Winter 2013/14 Benchmark and Revised Projections for New England Natural Gas Supplies and Demand

Presentation to

Planning Advisory Committee

April 29, 2014

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- Revised projection for gas supplies available to electric generators through 2020

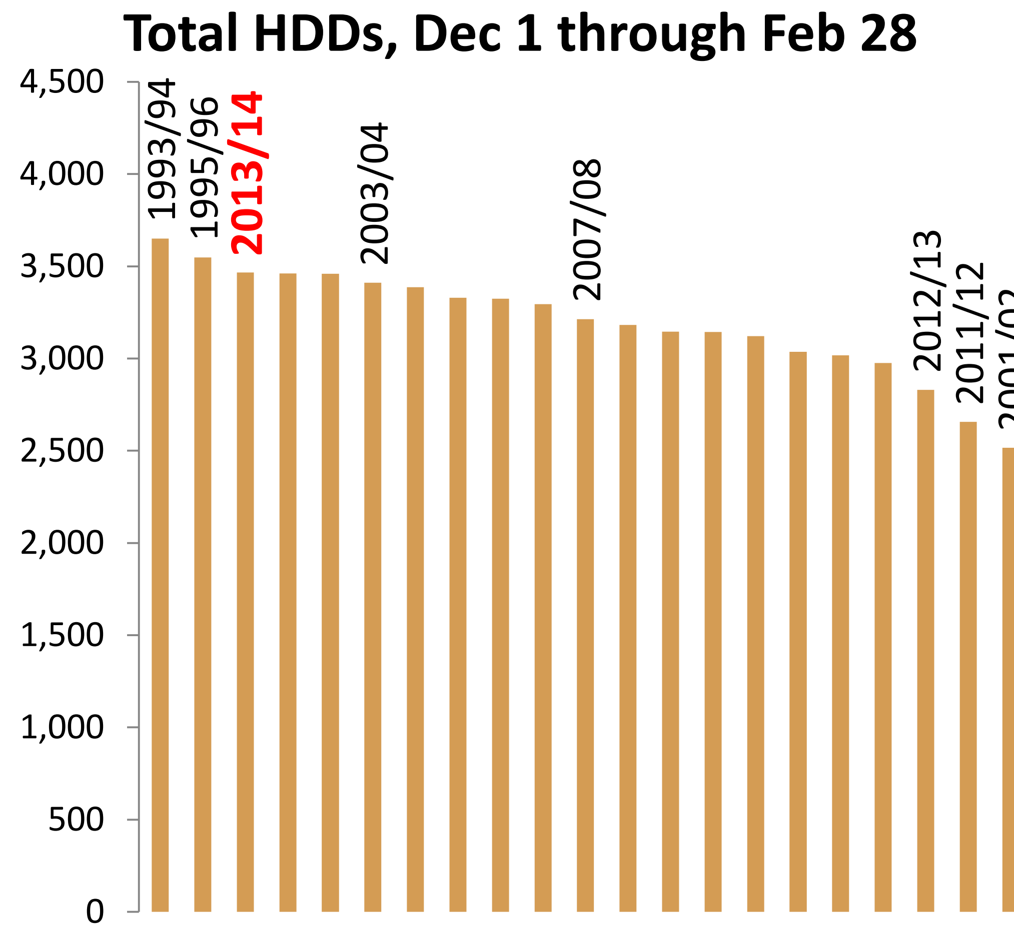
Introduction

- In 2013, ICF completed the Phase II assessment of New England natural gas supplies, firm LDC demand, and gas supplies remaining for electric generators through 2020.
  - Phase II included projections for the 90-day winter period (December 1 through February 28) and the peak summer day under a range of weather conditions, based on the prior 20-years of temperature data.
- The primary objective of this new “Benchmark” analysis is to re-evaluate the Phase II projections for New England natural gas supplies, firm LDC demand, and gas supplies remaining for electric generators based on data for gas system performance during the winter of 2013/14 (particularly during the polar vortex events), and make adjustment to the projections where necessary.
- ISO-NE also provided new projections for peak day winter and summer electric generation gas demand through 2020, based on the results of the latest Forward Capacity Auction (FCA 8).
  - ICF used these new gas demand projections and the revised projections for gas supplies remaining for electric generators to calculate potential gas supply surplus/deficits on peak winter and summer days through 2020.

Units used throughout this presentation:
1 Dekatherm (Dth) = 1 MMBtu = 1 Mcf = 1,000 cubic feet
1,000 Dth = 1 MMcf = 1,000,000 cubic feet

The Winter of 2013/14 was the 3rd Coldest in the Past 20 Years

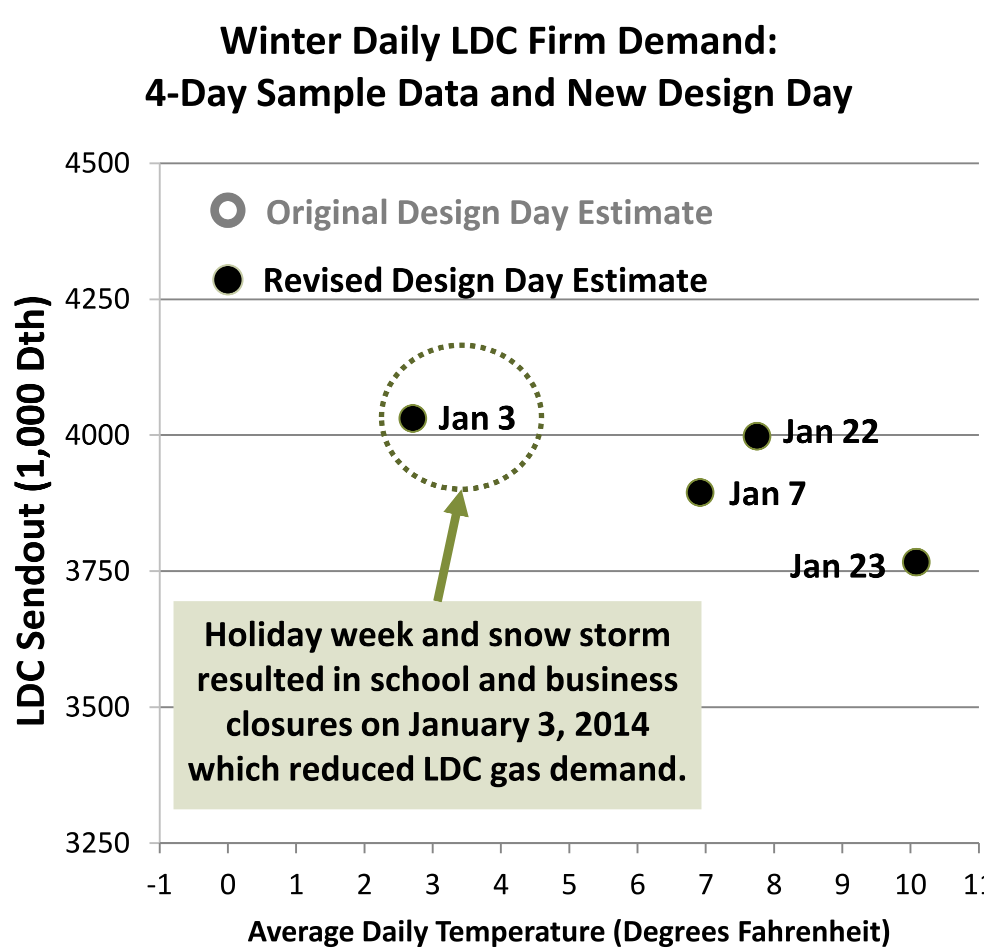
- The winter of 2013/14 was the coldest in New England since the 1990s.
  - Between Dec 1 and Feb 28 a total of ~3,500 Heating Degree Days (HDDs), about 10% colder than the 20 year average.
- Out of the past 21 years, the winter of 2013/14 ranks third in both total winter HDDs and the coldest average daily temperature.
  - The coldest day was January 3, 2014, when the weighted average daily temperature was 2.7 degrees F.*



