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2018 Market Efficiency Process Scope and Input Assumptions

Scope

Market Efficiency Analysis is performed as part of the overall Regional Transmission Planning Process (RTEP) to accomplish the following objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated or modified.

2. Identify new transmission upgrades that may result in economic benefits.

3. Identify economic benefits associated with modification to reliability-based enhancements already included in the RTEP that when modified would relieve one or more economic constraints. Such enhancements, originally identified to resolve reliability criteria violations, may be designed in a more robust manner to provide economic benefit as well.

Market Efficiency analysis is conducted using a market simulation tool which models the hourly security-constrained commitment and dispatch of generation over a future annual period. Economic benefits of transmission upgrades are determined by comparing results of simulations which include the study upgrade to results of simulations which do not include the study upgrade. Market simulations will be made for the following years: 2019, 2023, 2026, and 2029. A forecast of annual benefits for years beyond 2029 will be based on an extrapolation of the year 2019, 2023, 2026 and 2029 simulation results. Market simulations may be performed for year 2033 to validate the extrapolation results.

Market Simulation Model and Input Assumptions

The primary analytical tool used in this analysis is PROMOD IV from ABB. PROMOD is a production costing software application which simulates the hourly commitment and dispatch of generation to meet load while recognizing and maintaining transmission system security limits. The underlying source of PROMOD data is from ABB's Simulation Ready Data which initializes the PROMOD database. The data includes generating units and generating unit characteristics, fuel costs, emissions costs, load forecasts, and a power flow case. The base data for this analysis is from the Fall 2017 base case release with ABB fuel and emission updates consistent with a May 2018 release. ABB provides monthly gas forecast updates. The base data includes the August 2018 gas forecast update. PJM does modify key aspects of ABB's base release to make it more appropriate for RTEP Market Efficiency evaluation. These items would include an update of the power flow case, generation modification because of additional queued units and announced retirements, and using the latest load forecasts.

Fuel Cost

The PROMOD database contains a fuel cost forecast for each fuel type. The forecast prices for each fuel are developed by the ABB fuels group. For gas and oil, the prices are derived from a combination of NYMEX forward prices and a fundamental forecasting model. ABB's coal forecasting model uses numerous factors such as mining costs, transportation routes and pricing, and coal quality to derive a coal forecast. The resulting coal price forecast is on a plant specific delivered basis.

