DRAFT

FOR SSC DISCUSSION

Proposed Scenario Definition Parameters and Sensitivities

prepared for the

Eastern Interconnection Planning Collaborative

Gas-Electric System Interface Study

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LEVITAN & ASSOCIATES, INC.

100 Summer Street, Suite 3200
Boston, Massachusetts 02110
Tel 617-531-2818
Fax 617-531-2826

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GLOSSARY

AEO	Annual Energy Outlook
BRA	Base Residual Auction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CC	Combined Cycle
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DR	Demand Reduction
DSM	Demand-Side Reduction
EE	Energy Efficiency
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EPA	Environmental Protection Agency
INGAA	Interstate Natural Gas Association of America
IRP	Integrated Resource Plan
LAI	Levitan & Associates, Inc.
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
LRZ	Local Resource Zone
LTRA	Long-Term Reliability Assessment
MATS	Mercury and Air Toxics Standards
NERC	North American Electric Reliability Corporation
NYMEX	New York Mercantile Exchange
PPA	Participating Planning Authority
PRA	Planning Reserve Auction
RCI	Residential, Commercial and Industrial
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SIP	State Implementation Plan
SSC	Stakeholder Steering Committee
STEO	Short-Term Energy Outlook
UCAP	Unforced Capacity
WTI	West Texas Intermediate

Target

One of the four major areas of work described in the revised Statement of Work that will be completed as part of the Gas-Electric System Interface Study. The term "Target" is used rather than goals, tasks, or objectives, which have different meanings in a DOE grant.

PPA Area

The geographic area served by a PPA. This is the portion of the electric transmission system for which the PPA is the Planning Authority. "Area" is used rather than "region" to avoid confusion with Study Region which is defined below.

PPA Stakeholder Group

The assembly of stakeholders created by each PPA to provide input to the PPA on its activities and to fulfill any requirements it may have under FERC Order No. 890. These stakeholders include individuals with interest in electric transmission and electric generation, as well as end users, non-government organizations and representatives from the gas industry. An individual would be a "PPA Stakeholder". "PPA Stakeholder Group" is used rather than "regional stakeholder group".

Study Region

The portion of the Eastern Interconnection electric transmission system that will be considered in the study along with the natural gas pipelines that serve electric generation in that part of the Eastern Interconnection. The collective of the PPA Areas and the natural gas pipelines that supply these areas is included in the study even if an entire pipeline does not fall within the geographic area served by the PPAs.

Task

One of the 12 activities as defined in the original Statement of Project Objectives. Only Tasks 1, 11, and 12 are being revisited as part of the Gas-Electric System Interface Study.

Overview & Schedule

In this report, Levitan & Associates, Inc. (LAI) describes our proposed approach to defining the *Reference*, *High* and *Low Gas Demand Scenarios* for the Target 2, *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 expected market, regulatory, and operating conditions, and then to bracket the range of the probable bandwidth in gas demand for power generation under a consistent set of assumptions that either increases or decreases gas demand for power generation relative to the *Reference Gas Demand Scenario*. In addition, LAI and the PPAs present a preliminary list of sensitivities to be selectively run against the three *Gas Demand Scenarios.* The broad array of sensitivities will reveal the relative importance of various market, regulatory, planning and/or operating factors affecting the demand for natural gas. The approach, formulation of *Gas Demand Scenarios*, and delineation of potential sensitivities are intended for review and feedback from the six Eastern Interconnection Planning Collaborative (EIPC) Participating Planning Authorities (PPAs), the EIPC Stakeholder Steering Committee (SSC), and the PPA Stakeholder Groups. Development of the list of sensitivities will continue into Q1-2014 with input from the SSC and PPA Stakeholder Groups.

This document has been prepared to facilitate the SSC's understanding of the PPAs' and LAI's approach to the formulation of three distinct *Gas Demand Scenarios* to be tested in the Target 2 analysis. Two webinars will be held on December 20th in order for LAI to more fully inform the SSC on the approach, assumptions, and planning process, as well as to answer questions and respond to concerns.

LAI will evaluate three primary *Gas Demand Scenarios*: *Reference, High and Low*. Each of the *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 requirements.[1] The *Reference Gas Demand Scenario* represents a future that reflects a continuation of current market conditions along with changes to these markets that can be reasonably expected based on current knowledge, that is, the forecast which is in accord with EIPC's Roll-up Report. The *Reference Gas Demand Scenario* combines the expected economic, market, and regulatory assumptions characterizing each PPA's resource planning process over the 5-year and 10-year study horizons. Resultant gas burns by power generators will reflect the locations and hourly profiles of natural gas requirements across the Study Region during the Peak Winter Day and Peak Summer Day. For this study, the winter peak generator gas demand is assumed to be coincident with the winter peak RCI gas demand. Driven primarily by increased coal plant attrition relative to the *Reference Gas Demand Scenario* and competitive natural gas-to-coal price parity assumptions, the *High Gas Demand Scenario* represents a

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[1] These two demand sectors are typically referred to as core (RCI gas customers' demand) and non-core (gas-fired electric generation requirements) demand, reflecting the typical character of service distinction, with local distribution companies holding firm gas transportation entitlements to serve RCI / core customers and generation / non-core customers relying on non-firm transportation and secondary markets. Although LAI recognizes that some generators may hold firm transportation entitlements from liquid sourcing points to the station, for purposes of this study all gas-fired electric generation is referred to as non-core.

