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Simulation and Analysis of North American Natural Gas Supply and Delivery during a Winter High-Demand Event with Loss of Marcellus Production

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Simulation and Analysis of North American Natural Gas Supply and Delivery during a Winter High-Demand Event with Loss of Marcellus Production

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Abstract

This report presents analyses of the predicted response of the North American natural gas system to extremely high natural gas demand during the winter seasons of 2015 and 2030. These high-demand scenarios were simulated both with and without freeze-off of a fraction of Appalachia shale gas wells in January 2015 and 2030 that cause a loss of approximately 3% of total national production. Profiles of gas consumption, supply, price, and storage results are compared with those expected during normal conditions. The impacts of increased demand, with and without Appalachia production loss, are described for the United States and for its nine census regions.

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EXECUTIVE SUMMARY

In support of the U.S. Department of Energy's (DOE's) 2014 Quadrennial Energy Review, Sandia National Laboratories conducted critical infrastructure simulation analyses to investigate the predicted response of the North American natural gas system to extremely high-demand scenarios during the 2015 and 2030 winter seasons (December, January, and February), reminiscent of the January 2014 polar vortex event. These high-demand scenarios were simulated both with and without shale gas well freeze-offs in January 2015 and 2030 that cause a 33% loss in western Pennsylvania Marcellus, West Virginia Marcellus, and Ohio Utica shale gas production, which represents approximately 3% of total national production.

Sandia used the RBAC, Inc., Gas Pipeline Competition Model (GPCM) Natural Gas Market Forecasting System to model base case (normal supply and demand), high-demand, and high-demand with Appalachia freeze-off production loss scenarios. Profiles of gas consumption, supply, price, and storage resulting from the two high-demand scenarios were compared with those expected during normal supply-and-demand conditions (base case). The impacts of increased demand, with and without Appalachia basin shale gas production loss, are described both for the United States as a whole and for its nine census regions.

Both the winter high-demand scenario and the winter high-demand-with-production-loss scenario were predicted to adapt without a catastrophic effect on the natural gas market when looking at a month-long timescale for either the 2015 or 2030 cases. Simulations predict that North American and individual U.S. census regional markets are generally robust and able to adjust to a period of sustained high demand. However, shorter-term impacts were not studied and could potentially be significant.

Higher gas prices and increased storage withdrawals naturally occur during a high-demand event. Relative to base-case supply-and-demand conditions, gas prices were predicted to remain high, and gas consumption in the Electric Power sector was predicted to decrease for approximately one year following the high-demand event, as increased storage injections would be required to return gas storage amounts to normal levels.

Lost shale gas production from Appalachia wells only slightly amplified the changes that occurred from increased demand. For example, in the New England census region, a more drastic increase does not occur because gas consumption in the Electric Power sector decreases approximately 25% in response to higher prices. However, this work did not investigate how the Electric Power sector adjusts to compensate for decreased gas-fired electric power generation, and potential problems with decreased electric consumption were not examined.

Expected prices were higher and storage inventories stressed further, but the simulated natural gas market systems adapted to these scenarios without signs of significant inability to meet demand.

NOMENCLATURE

AEO	Annual Energy Outlook
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Association
EPSA	Energy Policy and Systems Analysis
GPCM	Gas Pipeline Competition Model
ISO-NE	ISO (Independent System Operator) New England, Inc.
LDC	local distribution company
LNG	liquefied natural gas
NYMEX	New York Mercantile Exchange
tcf	trillion cubic feet

1 INTRODUCTION

1.1 Background

The United States consumed 26.79 trillion cubic feet (tcf) of natural gas in 2014. Of that amount, 19% was used by residential consumers and 30% was used for electricity generation.[1] For 2014, this equates to 50% of U.S. homes being heated by natural gas and 27% of U.S. electricity being generated by natural gas.[2] When the extreme cold polar vortex event hit the northeastern United States in January 2014, the price of natural gas soared as demand increased to levels that pushed natural gas delivery systems to their design limits. Although not a significant issue in January 2014, unprotected gas-production wells are susceptible to freeze-offs when extremely cold weather freezes water and other liquids in the gas, which can diminish gas supply when demand is highest. Well freeze-offs have led to production falls in a number of U.S. census regions, including the Midcontinent, Southwest, and in the Northeast.[3]

Natural gas is initially gathered from production wells and piped to processing plants, where impurities are removed, before it is injected into the interstate pipeline system. Thousands of miles of large-diameter, high-pressure, interconnected pipelines transport natural gas from production areas to consumers throughout North America.[4] As natural gas flows through the pipeline network, compressor stations along each route maintain the required pressure until delivery to consumers or gas storage facilities. Gas storage facilities, created from depleted gas or oil fields, aquifers, or salt caverns, help balance variations in consumer demand, particularly between summer low-demand periods and winter peak demand.

Of the nine U.S. census regions addressed by the study, the New England region is of significant interest. Unlike other census regions of the United States, the New England region lacks significant gas storage due to unsuitable geology and is reliant on pipeline transportation of natural gas from distant production and storage fields.[5] This makes the New England region particularly vulnerable to upstream pipeline disruptions.

The interstate pipeline system is undergoing a period of considerable change, as rapid development of new natural gas production regions in the United States significantly alters historical patterns of gas flow. Recent advances in well drilling technology now allow the economic extraction of natural gas from "unconventional" reservoirs, such as shale. The development of these reservoirs has allowed the United States to transition from strong

[1] DOE EIA Monthly Energy Review, June 2015, http://www.eia.gov/totalenergy/data/monthly/archive/00351506.pdf, accessed July 1, 2015.
[2] DOE EIA, Everywhere but Northeast, fewer homes choose natural gas as heating fuel, September 25, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=18131, accessed July 1, 2015.
[3] Magill, Jim and Chris Newkumet. "Cold Winter Causes Gas Well Freeze-Offs To Spike; Data Can Lag By Several Months." March 28, 2014. http://www.platts.com/latest-news/natural-gas/houston/cold-winter-causes-gas-well-freeze-offs-to-spike-21398172 , accessed February 19, 2016.
[4] U.S. Energy Information Administration, About U.S. Natural Gas Pipelines–Transporting Natural Gas, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html, accessed July 1, 2015.
[5] Ibid.

dependence on oil and gas imports a decade ago into one of the world's largest producers. The Appalachian basin's Marcellus shale formation is one of the country's largest natural gas production areas, representing 36% of shale gas production and 18% of total dry natural gas production in the United States.[6]

1.2 Purpose and Scope

Conducted in support the U.S. Department of Energy's (DOE's) 2014 Quadrennial Energy Review, Sandia National Laboratories conducted critical infrastructure simulation analyses to investigate:

- Predicted response of the North American natural gas system to extremely high-demand scenarios reminiscent of the January 2014 polar vortex event (high demand).
- Potential effects of significant natural gas well freeze-offs through additional scenarios incorporating loss of production from shale gas reservoirs in the Appalachian basin coupled with high demand (high demand with 33% production loss from a subset of Appalachian shale gas regions).

Because U.S. natural gas infrastructure is undergoing a period of change in response to rapid and ongoing development of new unconventional reservoirs, these conditions were simulated for both 2015 (near future, as of the drafting of this report) and 2030 (far future) to evaluate the effects of anticipated changes in infrastructure on overall system resilience.

Profiles of gas consumption, supply, price, and storage resulting from these scenarios are compared with those expected during normal supply-and-demand conditions (base case). The impacts of increased demand, with and without Appalachia basin shale gas production loss, are described both for the United States as a whole and for its nine census regions.

[6] U.S. Energy Information Administration, Natural Gas Weekly Update (week ending March 25, 2015); released on March 26, 2015, http://www.eia.gov/naturalgas/weekly/archive/2015/03_26/index.cfm, accessed July 1, 2015.

2 METHOD

2.1 Model Description

Sandia analysts used the Gas Pipeline Competition Model (GPCM) Natural Gas Market Forecasting System, a commercial product developed by RBAC, Inc., to simulate average monthly natural gas flow and prices on pipelines and at market points across the North American natural gas system. A brief description of GPCM follows. (GPCM is explained in greater detail in Appendix A.)

GPCM is a node-arc network model. Nodes represent production areas, pipeline zones, pipeline interconnects, storage facilities, and aggregations of one or more customers. Arcs between nodes represent gas flows and are constrained by capacity limitations. Arcs connect pipeline zones to form the North American pipeline network. Each arc is defined by maximum flow, minimum flow, transportation costs, and efficiency to account for compressor fuel and other losses.

Supply, demand, storage, and interconnect nodes are treated as market points where supply and demand must be balanced. Producers and consumers of natural gas are modeled by supply and demand curves, respectively, and connected by the pipeline network model. Storage nodes are constrained by total storage capacity and maximum injection and withdrawal rates. GPCM reports monthly average flows and prices within the network for each month of the simulation. Infrastructure projects announced or expected to come into service by approximately 2020 are explicitly included in the GPCM dataset. To allow for likely pipeline capacity expansions after 2018, capacities on constrained pipelines were allowed to expand by up to 100% during the simulation, assuming an additional transportation cost of $0.10 per million Btu.[7]

2.2 Scenarios

Three key scenarios were simulated for both near future (2015) and distant future (2030) supply, demand, and infrastructure expectations as follows:

1. Base Case: Historical and projected monthly natural gas supply, demand, and infrastructure specifications for the North American natural gas system.[8] The Base Case dataset is provided for use with the GPCM model by GPCM's developer, RBAC, Inc., and updated quarterly.[9]

[7] The GPCM pipeline dataset was checked for consistency with Deloitte pipeline expansion projections. Where Deloitte predictions were explicit, there generally existed corresponding pipeline projects in GPCM. Where Deloitte predictions could not be matched with a specific pipeline project, there generally existed pipelines to allow for flow between the specified regions. For two pipeline additions by Deloitte (Tuscola-Chicago and Vector Chicago Dawn, both in the Midwest), GPCM conversely predicts reduced pipeline utilization between the associated regions (southern Illinois to Chicago to Ontario) during the study period, suggesting possible inconsistency between Deloitte and RBAC. Inc., regional supply and demand assumptions.

