

# RTEP 2025

## Regional Transmission Expansion Plan



April 17, 2026

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# Preface

## 1.0: Preface

The PJM Regional Transmission Expansion Plan (RTEP) Report is published annually to convey planning study results from throughout the year and to explain the rationale behind transmission system enhancement needs. In 2025, PJM observed several ongoing trends, which are discussed throughout this report.

- **Section 1** provides a high-level summary of the 2025 RTEP process, 2025 calendar-year activities and automation improvements implemented by PJM.
- **Section 2** includes an overview and detailed data from PJM's 2025 Long-Term Load Forecast Report.
- **Section 3** provides a summary of 2025 RTEP system enhancements approved by the PJM Board of Managers, including those driven by generator deactivations, and summarizes the reevaluation of previously approved projects.
- **Section 4** summarizes 2025 market efficiency process activity, including input parameters, acceleration analysis results, reevaluation of previously approved market efficiency projects and 2025 RTEP system enhancements approved by the PJM Board.
- **Section 5** provides an overview of PJM's interconnection process and related initiatives.
- **Section 6** provides state summaries, including a detailed breakdown of interconnection requests within each state, as well as transmission system enhancements identified as part of the RTEP analysis.

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<https://pjm.my.site.com/planning>

PJM's online communities create an easily accessible venue for stakeholders to collaborate with PJM staff and each other.

**The Planning Community** enables stakeholders to collaborate and find information on planning initiatives, proposal windows and processes. It includes features similar to the Member Community, along with:

- Access to PJM subject matter experts
- Moderated discussions among generation owners, transmission owners and PJM staff

- **Appendix 1** – Transmission Owner Zones and Locational Deliverability Areas
- **Glossary**
- **Topical Index**
- **Key Maps, Tables and Figures**
- **Appendix 5** – RTEP Project Statistics

# 2025 KEY HIGHLIGHTS

PJM's Regional Transmission Expansion Plan, or RTEP, process continues to identify transmission system additions and improvements needed to serve 67 million people throughout 13 states and the District of Columbia.



PJM and its stakeholders continued to work throughout 2025 to identify challenges and craft solutions toward maintaining a reliable grid and enhancing markets.

- + PJM's RTEP process identified 122 new baseline projects in 2025 at an estimated cost of \$11.8 billion, primarily to maintain system reliability.
- + 445 new network transmission projects at an estimated cost of \$959.1 million are required to enable the reliable delivery of generation seeking interconnection into PJM markets.



Load growth continues to increase, driven primarily by the proliferation of data centers.

- + PJM now projects its RTO-wide summer-normalized peak to grow 3.1% annually over the next 10 years, which is up 1.5 percentage points when compared with the 2024 forecast.



Accelerated generator retirements driven by unit age and environmental public policy, and that provide necessary attributes needed to maintain reliability, are outpacing new, mainly inverter-based resource additions.

- + PJM received more than 30 deactivation notifications totaling over 6.5 GW in 2025.
- + Approximately 36% of new interconnection requests to the PJM grid are solar resources.

## Additional Milestones:

- + Interconnection reforms that encompass a "first-ready, first-served" Cycle-based approach for new generators are allowing generator projects that are ready to proceed to do so while incentivizing those that are not ready to exit the interconnection process. In 2025, PJM analyzed and issued 130 Transition Cycle 1, Phase III System Impact Studies and 452 Transition Cycle 2, Phase I System Impact Studies as part of its reformed interconnection process.
- + As part of 2025 RTEP Window 1, PJM evaluated an unprecedented 134 proposal submissions and sought and received Board approval for an underground HVDC link.
- + PJM completed the reevaluation of Project 9A and received Board approval to modify the scope to retain the western portion and remove the eastern portion of the project, terminating the project's suspended status and restoring the western portion of the project to the RTEP models.

# Section 1: 2025 Year in Review

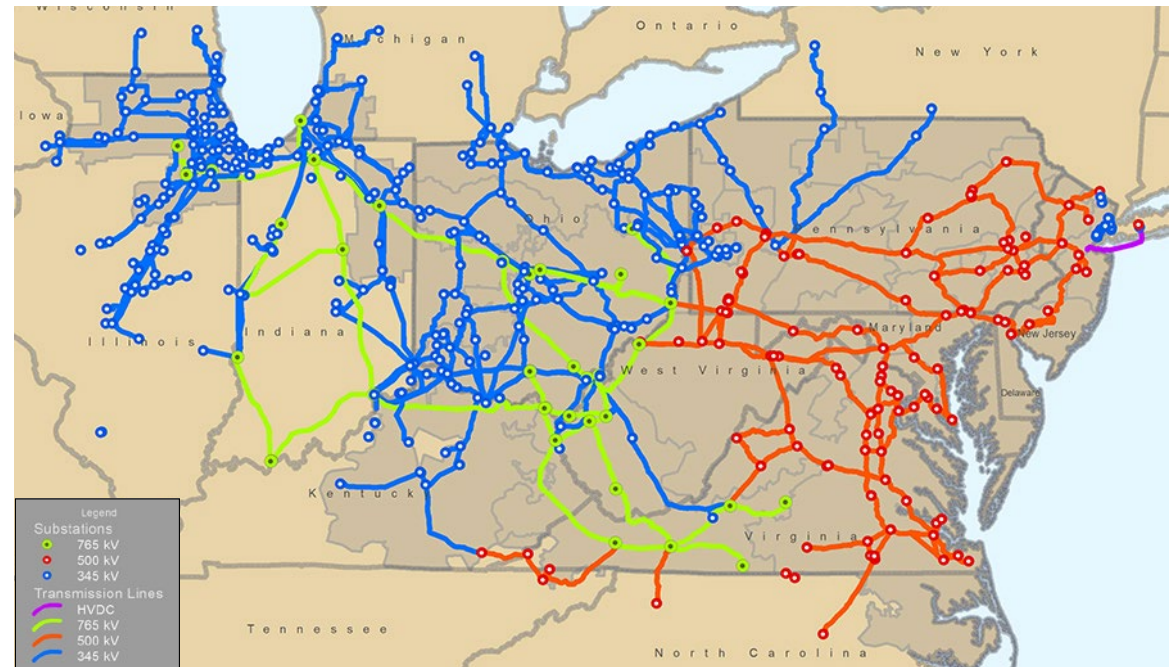
## 1.0: Executive Summary

The PJM Regional Transmission Expansion Plan (RTEP) Report is published annually to convey planning study results throughout the year and to explain the rationale behind transmission system enhancement needs. The report also examines trends that continued throughout 2025 and will drive PJM's grid of the future, including the ongoing shift from fossil fuels to renewables and the impact of public policy.

### 1.0.1 — Regional Planning

PJM, a Federal Energy Regulatory Commission (FERC)-approved regional transmission organization (RTO), coordinates the movement of wholesale electricity across a high-voltage transmission system in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, as shown on **Map 1.1**. PJM's footprint encompasses major U.S. load centers from the Atlantic Coast to the western border of Illinois, including the metropolitan areas in and around Baltimore, Chicago, Columbus, Cleveland, Dayton, Newark, Norfolk, Philadelphia, Pittsburgh, Richmond, Toledo and Washington, D.C.

Map 1.1: PJM Backbone Transmission System



PJM's RTEP process identifies transmission system additions and improvements needed to serve more than 67 million people. The PJM system includes key U.S. Eastern Interconnection transmission arteries, providing members with

access to PJM's regional power markets as well as those of adjoining systems. Collaborating with more than 1,000 members, PJM dispatches more than 185,000 MW of generation capacity over 88,000 miles of transmission lines.

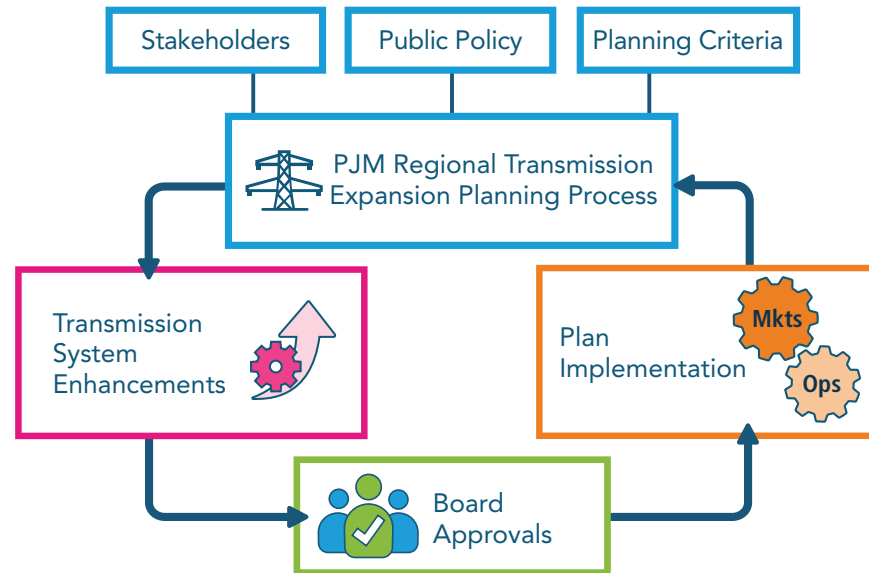
**RTO Perspective**

PJM's RTEP process spans state boundaries shown in **Map 1.1** and is a key RTO function, as shown in **Figure 1.1**. A regional perspective gives PJM the ability to identify one optimal, comprehensive set of solutions to solve reliability criteria violations, operational performance issues and market efficiency constraints. Specific system enhancements are identified and planned to meet local reliability requirements and deliver needed power to load centers across the region PJM serves. When the PJM Board of Managers approves recommended system enhancements, new facilities and upgrades to existing ones, these projects formally become part of PJM's RTEP. PJM recommendations can also include the removal of, or change in scope to, previously approved projects. Forecasted system conditions can change such that justification for a project no longer exists or requires modification to capture system changes.

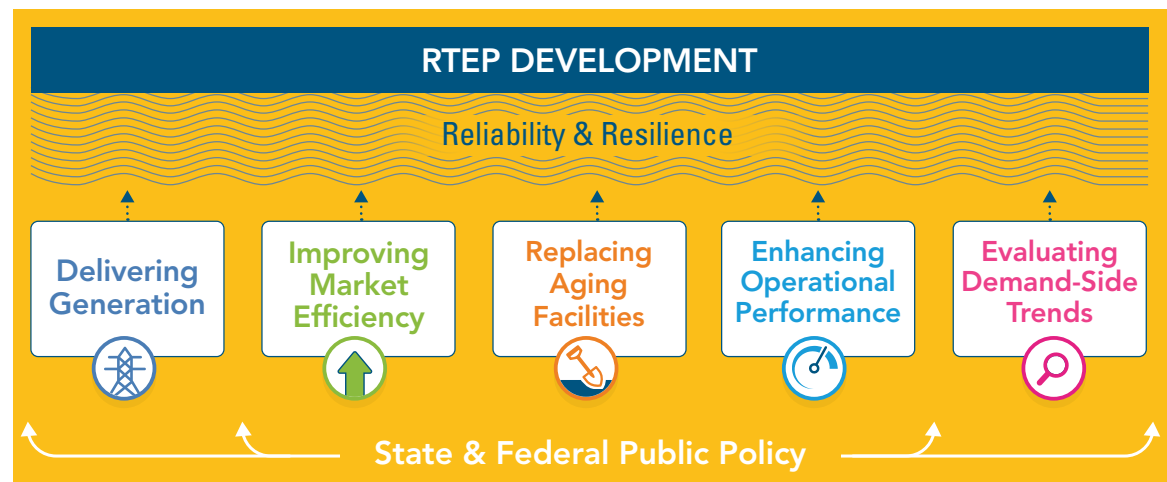
**System Enhancement Drivers**

A 15-year, long-term planning horizon allows PJM to consider the aggregate effects of many drivers, shown in **Figure 1.2**. Initially, with its inception in 1997, PJM's RTEP consisted of system enhancements mainly driven by load growth and generating resource interconnection requests. Today, PJM's RTEP process studies the interaction and impact of many drivers, including those arising out of reliability, aging infrastructure, operational performance, market efficiency, public policy and demand-side trends. Importantly, as **Figure 1.2** shows, RTEP development considers all drivers through a reliability criteria, market efficiency and resilience lens. PJM's RTEP process encompasses a comprehensive assessment of

**Figure 1.1:** RTEP Process – RTO Perspective



**Figure 1.2:** System Enhancement Drivers



system compliance with the thermal, reactive, stability and short-circuit requirements of the North American Electric Reliability Corporation (NERC) Standard TPL-001-5 as described in **Section 1.2**. Highlights of projects identified and approved by the PJM Board during 2025 appear in **Section 3**. Details of specific projects are presented in **Section 6**. **Section 1.3.7** and **Section 1.3.8** discuss PJM's anticipated implementation of its Long-Term Regional Transmission Plan (LTRTP) Protocol in compliance with FERC Order 1920.

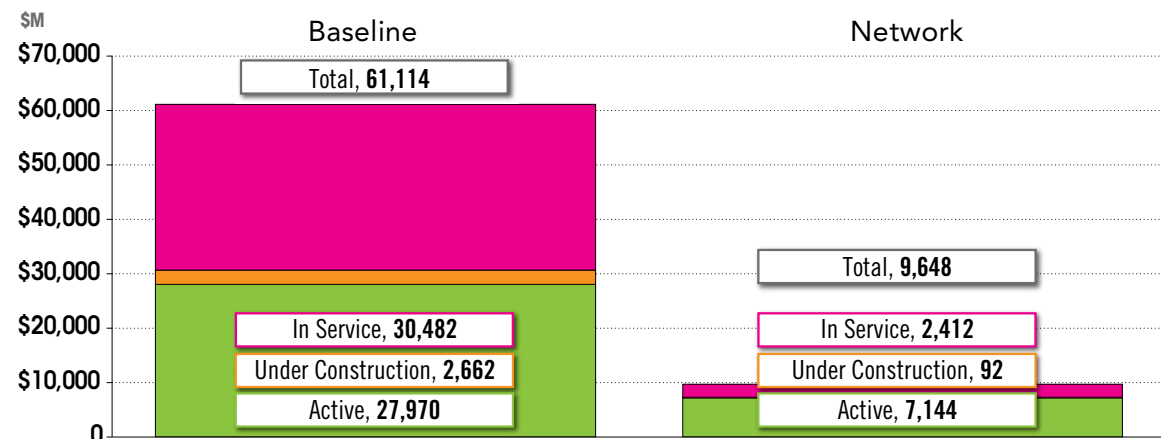
### 1.0.2 — 2025 Outcomes and Conclusions

The PJM transmission system ensures that electricity can be delivered reliably across the grid to customers the instant it is needed. PJM's 2025 RTEP process continued to yield grid enhancements to ensure delivery under a historic and unprecedented generation shift driven increasingly by public policy and fuel economics.

- The PJM Board approved 122 new baseline projects for the 2025 RTEP at an estimated \$11.8 billion to ensure that fundamental system reliability criteria across the grid are met.
- The Board also approved the inclusion of 445 new network transmission projects at an estimated \$959.1 million.

Since the RTEP process was implemented in 1997, the PJM Board has approved transmission system enhancements totaling approximately \$70.8 billion. Of this, approximately \$61.1 billion represents baseline projects to ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency

**Figure 1.3:** Board-Approved RTEP Projects as of Dec. 31, 2025



congestion relief. An additional \$9.7 billion represents network facilities to enable the reliable interconnection of new generation on the PJM system. A summary of projects by status as of the 2025 RTEP Board approval appears in **Figure 1.3**. Active Network Upgrades include those that are actively under study in PJM's interconnection process. Active baseline projects include those that have been recommended at the Transmission Expansion Advisory Committee or Subregional RTEP Committees, projects that are on hold, and PJM Board-approved projects. Projects listed as under construction have completed the interconnection process, and construction activities have commenced. The numbers provide a snapshot of one point in time, as with an end-of-year balance sheet.

The 2025 RTEP totals, and likewise those in **Figure 1.3**, reflect revised cost-estimate changes and project cancellations for previously approved

RTEP elements. For example, PJM can recommend canceling a network system enhancement from the RTEP when a valid New Service Request driving the need for the network project withdraws from the interconnection process. Withdrawals at this point in the interconnection process are typically driven by developer business decisions, including PJM Reliability Pricing Model (RPM) Auction activity, siting challenges, financing challenges or other business model factors.

Supplemental projects are identified and developed by transmission owners to address local reliability needs, including:

- Customer service
- Equipment material condition, performance and risk
- Operational flexibility and efficiency
- Infrastructure resilience

While supplemental projects are not subject to Board approval, PJM conducts do-no-harm studies to ensure that they do not introduce reliability criteria violations on the regional transmission system. A discussion of supplemental projects, including summaries by driver, is included in **Section 3.2**. RTEP power flow models are updated for projects accepted by PJM following do-no-harm studies and any necessary transmission owner (TO) follow-up.

### ***RTO Annual Load Growth***

PJM's 2025 RTEP baseline power flow models for study years 2030 and 2033 were based on the [2025 PJM Long-Term Load Forecast Report](#), summarized in **Section 2**, and show a 10-year RTO summer-normalized peak growth rate of 3.1% per year. Average 10-year-annualized summer growth rates for individual PJM zones ranged from 0.1% to 6.3%. Load forecasts from the past five years reflect broader trends in the U.S. economy and PJM model refinements to capture evolving customer behaviors. These include more efficient manufacturing equipment and home appliances and distributed energy resources, such as behind-the-meter, rooftop solar installations. Again in 2025, PJM identified trends of large load increases in specific areas driven primarily by new data centers, as discussed in **Section 3**.

### ***Changing Capacity Mix***

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by Demand Response and Energy Efficiency programs

As of Dec. 31, 2025, renewable resources continue to represent a significant portion of PJM's New Service Requests, as discussed in **Section 1.1**.

Solar-powered resources total nearly 40,116 MW of Capacity Interconnection Rights (CIRs), or around 36%, of the nearly 112,283 MW of total resources in PJM's New Service Requests, as shown in **Figure 1.5**. Solar generation has overtaken natural gas in PJM's New Service Requests. Natural gas plants total nearly 11,082 MW of CIRs and constitute around 9.9% of requested generation interconnections.

With respect to resource deactivation, i.e., supply exit, more than 48,023 MW of coal-fired generation has retired since 2011. Market factors as well as the economic impacts of environmental public policy, coupled with the age of these plants – many more than 40 years old – make ongoing operation prohibitively expensive. Throughout 2025, PJM continued to receive deactivation notifications (30 units totaling 6,532 MW), the impacts of which are discussed in **Section 3.3**.

### 1.1: Generation Landscape

PJM’s 185,542 MW of RPM-eligible existing installed capacity reflects a fuel mix of 47.5% natural gas, 20.2% coal and 17.5% nuclear, as shown in **Figure 1.4**. Hydro, wind, solar, oil, diesel, waste and other fuel resources constitute the remaining 14.8%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility.

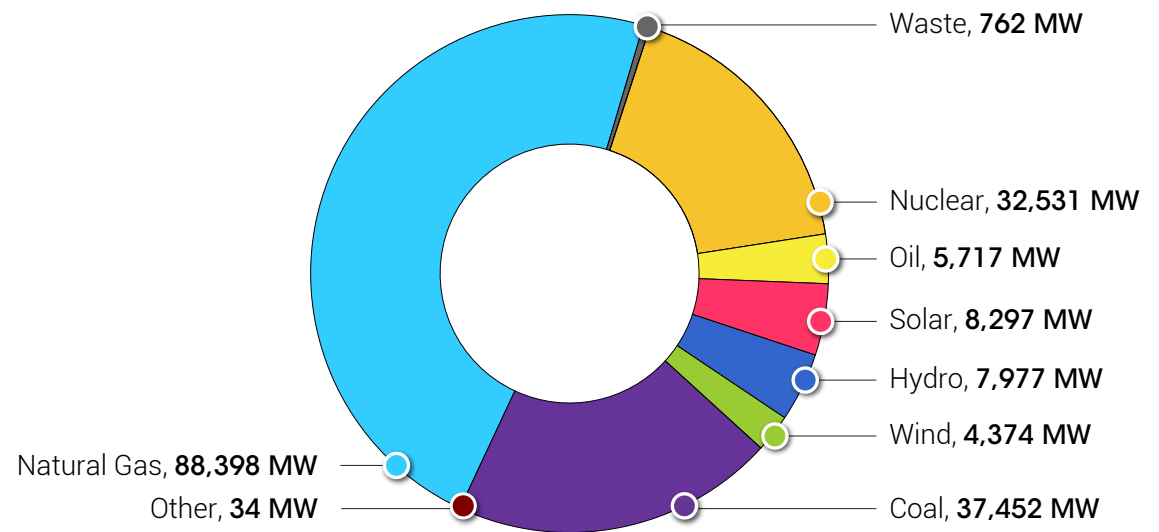
Totalling nearly 99,775 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM’s interconnection process. Solar energy makes up 36% of the generation of PJM’s New Service Requests, shown in **Figure 1.5**. An increase in solar Generation Interconnection Requests is attributable to state policies encouraging renewable generation. **Figure 1.5** shows PJM’s fuel mix based on requested CIRs for generation that was active or under construction as of Dec. 31, 2025.

Interconnection requests by fuel type and status for renewable and non-renewable fuels are summarized in **Table 1.1**.

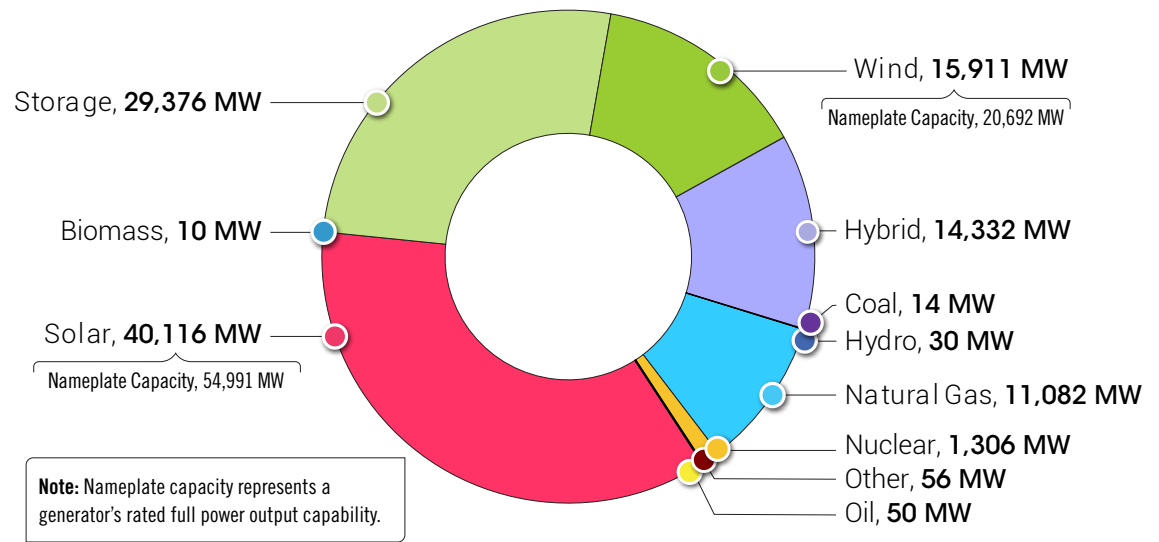
#### Renewables

PJM’s interconnection process continues to see renewable generation growth. As **Figure 1.5** and **Table 1.1** show, New Service Requests as of Dec. 31, 2025, for CIRs totaled around 15,911 MW of wind-powered generators that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 20,692 MW. Solar-powered generator requests for CIRs totaled 40,116 MW that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 54,991 MW.

**Figure 1.4:** PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2025)



**Figure 1.5:** Interconnection Service Request Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2025)



**Table 1.1:** Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2025)

		In Cycle						Complete				Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
<b>Non-Renewable</b>	Coal	1	14.0	0	0.0	0	0.0	54	2,174.2	70	33,577.6	125	35,765.8
	Diesel	0	0.0	0	0.0	0	0.0	6	60.3	16	56.5	22	116.8
	Natural Gas	50	6,572.5	1	1,235.0	11	3,274.5	398	58,422.0	731	266,681.6	1,191	336,185.6
	Nuclear	5	1,305.9	0	0.0	0	0.0	47	3,984.2	25	9,038.0	77	14,328.1
	Oil	0	0.0	0	0.0	1	50.0	23	525.8	23	2,314.0	47	2,889.8
	Other	5	56.3	0	0.0	0	0.0	5	330.3	14	1,112.2	24	1,498.8
	Storage	240	26,703.4	11	414.3	37	2,258.3	30	40.4	771	43,595.2	1,089	7,3011.7
<b>Renewable</b>	Biomass	1	10.0	0	0.0	0	0.0	8	131.8	41	899.9	50	1,041.7
	Hybrid	133	12,741.5	1	115.0	27	1,475.8	12	53.9	396	21,776.0	569	36,162.2
	Hydro	0	0.0	0	0.0	2	30.0	32	1,155.9	63	2,744.1	97	3,930.0
	Methane	0	0.0	0	0.0	0	0.0	72	311.7	95	485.8	167	797.5
	Solar	595	25,405.8	94	3,054.5	227	11,655.8	415	8,889.7	2,739	72,257.2	4,070	12,1263.0
	Wind	101	14,109.0	9	499.0	19	1,302.7	120	2,175.8	576	25,905.4	825	43,991.9
	Wood	0	0.0	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
	<b>Total</b>	<b>1,131</b>	<b>86,918.4</b>	<b>116</b>	<b>5,317.7</b>	<b>324</b>	<b>20,047.2</b>	<b>1,224</b>	<b>78,310.0</b>	<b>5,564</b>	<b>480,596.6</b>	<b>8,359</b>	<b>671,189.8</b>

### ***Nameplate Capacity vs. Capacity Interconnection Rights***

Nameplate capacity represents a generator's rated full power output capability. As **Figure 1.5** shows, nameplate capacity is typically much greater than CIRs for wind- and solar-powered generators. This arises from the fact that while some resources can operate continuously, like conventional fossil-fueled power plants, renewable resources, such as wind and solar, operate intermittently.

A wind turbine can generate electricity only when wind speed is within a range consistent with the turbine's physical specifications. This requires a special set of rules with respect to real-time operational dispatch and capacity rights. To address the latter concern, PJM has established a set of business rules unique to intermittent resources for determining capacity rights. This

value is used to ensure resource adequacy based on the amount of power output PJM can expect from each unit over peak summer hours. PJM business rules permit these values to change as annual operating performance data for individual units is analyzed. Until such time, class averages, or specific data provided by the developer, establish the amount of CIRs that a unit may initially request.

Generators powered by intermittent resources, such as wind, frequently require analytical studies unique to their particular characteristics. For example, wind-powered generator requests are clustered in areas that are most suitable to their operating characteristics and economics, but they have less access to robust transmission infrastructure. Such an injection of power increases system stress in areas already limited by real-time operating restrictions. Consequently, RTEP studies include complex power-system stability and low-voltage, ride-through analyses.

PJM's previous interconnection study process is described in [Manual 14A: New Service Request Process](#), and the newly reformed process is described in [Manual 14H: New Service Requests Cycle Process](#), available on the PJM website.

### 1.1.1 — New Service Requests

#### **Interconnection Activity**

As part of the interconnection process, PJM performs System Impact Studies to ensure that new resources interconnect without violating established NERC, PJM, transmission owner and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to interconnect and to participate in PJM capacity and energy markets.

#### **New Service Request Activity**

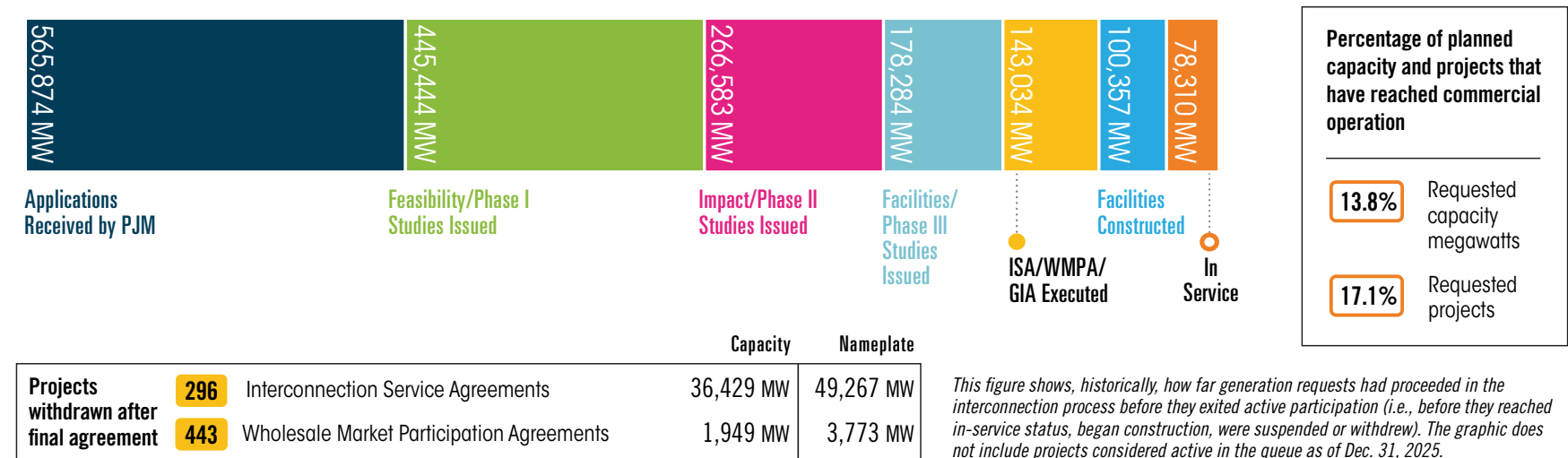
Through 2025, PJM markets have attracted generation proposals totaling 671,190 MW (CIRs), as shown in **Table 1.2**. Over 86,918 MW of capacity of New Service Requests were actively under study, over 20,047 MW of capacity were under construction and 5,318 MW of capacity were suspended as of Dec. 31, 2025. PJM's interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. While withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy as well as regulatory, industry, economic and other competitive factors. PJM's revised interconnection process based on a "first-ready, first-served" philosophy – which took effect in July 2023 – is discussed in **Section 5**.

**Table 1.2:** Interconnection Service Study Requests (Dec. 31, 2025)

	Number of Projects	Nameplate Capability (MW)	Capacity (MW)
<b>Active</b>	1,131	89,133	86,918
<b>In Service*</b>	1,224	97,009	78,310
<b>Under Construction**</b>	324	34,728	20,047
<b>Suspended</b>	116	9,749	5,318
<b>Withdrawn</b>	5,564	644,225	480,597
<b>Total</b>	<b>8,359</b>	<b>874,844</b>	<b>671,190</b>

\* Includes In Service and Under Construction-Partially In Service, \*\*Includes Under Construction and Engineering & Procurement

**Figure 1.6:** Interconnection Service Study Requests (Dec. 31, 2025)



**Interconnection Progression History**

PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. **Figure 1.6** shows that for all generation (both new resources and existing plant uprates) submitted in Queue A (1999) through Dec. 31, 2025, 78,310 MW (or 13.8%) reached commercial operation. As **Figure 1.6** also shows, 36,429 MW (or 6.4%) of that

account for withdrawals from the interconnection process after Interconnection Service Agreement (ISA) or Generation Interconnection Agreement (GIA) execution, and 1,949 MW (or 0.3%) represent withdrawals after wholesale market participant agreement (WMPA) execution, but before construction. Overall, 23.2% of projects that requested uprates to existing capacity reached commercial operation.

### Interconnecting Reliably

A key component of PJM's RTEP process is the assessment of New Service Requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. The PJM Board has approved network facility reinforcements totaling over \$9 billion since the inception of the RTEP process in 1997. The PJM Board approved the incorporation of 445 new network system enhancements totaling approximately \$959.1 million into the RTEP in 2025 alone.

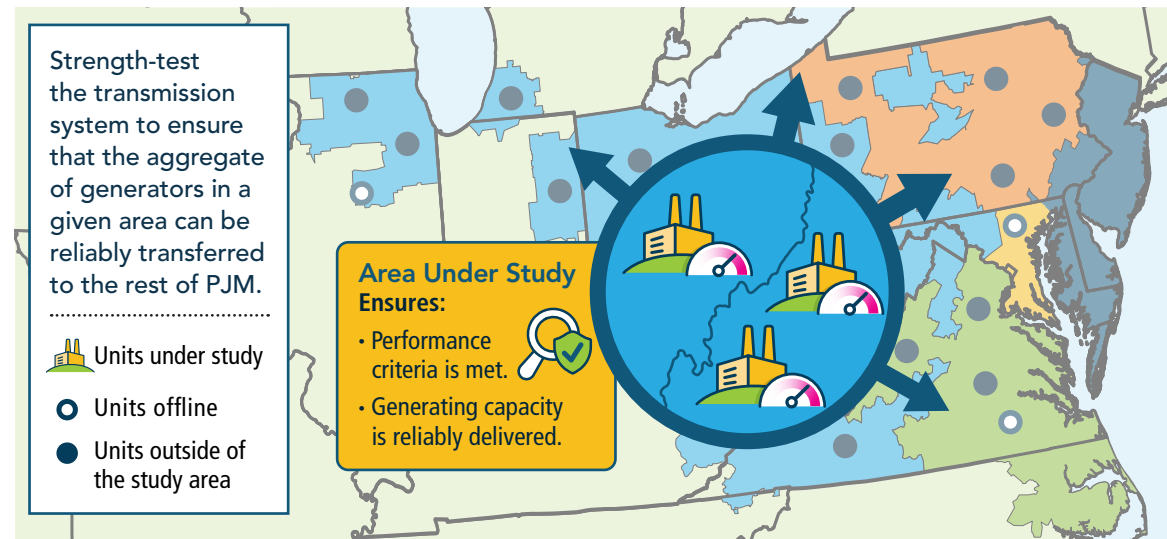
As described in **Section 1.2**, PJM tests for compliance with all reliability criteria imposed by NERC and PJM regional reliability criteria as well as transmission owner criteria. Specifically, NERC reliability standards require that PJM identifies the system conditions to be evaluated that sufficiently stress the transmission system to ensure that it meets the performance criteria specified in the standards. PJM's generator deliverability test ensures that sufficient transmission capability exists to deliver generating capacity reliably from a defined generator or area to the rest of PJM load, as illustrated in **Figure 1.7**.

#### 1.1.2 — Deactivations

PJM received 30 deactivation notifications in 2025 totaling 6,532 MW. **Map 1.2** shows the deactivation request locations received between Jan. 1, 2025, and Dec. 31, 2025.

Generator owners requested that the deactivation of these units takes place between December 2024 and December 2030. PJM maintains a list of formally [submitted deactivation requests](#), which is available on the PJM website.

**Figure 1.7:** Generator Deliverability Concept

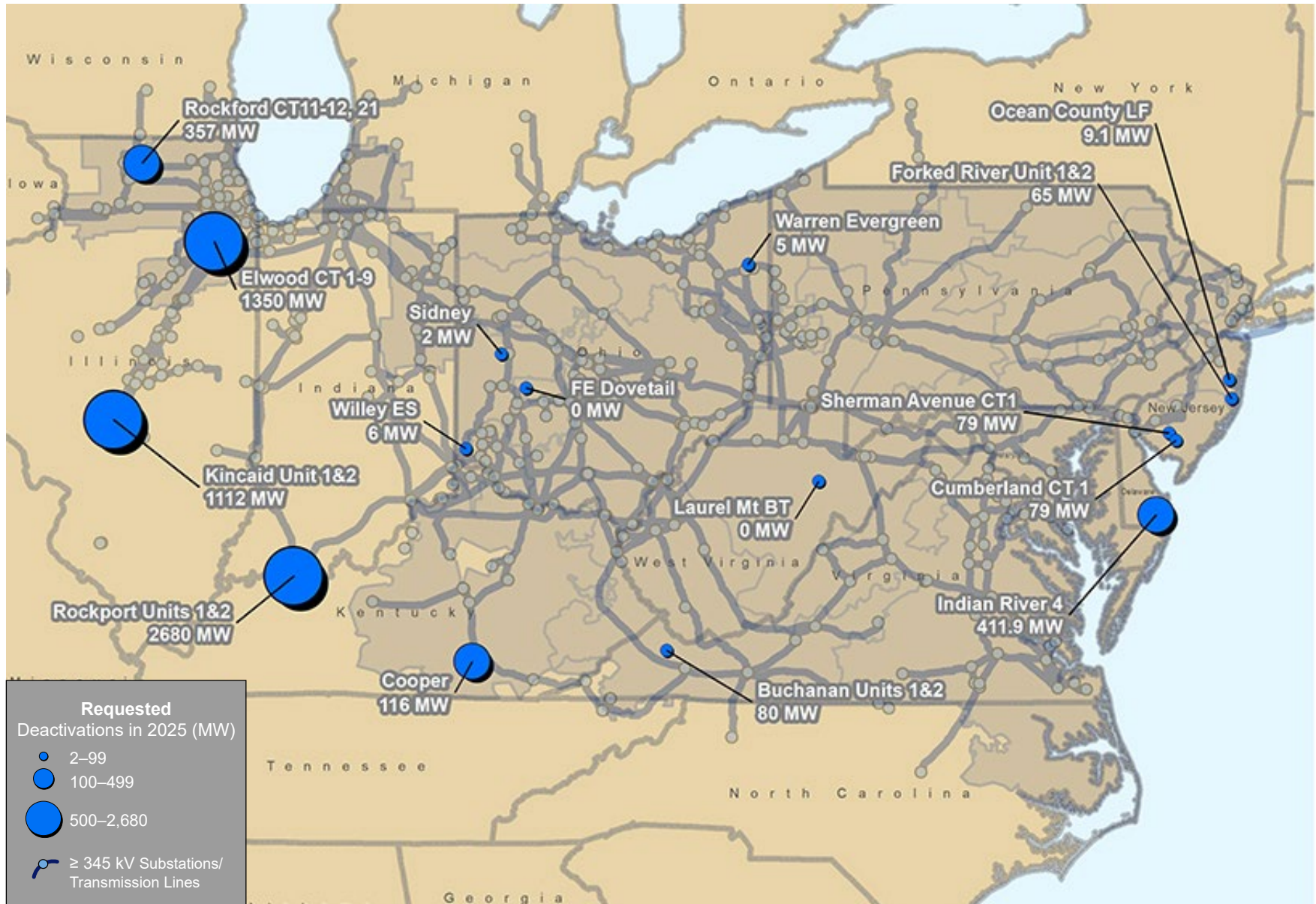


PJM will notify the generator owner, or its designated agent, of analyses results by:

- Feb. 28 of the following calendar year if the Transmission Provider received the Deactivation Notice between Oct. 1 and Dec. 31
- May 31 of the current calendar year if the Transmission Provider received the Deactivation Notice between Jan. 1 and March 31
- Aug. 31 of the current calendar year if the Transmission Provider received the Deactivation Notice between April 1 and June 30
- Nov. 30 of the current calendar year if the Transmission Provider received the Deactivation Notice between July 1 and Sept. 30

Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support. Deactivation reliability studies include thermal and voltage analysis, such as generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by a unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board.

Map 1.2: Deactivation Notifications Received in 2025



**Section 202(c) Emergency Orders**

The Department of Energy issued five emergency orders to PJM in 2025 under its Federal Power Act section 202(c) authority. Orders 202-25-4, 202-25-8 and 202-24-10 each directed PJM and Constellation Energy to ensure that Units 3 and 4 at the Eddystone Generation Station remain available for operation to “minimize the risk of generation shortfall that could lead to unnecessary power outages.” Orders 202-25-6 and 202-25-6A required PJM and Talen Energy Corporation to operate Unit 4 at the Wagner Generating Station “as PJM deems necessary beyond its environmental run-hour limitations” and to “meet anticipated electricity demands heading into the winter months.”

The Department of Energy’s summaries of each of the orders are available on the Department’s [website](#).

## 1.2: Baseline Project Drivers

### 1.2.1 — NERC Criteria – RTEP Perspective

PJM's RTEP process rigorously applies NERC's Planning Standard TPL-001-5 through a wide range of reliability analyses, including load and generation deliverability tests, over a 15-year planning horizon. PJM documents all instances where the system does not meet applicable reliability standards and develops system reinforcements to ensure compliance. NERC penalties for violation of a standard can be as high as \$1 million per violation, per day.

PJM addresses transmission expansion planning from a regional perspective, spanning transmission owner zonal boundaries and state boundaries, to address the comprehensive impact of many system enhancement drivers, including NERC reliability criteria violations. Reliability criteria violations may occur locally, in a given transmission owner zone, driven by an issue in that same zone. Violations may also be driven by some combination of regional factors.

#### **Bulk Electric System Facilities**

NERC's planning standards apply to all bulk electric system (BES) facilities, defined by ReliabilityFirst Corporation and the SERC Reliability Corporation, to include all of the following power system elements:

- Individual generation resources larger than 20 MVA, or a generation plant with aggregate capacity greater than 75 MVA, that are connected via step-up transformer(s) to facilities operated at voltages of 100 kV or higher

- Lines operated at voltages of 100 kV or higher
- Associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment)

The ReliabilityFirst definition of BES facilities excludes the following:

1. Radial facilities connected to load-serving facilities, or individual generation resources smaller than 20 MVA, or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher
2. The balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and its associated step-up transformer); these facilities would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions.
3. All other facilities operated at voltages below 100 kV

Given this definition, PJM conducts reliability analyses on PJM Tariff facilities, which may include facilities below 100 kV, in coordination with PJM markets, to ensure system compliance with NERC Standard TPL-001-5. If PJM identifies violations, it develops transmission expansion solutions to resolve them as part of its RTEP window process.

#### **NERC Reliability Standard TPL-001-5**

Under NERC Reliability Standard TPL-001-5, "planning events," as NERC refers to them, are categorized as PO through P7 and defined in the context of system contingency. PJM studies each event as part of one or more steady-state analyses as described in [PJM Manual 14B: PJM Region Transmission Planning Process](#), available on the PJM website.

- PO – No Contingency
- P1 – Single Contingency
- P2 – Single Contingency (bus section)
- P3 – Multiple Contingency
- P4 – Multiple Contingency (fault plus stuck breaker)
- P5 – Multiple Contingency (fault plus relay failure to operate)
- P6 – Multiple Contingency (two overlapping single contingencies)
- P7 – Multiple Contingency (common structure)

Consistent with NERC definitions, if an event comprises an equipment fault such that the physical design of connections or breaker arrangements also take additional facilities out of service, then they are taken out of service in the study as well for simulating the event. For example, if a transformer is tapped off a line without a breaker, both the line and transformer are removed from service as a single contingency event.

PJM N-0 analysis, shown in **Table 1.3** as a NERC planning event and mapped to planning event P0, examines the BES as is, with all facilities in service. PJM identifies facilities that have pre-contingency loadings that exceed applicable normal thermal ratings. Additionally, bus voltages that violate established limits are specified in [PJM Manual 3: Transmission Operations](#), available on the PJM website.

Similarly, N-1 analysis, mapped to planning events P1 and P2, requires that BES facilities be tested for the loss of a single generator, transmission line, transformer, shunt device, bus section fault or an internal breaker fault. Likewise, bus voltages that exceed limits specified by [PJM Manual 3](#) are also identified. While the generator deliverability test is applied to events P1 and P2, the load deliverability test is only applied to event P1 (loss of a single generator, transmission line, transformer or shunt device).

PJM N-1-1 analysis, mapped to planning events P3 and P6, examines the impact of two successive N-1 events with redispatch and system adjustment prior to the second event. Monitored facilities must remain within normal thermal and voltage limits after the first N-1 contingency and redispatch within applicable emergency thermal ratings and voltage limits after the second contingency as specified in [PJM Manual 3](#).

PJM's N-2 multiple contingency and common mode analyses evaluate planning events P4, P5 and P7 to look at the loss of multiple facilities that share a common element or system protection arrangement. These include stuck breaker events, delayed fault clearing due to failure of

**Table 1.3:** Mapping RTEP Analysis to NERC Planning Events

Steady-State Analysis	NERC Planning Events
Base case N-0 – No Contingency Analysis	P0
Base case N-1 – Single Contingency Analysis	P1, P2
Base case N-2 – Multiple Contingency Analysis	P4, P5, P7
N-1-1 Analysis	P3, P6
Generator Deliverability	P0, P1, P2
Common Mode Outage Procedure	P4, P5, P7
Load Deliverability	P0, P1
Light-Load Reliability Criteria	P1, P2, P4, P5, P7

a non-redundant component of a protection system or double-circuit tower line outages. N-2 analysis is conducted on the base case itself.

Common mode analysis is conducted within the context of PJM's deliverability testing methods, discussed in [PJM Manual 14B](#), available on the PJM website. NERC Standard TPL-001-5 includes extreme events as well. PJM studies system conditions following a number of extreme events, also known as maximum credible disturbances, judged to be critical from an operational perspective for risk and consequences to the system.

#### **Stability Requirements**

PJM conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operations throughout PJM's planning horizon. NERC criteria disturbances are those required by the NERC planning criteria applicable to system-normal, single-element outage and common mode, multiple-element outage conditions.

One of the new aspects of NERC Reliability Standard TPL-001-5 (compared to the previous TPL-001-4) is that it calls for evaluating the failure of a non-redundant component of a protection system, which significantly increases the scope of Category P5 planning events. Non-redundant components of a protection system to consider include:

- A single protective relay
- A single communication system associated with protective functions
- A single-station dc supply associated with protective functions
- A single-control circuitry associated with protective functions

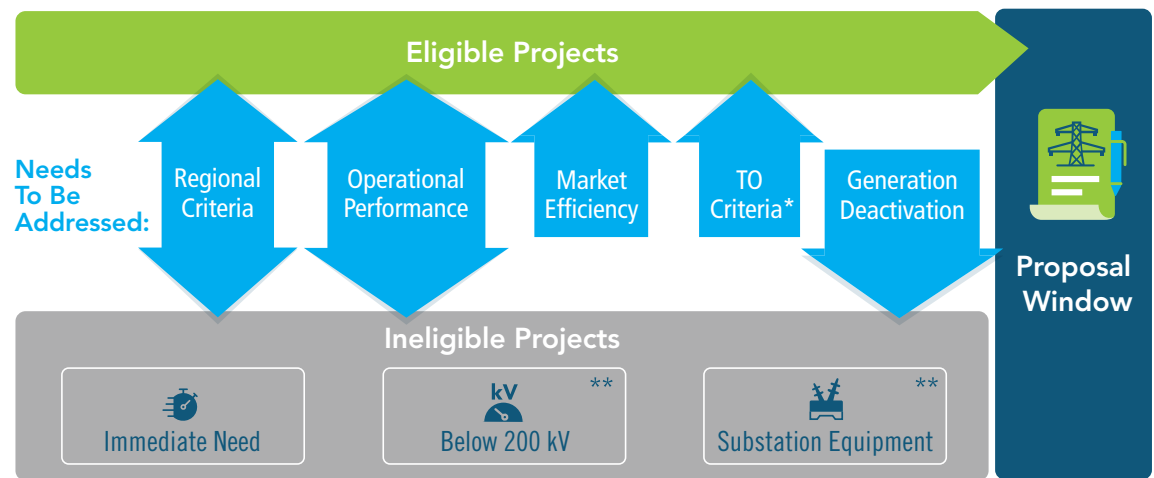
- Another new aspect of NERC Reliability Standard TPL-001-5 requires the planning coordinator or transmission planner to assess the stability impact of:
- Selected known outage(s) of transmission facility(ies) or generation
- The unavailability of major transmission equipment that has a lead time of one year or more in the near-term planning horizon

### 1.2.2 — Transmission Owner Criteria

The PJM Operating Agreement specifies that individual transmission owner (TO) planning criteria are to be evaluated as a part of the RTEP process in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions, such as in urban areas. TOs are required to include their individual criteria as part of their respective FERC Form 715 filings. [TO criteria](#) can be found on the PJM website.

As part of its RTEP process, PJM applies TO criteria to the respective facilities that are included in the [PJM Open Access Transmission Tariff \(OATT\)](#) facility list. Transmission enhancements driven by TO criteria are considered RTEP baseline projects and are eligible for proposal window consideration, as shown in **Figure 1.8**. Under the terms of the OATT, the costs of such projects are allocated 100% to the TO zone. (As of Jan. 1, 2020, TO criteria projects are included in PJM's competitive proposal process.)

**Figure 1.8:** RTEP Proposal Window Eligibility



**Note:** \*TO criteria-driven violations are eligible for proposal windows as of Jan. 1, 2020.

\*\*Projects below 200 kV and substation equipment projects could become eligible for competition if multiple needs share common geography/contingency or if the project has multi-zonal cost allocation.

### 2025 Transmission Owner Criteria-Driven Projects

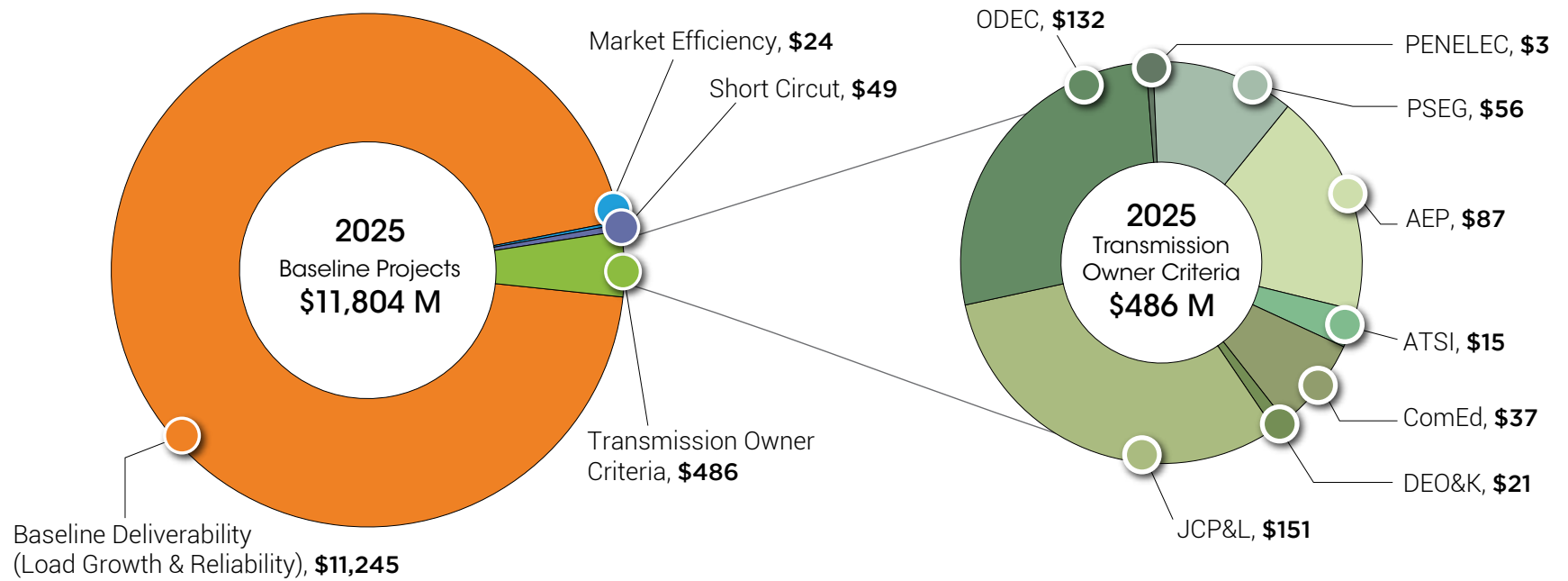
TO criteria are increasingly driving the need for baseline projects. Spare 500/230 kV transformers, aging 500 kV line rebuilds and other equipment enhancements approved in prior years are already part of the RTEP.

In other instances, TO criteria encompass local loss-of-load thresholds, particularly on radial facilities. The threshold for some is on a megawatt-mile basis, others on a megawatt-magnitude basis, to reduce the extent of load impacted under contingency or outage conditions.

### 1.2.3 — Developing Transmission Solutions

After PJM identifies a baseline transmission need, including needs arising out of market efficiency studies, PJM may open a competitive proposal window, depending on the required in-service date, voltage level and likely project scope. Window eligibility for project driver types is shown in **Figure 1.8**. Throughout each RTEP window, developers can submit project proposals to address one or more needs. When a window closes, PJM evaluates each proposal to determine if any meet all specified project requirements. If so, PJM then recommends a proposal to the PJM Board. Once the Board approves a proposal, the designated developer becomes responsible for financing, project construction, ownership, operation and maintenance.

**Figure 1.9: 2025 RTEP Baseline Project Drivers (\$Million)**



**2025 Baseline Project Drivers**

PJM RTEP baseline analysis identifies the need for transmission enhancement projects that span a range of drivers. Those projects identified by PJM and approved by the PJM Board for the 2025 RTEP were no different, as discussed in later sections of this report and summarized in **Figure 1.9**.

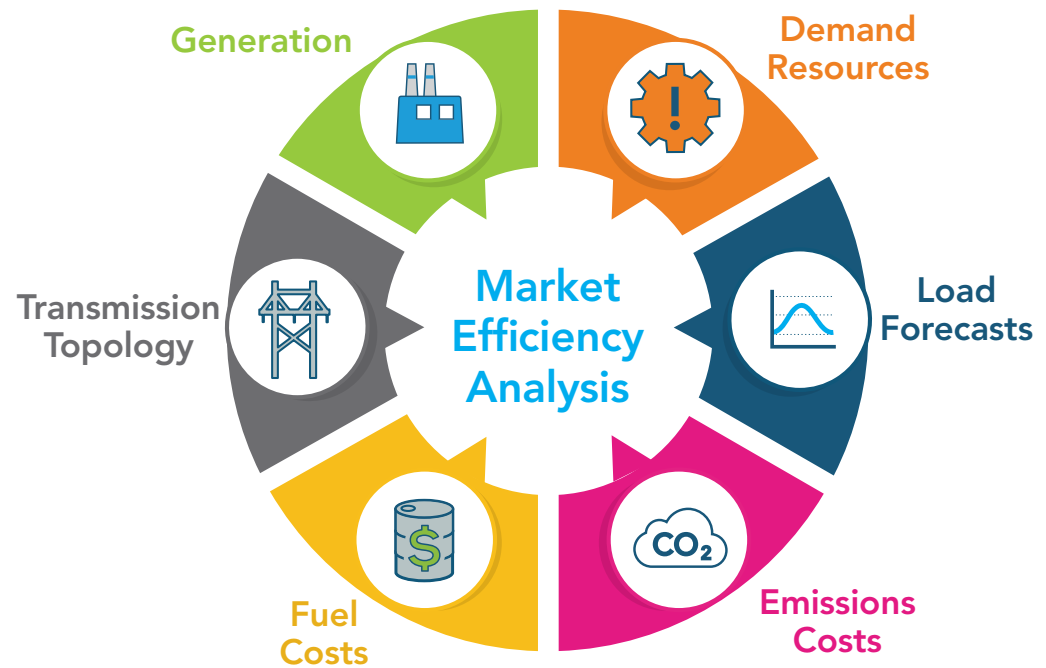
### Market Efficiency

PJM's RTEP process includes market efficiency analysis to accomplish the following goals:

- Determine which reliability-based enhancements have economic benefit if accelerated.
- Identify new transmission enhancements that may realize economic benefit.
- Identify the economic benefits associated with reliability-based enhancements already included in the RTEP that, if modified, would relieve one or more congestion constraints, providing additional economic benefit.

PJM identifies the economic benefit of proposed transmission projects by conducting production cost simulations accounting for the concepts in **Figure 1.10**. These simulations show the extent to which congestion is mitigated by a project for specific study-year transmission and generation dispatch scenarios. Economic benefit is determined by comparing future-year simulations both with and without the proposed transmission enhancement. The metrics and methods used to determine economic benefit are described in **Section 4.3**.

**Figure 1.10:** Market Efficiency Analysis Parameters



### 1.3: 2025 RTEP Process Improvement and Updates

As indicated in the [Energy Transition in PJM: Flexibility for the Future report](#), PJM could experience a potential supply shortfall by 2030 as demand continues to grow, resource retirements accelerate and new resource development lags. PJM continues to pursue a number of initiatives, as described in this report, to accelerate the pace of new entry to preserve reliability.

- Load Growth* – PJM is experiencing significant load growth driven primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing. Looking forward, the PJM [2025 Long-Term Load Forecast Report](#) predicts significant growth in electricity demand. As discussed in Section 2, PJM expects its summer peak to increase by 55,779 MW to 209,923 MW by 2035. This represents an annual average growth rate of 3.1% over the next 10 years.
- Supply Exit* – Accelerated generator retirements continue, driven by unit age and environmental public policy. Notably, thermal generators – which provide dispatchable generation and other attributes needed to maintain reliability – are retiring at a rapid pace. For perspective, PJM's Energy Transition in PJM: Flexibility for the Future studies modeled, in its Policy scenario, retirements totaling 41 GW of generators fueled by coal, natural gas and oil by 2030.
- Replacement Capacity* – New resource additions are reaching commercial operation more slowly than anticipated, a result of supply chain, permitting, financing and other issues. In short, generator retirements are outpacing new generator additions.

All generating resources do not have the same physical attributes, differing in their ability to provide installed capacity resource adequacy value and such NERC-defined essential reliability services (ERS) as ramping, voltage support, short-circuit current and frequency control, among others.

If current trends continue, PJM will continue to see more inverter-based resources (IBRs), including wind and solar generation, as shown in **Figure 1.5** earlier in **Section 1.1**, showing the breakdown of queued interconnection requests by fuel type as of Dec. 31, 2025. By contrast, fewer conventional synchronous generators, primarily driven by coal and oil deactivations, will be available to provide essential NERC-defined reliability functions. In their place, increasing amounts of variable, intermittent non-synchronous IBRs are connecting to the grid via inverters that utilize power-electronic devices to interconnect to the grid.

#### NOTE:

- On June 24, 2024, PJM published the [Energy Transition in PJM: Flexibility for the Future report](#).
- On Aug. 8, 2024, an [addendum](#) to the report was published.

**Resource Adequacy**

Growing levels of intermittent and limited-duration IBRs, such as wind, solar and battery storage, do not replace conventional large-scale generation installations megawatt for megawatt. Rather, they require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation technologies, available at different times, are required to replace a megawatt of thermal generating capacity.

**Essential Reliability Services**

As PJM and other RTOs have identified, IBRs currently do not supply the full range of reliability attributes (inertia, voltage control, stability, ramping and short-circuit current) that conventional, directly synchronized generators provide. Planners and operators must consider these factors as older conventional generators – coal-fired ones in particular – continue to retire. Maintaining an adequate level of generation resources with the right operational and physical characteristics is essential for PJM's ability to serve consumer demand. The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. Today, thermal resources supply essential reliability services. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability.

**RTEP Process Changes To Enhance Reliability**

To mitigate the risk of resource adequacy capacity shortage and ERS decline, PJM's Board of Managers has directed a number of planning process initiatives intended to enable capacity interconnection more expeditiously:

- Interconnection Process Reform
- Reliability Resource Initiative (RRI)
- Surplus Interconnection Service (SIS)
- Capacity Interconnection Rights (CIRs) Transfer Reforms

These initiatives are part of a broader set of actions, described in **Section 1.3**, that PJM has undertaken to ensure that reliability remains paramount.

**NOTE:**

Generator attributes and essential reliability services are described in detail in the following reports:

- [Energy Transition in PJM: Frameworks for Analysis](#), Dec. 15, 2021.
- [Reliability in PJM: Today and Tomorrow](#), March 11, 2021.

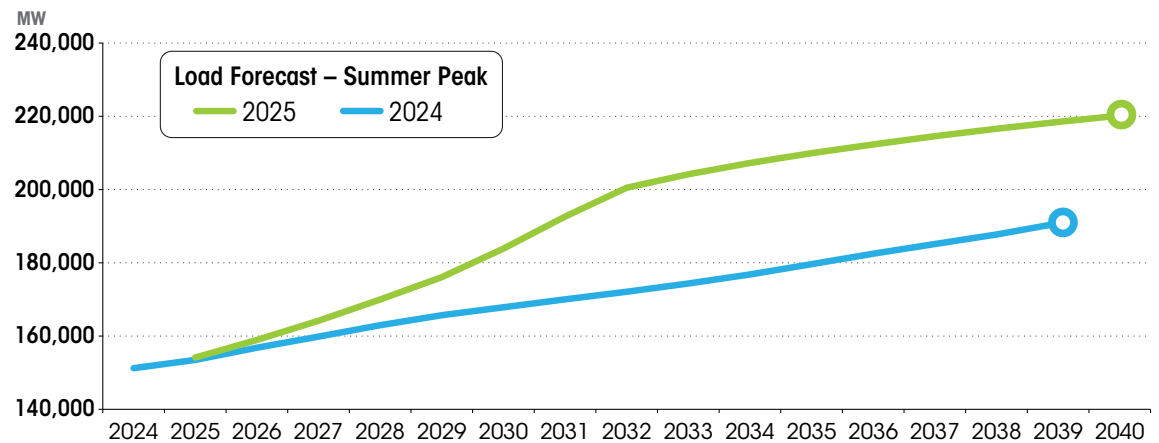
### 1.3.1 — Forecasting Increasing Demand for Electricity

Load forecasting fundamentally drives how PJM plans and operates the bulk electric system and related markets. The growth in electricity demand, or load, is now primarily being driven by the development of energy-intensive data centers and the electrification of vehicles and building heating systems as shown in **Figure 1.11**.

PJM has been identifying trends encompassing large load increases in specific areas, driven primarily by the construction of new data centers, and these were incorporated into PJM's 2025 RTEP cycle analyses for five-year (2030) and eight-year (2033) study-year models. The large load increases are driving heavier, increased regional transfers and consequent need for significant system reinforcement, as discussed further in **Section 3**. PJM's load forecasting process incorporates methods by which it solicits and applies large load adjustments by transmission zone.

Electrification itself is the process of converting conventional end-use load that uses fossil fuels (e.g., gas stoves and oil-burning furnaces) to use electricity instead, as well as the increased use of electric vehicles (EVs). This is having a significant impact on the magnitude of the load forecast and load shape. Notably, additional electric heating will narrow the gap between summer and winter peaks.

**Figure 1.11: Impact of Electrification and Data Center Load on Forecasts**



#### Looking Ahead

As part of compliance with FERC Order 1920, PJM extended its planning horizon from 15 to 20 years. The 20-year annualized growth rate in PJM's 2026 Long-Term Load Forecast for the summer peak is 2.4%, compared with the [2025 Long-Term Load Forecast](#), which saw a comparable growth rate of 2% through 2045. Similarly, PJM's winter peak growth rate is now up to 2.7%, compared with 2.4% for the previous 20-year forecast.

According to the forecast released in January 2026, PJM expects its summer peak to climb about 95,000 MW, to 250,000 MW,

over the next 20 years. For perspective, the record summer peak for the PJM footprint occurred in 2006 at 165,563 MW.

While winter peaks will remain slightly lower, the 2026 Long-Term Load Forecast shows winter closing the gap in peak electricity use, estimated at 235,000 MW by 2045/2046. PJM's record-high winter peak occurred on the morning of Jan. 22, 2025, at 143,336 MW.

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## LARGE LOAD FORECAST ADJUSTMENT PROCESS

Electric distribution companies (EDCs) are encouraged to provide PJM information about large changes that may not be captured in the forecast process. This enables PJM to review requests to determine if they are significant and removes the risk of double-counting based on trends that may already be captured in the economic forecast and/or may need to be removed from historical data.

PJM formally requests information from EDCs on potential load adjustments. Each September, PJM receives and begins to evaluate that information. Requesting EDC/LSEs present their adjustment to the Load Analysis Subcommittee (LAS) in September. PJM planners continue to evaluate and present preliminary accepted adjustments to the LAS. The final accepted adjustments are posted as part of the official PJM Long-Term Load Forecast in January.

PJM, in collaboration with stakeholders, created and published a [Load Adjustment Request Implementation](#) document to provide transparency in how PJM evaluates large load adjustment requests beginning with the 2026 Long-Term Load Forecast. Near-term forecast years are considered to be needing “firm” commitments such as an Electric Service Obligation (ESO) or Construction Commitment (CC), while longer-term projects will be considered “non-firm” and will be derated because of their greater uncertainty.

Notably, load adjustment requests for data centers, port electrification and voltage optimization programs (which conserve energy) have been identified in several PJM TO zones, some of which are impacted by multiple entities’ requests for adjustment. The Dominion transmission zone, for example, includes requests from Old Dominion Electric Cooperative (ODEC), Northern Virginia Electric Cooperative (NOVEC) and Dominion Energy.

Increasing the accuracy of load forecasts increases the accuracy of capacity markets and power flow modeling upon which RTEP process reliability studies are conducted.

### 1.3.2 — Interconnection Process Reform

PJM's interconnection process reform continued in 2025, yielding results described in **Section 5.3**. Interconnection requests for projects that were not eligible for the Expedited Process were studied by PJM under a new cluster study approach.

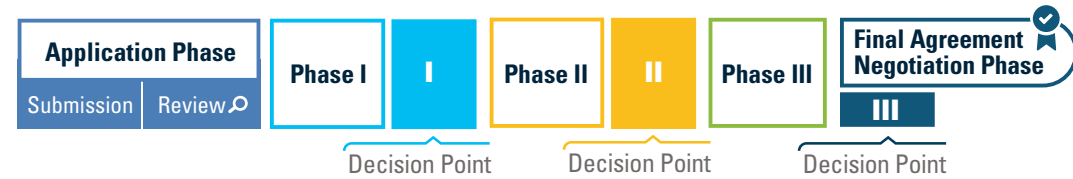
New Generation Interconnection Requests now proceed under PJM's reformed interconnection process that includes three study phases and three decision points before interconnection agreements are executed, as shown in **Figure 1.12**.

Transition Cycle 1, encompassing three phases, began in January 2024 with Final Agreements issued in December 2025. Transition Cycle 2, which began in June 2024, completed Decision Point I and began Phase II in December 2025.

#### ***New Service Request Study Phases***

Phase I of each study cycle includes peak analysis and light load generator deliverability power flow analysis and TO Interconnection Facilities' desk-side estimates. Phase II includes completion of power flow retool load flow, short-circuit analysis, stability analysis, voltage analysis, Facilities Study, Affected System Operator's Affected System Study where necessary (i.e., MISO, NYISO, Duke, LGEE and/or TVA), and any additional special studies specific to merchant transmission requests or storage requests. During Phase III, PJM conducts power flow retool load flow, short-circuit and stability studies based on decisions made by developers at Decision Point II, and coordinates required studies with Affected System Operators.

**Figure 1.12:** Reformed Interconnection Process



#### ***New Service Request Decision Points***

At Decision Point I, developers must provide the following in order to stay in the Transition Cycle, among other items as described in PJM Manual 14H:

- Second readiness deposit
- Demonstration of Site Control as a way of showing readiness
- Valid corresponding interconnection request with any required adjacent control areas
- Evidence of air and water permits

At Decision Point II, developers must submit the following, among other items as described in PJM Manual 14H:

- Third readiness deposit
- Evidence of executed Affected System Study Agreement
- Evidence of air and water permits
- Notification in writing that Project Developer elects to exercise the Option To Build for Stand-Alone Network Upgrades with respect to its New Service Request.

At Decision Point III, developers must submit the following:

- Sufficient security to cover Network Upgrade costs
- Evidence of 100% Site Control
- Evidence of fuel delivery agreement or water agreement (if necessary) and control of right-of-way for fuel and water interconnections
- Evidence of any necessary local, county and state site permits
- Notification in writing that the Project Developer or Eligible Customer elects to proceed to Final Agreement with respect to its New Service Request
- A signed memorandum of understanding (MOU) for acquisition of major equipment

New Service Requests that bear no cost responsibility for Network Upgrades, per PJM analysis, and do not require further studies may accelerate to Final Agreement at Decision Point I or Decision Point II.

**NOTE:** A full description of the New Service Requests Cycle Process can be found in [PJM Manual 14H](#).

### **Implementing Innovative Tools**

As part of a comprehensive modernization effort, PJM continues to enhance its suite of innovative interconnection tools: Queue Scope, Queue Destination, NextGen, DocuTrack and InfraTrack. Together, they provide streamlined, transparent and efficient processing at each interconnection request stage from initial exploration through construction and commercial operation.

- 1** *Queue Scope* is an interconnection screening tool that empowers Project Developers to evaluate potential Points of Interconnection (POI) even before formally entering the PJM interconnection process. By leveraging the most up-to-date system data, Queue Scope allows developers to assess grid impacts, estimate facility loading and analyze megawatt injection or withdrawal scenarios. This user-friendly tool provides a platform for developers to receive preliminary system loading conditions, enabling informed decision-making early in the process and reducing business-decision uncertainty.
- 2** *Queue Destination* complements Queue Scope by addressing the technical coordination of the interconnection process for projects accepted into a Cycle. It automates critical tasks, such as model creation, technical study management, result consolidation, cost allocation and report generation. By streamlining collaboration with TOs and facilitating cost estimates, Queue Destination ensures timely and accurate technical evaluations, establishing a solid foundation for each project Cycle. Results from Queue Destination are provided to developers at the conclusion of each Cycle phase, enabling them to review overloaded facilities and estimate reinforcement costs. Queue Destination also handles the agreement and post-agreement activities.
- 3** *NextGen* is a generation lifecycle management tool designed to replace elements of Queue Point in order to provide a “one-stop shop” for Generation Interconnection Requests, Transmission Interconnection Requests and Long-Term Firm Transmission Service Requests. The tool provides developers with more visibility on project studies, status and requirements. The tool increases the efficiency of the study process by automating manual tasks, interconnection process cycle management, task management and integration with other critical PJM tools. NextGen has been fully implemented and in use as of Transition Cycle 2, Decision Point 1.
- 4** *DocuTrack* is a document management system that streamlines PJM workflow that encompasses drafting, negotiating, finalizing and executing Interconnection Service Agreements. DocuTrack has been a valuable aid given the volume of agreements that PJM’s planning engineers and legal staff must process and track.
- 5** *InfraTrack* focuses on efficiently managing projects after interconnection agreement execution. Designed as an internal project management tool, InfraTrack supports PJM engineers who oversee generation interconnection projects that are under agreement. The tool helps maintain project files, document meeting minutes and action items; track agreement milestones; and maintain project completion evidence. InfraTrack ensures clear roles and responsibilities within PJM, highlights priorities at each phase of construction, and enables the team to focus efforts to bring needed generation online as efficiently as possible.

### 1.3.3 — Reliability Resource Initiative

PJM's Reliability Resource Initiative (RRI) creates a reliability on-ramp to Transition Cycle 2 under PJM's interconnection process reform discussed in **Section 5.1**. The RRI is a one-time procedure that expands the eligibility criteria for Transition Cycle 2 so that additional resources may submit Generation Interconnection Requests into the Cycle.

The RRI is intended – along with recent reforms to the capacity market, Surplus Interconnection Service, Capacity Interconnection Rights transfer provisions for deactivating Generation Facilities and other ongoing reliability enhancement initiatives – to address serious resource adequacy concerns discussed earlier:

- Load growth
- Accelerated generator retirements
- The slow pace of new generator additions
- The scope of intermittent and limited-duration resources in the interconnection queue

The multiyear, multiphase study PJM published, [Energy Transition in PJM: Resource Retirements, Replacements & Risks](#), examines these trends that pose increasing reliability risks through 2030.

#### **Recent Capacity Markets Point to Growing Supply and Demand Mismatch**

Recent PJM capacity auctions are already revealing a growing mismatch between electricity supply and demand. The capacity auction for the 2025/2026 Delivery Year held in July 2024 yielded results that showed almost all available capacity participating in

the auction clearing. That auction revealed that only 514 MW of annual Unforced Capacity was offered above the PJM region's reliability requirement. Moreover, the auction for the 2025/2026 Delivery Year resulted in much higher prices than the last several prior capacity auctions. In July 2025, the 2026/2027 Base Residual Auction met the reliability requirement target of 19.1% in reserves but with no excess. RTO-wide prices came in at the FERC-approved cap of \$329.17/MW-day. In December 2025, the 2027/2028 Base Residual Auction fell short of PJM's reliability requirement by 6,623 MW, the first time the auction had not met the reliability requirement since it was created in 2007 as forecasted demand growth continued to outpace new generation resources.

#### **Load Growth Trends**

PJM's [2025 Long-Term Load Forecast Report](#), released in January 2025, notes a projected average RTO summer peak load growth rate of 3.1% over the next 10 years (by 2035). PJM could not have anticipated this growth during the 2020–2022 time frame in which PJM was developing its comprehensive interconnection queue reform and implementation of Transition Cycle 1 and Transition Cycle 2.

#### **NOTE:**

The February 2023 paper titled [Energy Transition in PJM: Resource Retirements, Replacements & Risks](#) can be found on PJM's website.



#### **2025 Generation Additions**

As noted in **Section 1.3**, PJM faces an extreme and rapid tightening of supply and demand for capacity resources and needs additional resources to address PJM's near-term reliability challenge. Generator retirements, load growth, the pace of new entry, and the operating characteristics of intermittent and limited-duration resources that make up a large part of PJM's interconnection process pose increasing reliability risks through 2030 and drive the need for the RRI's implementation.

#### **Note:**

Resource or capacity adequacy of the PJM system is assessed using **loss-of-load expectation (LOLE)**. LOLE is a measure of how often, on average, the available capacity is expected to fall short of demand. LOLE is a statistical measure of the frequency of firm load loss and does not quantify the magnitude or duration of firm load loss. The use of LOLE to assess resource adequacy is an internationally accepted practice. PJM resource adequacy studies are computed using the LOLE criterion of one day in 10 years (translated as 0.1 days per year for annual analyses).

This RRI process is designed to accelerate the interconnection of “shovel-ready” reliability resources, i.e., resources that are able to reach commercial operation within one to three years of executing a Generation Interconnection Agreement (GIA), and to offer at least 10 MW of Unforced Capacity with higher ELCC ratings, into future capacity auctions.

### ***Solving a Potential Capacity Shortfall***

Projects in Cycle 1, under the reformed interconnection process rules, will not have effective interconnection-related service agreements until approximately mid-2028 at the earliest. Therefore, they likely will not be constructed and reach commercial operation until 2031. That will be too late to support identified resource adequacy needs for the 2030/2031 Delivery Year of the PJM capacity market when load growth and generator retirements are expected to outstrip installed capacity in PJM.

PJM currently projects a 10 GW capacity gap in the 2030/2031 Delivery Year. This projection assumes that 40% of eligible generation projects that submit an interconnection request will achieve commercial operation; an optimistic assumption that outpaces historical averages. This projected capacity shortfall could swell further as annual load forecasts are updated.

In contrast to Transition Cycle 1, projects in Transition Cycle 2 (the second and final Cycle during the transition period) can be expected to have effective interconnection-related service agreements by approximately mid-2027 and reach commercial operation by the 2029/2030 Delivery Year. PJM estimates that adding projects via the RRI process to Transition Cycle 2 could advance these shovel-ready projects’ commercial operation dates by at least 18 months. This 18-month head start is key to bringing a significant amount of Unforced Capacity to the PJM markets before 2028, when PJM anticipates the resource adequacy issues will become more severe, and in advance of the 2030/2031 Delivery Year when PJM anticipates that demand could begin to outgrow supply.

#### Note:

**Effective Load Carrying Capability (ELCC)** is a means of assessing resource reliability value (also referred to as capacity value) tied to the concepts of resource adequacy and probabilistic evaluation. For traditional resources, such as a thermal generator, ELCC will be approximately equal to its Unforced Capacity (UCAP) value (where UCAP value is determined based on the resource’s forced outage rate). For variable or energy-limited resources, such as wind, solar and energy storage, ELCC methodology can be applied to derive a UCAP-equivalent value. ELCC results are driven by those hours with high risk or high loss-of-load probability (i.e., hours experiencing shortage or near-shortage conditions).

## RRI FERC FILING

PJM submitted a FERC filing on Dec. 13, 2024, containing Open Access Transmission Tariff (OATT) revisions in Docket No. ER25-712-000 to implement RRI terms and conditions. Rather than opening Transition Cycle 2 to an unlimited number of New Service Requests, the Tariff reforms permit only a limited number of resources that meet detailed individual scoring based on reliability, viability and availability criteria. FERC accepted PJM's RRI filing on Feb. 11, 2025, with a Dec. 14, 2024, effective date, as requested. The application window for RRI projects opened Feb. 28, 2025, and closed March 14, 2025.

### *RRI Process Summary*

PJM has chosen to cap at 50 the number of RRI projects that may enter Transition Cycle 2 to limit the RRI projects' potential impact on legacy Transition Cycle 2 projects, but to allow nearly unrestricted applications to be considered for a spot among those 50. In the event of a tie among two or more projects for the 50<sup>th</sup> score, all projects with that score will be permitted to join Transition Cycle 2. PJM implemented certain minimum requirements for applicants for the RRI process, summarized below.

- First, projects applying for the RRI process must represent a minimum of 10 MW of Unforced Capacity to be considered.
- Second, a project must provide a critical path construction schedule and a signed attestation verifying the accuracy of the information, including all dates, and certify that the developer will exercise commercially reasonable best efforts to meet these dates.
- Third, a developer must provide an RRI deposit in the amount of \$4,000 per megawatt of energy or capacity, whichever is greater. These requirements, and certain post-construction commitments, will further enable the ability of Unforced Capacity to reach commercial operation more quickly.

### *Top 50 RRI Projects – Scoring and Weighting*

PJM has developed seven RRI scoring categories, broken into two groups of criteria:

#### 1. Market impact    2. Commercial operation date viability

Market impact criteria categories include the following:

- Amount of Unforced Capacity a project will provide, factoring in its ELCC rating. More megawatts at a higher ELCC rating means more impact per megawatt and per project.
- RRI ELCC class rating, indicative of a project's reliability profile. The higher the ELCC rating, the more likely the resource will be available to operate when it is needed for system reliability.
- Location, given that certain LDAs experienced much higher prices than other LDAs in the capacity auction for the 2025/2026 Delivery Year due to a scarcity of capacity.

Commercial operation date viability criteria categories include the following:

- Commercial operation date. This date must be supported by an attestation of an officer, rather than having a cutoff in-service date after which a project would not be eligible for the RRI process.
- Project support. Scoring for this category would be demonstrated by the following: (1) permits; (2) an engineering, procurement and construction agreement; (3) major equipment; and (4) financing, if necessary.
- RRI uprate to a base project already in commercial operation that has an effective interconnection-related service agreement or is being studied already. These projects generally can be brought online quickly.
- Headroom based on PJM power flowgate power flow analyses. PJM will use the project's Point of Interconnection (POI) to determine what reliability violations a prospective RRI project may cause and determine a project's violation points based on how many violations it triggers and at what voltage levels.

PJM crafted the scoring criteria and categories, and the weightings they were given, to ensure that its evaluation of RRI project applications would be as transparent as possible, objective and resource neutral. The RRI scoring and weighting also will allow smaller projects to compete against larger projects and intermittent or limited-duration projects to compete against larger-scale, conventional thermal generation projects.

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## RRI FERC FILING (CONT.)

### *RRI Implementation*

PJM selected 51 projects from 94 applicants using the scoring criteria. PJM originally planned to limit the number of projects in the initiative to 50, but a tie in the weighted scoring system for the last two projects resulted in 51 projects being selected.

The projects consist of 39 uprates and 12 new construction proposals. The uprates apply to existing natural gas, nuclear, coal and onshore wind resources. The uprates total an additional 2,488 MWE that the 39 resources can be expected to provide during times of highest system reliability risk. Of the 12 new projects, six are gas, five are batteries and one is nuclear. The new projects would contribute 9,305 MWE, for a combined total of 11,793 MWE.

The 51 approved RRI projects were added to Transition Cycle 2 and studied with the other Transition Cycle 2 projects during Phase I. Phase I results were posted in October 2025; 41 of the 51 RRI applicants, making up 7,932 MWE and 7,889 MWC, elected to move forward in the Cycle Process at Decision Point I.

#### NOTE:

- A full description of the RRI process, including Transition Cycle 2 integration, as well as project scoring and weighting, can be found in [PJM's RRI FERC filing](#) on PJM's website.
- FERC's [Feb. 11, 2025, order](#) approving the RRI process is available on PJM's website.

### 1.3.4 — Surplus Interconnection Service

Surplus Interconnection Service (SIS) refers to the unused portion of Interconnection Services established in an Interconnection Service Agreement or a Generation Interconnection Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same. The SIS process discussed here allows the installation of additional generation resources to provide energy when the original generation resource may not be performing up to their approved Interconnection Services. SIS is implemented outside of PJM's existing generation interconnection process and is only applicable if no transmission Network Upgrades are required. In the past, PJM's SIS rules did not permit SIS projects in circumstances where it would:

- Require new Network Upgrades.
- Impact determination of necessary Network Upgrades required for interconnection requests already in PJM's queue.
- Impact short-circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response.

### *Easing Reliability Issues*

PJM faces extreme and rapid tightening of supply and demand, driving the need for new capacity resources to meet emerging reliability challenges. PJM implemented Tariff changes in 2025 to encourage and facilitate the use of SIS from existing and planned generating units, such as pairing a renewable resource with battery storage. By taking a less restrictive approach to SIS, PJM is in a better position to maximize existing system use, enhancing resource adequacy without the need for additional Network Upgrades. Removing SIS limitations also allows developers to submit requests for its use earlier in a project's development cycle.

## STREAMLINED SURPLUS INTERCONNECTION SERVICE

On Dec. 20, 2024, PJM submitted a filing at FERC, [Docket ER25-778-000](#), to change existing SIS Tariff provisions to remove existing limitations to SIS. FERC accepted [PJM's filing](#) on Feb. 11, 2025, with a March 7, 2025, effective date, as requested. On March 4, 2025, the accompanying Manual 14H revisions were endorsed by stakeholders at the PJM Planning Committee, followed by endorsement at the Markets and Reliability Committee on March 19, 2025. Manual 14H, Section 12 covers the SIS process.

### *Physical Interconnection Facilities*

Language has been added to PJM's Tariff to explicitly allow the construction of additional physical interconnection facilities where developers need them to accommodate requested SIS. This allows parallel operation of a surplus generating unit and an existing or planned generator, which is important for solar facilities seeking to add a closed loop for storage resources.

### *Existing Versus New Network Upgrades*

PJM eliminated the prior restrictions on SIS in instances where the service:

1. [Affects the determination of Network Upgrades for projects already in the interconnection process](#)
2. [Results in material adverse impacts on short-circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response](#)

This change brings PJM's Tariff more in line with other RTOs, which allow for SIS except when it requires new Network Upgrades. Importantly, this ensures that granting SIS has no additional impacts on the determination of the need for upgrades for New Service Requests already in an interconnection process cycle.

### *Planned Generation*

PJM expanded SIS availability to projects that have an Interconnection Service Agreement or Generation Interconnection Agreement but have not reached commercial operation. Former Tariff provisions only permitted SIS requests from existing, operational generators. This reform enabled interconnection customers with unused interconnection service to let other generating facilities use that interconnection service earlier than was currently allowed.

### *Energy Storage*

PJM Tariff provisions now also allow SIS from resources that receive energy from the grid and store it for later grid injection, such as energy storage resources, thus providing them the same SIS opportunities as those available to generating resources.

#### Note:

**"Surplus Project Developer"** is defined in the Tariff as "a Project Developer whose Generating Facility is already interconnected to or has executed (or requested to file unexecuted) an Interconnection Service Agreement or Generation Interconnection Agreement to interconnect to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region."

### 1.3.5 — Interconnection Rights Transfer

Capacity Interconnection Rights (CIRs) permit generation seeking capacity resource status to inject power at a defined Point of Interconnection on the transmission system. Once a developer's generating facility is accredited as deliverable through the applicable Tariff procedures, the developer receives CIRs commensurate with the megawatts identified in its Generation Interconnection Agreement. CIRs continue to exist for one year following the actual unit deactivation date and can be transferred to another generating facility by the owner at the same Point of Interconnection. Once transferred, CIRs continue to exist so long as the new resource continues to meet deliverability testing requirements.

PJM stakeholders and Planning staff have recognized the need for an expedited interconnection process for a replacement resource seeking to use the CIRs of a deactivating resource. Doing so will enable much-needed Replacement Generation in PJM.

## CIR TRANSFER EFFICIENCY ENHANCEMENTS

Stakeholder efforts with PJM since May 2023 culminated in the endorsement of a CIR Transfer Efficiency proposal at the respective Nov. 21, 2024, meetings of the Markets and Reliability Committee and Members Committee. As endorsed, the proposed revisions will expedite the replacement of capacity from deactivating resources. The proposed Tariff revisions will expedite and enhance the transfer of CIRs from deactivating generation resources to Replacement Generation resources by providing a process for Replacement Generation Interconnection Requests that is separate from but parallel to PJM's three-phase, clustered Cycle Process.

On Jan. 31, 2025, PJM submitted a FERC filing in [Docket No. ER25-1128](#) to make the necessary revisions to the PJM Open Access Transmission Tariff provisions and the Reliability Assurance Agreement (RAA).

The revised Tariff:

- Clarifies that all types of resources are eligible to receive CIRs transferred from deactivating facilities, e.g., a deactivating thermal generation resource can be replaced by a battery storage facility, which expands the types of capacity resources that can utilize this faster process at a time when more capacity is needed
- Implements an efficient and timely process to minimize diverting PJM organizational resources away from clustered Cycle studies
- Applies “first-ready, first-served” principles to Replacement Generation Interconnection Requests in a transparent and nondiscriminatory manner
- Ensures that system capability is utilized to a greater extent and on a nondiscriminatory basis
- Clarifies the reliability analyses to be applied to Replacement Generation Interconnection Requests while ensuring that PJM system reliability and the scope of the necessary reliability studies are not degraded

The proposed changes do not apply to the current process of transferring CIRs when the replacement resource does not interconnect to the same substation (at the same or different breaker position in that substation) as the deactivating generator.

On Aug. 8, 2025, PJM's filing was rejected without prejudice by FERC, in part because it allowed a one-time option for a replacement developer to extend the project's commercial operation date. The lack of a maximum time limit undermined the purpose of the generator replacement process, FERC said.

PJM filed an amended proposal on Oct. 31, 2025, in Docket No. ER26-403-000. The updated proposal included the following amendments to the previously rejected filing:

- Modifications to the Replacement Generation Planned In-Service date requirements
- The removal of the one-time option for Replacement Generation to extend milestones once receiving a Generation Interconnection Agreement (GIA)
- The addition that in the event the Replacement Generation application is submitted with a Notice of Intent to Deactivate, Official Deactivation Notice must be supplied prior to the execution of the GIA or the project will be withdrawn
- The addition to allow a Replacement Generation Project Developer a one-time opportunity to submit project changes to address any identified Material Adverse Impact during the study process

On Jan. 29, 2026, FERC approved PJM's Tariff revisions for Replacement Generation Interconnection Service.

### 1.3.6 — State Agreement Approach

As part of the RTEP’s baseline planning process, PJM works with states to implement their public policy goals through various means, including the State Agreement Approach (SAA).

Under this approach, states that wish to build out the transmission system to meet public policy initiatives, such as offshore wind goals,

and are willing to fund them, can use PJM’s competitive planning process to efficiently develop and implement needed grid expansions.

#### ENABLING OFFSHORE WIND IN NEW JERSEY

As described in Section 1.3.5 of the [2023 RTEP Report](#), the New Jersey Board of Public Utilities (NJBPU) initiated an SAA request with PJM to study the transmission needs to locate wind-powered generation off the New Jersey coast. Initially in November 2020, the NJBPU request entailed 7,500 MW by 2035, which was also known as “SAA 1.0.” In October 2022, the NJBPU increased the amount to 11,000 MW by 2040, which became known as “SAA 2.0.” From 2020 through 2024, PJM initiated required RTEP process power flow and other reliability studies based on the respective, requisite SAA study agreements executed between the NJBPU and PJM, as also described in the 2023 RTEP Report.

- **SAA 1.0:** PJM analysis of the NJBPU’s SAA 1.0 request continued in 2024, including expansion of work at the Larrabee Collector substation to include certain pre-build provisions encompassing civil work to minimize disturbance to the shoreline and in the vicinity of the Larrabee substation.
- **SAA 2.0:** On May 28, 2024, the NJBPU announced: “... it will pause on moving forward with the Second State Agreement Approach (SAA) for coordinated offshore wind transmission planning with regional grid operator, PJM Interconnection (PJM). The decision to pause follows the Federal Energy Regulatory Commission’s (FERC) release of Order 1920, which addresses long-term regional transmission planning and PJM’s ongoing interconnection queue reform process, each of which impacts planning and costs. Pausing at this time affords Board staff the opportunity to fully evaluate the implications of the new FERC rule and participate in PJM’s process to ensure the best outcome to meet New Jersey’s transmission needs at the least cost to ratepayers.”

In June 2024, PJM announced that it was pausing further New Jersey SSA 2.0 work.

#### ENABLING OFFSHORE WIND IN MARYLAND

On June 23, 2025, the Maryland Public Service Commission (MDPSC) requested use of the SAA to study the transmission needs to locate wind-powered generation off the Delaware coast. The MDPSC has a public policy requirement to obtain 8,500 MW of offshore wind by 2032. PJM and the MDPSC have been in negotiations since to determine the scope and schedule for future studies.

In August 2025, the NJBPU issued an order requesting to delay transmission work related to the SAA 1.0. PJM and the BPU have been in discussions to ensure PJM respects the NJBPU’s order while maintaining system reliability.

### 1.3.7 — 2025 RTEP Long-Term Scenarios

As part of the 2025 RTEP, Scenario 5 studied the impact of policy-driven deactivations, and Scenario 6 studied the impact of battery dispatch.

Scenario 5 analyzed the reliability impact on the system from anticipated generator retirements due to federal and state environmental policies. In addition to policy-driven generation retirements, other factors such as state Renewable Portfolio Standards (RPS) targets, state resource-specific

targets and resource adequacy requirement targets would impact the future generation mix. Therefore, PJM first carried out an economic capacity expansion study taking all of these factors into account and then carried out a reliability assessment of the power flow cases developed based on a capacity expansion study. Additional details on Scenario 5 are provided in **Section 3.6.2**.

Scenario 6 analyzed the reliability impact on the system if battery storage facilities were dispatched in generation emergencies. PJM carried out a reliability assessment by developing summer and winter power flow models with battery storage facilities dispatched in the power flow cases. Additional details on Scenario 6 are provided in **Section 3.6.3**.