* Daily temperatures and total winter HDDs are based on the weighted average hourly temperatures for eight New England weather stations for the gas day (a 24-hour period starting 10 AM Eastern each day).

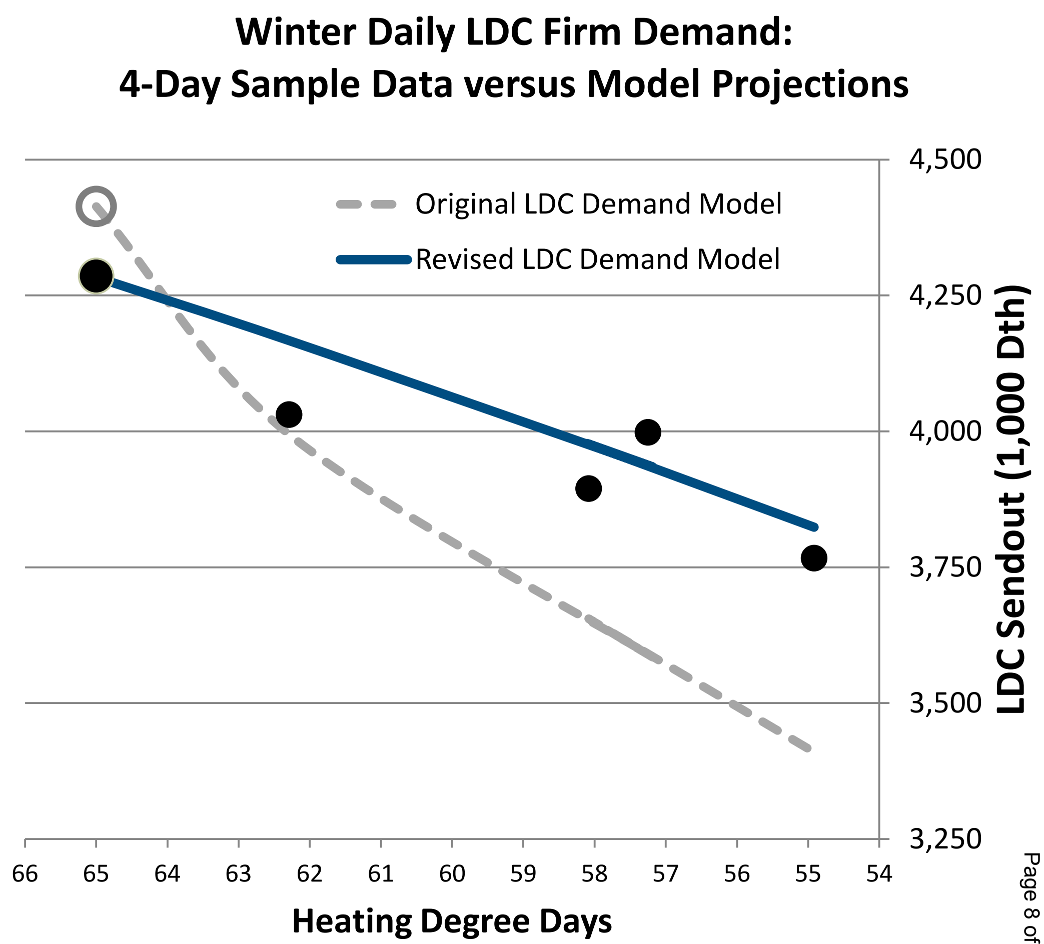
LDC Firm Demand:
Reported Sendout on Peak Days

- The Northeast Gas Association (NGA) provided ISO-NE with recent sendout data and revised design day estimates for 17 of the 21 New England LDCs.
  - The 17 LDCs represent 94% of the region's firm demand; the estimates for total New England LDC sendout were adjusted upward to account for the LDCs that did not report.
  - The LDCs did not report the temperatures assumed for the new design day estimates; ICF has assumed a design day temperature of 0 degrees F.
- Sendout data was provided for 4 days: January 3, 7, 22, and 23, of 2014.
  - These were 4 of the 6 coldest days this winter, with average daily temperatures ranging from 2.7 to 10.1 degrees F.
- The highest observed sendout this winter was on January 3, which was also the coldest day.
  - Even though it was the highest demand day, the combination of a holiday week and a regional snow storm resulted in January 3, 2014 demand being lower than we would have expected, given the temperature.