[8] See Appendix B: GPCM Base Case Comparison with Annual Energy Outlook 2014.

[9] The RBAC-provided GPCM dataset "14Q2mod1" was used for the Base Case. It is an updated version of their original "14Q2base" dataset, which contains an error resulting in >2x overestimation of future residential gas demand for CT, NJ, and ND.

2. High Demand: Base Case supply and infrastructure assumptions with increased winter demand (December through February). For winter 2015, the simulated monthly demand is the highest observed or predicted for the relevant month in years 2012-2015 for every demand area (state or sub-state) and sector (Residential, Commercial, Industrial, and Electric Power). For winter 2030, this demand is scaled to account for changes in market size, customer count, etc.[10]

3. 1/3 Freeze-off: High-Demand scenario assumptions through the winter (December through February) with a loss of 33% of gas production during January from "wet" shale formations (i.e., those with high natural gas liquid content) in the Appalachian basin (western Pennsylvania Marcellus, West Virginia Marcellus, and Ohio Utica shale formations). This case is representative of a 1/3 loss for 30 days in terms of instantaneous severity and, as mentioned above, constitutes approximately 3% of total national production.[11]

The effects of these scenarios on monthly average natural gas consumption, production, price, and storage are analyzed for the year preceding the event and the year-and-a-half following the event (i.e., January 2014[2029] through October 2016[2031]) to provide a holistic understanding of the events' effects on the natural gas market.[12]

The data and simulation tools used in this study report monthly average values for supply, demand, price, pipeline flow rates, etc. Time-averaging necessarily smooths shorter-term variations in the underlying data. Hourly or daily spikes in demand could, for example, lead to local pipeline flow constraints, or other supply shortages, and transient high prices that are not explicitly apparent when looking at the monthly average values.

[10] The High Demand scenarios should correlate with cold weather for Commercial and Residential sectors, but for Electric Power and Industrial sectors, the highest historical demand likely coincides with moderate weather when gas prices are relatively lower. The net result is a worse-than-worst-case demand picture. Specifying monthly temperatures to determine demand, as described in the official GPCM documentation, failed because GPCM's underlying demand correlations did not explicitly account for temperature for all states.

[11] The Freeze-off case demonstrates effects of a major freeze-off in the Marcellus region. If well protection in the region is adequate, a freeze-off of this magnitude is unlikely.

[12] Because GPCM resolves time only to individual months, simulated loss of production and increased demand occurs over the course of the entire month(s). In reality, loss of production and increased demand more likely occur over only a few days or one week.

3 RESULTS: UNITED STATES

3.1 Gas Consumption

Assumptions underlying the 2015 High-Demand scenario (December 2014–March 2015) result in monthly gas consumption amounts over 20% higher than the Base Case during high-demand months (Figure 1). Most of this consumption increase is spread among the Residential, Commercial, and Electric Power sectors, with Industrial sector gas consumption increasing only slightly (approximately 5%) relative to the Base Case.[13] The 1/3 Freeze-off scenario, which reduces total national production by 3% in January, shows consumption values indistinguishable from those of the High-Demand scenario over the course of the year, indicating that the system is able to adjust to the production loss event in January without reducing consumption. As described later, this adjustment mainly occurs through increased withdrawal from storage.

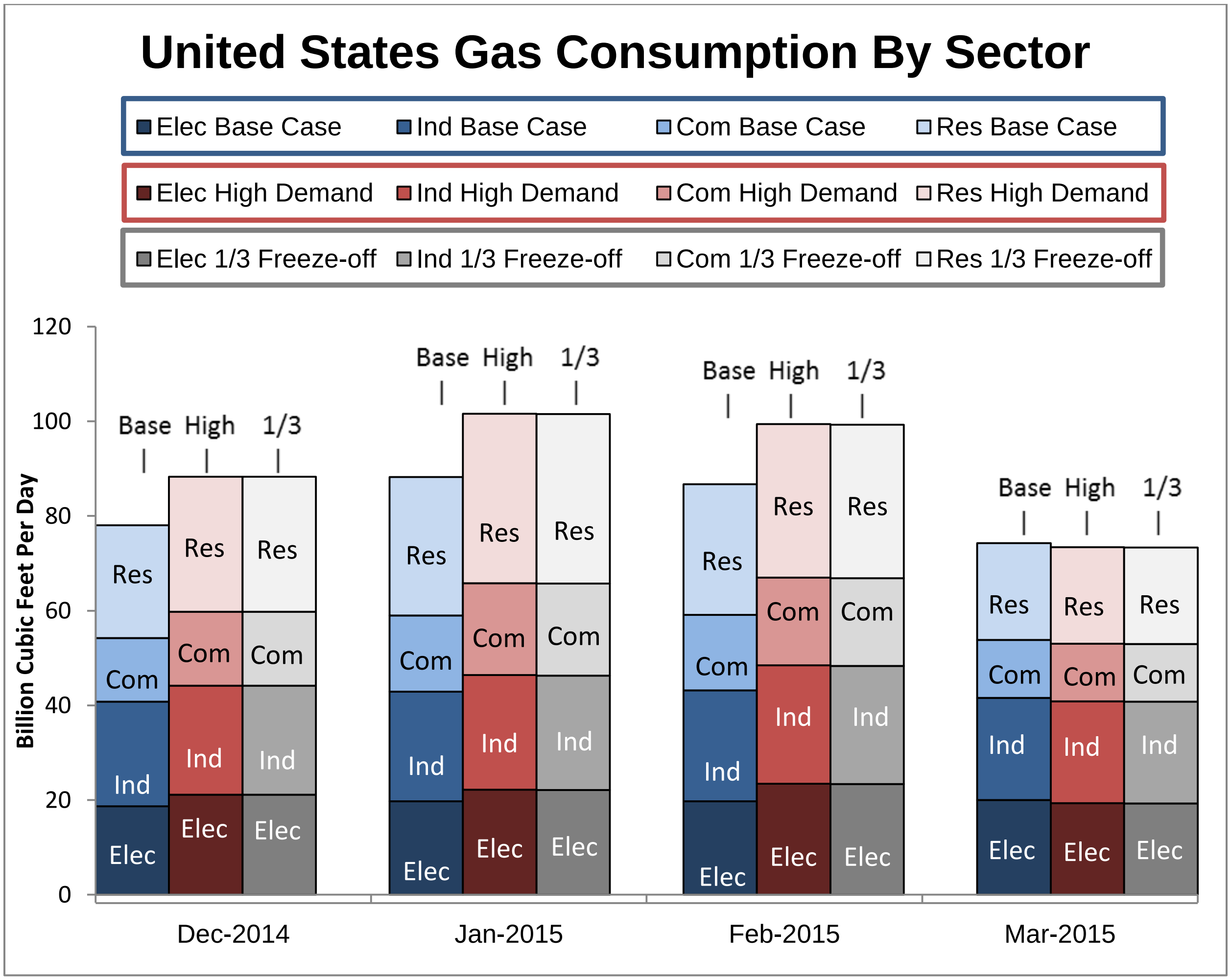

Figure 1. Winter 2015 U.S. natural gas consumption for Electric Power, Industrial, Commercial, and Residential sectors

[13] Industrial demand is expected to be generally less sensitive to variations in weather, which drives heating and cooling demand, than the other demand sectors.

In the summer of 2015 (not shown), Electric Power sector gas consumption is approximately 8% less than the Base Case as the industry increases the amount of gas injected for storage to recover from the unusually high-demand winter. Consumption by other sectors fell by only 0.5 to 1.3%. These data are consistent with the understanding Electric Power sector natural gas demand is relatively elastic and responsive in the short term to market price variations.

3.2 Gas Supply

Changes in U.S. gas imports via pipeline (typically from Canada) during the 2015 High-Demand and 1/3 Freeze-off scenarios are negligible, as shown in Figure 2. Gas imports comprise only a small portion (1.3% to 6.3%) of the total U.S. natural gas supply. Likewise, liquefied natural gas (LNG) imports (not shown) account for less than 1% of the U.S. natural gas supply, and changes in LNG and imports during the two scenarios are insignificant.