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## FERC ORDER 1920

The Federal Energy Regulatory Commission's Order 1920 requires the submission of two compliance filings. The first concerns long-term regional transmission planning, and the second concerns interregional transmission coordination requirements.

### *Long-Term Regional Transmission Planning*

Throughout 2025, PJM continued to develop a new process for the long-term planning of regional transmission facilities in compliance with FERC Order 1920 and filed a proposed planning protocol on Dec. 12, 2025. PJM's proposed long-term planning process will achieve the Final Rule's goal to transition transmission planning processes toward a more proactive and holistic long-term planning approach.

Consistent with Order 1920, PJM's proposed long-term planning approach relies on extensive collaboration with the PJM region's Relevant State Entities, including the development of the assumptions and scenarios used to identify long-term transmission needs and potential transmission solutions. PJM emphasized in its filing that it has developed a long-term approach that holistically accounts for all transmission system needs while accommodating 14 jurisdictions with disparate public policy goals, requirements and transmission needs. PJM's proposed Long-Term Regional Transmission Plan Protocol relies on extensive engagement with states and stakeholders to develop scenarios and identify long-term transmission needs and long-term transmission projects.

In 2026, while awaiting FERC's response on PJM's long-term transmission planning proposal, PJM will continue:

- Developing tools and processes to carry out long-term planning in accordance with the proposed planning protocol that PJM filed with FERC
- Revising applicable PJM manuals to incorporate long-term scenarios, extreme weather sensitivities, a 20-year planning horizon, categories of planning factors, a scenario-planning approach, and ultimate identification of transmission solutions to holistically address reliability, economics and policy needs
- Supporting transmission owners and states as necessary as they develop needed changes to make a FERC filing that implements one or more ex ante cost-allocation methodologies to apply to selected LTRTP processes

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## INTERREGIONAL TRANSMISSION COORDINATION

In 2025, PJM continued to coordinate with its neighbors in compliance with various joint operating agreements. This included participation in:

- The Joint ISO/RTO Planning Committee (JIPC), a collaborative group including PJM, NYISO and ISO-NE
- The Joint RTO Planning Committee (JRPC), which coordinates system planning under the Joint Operating Agreement between MISO and PJM
- The Interregional Planning Stakeholder Advisory Committee (IPSAC), which is facilitated by the JRPC and whose role is to provide stakeholder review and input into coordinated system planning

PJM is also participating in an effort with a neighboring grid operator to evaluate interregional processes and benefits calculation methods and meet FERC Order 1920 interregional compliance. PJM provided regular updates on these efforts at IPSAC meetings.

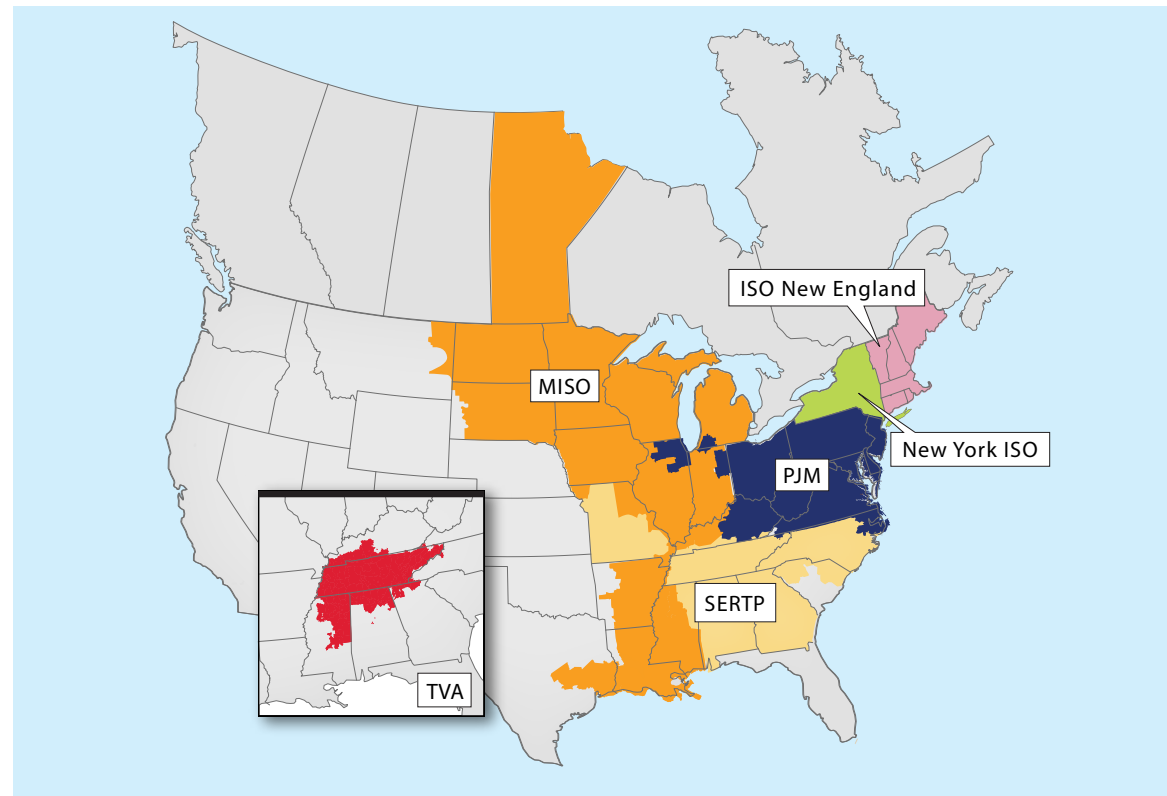
In 2026, PJM will continue to work with stakeholders and neighboring regions' Transmission Providers (TPs) to revise existing interregional transmission coordination procedures consistent with FERC Order 1920.

### 1.3.8 — Interregional Transfer Capability

As discussed in **Section 3.5**, PJM has interregional planning agreements with the New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), the Mid-Continent Independent System Operator (MISO), the Tennessee Valley Authority (TVA) and to the south through the Southeastern Regional Transmission Planning (SERTP) process, shown on **Map 1.3**. Under each interregional agreement, provisions governing coordinated planning ensure that critical cross-border operational and planning issues are identified and addressed before they impact system reliability or adversely impact efficient market administration.

As PJM's June 2024 report [Energy Transition in PJM: Flexibility for the Future](#) discusses, resource diversity across the Eastern Interconnection has allowed PJM and its neighbors to coordinate day-to-day power transfers to leverage economic opportunities and ensure reliability and resilience during periods of system stress. Increasing amounts of intermittent wind power, solar power and energy storage coupled with the retirement of large-scale thermal generation raise concerns about the ability of systems to lean on each other during periods of system stress and support greater interchange variability.

**Map 1.3:** PJM Interregional Planning



**NOTE:**

The June 24, 2024, [Energy Transition in PJM: Flexibility for the Future report](#) can be found on PJM's website.

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## PJM/MISO INTERREGIONAL TRANSFER CAPABILITY STUDY (ITCS)

On May 9, 2024, PJM and MISO announced they were embarking on [a study](#) to identify near-term upgrades that incrementally enhance transfer capability between the two RTOs. Increasing transfer capability between regions may help support greater grid resilience, particularly following extreme weather events and the influx of renewable generation resources with intermittent output. The study effort was driven by input from the Organization of PJM States (OPSI), the Organization of MISO States (OMS) and the Midwestern Governors Association (MGA). The study identified potential opportunities for near-term transmission enhancements along the seam shared by PJM and MISO.

In 2025, PJM and MISO completed the Interregional Transfer Capability Study, a significant effort that included the reliability, economic and transfer analyses using forward-looking models and assumptions for a 2032 model year. Results were presented at 2025 IPSAC meetings. In 2026, PJM and MISO have communicated their efforts to continue the 2025 work by focusing on potential interregional benefits determination calculation approaches and compliance with FERC Order 1920. PJM and MISO staff will continue to update the IPSAC in 2026.

This study, along with FERC Order 1920, will pave the way for future efforts focused on longer-term needs and greenfield solutions. Following the study, MISO and PJM will partner with states and stakeholders to identify and consider pursuing Joint Operating Agreement/Tariff adjustments as needed to bring solutions forward for implementation.

## 1.4: Optimizing Regional Transmission Infrastructure Investment

PJM's RTEP process identifies transmission projects needed to serve customers by ensuring compliance with national and regional reliability criteria to prevent overloaded facilities and potential blackouts. Today, PJM's RTEP process studies the interaction and impact of many system need drivers: load growth, generation retirement, new services like Generation Interconnection Requests, aging infrastructure, operational performance, market efficiency, public policy, electrification and other demand-side trends.

Fundamentally, in order to conduct these studies, PJM's RTEP process employs analytical deliverability tests that simulate stressed, emergency grid conditions as described in **Section 1.2**. This ensures power can be delivered when it is most needed, i.e., when local generation cannot meet customer demand. The outcome of these RTEP analyses yields three types of transmission projects.

1

**Baseline Projects.** In developing the RTEP, PJM tests the baseline adequacy of the transmission system to deliver energy and capacity resources to each load in the PJM region. The PJM transmission system provides the means for delivering the output of interconnected generators to the load centers in the PJM energy and capacity markets. Baseline reliability analyses ensure the security and adequacy of the transmission system to serve all existing and projected long-term firm transmission use including existing and projected native load growth as well as market efficiency and long-term firm transmission service.

2

**Customer-Funded Projects.** These encompass Network Upgrades, Local Upgrades or Merchant Network Upgrades, the cost of which are paid for by a New Service Customer. All entities requesting interconnection of a Generating Facility (including increases to the capacity of an existing generating unit) or requesting interconnection of a Merchant Transmission Facility within the PJM region must do so through PJM's interconnection process. PJM studies the interconnection and deliverability of Generation or Transmission Interconnection Requests or Upgrade Requests in the local area at the Point of Interconnection to determine whether customer-funded upgrades are required to either interconnect to the system or upgrade existing transmission facilities.

3

**Supplemental Projects.** These arise out of transmission owner-identified needs associated with a transmission expansion or enhancement not required to comply with PJM reliability, operational performance, FERC Form No. 715 or economic criteria. Transmission owners in the PJM footprint plan supplemental projects in accordance with the OATT Attachment M-3 Process. Projects planned through the OATT Attachment M-3 Process could include those that:

- Expand or enhance the transmission system.
- Address local reliability issues.
- Maintain the existing transmission system.
- Comply with regulatory requirements.
- Implement transmission owner asset management activities, including needs related to transmission facilities approaching the end of their useful life.

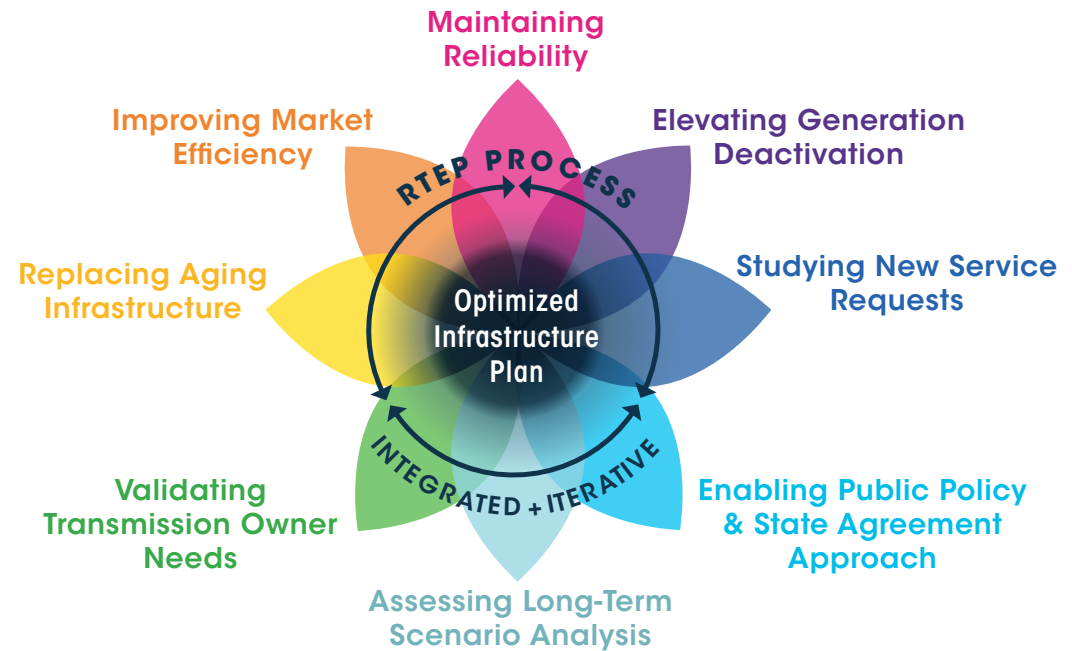
As **Figure 1.13** shows, PJM's comprehensive, regional transmission plan is the outcome of overlapping and interacting analytical processes, not siloed ones. PJM leverages opportunities to optimize regional transmission infrastructure investment under one plan by developing efficient solutions across all three types of transmission: baseline, customer-funded and supplemental.

#### 1.4.1 — Baseline Market Efficiency Opportunities

As discussed in **Section 4**, PJM performs market efficiency analysis as part of the RTEP process baseline analysis in pursuit of the following opportunities:

- Identify new transmission enhancements or expansions that could relieve transmission constraints (i.e., congestion) that have an economic impact on customers.
- Review costs and benefits of economic market efficiency-driven transmission projects previously included in the RTEP to assure that they continue to be cost beneficial.
- Determine which reliability-driven transmission projects, if any, provide an economic market efficiency benefit if accelerated or modified.
- Identify reliability-driven transmission projects already included in the RTEP that could be designed in a more robust manner in order to relieve one or more economic constraints or provide additional economic benefits.

**Figure 1.13:** Optimizing Regional Transmission Infrastructure Investment



PJM identifies the economic benefit of proposed transmission projects by conducting production-cost simulations. These simulations show the extent to which congestion is mitigated by a project for specific study-year transmission and generation dispatch scenarios. Economic benefits are determined by comparing future-year simulations both with and without the proposed transmission enhancement.

#### 1.4.2 — Optimizing Baseline Enhancements and Interconnection Upgrades

When PJM identifies instances where increasing the capability of an RTEP project would obviate the need for a separate Network Upgrade driven by a Generation Interconnection Request, the interconnection customer's incremental need(s) is (are) factored into the RTEP project, and the customer is responsible for the incremental cost of the project. This coordination across processes permits PJM to plan grid enhancements that benefit both load and interconnection customers.

Importantly, PJM has implemented common process controls and assumption alignment for generation interconnection and cases. This is accomplished by leveraging a common system modeling approach to ensure consistent annual power flow base case use for baseline reliability and market efficiency analyses that is then updated for interconnection analysis. This integrated approach ensures:

- Consideration of common load forecast assumptions (based on latest load forecast)
- Inclusion of RTEP baseline and supplemental projects
- Inclusion of previously identified customer-funded upgrades, including those for generation projects that have executed interconnection service agreements (ISAs)
- Alignment of base case assumptions with the model of the Eastern Interconnection
- Recently deactivated generators
- Accurate Capacity Interconnection Rights, or CIRs

PJM's RTEP process incorporates procedures that require the baseline studies to be completed annually to "lock down" the annual base case prior to commencing interconnection studies. This process provides a New Service Customer with a complete system model by which to make informed business decisions based on new system capabilities using the most recent Board-approved RTEP grid enhancements.

Notably, PJM Board-approved baseline projects, together with supplemental projects, are included in the RTEP and reflected in power flow base case models, so interconnection customers can take advantage of remaining system capability, i.e., "headroom," available on the transmission system before the need for customer-funded Network Upgrades are identified.

#### 1.4.3 — Baseline, Supplemental and Customer-Funded Investment

PJM works with stakeholders to identify any transmission projects that interact electrically. By doing so, PJM is able to develop more efficient or cost-effective solutions:

- Between an OATT Attachment M-3 project and an existing baseline project
- After a supplemental project is included in the Local Plan but not yet included in the RTEP base case
- After an RTEP project is included in the base case (in a prior RTEP cycle) and an identified supplemental project or customer-funded upgrade interacts with the RTEP project

PJM's process provides the opportunity to discuss these interactions with stakeholders at the TEAC and Subregional RTEP Committee meetings.

#### ***Achieving Baseline and OATT Attachment M-3 Process Efficiencies***

The OATT Attachment M-3 Process allows PJM transmission owners to plan supplemental projects. Instances arise in which projects driven by Operating Agreement, Schedule 6 (i.e., baseline projects), and the OATT Attachment M-3 Process (i.e., supplemental projects) require changes or upgrades to be made to the same transmission facilities on the system. PJM's RTEP process examines overlaps between baseline projects and TO supplemental projects.

During a review of the RTEP analysis, it may become apparent that a supplemental need identified in the OATT Attachment M-3 Process may interact with an identified violation, system condition, economic constraint or public policy requirement posted on the PJM website. In this case, PJM will provide notice of the potential interaction associated with the posted system condition by posting the newly available information to the PJM website and provide notification to stakeholders.

PJM may determine whether to lengthen an open proposal window in order to permit project proposers additional time to consider the availability of new or changed information. PJM can consider proposals, including proposals in its open proposal window, that more efficiently and cost-effectively address both the identified baseline need(s) and any related needs identified in the OATT Attachment M-3 Process.

After PJM has had an opportunity for stakeholder review and comment, PJM determines the action to take depending on the point in the RTEP process in which the electrical interaction has been identified, as described in Section 1.4 of PJM [Manual 14B, PJM Region Transmission Planning Process](#).

### Examples

The following examples show how PJM leverages opportunities to develop cost-effective transmission solutions that address overlapping transmission needs.

1

#### Line A 138 kV Overloads – Optimized Interstate Solution To Address Baseline and Supplemental Needs

In this example, PJM received four proposals to solve baseline overloads on an interstate 138 kV transmission line. As part of its review and analysis of the four window proposals, PJM identified its own solution based on converting six elements of an existing transmission owner supplemental project into a new PJM RTEP baseline project. PJM determined that doing so more cost-effectively addressed both the identified RTEP baseline reliability criteria violations and supplemental project drivers associated with aging infrastructure, operational performance and local power delivery needs. Notably, the cost estimate for the new baseline project was millions of dollars less than two of the original four transmission developer-submitted baseline proposals.

2

#### Local Area 69 kV Thermal Overloads – Optimized Area Solution To Address Baseline and Supplemental Needs

In this example, PJM received three proposals to solve 30 identified baseline thermal overloads on three local 69 kV transmission lines. PJM's review and technical analysis identified the first proposal, which encompassed rebuilds of the three lines as the more cost-effective solution. The project solves all 30 thermal violations and obviates the need to pursue existing M-3 Process local supplemental projects. The supplemental projects intended to address identified aging infrastructure issues on two transmission lines dating back to 1939 with deteriorating wood-pole structures.

#### NOTE:

After PJM has had an opportunity for stakeholder review and comment, PJM determines the action to take depending on the point in the RTEP process in which the electrical interaction has been identified, as described in Section 1.4 of PJM [Manual 14B, PJM Region Transmission Planning Process](#).

## 1.5: RTEP Process Technology Improvements

PJM maintains an ongoing commitment to investing in technological enhancements that automate and streamline the transmission planning process.

Over the past several years, PJM has developed web-based platforms that enable transmission owners, competitive transmission developers, generating resource developers and other stakeholders to submit data required for planning analyses and access information necessary for their respective decision-making processes. These platforms include:

- The Competitive Planner Portal
- The TO Planner Portal
- Transmission Exchange
- Gen Model
- NextGen
- The Queue Destination Transmission Owner Interface

These portals also enhance PJM's ability to efficiently review submitted data and integrate it into analytical workflows. In 2025, PJM made significant improvements to NextGen, enabling it to be used in Transition Cycle 2.

### Platforms

1

#### Competitive Planner Portal

PJM's Competitive Planner Portal allows competitive transmission developers review reliability issues identified by PJM and to submit transmission project proposals to address the reliability issues.

2

#### TO Planner Portal

Functionally similar to the Competitive Planner, PJM's TO Planner Portal is focused on noncompetitive projects and do-no-harm analysis.

3

#### Transmission Exchange

Transmission Exchange is a portal for transmission owners to provide status updates on the progress of under construction transmission projects.

4

#### Gen Model

Gen Model is PJM's tool for in-service generation to update required model data for the MOD-032-1 standard.

5

#### NextGen

NextGen is PJM's portal for resource developers to submit projects into an interconnection Cycle process.

6

#### Queue Destination Transmission Owner Interface

The Queue Destination Transmission Owner Interface is PJM's interface for transmission owners to review reliability issues identified by PJM through the interconnection Cycle process and proposed transmission projects to address the reliability issues.

PJM also continues to advance its analytical capabilities. In collaboration with PowerGEM, PJM has transitioned several internal, power flow-intensive reliability assessments (including N-1-1, Load Deliverability and Generation Deliverability analyses) to commercially available products. This transition improves tool quality and enables stakeholders to conduct preliminary analyses on their own before submitting proposals to PJM.

PJM has also completed work to batch and parallelize analysis using the commercially available job parallelization tool EnFuzion

via PJM’s internal Solutions Workbench. Additionally, PJM has developed internal applications such as Queue Destination to streamline the processing of analytical results, facilitate preliminary reinforcement assignments, automate cost allocation of reinforcements to queued projects and generate detailed reports published on the PJM website.

Effective planning process management and administration represent another area of continuous improvement. Planning Hub, which is an internally developed tool, maintains project status information for transmission system upgrades

and queued generation interconnection requests for staff across the PJM organization. PJM has also developed PowerTemplate to automate the drafting of Generation Interconnection Agreements and related legal documents. PJM’s InfraTrack tool monitors project milestones, critical dates, scope modifications and tasks associated with generation interconnection following agreement execution.

Additional details regarding the efficiencies achieved through these initiatives will be addressed in the future. More information about these tools is available on the [Planning Center](#).

Gen Model

Consistent with NERC's IROD-002-1 standard, each transmission owner, generation owner and load serving entity in PJM's footprint must provide steady state, dynamics, and short-circuit modeling data to PJM as outlined in the IROD-002 Steady State, Dynamics

Begin 2026 Submission

Submissions

Records per page: 100 (1 of 1)

Year	Plant Name	EIA Plant Code	Submission Status
2026	Eddystone Generating Station	3161	Not Started
2026	Brunot Island	2410	Submitted
2026	Herbert A Wagner	10061	Submitted
2026		594	In Progress
2026		591	In Progress
2026	Fonglove Solar Project, LLC	66841	In Progress

Planning Center

General Information

Plant Information

Transmission Owner Area \* [Select]

Plant Name \* [Select]

Number of Units \* [Text Field]

Individual Completing Data

Name \* [Text Field]

Email \* [Text Field]

Phone \* [Text Field]

EIA Generator Codes by Machine | Machine Id | Generator Code | Company Name

NextGen

NextGen

Cycle Timelines

Task Lists | Projects | Cycle Timelines | Letters of Credit | Groups

Transition Cycle 2 | Cycle 01 | Cycle 02

2015 | 2016 | 2017

Project List

Actions	Project ID	PJM Project Name	PO Project Name	Project Developer
[Icon]	AG2-014	Meadow Lake 345 kV	Black Prairie Storage I	Black Prairie Storage LLC
[Icon]	AG2-016	Oyster Creek-Whitings 34.5 kV	Ocean View Solar Farm	Lacey Holding / Ocean View Acres
[Icon]	AG2-029	Forest G. Hipple-Dunton Lake 345 kV	Southern Pike Solar 300 MW	Southern Pike Solar LLC
[Icon]	AG2-037	Findlay-Clinton 23 kV	PG Solar II	PG Solar LLC

## Section 2: Resource Adequacy Modeling

### 2.0: Power Flow Model Load

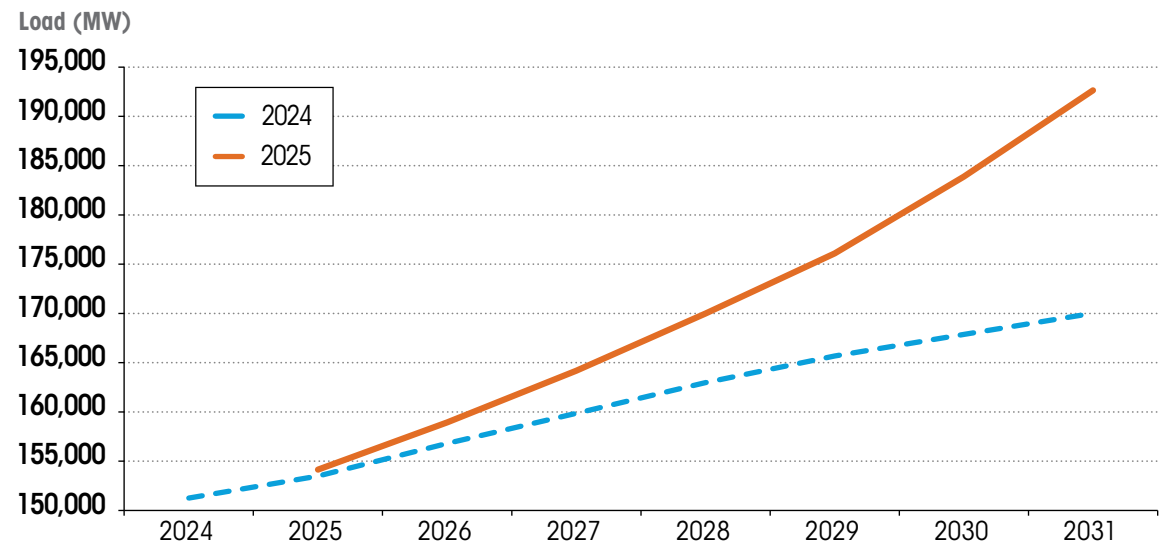
Fundamentally, PJM's planning process identifies future system transmission needs based on power flow studies that identify reliability criteria violations. Power flow study models incorporate the effect of many system expansion drivers. Zonal load forecasts are the basis for power flow case bus loads. Modeling load this way is essential if transmission expansion studies are to yield plans that will continue to ensure reliable and economic system operations.

In order to develop a power flow base case model, PJM first assigns zonal load from its yearly forecast to individual zonal buses according to ratios of each bus load to total zonal load. Ratios are supplied by each transmission owner. Given that loads in different geographical areas peak at different times, for load deliverability studies, zonal load is studied at its non-coincident level (i.e., at the time of the zone's peak).

#### **2025 RTEP Process Context**

PJM's 2025 RTEP baseline power flow model for study year 2030 was based on an overall RTO summer peak load of 183,883 MW as published in the [2025 PJM Long-Term Load Forecast Report](#). The Long-Term Load Forecast Report, which covers the 2025 through 2045 planning horizon, states that PJM projects its RTO-wide summer normalized peak to grow 3.1% annually over the next 10 years, shown in **Figure 2.1**, which is up 1.5 percentage points from the 2024 forecast.

**Figure 2.1: Summer Peak Load Forecast 2025 vs. 2024**



Significant load growth due to new construction of data centers is driving the need for additional sensitivity studies to assess the potential impacts of large, localized load increases on transmission adequacy. PJM will continue to work closely with local transmission owner planners to ensure these load additions are properly captured in future forecasts.

### Load Forecasting Process

PJM's load forecast model produces a 20-year forecast for each PJM zone, Locational Deliverability Area and the RTO. The model estimates the historical relationship between load (peak and energy) and a range of different drivers, including weather variables, economics, calendar effects, end-use characteristics (equipment/appliance saturation and efficiency), distributed solar and battery storage generation, and plug-in electric vehicles. The model then leverages those relationships to derive forecasted load, shown in **Figure 2.2**.

### Hourly Forecast Model Implementation

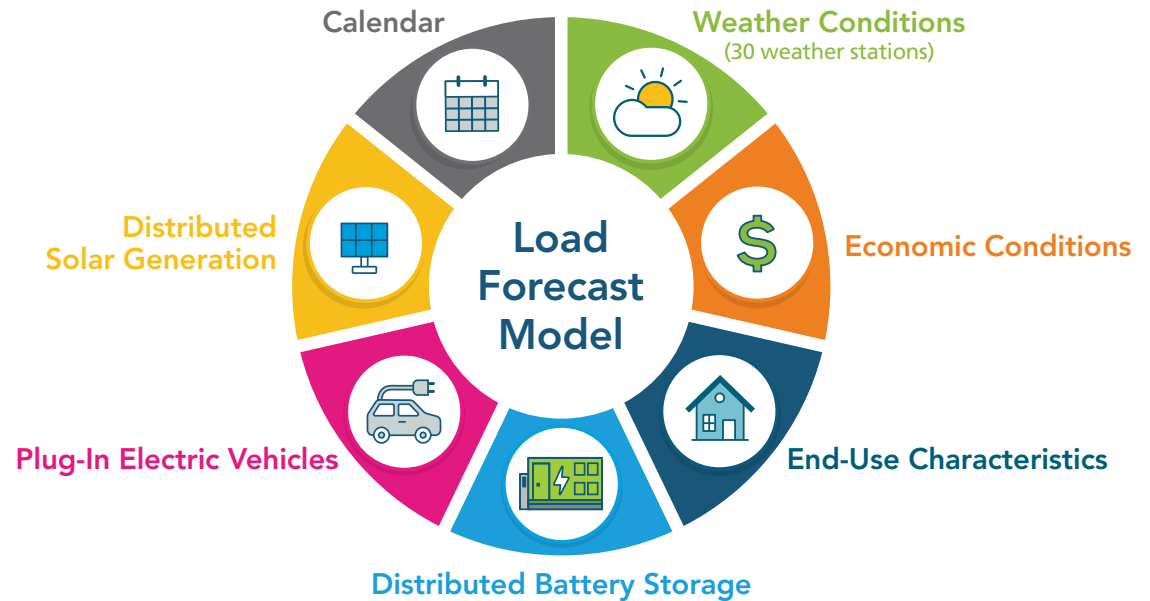
In 2022, based on guidance provided by an independent [consultant's report](#), PJM implemented changes to its hourly forecast model through stakeholder engagement at its Load Analysis Subcommittee and Planning Committee meetings.

Beginning with the 2023 Load Forecast Report, PJM implemented 24 hourly models in each zone. This granularity allows PJM to incorporate the impacts of new technologies on the grid more accurately, including distributed solar and electric vehicles. The forecast also uses monthly data to model residential, commercial and industrial sectors.

### Calibration

The forecast model takes advantage of publicly available sector data to calibrate the independent variables used to forecast load, such as end-use and economic trends. Load data used in the PJM forecast is at the transmission zone level, but unseen are the customers that contribute to that load. These customers broadly come from three sectors: residential, commercial and industrial.

**Figure 2.2:** Load Forecast Model



Understanding trends in each of these categories increases PJM's understanding of their holistic impact at zonal and RTO levels. PJM leverages data from the Energy Information Administration's (EIA) Form 861, the Annual Electric Power Industry Report, to better inform this understanding.

### Weather Conditions

PJM accounts for the impact on load driven by weather conditions through metrics including temperature, humidity and wind speed. PJM obtains weather data from over 30 weather stations across the PJM footprint.

### Calendar

Calendar effects are variables that represent the day of the week, month and holidays.

### Economic Conditions

PJM accounts for the impact of economic conditions on load forecasting by including such factors as real personal income, population and real gross domestic product. This allows for localized treatment of economic effects within a zone. PJM has contracted with an outside economic services vendor to provide forecasts for metropolitan areas within PJM.

### NOTE:

The 2025 Load Forecast was the first forecast that we moved from a 15-year forecast to a 20-year forecast horizon to work toward future 1920 compliance.

### End-Use Characteristics

Residential, commercial and industrial end-use characteristics are captured through three distinct variables: weather-sensitive heating, weather-sensitive cooling and non-weather-sensitive use. Each variable addresses a specific set of equipment types, accounting over time for both the saturation of that equipment type, as well as its respective efficiency. For instance, the cooling variable captures increasing central air conditioning unit efficiency.

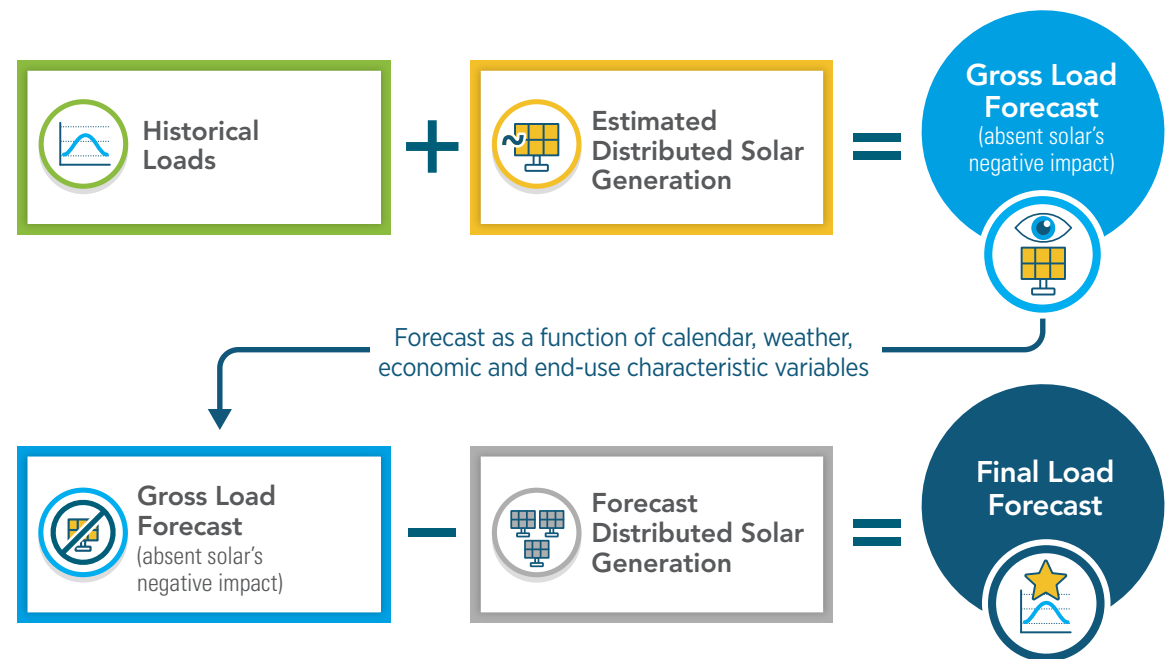
### Plug-In Electric Vehicles

PJM's load forecast incorporates an explicit adjustment for plug-in electric vehicle (PEV) charging in peak megawatt demand and energy forecasts. Starting with the 2024 Long-Term Load Forecast Report, PJM uses a vendor-supplied electric vehicle forecast for light-, medium- and heavy-duty vehicle charging impacts on a zonal basis.

### Distributed Solar and Battery Storage Generation

Distributed solar and battery storage generation lowers load from what it otherwise would be. Recent years have shown a significant ramp-up of behind-the-meter distributed solar resources. The level of distributed solar is significant in certain areas of the PJM region and is expected to increase more in the years ahead. Under PJM's model, distributed hourly solar generation impacts are reflected in its load forecast using the approach shown in **Figure 2.3** to determine a final load forecast.

**Figure 2.3:** Accounting for Distributed Solar Generation



PJM first adds back estimated distributed solar generation to its historical loads to obtain a hypothetical history of loads as if solar did not exist. PJM uses a vendor-supplied historical estimate of hourly distributed solar generation, based on the installation date and location of resources.

Having obtained a load forecast as if solar did not exist, PJM then subtracts existing and forecasted distributed solar and battery storage generation to obtain a final load forecast for each

zone and for the RTO. Forecasted distributed solar and battery storage generation is based on vendor-supplied capacity additions over the ensuing 20 years. The vendor forecast takes into consideration assumptions for federal and state policy, net energy metering policy, energy growth, solar photovoltaic capital costs, power prices and other factors.

## 2.1: 2025 Long-Term Load Forecast Report

The [2025 PJM Long-Term Load Forecast Report](#), used in 2025 RTEP studies, includes forecasted data for the 2025 through 2045 planning horizon. The PJM 2030 RTO-wide summer peak is forecasted to be 183,883 MW. Additional highlights from the forecast are summarized in this section.

### 2.1.1 — Forecasting Trends

**Table 2.1** summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2025 through 2035. All load forecasts in the table reflect adjustments for distributed solar and battery storage generation as well as PEVs. Adjustments to the summer 10-year forecast are summarized in **Table 2.2**. Adjustments to the winter forecast for distributed solar are approximately zero.

**Table 2.3** compares 10-year load growth rates for each PJM transmission owner zone and for the overall RTO over the past five years. PJM zones show higher load growth trends tied to electric vehicle charging and data center load. These trends are subsequently reflected in RTEP process power flow models.

**Table 2.1:** 2025 Long-Term Load Forecast Report: Summer and Winter Peaks

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2025	2035	Growth Rate	2024/25	2034/35	Growth Rate
Atlantic City Electric	2,584	2,619	0.1%	1,645	2,082	2.4%
Baltimore Gas and Electric	6,544	6,993	0.7%	5,897	6,508	1.0%
Delmarva Power	4,005	4,074	0.2%	3,731	3,956	0.6%
Jersey Central Power & Light	6,096	6,397	0.5%	3,995	5,885	3.9%
METED	3,115	3,572	1.4%	2,783	3,263	1.6%
PECO Energy Company	8,606	9,349	0.8%	6,568	7,440	1.3%
Pennsylvania Electric Company (Penelec)	2,944	3,014	0.2%	2,826	2,903	0.3%
PPL Electric Utilities	7,356	13,072	5.9%	7,510	13,228	5.8%
Potomac Electric Power Company (Pepco)	6,069	6,311	0.4%	5,389	5,702	0.6%
Public Service Electric & Gas Company (PSE&G)	10,341	11,785	1.3%	7,329	10,833	4.0%
Rockland Electric Company	415	420	0.1%	231	300	2.6%
UGI Utilities	201	203	0.1%	201	204	0.1%
Diversity – Mid-Atlantic	-1,454	-1,618		-892	-682	
<b>Mid-Atlantic</b>	<b>56,822</b>	<b>66,191</b>	<b>1.5%</b>	<b>47,213</b>	<b>61,622</b>	<b>2.7%</b>
American Electric Power	23,592	40,190	5.5%	22,727	40,379	5.9%
Allegheny Power (FirstEnergy)	8,707	11,151	2.5%	9,074	11,719	2.6%
American Transmission Systems, Inc. (FirstEnergy)	12,847	16,112	2.3%	10,662	14,186	2.9%
Commonwealth Edison	20,565	24,069	1.6%	14,875	19,876	2.9%
AES Ohio	3,348	3,757	1.2%	2,940	3,339	1.3%
Duke Energy Ohio and Kentucky	5,370	5,760	0.7%	4,563	4,976	0.9%
Duquesne Light Company	2,703	2,808	0.4%	1,988	2,125	0.7%
East Kentucky Power Cooperative	2,117	2,192	0.3%	2,761	2,843	0.3%
Ohio Valley Electric Corporation	85	85	0.0%	100	100	0.0%
Diversity – Western	-1,619	-1,803		-1,757	-1,789	
<b>Western</b>	<b>77,715</b>	<b>104,321</b>	<b>3.0%</b>	<b>67,933</b>	<b>97,754</b>	<b>3.7%</b>
Dominion Energy	23,351	42,846	6.3%	23,127	41,480	6.0%
<b>Southern</b>	<b>23,351</b>	<b>42,846</b>	<b>6.3%</b>	<b>23,127</b>	<b>41,480</b>	<b>6.0%</b>
Diversity – Total	-6,817	-6,856		-4,795	-5,152	
<b>PJM RTO</b>	<b>154,144</b>	<b>209,923</b>	<b>3.1%</b>	<b>136,127</b>	<b>198,175</b>	<b>3.8%</b>

**Table 2.2:** 2025 Long-Term Load Forecast Report: Distributed Solar Generation and PEV Adjusted to Summer Peak

Transmission Owner	Adjustment to Summer Peak (MW)					
	Distributed Solar Generation		Plug-In Electric Vehicle		Distributed Battery Storage	
	2025	2035	2025	2035	2025	2035
Atlantic City Electric	127	122	16	170	1	19
Baltimore Gas and Electric	222	289	60	547	3	75
Delmarva Power	118	144	17	173	1	26
Jersey Central Power & Light	309	359	71	600	2	48
METED	56	76	23	403	1	11
PECO Energy Company	86	230	55	477	2	24
Pennsylvania Electric Company (Penelec)	30	78	5	121	1	10
PPL Electric Utilities	152	246	17	209	3	24
Potomac Electric Power Company (Pepco)	236	346	38	277	2	53
Public Service Electric & Gas Company (PSE&G)	443	528	87	742	5	89
Rockland Electric Company	15	27	3	19	0	3
UGI Utilities	1	4	1	11	0	1
American Electric Power	146	399	45	649	2	62
Allegheny Power (FirstEnergy)	114	204	19	232	2	43
American Transmission Systems, Inc. (FirstEnergy)	85	241	43	550	2	34
Commonwealth Edison	479	1,005	141	1,252	11	243
AES Ohio	23	61	8	104	0	9
Duke Energy Ohio and Kentucky	18	77	26	255	1	13
Duquesne Light Company	31	63	18	198	1	8
East Kentucky Power Cooperative	6	22	4	73	0	3
Ohio Valley Electric Corporation	0	0	0	0	0	0
Dominion Energy	597	793	112	943	3	73
<b>PJM RTO</b>	<b>3,487</b>	<b>5,165</b>	<b>811</b>	<b>8,250</b>	<b>43</b>	<b>872</b>

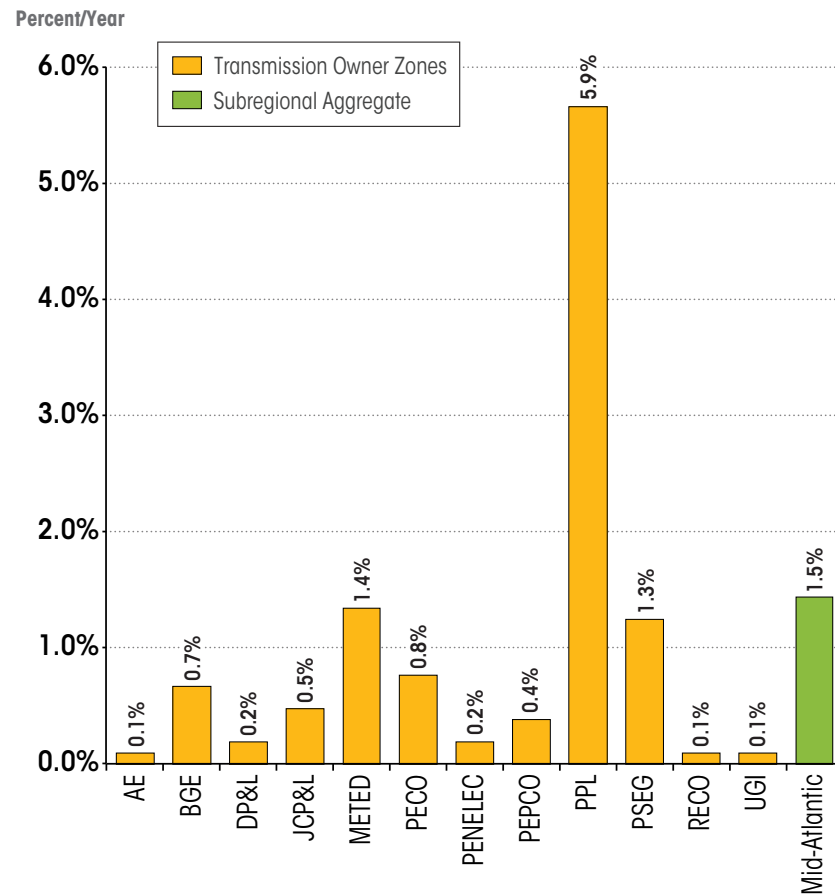
**Table 2.3:** 2025 Long-Term Load Forecast Report: Comparison of 10-Year Summer Peak Load Growth Rates

Transmission Owner	Load Forecast Report Summer Peak (MW)														
	2021			2022			2023			2024			2025		
	2021	2031	Growth Rate	2022	2032	Growth Rate	2023	2033	Growth Rate	2024	2034	Growth Rate	2025	2035	Growth Rate
Atlantic City Electric	2,470	2,605	0.5%	2,488	2,541	0.2%	2,549	2,418	-0.5%	2,593	2,715	0.5%	2,584	2,619	0.1%
Baltimore Gas and Electric	6,582	6,652	0.1%	6,414	6,350	-0.1%	6,474	6,060	-0.7%	6,491	6,931	0.7%	6,544	6,993	0.7%
Delmarva Power	3,895	3,976	0.2%	3,873	3,854	0.0%	3,861	3,666	-0.5%	3,945	4,050	0.3%	4,005	4,074	0.2%
Jersey Central Power & Light	5,876	6,193	0.5%	5,831	5,868	0.1%	6,072	5,830	-0.4%	6,052	6,750	1.1%	6,096	6,397	0.5%
METED	3,060	3,255	0.6%	2,934	3,060	0.4%	3,040	3,112	0.2%	3,036	3,715	2.0%	3,115	3,572	1.4%
PECO Energy Company	8,389	8,691	0.4%	8,370	8,471	0.1%	8,527	8,590	0.1%	8,581	9,031	0.5%	8,606	9,349	0.8%
Pennsylvania Electric Company (Penelec)	2,894	3,164	0.9%	2,812	2,832	0.1%	2,871	2,792	-0.3%	2,867	2,970	0.4%	2,944	3,014	0.2%
PPL Electric Utilities	7,204	7,758	0.7%	7,024	7,237	0.3%	7,175	7,248	0.1%	7,126	7,382	0.4%	7,356	13,072	5.9%
Potomac Electric Power Company (Pepco)	5,924	5,248	-1.2%	5,902	5,766	-0.2%	6,166	6,201	0.1%	6,053	6,440	0.6%	6,069	6,311	0.4%
Public Service Electric & Gas Company (PSE&G)	9,871	10,407	0.5%	9,543	9,857	0.3%	9,904	9,499	-0.4%	10,068	11,193	1.1%	10,341	11,785	1.3%
Rockland Electric Company	396	397	0.0%	391	388	-0.1%	414	416	0.0%	410	421	0.3%	415	420	0.1%
UGI Utilities	195	201	0.3%	193	191	-0.1%	195	189	-0.3%	197	203	0.3%	201	203	0.1%
Diversity – Mid-Atlantic	-986	-810		-629	-875		-1,512	-1,685		-1,586	-1,896		-1,454	-1,618	
<b>Mid-Atlantic</b>	<b>55,770</b>	<b>57,737</b>	<b>0.3%</b>	<b>55,146</b>	<b>55,540</b>	<b>0.1%</b>	<b>55,736</b>	<b>54,336</b>	<b>-0.3%</b>	<b>55,833</b>	<b>59,905</b>	<b>0.7%</b>	<b>56,822</b>	<b>66,191</b>	<b>1.5%</b>
American Electric Power	22,609	23,471	0.4%	22,183	22,496	0.1%	22,453	22,637	0.1%	22,902	26,408	1.4%	23,592	40,190	5.5%
Allegheny Power (FirstEnergy)	8,859	9,140	0.3%	8,675	8,762	0.1%	8,724	9,484	0.8%	8,835	9,755	1.0%	8,707	11,151	2.5%
American Transmission Systems, Inc. (FirstEnergy)	12,525	12,842	0.3%	12,273	12,551	0.2%	11,962	11,593	-0.3%	12,433	12,612	0.1%	12,847	16,112	2.3%
Commonwealth Edison	20,421	19,433	-0.5%	20,787	20,121	-0.3%	20,417	19,595	-0.4%	20,414	20,411	0.0%	20,565	24,069	1.6%
AES Ohio	3,415	3,550	0.4%	3,271	3,288	0.1%	3,295	3,255	-0.1%	3,319	3,385	0.2%	3,348	3,757	1.2%
Duke Energy Ohio and Kentucky	5,390	5,746	0.6%	5,239	5,427	0.4%	5,249	5,126	-0.2%	5,332	5,465	0.2%	5,370	5,760	0.7%
Duquesne Light Company	2,768	2,954	0.7%	2,742	2,837	0.3%	2,712	2,687	-0.1%	2,705	2,855	0.5%	2,703	2,808	0.4%
East Kentucky Power Cooperative	2,130	2,280	0.7%	2,091	2,228	0.6%	2,027	2,084	0.3%	2,070	2,211	0.7%	2,117	2,192	0.3%
Ohio Valley Electric Corporation	90	90	0.0%	90	90	0.0%	95	95	0.0%	90	90	0.0%	85	85	0.0%
Diversity – Western	-2,248	-2,224		-1,647	-1,674		-1,581	-1,676		-1,571	-1,801		-1,619	-1,803	
<b>Western</b>	<b>75,959</b>	<b>77,282</b>	<b>0.2%</b>	<b>75,704</b>	<b>76,126</b>	<b>0.1%</b>	<b>75,353</b>	<b>74,880</b>	<b>-0.1%</b>	<b>76,529</b>	<b>81,391</b>	<b>0.6%</b>	<b>77,715</b>	<b>104,321</b>	<b>3.0%</b>
Dominion Energy	20,150	21,269	0.5%	20,424	25,434	2.2%	21,920	35,789	5.0%	22,781	39,019	5.5%	23,351	42,846	6.3%
<b>Southern</b>	<b>20,150</b>	<b>21,269</b>	<b>0.5%</b>	<b>20,424</b>	<b>25,434</b>	<b>2.2%</b>	<b>21,920</b>	<b>35,789</b>	<b>5.0%</b>	<b>22,781</b>	<b>39,019</b>	<b>5.5%</b>	<b>23,351</b>	<b>42,846</b>	<b>6.3%</b>
Diversity – RTO	-5,889	-5,563		-4,612	-5,268		-7,043	-7,395		-7,053	-7,190		-6,817	-6,856	
<b>PJM RTO</b>	<b>149,224</b>	<b>153,759</b>	<b>0.3%</b>	<b>148,938</b>	<b>154,381</b>	<b>0.4%</b>	<b>149,059</b>	<b>160,971</b>	<b>0.8%</b>	<b>151,247</b>	<b>176,822</b>	<b>1.6%</b>	<b>154,144</b>	<b>209,923</b>	<b>3.1%</b>

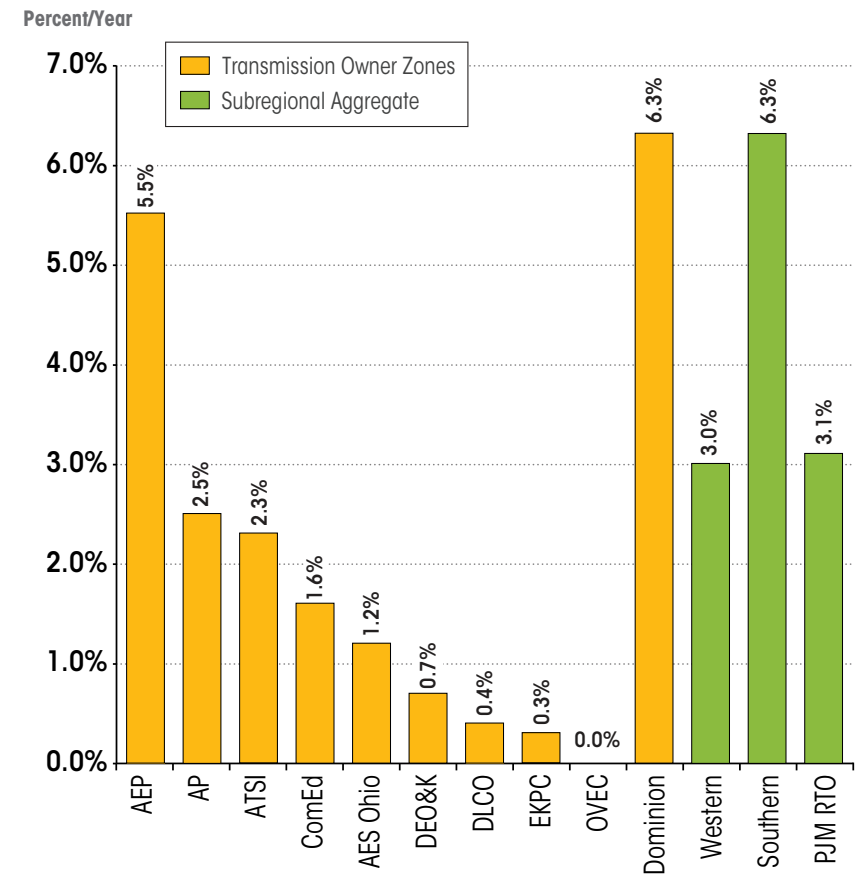
### 2025 Forecasted Summer Zonal Load Growth Rates

The PJM RTO weather-normalized summer peak is forecasted to grow at an average rate of 3.1% per year for the next 10 years. The PJM RTO summer peak is forecasted to be 209,923 MW in 2035, an increase of 55,779 MW over the 2025 peak of 154,144 MW. Individual geographic zone growth rates vary from 0.1% to 6.3%, as shown in **Figure 2.4** and **Figure 2.5**.

**Figure 2.4:** PJM Mid-Atlantic Summer Peak Load Growth 2025–2035



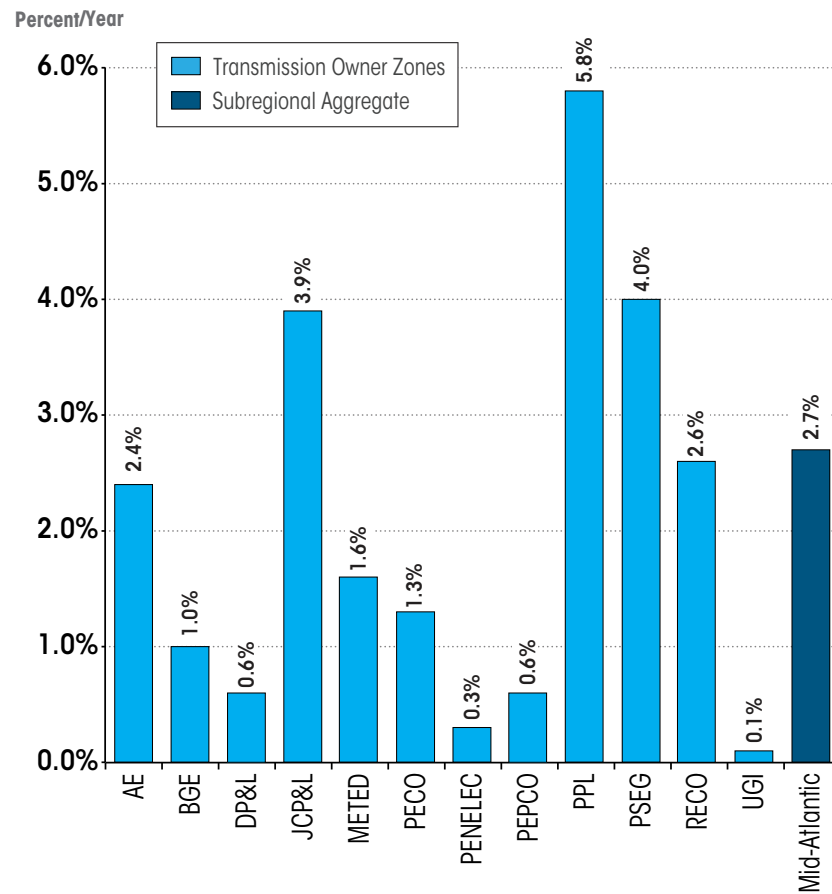
**Figure 2.5:** PJM Western and Southern Summer Peak Load Growth 2025–2035



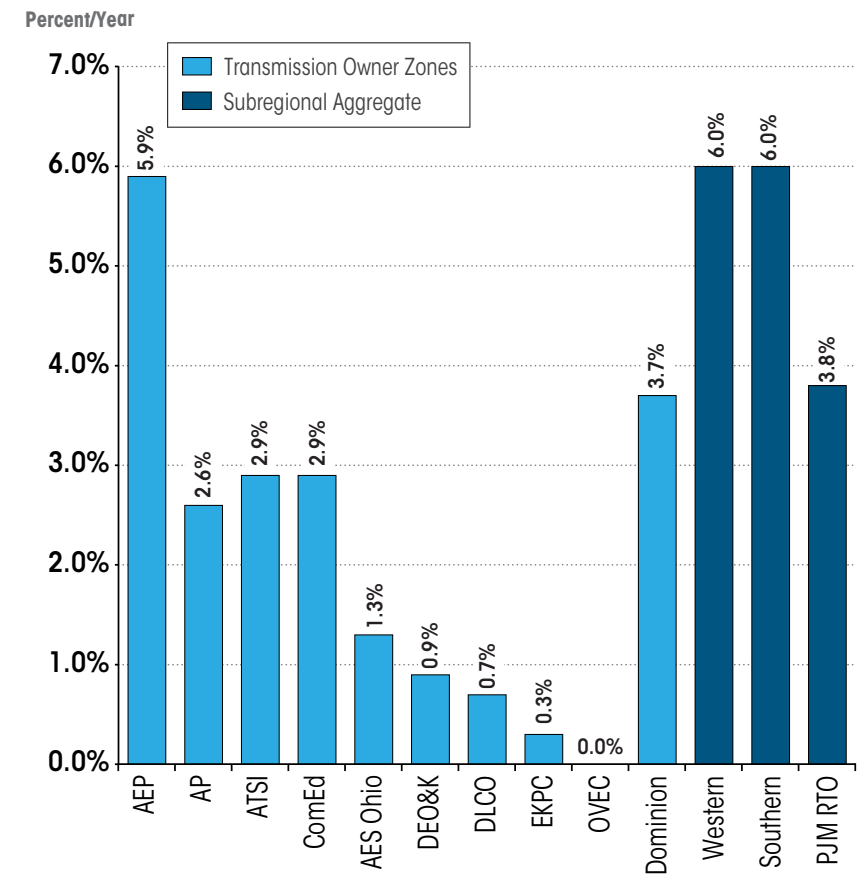
### 2025 Forecasted Winter Zonal Load Growth Rates

The PJM RTO weather-normalized winter peak is forecasted to grow at an average rate of 3.8% per year for the next 10 years. The PJM RTO winter peak is forecasted to be 198,175 MW in 2034/2035, an increase of 62,048 MW over the 2024/2025 peak of 136,127 MW. Individual geographic zone growth rates vary from 0.1% to 6.0%, as shown in **Figure 2.6** and **Figure 2.7**.

**Figure 2.6:** PJM Mid-Atlantic Winter Peak Load Growth 2025–2035



**Figure 2.7:** PJM Western and Southern Winter Peak Load Growth 2025–2035



### Subregional Forecast Trends

**Figure 2.8** provides a summary based on load growth rate trends from the respective January load forecast over each of the last five years, from 2021 through 2025, for the ensuing 10 years on a subregional basis. The growth trend reflects impacts from electric vehicle charging and data center growth, particularly in the Southern Region of PJM, which is growing at an increasing rate due to the large volume of data center activity in this area.

In particular, the 2025 report forecasted that the load growth rate for the RTO increased by 1.5 percentage points (from 1.6% to 3.1%) when compared to the 2024 report.

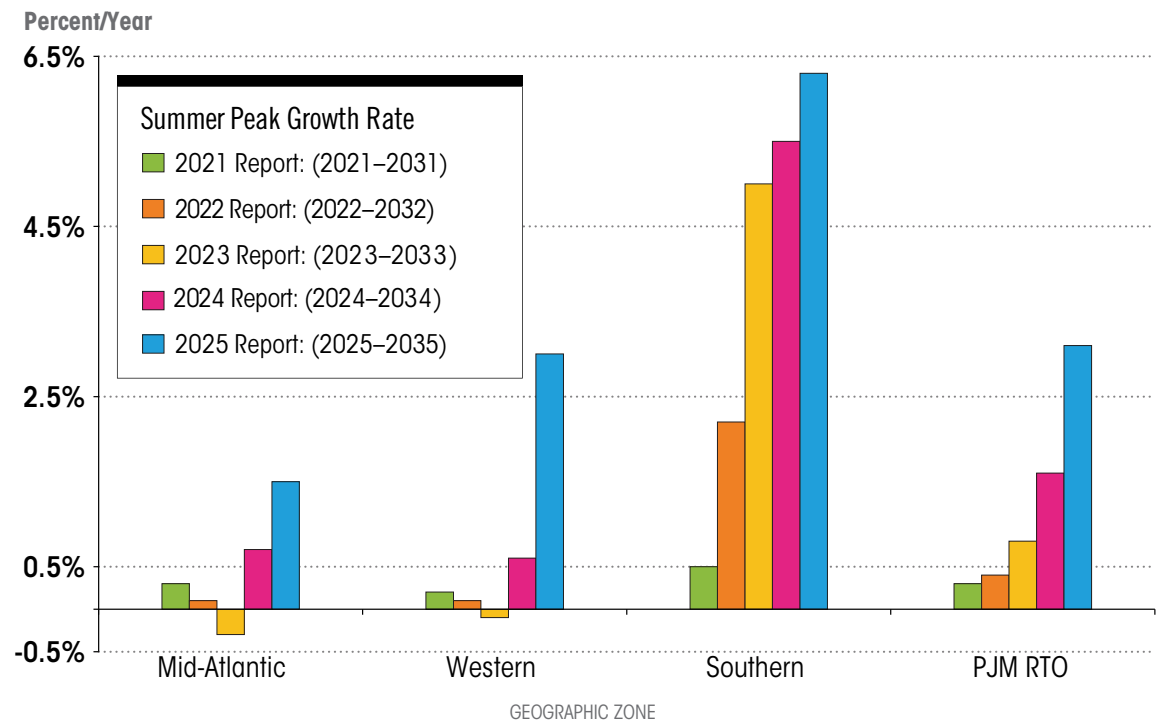
#### 2.1.2 — Discrete Load Adjustments

PJM annually solicits information from its member electric distribution companies (EDCs) and Load Serving Entities (LSEs) for known large load shifts (either positive or negative). Once the request has been verified per the guidelines in Attachment B of [Manual 19](#), PJM accounts for it in its load forecast. Each request is considered on a case-by-case basis, with particular caution paid to avoid double counting anticipated load increases or decreases. These adjustments are summarized in **Table 2.4**.

#### Data Center Load Growth

In the [2025 Long-Term Load Forecast Report](#), forecast adjustments to account for data center growth were made in the American Electric Power (AEP), Allegheny Power (FirstEnergy) (AP), American Transmission Systems, Inc. (FirstEnergy) (ATSI), Baltimore Gas and Electric (BGE), Commonwealth Edison (ComEd), AES Ohio, PECO Energy Company (PECO), PPL Electric Utilities (PPL), Public Service Electric & Gas

**Figure 2.8: PJM 10-Year Summer Peak Load Growth Rate Comparison 2021–2025 Long-Term Load Forecast Reports**



Company (PSEG), and Dominion Virginia Power zones. An adjustment in the Dominion zone has been in place in some form since the 2014 Load Forecast Report. The rationale for making an adjustment for data centers is that these centers have a load impact that is disproportionate with their economic impact. Data centers generally require minimum staffing and thus would not have a significant impact on economic variables but do have a considerable impact on energy demand.

#### Other Discrete Load Adjustments

In addition to data center load forecast adjustments, the [2025 PJM Long-Term Load Forecast Report](#) had adjustments for port electrification, industrial loads and voltage optimization. Port electrification is included in the PSEG zone, while industrial load adjustments are included in the DEO&K, ComEd and AEP zones. A negative adjustment for voltage optimization impacts the Dominion zone.

**Table 2.4:** 2025 Long-Term Load Forecast Report: Large Load Adjustments in 2025 and 2035

Transmission Owner	Total Load Associated With Adjustments to Summer Peak Load (MW) for Each PJM Zone	
	2025	2035
Atlantic City Electric	0	0
Baltimore Gas and Electric	12	318
Delmarva Power	0	0
Jersey Central Power & Light	0	0
METED	0	0
PECO Energy Company	0	427
Pennsylvania Electric Company (Penelec)	0	0
PPL Electric Utilities	93	5,528
Potomac Electric Power Company (Pepco)	0	0
Public Service Electric & Gas Company (PSE&G)	289	1,235
Rockland Electric Company	0	0
UGI Utilities	0	0
<b>Mid-Atlantic</b>		
American Electric Power	1,761	18,017
Allegheny Power (FirstEnergy) (AP)	8	2,239
American Transmission Systems, Inc. (FirstEnergy) (ATSI)	56	2,792
Commonwealth Edison	546	4,822
AES Ohio	0	334
Duke Energy Ohio and Kentucky	0	243
Duquesne Light Company	0	0
East Kentucky Power Cooperative	0	0
Ohio Valley Electric Corporation	0	0
<b>Western</b>		
Dominion Energy	4,970	23,464
<b>PJM RTO</b>	<b>7,735</b>	<b>59,419</b>

## 2.2: Demand Resources and Peak Shaving

PJM forecasts the amount of demand response (DR) resources based on committed quantities in previous Reliability Pricing Model (RPM) auctions. Those amounts, as reflected in the [2025 PJM Long-Term Load Forecast Report](#), are shown in **Table 2.5** for each transmission zone. An adjusted forecast (peak load forecast less forecasted DR) is then used in RTEP power flow model studies that focus on summer peak capacity emergency conditions, during which demand resources are assumed to be implemented. Consequently, DR can have a measurable impact on future system conditions and the potential need for transmission system enhancements to serve load. Forecasted values for each zone are determined based on the following steps:

1. Compute the final amount of committed DR for each of the three most recent delivery years. Express the committed DR amount as a percentage of the zone's 50/50 forecasted summer peak from the January load forecast report immediately preceding the respective delivery year.
2. Compute the most recent three-year-average committed DR percentage for each zone.
3. Multiply each zone's 50/50 forecasted summer peak by the results from step two to obtain the DR forecast for each zone.

Alternatively, load management can directly impact the unrestricted peak load forecast through a peak shaving program. Peak shaving program administrators provide

PJM with information on curtailment behavior (e.g., temperature/humidity trigger), which PJM then uses to adjust the load forecast accordingly. East Kentucky Power Cooperative (EKPC) included a peak shaving program starting with the 2023 Delivery Year that was included in the 2023, 2024 and 2025 load forecasts.

### **Capacity Performance Impacts**

PJM's RPM transition to Capacity Performance in 2016 has required a transition in the treatment of DR as well. **Table 2.5** assumes the following:

- Annual DR resources are assumed to be Capacity Performance DR and are based on actual committed quantities of DR products in the 2022/2023, 2023/2024, 2024/2025 and actual cleared quantities in the 2023/2024, 2024/2025 and 2025/2026 RPM Base Residual Auctions for Price Responsive Demand.
- Summer-period DR resources refer to DR that aggregates with winter-period resources to form a year-round commitment.

Both existing and planned DR may participate in auctions, provided the resource resides in a party's portfolio for the duration of the delivery year. Further details can be found in [PJM Manual 19](#), Load Forecasting and Analysis, available on the PJM website.

**Table 2.5:** 2025 Long-Term Load Forecast Report: Demand Resources

Transmission Owner	Total Load Management	
	2025	2035
Atlantic City Electric	50	51
Baltimore Gas and Electric	305	326
Delmarva Power	190	210
Jersey Central Power & Light	117	122
METED	161	185
PECO Energy Company	330	359
Pennsylvania Electric Company (Penelec)	241	247
PPL Electric Utilities	446	783
Potomac Electric Power Company (Pepco)	264	303
Public Service Electric & Gas Company (PSE&G)	254	290
Rockland Electric Company	2	2
UGI Utilities	0	0
<b>Mid-Atlantic</b>	<b>2,360</b>	<b>2,878</b>
American Electric Power	1,408	2,398
Allegheny Power (FirstEnergy) (AP)	559	716
American Transmission Systems, Inc. (FirstEnergy) (ATSI)	806	1,010
Commonwealth Edison	1,383	1,619
AES Ohio	172	193
Duke Energy Ohio and Kentucky	196	209
Duquesne Light Company	98	101
East Kentucky Power Cooperative	219	227
Ohio Valley Electric Corporation	0	0
<b>Western</b>	<b>4,841</b>	<b>6,473</b>
Dominion Energy	697	1,278
<b>Southern</b>	<b>697</b>	<b>1,278</b>
<b>PJM RTO</b>	<b>7,898</b>	<b>10,629</b>

# Section 3: Transmission Enhancements

## 3.0: 2025 RTEP Proposal Windows

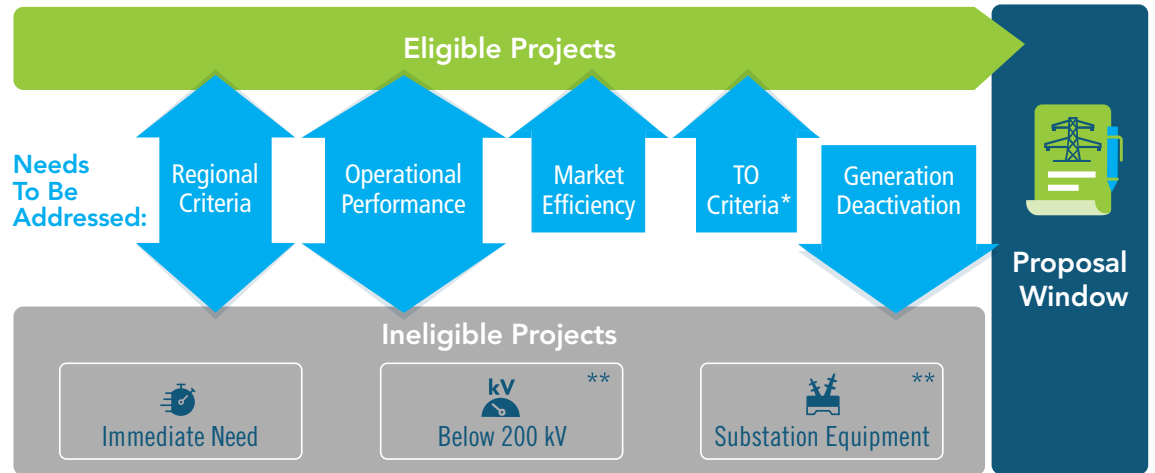
### 3.0.1 — RTEP Process Context

PJM seeks transmission proposals during each RTEP window to address one or more identified needs: reliability, market efficiency, operational performance and/or public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to PJM for consideration. When a window closes, PJM proceeds with analytical, constructability and financial evaluations to assess proposals for possible recommendation to the PJM Board. If selected, designated developers become responsible for project construction, ownership, operation, maintenance and financing. PJM’s Manual 14 series addresses the rules governing the RTEP process. In particular, [Manual 14F](#) describes PJM’s competitive transmission process, including all aspects of analysis and evaluation pertaining to proposal windows.

#### Proposal Window Exemptions

Certain flowgate violations are exempt from PJM’s competitive planning process and are designated to the incumbent transmission owner (TO) as described in the [PJM Operating Agreement](#), Schedule 6, section 1.5.8. These FERC-approved exemptions, as seen in **Figure 3.1**, were developed with collaborative input from PJM stakeholders:

Figure 3.1: RTEP Proposal Window Eligibility



**Note:** \*TO criteria-driven violations are eligible for proposal windows as of Jan. 1, 2020.

\*\*Projects below 200 kV and substation equipment projects could become eligible for competition if multiple needs share common geography/contingency or if the project has multi-zonal cost allocation.

- **Immediate-Need Exemption:** The required in-service date drives these projects, and they may be exempt from the competitive process to ensure they can be completed before the required in-service date.
- **Below 200 kV:** Solutions below 200 kV are exempt from the competitive process. Experience has demonstrated that the selected solutions at these voltage levels have, by and large, ultimately been those proposed by the incumbent TOs themselves.
- **Substation Equipment:** In situations where the limiting element causing a reliability criteria violation is a piece of substation equipment, then such solutions are designated to the incumbent TO.

**Transmission Owner FERC Form 715 Planning Criteria**

The [PJM Operating Agreement](#) specifies that individual TO planning criteria are to be evaluated as a part of the RTEP process in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions. TOs are required to include their individual criteria as part of their respective FERC Form 715 filings. [TO criteria](#) can be found on the PJM website.

As part of its RTEP process, PJM applies TO criteria to the respective facilities included in the transmission facilities list maintained by PJM. Transmission enhancements driven by TO criteria are considered RTEP baseline projects. Projects may be eligible for proposal window consideration as shown in **Figure 3.1**. Under the terms of the [PJM Open Access Transmission Tariff](#) (OATT), the costs of such projects follow existing baseline reliability cost allocation rules.

### 3.0.2 — 2025 RTEP Cycle

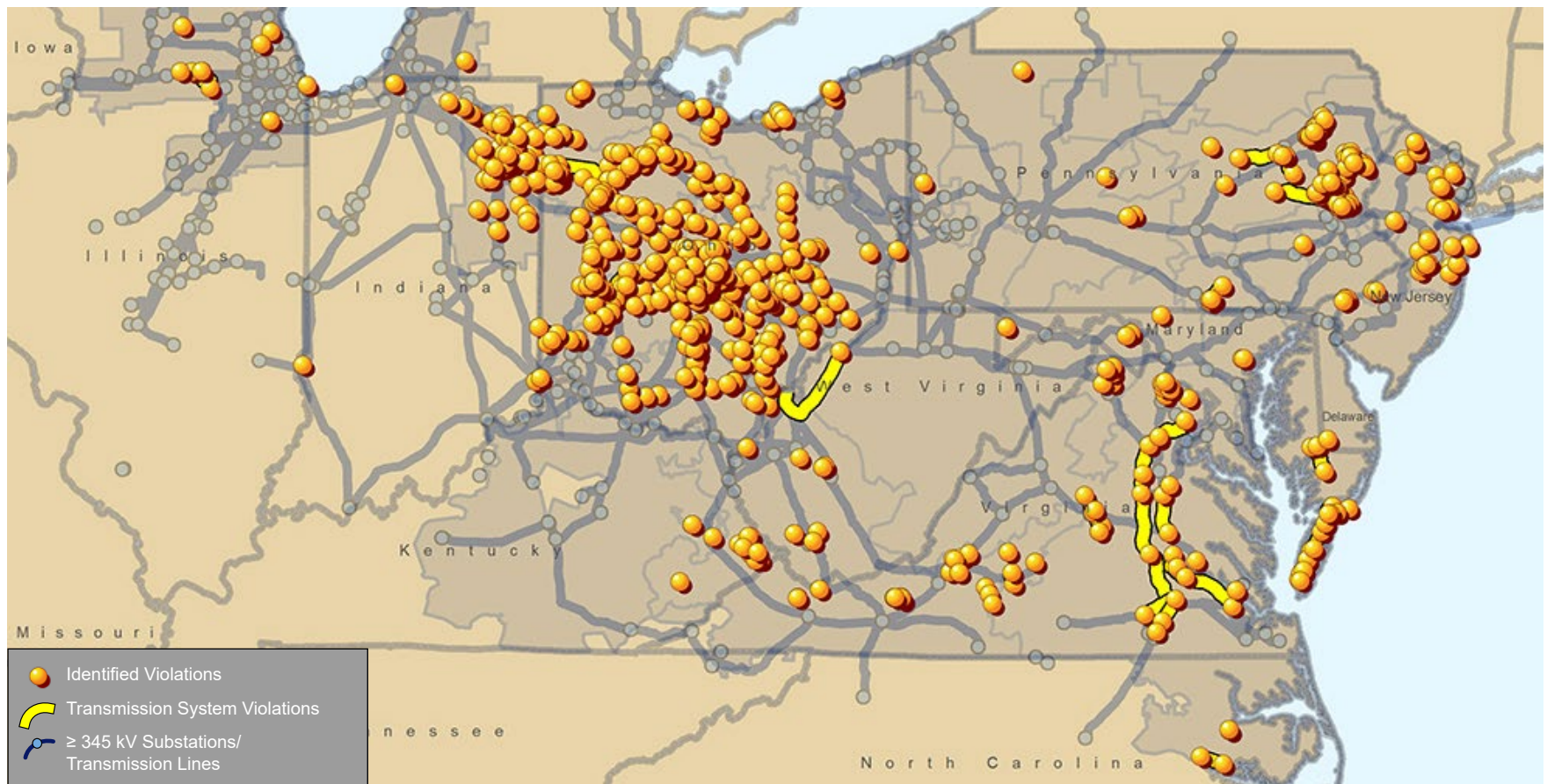
#### Baseline Analysis Results

PJM's analysis of 2030 and 2032 summer, winter and light load conditions identified 4,337 thermal, voltage and short-circuit criteria flowgate violations across PJM, as shown in **Map 3.1**, of which 1,412 were ineligible for competitive windows as defined in **Section 3.0.1**. The 2,925 remaining

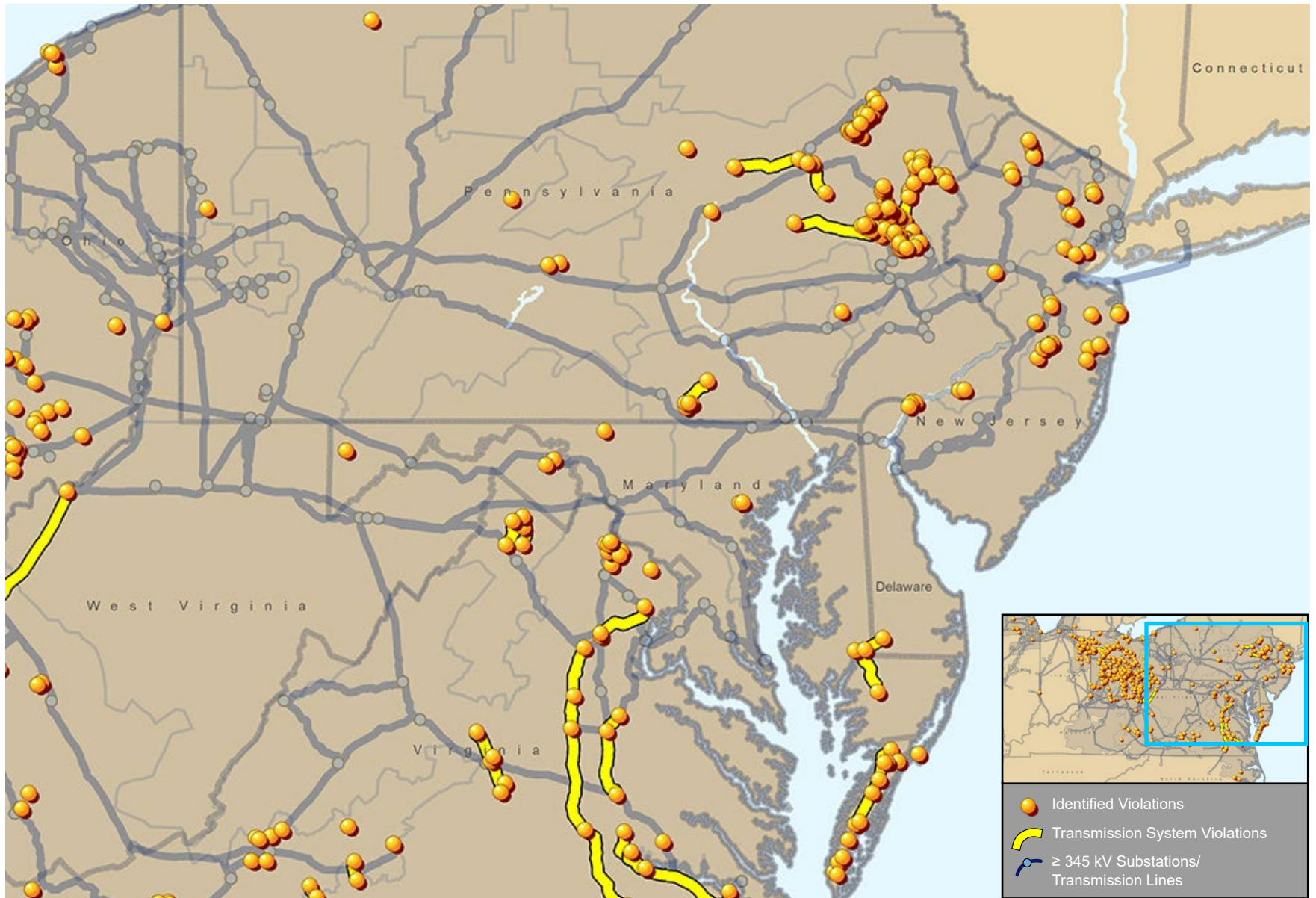
violations were addressed in the competitive 2025 RTEP Window 1 as discussed in **Section 3.0.3**. There were 1,278 flowgate violations that were driven by TO criteria. **Map 3.2**, **Map 3.3** and **Map 3.4** show all flowgate violations by PJM subregions.

- **Map 3.2** shows flowgate violations in PJM's Mid-Atlantic Region.
- **Map 3.3** shows flowgate violations in PJM's Southern Region.
- **Map 3.4** shows flowgate violations in PJM's Western Region.

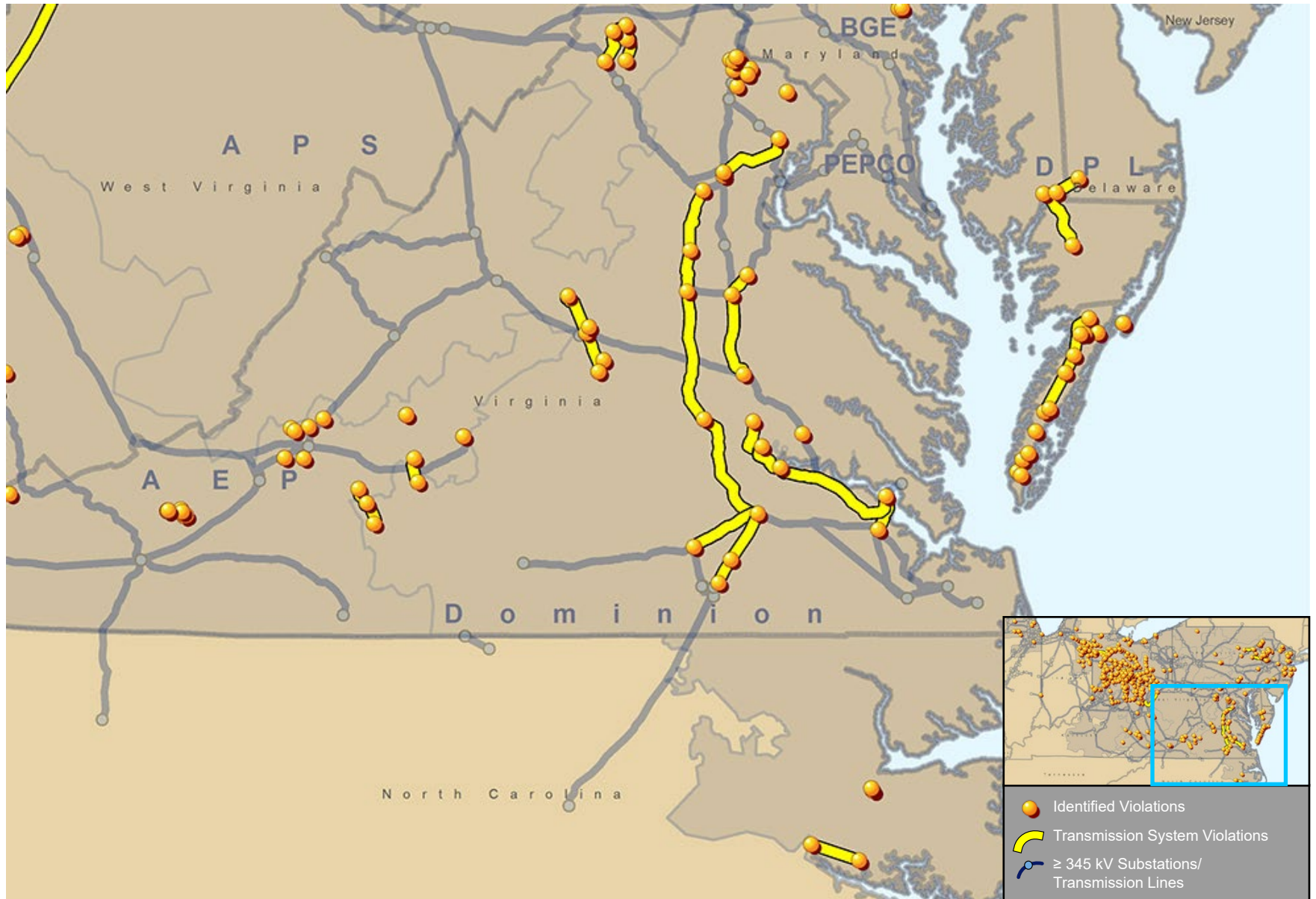
**Map 3.1: 2025 RTEP Baseline Thermal and Voltage Criteria Violations – Study Years 2030 and 2032**



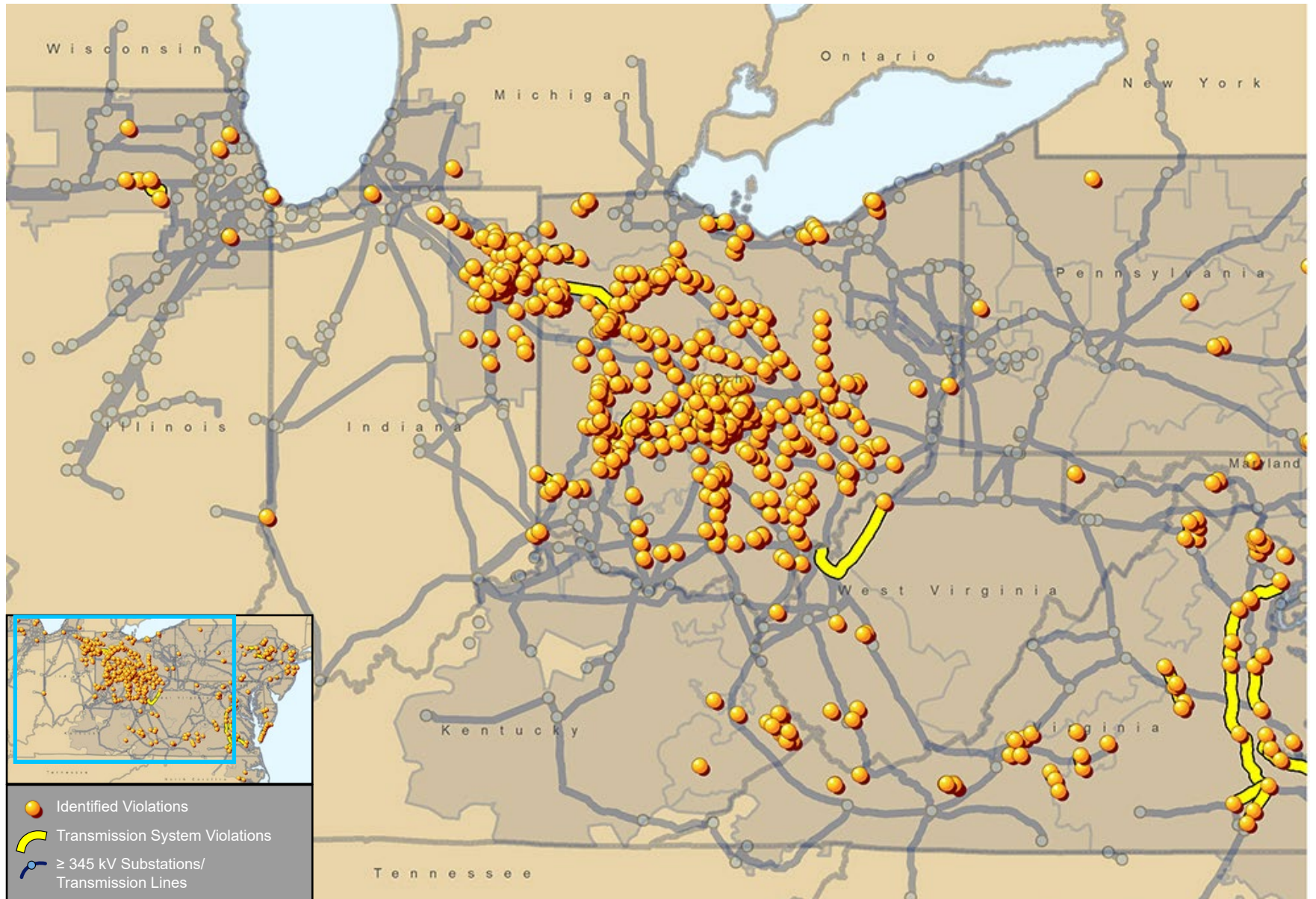
Map 3.2: 2025 RTEP Baseline Thermal and Voltage Criteria Violations – Mid-Atlantic – Study Years 2030 and 2032



**Map 3.3:** 2025 RTEP Baseline Thermal and Voltage Criteria Violations – South – Study Years 2030 and 2032



Map 3.4: 2025 RTEP Baseline Thermal and Voltage Criteria Violations – West – Study Years 2030 and 2032



All previously planned and Board-approved backbone transmission enhancements continue to perform well, and PJM did not see major regional transfer issues in the 2030 analysis. In the 2032 analysis, which also reflects conditions that may materialize earlier (i.e., by 2030 or earlier), there are several clusters showing extra high voltage (EHV) backbone overloads, primarily along the extremities of the backbone transmission network that was reinforced as part of the PJM 2022 RTEP Window 3 and 2024 RTEP Window 1 competitive transmission windows.

The large number of violations seen in the 2025 RTEP were driven by numerous factors. The west-to-east transmission backbone is heavily loaded, driven by large load increases in the Western Region, the Dominion transmission zone and the eastern area of the PJM footprint, as well as by a reduction in generation capacity in the eastern area of PJM due to planned generation delays or potential future retirements.

Additionally, there is an approximately 10 GW and 28 GW load increase for 2030 and 2032, respectively, between the load forecasts used for the 2024 and 2025 RTEPs. The significant load growth is primarily attributed to data centers, electrification and electric vehicle developments. While the proposed reinforcements recommended through previous large windows, such as 2022 RTEP Window 3 and 2024 RTEP Window 1, are performing well, there are additional pockets in the AEP, ATSI, Dominion, PECO, BGE and PPL transmission zones that need to be addressed primarily due to a shift in generation flow as a result of an overall system load increase and over 2 GW of announced generator deactivations.