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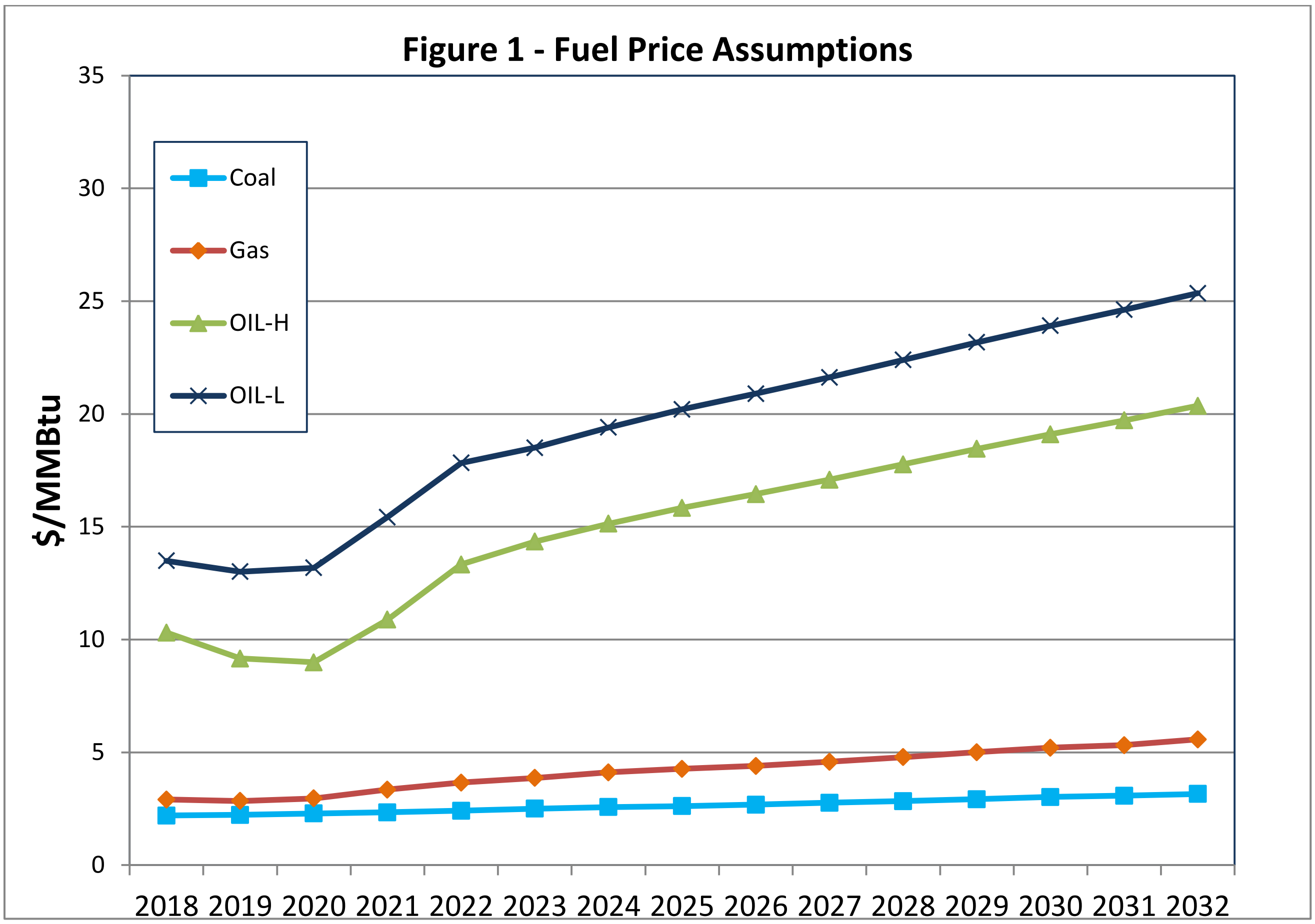
Figure 1 shows the average annual forecast values for light oil, heavy oil, natural gas, and coal. The natural gas prices depicted are representative of the commodity cost. PROMOD uses basis adders to capture the gas transportation costs of the commodity to the different PJM zones. The oil prices are representative of burner tip prices and are the same throughout PJM. The coal prices in Figure 1 are the average of each PJM coal plant's burner tip price. The PROMOD coal price forecast is on an individual plant specific delivered basis.



Load and Energy

Load and energy forecasts for the PJM RTO were developed by PJM's Resource Adequacy Planning Department and released in the January 2018 PJM Load Forecast Report. Table 1 shows the annual PJM peak and energy forecast that provides the basis for load input into the simulation.

Table 1 - 2018 PJM Peak Load and Energy Forecast

Load	2019	2023	2026	2029	2033
Peak (MW)	152,479	153,632	155,724	158,624	162,095
Energy (GWh)	809,000	816,817	828,788	845,058	864,236

Demand Response

Table 2 shows the level of demand response resource available for each of the Market Efficiency study years. The values are consistent with the 2018 Load Forecast Report.

Table 2 - 2018 PJM Demand Resource Forecast

	2019	2023	2026	2029	2033
Demand Resource (MW)	9,113	7,747	7,862	7,989	8,179

PJM Generation

Figure 2 shows a comparison of the assumed generation capacity within PJM's footprint to the projected peak net internal demand with reserve margin for two separate scenarios. The first scenario, represented by the purple line, includes capacity that is in-service plus active queue generation with not suspended Interconnection Service Agreements (ISA) minus announced future deactivations. The second scenario, represented by the green line, includes capacity that is in-service generation plus active queue generation with Interconnection Service Agreements (ISA) and those in the Facility Study Agreement phase minus announced future deactivations.

The net internal demand is consistent with the 2018 PJM Load Forecast Report and equates to the PJM Summer unrestricted peak forecast minus the projection of load management placed under PJM control. In either scenario, the simulated capacity is more than adequate to cover the reserve margin for the duration of the Market Efficiency study period.

