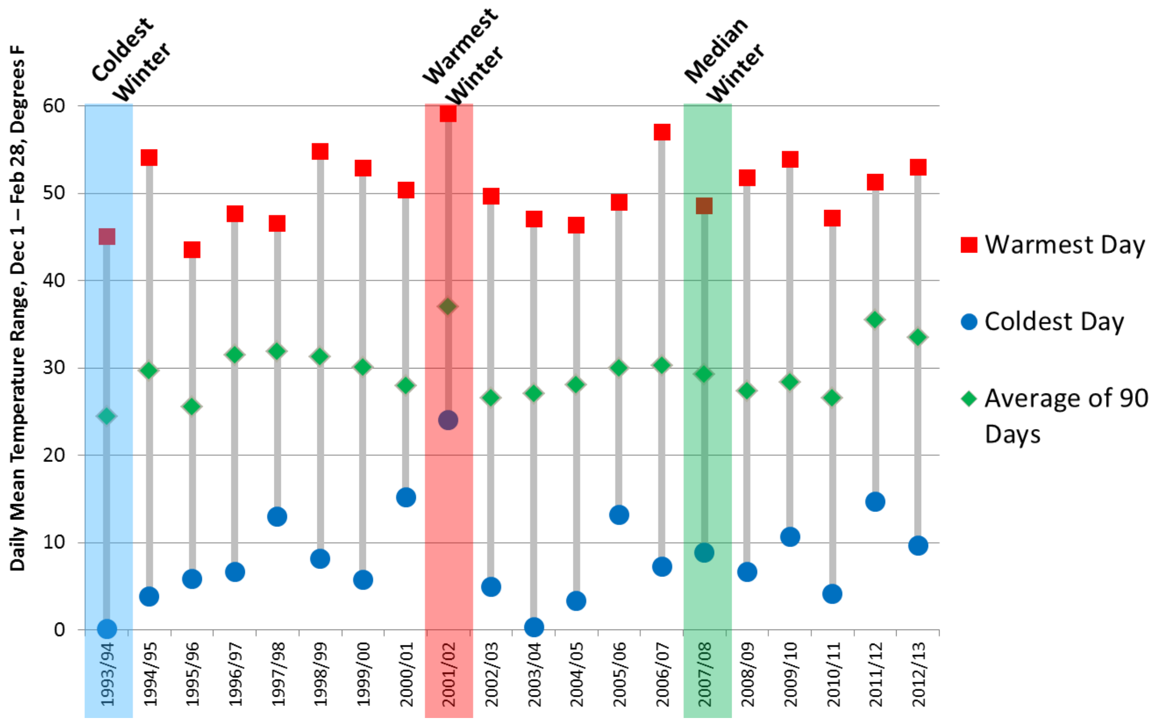
Exhibit 6-1. List of New England Weather Stations

State	Station Name	Station Code
CT	DANBURY MUNI ARPT	KDXR
CT	GROTON AAF	KGON
CT	NEW HAVEN TWEED AIRPORT	KHVN
MA	BOSTON/LOGAN INTL	KBOS
MA	NEW BEDFORD RGNL	KEWB
MA	WORCESTER RGNL	KORH
ME	PORTLAND/INTNL. JET	KPWM
NH	CONCORD MUNICIPAL	KCON
NH	MANCHESTER	KMHT
RI	PROVIDENCE/GREEN ST	KPVD
VT	BURLINGTON INTL	KBTV
VT	EDWARD F KNAPP STATE	KMPV
VT	RUTLAND STATE	KRUT

A chart representing the high, average, and low winter daily temperatures over the past 20 years is shown in Exhibit 6-2. Of the 20 years of data examined, the coldest winter (for both cumulative heating degree days throughout the winter and the coldest single day) was 1993/94; and the warmest winter was 2001/02.[14] While there are a number of winters that fall near the middle of the observed range, ICF selected 2007/08 (10th ranked in terms of total heating degree days) as representative of “median” winter temperatures.

[14] This ranking is based on temperatures for the peak winter gas demand period, which runs from December 1 through February 28. If the months of November and March are included, then the 2011/12 heating season would rank as the warmest.

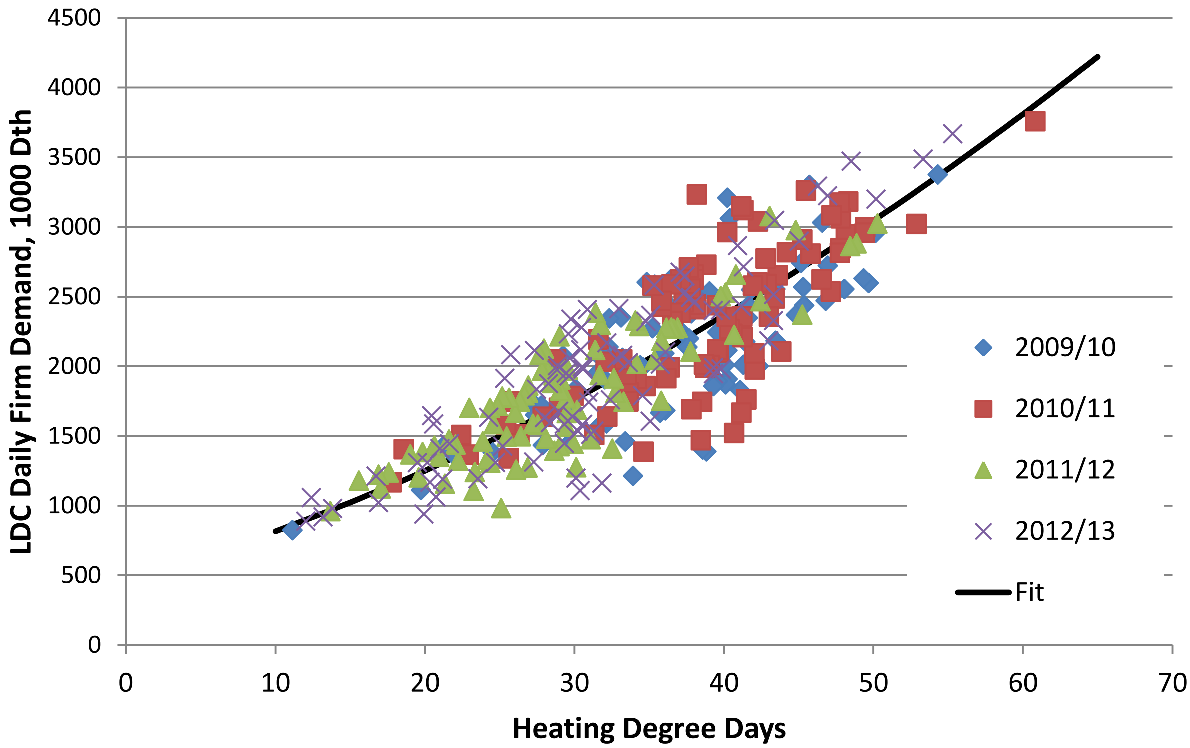
Exhibit 6-2. New England Winter Daily Mean Temperatures, 1993/94 through 2012/13



