EIPC

Eastern Interconnection Planning Collaborative

EIPC Gas-Electric Study

Scenario Definitions and Sensitivities

A Detailed Perspective

Stakeholder Steering Committee

December 20, 2013

LEVITAN & ASSOCIATES, INC.

MARKET DESIGN, ECONOMICS AND POWER SYSTEMS

Acknowledgement and Disclaimer

The EIPC appreciates and acknowledges the support of DOE for the Eastern Interconnections Studies Project

Acknowledgement:

- This material is based upon work supported by the Department of Energy, National Energy Technology Laboratory, under Award Number DE-OE0000343.

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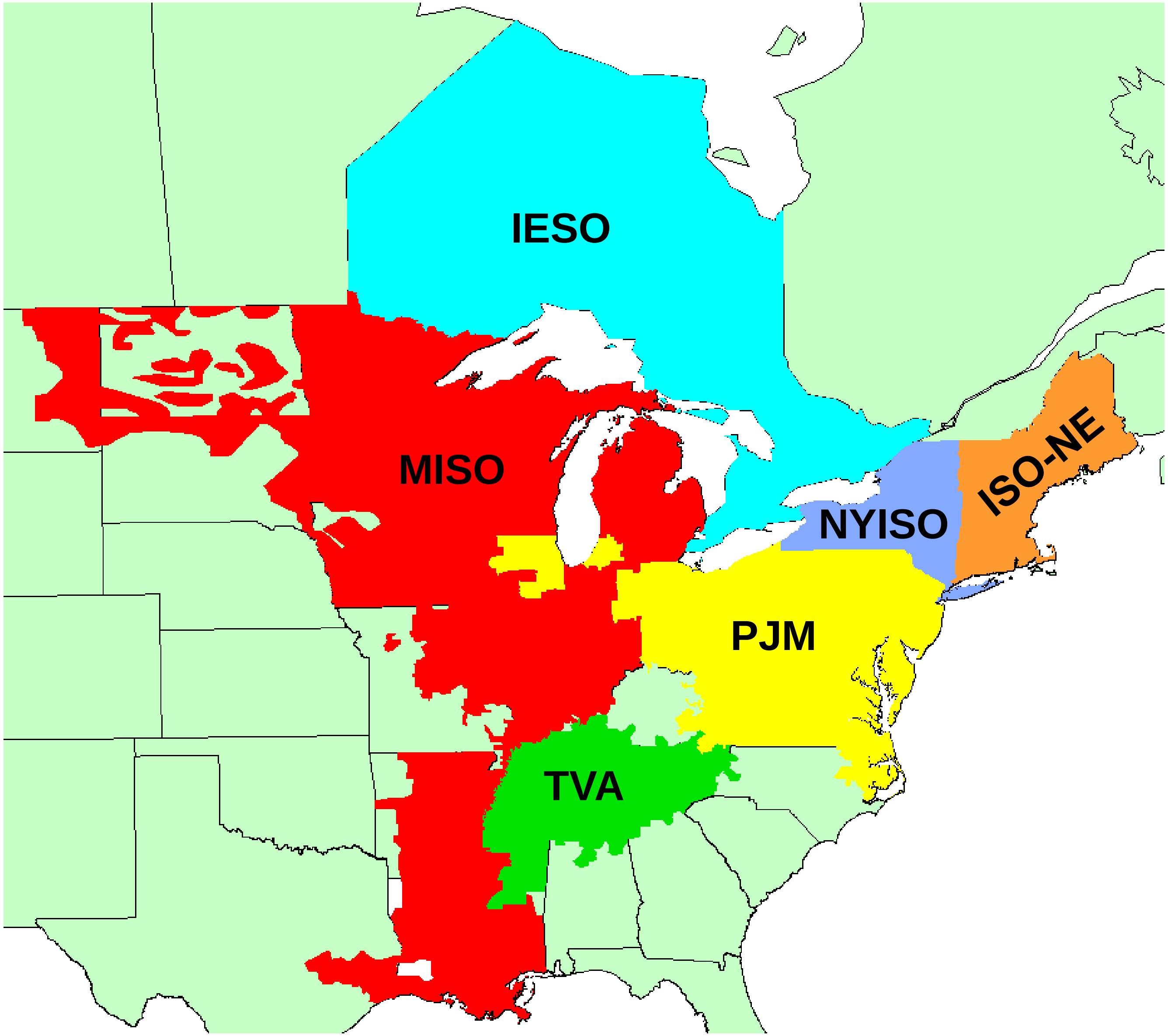
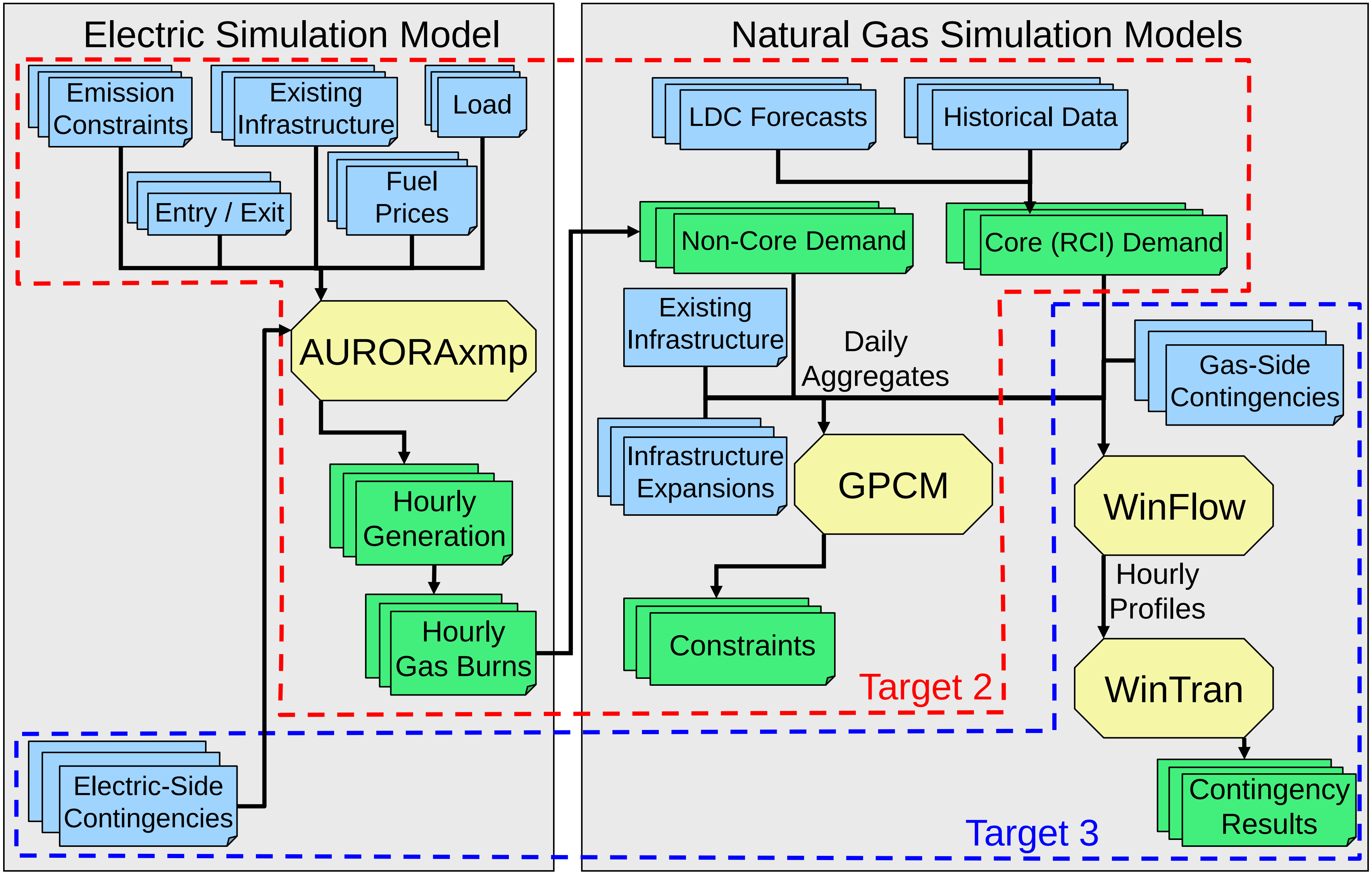
Study Region