"plausible maximum" level and profile of natural gas requirements for RCI and generation loads across the Study Region. Driven primarily by the higher delivered natural gas prices, corresponding slow-down in electricity demand growth, and higher-than-expected growth in renewables relative to the *Reference Gas Demand Scenario,* the *Low Gas Demand Scenario* represents a "plausible minimum" level and profile of natural gas requirements across the Study Region.

The three primary *Gas Demand Scenarios* will serve as the foundation for the array of sensitivities to be conducted in response to specific input from the PPAs, the SSC, and PPA Stakeholder Groups. Each sensitivity will be designed to test the impact of changing a single independent variable within one of the three *Gas Demand Scenarios*. In addition, the sensitivities can be combined to test the compounded impacts of changing multiple variables simultaneously.

***Reference Gas Demand Scenario* Definition**

Quantification of natural gas demand for power generation over the study horizon will necessitate use of a bulk power system simulation model. LAI will use the AURORAxmp simulation model licensed by EPIS. AURORAxmp is a chronological production simulation model, which will be used to forecast the consumption of natural gas by generators located in the footprint of the six participating PPA's. AURORAxmp simulates the commitment and dispatch of individual generating units based on the operating characteristics of each unit such as heat rate, fuel and emissions costs and minimum up and down times and ramp rates. For this study, we will use AURORAxmp's transport transmission (zonal) model. The cost of all generation fuels is an integral part of the AURORAxmp simulation modeling effort over the study horizon. In the *Reference Gas Demand Scenario*, the commodity cost of natural gas "into-the-pipe" corresponds to the U.S. Energy Information Administration's (EIA's) Short- and Long-Term Energy Outlook. The forecast of prices for other generation fuels will be taken from the EIA forecasts as well in order to maintain consistent oil-to-gas and gas-to-coal price parity ratios, to the maximum reasonable extent. Quantification of transportation "basis" to key pricing points or hubs across the Study Region will be developed by LAI using the GPCM modeling system.[2] LAI licenses GPCM from RBAC, Inc. to analyze natural gas economics and pipeline operations given the complex interactions among supply areas, storage facilities, pipeline networks, and customer demand – both RCI loads and power generation loads. 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.

<u>Fuel Price Forecasts</u>

LAI's fuel price forecasts will be based on the most recent EIA Annual Energy Outlook (AEO), supplemented by the most recent EIA Short-Term Energy Outlook (STEO) which produces monthly prices for the nearest 12 to 24 months. The longer-term price trends will be based on

[2] GPCM was formerly known as the Gas Pipeline Competition Model, but the licensor no longer uses this long-form convention.

the fuel price forecast trajectory taken from the 2013 AEO to obtain the input fuel prices for the 5-year and 10-year study horizons.

Natural Gas Price Forecast

LAI's forecast of natural gas prices will be based on a forecast of Henry Hub prices, the primary benchmark for natural gas trade in North America. To quantify regional gas prices, basis differentials will be calculated using GPCM. For the *Reference Gas Demand Scenario*, our Henry Hub price forecast will use the STEO forecast of near-term monthly prices at the Henry Hub and utilize the longer price trend from the 2013 AEO. While there are other sensible ways to forecast natural gas prices over the planning horizon, use of the 2013 AEO is a common industry approach, one that will promote standardized fuel prices across six PPAs. Pipeline congestion events periodically causing skyrocketing delivered prices – basis "blowouts" – for brief intervals along discrete pathways will not be incorporated in the *Reference Gas Demand Scenario* in order to quantify the level and profile of gas demand under normal conditions.

Pricing assumptions incorporated in the *Reference Gas Demand Scenario* will be based on the output from the GPCM model. Inputs to GPCM will reflect LAI's interpretation of AEO's forecast of the timing for the addition of new liquefied natural gas (LNG) export facilities. The expected level of LNG exports will cover the Gulf Coast, Atlantic Seaboard, and, if applicable, Atlantic Canada. The 2013 AEO anticipates three LNG export terminals to be in operation by 2024. The Sabine Pass project, already under construction, is forecast to be operational in 2016. Another export project is expected to be commercialized in 2022. At this preliminary juncture, LAI assumes that this will be the Dominion Cove Point facility. LAI assumes that the third LNG export is the Freeport project in Texas coming online in 2024. This forecast results in LNG exports of an average of 0.63 Bcf/d in 2016 reaching 1.2 Bcf/d in 2017, 1.7 Bcf/d in 2022, and 2.3 Bcf/d in 2023.

Use of GPCM will also require the incorporation of specific assumptions about the operating regime of the LNG import terminals across the Study Region. There are five LNG import terminals of relevance: Distrigas Suez, Repsol Canaport, Dominion Cove Point, and two offshore buoy facilities connected to the Algonquin Hubline pipeline segment off the coast of Boston – Excelerate and Neptune. The PPAs will solicit technical information from LNG import terminal owners regarding the amount of LNG they will regasify on a Peak Day in the winter or the summer. Absent technical input from the terminal owners, LAI will rely on historical data and other public information to develop assumptions about terminal operations over the study period. During the heating season, we will assume that regional generators do not enter into firm contracts with LNG terminals for purposes of a secure, peak energy supply.