Note: The generation expansion will be updated to exclude FSA and Suspended ISA generators if FERC approves the MEPETF changes endorsed by Members Committee on September 27th 2018.

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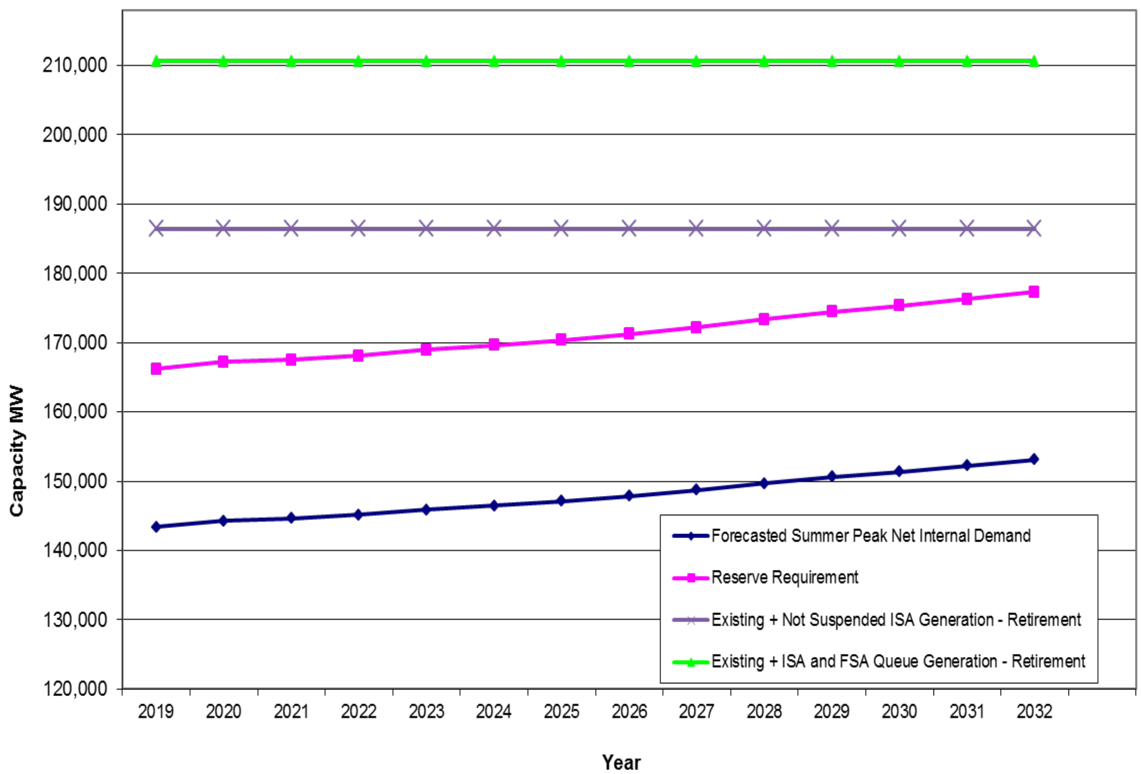
Figure 2 - PJM Market Efficiency Reserve Margin (with Uniform Expansion)



Note: Generation Includes existing and projected PJM internal capacity resources.
Model informed by 2023 Machines List.

Emission Allowance Price

The PROMOD database models three (3) major effluents: SO_2, NOx, and CO_2. Effluents (by trading program) are assigned to generators based on generator location and release rates are from a variety of sources including EPA CEMS data and the forecasted fuel used. ABB uses a proprietary Emission Forecast Model (EFM) to simulate emission control decisions and results simultaneously in the three cap-and-trade market price forecasts (SO_2, NOx Annual, NOx Seasonal). Ventyx uses a CO_2 emission forecast based on analysis associated with several legislative proposals.

Forecasts for SO_2 and NOx now reflect legislation associated with the Cross State Air Pollution Rule (CSAPR). CSAPR results in a more stringent requirement than the previous Clean Air Interstate Rule (CAIR). However, other requirements combined with low gas prices and subsequent coal retirements have resulted in a very low marginal cost of compliance. Figure 3 and Figure 4 show graphs of SO_2 and NOx prices assumed in the Market Efficiency base case.