6.2. LDC Daily Firm Demand versus Mean Daily Temperature

ICF developed winter load duration curves for the aggregate LDC firm demand based on a regression analysis of historical gas demand for New England LDCs and daily mean temperatures (expressed as heating degree days) for the winters of 2008/09 through 2012/13. Exhibit 6-3 shows a scatter plot of the 360 observations (90 winter days for each of the four years) used for the regression. Historical demands were based on an aggregation of New England LDC daily citygate receipts from interstate pipelines.

Exhibit 6-3. Historical LDC Daily Firm Demand versus Heating Degree Days



Based on the regression analysis, ICF derived the following equation used to projected LDC daily firm demand:

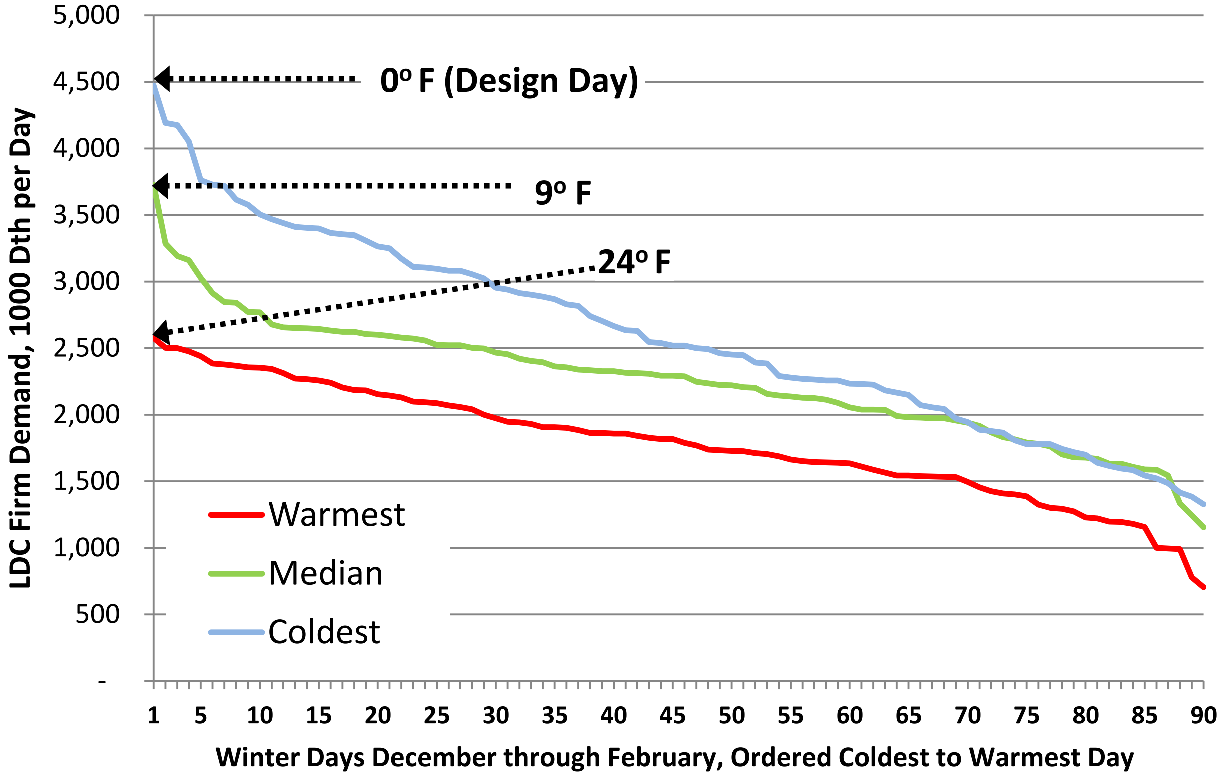
$$\text{Projected LDC Daily Firm Demand} = (a + (HDD * b) + (HDD^2 * c) * e$$

Where:
a (intercept) = 465 1000 Dth
b (HDD coefficient) = 31.0
c (HDD^2 coefficient) = 0.41
e (load growth factor) = $1.014^{(Year-2012)}$

The intercept and heating degree day coefficients were derived directly from the regression. The load growth factor (*e*) of 1.4% per year growth is based on the Phase I projection for growth in winter LDC firm gas demand.

Using this equation and the historical temperature data, ICF constructed daily load curve for each forecast year. For example, Exhibit 6-4 shows the projected LDC daily firm demand for the winter 2014/15 based on historical temperatures from 1993/94 (representing a cold winter, and including a design day), 2001/02 (representing a warm winter), and 2007/08 (representing median winter conditions). In the coldest winter case, 2014/15 LDC daily demand peaks at 4,500,000 Dth, and remains above 3,500,000 Dth for a total of 10 days.

