Energy Transition in PJM: Frameworks for Analysis Addendum

Introduction

This document contains supporting information for the PJM white paper, Energy Transition in PJM: Frameworks for Analysis, based on stakeholder questions and feedback. The assumptions described below were used in the first phase of analysis, which began in 2020. This body of work is intended to be a living study, in which assumptions are continually refined based on internal and external stakeholder feedback. Future phases of the study will include updates to core assumptions and additional sensitivities.

Scenario Development

State and Corporate Policy Analysis

In order to inform scenario development, PJM analyzed goals and policies that are driving clean energy development and potential generation retirements. PJM used two time frames to inform the scenario assumptions. The Policy case referenced medium-term policy goals through 2035, and the Accelerated case referenced policy goals through 2050. The goals and policies of states and utilities described below were accounted for in the first phase of analysis that began in 2020. As these policies and goals continue to evolve, PJM will continue to review and update how these inform the assumptions in future phases of the study.

State Goals

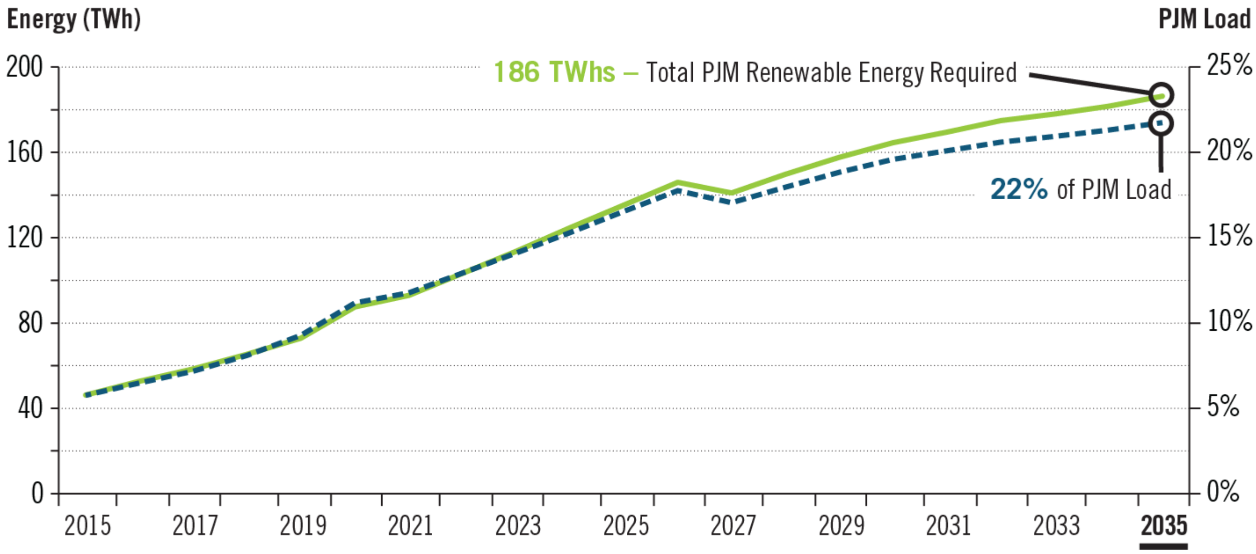
State renewable portfolio standards (RPS) require suppliers to use wind, solar and other renewable resources to serve increasing percentages of total demand. The following RPS policies in PJM were accounted for in the first phase of analysis:

NJ ■ 50% by 2030	**DC** ■ 100% by 2032	**VA** ■ 100% by 2050 (IOUs)	**MI** 15% by 2021
MD ■ 50% by 2030	**PA** ■ ■ 18% by 2021	**NC** ■ 12.5% by 2021 (IOUs)	**IN** ■ 10% by 2025
DE ■ 25% by 2026 (Updated in 2021 to 40% by 2035. This will be included in future study phases.)	**IL** ■ 25% by 2026	**OH** 8.5% by 2026	

Includes: ■ Minimum solar requirement ■ Non-renewable alternative energy resources (such as waste coal)

A cumulative analysis of RPS policies in PJM results in a requirement of about 22% of PJM load to be served by renewable energy by 2035 (see Figure 1).