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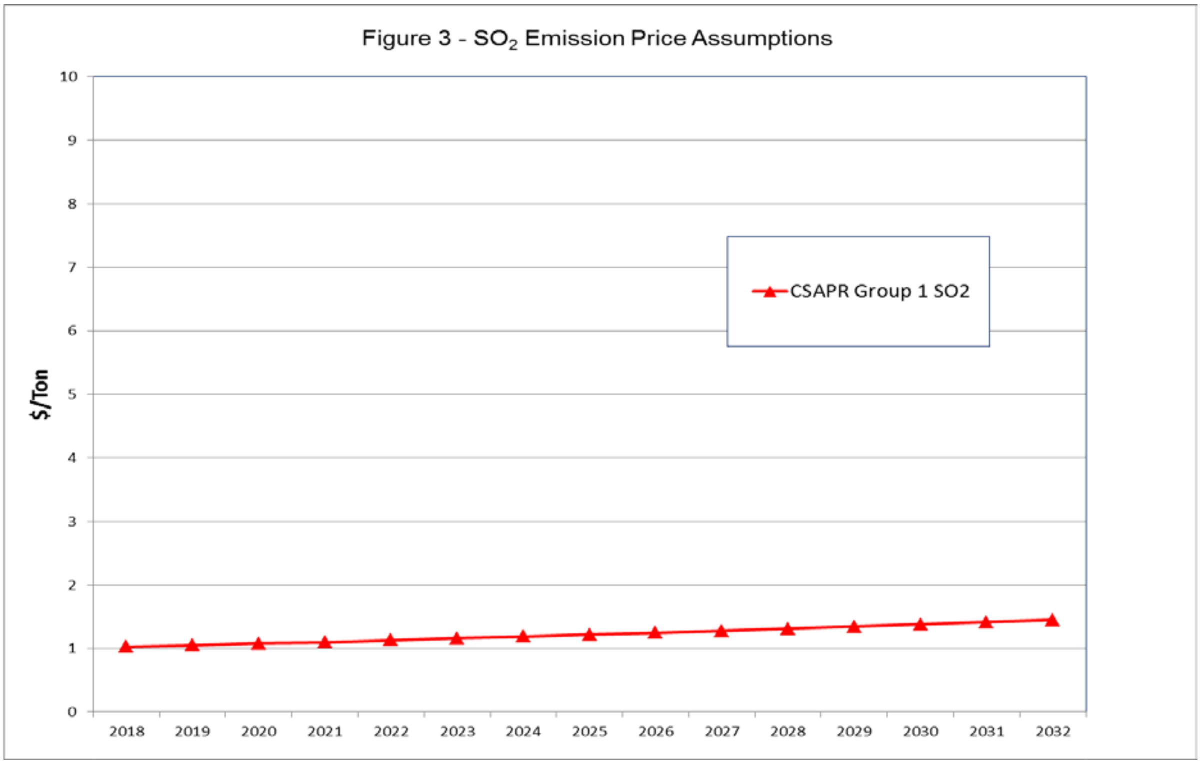

