Eastern Interconnection Planning Collaborative

Gas-Electric System Interface Study

Input Data and Assumptions

DOE Award Project

DE-OE0000343

Draft

April 28, 2014

LEVITAN & ASSOCIATES, INC.

Table of Contents

Table of Figures

Table of Tables

List of Exhibits

Note on Conversion Factors:

Natural gas is measured by volume or heating value. The standard measure of heating value in the English system of units is millions of British thermal units or "MMBtu." Dekatherms (Dth) are also a standard unit of measurement. One MMBtu approximately equals one Dth. The standard measure of heating value in the metric system is gigajoule (GJ); one GJ is slightly smaller than one MMBtu (1 GJ = .948 MMBtu).

The standard measure of gas volume in the English system of units is standard cubic feet or "scf." The "s" for standard is typically omitted in expressing gas volume in cubic feet. Therefore "scf" is typically short formed to "cf." Because the heating value of natural gas is not uniform across production areas, there is no one fixed conversion rate between gas volume and heating value. Pipeline gas in North America usually has a heating value reasonably close to 1,000 Btu/cf. Therefore, for discussion purposes, one thousand cubic feet (Mcf) is roughly equivalent to one million Btu (MMBtu).

The standard measure of gas volume in the metric system is cubic meters (m^3). The straightforward conversion between metric and English volumes is 1 m^3 = 35.31 cf. There are a number of different volumetric conventions used in Canada and the U.S.

$$\mathbf{1\ Mcf \approx 1\ MMBtu \approx 1\ Dth \approx 1\ GJ}$$

$$\mathbf{1\ Bcf = 1{,}000\ MMcf \approx 10^6 MMBtu \approx 10^6 Dth \approx 10^6\ GJ = 1\ PJ}$$

ACKNOWLEDGEMENT

This material is based upon work supported by the Department of Energy, National Energy Technology Laboratory, under Award Number DE-OE0000343. Information presented in this report has been facilitated or provided by the Interstate Natural Gas Association of America, various local distribution companies doing business in the Study Region, and by the Participating Planning Authorities.

DISCLAIMERS

The information and studies discussed in this report are intended to provide general information to policy-makers and stakeholders but are not a specific plan of action and are not intended to be used in any state electric facility approval or siting processes. The work of the Eastern Interconnection States Planning Council or the Stakeholder Steering Committee does not bind any state agency or Regulator in any state proceeding.

1 INTRODUCTION AND OVERVIEW

In this report, Levitan & Associates, Inc. (LAI) describes the input data and assumptions that define the *Reference*, *High* and *Low Gas Demand Scenarios* for the Target 2 analysis, *i.e.*, Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems analysis. Formulation of the three *Gas Demand Scenarios* is intended to reveal the level and profile of gas demand under a defined set of market, regulatory and operating conditions formulated to test the capability of natural gas infrastructure across the Study Region to meet the coincident gas requirements of gas utilities and gas-fired generators.[1] The input data and study assumptions for the *High* and *Low Gas Demand Scenarios* are designed to bracket the range of a probable bandwidth in gas demand relative to the *Reference Gas Demand Scenario*.[2] Each of the *Gas Demand Scenarios* is driven by a consistent set of primary gas demand drivers which reflect both residential, commercial, and industrial (RCI) gas customers' demand and gas-fired electric generation fuel requirements.

The *Reference Gas Demand Scenario* represents a forecast that is in accord with the economic, market, and regulatory assumptions characterizing each of the six Participating Planning Authorities' (PPAs') resource planning process over the five- and ten-year study horizons. The footprint of the six PPAs comprises the Study Region. The starting point for the *Reference Gas Demand Scenario* is the Roll-Up Integration Case of the Eastern Interconnection prepared by the EIPC Steady State Modeling and Load Flow Working Group (SSMLFWG).[3] The SSMLFWG consists of representatives from each NERC registered Planning Authority (PA) that is party to the EIPC Analysis Team Agreement. The Roll-Up Integration Case is an integrated power flow model incorporating the regional expansion plans for the Eastern Interconnection as the plans existed in 2013. The EIPC SSMLFWG prepared the 2018 and 2023 models by aggregating the resources, planning forecasts, and reliability standards of EIPC members, with sufficient analysis of the rolled-up plan to ensure simultaneous feasibility of the individual submitted plans. As a steady-state power flow model, the Roll-Up Integration Case simulates the integrated power system for two "snapshots," the 2018 and 2023 summer peak hours. Input data to the Roll-Up Integration Case were the load forecasts, energy efficiency and demand-side resources, existing and planned generation resources, and a representation of the electric transmission infrastructure, including planned transmission expansions for each of the EIPC PAs.

Two other future *Scenarios* are being constructed to bracket the range of probable bandwidth in gas demand and gas profile surrounding the *Reference Gas Demand Scenario*. These alternative *Gas Demand Scenarios* are not intended to reflect *extreme* conditions or low probability events, but reasonable bounds around the realm of plausible outcomes. The *High Gas Demand Scenario* represents a "plausible maximum" level and profile of gas requirements across the Study Region, driven primarily by increased deactivation or retirement of coal plants, lower delivered natural

---

[1] By design, the natural gas infrastructure was not intended to be able to support the non-firm gas requirements of gas-fired generators or other non-firm customers.

[2] Extreme (90:10) weather conditions will be examined in one or more sensitivity cases.

[3] Eastern Interconnection Planning Cooperative Steady State Modeling and Load Flow Working Group, *Report for 2018 and 2023 Roll-Up Integration Cases, Final Report*, February 14, 2014.

http://www.eipconline.com/uploads/FINAL_EIPC_Roll-up_Report_Feb14-2014.pdf gas prices, and higher electric loads. The *Low Gas Demand Scenario* represents a "plausible minimum" level and profile of gas requirements, driven primarily by the displacement of gas-fired generation vis-à-vis the addition of renewable resources, higher delivered natural gas prices, and lower electric loads. The *High* and *Low Gas Demand Scenarios* represent energy futures in which one or more of the primary factors driving natural gas demand fall significantly outside of the values reflected within the *Reference Gas Demand Scenario*.

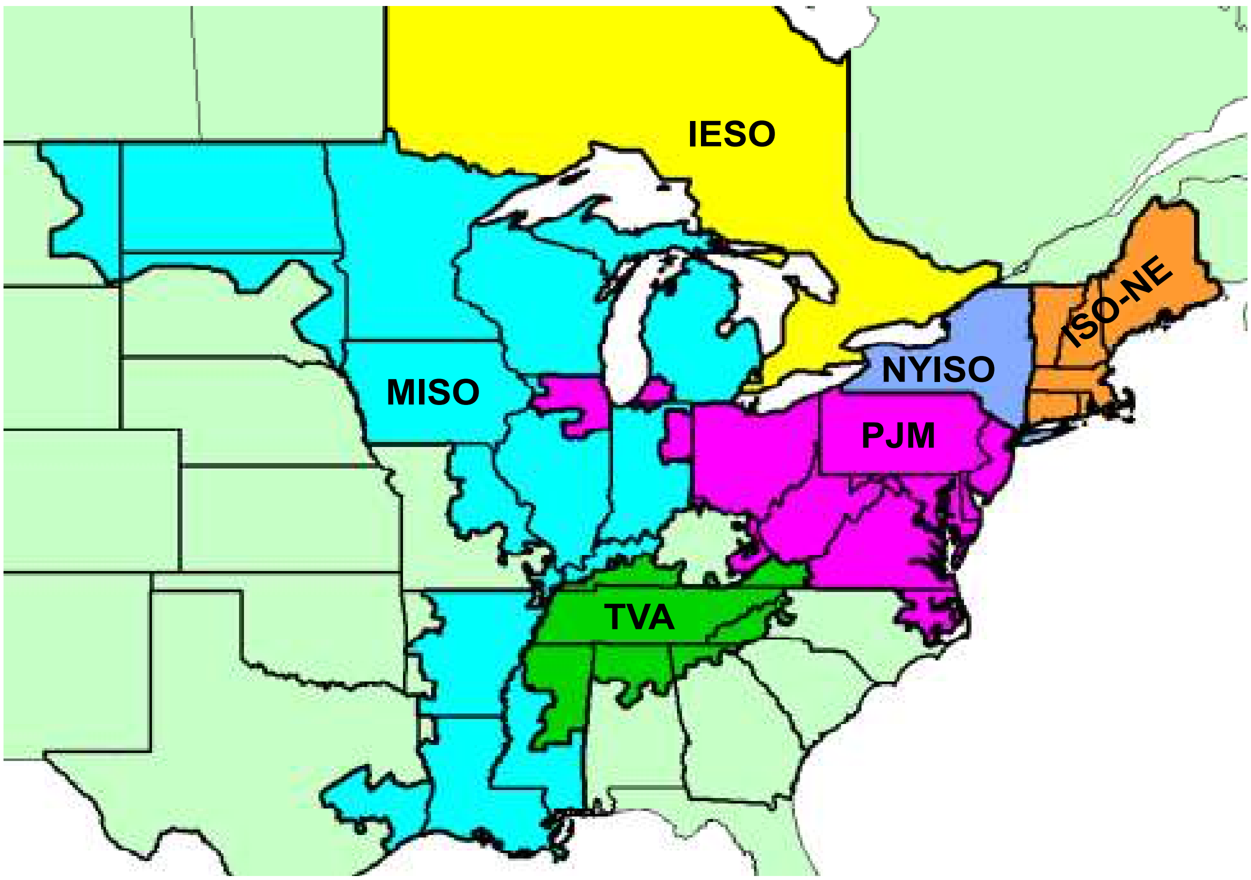
Since the lock-down of the Roll-Up Integration Case in late 2013, there have been certain infrastructure changes reflecting the ongoing annual nature of the PPA planning processes and updating of interconnection queues, thereby causing the PPAs to delineate updates to the input assumptions applicable to all three *Gas Demand Scenarios.* Accordingly, in Q1-2014, the PPAs provided LAI with lists of system updates, including new resources, new transmission projects, and new generator deactivations that have taken place since the development of the Roll-Up Integration Case. Also, certain generator ratings were revised based on new uprates and derates. These infrastructure changes, discussed in Section 4.1.2, have been incorporated in the *Reference Gas Demand Scenario* "Update" sensitivity.[4] Similarly, Update sensitivities for the *High Gas Demand Scenario* and the *Low Gas Demand Scenario* based on the updated infrastructure information will also be constructed. Hence, the *Gas Demand Scenario* Update sensitivities constitute the foundation for the array of other sensitivities that will be formulated to test the impact of changing a single variable or a set of variables on gas demand across the Study Region.