Figure 1. Renewable Energy Necessary To Meet Existing State Policies in PJM by 2035



In addition to RPS, additional resource-type specific programs and longer-term policy objectives were referenced for scenario development in the first phase of analysis, including:

MARYLAND

Maryland's policy objectives include:

- The Clean and Renewable Energy Standard, which sets a goal of 100% clean electricity by 2040
- SB 887, which is proposed legislation to phase out coal generation
- HB 1545, which calls for a near-term, phased shutdown of 12 coal-fired generating units at six Maryland generating stations

In addition, the Maryland Department of the Environment, in coordination with other agencies and stakeholders, has proposed the Greenhouse Gas Emissions Reduction Act. The plan is intended to achieve Maryland's goal of reducing greenhouse gas emissions 40% by 2030 while benefiting the state's economy and creating jobs. The plan includes a comprehensive set of measures to reduce and sequester greenhouse gases, including investments in energy efficiency and clean and renewable energy solutions and widespread adoption of electric vehicles.

NEW JERSEY

The New Jersey Energy Master Plan, published Jan. 27, 2020, calls for "100% clean energy status for the state by 2050." Electricity supply would be most impacted by these plan components:

- Meeting the 50% RPS by 2030 and exploring possible regulatory structures to enable New Jersey to transition to 100% clean energy by 2050
- Ensuring at least 75% of electricity demand is met by carbon-free renewable generation by 2050 and set interim targets
- 100% clean energy by 2050
- Developing 7,500 MW of offshore wind energy generation by 2035
- Continuing to grow New Jersey's community solar program and transition to a successor solar incentive program
- Developing mechanisms for achieving 600 MW of energy storage by 2021 and 2,000 MW of energy storage by 2030

NORTH CAROLINA

The North Carolina Clean Energy Plan includes:

- Reducing electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050
- Fostering long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes
- Accelerating clean energy innovation, development and deployment to create economic opportunities for both rural and urban areas of the state
- Developing carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options
- Developing and implementing policies and tools such as performance-based mechanisms, multiyear rate planning and revenue decoupling that better align utility incentives with public interest, grid needs and state policy
- Modernizing the grid to support clean energy resource adoption, resilience and other public interest outcomes

VIRGINIA

The Virginia Clean Economy Act (Senate Bill 851) includes:

- Mandatory RPS (excluding nuclear sale and corporate Power Purchase Agreements)
  - *Dominion:* 59% by 2035, 100% by 2045
  - *Appalachian Power:* 45% by 2035, 100% by 2050
  - *Estimated overall renewable energy required:* 37% by 2035, 66% by 2050
- Deadlines for closing coal power plants by 2030 and gas-fired power plants by 2045
- Additionally, as of the time of the study, Virginia was on track to become the fourth state in PJM (in addition to Delaware, Maryland and New Jersey) to participate in the Regional Greenhouse Gas Initiative (RGGI), a multistate carbon cap-and-trade program. Virginia's participation in RGGI is being challenged by the new administration in Richmond.

Corporate Utility Goals

Utility decarbonization targets were also referenced for scenario development in the first phase of analysis.

Dominion Energy	AEP Clean Energy Future	Public Service Enterprise Group (PSEG)
Corporate goal of net-zero carbon and methane emissions by 2050	80% reduction in carbon dioxide emissions from 2000 levels by 2050 and a 70% reduction by 2030	Goal to achieve net-zero greenhouse gas emissions by 2050 and to cease owning coal-fired generation by mid-2021*

AES Corporation

Target to reduce the power company's coal-fired generation to below 30% of its overall generation by the end of the 2019, and to less than 10% by 2030**

**This goal was accelerated in mid-2021 to be net-zero by 2030 – this will be included in future phases of analysis.*

*** AES Corporation also aims to reduce its overall carbon footprint by 50% by 2022 and by 70% by 2030 compared to 2016 levels.*

Generation Portfolio Assumptions

PJM developed resource expansion and resource retirement assumptions by analyzing government and corporate policies driving clean-energy growth and generation retirements across PJM states, trends in the PJM interconnection queue and industry projections of the evolving system mix.[1] Table 1 contains installed capacity (ICAP) by resource type for each scenario. Onshore wind, offshore wind and solar resources were considered for expansion in the first phase. Future phases of analysis will consider the expansion of battery energy storage and solar-storage hybrid resources.

Table 1. Nameplate Capacity, by Fuel Type, for Each Scenario in Megawatts

Study Case	Base	Policy	Accelerated
Offshore Wind	260	11,701	28,837
Onshore Wind	11,194	18,524	35,770
Solar	3,977	24,020	55,062
Other Renewable	1,785	1,785	1,785
Hydro	8,865	8,865	8,865
Coal	42,382	38,974	34,197
Natural Gas	96,821	96,821	96,821
Nuclear	35,146	30,980	30,980
Oil	4,468	4,468	4,468
Other	293	293	293
Demand Response	8,202	8,202	8,202

[1] Industry sources: IHS Markit North American Power Market Outlook and EIA Annual Energy Outlook.