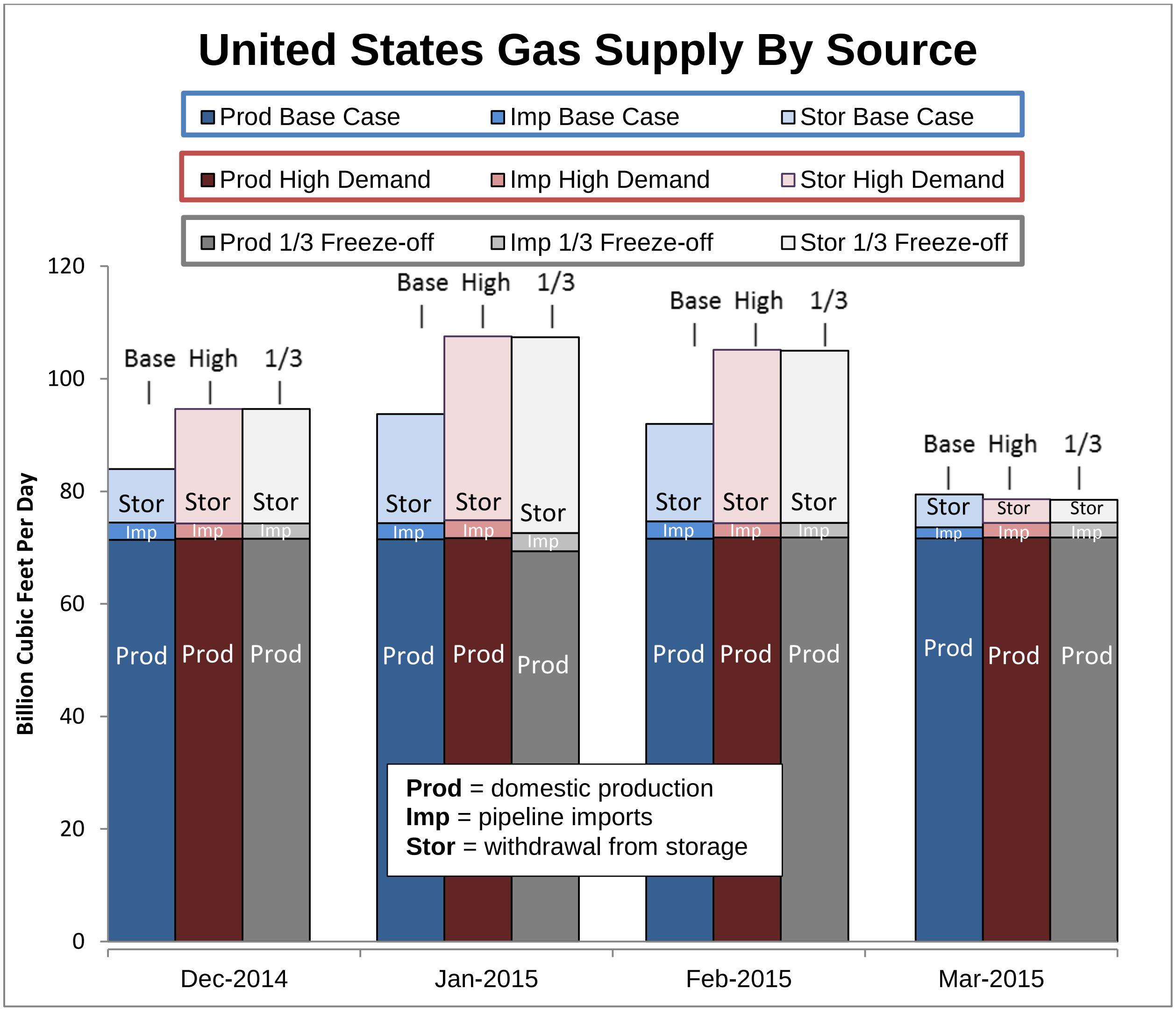

Figure 2. U.S. natural gas supply levels: winter + one month after increased demand/production loss

Domestic gas production is the primary initial source of natural gas in the United States. However, because natural gas production is generally located far from market centers, it is typically not used to meet short-term increases in demand. Instead, where possible, it is more economical to locate natural gas storage close to major market centers, meeting short-term increases in natural gas demand with withdrawals from storage. Within this system, production rates are relatively inelastic to gas price changes in the short term, and gas production does not change significantly during a temporary period of increased demand. Increases in demand are instead primarily met by increased storage withdrawals. During the 1/3 Freeze-off scenario, U.S. national production drops by approximately 3% in January from loss of production in the Appalachia shale wells, which is then compensated for by increased storage withdrawal.

3.3 Gas Storage

For the 2015 High-Demand scenario, storage withdrawal increases significantly, relative to the Base Case, to meet increased consumer demand (Figure 3). Storage levels take approximately one year to return to the Base Case level. Predicted minimum storage levels in March 2015 are similar to those observed in March 2014 following the polar vortex event.

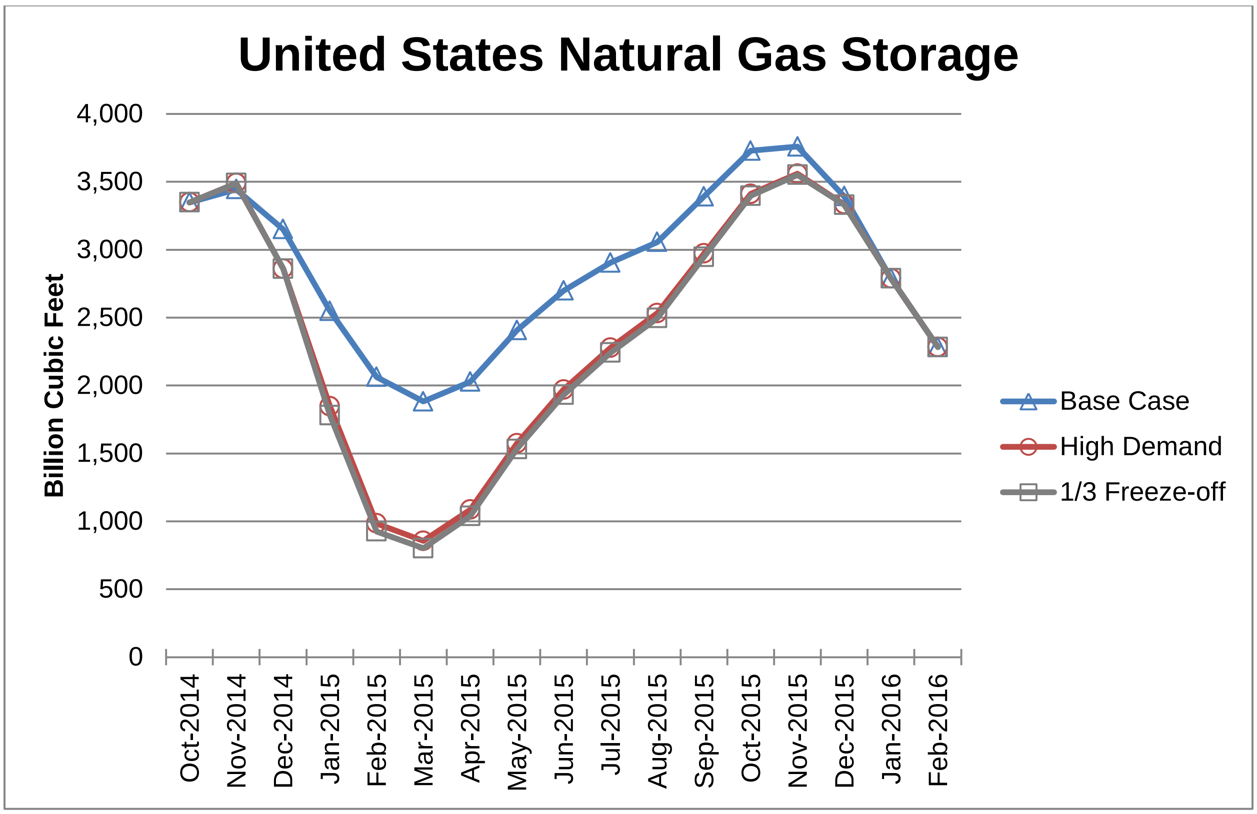

Figure 3. U.S. natural gas storage levels: October 2014-February 2016

During the 2015 1/3 Freeze-off scenario, loss of Appalachia production during a period of increased demand leads to slightly greater storage withdrawal in January, relative to the High-Demand scenario. It takes the same amount of time for the U.S. natural gas storage levels to return to Base Case levels as with the High-Demand scenario.

3.4 Gas Price

The High-Demand scenario leads to higher predicted monthly average gas prices until February 2016, as shown in Figure 4. Prices peak in January 2015 at $6.17 per million Btu in the High-Demand scenario, 26% higher than in the Base Case scenario. Increased storage injections maintain elevated gas prices for the subsequent year until storage levels return to normal. The 1/3 Freeze-off scenario leads to a negligible price increase in comparison to the elevated High-Demand scenario prices.

Note that the prices predicted by GPCM are monthly averages based on fitting simulation parameters to historical data. These predictions are qualitative, not quantitative. Shorter-term, hourly or daily gas prices during an actual high-demand or production-loss event could spike much higher than the GPCM-predicted monthly average value because the monthly average value smooths shorter-term variations in demand and price. Nonetheless, the price predictions are instructive with regard to longer-term trends and are consistent with realistic market behavior.

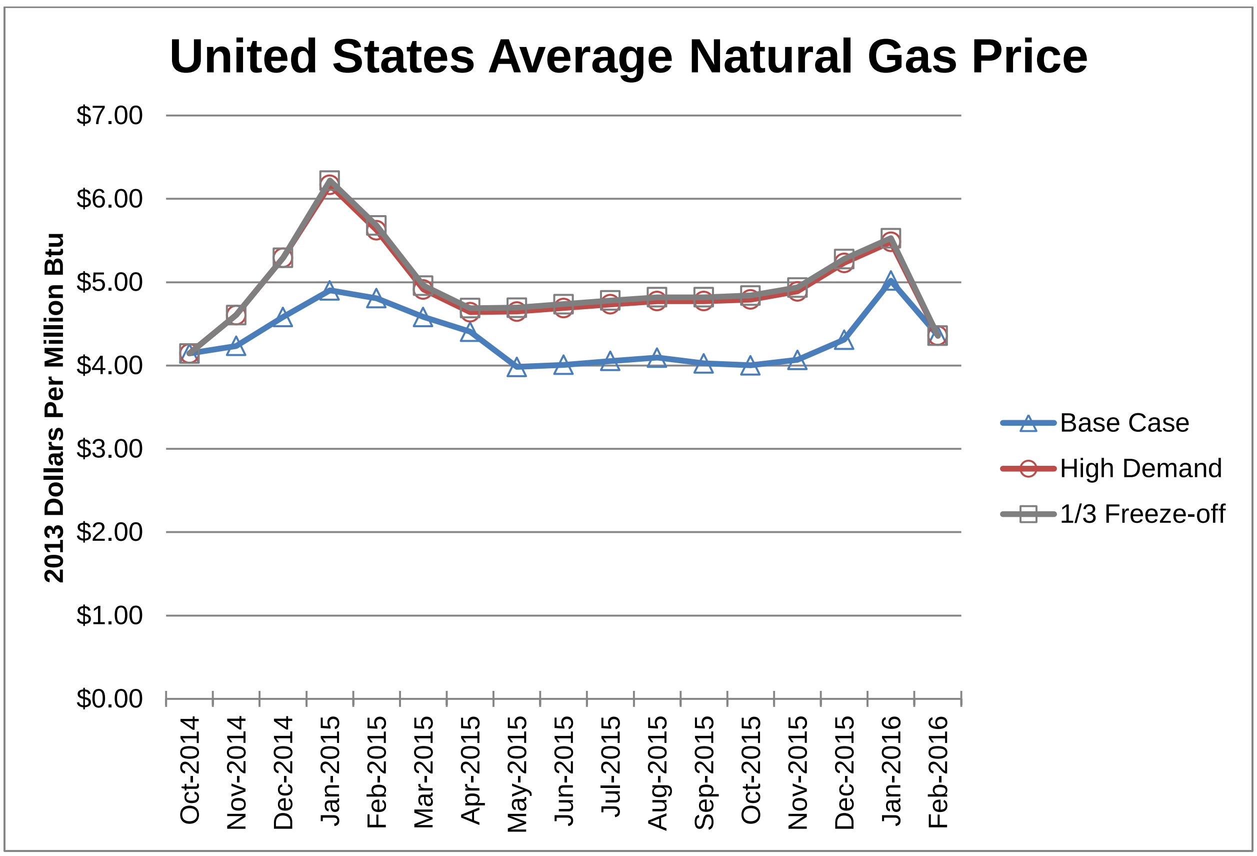

Figure 4: Comparison of U.S. average natural gas prices from the three scenarios: October 2014-February 2016 (GPCM prices are intuitive/volume-weighted average)