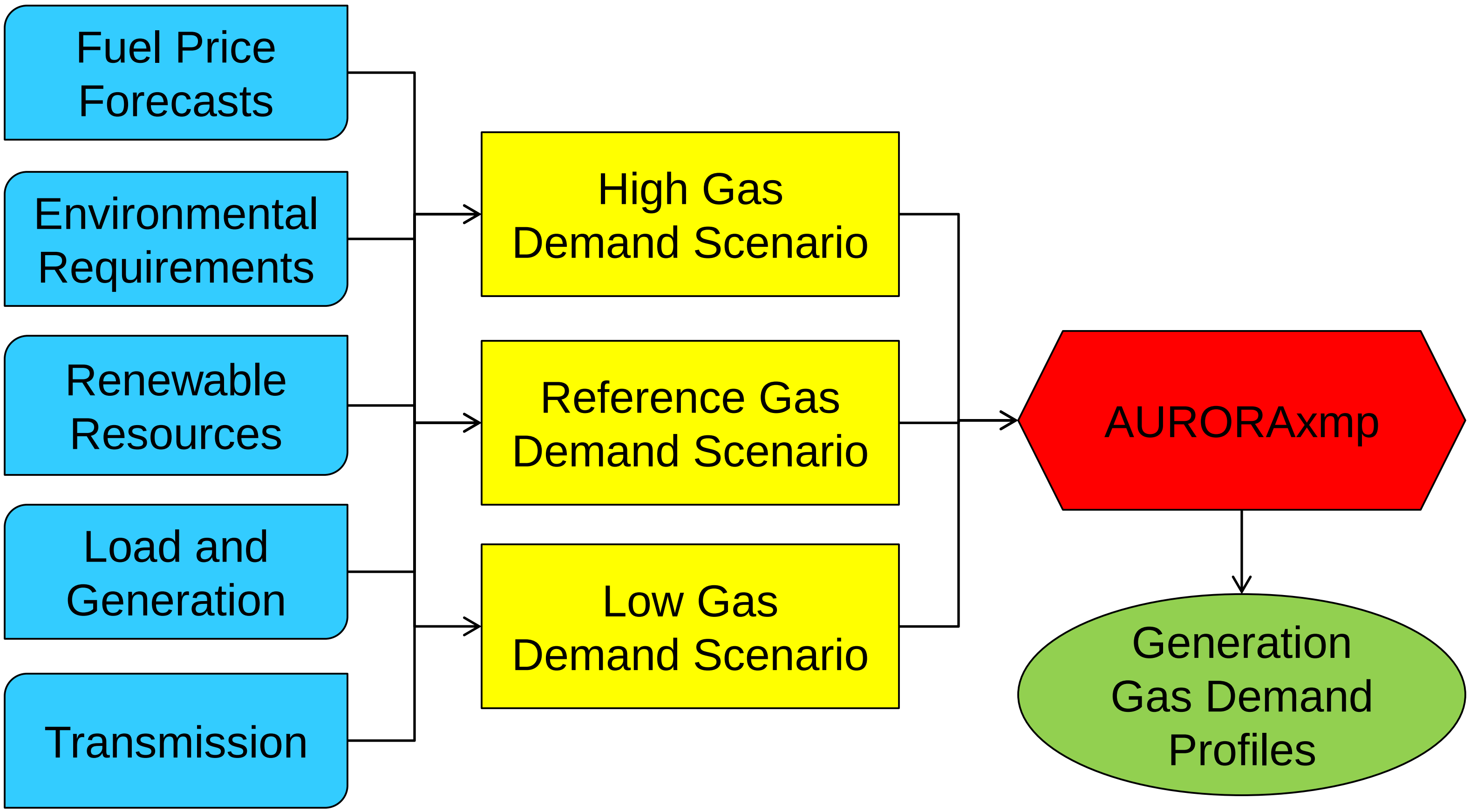


Modeling System Interactions



Reference Gas Demand Scenario

Modeling Systems Overview – Electric-Side



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Fuel Price Forecast – Natural Gas

- GPCM inputs for basis differential calculations based on STEO / AEO Henry Hub forecasts
- Average monthly prices used in simulation model to avoid oil substitution during congestion events
- LNG Export Terminals
  - AEO: Three export terminals operating by 2024
  - Sabine Pass (2016), Cove Point (2022), Freeport (2024)
- Operating regime of LNG terminals based on operator input (if available) or historical data and public forecasts

Fuel Price Forecast – Other Fuels

- Oil Price Forecast
  - STEO monthly prices extended over study horizon based on AEO escalation rate
  - Crude: WTI
  - Other products based on statistical relationship to WTI plus regional basis
- Coal Price Forecast
  - Central Appalachia, Northern Appalachia, Illinois and Powder River Basins
  - Current transportation costs escalated at inflation to calculate consuming region delivered prices
- Nuclear Fuel Price Forecast
  - Based on NYMEX U_3O_8 futures
  - Escalation rate consistent with AEO assumptions