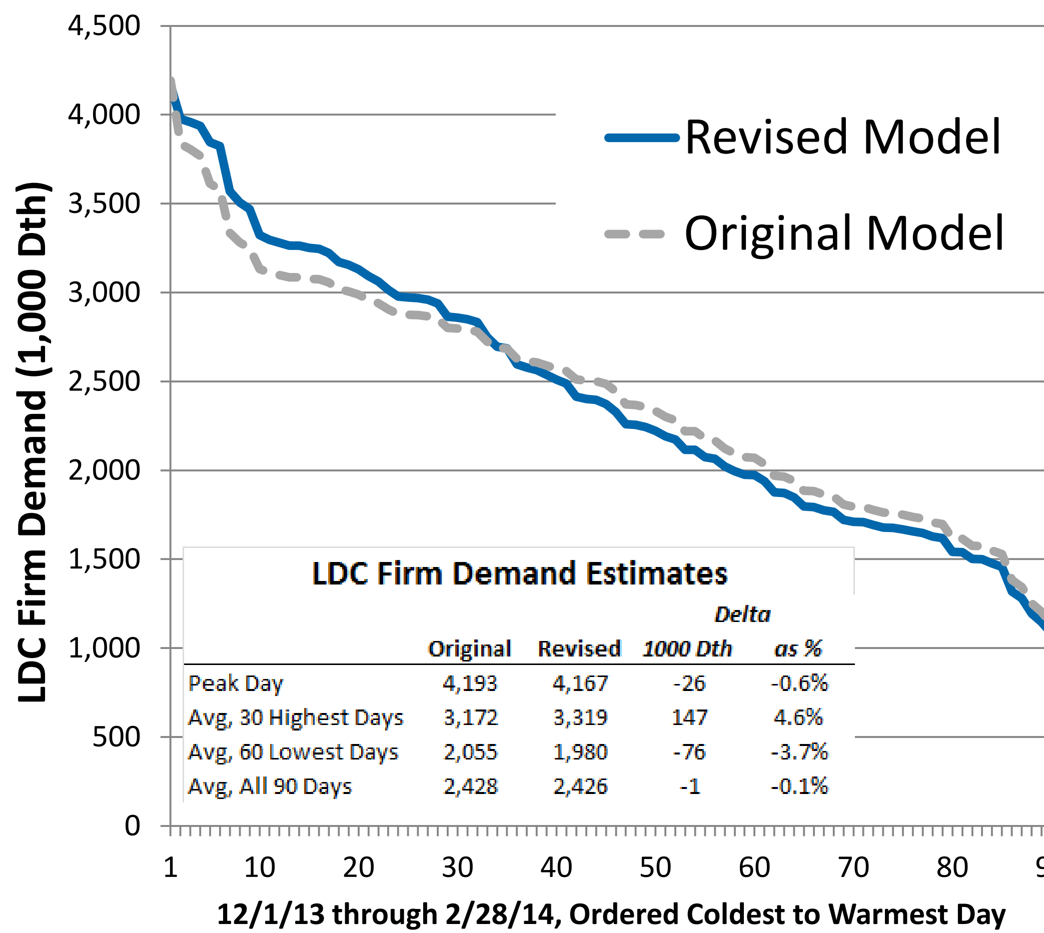
LDC Firm Demand:
Revision to LDC Firm Demand Model

- Based on the new LDC sendout data, ICF redesigns its model for winter daily LDC firm demand.
- The revised design day demand is about 3% lower than ICF's original estimate at the peak.
- However, the revised projections for demands between 63 and 45 HDDs (2 to 20 degrees F) are higher than ICF's original projection.



LDC Firm Demand:
Original and Revised Estimates for Winter 2013/14

- Based on this winter's average daily temperatures, the Original and Revised models have similar results for both Peak-Day Demand and 90-Day Total Demand.
- However, the Revised model's load curve has a ***Steeper Slope*** than the Original model:
  - LDC demand averages 5% higher on the 30 Highest Days.
  - LDC demand averages 4% lower on the 60 Lowest Days.



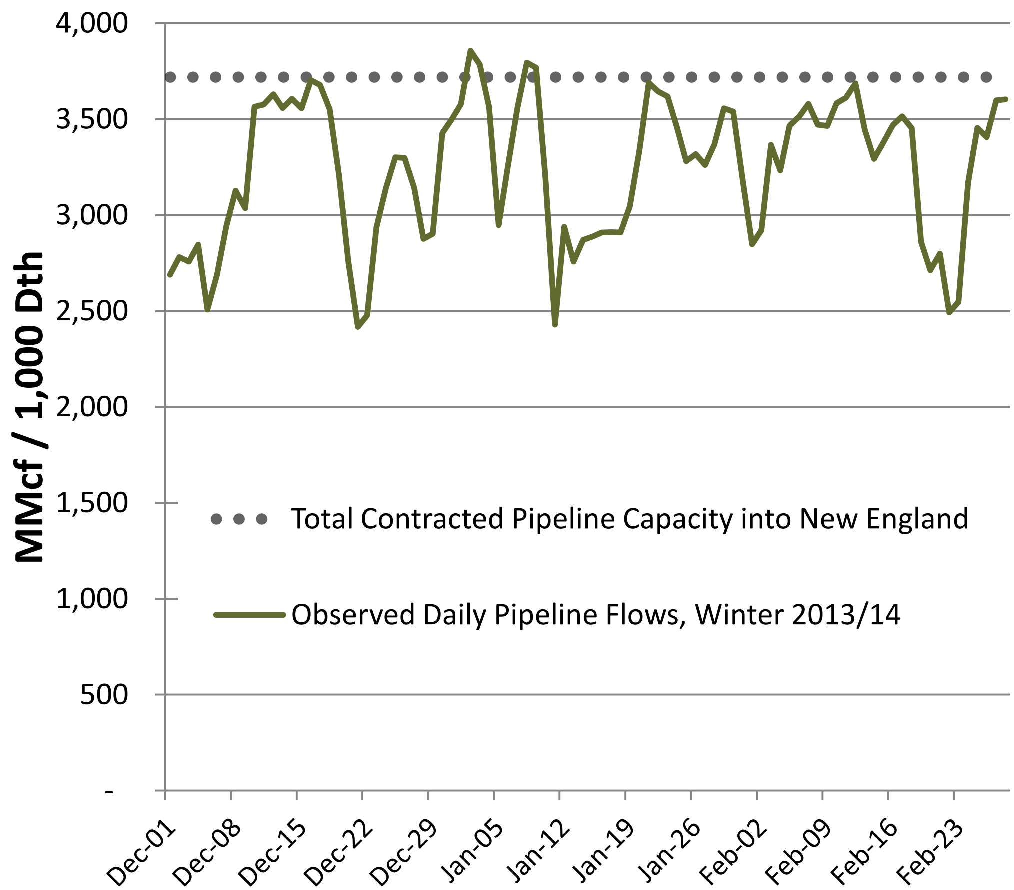
LDC Firm Demand Estimates

	Original	Revised	*Delta* *1000 Dth*	*as %*
Peak Day	4,193	4,167	-26	-0.6%
Avg, 30 Highest Days	3,172	3,319	147	4.6%
Avg, 60 Lowest Days	2,055	1,980	-76	-3.7%
Avg, All 90 Days	2,428	2,426	-1	-0.1%