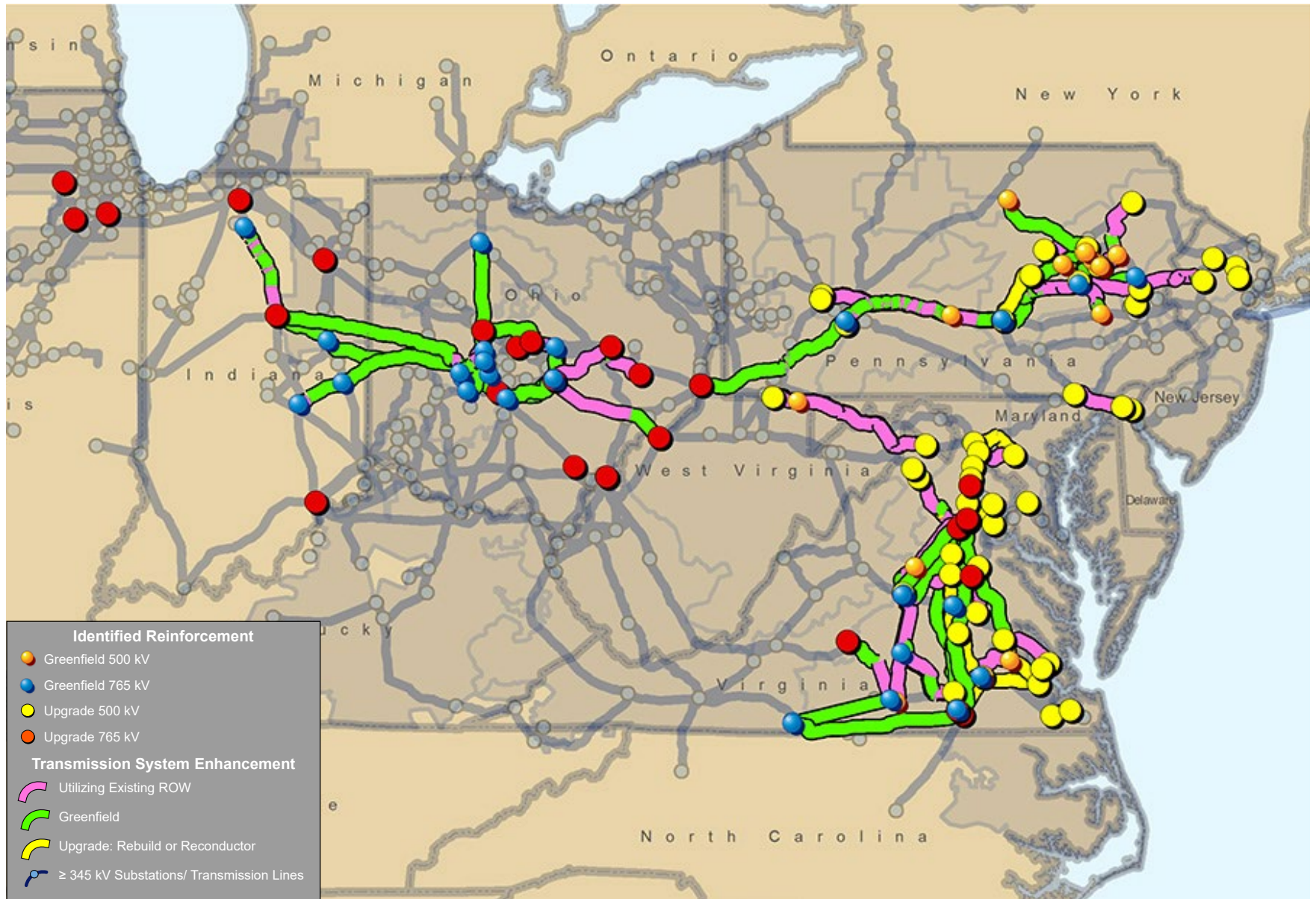
### 3.0.3 — 2025 RTEP Window 1

PJM opened the 2025 RTEP Window 1 on June 18, 2025. PJM sought proposals to resolve reliability criteria violations identified in the 2030 model-year analysis as well as those in the 2032 model year that may require long-lead-time transmission solutions. The objective of this is to develop holistic and robust solutions to address the identified criteria violations and avoid redundancy by introducing right-sized transmission developments that consider future long-term load and resource conditions.

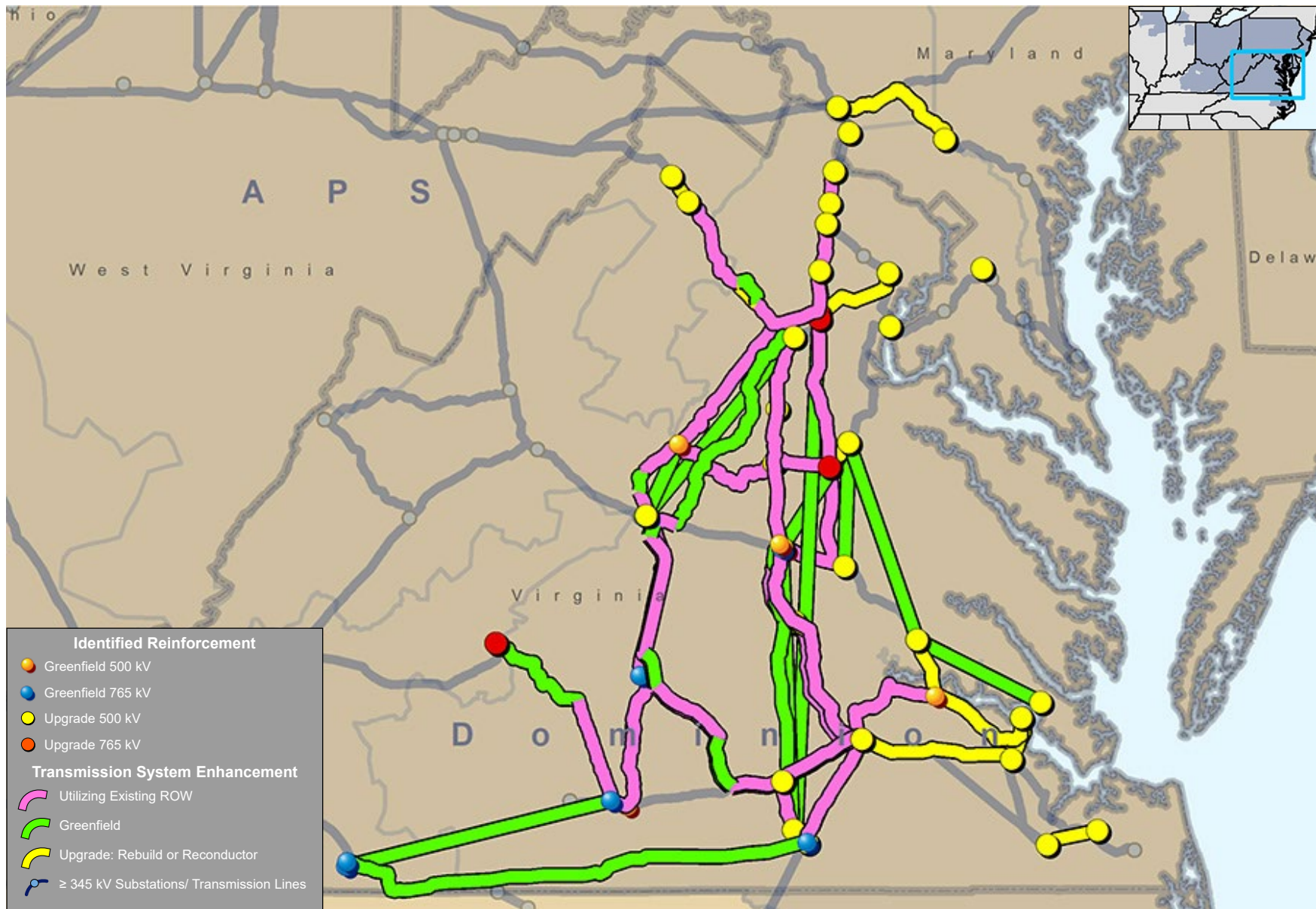
The 2025 RTEP Window 1 closed on Aug. 18, 2025. PJM received 134 competitive proposals from 19 entities as shown in **Table 3.1**. Of these, 57 proposals were greenfield, and the remaining 77 were upgrades to existing transmission infrastructure. Cost containment provisions were included in 90 of the proposals. **Map 3.5, Map 3.6, Map 3.7** and **Map 3.8** present the different types of proposed solutions submitted in the 2025 RTEP Window 1:

- **Map 3.5** shows proposed solutions made up of 500 kV-and-above upgrades to resolve competitive violations.
- **Map 3.6** shows proposed solutions to resolve competitive violations in PJM's Southern Region.
- **Map 3.7** shows proposed solutions to resolve competitive violations in PJM's Mid-Atlantic Region.
- **Map 3.8** shows proposed solutions to resolve competitive violations in PJM's Western Region.

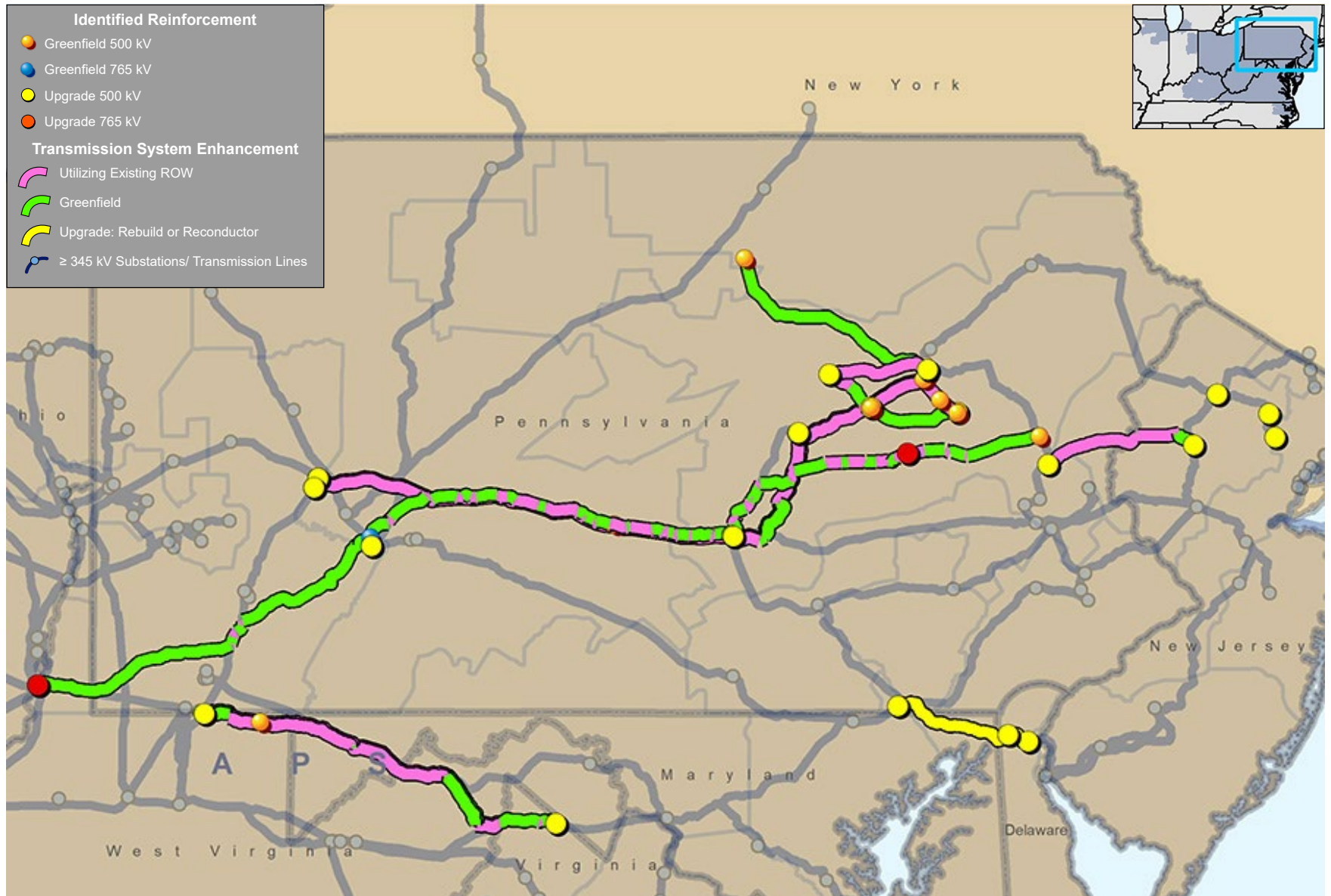
Map 3.5: 2025 RTEP Window 1 Submittals – Regional



Map 3.6: 2025 RTEP Window 1 Submittals – South



Map 3.7: 2025 RTEP Window 1 Submittals – Mid-Atlantic



Map 3.8: 2025 RTEP Window 1 Submittals – West

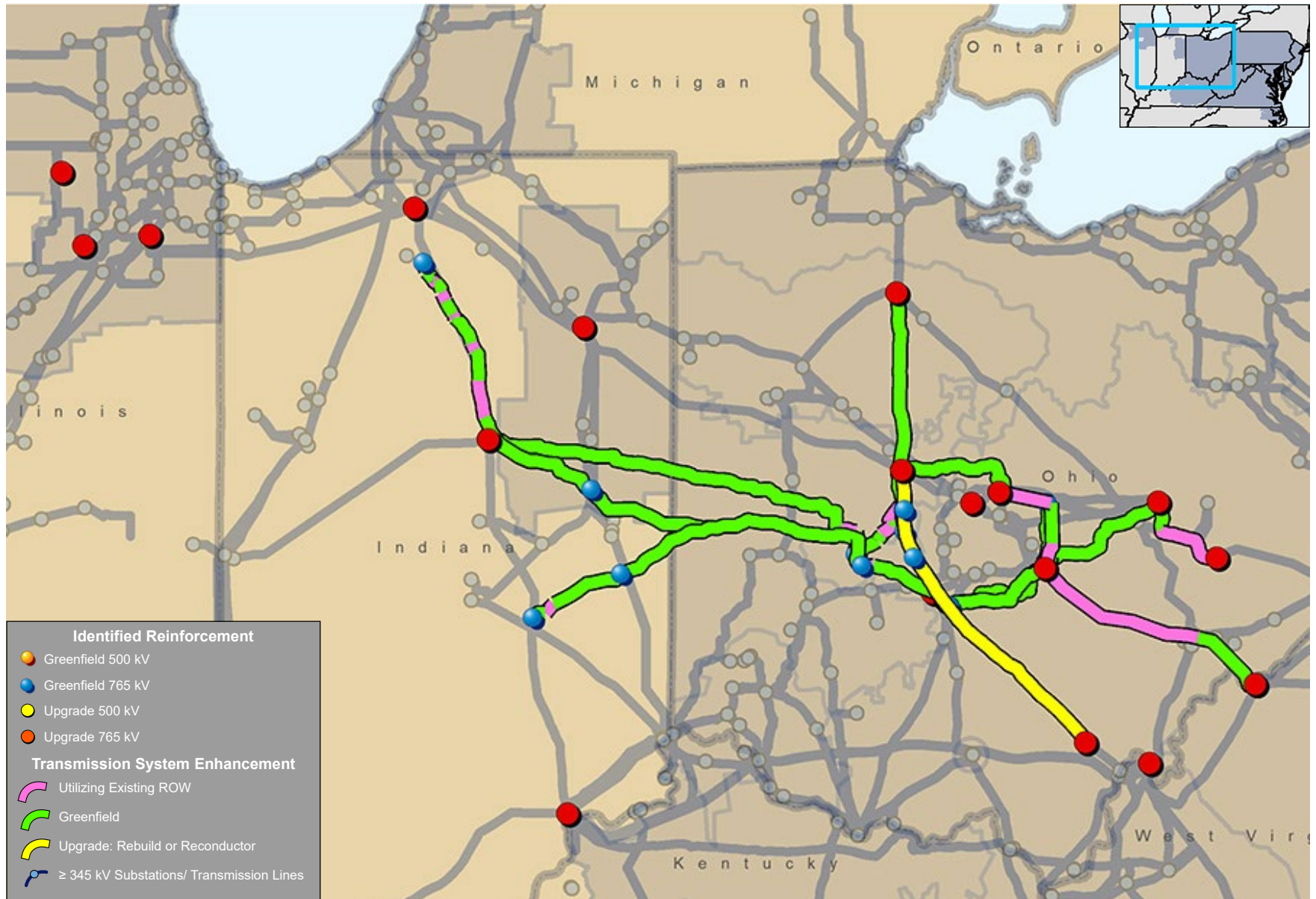


Table 3.1: 2025 RTEP Window 1 Submittals

Proposal ID	Proposing Entity	Focus Area	Project Type	Cost Containment	Submitted Cost (\$M)	Project Title
63	AEPST	AEPC5	Upgrade	No	\$39.40	Smith Mountain-Rockcastle-Moneta 138 kV rebuild
195		No Competition	Upgrade	No	\$41.59	Mound Street-St Clair 138 kV underground line rebuild
298		No Competition	Upgrade	No	\$7.81	Hyatt-Celtic 345 kV rerate
341		AEPC4	Upgrade	No	\$37.38	Allen-Sorenson 345 kV sag study
348		AEPC2	Upgrade	No	\$16.23	Trabue-Hilliard-Davidson 69 kV rebuild and relay upgrades
354		AEPC8	Upgrade	No	\$15.79	Green Chapel-Curleys 345 kV circuit
377		AEPC6	Upgrade	No	\$29.63	Beatty-Bolton-Phillipi 138 kV line
385		AEPC1	Upgrade	No	\$1.65	Platter Creek 69 kV station reconfiguration
431		No Competition	Upgrade	No	\$3.23	McComb 138 kV station reconfiguration
439		No Competition	Upgrade	No	\$15.17	Maliszewski-Polaris 138 kV circuit rebuild
459		AEPC8	Greenfield	No	\$27.28	Green Chapel-Bermuda 345 kV circuit
515		AEPC3	Upgrade	No	\$35.74	Harrison-Obetz-Marion Road 138 kV line rebuild
517		AEPSTATCOM	Upgrade	No	\$736.61	Central Ohio STATCOM installations and station upgrades
626		AEPC6, AEPC7	Upgrade	No	\$31.04	Beatty-Cole 345 kV circuit No. 2
662		AEPC3	Upgrade	No	\$14.82	Harrison-Obetz-Marion Rd 138 kV line sag study and terminal equipment upgrades
689		AEPC5	Upgrade	No	\$9.88	Smith Mountain-Rockcastle-Moneta 138 kV sag study
724		AEPC1	Upgrade	No	\$28.68	Platter Creek-Sherwood-Auglaize 69 kV line rebuild
729		No Competition	Upgrade	No	\$10.42	Beatty-McComb 138 kV line
749		AEPSTATCOM	Upgrade	No	\$589.74	Central Ohio STATCOM installations
757		AEPC7	Upgrade	No	\$63.20	Clinton-St Clair 138 kV underground line
873		AEPC8	Upgrade	No	\$58.57	Green Chapel-Vassell 345 kV circuit No. 2
940		AEPC2	Upgrade	No	\$79.26	Trabue-Hilliard-Davidson 138 kV conversion
980		AEPC6	Upgrade	No	\$7.27	Beatty-Bolton 138 kV line
981		AEPSTATCOM	Greenfield	No	\$976.34	Patina 765/345 kV station and underground line rebuilds
996		AEPC4	Upgrade	No	\$70.64	Allen-Sorenson 345 kV line rebuild
239		ATSI	ATSI/AEP/AES Ohio	Greenfield	Yes	\$1,492.41
334	ATSI/AEP/AES Ohio		Greenfield	Yes	\$1,690.26	West Glade Run 765/345 kV solution
156	CINSI	No Competition	Upgrade	No	\$58.47	College Corner-Collinsville 138 kV rebuild

Table 3.1: 2025 RTEP Window 1 Submittals (Cont.)

Proposal ID	Proposing Entity	Focus Area	Project Type	Cost Containment	Submitted Cost (\$M)	Project Title
20	CNTLTM	PPL	Greenfield	Yes	\$494.29	Tri-segment 500 kV transmission project
260		DOM2032_1 (Regional)	Greenfield	Yes	\$2,207.36	Virginia transmission project
543		ATSI/AEP/AES Ohio	Greenfield	Yes	\$121.41	Greene-South Bird transmission project
672		AEPC4	Greenfield	Yes	\$105.92	Allen-Sorenson transmission project
402	COMED	No Competition	Upgrade	No	\$87.90	Install new 765/345 kV transformer at Plano
457		No Competition	Upgrade	No	\$66.30	Install new 765/345 kV transformer at Collins
906		No Competition	Upgrade	No	\$45.81	Install new 765/345 kV transformer 91 at Wilton Center
465	DPL	No Competition	Greenfield	No	\$491.16	New 500 kV circuit Keeney (DPL)-Bramah
823		No Competition	Upgrade	No	\$90.70	Red Lion-Keeney facility upgrades
140	JCPL	No Competition	Upgrade	Yes	\$66.83	Montville 500/230 kV transformer installation and associated upgrades
493	MATLIT	MAAC Regional	Greenfield	Yes	\$1,515.23	PPL load addition proposal: Keystone-Susquehanna dual 500 kV double circuits with Jack's Mt.
578		MAAC Regional	Greenfield	Yes	\$2,418.26	PPL load addition proposal: Keystone-Susquehanna dual 500 kV single circuits with Jack's Mt.
826		MAAC Regional	Greenfield	Yes	\$1,348.91	PPL load addition proposal: Keystone-Susquehanna 500 kV double circuit
838		MAAC Regional	Greenfield	Yes	\$2,251.95	PPL load addition proposal: Keystone-Susquehanna dual 500 kV single circuits
237	NXTMID	MAAC Regional	Greenfield	Yes	\$1,738.59	Kammer-Juniata
109		ATSI/AEP/AES Ohio	Greenfield	Yes	\$3,322.00	Muckshaw-Johnstown 765 kV
152		ATSI/AEP/AES Ohio	Greenfield	Yes	\$2,921.12	Gwynneville-Johnstown 765 kV
687		MAAC Regional	Greenfield	Yes	\$3,238.74	Kammer-Juniata-Spicewood 765 kV
771		PPL	Greenfield	Yes	\$539.25	Montour-Slykerville reinforcement
987		Scenario	Greenfield	Yes	\$6,731.58	Combined solution
871		MAAC Regional	Greenfield	Yes	\$1,136.38	Blockhouse Creek-Susquehanna and Montour-Stoney Creek
896		MAAC Regional	Greenfield	No	\$571.70	Fort Martin-Woodside double-circuit 500 kV
125	PE	No Competition	Upgrade	No	\$67.58	Trainer (PECO)-Delco Tap (PECO)-Mickleton (ACE)
579		No Competition	Upgrade	No	\$10.60	220-84 Linwood-Claymont 230 kV tie-line facility upgrade
758		No Competition	Upgrade	No	\$76.85	220-85 Linwood-Edgemoor 230 kV tie-line facility upgrade
371	PEPCO	MAAC-PEPCO	Greenfield	No	\$857.22	Dickerson 500 kV substation and new Dickerson-Brighton 500 kV line
851		MAAC-PEPCO	Upgrade	No	\$101.86	Brighton-Doubs 500 kV rebuild
919		MAAC-PEPCO	Upgrade	No	\$257.61	Dickerson 500 kV substation

Table 3.1: 2025 RTEP Window 1 Submittals (Cont.)

Proposal ID	Proposing Entity	Focus Area	Project Type	Cost Containment	Submitted Cost (\$M)	Project Title
631	POTOED	No Competition	Greenfield	No	\$23.87	McCanns Rd 138 kV switching station
692		No Competition	Upgrade	No	\$9.15	Garrett Tap-Garrett 115 kV line rebuild
16	PPLTO	PPL	Upgrade	Yes	\$162.89	Juniata-Sunbury 500 kV line EOL SCT rebuild
158		PPL	Upgrade	Yes	\$415.07	Portfolio proposal 1: Year 2030 area 229 essential reliability solution
190		PPL	Upgrade	Yes	\$40.64	Glen Brook-Susquehanna T10-Susquehanna 230 kV 1 and 2 DCT line rebuild
199		PPL	Upgrade	Yes	\$124.27	Siegfried 500/230 kV substation expansion project
290		PPL	Upgrade	Yes	\$88.16	Siegfried-Drakestown 500 kV line (PA segment)
317		PPL	Greenfield	Yes	\$227.42	Sunbury-Susquehanna 500 kV line bifurcation and reroute through Kelayres 500 kV station
333		PPL	Greenfield	Yes	\$20.13	Kelayres-Tresckow 230 kV No. 3 line
422		PPL	Upgrade	Yes	\$60.82	Susquehanna-Tomhicken 230 kV 1 and 2 separated lines with reconductors
434		PPL	Greenfield	Yes	\$184.73	Sandy Run-Kelayres 500 kV line project
491		PPL	Greenfield	Yes	\$32.58	Glen Brook-Nescopeck 230 kV line
556		PPL	Greenfield	Yes	\$464.86	Lackawanna-Sandy Run-Siegfried 500 kV line project
558		PPL	Upgrade	Yes	\$536.39	Portfolio Proposal 2: Year 2032 Area 229 essential reliability solution
588		PPL	Upgrade	Yes	\$27.31	Glen Brook-Susquehanna T10 1 & 2 DCT line reconductor and Susquehanna T10-Susquehanna No. 3 line
647		PPL	Upgrade	Yes	\$10.17	Jenkins 230/69 kV substation transformers retermination
688		PPL	Upgrade	Yes	\$39.21	Monroe 230/138 kV substation upgrade
756		PPL	Upgrade	Yes	\$217.93	Juniata-Sunbury 500 kV line EOL DCT rebuild
769		PPL	Greenfield	Yes	\$418.11	Mohrsville-Kelayres 500 kV line
794		PPL	Upgrade	Yes	\$253.50	Frackville-Siegfried 500 kV line
824		PPL	Upgrade	Yes	\$29.73	Susquehanna-Tomhicken 230 kV 1 and 2 DCT line reconductor
853		PPL	Upgrade	Yes	\$797.94	Portfolio proposal 3: Year 2032 + 4 GW area 229 essential reliability solution
855		PPL	Upgrade	Yes	\$145.75	Nescopeck-Kelayres 500 kV line project
918		PPL	Greenfield	Yes	\$347.99	Sunbury-Kelayres 500 kV line
945		PPL	Greenfield	Yes	\$159.08	Juniata-Lewistown 230 kV No. 2 line
946	PPL	Greenfield	Yes	\$181.32	Susquehanna-Wescosville 500 kV line bifurcation and reroute through Kelayres 500 kV station	
958	PPL	Upgrade	Yes	\$39.65	Montour-Glen Brook 230 kV 1 and 2 DCT line reconductor or rebuild	

Table 3.1: 2025 RTEP Window 1 Submittals (Cont.)

Proposal ID	Proposing Entity	Focus Area	Project Type	Cost Containment	Submitted Cost (\$M)	Project Title
656	PSEG	No Competition	Upgrade	No	\$9.93	Roseland-Livingston and Roseland-Laurel 230 kV reconductoring
60	PSEGRT	ATSI/AEP/AES Ohio	Greenfield	Yes	\$1,333.61	765 kV standalone solution
241		ATSI/AEP/AES Ohio	Greenfield	No	\$143.36	STATCOM solution
423		ATSI/AEP/AES Ohio	Greenfield	Yes	\$475.11	345 kV standalone solution
619		ATSI/AEP/AES Ohio	Greenfield	Yes	\$1,942.65	345 kV solution + 765 kV solution (alternative)
907		ATSI/AEP/AES Ohio	Greenfield	Yes	\$1,841.18	345 kV/765 kV combined project
938	TRAIL	DOM2032_1 (Regional)	Greenfield	Yes	\$3,426.93	Dominion regional solution
552	TRNSLK	PPL	Greenfield	Yes	\$194.25	Siegfried-Drakestown 500 kV line (brownfield NJ segment route)
51	TRNSRC	ATSI/AEP/AES Ohio	Greenfield	Yes	\$1,051.22	Ohio five-year solution
331		DOM2032_1 (Regional)	Greenfield	Yes	\$2,895.32	Virginia area seven-year solution 1
570		ATSI/AEP/AES Ohio	Greenfield	Yes	\$2,775.19	Ohio seven-year solution
781		DOM2032_1 (Regional)	Greenfield	Yes	\$1,986.45	Virginia area seven-year solution 2
9	VEPCO	DOM2032_2 (Components)	Upgrade	Yes	\$104.86	Line 576 partial rebuild: Vontay-Midlothian
24		DOM2032_2 (Components)	Upgrade	Yes	\$48.59	Line 568 partial rebuild: Ladysmith-Kraken
48		DOM2032_2 (Components)	Greenfield	Yes	\$121.09	New 500 kV line: North Anna-Vontay
55		DOM2032_2 (Components)	Greenfield	Yes	\$1,665.29	New 765 kV line: Heritage-Yeat
98		DOM2032_2 (Components)	Greenfield	Yes	\$414.94	New 500 kV line: Chickahominy-Kraken
117		DOM2032_2 (Components)	Upgrade	Yes	\$125.25	Line 539 rebuild: Yeat-Ox
126		DOM2032_2 (Components)	Upgrade	Yes	\$2.49	Line 567 terminal upgrade Chickahominy and Surry
238		DOM2032_2 (Components)	Upgrade	Yes	\$237.06	Line 563 rebuild: Carson-Midlothian
243		DOM2032_2 (Components)	Upgrade	Yes	\$14.21	Carson substation equipment upgrade
245		DOM2032_2 (Components)	Upgrade	Yes	\$16.25	Line 5008 cut-in into Mosby substation
247		DOM2032_2 (Components)	Greenfield	Yes	\$239.49	New 765/500 kV switching station: Vontay
253		DOM2032_2 (Components)	Upgrade	Yes	\$16.25	Line 5008 cut-in into Mosby substation
264		DOM2032_2 (Components)	Upgrade	Yes	\$132.37	Line 539 rebuild: Bristers-Ox
275		DOM2032_1 (Regional)	Upgrade	Yes	\$4,819.51	HVDC backbone: Portfolio 1A
302		DOM2032_2 (Components)	Greenfield	Yes	\$265.29	New 500 kV line: Vontay-Kraken
306		DOM2032_2 (Components)	Greenfield	Yes	\$180.30	New 500 kV line: Elmont-Kraken
311		DOM2032_2 (Components)	Upgrade	Yes	\$3.90	Line 578 (Septa-Surry) terminal equipment upgrade
321		DOM2032_4	Greenfield	Yes	\$545.00	New 765 kV line from Joshua Falls-Durandal

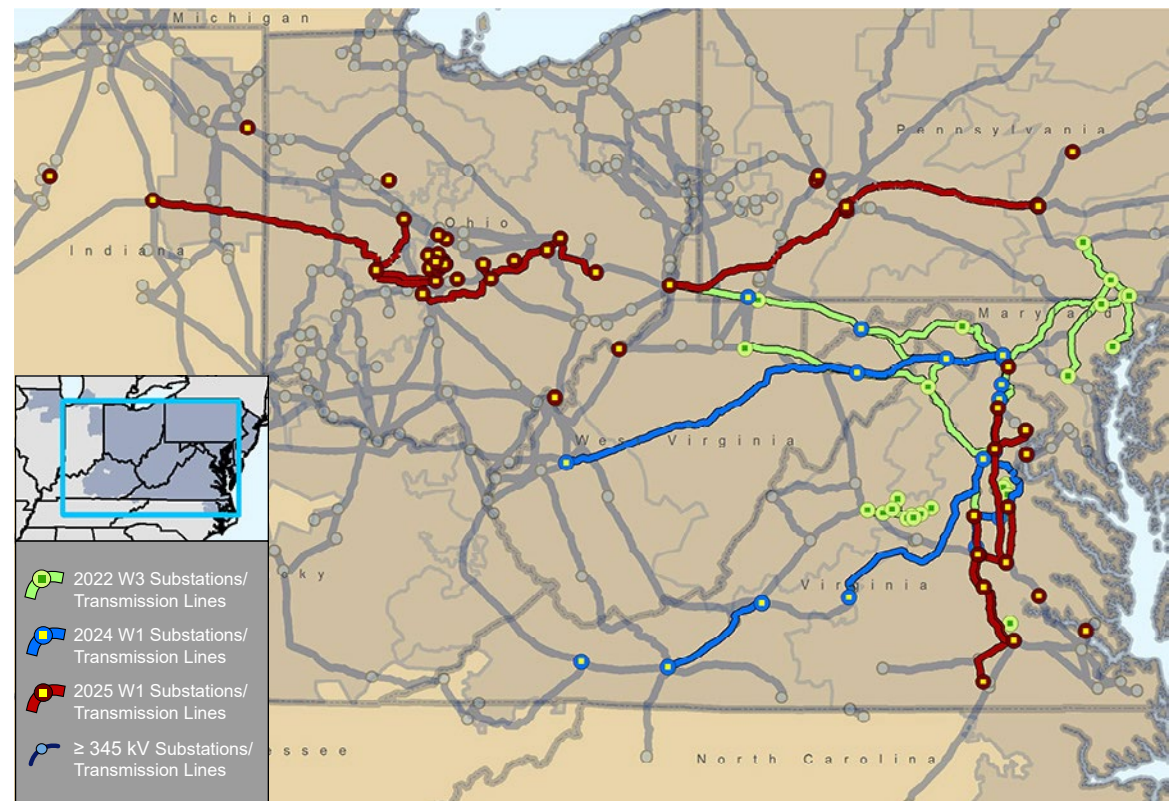
Table 3.1: 2025 RTEP Window 1 Submittals (Cont.)

Proposal ID	Proposing Entity	Focus Area	Project Type	Cost Containment	Submitted Cost (\$M)	Project Title
326	VEPCO	DOM2032_1 (Regional)	Upgrade	Yes	\$5,009.03	HVDC backbone: Portfolio 1B
339		DOM2032_2 (Components)	Upgrade	Yes	\$104.86	Line 576 partial rebuild: North Anna-Vontay
352		DOM2032_1 (Regional)	Upgrade	Yes	\$5,013.97	HVDC backbone: Portfolio 1D
409		DOM2032_2 (Components)	Greenfield	Yes	\$539.55	New 500 kV line: Morrisville-Cunningham
458		DOM2032_2 (Components)	Greenfield	Yes	\$794.27	New 500 kV line: Heritage-Morrisville
474		DOM2032_1 (Regional)	Upgrade	Yes	\$2,273.85	765 kV backbone: Portfolio 2C
476		DOM2032_3 (Safety)	Greenfield	Yes	\$1,441.10	Safety solutions
547		DOM2032_1 (Regional)	Upgrade	Yes	\$4,904.50	HVDC backbone: Portfolio 1C
557		DOM2032_2 (Components)	Greenfield	Yes	\$292.89	New 500kV line: Skiffes Creek-Chickahominy
616		DOM2032_1 (Regional)	Upgrade	Yes	\$2,349.26	500 kV backbone: Portfolio 3
627		DOM2032_2 (Components)	Upgrade	Yes	\$102.05	Line 597 rebuild: Spotsylvania-Morrisville
705		DOM2032_1 (Regional)	Upgrade	Yes	\$2,864.73	765 kV backbone: Portfolio 2A
755		DOM2032_2 (Components)	Upgrade	Yes	\$210.99	Line 576 rebuild: North Anna-Midlothian
815		DOM2032_2 (Components)	Greenfield	Yes	\$3,790.85	New HVDC transmission link from Heritage-Mosby
825		DOM2032_2 (Components)	Greenfield	Yes	\$483.74	New 500 kV line: Finneywood-Cunningham
848		DOM2032_1 (Regional)	Upgrade	Yes	\$2,969.05	765 kV backbone: Portfolio 2B
868		DOM2032_2 (Components)	Upgrade	Yes	\$10.03	Topology changes at Ladysmith, Kraken and Carson substations
911		DOM2030_1	Upgrade	No	\$314.91	2030 solution
916		DOM2032_2 (Components)	Upgrade	Yes	\$3.89	Line 560 rebuild: Possum Point-Burches Hill
948		DOM2032_2 (Components)	Upgrade	Yes	\$103.03	Line 573 rebuild: North Anna-Spotsylvania
975	DOM2030_2	Greenfield	No	\$318.17	2030 Western solution	

### 3.0.4 — 2025 RTEP Cycle Baseline Solutions

After the 2025 RTEP Window 1 closed, PJM evaluated the submitted proposals to develop and recommend solutions that meet all reliability and constructability requirements as detailed in the [Reliability Analysis Report](#) and [Constructability & Financial Analysis Report](#), accessible on the Transmission Expansion Advisory Committee [web page](#). The PJM Board approved \$10.9 billion of competitive baseline solutions and \$899 million of noncompetitive baseline solutions to address 2025 RTEP violations. Of these, 500 kV-and-above upgrades totaled \$9.8 billion and TO criteria-driven projects totaled \$486 million. Summaries of the 2025 RTEP baseline projects are shown in **Section 6**. 2025 RTEP baseline projects 500 kV and above, along with those from the 2024 RTEP Window 1 and 2022 RTEP Window 3, are depicted in **Map 3.9**. More detailed descriptions of 2025 RTEP baseline projects can be found in the [TEAC PJM Board white paper](#).

**Map 3.9:** 500 kV and Above Projects From 2025 RTEP Window 1, 2024 RTEP Window 1 and 2022 RTEP Window 3



### 3.1: Supplemental Projects

#### 3.1.1 — Project Drivers

Supplemental projects are not required for system reliability, operational performance or market efficiency economic criteria compliance. They are put forward by TOs as transmission expansions or enhancements that enable the continued reliable operation of the transmission system by meeting customer service needs, enhancing grid resilience and security, promoting operational flexibility, addressing transmission asset health, and ensuring public safety, among other drivers.

Supplemental projects may also address reliability issues for transmission facilities that are on non-bulk electric system (BES) facilities or not considered under NERC requirements or other PJM criteria. Maintenance work and emergency work (i.e., work that is unplanned, including necessary work resulting from an unanticipated customer request, repair of equipment or facilities damaged by storms or other causes, or replacement of failing or failed equipment) do not constitute supplemental projects.

**Figure 3.2** reflects the primary drivers of supplemental projects. Transmission expansions or enhancements that replace facilities that are near or at the end of their useful lives are a primary focus of equipment material condition, performance and risk. TOs develop and apply their own factors and considerations for addressing facilities at or near the end of their useful lives. Each TO explains the criteria, assumptions and models it uses to identify project drivers at the annual assumptions meeting provided under the OATT Attachment M-3 process.

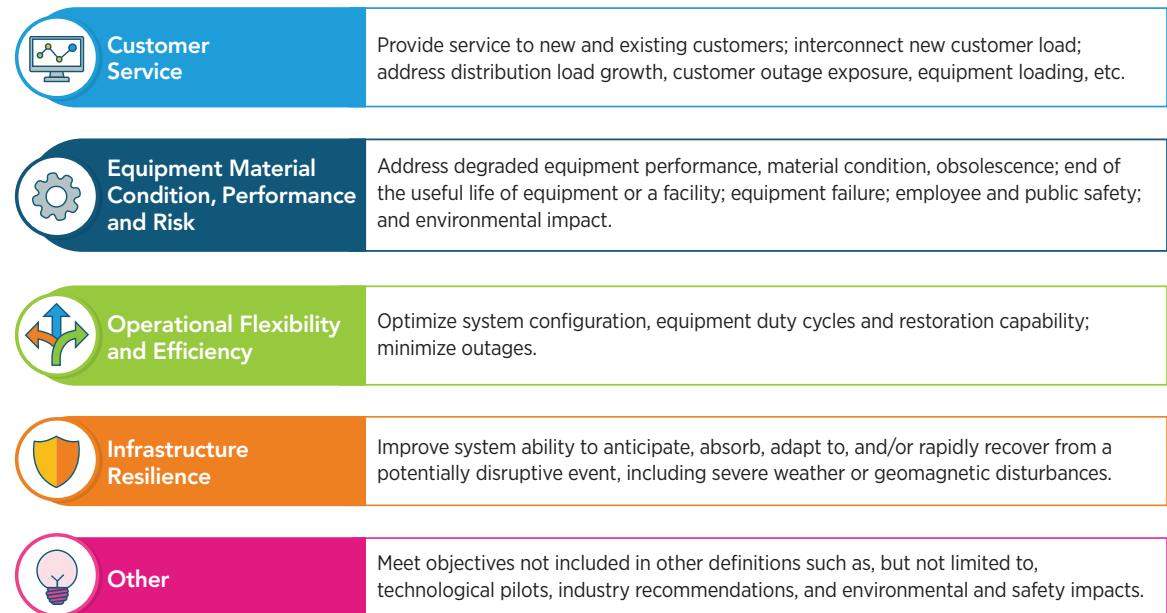
#### 3.1.2 — OATT Attachment M-3 Process

While not subject to PJM Board approval, supplemental projects are included in PJM's RTEP models. The OATT Attachment M-3 process of the PJM Tariff describes the FERC-approved process that PJM and TOs must follow.

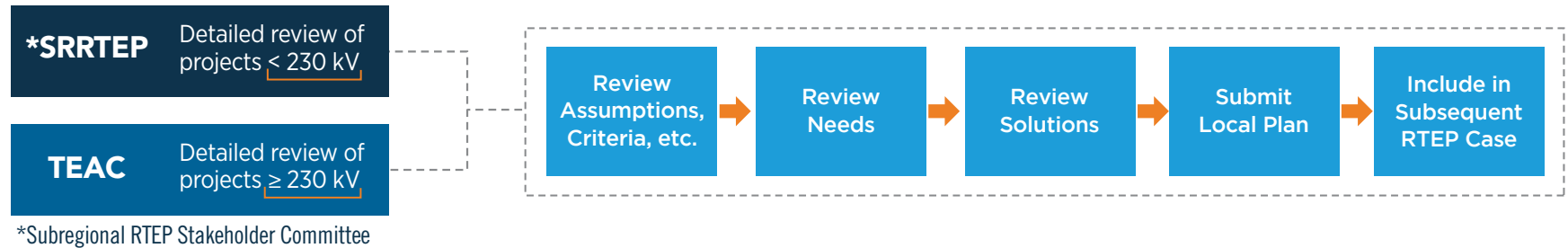
PJM, in its role as a facilitator in the OATT Attachment M-3 process, is responsible for the following:

- Provide necessary facilitation and logistical support so that supplemental project planning meetings can be conducted as outlined in the OATT Attachment M-3 process of the PJM Tariff.
- Provide the applicable TO with modeling information so that TOs can determine if a stakeholder-proposed project can address a supplemental project need.
- Perform do-no-harm analysis to ensure that a supplemental project that a TO elects for inclusion in its local plan does not cause additional reliability violations.
- Collaborate with TOs and stakeholders to improve OATT Attachment M-3 process transparency.

**Figure 3.2:** Primary Supplemental Project Drivers



**Figure 3.3:** OATT Attachment M-3 Process for Supplemental Projects

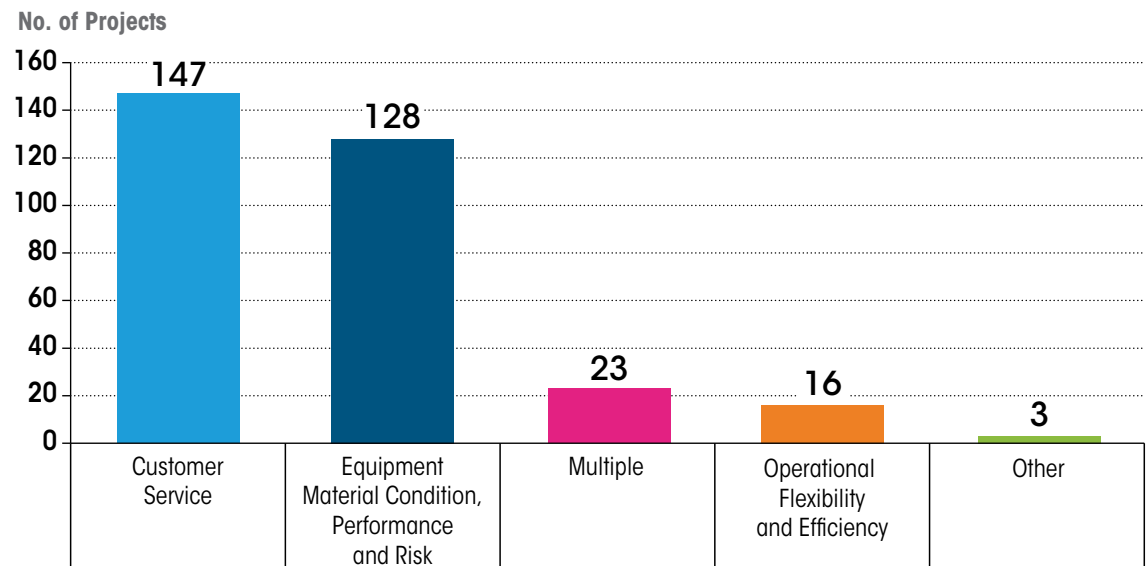


The OATT Attachment M-3 process provides stakeholders, via the PJM Transmission Expansion Advisory Committee (TEAC) and subregional RTEP committees, the meaningful opportunity to review supplemental projects and provide feedback, including written comments, as shown in **Figure 3.3**. Stakeholders interested in providing feedback can do so via [PJM’s Planning Community](#).

**3.1.3 — 2025 Supplemental Projects**

PJM evaluated over \$5.8 billion of TO supplemental projects for the 2025 Local Plan. **Figure 3.4** shows a breakdown of supplemental solutions by driver, presented at the TEAC and to subregional RTEP committees over the past year. It suggests that the largest driver is customer service, which totals approximately \$3.4 billion. Projects driven by equipment material condition, performance and risk, and operational flexibility and efficiency total \$1.9 billion and \$277 million, respectively. The remaining \$289 million is required by projects with another driver or with multiple drivers.

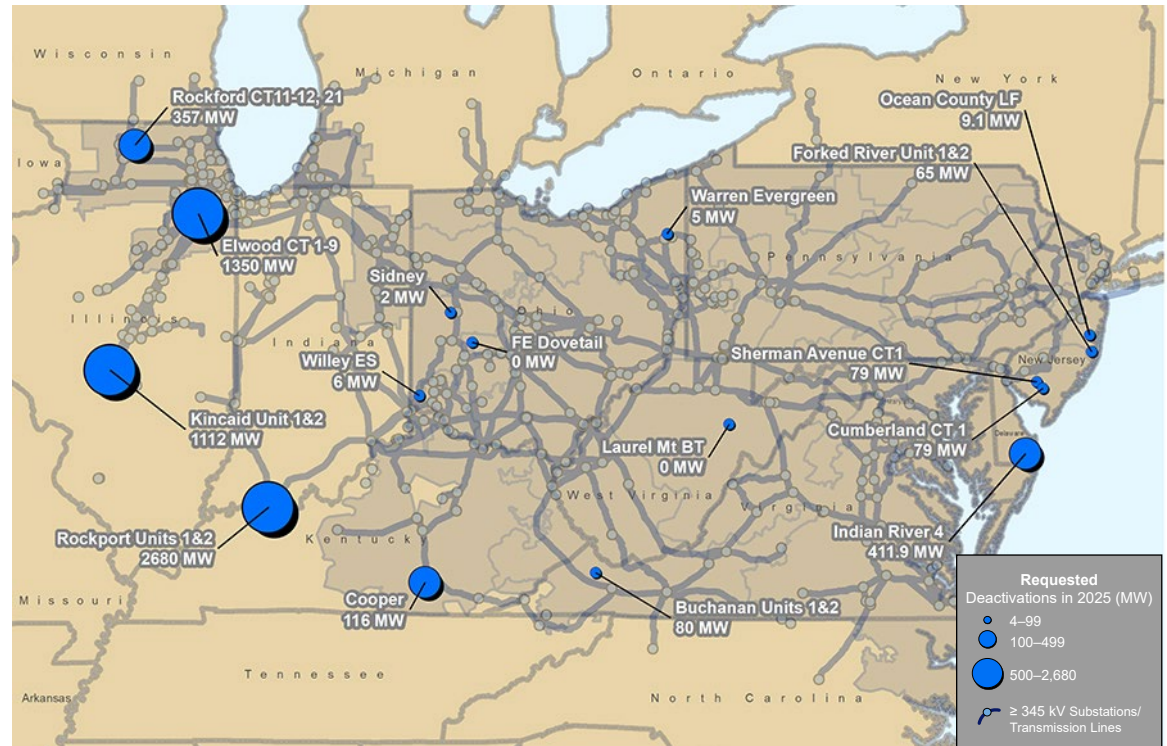
**Figure 3.4:** 2025 Supplemental Projects by Driver



### 3.2: Generator Deactivations

In 2025, PJM received 30 deactivation notices totaling 6,532 MW of generation, which are shown in **Map 3.10** and **Table 3.2**.

**Map 3.10:** Deactivation Notifications Received in 2025



**Table 3.2:** Deactivation Notifications Received in 2025

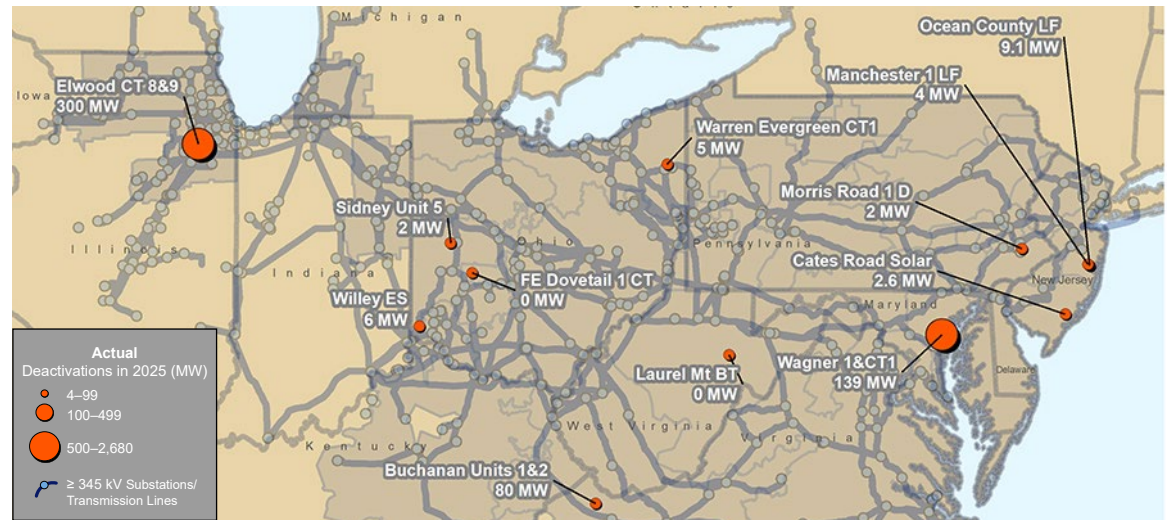
Unit	Capacity (MW)	TO Zone	Fuel Type	Age (Years)	Owner Request Date	Requested Deactivation Date	Projected Deactivation Date
Sidney Unit 5	2.0	AES Ohio	Diesel	57	10/8/2025	10/8/2025	10/8/2025
FE Dovetail 1 CT	0.0	ATSI	Biomass	25	9/24/2025	9/24/2025	9/24/2025
Kincaid Unit 2	556.0	ComEd	Coal	57	7/22/2025	11/30/2027	11/30/2027
Kincaid Unit 1	556.0	ComEd	Coal	58	7/22/2025	11/30/2027	11/30/2027
Warren Evergreen CT1	5.0	ATSI	Natural Gas	44	5/29/2025	7/2/2026	7/1/2026
Cooper 1	116.0	EKPC	Coal	60	4/3/2025	12/31/2030	12/31/2030
Laurel Mountain Battery	0.0	AP	Battery	14	4/1/2025	7/2/2025	7/2/2025
Rockport Unit 1	1,380.0	AEP	Coal	41	3/28/2025	12/31/2028	12/31/2028
Rockport Unit 2	1,300.0	AEP	Coal	41	3/28/2025	12/31/2028	12/31/2028

Table 3.2: Deactivation Notifications Received in 2025 (Cont.)

Unit	Capacity (MW)	TO Zone	Fuel Type	Age (Years)	Owner Request Date	Requested Deactivation Date	Projected Deactivation Date
Willey Energy Storage	6.0	DEO&K	Battery	9	3/21/2025	9/1/2025	9/1/2025
Buchanan Units 1	40.0	AEP	Natural Gas	23	3/14/2025	7/1/2025	7/1/2025
Buchanan Unit 2	40.0	AEP	Natural Gas	23	3/14/2025	7/1/2025	7/1/2025
Elwood CT 9	150.0	ComEd	Natural Gas	25	3/21/2025	6/1/2025	6/1/2025
Elwood CT 8	150.0	ComEd	Natural Gas	25	3/21/2025	6/1/2025	6/1/2025
Elwood CT 7	150.0	ComEd	Natural Gas	25	3/21/2025	6/1/2026	6/1/2026
Elwood CT 6	150.0	ComEd	Natural Gas	25	3/21/2025	6/1/2026	6/1/2026
Elwood CT 5	150.0	ComEd	Natural Gas	25	3/21/2025	6/1/2026	6/1/2026
Elwood CT 4	150.0	ComEd	Natural Gas	25	3/21/2025	6/1/2026	6/1/2026
Elwood CT 3	150.0	ComEd	Natural Gas	25	3/21/2025	6/1/2026	6/1/2026
Elwood CT 2	150.0	ComEd	Natural Gas	25	3/21/2025	6/1/2026	6/1/2026
Elwood CT 1	150.0	ComEd	Natural Gas	25	3/21/2025	6/1/2026	6/1/2026
Ocean County LF	9.1	JCP&L	Biomass	37	2/26/2025	7/1/2025	7/1/2025
Forked River Unit 1	34.0	JCP&L	Natural Gas	36	2/25/2025	6/1/2027	6/1/2027
Forked River Unit 2	31.0	JCP&L	Natural Gas	36	7/22/2025	6/1/2026	6/1/2027
Rockford CT11	179.0	ComEd	Natural Gas	25	5/1/2025	6/1/2026	6/1/2027
Rockford CT12	178.0	ComEd	Natural Gas	25	5/1/2025	6/1/2026	6/1/2027
Rockford CT21	180.0	ComEd	Natural Gas	23	5/1/2025	6/1/2026	6/1/2027
Sherman Avenue CT1	79.0	AE	Natural Gas	34	1/28/2025	6/1/2027	6/1/2027
Cumberland CT 1	79.0	AE	Natural Gas	35	1/28/2025	6/1/2027	6/1/2027
Indian River 4	411.9	DP&L	Coal	41	2/18/2025	12/20/2024	2/24/2025

Fifteen generators totaling 547.1 MW deactivated in the PJM region during 2025, as shown in **Map 3.11** and **Table 3.3**. PJM completed the required analysis to identify any reliability criteria violations caused by deactivations. No NERC reliability criteria violations were identified. Consequently, no new RTEP baseline enhancements were required. As **Table 3.2** shows, requested deactivation dates, at the time notifications were received, ranged from December 2024 through December 2030.

**Map 3.11: Actual Generator Deactivations in 2025**



**Table 3.3: Actual Generator Deactivations in 2025**

Unit	Capacity (MW)	TO Zone	Fuel Type	Age (Years)	Owner Request Letter	Requested Deactivation Date	Projected Deactivation Date	Actual Deactivation Date
Sidney Unit 5	2.0	AES Ohio	Diesel	57	10/8/2025	10/8/2025	10/8/2025	10/8/2025
FE Dovetail 1 CT	0.0	ATSI	Biomass	25	9/24/2025	9/24/2025	9/24/2025	9/24/2025
Warren Evergreen CT1	5.0	ATSI	Natural Gas	44	5/29/2025	10/1/2025	10/1/2025	10/1/2025
Laurel Mountain Battery	0.0	AP	Battery	14	4/1/2025	7/2/2025	7/2/2025	7/1/2025
Willey Energy Storage	6.0	DEO&K	Battery	9	3/21/2025	9/2/2025	9/1/2025	9/2/2025
Buchanan Units 1	40.0	AEP	Natural Gas	23	3/14/2025	7/1/2025	7/1/2025	7/2/2025
Buchanan Unit 2	40.0	AEP	Natural Gas	23	3/14/2025	7/1/2025	7/1/2025	7/2/2025
Ocean County LF	9.1	JCP&L	Biomass	37	2/26/2025	7/1/2025	7/1/2025	7/1/2025
Cates Road Solar	2.6	AE	Solar	10	12/30/2024	4/1/2025	4/1/2025	4/1/2025
Manchester 1 LF	4.0	JCP&L	Methane	36	11/14/2024	4/1/2025	4/1/2025	4/1/2025
Morris Road 1 D	2.0	PECO	Oil	14	7/17/2024	5/31/2025	5/31/2025	5/31/2025
Elwood CT 9	150.0	ComEd	Natural Gas	25	5/29/2024	6/1/2025	6/1/2025	6/1/2025
Elwood CT 8	150.0	ComEd	Natural Gas	25	5/29/2024	6/1/2025	6/1/2025	6/1/2025
Wagner CT 1	13.0	BGE	Diesel	56	10/16/2023	6/1/2025	6/1/2025	6/1/2025
Wagner 1	126.0	BGE	Natural Gas	67	10/16/2023	6/1/2025	6/1/2025	6/1/2025

### 3.3: 2025 Retool Impacts

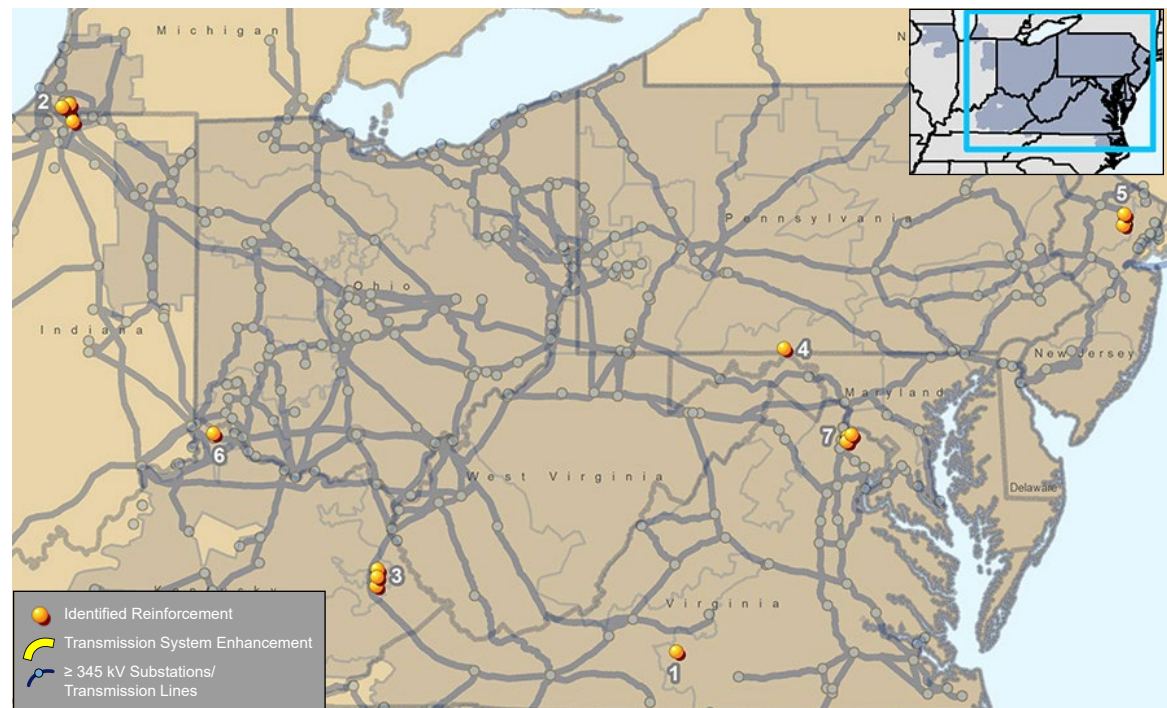
As part of each RTEP cycle, PJM conducts retool studies to evaluate how changes to input assumptions impact study results from prior RTEP cycles. Sensitivity studies evaluate the impacts of changes to generator models, load models, project configurations and scope, and other power flow input parameters. Retool studies conducted during 2025 for several projects are shown on **Map 3.12** and **Table 3.4**.

#### 3.3.1 — Baseline Project B3800.210–.212 in Dominion

A Dominion zone retool study assessed the impact of the scope change of baseline project B3800.210-.212.

- The original project scope involved building new 230 kV lines on Mars-Lockridge-Golden and 500 kV lines on Mars-Golden on 500/230 kV double-circuit structures.
- The solution was revised to remove 230 kV line No. 2095 Mars-Shellhorn and line No. 2292 Mars-Sojourner in the existing transmission corridor between Sojourner and Mars substations to allow for termination of line No. 2413 and 5003 Golden-Mars 230 and 500 kV circuits into Mars substation.
- The 230 kV line No. 2095 Mars-Shellhorn was cut into Sojourner substation, creating 230 kV line No. 2427 (Mars-Sojourner) and 230 kV line No. 2095 (Sojourner-Shellhorn).
- Additionally, four 230 kV circuit breakers were upgraded at Sojourner substation from 63 kA to 80 kA.

Map 3.12: 2025 RTEP Cycle Retool Studies



The reason for this scope change was due to the new Golden-Mars 230 kV and 500 kV lines intersecting with the existing transmission corridor containing the following lines (just east of the Old Ox/Carters School Road intersection):

- Mars-Shellhorn 230 kV (No. 2095)
- Mars-Sojourner 230 kV (No. 2292)
- Celestial-Mars 230 kV (No. 2161)
- Cabin Run-Mars 230 kV (No. 2287)

In 2025, this project underwent a second scope change. The Golden-Mars 230 kV line was originally cut and terminated into Lockridge substation. The revised scope instead terminates the 230 kV Golden to Mars line into a nearby Prentice Drive substation and removes the two 230 kV, 80 kA circuit breakers and associated terminal equipment from Lockridge substation and installs the breakers and equipment at Prentice Drive substation. The revised scope requires less right-of-way and reduces transmission line material costs, as well as avoids heavily constrained areas near Prentice Drive with

Table 3.4: 2025 RTEP Cycle Retool Study Impacts

Map ID	Project	Description
1	B4000.207	Perform upgrade at Leesville station 138 kV: Replace 795 KCM AAC, 37-stranded IPS Sch. 40 1272 KCM AAC, 61-stranded 1272 KCM AAC, 61-stranded PH A,B,C ALTA VISTA CB-A BUS DISC ALTA VISTA CB-A LINE DISC wave trap (1200A) relay thermal limit 1,356 amps.
	B4000.360	Replace two switches, a wave trap and leads to upgrade all related substation equipment to 2000A at Altavista 138 kV substation.
2	S2167	Perform area improvements at Niles.
3	S2470.1	Construct a greenfield line (Kenwood 69 kV extension) to be operated at 46 kV. The new extension will provide looped service into Kenwood substation. It will be ~2.25 miles of single-circuit construction through mountainous terrain in Floyd and Johnson counties in Kentucky. The extension will tap the existing Prestonsburg-Thelma 46 kV line around structure K346-50.
	S2470.2	Rebuild the existing ~1.77-mile Kenwood tap line from Kenwood to Van Lear tap structure on the existing center line.
	S2470.3	Provide splicing for 2.25 miles of 96 count OPGW on the Kenwood 69 kV extension line and 1.77 miles of Kenwood tap line. This extension spans from Kenwood station to the Prestonsburg-Thelma 46 kV line.
	S2470.4	Extend the walk bus at Kenwood substation and add a second 46 kV line to set up Kenwood station as a looped station with MOABS protecting each exit. Add a new H-frame dead end with MOAB and single-phase CCVT. Add MOAB and single-phase CCVT to the existing line and relocate the three-phase CCVTs from cap bank AA to the 46 kV bus. Add a three-bay transclosure and separate the battery enclosure. Replace the battery and charger.
	S2470.5	Retire Van Lear switching station.
	S2470.6	Perform remote end work at Prestonsburg substation.
	S2470.7	Retire the ~1.5-mile 46 kV line section from structure 52 to Van Lear switching station.
4	B3773	Install one 31.7 MVAR switched capacitor, 138 kV breaker and associated relaying at Warfordsburg substation.
5	B2003	Construct a Whippany-Montville 230 kV line (6.4 miles).
6	S3600.1	Build a new substation, Turfway, with a four-breaker ring bus with nonadjacent feeders supplying two 138/34 kV, 22.5 MVA transformers with two distribution exits each. Intercept the Donaldson-Woodspoint 138 kV circuit looping it through Turfway. The total length of new feeder and right-of-way is ~2 miles.
7	B3800.210	Build a new 230 kV line from Mars-Prentice Drive on 500/230 kV double-circuit structures to achieve a summer rating of 1573 MVA. Install 230 kV equipment at Mars and Prentice Drive. Remove 230 kV line No. 2095 Mars-Shellhorn and 230 kV line No. 2292 Mars-Sojourner in the existing transmission corridor between Sojourner and Mars substations so that they can be rerouted to the south side of Mars substation, adding approximately 2 miles of new conductor. This is to allow for termination of the line No. 2413 and 5003 Golden-Mars 230 and 500 kV circuits into Mars substation. Cut 230 kV line No. 2095 Mars-Shellhorn into Sojourner substation, creating 230 kV line No. 2427 (Mars-Sojourner) and 230 kV line No. 2095 (Sojourner-Shellhorn). Upgrade four 230 kV breakers at Sojourner substation from 63 kA to 80 kA.
	B3800.211	Build a new 230 kV line from Prentice Drive-Golden on 500/230 kV double-circuit structures to achieve a summer rating of 1573 MVA. Install 230 kV equipment at Golden and Prentice.
	B3800.212	Build a new 500 kV line from Mars-Golden on 500/230 kV double-circuit structures with substation upgrades at Golden and Mars. New conductor to have a minimum summer normal rating of 4357 MVA.

underground utilities and eliminates crossings of Lockridge Road and a distribution line. Prentice Drive substation also allows alternating outages, unlike Lockridge, which would require a full substation outage or temporary configurations.

**3.3.2 — Baseline Project B4000.360 in Dominion**  
Baseline project B4000.360 replaces two switches, a wave trap and leads to upgrade all related substation equipment to 2000A at Altavista 138 kV substation. This is a scope addition in the Dominion zone to the originally approved baseline project B4000.207 designated to American Electric Power (AEP) that upgrades the substation equipment at the Leesville 138 kV station to increase the line rating on the Leesville-Altavista 138 kV line, a tie line between AEP and Dominion.

**3.3.3 — Supplemental Project S2167 in AEP**  
An AEP zone retool study assessed the scope change for supplemental project S2167. The original project has a scope that replaced 69 kV circuit breakers and transformer No. 2 at Niles substation, and rebuilds the approximately 11.8-mile South Bend-Niles 69 kV line as the South Bend-Boundary-Niles 69 kV line, and installs a 69 kV bus tie circuit breaker at Swanson station to separate the four motor-operated air break switches in series.

However, during detailed engineering and design for the proposed work at Niles station, it was determined that the work could not be completed without the use of multiple mobiles or skids and would leave all customers served from the station on long radials for extended periods of time under various required outages. The only vehicle access to

the station is surrounded by water on both sides, is prone to flooding and can be extremely dangerous in adverse weather conditions. For this reason, AEP has decided instead to retire the Niles station.

AEP will build a new FourFlag station to replace Niles, consisting of five 69 kV circuit breakers configured in a ring bus.

FourFlag station will have:

- A 14.4 MVAR cap bank
- A new 69/34.5 kV transformer with high-side circuit switcher
- Two new 34.5 kV circuit breakers toward the City of Niles and Bertrand

The Mayflower 69 kV, Lake Street 69 kV, South Bend 69 kV and City of Niles 34.5 kV lines will also be rerouted into the FourFlag station. Additionally, a 34.5 kV circuit breaker will be installed at South Side Station (owned by City of Niles) to coordinate with the new breakers at FourFlag station. The original 11.8-mile line rebuild from South Bend-Niles 69 kV will likewise now terminate at FourFlag station instead of Niles station, creating a South Bend-Boundary-FourFlag 69 kV line.

At Swanson station, AEP distribution has requested the station be rebuilt in the clear due to outage risks associated with aging asset conditions installed in the 1950s and 1970s. The Swanson station also has 34.6 MVA of load that is non-recoverable and nontransferable to neighboring stations in the event of equipment loss or for outage recovery. As a result, AEP has decided to rebuild Swanson substation.

**3.3.4 — Supplemental Project S2470 in AEP**  
Another AEP zone retool study assessed the cancellation of supplemental project S2470. The project involved a 69 kV greenfield line extension that would provide looped service into Kenwood substation. It was determined that the need associated with AEP-2020-AP29 will be addressed by baseline project B3361, which rebuilds the Prestonsburg-Thelma 46 kV circuit connecting through Kenwood station, approximately 12.7 miles. As a result, the supplemental project was canceled.

### **3.3.5 — Baseline Project B3773 in Allegheny Power (FirstEnergy) Zone**

An Allegheny Power (FirstEnergy) (AP) zone retool study assessed the impact of baseline project B3773 scope change. This project originally involved the installation of a 33 MVAR switch capacitor, 138 kV circuit breaker and associated relaying at McConnellsburg substation.

FirstEnergy identified significant challenges with installing a 138 kV capacitor at McConnellsburg substation, including the need for a fence expansion and new control building, and therefore, proposed to install the 138 kV capacitor at Warfordsburg substation instead.

As a result, the baseline project will instead install a 31.7 MVAR switch capacitor, 138 kV circuit breaker and associated relaying at Warfordsburg substation.

### 3.3.6 — Supplemental Project S3600.1 in DEO&K

A Duke Energy Ohio and Kentucky (DEO&K) zone retool study assessed the impact of supplemental project S3600.1 scope change. This project involved building a new substation, Turfway, with a switch-connected straight bus configuration and two circuit-switcher-connected 138/34 kV, 22.5 MVA transformers with two distribution exits each. The Donaldson-Woodspoint 138 kV circuit would loop through the new Turfway substation. The planned new 138 kV Turfway substation was changed from a straight bus to four-breaker ring bus to improve reliability and operational functionality of the substation.

No criteria violations were identified as a result of the retool studies, and therefore, the baseline and supplemental projects' scope changes and cancellations were able to move forward.

### 3.3.7 — Baseline Project B2003 in JCP&L

One retool study in the Jersey Central Power & Light (JCP&L) zone still requires continued evaluation. The study assessed the impact of baseline project B2003 cancellation. This project involved the construction of the Whippany-Montville 230 kV line (6.4 miles).

Due to routing and permitting issues, FirstEnergy has requested this project be canceled and has notified PJM that an alternative solution must be selected. Given the infeasibility of the project, PJM has canceled the baseline and will assess alternative solutions.

### 3.4: Interregional Planning

#### 3.4.1 — Adjoining Systems

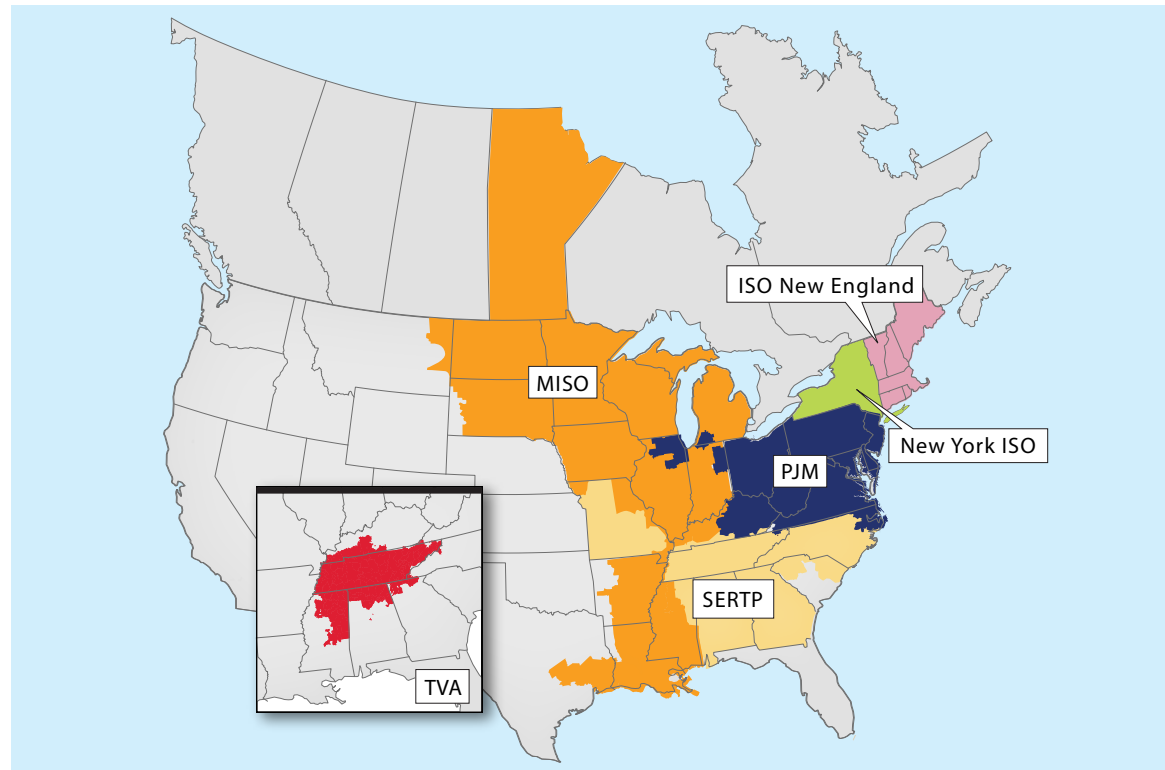
PJM's interregional planning activities continue to foster increased interregional coordination. The nature of these activities includes structured, Tariff-driven analyses, as well as sensitivity evaluations to target specific issues that may arise each year. PJM currently has interregional planning arrangements with the New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), the Mid-Continent Independent System Operator (MISO), the Tennessee Valley Authority (TVA), and to the south through the Southeastern Regional Transmission Planning (SERTP) process, shown on **Map 3.13**. PJM's interactions with its neighbors are also frequently part of NERC activity under the neighboring Regional Reliability Organizations (RROs) shown in **Map 3.14**. In addition, PJM actively participates in the Eastern Interconnection Planning Collaborative.

#### *Interregional Agreements*

Under each interregional agreement, provisions governing coordinated planning ensure that critical cross-border operational and planning issues are identified and addressed before they impact system reliability or efficient market administration. The planning processes applicable to each of PJM's three external transmission interfaces include provisions to address issues of mutual concern, including:

- Interregional impacts of regional transmission plans
- Impacts of interconnection requests and deactivation requests

**Map 3.13: PJM Interregional Planning**



- Opportunities for improved market efficiencies at interregional interfaces
- Solutions to reliability and congestion constraints
- Interregional planning impacts of national and state public policy objectives
- Enhanced modeling accuracy within individual planning processes from periodic exchange of power system modeling data and information

Each study is conducted in accordance with the PJM Tariff and respective interregional agreements. Studies may include cross-border analyses that examine reliability, market efficiency or public policy needs. Reliability studies may assess power transfers, stability, breaker-interrupting duty, generation, merchant transmission interconnection analyses and generator deactivation. Taken together, these coordinated planning activities enhance the reliability, efficiency and cost-effectiveness of regional transmission plans.

### 3.4.2 — MISO

The 2025 planning efforts under Article IX of the MISO/PJM Joint Operating Agreement continued to ensure the coordination of regional reliability, market efficiency, generator interconnection requests and deactivation notifications. Interconnection-driven network transmission enhancements are summarized in **Section 5**. Deactivation-driven baseline analyses are summarized in **Section 3.3**.

Annually, stakeholder input and feedback to the interregional planning process are coordinated through the MISO/PJM Interregional Planning Stakeholder Advisory Committee (IPSAC).

#### ***MISO Long-Range Transmission Planning Process***

As part of its own long-range transmission planning (LRTP) process, MISO has reached out to PJM to discuss long-range studies that have identified the need for MISO system expansion to support greater system transfers to solve thermal and voltage violations, resolve wide-area congestion, and enable significant amounts of new generation. MISO LRTP studies completed in 2024 examined “Tranche 2.1,” which encompasses a portfolio of 24 new 765 kV and 345 kV projects, seven of which would terminate in PJM’s western subregion, as summarized in the [MISO/PJM LRTP Update presentation](#) at the Nov. 22, 2024, IPSAC meeting.

While PJM’s own RTEP analyses have not identified the need for MISO’s LRTP Tranche 2.1 transmission, PJM continues to work with MISO and impacted PJM transmission owners via the M-3 process. PJM has performed initial reliability “no-harm” analyses with impacted

transmission owners. Preliminary results indicate that upgrades to the PJM system would be needed to accommodate Tranche 2.1 MISO facilities. Such upgrades, if they were to go forward, would be funded by MISO, as further discussed in the [IPSAC proposal](#).

Supplemental projects for upgrades to address findings of the “no-harm” analysis were summarized in:

- [MISO/PJM LRTP Tranche 2.1 Update presentation](#) at the June 25, 2025, IPSAC meeting
- [MISO/PJM LRTP Tranche 2.1 Evaluation presentation](#) at the Dec. 5, 2025, IPSAC meeting

#### ***Joint Interregional Transfer Capability Study (ITCS)***

On May 9, 2024, PJM and MISO [announced](#) that the organizations would collaborate on an interregional transfer capability study, which was performed during the second half of 2024 and first half of 2025. Specifically, the ITCS explored opportunities to:

- Engage in joint transmission analysis and coordinated modeling.
- Identify transfer, reliability and economic needs along the seam.
- Pursue solutions through existing processes as appropriate.
- Identify and pursue JOA/Tariff adjustments to implement additional solutions and further improve joint planning processes.

Continuing study work from 2024, PJM and MISO updated their blended study model in 2025 by incorporating Board-approved MISO Tranche 2.1 into the model. PJM and MISO presented an [ITCS preliminary results and timeline](#) at the June 25, 2025, IPSAC meeting. PJM and MISO presented [ITCS benefits for FERC Order 1920](#) and outlined future work for cost allocation and Tariff updates at the Dec. 5, 2025, IPSAC meeting.

#### ***2024 Coordinated System Plan Activities***

As part of the annual issues review process under section 9.3.7.2 of the [MISO/PJM Joint Operating Agreement](#), PJM and MISO reviewed:

- Newly approved projects near the seam
- New regional issues
- Market-to-market historical congestion
- Third-party issues

After rigorous review and analysis, and considering the initiation of the ITCS, the Joint Reliability Planning Committee (JRPC) determined that a CSP study would not be performed in 2025.

### 3.4.3 — New York ISO and ISO New England

#### ***Northeast Coordinated System Plan***

PJM, NYISO and ISO-NE presented a Draft 2025 Northeast Coordinated System Plan (NCSP25) [Scope of Work](#) at the NYISO and ISO-NE IPSAC meeting on Dec. 5, 2025, covering the work plan and anticipated 2026 activities to be performed under the auspices of the Joint ISO/ RTO Planning Committee (JIPC). The 2026 work will include continued coordination, a review of transmission needs and solutions proposed by neighboring systems, coordination of interconnection requests, long-term firm transmission service, and transmission projects that potentially impact interregional system performance. The [NCSP25 Report](#) for stakeholder review was posted on April 3, 2026.

#### ***JIPC Loss of Source Study***

In March 2023, ISO-NE formally requested, via [letter](#), that the JIPC conduct a study to determine the feasibility of raising the minimum loss of source value for New England from its existing 1,200 MW level to a proposed 2,000 MW level. In August 2023, the JIPC posted a [response](#) agreeing to collaboratively participate in the study. Study activities commenced in Q4 2023 and continued throughout 2024 and 2025. ISO-NE presented a [Loss of Source Study Status](#) at the NYISO and ISO-NE IPSAC meeting on May 2, 2025. However, at the NYISO and ISO-NE IPSAC meeting on Dec. 5, 2025, ISO-NE announced a [Suspension of the Loss of Source Study](#) along with key insights from the study to date.

### 3.4.4 — Adjoining Systems

#### South of the PJM Region

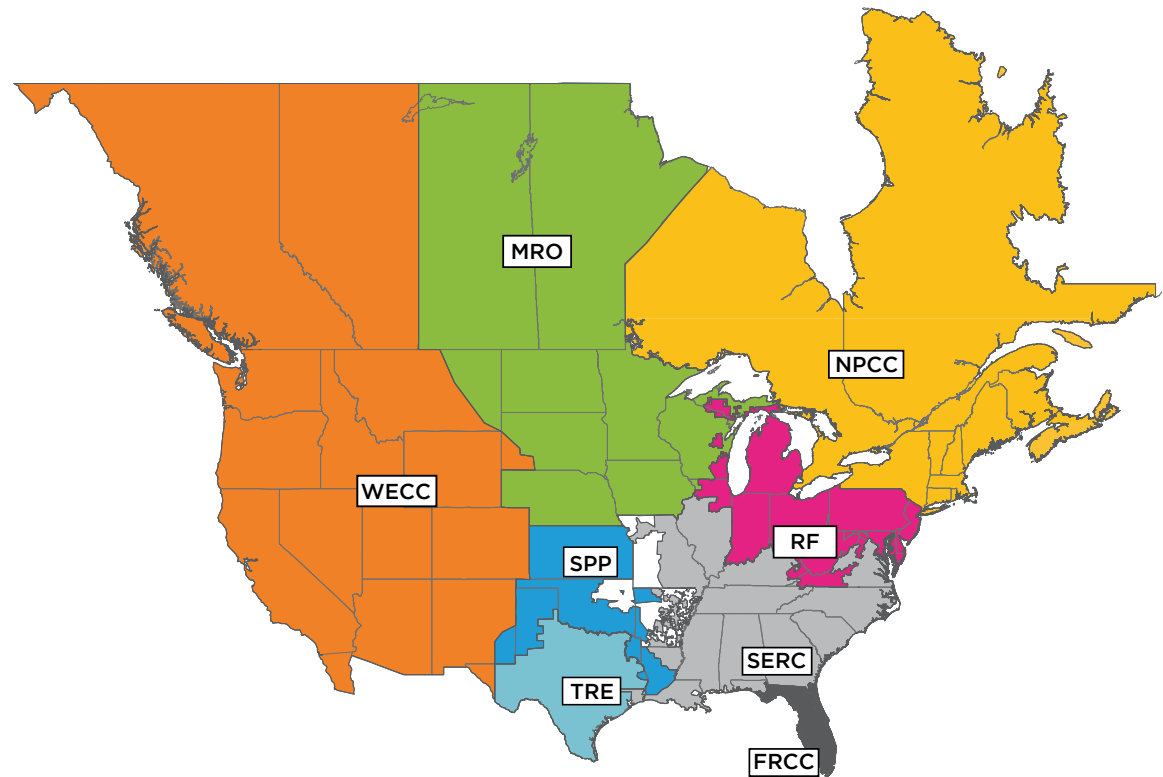
Interregional planning activities with entities south of the region PJM serves are conducted mainly under the auspices of the Southeastern Regional Transmission Planning (SERTP) process and SERC Reliability Corp.

#### ***Southeastern Regional Transmission Planning***

PJM and the [SERTP](#), shown earlier on **Map 3.13**, continued interregional data exchange and interregional coordination during 2025. SERTP membership includes several entities under FERC jurisdiction and voluntary participation among six non-jurisdictional entities. The jurisdictional entities include Southern Co., Duke Energy (including Duke Energy Carolinas and Duke Energy Progress), and Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E and KU). Duke Energy, LG&E and KU are directly connected to PJM. Of the non-jurisdictional entities, only TVA is directly connected to PJM. The remaining five SERTP participants are planning areas south and west of Duke Energy and TVA.

SERTP input occurs through each region's respective planning process stakeholder forums. Stakeholders who have reviewed their respective region's needs and transmission plans may provide input regarding any potential interregional opportunities that may be more efficient or cost-effective than individual regional plans. Successful interregional project proposals can displace the respective regional plans. PJM discussions of SERTP planning, as well as reports on other interregional planning, occur at the Transmission Expansion Advisory Committee (TEAC).

**Map 3.14: NERC Regional Reliability Organizations**



#### ***SERC Activities***

PJM continues to support its members that are located within SERC, Dominion Energy and East Kentucky Power Cooperative (EKPC), as shown on **Map 3.14**. This support includes active participation in various committees and working groups, such as the Engineering Committee, Planning Coordination Subcommittee, Long-Term Working Group, Reliability Risk Working Group,

Dynamics Working Group, Short-Circuit Database Working Group, Resource Adequacy Working Group and Near-Term Working Group.

In 2025, PJM actively contributed to SERC committee and working group activities to coordinate model development, perform study activities, review results, and collaborate on industry risk identification and mitigation.

### 3.4.5 — Eastern Interconnection Planning Collaborative

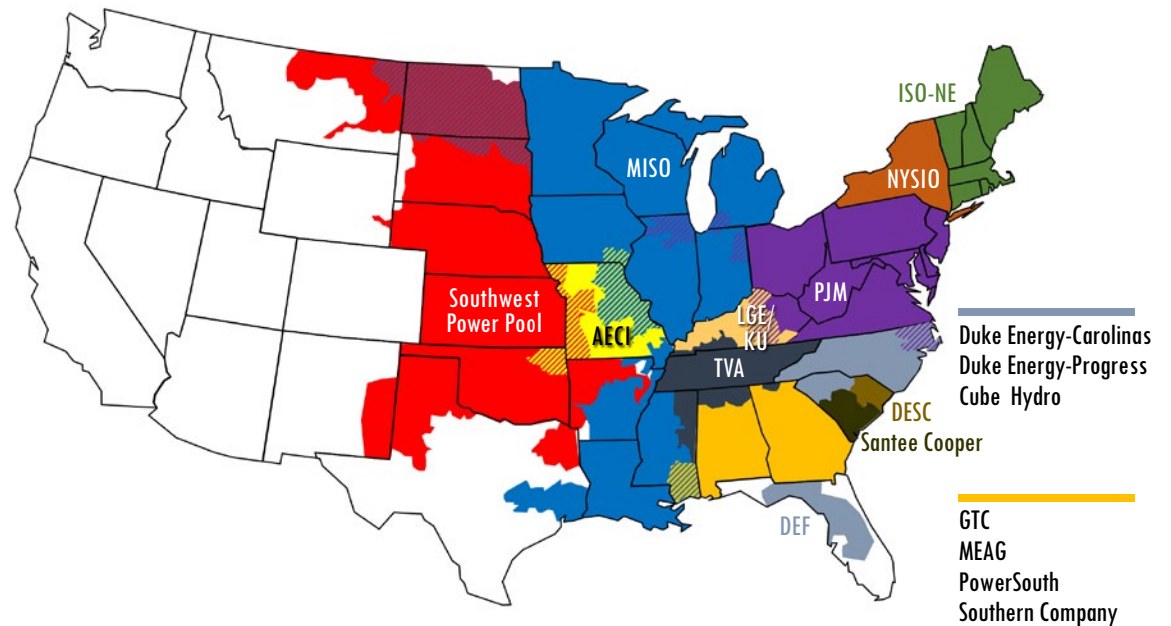
The Eastern Interconnection Planning Collaborative (EIPC) is an interconnection-wide transmission planning coordination effort among NERC planning authorities in the Eastern Interconnection, shown on **Map 3.15**. EIPC consists of 19 planning coordinators representing over 90% of the Eastern Interconnection load. EIPC coordinates analysis of regional transmission plans to ensure their coordination and provides resources to analyze emerging issues impacting the transmission grid. EIPC's work builds on, rather than replaces, the existing regional and interregional transmission planning processes of participating planning authorities. EIPC's efforts are intended to inform regional planning processes.

#### ***EIPC Activities***

During 2025, EIPC continued to engage power system planning analysis activities including the following:

- The EIPC has a new initiative to increase EIPC review and discussion of emerging and upcoming NERC compliance activities.
- The EIPC formed a NERC Large Load Task Force to facilitate EIPC discussion, consensus and information-sharing among EIPC members.
- The EIPC Modeling Coordination Working Group (MCWG) continued to provide coordination between EIPC and the Multiregional Modeling Working Group (MMWG) in order to facilitate and enhance the Eastern Interconnection model-building process.

**Map 3.15:** Eastern Interconnection Planning Collaborative



### 3.5: Stage 1A ARR 10-Year Analysis

#### RTEP Context

Auction Revenue Rights (ARRs) are the mechanisms by which the proceeds from the annual FTR Auction are allocated. ARR holders are entitled to receive an allocation of the revenues from the annual FTR Auction. Incremental ARRs (IARRs) are additional ARRs created by new transmission expansion projects. [The PJM Operating Agreement](#), Schedule 1, section 7.8, sets forth provisions permitting any party to request IARRs by agreeing to fund transmission expansions necessary to support the requested financial rights. Requests must specify a source, sink and megawatt amount. PJM conducts annual studies to determine if transmission system expansions are required to accommodate the requested IARRs so that all are simultaneously feasible for a 10-year period.

#### Scope

Each year, PJM conducts an analysis to test the transmission system's ability to support the simultaneous feasibility of all Stage 1A ARRs up to 60% of network service peak load plus the projected 10-year load growth. If needed, PJM will recommend expansion projects to be included in the RTEP with required in-service dates based on results of the 10-year analysis itself. As with all other RTEP expansion recommendations, those for ARRs will include the driver, cost, cost allocation and analysis of project benefits, provided that such projects will not otherwise be subject to a market efficiency cost/benefit analysis. Project costs are allocated across transmission zones based on each zone's Stage 1A eligible ARR flow contribution to the total Stage 1A eligible ARR flow on the facility that limits feasibility.

**Table 3.5:** 2024/2025 Stage 1A ARR 10-Year Infeasible Facilities

Facility Name	Upgrade Expected To Fix Infeasibility	Expected In-Service Date
Cooper-Graceton 230 kV	2022 RTEP Reliability Window 3 (B3780, B3800)	2027–2028
Cooper-Peach Bottom Tap 230 kV		
Nottingham 1-3 Bus Tie 230 kV		
Nottingham 2-3 Bus Tie 230 kV		
Nottingham-Peach Bottom Tap 230 kV		
Conastone-Peach Bottom 500 kV		
Colora-Conowingo 230 kV	Rebuild 5.4 miles of 115 kV line No. 100 Locks-Harrowgate (B3694)	2026
Harrowgate-Locks 115 kV		

#### Results: 2025/2026 Stage 1A ARR 10-Year Analysis

In 2025, PJM staff completed a 10-year simultaneous feasibility analysis for 2025/2026 Stage 1A ARR selections. The power flow case used in the 10-year feasibility analysis is the same one used in the 2025/2026 annual ARR allocation, but without any modeled maintenance transmission outages. The results of the 10-year analysis identified violations on several PJM internal facilities. **Table 3.5** lists the facilities of concern and the solutions expected to address the violations identified in the analysis.

