



Market Efficiency Process Scope and Input Assumptions

2024/2025 Market Efficiency Mid-Cycle Update

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Scope

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

- Determine which reliability-based transmission projects, if any, have an economic benefit if accelerated or modified.
- Identify new transmission projects that may result in economic benefits.
- Review cost and benefits of economic-based transmission projects included in the Regional Transmission Expansion Plan (RTEP) to assure that they continue to be cost beneficial.
- Identify economic benefits associated with modification of reliability-based transmission projects already included in the RTEP that when modified would relieve one or more economic constraints. Such projects, originally identified to resolve reliability criteria violations, may be designed in a more robust manner to provide economic benefits as well.

Market Efficiency analysis is conducted using market simulation software, which models the market conditions and 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 with and without the proposed transmission enhancement or expansion. For the 2024/2025 Market Efficiency cycle, market simulations will be performed for the following years: 2025, 2029, 2032 and 2035. A forecast of annual benefits for years beyond 2035 will be based on an extrapolation of the years 2025, 2029, 2032 and 2035 simulation results. Market simulations may be performed for year 2039 to validate the extrapolation results.

Market Simulation Model and Input Assumptions

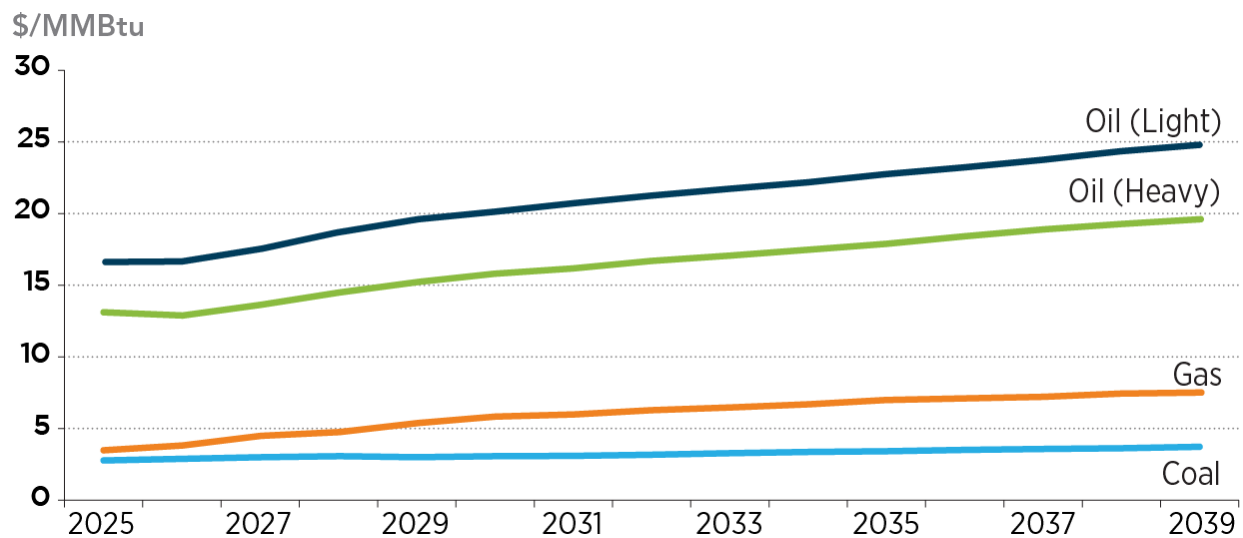
The primary analytical software used by PJM to determine potential Market Efficiency benefits is PROMOD IV from Hitachi Energy. PROMOD IV is a production costing software application that simulates the hourly commitment and dispatch of generation to meet input load while recognizing and maintaining transmission system security limits. The underlying source of the initial PROMOD IV input database is the Simulation Ready Data from Hitachi Energy. Data includes generating unit characteristics, fuel costs, emissions costs, load forecasts and a power flow case. The Simulation Ready Data for the 2024/2025 Market Efficiency cycle is from the Fall 2023 base case release with Hitachi Energy fuel and emission updates consistent with the Spring 2024 release. PJM does tailor key aspects of the base release for RTEP Market Efficiency evaluation. These items would include an update of the power flow case, a generation modification because of additional queued units and announced retirements, and the utilization of the most recent 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 Hitachi Energy Fuels Group. For gas and oil, the prices are derived from a combination of NYMEX forward prices and a fundamental forecasting model. The 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.

0 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 are the average of each PJM coal plant's burner tip price. The coal price forecast is on an individual plant-specific delivered basis.