Gas Supplies:
Pipeline Capacities and Flows

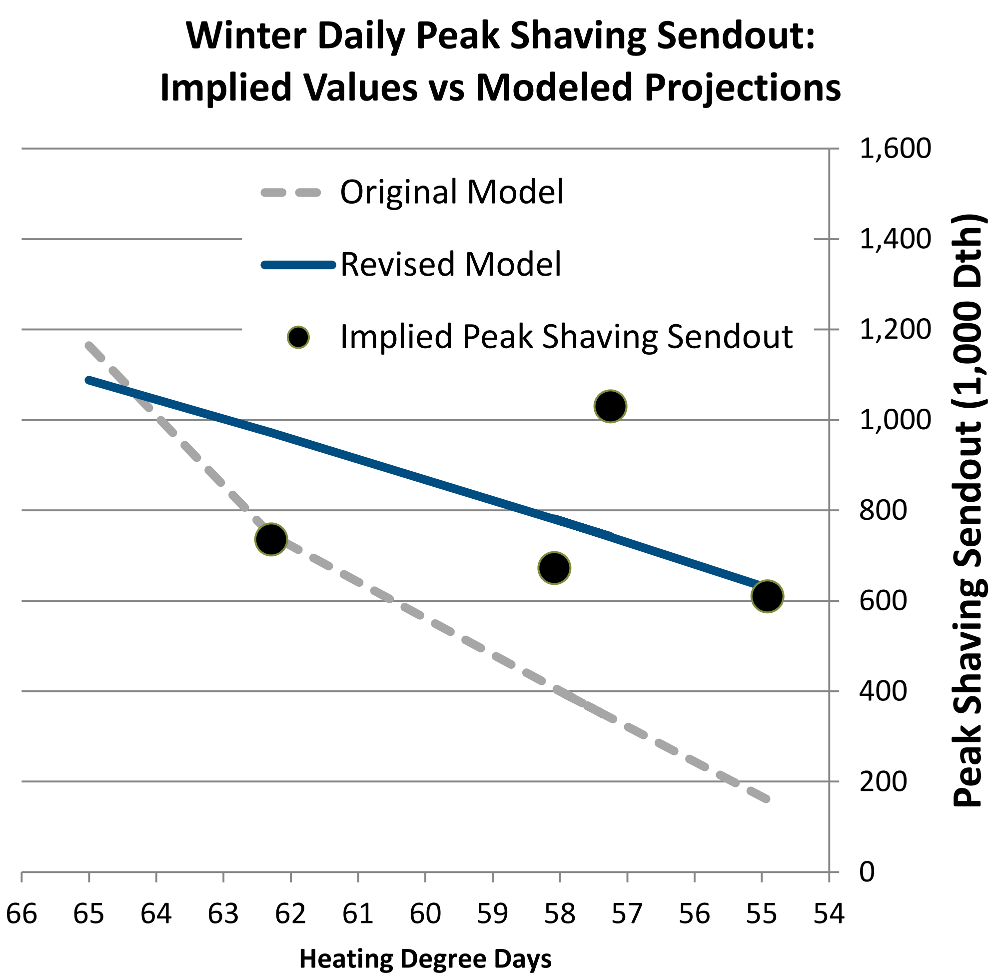
- In Phase II, ICF updated it's assessment of contracted pipeline capacity into New England.
  - For Phase II, ICF estimated contracted capacity into the region is 3,719 MMcf/d.
  - ICF currently projects that capacity additions on Algonquin and Tennessee will add a total of 414 MMcf/d of capacity in November 2016; this is slightly lower than the Phase II projection of 450 MMcf/d.
- ICF compared this winter's daily flows (derived from nomination data posted on the pipelines' electronic bulletin boards) to our current capacity assumption.
- As in past years, we observed that nominations on several pipelines were slightly higher than ICF's estimate of contracted capacity on a few days; on January 3 (the peak demand day), total flows were about 100 MMcf/d (~2%) above aggregate pipeline capacity.
  - However, flows were <u>below</u> aggregate capacity on several other high demand days; therefore we have <u>not</u> <u>changed</u> our estimate of current pipeline capacity.

New England In-Bound Pipelines:
Aggregate Flows versus Aggregate Capacity



Gas Supplies:
LNG and Propane-Air Peak Shaving Sendout

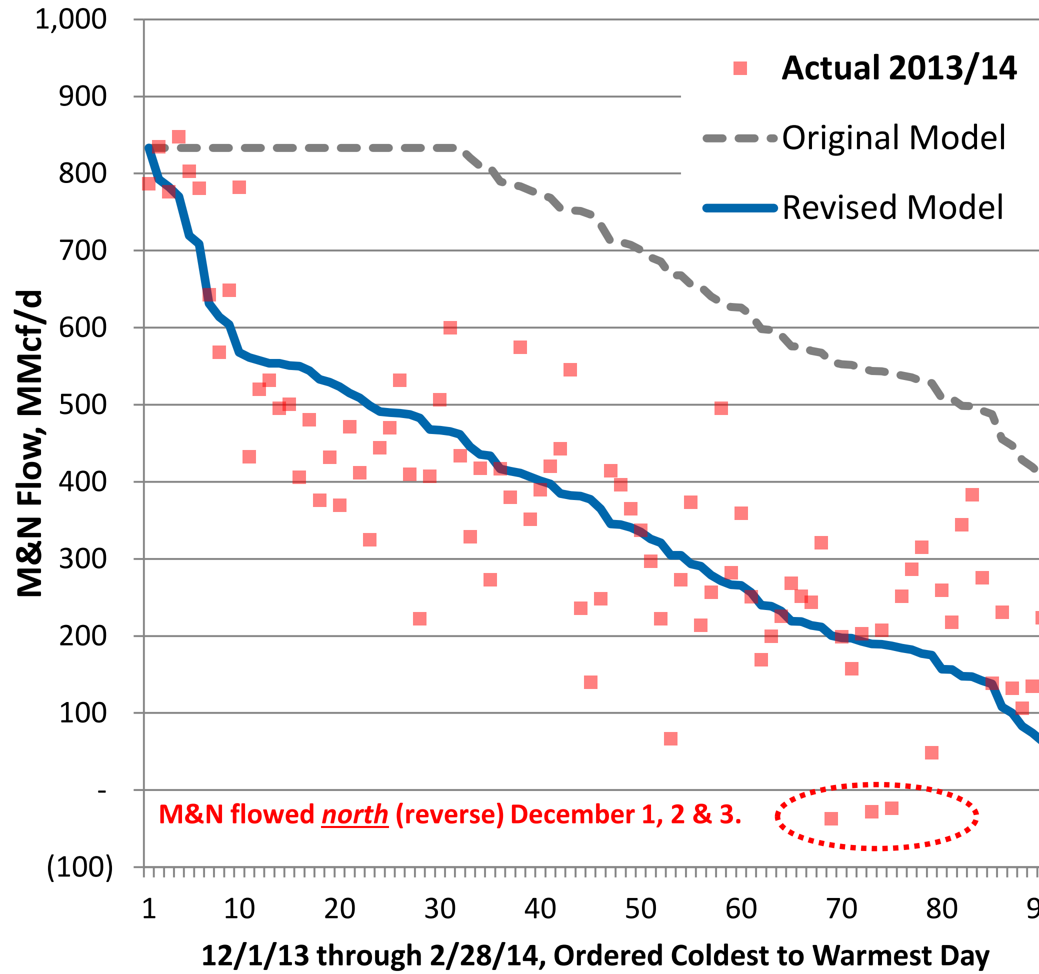
- The LDCs meet a portion of their peak winter loads with satellite LNG and propane-air peak shaving facilities.
- The LDCs did not provide any data on daily sendout from their peak shaving facilities, but we can implicitly arrive at usage:
  Implied Peak Shaving Sendout = LDC Sendout
  - LDC Pipeline Nominations
- The Revised Model of peak shaving sendout indicates higher utilization on "near-peak" winter days, when temperatures are below 10 degrees F.