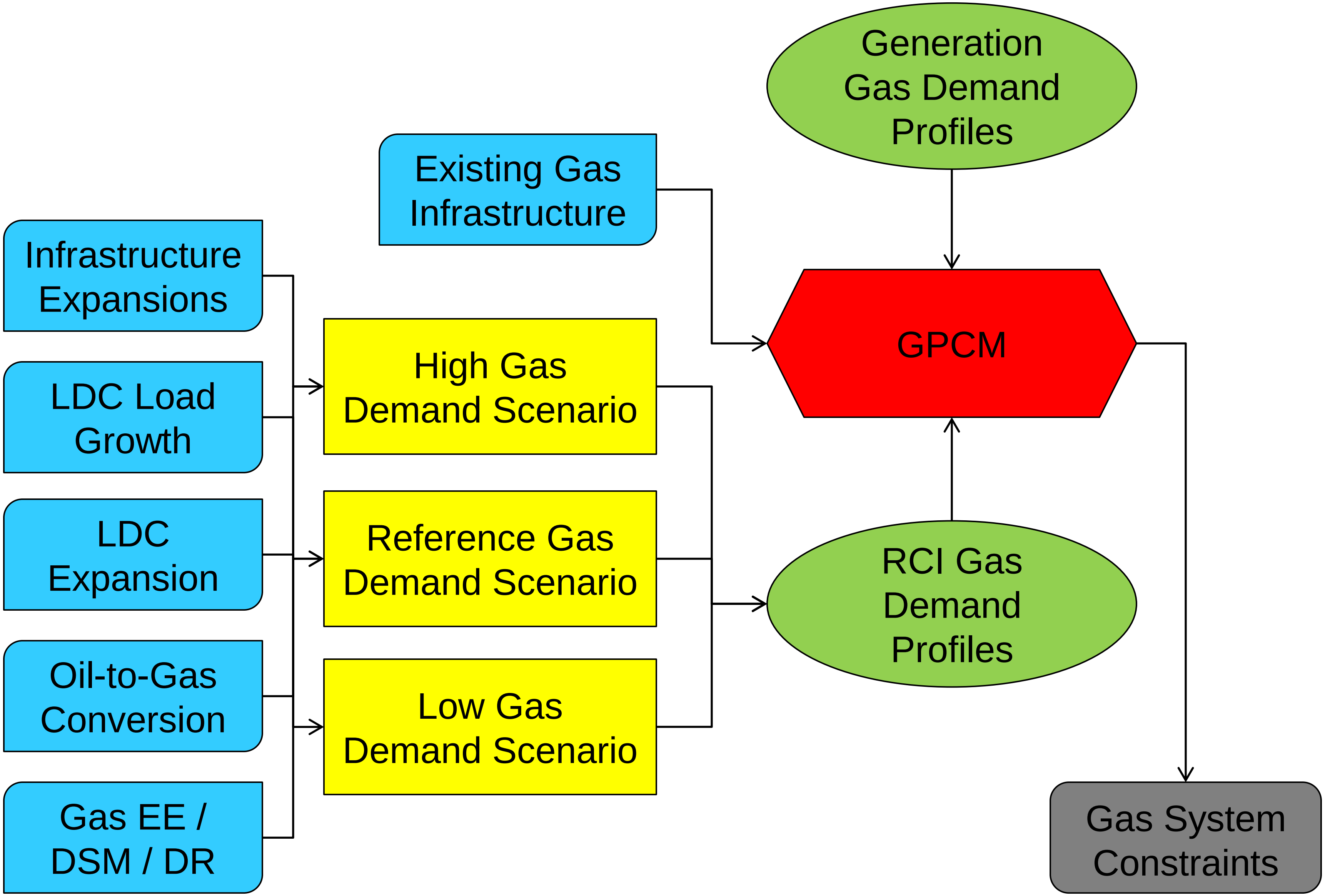
Environmental / Emissions

- Emission Allowance Price Forecast
  - NO_x and SO_2 emission allowances remain continuation of CAIR, state programs
  - Allowance prices escalated from 2013 trading levels
    - Ann. NO_x: $45/ton / Seas. NO_x: $16.75/ton / SO_2: $1.34/ton
- RGGI will maintain current footprint
  - Through 2020 allowance prices based on ICF study
  - After 2020 based on ICF forecast trendline
  - Assume Ontario GHG reduction goals will not entail allowance program
- Assume MATS will survive legal challenges

Generation and Transmission

- Retirements consistent with Roll-up Report
  - Existing units consistent with Roll-up Report
  - Retirement, idling and mothball decisions also reflected according to regional practices
- Renewable resources consistent with Roll-up Report
- Electric DR represented by “virtual generators”
  - DR activation levels very low in heating season relative to cooling season
- Transmission system representation consistent with Roll-up Report
  - Seasonal transfer limits prepared by EIPC Technical Committee

Modeling System Overview – Gas-Side



RCI Demand

- Natural Gas Infrastructure Expansions
  - Projects serving LDCs reviewed for inclusion
  - Additional generic expansions added to meet LDC demand beyond existing / expansion contract levels
- LDC Load Growth
  - Starting point will be LDCs' filed load forecasts / IRPs
  - Locational granularity increased based on pipeline data
  - Pipeline data also used to support forecast development where load forecasts not available
- State Planning initiatives related to LDC expansion, oil-to-gas conversion and gas EE/DSM/DR compared to load forecasts
  - Programs not included in forecasts will be added to the filed forecast demand growth rates

High Gas Demand Scenario

Fossil Plant Retirements and New Entry

- Incremental "at risk" generators identified by PPAs
  - Alternatively based on "Conceptual" retirements in NERC's 2013 NERC LTRA
    - Units selected for deactivation generically based on average capacity factor, age, emissions reduction equipment
  - Only aggregate data will be reported
- Deactivated units replaced MW-for-MW by a mix of gas-fired CCs and CTs
  - At same location to simplify transmission analysis
  - Ratio of CCs/CTs determined by LAI
  - Assumption designed to stress the gas transportation network