Exhibit 6-4. LDC Daily Firm Demand Projections, Winter 2014/15

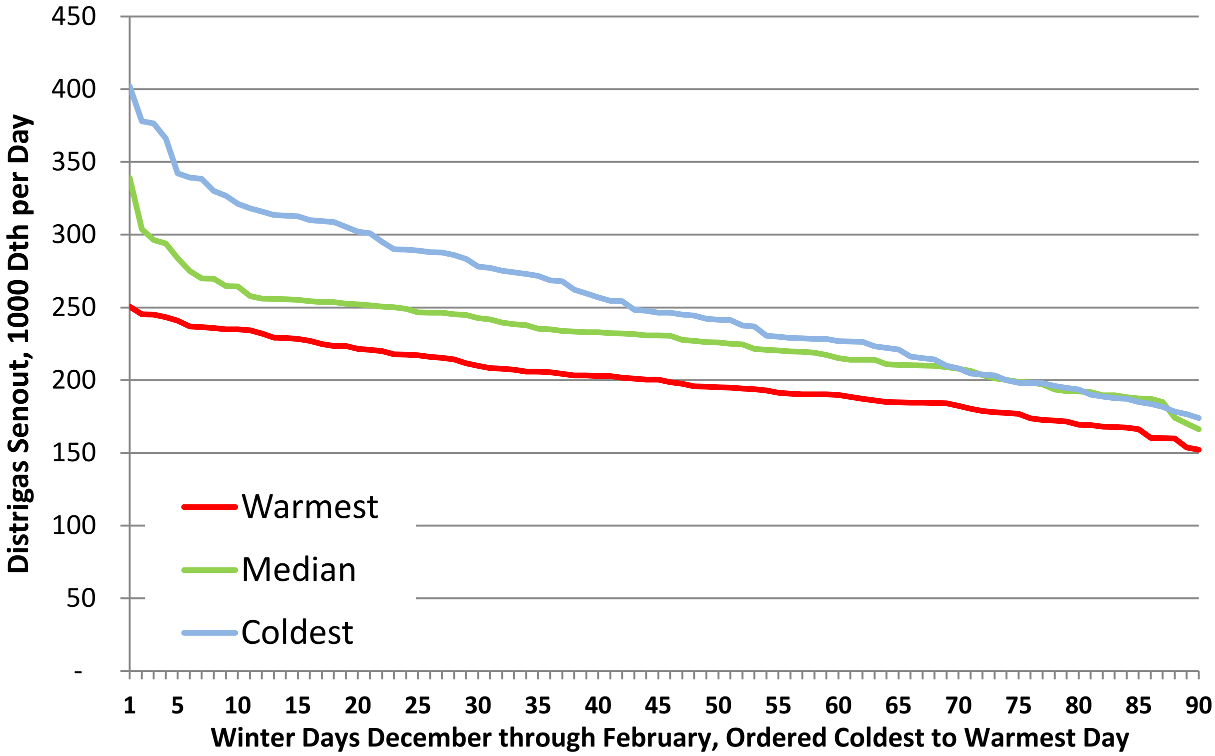


6.3. Projected Daily Sendout from Distrigas LNG and Daily Flows on M&N Pipeline

The projected daily sendout from Distrigas LNG and the daily flows on M&N Pipeline are based on the analysis of historical data described in Section 5.5.2 above.

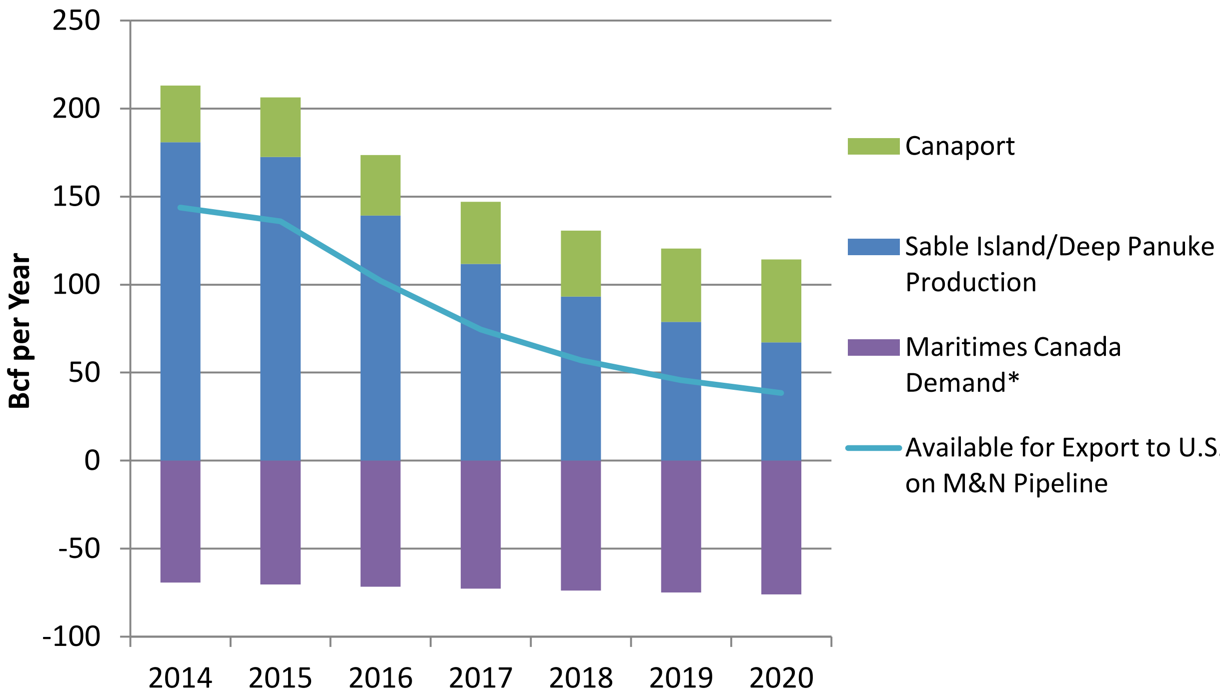
The forecast of Distrigas daily sendout is based on the observed values for the winter of 2012/13, based on the assumption that the future mix of long- and short-term supply contracts to Distrigas will be similar to the past year. Exhibit 6-5 shows the forecast daily sendout for 2014/15. Even under the coldest condition, Distrigas sendout is projected to be only about 400,000 Dth, or about 56 percent of its rated capacity.