Generation Expansion

In order to increase the amount of utility-scale solar, onshore wind and offshore wind in the policy and accelerated scenarios, existing and queue units were scaled up to a reference project size[2] by technology type (150 MW for solar sites, 200 MW for onshore wind sites and 2,100 MW for offshore wind sites). In the Accelerated scenario, additional solar and wind sites were needed to fulfill the capacity targets. Data from the National Renewable Energy Laboratory (NREL)[3] was used to determine these site locations based on annual capacity factor, proximity to existing equipment and voltage level. These sites were then mapped to PJM buses 230 kV and above.

Generation Retirement Assessment

The portfolio assumptions included three categories of retirements:

1 | **Formal deactivation notices.**[4] These retirements were included in all scenarios.

2 | **State or utility policies/agreements that include the shutdown of coal and oil generation.** These retirements, which are in addition to units that have formally submitted deactivation notices to PJM referenced above, were included in all scenarios.

3 | **Retirements to offset the additional capacity being added by the renewable buildout.** These were included only in the Policy and Accelerated scenarios.[5]

[2] For units that have ICAP greater than the reference size in the Base scenario, the ICAP for Policy and Accelerated scenarios were kept constant.

[3] NREL, Solar Power Data for Integration Studies, https://www.nrel.gov/grid/solar-power-data.html; NREL, Eastern Wind Dataset, https://www.nrel.gov/grid/eastern-wind-data.html; NREL, Wind Toolkit Data, https://developer.nrel.gov/docs/wind/wind-toolkit/wtk-download/.

[4] PJM, Generation Deactivations, https://www.pjm.com/planning/services-requests/gen-deactivations.aspx.

[5] Portfolio-Specific Effective Load Carrying Capability (ELCC) analysis was performed to determine the equivalent amount of unforced capacity (UCAP) to be retired in each scenario. To fill each retirement quantity, units were selected from an ordered list of thermal units based on an economic assessment considering net energy and ancillary service revenues, capacity revenues, and ACRs. The risk assessment was not intended to forecast the long-term financial health of any individual resource, but only to provide a ranking of resources that could be retired for the purposes of this analysis.

Additional Resource Assumptions

Run of River Hydro and Other Renewables: Installed capacity was assumed to remain constant in each scenario. Energy dispatch was economically optimized at a $0 merit order price.

Nuclear: This phase of the study assumes that existing nuclear generation resources complete the Subsequent License Renewal process to remain operational through the policy reference years. No new-build nuclear generation was be included.

Coal: No additional coal generation capacity was included. Retirements were considered based on the assessment described above.

Natural Gas: The amount of natural gas generation capacity included new units from the interconnection queue.

Pumped-Storage Hydro: Pumped-hydro capacity was assumed to remain constant in each scenario. Energy dispatch was economically optimized with head and tail reservoir storage capability and was allowed to set price with inter-temporal opportunity costs. Pump load was treated as negative generation and was netted against resource generation for reporting purposes. Historical generation profiles were not used.

Demand Response: The assumed amount of demand response will be constant across models: 5% of the total capacity requirement. All demand response was modeled as economic supply and dispatched at a $1,700 merit price.

Installed Reserve Margin

The Installed Reserve Margin (the percent of nameplate needed to meet the 1-in-10 loss of load criterion) as a calculation is sensitive to the relative performance of the generation fleet as determined by forced outage rate or ELCC calculations. In the case of the Renewable Integration Study, each scenario has a predetermined amount of renewables (onshore wind, offshore wind, solar).

To get to an IRM associated with each of the scenarios, the UCAP requirement (forecasted peak multiplied by the forecast pool requirement) is reduced by the capacity value of the renewables determined through ELCC. This remainder is the UCAP amount needed for non-renewables, which is then converted to installed capacity, or ICAP, using forced-outage rates. The ICAP totals of renewables plus non-renewables can then be divided by the forecasted peak to get to the IRM, which is 22%, 41% and 78% for the Base, Policy and Accelerated scenarios, respectively.

Load Assumptions

The gross load from the long-term load forecast for the year 2035 was used in all three scenarios, with a summer peak load of 169,741 MW. The net load varied in each scenario by accounting for the impact of behind-the-meter (BTM) solar in each scenario. Electrification was not considered during this phase of analysis but will be included as a sensitivity in future analysis.

