June 18, 2014

EIPC Gas-Electric System Interface Study
Target 2 First Set of Sensitivity Descriptions and Modeling Assumptions

These sensitivities are summarized in the posted Sensitivity Matrix dated 5/28/14, which can be downloaded at: http://www.eipconline.com/uploads/Combined_Target_2_Sensitivity_List_5-28-14.pdf

NOTE: ALL Sensitivities are run on the updated, or "Prime Case" Scenario(s), as applicable.

Sensitivity 1 – Adjust basis adder to regional natural gas prices to reflect market pricing on a winter peak day, but not the highest (Polar Vortex) day. This change is applied to all three scenarios: Reference Gas Demand Scenario (RGDS), High Gas Demand Scenario (HGDS), and Low Gas Demand Scenario (LGDS).

- Based on a historic winter peak day, selected as January 27, 2014, inflated to 2018 and 2023. For each of 21 Inter-Continental Exchange (ICE) spot gas market trading days in January 2014, this day had highest average of 6 pricing points (Chicago CG, TZ6 NY, Tetco M3, Algonquin CG, Texas Gas Zone 1, and Dawn - one pricing point per PPA).
- Winter Peak Day modeling prices are consistent with observed locational gas pricing. Summer Peak Day may require statistical adjustments in New England to reflect increased basis differentials.
- No changes to each PPA's peak electrical load – using 50/50 electrical load forecast.
- Run AURORAxmp with higher natural gas prices within each of the three Scenarios, all other assumptions stay the same.
- No change to RCI gas demand forecast(s).

Sensitivity 3 – Significantly lower delivered natural gas prices.

- This change will be applied to the RGDS. RGDS to be run in AURORAxmp with same regional natural gas prices as used in the HGDS.

Sensitivity 5a, 5b, and 5c – Deactivate additional coal and nuclear resources and replace their capacity with other types of resources.

- Sensitivity 5a, 5b, and 5c will each be applied to the RGDS.
- Sensitivity 5a - Add the same amounts of wind and solar resource capacity as in the LGDS.
    - Derate coal capacity uniformly across Study Region in 2018 to match the increment of onshore wind and solar capacity (on a UCAP equivalent basis).
    - Derate nuclear capacity uniformly across Study Region in 2023 (in addition to coal deratings from 2018) to match increment of wind and solar UCAP. (UCAP factor for solar is 38%; UCAP factor for wind is 13%; UCAP factor for all thermal resource(s) is 95%)
    - The rationale for deactivating coal resources only in 2018 is that the primary environmental drivers for coal resource retirements will be effective prior to 2018; environmental drivers for nuclear derates are likely to have compliance dates after 2018 (e.g., US EPA 316b rules are triggered only when water permits that are up for renewal,

and even then, permits can be administratively extended through temporary waivers while impact/reliability studies are ongoing.)

- Sensitivity 5b - This sensitivity examines the addition of bulk electric transmission into NYISO and ISO-NE.
    - Add the proposed 1,000 MW Champlain-Hudson Power Express (CHPE) transmission project, from Hydro Quebec and terminating in New York City at the Astoria power plant, and the proposed 1,000 MW Clean Power Link (CPL) transmission project, from Hydro Quebec and terminating in Ludlow, VT, near the Vermont Yankee nuclear power station.
    - Both proposed transmission projects assume an in-service date (ISD) prior to the 2023 study year (but after the 2018 study year), so this sensitivity will only be run for the 2023 study year.
    - The assumed summer capacity factors for both of these proposed transmission projects are 100% for on-peak hours and 75% for off-peak hours. Winter capacity factors for both of these proposed transmission projects are 60% for on-peak hours and 40% for off-peak hours. These schedules will be modeled as fixed injections to NYISO – Zone J and ISO-NE – ROS.
    - Correspondingly to the proposed transmission projects ISD, LAI will derate the UCAP-equivalent amounts of coal and nuclear capacity within both ISO-NE and NYISO (equivalent to 1,000 MW ICAP within each PPA).

Sensitivity 5c - This sensitivity examines an increase of energy efficiency (EE).

- To emphasize the impacts on electric sector gas consumption during the winter peak days, this sensitivity is modeled as a system-wide increase in EE rather than a mix of EE and dispatchable demand response (DR). EE will be modeled as a *pro rata* reduction to electrical load across the Study Region, totaling 3,000 MW for the summer 2018 and 6,300 MW (cumulative) for the summer 2023 peak periods. Since the PPAs' forecast of EE is already included in the RGDS load forecast, the increment for Sensitivity 5c is intended to be a feasible "stretch" over that already incorporated in the RGDS. Thus, the incremental EE quantity is assumed to be 1.4%, slightly more than the incremental EE (1.2%) projected by the NERC *2013 Long-Term Reliability Assessment*, which matches the forecast within the 2009 EPRI report entitled *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010-2030).*
- Correspondingly, LAI will derate coal resources in 2018 across the Study Region on a UCAP equivalent basis relative to the 3,000 MW EE plus 15% reserve margin. LAI will also derate nuclear resources in 2023 across the Study Region on a UCAP-equivalent basis relative to the incremental 3,300 MW of EE plus 15% reserve margin.