Unless otherwise informed by Dominion, LAI will assume that Cove Point is primarily used as an import terminal through 2018, after which the terminal will be contractually committed exclusively for exports throughout the remainder of the study horizon. In rare instances, short-term arbitrage between EU and U.S. markets might warrant regasification into Transco or Columbia for brief intervals during cold snaps or outage contingencies.[3]

Oil Price Forecast

For dual-fuel units, oil products are the primary backup fuel when natural gas is not available. The input crude and fuel oil prices will start with the monthly prices taken from the most recent STEO focusing on West Texas Intermediate (WTI), the primary benchmark crude for oil trade in the U.S. Regional refined petroleum product prices will be consistent with the STEO forecast. To the extent that a forecast for any specific regional fuel is not available from the STEO, LAI will develop those prices based on the EIA forecasts of WTI or other relevant fuel and statistical relationships between each product and WTI.[4] Regional fuel oil prices will reflect transportation costs and local market conditions. For the *Reference Gas Demand Scenario*, our WTI and fuel oil product price forecasts will use the STEO monthly prices extended as needed for the out years based on the annual rate of escalation for the specific fuels presented in the 2013 AEO.

Coal Price Forecast

LAI's forecast of coal prices will be based on the long-term trends in prices for each of the coal supply basins of relevance: Central Appalachia, Northern Appalachia, Illinois and Powder River. The prices will be consistent with the STEO and the relevant NYMEX futures prices to supplement the STEO forecasts. For the *Reference Gas Demand Scenario*, the long-term coal prices will be consistent with the AEO Reference Case basin forecasts. LAI will add current transportation costs between the supply basin and major consuming areas, escalated at the rate of inflation, to the basin prices to obtain delivered coal prices for each consuming region.

Nuclear Fuel Price Forecast

LAI's forecast of nuclear fuel prices will be driven by uranium (U_3O_8) prices, which contribute on average 54% of total nuclear fuel costs. Nuclear fuel costs also include the costs of conversion (5%), enrichment (29%) and fabrication (12%).[5] The EIA does not provide any granular forecasts of nuclear fuel prices. Therefore we will develop 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 will start with a forward price curve that provides monthly prices through 2017.[6] This price curve shows prices averaging $36/lb in 2014 increasing to an average of $44/lb in 2017. A number of supply developments are expected to impact prices including planned production increases in Canada, Australia and Kazakhstan. However, the loss of Highly Enriched Uranium supplies and growing demand

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[3] Sensitivities in GPCM may warrant scheduling changes in the liquefaction regime to the extent bottlenecks materialize on one or both pipelines in Maryland.

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

[5] 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.

[6] Globex NYMEX futures prices updated August 16, 2013.

driven by new nuclear plants planned and under construction around the world, particularly in China, will result in prices that are expected to escalate at an average annual rate that is above the general rate of inflation starting in 2014. The escalation rate to be used will be consistent with the AEO forecast assumptions and reflect the slower growth in nuclear construction that has resulted since the Fukushima accident.

Environmental Requirements

Compliance with new environmental requirements under federal (U.S. and Canadian), state, and provincial laws, regulations, and policies, will have significant impacts on wholesale energy and capacity prices, as well as on the fuel mix going forward in the Study Region. In each of the three *Gas Demand Scenarios*, the definition of environmental drivers will directly affect the quantity of unit retirements and the consequent level of natural gas required for power generation by each PPA. Increasingly stringent emissions limits, most notably through the implementation of the Mercury and Air Toxics Standards (MATS), will impact the economics of fossil fuel plants, mostly coal-fired plants. A number of older coal plants have announced retirements rather than investing in retrofitting the emissions controls necessary to comply with MATS. In addition to the emissions requirements associated with the Clean Air Interstate Rule (CAIR) and the replacement for or reinstatement of the Cross State Air Pollution Rule (CSAPR), 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 potential regulation of greenhouse gases on existing fossil units under Section 111(d) the Clean Air Act (CAA), the regulation of cooling water use under Section 316(b) of the Clean Water Act, the U.S. Environmental Protection Agency's (EPA's) review of National Ambient Air Quality Standards, the Coal Combustion Residual Rule, and the Regional Haze rule.

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 retirements within the Province. The *Reference Gas Demand Scenario* will reflect the announced and pending retirement of all of Ontario's incumbent coal generation. Lambton has been shuttered since October 2013, and Nanticoke is expected to follow before the end of the year. The Ontario provincial government recently announced the conversion of the Thunder Bay station, 300 MW, to advanced biomass by 2015. The Atikokan station is in the process of converting to biomass and is expected to return to service in 2014.

The inputs to the electric market simulation model will be focused on reflecting the costs and operating implications associated with the existing state, provincial and federal environmental compliance requirements that are of relevance over the study horizon. Key inputs include assumptions regarding likely emissions control retrofits for existing plants, and forecasts of emission allowance prices.