Gas Supplies:

M&N Pipeline Winter Daily Flows

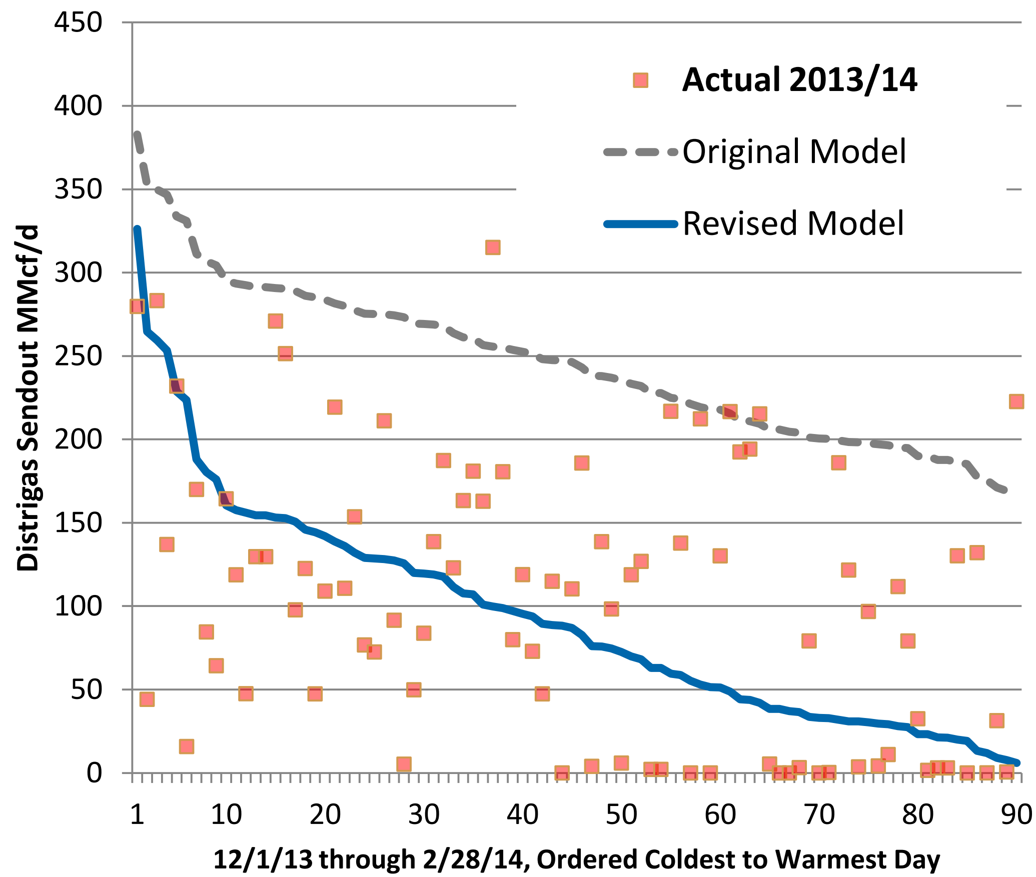
- M&N gas supplies come from a combination of Eastern Canadian offshore production and LNG sendout from the Canaport terminal.
- The Phase II projections anticipated higher average daily flows on M&N this winter due to the startup of Deep Panuke in August 2013.
  - The Deep Panuke offshore platform has a maximum capacity of 300 MMcf/d, but flows have been intermittent since startup.
- Based on the current data, ICF has reduced its projection for M&N average winter flows.
  - M&N is still likely to flow full on the coldest days.
  - However, projected flows on off-peak days now average about 300 MMcf/d less.
  - Declining offshore production and increasing demands in Eastern Canada will continue to reduced supplies available for export through 2020.



Gas Supplies:

Distrigas Winter Daily Sendout

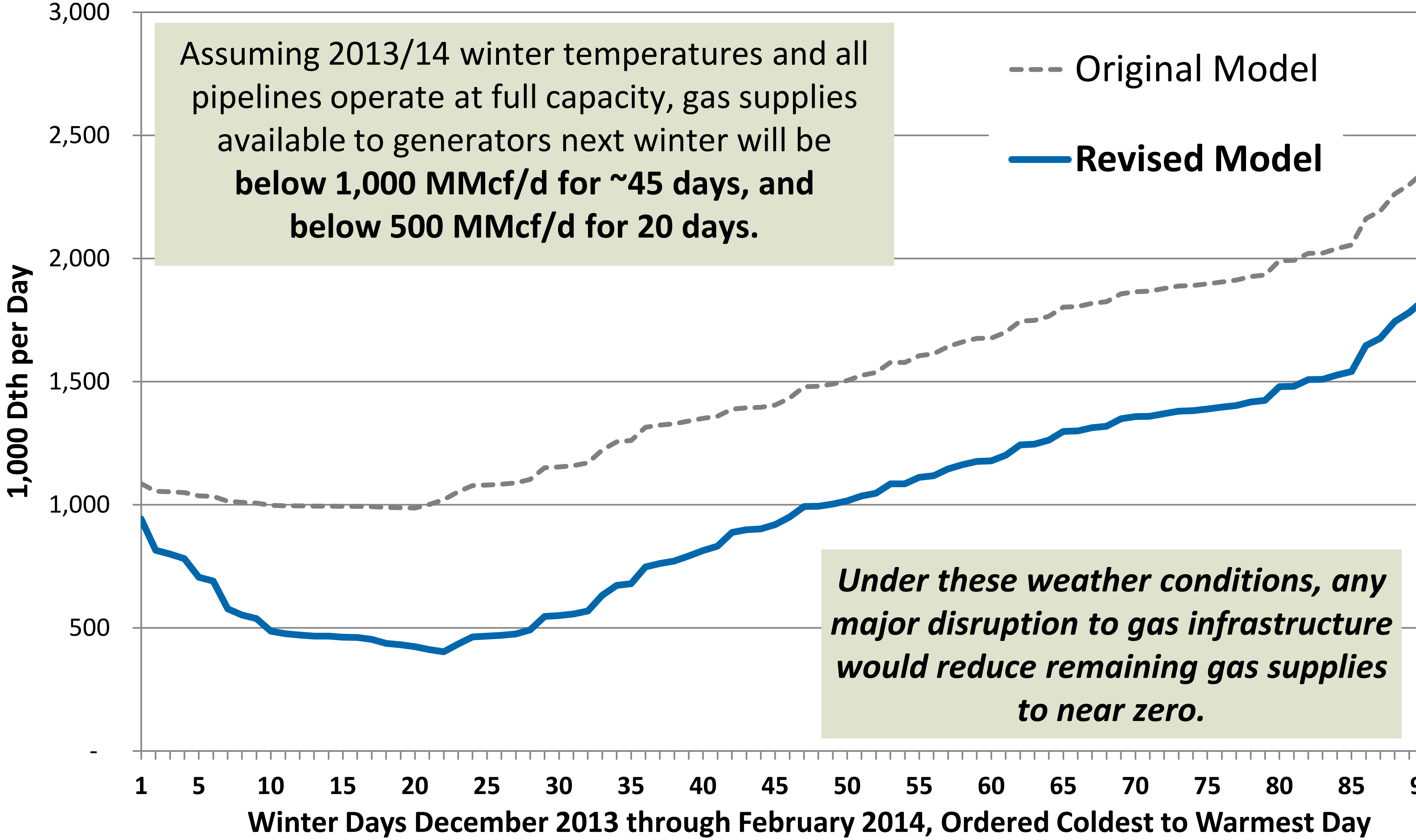
- The original model for Distrigas sendout was based on the historical 2012/13 winter sendout.*
  - During the 2012/13 winter, Distrigas sendout averaged 280 MMcf/d.
- This winter, Distrigas sendout averaged only about 100 MMcf/d.
  - The Revised model has sendout about 50 MMcf/d lower on peak, and averaging about 150 MMcf/d lower throughout the winter.



* Distrigas daily sendout includes regasification to Mystic 8 & 9, and deliveries to Algonquin and Tennessee pipelines; does not include trucked deliveries or direct connection to Boston Gas.

Revised Model Results for 2014/15 Winter:

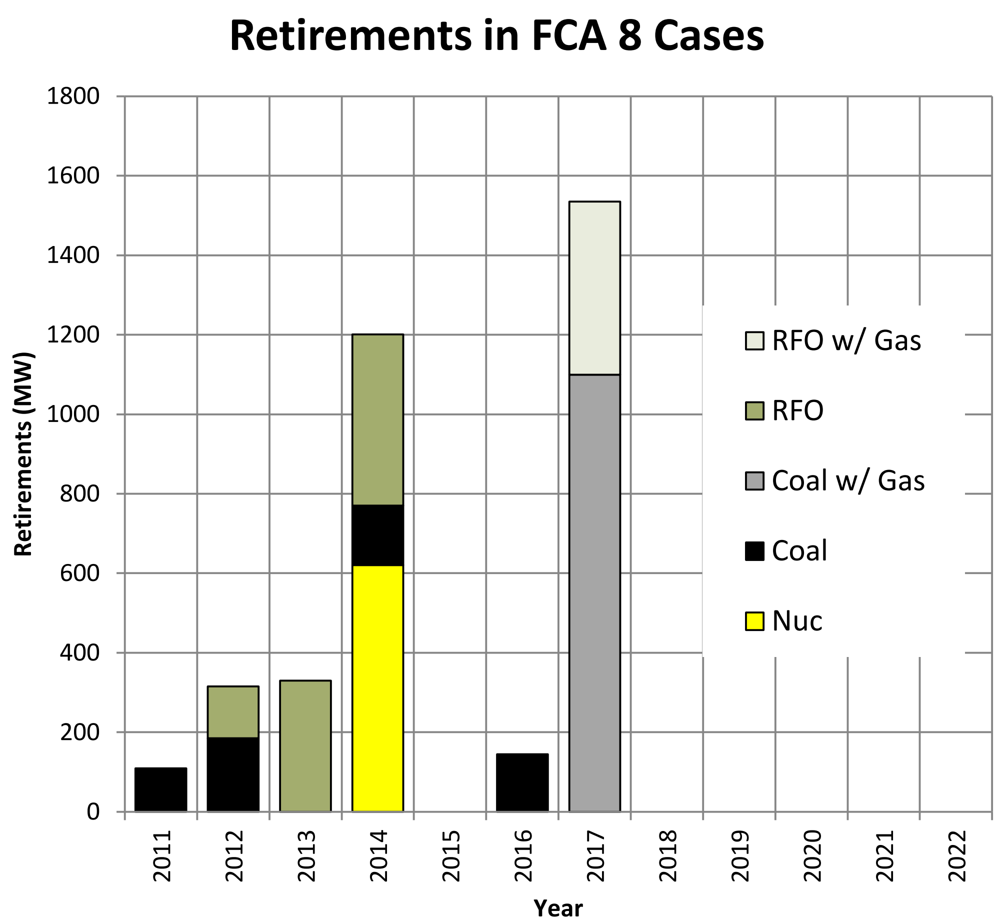
Gas Supplies Remaining for Electric Generators



Electric Generation Retirements in the FCA 8 Cases

Area	Unit Name	Type	Primary Fuel	Change in Capacity (MW)
SEMA	SOMERSET 6	ST	BIT	-109.1
CT	AES THAMES	ST	BIT	-184.7
SWCT	BRIDGEPORT HARBOR 2	ST	RFO	-130.5
NOR	NORWALK HARBOR 2	ST	RFO	-168.0
NOR	NORWALK HARBOR 1	ST	RFO	-162.0
BOST	SALEM HARBOR 4	ST	RFO	-431.0
BOST	SALEM HARBOR 3	ST	BIT	-149.8
VT	VT YANKEE NUCLEAR	ST	NUC	-620.2
WMA	MT TOM	ST	BIT	-144.4
RI	BRAYTON PT 3	ST	BIT	-612.0
RI	BRAYTON PT 4	ST	RFO	-435.0
RI	BRAYTON PT 2	ST	BIT	-244.0
RI	BRAYTON PT 1	ST	BIT	-243.5