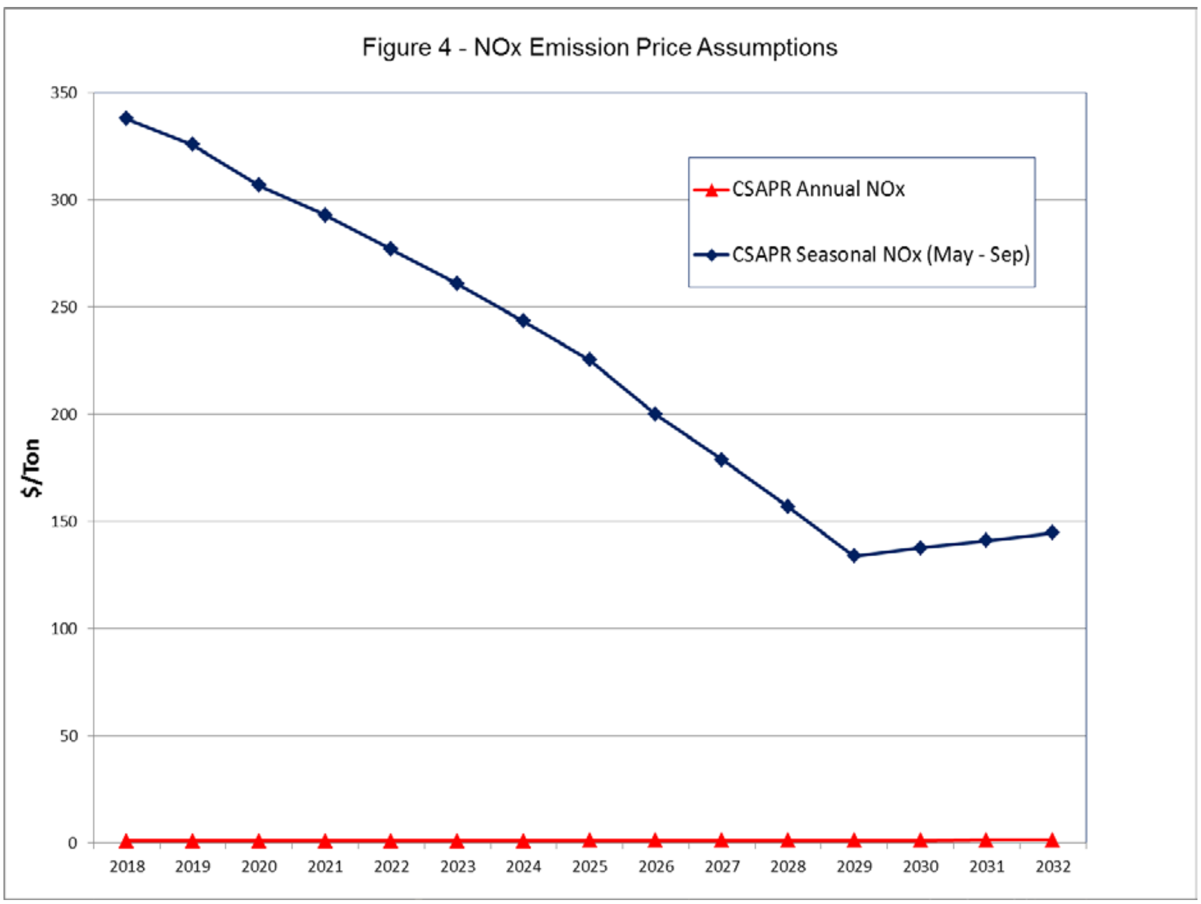

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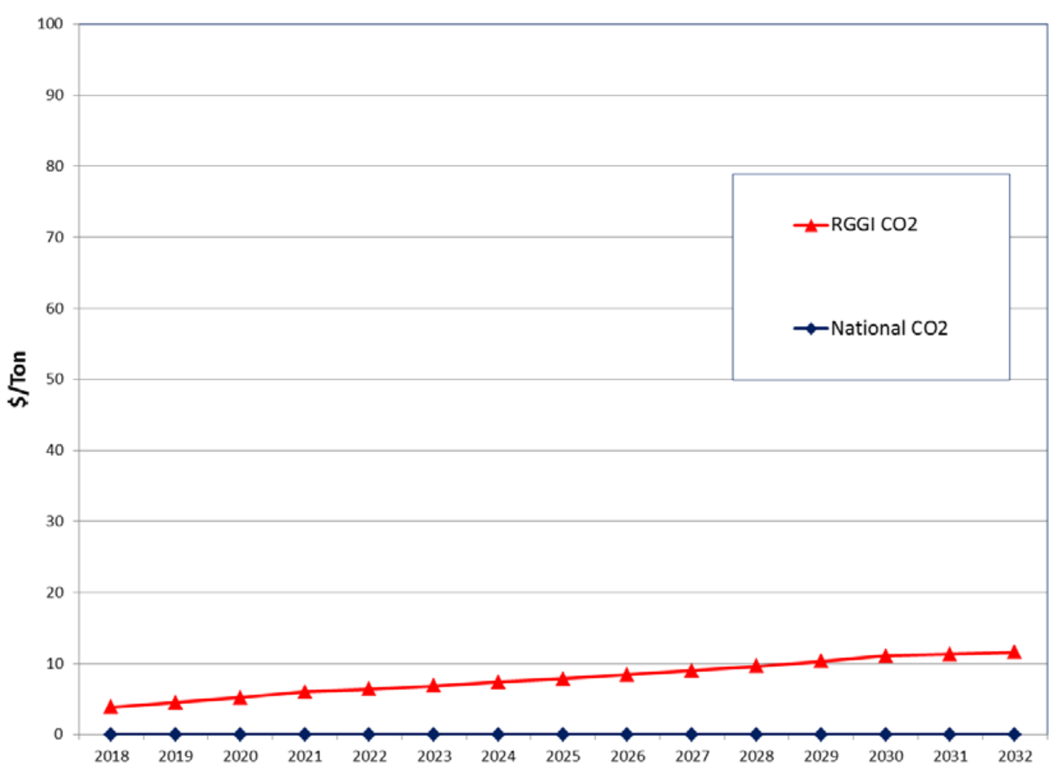
The forecast of a national CO_2 emission price reflects the stalled federal legislation regarding greenhouse gases. Accordingly, the CO_2 emission prices set to zero for all study years. Currently, Maryland and Delaware participate in the Regional Greenhouse Gas Initiative (RGGI). Forecast prices for RGGI CO_2 are shown in Figure 5. New Jersey and Virginia are considering joining the RGGI program, however these initiatives are in initial phases. If regulatory changes show clear commitment to these initiatives then the base data will be updated accordingly.