3.5 2030 versus 2015 Scenario Year Results

By 2030, natural gas production and consumption in the United States are both expected to increase by approximately 30%. Because of continued improvements in energy efficiency, the Residential sector is predicted to consume less natural gas for the majority of the year (1% to 14% less); the net increase in gas consumption stems from the other sectors, which are expected to consume significantly more natural gas. The Electric Power sector is predicted to have the largest increase in gas consumption (57%). Even with this increase, the United States is still expected to become a net natural gas exporter. Beyond this difference, the 2030 simulations demonstrate qualitatively similar behavior as the 2015 scenarios (see Appendix D). Note that storage in the 2030 scenarios begins at typical values rather than the slightly depleted state used for the 2015 scenarios, which factored November 2014 depletions from the January 2014 polar vortex event.

4 RESULTS BY CENSUS REGION

Figure 5 shows the nine U.S. census regions considered within scope for this study.

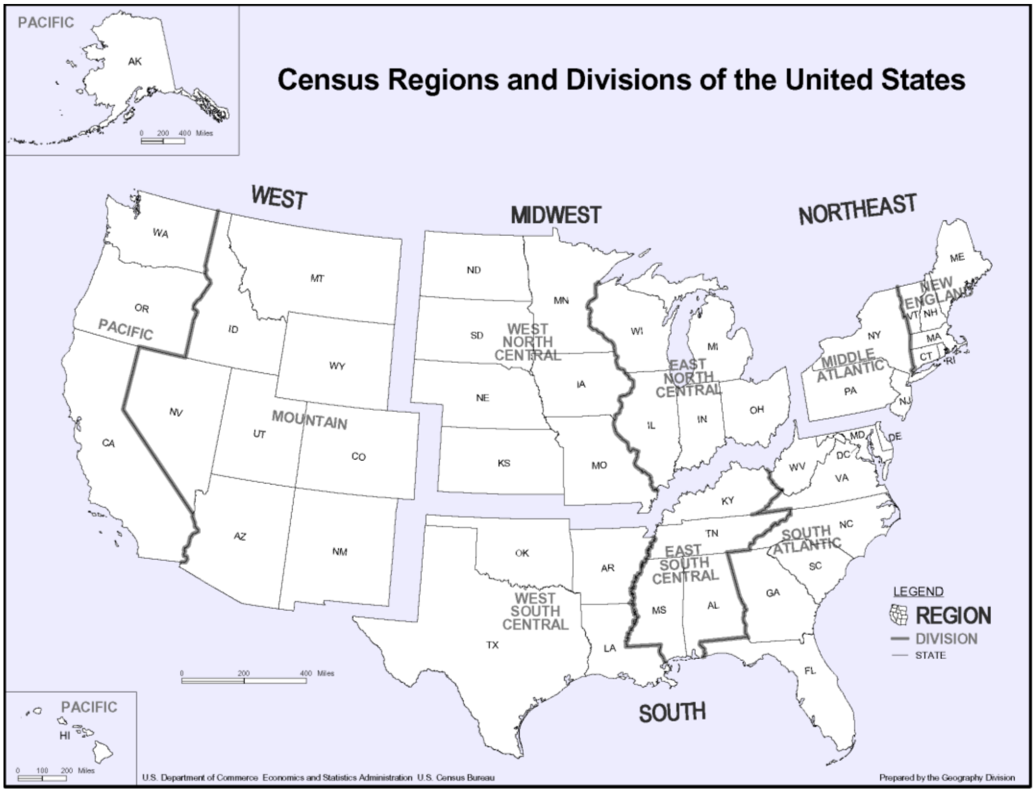

Figure 5. Census Regions of the United States (source: U.S. Census Bureau)

4.1 New England Region

Unlike other census regions of the United States, the New England region, which is heavily dependent on natural gas for both heating and electricity production, lacks significant gas storage due to unsuitable geology and is reliant on pipeline transportation of natural gas from distant production and storage fields.[14] This makes the New England region particularly vulnerable to upstream pipeline disruptions.

There is no significant difference between results for the 2015 High-Demand and 1/3 Freeze-off scenarios. In both scenarios, net consumption increases up to 8.5% more than the Base Case. A more drastic increase does not occur because gas consumption in the Electric Power sector decreases approximately 25% in response to higher prices, partially offsetting increased consumption in the other sectors.[15]

[14] U.S. Energy Information Administration, About U.S. Natural Gas Pipelines–Transporting Natural Gas, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html, accessed July 1, 2015.

[15] This work did not explicitly investigate how the New England region Electric Power sector would adjust to compensate for decreased gas-fired electric power generation. See Appendix E for a discussion of electric power generation using other resources during periods of decreased gas availability.

Because the New England region has no underground storage or gas production, only pipeline gas and LNG imports increase to meet the increase in net consumption. Because of pipeline constraints, significant increases in gas price are predicted during winter high-demand periods. Electric Power sector gas consumption remains lower, prices remain higher, and gas imports decrease relative to the Base Case until January 2016 while other parts of the country replenish gas storage.

Compared with the 2015 scenarios, greater net gas consumption is predicted in the winter of 2030. The Residential sector is the largest contributor to consumption increase (an average of 15% over the course of the simulation). General trends otherwise remain the same as in 2015.

4.2 Middle Atlantic Region

Compared with the Base Case scenario, the 2015 High-Demand scenario predicts significant increases in storage withdrawal and significant decreases in pipeline exports (to other regions) during the winter high-demand period. The 1/3 Freeze-off scenario results in a 10% decrease in regional production during January, leading to a further increase in storage withdrawal and a decrease in pipeline exports. If more shale wells were affected by freeze-off, the Middle Atlantic region could be forced to import rather than export natural gas during a period of high demand.[16]

Net regional gas production approximately doubles between 2015 and 2030. As a result, exports from the region are greatly increased. The responses to the 2030 High-Demand and 1/3 Freeze-off scenarios are qualitatively similar to those observed for the 2015 cases, except that 2030 export amounts are less affected because regional consumption consumes a much smaller fraction of regional production.

4.3 South Atlantic Region

Pipeline gas imports and storage withdrawal significantly increase during the 2015 High-Demand and 1/3 Freeze-off scenarios. At their peak in January 2015, pipeline gas imports are 22% (High Demand) and 28% (1/3 Freeze-off) more than the Base Case scenario; storage withdrawals increase by up to 74% (High Demand) and 78% (1/3 Freeze-off). Regional natural gas production decreases by approximately 25% in January 2015 for the 1/3 Freeze-off scenario from loss of production from Marcellus shale in West Virginia. Pipeline gas imports decrease slightly and storage injection rates increase slightly, relative to the Base Case, from April 2015 until February 2016. During this time, reductions in available consumer supply are compensated for by decreased Electric Power sector consumption.

Regional gas consumption by the Electric Power sector is predicted to increase approximately 30% between 2015 and 2030. Demand in other sectors increases only slightly. Demand increases are balanced by increases in pipeline imports. The responses to the 2030 High-Demand and 1/3 Freeze-of scenarios are qualitatively similar to those observed for the 2015 cases.

[16] See Appendix C for more information on the effects of a Full-Freeze scenario.

4.4 East North Central Region

The 2015 High-Demand and 1/3 Freeze-off scenario results exhibit minimal differences. In each case, a small increase in pipeline gas imports, coupled with a significant increase in storage withdrawal, compensate for increased consumption. Pipeline imports increase during the scenarios by, at most, 5% during the winter while storage withdrawals increase to 68% more than the Base Case in December 2014. To replenish gas storage, pipeline imports increase to 17% more than the Base Case during the subsequent summer of 2015.

Demand for natural gas by the Electric Power sector approximately doubles between 2015 and 2030. Demand in other sectors increases only slightly. Demand increases are balanced by increases in regional gas production and pipeline imports. The responses to the 2030 High-Demand and 1/3 Freeze-of scenarios are qualitatively similar to those observed for the 2015 cases.

4.5 East South Central Region

The 2015 High-Demand and 1/3 Freeze-off scenario results display minimal differences. The increased demand and loss of production are met by a large increase in storage withdrawal of more than double the Base Case scenario quantity (92% to 135% more). The decrease in pipeline gas imports (9%–16% less than the Base Case) in the winter implies that this gas is being diverted elsewhere. Beginning in April 2015, pipeline imports increase and Electric Power sector demand consumption decreases until January 2016 while natural gas storage is replenished.

In 2030, the general trends remain the same. Increases in net regional demand between 2015 and 2030 are met in the Base Case primarily by increased pipeline imports. During the High-Demand and 1/3 Freeze-off scenarios, demand is met by increased pipeline gas imports and storage withdrawals.