Exhibit 6-5. Distrigas Daily Sendout Projections, Winter 2014/15



The projections for daily flows on M&N Pipeline are based on a combination of factors. As shown in Exhibit 6-6, total production from the Eastern Canadian offshore fields is projected to increase through 2014 (as Deep Panuke production ramps up to full capacity), and then decline as both the Deep Panuke and Sable Island fields are depleted. Demand in Maritimes Canada is expected to increase only modestly, reaching about 76 Bcf per year by 2020, about 200 MMcf/d?. The Canaport LNG terminal is assumed to continue receiving imports, but only at a fraction of its rated capacity. By 2020, the net supply available for export from Eastern Canada to the U.S. on the M&N Pipeline declines to about 40 Bcf per year.

Exhibit 6-6. Eastern Canadian Projected Supply, Demand, and Exports on M&N Pipeline



* All demands, including residential, commercial, industrial, power generation, lease, plant, and pipeline fuel

Exhibit 6-7 shows a comparison of projected M&N flows for 2014/15 based on the cold, median, and warm daily temperature series. Due to the anticipated ramp-up of Deep Panuke production, M&N projected to have the highest winter flows in 2014/15. Under the median (2007/08) temperature scenario, M&N is projected to flow at or very near its rated capacity for the 15 coldest days, and average about 700,000 Dth per day during the winter of 2014/15. However, after 2014/15, M&N flows are projected to decrease at an average rate of about 11 percent per year, due to both the depletion of offshore fields and the increased in Maritimes gas demand. Exhibit 6-8 shows the actual daily flows for 2012/13 and projected flows for 2014/15 and 2019/20, based on the median historical daily temperatures. Through 2014/15, the average daily winter flows on M&N Pipeline are projected to increase by about 6 percent, as Deep Panuke production increases. By the winter 2019/20, the projected average daily flows are less than 50 percent of the pipeline's rated capacity.

Exhibit 6-7. M&N Pipeline Daily Flow Projections, Winter 2014/15

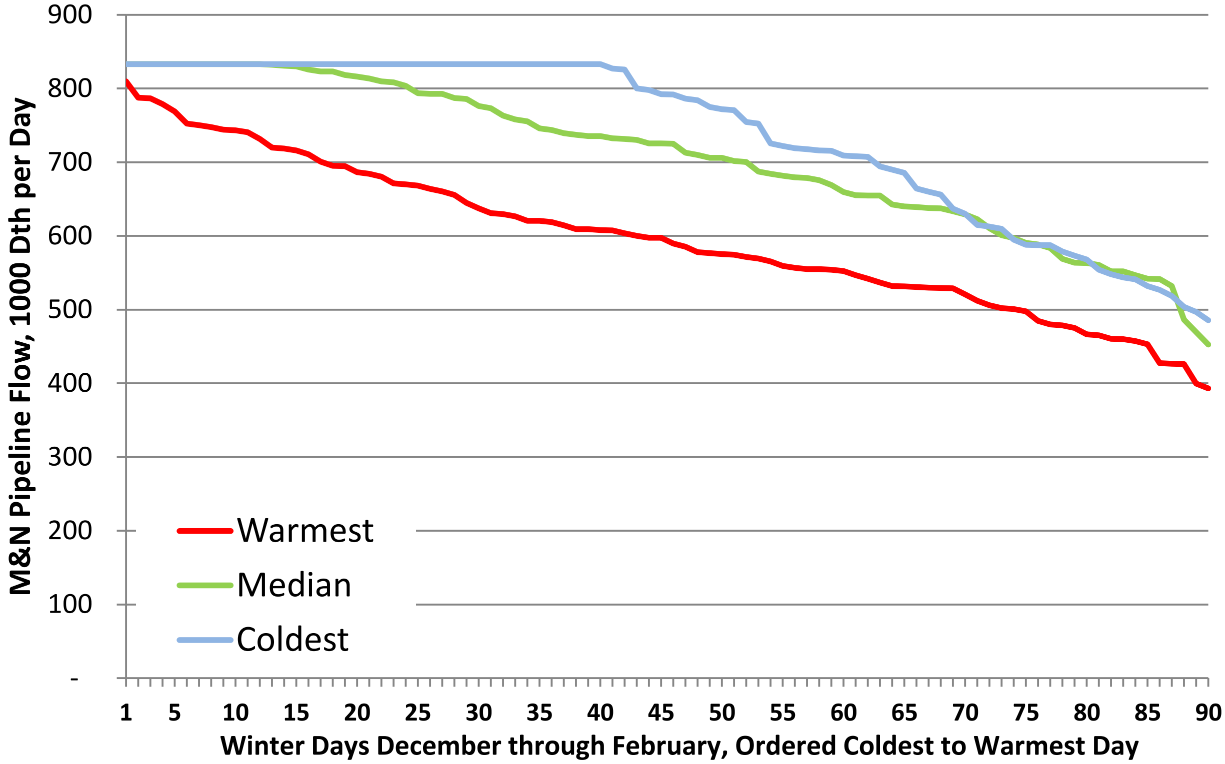
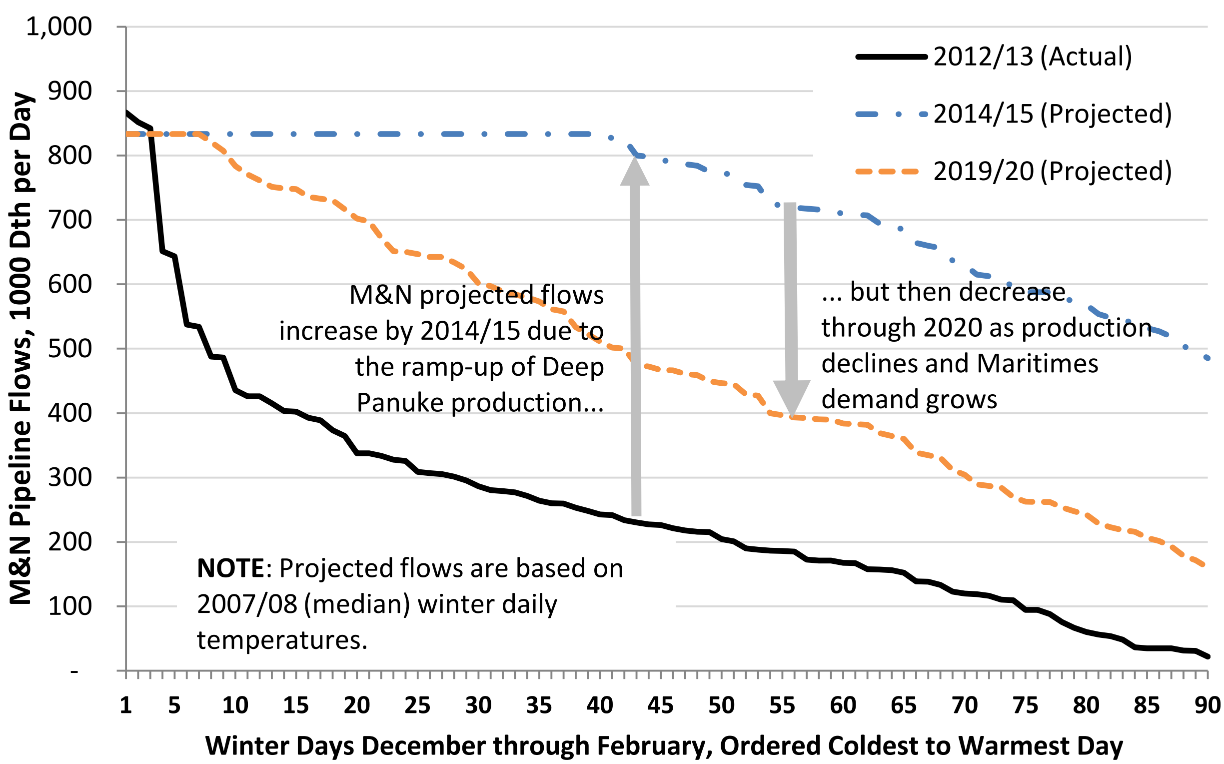