[4] Also referred to as "Sensitivity 0."

2 ELECTRIC TRANSMISSION TOPOLOGY

A series of electric system production simulation runs will be conducted using the AURORAxmp platform in order to delineate the level and profile of gas demand for gas-fired generators on a peak winter and peak summer day. The simulations will be conducted for two study years, 2018 and 2023. The Study Region encompasses the market areas for all six PPAs, shown in Figure 1, but also incorporates transmission interchange between neighboring control areas. The neighboring control areas include Quebec, New Brunswick, Manitoba, Midwest Reliability Organization (MRO-US West), Southwest Power Pool (SPP), SERC South, VACAR South, Associated Electric Cooperative Inc. (AECI), and LG&E and KU Services Company (LGE).[5]

Figure 1. Geographic Overview of Study Region



Each of the PPAs is divided into Zones based on transmission constraints for dispatch and pricing purposes. Each Zone is comprised of one or more Local Delivery Areas (LDA, or Area). Exhibit 1 provides a list of the PPAs, Zones, and Areas included in the Study Region.

[5] Manitoba is part of the MISO reliability coordination area, but is not part of the MISO market area. Market areas for the PPAs are used as the geographic basis for this study.

The PPAs provided information regarding the transfer limits between PPAs, between Zones within each PPA (including multi-Zone simultaneous interface limits), and between Zones and adjacent control areas. LAI assembled the information provided by the PPAs to create the "bubble diagram" shown in Exhibit 2, which is consistent with the transmission system represented within the Roll-up Integration Case model. The *High Gas Demand Scenario* and the *Low Gas Demand Scenario* also utilize the transmission topology shown in Exhibit 2. In the *High Gas Demand Scenario,* the PPAs have made the simplifying assumption that new gas-fired generation resources would likely be located at or around deactivated generation stations in order to more fully utilize existing electric transmission infrastructure. In the *Low Gas Demand Scenario*, the PPAs have made the simplifying assumption that the additional renewable resources would likely be sited near the existing renewable resource locations across the Study Region. These assumptions allow for the testing of gas constraints utilizing the existing and planned infrastructure to serve different levels of resources so as to keep the focus of the analysis on gas system infrastructure. The location of the specific new generation is ultimately determined by generation providers taking into account a number of factors, only one of which includes existing and planned gas infrastructure.

3 ELECTRIC LOAD

3.1 REFERENCE GAS DEMAND SCENARIO

Load data were provided by each PPA in different formats. Each PPA provided some combination of the following data sets: historic locational hourly load data, hourly load profile shapes, and annual peak demand and energy forecasts or demand growth factors over the Study Period. LAI supplemented the load data provided by the PPAs with publicly available information to create load input data for AURORAxmp.[6] These data consist of hourly profiles by modeled Area for a base (typical) year expressed as percentages of annual average demand, annual average demand (MWh/h) by Area for the base year, annual peak demand (MW) by Area for the base year, annual growth factors for peak demand over the Study Period, and average growth factors for annual total energy load by Area over the Study Period. The model aggregates hourly Area loads into Zonal loads.

Annual average energy and peak load data by Zone for the *Reference Gas Demand Scenario* are included in Exhibit 3. The *Reference Gas Demand Scenario* load represents normal (50:50) weather conditions.

3.2 ALTERNATIVE GAS DEMAND SCENARIOS

The *High Gas Demand Scenario* incorporates higher electric loads, driven by an assumed increase in economic activity relative to the *Reference Gas Demand Scenario*. The *Low Gas Demand Scenario* incorporates lower electric loads, reflecting a decrease in economic activity relative to the *Reference Gas Demand Scenario*.[7] For the U.S. PPAs, the electric loads in the alternative *Gas Demand Scenarios* were scaled using factors calculated from the regional electricity forecasts tabulated as "Delivered Energy Consumption All Sectors" in the EIA Annual Energy Outlook 2013 (AEO2013).[8] For each region modeled in the AEO2013 that is within the EIPC footprint, the ratios of the High Economic Growth Case electricity consumption relative to the Reference Case electricity consumption were calculated for 2018 and 2023. Similarly, the ratios of the AEO2013 Low Economic Growth Case to the Reference Case were calculated for 2018 and 2023 for each region. The ratios calculated from the AEO2013 geographic regions were applied to the corresponding Areas. For Areas that straddle two different AEO2013 regions, the ratios were averaged. The *Reference Gas Demand Scenario* load data in the corresponding Areas were multiplied by these ratios for each of the two study years to derive the electric load input assumptions for the *High Gas Demand Scenario* and the *Low Gas Demand Scenario*. For Ontario, the electric loads for the *High Gas Demand Scenario* are based on IESO's high growth demand forecast, while the electric loads for the *Low Gas Demand Scenario*

---

[6] http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx

http://www.iso-ne.com/trans/celt/report/

http://www.iso-ne.com/trans/rsp/index.html

http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2013_GoldBook.pdf

[7] Extreme (90:10) weather conditions will be examined in one or more sensitivity cases.

[8] http://www.eia.gov/forecasts/archive/aeo13/

were assumed to have an annual decline of 0.5% from the *Reference Gas Demand Scenario*. The multipliers are provided in Exhibit 4.

4 RESOURCES

4.1 REFERENCE GAS DEMAND SCENARIO

4.1.1 Summary of Resources Based on Roll Up Integration Case

Resources in the *Reference Gas Demand Scenario* conform to the resources in the Roll Up Integration Case. Detailed lists of resources by PPA included in the *Reference Gas Demand Scenario* are provided in Exhibit 5. The list of resources and their capacities began with the data from the Roll Up Integration Case. This data set, at the bus level, was mapped to resources defined in the EPIS database for AURORAxmp. Some resources not found in the Roll-up data were removed. The focus of the reconciliation was on units larger than 15 MW, but some smaller resources are also included based on data from the PPAs or default EPIS data. Aggregation or disaggregation of individual units at a generating station to a named resource entity was done, as required for consistency. Some busses are common for multiple units, and some resources consist of multiple units. The capacities of the resources in Exhibit 5 are the result of this reconciliation process.[9] Capacities shown for thermal resources are their summer ratings, taken to the extent possible from the Roll Up Integration Case, while full or nameplate ratings are shown for hydro, wind, solar, and demand response (DR) resources. In the AURORAxmp model, net capability by season is used.

4.1.2 Summary of Resources Based on Update Sensitivity

The PPAs provided LAI with a list of existing or planned infrastructure changes that have occurred since the Roll-Up Integration Case data was finalized. These changes include:

- New generation resources not included in the Roll-Up Integration Case.
- Removal of planned new resources based on queue withdrawal notices.
- Uprates and derates of existing resources
- Unit retirements or deactivations which have occurred or will occur during the Study Period
- PPA-approved new transmission projects and transfer limit changes to existing transmission lines

This updated information has been used to construct the list of resources in the *Reference Gas Demand Scenario* for the Update sensitivity. The updates to resources are also included in Exhibit 5.

[9] Due to the different methods that the PPAs used to provide data for the Roll Up Integration Case and the varying amounts of supplemental data provided by the PPAs, certain unit capacities may represent gross output with a corresponding bus for the unit's auxiliary load. The incorporation of gross output for a limited number of unit capacities has no bearing on Target 2 research objectives.

4.1.3 Energy Profiles for Renewable Resources

The AURORAxmp database includes hourly energy production profiles ("wind shapes") for existing and planned wind resources in most Areas. For U.S. locations, these production profiles are based on the National Renewable Energy Laboratory (NREL) Eastern Wind Dataset, which includes onshore and offshore energy production data.[10] Where such data were missing in the default AURORAxmp database from EPIS for U.S. areas, LAI supplemented the data set using information from the NREL Eastern Wind Dataset. NREL data cover three years, 2004 through 2006. The average of these three years was used to develop the wind shapes. For Ontario, the IESO provided LAI with ten years of hourly wind shape data for each Zone within IESO. The average of the wind data for the same three years, 2004 to 2006, was used for the IESO Zones.