Emission Allowance Price Forecast

AURORAxmp incorporates NO_x, SO_2, and CO_2 emission rates and applicable emission allowance costs for all fossil fuel units in the model. All allowances, including those which are allocated to generators at no cost and auctioned allowances, will be 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.[7]

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*, LAI's forecast will assume 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 \$45/ton. Seasonal NO_x allowance prices have averaged approximately \$16.75/ton (average of bid-ask spread), and SO_2 allowances have recently held steady at \$1.34/ton.[8] We propose to escalate these emission allowance prices from the 2013 price levels at the annual rate of inflation over the rest of the study horizon.

In the *Reference Gas Demand Scenario* LAI will also assume that the Regional Greenhouse Gas Initiative (RGGI) will persist in its current structure over the study horizon. Prior to 2021, CO_2 allowance prices for fossil generators within the RGGI footprint will be assumed to be equal to the price forecast prepared by ICF on behalf of the RGGI Working Group, as part of the Program Review. LAI has elected to average ICF's forecasts for the 91 million cap Model Rule and an alternative banking sensitivity as the basis of our forecast; after the forecast ends in 2020, we will apply a trendline to the forecast to develop estimates for the remainder of the study horizon.

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*, we will utilize the retirements schedule embedded in the Roll-up Report while noting that a limited number of sensitivities can be run around this *Scenario*. No additional variable operating costs for fossil units will be

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[7] For simplicity, we assume that there is no banking, that is, the allowance is retired in the same year that it is acquired by the regulated generation unit.

[8] Platts *Megawatt Daily*, November 8, 2013.

assumed for the *Reference Gas Demand Scenario*. Similarly, for Ontario the *Reference Gas Demand Scenario* schedule of coal plant retirements is assumed to satisfy all federal 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 assume that other measures will be used to accomplish reduction goals, and in the *Reference Gas Demand Scenario* we will not assign an allowance price for fossil generating units in Ontario.

Mercury

We assume that MATS will survive all legal challenges and remain applicable to emissions of mercury, other toxic metals, and acid gases from coal and oil-fired plants. These rules will require many existing plants to either make significant capital expenditures for emissions controls or retire. 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 would create reliability concerns. We assume that the *Reference Gas Demand Scenario* schedule of coal and oil unit retirements in the PPA's 5 and 10-year resource planning models reflects the decision by those plants that it would be uneconomic to retrofit the necessary emissions control equipment to meet the stringent MATS requirements within the 5-year outlook. We further assume that the variable O&M costs embedded in the PPAs' assumptions underlying the Roll-Up model reflect any incremental costs for activated carbon injection, dry sorbent injection, or comparable controls.

<u>Renewable Portfolio Standards</u>

For the *Reference Gas Demand Scenario*, LAI will incorporate the quantity, technology type and location of the renewable energy resources previously incorporated by the PPAs in the Roll-up Report. LAI may make necessary technical adjustments for the purpose of reconciling the 5- and 10-year resource plans with the tools being used to study gas infrastructure in this analysis.

<u>Load and Generation</u>

The load and generation assumptions for the *Reference Gas Demand Scenario* will be consistent with the PPAs' assumptions underlying the EIPC Roll-up powerflow models for 2018 and 2023 presented to Stakeholders at a December 13, 2013 webinar.[9] Specifically, the load forecasts for

[9] A copy of the associated Roll-up report will be posted at http://www.eipconline.com/Non-DOE_Documents.html. The EIPC Steady State Modeling and Load Flow Working Group prepared the 2018 and 2023 models based on rolling up the individual plans of EIPC members and sufficient analysis of the rolled up plan to ensure simultaneous feasibility of the individually submitted plans. In addition to providing load and resource assumptions for AURORAxmp simulations in the gas/electric study, they will be used in non-DOE scenario analyses planned for 2014.

the planning areas and the assumptions regarding generation additions and retirements will be the same as those used in the Roll-up models.

Generation Unit Retirements

For the *Reference Gas Demand Scenario*, LAI will conform the resource list in the AURORAxmp model to the Roll-up results to account for existing units that were assumed to be idled, mothballed, or retired before the 2018 test year for which the Roll-up model was developed. We assume that retirement, idling, and mothball decisions are consistent with assumptions regarding environmental compliance and fuel price assumptions detailed here for the *Reference Gas Demand Scenario*.

Load and Demand Side Management

For the *Reference Gas Demand Scenario*, load forecast inputs to AURORAxmp will be consistent with the loads underlying the Roll-up model. Loads and resources in AURORAxmp will be revised as necessary to the extent that the loads included in the Roll-up model have been adjusted to represent demand response (DR) / energy efficiency (EE) programs. The load model will be in accord with the Roll-Up model: the PPAs will provide the hourly load shape to LAI, a requirement to AURORAxmp. EE will be modeled as load and energy consumption modifications. For each *Gas Demand Scenario*, LAI will run the peak day in the heating and cooling season for purposes of quantifying generator gas requirements. In consultation with the PPAs, emphasis will be placed on the derivation of DR available during the Peak Heating season. Activation levels of DR during the Peak Heating season are expected to be low relative to the Peak Cooling season, but will correlate with the real time energy market prices.

DR will be represented in AURORAxmp by "virtual generators" dispatched when the price reaches a certain level. The more expensive DR generators will be large enough to ensure there would be some DR to be activated during the winter peak day if the price exceeds their respective strike prices. Incremental DR resources would likely require higher compensation than existing program participants, which is consistent with the modeling assumptions.