Exhibit 6-8. M&N Pipeline Daily Flow Projections, Winter 2013/14 through 2019/20



6.4. Projected Peak Shaving Storage Daily Sendout

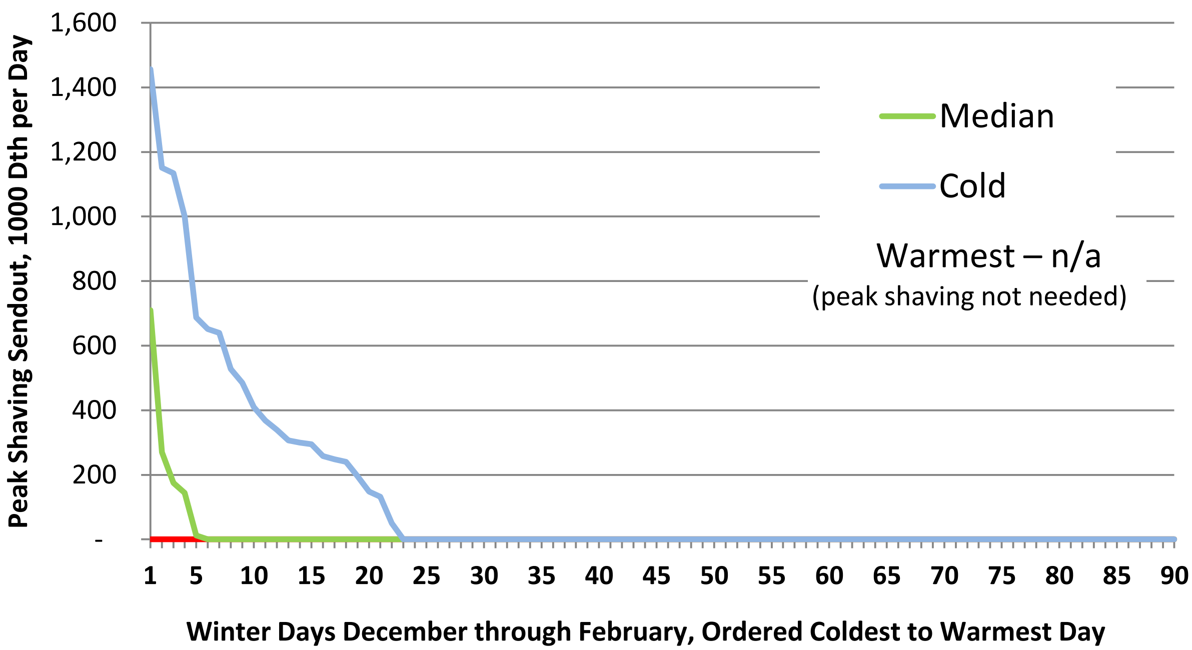
New England peak shaving facilities are operated by the regional LDCs, and there are no publically available data on their daily operations.[15] To account for the contribution of peak shaving storage to regional gas supplies, ICF has estimated peak-shaving sendout as a function of the projected LDC daily firm demand and the LDCs' contracted pipeline capacity:

$$\text{Projected Daily Peak Shaving Sendout} = \\ Max[(Projected\ LDC\ Daily\ Firm\ Demand - \ Pipeline\ Capacity\ Contracted\ by\ LDCs), \\ Maximum\ Daily\ Peak\ Shaving\ Sendout]$$

In other words, it is assumed the LDCs will use their peak shaving resources whenever their daily gas load is greater than their contracted pipeline capacity. The projected peak shaving sendout is limited by the combined maximum re-vaporization capability of the facilities (approximately 1,500,000 Dth per day) and the total capacity of the storage tanks (about 16.7 Bcf). At maximum sendout, the total peak shaving storage capacity would be depleted within 11 days.