4.6 West North Central Region

The 2015 High-Demand and 1/3 Freeze-off scenario results display minimal differences. Pipeline gas imports and storage withdrawals increase, relative to the Base Case, during the winter high-demand period. Other than increased storage injection, demand for natural gas during the summer following the period of high demand is not significantly altered.

Increases in regional gas production between 2015 and 2030 meet increased consumption demands without additional pipeline imports. The responses to the 2030 High-Demand and 1/3 Freeze-off scenarios are qualitatively similar to those observed for the 2015 cases.

4.7 West South Central Region

The 2015 High-Demand and 1/3 Freeze-off scenario results display minimal differences. This region is a significant net exporter of natural gas. During the winter high-demand period, exports to other regions increase significantly. Increased regional demand and increased export demand are met by increasing storage withdrawal. Consumption by the Electric Power sector decreases slightly from March 2015 to January 2016 while storage supplies are replenished.

Regional production increases significantly between 2015 and 2030 to meet increased regional demand in the Electric Power and Industrial sectors. Natural gas exports from the region increase only slightly between 2015 and 2030. The responses to the 2030 High-Demand and 1/3 Freeze-off scenarios are qualitatively similar to those observed for the 2015 cases.

4.8 Mountain Region

The 2015 High-Demand and 1/3 Freeze-off scenario results display minimal differences. This region is a significant net exporter of natural gas. During the winter high-demand period, net exports are unchanged. Increased regional demand is met by increased storage. Consumption by the Electric Power sector is anticipated to decrease by approximately 10% from March 2015 to January 2016 while storage supplies are replenished.

Regional production and net pipeline exports are expected to decrease between 2015 and 2030. Consumption by the Electric Power sector increases significantly while other sectors remain relatively flat. The responses to the 2030 High-Demand and 1/3 Freeze-of scenarios are qualitatively similar to those observed for the 2015 cases.

4.9 Pacific Region

The 2015 High-Demand and 1/3 Freeze-off scenario results display minimal differences, implying the freeze-off in the Appalachia shale gas is not felt on the West Coast. Pipeline gas imports and storage withdrawals increase, relative to the Base Case, during the winter high-demand period. From April 2015 until January 2016, pipeline imports increase and Electric Power sector consumption decreases while natural gas storage is replenished.

Demand for natural gas by the Electric Power sector significantly increases between 2015 and 2030. Demand in other sectors increases only slightly, but are balanced by increased pipeline imports. The responses to the 2030 High-Demand and 1/3 Freeze-of scenarios are qualitatively similar to those observed for the 2015 cases.

5 CONCLUSIONS

A repeat of the winter of 2013-2014's extreme cold weather and increased demand for natural gas would result in many of the same interrelated problems observed during that event: storage depletion, localized pipeline constraints, delivery shortages, and extremely high prices.[17] Some regions, such as New England, should be less negatively affected due to recent and ongoing increases in pipeline delivery capacity and programs to increase flexibility and reliability in the Electric Power sector. Production loss would amplify the aforementioned problems associated with increased demand, however, for the freeze-off scenarios investigated in this study, the current and future natural gas systems appear sufficiently robust, even with the slightly lower-than-historical storage levels used for the 2015 scenarios.

Keys to the resilience of the North American natural gas system include gas storage near demand areas and flexibility for routing gas between regions on the pipeline network. Further, the United States is predicted to become a significant exporter of LNG within the next decade. In the event of an extreme winter that causes either high demand, loss of supply, or both, resilience may be increased if diverting gas from LNG export to domestic consumption is an option; however, the caveat is that export contracts may limit LNG producers' flexibility to redirect natural gas back to the United States during an emergency.

Due to significant increases in production brought about by the shale gas revolution, North American natural gas infrastructure is undergoing rapid change. Of concern is whether infrastructure developments in the long term could result in a region becoming dependent on natural gas from a single, vulnerable supply. The Freeze-off scenario described in this study was meant to investigate the vulnerability of regions to loss of supply from the Appalachia basin, particularly the New England region, which sits at the terminal edge of the natural gas pipeline system. Simulation results suggest that reliance on a single supply is not a significant threat because credible levels of production loss can be compensated for by reducing gas flow to regions south and west, which have other supply options.

Future work could entail looking at larger-scale freeze-offs beyond an Appalachian freeze-off. Changing the rate of pipeline expansion allowed in the simulation and the cost of expansion might yield different results. Illustrating pipeline constraints might also shed some light on possible localized pipeline constraints. Additionally, looking at the effects of the freeze-off on a daily, or even hourly, timescale would be useful to fully explore potential vulnerably. Since completion of this study, a daily version of GPCM is now available.

[17] Local distribution companies (LDCs) plan and contract with peak demand in mind, and pipeline operators work to meet these firm contracts. Because reality rarely exceeds LDC design-day expectations, residential and commercial customers are generally safe from gas delivery shortages. Gas-fired power plants in many regions, however, use interruptible (non-firm) gas delivery contracts, which can lead to difficulty sourcing gas during periods of high demand.

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APPENDIX A: GPCM DESCRIPTION

Description of the GPCM Natural Gas Market Forecasting System

The GPCM Natural Gas Market Forecasting System is a commercial product, licensed by Sandia National Laboratories and developed by RBAC, Inc., for predictive modeling of natural gas flow and pricing throughout North America. Based on a pipeline network model, GPCM is used to study complex, time-dependent, continent-wide interactions among producers, pipelines, storage facilities, gas marketers, and consumers. The natural gas market is represented by a partial-equilibrium economics model, which balances supply against demand while minimizing gas transportation costs.

In addition to pipeline network connectivity, GPCM requires:

- Supply curves (price versus quantity supplied) for each supplier,
- Demand curves (price versus quantity demanded) for each customer,
- Capacities and costs for gas transport in each pipeline zone, and
- Capacities and prices for gas injection and withdrawal for each storage area.

Economic and infrastructure data for simulating the North American natural gas market are supplied with GPCM but can be modified by the user as needed. For example, pipeline capacities can be modified to represent outages, and demand curves can be adjusted to reflect different levels of demand by electric generators.

The GPCM dataset includes monthly demand curves (quantity versus price out to 2035) discretized to the state or sub-state level for each consumer sector (Residential, Commercial, Industrial, and Electric Power). Demand in each sector is generally derived from historical correlations with economic variables, time period, and weather. For the Residential sector, demand is a function of price, number of customers, weather (heating degree days), and some non-weather seasonality in mid- to late summer. For the Commercial sector, demand is a function of price, economics (the non-manufacturing Gross State Product), weather (heating degree days), and some summer seasonality. For the Electric Power sector, demand is a function of price, weather (heating and cooling degree days), and the total amount of power generated from all sources, estimated using U.S. Energy Information Association Annual Energy Outlook (EIA AEO) 2014 assumptions.[18]

The input data provided with GPCM includes over 200 pipelines, 400 storage areas, 85 production areas, 15 LNG import/export terminals, and nearly 500 demand centers. The data include historical values back to 2006, forecasted values to 2035, and announced or expected future infrastructure projects, which become active in a simulation starting at the time they are planned to become operational. This supplied dataset is updated quarterly.

[18] See Appendix B for a comparison of GPCM data to EIA AEO assumptions.

Time within GPCM simulations is resolved to months. Multi-year scenarios can be run to study seasonal and other dynamic (e.g., outage, weather) patterns of production, transportation, storage, consumption, and pricing. Demand is organized by consumer category (e.g., residential, commercial, industrial, electric) and resolved to the level of individual large customers (e.g., local gas distribution companies, electric utilities) or collections of smaller customers (e.g., all other residential, commercial, or industrial demand) within a given state or sub-state region. Smaller individual assets, such as compressor stations and gas-fired power plants, are not explicitly modeled by GPCM. This level of resolution allows running multi-year simulations of the North American natural gas market with reasonable computational effort.

GPCM Model Detail

GPCM is built on a network model composed of nodes and links. There are five types of nodes in GPCM: supply, demand, storage, interconnect, and pipeline zone. Gas is introduced into the network at supply nodes (e.g., producers and importers) and removed from the network at demand nodes (consumers). Storage nodes represent natural gas storage areas and interconnect nodes represent links between different pipelines. Pipeline zone nodes represent sections of a pipeline where gas can be injected into or removed from that pipeline. Nodes are connected to one another by links, which allow flow between nodes. Supply, demand, storage, and interconnect nodes only connect to pipeline zone nodes. Pipeline zone nodes can connect to any type of node, including other pipeline zones. Each node is treated as a market point with a price calculated to balance supply and demand across the network. Each link is defined by four quantities: maximum flow (capacity), minimum flow (if any), cost per unit of flow, and efficiency of flow (one minus the fraction of gas burned as compressor fuel or otherwise lost or unaccounted for on that link).

Prices and flows are calculated by GPCM for all locations and all times simultaneously using an optimization method called the simplex algorithm to minimize costs. To do this, the network is duplicated for each time point (e.g., each month to be simulated) with successive times connected through the storage nodes. That is, a given node, say n_i, is duplicated so that there is a copy of it for each time: $n_{i\,j}$, j = 1,..., J, where J is the number of time steps in the simulation. The links are duplicated as well such that each $n_{i\,j}$ has the appropriate connections to other nodes $n_{k\,j}$ at the same time. Then, the sub-networks for successive times are connected through the storage nodes: If n_i is a storage node, links are added connecting n_{i1} to n_{i2}, n_{i3} to n_{i4}, etc. In this formulation, there is no accumulation of gas at nodes, including storage nodes. Rather, storage is represented by a flow from a node to the corresponding node at the next time. For example, gas that flows from $n_{i\,j}$ to $n_{i(j+1)}$ is gas that is remaining in storage at location n_i from month j to month j+1.

Flows are driven by price differentials, both from:

- Location to location: Gas is piped from the Gulf Coast to other parts of the country because the price is higher in those other locations.
- Time to time: Prices are higher during peak demand months, so gas flows to those months by being injected into storage during low-demand months and then withdrawn from storage during high-demand months.