Total = 3,634 MW



Assumed Fuel Prices for the FCA 8 Cases

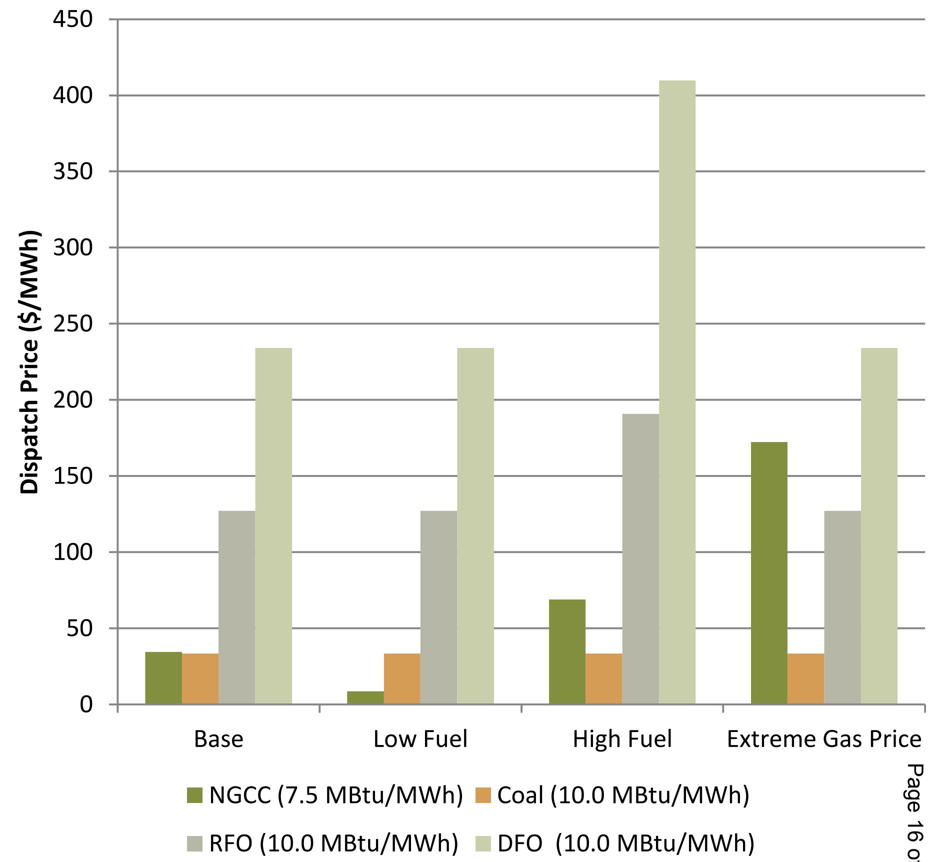
FUEL PRICES ($/MMBtu)

	Base	Low	High	Extreme	Assumed Heat Rate (MMBtu/ MWh)
Natural Gas	$4.6	$1.15	$9.19	$22.98	7.5
Coal	$3.34	$3.34	$3.34	$3.34	10.0
Oil	$12.72	$12.72	$19.08	$12.72	10.0
Distillate	$23.42	$23.42	$40.98	$23.42	10.0

ILLUSTRATIVE DISPATCH PRICES ($/MWh)

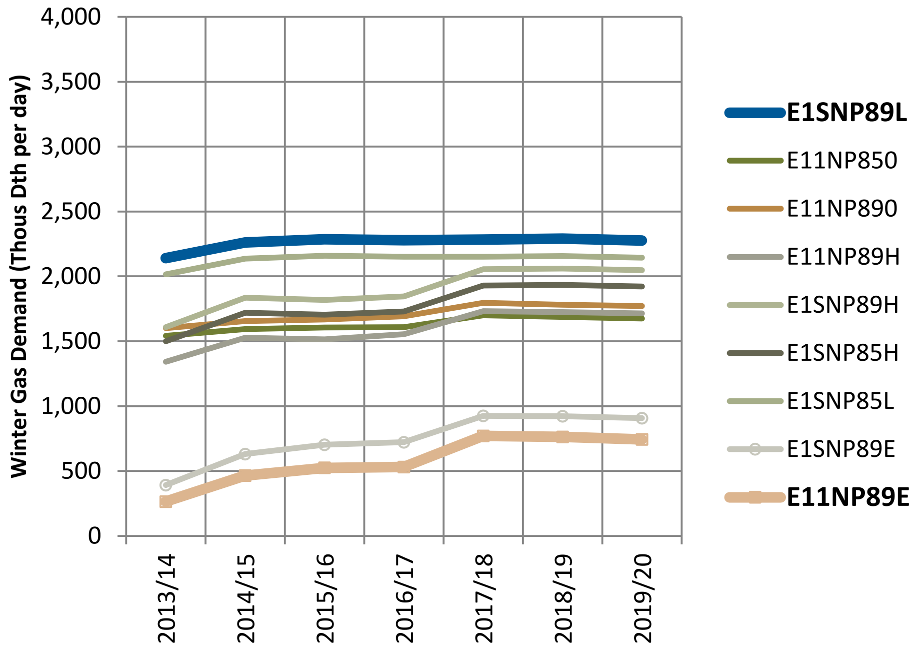
	Base	Low	High	Extreme
NGCC	$34.47	$8.62	$68.93	$172.35
Coal	$33.38	$33.38	$33.38	$33.38
RFO	$127.21	$127.21	$190.81	$127.21
DFO	$234.18	$234.18	$409.82	$234.18

Illustrative Dispatch Prices ($/MWh)

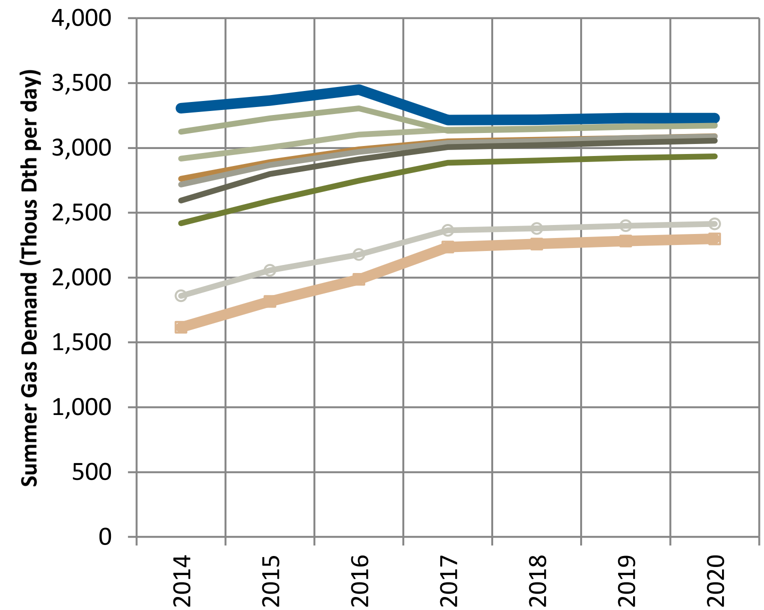


New ISO-NE Projections for Electric Generation Gas Demand (continued)