Exhibit 6-9 shows the projected peak shaving sendout in the winter of 2014/15 for the cold and median temperature scenarios; under the warm temperature scenario, LDC daily firm demand is consistently below contracted capacity, and therefore peak shaving supplies would not be needed.

Exhibit 6-9. Peak Shaving Daily Sendout Projections, Winter 2014/15



[15] LNG peak shaving operators report annual net additions to and withdrawals from LNG storage in Form EIA-176 (Annual Report of Natural and Supplemental Gas Supply and Disposition), but not winter daily sendout.

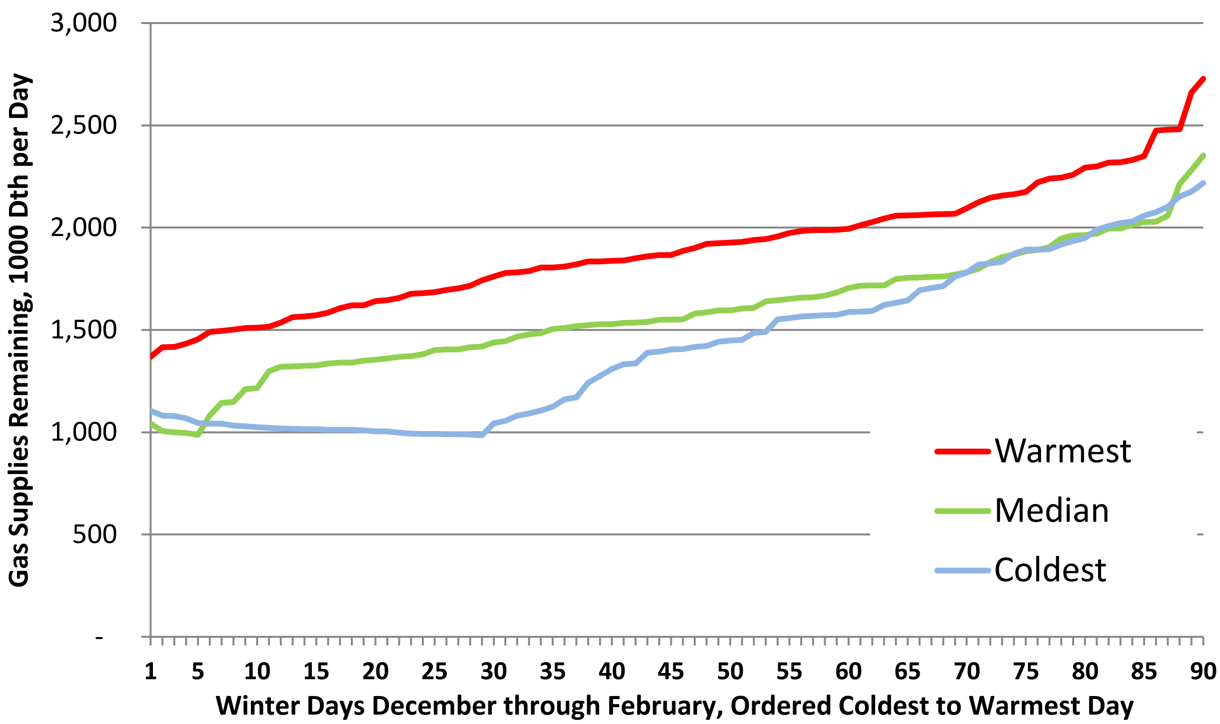
6.5. Winter Daily Gas Supplies Available to Electric Generators (Duration of Risk)

The projected winter daily values for gas supply and LDC firm demand described above were combined to arrive at gas supplies remaining for electric generators:

Contracted Pipeline Capacity (excluding M&N Pipeline)
+ Distrigas LNG daily sendout
+ M&N Pipeline daily flow
+ Peak shaving storage daily sendout
- LDC firm daily demand
= **Gas Supplies Remaining for Electric Generators**

For example, Exhibit 6-10 shows the projected gas supply remaining for electric generators for winter 2014/15 under the warm, median, and cold weather scenarios. Under the median weather scenario, gas supplies remaining are 1,100,000 Dth or less for only 6 days, and then increases as temperatures increase above 20 degrees F. Under the cold weather scenario, gas supplies remaining are under 1,100,000 Dth for 33 days. Under the warm weather scenario, daily temperatures are 24 degrees F or higher throughout the winter, and gas supplies remaining are above 1,300,000 Dth on all days.