## 3.6: Scenario Studies

### 3.6.1 — Introduction

As part of the 2025 RTEP, a series of power flow models was developed using various scenarios:

- *Scenario 1* represents the five-year (2030) power flow model used by PJM to solicit transmission solutions in the competitive window.
- *Scenario 2* was the five-year (2030) power flow model provided for informational purposes to help transmission developers “right size” any proposed solution.
- *Scenario 3* was the long-term seven-year (2032) power flow model developed for the same purpose as Scenario 2.

Scenarios 4 through 6 were sensitivity studies that modified and were compared with the long-term power flow model of Scenario 3:

- *Scenario 4* studied the impact of removing New Jersey/Delaware offshore wind.
- *Scenario 5* studied the impact of state and federal policy-driven deactivations.
- *Scenario 6* studied the impact of battery dispatch.

**Section 3.6.2** and **Section 3.6.3** describe Scenarios 5 and 6 in detail and summarize their reliability assessments.

### 3.6.2 — Policy-Driven Deactivation: Scenario 5

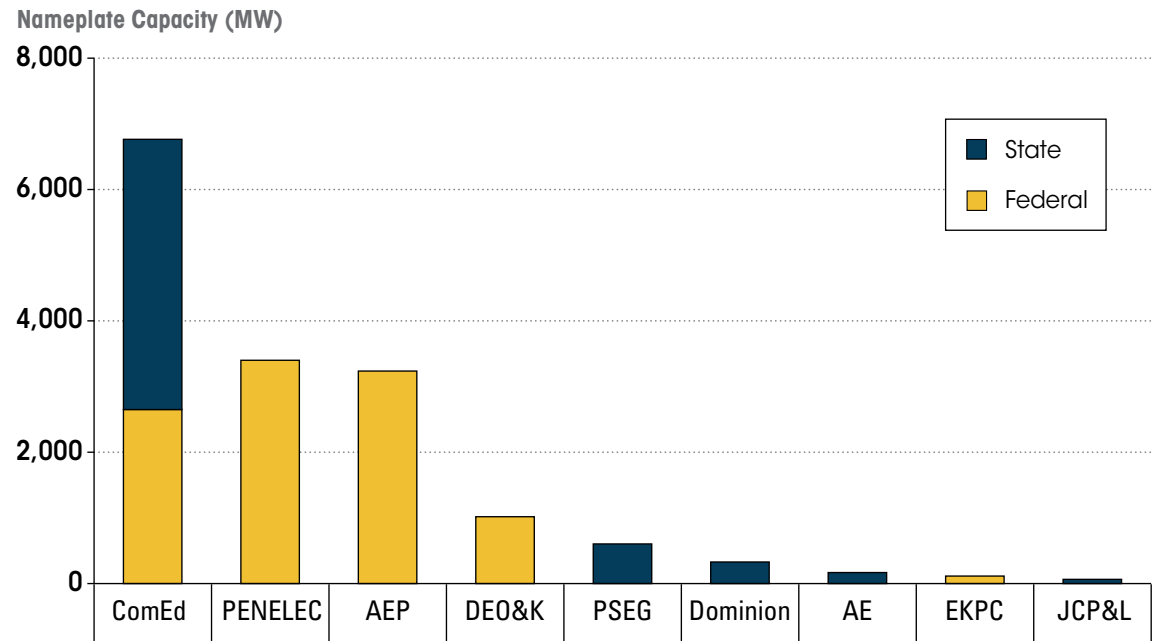
#### Overview

Scenario 5 analyzed the reliability impacts on the system due to anticipated generator retirements in the PJM region resulting from federal and state policies. This sensitivity study identified relevant generators at risk of deactivation, associated megawatts, locations and anticipated date of deactivation as shown in **Figure 3.5**, with input from the Independent State Agencies Committee (ISAC). The nameplate capacity of state and federal policy-driven deactivations is shown in **Figure 3.5**.

PJM determined that the projected policy-driven deactivations would result in insufficient generation to support the projected load growth within PJM, and PJM would have been unable to perform the requested reliability analysis. Therefore, PJM carried out a capacity expansion study to forecast the replacement generation.

In addition to policy-driven deactivations, the capacity expansion study accounted for load growth, state Renewable Portfolio Standards' (RPS) targets, states' resource-specific targets and resource adequacy requirement targets. The capacity expansion study also included additional assumptions, such as economic data, the generation interconnection queue and generation build limits for year 2032. Then, PJM developed three seasonal power flow models by modeling generation in accordance with the capacity expansion study, carried out a reliability assessment, and assessed impact of economical capacity expansion by comparing the reliability assessment with Scenario 3.

**Figure 3.5:** Policy-Driven Deactivation

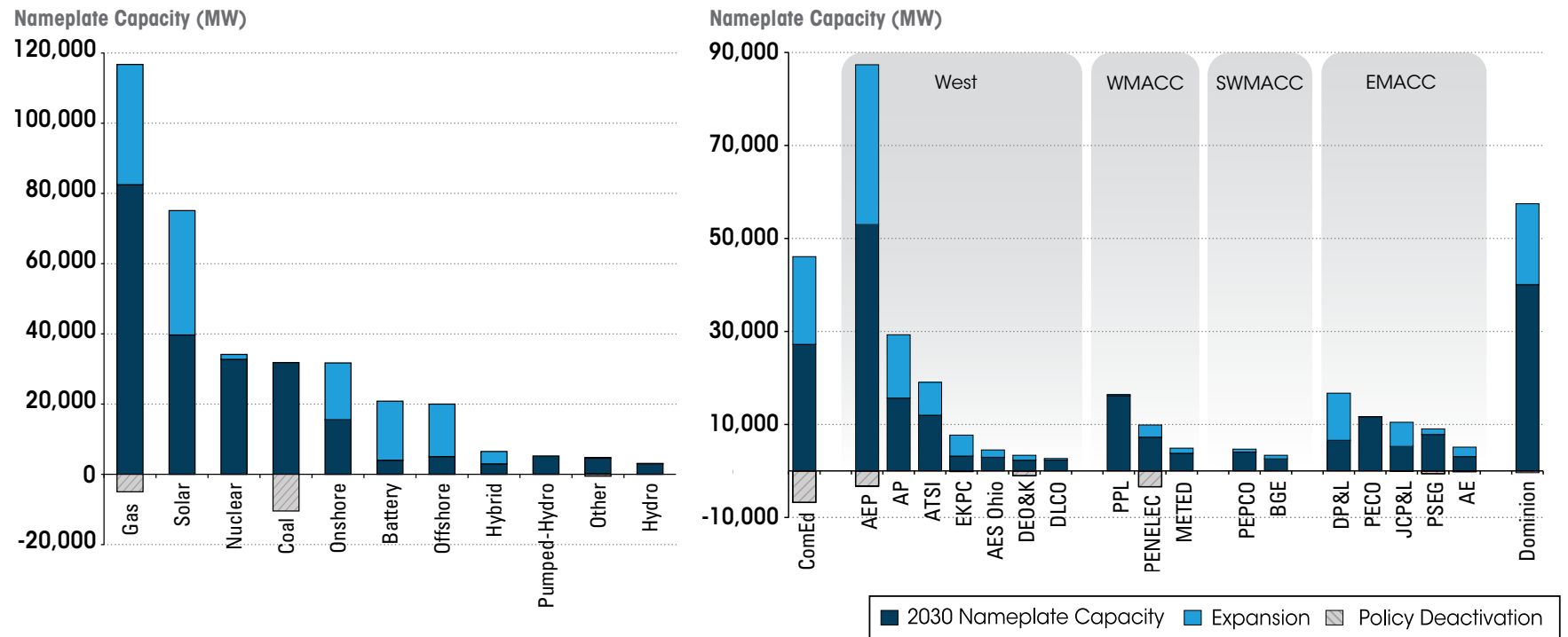


#### Policy-Driven Deactivation Capacities

The following is a summary of the policy-driven deactivations included in the analysis:

- 15.7 GW of generation is expected to retire by 2030 as a result of state and federal policies.
- ComEd, PENELEC and AEP account for 85% of the potential policy-driven deactivations.
- In ComEd, the majority of deactivations are driven by state policy.
- Outside of ComEd, the majority of deactivations are driven by federal policy.

**Figure 3.6: Economic Capacity Expansion**



**Economic Capacity Expansion**

Economic capacity expansion accounted for states’ RPS targets in determining the replacement generation:

- Eleven out of 13 states in the PJM footprint have RPS targets.
- The majority of those states have minimum solar requirements.

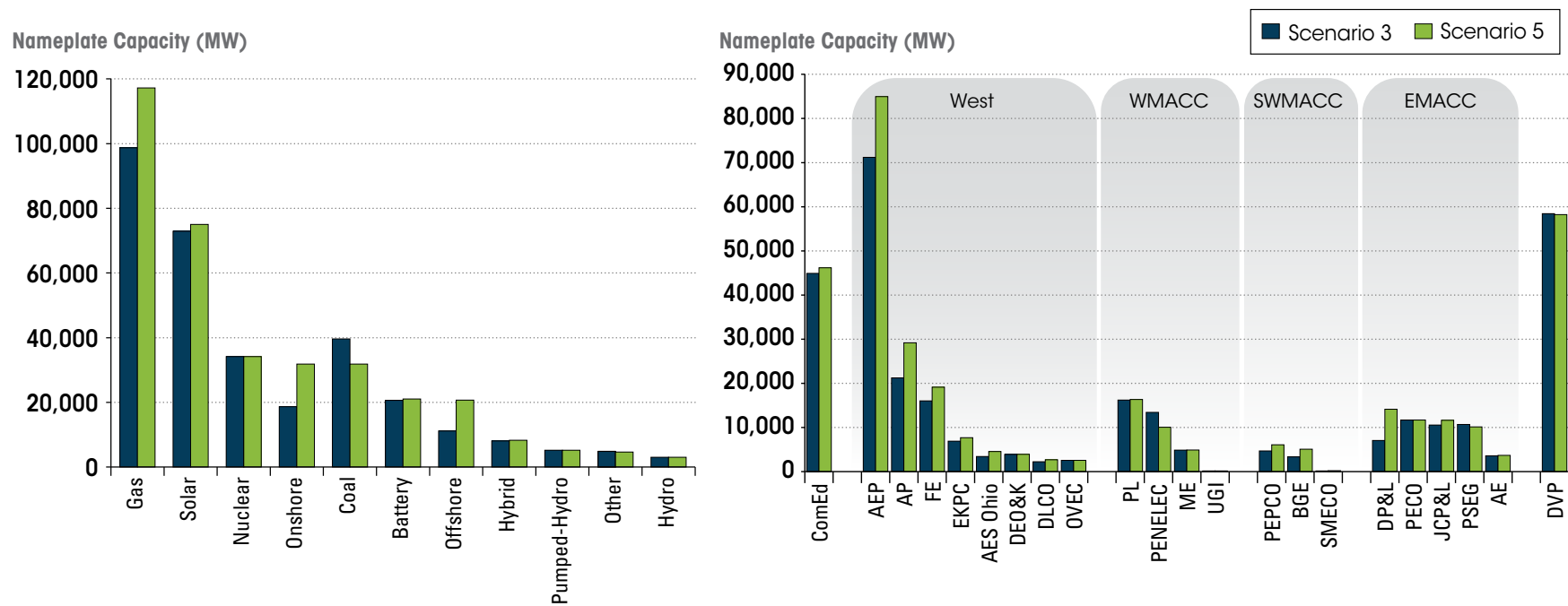
In the capacity expansion study, the following constraints on generation build limits were applied:

- Minimum build limit by 2032: TC1 and TC2, with the Reliability Resource Initiative (RRI) from the generation interconnection queue
- Maximum build limit by 2032: two times the 2030 nameplate capacity plus the queue for renewable, battery, hybrid and gas generation builds

2030 nameplate capacity, capacity expansion and policy deactivations are shown in **Figure 3.6**. The following is a summary of capacity expansion:

- Significant new generation (123 GW) is needed by 2032 to meet resource adequacy criteria.
- The majority of the new generation is added in the western region (63 GW).
- The majority of additional generation is gas (34 GW) and solar (35 GW).

**Figure 3.7:** Nameplate Capacity in Scenario 3 and Scenario 5 (by Transmission Owner and Fuel Type)



**Power Flow Model:**

PJM developed three seasonal power flow models by modeling generation in accordance with the capacity expansion study.

Nameplate capacity in Scenario 3 and Scenario 5 is compared in **Figure 3.7**. The following is a summary comparing the power flow models of Scenario 3 and Scenario 5:

- Scenario 5 has 36 GW of additional nameplate capacity compared with Scenario 3.
- In Scenario 5, the largest amount of nameplate capacity compared with Scenario 3 is for gas (19 GW), wind (13 GW) and OSW (10 GW).
- The nameplate capacity of coal generation in Scenario 5 is 8 GW less than in Scenario 3.
- Scenario 5 has a significantly different regional generation profile compared with Scenario 3, resulting in higher west-to-east transfers.

**Reliability Assessment**

The comparison of reliability study results of Scenario 3 and Scenario 5 in **Table 3.6** shows that:

- Overall, the number of unique bulk electric system facilities overloaded is 60% higher in Scenario 5 than in Scenario 3.
- The number of overloaded 500 kV-and-above facilities in Scenario 5 is more than 2.5 times that of Scenario 3.

////////////////////////////////////

Summary:

The following is a summary of Scenario 5, which analyzed reliability impact on the system in 2032 due to anticipated generator retirements resulting from federal and state environmental policies, load growth, state RPS targets, state resource-specific targets, and resource adequacy requirement targets:

- Due to state and federal policies, 15.7 GW of generation is at risk of deactivation by 2032.
- The forecasted generation expansion will result in higher west-to-east transfers.
- The number of violations is significantly higher in Scenario 5 compared with Scenario 3.

**Table 3.6:** Additional Number of Facilities Overloaded in Scenario 5 Compared With Scenario 3

	230–345 kV		500–765 kV		Total
	Line	Transformer	Line	Transformer	
AE	0	0	0	0	0
AEP	20	0	14	2	35
AP	2	0	8	3	13
ATSI	5	0	0	0	5
BGE	3	0	2	1	6
ComEd	7	0	1	0	7
AES Ohio	1	0	0	0	1
DEO&K	2	0	0	0	2
DLCO	1	0	0	0	1
Dominion	7	0	6	2	15
DP&L	19	0	2	2	23
EKPC	0	0	0	0	0
JCP&L	9	2	0	0	11
METED	1	0	0	1	2
OVEC	1	0	0	0	1
PECO	6	0	1	0	7
PENELEC	5	0	3	1	9
PEPCO	6	0	3	1	10
PPL	2	0	1	0	3
PSEG	7	0	0	1	8
<b>Total</b>	<b>101</b>	<b>2</b>	<b>39</b>	<b>13</b>	<b>155</b>

Note: Tie lines between two zones are counted with 0.5 weight for both the zones.

- The proposed 2025 RTEP Window 1 projects will mitigate some of the impacts of this generation expansion.
- Additional transmission reinforcements would be needed to address additional reliability violations should the generation capacity expand economically to meet resource adequacy criteria.

### 3.6.3 — Battery Dispatch: Scenario 6

#### Overview

Scenario 6 analyzed the reliability impact on the system if battery storage facilities were dispatched in case of generation emergencies. PJM developed summer and winter power flow models by dispatching battery storage facilities and modifying Scenario 3. The megawatt dispatch of a battery storage facility was determined based on the season and its storage duration. Then, PJM carried out reliability assessments and evaluated the impact of battery dispatch by comparing the reliability assessment with Scenario 3.

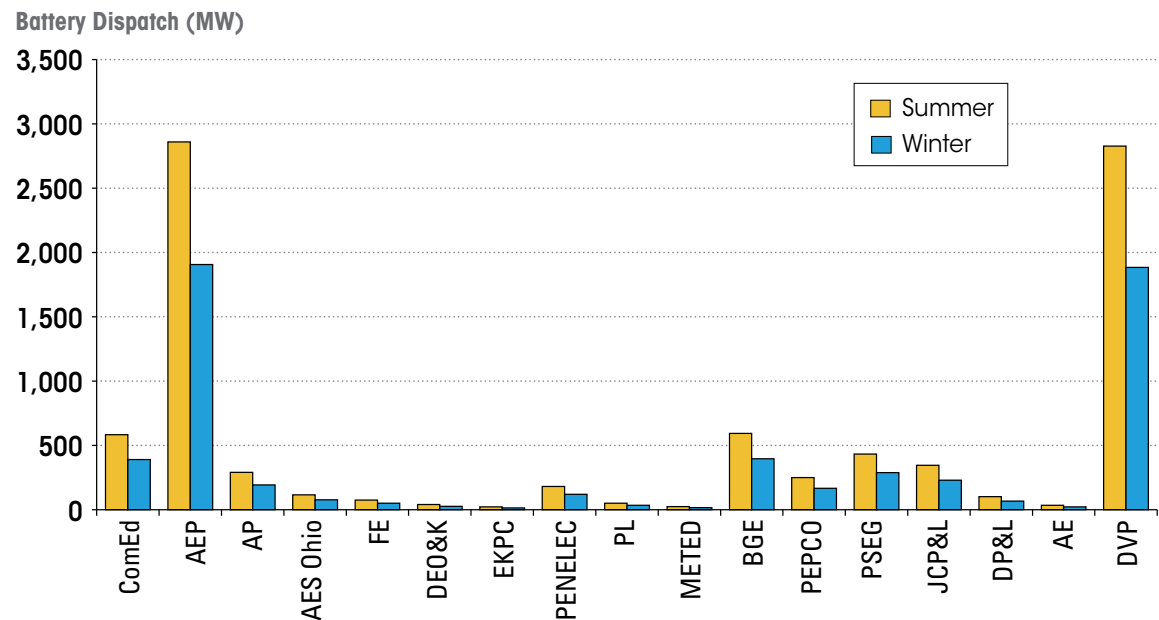
#### Power Flow Model:

The Scenario 6 power flow model for the summer and winter seasons was developed by modifying Scenario 3 as follows:

- In the summer power flow model, over 8,000 MW of battery facilities were dispatched based on the assumption that battery Capacity Interconnection Right (CIR) megawatts would be available for eight hours.
- In the winter power flow model, over 5,000 MW of battery facilities were dispatched based on the assumption that battery CIR megawatts would be available for 12 hours.

In both power flow models, the remainder of PJM generation was scaled down to maintain power balance. The dispatched megawatts of battery facilities in summer and winter power flow models for each zone are shown in **Figure 3.8**.

**Figure 3.8:** Battery MW Dispatch in Scenario 6 by Zone



#### Reliability Assessment

The impact of battery dispatch on reliability is shown in **Table 3.7**. The following is a summary of the comparison of the reliability assessments of Scenario 3 and Scenario 6:

- No new violations on the bulk electric system were observed in Scenario 6.
- The majority of the violations of Scenario 3 were not impacted in Scenario 6.
- Overloads on some facilities in Scenario 3 were reduced in Scenario 6.
- Overloads on a comparable number of facilities were aggravated in Scenario 6.

#### Summary:

The following is a summary of Scenario 6, which analyzed reliability impact on the system when battery storage generation dispatch displaced other generation:

- Dispatching battery storage would affect reliability.
- Due to fewer battery storage facilities in 2032, the impact is not significantly adverse.
- The future impact on reliability due to battery storage would depend on location and size of the additional battery storage and their megawatt dispatch methodology.

**Table 3.7:** Impact of Battery Dispatch: Number of Facilities by kV Level, Facility Type and Impact Categories

Zone	230–345 kV			500–765 kV						Total		
	Transmission Lines			Transmission Lines			Transformer			No Impact	Relieved	Aggravated
	No Impact	Relieved	Aggravated	No Impact	Relieved	Aggravated	No Impact	Relieved	Aggravated			
AE	2	0	0	0	0	0	0	0	0	2	0	0
AEP	23	3	8	3	1	3	1	0	0	27	4	11
AP	1	0	0	0	0	0	0	0	0	1	0	0
ATSI	1	0	10	0	0	0	0	0	0	1	0	10
BGE	0	0	0	0	0	0	0	1	0	0	1	0
ComEd	20	6	0	0	0	0	3	1	0	23	7	0
AES Ohio	2	0	0	0	0	0	0	0	0	2	0	0
DEO&K	3	0	1	0	0	0	0	0	0	3	0	1
DLCO	1	0	0	0	0	0	0	0	0	1	0	0
DP&L	1	0	2	0	1	0	0	0	0	1	1	2
DVP	30	32	22	3	5	4	7	1	2	40	38	28
EKPC	1	0	0	0	0	0	0	0	0	1	0	0
JCP&L	1	0	0	1	0	0	0	0	0	2	0	0
METED	2	0	0	0	0	0	0	0	0	2	0	0
OVEC	1	0	2	0	0	0	0	0	0	1	0	2
PECO	10	0	2	1	1	0	0	0	0	11	1	2
PENELEC	2	0	2	0	0	1	0	0	0	2	0	2
PEPCO	1	1	0	0	0	1	1	0	0	2	1	1
PL	10	0	2	0	0	1	0	0	1	10	0	3
PSEG	7	0	0	0	0	0	0	0	0	7	0	0
<b>Total</b>	<b>116</b>	<b>41</b>	<b>49</b>	<b>8</b>	<b>7</b>	<b>8</b>	<b>12</b>	<b>3</b>	<b>3</b>	<b>136</b>	<b>51</b>	<b>60</b>

Note: Tie lines between two zones are counted with 0.5 weight for both the zones.

**No Impact:** The difference in the facility's maximum loading between Scenario 3 and Scenario 6 is less than 2%.

**Relieved:** Facility's maximum loading in Scenario 6 is reduced by more than 2% compared with Scenario 3.

**Aggravated:** Facility's maximum loading in Scenario 6 is more than 2% compared with Scenario 3.

## Section 4: Market Efficiency Analysis

### 4.0: Scope

#### **RTEP Process Context**

PJM performs market efficiency analysis as part of the overall Regional Transmission Expansion Plan (RTEP) process to accomplish the following objectives:

- Identify new transmission enhancements or expansions that could relieve transmission constraints that have an economic impact.
- Review costs and benefits of economic-based transmission projects previously included in the RTEP to assure that they continue to be cost-beneficial.
- Determine which reliability-based transmission projects, if any, have an economic benefit if accelerated or modified.
- Identify economic benefits associated with changes to reliability-based transmission projects already included in the RTEP that, when modified, would relieve one or more economic constraints. Such projects, originally identified to solve reliability criteria violations, may be designed in a more robust manner to provide economic benefit as well.

PJM identifies the economic benefit of proposed transmission projects by conducting production cost simulations. These simulations show the extent to which congestion is mitigated by the project for specific study year transmission and generation dispatch scenarios. Economic benefits are

determined by comparing future-year simulations both with and without the proposed transmission enhancement. The metrics and methods used to determine economic benefits are described in:

- [PJM Manual 14B](#), Section 2.6
- [PJM Operating Agreement](#), Schedule 6, section 1.5.7

#### **Market Simulation Analysis**

To conduct a market efficiency analysis, PJM uses a market simulation tool that models forecasted PJM market conditions. The resulting solution, from an hourly security-constrained generation commitment and economic dispatch algorithm, provides the basis for the specific evaluations. Several evaluation base cases are developed. The primary difference among these cases is the transmission topology to which the simulation data corresponds:

- An “as-planned” base case power flow models PJM Board-approved RTEP projects included in the five-year-out study year.
- An “as-is” base case power flow models a one-year-out study year transmission topology.
- Project analysis includes topology for specific projects under study.

PJM can determine a transmission project’s economic value by comparing the results of these multiple simulations with the same input assumptions and operating constraints but different transmission topologies. Combining the resulting comparisons with benefit analysis allows PJM to evaluate if specific proposed transmission enhancements or expansions are economically beneficial.

System modeling characteristics included in these databases are broadly described in **Section 4.1**. Importantly, the simulated transmission congestion results and published databases provide key system information and trends to PJM stakeholders.

**24-Month Cycle**

PJM's 2024/2025 24-month market efficiency timeline is shown in **Figure 4.1**. The 2025 market efficiency body of analysis is represented by the second year of the 24-month cycle and focused on the following:

- Updating mid-cycle base case models
- Reevaluating previously approved economic transmission projects
- Performing analysis considering the benefits of accelerating baseline projects previously approved for reliability not yet built

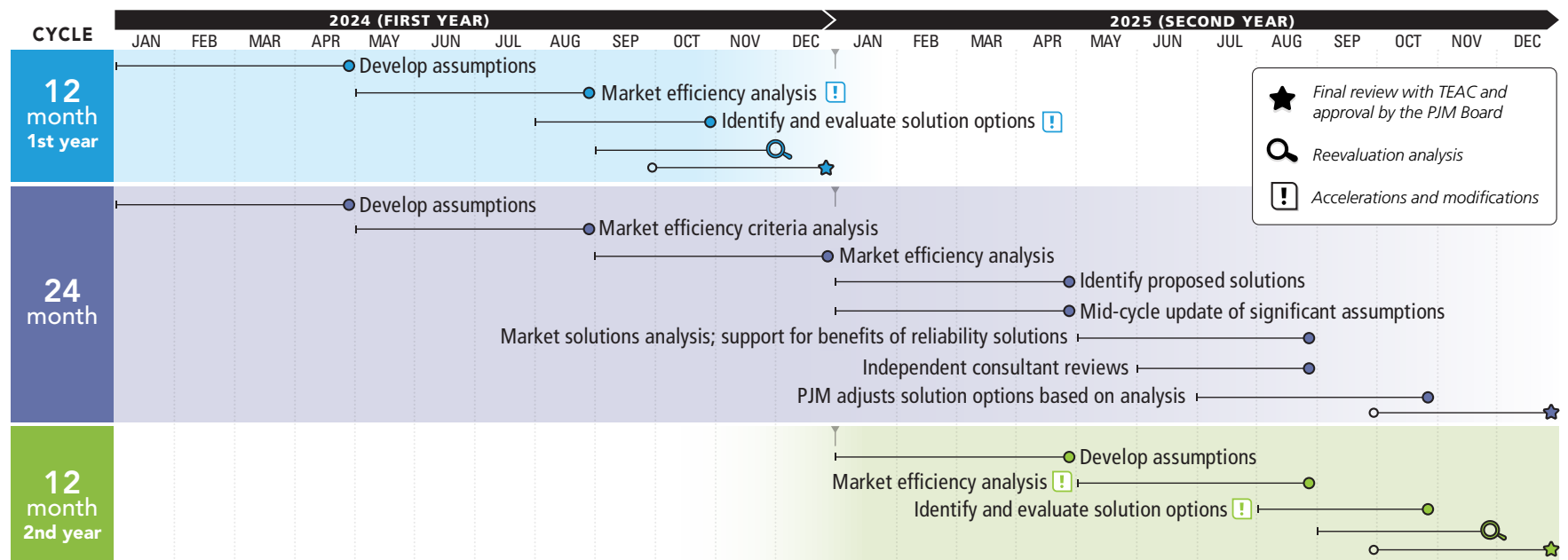
- Identifying the congestion drivers associated with the 2024/2025 Long-Term Market Efficiency Window
- Evaluating proposals submitted in the 2024/2025 Long-Term Window

**Market Efficiency Window Simulations**

To quantify future transmission system market efficiency needs, PJM develops a simulation database for use as part of the 24-month market efficiency study process. The database is mapped to the RTEP power flow case (i.e., “as-planned” base case).

Market efficiency projects identified during the 2024/2025 Long-Term Market Efficiency Window are evaluated using the database initially developed during 2024. However, during the project evaluation phase, PJM develops a mid-cycle update case that incorporates significant RTEP modeling assumption changes. The mid-cycle update case includes potentially significant forecast changes in topology, generation, load and fuel costs. The purpose of the mid-cycle update case is to ensure that potential projects are evaluated using an up-to-date forecast of future conditions.

**Figure 4.1: 2024/2025 Market Efficiency 24-Month Cycle**



PJM calculates a benefit-to-cost ratio to determine if there is market efficiency justification for a particular transmission enhancement. The benefit-to-cost ratio is calculated by comparing the net present value of annual benefits for a 15-year period starting with the RTEP year compared to the net present value of the project's revenue requirement for the same 15-year period. Market efficiency transmission proposals that meet or exceed a 1.25 benefit-to-cost ratio threshold are further assessed to examine their economic, system reliability and constructability impacts. PJM's Operating Agreement requires that projects with a total cost exceeding \$50 million also undergo an independent third-party cost review.

For the majority of proposed projects, PJM determines market efficiency benefits based on energy market simulations. Transmission projects that may impact PJM Reliability Pricing Model Auction activities may derive additional economic benefit as determined through capacity market simulations.

Market efficiency process [training resources](#) are available on the PJM website using a PJM.com account.

### **Project Acceleration Analysis**

For acceleration analysis, PJM compares simulations of near-term topologies (i.e., “as-is” base case) with those of planned topologies (i.e., “as-planned” base case) to assess the individual and collective congestion benefits of RTEP transmission enhancements not yet in service. For example, if a constraint causes significant congestion in the 2025 “as-is” simulation but not in the 2029 “as-planned” simulation, then the project that eliminates this congestion may be a candidate for acceleration. The acceleration cost is considered against the benefit of accelerating a project before any recommendation is made to the PJM Board.

This process allows PJM to:

- Quantify the transmission congestion reduction due to the collection of recently planned RTEP enhancements.
- Reveal if specific, already-planned transmission enhancements may eliminate or relieve congestion so that the constraint is no longer an economic concern.
- Identify if a project may provide benefits that would make it a candidate for acceleration or modification.

In 2025, PJM quantified the transmission congestion reduction due to recently planned RTEP enhancements by comparing the simulation differences between the “as-is” base case and the “as-planned” base case for the 2025 and 2029 study years.

### **Reevaluation of Previously Approved Market Efficiency Projects**

PJM's annual analysis includes a reevaluation of approved projects from previous market efficiency window processes. The reevaluation criteria include the following:

- Projects that are under construction or that have a Certificate of Public Necessity (CPCN) are not required to be reevaluated.
- Projects not under construction or without a CPCN with capital costs less than \$20 million:
  - Will have projected costs updated and using previously determined benefits
  - Should maintain a benefit-to-cost ratio greater than 1.25
- Projects not under construction or without a CPCN with capital costs greater than \$20 million:
  - Will have projected costs updated and benefits reevaluated
  - Should maintain a benefit-to-cost ratio greater than 1.25

In 2025, PJM reevaluated a previously approved market efficiency transmission project.

## 4.1: Input Parameters – 2025 Base Case

### Overview

PJM licenses a commercially available database containing the necessary data elements to perform detailed market simulations. This database is periodically updated, allowing for an up-to-date representation of the Eastern Interconnection and PJM in particular. The PJM Transmission Expansion Advisory Committee (TEAC) reviews key analysis input parameters as shown in **Figure 4.2**. These parameters include fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology and several financial valuation assumptions.

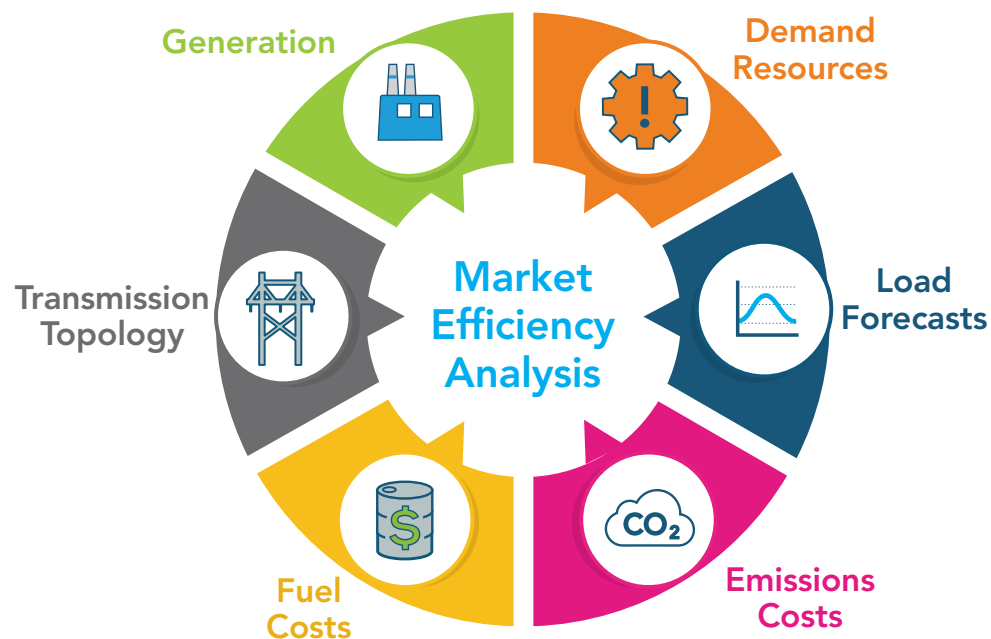
### Transmission Topology

Market efficiency power flow models were developed to represent:

- The 2025 “as-is” transmission system topology
- The expected 2029 system topology for the four-year-out RTEP year

PJM derived the “as-is” system topology from its review of the Eastern Interconnection Reliability Assessment Group’s Series 2024 Multi-Regional Modeling Working Group 2025 summer peak case. It included transmission enhancements expected to be in service by the summer of 2025. PJM derived system topologies for 2029 from the 2029 RTEP case and included several significant RTEP projects approved during the 2024 RTEP cycle.

Figure 4.2: Market Efficiency Analysis Parameters



### Monitored Constraints

Specific thermal and reactive interface transmission constraints are modeled for each base topology. Monitored thermal constraints are based on actual PJM market activity, historical PJM congestion events, PJM planning studies or studies compiled by NERC. PJM reactive interface limits are modeled as thermal values that correlate to power flows

beyond which voltage violations may occur. The modeled interface limits are based on voltage stability analysis and a review of historical values. Modeled values of future-year reactive interface limits incorporate the impact of approved RTEP enhancements on the reactive interfaces.

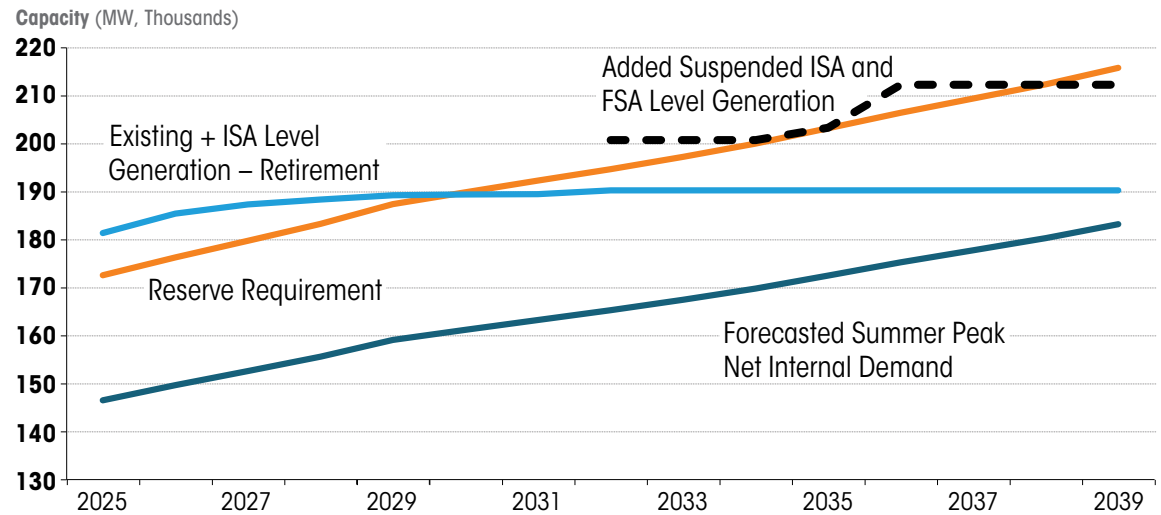
**Generation Modeled**

Market efficiency simulations model existing in-service generation plus actively queued generation, less planned generator deactivations that have given formal notification. Recent market efficiency cycles have had enough generation with at least an executed Interconnection Service Agreement (ISA) to meet the reserve requirement. The 2024/2025 base case required additional suspended ISA and Facility Service Agreement (FSA) level units to meet the reserve requirement for the entire study period. **Figure 4.3** shows a comparison of the modeled generation capacity within PJM's footprint to the projected peak net internal demand with reserve requirement being used for the market efficiency base case.

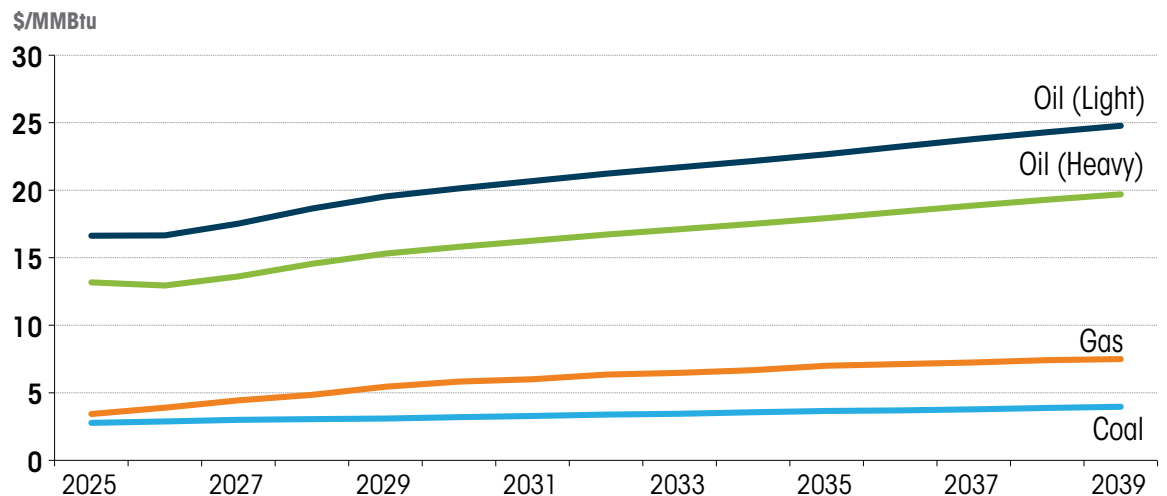
**Fuel Price Assumptions**

PJM uses a commercially available database tool that includes generator fuel price forecasts. Forecasts for short-term gas and oil prices are derived from New York Mercantile Exchange future prices. Long-term forecasts for gas and oil are obtained from commercially available databases, as are all coal price forecasts. Vendor-provided basis adders are applied as well to account for commodity transportation cost to each PJM zone. The fuel price forecasts used in PJM's 2025 market efficiency analysis are represented in **Figure 4.4**.

**Figure 4.3: 2024/2025 PJM Market Efficiency Reserve Margin**



**Figure 4.4: 2024/2025 Market Efficiency Fuel Price Assumptions**



### Load and Energy Forecasts

PJM's 2024 Load Forecast Report, adjusted to include additional nonconforming loads identified in the latest RTEP case, provides the transmission zone peak load and energy data modeled in the market efficiency base simulations. **Table 4.1** summarizes the PJM peak load and energy values used in the 2025 market efficiency cases.

### Demand Resources

The amount of demand resources modeled in each transmission zone is based on the 2024 PJM Load Forecast Report. **Table 4.2** summarizes PJM demand resource totals by year.

### Emission Allowance Price Assumptions

PJM currently models three major effluents (SO<sub>2</sub>, NO<sub>x</sub> and CO<sub>2</sub>) within its market efficiency simulations. SO<sub>2</sub> and NO<sub>x</sub> emission price forecasts reflect implementation of the Cross-State Air Pollution Rule (CSAPR) and are shown in **Figure 4.5** and **Figure 4.6**, respectively. PJM unit CO<sub>2</sub> emissions are modeled as either part of the national CO<sub>2</sub> program or the Regional Greenhouse Gas Initiative (RGGI) program. The spring 2024 emission forecast has units located in the states of Maryland, Delaware and New Jersey participating in the RGGI. The emission price assumptions for both the national CO<sub>2</sub> and RGGI CO<sub>2</sub> programs are shown in **Figure 4.7**.

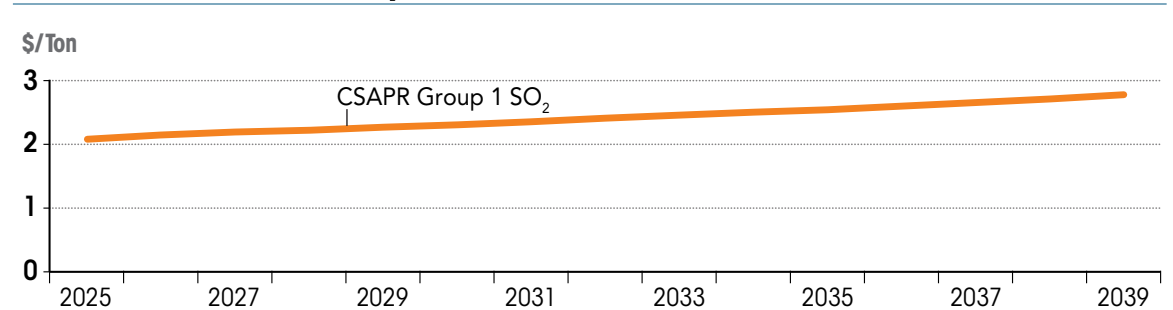
**Table 4.1:** 2024/2025 Market Efficiency PJM Peak Load and Energy Forecast

Load	2025	2029	2032	2035	2039
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

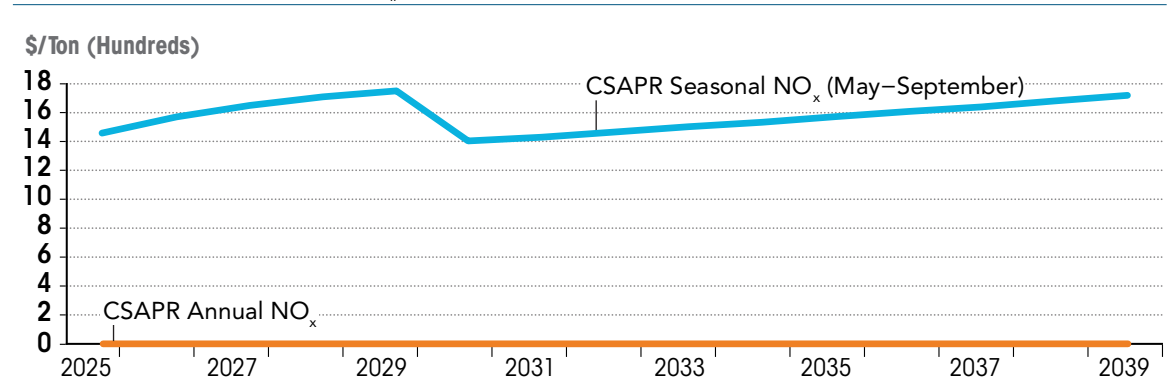
**Table 4.2:** 2024/2025 Market Efficiency Demand Resource Forecast

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

**Figure 4.5:** 2024/2025 Market Efficiency SO<sub>2</sub> Emission Price Assumption

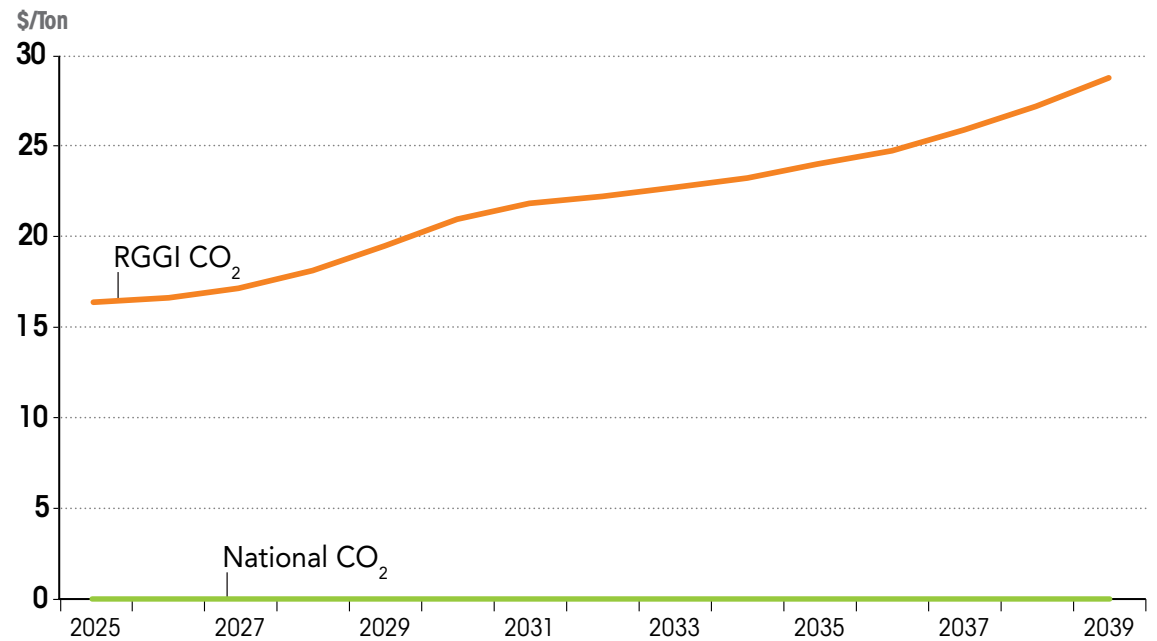


**Figure 4.6:** 2024/2025 Market Efficiency NO<sub>x</sub> Emission Price Assumption



**Carrying Charge Rate and Discount Rate**

The evaluation of a proposed market efficiency project 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 is 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 Information Center (TCIC) available on the [PJM website](#). The annual carrying charge rate and discount rate for these analyses are 12.09% and 7.20%, respectively.

**Figure 4.7: 2024/2025 Market Efficiency CO<sub>2</sub> Emission Price Assumption**

## 4.2: 2025 Results From Project Acceleration Analysis

PJM's 2025 cycle of analysis included near-term simulations for study years 2025 and 2029. They identified collective and constraint-specific transmission system congestion due to the impacts of previously approved RTEP projects not yet in service. PJM conducted these simulations under two different transmission topologies:

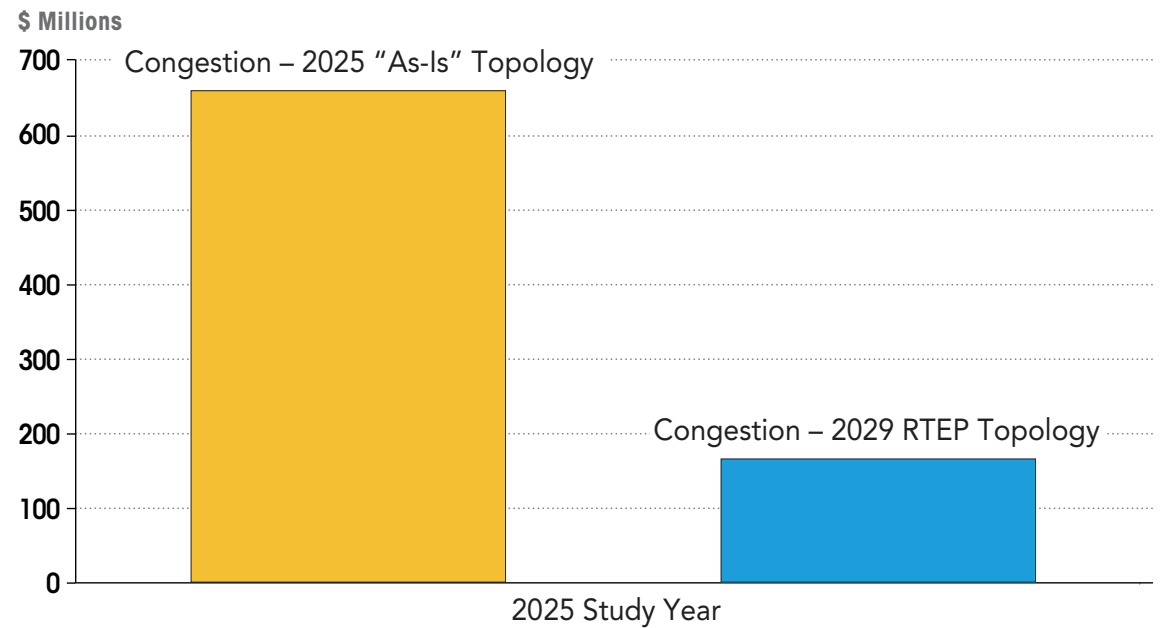
1. 2025 “as-is” PJM transmission system topology
2. 2029 “as-planned” RTEP PJM transmission system topology

By comparing results of multiple simulations with the same fundamental supply, demand and operating constraints but with differing transmission topologies, the economic value of a transmission enhancement can be determined. This technique allows PJM to perform the following:

1. Value collectively the congestion benefits of approved RTEP upgrades.
2. Evaluate the congestion benefits of accelerating or modifying specific RTEP projects.

PJM congestion cost net reductions comparing the 2025 “as-is” topology with the 2029 RTEP topology from market simulations for study year 2025 are shown in **Figure 4.8**. Annual congestion cost reductions of more than \$493 million for the 2025 simulation are shown. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

**Figure 4.8:** 2025 Simulated PJM Congestion Cost Net Reduction: RTEP Topology Compared to “As-Is” Topology



**Project-Specific Acceleration Analysis**

PJM identified and evaluated specific RTEP enhancements that were most responsible for the congestion reductions identified in the acceleration simulations. The identified baseline reliability enhancements, viewed within the context of the short-term analysis, will not be recommended for acceleration. These projects are not practical to accelerate, because they have been identified with one or more of the following:

- The project has a near-term in-service date.
- The project is currently in the siting and permitting process, and schedules are not final.
- The cost of acceleration is greater than the simulated market efficiency benefits.
- PJM and the transmission owners are working to coordinate the implementation of the project work to meet the current expected in-service dates.
- An analysis of the outage schedule shows no ability to accelerate.

**Table 4.3** identifies specific RTEP reliability projects and related congestion reductions considered as part of the 2025 study year acceleration analysis.

**Table 4.3:** RTEP Projects Reducing Specific Congestion Drivers: 2025 Study Year Analysis

Constraint	RTEP Upgrade	Area	Simulated 2025 Annual Congestion Savings (\$M)
AP South Interface	B4000: 2024W1 Regional Cluster	PJM	\$147
Straban-Lincoln 115 kV	B3800: Build new Hunterstown-Carroll 230 kV circuit	METED	\$88
Messick Rd.-Ridgeley 138 kV	B3800: 2022W3 Western Cluster	AP	\$47
Charlottesville-Proffit Rd Del Pt 230 kV	B3800: Rebuild 230 kV line #2054	Dominion	\$44
Haumesser Rd. (R)-W De Kalb Tap (R) 138 kV	B3811: Rebuild Haumesser Road to H-452 138 kV	ComEd	\$28
Dumont-Stillwell 345 kV	B3775: Dumont-Stillwell 345 kV sag study	AEP-NIPSCO	\$27
Northwest-Conastone 230 kV	B3771: Reconductor Northwest-Conastone 230 kV circuits	BGE	\$25
Safe Harbor-Graceton 230 kV	B3800: 2022W3 Eastern Cluster	PPL-BGE	\$24
Gore-Stonewall 138 kV	B3800: 2022W3 Western Cluster	AP	\$16
Roxbury-Aspen Road Solar 115 kV	B3751, B3752: Rebuild Roxbury-Shade Gap 115 kV	PENELEC	\$14
Olive-Univ. Pk. N. 345 kV	B3775: Olive-University Park 345 kV sag study	AEP-ComEd	\$12
Saint John-Crete 345 kV	B3775: Reconductor/Rebuild Crete-St John 345 kV	NIPSCO-ComEd	\$11
Nottingham Reactor 230 kV	B3800: 2022W3 Eastern Cluster	PECO	\$10
Juniata TR 500/230 kV	B3664: Replace station equipment at Juniata 230 kV	PPL	\$9
North Delphos-East Delphos 69 kV	B3346: Rebuild North Delphos-East Delphos-Elida Road	AEP	\$9
Clifford-Colleen 138 kV	B4000: 2024W1 Regional Cluster	AEP	\$8
Remington CT-Marsh Run 230 kV	B4000: 2024W1 Regional Cluster	Dominion	\$4
Fork Union-Bremo 115 kV	B4000: 2024W1 Regional Cluster	Dominion	\$3
Chesterfield 1-Hopewell 230 kV	B3694: Reconductor Hopewell-Chesterfield 230 kV	Dominion	\$2
Shade Gap-Aspen Road Solar 115 kV	B3751, B3752: Rebuild Roxbury-Shade Gap 115 kV	PENELEC	\$2
Spartan-Stafford 230 kV	B3694: Rebuild Cranes Corner-Stafford 230 kV	Dominion	\$1

*Note: The 2025 study year congestion savings are calculated as the difference in simulated congestion between the RTEP and the as-is topology.*

### 4.3: 2025 Reevaluation of Previously Approved Market Efficiency Projects

PJM's 2025 analysis included a reevaluation of an approved project from previous market efficiency window processes.

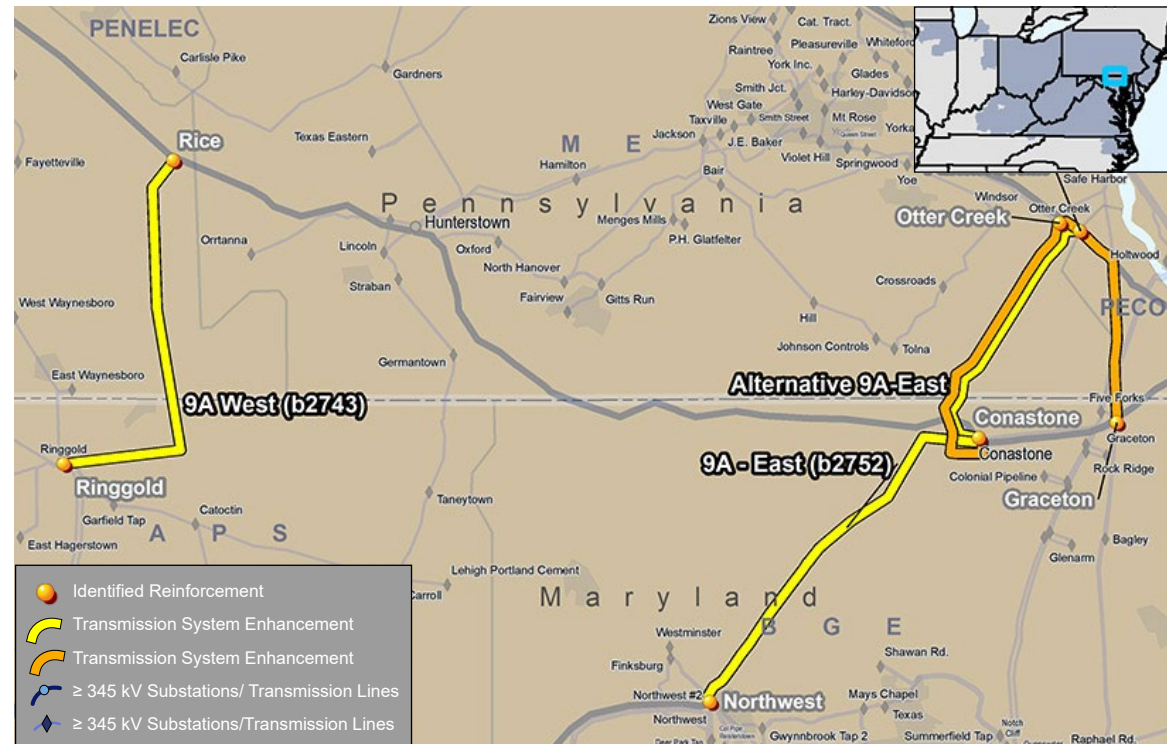
One previously approved project with capital costs greater than \$20 million has yet to begin construction or receive full CPCN certification. This project, identified as Project 9A, made up of an eastern portion (B2752) and a western portion (B2743), was originally approved in 2016 and updated with a 9A-East Alternative that was conditionally approved in 2019. The project is depicted on **Map 4.1**. On Sept. 22, 2021, the PJM Board endorsed PJM's recommendation to suspend the project due to siting risks in order to remove it from the models pending any future developments in the regulatory process. Subsequent reevaluations have resulted in the project remaining in suspension through 2024 and not part of the RTEP base models.

The project has both eastern and western components, and since being placed in suspension, a number of other RTEP projects have been approved or constructed that occupy the same physical location or right-of-way as the 9A East components.

The 2025 reevaluation indicated a benefit-to-cost ratio greater than 1.25 for the project. See **Table 4.4** for the benefit-to-cost ratio and estimated project cost used in the 2025 reevaluation for various project configurations.

PJM obtained Board approval to modify the scope of Project 9A to retain the western portion and remove the eastern portion of the project, terminate the project's suspended status, and restore the western portion of the project to the RTEP models.

**Map 4.1:** Project 9A – RTEP Baseline Project B2743 and B2752



**Table 4.4:** 2025 Project 9A Reevaluation

Reevaluation	Base Case Ratio	Cost (\$M)
Original 9A (9A West + 9A East)	3.74	\$430.41
Alternate 9A (9A West + Alt 9A East)	3.42	\$584.57
9A West Only	3.85	\$264.61

#### 4.4: 2024/2025 Long-Term Market Efficiency Window Proposals

The 2024/2025 Long-Term Market Efficiency Window process uses study years 2025, 2029, 2032 and 2035 to identify and quantify transmission system congestion. These simulations use the 2029 RTEP “as-planned” transmission system topology and include RTEP projects approved through the 2024 RTEP cycle.

Overall, congestion levels in PJM’s market efficiency analysis have been increasing, particularly for the 4-, 7- and 10-year-out cases compared to recent RTEP cycles. This is due in part to increasing forecasted load growth, particularly for zones with expected large load additions that result in increased simulated regional flows. Some of this congestion is being mitigated within the market efficiency simulations by the regional transmission solutions identified in the reliability windows. The topology in the 2024/2025 Long-Term Market Efficiency Window included the approved projects from 2024 RTEP Window 1.

PJM solicited stakeholder proposals for market efficiency projects as part of an RTEP proposal window focusing on congestion identified in the market efficiency analysis. It sought solution alternatives to resolve or alleviate market efficiency congestion identified in the simulations. Market efficiency evaluation criteria include the following, which are further described in [PJM Manual 14F: Competitive Planning Process](#). Projects must address a specified congestion driver and produce a benefit-to-cost ratio greater than 1.25. Other factors considered in selecting a successful project include risk assessment, model sensitivity evaluation, reliability impact and outage impact.

PJM identified congestion drivers – facilities and their simulated congestion levels – as part of soliciting proposals during the 2024/2025 RTEP Long-Term Market Efficiency Window, as shown in **Table 4.5**. The window opened on April 11, 2025, and closed on June 10, 2025.

Five qualified entities submitted 14 proposals during the 2024/2025 Long-Term Market Efficiency Window. Proposals ranged in cost from \$1.8 million to \$1.6 billion and included transmission upgrades from transmission owners and greenfield projects from both incumbent and non-incumbent transmission entities. Two battery energy storage system (BESS) proposals were received.

**Table 4.5:** 2024/2025 Long-Term Market Efficiency Window Congestion Drivers

Constraint	Area	Base Simulation Annual Congestion (\$M)	
		2029	2032
Museville-Smith Mountain 138 kV	AEP	\$11.4	\$24.9
West Point-Lanexa 115 kV	Dominion	\$2.0	\$1.7
Garrett-Garrett Tap 115 kV	PN-AP	\$1.8	\$2.1

## 4.5: 2024/2025 Long-Term Market Efficiency Window – Results

The proposals were grouped and evaluated according to the constraint being addressed. Redacted [public proposals](#) for current and closed windows are available at PJM.com.

### **Museville-Smith Mountain 138 kV Constraint – B4035**

Six proposals, submitted through PJM's Competitive Planner Tool, were evaluated for this constraint. The proposals are summarized in **Table 4.6** and depicted on **Map 4.2**.

PJM completed a comprehensive analysis considering economic benefits, reliability and operational impacts of the proposals. Each of the proposals was evaluated to determine which projects address the congestion driver and satisfy the market efficiency criteria of having a benefit-to-cost ratio greater than 1.25. PJM then determined which project addressed the identified congestion in the most cost-effective manner while considering cost and constructability risk.

Map 4.2: Proposals – Museville-Smith Mountain 138 kV

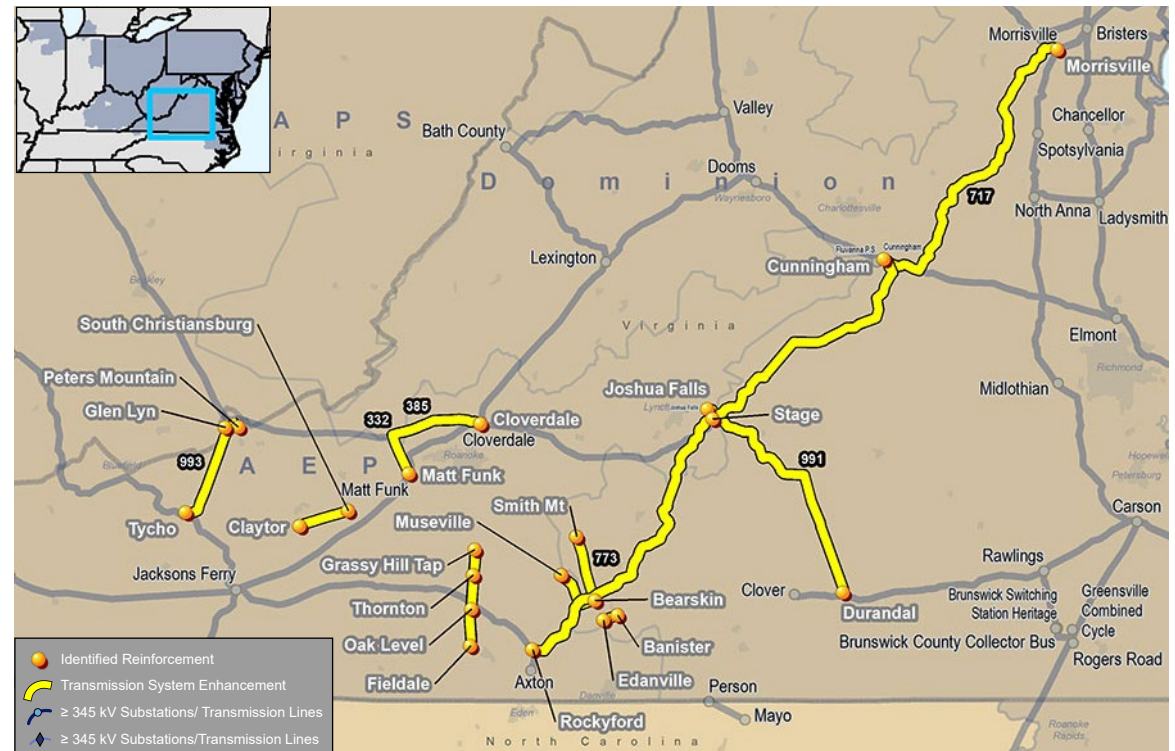


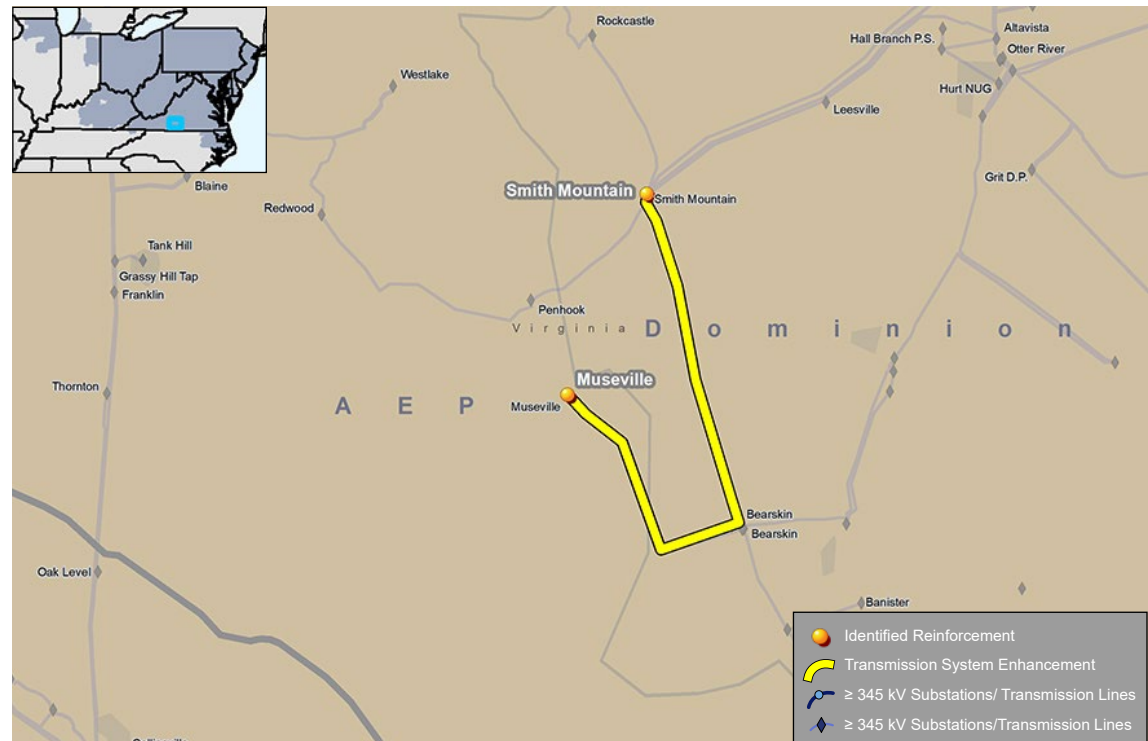
Table 4.6: Proposals – Museville-Smith Mountain 138 kV

Proposal ID	In-Service Cost (\$M)	In-Service Year	Congestion Driver Mitigated (%)	Base Case Ratio
332	\$86.11	2029	100%	20.55
385	\$131.64	2029	100%	13.44
717	\$1,568.72	2030	81%	2.97
733	\$1.81	2027	75%	136.55
991	\$520.38	2029	82%	2.68
993	\$270.09	2029	17%	6.45

Based on the analysis performed, PJM selected Proposal 733, which is to rebuild one span of the Museville-Smith Mountain 138 kV line and replace the disconnect switches at Smith Mountain station. The project, which is identified as RTEP baseline project B4035, is shown on **Map 4.3**. The project has an estimated cost of \$1.81 million with a 2027 in-service date. It was determined to be the least expensive project and yielded a benefit-to-cost ratio that exceeds the other proposals.

In addition to the market efficiency base case analysis for the recommended proposal, PJM performed sensitivity analyses on key input variables: natural gas price, PJM load forecast and generation expansion. A reliability analysis of the project did not identify any reliability criteria violations.

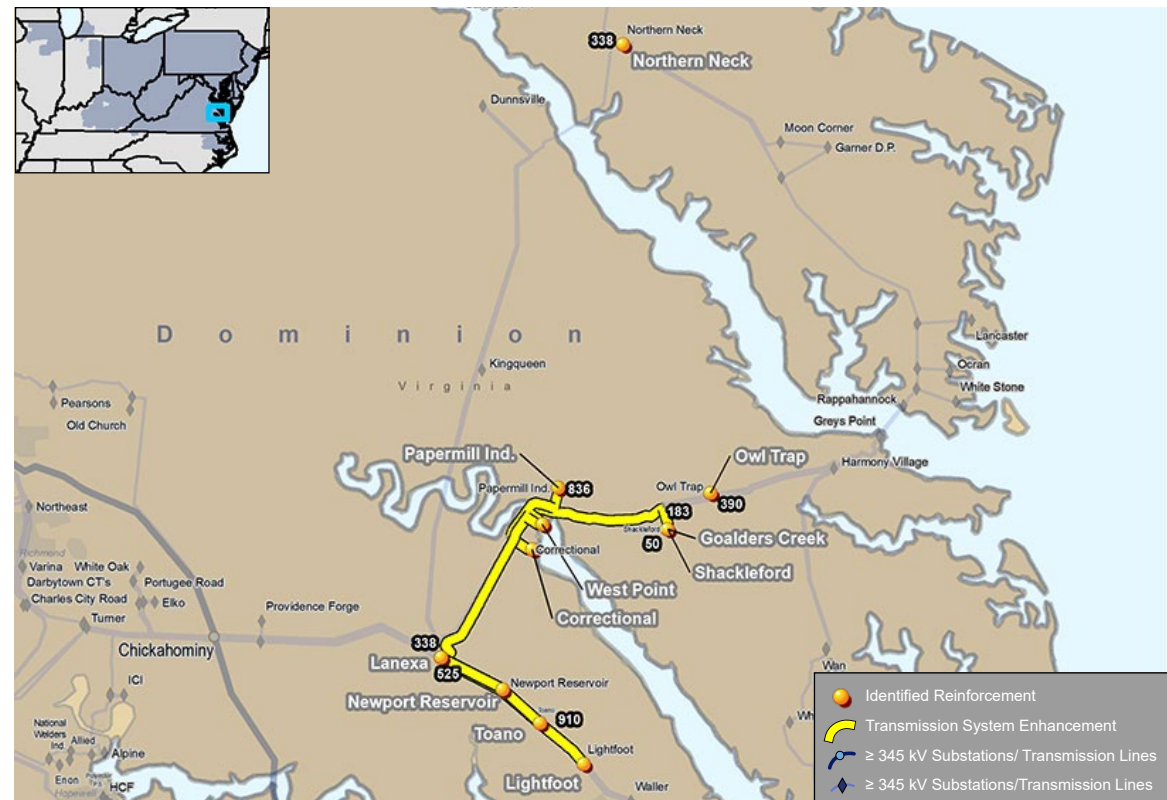
**Map 4.3:** Baseline Project B4035 – Museville-Smith Mountain 138 kV Upgrades



**West Point-Lanexa 115 kV Constraint – B4034**

Seven proposals, submitted through PJM's Competitive Planner Tool, were evaluated for this constraint. The proposals are summarized in **Table 4.7** and depicted on **Map 4.4**.

PJM completed a comprehensive analysis considering economic benefits, reliability and operational impacts of the proposals. Each of the proposals was evaluated to determine which projects address the congestion driver and satisfy the market efficiency criteria of having a benefit-to-cost ratio greater than 1.25. PJM then determined which project addressed the identified congestion in the most cost-effective manner while considering cost and constructability risk.

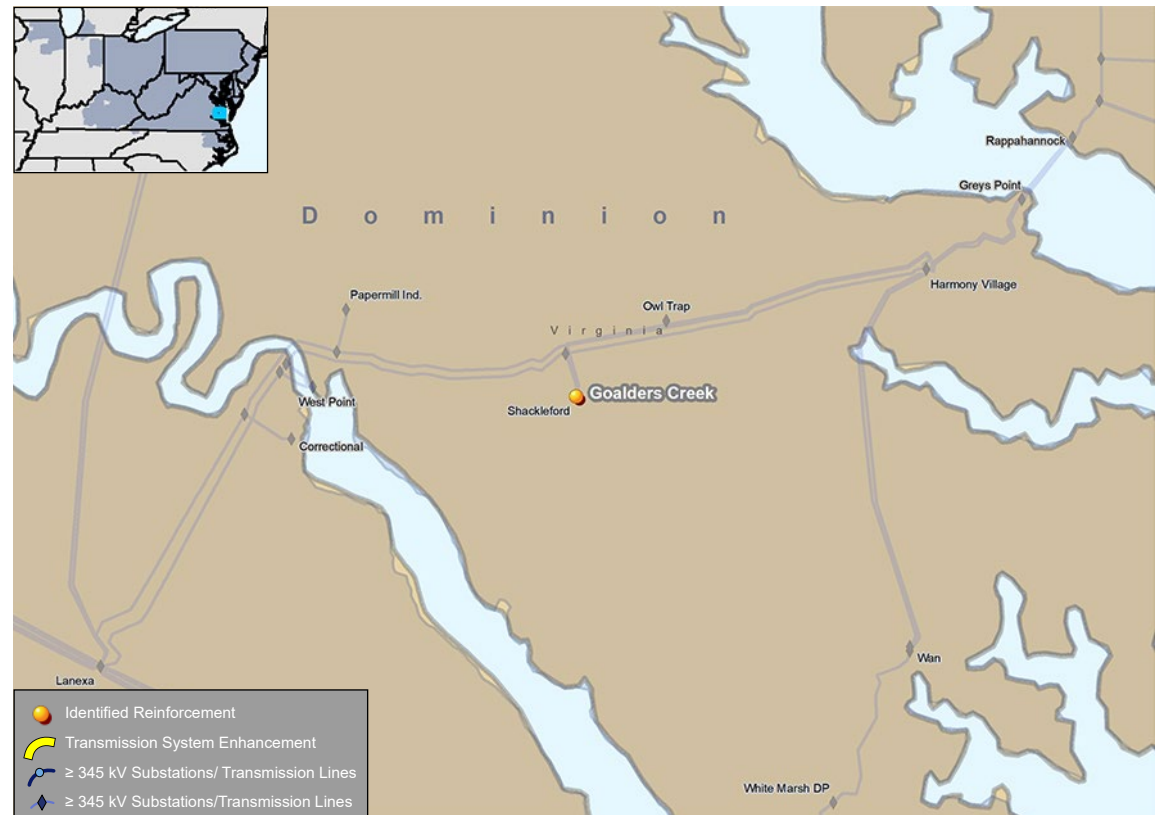
**Map 4.4:** Proposals – West Point-Lanexa 115 kV**Table 4.7:** Proposals – West Point-Lanexa 115 kV

Proposal ID	In-Service Cost (\$M)	In-Service Year	Congestion Driver Mitigated (%)	Base Case Ratio
50	\$83.92	2029	52%	0.26
183	\$221.74	2029	59%	0.30
338	\$28.11	2028	100%	0.97
390	\$21.41	2029	100%	3.05
525	\$23.41	2029	100%	2.71
836	\$62.58	2028	100%	0.13
910	\$90.89	2028	100%	0.55

Based on the analysis performed, PJM selected Proposal 525 – Goalders Creek 230 kV/115 kV switching station. The project, which is identified as RTEP baseline project B4034, is shown on **Map 4.5**. The project has an estimated cost of \$23.41 million with a 2029 in-service date. While not the least expensive solution, it yielded a robust benefit-to-cost ratio that exceeded most other proposals. The design of Proposal 525 is considered to be more reliable in terms of system protection and operational efficiency compared to Proposal 390, resulting in significantly fewer outages required for long-term maintenance.

In addition to the market efficiency base case analysis for the recommended proposal, PJM performed sensitivity analyses on key input variables: natural gas price, PJM load forecast and generation expansion. A reliability analysis of the project did not identify any reliability criteria violations.

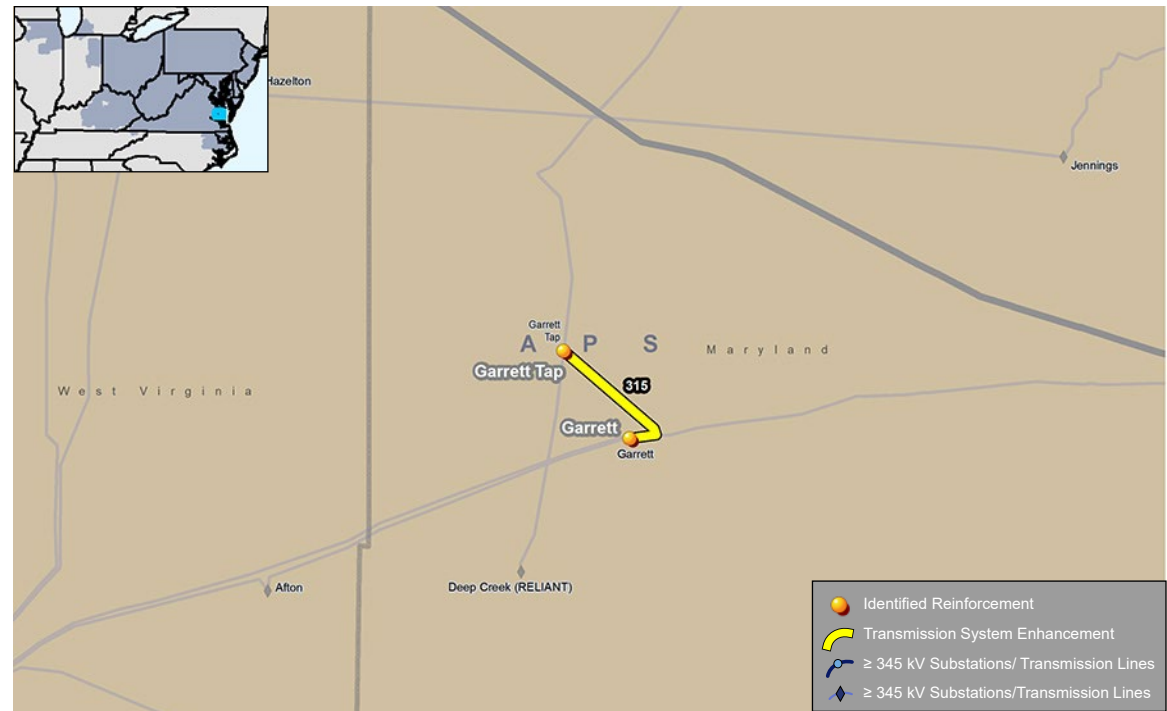
**Map 4.5:** Baseline Project B4034 – Goalders Creek 230 kV/115 kV Switching Station



**Garrett-Garrett Tap 115 kV Constraint – B4002**

One proposal (Proposal 315), submitted through PJM's Competitive Planner Tool, was evaluated for this constraint. The proposal is summarized in **Table 4.8** and depicted on **Map 4.6**. This proposal was also submitted as part of the 2025 Window 1 – Reliability Window (Proposal 692).

Based on the analysis performed, PJM selected Proposal 315 – Garrett Tap-Garrett 115 kV line rebuild. The project, which is identified as RTEP baseline project B4002, is shown on **Map 4.6**. The project has an estimated cost of \$9.9 million with a 2029 in-service date. It has been accepted as a 2025 Window 1 reliability solution.

**Map 4.6:** Proposal 315 – Garrett-Garrett Tap 115 kV**Table 4.8:** Proposal 315 – Garrett-Garrett Tap 115 kV

Proposal ID	In-Service Cost (\$M)	In-Service Year	Congestion Driver Mitigated (%)	Base Case Ratio
315	\$9.90	2029	100%	N/A

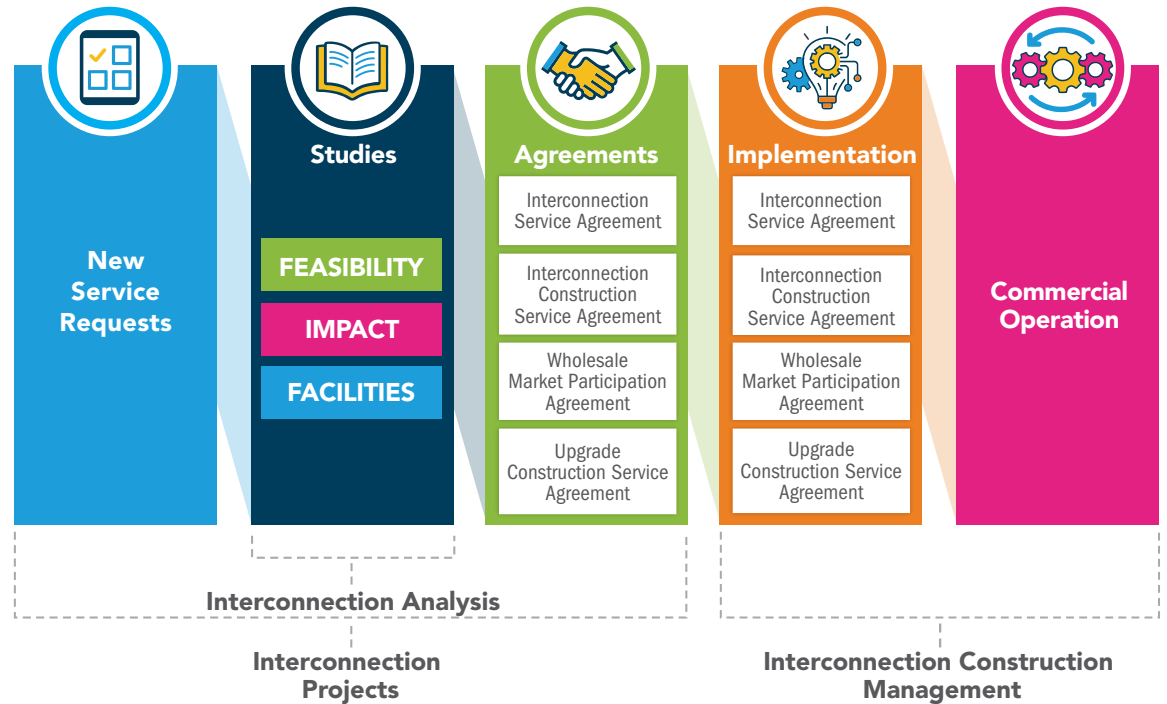
# Section 5: Facilitating Interconnection

## 5.0: Interconnection Reliability

A key component of PJM’s RTEP process is the assessment of New Service Requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. The PJM Board has approved network transmission projects totaling approximately \$9.7 billion since the inception of the RTEP process in 1999. Approved network projects in 2025 totaled approximately \$1 billion. As described in **Section 1.2**, PJM tests for compliance with the North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identify system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

PJM’s generator deliverability test prescribes the test conditions for ensuring that sufficient transmission capability exists to deliver generating capacity reliably from a defined Point of Interconnection to PJM load. PJM also conducts this deliverability test as part of baseline analysis under summer and winter peak load conditions, when capacity is most needed to serve load, as well as under light load conditions to ensure that a range of resource combinations and conditions is examined.

**Figure 5.1:** Interconnection Process Prior to July 10, 2023



### Interconnection Process Overview

PJM’s interconnection process, as it existed prior to July 2023 reforms, consisted of five phases as shown in **Figure 5.1** and is described in Section 5 of the 2023 RTEP Report. Requests for generation interconnection could be submitted during one of two six-month queue windows: April through September and October through March.

**Section 5.2** discusses interconnection process initiatives in 2023 and beyond, including those arising out of the Interconnection Process Reform Task Force (IPRTF) stakeholder process and in compliance with FERC’s recent Generation Interconnection Process NOPR.

## 5.1: Interconnection Process Reforms

### 5.1.1 — Energy Transition in PJM

Accelerating the pace of new generation resource entry is critical for maintaining reliability. The [2027/2028 Base Residual Auction](#) was the first auction in which the entire PJM RTO, including Fixed Resource Requirement areas, fell short of the reliability requirement.

To mitigate the risk of capacity shortages and the decline of essential reliability services, the PJM Board directed PJM to engage in a number of targeted planning process initiatives, discussed previously in **Section 1.3**, which are intended to expedite the interconnection of capacity resources. These targeted initiatives are in addition to the interconnection process reforms that are discussed throughout the remainder of **Section 5**.

### 5.1.2 — First-Ready, First-Served

On June 14, 2022, PJM filed Tariff revisions with FERC for interconnection process reform. The filing constituted PJM's reforms designed to more efficiently process New Service Requests. PJM's transition from a serial "first-come, first-served" queue approach to a "first-ready, first-served" Cycle approach is shown in **Figure 5.2**. This new approach, described in **Section 5.2**, is utilized by other regional transmission organizations and standalone transmission providers. The reforms detailed in the Tariff filing represent the culmination of an 18-month stakeholder effort through the IPRTF.

#### The Tariff reforms include:

- Moving from a serial queue process to a clustered Cycle process for interconnection studies and cost allocation

- Implementing multiple Decision Points at which the parties seeking interconnection-related services must provide readiness deposits and meet other threshold requirements to move forward

*This has allowed projects that are ready to proceed to do so in a more efficient manner than before. In contrast, projects that are not ready were incentivized to exit the interconnection process.*

- Implementing a transition mechanism to ensure a timely transition to the new "first-ready, first-served" Cycle approach

*Projects in the existing interconnection queue that were close to completing the interconnection analysis process were eligible for an Expedited Process.*

- Consolidating PJM's interconnection-related service agreements and forms

*The interconnection reforms are set forth in their entirety in FERC Docket No. ER22-2110 and are described in PJM [Manual 14H](#).*

#### **FERC Approval and Next Steps**

On Nov. 29, 2022, FERC issued an order conditionally approving PJM's interconnection reform filing subject to two compliance filings. PJM's new Tariff Parts VII and IX were integrated into PJM's Tariff with an effective date of Jan. 3, 2023, and Part VIII with an effective

date of Oct. 5, 2023. The transition to the new interconnection process started on July 10, 2023. In 2023, PJM completed its Transition Sorting Analysis to determine which AE1-AG1 projects were eligible for the Expedited Process and which would be re-prioritized into Transition Cycle 1.

**Figure 5.2:** Interconnection Process Reform Timeline (as of March 18, 2026, 10:21 a.m. EPT)

Phase	Transition Cycle 1			Transition Cycle 2			Cycle 1		
	Start Date	End Date	Duration	Start Date	End Date	Duration	Start Date	End Date	Duration
<b>Fast Lane End Date</b> <i>executed by Developer &amp; TO or filed unexecuted</i>	12/15/2023	4/18/2025							
<b>Application Deadline</b>	N/A	N/A	N/A	12/17/2024	12/17/2024	0	4/27/2026	4/27/2026	0
<b>Application Review</b>	N/A	N/A	N/A	12/18/2024	7/6/2025	201	4/28/2026	7/27/2026	91
<b>Model Posting</b>	2/1/2024	2/1/2024	0	6/6/2025	6/6/2025	0	6/26/2026	6/26/2026	0
<b>Phase I</b>	1/22/2024	5/20/2024	120	7/7/2025	10/31/2025	117	7/28/2026	11/24/2026	120
<b>Decision Point I</b>	5/21/2024	6/20/2024	31	11/3/2025	12/2/2025	30	11/25/2026	12/24/2026	30
<b>Phase II</b>	6/21/2024	12/20/2024	183	12/3/2025	6/1/2026	181	1/28/2027	7/26/2027	180
<b>Decision Point II</b>	12/23/2024	1/21/2025	30	6/2/2026	7/1/2026	30	7/27/2027	8/25/2027	30
<b>Phase III</b>	4/21/2025	9/19/2025	152	7/2/2026	12/28/2026	180	8/26/2027	2/22/2028	181
<b>Decision Point III</b>	9/22/2025	10/21/2025	30	12/29/2026	1/27/2027	30	2/23/2028	3/23/2028	30
<b>Final Agreement Negotiation</b>	9/22/2025	11/20/2025	60	12/29/2026	2/26/2027	60	2/23/2028	4/24/2028	62

**Notes:**

- **Transition Cycle 2 Phase III** start date is dependent on Transition Cycle 1 GIAs executed or withdrawn.
- **Cycle 1 Phase I** start date is dependent on Transition Cycle 2 Decision Point II close, Cycle 1 Review completion and Cycle 1 Model being posted for 30 days.
- **Cycle 1 Phase II** start date is dependent on Transition Cycle 2 Decision Point III close.
- **Cycle 1 Phase III** start date is dependent on the conclusion of the Transition Cycle 2 Final Agreement Negotiation Phase.

**Legend**

Actual date  
Projected date

As shown in **Figure 5.2**, the initial study phase of Transition Cycle 1 began on Jan. 22, 2024.

- Phase I System Impact Study reports were posted on the PJM Website on May 20, 2024, followed by the Decision Point I period, which closed June 20, 2024.
- Transition Cycle 1 projects that elected to proceed to the next phase of study were studied in Phase II, which concluded on Dec. 20, 2024, followed by the Decision Point II period, which closed Jan. 21, 2025.
- Transition Cycle 1 projects proceeding further were studied in Phase III, which concluded on Sept. 19, 2025, followed by the Decision Point III period, which closed Oct. 21, 2025.
- Final Agreements for Transition Cycle 1 were issued for signature on Dec. 17, 2025.

The Application Phase for Transition Cycle 2 opened June 21, 2024, for AG2 and AH1 projects that chose to reapply under the new interconnection process rules. The Transition Cycle 2 application phase closed Dec. 17, 2024.

- Transition Cycle 2 projects that passed application reviews by July 6, 2025, were studied in Phase I, which concluded on Oct. 31, 2025, followed by the Decision Point I period, which closed Dec. 2, 2025.
- Transition Cycle 2 projects that elected to proceed further are currently being studied in Phase II, which commenced on Dec. 3, 2025.

With the completion of the transition process, PJM will begin processing New Service Requests under Tariff, Part VIII, starting with Cycle 1, which is currently scheduled to begin in the second quarter of 2026.

**Stakeholder Engagement**

The Interconnection Process Subcommittee (IPS) was established by the Planning Committee in April 2022 to continue the work of the IPRTF. The IPS provides a stakeholder forum to resolve specific issues related to the interconnection process and associated agreements, governing documents and manuals. Since its inception, the IPS has been the main forum for communicating details of the implementation of the new interconnection process, as well as for discussing future improvements.

**5.1.3 — FERC Interconnection Process NOPR**

On July 28, 2023, FERC issued Order 2023, a Final Rule adopting reforms to address interconnection queue backlogs and promote new technologies through generation interconnection procedures and agreements. The Final Rule encompassed several reforms, including:

- The adoption of a first-ready, first-served cluster study process with greater financial commitments for interconnection applicants
- The imposition of firm deadlines and penalties in the event transmission providers fail to complete their interconnection studies on time
- The incorporation of technological advancements into the interconnection process
- An update of modeling and performance requirements for inverter-based resources to ensure continued system reliability

**Aug. 28, 2023** .....

PJM filed a Request for Clarification and Rehearing of Order 2023 stating that PJM has already developed a reformed interconnection process and received FERC approval in November 2022 that meets the Commission’s intent and substantially satisfies the requirements of the Final Rule.



**Sept. 28, 2023**

FERC essentially denied PJM’s rehearing motion by operation of law and would issue a future order providing more detail related to the rehearing request.

**March 21, 2024** .....

FERC Order 2023-A issued, reaffirmed and clarified the reforms introduced in Order 2023 to streamline the generation interconnection process.



**May 16, 2024**

PJM submitted its Order 2023 and Order 2023-A compliance filing with FERC. The filing demonstrated that PJM’s Tariff already substantially complied with the Final Rule, paralleling many reforms PJM has already implemented.

**July 31, 2024** .....

FERC requested additional information concerning PJM’s compliance filing regarding deviations from the Final Rule and explanations as to how the compliance filing satisfies the independent entity standard.



**Oct. 29, 2024**

PJM submitted a response to FERC’s data request.