Figure 1. Fuel Price Assumptions



Peak Load and Annual Energy

Peak load and annual energy forecasts for the PJM RTO were developed from the PJM Resource Adequacy Planning Department's February 2024 PJM Load Forecast Report but adjusted to include additional non-conforming loads identified in the latest RTEP case. These include adjustments for Dominion load supported by State Queue generation and PPL, ME, PN, and APS non-conforming load. **Table 1** shows the annual PJM peak and annual energy forecast that provides the basis for load input into the simulation.

Table 1. 2024 PJM Peak Load and Energy Forecast with Adjusted Load

Load	2025	2029	2032	2035	2039
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Peak (MW)	154,333	167,389	173,817	181,330	192,460
Energy (GWh)	832,674	943,741	1,001,807	1,051,812	1,131,523

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 2024 Load Forecast Report.

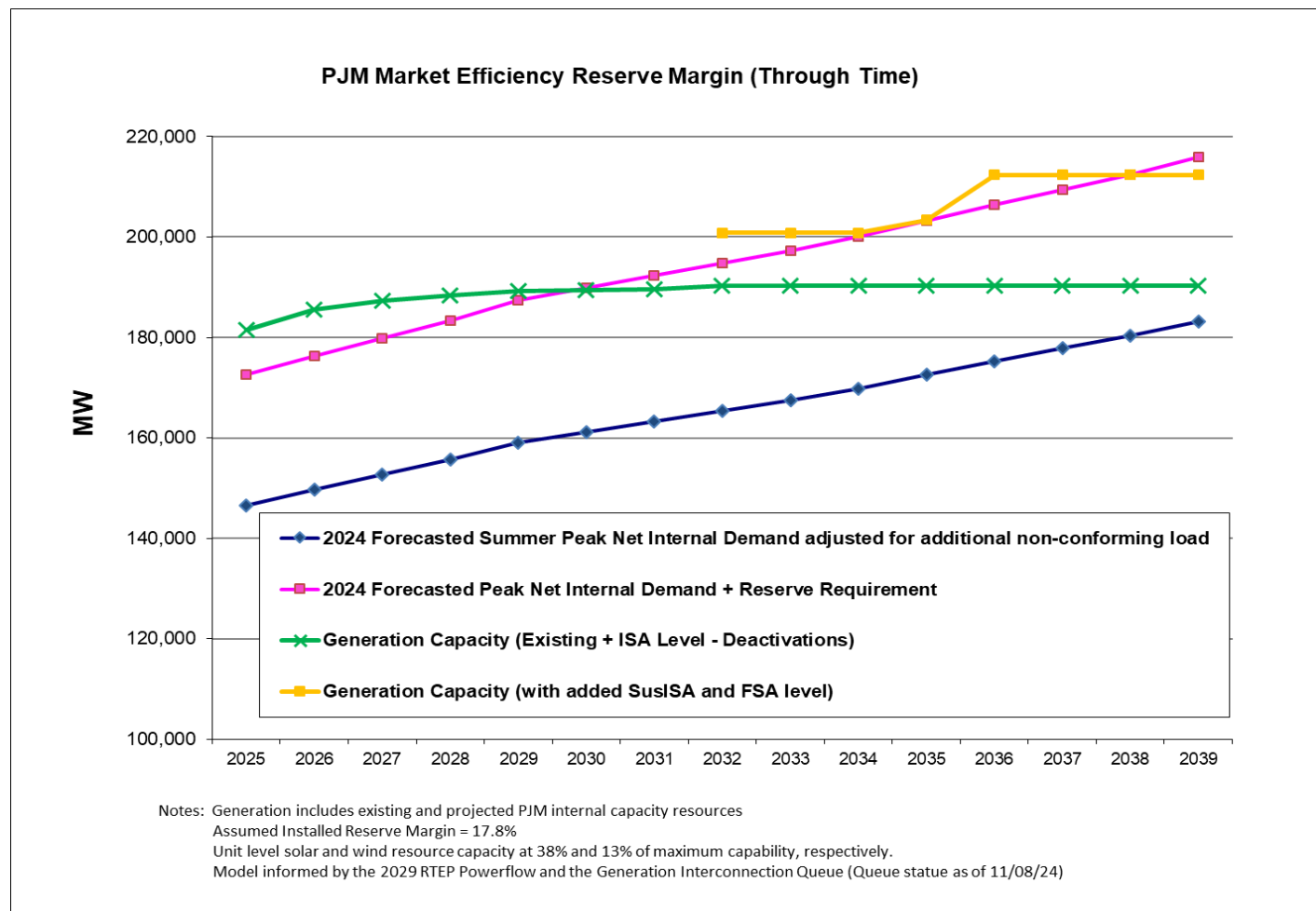
Table 2. 2024 PJM Demand Resource Forecast