Exhibit 6-10. Projected Gas Supplies Remaining for Electric Generators, Winter 2014/15

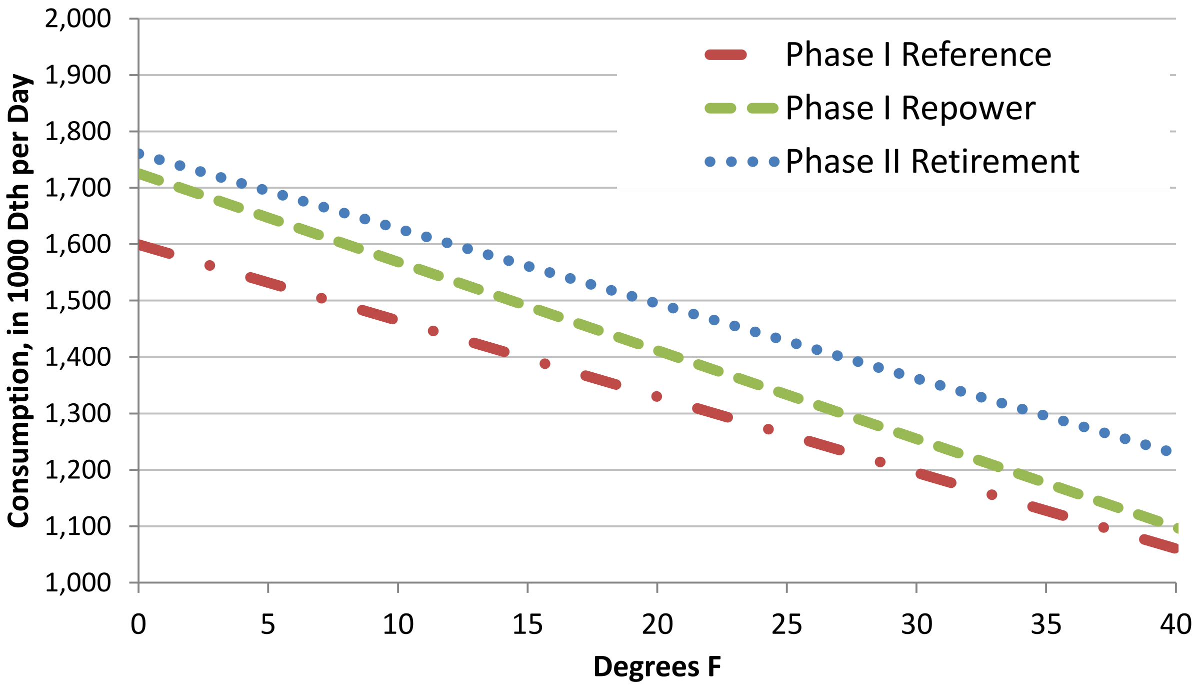


To investigate the impact of temperature on winter near-peak day gas demands, ISO-NE developed alternate projections for 2019/20 winter day gas demand for the Phase I Reference, Phase I Repower, and Phase II Retirement case. The alternate projections use different combinations of load and nuclear outages to represent gas demands over a range of temperatures:

- A peak load day using the ISO-NE 90/10 load projection, to represent gas loads at a temperature of 1.61 degrees F;
- A peak load day using the ISO-NE 50/50 load projection and 1,200 MW of nuclear capacity offline, to represent gas loads at a temperature of -2.97 degrees F; and
- A peak load day using the ISO-NE 90/10 load projection and 1,200 MW of nuclear capacity offline, to represent gas loads at a temperature of -8.39 degrees F.

Based on results from the ISO-NE cases, ICF developed linear projections of electric generation gas consumption over the 90 day of the 2019/20 winter as a function of the mean daily temperature, as shown in Exhibit 6-11.

Exhibit 6-11. Projected Electric Generator Gas Consumption as a Function of Temperature, Winter 2019/20



Using the 20-years of historical temperature data described in Section 6.1, ICF then calculated for the winter of 2019/20 the gas supplies remaining for electric generators versus the projected daily electric generation gas demand to determine:

1) the number of days during which gas demand would exceed available supplies for each temperature scenario, and
2) the quantity (total Dth shortfall over the 90 days of winter) of the gas supply in deficit for each temperature scenario.

A summary of these results are shown in Exhibit 6-12 (duration of deficit) and Exhibit 6-13 (size (Dth) of deficit). The results indicate median values of between 24 and 34 days for duration of the winter 2019/20 deficit, depending on which of the electric sector scenario is assumed. Assuming an equal probability for each of the 20 years of temperature data, there is an equal probability (50/50) that the duration of the deficit would be greater or less than the median values. Looking across all the temperature and electric sector scenarios, the duration of the deficit ranges from 0 days (Phase I Reference, assuming the warmest temperature scenario) to 51 days (Phase II Retirement, assuming the coldest temperature scenario). The median total quantity of the deficit ranges from about 6,000,000 Dth to about 10,700,000 Dth. The minimum deficit quantity was 0 Dth (no shortfall in Phase I Reference, assuming the warmest temperature scenario), and the maximum quantity was over 21,900,000 Dth (greatest shortfall in Phase II Retirement, assuming the coldest temperature scenario).

Exhibit 6-12. Duration of Gas Supply Deficit in Days, Winter 2019/20

Electric Sector Scenario	Duration of Deficit, in Days		
	Median (50/50)	Minimum (5/95)	Maximum (95/5)
Phase I Reference	24	0	42
Phase I Repower	29	1	46
Phase II Retirement	34	5	51