There are only a small number of Areas with Solar PV resources in the Phase 1 Roll-up Report. LAI used NREL's PVWATTS model to generate hourly solar shapes for each area where solar PV resources are installed in each scenario.[11]

4.1.4 Demand Response Resources

Active DR resources are represented in AURORAxmp as "virtual generators" dispatched when the price reaches a certain level. Passive DR programs and energy efficiency (EE) are embedded in the load forecast and therefore are not explicitly modeled as resources.

The levels of the activation or "trigger" energy prices for "virtual generators" representing DR resources are set by considering the number of hours that the DR resource can be activated in a season or year for each program. The DR trigger prices are set at the level that would result in activation of the DR resources for the applicable number of program hours during certain system conditions. The trigger price of virtual generators representing EE resources is set at zero to ensure activation of the EE resources at all system conditions.

4.1.5 Deactivated Units

The resources in the AURORAxmp model exclude existing units that the PPAs have designated as being idled, mothballed, retired, or otherwise deactivated prior to the 2018 or 2023 study years. The *Reference Gas Demand Scenario* resource list conforms to the Roll Up Integration Case, and the *Reference Gas Demand Scenario* Update includes updated retirement information provided by the PPAs.

4.2 HIGH GAS DEMAND SCENARIO

The *High Gas Demand Scenario* is premised on a significant increase in the deactivation or retirement of coal-fired units relative to the level of coal plant deactivations represented in the *Reference Gas Demand Scenario.* In the *High Gas Demand Scenario*, the loss of coal-fired capacity is replaced entirely by generic natural gas-fired resources. The increased coal-fired capacity attrition reflects increased pressure on the "dark spread," *i.e.*, the difference between the

---

[10] http://www.nrel.gov/electricity/transmission/eastern_wind_methodology.html

[11] http://rredc.nrel.gov/solar/calculators/pvwatts/version1/

value of electric energy in wholesale markets versus the marginal cost of coal-fired energy, which also includes higher environmental compliance costs relative to the *Reference Gas Demand Scenario*.

To determine which fossil resources are deactivated for the *High Gas Demand Scenario*, LAI started with the resource list for the *Reference Gas Demand Scenario* and its Update. , From these resources, LAI removed all of the "at-risk" units that were identified by several of PPAs. These at-risk units may include oil-fired steam units as well as coal resources. For PPAs that did not provide "at risk" lists, LAI relied on published reports that forecast potential future coal retirements, on a net summer capacity basis aggregated by region. These reports are listed in Table 1. Data in the EIA and NERC studies were reasonably consistent across the Study Region. Absent a specific at-risk list from a PPA, the net attrition of coal plants for each study year relative to 2014 was used to derive the total amount of coal-fired resources deactivated in the PPA region. Adjustments were made to conform NERC regions to the PPA footprint. The recent MISO survey of generation owners (listed in Table 1) provided an indication of the strategies that coal plants expect to undertake to comply with new EPA regulations. Thus for MISO, the quantity of deactivated coal-fired capacity in the *High Gas Demand Scenario* is based on the reported capacity of coal-fired plants where survey results indicated that repowering to a non-coal fuel is likely or that it will be uneconomic to meet environmental requirements. In IESO, there are no remaining coal resources in the *Reference Gas Demand Scenario*.

Table 1. Sources of Deactivated Coal Capacity Forecasts

EIA Annual Energy Outlook (AEO) 2014 Early Release[12] http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm
North American Electric Reliability Corporation (NERC) 2013 Long-Term Reliability Assessment, December 9, 2013. http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
4th Quarter 2013 EPA Survey Update, MISO Planning Advisory Committee Meeting, 2/19/2014. Sum of capacity responding as "Uneconomic/Replace" and "Repower" plus half of capacity under "TBD" and "No Response" https://www.misoenergy.org/Library/MeetingMaterials/Pages/PAC.aspx

The reports listed in Table 1 do not identify the specific units deemed to be "at risk." If the total capacity of the designated at-risk units provided by a PPA, plus the new deactivations not included in the Roll Up Integration Case was less than the target retirement quantity based on the reports listed in Table 1, we applied the following criteria to prioritize additional units for deactivation:

1. Low capacity factor − Units that had a capacity factor of less than 50% in 2013, based on EPA's (Environment Protection Agency) CEMS (continuous emission monitoring system) data

[12] The Final AEO2014 has been released, in part, by EIA. The regional data tables required to derive the quantity of deactivated coal resources by Area has not yet been published. However, there does not appear to be any difference in the total US coal capacity forecast between the Early Release and the Final AEO2014.

2. Low efficiency − Smaller units with higher heat rates

3. Lack of mercury emission controls – Coal units that do not have an emissions control strategy, in particular activated carbon injection (ACI) to control mercury emissions, will need significant upgrades and consequently will require large investments to comply with current and future regulations

4. Age − Older coal units are deactivated before newer units

For purposes of this analysis, the PPAs have made the assumption that replacement gas-fired capacity is located in the same Area as the deactivated coal units. Therefore, no change to the determination of transfer capability limits across the Study Region is required. For the purposes of the zonal electric modeling topology, the location specificity need only be at the Zone level. For purposes of associating the generic gas units with a gas market pricing point, the Area level provides the nearest location reference. Some replacement gas-fired capacity could be repowered at the sites of deactivated coal units, but that is not a focus of this study or an explicit selection criterion.

4.3 LOW GAS DEMAND SCENARIO

The *Low Gas Demand Scenario* incorporates an increased penetration of renewable resources and EE/DR, and a decrease in gas-fired resources relative to the *Reference Gas Demand Scenario*. The resource changes in the *Low Gas Demand Scenario* are as follows:

- Incremental renewable resources are assumed to be onshore wind and solar PV resources in the Study Region.[13]

- For TVA, the incremental onshore wind is based on the "Strategy C - Diversity Focused Resource Portfolio" developed for TVA's 2011 Integrated Resource Plan, which envisions 2,500 MW of new renewable resources by 2020.[14]

- For IESO, wind and solar resources are the same as the resources in the *Reference Gas Demand Scenario* Update sensitivity.

- For the remaining PPAs, incremental wind and solar PV was added to achieve approximately the total aggregate requirements of the states' renewable portfolio standard (RPS) for the two study years. For states which do not have an RPS but have renewable energy policy goals, one-half of the renewable energy goal was included in the aggregate total.

- Gas-fired resources included in the Roll Up Integration Case as "new resources" but with the status "Proposed" were deleted. Gas-fired resources included in the Roll Up

---

[13] Offshore wind resources are limited to the Cape Wind project in ISO-NE and roughly 1,000 MW of offshore wind in New Jersey, the same as for the *Reference Gas Demand Scenario*.

[14] TVA, *Integrated Resource Plan, TVA's Environmental and Energy Future*, March 2011, p. 99. TVA is in the process of developing a new IRP.

Integration Case as new resources, but with status "Development" or "Committed" were assumed to be sufficiently along the development process to meet commercial milestones. Hence, LAI did not consider deactivation of "Development" or "Committed" resources from the *Low Gas Demand Scenario*. However, gas-fired resources which have a status of "Proposed" but are required to meet installed reserve margin or reliability objectives were *not* removed but were retained in the *Low Gas Demand Scenario*.

- The lower electric load forecast used for the *Low Gas Demand Scenario* implicitly embeds a higher penetration rate of DR and EE resources.

5 FUEL PRICE FORECAST

5.1 REFERENCE GAS DEMAND SCENARIO

The fuel price forecasts utilized as inputs to the AURORAxmp and GPCM modeling are based on the EIA Annual Energy Outlook 2013 (AEO2013), supplemented by the EIA's February 2014 Short-Term Energy Outlook (STEO).[15] AEO2013 provided the longer-term annual fuel price trends for the forecast of the input fuel prices for the 5-year and 10-year study modeling horizons. The STEO provided near-term monthly and quarterly fuel prices, which along with some supplemental monthly prices based on NYMEX futures, provided the monthly price patterns that were projected over the study horizons based on the AEO2013 Reference Case annual fuel price trajectories. The STEO and AEO2013 forecasts of generation fuel prices provided consistent oil-to-gas and gas-to-coal price parity ratios to the maximum extent that was reasonable.

The AEO2013 forecasts are based on the laws and regulations that were in effect as of the end of September 2012 and the regulations that the EIA considered would clearly be enacted shortly after the completion of the AEO2013 forecasts. These regulations are assumed to remain unchanged over the AEO2013 forecast period. The forecast assumptions regarding environmental regulations include the continuation of the Clean Air Interstate Rule (CAIR) in response to the court vacation of the Cross-State Air Pollution Rule (CSAPR) and the scheduled implementation of the Mercury and Air Toxics Standards (MATS).

Other key assumptions for AEO2013 include: GDP growth of 2.75 percent annually over the study period (through 2023), overall U.S. population growth averaging 0.95 percent per year, non-farm employment of 1.2 percent each year, and average annual inflation of 1.6 percent.[16]

5.1.1 Natural Gas Price Forecast

In the *Reference Gas Demand Scenario*, the commodity cost of natural gas "into-the-pipe" corresponds to the Henry Hub price forecasts from the STEO and AEO2013. The STEO provides a forecast of monthly gas prices at the Henry Hub through December 2015. AEO2013 provides a forecast of annual prices at Henry Hub through 2040. In order to obtain the monthly gas prices for the electric production simulation modeling, the monthly Henry Hub gas profile for 2015 was projected forward through the end of the Study Period at the annual escalation rates for gas prices presented in AEO2013.