<u>Transmission</u>

For the *Reference Gas Demand Scenario*, AURORAxmp will be used in a transport transmission mode. LAI will prepare a set of load zones and associated transfer limits for review by the PPAs. The PPAs will approve or revise the transfer limits such that, in the PPAs judgment, the transfer limits are reasonably consistent with the transmission system represented in the Roll-up model.

<u>Residential, Commercial and Industrial Demand</u>

The level of RCI demand will be combined with the generator gas demands calculated by AURORAxmp and run in the GPCM model to determine total gas demand over the 5- and 10-year study horizons. RCI growth over the Study Period will be accommodated through already-announced pipeline expansions to serve local distribution company (LDC) growth. To the extent that RCI load growth cannot be satisfied through these expansions due to planning horizon limitations, LAI will exercise professional judgment regarding the nature, size and location of incremental pipeline and/or storage deliverability improvements needed to satisfy the unmet demand.[10] Prior studies on factors affecting RCI demand will be reviewed and incorporated where appropriate.[11]

Natural Gas Infrastructure Expansion

For the *Reference Gas Demand Scenario*, LAI will review pipeline expansion projects pending before the U.S. Federal Energy Regulatory Commission, the Canadian National Energy Board, and state / provincial commissions that expand deliveries to LDCs. Based on public information sources and the anticipated information response from pipeline operators,[12] we will review other announced projects to identify those that will be needed to meet RCI demand over the forecast period. Incremental pipeline expansions for the 10-year horizon, which is beyond the standard timeframe for public announcement of planned pipeline expansions, will be treated on a generic basis to meet future LDC demand to serve RCI customers beyond current contract levels (including increments associated with any known expansion projects). Producer and/or LDC-sponsored pipeline expansions that have already been announced may be included in the *Reference Gas Demand Scenario*. Beyond the horizon of announced projects, generic producer-sponsored expansions will be considered among the options for constraint mitigation.

LDC Load Growth to Serve RCI Customers

For the *Reference Gas Demand Scenario*, LAI will rely on the load growth assumptions included in the LDC forecasts filed with the respective state public service commissions, where required. Target 2 research conducted to date confirms the lack of consistency in regard to the availability and content in LDCs' integrated resource plans (IRPs), load forecasting methods, and the building block assumptions used by various LDCs to support their resource plans before the approximately thirty state and provincial regulatory commissions within the Study Region. The forecast period varies across the states that require these filings, but is often less than ten years. Therefore load growth beyond the available LDC reporting period will be extrapolated based on data from the filed forecasts and other public sources. Where LDC forecasts of RCI demand are not available, historical LDC deliveries, adjusted for generator gas usage, will be combined with regional load growth assumptions to develop demand forecasts.[13]

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[10] LDC growth attributable to CNG or LNG fleet conversion may not require new pipeline or storage facility expansion based on the anticipated character of service associated with the refill stations. This issue remains under review and may warrant regional solutions rather than a fixed approach across the Study Region.

[11] For example, FC Gas Intelligence has prepared the "Natural Gas Vehicle Market Whitepaper USA, 2013-2014" and ICF recently completed a white paper for ISO-NE on "Implications of Demand-Side Management Programs for Natural Gas Use in New England."

[12] Direct outreach efforts have commenced to both Interstate Natural Gas Association of America (INGAA) and non-INGAA members serving customer loads in the Study Region.

[13] The demand forecasts are based on the physical throughput on the LDC systems serving RCI customers, regardless of the commercial arrangements made with third-party alternative suppliers under customer choice programs.

LDC Expansion

Emphasis will be placed on plans to expand service territories and customer bases, which have become increasingly common in the Northeast, a region that continues to experience a high saturation of oil and propane use for residential and commercial heating. LAI will review state planning initiatives regarding the expansion of gas service to new areas as well as infill within existing LDC service territories.[14] LAI will review the available LDC load forecasts and expansion project applications filed with state commissions and the Ontario Energy Board, where appropriate, to determine whether both extension and infill initiatives have been incorporated.[15] For the *Reference Gas Demand Scenario*, where expansion programs are not included in LDC filings or are beyond the reporting period for the filings, LAI will add incremental RCI demand to meet the planning targets.

Oil-to-Gas Conversion

Similarly to treatment of LDC expansion, LAI will review planned oil-to-gas conversion programs and determine whether they have been incorporated in the LDC load forecast filings. For the *Reference Gas Demand Scenario*, incremental RCI demand will be added where appropriate to meet expected planning targets.[16] LAI will also rely on LDC IRPs where they are available and other relevant public sources to forecast RCI demand in regard to the penetration of compressed natural gas (CNG) and/or LNG for fleet conversion.

Gas EE / Demand-Side Management (DSM) / DR Programs

Similarly to treatment of LDC expansion and oil-to-gas conversion, LAI will review load reduction programs and determine whether they have been incorporated in LDC load forecast filings, where those filings are available. For the *Reference Gas Demand Scenario*, decrements to RCI demand ascribable to gas-side EE / DSM / DR will be applied where appropriate to meet expected planning targets.

Alternative *Gas Demand Scenarios*

The *High* and *Low Gas Demand Scenarios* represent futures in which one or more of the primary factors driving natural gas demand fall significantly outside of the expected values. 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. Sensitivities will be subsequently developed by changing a single independent variable one at a time, such as substitution of renewables for gas capacity, with the opportunity to compound sensitivities to study multiple factors simultaneously.