APPENDIX B: GPCM BASE CASE COMPARISON WITH ANNUAL ENERGY OUTLOOK 2014

GPCM dry gas production values are comparable to those predicted by the Annual Energy Outlook (AEO) out to 2035.[19] The AEO consistently predicts greater exports than GPCM predicts, particularly after 2025. Given the small scale of exports relative to production, net domestic gas availability is roughly the same in both AEO and GPCM predictions. (Figure B- 1)

Relative to the AEO, GPCM predicts significantly greater future gas use by the Electric Power sector and slightly greater use by the Residential sector. These differences begin in the near future and remain relatively constant until 2035. GPCM also predicts slightly greater growth in Industrial and Transportation sector demand, particularly after 2025. (Figure B- 2)

While GPCM predicts a relatively steady increase in nominal Henry Hub spot prices, the AEO price prediction increases significantly after 2025, which is roughly when the AEO case also begins to predict significantly greater LNG and pipeline export. (Figure B- 3)[20]

The following three figures compare GPCM Base Case supply, consumption, and Henry Hub price predictions, respectively, with those in the AEO 2014 reference case.

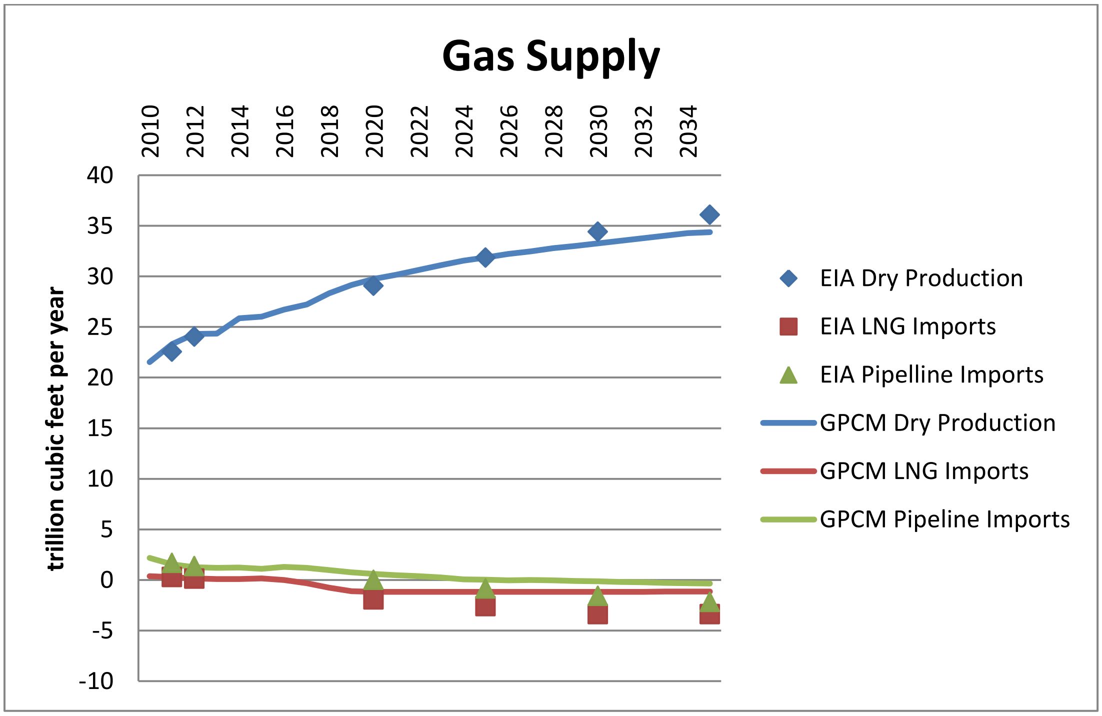

Figure B- 1. GPCM Base Case supply compared with AEO 2014 reference case

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[19] GPCM regional production forecasts result from a mixture of historical correlations involving drilling, production, and reserves data combined with best guesses about future resource potential (e.g., reserves estimates) and market behavior (e.g., involving NGLs).

[20] Henry Hub is the official delivery location for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). The Henry Hub spot price is the traditional natural gas benchmark price for natural gas in North America.

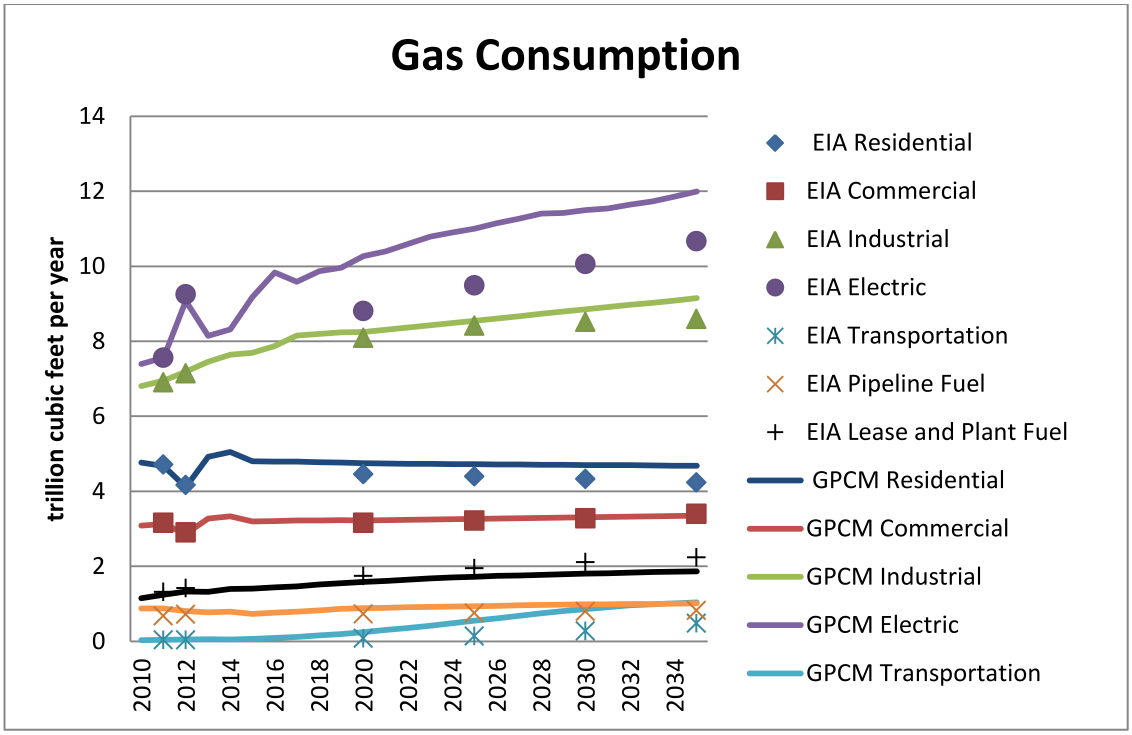

Figure B- 2. GPCM Base Case consumption compared with AEO 2014 reference case

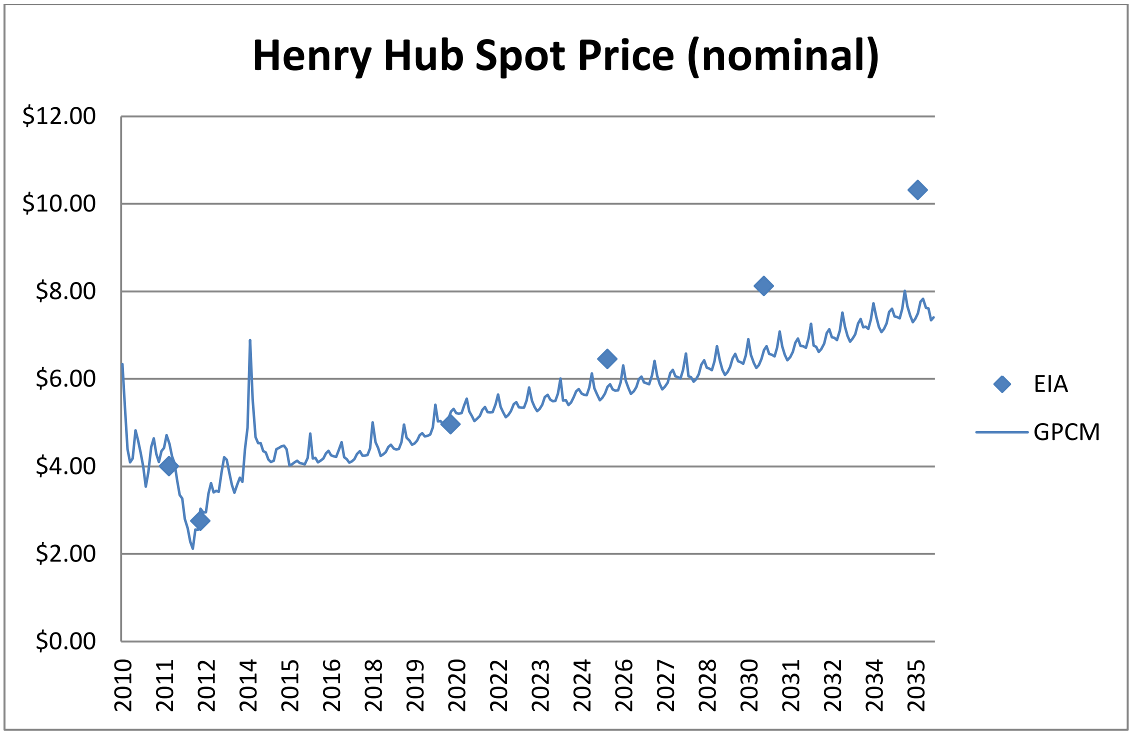

Figure B- 3. GPCM Base Case Henry Hub spot price compared with AEO 2014 reference case

APPENDIX C: FULL-FREEZE ANALYSIS

Not discussed in the report, a Full-Freeze scenario was modeled as high demand through the winter (December through February) and freezing (production loss) of 100% of Appalachia shale gas wells with significant wet gas production. This level of production loss is considered an unrealistically severe worst case and was omitted from the general report for this reason.