The AEO2013 Reference Case represents a scenario in which gas production continues to grow through 2023 and beyond, driven primarily by the continued development of shale gas. Under this scenario, the U.S. is projected to be a net natural gas exporter by 2020. LNG exports are projected to increase from 30 Bcf in 2013 to 830 Bcf by 2023, based on the assumption that three LNG export terminals will become operational during this period. LAI has assumed that the Dominion Cove Point LNG terminal will be one of the export terminals. In addition, two LNG

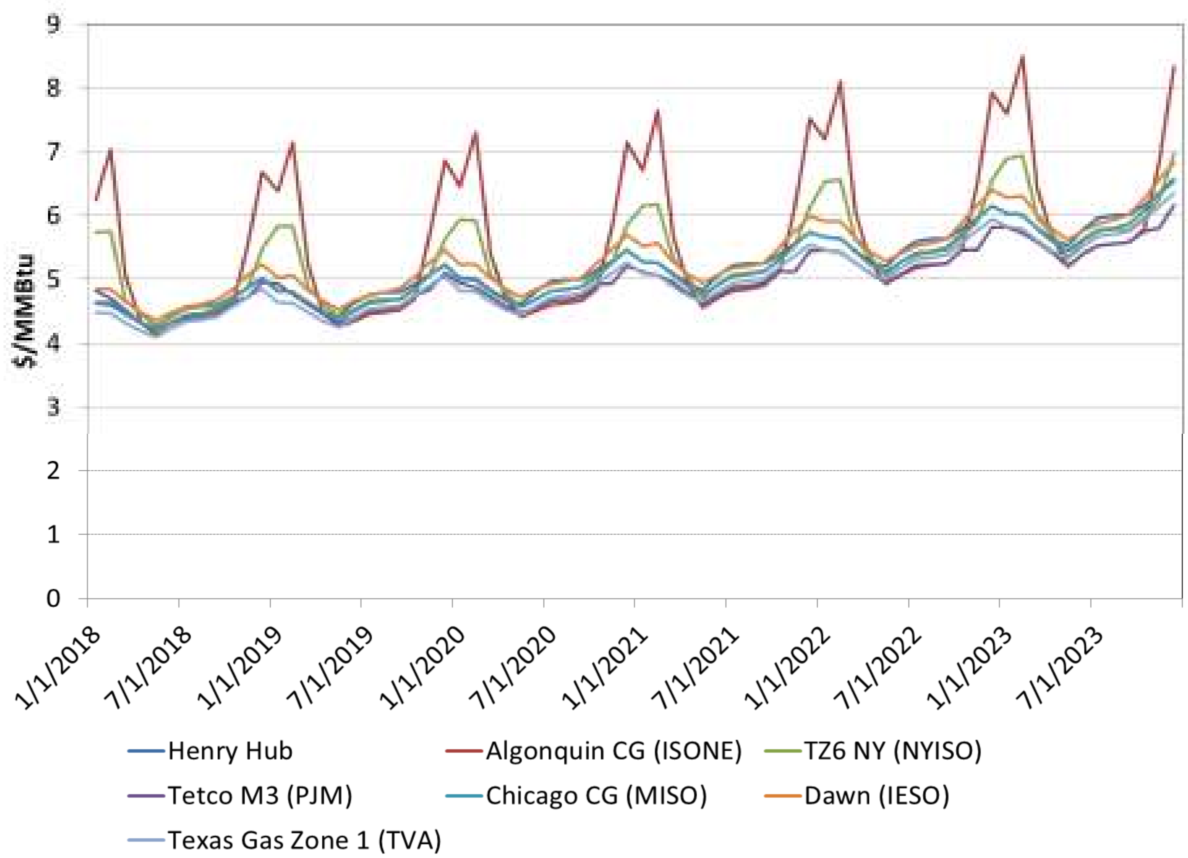
[15] GPCM, originally known as the Gas Pipeline Competition Model, is the gas pipeline network model that LAI licenses from RBAC, Inc.

[16] AEO2013 Macroeconomic Indicator Table.

export terminals on the Gulf Coast are assumed to be operational during this period – Sabine Pass in Louisiana, which is currently under construction, and Freeport, Texas. Lower 48 gas production is projected to increase from 23.7 Tcf in 2013 to 27.5 Tcf in 2023, reflecting a 42% increase in shale gas production. By 2023 shale gas production is expected to comprise almost one-half of total US gas production.

The EIA projections show total natural gas consumption growing at an average of 0.7% each year, with residential and commercial consumption remaining flat and industrial gas consumption growing by a total of almost 15% through 2023. Gas use in the electric generation sector declines slightly from 2013 through 2015, then grows through 2018, leveling off at around 8.3 Tcf/year over the planning horizon. Natural gas prices remain relatively low over the study period. Henry Hub gas prices are projected to increase at an average annual rate of 5.4% in nominal terms, reaching an average price for 2023 of $5.68/MMBtu from an annual average price of $3.36/MMBtu in 2013.[17] Figure 2 shows the forecast of Henry Hub prices as well as forecasts of the prices at several key regional gas pricing points for the AURORAxmp modeling period.

Figure 2. Natural Gas Price Forecast ***(Reference Gas Demand Scenario)***



[17] Fuel prices are expressed in nominal dollars.

The regional pricing point basis differentials relative to Henry Hub that are shown in Figure 2 were developed using RBAC, Inc.'s GPCM 13Q4base database.[18] Exhibit 6 presents selected input information that is included in this database, including:[19]

- Pipelines included in the model,
- Max flow volume within each pipeline zone,
- Max flow volume between the zones of each pipeline,
- Interconnection volume between the zones of different pipelines, and
- Storage facility maximum injection and withdrawal rates.

5.1.2 Oil Price Forecast

The liquid fuel price forecasts used as inputs to the production simulation modeling are based on the STEO and AEO2013 forecasts of crude oil. AEO2013 includes forecasts for both Brent Crude, an international crude oil benchmark, and West Texas Intermediate crude (WTI), which is the most commonly used North American crude oil benchmark. The forecast of fuel oil prices starts with the STEO WTI crude monthly prices through December 2015, and is extended over the rest of the Study Period at a rate that is consistent with the WTI price escalation in AEO2013.

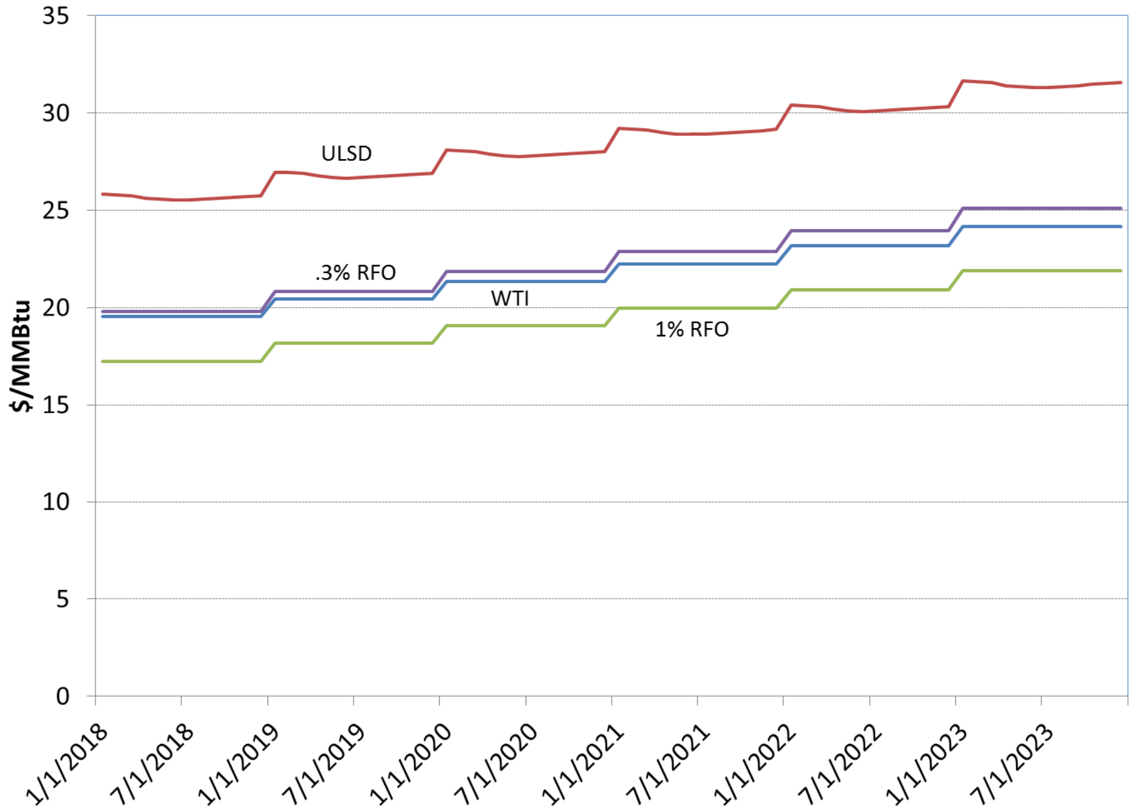
Regional refined petroleum product prices for the most commonly used liquid fuels, including ultra-low sulfur diesel (ULSD), kerosene, and residual fuel oil (RFO), were projected based on the WTI price forecast and the historical relationships between WTI and product prices.[20] Figure 3 shows the price forecasts for WTI and the relevant fuel prices in $/MMBtu. The forecast of WTI prices reaches $134/BBl in 2023 as compared with the average annual price in 2013 of $90.88/BBl. The fuel oil price forecasts reflect the prices at the New York Harbor pricing point. LAI has made adjustments to the prices to reflect conditions in regional markets relevant to the Study Region. The regional adjustments to fuel oil prices reflect the differences between regional market prices and the New York Harbor price, based on the AEO distillate fuel oil regional price differentials.