	2025	2029	2032	2035	2039
Demand Resource (MW)	7,814	8,265	8,500	8,772	9,210

PJM Generation

Figure 2 shows a comparison of the modeled generation capacity within PJM's footprint to the projected peak net internal demand with reserve margin. The net internal demand (blue line) is derived from information included in the 2024 PJM Load Forecast Report but adjusted to include additional non-conforming loads identified in the latest RTEP case. The net internal demand is equivalent to the adjusted PJM Summer unrestricted peak forecast minus the projection of load management placed under PJM control. For the purposes of Market Efficiency evaluation, the reserve requirement is assumed to remain at 17.8% for the entire 15-year study period. The modeled capacity (green line) includes capacity that is in-service plus active queue generation with Interconnection Service Agreements (ISA) minus announced future deactivations. The base case will require the addition of Suspended ISA and Facility Study Agreement (FSA) resources in order to meet the reserve requirement for the 2032 and 2035 study years (yellow line). The reserve requirement will not be met in the 2039 study year.

Figure 2. PJM Market Efficiency Reserve Margin

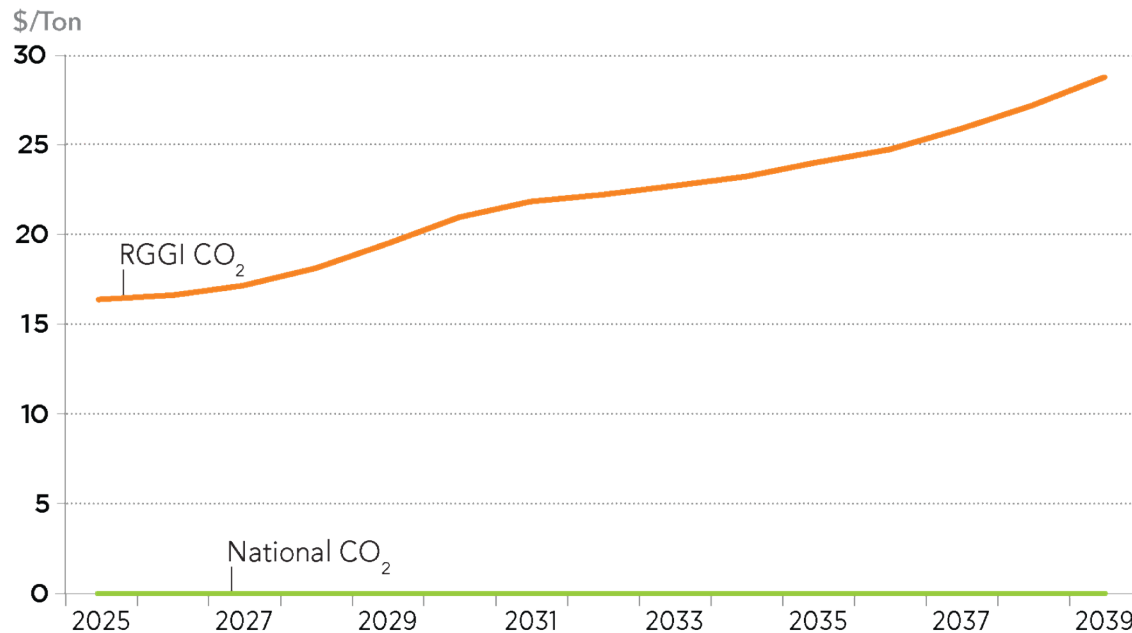


Emission Allowance Price

The PROMOD database models three major effluents: CO₂, NO_x, and SO₂. 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. Hitachi Energy uses a proprietary Emission Forecast Model (EFM) to simulate emission control decisions and simultaneously results in the three cap-and-trade market price forecasts (NO_x Annual, NO_x Seasonal, SO₂). Hitachi Energy uses a CO₂ emission forecast based on analysis associated with national and regional legislative proposals.

The forecast of a national CO₂ emission price reflects the current federal legislation regarding greenhouse gases. Accordingly, the national CO₂ emission prices are set to zero for all study years. The Spring 2024 Forecast has Maryland, Delaware and New Jersey participating in the Regional Greenhouse Gas Initiative (RGGI). Forecast prices for RGGI CO₂ are shown in **Figure 3**.