<u>Sensitivity 9</u> – All Ontario nuclear units that are scheduled to be refurbished in the RGDS, instead retire when they reach their end of life between 2018 and 2023. Indian Point #2 & #3 in NYISO retires by the

end of 2015. The HGDS is the starting point for the nuclear unit retirement assumptions. This sensitivity is only applied to the HGDS.

- IESO nuclear units that are scheduled for refurbishments, retire instead of returning to service. Only 2 nuclear units (Bruce #1 & #2) will remain in IESO by 2023.
- NYISO Indian Point nuclear units #2 and #3 are retired prior to the 2018 study year.
- Nuclear capacity that is deactivated in NYISO is replaced by 1,000 MW of generic gas-fired combined-cycle (CC) units in Zones G-H-I in 2018, with additional generic gas-fired capacity added for load growth in 2023. Nuclear capacity deactivated within IESO is replaced by a UCAP equivalent of generic gas-fired CCs, in the same IESO Zones where the nuclear units were located.

Sensitivity 13 – Increased infrastructure to enable additional Marcellus/Utica natural gas flows into neighboring PPAs. This sensitivity is applied to the RGDS.

- This sensitivity will initially be run without changing the gas price forecast.
- In a second iteration to be performed in July, revised gas prices resulting from the additional gas flows will be derived from GPCM, and then run as AURORAxmp inputs to produce new electric generation gas burns.
- LAI is including the specific Marcellus projects which have been announced but did not meet the 2-prong test criteria set forth for inclusion within the three Scenarios. This is the set of infrastructure projects that was presented at the May 7th SSC webinar, and refined based on stakeholder feedback. There are gas infrastructure projects impacting all of the PPAs.
- No change to RCI gas demand forecast or the PPA electric demand forecasts.

Sensitivity 14 – Increased underground gas storage deliverability. This sensitivity is applied to the RGDS.

- This sensitivity will initially be run without changing the gas price forecast.
- In a second iteration to be performed in July, 2014, revised gas prices resulting from the change to storage deliverability will be derived from GPCM, and then run as AURORAxmp inputs to produce new electric generation gas burns.
- In GPCM, increase gas storage deliverability and pipeline header capacity to/from existing underground storage facilities is increased by 10% across the Study Region by 2018.
- Increased gas storage deliverability reflects both FERC jurisdictional and state / provincial facilities.
- No change in either the RCI gas demand forecasts or the PPA electric demand forecasts.

Sensitivity 16 – Increased LNG sendout from Canaport and Distrigas LNG import terminals. This sensitivity is applied to the RGDS.

- This sensitivity will initially be run without changing the gas price forecast.
- In a second iteration to be performed in July, 2014, revised gas prices resulting from the additional gas flows will be derived from GPCM, and then run as AURORAxmp inputs to produce new electric generation gas burns.
- Assume north-to-south flows on the Maritimes and Northeast (M&N) pipeline = 850 MMcf/d
    - Adjust for net of Sable Island / Deep Panuke production exports at Baileyville, Maine

  - Regasification from the Canaport LNG terminal accounts for the difference between the two flows
  - No change in the RCI gas demand forecast or the PPA electric demand forecasts.
- Assume increased regasification from the Distrigas LNG terminal into the Tennessee Gas Pipeline (TGP) and the Algonquin Gas Transmission System (AGT) based on 2011 winter peak day sendout.
  - ~240 MDth/d into the medium pressure of AGT
  - ~116 MDth/d into the high pressure system of TGP
  - No change in regasification quantities to directly serve the New Mystic station
  - No change in the RCI gas demand forecast
  - No change in LNG truck transported liquids to LDCs

Sensitivity 18 – High Electric Load Growth. This sensitivity is applied to the RGDS.

- Starting with RGDS, replace the electric load forecast with load forecast from HDGS (differentiated by Zone.) The HGDS electrical load forecast uses multipliers differentiated by Zone based on electricity sales by census division as obtained from the U.S. -EIA AEO13 High Economic Growth Case.
- Increase PPA resources to serve the increase electrical demand (by PPA) by adding generic CCs of UCAP equivalent to achieve a 15% reserve margin across each PPA by matching electrical load growth in each Zone.
- No change to the RCI gas demand forecast.

Sensitivity 19 – High industrial natural gas demand. This sensitivity is applied to the RGDS.

- This sensitivity will initially be run without changing the gas price forecast.
- In a second iteration to be performed in July, 2014, revised gas prices resulting from the increased industrial demand will be derived from GPCM, and then run as AURORAxmp inputs to produce new electric generation gas burns.
- Use the R/C/I ratios from GPCM to separate out the industrial demand within each gas customer (GPCM location) and then scale upward based upon the U.S. EIA - AEO13 High Economic Case industrial sector growth rate for each census division, applicable to GPCM customer locations.
- The increase in industrial demand is differentiated locationally by GPCM location.
- No change to each PPA's electric load forecast.

Sensitivity 30 – Dual fuel units run only on their backup fuel (generally liquids), instead of natural gas. Dual fuel coal/gas units run only on coal. This sensitivity is applied to the RGDS and HGDS.

- Force dual fuel units to burn oil (or coal, if applicable) by omitting their gas fuel capability.
- Make no change to regional fuel prices.
- Evaluate on both winter and summer peak days, study year 2018 only.