[18] As described in the December 13, 2013 draft Proposed Scenario Definition Parameters and Sensitivities report, GPCM is an optimization model that uses partial equilibrium economics to reach a solution where supply and demand are balanced for existing and forecast conditions.

[19] This database will be modified by LAI for purposes of the pipeline utilization and constraint identification analysis, including updates to reflect LAI's understanding of the current natural gas infrastructure and expansion projects through 2023.

[20] The strong historical correlations between WTI prices and the prices for distillate and RFO are expected to continue over the study period.

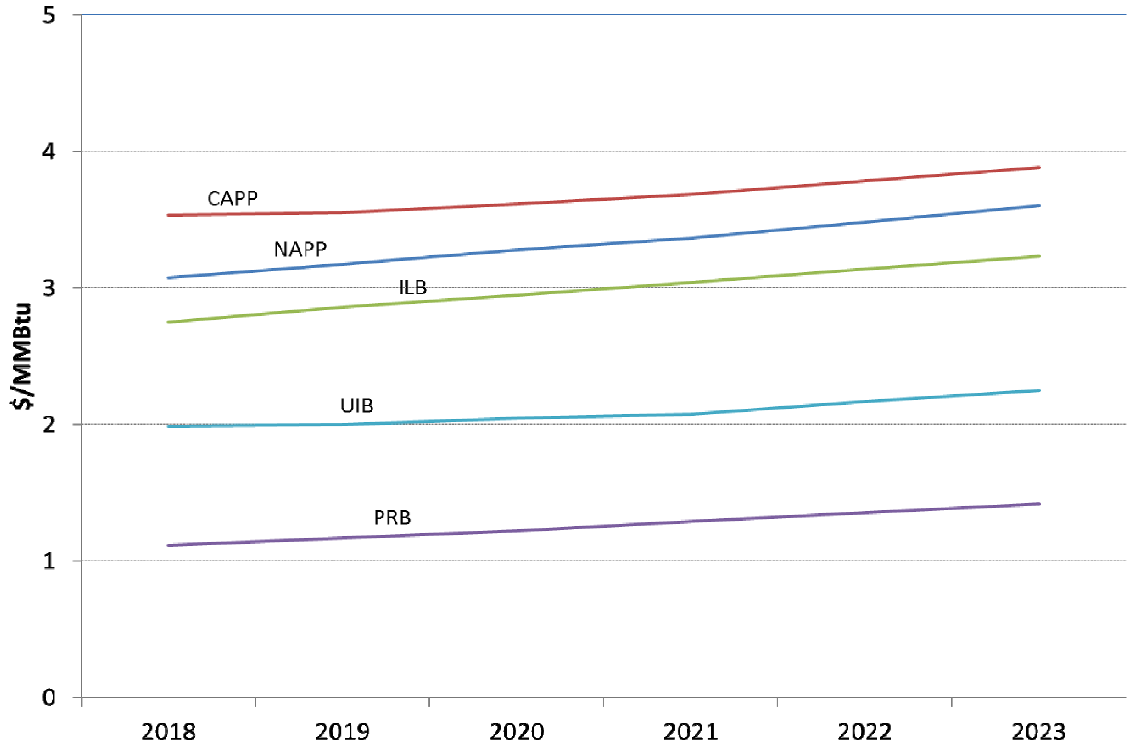
Figure 3. Fuel Oil Price Forecasts *(Reference Gas Demand Scenario)*



5.1.3 Coal Price Forecast

The forecast of coal prices, shown in Figure 4, is based on the long-term trends in prices for each of the coal supply basins of relevance: Central Appalachia (CAPP), Northern Appalachia (NAPP), Illinois Basin (ILB), Powder River Basin (PRB), and Uinta Basin (UIB), representative of Rocky Mountain bituminous coal. Current basin prices were escalated at the average annual escalation rates for these five basins taken from AEO2013. Current transportation costs between the supply basin and major consuming areas, escalated at the rate of general inflation, have been added to the basin prices to obtain delivered coal prices for each consuming region.

Figure 4. Coal Price Forecast *(Reference Gas Demand Scenario)*



5.1.4 Nuclear Fuel Price Forecast

The forecast of nuclear fuel prices is driven by uranium (U_3O_8) prices, which are expected to amount to about 40% of total nuclear fuel costs over the forecast horizon. Nuclear fuel costs also include the costs of conversion (6%), enrichment (38%) and fabrication (16%).[21] The EIA does not provide any granular forecasts of nuclear fuel prices. Therefore we have developed a forecast of nuclear fuel prices based on expected uranium prices that is consistent with EIA's available price forecasts. For the *Reference Gas Demand Scenario*, the forecast of uranium prices starts with a forward price curve that provides monthly prices through 2017.[22] Uranium prices, as shown in Figure 5, are projected to average $36/lb in 2013 increasing to an average of $45/lb in 2018, and to an average of $54/lb in 2023. Also shown in Figure 5 are nuclear fuel prices expressed on a $/MMBtu equivalent basis, which increase from $0.53/MMBtu in 2013 to $0.69/MMBtu in 2023. A number of supply developments are expected to impact prices, including planned production increases in Canada, Australia and Kazakhstan. The highly enriched uranium (HEU) down blending agreement with Russia provided the equivalent of 20 million pounds of U_3O_8 to the market annually. This program ended as of December 2013. The loss of this HEU supply and growing demand driven by new nuclear plants planned and under construction in China, in particular, as well as other worldwide locations will result in prices that

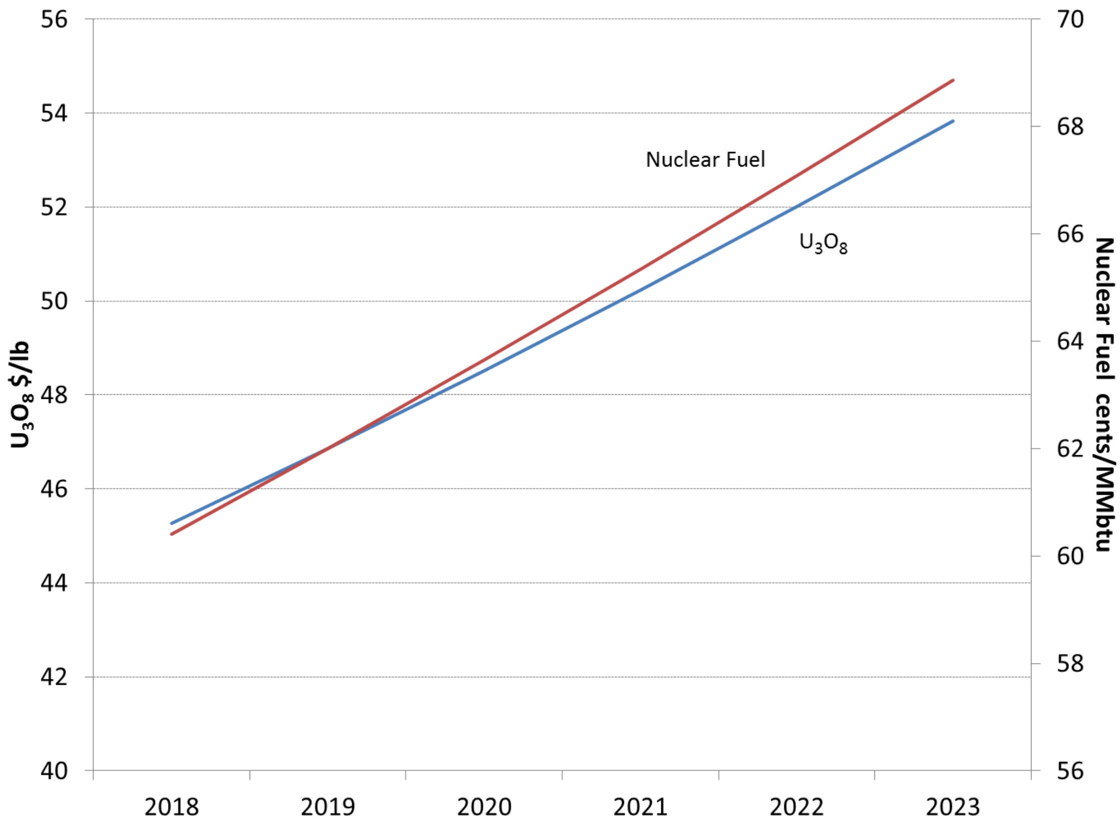
---

[21] Nuclear fuel supply is comprised of mined and enriched U_3O_8, utility stockpiles of uranium, and secondary sources such as recycled spent fuel and recycled weapons grade uranium and plutonium.

[22] Globex NYMEX futures prices updated in December 2013.

are expected to escalate at an average annual rate that exceeds the general rate of inflation. The escalation rate used is consistent with the AEO forecast assumptions and reflects the slower growth in nuclear construction post-Fukushima.