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[14] For example, LAI will include the LDC expansion plans included in the 2013 Comprehensive Energy Strategy for Connecticut, which were recently approved by state regulators.

[15] For example, in New York, LAI will review any Article VII applications for significant LDC expansions before the New York Public Service Commission, including those of Con Edison and National Grid.

[16] For example, LAI will compare Con Edison's and National Grid's load forecasts to the timeline for phase-out of heavy heating oils in New York City Department of Environmental Protection regulations.

Key drivers of the *High Gas Demand Scenario* relative to the *Reference Gas Demand Scenario* include: colder-than-average weather, lower delivered gas prices, greater than anticipated retirement of coal, oil, and nuclear units, and higher than anticipated electric demand growth. Other important factors include greater penetration of hybrid and all-electric vehicles, increased penetration of CNG and/or LNG fleet conversions, and increased penetration of RCI oil-to-gas conversions.

Conversely, key drivers of the *Low Gas Demand Scenario* are: milder-than-average weather, higher delivered gas prices, fewer than anticipated retirements or deactivations of coal, oil, and nuclear units, and lower than anticipated electric demand growth, including increased penetration of DR/EE. At this juncture, LAI does not intend to test a significant increase in dispatchable electric-side DR during the Peak Heating season. Many of these factors, in turn, are magnified (or mitigated) by changes to federal, state or provincial environmental regulations, market rules, and technology that may either increase or decrease gas demand.

While the *High* and *Low Gas Demand Scenarios* could be formulated by stipulating to a forecast or future state for a host of gas demand drivers, it would then become difficult to meaningfully interpret the model results; causal relationships would be obscured. On the other hand, it is impractical and illogical to construct the alternative *Gas Demand Scenarios* by varying just one factor – several of the key drivers are correlated. Retirement of coal plants is highly sensitive to changes in natural gas prices. The North American Electric Reliability Corporation's (NERC's) attrition analysis in the 2011 Long-Term Reliability Assessment (LTRA) found that decreasing the Henry Hub natural gas price by $2.00/MMBtu (real $) roughly doubled the MW of predicted coal retirements by 2018.[17] Changing a single factor may yield a change in gas demand that is too small to be significant. Alternative *Gas Demand Scenarios* that reflect an internally consistent but limited set of primary demand drivers are the goal.

Following the SSC webinars on December 20th, stakeholders will have the opportunity to provide written comments, which the PPAs and LAI will take into consideration when finalizing the *Gas Demand Scenario* definitions later in January.

Definition of the *High Gas Demand Scenario*

Fossil Plant Retirements

In addition to the retirements embedded in the *Reference Gas Demand Scenario*, some of the PPAs have identified other potential deactivations and/or mothballed units that are deemed "at risk" due to economic pressure. The additional generation deemed at risk is explained by pressure on the "dark spread" attributable to low natural gas prices as well as the potential incremental capital investment, operating expenses and/or operational limitations associated with environmental compliance requirements.

[17] NERC, 2011 Long-Term Reliability Assessment, November 2011, Table 35, p. 147. http://www.nerc.com/files/2011ltra_final.pdf

The *High Gas Demand* Scenario will incorporate as incremental retirements and deactivations all of the "at risk" generators that are provided by PPAs. For PPA regions where "at risk" generation has not been identified or provided to LAI, LAI proposes to rely on NERC's 2013 LTRA to estimate incremental retirements.[18] This analysis projects a net decrease of approximately 70 GW of coal- and oil-fired generation across the entire NERC region by 2023, due to the combination of final and potential environmental regulations, low natural gas prices, and other economic factors. This study breaks out the capacity as "Planned" and "Conceptual" by fuel type and NERC region. The "Planned" capacity reported by NERC is expected to generally correspond to the known and publicly announced retirements incorporated in the *Reference Gas Demand Scenario*. We propose that the retirements inferred from the tabulation of "Conceptual" capacity by NERC region would then represent the incremental retired capacity for the *High Gas Demand Scenario*.

Because NERC regions do not map exactly to the PPA regions, we will exercise judgment regarding the appropriate spatial adjustments. Since the NERC data only reports aggregate capacity (MW), we will need to identify in the AURORAxmp model the specific units to be retired corresponding to the "Conceptual" total. For each PPA region and within each load zone, we will prioritize incremental retirements based upon several factors: (1) average capacity factor for the last year; (2) age of unit; and (3) whether the unit has selective catalytic reduction and/or flue gas desulfurization.

The characteristics of the known retired units in the *Reference Gas Demand Scenario* will inform the rank ordering of these factors. Importantly, LAI notes that the unit deactivations / retirements assumed in any given PPA region (and load zone therein) are intended to be generic removals of coal-fired capacity, and not a conclusive identification of specific units deemed to be at risk. For this reason, we will not publicly identify specific units that are assumed to be retired in each of the three *Gas Demand Scenarios* despite the operative necessity of incorporating specific assumptions in AURORAxmp.