**July 24, 2025** .....

FERC issued an Order on Compliance accepting PJM’s compliance filing in part, while directing PJM to submit a further compliance filing providing certain Tariff language revisions.



**Oct. 22, 2025**

PJM submitted a further compliance filing consistent with FERC’s Final Rule on Improvements to Generator Interconnection Procedures and Agreements as directed in the July 24 order. PJM is awaiting FERC’s ruling on its compliance filing.

## 5.2: Cycle-Based Process

### 5.2.1 — New Service Requests

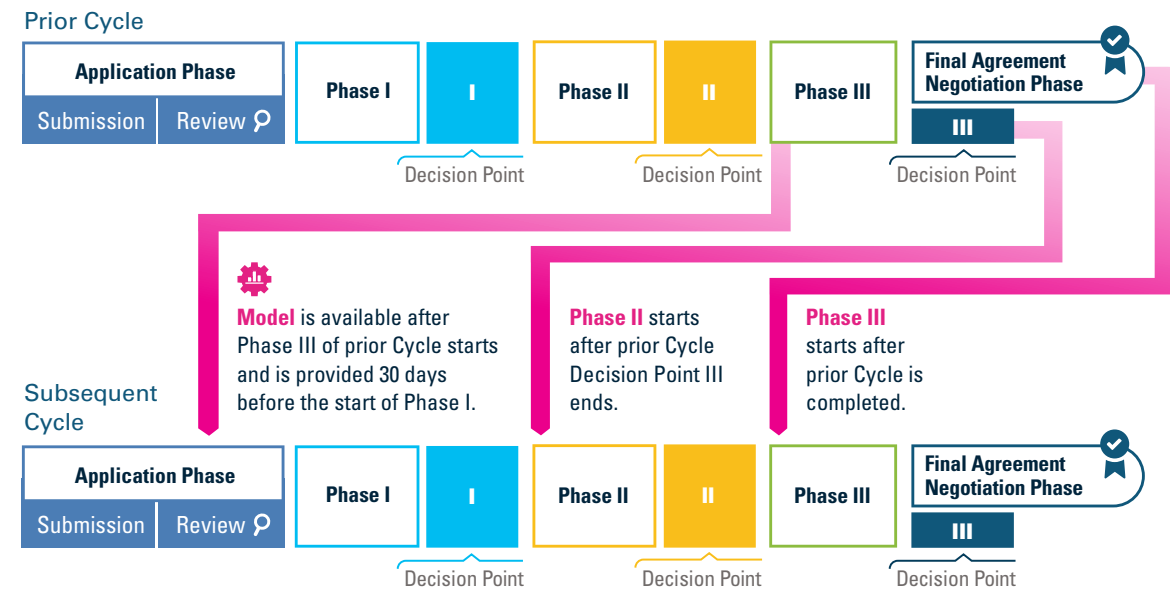
PJM has transitioned to a “first-ready, first-served” Cycle-based interconnection study approach for New Service Requests as outlined in PJM [Manual 14H](#). Project Developers with a Generation or Transmission Interconnection Request as well as Eligible Customers with Long-Term Firm Transmission Service Requests are now following the new Cycle process. Additional types of requests are also studied under a parallel process outside of the Cycle process. These include Upgrade Requests, Surplus Interconnection Requests, Affected System Study Requests, Generator Replacement Requests and requests to convert an existing two-party Interconnection Agreement to a PJM three-party Generation Interconnection Agreement (GIA), as also described in [Manual 14H](#).

### 5.2.2 — Cycle Process Phases

A Cycle is the period of time between the start of an Application Phase and the conclusion of the corresponding Final Agreement Negotiation Phase. As shown in **Figure 5.3**, each Cycle consists of the following:

- Application Phase
- Phase I System Impact Study
- Decision Point I
- Phase II System Impact Study
- Decision Point II
- Phase III System Impact Study
- Decision Point III
- Final Agreement Negotiation Phase

**Figure 5.3:** New Interconnection Request Cycles



The Application Phase includes the submission of New Service Requests by the Project Developer or Eligible Customer and review and validation by PJM.

During Phases I, II and III, PJM performs System Impact Studies. All three phases include load flow analysis. Stability and short-circuit analyses are performed during Phases II and III. Electromagnetic transient analyses are performed on an as-needed basis during Phase III.

Decision Points I, II and III are each a period of 30 days commencing on the first business day immediately following the prior phase of the Cycle. At each Decision Point, the Project

Developer or Eligible Customer decides to proceed to the next phase or withdraw. During the Decision Point periods, the applicant provides required data, evidence (such as permits, Site Control, etc.) and deposits, as specified in the [PJM Tariff](#) and as described in [Manual 14H](#). The applicant can also submit any modification as permitted by the PJM Tariff, and, if eligible, may accelerate to the Final Agreement Negotiation Phase. PJM reviews the provided information, validates the applicant’s submission and advances the applicant to the subsequent phase.

After the third study phase and prior to the negotiation of Final Agreements, PJM will provide the Project Developers in the Cycle with drafts of the applicable interconnection-related agreements. These agreements will be prepared based upon the most recently completed studies. If any New Service Requests are withdrawn during Decision Point III, PJM will conduct a restudy/retool and reissue updated agreements to any Project Developers with New Service Requests remaining in the Cycle if their required Network Upgrades and/or cost allocation are impacted by the restudied/retooled results.

Once Phase III is complete, the Final Agreement Negotiation Phase begins. Key activities during this phase include negotiation of draft agreements and issuance of new drafts. Once the agreements are issued for execution, the Project Developer and Transmission Owner can exercise options such as executing the agreement, requesting to file the agreement unexecuted with FERC or withdrawing. After an agreement has been executed by all parties, a construction kickoff call is scheduled, generally within a few weeks of the agreement becoming effective, allowing construction activities to commence.

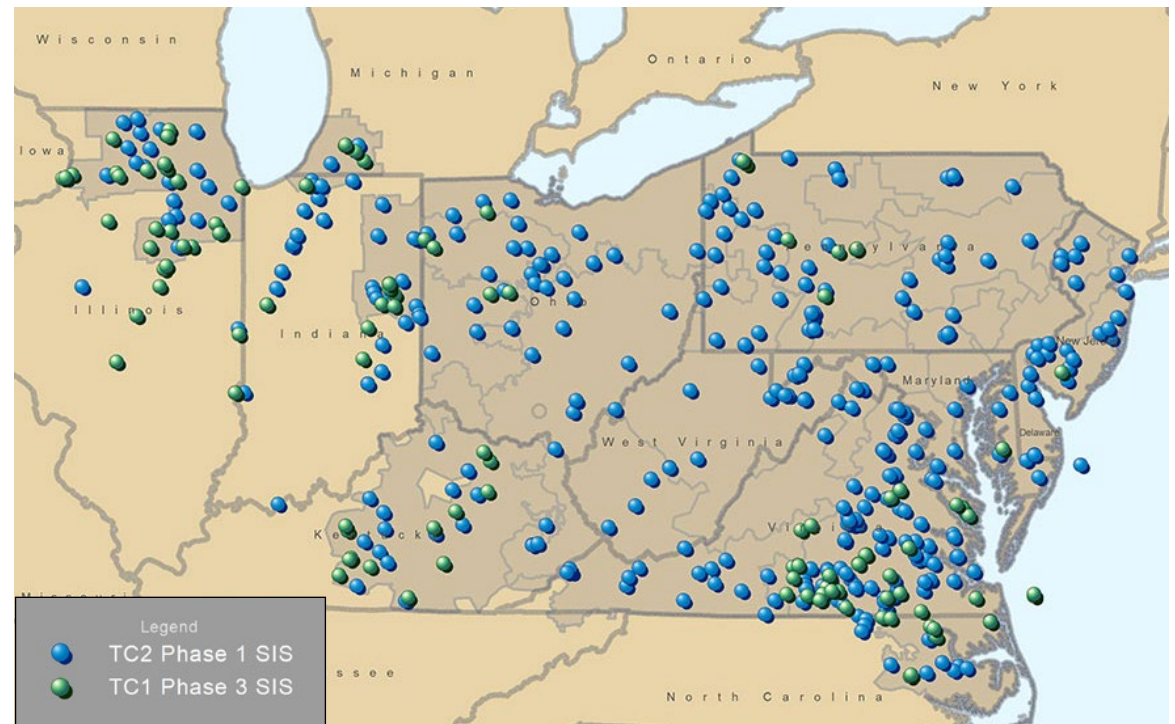
A subsequent Cycle process does not begin until certain milestones in the prior Cycle have been achieved, as described in [Manual 14H](#), Section 1.3.2, “Cycle Process Overview.”

### 5.3: New Service Request Activity

PJM markets have attracted generation proposals totaling 671,190 MW of capacity, as shown in **Table 5.1**. Over 86,918 MW of capacity of New Service Requests were actively under study during 2025. PJM analyzed and issued 130 Transition Cycle 1, Phase III System Impact Studies and 452 Transition Cycle 2, Phase I System Impact Studies, the locations of which throughout the PJM footprint are shown on **Map 5.1**.

Over 20,047 MW of capacity of new generation was under construction as of Dec. 31, 2025, across all fuel types. While withdrawn projects make up a significant portion of total New Service Request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy and regulatory, industry, economic and other competitive factors.

**Map 5.1:** System Impact Studies Performed in 2025



**Interconnection Progression History**

PJM reviews the progression of generation interconnection annually to understand overall developer trends more fully and their impact on PJM’s interconnection process.

**Figure 5.4** shows that for generation submitted in Queue A in 1999 through Dec. 31, 2025, only 78,310 MW, or 13.8%, reached commercial operation. Note that **Figure 5.4** reflects requested Capacity Interconnection Rights, which are lower than nameplate capability given the intermittent operational nature of wind- and solar-powered plants.

Following execution of an ISA/GIA or WMPA, 36,429 MW of capacity with ISAs/GIAs and 1,949 MW of capacity with WMPAs withdrew from PJM’s interconnection process.

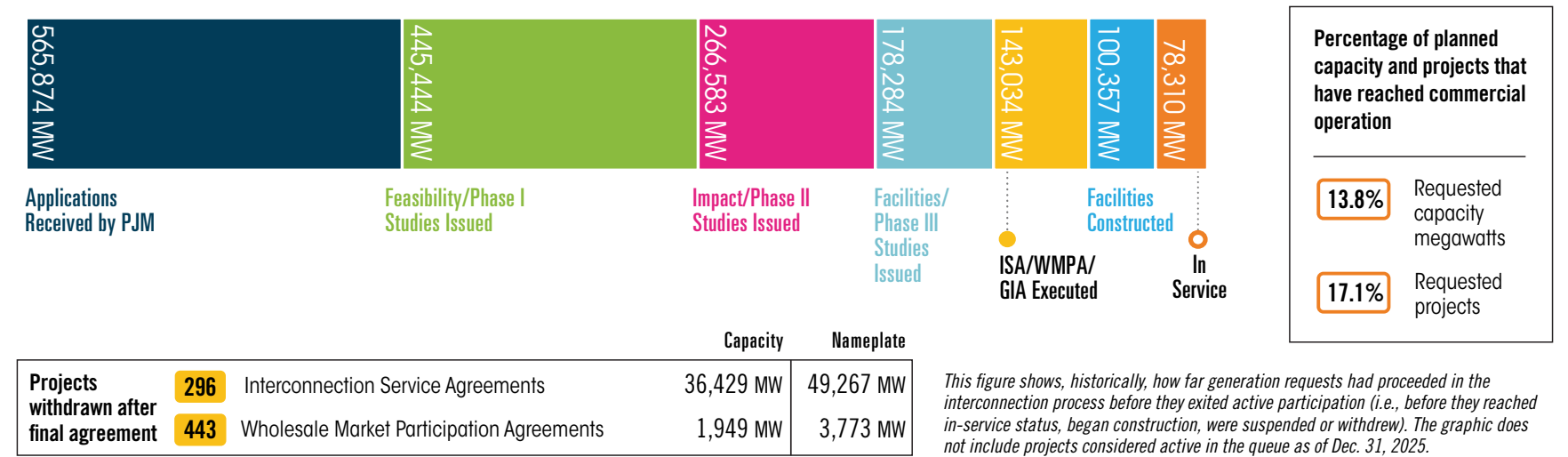
**Table 5.1:** Interconnection Requests Studied in 2025

	Projects	Nameplate Capacity (MW)	Capacity (MW)
Active	1,131	89,133	86,918
In Service*	1,224	97,009	78,310
Under Construction**	324	34,728	20,047
Suspended	116	9,749	5,318
Withdrawn	5,564	644,225	480,597
<b>Total</b>	<b>8,359</b>	<b>874,844</b>	<b>671,190</b>

\* Includes In Service and Under Construction-Partially In Service, \*\*Includes Under Construction and Engineering & Procurement

Overall, 33% of projects that requested updates to existing capacity reached commercial operation. Only 14% of new generation requests reached commercial operation.

**Figure 5.4:** New Service Request Progression



## Section 6: State Summaries

**This section contains state-specific information on the following topics:**

- > Load forecast
- > Existing generation mix
- > Interconnection requests
- > Generation deactivations
- > Baseline projects
- > Network projects
- > Supplemental projects
- > Merchant transmission project requests

If a topic is absent from a state summary, it means that no deactivations occurred during the 2025 calendar year or no projects were approved for the 2025 RTEP for that state.

### 6.0: 2025 Development and Milestones

#### *Load Growth*

##### *Load Forecast Accuracy Model Improvements*

The 2025 Long-Term Load Forecast model uses an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., energy efficiency improvements, distributed resources).

A continuing challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process. Load forecast impacts are discussed further in **Section 1.3.1**.

#### *Existing Generation*

##### *Changing Capacity Mix*

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

#### **Use the navigation bar**

at the bottom of the page to quickly jump between state summaries.

[View state summaries:](#)

### ***Evaluating Interconnection Requests***

A key component of PJM's RTEP process is the assessment of interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance. PJM's generator deliverability test prescribes the test conditions for ensuring that sufficient transmission capability exists to deliver generating capacity reliably from a defined generator or area to PJM load.

### ***Interconnection Process Reform***

PJM interconnection process reform continued through 2025. PJM conducted interconnection studies for projects that were not eligible under the Expedited Process using a new cluster Cycle approach. As discussed earlier in this report, Transition Cycle 1, encompassing three phases, began in January 2025, and Final Agreements were issued in December 2025. Transition Cycle 2, which began in June 2025, completed Decision Point I and began Phase II in December 2025.

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**Generation Deactivation**

**Deactivation Reliability Studies**

Deactivation reliability studies comprise thermal and voltage analysis, including generation deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board.

This topic will only appear in states with generating unit **deactivations and requests** received between Jan. 1, 2025, and Dec. 31, 2025, as part of the 2025 RTEP.

The following states include information about **deactivation requests**:

--	--	--	--	--	--	--

**Baseline Projects**

PJM tests the baseline adequacy of the transmission system to deliver energy and capacity resources to each load in the PJM region. The system is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst Corporation or SERC Reliability Corporation) standards, nuclear plant licensee requirements, PJM reliability standards and PJM design standards. Areas not in compliance with the standards are identified, and enhancement plans to achieve compliance are developed. Baseline expansion plans serve as the base system for generation, merchant transmission and long-term firm transmission service interconnection studies. This subsection will only appear in states with RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP. Some baseline projects are not able to be displayed on maps due to the location(s) of the project being Critical Energy/Electric Infrastructure Information (CEII).

This subsection will only appear in states with RTEP **baseline system enhancements** approved by the PJM Board in 2025.

The following states include information about **baseline projects**:

--	--	--	--	--	--	--

**Network Projects**

Network reinforcements are modifications or additions to transmission-related facilities that are integrated with and support the transmission provider’s overall transmission system for the general benefit of all users of such a transmission system.

This topic will only appear in states with RTEP **network projects** approved by the PJM Board in 2025. PJM Board-approved project details are accessible on the [Project Status](#) page of the PJM website.

The following states include information about **network projects**:

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**Use the navigation bar** at the bottom of the page to quickly jump between state summaries.

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**Supplemental Projects**

A supplemental project refers to a regional RTEP project or a subregional RTEP project that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

This topic will only appear in states with **supplemental projects** included in the 2025 Local Plan.

The following states include information about **supplemental projects**:

--	--	--	--	--	--

**Merchant Transmission Project Requests**

Merchant transmission facilities are AC or DC transmission facilities that are interconnected with, or added to, the transmission system in accordance with the PJM Open Access Transmission Tariff. These facilities are not existing facilities within the transmission system, transmission facilities included in the rate base of a public utility on which a regulated return is earned, transmission facilities included in previous RTEPs, or customer interconnection facilities.

This topic will only appear in states with **merchant transmission project requests** identified as part of the 2025 RTEP. PJM Board-approved project details are accessible on the [Project Status](#) page of the PJM website.

The following state includes information about merchant transmission requests:

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## 6.1: Delaware RTEP Summary

### 6.1.1 — RTEP Context

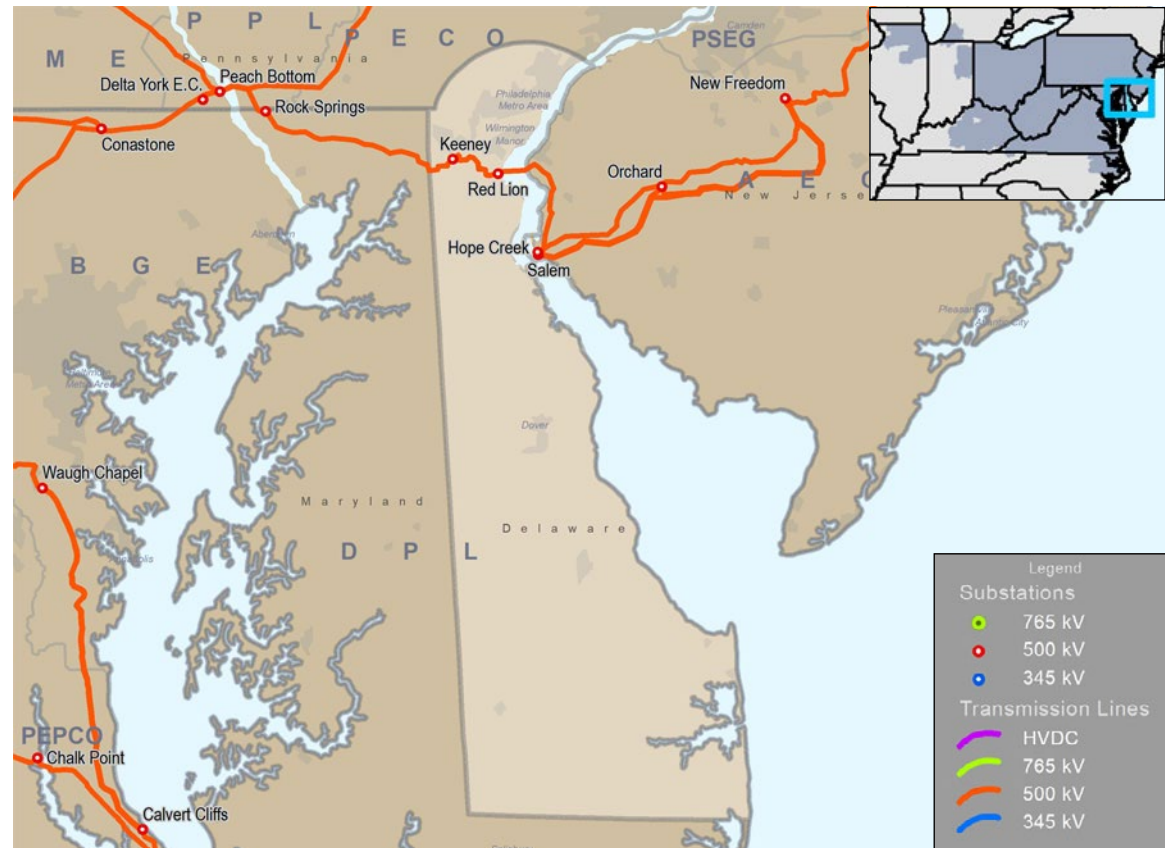
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Delaware, including facilities owned and operated by the Delaware Municipal Electric Corporation (DEMEC), Delmarva Power (DP&L) and Old Dominion Electric Cooperative (ODEC) as shown on **Map 6.1**. Delaware's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

#### **Renewable Portfolio Standards**

Delaware has a mandatory renewable portfolio standard (RPS) of 40% by 2035. This target includes a minimum solar carve-out of 10% by 2035.

Delaware also is pursuing decarbonization through additional efforts. In 2023, Delaware enacted the Climate Change Solutions Act, which calls for Delaware to reduce statewide greenhouse gas emissions by at least 50% from 2005 levels by 2030 and reach statewide net-zero emissions by 2050.

**Map 6.1:** PJM Service Area in Delaware

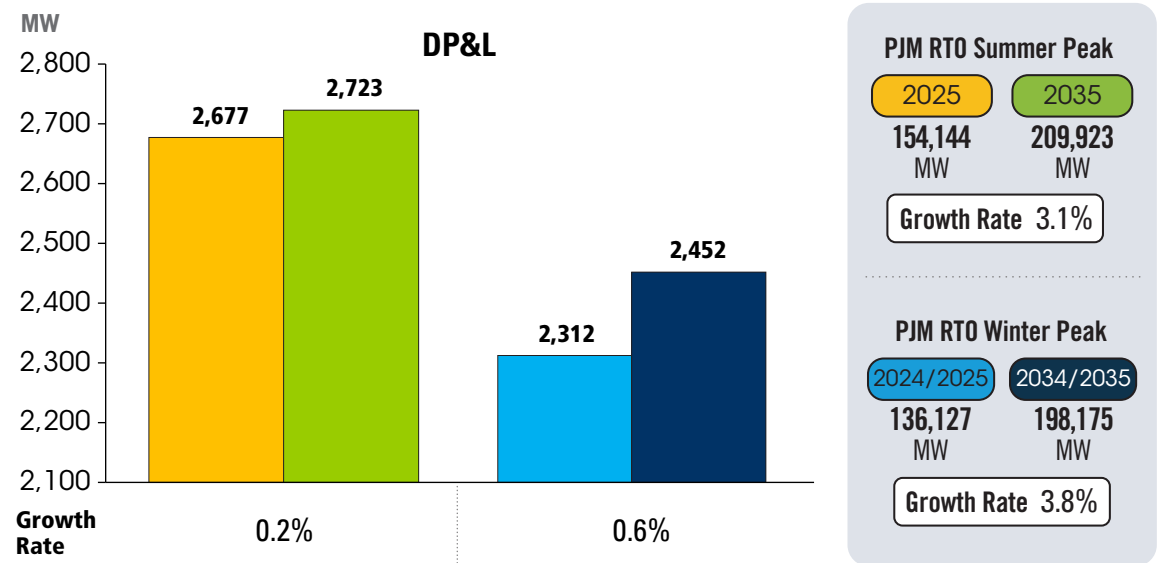


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### 6.1.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.1** summarizes the expected loads within the state of Delaware and across the PJM region.

**Figure 6.1:** Delaware – 2025 Long-Term Load Forecast



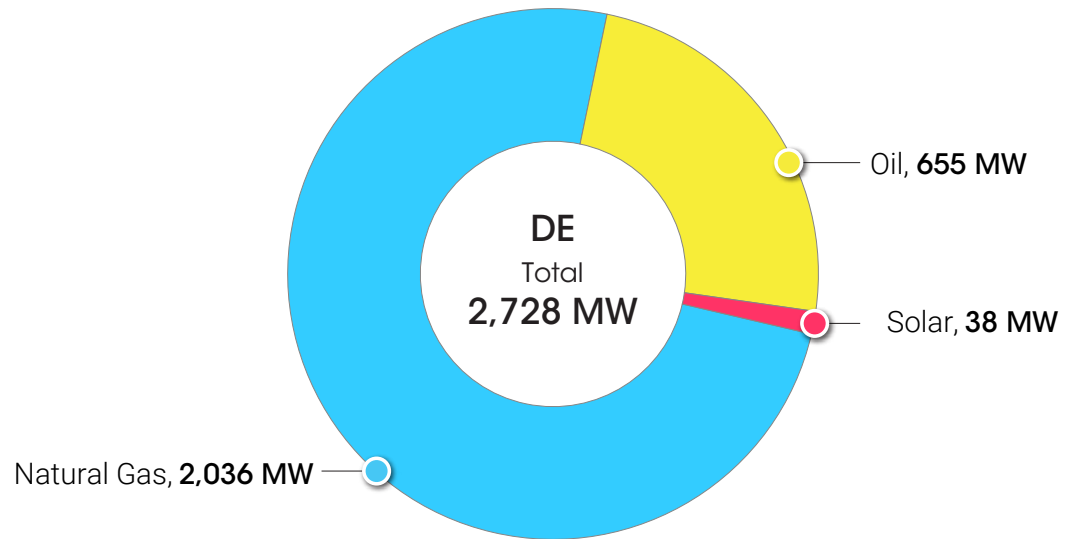
PJM notes that DP&L serves load other than in Delaware. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by DP&L solely in Delaware. Estimated amounts were calculated based on the average share of DP&L's real-time summer and winter peak load located in Delaware over the past five years.

[View state summaries:](#)

**6.1.3 — Existing Generation**

Existing generation in Delaware as of Dec. 31, 2025, is shown by fuel type in **Figure 6.2**.

**Figure 6.2:** Delaware – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



**6.1.4 — Interconnection Requests**

In Delaware, as of Dec. 31, 2025, 18 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.1**, **Table 6.2**, **Figure 6.3**, **Figure 6.4** and **Figure 6.5**.

**Table 6.1:** Delaware – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

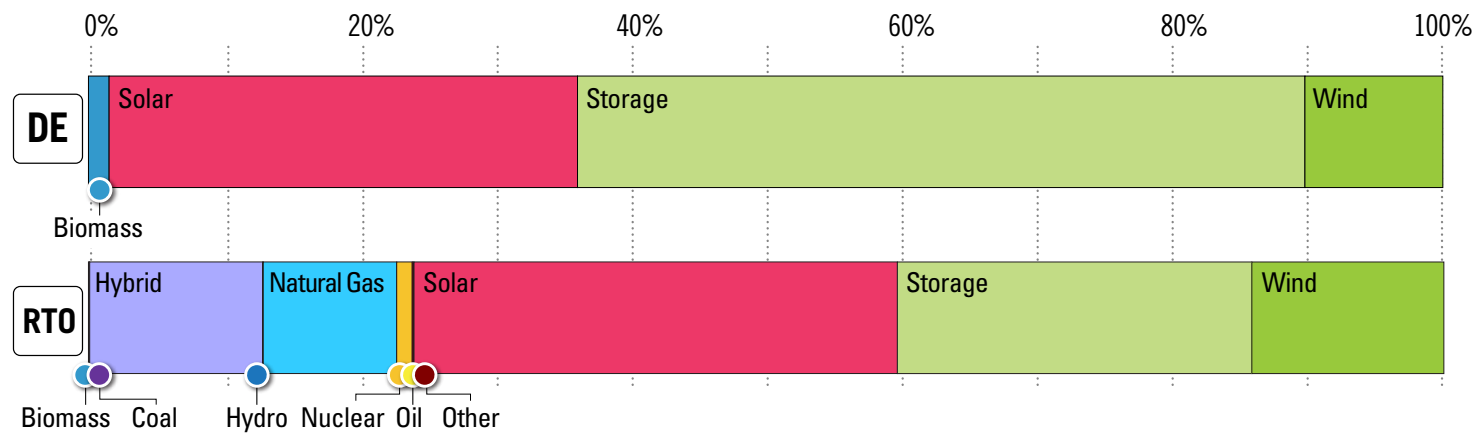
	Delaware Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
<b>Biomass</b>	10.0	1.53%	10.0	0.01%
<b>Coal</b>	0.0	0.00%	14.0	0.01%
<b>Hybrid</b>	0.0	0.00%	14,332.3	12.76%
<b>Hydro</b>	0.0	0.00%	30.0	0.03%
<b>Natural Gas</b>	0.0	0.00%	11,082.0	9.87%
<b>Nuclear</b>	0.0	0.00%	1,305.9	1.16%
<b>Oil</b>	0.0	0.00%	50.0	0.04%
<b>Other</b>	0.0	0.00%	56.3	0.05%
<b>Solar</b>	225.2	34.57%	40,116.0	35.73%
<b>Storage</b>	350.0	53.72%	29,376.0	26.16%
<b>Wind</b>	66.3	10.18%	15,910.7	14.17%
<b>Grand Total</b>	<b>651.5</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

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**Table 6.2:** Delaware – Interconnection Requests (Dec. 31, 2025)

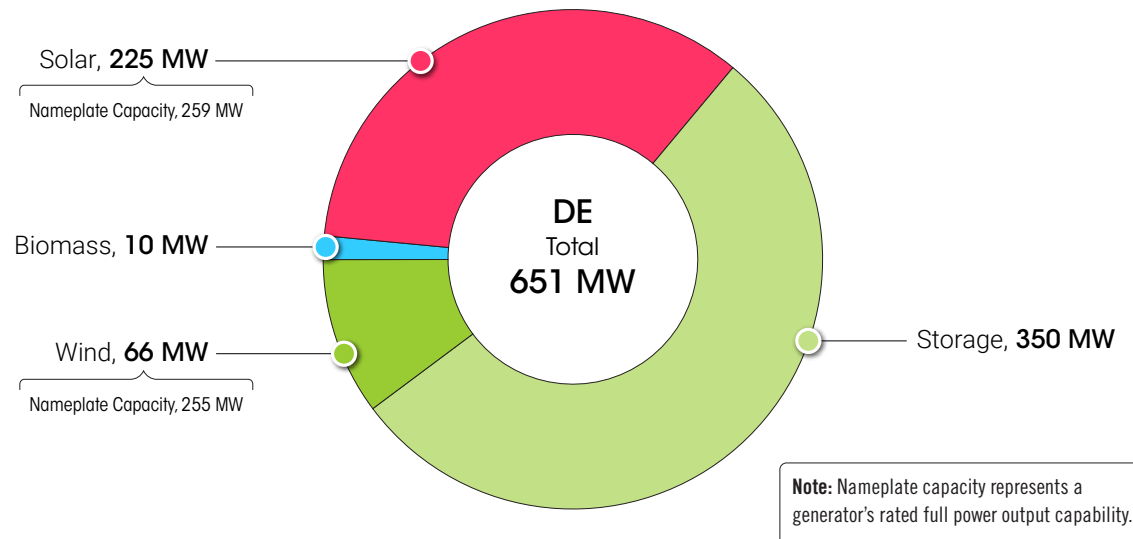
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	1	5.0	1	630.0	2	635.0
	Natural Gas	0	0.0	0	0.0	0	0.0	18	1,281.1	20	6,007.4	38	7,288.5
	Oil	0	0.0	0	0.0	0	0.0	5	168.2	1	1.0	6	169.2
	Other	0	0.0	0	0.0	0	0.0	2	26.3	1	0.0	3	26.3
	Storage	2	350.0	0	0.0	0	0.0	0	0.0	13	416.66	15	766.7
Renewable	Biomass	1	10.0	0	0.0	0	0.0	1	0.0	4	24.0	6	34.0
	Hybrid	0	0.0	0	0.0	0	0.0	0	0.0	2	104.7	2	104.7
	Methane	0	0.0	0	0.0	0	0.0	4	9.0	3	28.8	7	37.8
	Solar	4	162.9	6	43.3	3	19.0	1	37.6	42	582.79	56	845.6
	Wind	0	0.0	2	66.3	0	0.0	0	0.0	19	2,412.8	21	2,479.1
<b>Grand Total</b>		<b>7</b>	<b>522.9</b>	<b>8</b>	<b>109.6</b>	<b>3</b>	<b>19.0</b>	<b>32</b>	<b>1,527.2</b>	<b>106</b>	<b>10,208.2</b>	<b>156</b>	<b>12,386.9</b>

**Figure 6.3:** Delaware – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

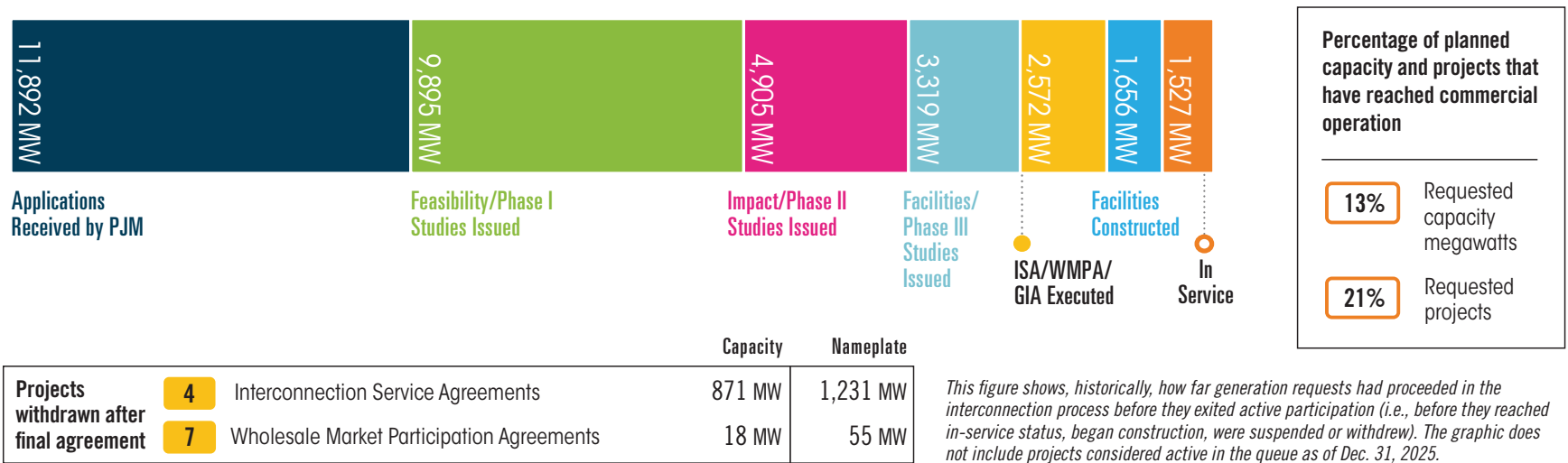


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**Figure 6.4:** Delaware Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.5:** Delaware Progression of Interconnection Requests (Dec. 31, 2025)

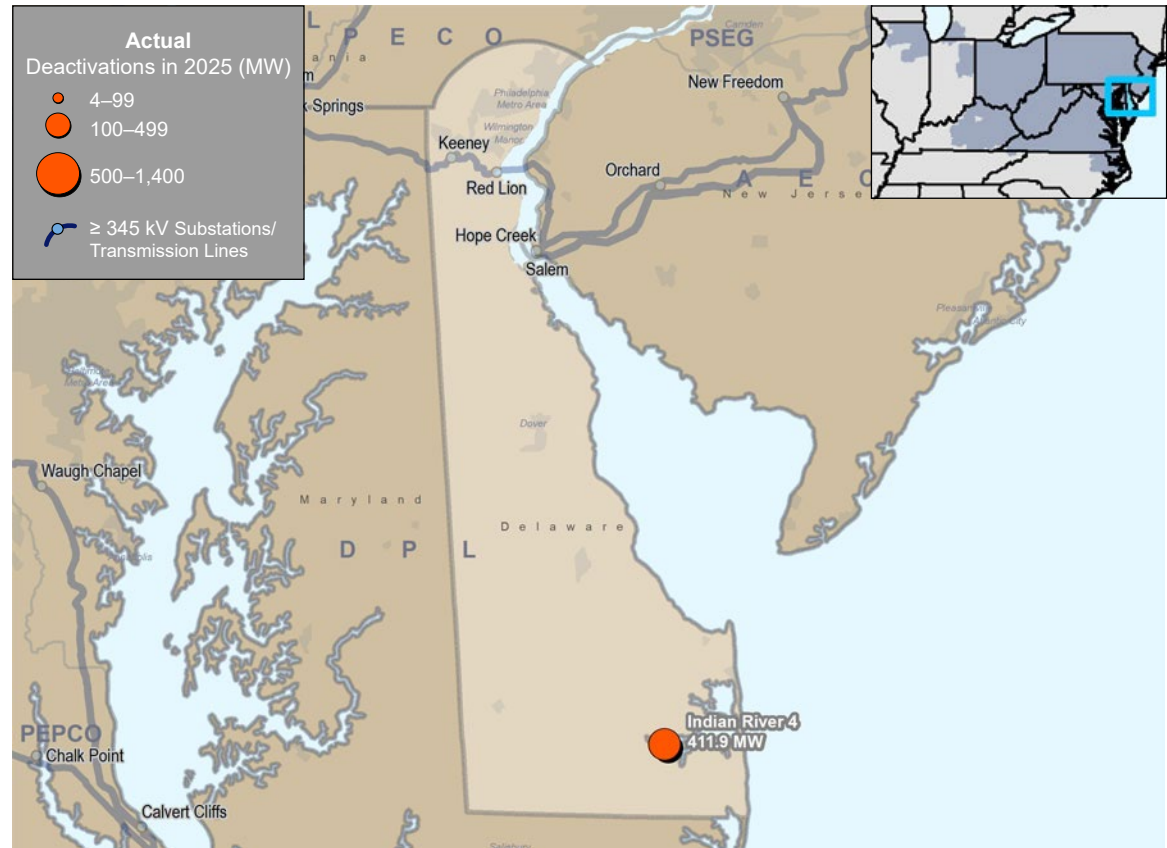


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### 6.1.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Delaware between Jan. 1, 2025, and Dec. 31, 2025, are summarized in **Map 6.2** and **Table 6.3**.

**Map 6.2:** Delaware Generation Deactivations (Dec. 31, 2025)



**Table 6.3:** Delaware Generation Deactivations (Dec. 31, 2025)

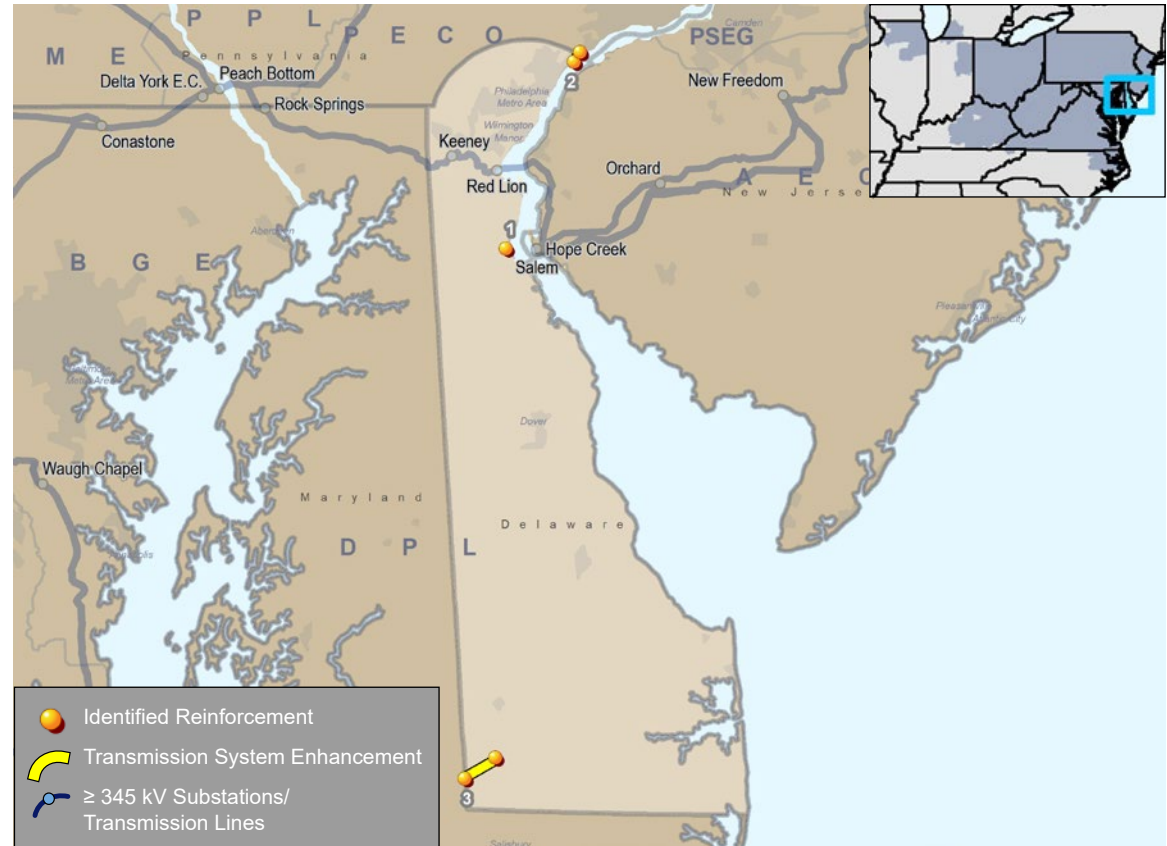
Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Indian River 4	DP&L	Coal	2/18/2025	2/24/2025	41	411.9

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**6.1.6 — Baseline Projects**

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in Delaware are summarized in **Map 6.3** and **Table 6.4**.

**Map 6.3:** Delaware Baseline Projects (Dec. 31, 2025)



**Table 6.4:** Delaware Baseline Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B3793.4	Replace three 1-1590 ACSR jumpers and one air disconnect switch at Silver Run 230 kV substation.	6/1/2028	\$0.58	DP&L	5/6/2025	N/A - Scope Change	Baseline Load Growth Deliverability & Reliability
2	B4004.1	Upgrade existing 1590 ACSR stranded bus at Claymont substation to increase the rating on the Claymont-Linwood 230 kV circuit.	6/1/2030	\$0.03	DP&L	11/4/2025	No	Baseline Load Growth Deliverability & Reliability

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**Table 6.4:** Delaware Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
3	B4024.1	Rebuild existing Sharptown-Laurel 69 kV circuit utilizing 954 ACSR "Rail" 45/7 conductor.	6/1/2030	\$36.55	DP&L	11/13/2025	No	Baseline Load Growth Deliverability & Reliability
	B4024.2	Upgrade breaker, rigid bus, relay and disconnect switch at Laurel substation on the Sharptown-Laurel facility.	6/1/2030	\$1.70	DP&L	11/13/2025	No	
CEII	B4076.1	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-DP&L01.	6/1/2029	\$0.02	DP&L	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4076.2	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-DP&L02.	6/1/2029	\$0.02	DP&L	12/8/2025	No	
	B4076.9	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-DP&L10, 2024-P5DYN-DP&L02.	6/1/2029	\$0.02	DP&L	12/8/2025	No	

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## 6.2: Northern Illinois RTEP Summary

### 6.2.1 — RTEP Context

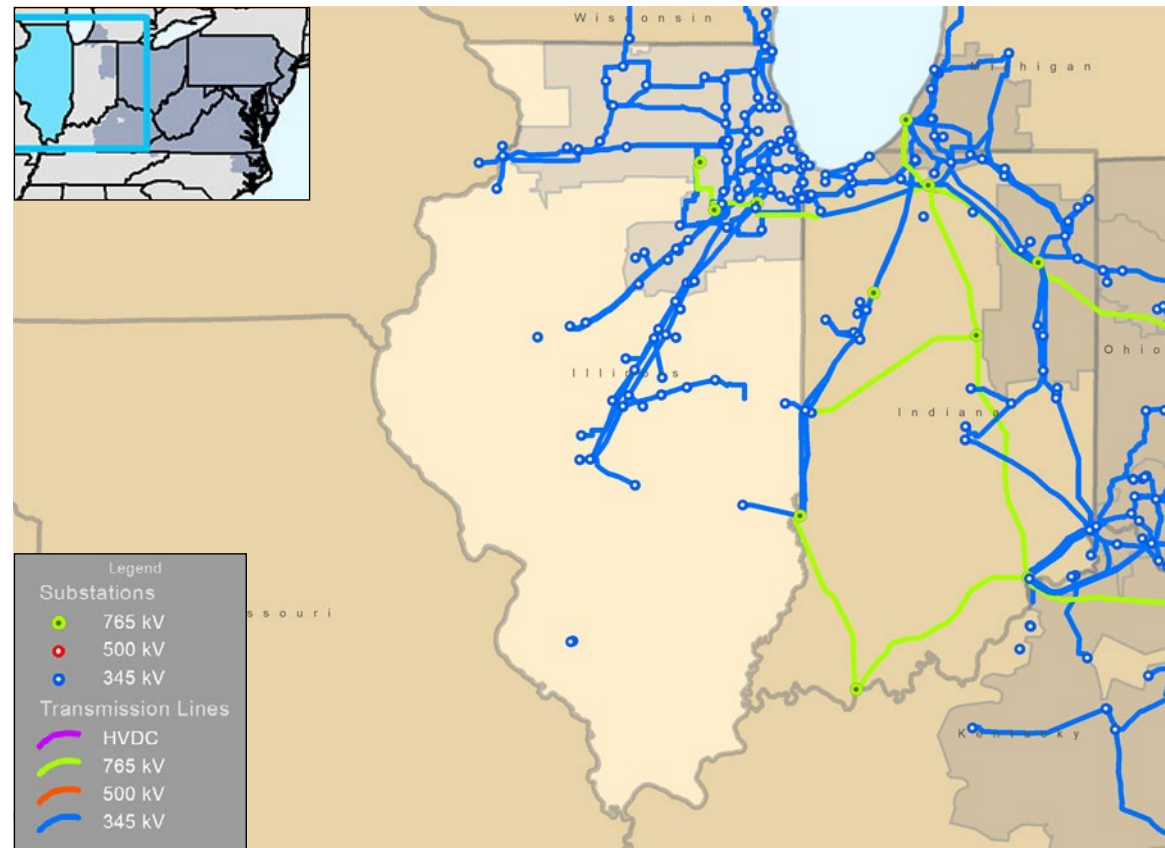
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in northern Illinois, including facilities owned and operated by Commonwealth Edison (ComEd) and the city of Rochelle as shown on **Map 6.4**. The transmission system in northern Illinois delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

#### **Renewable Portfolio Standards**

Illinois has a mandatory renewable portfolio standard (RPS) of 40% renewable energy by 2030 and 50% by 2040. The RPS target was established by the Climate and Equitable Jobs Act (CEJA), which was enacted in 2021 and contains specific carve-outs for solar, wind and hydro resources. CEJA also established a clean electricity target of 100% for Illinois by 2050.

CEJA includes a number of provisions to advance Illinois' decarbonization efforts. It requires all privately owned facilities that use coal or oil to reduce their carbon emissions to zero by 2030. Publicly owned coal facilities must reduce CO<sub>2</sub> emissions by 45% by 2035 and be zero-carbon by 2045. Privately owned natural gas facilities must reduce their carbon emissions to zero on a tiered schedule ranging from 2030 to 2045 depending on

**Map 6.4:** PJM Service Area in Northern Illinois



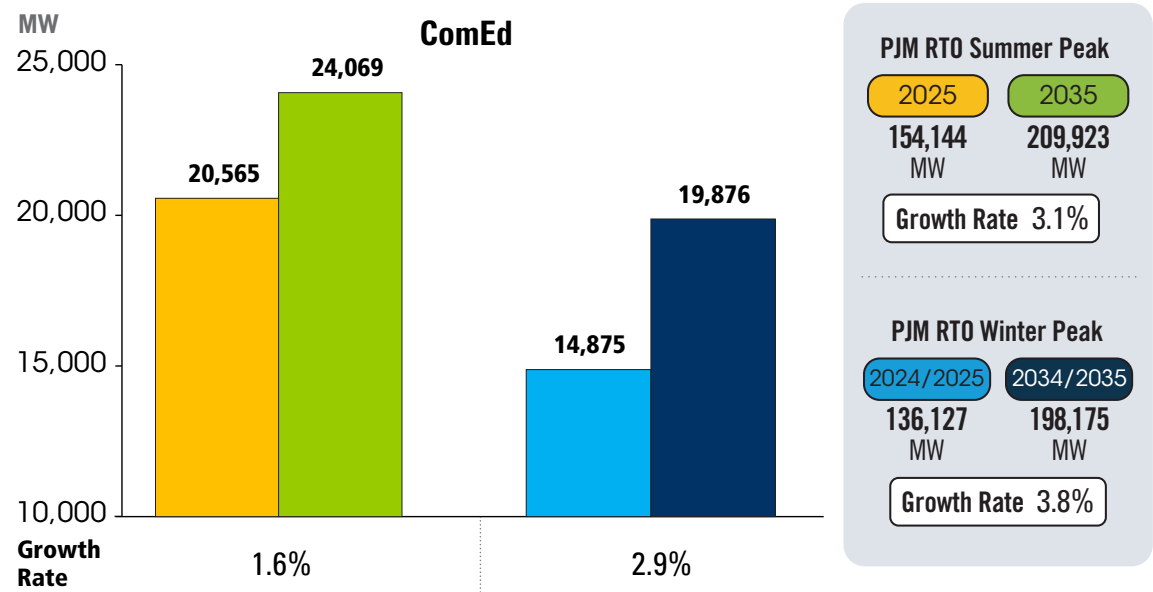
proximity to designated environmental justice communities as well as operating parameters and emission intensity. In certain cases, these facilities also have interim emission reduction targets. CEJA also provides funding for electric vehicle infrastructure and deployment.

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### 6.2.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.6** summarizes the expected loads within the state of Illinois and across the PJM region.

**Figure 6.6:** Northern Illinois – 2025 Long-Term Load Forecast



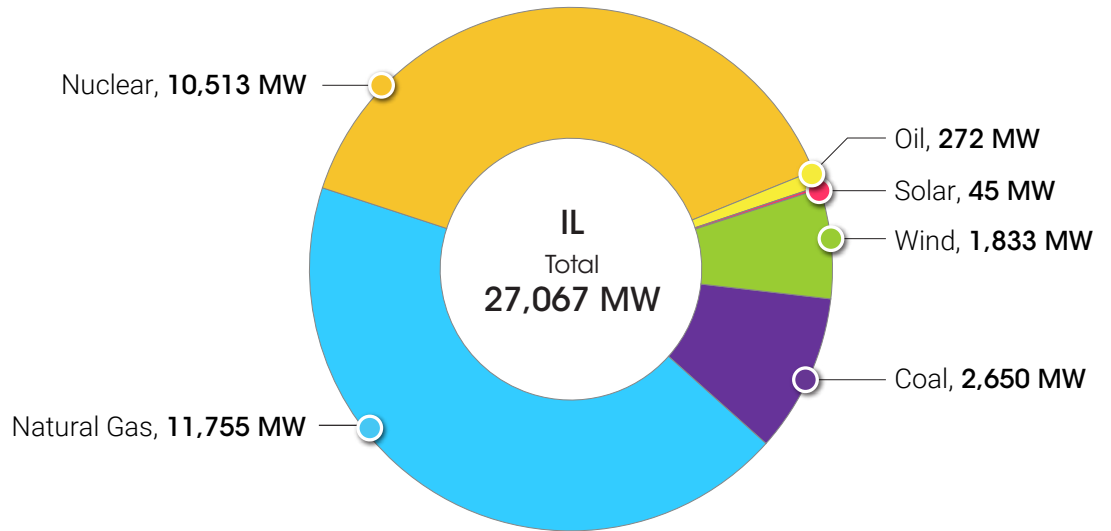
PJM notes that it does not serve the entire state of Illinois. The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by ComEd in northern Illinois. Estimated amounts were calculated based on the average share of ComEd's real-time summer and winter peak load in northern Illinois over the past five years.

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**6.2.3 — Existing Generation**

Existing generation in Illinois as of Dec. 31, 2025, is shown by fuel type in **Figure 6.7**.

**Figure 6.7:** Northern Illinois – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



**6.2.4 — Interconnection Requests**

In Illinois, as of Dec. 31, 2025, 197 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.5**, **Table 6.6**, **Figure 6.8**, **Figure 6.9** and **Figure 6.10**.

**Table 6.5:** Northern Illinois – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

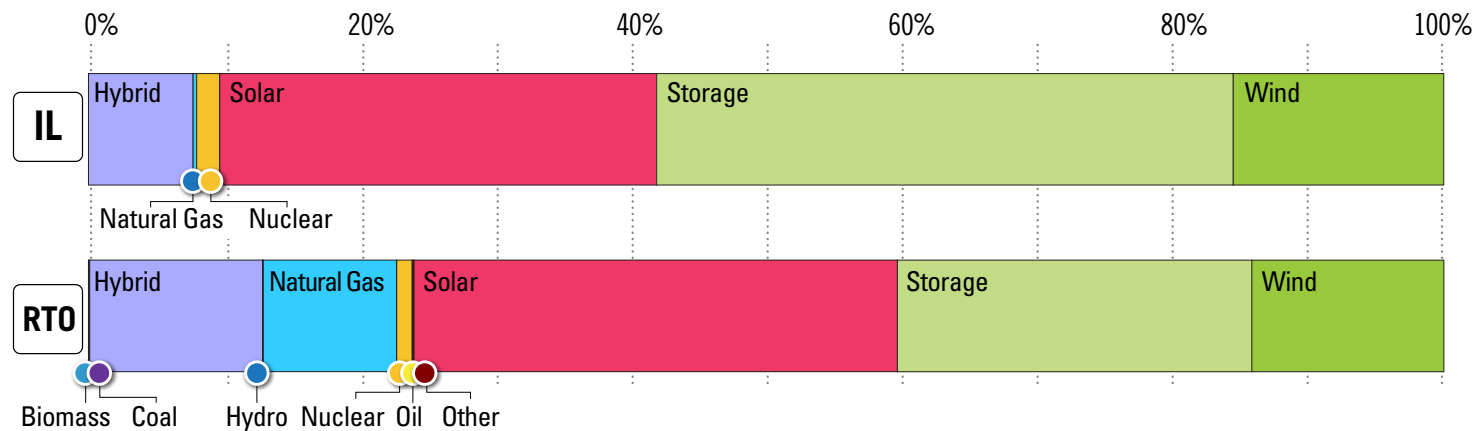
	Northern Illinois Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
<b>Biomass</b>	0.0	0.00%	10.0	0.01%
<b>Coal</b>	0.0	0.00%	14.0	0.01%
<b>Hybrid</b>	1,247.8	7.73%	14,332.3	12.76%
<b>Hydro</b>	0.0	0.00%	30.0	0.03%
<b>Natural Gas</b>	43.0	0.27%	11,082.0	9.87%
<b>Nuclear</b>	274.7	1.70%	1,305.9	1.16%
<b>Oil</b>	0.0	0.00%	50.0	0.04%
<b>Other</b>	0.0	0.00%	56.3	0.05%
<b>Solar</b>	5,205.8	32.25%	40,116.0	35.73%
<b>Storage</b>	6,866.8	42.53%	29,376.0	26.16%
<b>Wind</b>	2,506.3	15.52%	15,910.7	14.17%
<b>Grand Total</b>	<b>16,144.4</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

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**Table 6.6:** Northern Illinois – Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

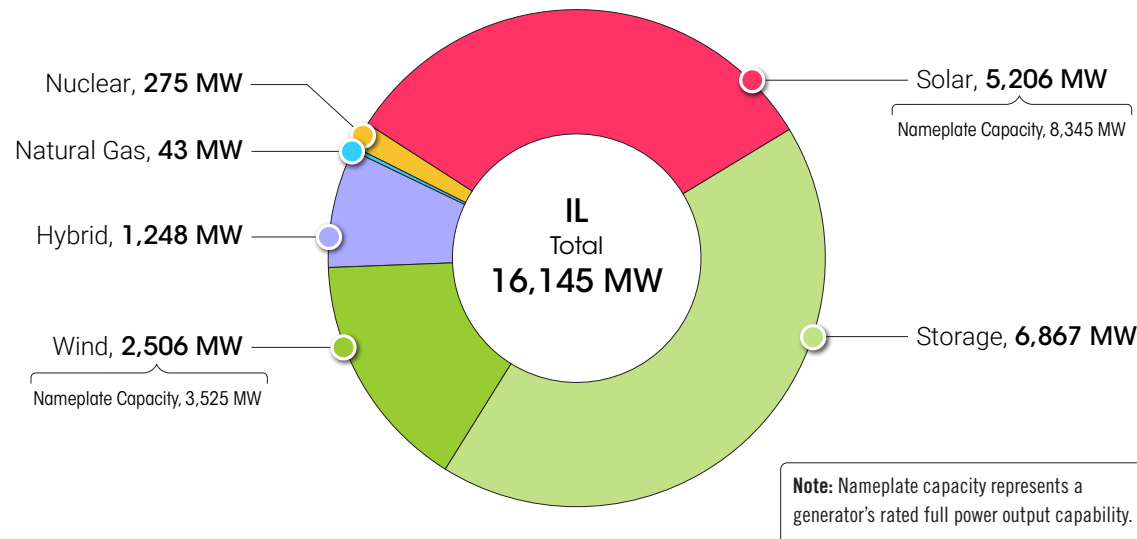
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	0	0.0	6	3,652.0	6	3,652.0
	Diesel	0	0.0	0	0.0	0	0.0	2	22.0	0	0.0	2	22.0
	Natural Gas	2	43.0	0	0.0	0	0.0	34	4,639.9	29	10,943.5	65	15,626.4
	Nuclear	3	274.7	0	0.0	0	0.0	10	385.8	5	782.0	18	1,442.5
	Storage	57	6,794.8	1	4.0	4	68.0	4	0.0	66	4,845.3	132	11,712.1
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	3	90.0	3	90.0
	Hybrid	12	1,231.9	0	0.0	1	15.9	1	2.2	18	1,318.4	32	2,568.4
	Hydro	0	0.0	0	0.0	0	0.0	0	0.0	5	27.0	5	27.0
	Methane	0	0.0	0	0.0	0	0.0	2	19.7	14	63.9	16	83.6
	Solar	61	4,605.0	2	134.3	11	466.5	3	45.4	117	5,847.2	194	11,098.4
	Wind	34	2,103.5	2	44.2	7	358.6	39	1,002.5	143	4,095.2	225	7,604.0
<b>Grand Total</b>		<b>169</b>	<b>15,052.8</b>	<b>5</b>	<b>182.5</b>	<b>23</b>	<b>909.0</b>	<b>95</b>	<b>6,117.5</b>	<b>406</b>	<b>31,664.5</b>	<b>698</b>	<b>53,926.4</b>

**Figure 6.8:** Northern Illinois – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2025)

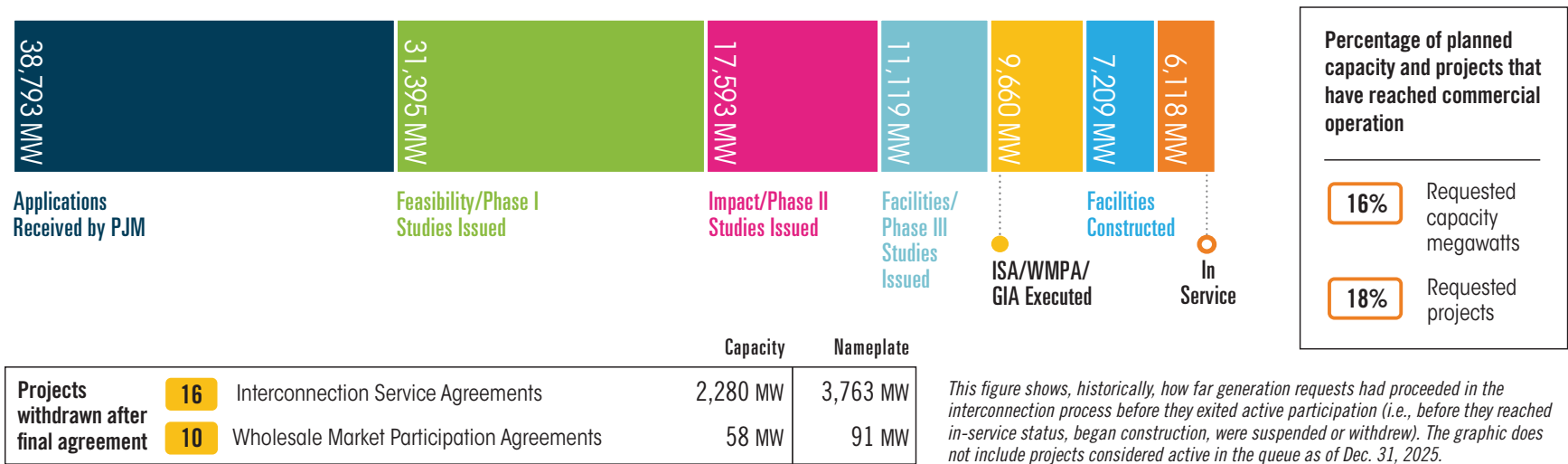


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**Figure 6.9:** Northern Illinois Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.10:** Northern Illinois Progression of Interconnection Requests (Dec. 31, 2025)

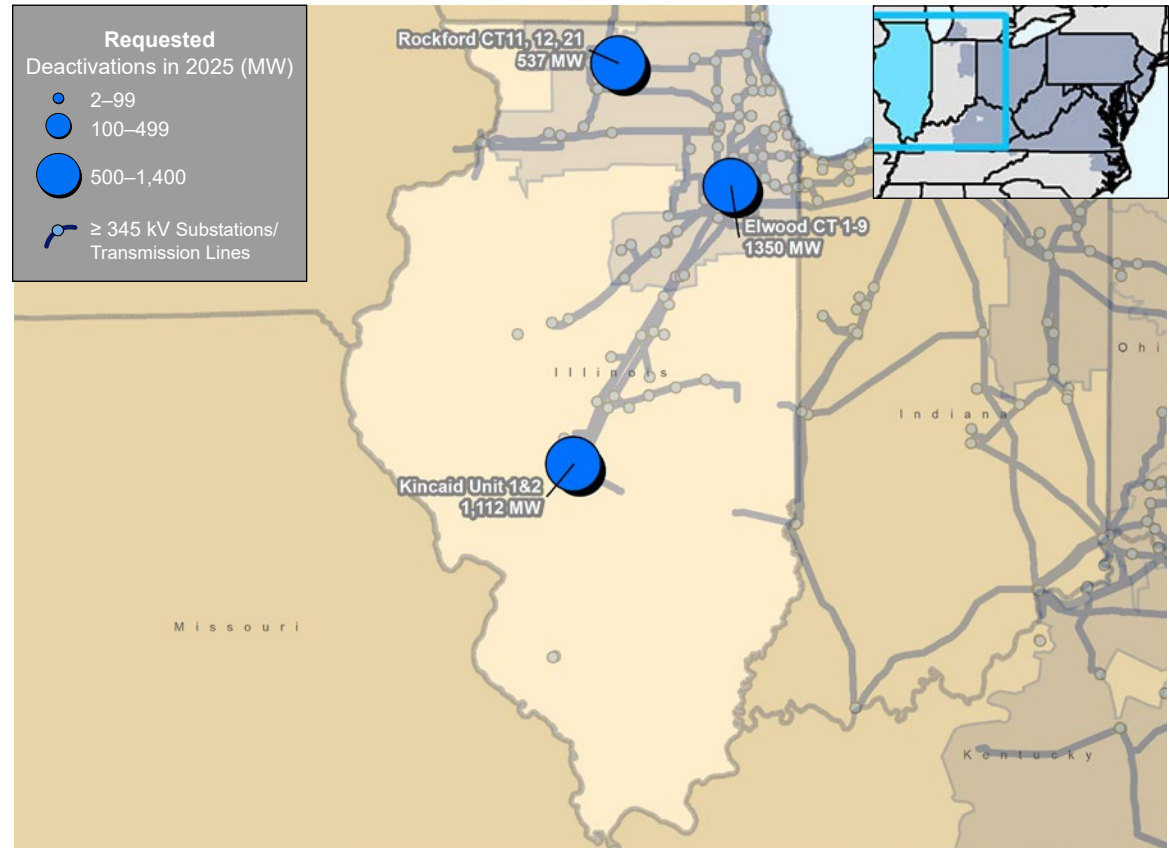


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### 6.2.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in northern Illinois between Jan. 1, 2025, and Dec. 31, 2025, are summarized in **Map 6.5** and **Table 6.7**.

**Map 6.5:** Northern Illinois Generation Deactivations (Dec. 31, 2025)



**Table 6.7:** Northern Illinois Generation Deactivations (Dec. 31, 2025)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Kincaid Unit 2	ComEd	Coal	7/22/2025	11/30/2027	57	556
Kincaid Unit 1	ComEd	Coal	7/22/2025	11/30/2027	58	556

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**Table 6.7:** Northern Illinois Generation Deactivations (Dec. 31, 2025) (Cont.)

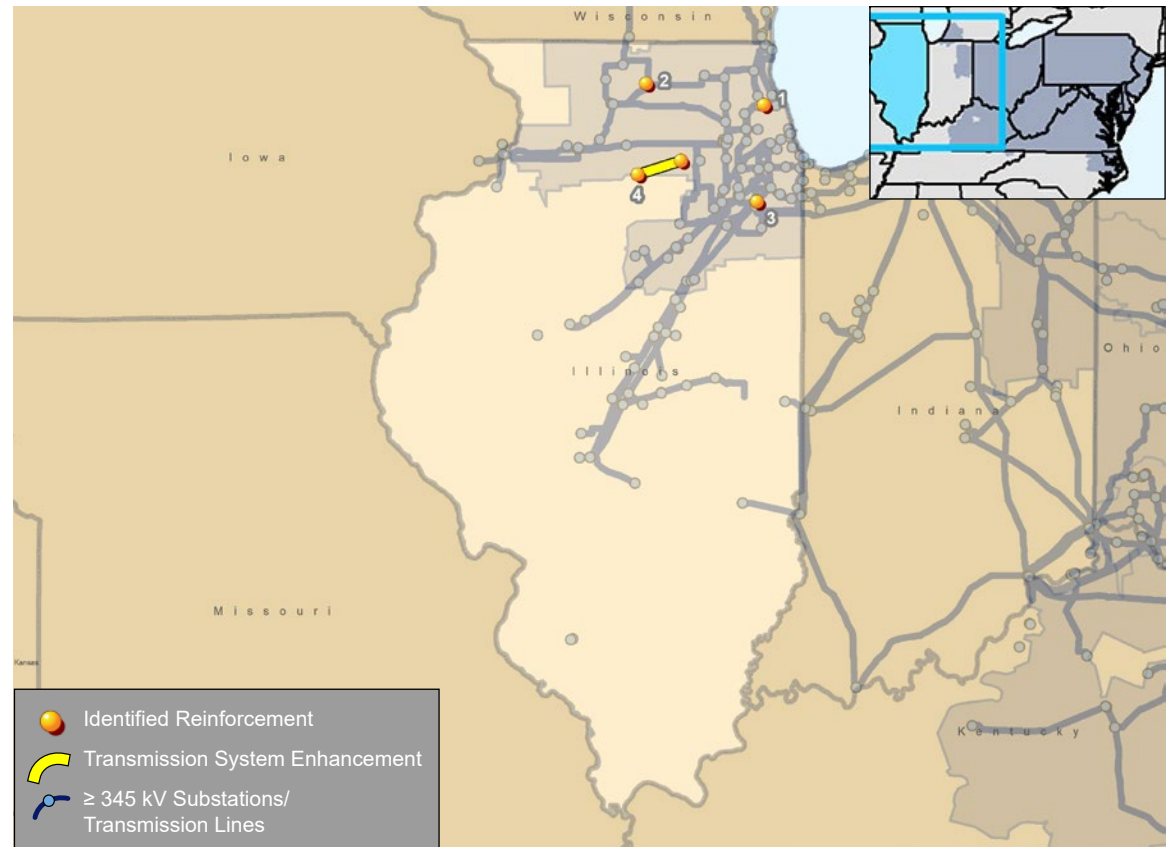
Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Rockford CT11	ComEd	Natural Gas	5/1/2025	6/1/2027	25	179
Rockford CT12	ComEd	Natural Gas	5/1/2025	6/1/2027	25	178
Rockford CT21	ComEd	Natural Gas	5/1/2025	6/1/2027	23	180
Elwood CT 9	ComEd	Natural Gas	3/21/2025	6/1/2025	25	150
Elwood CT 8	ComEd	Natural Gas	3/21/2025	6/1/2025	25	150
Elwood CT 7	ComEd	Natural Gas	3/21/2025	6/1/2026	25	150
Elwood CT 6	ComEd	Natural Gas	3/21/2025	6/1/2026	25	150
Elwood CT 5	ComEd	Natural Gas	3/21/2025	6/1/2026	25	150
Elwood CT 4	ComEd	Natural Gas	3/21/2025	6/1/2026	25	150
Elwood CT 3	ComEd	Natural Gas	3/21/2025	6/1/2026	25	150
Elwood CT 2	ComEd	Natural Gas	3/21/2025	6/1/2026	25	150
Elwood CT 1	ComEd	Natural Gas	3/21/2025	6/1/2026	25	150

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### 6.2.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in northern Illinois are summarized in **Map 6.6** and **Table 6.8**.

**Map 6.6:** Northern Illinois Baseline Projects (Dec. 31, 2025)



**Table 6.8:** Northern Illinois Baseline Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B3981.1	Install a new 345/138 kV TR83 at Elk Grove and associated equipment. Install three 138 kV and one 345 kV circuit breakers and associated equipment at Elk Grove substation.	6/1/2030	\$28.96	ComEd	11/14/2025	No	TO Criteria Violation

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**Table 6.8:** Northern Illinois Baseline Projects (Dec. 31, 2025) (Cont.)

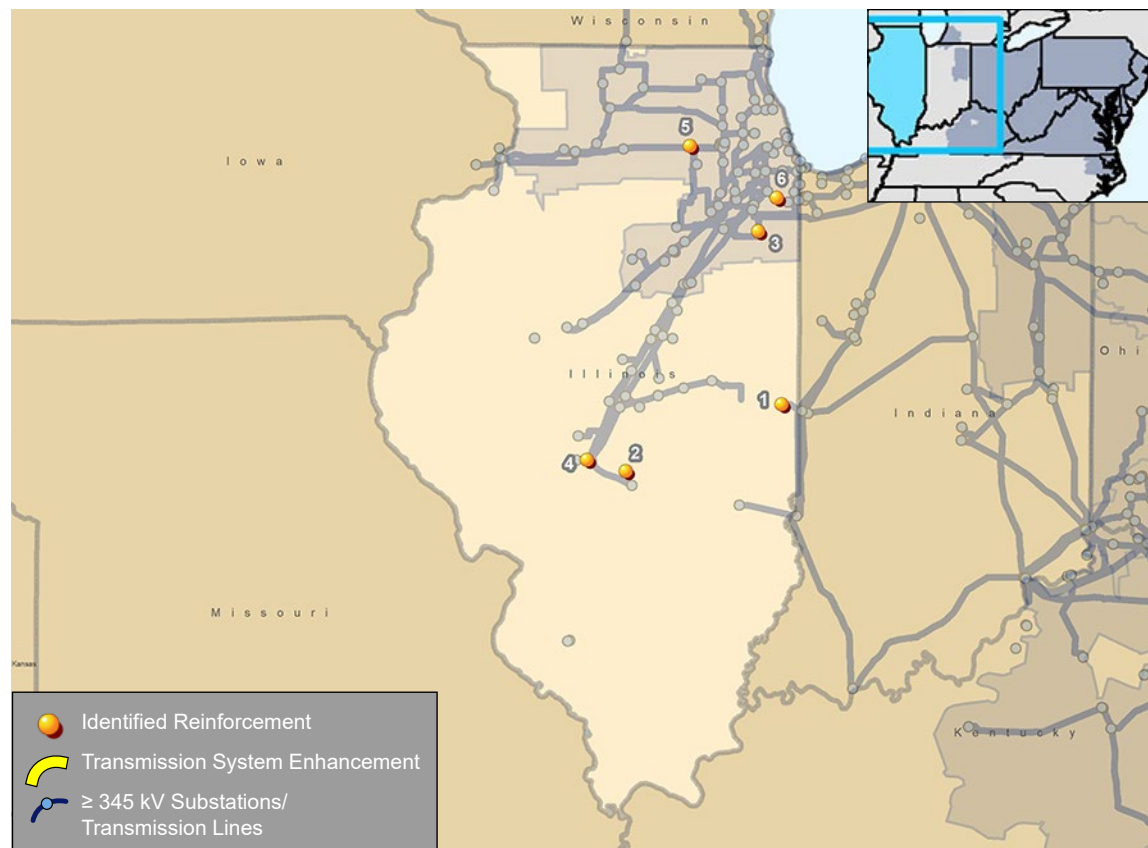
Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
2	B3982.1	Disconnect and remove the 34 kV tertiary cap bank on the Cherry Valley 345/138 kV transformer TR 82 and install a 138 kV bus 3 cap bank and associated equipment at Cherry Valley substation.	6/1/2030	\$7.73	ComEd	11/14/2025	No	TO Criteria Violation
3	B4006.1	Install 765/345 kV TR 91 and associated 765 kV and 345 kV circuit breakers at Wilton Center.	12/1/2030	\$45.81	ComEd	11/4/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
4	B4025.1	Build new 28-mile transmission line from Mendota to Sandwich.	4/15/2030	\$159.57	ComEd	12/12/2025	No	Baseline Load Growth Deliverability & Reliability
	B4025.2	Convert Mendota straight bus to ring by installing four new 138 kV circuit breakers.	4/15/2030	\$10.37	ComEd	12/12/2025	No	
	B4025.3	Install 138 kV BT circuit breaker and associated equipment at Sandwich.	4/15/2030	\$1.95	ComEd	12/12/2025	No	
CEII	B4073.1	2024W1 P5: Install battery monitoring. Addresses flowgate No. 2024-P5-COMETEDD01.	6/1/2029	\$0.25	ComEd	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4073.2	2024W1 P5: Install battery monitoring. Addresses flowgate No. 2024-P5-COMETEDD30.	6/1/2029	\$0.10	ComEd	12/8/2025	No	
	B4073.3	2024W1 P5: Install battery monitoring. Addresses flowgate No. 2024-P5-COMETEDD28.	6/1/2029	\$0.05	ComEd	12/8/2025	No	
	B4073.4	2024W1 P5: Install battery monitoring. Addresses flowgate No. 2024-P5-COMETEDD31.	6/1/2029	\$0.10	ComEd	12/8/2025	No	
	B4073.5	2024W1 P5: Install battery monitoring. Addresses flowgate No. 2024-P5-COMETEDD29.	6/1/2029	\$0.10	ComEd	12/8/2025	No	
	B4073.6	2024W1 P5: Install battery monitoring. Addresses flowgate No. 2024-P5-COMETEDD14.	6/1/2029	\$0.10	ComEd	12/8/2025	No	

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### 6.2.7 — Network Projects

Network projects in northern Illinois for 2025 are summarized in **Map 6.7** and **Table 6.9**.

**Map 6.7:** Northern Illinois Network Projects (Dec. 31, 2025)



**Table 6.9:** Northern Illinois Network Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	N5808	Install two new 345 kV circuit breakers, relocate the Bunsonville 345 kV line connection, relocate and replace the Bunsonville 345 kV metering at the Eugene 345 kV station.	AD1-100	6/1/2018	\$3.42	AEP	10/8/2025

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Table 6.9: Northern Illinois Network Projects (Dec. 31, 2025) (Cont.)

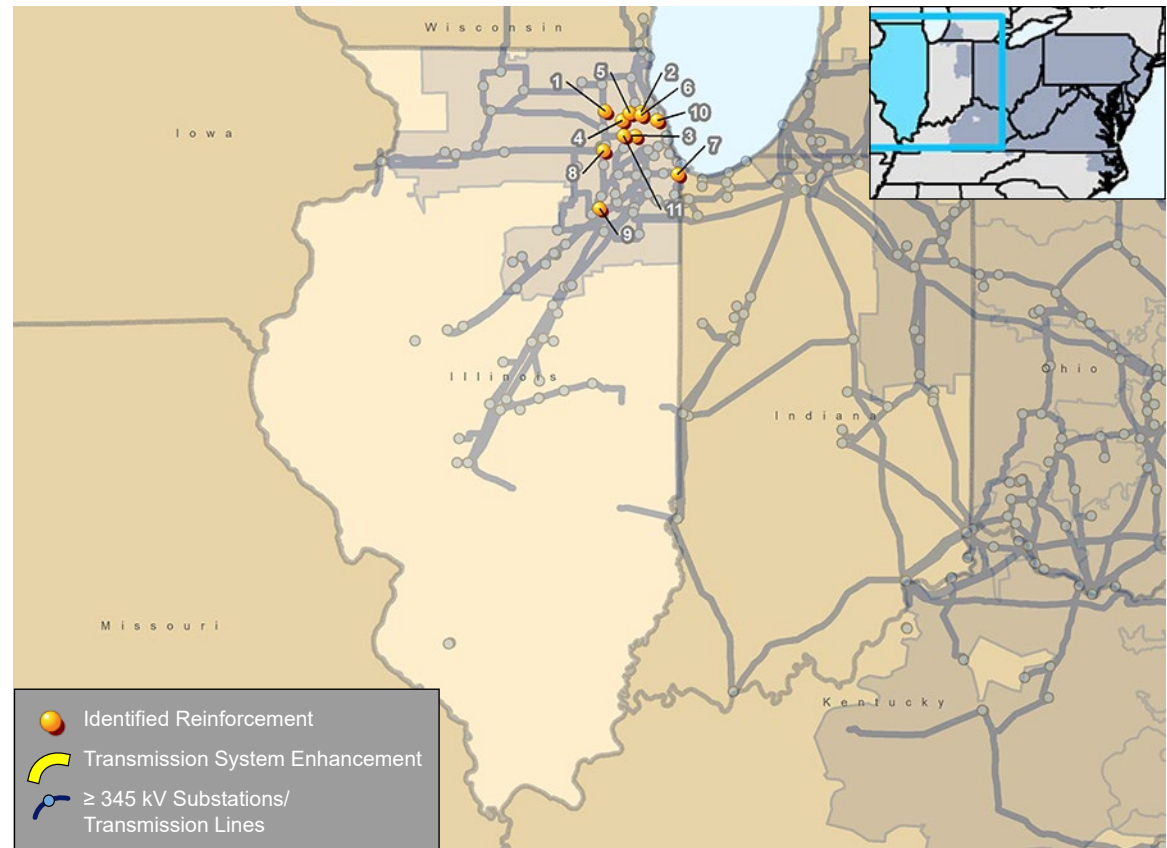
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
2	N6860	The upgrade will require a ComEd relay group review of the 765 kV bus tie 3-4 circuit breaker current transformer settings. A possible upgrade of the relay scheme may be required. A preliminary estimate for this upgrade is \$1M with an estimated construction timeline of 18 months. Upon completion of this upgrade, the ratings will be 4142/4460/5331/6368 MVA (SN/SLTE/SSTE/SLD).	AF1-090	12/31/2029	\$1.00	ComEd	10/8/2025
	N8591.0	Revise relay settings for TSS 964 substation.	AF1-090	12/31/2029	\$0.15	ComEd	10/8/2025
	N8592.0	L96407 345 kV line tie in to new TSS 931 Cottonwood Creek substation.	AF1-090	12/31/2029	\$14.10	ComEd	10/8/2025
	N8593.0	At TSS 931 Cottonwood Creek substation, transmission line tie-in fiber (OPGW).	AF1-090	12/31/2029	\$0.61	ComEd	10/8/2025
	N9038.0	At TSS 931 Cottonwood creek substation, distribution for auxiliary power.	AF1-090	12/31/2029	\$5.45	ComEd	10/8/2025
3	N8052.1	Substation to be expanded with one new gas 138 kV circuit breaker, two new 138 kV MODs, new 138 kV CCVTs and associated equipment.	AC2-154	12/31/2019	\$2.98	ComEd	10/8/2025
	N8052.2	Install new primary, backup and control relay and protection equipment for the new terminal.	AC2-154	12/31/2019	\$0.53	ComEd	10/8/2025
4	N8509.1	Install bus-tie circuit breaker and all related relays and appurtenance at STA 21 Kincaid to interconnect AF2-032.	AF2-032	8/30/2026	\$3.50	ComEd	10/8/2025
	N8509.2	Install deadend and metering to interconnect AF2-032.	AF2-032	8/30/2026	\$2.80	ComEd	10/8/2025
5	N8781.0	Expand the TSS 189 Crego Road substation to accommodate the AF2-366 project.	AF2-366	3/29/2028	\$6.34	ComEd	10/8/2025
	N8782.0	Relocate L8302 and L11106 138 kV lines to new dead ends at TSS 189 Crego Road substation.	AF2-366	3/29/2028	\$1.46	ComEd	10/8/2025
6	N8958.0	Review and revise protective relay settings at University Park 345 kV.	AF2-359	12/5/2026	\$0.45	ComEd	10/8/2025

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**6.2.8 — Supplemental Projects**

Supplemental projects included in the 2025 Local Plan in northern Illinois are summarized in **Map 6.8** and **Table 6.10**.

**Map 6.8:** Northern Illinois Supplemental Projects (Dec. 31, 2025)



**Table 6.10:** Northern Illinois Supplemental Projects (Dec. 31, 2025)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S3578.1	New customer will be radially served by two new 2.5-mile 138 kV lines from Tollway substation to the customer site. Customer substation will be double ring bus configuration with four 138/34 kV transformers. At Tollway, replace 138 kV BT 2-3 circuit breakers with two 138 kV BT circuit breakers.	12/31/2026	\$3.00	ComEd	3/15/2024
2	S3579.1	Expand TSS Elk Grove to the east and build a new 138 kV GIS building. Existing overhead 138 kV transmission lines, L.18407 and L.18408, will be cut over from the exiting GIS building to the new GIS building via overhead conductors. The new GIS will be tied to the existing GIS through two new bus ties. The new GIS station will install fourteen 138 kV circuit breakers in a breaker-and-a-half configuration. Customer will be radially served with four 138/34 kV, 112 MVA transformers.	12/31/2027	\$130.90	ComEd	6/14/2024

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Table 6.10: Northern Illinois Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	S3580.1	Install two new 60 MVA, 138/34 kV distribution transformers at Elmhurst to a new 34 kV terminal. Install two new 138 kV BT circuit breakers between bus 3 and bus 4.	8/1/2025	\$6.00	ComEd	6/14/2024
	S3580.2	Install third new 60 MVA 138/34 kV distribution transformer at Elmhurst.	6/1/2027	\$0.00	ComEd	6/14/2024
4	S3581.1	At Bexley, work will be performed to address asset renewal concerns associated with the site and transmission equipment including work to allow for the retirement of the existing 40 kV yard at the station. This includes replacing 138 kV circuit breaker "106" with a 138 kV, 63 kA 3000+76:82A circuit breaker. Note that 138 kV breaker "105" that was identified in the original need statement failed in the field and has been subsequently replaced.	12/1/2026	\$9.90	ComEd	6/14/2024
5	S3582.1	Cut into existing 138 kV Elk Grove-Schaumburg lines, extend four lines to a new customer substation. Customer substation will be sixteen 138 kV circuit breaker, double ring bus configuration with five 138/34 kV, 112 MVA transformers. Reconductor 1.25 miles of existing 636 ACSR with 1033.5 ACSS on each 138 kV line from Elk Grove to new customer site. Replace existing 1600 XLPE underground cables with 2500 XLPE underground cables (two per phase) on each 138 kV line out of Elk Grove to customer site.	12/31/2026	\$0.00	ComEd	8/6/2024
	S3582.2	Cut into existing 345 kV Des Plaines-Lombard lines and extend four lines to a new Elk Grove twelve circuit breaker 345 kV GIS bus in a breaker-and-a-half configuration. Install two new 420 MVA 345/138 kV autotransformers at Elk Grove.	6/30/2027	\$158.00	ComEd	8/6/2024
6	S3583.1	New customer will be radially served by two new 1.7-mile 138 kV lines from Elk Grove East substation (ComEd-2023-005) to the customer site. Customer substation will be a 15 circuit breaker, double ring bus configuration with six 138/34 kV, 112 MVA transformers. Install four new 138 kV GIS circuit breakers to the breaker-and-a-half configuration at Elk Grove East to connect the new radial lines to the customer substation.	12/31/2026	\$12.00	ComEd	8/6/2024
	S3583.2	Install two new 345 kV circuit breakers, two new 138 kV circuit breakers and two new 345/138 kV, 420 MVA autotransformers at Itasca substation.	12/31/2027	\$28.60	ComEd	8/6/2024
	S3584.1	New customer will be radially served by two new 1.7-mile 138 kV underground lines from ComEd Dierking substation (ComEd-2024-004) to the customer site. Customer substation will be an eleven circuit breaker, double ring bus configuration with three 138/34 kV, 112 MVA transformers. Install two new 138 kV circuit breakers to the double ring bus configuration at ComEd Dierking substation (ComEd-2024-004) to connect the new radial lines to the customer substation.	12/31/2027	\$121.40	ComEd	9/20/2024
	S3584.2	Install second 1600 XLPE cable per phase on two 1.5-mile 138 kV underground lines from ComEd Elk Grove East substation (ComEd-2023-005) to ComEd Dierking substation (ComEd-2024-004). Install second 1600 XLPE cable per phase on two 3-mile 138 kV underground lines from ComEd Itasca substation to ComEd Pine substation (ComEd-2023-009). Install two new 138 kV circuit breakers to the double ring bus configuration at ComEd Pine substation (ComEd-2023-009) to connect the new radial lines to the customer substation. Install two new 3-mile 138 kV underground lines from ComEd Pine substation (ComEd-2023-009) to the customer site.	12/31/2028	\$168.00	ComEd	9/20/2024
7	S3585.1	Replace existing 345 kV, 50 kA oil BT1-2 circuit breaker with new 345 kV, 63 kA SF6 circuit breaker at Burnham.	12/31/2024	\$2.10	ComEd	11/6/2024
	S3586.1	Replace existing 345 kV, 50 kA oil BT2-13 circuit breaker with new 345 kV, 63 kA SF6 circuit breaker at Burnham.	12/31/2027	\$2.10	ComEd	11/6/2024
	S3587.1	Replace existing 345 kV, 50 kA oil BT12-13 circuit breaker with new 345 kV, 63 kA SF6 circuit breaker at Burnham.	12/31/2027	\$2.10	ComEd	11/6/2024
8	S3592.1	New customer will be radially served by two new 1.0 mile 138 kV lines from Electric Junction substation to the customer site. Customer substation will be double ring bus configuration with four 138/34 kV, 60 MVA transformers.	12/31/2026	\$0.00	ComEd	11/15/2024
9	S3725.1	Replace Dresden 345 kV BT4-8 oil circuit breaker with new SF6 circuit breaker.	12/31/2026	\$2.70	ComEd	3/4/2025
10	S3726.1	Complete the following at Devon substation: Replace three 138 kV oil circuit breakers for 138 kV lines L11415 (Northwest-Rosehill-Devon), L11414 (Northwest-Rosehill-Devon), L11411 (Northwest-Devon). Install 138 kV 3000A SF6 line circuit breakers on 138 kV lines L11416 (Northwest-Devon), L11416 (Devon-Skokie), and L8810 (Devon-Skokie). Install 138 kV, 3000A SF6 circuit breakers on high side of 138-12 kV transformers 73 and 74.	12/31/2026	\$18.90	ComEd	3/14/2025
11	S3727.1	Upgrade wave trap at Lombard on 138 kV Lombard-Lisle line L10301.	12/31/2025	\$0.15	ComEd	2/14/2025
	S3728.1	Upgrade wave trap at Lombard on 138 kV Lombard-Lisle line L10302.	12/31/2027	\$0.15	ComEd	2/14/2025

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### 6.3: Indiana RTEP Summary

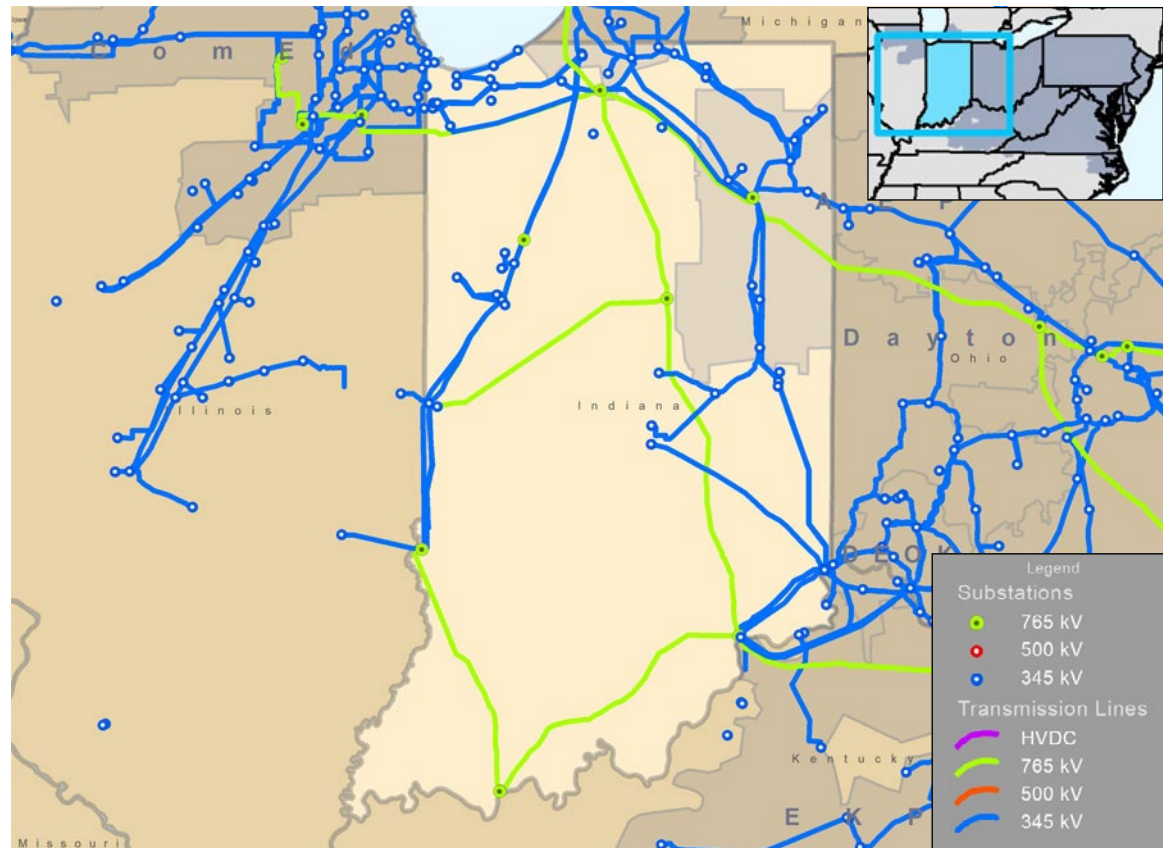
#### 6.3.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Indiana, including facilities owned and operated by American Electric Power (AEP) as shown on **Map 6.9**. Indiana's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

#### **Renewable Portfolio Standards**

Indiana has a voluntary clean energy portfolio standard of 10% by 2025. This target can be met with eligible clean energy technologies, and 50% of the qualifying energy must come from within Indiana.