Figure 5. Nuclear Fuel Price Forecast *(Reference Gas Demand Scenario)*

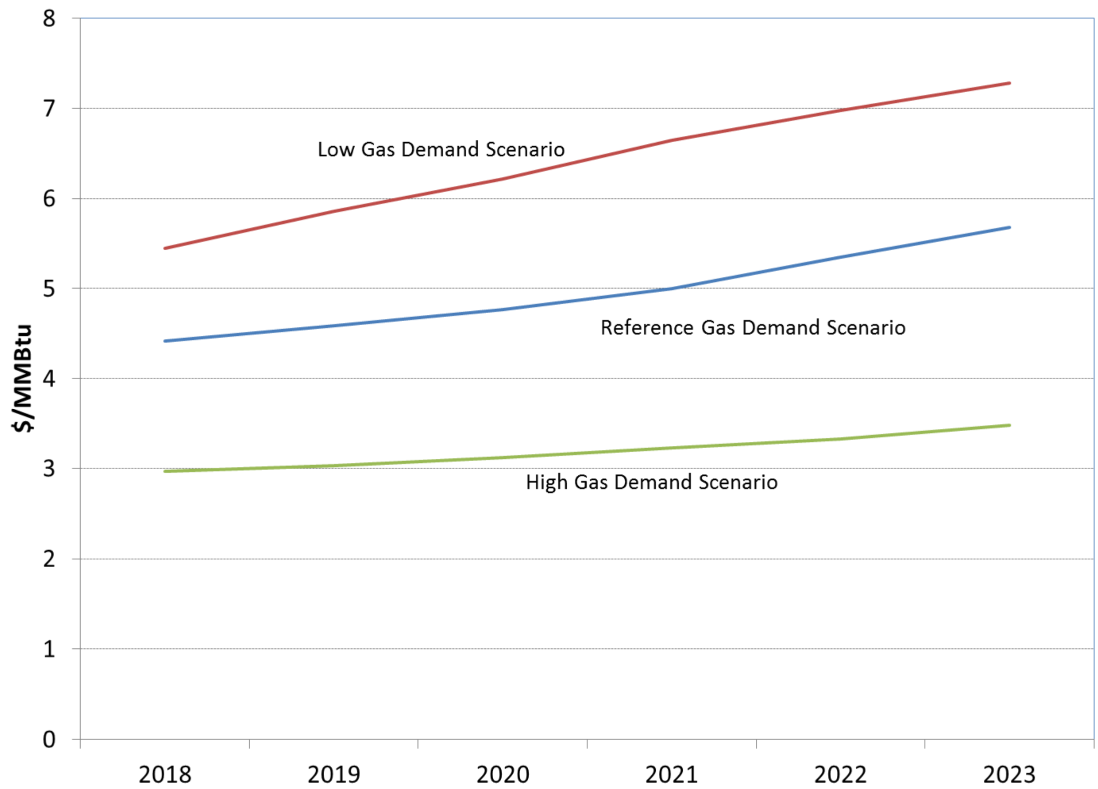


5.2 HIGH GAS DEMAND SCENARIO

5.2.1 Natural Gas Price Forecast

The forecast of natural gas prices for the *High Gas Demand Scenario* is based on the AEO2013 High Oil and Gas Resource Case which results in gas prices that average 29% lower over the period of 2013 through 2023 as compared with the AEO2013 Reference Case forecast. The AEO2013 High Oil and Gas Resource Case assumes that the estimated ultimate recoveries for shale gas are 100% higher than in the Reference Case. Undiscovered resources are 50% higher. These assumptions result in more gas produced at lower costs for a longer period, thereby sustaining a lower gas price trajectory than the Reference Case. Figure 6 shows the Henry Hub gas price forecasts for the *Reference Gas Demand Scenario*, the *High Gas Demand Scenario* and the *Low Gas Demand Scenario* based on the different AEO2013 Oil and Gas Resource Cases.

Figure 6. Comparison of Alternative *Gas Demand Scenario* Henry Hub Gas Prices



5.2.2 Oil Price Forecast

The crude oil and fuel oil price forecasts for the *High Gas Demand Scenario* are the same as the forecasts for the *Reference Gas Demand Scenario*.

5.2.3 Coal Price Forecast

The basin coal price forecasts for the *High Gas Demand Scenario* are unchanged from the *Reference Gas Demand Scenario*. The coal price escalations remain based on the AEO2013 Reference Case coal supply basin forecasts.

5.2.4 Nuclear Fuel Price Forecast

The forecast of nuclear fuel prices in the *High Gas Demand Scenario* is unchanged from the *Reference Gas Demand Scenario*.

5.3 Low Gas Demand Scenario

5.3.1 Natural Gas Price Forecast

The forecast of natural gas prices at the Henry Hub for the *Low Gas Demand Scenario* is based on the AEO2013 Low Oil and Gas Resource Case, which results in gas prices that are 23% higher than for the AEO2013 Reference Case forecast. For this forecast case the EIA assumed that estimated ultimate recoveries for shale gas would be 50% lower than for the Reference Case. This results in higher gas costs and lower production, which in turn results in the higher gas prices for the *Low Gas Demand Scenario* shown in Figure 6.

5.3.2 Oil Price Forecast

The crude oil and fuel oil price forecasts for the *Low Gas Demand Scenario* are the same as the forecasts for the *Reference Gas Demand Scenario*.

5.3.3 Coal Price Forecast

The forecast of supply basin coal prices remains the same as for the *Reference Gas Demand Scenario*.

5.3.4 Nuclear Fuel Price Forecast

The forecast of nuclear fuel prices in the *Low Gas Demand Scenario* is unchanged from the *Reference Gas Demand Scenario*.

6 ENVIRONMENTAL REQUIREMENTS AND ASSUMPTIONS

6.1 REFERENCE GAS DEMAND SCENARIO

Federal (U.S. and Canadian), state, and provincial environmental laws and regulations establish requirements for emissions, cooling water intake and discharge, fuel type, and other operating conditions for generating units, particularly fossil-fired units. Increasingly stringent emissions limits, most notably through the implementation of MATS, will materially impact the economics of fossil-fueled plants, particularly coal-fired plants.[23] Currently, the rules will go into effect in 2015, but a one-year extension will be generally granted for plants that need to install emissions control equipment, and an additional year may be granted if the extended maintenance outage or unit retirement would create reliability concerns.

In addition to the emissions requirements associated with CAIR (or its replacement), which will impact primarily SO_2 and NO_x emissions and govern the use of emission allowances, other pending or proposed regulations may also impact the cost of generating power at fossil fueled units. Among these pending or proposed regulations are the regulations regarding greenhouse gases on existing fossil units under Section 111(d) of the Clean Air Act (CAA), the regulation of cooling water intakes under Section 316(b) of the Clean Water Act (deadline extended to May 2014), stricter National Ambient Air Quality Standards (NAAQS) for ozone and other criteria pollutants, the Coal Combustion Residual Rule (due December 19, 2014), and the Regional Haze rule.

Generating resources which cannot rationalize new capital investment, increases in variable operating cost, or operating constraints that may be needed to comply with current or anticipated new requirements will retire or possibly repower. A number of older coal plants have already made the decision to retire rather than investing in retrofitting the emissions controls necessary to comply with MATS and other pending rules. The *Reference Gas Demand Scenario* resources are consistent with announced plant retirements reflected in the Roll Up Integration Case and in the updates provided by the PPAs.

Canada's "Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations" established performance standards for new coal units and also for existing units that have reached the end of their useful life, generally assumed to be 50 years. While the federal regulation requires the first wave of coal plant retirements no later than 2019, the Ontario government has accelerated the schedule of coal retirements within the Province. The *Reference Gas Demand Scenario* reflects the announced and pending retirement of all coal generation in IESO. Lambton was retired in October 2013. Nanticoke also retired at the end of 2013. The Ontario provincial government recently announced the conversion of one 150 MW generator at the Thunder Bay station to a biomass facility by 2015, with the second generator being retired in 2014. The Atikokan station is in the process of converting to biomass and is expected to return to service in 2014.

[23] Residual oil-fired units that operate for a limited number of hours per year may avoid the majority of the new MATS requirements.

6.1.1 Allowance Price Forecast

AURORAxmp incorporates NO_x, SO_2, and CO_2 unit-specific emission rates and applicable emission allowance costs for all fossil fueled facilities in the model. All allowances, including those which are allocated to generators at no cost and auctioned allowances, are treated as variable operating costs and priced at their opportunity cost, that is, the market price for the year that the allowance is used or retired.

In July 2011, the EPA issued CSAPR as a replacement for CAIR, which was vacated by the U.S. Court of Appeals for the D.C. Circuit in 2008 and remanded to EPA. CSAPR, as originally proposed, would have significantly reduced SO_2 and NO_x emissions but was also struck down in federal court in August 2012. EPA's petition for rehearing was denied in January 2013; however, the U.S. Supreme Court has agreed to review CSAPR. During the interim, CAIR remains in place until EPA devises a viable replacement program.