Winter Peak Day Gas Demand



Summer Peak Day Gas Demand

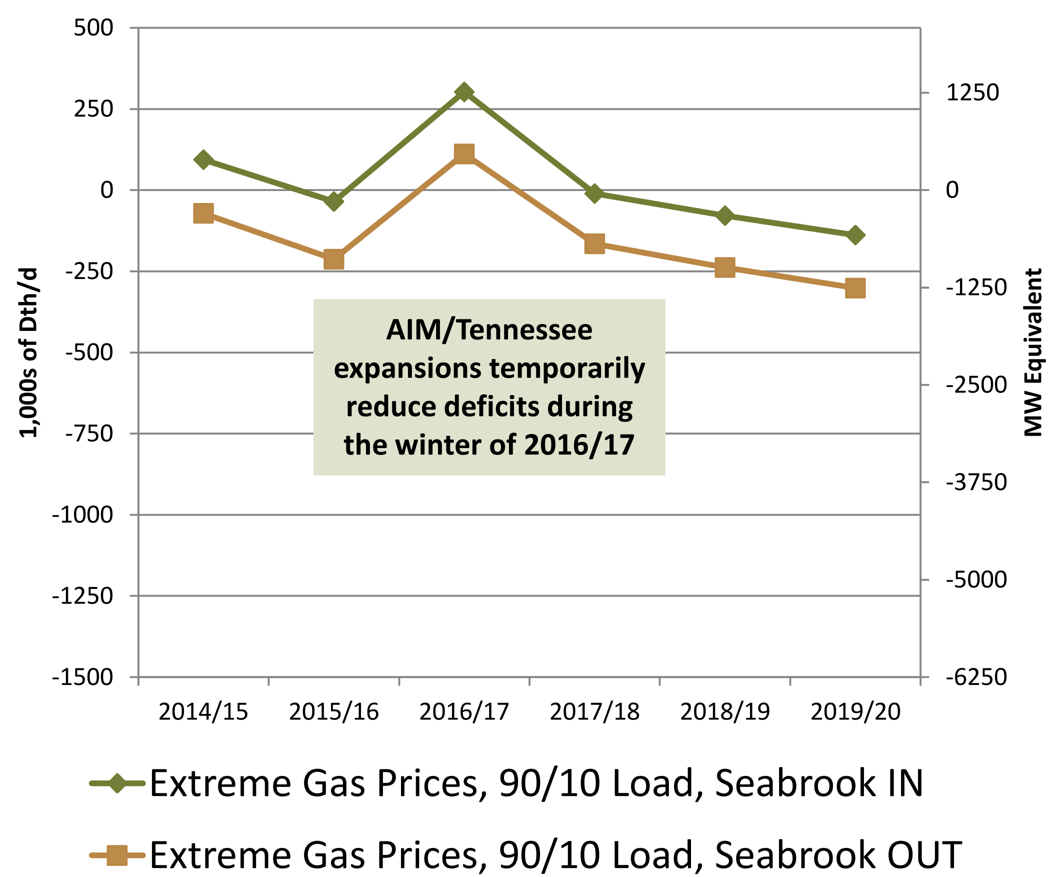


Highest Gas Demand	**E1SNP89L**	**Low Gas Prices, Seabrook-Out, 90/10 Forecast**
	E11NP850	Base Gas Prices, Seabrook-In, 50/50 Forecast
	E11NP890	Base Gas Prices, Seabrook-In, 90/10 Forecast
	E11NP89H	High Gas Prices, Seabrook-In, 90/10 Forecast
	E1SNP89H	High Gas Prices, Seabrook-Out, 90/10 Forecast
	E1SNP85H	High Gas Prices, Seabrook-Out, 50/50 Forecast
	E1SNP89E	EXTREME Gas Prices, Seabrook-Out, 90/10 Forecast
Lowest Gas Demand	**E11NP89E**	**EXTREME Gas Prices, Seabrook-In, 90/10 Forecast**

Revised Projection for Winter Peak Day Gas Deficit with "Extreme Gas Prices"

- Two of the new dispatch cases provided by ISO-NE assume $23/MMBtu gas prices (similar to this winter's average spot price).
  - These "Extreme Gas Price" cases make most (but not all) of the gas-fired units more expensive to dispatch than other resources.
- Assuming winter 2013/14 weather conditions, most oil-fired units in-merit, and Seabrook included in the dispatch, gas supplies available to generators are barely adequate through 2017/18, and then in deficit by about 100 MMcf/d (~400 MW).
- With Seabrook offline, gas supplies are in deficit throughout the forecast by as much as 300 MMcf/d (1,250 MW).

Power Sector Winter Peak Day Supply Deficits, "Extreme Gas Price" Scenarios Assuming 2013/14 Weather



Summary and Conclusions

- Compared the Phase II projections, the Revised projections for gas supplies available to electric generation throughout the winter average nearly 500 MMcf/d lower.
  - Revised projection for LDC firm demand is slightly lower on the design day (0 degrees F), but higher on days with temperatures between 3 and 30 degrees F.
  - Lower anticipated production from Eastern Canadian offshore fields reduces expected supplies via M&N Pipeline; Canaport LNG sendout limited to only the highest demand days.
  - Distrigas sendout this winter averaged about 110 MMcf/d (*~150 less than last year*) despite colder temperatures.
- Given the projected gas supplies, electric system reliability during the winter months would be compromised by sustained cold weather.
  - If we assume "Extreme Gas Prices" (>$20/MMBtu, meaning many oil units would be in-merit) and the same weather conditions as this past winter, winter peak day gas supplies will be barely adequate or slightly in deficit through 2020, *as long as there are no major non-gas fired capacity outages*; a disruption to gas supplies or a nuclear unit outage would result in a serious gas supply deficit.
- During the summer, LDC firm demand is only about 20% of the winter peak demand, so pipeline capacity is less likely to be constrained.
  - The AIM/Tennessee expansions will add 414 MMcf/d of capacity by November 2016, so the total in-bound pipeline capacity will increase to about 4,100 MMcf/d, well above projected summer peak day electric sector gas demand.
    - However, that total includes 833 MMcf/d of capacity on M&N Pipeline. M&N is unlikely to contribute much to New England's summer gas supplies; in fact, M&N can actually reversed flow, reducing net supplies available in New England.
  - Certain events or combinations of events (high load conditions, pipeline capacity offline for maintenance, nuclear outages, etc.) could result in a gas supply constraints even within the summer.

Questions/Comments