Figure 5 - CO2 Emission Price Assumptions



Financial Parameters - Carrying Charge Rate and Discount Rate

Evaluation of proposed Market Efficiency projects requires a benefit to cost analysis. As part of this evaluation the present value of annual benefits projected for the first 15 years of a project's life are compared to the present value of the annual cost for the same 15-year period. If the benefit-to-cost ratio exceeds a threshold of at least 1.25:1, then the project can be recommended for inclusion in the PJM RTEP. The annual cost of the upgrade will be based on the total capital cost of the project multiplied by a levelized annual carrying charge rate. A discount rate will be used to determine the present value of the project's annual costs and annual benefits. The annual carrying charge rate and discount rate are developed using information contained in the transmission owners' formula rate sheets that are posted on the PJM web site. The annual carrying charge rate and discount rate for this analysis will be 12.84% and 7.37%, respectively.

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Market Efficiency Process Enhancement Task Force (MEPETF) Update

The Market Efficiency Process Enhancement Task force Problem Statement and Issue Charge was approved at the January 2018 meeting of the Planning Committee to address challenges and opportunities for improvements to the Market Efficiency process since implementing Order 1000 processes in two phases. Phase 1 was completed in August 2018. Phase 2 is scheduled to complete by Q2 2018.
Phase 1 key discussion areas:

- Benefits-to-Cost Calculation (Energy and Capacity) - recommend partial push to phase 2
- Regional Targeted Market Efficiency Projects – recommend push to phase 2
- Modeling of Facility Study Agreement (FSA) Generators
- Market Efficiency Reevaluation Process – recommend push to phase 2
- Interregional Market Efficiency Project Selection Process (See M-14F update)

At the August 23rd meeting, PJM Markets & Reliability Committee endorsed the Market Efficiency phase 1 proposal “G” , and the associated OATT revisions on behalf of PJM:

Component	PJM Modification
FSA Modeling	By default, exclude from the base case the FSA and Suspended ISA resources, and their associated network upgrades at time of case build. FSA sensitivity studies will be used for proposal evaluations, but not for B/C ratio test.
FSA Exception	If FSA or Suspended ISA resources are included in the base case at time of case build or mid-cycle update, TEAC will be notified and the assumptions will be reviewed at TEAC on an as needed basis.
Criterion to Include FSAs	In case of a reserve deficiency, include FSA and Suspended ISA resources (as well as the expected network upgrades) ranked by their commercial probability, until the reserve requirement is met.

At the September 27th meeting, Members Committee endorsed the above changes to the Operating Agreement for December 1, 2018 effective date. Any potential changes will be effective for 18/19 Long Term Window