Solar resource deployment in the PJM states can occur at the utility scale as transmission-connected assets, or at the distribution scale at retail-connected load centers. When generating resources are connected to the distribution network, they act as demand-reducing assets from the RTO/ISO perspective. Their energy production offsets the energy demanded from the transmission networks.

Load Shape Methodology

1 | For each weather year under study, historical loads are grossed up with BTM solar estimates to determine gross load. Gross load is then per-unitized on each month's peak, which gives us the gross load shape.

2 | To get to a forecast year, the gross load shape is then multiplied by monthly forecasted peaks associated with each weather year, which gives us the gross loads.

3 | To get solar impact, BTM solar shapes are applied to forecasted nameplate BTM solar.

4 | To get net loads, gross loads are reduced by the solar impact.

This is computed for weather years 2012 through 2018, with each weather year beginning June 1, and ending the following May 31 (i.e., a delivery year). For use in the production cost simulation, a single weather year is chosen – in this case, 2018. This year was chosen as it is recent and is roughly in line with 50/50 summer peak conditions. For use in reliability evaluation or ELCC calculations, multiple weather years are used, as these calculations are very sensitive to the relationship of load and generation profiles.

Behind-the-Meter Solar Forecast

For the Base and Policy scenarios, the IHS BTM solar forecast was used to determine the renewable energy contribution from BTM solar resources. The Base scenario used the expected BTM solar penetration in 2023 from the IHS solar forecast and scaled it up to 2035 load levels, whereas the Policy scenario used IHS's 2035 BTM solar forecast. In order to produce BTM solar values for the Accelerated scenario, guidance was taken from the Energy Information Administration on regional BTM solar growth between 2035 and 2050 to scale up the Policy scenario values.

Transmission Topology

The base topology for the production cost model utilized in the energy and ancillary services market simulations was developed from the 2023/2024 Regional Transmission Expansion Plan case and market efficiency processes, and includes monitored contingencies included in the 2023/2024 Market Efficiency case.[6] The energy and ancillary services market simulations performed in the first phase of the study did not include any transmission expansion that may be needed for reliability. Future phases of the study will consider additional to incorporate impacts with future transmission upgrades that are likely needed to integrate the future renewable generation and will be conducted in coordination with the PJM Offshore Wind Transmission Study.[7]

External Interchange

In the first phase of the study, the production cost model allowed flow over external interfaces up to the total transfer capability, assuming perfect market-to-market coordination. Hurdle rates that aim to produce external interchange that aligns with historical level were not used. All external transmission zones that directly neighbor PJM were included in the model. Future phases of the study will include analysis of additional methods to account for the dynamic relationships between PJM and its neighbors as the resource mix across the regions evolves.

[6] PJM, Market Efficiency, https://www.pjm.com/planning/rtep-development/market-efficiency.aspx.

[7] PJM, Offshore Wind Transmission Study: Phase 1 Results, https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

Fuel Price Forecasts

Monthly fuel price forecasts for natural gas, coal and oil from the IHS Fast Transition Case for 2035 were utilized in all scenarios. Mapping of units to fuel price points was derived from PJM fuel cost policies.

Emissions

Carbon dioxide (CO_2) emissions were modeled based on carbon content (lb/MMBtu) by fuel type.[8] CO_2 emissions on a unit basis were calculated via simulation based on unit dispatch, fuel use and heat rate. The CO_2 allowance costs were applied to generators within the scope of the RGGI program. This included fossil-fuel-fired electric power generator with a capacity of 25 MW or greater located in participating states. The RGGI program allowance price floor (Emissions Containment Reserve) trigger price for 2030, escalated to 2035, was used for the allowance price.[9]

Nitrogen oxides (NO_x) and sulfur dioxide (SO_2) were modeled on a unit basis using EPA emissions rate and allowance price data from 2018.[10] SO_2 rates were an annual average. NO_x rates were averaged separately for the ozone season (May through September) and the remainder of the year.

[8] EPA, GHG Emission Factors Hub, https://www.epa.gov/climateleadership/ghg-emission-factors-hub.

[9] RGGI 2017 Model Rule, https://www.rggi.org/sites/default/files/Uploads/Design-Archive/Model-Rule/2017-Program-Review-Update/2017_Model_Rule_revised.pdf.

[10] EPA, Air Markets Program Data, https://ampd.epa.gov/ampd/.