Full-Freeze scenario results were qualitatively similar to those observed for the 1/3 Freeze-off scenarios. By rerouting gas delivery and increasing withdrawal from storage, the natural gas market was still able to compensate and recover from this greater loss of production. A regional difference is that in the Middle Atlantic region where the production loss resulting from the Full-Freeze disruption in January 2015 caused this region to become a net importer of pipeline gas, whereas in the three other scenarios, including the 1/3 Freeze-off scenario, the Middle Atlantic region is a net exporter (Figure C- 1).

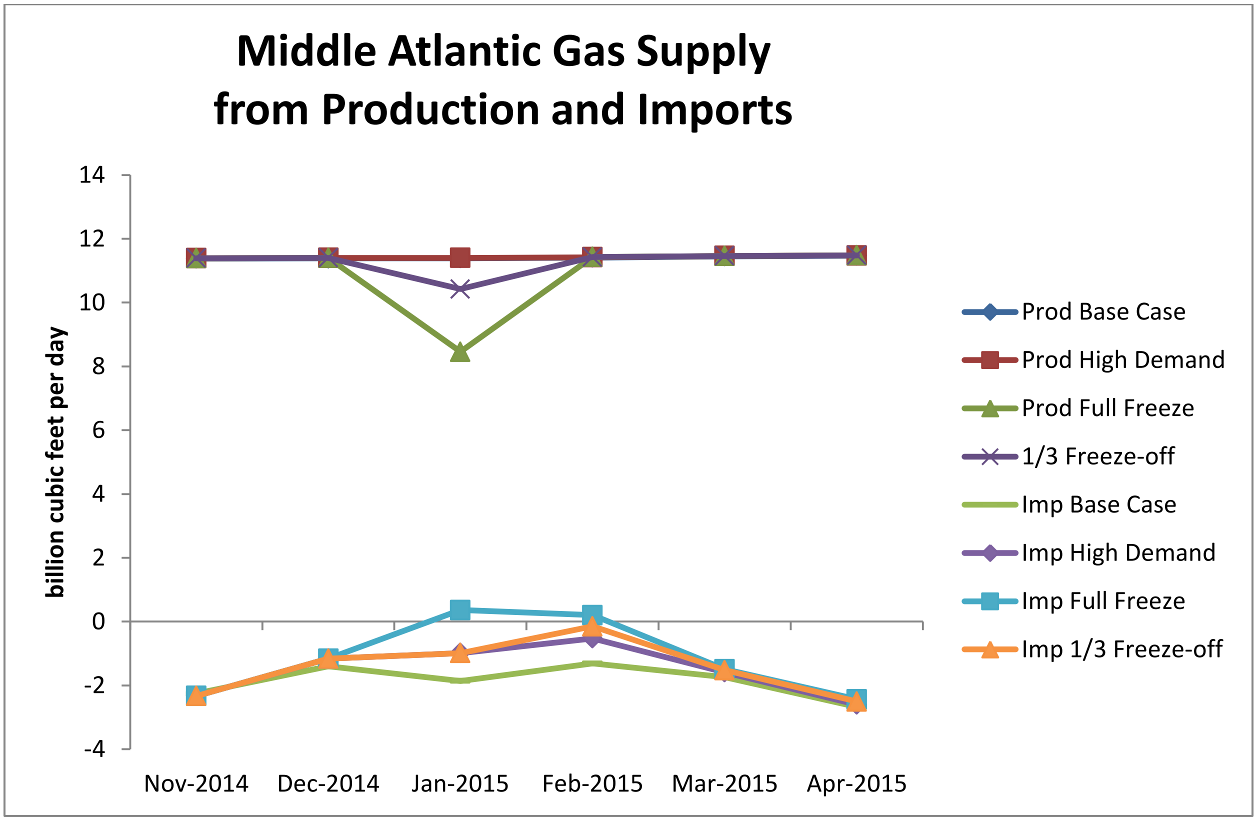

Figure C- 1. Comparison of Middle Atlantic gas supply from production and imports during the four scenarios