Fuel Price Forecast and Electricity Demand

- Henry Hub prices decreased by $1.00/MMBtu or more over study period relative to *Reference Gas Demand Scenario*
  - Based on NERC 2011 LTRA finding that $2.00/MMBtu decrease in gas prices doubled coal plant attrition
  - Price decrement illustrative at this stage, may be adjusted
  - GPCM will be run to recalibrate basis
- Price forecasts for other fuels not changed
  - Oil-to-gas and coal-to-gas parity ratios will increase
- Electric demand increased to reflect demand elasticity associated with lower gas prices
  - Based on existing public long-run studies
  - May vary by PPA

RCI Gas Demand

- Regional scaling factors on growth rates will be based on alternative AEO cases, *e.g.*, the "High Oil and Gas Resource Case"
- Alternative forecast cases presented in LDC filings and prior regional studies will also be considered

Low Gas Demand Scenario

Fuel Price Forecast and Electricity Demand

- Henry Hub prices increased by $1.00/MMBtu over study period relative to *Reference Gas Demand Scenario*
  - Price increment illustrative at this stage, may be adjusted
  - GPCM will be run to recalibrate basis
- Price forecasts for other fuels not changed
  - Oil-to-gas and coal-to-gas parity ratios will decrease
- Electric demand increased to reflect demand elasticity associated with lower gas prices
  - Based on existing public long-run studies
  - May vary by PPA

New Entry

- Increased renewable penetration rate will reduce gas entry
  - Renewable buildout based on EIPC Phase I Future 6 / Phase II Scenario 2
  - 30% renewable resources nationwide by 2030 – scaled to 2023
- Electric simulation will reflect increased ancillary services to accommodate renewable intermittency effects

RCI Gas Demand

- Regional scaling factors on growth rates will be based on alternative AEO cases, *e.g.*, the "High Demand Technology Case"
  - Accounts for increased gas DR/EE
- Alternative forecast cases presented in LDC filings and prior regional studies will also be considered

Potential Sensitivities

Array of Case Sensitivities

- Applied to one or more of the three Scenarios
- Developed by changing a single independent variable
- Multiple sensitivities could be combined to test multiple factors simultaneously
- Suggested factor variations should represent relatively small excursions around key uncertainty factors rather than paradigm shifts

Reference Gas Demand Scenario

- Significant substitution of renewable energy technology for conventional gas-fired UCAP additions
- Significant substitution of renewable energy technology and electric DR/EE for conventional gas-fired UCAP additions
- Significant substitution of different renewable energy technology types and locations for conventional gas-fired UCAP additions, including energy storage
- Significantly higher or lower delivered natural gas prices
- Material changes to the expected deactivation of coal plants and the retirement and/or the delayed restart of various nuclear units

High Gas Demand Scenario (1)

- 25% or 50% substitution of wind / other renewables for new gas-fired combined cycle or gas turbine plants
- Inclusion of additional coal retirements plus the retirement of Indian Point 2/3, a significant delay in the anticipated restart of nuclear units in Ontario
- Inclusion of additional coal and nuclear retirements – oil retirements in New England, plus the postponement / cancellation of NPT and/or Maritime Link

High Gas Demand Scenario (2)

- Increased LDC load growth attributable to increased oil-to-gas conversions (including fleet conversions)
- Substantially lower delivered commodity gas prices due to technology progress and shale gas economics
- Greater economic activity over the 5- or 10-year period

Low Gas Demand Scenario (1)

- Increased electric-side and gas-side EE/DR penetration, including potential increase in dispatchable gas-side DR during the Peak Heating Season
- Increased renewable penetration, including 1000 MW of hydro imports from Quebec to Ontario and additional hydro-by-wire into New York and / or New England
- Stringent environmental restrictions that materially increase wellhead gas prices in shale producing basins

Low Gas Demand Scenario (2)

- Increased renewable penetration rate coupled with increased EE/DR penetration
- Increased LNG exports along the Gulf of Mexico and Atlantic Seaboard
- Prolonged economic stagnation over the 5- or 10-year period