Generic New Entry

As a starting point, LAI proposes to substitute, on a MW-for-MW unforced capacity (UCAP) basis (to maintain reserve margins), gas-fired capacity for the incremental retirements. The new gas-fired capacity will consist of combined-cycle (CC) units and combustion turbines (CTs) in an appropriate ratio to be determined by LAI.[19] While this assumption does not reflect the resource mix that would be deployed, including renewable generation, it serves to stress the gas system in order to uncover where congestion could occur in the *High Gas Demand Scenario*. To reasonably minimize consequent transmission analysis pertaining to the determination of transfer

[18] NERC, 2013 Long-Term Reliability Assessment, December 2013. http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf

[19] It is outside the scope of this analysis to perform multiple AURORAxmp runs by PPA to determine the blend of CCs/CTs over the study horizon.

capability limits, LAI will assume that the replacement UCAP will be at the same electrical location as the removed capacity for purposes of electric production simulation modeling.[20]

Fuel Prices

LAI will use the relationship revealed by NERC's 2011 LTRA as described on page 11 – a $2.00/MMBtu decrease in natural gas prices doubles coal plant attrition. Based on the relative capacity included in the 2013 LTRA's "Planned" and "Conceptual" capacity groupings, we will reasonably assume that these incremental retirements would be driven by a $1.00/MMBtu decrease in the Henry Hub price over the study horizon, relative to the *Reference Gas Demand Scenario*.[21] Because LAI does not intend to significantly change the WTI benchmark price or, for that matter, the price of ultra-low sulfur distillate or distillate oil over the forecast period, the resultant gas-to-oil parity ratios will change significantly in the *High* and *Low Gas Demand Scenarios*. Additional sensitivities can be performed that hold constant or otherwise modify the gas-to-oil parity ratios.

Similarly, the basin coal price forecast will be held constant in the *High Gas Demand Scenario*, consistent with a squeeze on the "dark spread" that is assumed to be a primary driver for additional coal plant retirements. The dark spread is the difference between the locational energy price and the marginal cost of producing coal-fired energy, including unitized emission allowance costs.[22]

Nuclear fuel prices will be held constant in the *High* and *Low Gas Demand Scenarios*.

Electricity Demand

Based on a review of long-run electricity demand econometric and qualitative studies in the public domain, we will develop assumptions regarding the short-term and long-term relationship between electricity demand and gas prices, summarized as the cross-commodity demand elasticity. That is, the percent change in electricity demand per one percent change in the price of natural gas. If warranted by our findings, we will increase electric demand in the *High Gas Demand Scenario* to reflect an appropriate degree of demand elasticity relative to the *Reference Gas Demand Scenario.*[23]

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[20] Target 2 analysis will include the use of GPCM, thereby revealing constrained versus unconstrained pipeline segments in response to the addition of new gas-fired generation. Second-order feedback effects between GPCM and AURORAxmp are outside Target 2 research objectives.

[21] The $1.00/MMBtu decrease is illustrative at this preliminary juncture. It may be appropriate to use a larger or smaller commodity gas price decrease in order to induce the significant change in gas demand. See https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/AC/2013/20131211/20131211%20AC%20Item%2002%20Phase%20III%20Gas%20Study%20Companion%20Doc.pdf

[22] The marginal cost of producing coal-fired energy includes the delivered cost of coal, plus variable O&M costs, and emission allowance costs. As such the dark spread excludes fixed O&M costs as well as return on investment.

[23] It may be appropriate to incorporate different demand elasticities by PPA, if the share of natural gas on the margin or the pass-through of wholesale energy prices to retail rates varies substantially across the study region.

Residential, Commercial and Industrial Demand

EIA has its own estimates for gas consumption for the RCI, transportation, and power generation sectors by census region (Northeast, Middle Atlantic, *etc*.). LAI will examine the bandwidths between alternative consumption cases for the EIA forecasts and determine appropriate scaling factors relative to the *Reference Gas Demand Scenario* growth rates for each census region. The AEO's "High Oil and Gas Resource" case is one potential forecast to be examined for the *High Gas Demand Scenario*. LAI will also review other public sources to supplement the AEO-based estimates where appropriate. As previously mentioned, the literature and granularity behind LDC forecasts varies significantly. Hence, we will utilize any sensitivities or scenarios available in forecasts, to the extent applicable. Where available, we will review expansion and demand-side filings to determine possible increments or decrements to demand beyond those incorporated in the *Reference Gas Demand Scenario*.

<u>Definition of *Low Gas Demand Scenario*</u>

Fossil Plant Retirements

LAI does not expect to reduce the level of plant deactivations / retirements from that contained in the *Reference Gas Demand Scenario.* To the extent the PPAs designate the reactivation of various mothballed and idled units, such modifications can be incorporated.

Gas Prices

LAI will increase Henry Hub prices by $1.00/MMBtu or more over the forecast period. GPCM will be rerun with the change in commodity prices at the Henry Hub and across various production regions over the Study Region to recalibrate basis.

Electricity Demand

Consistent with the approach described above for the *High Gas Demand* Scenario, LAI will decrease electric demand in the *Low Gas Demand Scenario* to reflect an appropriate degree of demand elasticity relative to the *Reference Gas Demand Scenario*.