APPENDIX D: 2030 SCENARIO GRAPHS

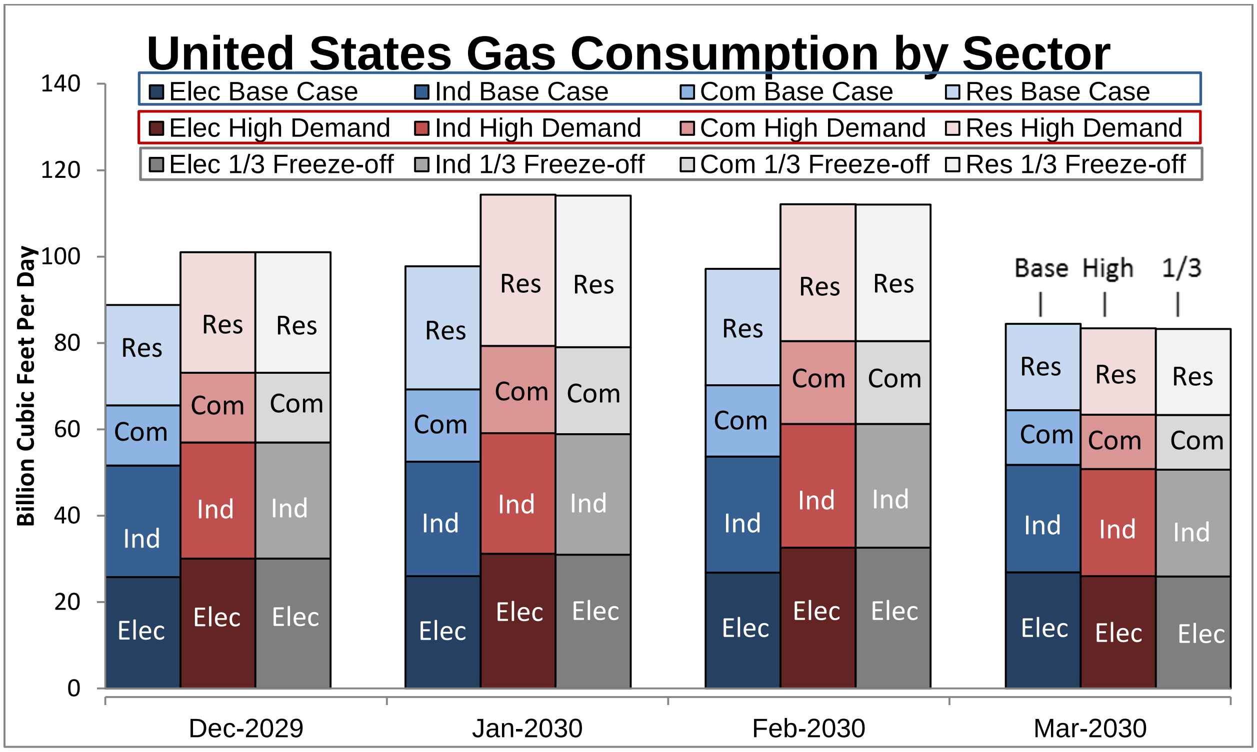

Figure D- 1. Comparison of U.S. gas consumption in 2030 by sector

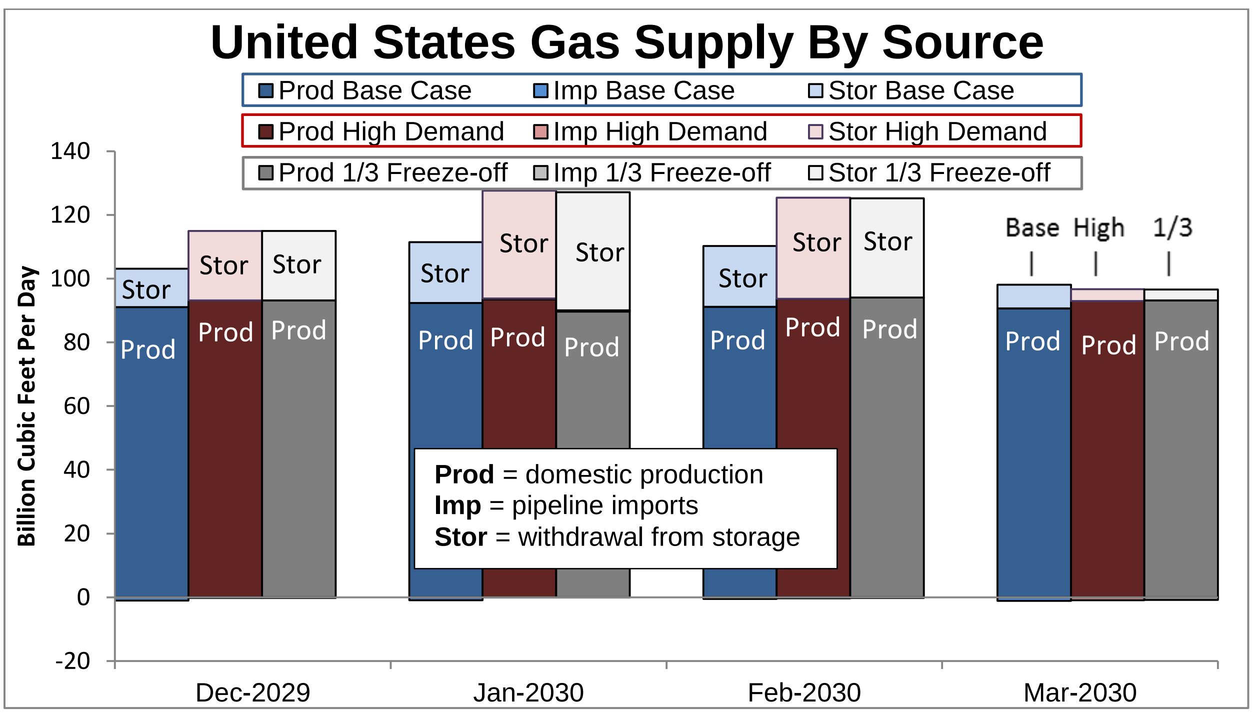

Figure D- 2. Comparison of the three 2030 scenarios by natural gas source

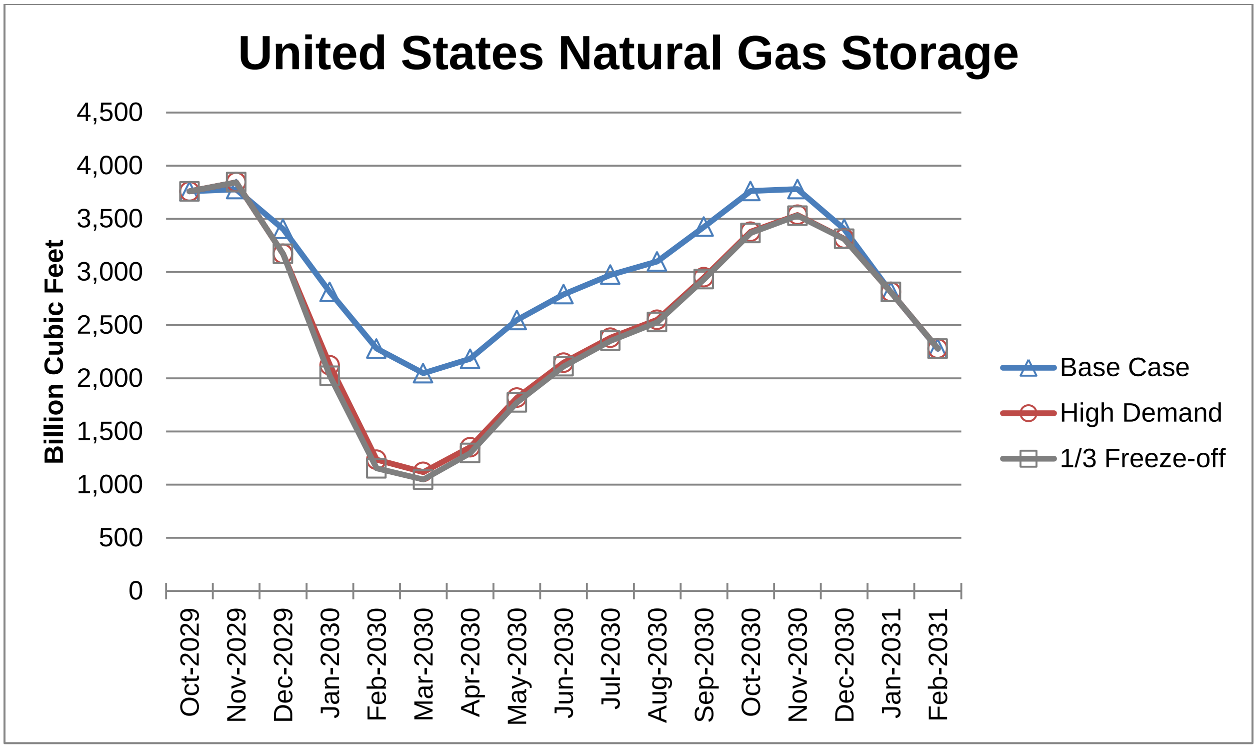

Figure D- 3. Comparison of the natural gas storage levels during the High-Demand and 1/3 Freeze-off to the Base Case in 2030

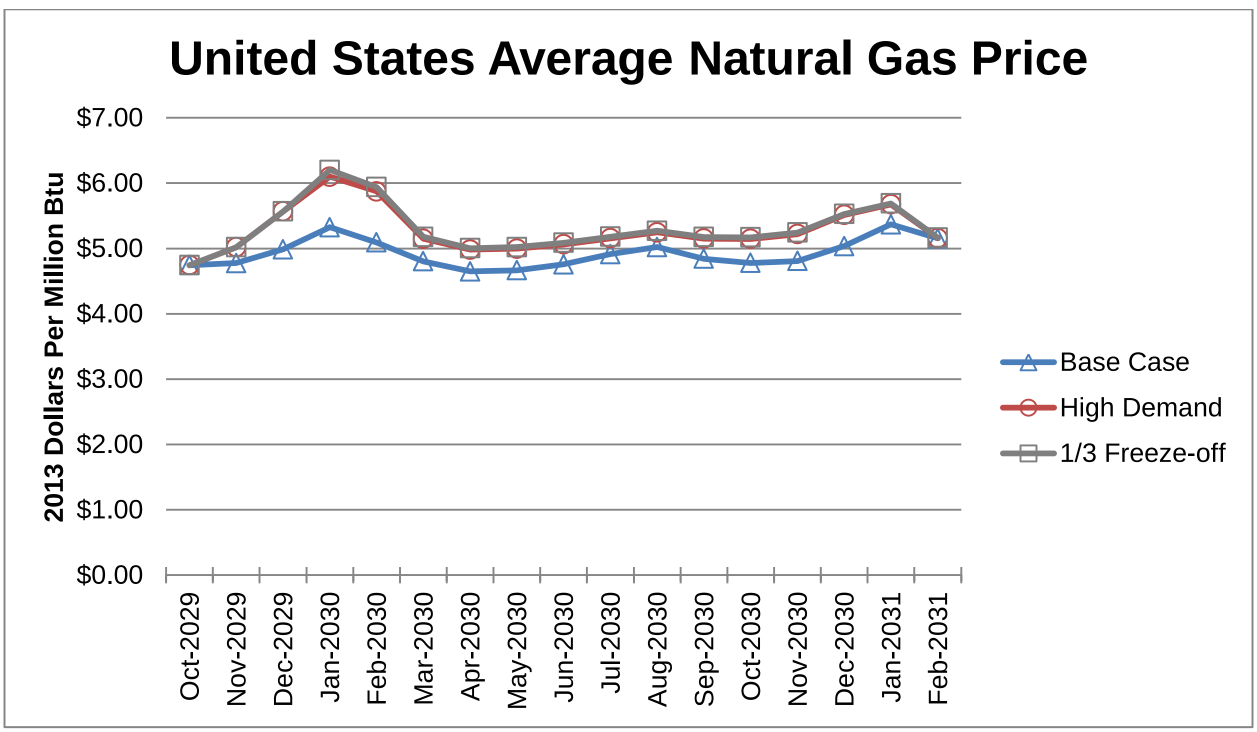

Figure D- 4. Comparison of the average price of natural gas during the High-Demand and 1/3 Freeze-off to the Base Case in 2030

APPENDIX E: 2015 ISO-NE DAILY GENERATION BY FUEL TYPE

As the New England region relies more on natural gas for electric power generation, coal- and oil-fired generation have been used to compensate during periods of decreased gas availability. For example, recent data from ISO-New England, Inc. (ISO-NE) that were not available when this study was conducted demonstrates that natural gas use for electricity generation was approximately halved from average baseline levels for two one-week periods in late February 2015, and power generation from oil increased greatly (Figure E- 1). It should be noted, however, that future retirements of nuclear-, coal-, and oil-fired electric power plants may require very different strategies for dealing with periods of winter high gas demand.

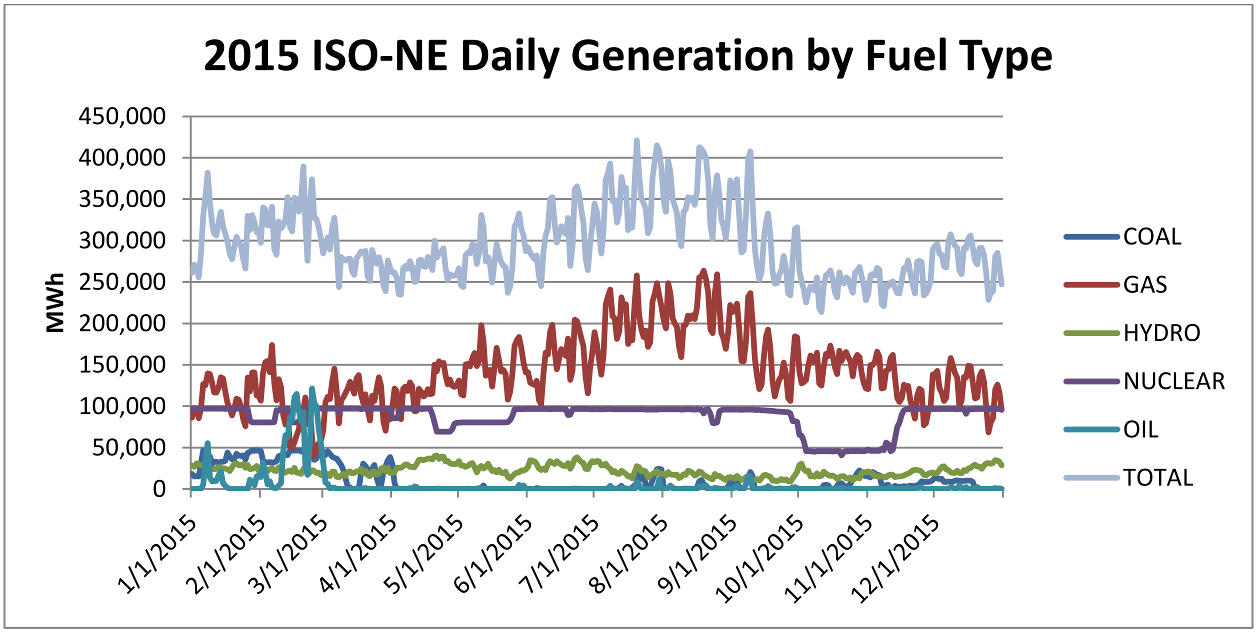

Figure E- 1. ISO-NE daily generation by fuel type in 2015

(ISO New England Operations Reports – Daily Generation by Fuel Type, http://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type, accessed January 29, 2016).

For Figure E- 1, renewable and other energy sources represent relatively small and non-adjustable contributions and are omitted for clarity.

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