For the *Reference Gas Demand Scenario*, the emissions allowance price forecast assumes that the federal NO_x and SO_2 cap-and-trade program essentially remains a continuation of CAIR, applicable to states where CAIR currently applies. CAIR allowances continue to be traded, albeit thinly. Current CAIR annual NO_x allowances have recently traded at \$44/ton, and seasonal NO_x allowance prices at \$20/ton.[24] SO_2 allowances have recently held steady at approximately \$1.44/ton.[25] For modeling purposes, we have applied these reported prices, escalated at the assumed annual rate of inflation over the study period.

6.1.2 Carbon Assumptions

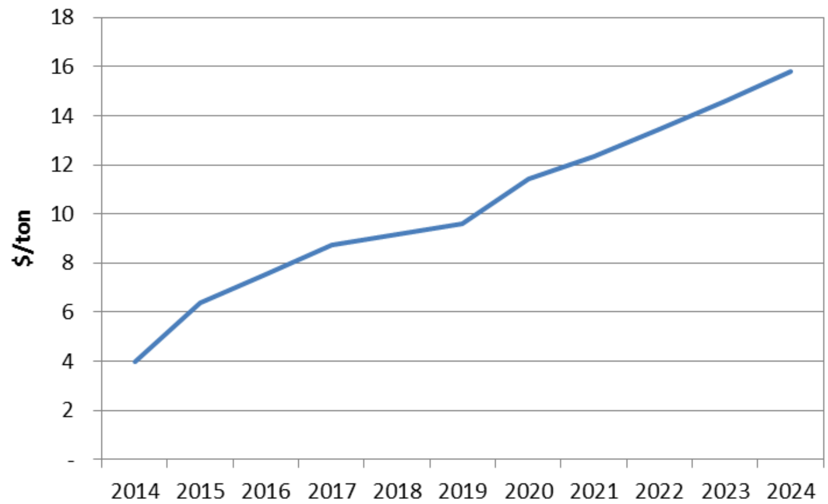
In the *Reference Gas Demand Scenario,* we assume that the Regional Greenhouse Gas Initiative (RGGI) model rule and allowance market, as modified by the 2012 RGGI Program Review, will persist over the study period for the current RGGI footprint. We have adopted the CO_2 allowance price forecasts developed by the RGGI Working Group for the 2012 Program Review, and have averaged the "91 Cap Bank Model Rule" and the "91 Cap Alt Bank Model Rule" as the basis for the price forecast.[26] Beyond 2020, we applied a trendline to extend the forecast for the remainder of the study period, as shown in Figure 7. These CO_2 allowance prices apply only to fossil units located within the current RGGI footprint.

[24] Argus Air Daily, January 13, 2014.

[25] Platts *Megawatt Daily*, March 13, 2014.

[26] See: http://www.rggi.org/docs/ProgramReview/February11/13_02_11_IPM.pdf

Figure 7. CO_2 Allowance Price Forecast



EPA has been working on developing draft carbon standards applicable to existing power plants using its authority under Section 111(d) of the CAA. A Presidential Memorandum directs EPA to issue draft standards no later than June 1, 2014, and final standards one year later. Section 111(d) does not prescribe specific emission rate limits for existing plants, but instead requires EPA to issue guidelines and standards of performance for states to use in developing their respective state implementation plans (SIPs). EPA has indicated that it is seeking to issue standards that afford each state considerable flexibility in developing its own implementation plan, which may include a "portfolio of measures," including those that could be taken beyond the affected sources. For the *Reference Gas Demand Scenario*, LAI has implicitly assumed that the mix of resources and operation of these units is unaffected by any new greenhouse gas requirements that might arise from new rules. Similarly, for IESO the *Reference Gas Demand Scenario* schedule of coal plant retirements is assumed to satisfy all federal and provincial greenhouse gas regulations.

Along with Quebec, British Columbia, Manitoba, California, and several other western U.S. States, Ontario is a member of the Western Climate Initiative. In 2009, Ontario enacted Bill 185, which requires the Ministry of Environment to develop a greenhouse gas reduction program. While the law enables the implementation of a provincial cap-and-trade system for CO_2 emissions, we have assumed that other measures will be used to accomplish reduction goals, and in the *Reference Gas Demand Scenario* we have not assigned an allowance price for fossil generating units in IESO.

6.2 ALTERNATIVE GAS DEMAND SCENARIOS

To construct the *High Gas Demand Scenario*, we assume that the cost of compliance with pending or proposed environmental rules, compounded by increased pressure on the "dark spread," would drive further fossil unit retirements relative to the *Reference Gas Demand Scenario*. We have not postulated any specific new regulations or requirements, but simply make the assumption that the resource mix in the *High Gas Demand Scenario* is a result of and consistent with the projected fuel prices and environmental mandates. These incremental retirements are only in the US PPAs. In IESO, there are no remaining coal units to remove for the *High Gas Demand Scenario*.

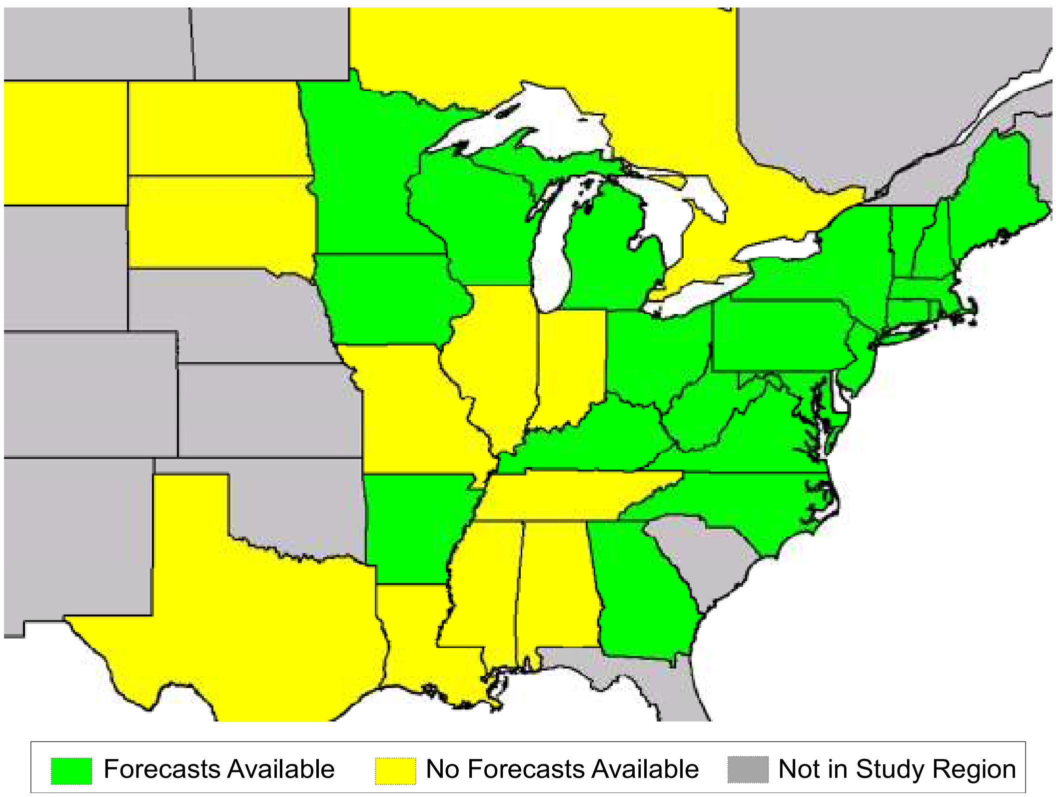
For the *High Gas Demand Scenario*, we assume that the environmental requirements do *not* include any departure from *Reference Gas Demand Scenario* assumptions regarding RGGI or emission allowance prices. The emission allowance prices in the *High Gas Demand Scenario* and the *Low Gas Demand Scenario* are held constant with the *Reference Gas Demand Scenario*.

In the *Low Gas Demand Scenario*, the larger penetration of renewables in the capacity mix track Renewable Portfolio Standard (RPS) requirements. In part, public policy to maintain or strengthen scheduled increases in annual RPS requirements is driven by environmental concerns.

7 RCI GAS DEMAND

LAI's forecasts of LDC gas demands for residential, commercial, and industrial (RCI) customers were derived primarily based on historical pipeline delivery data and public LDC forecasts and Integrated Resource Plans. Figure 8 shows the states where public demand forecasts were available for some or all LDCs. Exhibit 7 lists the forecast filings and other documents collected by LAI for specific LDCs operating in the Study Region.[27]

Figure 8. Availability of Publicly-Filed LDC Demand Forecasts[28]



7.1 Reference Gas Demand Scenario

Using historical pipeline data from 2011 through 2013, LAI first developed annual profiles of demand for LDC and industrial customers within each GPCM location.[29] The seasonal peak

[27] States across the Study Region maintain diverse filing requirements, which may include Integrated Resource Plans, Long-Term Gas Supply Plans, Gas Hedging and Purchase Strategies, Winter Supply Plans, or other filings which embed long-term forecasts. Filings which compare peak day supply and demand, commonly known as "resources and requirements" tables, are useful insofar as they delineate supply sources behind the citygate.

[28] Some state commissions allow for LDCs to keep demand forecast filings confidential. Some state commissions conduct informal meetings regarding procurement practices and portfolio management. LDC filing requirements are generally more comprehensive and, to a limited extent, more transparent in the Northeast, particularly in states that are promoting oil-to-gas conversions.