**Map 6.9:** PJM Service Area in Indiana

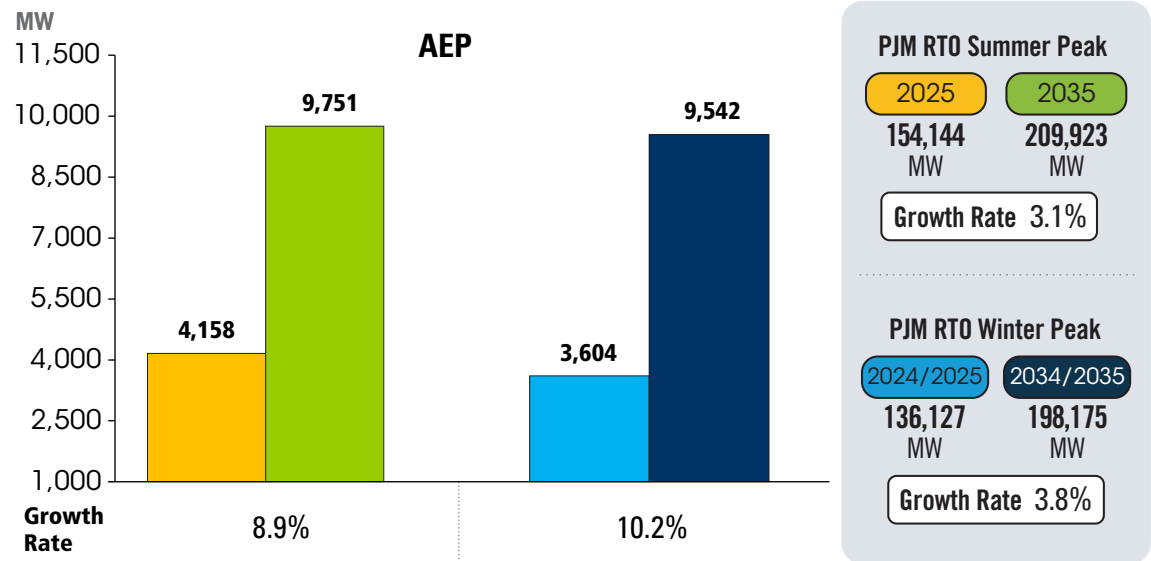


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### 6.3.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.11** summarizes the expected loads within the state of Indiana and across the PJM region.

**Figure 6.11:** Indiana – 2025 Long-Term Load Forecast



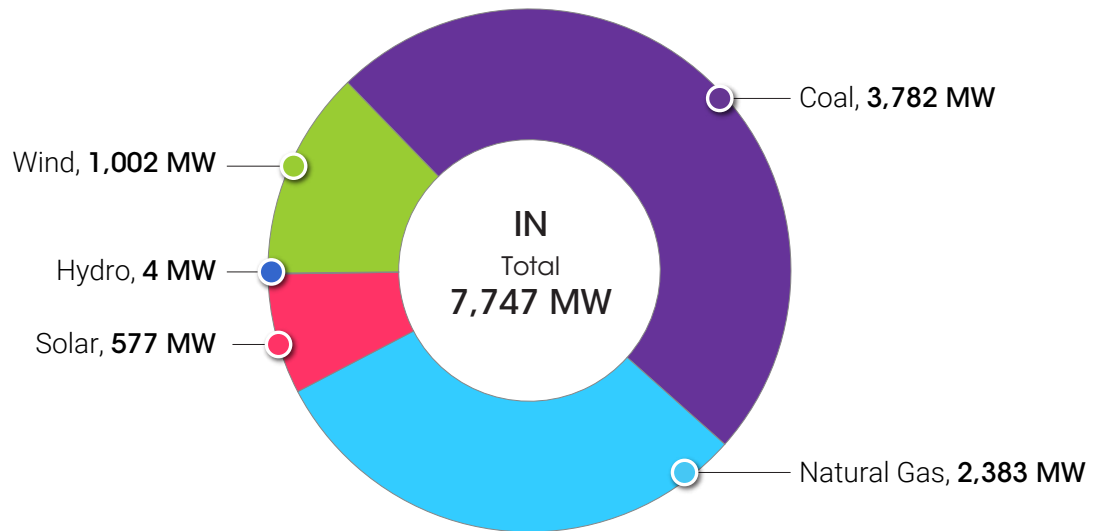
PJM notes that AEP serves load other than in Indiana. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by AEP solely in Indiana. Estimated amounts were calculated based on the average share of AEP's real-time summer and winter peak load located in Indiana over the past five years.

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**6.3.3 — Existing Generation**

Existing generation in Indiana as of Dec. 31, 2025, is shown by fuel type in **Figure 6.12**.

**Figure 6.12:** Indiana – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



**6.3.4 — Interconnection Requests**

In Indiana, as of Dec. 31, 2025, 161 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.11**, **Table 6.12**, **Figure 6.13**, **Figure 6.14** and **Figure 6.15**.

**Table 6.11:** Indiana – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

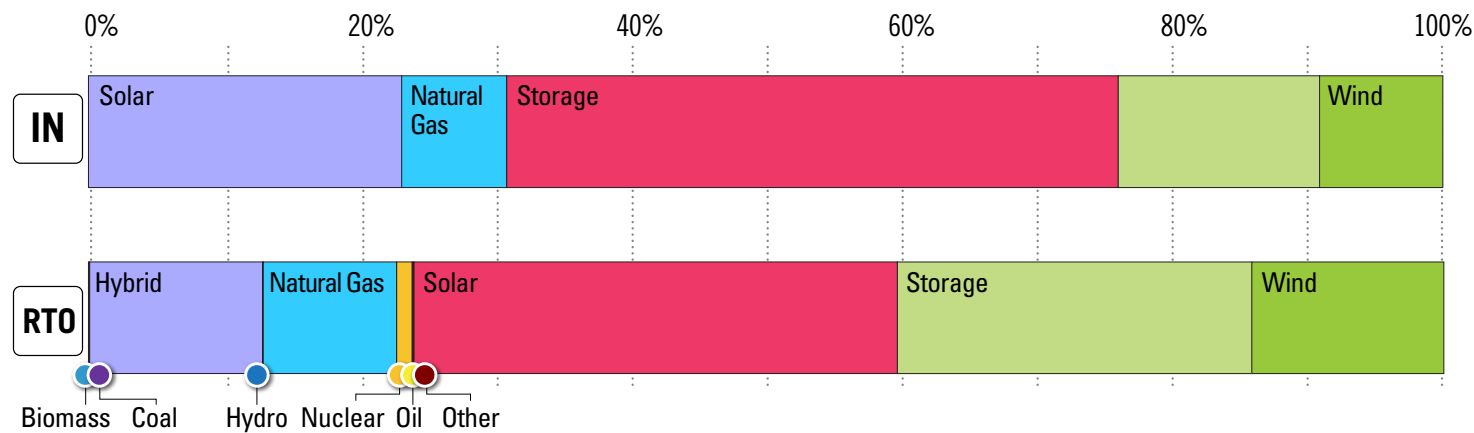
	Indiana Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
<b>Biomass</b>	0.0	0.00%	10.0	0.01%
<b>Coal</b>	0.0	0.00%	14.0	0.01%
<b>Hybrid</b>	3,277.9	23.12%	14,332.3	12.76%
<b>Hydro</b>	0.0	0.00%	30.0	0.03%
<b>Natural Gas</b>	1,100.0	7.76%	11,082.0	9.87%
<b>Nuclear</b>	0.0	0.00%	1,305.9	1.16%
<b>Oil</b>	0.0	0.00%	50.0	0.04%
<b>Other</b>	0.0	0.00%	56.3	0.05%
<b>Solar</b>	6,403.6	45.16%	40,116.0	35.73%
<b>Storage</b>	2,109.0	14.87%	29,376.0	26.16%
<b>Wind</b>	1,288.2	9.09%	15,910.7	14.17%
<b>Grand Total</b>	<b>14,178.6</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

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**Table 6.12:** Indiana – Interconnection Requests by Fuel Type (Dec. 31, 2025)

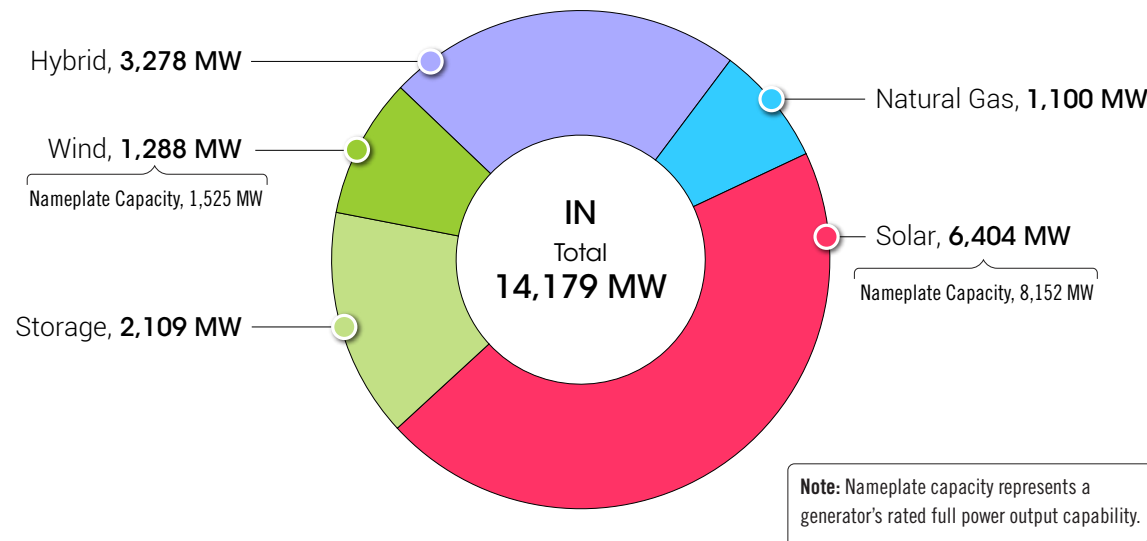
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	4	66.0	2	901.0	6	967.0
	Natural Gas	1	0.0	0	0.0	2	1,100.0	6	861.0	4	3,161.0	13	5,122.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	1	253.4	1	253.4
	Storage	17	1,919.0	1	40.0	3	150.0	0	0.0	48	3,292.5	69	5,401.5
Renewable	Hybrid	17	2,786.6	1	115.0	4	376.3	0	0.0	18	3,710.3	40	6,988.2
	Methane	0	0.0	0	0.0	0	0.0	2	8.0	1	3.6	3	11.6
	Solar	64	4,098.5	6	302.7	23	2,002.4	13	676.7	85	7,028.5	191	14,108.7
	Wind	17	1,184.6	2	26.0	3	77.6	12	409.0	53	2,053.9	87	3,751.0
<b>Grand Total</b>		<b>116</b>	<b>9,988.7</b>	<b>10</b>	<b>483.7</b>	<b>35</b>	<b>3,706.3</b>	<b>37</b>	<b>2,020.6</b>	<b>212</b>	<b>20,404.1</b>	<b>410</b>	<b>36,603.4</b>

**Figure 6.13:** Indiana – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

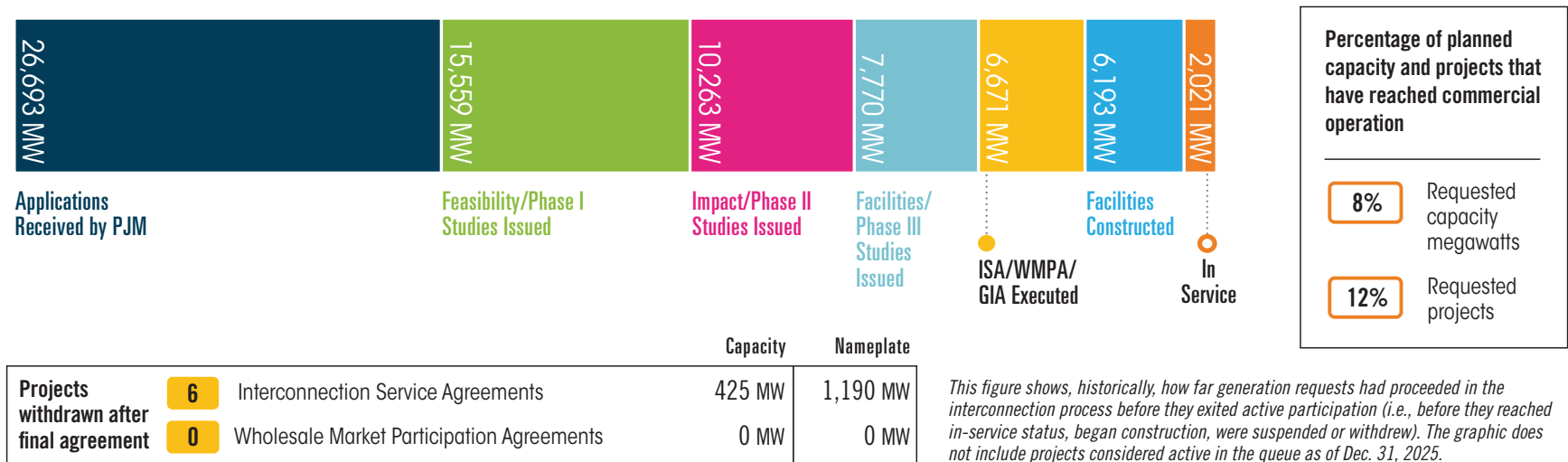


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**Figure 6.14:** Indiana Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.15:** Indiana Progression of Interconnection Requests (Dec. 31, 2025)

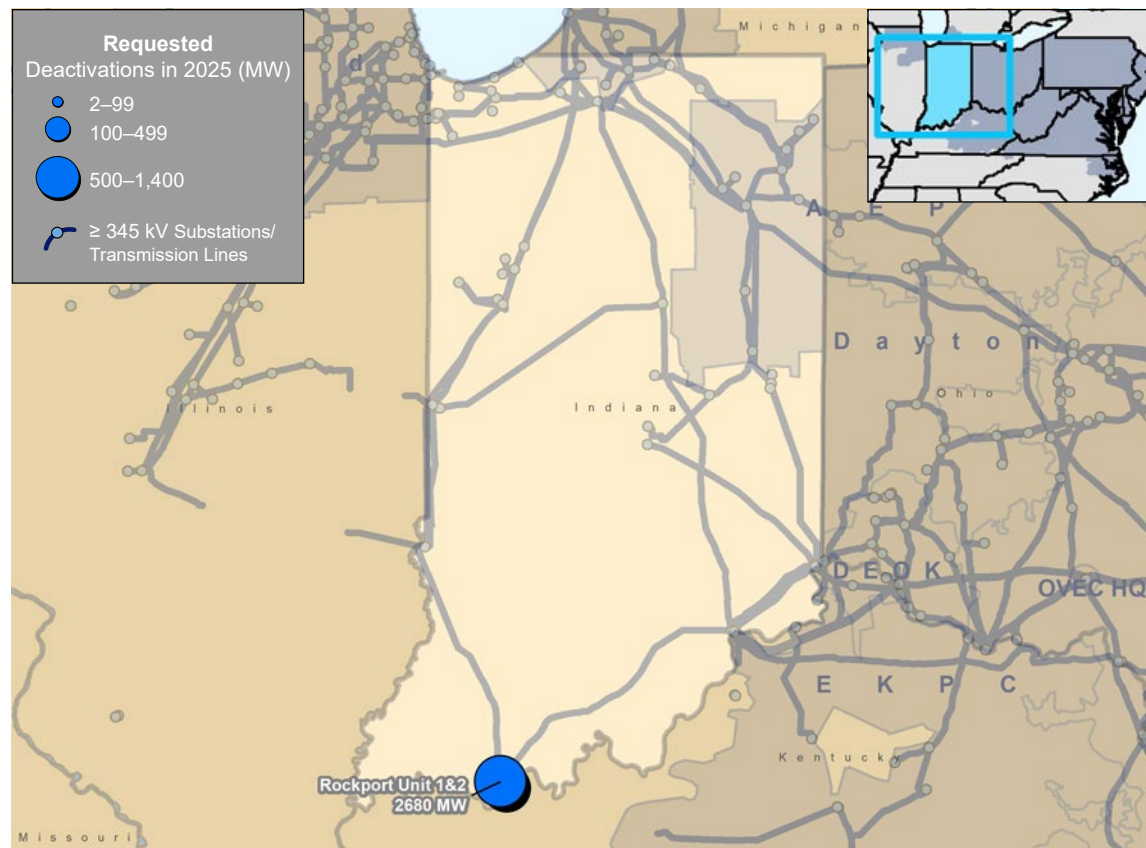


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### 6.3.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Indiana between Jan. 1, 2025, and Dec. 31, 2025, are summarized in **Map 6.10** and **Table 6.13**.

**Map 6.10:** Indiana Generation Deactivations (Dec. 31, 2025)



**Table 6.13:** Indiana Generation Deactivations (Dec. 31, 2025)

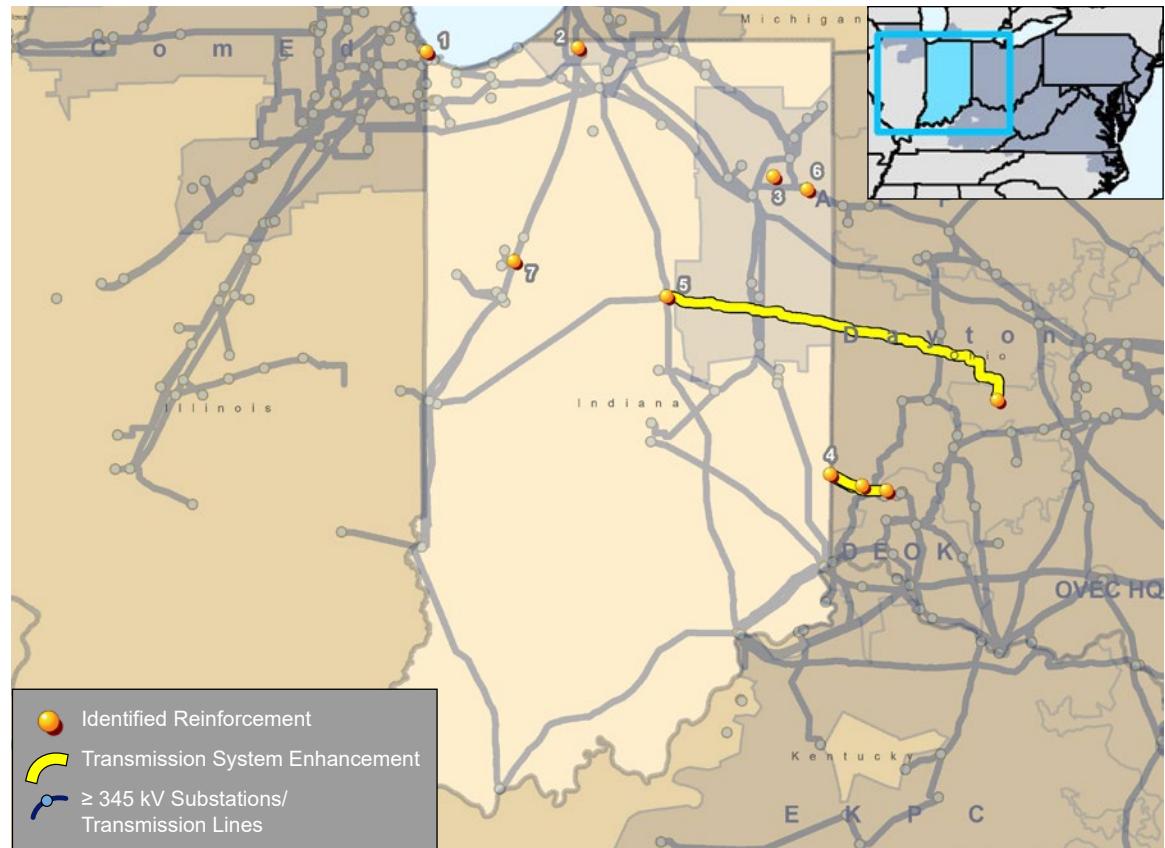
Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Rockport Unit 1	AEP	Coal	3/28/2025	12/31/2028	41	1,380
Rockport Unit 2	AEP	Coal	3/28/2025	12/31/2028	41	1,300

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**6.3.6 — Baseline Projects**

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in Indiana are summarized in **Map 6.11** and **Table 6.14**.

**Map 6.11:** Indiana Baseline Projects (Dec. 31, 2025)



**Table 6.14:** Indiana Baseline Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B3943.1	Install a new 345/138 kV transformer TR 84 and associated equipment at State Line substation. Install two 345 kV circuit breakers, one 138 kV circuit breaker and associated equipment; also replace the 138 kV BT 732 circuit breaker at State Line substation.	12/1/2030	\$20.81	ComEd	11/14/2025	No	Baseline Load Growth Deliverability & Reliability
2	B3953.1	Replace 138 kV circuit switcher XT3 with a higher fault-current-capable circuit breaker at New Carlisle.	6/1/2030	\$1.02	AEP	11/14/2025	No	Short Circuit

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Table 6.14: Indiana Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
3	B3954.1	At Thomas Road, replace 69 kV circuit switcher XT1 with a 40 kA circuit switcher.	6/1/2030	\$0.71	AEP	11/14/2025	No	TO Criteria Violation
4	B4003.1	Rebuild the College Corner (AEP)-Collinsville (DEO&K) 138 kV circuit from the OH/IN state line (tower 10P-X1-129) to Collinsville substation. AEP owns ~0.1 miles of the line from College Corner substation to the OH/IN state line. DEO&K owns the remaining 11.90 miles from the state line to Collinsville substation. The entire 11.90-mile section that DEO&K owns will be rebuilt with 954ACSS/TW conductor (@ 200C) and new double-circuit structures. The College Corner (AEP)-Trenton (DEO&K) line is on the other side of the double-circuit structure and will also be rebuilt. DEO&K will be doing a route survey to see if easement updates and/or additional structures are required.	6/1/2030	\$45.11	DEO&K	11/4/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4003.2	Rebuild parts of the College Corner (AEP)-Trenton (DEO&K) 138 kV circuit that shares a common structure with the College Corner (AEP)-Collinsville (DEO&K) circuit from the OH/IN state line (Tower 10P-X1-129) to Collinsville substation. AEP owns ~0.1 miles of the line from College Corner substation to the OH/IN state line. DEO&K owns the remaining 24.19 miles from the state line to Trenton substation. Only the 11.90-mile DEO&K section that shares a common structure with College Corner (AEP)-Collinsville (DEO&K) will be rebuilt with 954ACSS/TW conductor (@ 200C) and new double-circuit structures. The remaining sections from Collinsville-Trenton will be left untouched. DEO&K will be doing a route survey to see if easement updates and/or additional structures are required.	6/1/2030	\$13.24	DEO&K	11/4/2025	Yes (Reliability W1)	
	B4003.3	Relay Settings at College Corner station needed due to Duke rebuilding their College Corner-Collinsville 138 kV line section.	6/1/2030	\$0.06	AEP	11/4/2025	Yes (Reliability W1)	
	B4003.4	Update relay settings for the College Corner-Collinsville line at DEO&K's Collinsville substation.	6/1/2030	\$0.03	DEO&K	11/4/2025	Yes (Reliability W1)	
	B4003.5	Update relay settings for the College Corner-Trenton line at DEO&K's Trenton substation.	6/1/2030	\$0.03	DEO&K	11/4/2025	Yes (Reliability W1)	

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**Table 6.14:** Indiana Baseline Projects (Dec. 31, 2025) (Cont.)

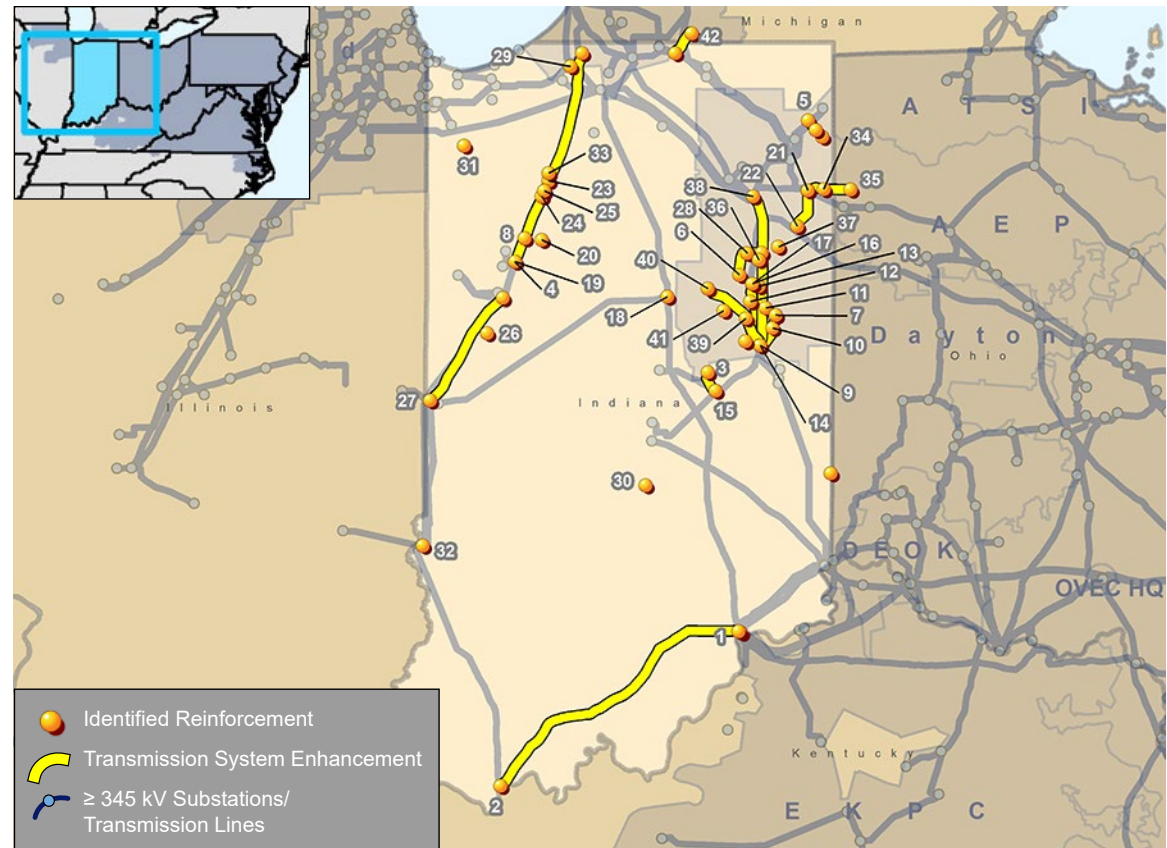
Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
5	B4068.1	Greentown 765 kV substation scope (AEP): Create a new 765 kV line position with three 100 MVAR single-phase reactors. Install two 765 kV circuit breakers.	6/1/2030	\$45.29	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.2	Greentown-Teddy 765 kV line: Construct a 60-mile 765 kV AC overhead transmission line between the existing Greentown 765 kV substation and the proposed Teddy 765 kV substation (AEP Portion). The total line length is 137 miles of the Greentown to Teddy 765 kV line.	6/1/2030	\$277.57	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.3	Greentown-Teddy 765 kV line: Construct a 49.92-mile 765 kV AC overhead transmission line between the existing Greentown 765 kV substation and the proposed Teddy 765 kV substation (AES Ohio Portion). The total line length is 137 miles of the Greentown to Teddy 765 kV line.	6/1/2030	\$230.94	GGOHLIC	1/6/2026	Yes (Reliability W1)	
	B4068.4	Greentown-Teddy 765 kV line: Construct a 27.08-mile 765 kV AC overhead transmission line between the existing Greentown 765 kV substation and the proposed Teddy 765 kV substation (ATSI Portion). The total line length is 137 miles of the Greentown to Teddy 765 kV line.	6/1/2030	\$125.28	GGOHLIC	1/6/2026	Yes (Reliability W1)	
6	B4068.31	Replace bus conductor at Allen 138 kV substation.	6/1/2030	\$0.05	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
7	B4068.38	Replace four 345 kV circuit breakers at Meadow Lake 345 kV substation.	6/1/2030	\$4.00	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
CEII	B3936.4	AEP Zone 2024W1 P5 Solution #4: Install battery chargers and associated equipment at AEP substation. Addresses the following flowglates: 2024-P5-AEP05.	6/1/2029	\$0.12	AEP	7/8/2025	No	Baseline Load Growth Deliverability & Reliability

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**6.3.7 — Network Projects**

Network projects in Indiana for 2025 are summarized in **Map 6.12** and **Table 6.15**.

**Map 6.12:** Indiana Network Projects (Dec. 31, 2025)



**Table 6.15:** Indiana Network Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	N4106.1	Replace four Clifty switches on the Jefferson-Clifty 345 kV line.	AE2-045	12/31/2022	\$0.83	AEP	10/8/2025
	N4106.4	Reconductor 0.75 miles of the Jefferson-Clifty 345 kV line.	AE2-045	12/31/2022	\$2.50	AEP	10/8/2025
	N4106.6	Replace Jefferson Breaker (5000A).	AF1-207	12/31/2022	\$1.20	AEP	10/8/2025
2	N6497.4	Replace three 3000A wave traps at Rockport and three 3000A wave traps at Jefferson on the Rockport-Jefferson 765 kV line.	AF1-322	8/15/2022	\$0.43	AEP	10/8/2025
	N6497.5	Replace 12 3000A switches at Rockport.	AF1-322	12/31/2023	\$6.00	AEP	10/8/2025

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Table 6.15: Indiana Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	N7092	Perform a sag study on the Fall Creek-Madison 138 kV line.	AF2-408	6/1/2022	\$0.03	AEP	10/8/2025
4	N7618	Replace two Meadow Lake circuit breakers (3000A).	AG1-237	12/31/2024	\$2.00	AEP	10/8/2025
	N8803	Upgrade at Meadow Lake 345 kV; reconfigure the carrier ethernet switch with one new, small form-factor transceiver at the Meadow Lake 345 kV station.	AF1-207	11/4/2026	\$0.06	AEP	10/8/2025
	N8621	Upgrade the existing Meadow Lake 345 kV station.	AF1-322	7/1/2027	\$2.23	AEP	10/8/2025
5	N8528.1	Construct a new 138 kV breaker-and-a-half station, to be operated as a three-circuit breaker ring bus, initially expandable to six circuit breakers at Varner-Sowers 138 kV.	AF1-091	6/1/2023	\$9.18	AEP	10/8/2025
	N8528.2	Transmission line tie-in at Varner-Sowers 138 kV.	AF1-091	6/1/2023	\$1.56	AEP	10/8/2025
	N8528.3	Review and revise the protective relay settings at Varner 138 kV.	AF1-091	6/1/2023	\$0.09	AEP	10/8/2025
	N8528.4	Review and revise the protective relay settings at Sowers 138 kV.	AF1-091	6/1/2023	\$0.09	AEP	10/8/2025
	N8528.5	Final tie-in for fiber: Install in new right-of-way at Varner-AF1-091 station-Sowers 138 kV.	AF1-091	6/1/2023	\$0.32	AEP	10/8/2025
6	N8531.1	Install two new steel, 80' single-circuit, single-pole dead-end structures on concrete piers with anchor bolt cages and two spans of aluminum conductor steel-reinforced cable (ACSR) 795 (Drake) transmission line conductor with #10 alumoweld shield wire at Van Buren 69 kV.	AE2-234	7/31/2021	\$0.81	AEP	10/8/2025
	N8531.2	Review and revise the protective relay settings at the Van Buren 69 kV station.	AE2-234	7/31/2021	\$0.09	AEP	10/8/2025
	N8531.3	Replace the protective relays at the Liberty Center 69 kV station, updating to accommodate the dual current differential scheme.	AE2-234	7/31/2021	\$0.24	AEP	10/8/2025
7	N8551	Review and revise the protective relay settings at Jay 138 kV to account for the additional AG1-071 generation.	AG1-017	9/30/2020	\$0.06	AEP	10/8/2025
	N8682	Protection relays review and revise (as needed) the protective relay settings at the Jay 138 kV station. Reconfigure the ICON with one new SFP transceiver at the Jay 138 kV station for communication toward the proposed AF1-268 138 kV station.	AF1-268	12/31/2027	\$0.13	AEP	10/8/2025
	N8765	For Jay CES upgrade, reconfigure the CES with one new Small Form-Factor Pluggable (SFP) transceiver at the Jay station.	AF1-202	6/10/2026	\$0.03	AEP	10/8/2025
	N8829	Review and revise the protective relay settings to account for the additional generation of AG1-047.	AG1-047	5/1/2026	\$0.06	AEP	10/8/2025
8	N8557	Construct a new 345 kV breaker-and-a-half switching station at Olive-Reynolds 345 kV, to be operated as a three-circuit breaker ring bus, initially expandable to six circuit breakers.	AE2-045	12/31/2022	\$16.43	AEP	10/8/2025
	N8558	Replace the protective relays and circuit breaker control and install a new ethernet switch at Olive 345 kV.	AE2-045	12/31/2022	\$0.85	AEP	10/8/2025
	N8559	Tie in the new AE2-045 345 kV switching station at Olive-Reynolds 345 kV.	AE2-045	12/31/2022	\$2.40	AEP	10/8/2025
	N8801	Interconnection substation tie-in: Remove one steel lattice structure along the Olive-Reynolds 345 kV circuit. Install two new steel, single-circuit, single-pole dead-end structures on concrete piers with anchor bolt cages along the existing Olive-Reynolds No. 1 (NIPSCO) 345 kV circuit. Install one new steel, single-circuit, single-pole running angle structure on a concrete pier with an anchor bolt cage along the existing Olive-Reynolds (NIPSCO) 345 kV circuit, raising the Olive-Reynolds No. 2 circuit for the Olive-Reynolds No. 1 circuit to pass underneath. Install two single-pole, single-circuit steel dead-end structures on concrete piers with anchor bolt cages along the perimeter of the proposed 345 kV switching station, four spans of double-bundle ACSR 954 (Cardinal) transmission line conductor with Guinea shield wire, cutting in the proposed 345 kV switching station in an in-and-out arrangement.	AF1-207	11/4/2026	\$3.54	AEP	10/8/2025

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Table 6.15: Indiana Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
8	N8800	New 345 kV three-breaker ring bus switching station with control relaying, one drop-in control module, nine motorized disconnect switches, six single-phase coupling capacitor voltage transformers, three each on the line exits to the proposed AE2-045 and Reynolds 345 kV stations, one line discharging ground switch, two single-phase line traps for the line exit to the proposed AE2-045 345 kV station, two single-phase station service voltage transformers, two A-frame line exit structures, one each for line exits to the proposed AE2-045 and Reynolds 345 kV stations, a dual Directional Comparison Blocking line protection relaying scheme for the line to the proposed AE2-045 345 kV station, a direct fiber-based dual current differential line protection relaying scheme for the line to the Reynolds (NIPSCO) 345 kV station, associated conductors (bus work, ground grid, jumpers), telecom terminal equipment, insulators, arresters, foundations and structures.	AF1-207	11/4/2026	\$14.37	AEP	10/8/2025
	N8802	Remote settings at Olive 345 kV: Review and revise (as needed) the protective relay settings at the Olive 345 kV station.	AF1-207	11/4/2026	\$0.07	AEP	10/8/2025
	N8900	Transmission 345 kV tie-in: Install two new 150' steel, single-circuit, single-pole dead-end structures on concrete piers with anchor bolt cages in the existing Olive-Reynolds No. 2 345 kV circuit right-of-way. Install one 170' steel, single-circuit, single-pole running angle structure on a concrete pier with an anchor bolt cage to support the Olive-Reynolds No. 1 345 kV circuit, maintaining clearances with the Olive-Reynolds No. 2 345 kV circuit. Install two spans of double-bundle ACSR 954 (Cardinal) transmission line conductor with Guinea 159 ACSR 12/7 shield wire, cutting in the new 345 kV switching station in an in-and-out arrangement.	AF2-205	3/22/2027	\$1.87	AEP	10/8/2025
	N8957	Review and revise protective relay settings at Olive 345 kV.	AF2-359	12/5/2026	\$0.07	AEP	10/8/2025
	N8979	Review and revise protective relay settings at Olive 345 kV.	AF2-132	2/9/2027	\$0.07	AEP	10/8/2025
	N9002	Transmission 345 kV tie-in: Install two 120' steel, double-circuit, single-pole dead-end structures on concrete piers with anchor bolt cages in the existing Reynolds-Olive No. 2 345 kV circuit right-of-way. Install two 120' steel, single-circuit, single-pole dead-end structures along the perimeter of the proposed new 345 kV switching station. Install four spans of double-bundle ACSR 954 (Cardinal) transmission line conductor with 7#8 alumoweld shield wire, cutting in the proposed 345 kV station in an in-and-out arrangement. Remove one existing steel lattice structure (structure No. 226).	AF2-133	2/6/2027	\$2.49	AEP	10/8/2025
9	N8681	Remote protection including one wave trap at the Desoto 138 kV station: Upgrade current remote-end protection to a dual fiber-based ICON MUX relaying scheme, two Small Form-factor Pluggable (SFP) transceivers.	AF1-268	12/31/2027	\$0.42	AEP	10/8/2025
	N8704	Final tie-in for fiber install from AF1-268-Desoto 138.	AF1-268	12/31/2027	\$0.33	AEP	10/8/2025
	N8763	Desoto upgrade 345 kV: Review and revise protective relay to match the new 345 kV switching station; install one new line trap.	AF1-202	6/10/2026	\$0.12	AEP	10/8/2025
10	N8683	Reconfigure the CES with one new SFP transceiver at the Perch 138 kV station.	AF1-268	12/31/2027	\$0.06	AEP	10/8/2025
11	N8685	Review and update relay settings at proposed AF1-202 345 kV switching station.	AF1-119	1/31/2028	\$0.07	AEP	10/8/2025
12	N8686	Reconfigure existing ethernet switch at Hartford City 69 kV station.	AF1-119	1/31/2028	\$0.06	AEP	10/8/2025
	N8687	Reconfigure existing ethernet switch at Hartford City 69 kV station.	AF1-119	1/31/2028	\$0.06	AEP	10/8/2025
	N8764	Hartford CES upgrade: Reconfigure the CES with one new SFP transceiver at the Hartford City station.	AF1-202	6/10/2026	\$0.03	AEP	10/8/2025
	N8760	New 345 kV three-breaker ring bus switching station with control relaying, one drop-in control module, nine motorized disconnect switches, one three-phase coupling capacitor voltage transformers (CCVT), three single-phase coupling capacitor voltage transformers (CCVT), two single-phase station service voltage transformers, two A-frame line exit structures, four single-phase line trap for line exit, r, two dual-directional comparison blocking for each line exit, associated conductors, telecom terminal equipment, insulators, arresters, foundations and structures.	AF1-202	6/10/2026	\$18.22	AEP	10/8/2025

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Table 6.15: Indiana Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
12	N8761	Transmission line tie-in: Remove two existing structures and install two new dead-end structures on concrete pier and anchor bolts, two additional steel single-pole dead-end structures on concrete piers with anchor bolts, four spans of double-bundle T-line conductor in an in-and-out arrangement.	AF1-202	6/10/2026	\$10.48	AEP	10/8/2025
	N8766	Install two 0.1-mile All Dielectric Loose Tube (ADLT) station exit transitions and two new fiber-optic cable paths consisting of 3.2 miles of 48-count All Dielectric Self Supporting (ADSS).	AF1-202	6/10/2026	\$0.77	AEP	10/8/2025
13	N8688	Final tie-in of fiber install at AF1-119 345 kV switching station.	AF1-119	1/31/2028	\$0.47	AEP	10/8/2025
	N8689	Review relay settings at proposed AF1-119 345 kV switching station.	AF2-162	1/31/2028	\$0.06	AEP	10/8/2025
	N8690	AF1-119 switching station tie-in to Keystone-Desoto 345 kV.	AF1-119	6/1/2022	\$1.87	AEP	10/8/2025
14	N8703	Tie the proposed 138 kV switching station into the existing Desoto-Jay circuit. Install two new steel, 85' single-circuit, single-pole dead-end structures and two spans of aluminum conductor steel-reinforced (ACSR) 795 Drake (26/7) transmission line conductor with 7#8 Alumoweld shield wire in the existing Desoto-Jay 138 kV right-of-way, cutting in the proposed 138 kV switching station in an in-and-out arrangement.	AF1-268	12/31/2027	\$1.18	AEP	10/8/2025
15	N8722	Install one new 138 kV, 3000A circuit breaker. Install two new 3000A disconnect switches. Review and revise (as necessary) the protective relay settings for the remainder of the Fall Creek 138 kV station. Replace associated conductors, telecom terminal equipment, insulators, arresters, foundations and structures.	AF2-408	12/7/2027	\$0.67	AEP	10/8/2025
16	N8748	Review and revise (as necessary) the protective relay settings at the Keystone-Desoto 345 kV station to account for the additional generation.	AF1-223	3/10/2026	\$0.06	AEP	10/8/2025
17	N8762	Keystone upgrade 345: Replace/upgrade protective relay to match the new 345 kV switching station. Install one new line trap.	AF1-202	6/10/2026	\$0.38	AEP	10/8/2025
18	N8804	Upgrade at Greentown 345 kV: Reconfigure the CES with one new SFP transceiver at the Greentown 345 kV station.	AF1-207	11/4/2026	\$0.06	AEP	10/8/2025
19	N8805	Install two new fiber-optic All Dielectric Loose Tube (ADLT) station exit transitions and two new fiber-optic cable paths consisting of 2.6 miles of 144 count ADLT cable installed in new underground right-of-way to existing splices on the Reynolds-Meadow Lake fiber cable. This installation is required to accommodate fiber-based relaying between the proposed AF1-207 and Reynolds 345 kV stations, supervisory control and data acquisition connectivity, and carrier ethernet switch connectivity.	AF1-207	11/4/2026	\$0.76	AEP	10/8/2025
20	N8806	Complete final tie-in for fiber install in new right-of-way at Monticello 345 kV.	AF1-207	11/4/2026	\$0.32	AEP	10/8/2025
21	N8846	IMTCo will review and revise (as necessary) the protective relay settings at the proposed AF1-207 345 kV station to account for the additional generation.	AF2-078	5/5/2027	\$0.06	AEP	10/8/2025
	N8854	IMTCo will review and revise (as necessary) the protective relay settings at the Allen 345 kV station to account for the additional generation.	AG1-365	12/23/2027	\$0.06	AEP	10/8/2025
	N8855	IMTCo will review and revise (as necessary) the protective relay settings at the Allen 345 kV station to account for the additional generation.	AG1-366	12/23/2027	\$0.06	AEP	10/8/2025
	N8885	Expand Magley 138 kV substation. Install one new 138 kV, 3000A circuit breaker with associated control relaying, creating a new line exit position on the western face of the 138 kV box bay. Install two new 138 kV breaker disconnect switches. Install three single-phase capacitor coupled voltage transformers (CCVT) for the new line exit to the Allen 138 kV station. Install associated conductors, insulators, arresters, foundations and structures required for the Magley 138 kV substaion expansion. Review and revise (as necessary) the protective relay settings for the remainder of the Magley 138 kV station.	AG1-232	1/19/2028	\$0.90	AEP	10/8/2025

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Table 6.15: Indiana Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
22	N8886	The Magley-Allen 138 kV circuit will be reterminated into the western face of the 138 kV box bay at the Magley 138 kV station. The circuit will then be rerouted to the north, creating sufficient clearance for the install of the new line exit to the AG1-232 generation facilities. Required facilities will include but are not limited to: Install two single-pole, single-circuit steel running angle structures on concrete piers with anchor bolt cages. Install one single-pole, single-circuit steel dead-end structure on a concrete pier with an anchor bolt cage. Install three spans of aluminum conductor steel-reinforced (ACSR) 795 (Drake) transmission line conductor with 7#8 Alumoweld shield wire. Remove one existing steel pole structure in the Magley-Allen 138 kV circuit right-of-way.	AG1-232	1/19/2028	\$0.90	AEP	10/8/2025
	N9285	Remove the existing 138/69 kV TR1 transformer. Remove the existing dual 2000 kCM strain bus assembly on the 138 kV side.	AG1-232	1/19/2028	\$0.29	AEP	10/8/2025
	N9286	Replace existing 138/69 kV TR1 transformer with a 130 MVA transformer. This replacement is required due to a criteria violation not considered under the PJM studies. AEP performs a separate study that monitors non-PJM monitored (sub-transmission) utility equipment. Move the primary station service with the new transformer. Replace the TR1 transformer low-side jumpers to reach the box bay structure.	AG1-232	1/19/2028	\$2.50	AEP	10/8/2025
23	N8892	Three 63 kA circuit breakers with associated control relaying. One 16' x 48' Drop-In Control Module (DICM). Nine motorized disconnect switches. Six single-phase coupling capacitor voltage transformers (CCVT), three each on the line exits to the proposed AF1-215 and AF2-133 345 kV stations. Two single-phase station service voltage transformers (SSVT). Two A-frame line exit structures, one each on the line exits to the proposed AF1-215 and AF2-133 345 kV stations. Two single-phase line traps on the line exit to the proposed AF1-215 345 kV station. A fiber-based Integrated Communications Optical Network Multiplexor (ICON MUX) dual current differential line protection relay scheme for the line to the proposed AF2-133 345 kV station. A Dual Directional Comparison Blocking (DCB) with Direct Transfer Trip (DTT) line protection relay scheme for the line to the proposed AF1-215 345 kV station. Associated conductors (bus work, ground grid, jumpers), telecom terminal equipment, insulators, arresters, foundations and structures.	AG1-349	9/30/2027	\$13.92	AEP	10/8/2025
	N8893	Install two All Dielectric Loose Tube (ADLT) fiber-optic cable station exit transitions. Two new fiber-optic cable paths consisting of 14.4 miles of 144 count ADLT cable installed in new underground right-of-way. This installation is required to accommodate fiber-based relaying between the new 345 kV switching station and proposed AF2-133 345 kV stations, supervisory control and data acquisition (SCADA) connectivity, and carrier ethernet switch (CES) connectivity.	AG1-349	9/30/2027	\$4.19	AEP	10/8/2025
	N8894	Remove three existing steel lattice structures (structures 205, 206 and 207). Install two new steel, single-circuit, single pole dead-end structures on concrete piers with anchor bolt cages. Install two steel, single-circuit, single pole running angle structures on concrete piers with anchor bolt cages. Install three steel, single-circuit, single pole tangent structures on concrete piers with anchor bolt cages. Install four spans of double bundle ACSR 954 (Cardinal) transmission line conductor with 7#8 alumoweld shield wire.	AG1-349	9/30/2027	\$6.20	AEP	10/8/2025
	N8895	Replace the protective relays to accommodate a fiber-based ICON MUX dual current differential line protection scheme at the proposed AF2-133 345 kV station.	AG1-349	9/30/2027	\$0.34	AEP	10/8/2025
	N8896	Review and revise the protective relay settings at the proposed AF1-215 345 kV station.	AG1-349	9/30/2027	\$0.07	AEP	10/8/2025
	N8897	Reconfigure the Carrier Ethernet Switch (CES) with a new Small Form-Factor Pluggable (SFP) transceiver at the proposed AF2-205 345 kV station.	AG1-349	9/30/2027	\$0.05	AEP	10/8/2025
	N8898	Final tie-in for fiber install in new right-of-way.	AG1-349	9/30/2027	\$0.32	AEP	10/8/2025

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Table 6.15: Indiana Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
24	N8899	Stand-alone network: New 345 kV three-breaker ring bus switching station with control relaying, one Drop-In Control Module (DICM), nine motor operated disconnect switch, two single-phase station Service Voltage Transformers (SSVT), six single-phase coupling capacitor voltage transformers (CCVT), two A-frame line exit structures, four single-phase line trap for line exit, two dual directional comparison blocking (DCB), associated conductors, telecom terminal equipment, insulators, arresters, foundations and structures.	AF2-205	3/22/2027	\$13.97	AEP	10/8/2025
	N8901	AF2-215 345 kV: Review and revise protective relay settings.	AF2-205	3/22/2027	\$0.07	AEP	10/8/2025
	N9003	AF2-215 345 kV: Review and revise protective relay settings.	AF2-133	2/6/2027	\$0.07	AEP	10/8/2025
	N8904	Fiber tie-in: Install two new All Dielectric Loose Tube (ADLT) fiber-optic cable station exit transitions and 9.4 miles of 96 count ADLT cable installed in new underground right-of-way. This installation is required to accommodate fiber-based relaying between the proposed New AF2-133 and AF2-205 345 kV switching stations, Supervisory Control and Data Acquisition (SCADA) connectivity, and carrier ethernet switch (CES) connectivity.	AF2-205	3/22/2027	\$0.32	AEP	10/8/2025
25	N8902	AF2-133 345 kV: Review and revise protective relay settings.	AF2-205	3/22/2027	\$0.39	AEP	10/8/2025
	N9004	AF2-133 345 kV: Review and revise protective relay settings.	AF2-133	2/6/2027	\$0.07	AEP	10/8/2025
	N8903	Stand-alone fiber install in new right-of-way if AF2-133 project executed: Replace the DCB line protection relay scheme for the line to the new AF1-215 345 kV switching station with a dual fiber-based Integrated Communications Optical Network Multiplexor (ICON MUX) current differential relaying scheme for the line to the proposed AF2-133 345 kV station. Remove two line traps on the line exit to the New AF1-215 345 kV switching station at the new AF2-205 345 kV switching station.	AF2-205	3/22/2027	\$2.74	AEP	10/8/2025
	N9001	Stand-alone network: New 345 kV three-breaker ring bus switching station with control relaying, one Drop-In Control Module (DICM), nine motor operated disconnect switch, two single-phase station Service Voltage Transformers (SSVT), six single-phase coupling capacitor voltage transformers (CCVT), two A-frame line exit structures, two single-phase line trap for line exit, two Dual Directional Comparison Blocking (DCB), associated conductors, telecom terminal equipment, insulators, arresters, foundations and structures.	AF2-133	2/6/2027	\$0.41	AEP	10/8/2025
	N9005	Fiber tie-in: Install two new All Dielectric Loose Tube (ADLT) fiber-optic cable station exit transitions, splicing into the new fiber-cables to be installed by the proposed AF2-205 switching station project.	AF2-133	2/6/2027	\$0.27	AEP	10/8/2025
26	N8905	Three 63 kA circuit breakers with associated control relaying. One 16' x 48' Drop-In Control Module (DICM). Nine motorized disconnect switches. Six single-phase coupling capacitor voltage transformers (CCVT), three each on the lines to the Eugene and Dequine 345 kV stations. Two single-phase station service voltage transformers (SSVT). Two A-frame line exit structures, one each on the line exits to the Eugene and Dequine 345 kV stations. Associated conductors (bus work, ground grid, jumpers), telecom terminal equipment, insulators, arresters, foundations and structures. A fiber-based Integrated Communications Optical Network Multiplexor (ICON MUX) dual current differential line protection relay scheme for the line to the Dequine station. A fiber-based Integrated Communications Optical Network Multiplexor (ICON MUX) dual current differential line protection relay scheme for the line to the Eugene station. The civil work required to develop a site that accommodates the install of the above station includes grading of a 580' x 370' pad with an assumed fall across the pad of 18' and a minimum of 200' x 24' of access road.	AG1-237	1/19/2028	\$16.46	AEP	10/8/2025
	N8906	Remove one double-circuit lattice tower along the existing Dequine-Eugene 345 kV circuit. Install two 120' new steel, single-circuit, single pole dead-end structures on concrete piers with anchor bolt cages along the existing Dequine-Eugene 345 kV circuit. Install one 120' steel, single-circuit, single pole running angle structure on a concrete pier with an anchor bolt cage to support the Dequine-Sullivan 345 kV circuit, maintaining clearances to the Dequine-Eugene 345 kV circuit. Install two spans of double bundle ACSR 954 (Cardinal) transmission line conductor with ACSR Guinea shield wire, cutting in the proposed 345 kV station in an in-and-out arrangement.	AG1-237	1/19/2028	\$1.87	AEP	10/8/2025

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Table 6.15: Indiana Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
27	N8907	IMTCo will review and revise (as needed) the protective relay settings at the Dequine 345 kV station. IMTCo will reconfigure the existing carrier ethernet switch (CES) and dual ICON MUX, installing three new transceivers at the Dequine station. IMTCo will upgrade the existing relays at the Dequine 345 kV station by installing a new dual fiber-based ICON MUX current differential protection scheme.	AG1-237	1/19/2028	\$0.50	AEP	10/8/2025
	N8908	IMTCo will review and revise (as needed) the protective relay settings at the Eugene 345 kV station. IMTCo will upgrade the existing relays at the Eugene 345 kV station by installing a new dual fiber-based ICON MUX current differential protection scheme. IMTCo will reconfigure the existing carrier ethernet switch (CES) and dual ICON MUX, installing three new transceivers at the Eugene station.	AG1-237	1/19/2028	\$0.49	AEP	10/8/2025
	N8909	IMTCo will install two new fiber-optic cable station exit transitions to new splices on the existing Eugene-Dequine 345 kV OPGW. This installation is required to accommodate ICON MUX relaying between the proposed AG1-237, Eugene and Dequine 345 kV stations, supervisory control and data acquisition (SCADA) connectivity, and carrier ethernet switch (CES) connectivity.	AG1-237	1/19/2028	\$0.30	AEP	10/8/2025
	N9051	Expand existing Dequine 345 kV substation.	AG1-555	1/31/2028	\$1.45	AEP	10/8/2025
28	N8947	Install two new fiber optic cable paths consisting of 0.5 miles of 48 count ADLT cable installed in new underground right-of-way and associated terminating equipment and devices (transceivers, multiplexors, routers).	AE2-234	5/15/2027	\$0.40	AEP	10/8/2025
29	N8956	New AF2-359 345 kV switching station tie-in.	AF2-359	12/5/2026	\$2.12	AEP	10/8/2025
30	N8977	(Oversight) Stand-alone network: New 345 kV three-breaker ring bus switching station with control relaying, one Drop-In Control Module (DICM), nine motor operated disconnect switch, one phase-to-ground switch, two single-phase station service voltage transformers (SSVT), six single-phase coupling capacitor voltage transformers (CCVT), two A-frame line exit structures, four single-phase line trap for line exits, two dual directional comparison blocking (DCB), two A-frame line exit structures, associated conductors, telecom terminal equipment, insulators, arresters, foundations and structures.	AF2-132	2/9/2027	\$0.41	AEP	10/8/2025
	N8978	Transmission 345 kV tie-in: Two new 130' custom steel, single-circuit, three-pole dead-end structures on concrete piers with anchor bolt cages, one new 140' custom steel, single-circuit, single-pole dead-end structure on a concrete pier with an anchor bolt cage, two spans of aluminum conductor steel reinforced (ACSR) 2156 (Bluebird) transmission line conductor with ACSR 159 (Guinea) shield wire.	AF2-132	2/9/2027	\$2.74	AEP	10/8/2025
31	N8980	AE2-045 345 kV: Review and revise protective relay settings.	AF2-132	2/9/2027	\$0.07	AEP	10/8/2025
32	N8987	IMPCo will review and revise (as necessary) the protective relay settings at the Sullivan 345 kV station to account for the additional generation.	AE2-276	1/26/2028	\$0.06	AEP	10/8/2025
33	N9022	Review and revise the protective relay settings at the new AF2-132 switching station to account for additional generations.	AG1-302	1/15/2028	\$0.06	AEP	10/8/2025
34	N9054	Upgrade the existing Tillman 138 kV switching station.	AG1-368	3/2/2028	\$2.62	AEP	10/8/2025
	N9058	Expand to the south and east by roughly 120' x 60' including civil pad work, fencing and ground grid.	AG1-368	3/2/2028	\$0.61	AEP	10/8/2025
35	N9055	Allen-Timber switch 138 kV circuit reroute.	AG1-368	3/2/2028	\$1.00	AEP	10/8/2025
	N9057	Reconfigure the existing ICON and review and revise the protective relay settings plus replace aluminum conductor jumper.	AG1-368	3/2/2028	\$0.08	AEP	10/8/2025
36	N9065	Reconfigure the existing CES, installing one new transceiver at Hartford 345 kV	AF1-118	12/29/2028	\$0.06	AEP	10/8/2025
	N9067	Final fiber tie-in at the new 345 kV switching station.	AF1-118	12/29/2028	\$0.32	AEP	10/8/2025
37	N9066	Reconfigure the existing CES, installing one new transceiver at Bluffton 345 kV.	AF1-118	12/29/2028	\$0.06	AEP	10/8/2025

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**Table 6.15:** Indiana Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
38	N9068	New 345 kV switching station tie-in to Sorenson-Desoto 345 kV.	AF1-118	12/29/2028	\$1.87	AEP	10/8/2025
	N9069	Review and revise the protective relay settings and install one single-phase line trap on the line exit at Desoto 345 kV.	AF1-118	12/29/2028	\$0.15	AEP	10/8/2025
	N9070	Review and revise the protective relay settings and install one single-phase line trap on the line exit at Sorenson 345 kV.	AF1-118	12/29/2028	\$0.15	AEP	10/8/2025
39	N9079	Expand Mississinewa substation property and remove existing equipment.	AG1-414	1/31/2028	\$0.90	AEP	10/8/2025
	N9080	Upgrade the existing Mississinewa 138 kV station for interconnection of PJM queue project AG1-414.	AG1-414	1/31/2028	\$3.88	AEP	10/8/2025
40	N9081	Modify the existing Deer Creek-Wes Del 138 kV circuit, raising the circuit to accommodate the crossing of the generation lead circuit underneath.	AG1-414	1/31/2028	\$1.85	AEP	10/8/2025
	N9082	Upgrade the protective relaying at the Deer Creek substation.	AG1-414	1/31/2028	\$0.40	AEP	10/8/2025
41	N9083	Upgrade the protective relaying at the proposed AE1-207 138 kV switching station.	AG1-414	1/31/2028	\$0.36	AEP	10/8/2025
42	N7017	Perform a sag study on the 7.8 mile section of ACSR 477 26/7 HAWK on the Mottv-E Elkhart 138 kV line.	AF2-389	10/31/2023	\$0.03	AEP	10/8/2025

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Table 6.16: Indiana Supplemental Projects (Dec. 31, 2025)

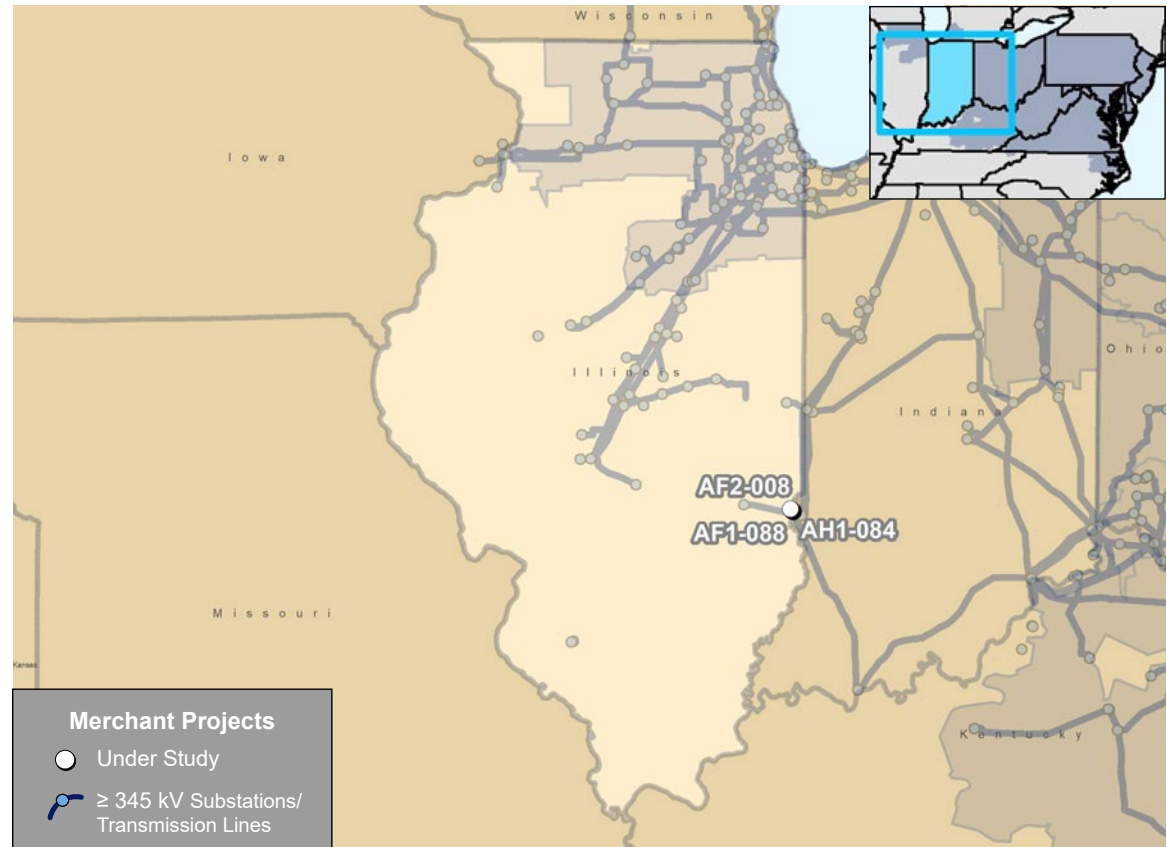
Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S3588.1	Construct a new station in a breaker-and-a-half configuration consisting of 16 345 kV, 5000A 63 kA breakers, six 345 kV meters, and station fiber cable to serve 550 MW of new load. Construct six 345 kV bus ties from AEP's Larrison Drive 345 kV station to the customer station. Cut in the Elderberry-Dumont and Dumont-Olive Bypass 345 kV line into the new station.	12/15/2026	\$70.38	AEP	10/8/2024
	S3588.2	New station to be constructed in a breaker-and-a-half configuration consisting of 16 345 kV, 5000A 63 kA breakers, six 345 kV meters and station fiber cable. Construct six bus ties from AEP's New Prairie 345 kV station to the customer station. Cut in the Elderberry-Dumont and Dumont-Olive Bypass 345 kV line into the new station.	12/15/2026	\$79.53	AEP	10/8/2024
	S3588.3	Remote end settings work at Elderberry station to facilitate the construction of Larrison Drive and New Prairie 345 kV stations.	12/15/2026	\$1.72	AEP	10/8/2024
	S3588.4	Remote end work at Dumont station to facilitate the construction of Larrison Drive and New Prairie 345 kV stations.	12/15/2026	\$1.72	AEP	10/8/2024
	S3588.5	Remote end work at Sorenson station to facilitate the construction of Larrison Drive and New Prairie 345 kV stations.	12/15/2026	\$1.72	AEP	10/8/2024
	S3588.7	Replace overdutied 345 kV circuit breakers B, B1, B2, D1 and D2. Bring in the Olive Bypass (Dumont-Sorenson 345 kV circuit) and install three new 345 kV circuit breakers for new "C" string.	5/1/2026	\$29.29	AEP	10/8/2024
	2	S3591.1	Install one 138 kV circuit breaker to at Charger station. Install two 138/12kV distribution banks with feeders at Charger station.	9/14/2027	\$1.60	AEP
S3591.2		Retire 138/12kV Ligonier station and remove ~0.25 miles of 138 kV transmission line from Charger-Ligonier station.	9/14/2027	\$0.40	AEP	10/18/2024
3	S3594.1	Rebuild ~68.1 miles of double-circuit 345 kV on centerline. Costs include transmission line removal, OPGW and right-of-way.	5/30/2031	\$452.64	AEP	12/3/2024
4	S3595.1	Rebuild ~2.4 miles of 34.5 kV line (built to 69 kV line standards) between Spy Run and Bass. Costs include removal and right-of-way. This line rebuild is in an urban area with distribution underbuild. Additionally, there is an existing 138 kV/34.5 kV line crossing with the Industrial Park-Spy Run 138 kV transmission line, to accommodate the 69 kV line rebuild two 138 kV towers will need to be raised for the crossing.	3/17/2028	\$6.76	AEP	1/17/2025
5	S3632.1	Construct 15 miles of new 345 kV line between AEP's Elderberry substation and NIPSCO's Stillwell substation. This line will be a MISO facility and has been studied through MISO's planning process. It is being submitted to facilitate study coordination between the two RTOs.	12/31/2028	\$0.00	WVPA	4/1/2025
	S3632.2	Expand the Elderberry 345 kV bus to add a new line terminal. This terminal will transition to a MISO facility following completion of the project.	12/31/2028	\$0.00	WVPA	4/1/2025
6	S3723.1	345 kV relay upgrades due to the Fall Creek station circuit breaker install.	5/27/2026	\$1.18	AEP	7/8/2025
	S3723.2	Install telecom at Aladdin station for the area.	5/27/2026	\$0.20	AEP	7/8/2025
	S3723.3	Install three 345 kV, 63 kA breakers in the current "K" string. Extend 345 kV bus. Remove 345 kV switch.	5/27/2026	\$7.95	AEP	7/8/2025

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**6.3.9 — Merchant Transmission Project Requests**

As of Dec. 31, 2025, PJM's queue contained three merchant transmission project requests with a terminal in Indiana as shown in **Map 6.14** and **Table 6.17**.

**Map 6.14:** Indiana Merchant Transmission Project Requests (Dec. 31, 2025)



**Table 6.17:** Indiana Merchant Transmission Project Requests (Dec. 31, 2025)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AF1-088	Sullivan 345 kV	AEP	Active	12/31/2025	1,000
AF2-008					2,000
AH1-084					500

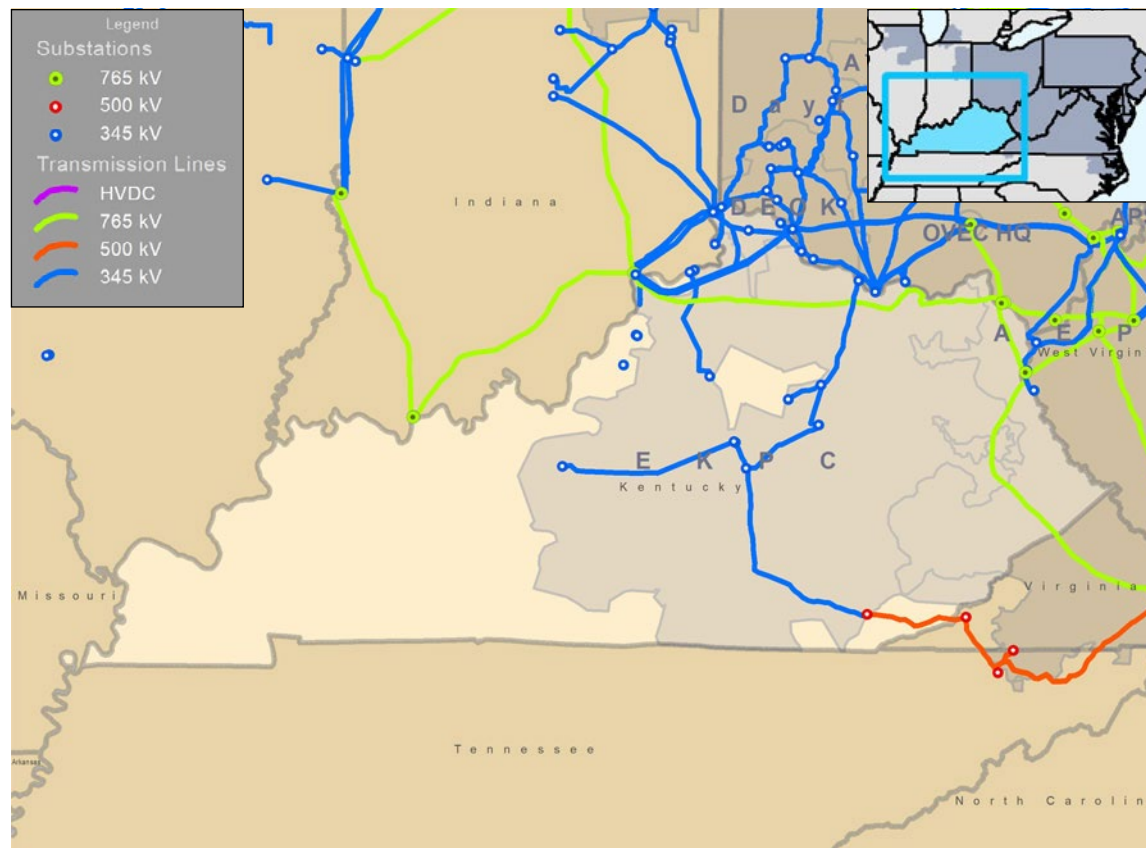
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## 6.4: Kentucky RTEP Summary

### 6.4.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Kentucky, including facilities owned and operated by American Electric Power (AEP), Duke Energy Ohio and Kentucky (DEO&K), and East Kentucky Power Cooperative (EKPC) as shown on **Map 6.15**. Duke Energy Ohio and Kentucky owns the Duke transmission delivery facilities in Kentucky rated over 69 kV. Kentucky's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

Map 6.15: PJM Service Area in Kentucky

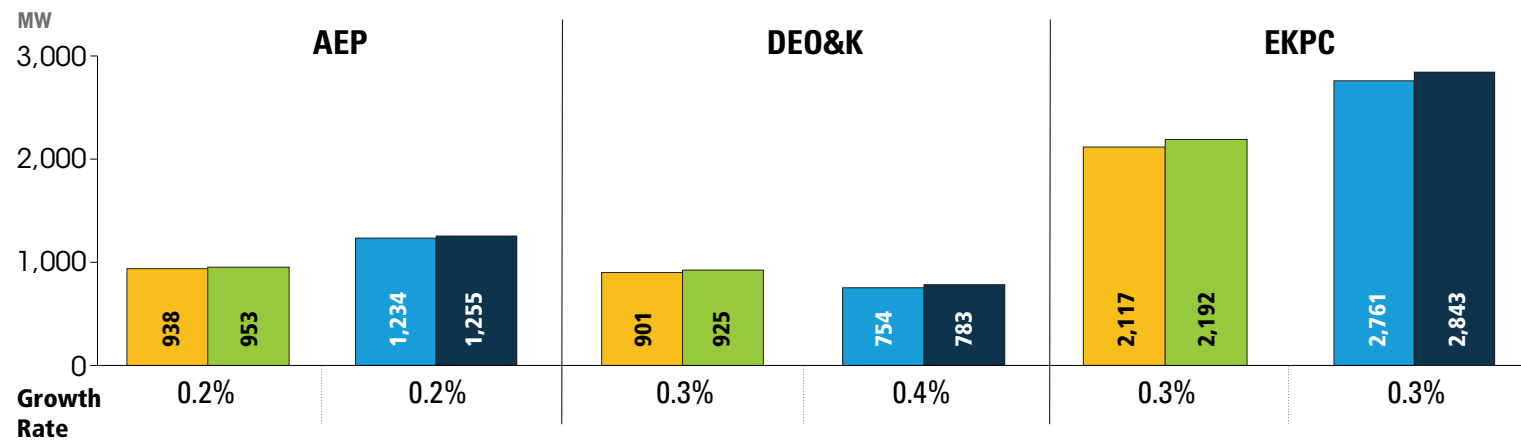


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### 6.4.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.16** summarizes the expected loads within the state of Kentucky and across the PJM region.

**Figure 6.16:** Kentucky – 2025 Long-Term Load Forecast



PJM RTO Summer Peak		PJM RTO Winter Peak	
2025	2035	2024/2025	2034/2035
154,144	209,923	136,127	198,175
MW	MW	MW	MW
Growth Rate 3.1%		Growth Rate 3.8%	

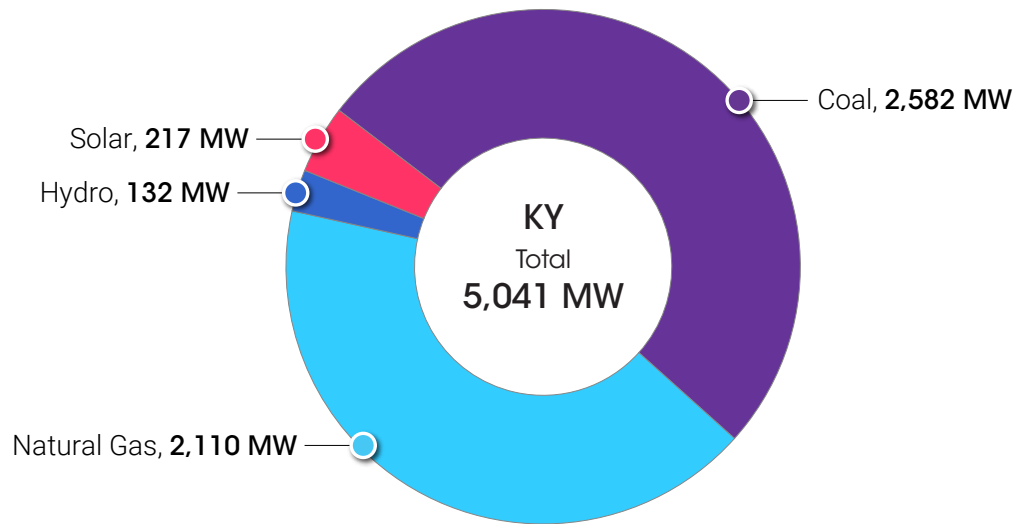
PJM notes that AEP and DEO&K serve load other than in Kentucky. The summer and winter peak megawatt values in this figure each reflect an estimated amount of forecasted load to be served by each of those transmission owners solely in Kentucky. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Kentucky over the past five years.

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**6.4.3 — Existing Generation**

Existing generation in Kentucky as of Dec. 31, 2025, is shown by fuel type in **Figure 6.17**.

**Figure 6.17:** Kentucky – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



**6.4.4 — Interconnection Requests**

In Kentucky, as of Dec. 31, 2025, 64 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.18**, **Table 6.19**, **Figure 6.18**, **Figure 6.19** and **Figure 6.20**.

**Table 6.18:** Kentucky – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

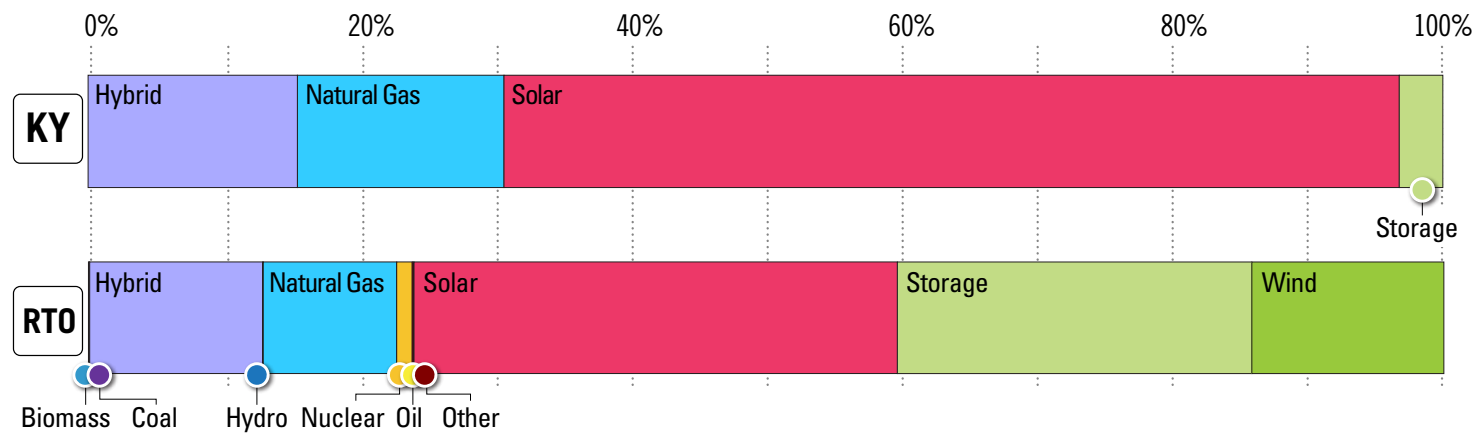
	Kentucky Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
<b>Biomass</b>	0.0	0.00%	10.0	0.01%
<b>Coal</b>	0.0	0.00%	14.0	0.01%
<b>Hybrid</b>	770.5	15.47%	14,332.3	12.76%
<b>Hydro</b>	0.0	0.00%	30.0	0.03%
<b>Natural Gas</b>	759.0	15.24%	11,082.0	9.87%
<b>Nuclear</b>	0.0	0.00%	1,305.9	1.16%
<b>Oil</b>	0.0	0.00%	50.0	0.04%
<b>Other</b>	0.0	0.00%	56.3	0.05%
<b>Solar</b>	3,292.1	66.09%	40,116.0	35.73%
<b>Storage</b>	160.0	3.21%	29,376.0	26.16%
<b>Wind</b>	0.0	0.00%	15,910.7	14.17%
<b>Grand Total</b>	<b>4,981.6</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

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**Table 6.19:** Kentucky – Interconnection Requests by Fuel Type (Dec. 31, 2025)

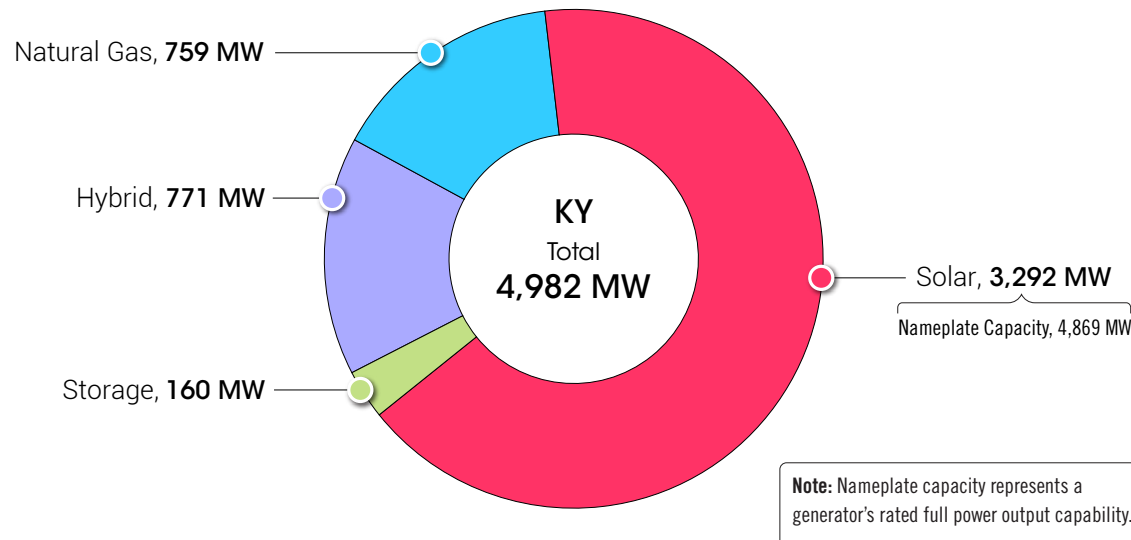
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity MW	Projects	Capacity MW	Projects	Capacity MW	Projects	Capacity MW	Projects	Capacity MW	Projects	Capacity MW
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	0	0.0	6	2,969.0	6	2,969.0
	Natural Gas	1	759.0	0	0.0	0	0.0	5	71.0	8	3,020.7	14	3,850.7
	Storage	1	100.0	0	0.0	1	60.0	0	0.0	14	848.2	16	1,008.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	5	198.5	5	198.5
	Hybrid	13	706.9	0	0.0	1	63.6	0	0.0	23	1,442.2	37	2,212.7
	Hydro	0	0.0	0	0.0	0	0.0	0	0.0	1	70.0	1	70.0
	Solar	31	2,255.4	3	171.9	13	864.9	5	132.3	97	5,331.2	149	8,755.7
	Wind	0	0.0	0	0.0	0	0.0	0	0.0	2	27.3	2	27.3
	<b>Grand Total</b>		<b>46</b>	<b>3,821.2</b>	<b>3</b>	<b>171.9</b>	<b>15</b>	<b>988.5</b>	<b>10</b>	<b>203.3</b>	<b>156</b>	<b>13,907.1</b>	<b>230</b>

**Figure 6.18:** Kentucky – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

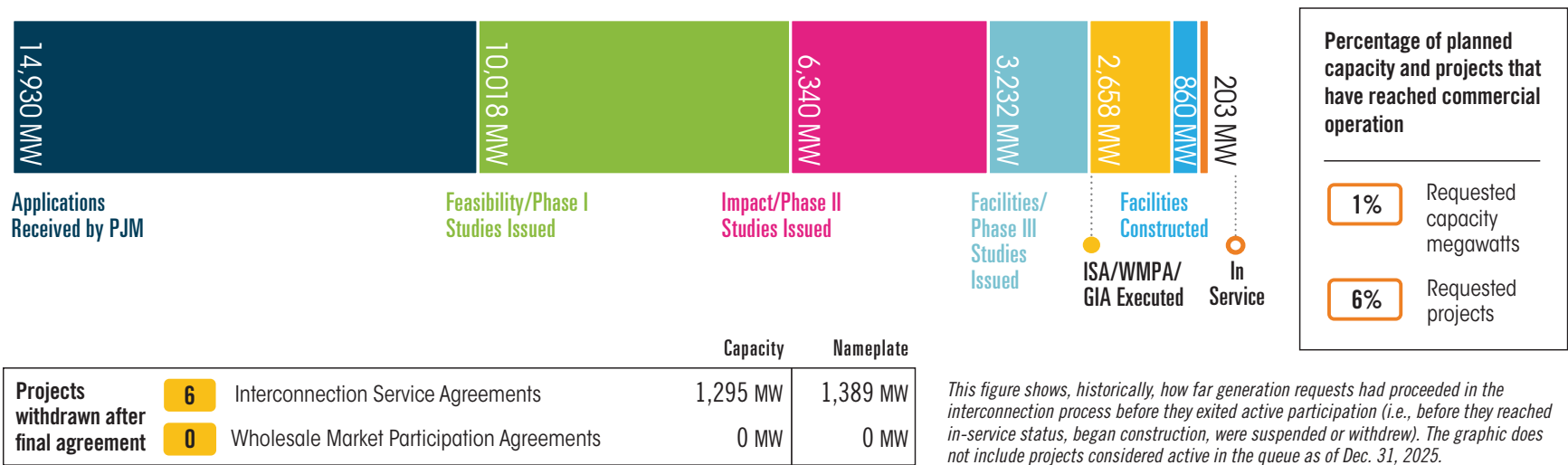


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**Figure 6.19:** Kentucky Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.20:** Kentucky Progression of Interconnection Requests (Dec. 31, 2025)

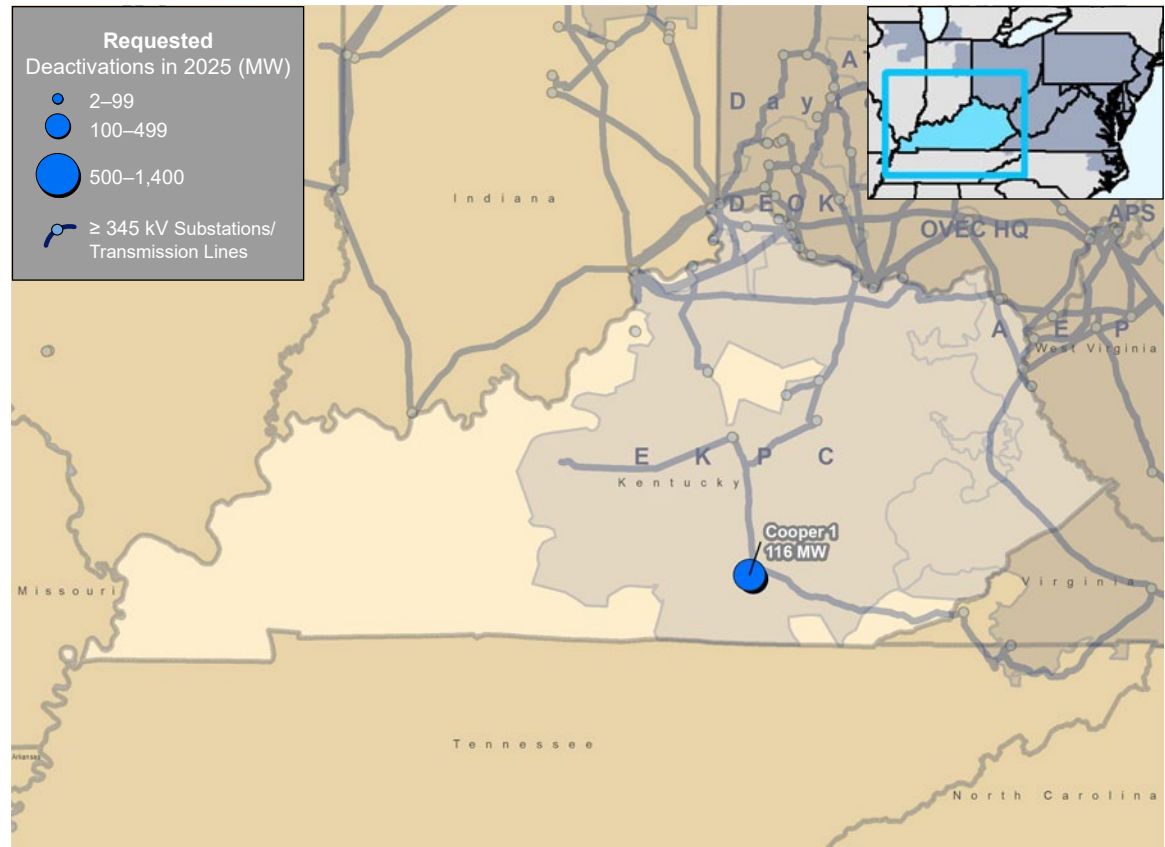


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**6.4.5 — Generation Deactivation**

Formal generator deactivations and requests received by PJM in Kentucky between Jan. 1, 2025, and Dec. 31, 2025, are summarized in **Map 6.16** and **Table 6.20**.

**Map 6.16:** Kentucky Generation Deactivations (Dec. 31, 2025)



**Table 6.20:** Kentucky Generation Deactivations (Dec. 31, 2025)

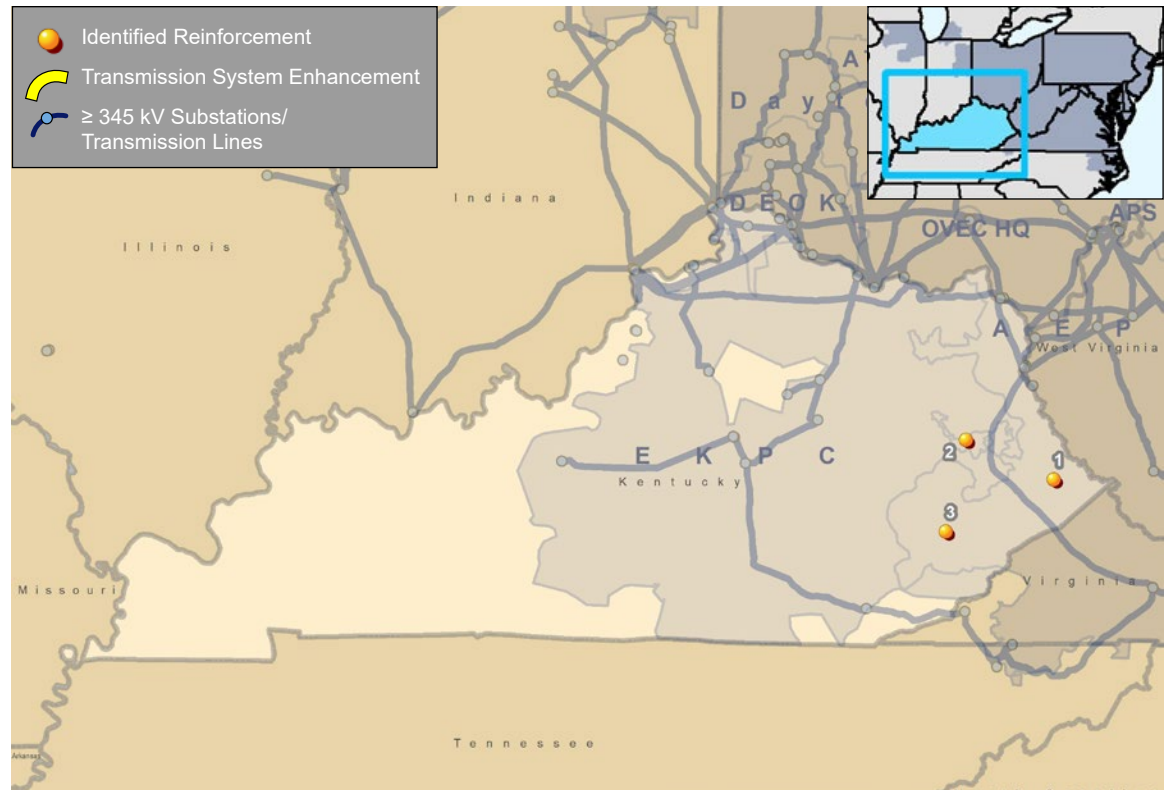
Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Cooper 1	EKPC	Coal	5/13/2025	12/31/1930	60	116

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**6.4.6 — Baseline Projects**

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in Kentucky are summarized in **Map 6.17** and **Table 6.21**.