New Entry

The *Low Gas Demand* Scenario will include increased renewable resources in lieu of conventional gas-fired generation, coupled with increased electric and, if relevant, gas-side DR/EE. AURORAxmp simulation runs will reflect increased Automatic Generation Control, 10-minute spin and other ancillary services to preserve the requisite operating hedge against intermittency effects. Line pack constraints will be tested in the Target 3 hydraulic models, not GPCM or AURORAxmp. Importantly, there will be no significant increase in dispatchable electric DR during the peak heating season. The combination of an increased renewable penetration rate and increased electric side DR/EE will reduce gas demand in the *Low Gas Demand Scenario*.

In the *Low Gas Demand Scenario*, we will refer to the renewable buildout from the Phase 1 Report - Future 6 – National Renewable Portfolio Standard – Regional Implementation. Future 6 meets 30% of the nation's electricity requirements from renewable resources by 2030 by utilizing a regional implementation strategy. LAI will be modeling these renewable additions only through 2023, not through 2030 as was done in Phase 1 and 2.

RCI Demand

LAI will use scaling factors and/or statistical measures to capture market fundamentals, as discussed above. The AEO's "High Demand Technology" case is one potential forecast to be examined for the *Low Gas Demand Scenario*. We will assume that all RCI demand is met through firm transportation and storage entitlements.

Potential Sensitivities

From the foregoing, LAI and the PPAs wish to put forward for stakeholder consideration a broad array of potential sensitivities that could be tested relative to the *Reference Gas Demand Scenario,* as well as the *High* and *Low Gas Demand Scenarios*. They are presented below for discussion purposes in no particular order. The array of sensitivities oriented around the *Gas Demand Scenarios* can include significant changes to delivered natural gas prices, greater / lesser coal unit attrition, changes in nuclear retirements or availability, hydro-electric generation by wire transmission interchange in New England, New York and Ontario, greater / lesser DR/EE, as well as significant differences in the level, composition, location, and performance of renewable generation. Subject to the constraints of the study schedule and budget, LAI will be prepared to accommodate a reasonable number of suggested sensitivities recommended by the PPAs, the PPA Stakeholder Groups, and the SSC. As noted earlier, sensitivities will be developed by changing a *single independent variable*, and these single-variable sensitivities can then be compounded to simultaneously test multiple variables.

At this preliminary juncture, the following list of potential sensitivities is intended to provide context for the framework of the analysis and as a starting point for the discussion of which sensitivities should be analyzed. It is not a working list of sensitivities that will be run.

i) *Reference Gas Demand Scenario* reflects a significant substitution of renewable energy technology for conventional gas-fired UCAP additions;

ii) *Reference Gas Demand Scenario* reflects a significant substitution of renewable energy technology and DR/EE for conventional gas-fired UCAP additions;

iii) *Reference Gas Demand Scenario* reflects a significant substitution of different renewable energy technology types and locations for conventional gas-fired UCAP additions, including energy storage technologies;

iv) *Reference Gas Demand Scenario* reflects significant delivered natural gas pricing assumptions – either higher or lower – thereby significantly changing both the coal-to-gas and oil-to-gas parity ratios over the study period;

v) *Reference Gas Demand Scenario* reflects material changes to the expected deactivation of coal plants and the retirement and/or the delayed restart of various nuclear units in response to softer-than-anticipated natural gas prices;

vi) *High Gas Demand Scenario* reflects the 25% or 50% substitution of wind / other renewables for new gas-fired combined cycle or gas turbine plants, thereby lowering the gas demand for electric generation, but reflecting a portfolio approach for resource planning purposes;

vii) *High Gas Demand Scenario* reflects the inclusion of additional, unconfirmed coal retirements as well as the retirement of Indian Point 2/3 in the NYCA and potential delays in the anticipated restart of nuclear units being refurbished in Ontario;

viii) *High Gas Demand Scenario* reflects the inclusion of additional unconfirmed coal and nuclear retirements, except in New England where greater than anticipated retirements of oil-fired generation are incorporated as well as the postponement or cancellation of NPT and Maritime Link;

ix) *High Gas Demand Scenario* reflects increased LDC load growth attributable to increased oil-to-gas conversions in major municipal areas and/or higher than anticipated penetration of CNG or LNG fleet conversion programs;

x) *High Gas Demand Scenario* reflects substantially lower delivered commodity gas prices due to technology progress and economics of shale gas production;

xi) *Low Gas Demand Scenario* reflects increased electric-side and gas-side EE/DR penetration, including potential increase in dispatchable gas-side DR during the Peak Heating Season;

xii) *Low Gas Demand Scenario* reflects increased renewable penetration, including potential hydro-electric imports of up to 1,000 MW from Quebec to Ontario, as well as additional hydro-by-wire into New York and New England;

xiii) *Low Gas Demand Scenario* reflects interim fracking moratorium or otherwise draconian environmental restrictions that materially increases wellhead gas prices;

xiv) *Low Gas Demand Scenario* reflects increased renewable penetration rate and, perhaps, a coupling of increased renewables with increased EE/DR penetration;

xv) *Low Gas Demand Scenario* reflects increased LNG exports along the Gulf of Mexico and Atlantic Seaboard;

xvi) *High* and/or *Low Gas Demand Scenarios* reflect the impact of greater economic activity or prolonged economic stagnation, respectively, over the 5 or 10 year period;

xvii) *High Gas Demand Scenario* reflects increased operating reserves and other ancillary services to balance the variable output of large wind and large solar resources on the electric grid.