[29] For LDCs serving local gas-fired generation, generation demand was subtracted from the pipeline deliveries using heat input data from EPA's Clean Air Markets Program CEMS database (http://ampd.epa.gov/ampd/).

days within each year were identified for each pipeline delivery point operator (non-coincident) and for the Study Region as a whole (coincident).[30]

For LDCs which have filed a publicly-available demand forecast, the seasonal peak day information for 2018 and 2023 was either extracted or extrapolated.[31,32] Most LDCs report only an annual peak day, representing the winter peak. In the absence of a forecast for summer load growth rate, LAI applied an LDC's winter load growth rate on a percentage basis to the summer as well in order to account for LDC-specific forecast assumptions, such as customer expansion. For LDCs where no forecast was found to be publicly-available, LAI escalated the 2013 non-coincident peak demands, which were calculated from the pipeline delivery data, using a load growth rate based on the total gas consumption forecast for the residential, commercial, industrial and transportations sectors in the AEO2013 Reference Case. The consumption forecast is differentiated by census division, therefore the load growth rates, shown in Table 2 were applied based on each LDC's or customer's location.

Table 2. *Reference Gas Demand Scenario* RCI Load Growth Rates

	2018		2023	
Census Division	**Total Growth Rel. to 2013**	**Annual Growth Rate**	**Total Growth Rel. to 2018**	**Annual Growth Rate**
New England (CT, ME, MA, NH, RI, VT	2.91%	0.58%	2.55%	0.51%
Middle Atlantic (NJ, NY, PA)	1.41%	0.28%	0.92%	0.18%
East North Central (IL, IN, MI, OH, WI)	0.80%	0.16%	-1.22%	-0.24%
West North Central (IA, MN, MO, ND, SD)	2.67%	0.53%	-0.45%	-0.09%
South Atlantic (DC, DE, GA, MD, NC, VA, WV)	6.19%	1.24%	2.97%	0.59%
East South Central (AL, KY, MS, TN)	2.56%	0.51%	1.29%	0.26%
West South Central (AR, LA, TX)	7.21%	1.44%	3.31%	0.66%
Mountain (MT)	2.93%	0.59%	1.88%	0.38%

[30] In some cases, multiple adjacent delivery point operators were grouped in order to streamline the analysis.

[31] Most LDCs report only an annual winter peak day.

[32] LDC filings generally cover a forecast period from 3 to 5 years. Target 2 research objectives require study parameters to be extended to 2023, a year that is outside the forecast period for most LDCs in the Study Region. LAI has applied the average of the growth rates reported in the demand forecasts over the study period.

Incremental conversion/expansion projects and decremental gas DR/EE initiatives are then combined with the load growth factors to calculate a total non-coincident gas demand forecast for each LDC / industrial customer in 2018 and 2023.[33] A scaling factor calculated from the historical data was then applied to account for the difference between the non-coincident and coincident peak day values. This adjustment is necessary because RCI customers' peak demands do not occur simultaneously across the Study Region, and to simply combine the non-coincident peak forecasts would result in an overestimation of peak day RCI demand. An example scaling factor calculation is shown in Table 3 for Connecticut Natural Gas.

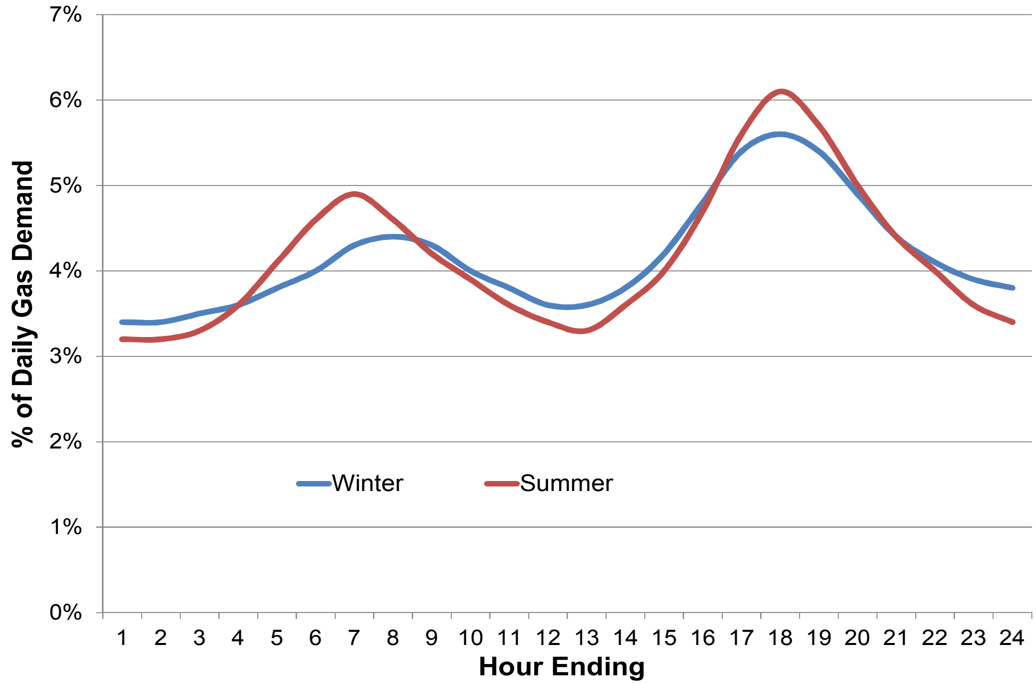
Table 3. Coincident v. Non-Coincident Scaling Factor Calculation

	Winter			Summer		
Year	**Non-Coincident Peak (Dth/d)**	**Coincident Peak (Dth/d)**	**Scaling Factor**	**Non-Coincident Peak (Dth/d)**	**Coincident Peak (Dth/d)**	**Scaling Factor**
2011	263,868	263,868	100%	59,568	48,015	81%
2012	247,314	247,314	100%	85,499	61,415	72%
2013	255,438	220,515	86%	52,487	39,707	76%
Average			95%			76%

LAI will use a peak hour construct in order to test the natural gas infrastructure at maximum utilization. Based on the intraday profiles shown in Figure 9, which were developed using LAI's professional judgment, 5.6% and 6.1% of the daily demand is delivered to customers during the peak hour on a winter and summer day, respectively. These values were then normalized to a daily demand value to be tested in the utilization model by multiplying by 24.

[33] Quantification of gas DR and EE initiatives varies based on the goals of each program, and reported progress to date.

Figure 9. Intraday Seasonal Gas Demand Profiles



7.2 HIGH GAS DEMAND SCENARIO

If an LDC included a lower load growth case in its publicly-filed forecast, LAI used that information. For LDCs without a relevant publicly-available forecast, LAI applied a load growth rate based on the AEO2013 High Economic Growth Case, shown in Table 4.

Table 4. *High Gas Demand Scenario* RCI Load Growth Rates

Census Division	2018		2023		% Change Rel. to EIA Reference Case	
	Total Growth Rel. to 2013	Annual Growth Rate	Total Growth Rel. to 2018	Annual Growth Rate	2018	2023
New England (CT, ME, MA, NH, RI, VT)	4.52%	0.90%	3.82%	0.76%	55%	50%
Middle Atlantic (NJ, NY, PA)	2.70%	0.54%	2.05%	0.41%	91%	122%
East North Central (IL, IN, MI, OH, WI)	2.33%	0.47%	-0.23%	-0.05%	190%	-81%
West North Central (IA, MN, MO, ND, SD)	4.03%	0.81%	0.46%	0.09%	51%	-202%
South Atlantic (DC, DE, GA, MD, NC, VA, WV)	8.18%	1.64%	4.57%	0.91%	32%	54%
East South Central (AL, KY, MS, TN)	4.79%	0.96%	2.85%	0.57%	87%	121%
West South Central (AR, LA, TX)	10.06%	2.01%	5.08%	1.02%	39%	54%
Mountain (MT)	5.14%	1.03%	4.29%	0.86%	76%	129%

7.3 LOW GAS DEMAND SCENARIO

If an LDC included a lower load growth case in its publicly-filed forecast, LAI used that information. For LDCs without a relevant publicly-available forecast, LAI applied a load growth rate based on the AEO2013 Low Economic Growth Case, shown in Table 5.

Table 5. ***Low Gas Demand Scenario*** **RCI Load Growth Rates**

Census Division	2018		2023		% Change Rel. to EIA Reference Case	
	Total Growth Rel. to 2013	Annual Growth Rate	Total Growth Rel. to 2013	Annual Growth Rate	2018	2023
New England (CT, ME, MA, NH, RI, VT	1.52%	0.30%	0.96%	0.19%	-48%	-63%
Middle Atlantic (NJ, NY, PA)	0.54%	0.11%	-0.29%	-0.06%	-62%	-131%
East North Central (IL, IN, MI, OH, WI)	-0.85%	-0.17%	-2.39%	-0.48%	-206%	95%
West North Central (IA, MN, MO, ND, SD)	0.99%	0.20%	-1.35%	-0.27%	-63%	202%
South Atlantic (DC, DE, GA, MD, NC, VA, WV)	4.37%	0.87%	1.24%	0.25%	-29%	-58%
East South Central (AL, KY, MS, TN)	0.28%	0.06%	-0.61%	-0.12%	-89%	-147%
West South Central (AR, LA, TX)	4.04%	0.81%	1.07%	0.21%	-44%	-68%
Mountain (MT)	0.65%	0.13%	0.48%	0.10%	-78%	-75%