**Map 6.17: Kentucky Baseline Projects (Dec. 31, 2025)**



**Table 6.21: Kentucky Baseline Projects (Dec. 31, 2025)**

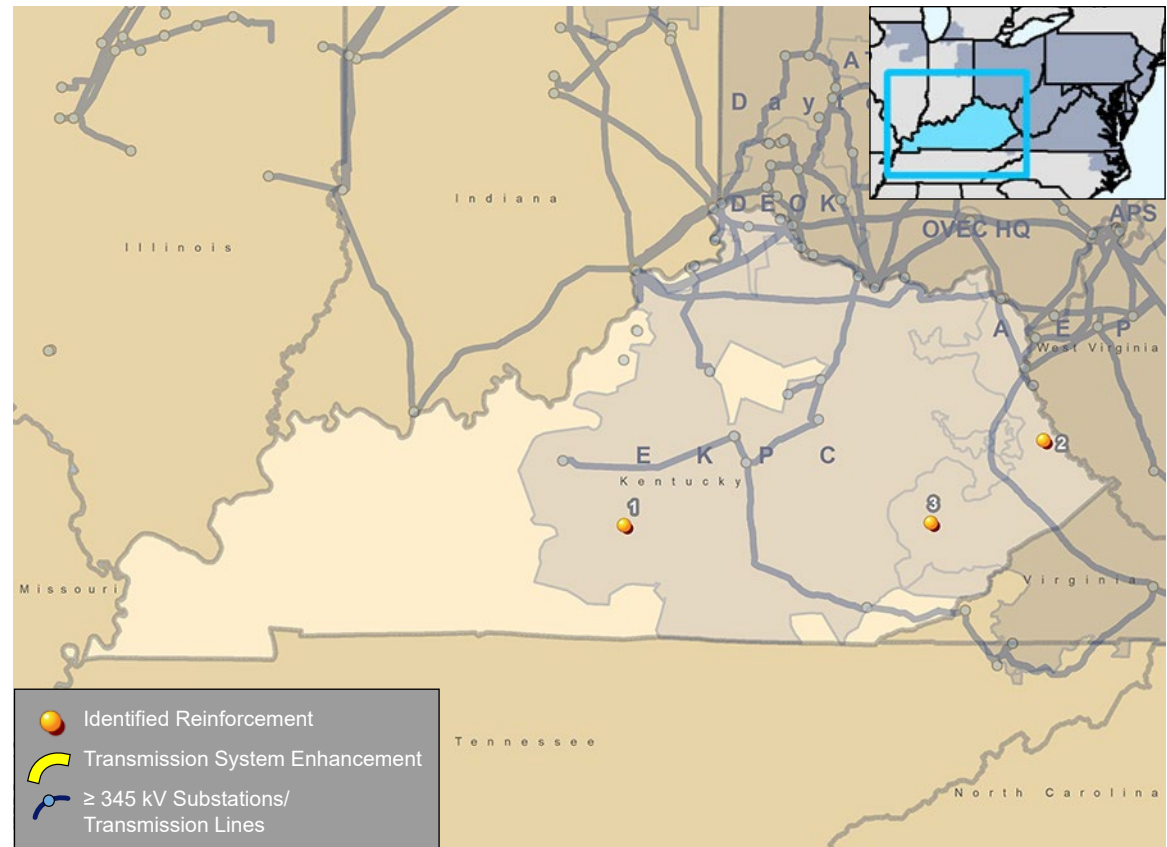
Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B3948.1	Replace the existing 9.6 MVAR 69 kV capacitor bank at Johns Creek station with a 17.2 MVAR capacitor bank. Circuit switcher "AA" will also be replaced.	4/15/2030	\$1.48	AEP	11/14/2025	No	TO Criteria Violation
2	B3951.1	To solve the voltage violations, a 69 kV circuit switcher and an 11.5 MVAR capacitor bank will be installed on the 69 kV bus at Falcon station. Falcon station will need to be expanded to fit the capacitor bank.	4/15/2030	\$3.35	AEP	11/14/2025	No	TO Criteria Violation
3	B3974.1	Replace circuit breaker "R" with a new 69 kV, 40 kA circuit breaker at Hazard substation.	6/1/2030	\$0.85	AEP	11/14/2025	No	TO Criteria Violation

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### 6.4.7 — Network Projects

Network projects in Kentucky for 2025 are summarized in **Map 6.18** and **Table 6.22**.

**Map 6.18:** Kentucky Network Projects (Dec. 31, 2025)



**Table 6.22:** Kentucky Network Projects (Dec. 31, 2025)

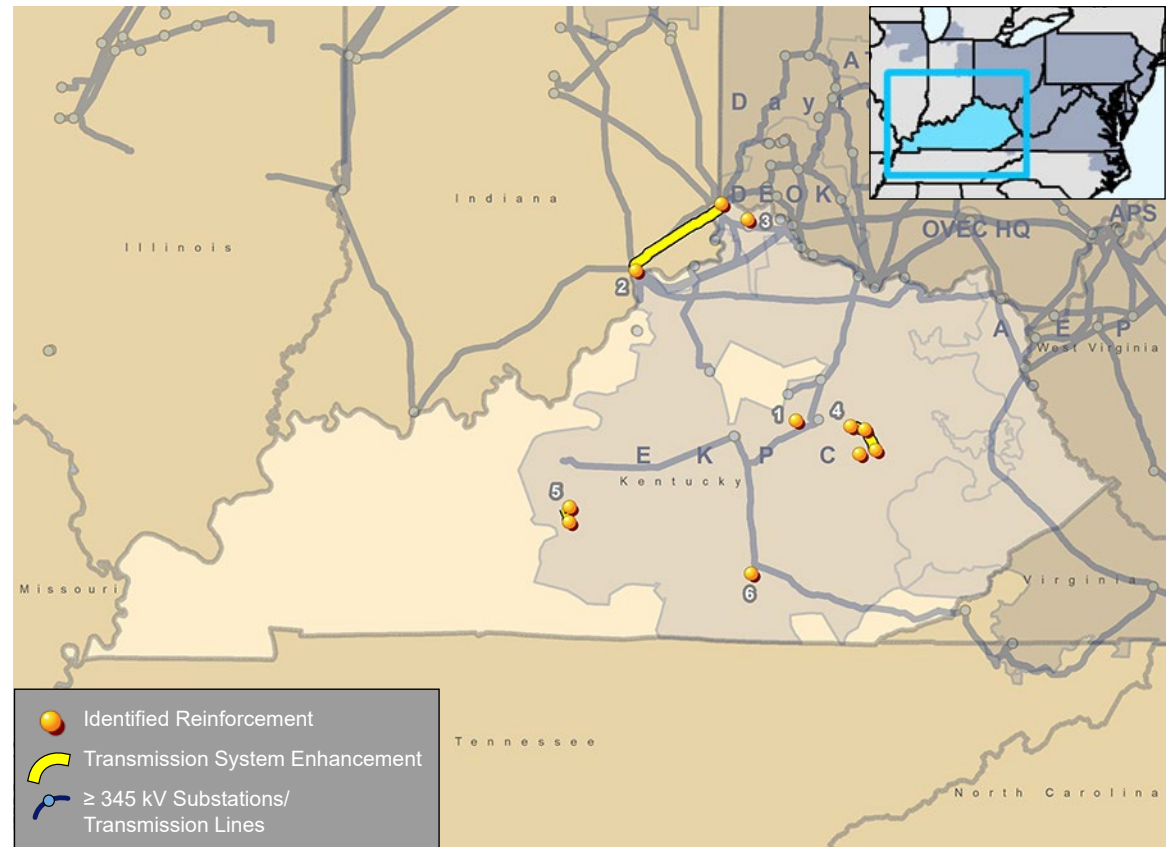
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	N8396	Replace the existing Green County 161/69 kV, 93 MVA transformer with a 150 MVA transformer.	AG1-351	12/31/2024	\$2.28	EKPC	10/8/2025
2	N8633.0	Upgrade the existing Inez 138 kV station.	AF2-018	3/30/2028	\$1.76	AEP	10/8/2025
	N9084.0	KPCo will review and revise the protective relay settings at the Inez 138 kV station.	AF1-162	2/29/2028	\$0.06	AEP	10/8/2025
3	N8788.0	Install one 16' x 12' drop-in control module, relocate the circuit breaker "D" bus side disconnect switch.	AG1-066	1/22/2027	\$0.38	AEP	10/8/2025

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**6.4.8 — Supplemental Projects**

Supplemental projects included in the 2025 Local Plan in Kentucky are summarized in **Map 6.19** and **Table 6.23**.

**Map 6.19:** Kentucky Supplemental Projects (Dec. 31, 2025)



**Table 6.23:** Kentucky Supplemental Projects (Dec. 31, 2025)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S2873.1	Rebuild the Dale substation as a 138 kV transmission station only, retiring the last remaining 69 kV transmission equipment at the station.	6/1/2029	\$8.80	EKPC	10/18/2024

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Table 6.23: Kentucky Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
2	S3598.1	Retire the 138 kV feeder from Miami Fort (Duke Energy)-Clifty Creek (OVEC). This line is 93 years old, 47 miles long, and constructed of single-circuit lattice towers with 336 ACSR conductor. Near Petersburg, Kentucky a 2,000-foot section of static failed dropping onto the B phase conductor. The breaker at Clifty Creek opened due to the fault. The protection at Miami Fort failed to operate, which caused B phase to see 900 amps. The line is rated at 542 amps. After fifteen minutes, nine miles west of the initial static failure, a B phase conductor failed falling to the ground. Flexing of the towers snapped two statics. 3,700 feet of line is damaged at this location. An analysis of the failed conductor was performed. Visual inspection found extensive corrosion and pitting on the outer conductor. Rust was noted to various degrees on the steel core. Tensile testing on the core showed breaking strength ~26% lower than the ASTM requirement. Zinc coating was found to have an area density 15% lower than the required minimum. We believe these test results to be indicative of the condition of the remaining line.	12/31/2026	\$39.00	DEO&K	9/20/2024
3	S3600.1	Build a new substation, Turfway, with a four-breaker ring bus with nonadjacent feeders supplying two 138/34 kV, 22.5 MVA transformers with two distribution exits each. Intercept the Donaldson-Woodspoint 138 kV circuit looping it through Turfway. The total length of new feeder and right-of way is ~two miles.	7/25/2029	\$13.00	DEO&K	3/14/2025
4	S3689.1	Rebuild the Powell County-Bowen-High Rock-Zachariah 69 kV line section.	12/31/2029	\$16.56	EKPC	10/18/2024
5	S3690.1	Construct a 69/25 kV, 12/16/20 MVA distribution substation ("Cub Run").	12/31/2026	\$0.00	EKPC	10/18/2024
	S3690.2	Construct a new 11.4 mile 69 kV transmission line from EKPC's Bonnieville substation to serve the Cub Run distribution substation.	12/31/2026	\$0.00	EKPC	10/18/2024
	S3690.3	Construct a new 69 kV box structure, install three new 69 kV breakers and reconfigure Bonnieville 69 kV circuits to accommodate the Cub Rub circuit.	12/31/2026	\$1.58	EKPC	10/18/2024
6	S3692.1	Install a new 40.818 MVAR capacitor bank at Cooper 69 kV substation.	6/1/2026	\$0.66	EKPC	12/13/2024

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## 6.5: Maryland/District of Columbia RTEP Summary

### 6.5.1 — RTEP Context

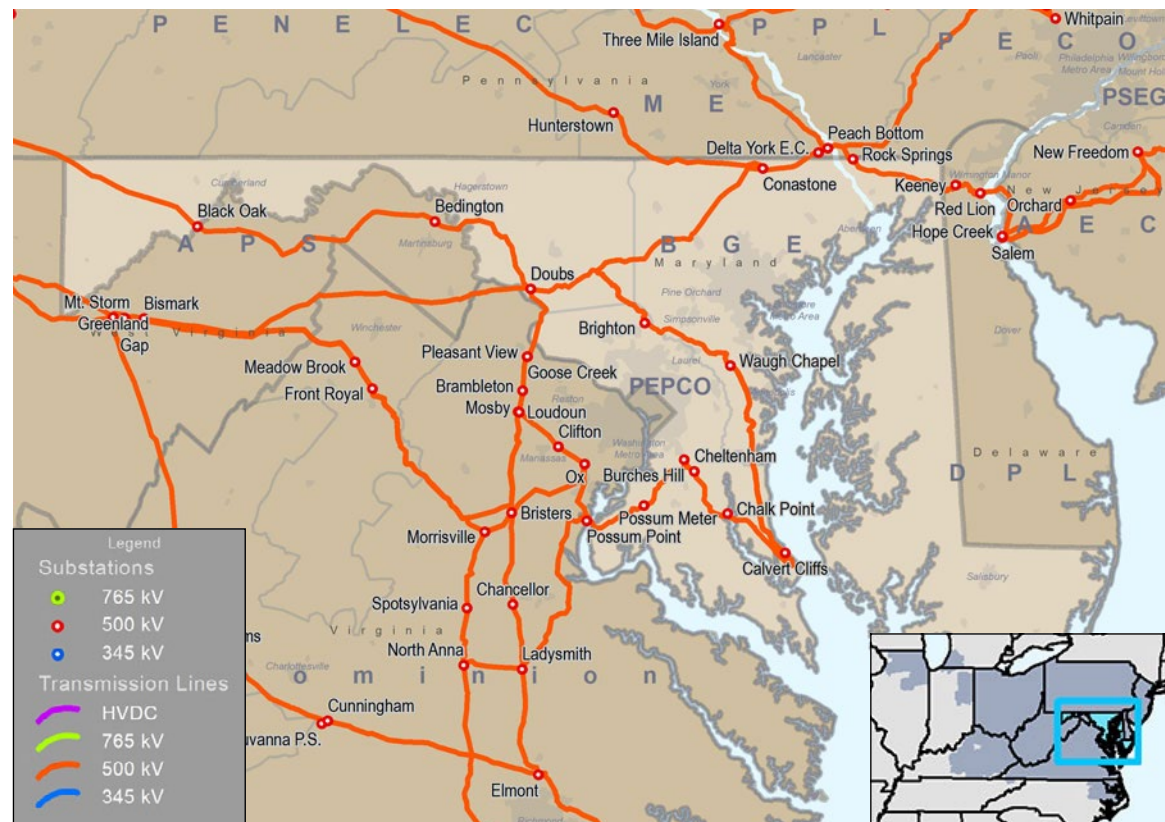
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Maryland and the District of Columbia, including facilities owned and operated by Allegheny Power (FirstEnergy) (AP), Baltimore Gas and Electric (BGE), Delmarva Power (DP&L), Potomac Electric Power Company (PEPCO) and Southern Maryland Electric Cooperative (SMECO) as shown on **Map 6.20**. Maryland and the District of Columbia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

### Renewable Portfolio Standards

Maryland has a mandatory renewable portfolio standard (RPS) target of 50% Tier 1 renewable resources by 2030. This includes a solar carve-out target of at least 14.5% by 2030, which must come from in-state solar resources. The state also requires 2.5% Tier 2 renewable resources each year. In 2024, Gov. Moore signed an executive order targeting 100% clean electricity by 2035.

Maryland is advancing offshore wind to support its clean energy policies and has awarded offshore wind renewable energy credits (ORECs) to projects totaling 2,022.5 MW. In 2023, Maryland enacted the Maryland POWER Act. The POWER Act increased the state's offshore wind target to 8,500 MW by 2031. The POWER Act also directs the Maryland Public Service Commission and

**Map 6.20:** PJM Service Area in Maryland/District of Columbia



Maryland Energy Administration to work with PJM in exploring competitive transmission solutions that support the state's offshore wind facilities.

Maryland is also pursuing decarbonization through additional efforts. In 2022, Maryland enacted the Climate Solutions Now Act, which calls for Maryland to reduce statewide greenhouse gas emissions 60% from 2006 levels by 2031 and reach statewide net-zero emissions by 2045. In 2023, Maryland

enacted H.B. 910, which established an energy storage target of 3,000 MW by 2033.

The District of Columbia has a mandatory renewable portfolio standard (RPS) target of 100% by 2032. The District's RPS target is one of two in the PJM region set at 100%, with the other being Virginia's RPS. The resources serving D.C.'s RPS target must be located within the PJM region. The RPS target also includes a solar carve-out target of 9% by 2032 and 15% by 2041.

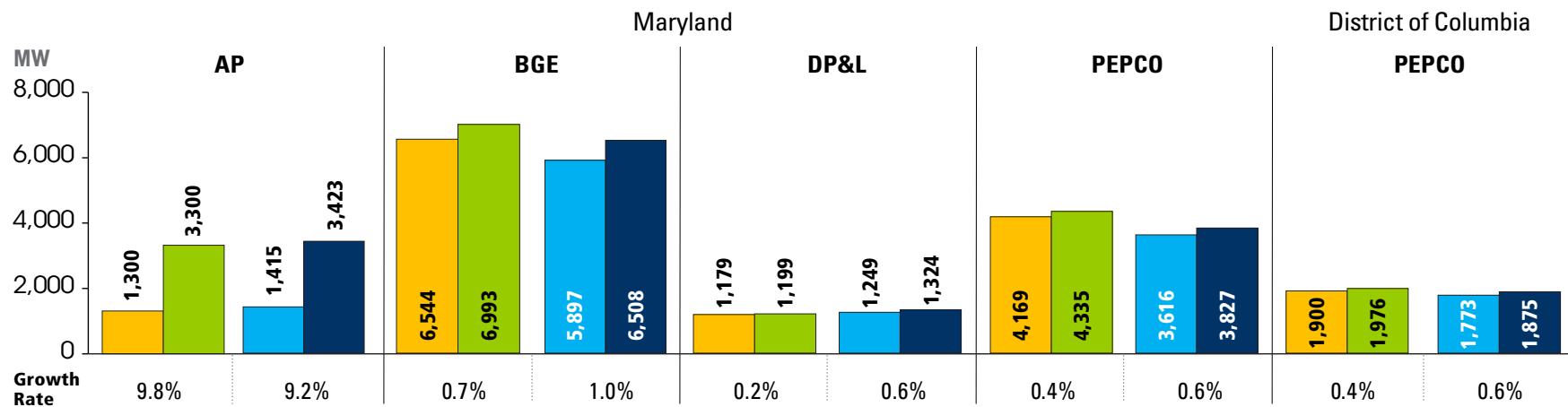
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### 6.5.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses.

**Figure 6.21** summarizes the expected loads within the state of Maryland and the District of Columbia and across the PJM region.

**Figure 6.21:** Maryland/District of Columbia – 2025 Long-Term Load Forecast



PJM RTO Summer Peak		PJM RTO Winter Peak	
2025	2035	2024/2025	2034/2035
154,144 MW	209,923 MW	136,127 MW	198,175 MW
Growth Rate 3.1%		Growth Rate 3.8%	

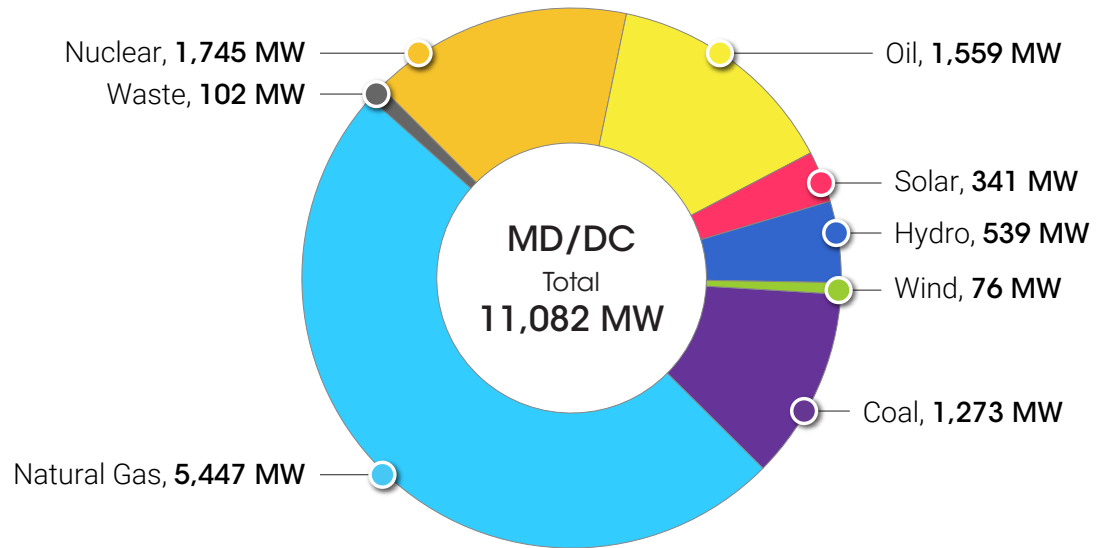
PJM notes that AP, DP&L serve load other than in Maryland, and PEPCO serves load other than in the District of Columbia. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in Maryland, as well as for PEPCO solely in the District of Columbia. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Maryland the District of Columbia over the past five years.

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**6.5.3 — Existing Generation**

Existing generation in Maryland and the District of Columbia as of Dec. 31, 2025, is shown by fuel type in **Figure 6.22**.

**Figure 6.22:** Maryland/District of Columbia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



**6.5.4 — Interconnection Requests**

In Maryland and the District of Columbia, as of Dec. 31, 2025, 64 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.24**, **Table 6.25**, **Figure 6.23**, **Figure 6.24** and **Figure 6.25**.

**Table 6.24:** Maryland/District of Columbia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

	Maryland/District of Columbia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
<b>Biomass</b>	0.0	0.00%	10.0	0.01%
<b>Coal</b>	0.0	0.00%	14.0	0.01%
<b>Hybrid</b>	1,026.3	20.15%	14,332.3	12.76%
<b>Hydro</b>	0.0	0.00%	30.0	0.03%
<b>Natural Gas</b>	93.3	1.83%	11,082.0	9.87%
<b>Nuclear</b>	0.0	0.00%	1,305.9	1.16%
<b>Oil</b>	0.0	0.00%	50.0	0.04%
<b>Other</b>	0.0	0.00%	56.3	0.05%
<b>Solar</b>	771.7	15.15%	40,116.0	35.73%
<b>Storage</b>	3,142.5	61.70%	29,376.0	26.16%
<b>Wind</b>	59.7	1.17%	15,910.7	14.17%
<b>Grand Total</b>	<b>5,093.4</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

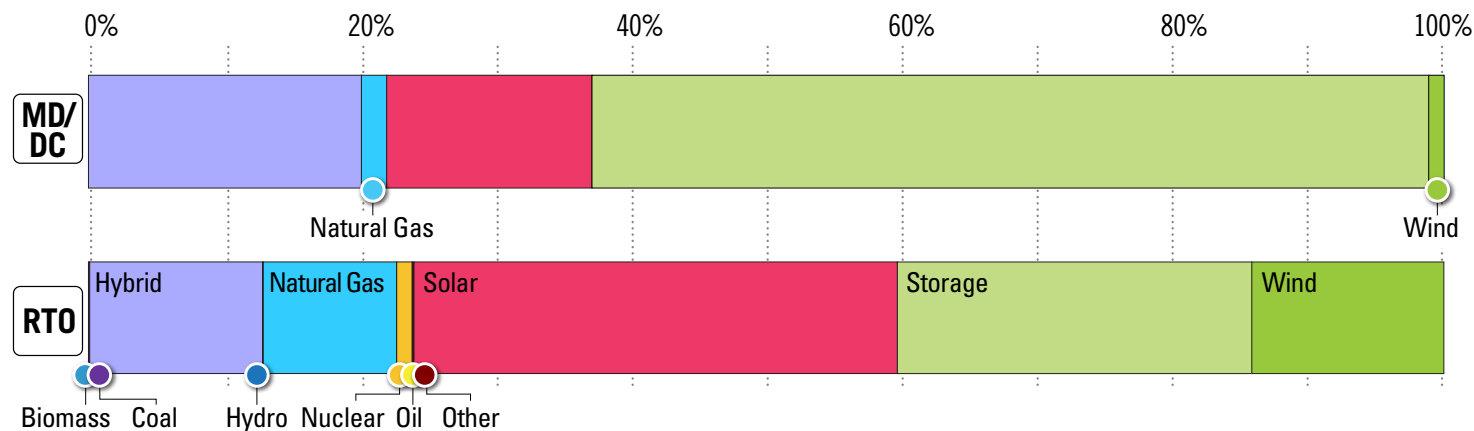
**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

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**Table 6.25:** Maryland/District of Columbia – Interconnection Requests by Fuel Type (Dec. 31, 2025)

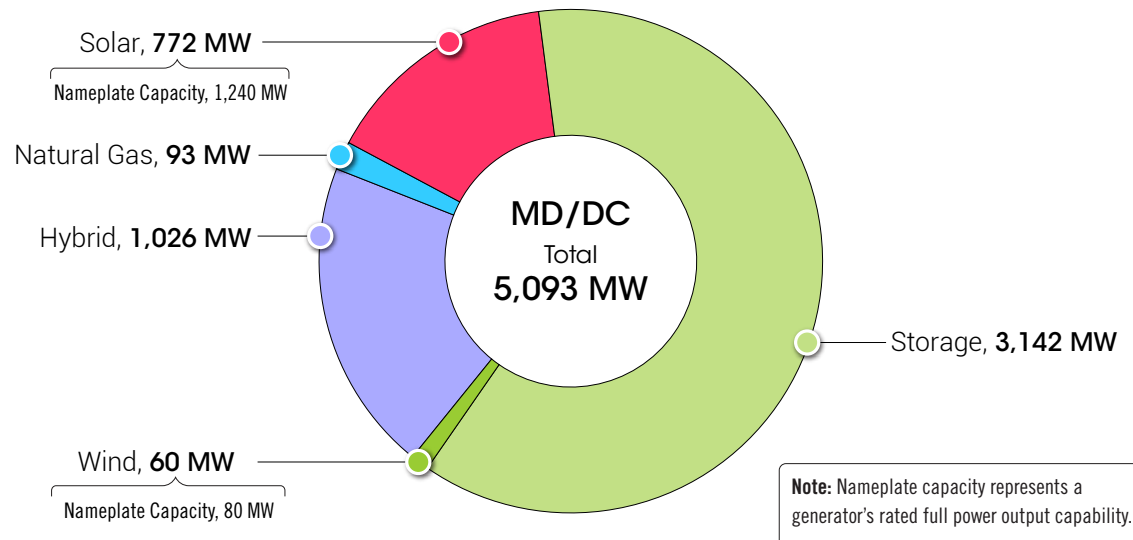
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity MW	Projects	Capacity MW	Projects	Capacity MW	Projects	Capacity MW	Projects	Capacity MW	Projects	Capacity MW
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	1	10.0	0	0.0	1	10.0
	Diesel	0	0.0	0	0.0	0	0.0	1	0.0	1	5.0	2	5.0
	Natural Gas	2	93.3	0	0.0	0	0.0	34	3,824.2	71	33,060.4	107	36,977.9
	Nuclear	0	0.0	0	0.0	0	0.0	4	37.4	4	4,955.0	8	4,992.4
	Oil	0	0.0	0	0.0	0	0.0	1	0.0	2	16.0	3	16.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	1	132.0	1	132.0
	Storage	14	2,642.5	0	0.0	1	500.0	2	0.7	64	3,126.7	81	6,269.9
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	12	227.6	12	227.6
	Hybrid	4	799.4	0	0.0	4	226.9	0	0.0	12	365.4	20	1,391.7
	Hydro	0	0.0	0	0.0	0	0.0	3	60.0	5	102.4	8	162.4
	Methane	0	0.0	0	0.0	0	0.0	5	14.5	5	8.0	10	22.5
	Solar	22	442.1	8	182.8	6	146.8	36	382.8	236	2,272.2	308	3,426.7
	Wind	2	47.9	0	0.0	1	11.8	7	57.2	10	265.6	20	382.5
<b>Grand Total</b>		<b>44</b>	<b>4,025.2</b>	<b>8</b>	<b>182.8</b>	<b>12</b>	<b>885.5</b>	<b>94</b>	<b>4,386.8</b>	<b>423</b>	<b>44,536.3</b>	<b>581</b>	<b>54,016.6</b>

**Figure 6.23:** Maryland/District of Columbia – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

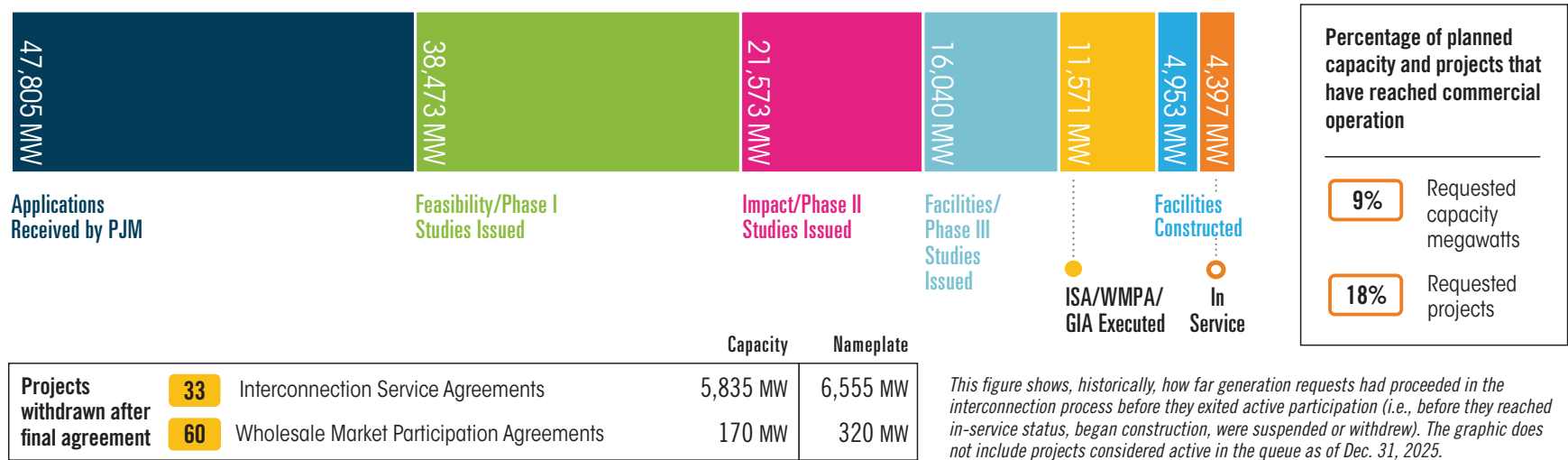


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**Figure 6.24:** Maryland/District of Columbia Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.25:** Maryland/District of Columbia Progression of Interconnection Requests (Dec. 31, 2025)

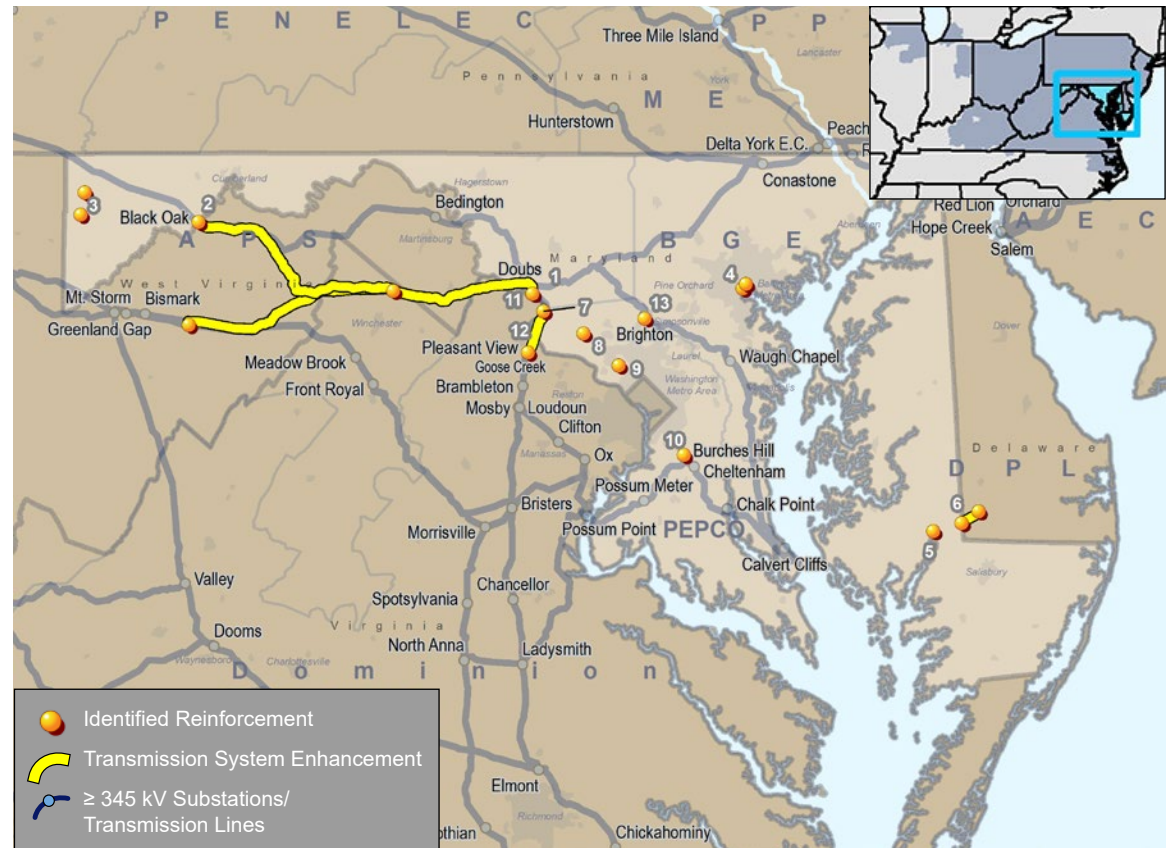


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**6.5.5 — Baseline Projects**

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in Maryland and the District of Columbia are summarized in **Map 6.21** and **Table 6.26**.

**Map 6.21: Maryland/District of Columbia Baseline Projects (Dec. 31, 2025)**



**Table 6.26: Maryland/District of Columbia Baseline Projects (Dec. 31, 2025)**

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B4000.15	Construct a new 86-mile Welton Spring to Rocky Point 765 kV line (Welton Spring to DVP local area, roughly 50 miles) (WV Portion).	6/1/2029	\$248.50	AP	6/5/2025	N/A - Scope Change	Baseline Load Growth Deliverability & Reliability

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Table 6.26: Maryland/District of Columbia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
2	B4000.14	Install two new 500 kV dead-end structures near Black Oak substation to interconnect the 502 Junction-Woodside 500 kV transmission line. Adjust Woodside protection scheme for Black Oak loop-in and remove 502 Junction tie (NEET Scope).	6/1/2029	\$3.00	NEET	6/5/2025	N/A - Scope Change	Baseline Load Growth Deliverability & Reliability
3	B4002.1	Rebuild ~1.9 miles of Garrett-Garrett tap 115 kV line with larger conductor. Install OPGW for the static and install one new SCADA-controlled 2000A disconnect with whips.	4/15/2030	\$9.02	AP	11/4/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4002.2	Adjust the relay settings at Penn Mar, Garrett and Deep Creek substations to accommodate the new ratings and impedance changes associates with the Garrett-Garrett tap 115 kV line rebuild.	4/15/2030	\$0.13	PENELEC	11/4/2025	Yes (Reliability W1)	
4	B4022.1	Replace ~2 miles per circuit of existing HPFF cables (Greene St.-Constitution St. 115 kV) with new 3500 KCM CU LPP HPFF cables.	6/1/2030	\$58.49	BGE	11/13/2025	No	Baseline Load Growth Deliverability & Reliability
5	B4023.1	Upgrade existing 500 and 750 SDCU on Vienna side of Vienna-Loretto facility with 2x954 ACSR. Replace three 138 kV, 600A disconnect switches with 2000A-rated units.	12/1/2030	\$1.81	DP&L	11/4/2025	No	Baseline Load Growth Deliverability & Reliability
6	B4024.1	Rebuild existing Sharptown-Laurel 69 kV circuit utilizing 954 ACSR "Rail" 45/7 conductor.	6/1/2030	\$36.55	DP&L	11/13/2025	No	Baseline Load Growth Deliverability & Reliability
7	B4052.1	Construct new 500/230 kV substation (Dickerson) by cutting into the Aspen-Rocky Point 500 kV line.	6/1/2032	\$161.83	PEPCO	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4052.2	Install two 500/230 kV transformers connecting a new 500 kV Dickerson station and Dickerson "H" 230 kV station including 230 kV substation work.	6/1/2032	\$67.05	PEPCO	1/6/2026	Yes (Reliability W1)	
	B4052.3	Perform Rocky Point-Dickerson (new 500 kV) termination work at Dickerson 500 kV.	6/1/2032	\$9.49	PEPCO	1/6/2026	Yes (Reliability W1)	
	B4052.4	Perform Aspen-Dickerson (new 500 kV) termination work at Dickerson 500 kV.	6/1/2032	\$9.49	PEPCO	1/6/2026	Yes (Reliability W1)	
	B4052.7	Install 3.2% 230 kV series reactor at Dickerson "H" terminal side of the Edwards Ferry-Dickerson circuit.	6/1/2032	\$0.85	PEPCO	1/6/2026	Yes (Reliability W1)	
	B4052.8	Relocate Dickerson "D"-Quince Orchard 23035 to terminate at Dickerson "H" at Dickerson No. 2 tie location.	6/1/2032	\$8.88	PEPCO	1/6/2026	Yes (Reliability W1)	
8	B4052.10	Replace one stranded bus conductor, three thermal relays, two disconnect switches at Quince Orchard 230 kV substation.	6/1/2032	\$3.75	PEPCO	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
9	B4052.11	Replace Bells Mill T3 transformer with new PEPCO standard 260 MVA 230/138 kV transformer.	6/1/2032	\$12.80	PEPCO	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
10	B4053.29	Uprate 500 kV line No. 560 terminal equipment at Burches Hill substation in PEPCO so as not to limit the conductor rating. The scope includes upgrading/replacing two circuit breakers, four switches and two different portions of stranded bus.	6/1/2032	\$10.31	PEPCO	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability

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Table 6.26: Maryland/District of Columbia Baseline Projects (Dec. 31, 2025) (Cont.)

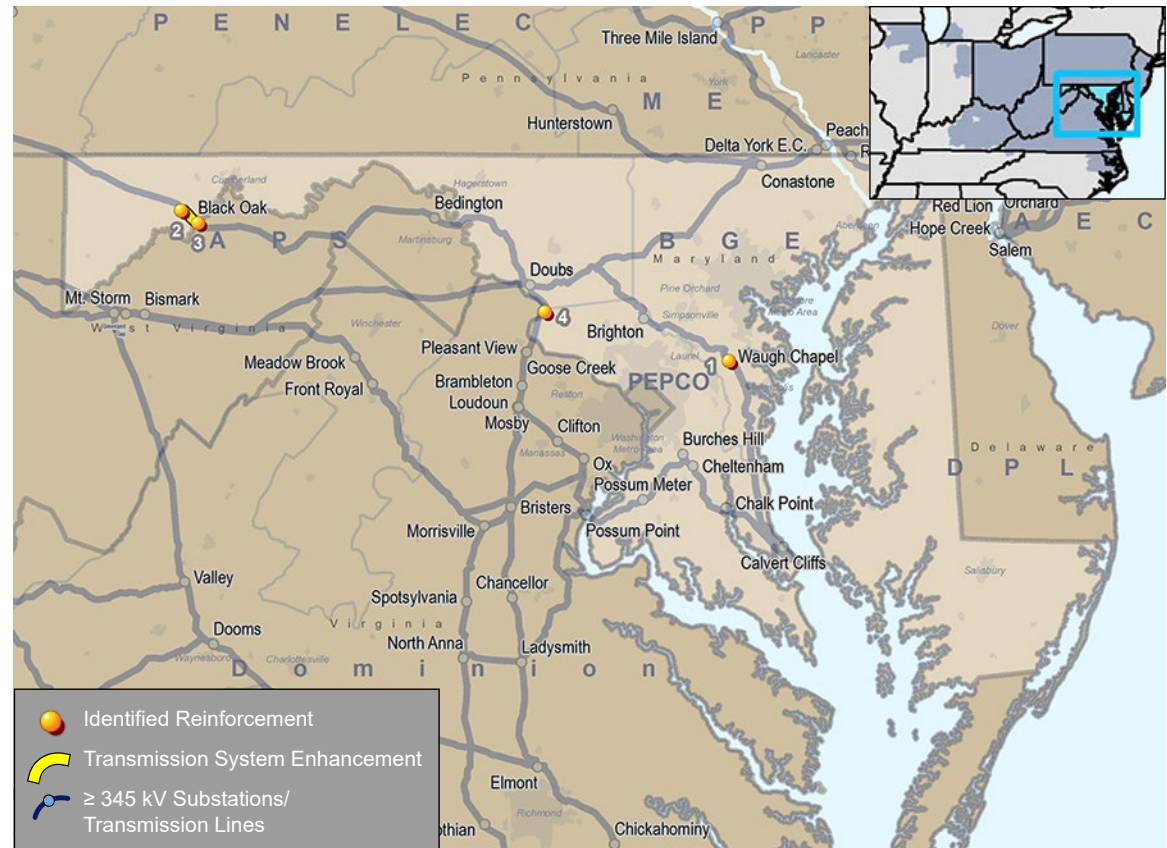
Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
11	B4052.5	Perform Rocky Point 500 kV remote work for Dickerson (new 500 kV)-Rocky Point line.	6/1/2032	\$0.00	AP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
12	B4052.6	Perform Aspen 500 kV remote work for Dickerson (new 500 kV)-Aspen line.	6/1/2032	\$0.00	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
13	B4052.9	Replace two breakers, one bushing CT, one stranded bus conductor, four disconnect switches at Brighton 500 kV substation.	6/1/2032	\$8.00	PEPCO	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
CEII	B4007.1	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-BGE03.	6/1/2029	\$0.02	BGE	11/4/2025	No	Baseline Load Growth Deliverability & Reliability
	B4007.2	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-BGE07.	6/1/2029	\$0.06	BGE	12/8/2025	No	
	B4007.3	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-BGE11.	6/1/2029	\$0.04	BGE	12/8/2025	No	
	B4007.4	2024W1 P5: Install trip coil monitors. Addresses flowgate No. 2024-P5-BGE14.	6/1/2029	\$0.10	BGE	12/8/2025	No	
	B4007.5	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-BGE05.	6/1/2029	\$0.02	BGE	12/8/2025	No	
	B4007.6	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-BGE04.	6/1/2029	\$0.08	BGE	12/8/2025	No	
	B4007.7	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-BGE13.	6/1/2029	\$0.02	BGE	12/8/2025	No	
	B4039.1	2024W1 P5: Replace three relay panels and modify relay wiring. Addresses flowgate No. 2024-P5-AP24.	6/1/2029	\$4.22	AP	12/8/2025	No	
	B4039.3	2024W1 P5: Replace one relay panel at a confidential substation connected to the substation associated with B4039.1. Addresses flowgate No. 2024-P5-AP24.	6/1/2029	\$0.00	AP	12/8/2025	No	
	B4040.1	2024W1 P5: Install battery monitoring, DC panel and modify relay wiring. Addresses flowgate No. 2024-P5-AP03.	6/1/2029	\$0.97	AP	12/8/2025	No	
	B4076.3	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-DP&L03.	6/1/2029	\$0.02	DP&L	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4076.4	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-DP&L04.	6/1/2029	\$0.02	DP&L	12/8/2025	No	
	B4076.6	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-DP&L07.	6/1/2029	\$0.02	DP&L	12/8/2025	No	
	B4076.7	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-DP&L08.	6/1/2029	\$0.02	DP&L	12/8/2025	No	
B4076.8	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-DP&L09.	6/1/2029	\$0.02	DP&L	12/8/2025	No		
B4076.10	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5DYN-DP&L01.	6/1/2029	\$0.02	DP&L	12/8/2025	No	Baseline Load Growth Deliverability & Reliability / Stability	

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**6.5.6 — Network Projects**

Network projects in Maryland and the District of Columbia for 2025 are summarized in **Map 6.22** and **Table 6.27**.

**Map 6.22: Maryland/District of Columbia Network Projects (Dec. 31, 2025)**



**Table 6.27: Maryland/District of Columbia Network Projects (Dec. 31, 2025)**

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	<b>N8620.0</b>	Expand the Waugh Chapel 230 kV substation by adding a new breaker in position B29.	AG1-104	6/1/2029	\$8.34	BGE	10/8/2025
2	<b>N8840.0</b>	Construct new three-breaker ring along Back Oak-Hatfield 500 kV line.	AG1-363	12/10/2029	\$0.90	AP	10/8/2025

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**Table 6.27: Maryland/District of Columbia Network Projects (Dec. 31, 2025) (Cont.)**

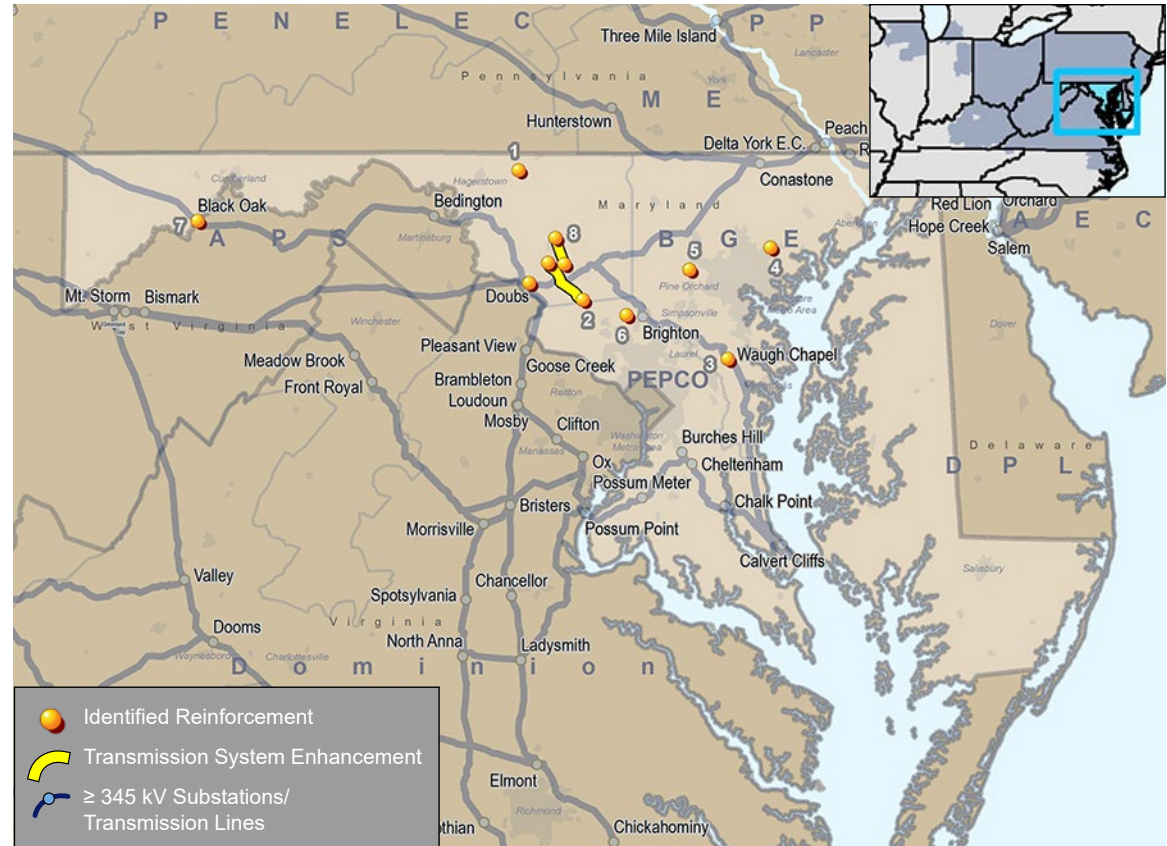
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	N8841.0	Install/test 3,115 feet underground 96,888 aerial 48F/SM ADSS from Jade Meadow AG1-363 substation control house to Black Oak No. 1 substation control house.	AG1-363	12/10/2029	\$3.42	AP	10/8/2025
	N8843.0	Cut existing Hatfield-Black Oak 500 kV ~5.3 miles from Black Oak substation and 56 miles from Hatfield substation to create loop into new substation.	AG1-363	12/10/2029	\$7.00	AP	10/8/2025
	N8844.0	Install one line relaying panel at Black Oak substation.	AG1-363	12/10/2029	\$0.66	AP	10/8/2025
4	N9099.0	Install new 230 kV breaker, switches, foundations and structures in the existing Dickerson 230 kV breaker-and-a-half bay.	AG1-483	8/1/2030	\$4.94	PEPCO	10/8/2025

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**6.5.7 — Supplemental Projects**

Supplemental projects included in the 2025 Local Plan in Maryland and the District of Columbia are summarized in **Map 6.23** and **Table 6.28**.

**Map 6.23: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2025)**



**Table 6.28: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2025)**

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S3540.1	At Doubs, replace line trap, substation conductor and relaying. At Ringgold, replace line trap, disconnect switches, substation conductor and relaying.	8/31/2027	\$6.30	AP	8/6/2024
2	S3541.1	At Lime Kiln, replace CVT on bus, substation conductor and relaying. At Montgomery, replace CVT on bus, disconnect switches, substation conductor and relaying.	10/31/2026	\$9.20	AP	8/6/2024

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**Table 6.28:** Maryland/District of Columbia Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	S3560.1	Replace Waugh Chapel circuit breaker B4. Existing rating is 2500A 63 kA. Proposed rating is 3000A 63 kA.	4/10/2025	\$0.75	BGE	2/13/2025
	S3561.1	Replace Waugh Chapel circuit breaker B7. Existing rating is 2500A 63 kA. Proposed rating is 3000A 63 kA.	10/9/2025	\$0.70	BGE	2/13/2025
	S3562.1	Replace Waugh Chapel circuit breaker B10. Existing rating is 2500A 63 kA. Proposed rating is 3000A 63 kA.	5/15/2025	\$0.75	BGE	2/13/2025
	S3563.1	Replace Waugh Chapel circuit breaker B12. Existing rating is 2500A 63 kA. Proposed rating is 3000A 63 kA.	11/13/2025	\$0.70	BGE	2/13/2025
4	S3564.1	Replace Windy Edge circuit breaker B3. Existing rating is 2000A 50 kA. Proposed rating is 3000A 63 kA.	4/3/2025	\$0.75	BGE	2/13/2025
	S3565.1	Replace Windy Edge circuit breaker B4. Existing rating is 1600A 50 kA. Proposed rating is 3000A 63 kA.	5/8/2025	\$0.75	BGE	2/13/2025
	S3566.1	Replace Windy Edge circuit breaker B24. Existing rating is 1600A 50 kA. Proposed rating is 3000A 63 kA.	12/11/2025	\$0.70	BGE	2/13/2025
	S3567.1	Replace Windy Edge circuit breaker B28. Existing rating is 1600A 50 kA. Proposed rating is 3000A 63 kA.	10/2/2025	\$0.70	BGE	2/13/2025
5	S3568.1	Replace Granite circuit breaker B2. Existing rating is 3000A 50 kA. Proposed rating is 3000A 63 kA.	5/1/2025	\$0.70	BGE	2/13/2025
6	S3572.1	Install 12 3000 amp 230 kV breakers at Mt. Zion.	6/1/2030	\$13.62	PEPCO	1/7/2025
	S3572.2	Install relays for each new breaker and at the remote end stations.	6/1/2030	\$0.69	PEPCO	1/7/2025
	S3572.3	Install new telecom equipment to support breaker protection.	6/1/2030	\$0.69	PEPCO	1/7/2025
	S3572.4	Replace 24 disconnects switches with 24 3000 amp motor operated disconnects (MODs).	6/1/2030	\$7.00	PEPCO	1/7/2025
7	S3646.1	Rebuild ~22 miles of the Black Oak-Junction 138 kV line.	12/14/2029	16.27	AP	3/14/2025
8	S3646.2	At Black Oak substation, replace circuit breaker, disconnect switches, substation conductor and relaying.	12/14/2029	\$16.27	AP	3/14/2025
	S3713.1	At Black Oak, replace circuit breakers, disconnect switches, line trap, CCVT and line relaying. At Cross School, replace line trap and line relaying.	12/31/2026	\$4.55	AP	7/18/2025
9	S3656.1	At Frederick A substation: Replace existing line relaying. Replace two 230 kV disconnect switches. Replace substation conductor. At Monocacy substation: Replace one 230 kV circuit breaker. Replace existing line relaying. Replace two 230 kV disconnect switches. Replace substation conductor.	11/24/2027	\$3.90	AP	4/1/2025
	S3573.1	Replace No. 4 230/138 kV 224 MVA transformer with a new 266 MVA unit. Replace transformer conductor, circuit breakers, disconnect switches and relaying	12/31/2027	\$9.00	AP	11/6/2024

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## 6.6: Southwestern Michigan RTEP Summary

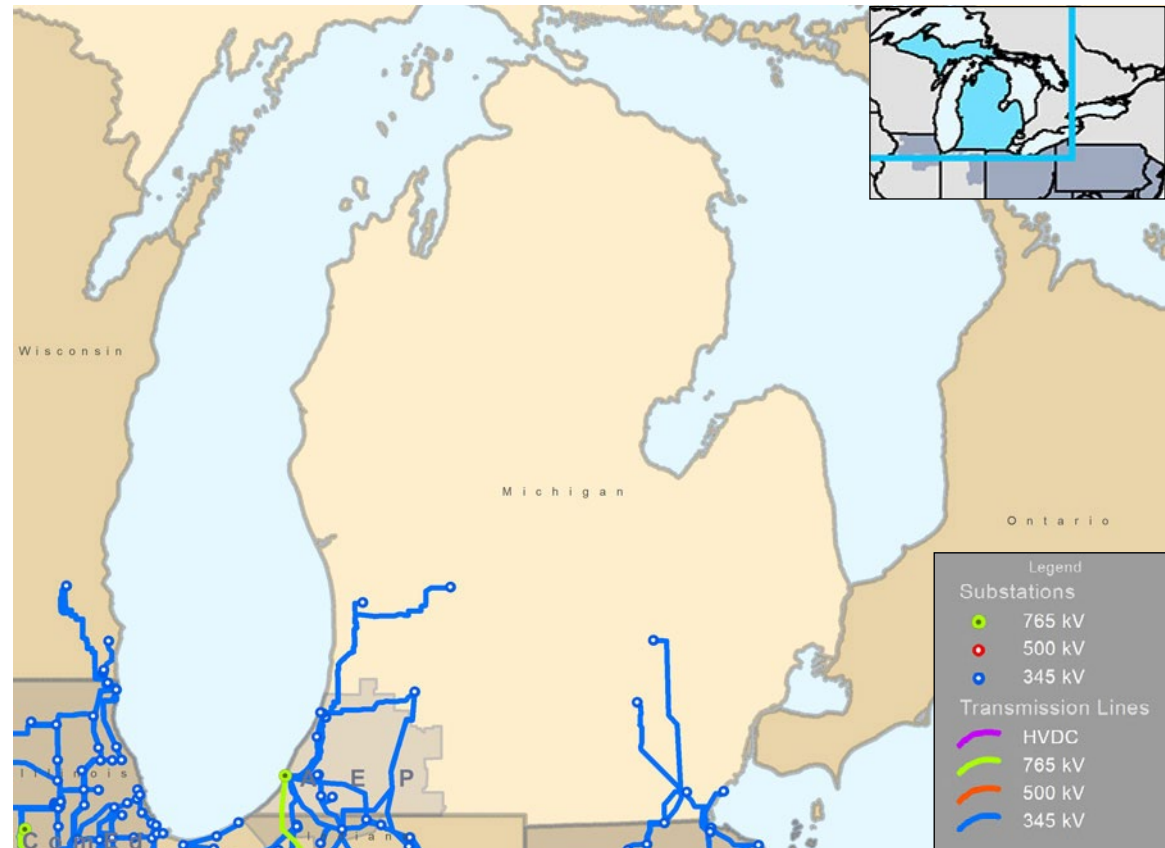
### 6.6.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in southwestern Michigan, including facilities owned and operated by American Electric Power (AEP) and ITC Interconnection (ITCI) as shown on **Map 6.24**. The transmission system in southwestern Michigan delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

### Renewable Portfolio Standards

Michigan has a mandatory renewable portfolio standard (RPS) target of 15% annually until 2029, 50% from 2030 through 2034, and the target increases to 60% for 2035 and each year thereafter. This new RPS target was established in 2023 when Michigan enacted S.B. 271. Through S.B. 271, Michigan also established a clean energy standard for its regulated utilities. The clean energy targets are 80% from 2035 through 2039 and a 100% target beginning in 2040. The legislation also set an energy storage target of 2,500 MW by 2029.

Map 6.24: PJM Service Area in Southwestern Michigan

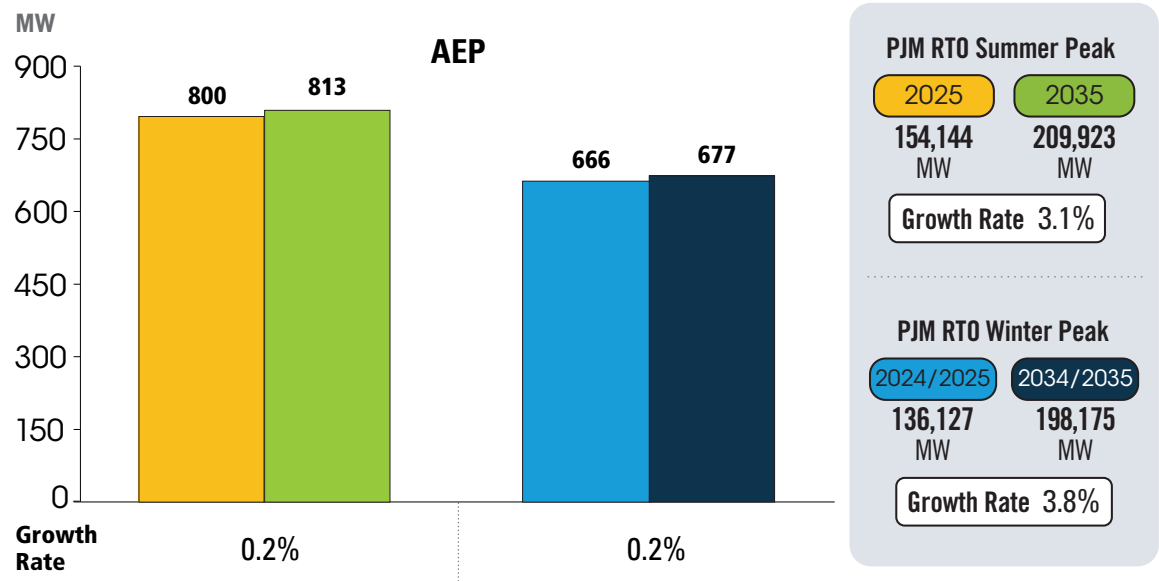


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### 6.6.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.26** summarizes the expected loads within southwestern Michigan and across the PJM region.

**Figure 6.26:** Southwestern Michigan – 2025 Long-Term Load Forecast



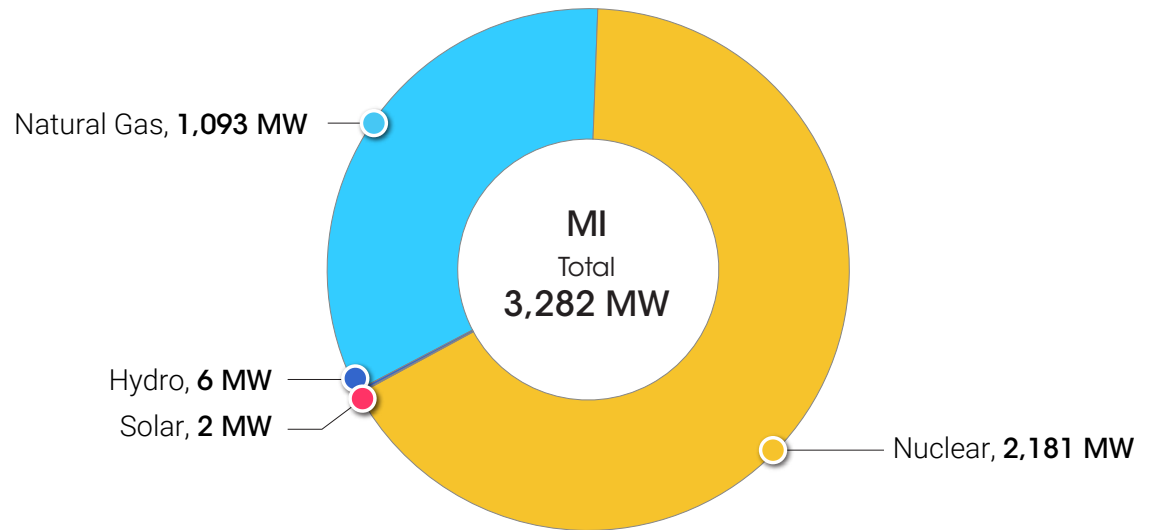
PJM notes that AEP serves load other than in Michigan. The summer and winter peak megawatt values in this table each reflect the estimated amount of forecasted load to be served by AEP solely in Michigan. Estimated amounts were calculated based on the average share of AEP's real-time summer and winter peak load located in Michigan over the past five years.

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### 6.6.3 — Existing Generation

Existing generation in southwestern Michigan as of Dec. 31, 2025, is shown by fuel type in **Figure 6.27**.

**Figure 6.27:** Southwestern Michigan – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



### 6.6.4 — Interconnection Requests

In southwestern Michigan, as of Dec. 31, 2025, 21 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.29**, **Table 6.30**, **Figure 6.28**, **Figure 6.29** and **Figure 6.30**.

**Table 6.29:** Southwestern Michigan – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

	Southwestern Michigan Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Biomass	0.0	0.00%	10.0	0.01%
Coal	0.0	0.00%	14.0	0.01%
Hybrid	707.7	44.86%	14,332.3	12.76%
Hydro	0.0	0.00%	30.0	0.03%
Natural Gas	0.0	0.00%	11,082.0	9.87%
Nuclear	0.0	0.00%	1,305.9	1.16%
Oil	0.0	0.00%	50.0	0.04%
Other	0.0	0.00%	56.3	0.05%
Solar	638.5	40.48%	40,116.0	35.73%
Storage	231.3	14.66%	29,376.0	26.16%
Wind	0.0	0.00%	15,910.7	14.17%
<b>Grand Total</b>	<b>1,577.5</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

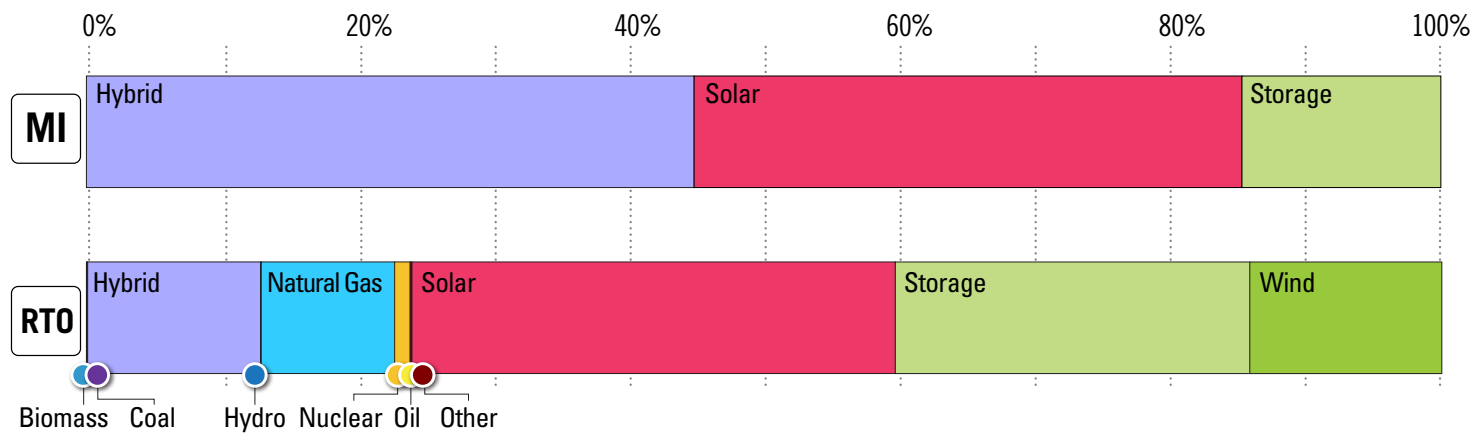
**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

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**Table 6.30:** Southwestern Michigan – Interconnection Requests by Fuel Type (Dec. 31, 2025)

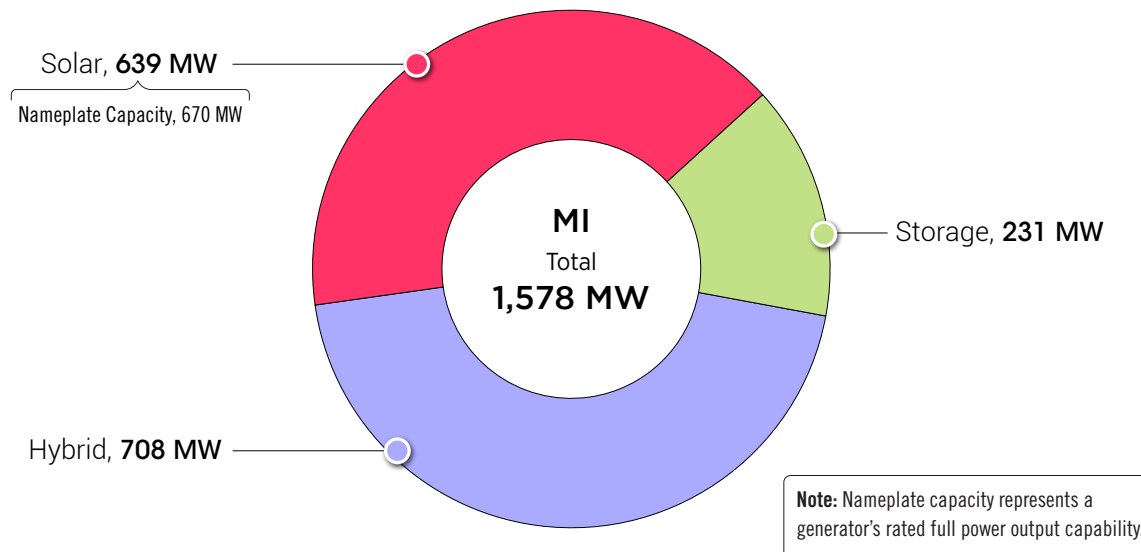
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Natural Gas	0	0.0	0	0.0	0	0.0	4	2,140.0	2	1,265.0	6	3,405.0
	Nuclear	0	0.0	0	0.0	0	0.0	3	205.0	0	0.0	3	205.0
	Storage	4	231.3	0	0.0	0	0.0	0	0.0	1	75.0	5	306.3
Renewable	Hybrid	5	707.7	0	0.0	0	0.0	0	0.0	4	169.2	9	876.9
	Methane	0	0.0	0	0.0	0	0.0	3	10.4	0	0.0	3	10.4
	Solar	8	359.5	1	63.0	3	216.0	1	2.3	10	420.3	23	1,061.1
	Wind	0	0.0	0	0.0	0	0.0	0	0.0	1	26.0	1	26.0
<b>Grand Total</b>		<b>17</b>	<b>1,298.5</b>	<b>1</b>	<b>63.0</b>	<b>3</b>	<b>216.0</b>	<b>11</b>	<b>2,357.7</b>	<b>18</b>	<b>1,955.5</b>	<b>50</b>	<b>5,890.7</b>

**Figure 6.28:** Southwestern Michigan – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

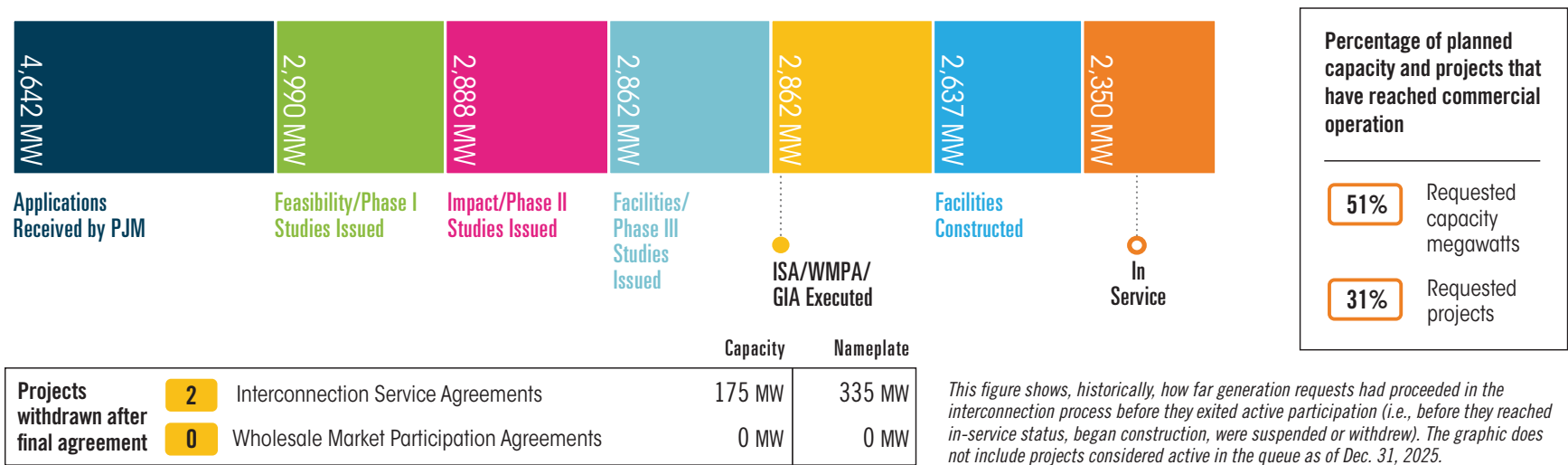


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**Figure 6.29:** Southwestern Michigan Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.30:** Southwestern Michigan Progression of Interconnection Requests (Dec. 31, 2025)

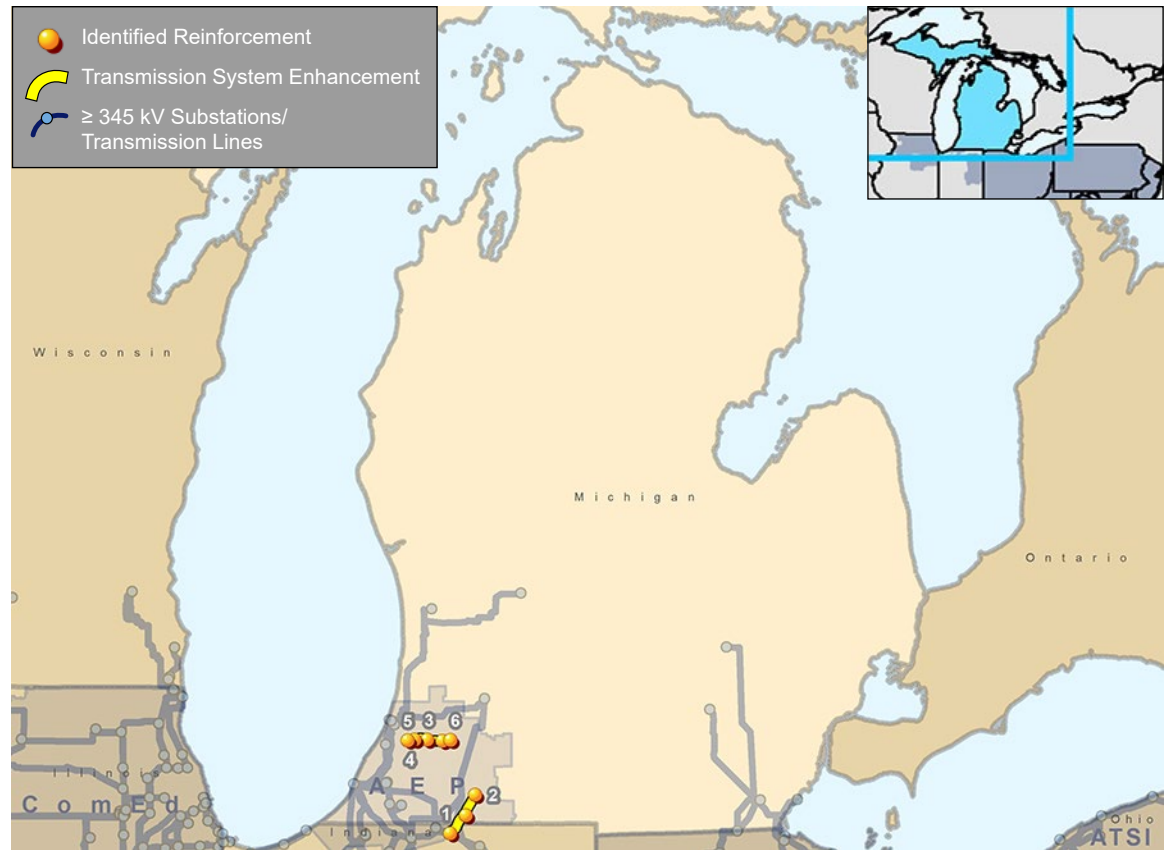


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**6.6.5 — Network Projects**

Network projects in southwestern Michigan for 2025 are summarized in **Map 6.25** and **Table 6.31**.

**Map 6.25:** Southwestern Michigan Network Projects (Dec. 31, 2025)



**Table 6.31:** Southwestern Michigan Network Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	N7017	Perform a sag study on the 7.8-mile section of ACSR 477 26/7 HAWK on the Mottv-E Elkhart 138 kV line.	AF2-389	10/31/2023	\$0.03	AEP	10/8/2025
2	N7018	Perform a sag study on the 8.5-mile section of ACSR 477 26/7 HAWK on the Corey-Mottv 138 kV line.	AF2-389	10/31/2023	\$0.03	AEP	10/8/2025

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**Table 6.31:** Southwestern Michigan Network Projects (Dec. 31, 2025) (Cont.)

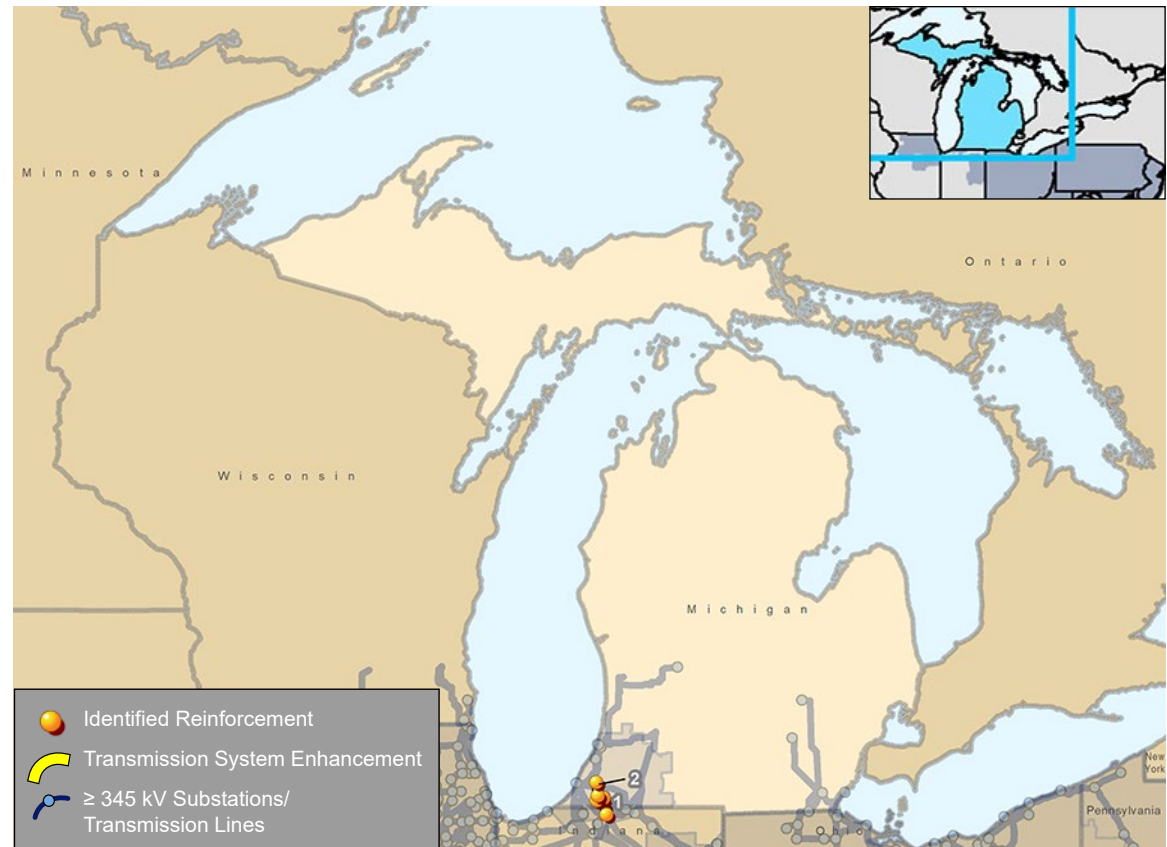
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	N8513.1	Construct the proposed 69 kV breaker-and-a-half station, to be operated as a three-circuit breaker ring bus, initially expandable to six circuit breakers at East Hartford-Murch 69 kV.	AF1-084	1/15/2027	\$6.41	AEP	10/8/2025
	N8513.5	Install two new fiber optic cable paths consisting of 0.2 miles of 48 count ADLT cable installed in new underground right-of-way and associated terminating equipment and devices (transceivers, multiplexors, routers) at proposed AF1-084 69 kV, Hartford 69 kV and Almena 69 kV stations new right-of-way.	AF1-084	1/15/2027	\$0.24	AEP	10/8/2025
4	N8513.2	Install two new steel, 80' single-circuit, single-pole dead-end structures on concrete piers with anchor bolt cages and two spans of aluminum conductor steel-reinforced cable (ACSR) 795 (Drake) transmission line conductor with 7 #10 alumoweld shield wire at East Hartford-Murch 69 kV.	AF1-084	1/15/2027	\$1.18	AEP	10/8/2025
5	N8513.3	Review and revise the protective relay settings at the Hartford 69 kV station.	AF1-084	1/15/2027	\$0.10	AEP	10/8/2025
6	N8513.4	Review and revise the protective relay settings at the Almena 69 kV station.	AF1-084	1/15/2027	\$0.10	AEP	10/8/2025

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### 6.6.6 — Supplemental Projects

Supplemental projects included in the 2025 Local Plan in southwestern Michigan are summarized in **Map 6.26** and **Table 6.32**.

**Map 6.26:** Southwestern Michigan Supplemental Projects (Dec. 31, 2025)



**Table 6.32:** Southwestern Michigan Supplemental Projects (Dec. 31, 2025)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S2167.12	Build the new FourFlag station to replace Niles consisting of five 69 kV circuit breakers configured in a ring bus. Install a 14.4 MVAR cap bank. Install a new 69/34.5 kV transformer with high-side circuit switcher and two new 34.5 kV breakers toward the City of Niles and Bertrand. Install distribution equipment.	3/13/2026	\$17.90	AEP	7/18/2025
	S2167.13	Route the Mayflower 69 kV, Lake Street 69 kV, South Bend 69 kV and City of Niles 34.5 kV lines into FourFlag station.	3/13/2026	\$8.50	AEP	7/18/2025
	S2167.14	Install a 34.5 kV circuit breaker at South Side station (owned by City of Niles) to coordinate with the new breakers at FourFlag.	3/13/2026	\$2.10	AEP	7/18/2025
2	S3588.6	Complete sag study and mitigation on the Kenzie Creek-Thomson 345 kV line.	12/15/2026	\$0.62	AEP	10/8/2024

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## 6.7: New Jersey RTEP Summary

### 6.7.1 — RTEP Context

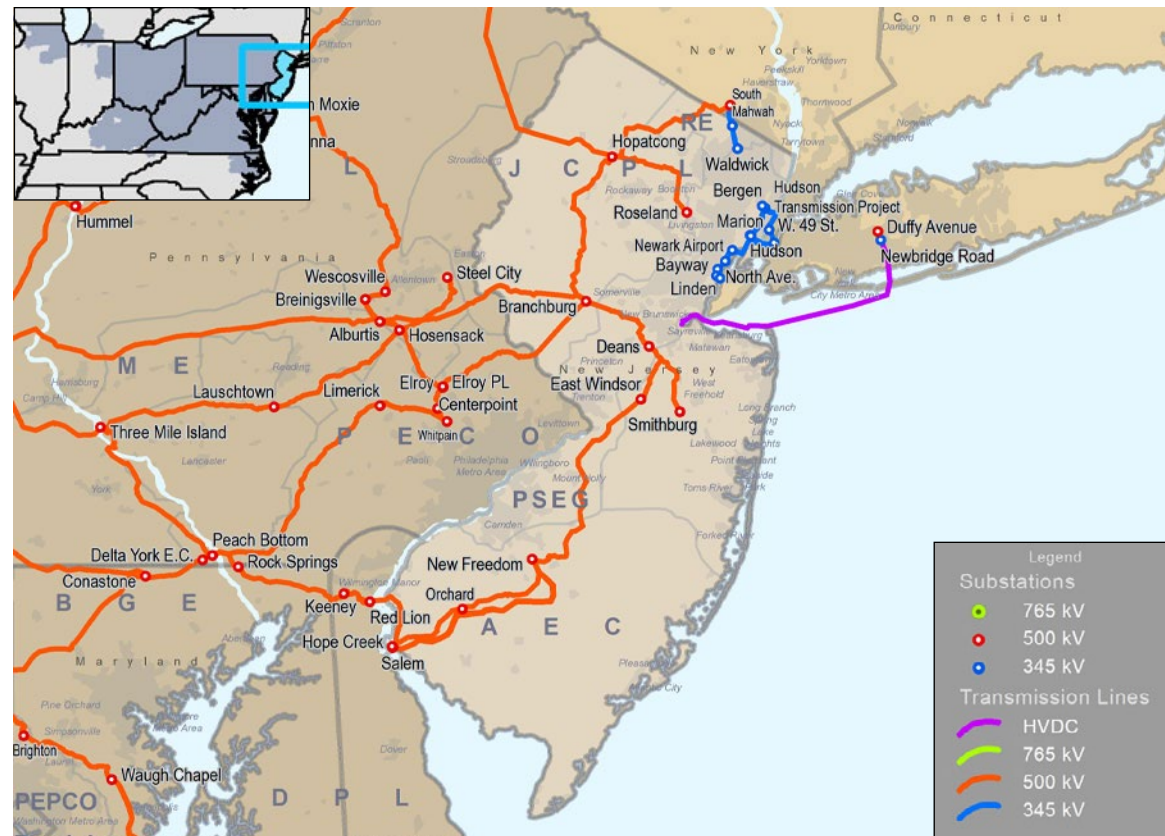
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in New Jersey, including facilities owned and operated by Atlantic City Electric (AE), Jersey Central Power & Light (JCP&L), Linden VFT (VFT), Neptune Regional Transmission System (Neptune RTS), Public Service Electric & Gas Company (PSEG), and Rockland Electric Company (RECO) as shown on **Map 6.27**. New Jersey's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

### Renewable Portfolio Standards

New Jersey has a mandatory renewable portfolio standard (RPS) target of 50% Class I renewable resources by 2030. The state also requires 2.5% Class II renewable resources each year. In 2021, New Jersey implemented a solar incentive program that seeks up to 3,750 MW of new solar generation by 2026. Legislation to accommodate an additional 3,000 MW of community solar was signed into law in 2025.

New Jersey is advancing offshore wind to support its clean energy objectives. The Clean Energy Act of 2018 required New Jersey to procure at least 3,500 MW of offshore wind. In 2019, Gov. Murphy increased the state's offshore wind target to 7,500 MW by 2035 through Executive Order No. 92. In 2022, that target was again increased to 11,000 MW by 2040 through Executive Order No. 307.

Map 6.27: PJM Service Area in New Jersey



New Jersey is supporting the development of its offshore wind projects by proactively planning for the transmission needed to interconnect its overall target of 11,000 MW by 2040. In October 2022, the New Jersey Board of Public Utilities (NJBPU) issued an Order approving transmission solutions as part of the State Agreement Approach (SAA) to support the interconnection of the first 7,500 MW target. Because of current challenges in the offshore wind industry, the NJBPU issued

an order in August 2025 requiring that the SAA projects be placed on a two-and-a-half-year pause.

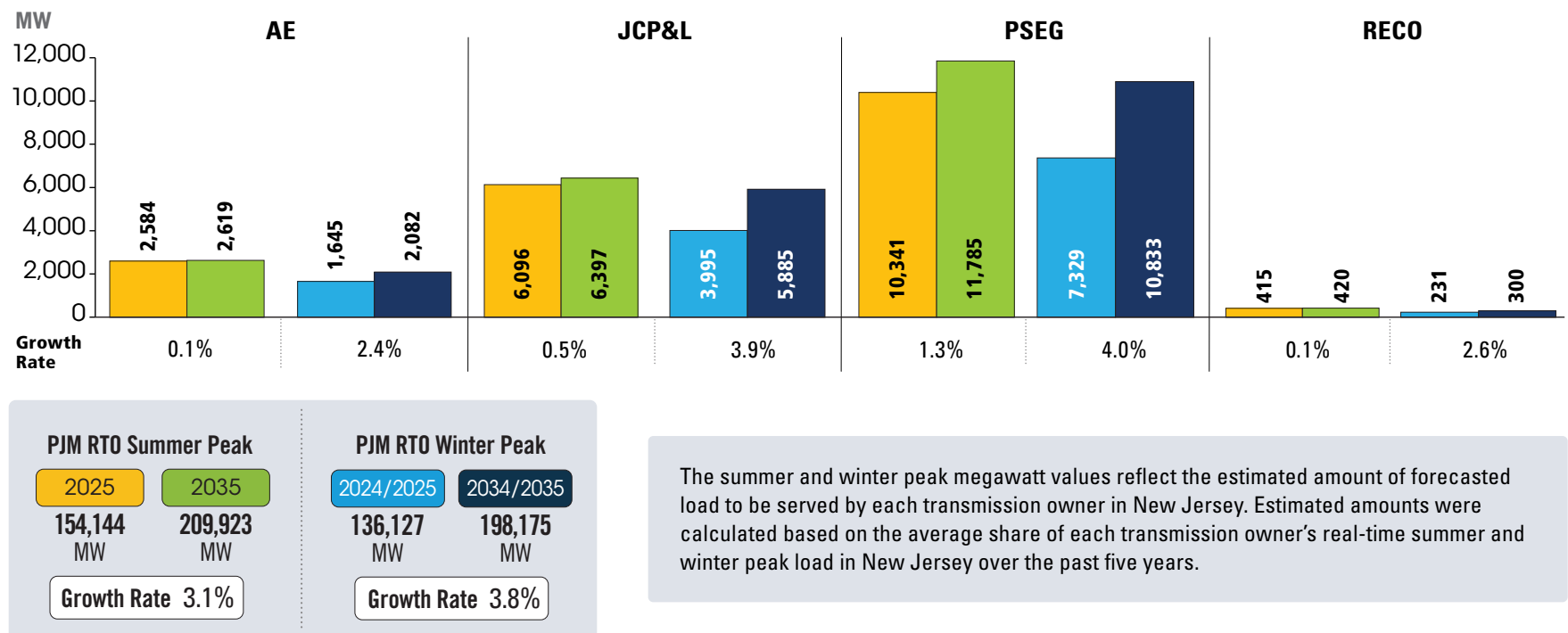
New Jersey is also pursuing decarbonization through additional efforts. In 2023, the New Jersey Department of Environmental Protection implemented CO<sub>2</sub> regulations for existing and proposed fossil-fuel resources. This has eliminated the ability of several generating facilities from operating beyond 2024. New Jersey is also pursuing an energy storage target of 2,000 MW by 2030.

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### 6.7.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.31** summarizes the expected loads within the state of New Jersey and across the PJM region.

**Figure 6.31:** New Jersey – 2025 Long-Term Load Forecast

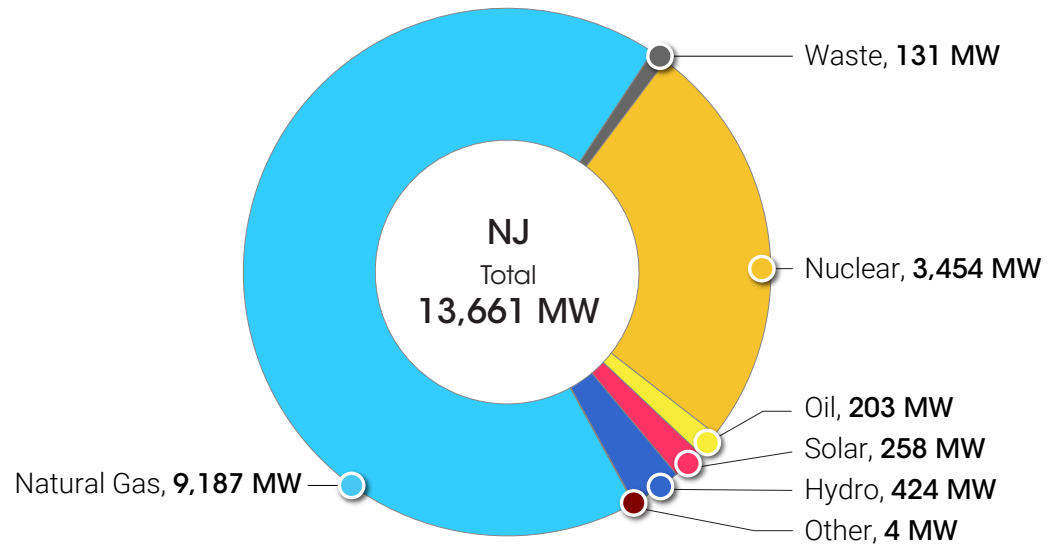


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### 6.7.3 — Existing Generation

Existing generation in New Jersey as of Dec. 31, 2025, is shown by fuel type in **Figure 6.32**.

**Figure 6.32:** New Jersey – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



### 6.7.4 — Interconnection Requests

In New Jersey, as of Dec. 31, 2025, 86 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.33**, **Table 6.34**, **Figure 6.33**, **Figure 6.34** and **Figure 6.35**.