Exhibit 6-13. Size of Gas Supply Deficit in 1,000 Dth, Winter 2019/20

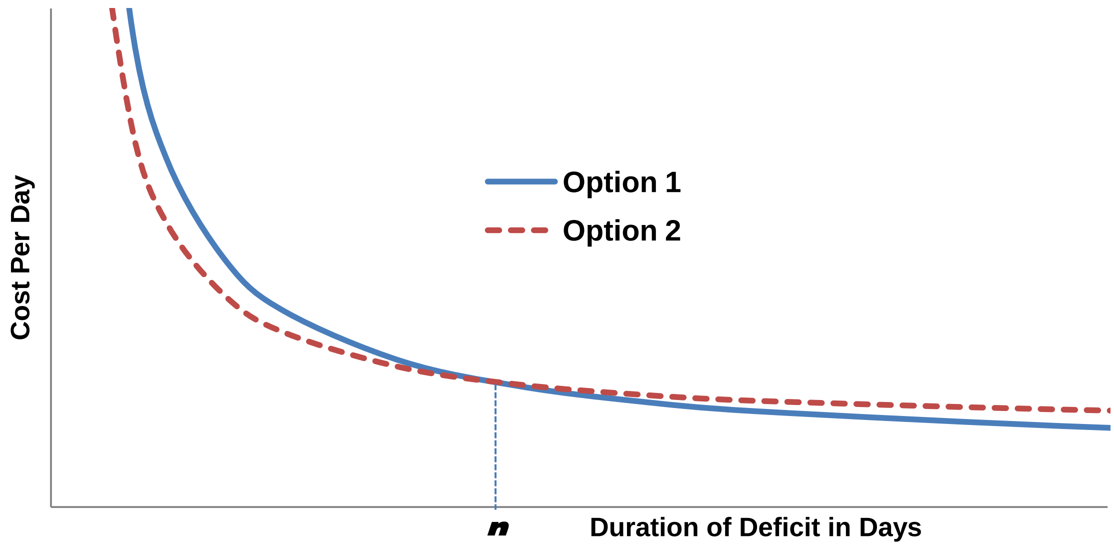
Electric Sector Scenario	Total Winter Deficit (1000 Dth)		
	Median (50/50)	Minimum (5/95)	Maximum (95/5)
Phase I Reference	6,047	0	14,436
Phase I Repower	8,107	66	18,361
Phase II Retirement	10,680	439	21,931

6.6. Duration of Risk and Analysis of Options

There are a wide variety of potential solutions to the projected supply deficit. The most obvious solution would be increases natural gas pipeline capacity, either through construction of a new pipeline or additional expansions of existing pipelines. Other options to increase regional fuel supplies include increasing LNG imports, adding peak-shaving gas storage to serve the electric sector, and the expansion of dual-fuel capability. Another set of options involve reducing electric generation gas demand by reducing winter peak electric load (through enhanced electric efficiency and demand side management programs) or adding new electric transmission capacity.

An approach for assessing the costs of each option is to create “cost duration curves,” constructed by allocating the fixed and variable costs associated with each option over number of days the option is to be used. The example cost durations curves shown in Exhibit 6-14 compare “Option 1” and “Option 2”. In this example, for a deficit that that is less than *n* days in duration, Option 2 has the lower cost. However, to serve loads greater than *n* days, Option 1 has the lower cost.

Exhibit 6-14. Example Cost Duration Curves



Generally, options with a high fixed cost component (such as a new gas pipeline) become more economical the more days they are used. For example, if a new pipeline were built from the northeastern Pennsylvania (part of the Marcellus shale supply area) to eastern Massachusetts, it may cost as much as $1.8 billion (Exhibit 6-15). Using a capital recovery factor of 14 percent, the capital cost component of the pipeline's tariff would be $252 per Dth each year; the variable operating costs (fuel charges plus non-fuel O&M) would be only about $0.05 per Dth. If the pipeline were only needed to meet a supply deficit that last 10 days per year, then the cost would be over $25 per Dth per day. However, if the pipeline were needed for 40 days per year, then the costs drops to just over $6 per Dth per day.

Exhibit 6-15. Example Costs for New Pipeline from Marcellus to New England

Pipeline Length (miles)	250
Pipeline Diameter (inch)	36
Pipeline Capacity (Dth per Day)	1,000,000
Total Inch-Miles of Pipeline	9,000
Cost per Inch-Mile ($)	200,000
Capital Cost of Pipeline ($)	1,800,000,000
Capital Cost per Unit of Transport ($/Dth)	1,800
Capital Cost Recovery ($/Dth/Year) /1	252
Variable O&M Costs ($/Dth)	0.01
Pipeline Fuel Cost ($/Dth) /2	0.04

1. Assuming a capital recovery factor of 14% per year.
2. Assuming pipeline fuel use of 1% and a gas price of $4.00 per Dth.

In contrast, options that have high variable costs but low capital cost can be more economical for serving fuel needs of a shorter duration. Exhibit 6-16 has example cost for adding 600 MW of distillate fuel switching capability to existing gas-fired capacity (enough to displace about

100,000 Dth per day of gas consumption). In this example, the capital cost for the fuel switching capability is $14.4 million and fixed O&M costs are $270 thousand. Using the same 14 percent capital cost recovery factor as for the pipeline, the annualized capital cost is only $20 per Dth per year. For a supply deficit of only 10 day, the capital cost component would be only $2 per Dth per day. However, because the cost of distillate fuel oil is very high, the variable cost is nearly $20 per Dth. Comparing this example to the example pipeline costs in Exhibit 6-15, the pipeline becomes the more economic option as the number of days the option is used increased beyond 11 days.

Exhibit 6-16. Example Costs for Adding Distillate Fuel Oil Switching

MW of Fuel Switching Capacity	600
Displaced Gas Use (Dth per Day)	100,000
Capital Cost ($)	14,400,000
Capital Cost Recovery ($/Dth/Year) /1	20.16
Fuel Cost ($/Dth) /2	19.66

1. Assuming a capital recovery factor of 14% per year.
2. Based on crude oil cost of $95/bbl.

Given that the Distrigas LNG terminal is currently operating below its rated capacity, another potential supply option would be to import additional LNG to Distrigas. Based on currently Atlantic Basin LNG prices, the cost of LNG delivered to the Distrigas terminal would be between $14 and $15 per Dth. To this would be added the Distrigas terminal fee, which is relatively low since it only covers marginal operating costs and does not include any capital recovery. As with oil fuel switching, the relative high fuel cost of imported LNG makes it a more attractive option for serving shorter duration loads.

In reality, many factors other than costs (for example, electric reliability, environmental issues, and fuel security concerns) must also be considered when assessing options for meeting electric generators' incremental fuel requirements. However, the cost duration analysis is a practical and balanced method of assessing the relative costs of each option.