Figure 3. CO₂ Emission Price Assumption



Forecasts for NO_x and SO₂ reflect legislation associated with the Cross State Air Pollution Rule (CSAPR). **Figure 4** and **0** show graphs of NO_x and SO₂ prices assumed in the Market Efficiency base case.

Figure 4. NO_x Emission Price Assumptions

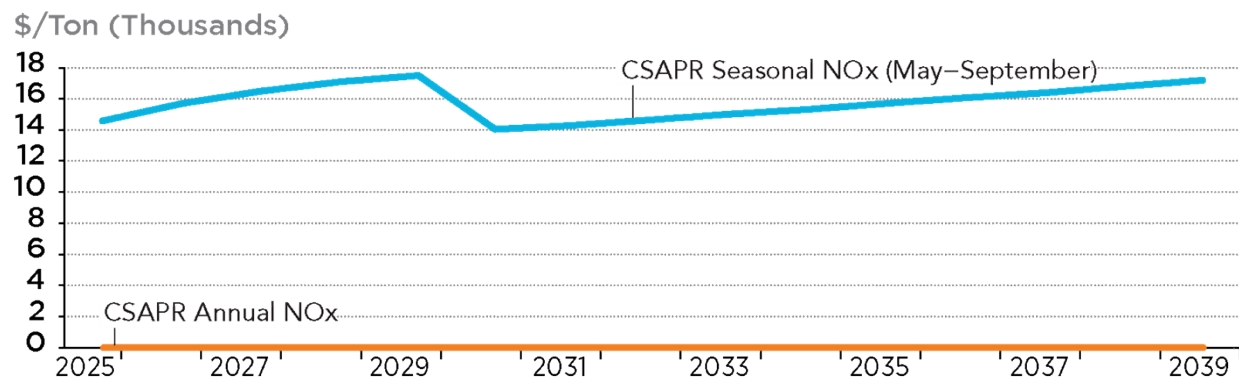
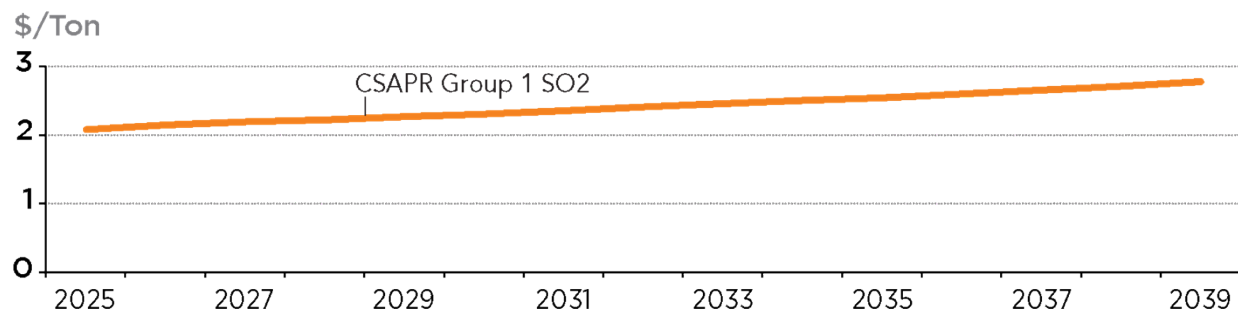


Figure 5. SO₂ Emission Price Assumption



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 a 15-year period starting with the RTEP year are compared to the present value of the annual cost for the same 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 and incorporated in the [Transmission Cost Planner \(TC Planner\)](#) tool. The annual carrying charge rate and discount rate for this year's analysis will be 12.09% and 7.20%, respectively.

Input Assumption Sensitivities

Consistent with Schedule 6 of the PJM Operating Agreement, sensitivities of future assumptions are considered within the Market Efficiency project selection process in order to mitigate the potential for inappropriately including or excluding Market Efficiency projects. PJM typically will evaluate the impacts of load forecast, fuel cost assumption, and a generation expansion variation. PJM expects to also create a demand resource forecast variation sensitivity.

With the advent of recent large load forecast changes and policies that are driving generation portfolio shifts, it is important that the sensitivities consider input from other recent and on-going long-dated studies. The Market Efficiency load, fuel, demand resource and generating capacity sensitivities will be determined before opening of the 2024/2025 Long-Term Window. These may consider modeling assumptions consistent with PJM Reliability Planning processes including NJ SAA, Generation at Risk Analysis, and Long-Term Regional Transmission Planning (LTRTP).