**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

**Table 6.33:** New Jersey – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

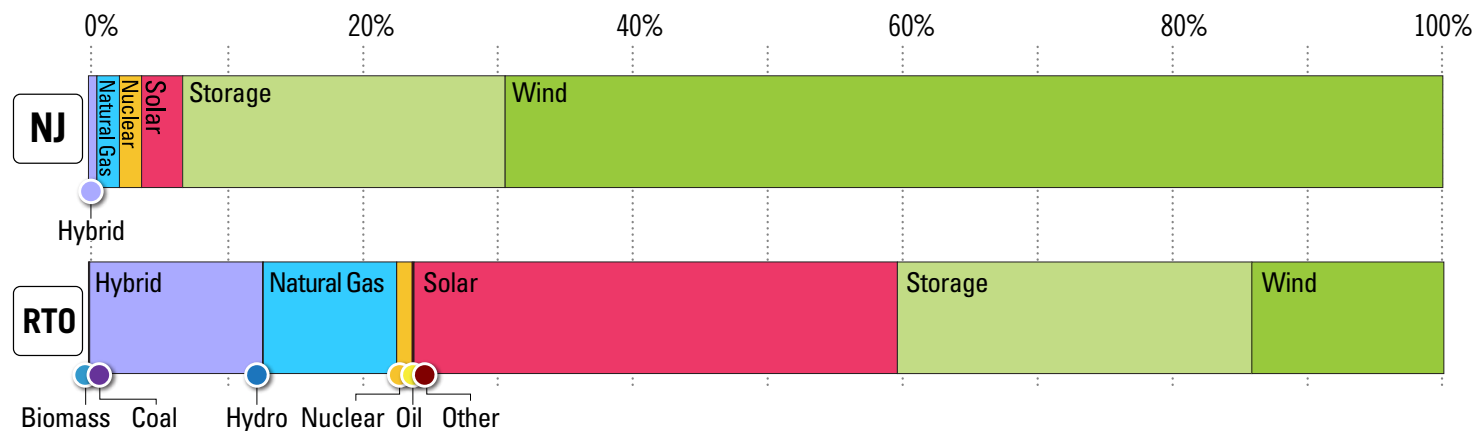
	New Jersey Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Biomass	0.0	0.00%	10.0	0.01%
Coal	0.0	0.00%	14.0	0.01%
Hybrid	87.3	0.63%	14,332.3	12.76%
Hydro	0.0	0.00%	30.0	0.03%
Natural Gas	229.4	1.65%	11,082.0	9.87%
Nuclear	228.2	1.64%	1,305.9	1.16%
Oil	0.0	0.00%	50.0	0.04%
Other	0.0	0.00%	56.3	0.05%
Solar	420.5	3.02%	40,116.0	35.73%
Storage	3,313.7	23.82%	29,376.0	26.16%
Wind	9,634.7	69.25%	15,910.7	14.17%
<b>Grand Total</b>	<b>13,913.7</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

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**Table 6.34:** New Jersey – Interconnection Requests by Fuel Type (Dec. 31, 2025)

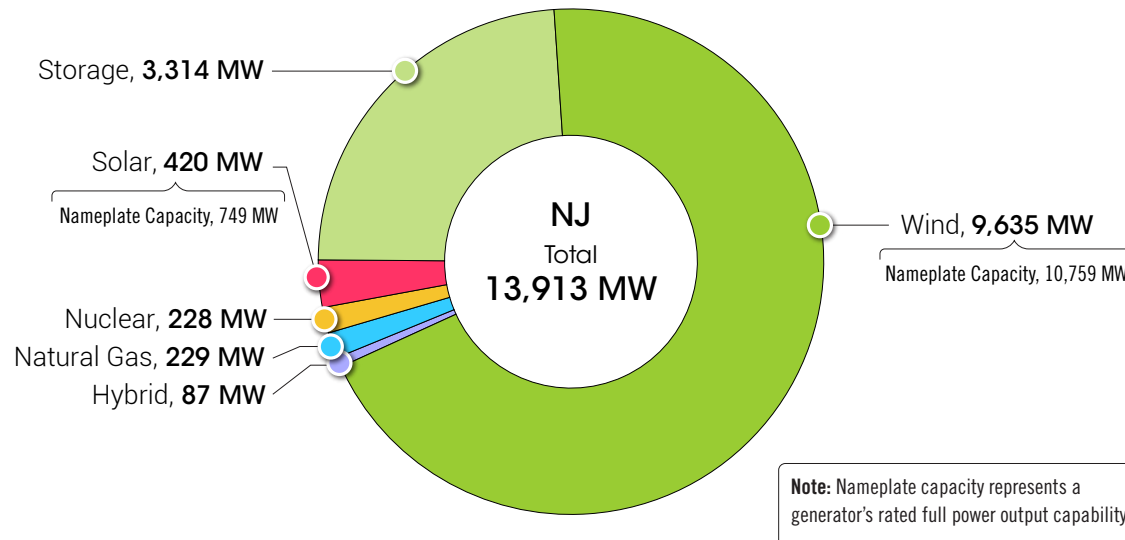
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	0	0.0	1	15.0	1	15.0
	Natural Gas	3	229.4	0	0.0	0	0.0	77	7,765.1	184	52,599.3	264	60,593.8
	Nuclear	1	228.2	0	0.0	0	0.0	6	381.0	0	0.0	7	609.2
	Oil	0	0.0	0	0.0	0	0.0	1	17.0	8	945.0	9	962.0
	Other	0	0.0	0	0.0	0	0.0	1	0.0	2	45.5	3	45.5
	Storage	14	2,703.7	0	0.0	11	610.0	13	4.0	98	1,985.8	136	5,303.5
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	2	10.0	2	10.0
	Hybrid	1	20.0	0	0.0	2	67.3	6	0.9	32	615.3	41	703.5
	Hydro	0	0.0	0	0.0	0	0.0	2	20.5	3	1,031.1	5	1,051.6
	Methane	0	0.0	0	0.0	0	0.0	11	20.5	9	40.6	20	61.1
	Solar	29	282.8	3	96.6	7	41.0	131	294.4	543	2,232.1	713	2,947.0
	Wind	13	9,284.0	2	350.7	0	0.0	1	0.0	46	8,340.9	62	17,975.6
<b>Grand Total</b>		<b>61</b>	<b>12,748.1</b>	<b>5</b>	<b>447.3</b>	<b>20</b>	<b>718.3</b>	<b>249</b>	<b>8,503.4</b>	<b>928</b>	<b>67,860.7</b>	<b>1,263</b>	<b>90,277.8</b>

**Figure 6.33:** New Jersey – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

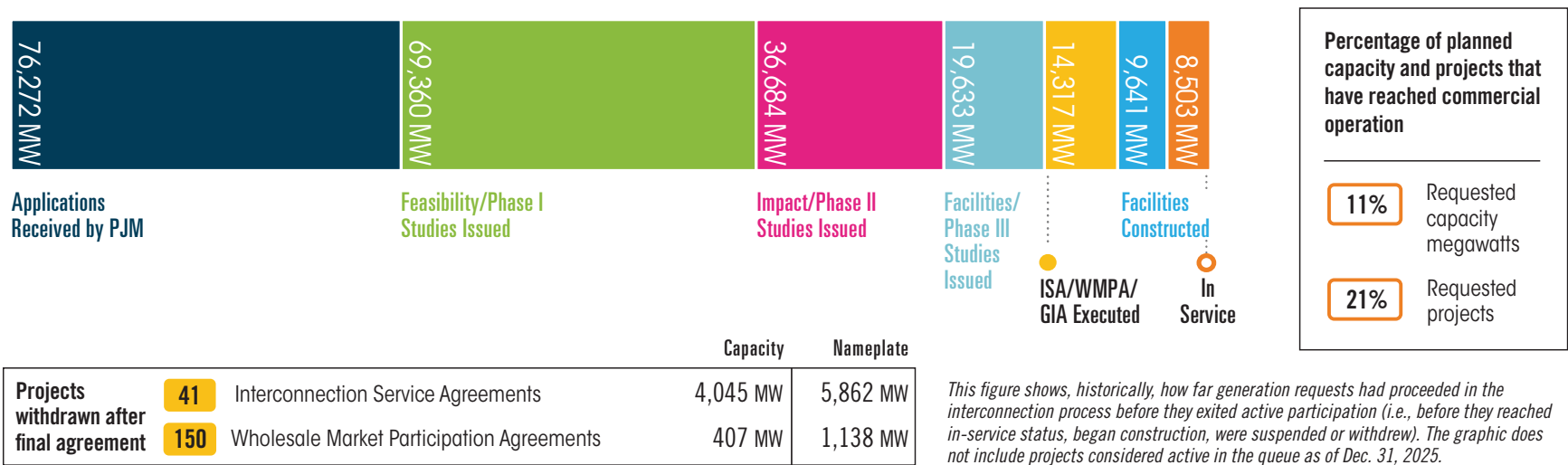


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**Figure 6.34:** New Jersey Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.35:** New Jersey Progression of Interconnection Requests (Dec. 31, 2025)

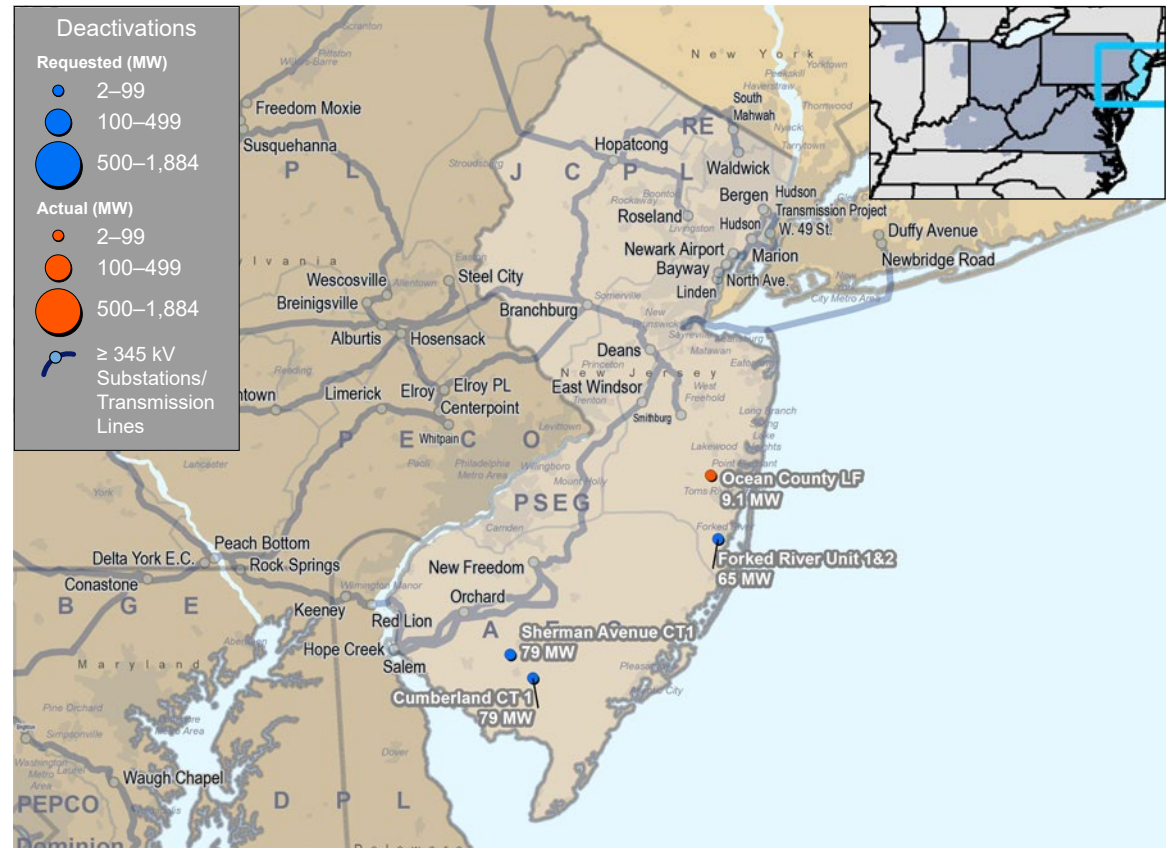


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### 6.7.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in New Jersey between Jan. 1, 2025, and Dec. 31, 2025, are summarized in **Map 6.28** and **Table 6.35**.

**Map 6.28:** New Jersey Generation Deativations (Dec. 31, 2025)



**Table 6.35:** New Jersey Generation Deactivations (Dec. 31, 2025)

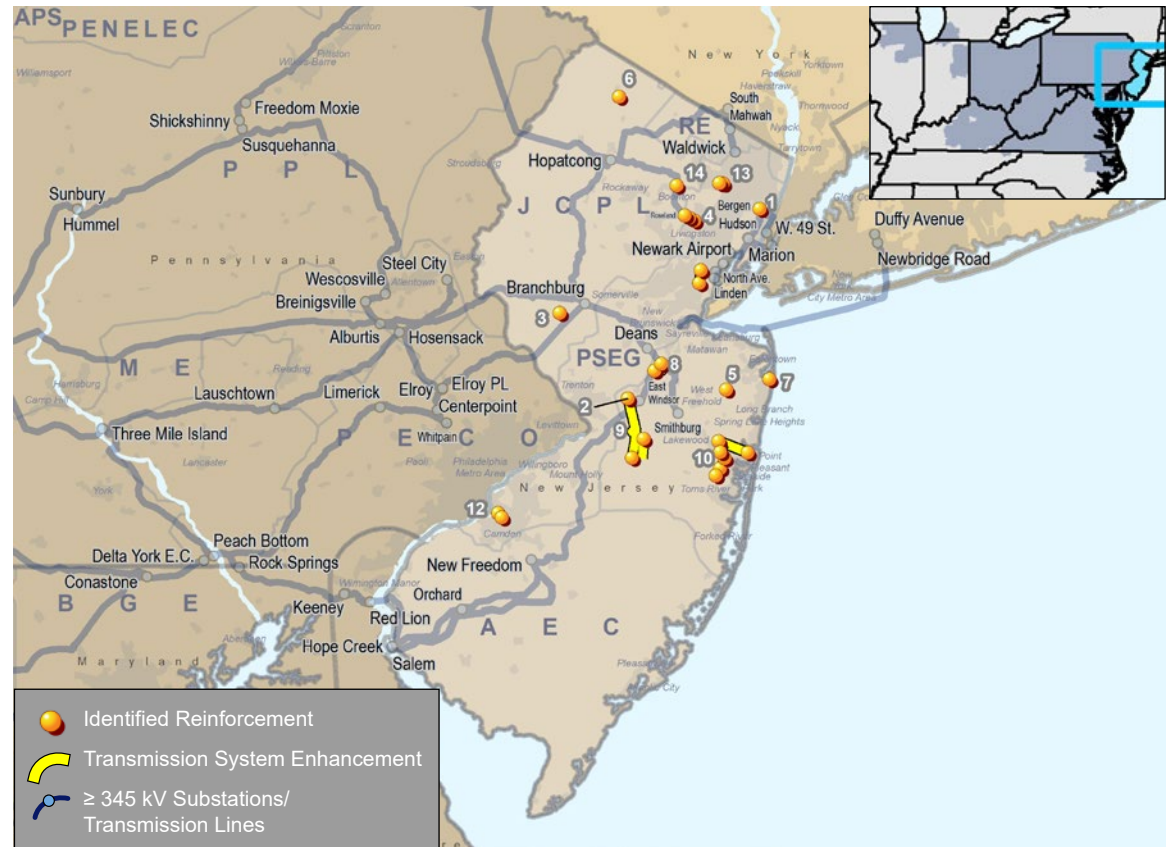
Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Ocean County LF	JCP&L	Biomass	2/26/2025	7/1/2025	37	9.1
Forked River Unit 1	JCP&L	Natural Gas	2/25/2025	6/1/2027	36	34
Forked River Unit 2	JCP&L	Natural Gas	7/22/2025	6/1/2027	36	31
Sherman Avenue CT1	ACE	Natural Gas	1/28/2025	6/1/2027	34	79
Cumberland CT 1	ACE	Natural Gas	1/28/2025	6/1/2027	35	79

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**6.7.6 — Baseline Projects**

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in New Jersey are summarized in **Map 6.29** and **Table 6.36**.

**Map 6.29: New Jersey Baseline Projects (Dec. 31, 2025)**



**Table 6.36: New Jersey Baseline Projects (Dec. 31, 2025)**

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B3869.3	Replace the two Bergen 138 kV series reactors with two new dry-type 138 kV series reactors.	12/1/2029	\$12.77	PSEG	10/16/2025	N/A - Scope Change	Baseline Load Growth Deliverability & Reliability

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**Table 6.36:** New Jersey Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
2	B3986.1	Replace Windsor 34.5 kV breakers: KQ, Q143, 324-B-25 (J136-1), 324-B-22 (J2), 324-B-31 (MG), 324-B-34 (K137-1), 324-B-19 (BK2), 324-B-28 (M65-1), 324-B-16 (G215-1), BK4, 324-B-7 (H4), 324-B-8 (H60), 324-B-54 (BK5_BBUS), 324-B-51 (BK5_ABUS).	6/1/2030	\$8.36	JCP&L	11/13/2025	No	TO Criteria Violation
3	B3987.1	Replace East Flemington 34.5 kV circuit breakers C731, V724, A729, TC, H736, AV, YH and Y727 with 3000A 40 kA breakers.	6/1/2030	\$3.46	JCP&L	11/13/2025	No	TO Criteria Violation
4	B4005.1	Replace the existing 1590 ACSR single conductor on the Roseland to Livingston 230 kV line with a 1590 ACSS single conductor.	6/1/2030	\$4.87	PSEG	11/4/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4005.2	Replace the existing 1590 ACSR single conductor on the Roseland to Laurel Ave 230 kV line with a 1590 ACSS single conductor.	6/1/2030	\$5.06	PSEG	11/4/2025	Yes (Reliability W1)	
5	B4013.1	Install a 10.8 MVAR capacitor at Colts Neck 34.5 kV substation.	6/1/2030	\$2.69	JCP&L	11/13/2025	No	TO Criteria Violation
6	B4014.1	Install a 5.4 MVAR capacitor at Sussex 34.5 kV substation.	6/1/2030	\$2.28	JCP&L	11/13/2025	No	TO Criteria Violation
7	B4015.1	Replace the 34.5 kV line terminal disconnect switch at Long Branch substation.	6/1/2030	\$0.53	JCP&L	11/13/2025	No	TO Criteria Violation
8	B4016.1	Rebuild the Jamesburg-Monroe 34.5 kV N40 line from Jamesburg substation to Monroe Junction substation, ~1.2 miles.	6/1/2030	\$5.13	JCP&L	11/13/2025	No	TO Criteria Violation
	B4016.2	Replace limiting conductor and revise relay settings at Monroe substation.	6/1/2030	\$0.21	JCP&L	11/13/2025	No	
	B4016.3	Install new relay and revise relay settings at Costco substation.	6/1/2030	\$0.25	JCP&L	11/13/2025	No	
	B4016.4	Rebuild a section of the Englishtown-Monroe Junction 34.5 kV H34 line that is mutual with the Costco-Monroe Junction 34.5 kV N40 line near Monroe Junction substation, ~0.4 miles.	6/1/2030	\$0.76	JCP&L	11/13/2025	No	

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Table 6.36: New Jersey Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
9	B4017.1	Upgrade line relaying at Van Hiseville substation.	6/1/2030	\$0.55	JCP&L	11/13/2025	No	TO Criteria Violation
	B4017.2	Rebuild Great Adventure 34.5 kV substation as an 11-breaker, breaker-and-a-half station.	6/1/2030	\$26.17	JCP&L	11/13/2025	No	
	B4017.3	Upgrade line relaying at Windsor substation.	6/1/2030	\$0.08	JCP&L	11/13/2025	No	
	B4017.4	Rebuild the Cookstown-Windsor 34.5 kV H60 line from Cookstown substation to structure No. 58 as a double circuit, ~4.7 miles. Terminate new line into Cookstown substation.	6/1/2030	\$14.59	JCP&L	11/13/2025	No	
	B4017.5	Rebuild the Cookstown-Van Hiseville 34.5 kV V22 line from structure No. 91445 to Great Adventure substation as a double circuit, ~5.2 miles.	6/1/2030	\$17.93	JCP&L	11/13/2025	No	
	B4017.6	At Cookstown substation, replace 34.5 kV breaker, two disconnect switches, relaying and ancillary terminal equipment.	6/1/2030	\$2.36	JCP&L	11/13/2025	No	
10	B4018.1	Purchase land needed to support construction of new 34.5 kV switching station.	6/1/2030	\$0.15	JCP&L	11/13/2025	No	TO Criteria Violation
	B4018.10	Install new hardware and wire on the Herbertsville-Larrabee 34.5 kV Q43 line to support the rebuild project of ~2.6 miles.	6/1/2030	\$14.82	JCP&L	11/13/2025	No	
	B4018.11	Install new hardware and wire on the Larrabee - Point Pleasant No. 2 34.5 kV R44 line to support the rebuild project, ~2.6 miles.	6/1/2030	\$17.80	JCP&L	11/13/2025	No	
	B4018.12	Install a new tie line (Ckt 1) from the existing Vermont Avenue substation to the new 34.5 kV ring bus station, ~0.1 miles.	6/1/2030	\$0.75	JCP&L	11/13/2025	No	
	B4018.13	Install a new tie line (Ckt 2) from the existing Vermont Avenue substation to the new 34.5 kV ring bus station, ~0.1 miles.	6/1/2030	\$0.68	JCP&L	11/13/2025	No	
	B4018.2	Replace line relaying at South Lakewood substation.	6/1/2030	\$0.15	JCP&L	11/13/2025	No	
	B4018.3	Terminate 34.5 kV lines to new 34.5 kV ring bus station.	6/1/2030	\$0.22	JCP&L	11/13/2025	No	
	B4018.4	Replace limiting conductor at Larrabee substation.	6/1/2030	\$0.13	JCP&L	11/13/2025	No	
	B4018.5	Remove equipment and add breakers and switches at Metedeconk substation. Remove equipment to isolate transformers.	6/1/2030	\$14.46	JCP&L	11/13/2025	No	
	B4018.6	Replace line relaying at Leisure Village substation.	6/1/2030	\$0.15	JCP&L	11/13/2025	No	
	B4018.7	Reconfigure 34.5 kV switchyard at Metedeconk substation to a breaker-and-a-half yard.	6/1/2030	\$2.18	JCP&L	11/13/2025	No	
	B4018.8	Build a new 34.5 kV ring bus switching station (adjacent to Vermont Avenue substation).	6/1/2030	\$13.33	JCP&L	11/13/2025	No	
B4018.9	Loop the Leisure Village-South Lakewood 34.5 kV F214 line into the new 34.5 kV ring bus station, ~0.1 miles.	6/1/2030	\$0.92	JCP&L	11/13/2025	No		

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Table 6.36: New Jersey Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
11	B4019.1	Replace/update riser structure, pot head, cable and sweeps as required to accept high-capacity conductor at Rahway 69 kV. Rebuild duct banks as needed.	6/1/2030	\$1.05	PSEG	11/13/2025	No	TO Criteria Violation
	B4019.2	Replace/update riser structure, pot head, cable and sweeps as required to accept high-capacity conductor at Roselle 69 kV. Rebuild duct banks as needed.	6/1/2030	\$1.35	PSEG	11/13/2025	No	
	B4019.3	Reconductor 69 kV line from Rahway to Roselle station. ~2 miles of OH will be wrecked and rebuilt, 2.5 miles of OH will be new construction and 0.2 miles of UG will have fiber replaced as required. High-capacity conductor to be rated at least 1,100 summer normal and 1,200 summer emergency.	6/1/2030	\$27.00	PSEG	11/13/2025	No	
12	B4020.1	Replace/update pole riser, pot head riser, associated sweeps and cable as required to accept high-capacity conductor at Gloucester 230 kV. Replace LP41K relays with new primary SEL-311L and backup SEL-411L relays and also replace duct banks as required.	6/1/2030	\$1.20	PSEG	11/13/2025	No	TO Criteria Violation
	B4020.2	Replace existing OH wire with high-capacity conductor at Nicholson 230 kV. Also replace LP10K relays with new primary SEL-311L and backup SEL-411L relays.	6/1/2030	\$0.15	PSEG	11/13/2025	No	
	B4020.3	Wreck and rebuild OH Gloucester-Nicholson 69 kV circuit including transfer of any underbuilt circuits below the 69 kV. Install composite poles instead of wood poles. Install shield wire, fiber and all necessary fiber accessories, and high-capacity conductor from Gloucester to Nicholson. Replace the UG cable with high-capacity conductor and sweeps as required.	6/1/2030	\$9.45	PSEG	11/13/2025	No	
13	B4021.1	Upgrade the Pfisterer connection inside of Prospect Park to accept new high-capacity cable; modify conduit as needed.	6/1/2030	\$0.67	PSEG	11/13/2025	No	TO Criteria Violation
	B4021.2	Upgrade the Pfisterer connection inside of North Paterson to accept new high-capacity cable; reconfigure duct banks in North Paterson to accommodate new high-capacity cable.	6/1/2030	\$1.17	PSEG	11/13/2025	No	
	B4021.3	Reconductor 69 kV line from Prospect Park to North Paterson with a high-capacity conductor, including installing new composite poles and manholes along the line as required.	6/1/2030	\$13.87	PSEG	11/13/2025	No	
	B4024.1	Rebuild existing Sharptown-Laurel 69 kV circuit utilizing 954 ACSR "Rail" 45/7 conductor.	6/1/2030	\$36.55	DP&L	11/13/2025	No	Baseline Load Growth Deliverability & Reliability

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Table 6.36: New Jersey Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
14	B4032.1	Install a 500 kV double-breaker double-bus at Montville substation. Install a 500/230 kV transformer and 500 kV breaker. Install new breaker string in the 230 kV yard to create a breaker-and-a-half layout. Reterminate the 230-34.5 kV transformers.	6/1/2030	\$72.14	JCP&L	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4032.2	Replace the double-pole wood structure No. 154 on the Montville-Whippany 34.5 kV, K115 line with a monopole and UG riser. Install ~200 ft. of new UG conductor to be spliced with existing section of UG conductor into Montville substation.	6/1/2030	\$1.49	JCP&L	1/6/2026	Yes (Reliability W1)	
	B4032.3	Replace the double-pole wood structure No. 154 on the Montville-Whippany 34.5 kV O93 line with a monopole UG riser and install ~200 ft. of new UG conductor to be spliced with existing section of UG conductor into the Montville substation.	6/1/2030	\$1.13	JCP&L	1/6/2026	Yes (Reliability W1)	
	B4032.4	Loop the Roseland-Hopatcong 500 kV line into JCP&L Montville substation.	6/1/2030	\$9.04	PSEG	1/6/2026	Yes (Reliability W1)	
	B4032.5	Upgrade 500 kV terminal at Hopatcong and Roseland. Loop the Roseland-Hopatcong 500 kV line into Montville substation.	6/1/2030	\$0.65	PSEG	1/6/2026	Yes (Reliability W1)	
	B4032.6	Rework PSEG 230 kV lines into JCP&L Montville substation.	6/1/2030	\$13.63	PSEG	1/6/2026	Yes (Reliability W1)	
CEII	B3939.1	2024W1 PSEG P5 Solution #1 – Battery monitoring upgrades at PSEG substation. Addresses flowgate #2024-P5-PSEG01.	6/1/2029	\$0.08	PSEG	7/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B3939.2	2024W1 PSEG P5 Solution #2 – Battery monitoring upgrades at PSEG substation. Addresses flowgate #2024-P5-PSEG02.	6/1/2029	\$0.08	PSEG	7/8/2025	No	
	B3939.3	2024W1 PSEG P5 Solution #3 – Battery monitoring upgrades at PSEG substation. Addresses flowgate #2024-P5-PSEG03.	6/1/2029	\$0.08	PSEG	7/8/2025	No	
	B3939.4	2024W1 PSEG P5 Solution #4 – Battery monitoring upgrades at PSEG substation. Addresses flowgate #2024-P5DYN-PSEG01.	6/1/2029	\$0.08	PSEG	7/8/2025	No	
	B3939.5	2024W1 PSEG P5 Solution #5 – Battery monitoring upgrades at PSEG substation. Addresses flowgate #2024-P5DYN-PSEG02.	6/1/2029	\$0.08	PSEG	7/8/2025	No	
	B4042.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5DYN-JCP&L03.	6/1/2029	\$0.48	JCP&L	12/8/2025	No	
	B4043.1	2024W1 P5: Modify relay wiring. Addresses flowgate No. 2024-P5-JCP&L06.	6/1/2029	\$0.66	JCP&L	12/8/2025	No	Baseline Load Growth Deliverability & Reliability

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**Table 6.36:** New Jersey Baseline Projects (Dec. 31, 2025) (Cont.)

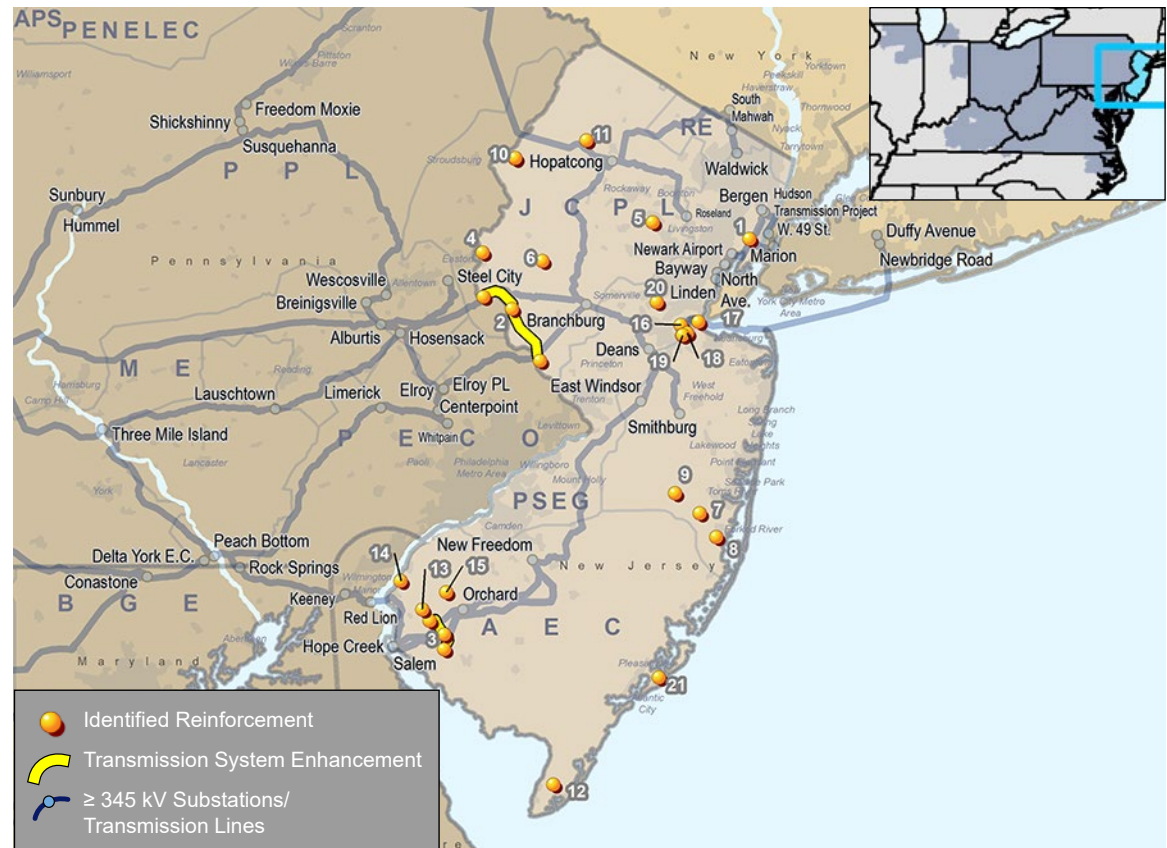
Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
CEII	B4045.1	2024W1 P5: Install relay panel and modify relay wiring. Addresses flowgate No. 2024-P5-JCP&L01.	6/1/2029	\$0.66	JCP&L	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4046.1	2024W1 P5: Install battery monitoring, DC panel and modify relay wiring. Addresses flowgate No. 2024-P5DYN-JCP&L04.	6/1/2029	\$0.81	JCP&L	12/8/2025	No	Stability
	B4047.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5-JCP&L03.	6/1/2029	\$0.64	JCP&L	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4049.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5DYN-JCP&L02.	6/1/2029	\$0.97	JCP&L	12/8/2025	No	Stability
	B4067.1	2024W1 P5: Install battery monitoring, DC panel and modify relay wiring. Addresses flowgate No. 2024-P5DYN-JCP&L01.	6/1/2029	\$0.81	JCP&L	12/8/2025	No	Stability
	B4075.1	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-AEC01.	6/1/2029	\$0.02	ACE	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4075.2	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-AEC02.	6/1/2029	\$0.02	ACE	12/8/2025	No	
	B4075.3	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-AEC03.	6/1/2029	\$0.02	ACE	12/8/2025	No	
	B4075.4	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-AEC04.	6/1/2029	\$0.02	ACE	12/8/2025	No	
	B4075.5	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-AEC05.	6/1/2029	\$0.02	ACE	12/8/2025	No	
	B4075.6	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-AEC06.	6/1/2029	\$0.02	ACE	12/8/2025	No	
	B4075.7	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-AEC07.	6/1/2029	\$0.02	ACE	12/8/2025	No	
	B4075.8	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-AEC08.	6/1/2029	\$0.02	ACE	12/8/2025	No	

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**6.7.7 — Network Projects**

Network projects in New Jersey for 2025 are summarized in **Map 6.30** and **Table 6.37**.

**Map 6.30: New Jersey Network Projects (Dec. 31, 2025)**



**Table 6.37: New Jersey Network Projects (Dec. 31, 2025)**

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	N8529	New relays to accommodate the AF1-245 generator lead line.	AF1-245	12/1/2028	\$0.08	PSEG	10/8/2025

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Table 6.37: New Jersey Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
2	N8532.1	Install two 34.5 kV load-break air switches with SCADA control on the Gilbert-Rocktown Road 34.5 kV line ~1.2 miles from Frenchtown and 3.5 miles from Frenchtown Solar 3. Provide 120V AC power supply to accommodate SCADA-controlled line switches.	AG1-495	10/1/2027	\$1.38	JCP&L	10/8/2025
	N8532.2	Build new structures on the A729 West Flemington 34.5 kV line to facilitate construction of new tap on the Gilbert-Rocktown Road 34.5 kV line.	AG1-495	10/1/2027	\$0.82	JCP&L	10/8/2025
	N8532.3	Review relay settings at Gilbert substation.	AG1-495	10/1/2027	\$0.05	JCP&L	10/8/2025
	N8547	At Gilbert substation, remove circuit switcher BK12. Install one 230 kV H-frame, three CVTs, three surge arresters and one MOAB disconnect switch, and relaying. Install prewired relay panel and update relay settings.	AG1-487	12/31/2026	\$2.05	JCP&L	10/8/2025
	N8532.4	Review relay settings at Rocktown Road substation.	AG1-495	10/1/2027	\$0.05	JCP&L	10/8/2025
3	N8535	Construct a new 69 kV three-position ring bus substation off the right-of-way for line (Laurel-Roadstown) No. 0799. Two of the positions will be transmission line terminals for the tie-in of line No. 0799 to the substation. The third position will be a terminal configured for the interconnection of the AF1-208 generator.	AF1-208	12/31/2028	\$12.95	ACE	10/8/2025
	N8536	Cut and loop in No. 0799 transmission line (Laurel-Roadstown) to the new 69 kV three-position ring bus substation. The line from the new ring bus to Laurel will remain as No. 0799, while the line from the new ring bus to Roadstown will be named No. 06XX.	AF1-208	12/31/2028	\$1.95	ACE	10/8/2025
	N8537	Update relaying at Laurel substation for the No. 0799 line from Laurel to the new AF1-208 substation.	AF1-208	12/31/2028	\$0.13	ACE	10/8/2025
	N8538	Update relaying at Roadstown substation for the No. 06XX line from the new AF1-208 substation to Roadstown.	AF1-208	12/31/2028	\$0.13	ACE	10/8/2025
4	N8548	At Morris Park substation, update the relay settings for the 230 kV Gilbert-Morris Park line terminal.	AG1-487	12/31/2026	\$0.06	JCP&L	10/8/2025
5	N8549	At Morristown substation, update the relay settings for the 230 kV Gilbert-Morristown line terminal.	AG1-487	12/31/2026	\$0.06	JCP&L	10/8/2025
6	N8550	At Glen Gardner substation, update the relay settings for the 230 kV Gilbert-Glen Gardner line terminal.	AG1-487	12/31/2026	\$0.06	JCP&L	10/8/2025
7	N8565	At Oyster Creek-Whitings 34.5 kV, install two line switches, one on each side of tap on the Q121 Oyster Creek-Whitings 34.5 kV line, ~1.5 miles from Bamber Lake to the generator facility near structure 90200.	AG1-188	3/31/2027	\$1.09	JCP&L	10/8/2025
	N8583	At Oyster Creek-Whitings 34.5 kV, install two line switches, one on each side of tap on the Q121 Oyster Creek-Whitings 34.5 kV line, ~4.5 miles from Oyster Creek and 4 miles from Bamber Lake to the generator facility near structure 90253.	AG1-189	3/31/2027	\$1.02	JCP&L	10/8/2025
8	N8566	Revise relay settings at Oyster Creek substation.	AG1-188	3/31/2027	\$0.07	JCP&L	10/8/2025
	N8584	Revise relay settings at Oyster Creek substation.	AG1-189	3/31/2027	\$0.07	JCP&L	10/8/2025
9	N8567	Revise relay settings at Whitings substation.	AG1-188	3/31/2027	\$0.07	JCP&L	10/8/2025
	N8585	Revise relay settings at Whitings substation.	AG1-189	3/31/2027	\$0.07	JCP&L	10/8/2025
10	N8568	At Kittatinny substation, install new 230 kV breakers, disconnect switches and line terminal for AG1-511 direct connection.	AG1-511	5/31/2028	\$4.70	JCP&L	10/8/2025
	N8569	Relay setting changes at Yards Creek substation.	AG1-511	5/31/2028	\$0.07	JCP&L	10/8/2025
11	N8570	Relay setting changes at Newton substation.	AG1-511	5/31/2028	\$0.07	JCP&L	10/8/2025
12	N8660.0	Add a new terminal position "F" at 138/69 kV Middle substation 69 kV bus No. 1, including new circuit breakers, disconnect switches, supporting foundations and structures, among other physical equipment.	AF2-019	4/30/2028	\$2.56	ACE	10/8/2025

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Table 6.37: New Jersey Network Projects (Dec. 31, 2025) (Cont.)

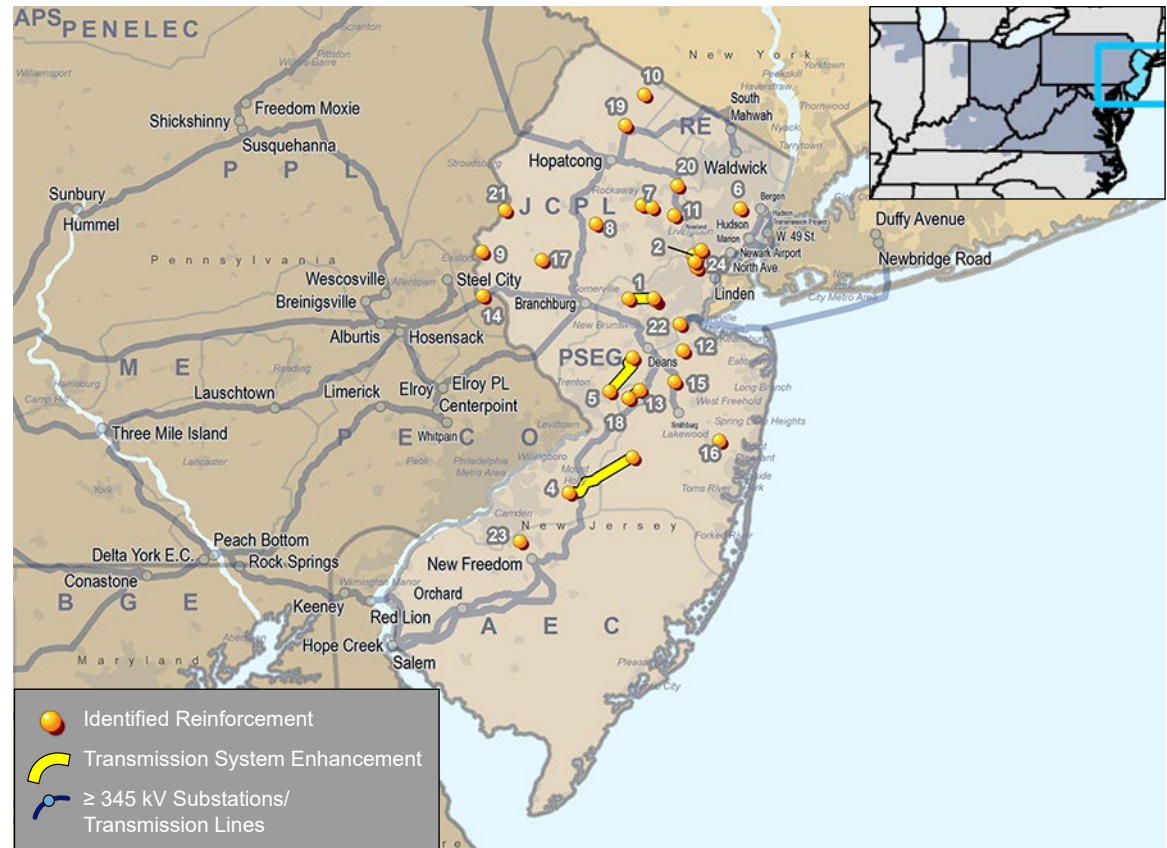
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
13	N8943.0	Construct a new 69 kV substation consisting of a three-position ring bus off the right-of-way for line No. 0724 (Salem-Woodstown). Two of the positions on the ring bus will be transmission line terminals for the tie-in of line No. 0724 to the substation. The third position will be a terminal configured for the interconnection of the AG1-254 generator. Install new protective relays for the AG1-254 terminal and ACE line terminals on the new three-breaker ring bus.	AG1-254	5/1/2029	\$11.12	ACE	10/8/2025
	N8946.0	Modify line No. 0724 to loop it in and out of the new ring bus. Install two steel poles and two overhead spans to the new substation.	AG1-254	5/1/2029	\$1.28	ACE	10/8/2025
14	N8944.0	Update primary relaying for line No. 0724 at Churchtown substation.	AG1-254	5/1/2029	\$0.02	ACE	10/8/2025
15	N8945.0	Update primary relaying for line No. 0724 at Woodstown substation.	AG1-254	5/1/2029	\$0.02	ACE	10/8/2025
16	N8948.0	Reconfigure Raritan River substation and add a new 230 kV circuit breaker to support AF2-413 generator interconnection.	AF2-413	11/30/2029	\$4.47	JCP&L	10/8/2025
17	N8949.0	Upgrade relay settings for EH Werner substation.	AF2-413	11/30/2029	\$0.06	JCP&L	10/8/2025
18	N8950.0	Upgrade relay settings for Parlin substation.	AF2-413	11/30/2029	\$0.06	JCP&L	10/8/2025
19	N8951.0	Upgrade relay settings for Red Oak substation.	AF2-413	11/30/2029	\$0.06	JCP&L	10/8/2025
	N8952.0	Upgrade relay settings for South River substation.	AF2-413	11/30/2029	\$0.06	JCP&L	10/8/2025
20	N8985.0	Update relay settings at Lake Nelson for the two circuits entering the station from JCP&L's Raritan River station.	AF2-413	11/30/2029	\$0.31	PSEG	10/8/2025
21	N9100.0	Install new 69 kV terminal position at Ontario 69 kV substation.	AF2-025	2/28/2028	\$9.13	ACE	10/8/2025

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**6.7.8 — Supplemental Projects**

Supplemental projects included in the 2025 Local Plan in New Jersey are summarized in **Map 6.31** and **Table 6.38**.

**Map 6.31: New Jersey Supplemental Projects (Dec. 31, 2025)**



**Table 6.38: New Jersey Supplemental Projects (Dec. 31, 2025)**

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S3261.2	At Bridgewater switch and Lake Nelson substation, replace primary and backup I-1023 line relays with new relays. Remove all existing power-line communication (PLC) equipment and line traps in switchyard and the PLC equipment in the control house. Between Bridgewater switch and Middlesex (FirstEnergy), install new 96-strand OPGW (~6.18 miles) from Bridgewater to Middlesex (FirstEnergy). Between Lake Nelson substation and Middlesex (FirstEnergy), install new ADSS from Middlesex (FirstEnergy) to intercept and splice into the existing 230 kV GBLN circuit ADSS fiber cable.	12/21/2027	\$9.50	PSEG	1/7/2025

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Table 6.38: New Jersey Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
2	S3439.1	Build new Galloping Hill 230/69 kV substation. Cut and loop Springfield Road-Aldene 230 kV circuit into new 230/69 kV station. Install one 230/69 kV transformer. Construct a 69/13 kV substation. Cut and loop Springfield Road-Roselle 69 kV circuit into the new substation. Install two 69/13 kV transformers.	12/30/2029	\$72.40	PSEG	7/9/2024
	S3439.2	Construct a 69/13 kV substation. Cut and loop Springfield Road-Roselle 69 kV circuit into the new substation.	12/30/2029	\$51.40	PSEG	7/9/2024
	S3439.3	Install one 230/69 kV transformer. Install two 69/13 kV transformers.	12/30/2029	\$45.20	PSEG	7/9/2024
3	S3569.1	Build a new Pemberton 230/13 kV substation.	12/31/2029	\$47.40	PSEG	12/3/2024
4	S3569.2	Cut and loop 230 kV line from Lumberton (PSE&G) to Cookstown (JCP&L) and upgrade to fiber protection.	12/31/2029	\$15.30	PSEG	12/3/2024
	S3569.3	First Energy (JCP&L) to install a fiber connection on JCP&L owned portion from Pemberton to Cookstown.	12/31/2029	\$1.80	PSEG	12/3/2024
5	S3570.1	Cut and loop 69 kV line from Ridge Road station to West Windsor station into customer's new station.	6/30/2026	\$3.40	PSEG	1/16/2025
6	S3604.1	Replace existing 138/26 kV transformers 132-1 and 132-2 and add two 138 kV transformer head breakers.	5/31/2028	\$41.90	PSEG	9/19/2024
	S3604.2	Add one 138 kV bus-tie breaker to existing 138 kV straight bus.	5/31/2028	\$1.50	PSEG	9/19/2024
7	S3609.1	Rebuild ~14.1 miles of Greystone-Morristown-Whippany 34.5 kV I61 line. Install new conductor on 2.3 miles of rebuilt double-circuit structures, shared with the Greystone-Whippany 34.5 kV I61 line.	6/11/2027	\$20.10	JCP&L	3/13/2025
8	S3610.1	Replace No. 1 230/34.5 kV transformer at Chester substation. Replace associated 34.5 kV breaker and limiting terminal components.	11/12/2027	\$7.30	JCP&L	3/4/2025
	S3617.1	Replace No. 4 230-34.5 kV transformer at Chester substation. Replace associated 230 kV circuit switcher and 34.5 kV breaker. Replace limiting terminal components.	12/31/2029	\$7.30	JCP&L	3/4/2025
9	S3611.1	Convert Morris Park 230 kV substation into a four-breaker ring bus. Build 1,600 feet of new 230 kV line to loop in the Gilbert-Martins Creek 230 kV P2016 line into the Morris Park substation 230 kV ring bus. Install a second 230-34.5 kV transformer at Morris Park substation. Remove the existing 115-34.5 kV transformer and all associated 115 kV equipment from Morris Park substation.	1/29/2027	\$15.40	JCP&L	11/6/2024
10	S3612.1	Replace the No. 4 115-34.5 kV transformer at Vernon substation. Replace the 115 kV circuit switcher with a circuit breaker. Replace the 34.5 kV circuit breaker. Upgrade transformer relaying.	8/31/2029	\$7.00	JCP&L	11/14/2024
11	S3613.1	Replace No. 12 230/115 kV transformer at Whippany substation. Replace transformer relaying and limiting substation conductor.	3/7/2030	\$8.10	JCP&L	3/4/2025
12	S3614.1	Replace the No. 2 115-34.5 kV transformer at Deep Run substation. Replace 115 kV circuit switcher with circuit breaker. Upgrade transformer relaying.	12/31/2027	\$8.00	JCP&L	11/14/2024
13	S3615.1	Replace the Windsor No. 3 230-34.5 kV transformer with a larger unit. Replace 230 kV circuit switcher with MOAB. Replace two 34.5 kV circuit breakers. Replace the transformer relaying.	12/22/2028	\$9.70	JCP&L	12/3/2024
14	S3616.1	Replace the No. 2 and No. 3 115-34.5-13.2 kV transformers at Gilbert substation with one new unit. Upgrade transformer relaying.	12/31/2028	\$8.00	JCP&L	11/14/2024
15	S3618.1	Replace the No. 1 115-34.5 kV transformer at Englishtown substation. Replace 115 kV circuit switcher with circuit breaker. Upgrade transformer relaying.	12/31/2027	\$7.00	JCP&L	11/14/2024
16	S3619.1	Replace the 230-34.5 kV No. 3 transformer at Larrabee substation. Replace 230 kV MOAB Replace 34.5 kV circuit breaker and disconnect switches. Upgrade transformer relaying.	4/12/2027	\$7.30	JCP&L	2/4/2025
17	S3620.1	Replace the 230-34.5 kV No. 2 Transformer at Glen Gardner substation. Replace 230 kV circuit switcher with circuit breaker. Replace 34.5 kV circuit breaker and disconnect switch. Upgrade transformer relaying.	5/1/2025	\$7.50	JCP&L	2/4/2025

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Table 6.38: New Jersey Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
18	S3621.1	Build a new 34.5 kV, 12-breaker, breaker-and-a-half substation. Cut into the Windsor-Wyckoff Street M65 34.5 kV line near structure No. 533 and construct approximately one to two spans of transmission line from the M65 line to the new FirstEnergy substation. Cut into the Windsor-Wyckoff Street J136 34.5 kV line near structure No. 53 and construct approximately two 1.2-mile transmission lines from the J136 line to the new FirstEnergy substation. Install three new 34.5 kV breakers at Windsor substation and build two 3.0-mile transmission lines from Windsor substation to the new FirstEnergy substation on shared structures. Build two spans of transmission line from the new substation to the point of interconnection with the customer. Install two 34.5 kV revenue metering packages at customer substation. Modify relay settings at Wyckoff Street, Windsor, Coke and McGraw Hill substations.	7/24/2027	\$54.00	JCP&L	10/17/2024
19	S3636.1	Replace 115-34.5 kV transformer No. 1 at Franklin substation. Replace limiting substation conductor and relaying.	12/28/2029	\$6.00	JCP&L	4/10/2025
20	S3637.1	Montville Automatic Restoration Project: At Montville-Riverdale 34.5 kV L116 line, upgrade line protection at Montville substation. At Montville-Riverdale 34.5 kV M117 line, upgrade line protection at Montville substation.	7/5/2026	\$0.15	JCP&L	4/10/2025
21	S3638.1	Pequest River No. 1 115-34.5 kV transformer: Replace No. 1 115/34.5 kV transformer at Pequest River substation. Replace 34.5 kV disconnect switches. Replace limiting substation conductor and relaying.	1/30/2030	\$6.90	JCP&L	4/10/2025
22	S3639.1	Raritan River No. 4 115/34.5 kV transformer: Replace No.4 115/34.5 kV transformer at Raritan River substation. Replace 115 kV circuit switcher with 115 kV circuit breaker. Replace 115 kV disconnect switches. Replace 34.5 kV disconnect switches. Replace limiting substation conductor and relaying.	3/30/2029	\$6.91	JCP&L	4/10/2025
23	S3664.1	Rebuild Pine Hill as a seven-position indoor GIS breaker-and-a-half substation. Split the existing three-terminal Sickler-Pine Hill-Stratford line at Pine Hill to create Sickler-Pine Hill and Pine Hill-Stratford transmission circuits.	9/1/2029	\$35.53	ACE	2/13/2025
24	S3729.1	Cut and loop the 69 kV (prior approved) line from Roselle to Galloping Hill into the customer's new substation.	6/1/2026	\$15.65	PSEG	3/13/2025
	S3729.2	Construct a new 69 kV circuit from the new customer substation to Stanley Terrace substation.	6/1/2029	\$36.00	PSEG	3/13/2025
	S3729.3	Install cap bank at 69 kV Roselle.	6/1/2026	\$4.35	PSEG	3/13/2025
	S3729.4	Install cap bank at 69 kV Galloping Hill.	6/1/2029	\$6.15	PSEG	3/13/2025
	S3729.5	Install cap bank at 69 kV Kenilworth Data Center.	6/1/2026	\$4.65	PSEG	3/13/2025

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## 6.8: North Carolina RTEP Summary

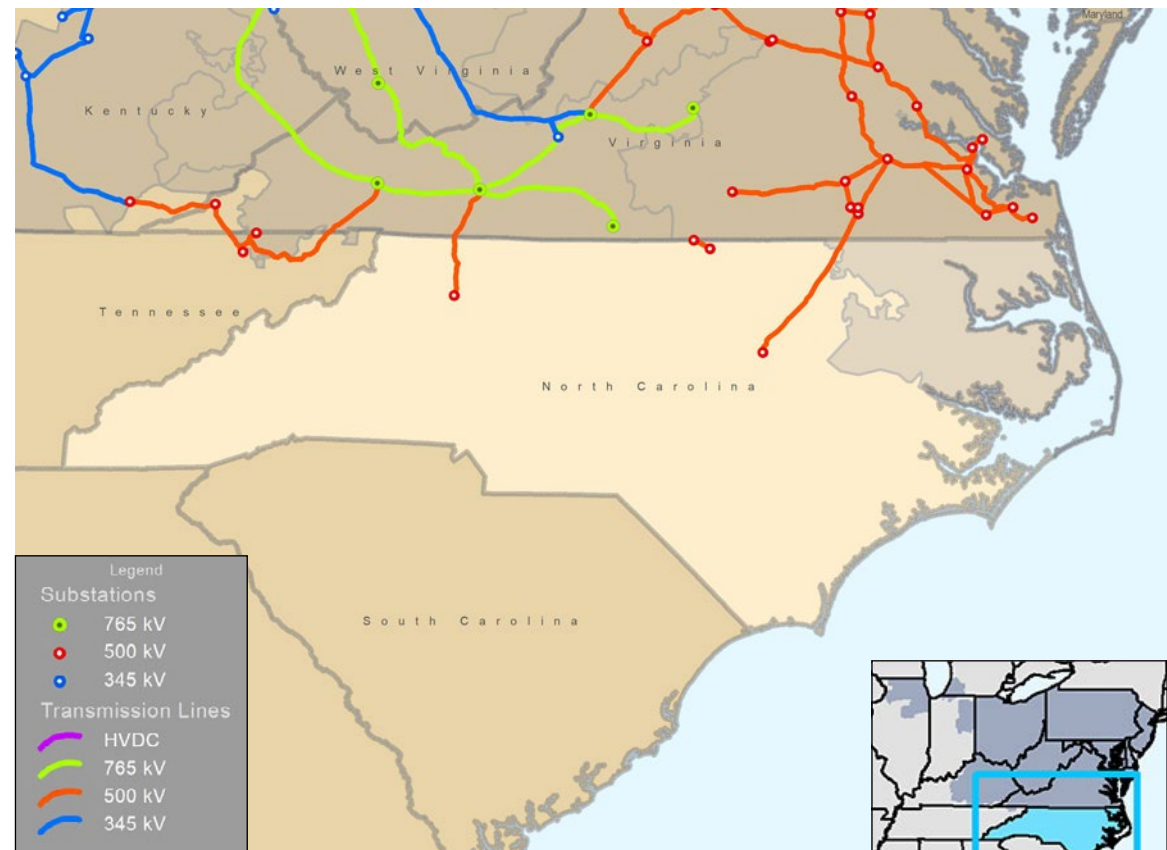
### 6.8.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in North Carolina, including facilities owned and operated by Dominion Energy as shown on **Map 6.32**. North Carolina's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

#### **Renewable Portfolio Standards**

North Carolina has a mandatory renewable portfolio standard (RPS) target of 12.5% for investor-owned utilities. The target is 10% for the state's electric cooperatives and municipalities.

**Map 6.32:** PJM Service Area in North Carolina

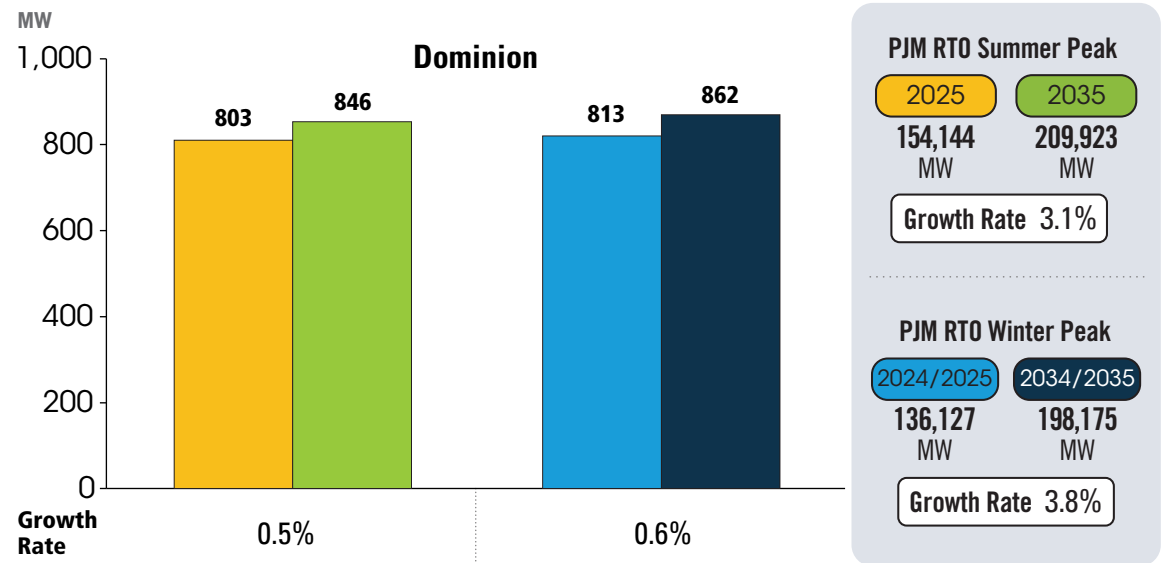


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### 6.8.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.36** summarizes the expected loads within the state of North Carolina and across the PJM region.

**Figure 6.36:** North Carolina – 2025 Long-Term Load Forecast



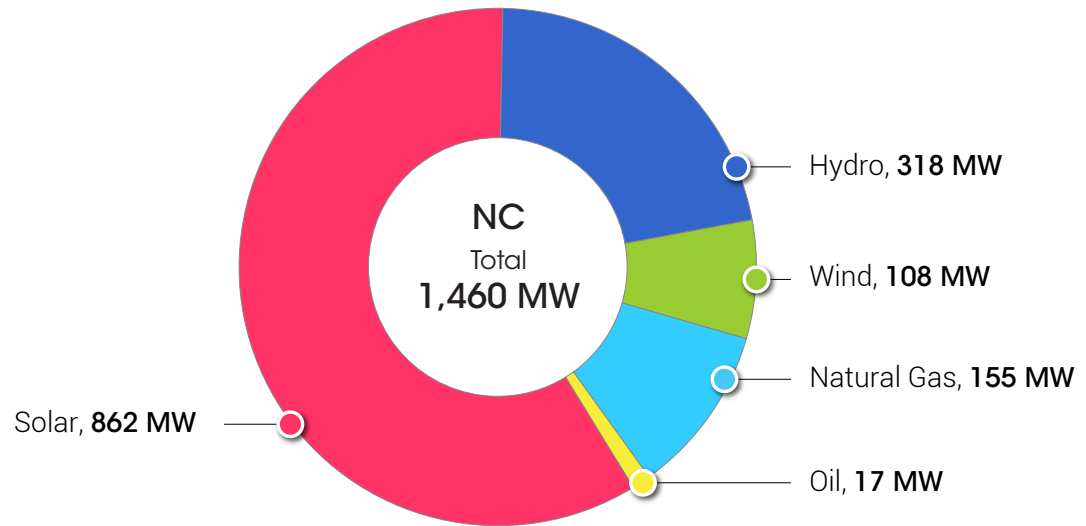
PJM notes that Dominion Energy serves load other than in North Carolina. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by Dominion solely in North Carolina. Estimated amounts were calculated based on the average share of Dominion's real-time summer and winter peak load located in North Carolina over the past five years.

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**6.8.3 — Existing Generation**

Existing generation in North Carolina as of Dec. 31, 2025, is shown by fuel type in **Figure 6.37**.

**Figure 6.37:** North Carolina – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



**6.8.4 — Interconnection Requests**

In North Carolina, as of Dec. 31, 2025, 31 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.39**, **Table 6.40**, **Figure 6.38**, **Figure 6.39** and **Figure 6.40**.

**Table 6.39:** North Carolina – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

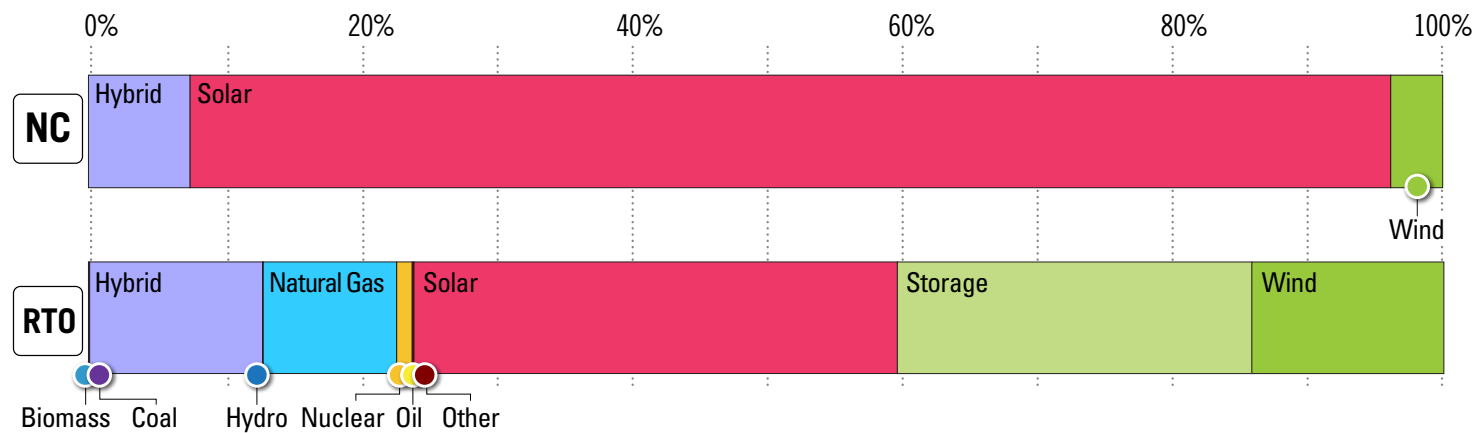
	North Carolina Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Biomass	0.0	0.00%	10.0	0.01%
Coal	0.0	0.00%	14.0	0.01%
Hybrid	110.0	7.52%	14,332.3	12.76%
Hydro	0.0	0.00%	30.0	0.03%
Natural Gas	0.0	0.00%	11,082.0	9.87%
Nuclear	0.0	0.00%	1,305.9	1.16%
Oil	0.0	0.00%	50.0	0.04%
Other	0.0	0.00%	56.3	0.05%
Solar	1,295.6	88.62%	40,116.0	35.73%
Storage	0.0	0.00%	29,376.0	26.16%
Wind	56.4	3.86%	15,910.7	14.17%
<b>Grand Total</b>	<b>1,462.0</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

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**Table 6.40:** North Carolina – Interconnection Requests by Fuel Type (Dec. 31, 2025)

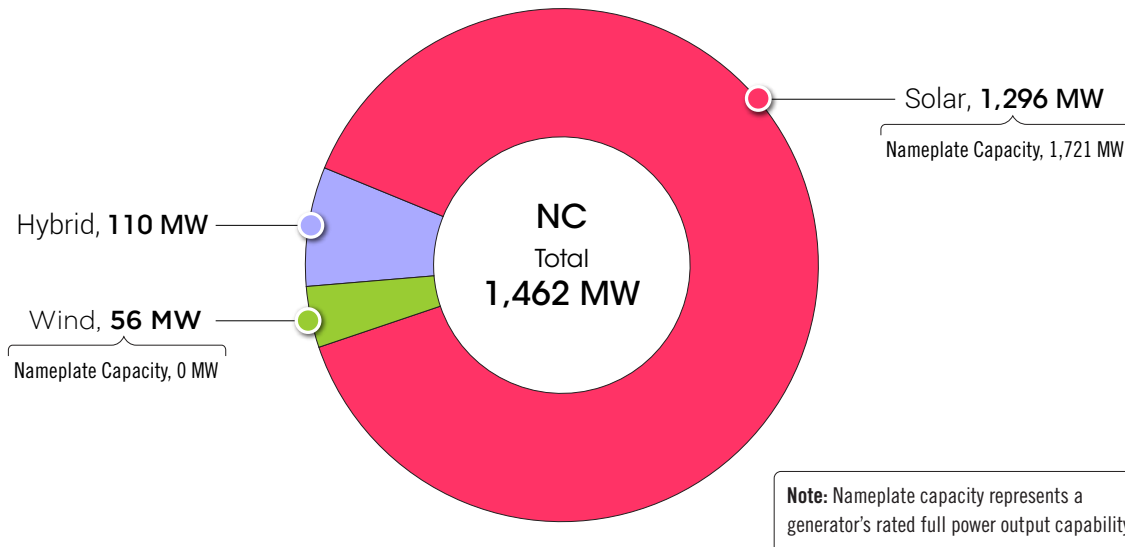
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
<b>Non-Renewable</b>	Storage	1	0.0	0	0.0	0	0.0	0	0.0	14	773.5	15	773.5
<b>Renewable</b>	Hybrid	1	7.0	0	0.0	2	103.0	0	0.0	16	903.6	19	1,013.6
	Methane	0	0.0	0	0.0	0	0.0	0	0.0	1	12.0	1	12.0
	Solar	13	426.7	3	103.4	10	765.6	32	992.6	99	4,753.8	157	7,042.1
	Wind	1	56.4	0	0.0	0	0.0	2	51.5	9	195.3	12	303.2
	Wood	0	0.0	0	0.0	0	0.0	1	50.0	1	80.0	2	130.0
	<b>Grand Total</b>	<b>16</b>	<b>490.1</b>	<b>3</b>	<b>103.4</b>	<b>12</b>	<b>868.6</b>	<b>35</b>	<b>1,094.1</b>	<b>140</b>	<b>6,718.2</b>	<b>206</b>	<b>9,274.3</b>

**Figure 6.38:** North Carolina – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

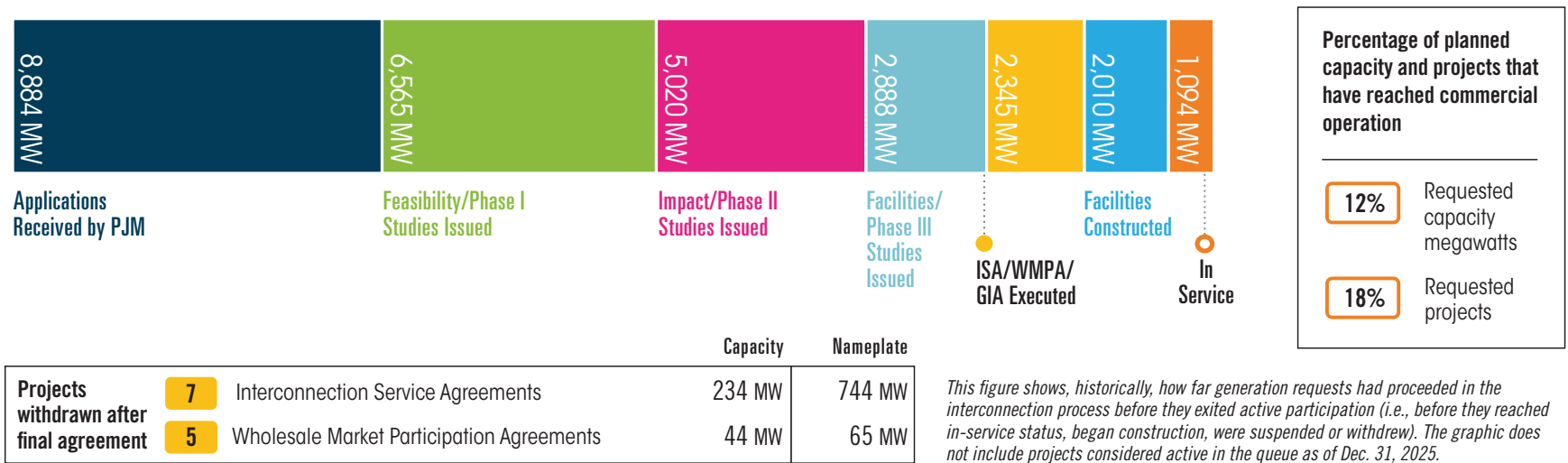


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**Figure 6.39:** North Carolina Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.40:** North Carolina Progression of Interconnection Requests (Dec. 31, 2025)

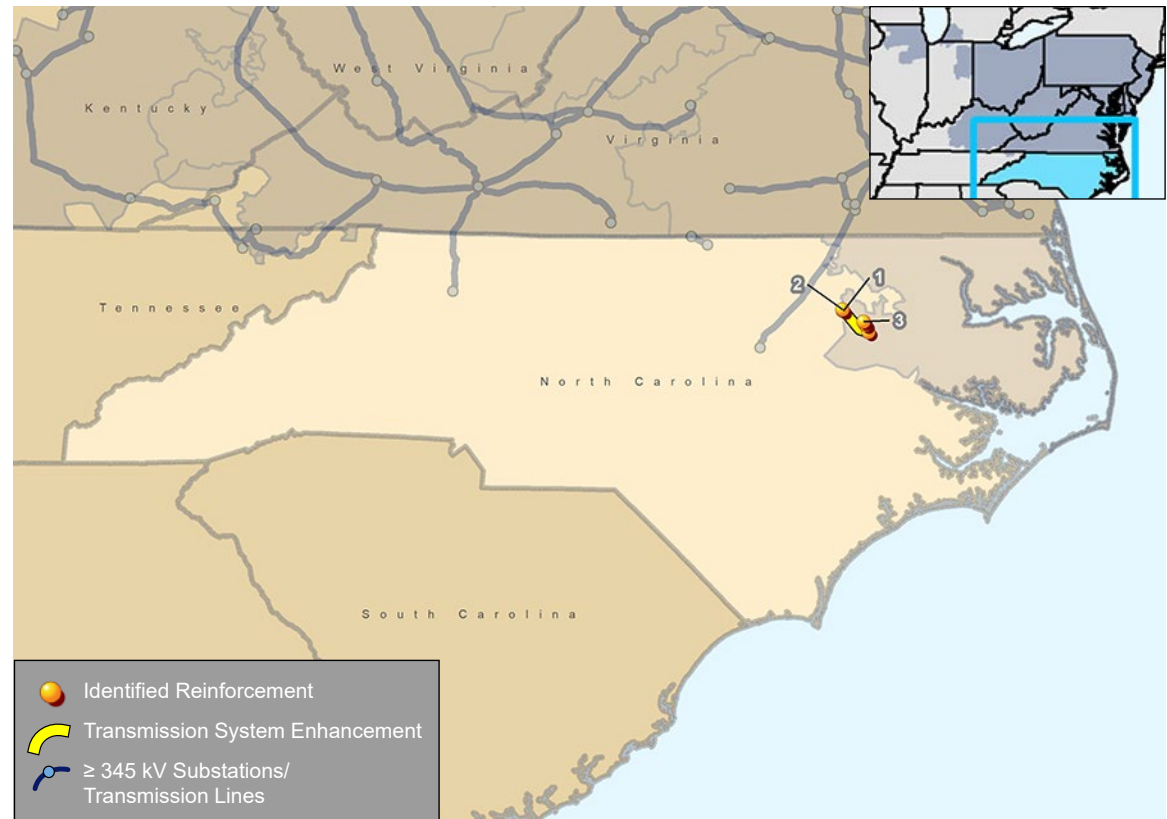


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### 6.8.5 — Network Projects

Network projects in North Carolina for 2025 are summarized in **Map 6.33** and **Table 6.41**.

**Map 6.33:** North Carolina Network Projects (Dec. 31, 2025)



**Table 6.41:** North Carolina Network Projects (Dec. 31, 2025)

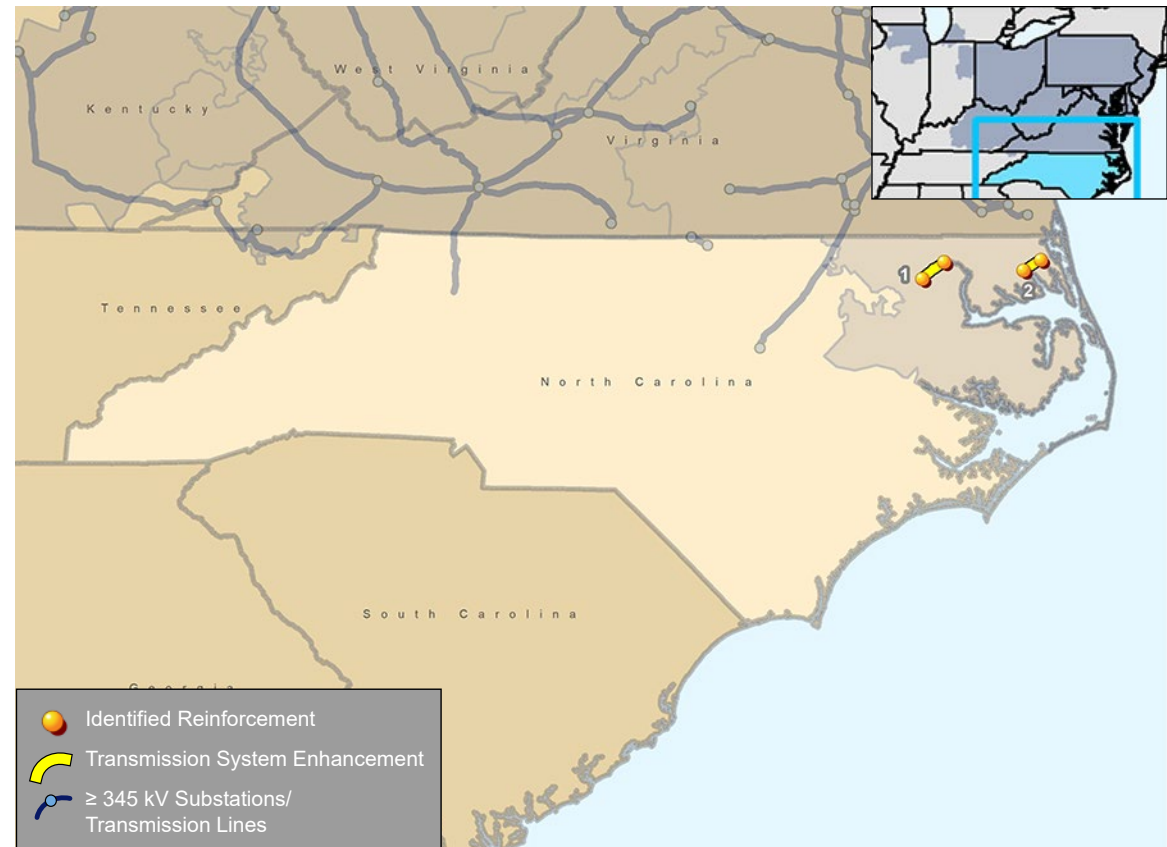
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	<b>N8936.1</b>	Construct a new 230 kV generation interconnect line into the Edgecombe Nug station. This will involve a total demo and rebuild of the existing Edgecombe Nug station.	AG1-000A	9/1/2029	\$10.47	Dominion	10/8/2025
2	<b>N8936.2</b>	Reenergize line 229 and line 2167 to interconnect Edgecombe 230 kV substation.	AG1-000A	9/1/2029	\$4.07	Dominion	10/8/2025
	<b>N8936.3</b>	Remote protection and communication work at Hathaway and Tarboro 230 kV substations.	AG1-000A	9/1/2029	\$0.39	Dominion	10/8/2025
3	<b>N9293.0</b>	Construct 12.5 kV circuit to Tar River substation.	AG1-007	6/1/2028	\$4.50	Dominion	10/8/2025
	<b>N9294.0</b>	Expand Tar River substation.	AG1-007	6/1/2028	\$1.50	Dominion	10/8/2025

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### 6.8.6 — Supplemental Projects

Supplemental projects included in the 2025 Local Plan in North Carolina are summarized in **Map 6.34** and **Table 6.42**.

**Map 6.34:** North Carolina Supplemental Projects (Dec. 31, 2025)



**Table 6.42:** North Carolina Supplemental Projects (Dec. 31, 2025)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S3597.1	Rebuild ~14.8 miles of line 136 between Earleys and Tunis to current 115 kV standards. The normal rating of the line conductor will be 393 MVA.	12/31/2028	\$50.00	Dominion	12/12/2024
2	S3685.1	Rebuild ~10.3 miles of line 2021 between Shawboro and Elizabeth City to current 230 kV standards. The normal rating of the line conductor will be 1573 MVA.	5/30/2025	\$30.60	Dominion	3/4/2025

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## 6.9: Ohio RTEP Summary

### 6.9.1 — RTEP Context

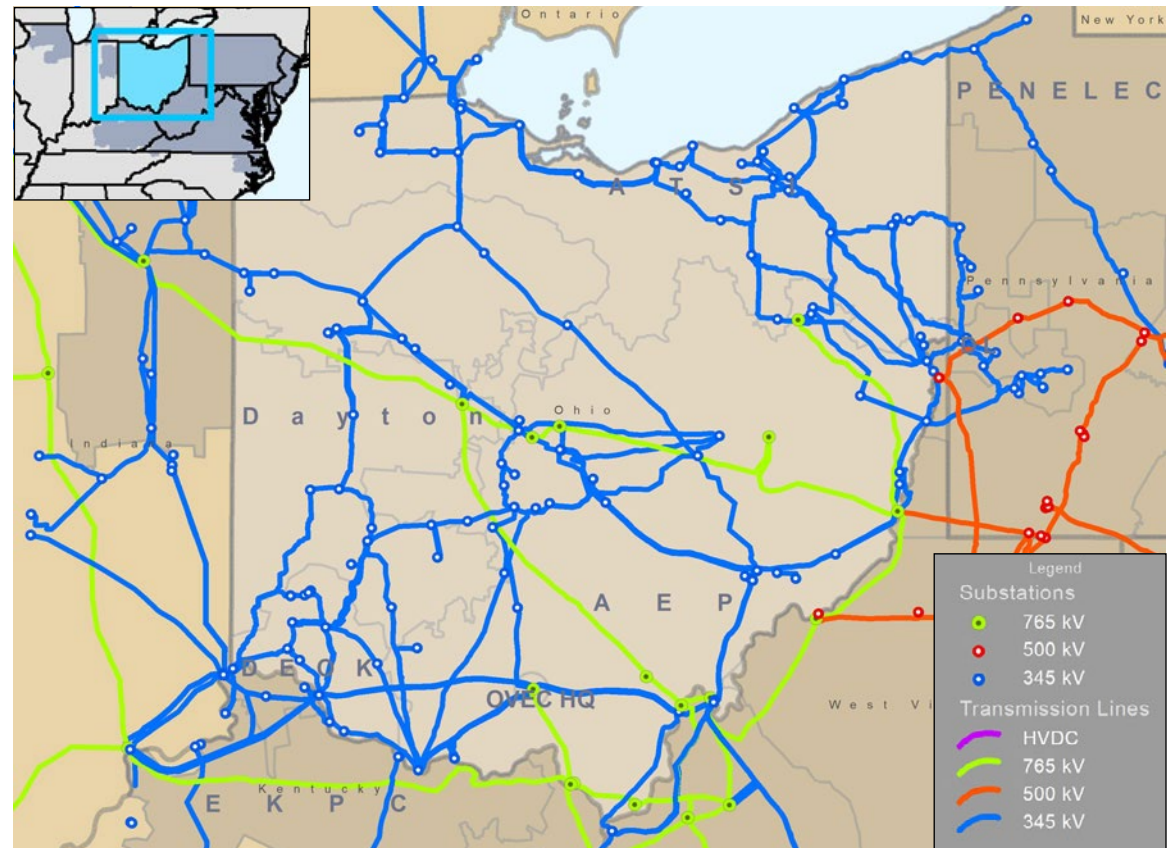
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Ohio, including facilities owned and operated by American Electric Power (AEP), AES Ohio, American Transmission Systems, Inc. (FirstEnergy) (ATSI), Duke Energy Ohio and Kentucky (DEO&K), the city of Cleveland and the city of Hamilton as shown on **Map 6.35**.

Ohio's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

#### **Renewable Portfolio Standards**

Ohio has a mandatory renewable portfolio standard (RPS) target of 8.5% by 2026.

**Map 6.35: PJM Service Area in Ohio**



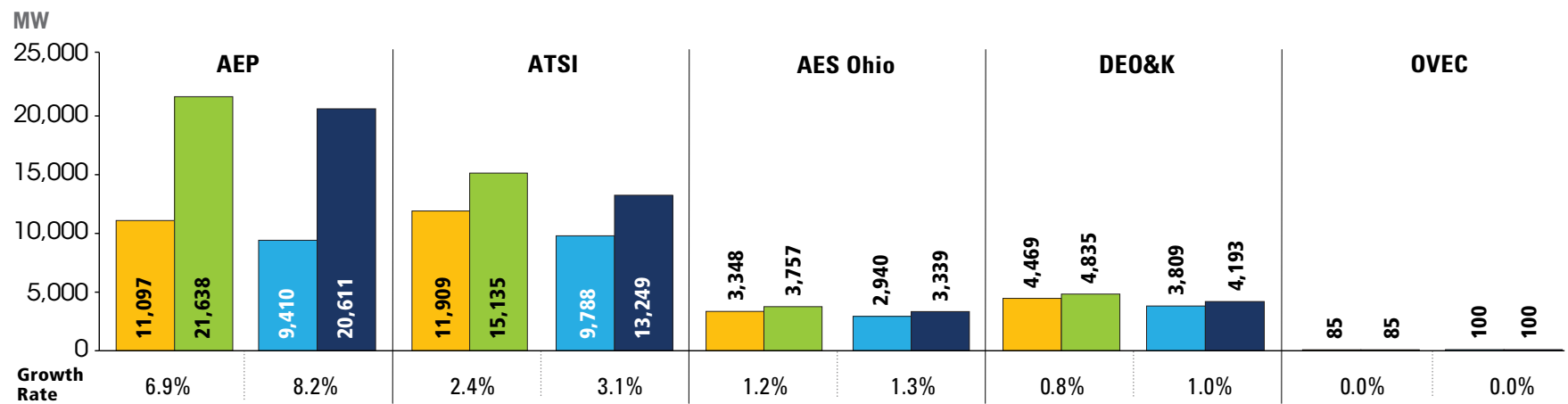
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### 6.9.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses.

**Figure 6.41** summarizes the expected loads within the state of Ohio and across PJM.

**Figure 6.41:** Ohio – 2025 Long-Term Load Forecast



PJM RTO Summer Peak		PJM RTO Winter Peak	
2025	2035	2024/2025	2034/2035
154,144	209,923	136,127	198,175
MW	MW	MW	MW
Growth Rate 3.1%		Growth Rate 3.8%	

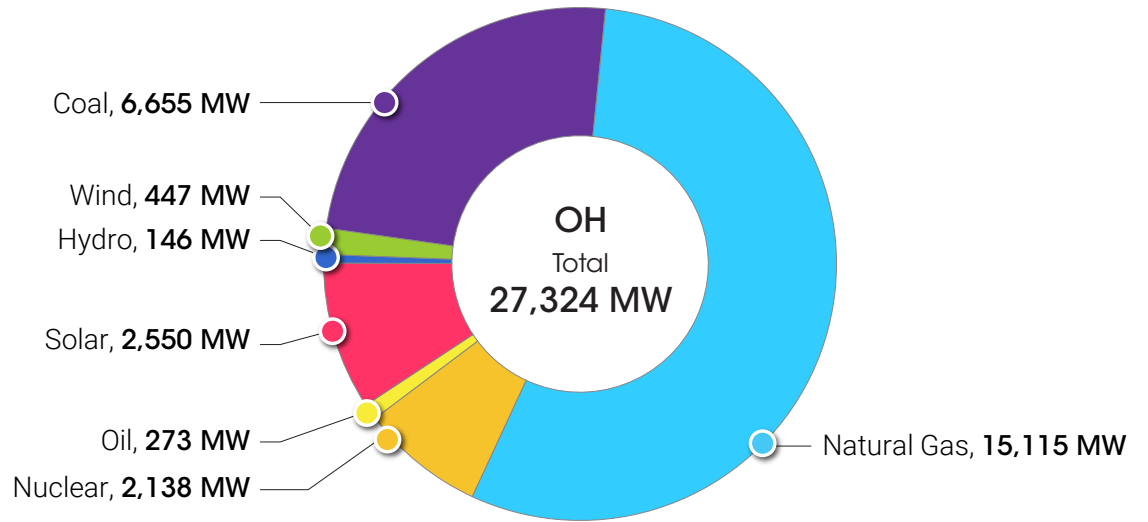
PJM notes that AEP, ATSI and DEO&K serve load other than in Ohio. The summer and winter peak megawatt values in this figure each reflect an estimated amount of forecasted load to be served by each of those transmission owners solely in Ohio. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Ohio over the past five years.

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**6.9.3 — Existing Generation**

Existing generation in Ohio as of Dec. 31, 2025, is shown by fuel type in **Figure 6.42**.

**Figure 6.42:** Ohio – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



**6.9.4 — Interconnection Requests**

In Ohio, as of Dec. 31, 2025, 242 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.43**, **Table 6.44**, **Figure 6.43**, **Figure 6.44** and **Figure 6.45**.

**Table 6.43:** Ohio – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

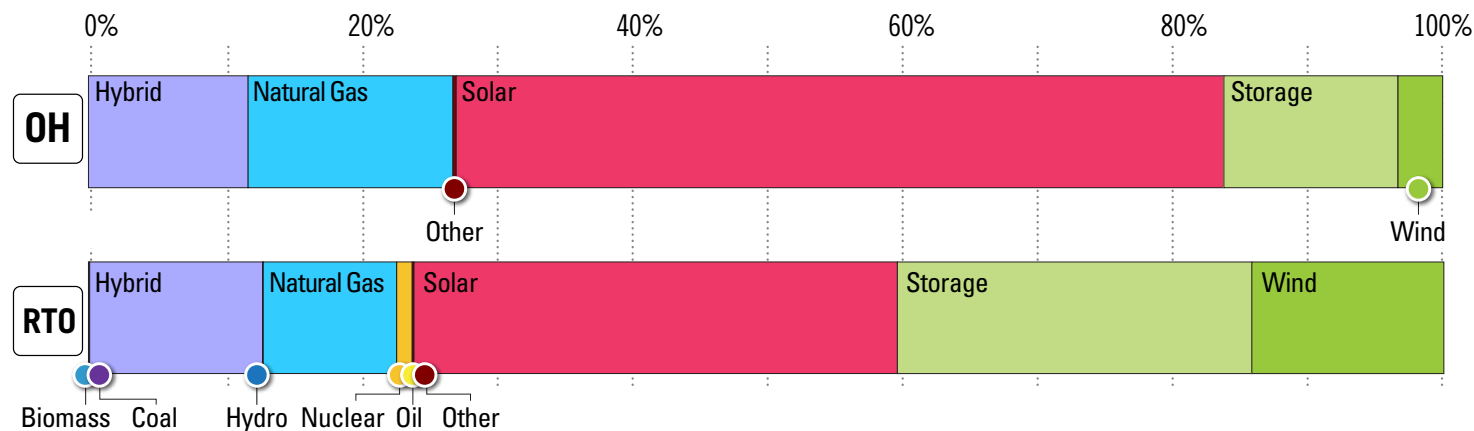
	Ohio Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
<b>Biomass</b>	0.0	0.00%	10.0	0.01%
<b>Coal</b>	0.0	0.00%	14.0	0.01%
<b>Hybrid</b>	1,818.9	11.77%	14,332.3	12.76%
<b>Hydro</b>	0.0	0.00%	30.0	0.03%
<b>Natural Gas</b>	2,342.8	15.16%	11,082.0	9.87%
<b>Nuclear</b>	0.0	0.00%	1,305.9	1.16%
<b>Oil</b>	0.0	0.00%	50.0	0.04%
<b>Other</b>	33.4	0.22%	56.3	0.05%
<b>Solar</b>	8,763.2	56.70%	40,116.0	35.73%
<b>Storage</b>	1,984.7	12.84%	29,376.0	26.16%
<b>Wind</b>	513.6	3.32%	15,910.7	14.17%
<b>Grand Total</b>	<b>15,456.7</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

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**Table 6.44:** Ohio – Interconnection Requests by Fuel Type (Dec. 31, 2025)

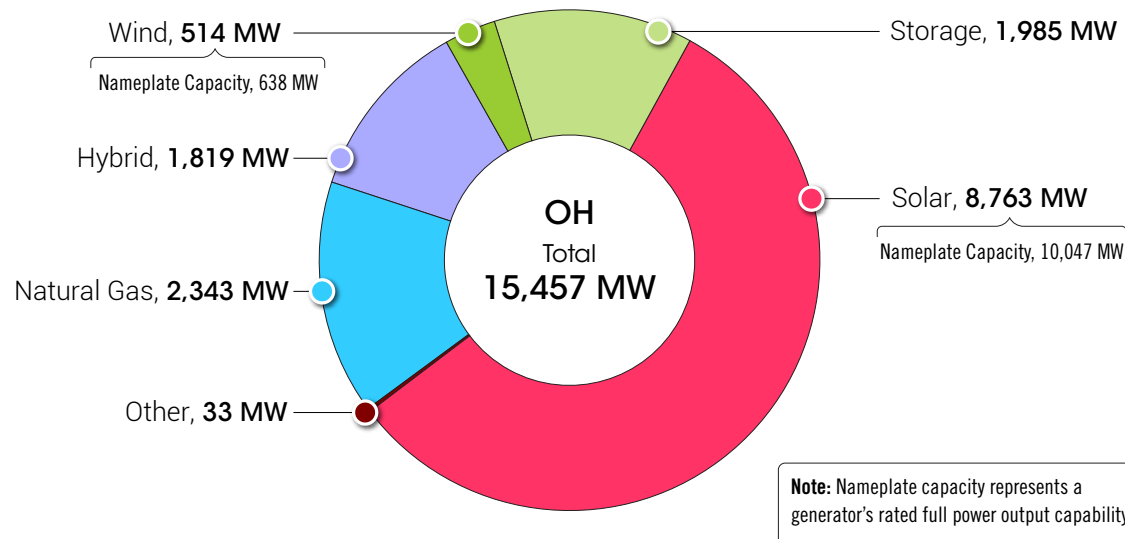
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	13	259.0	16	8,923.0	29	9,182.0
	Diesel	0	0.0	0	0.0	0	0.0	1	7.0	0	0.0	1	7.0
	Natural Gas	10	1,906.3	0	0.0	4	436.5	37	8,402.3	41	17,240.4	92	27,985.5
	Nuclear	0	0.0	0	0.0	0	0.0	1	16.0	0	0.0	1	16.0
	Oil	0	0.0	0	0.0	0	0.0	1	1.5	1	5.0	2	6.5
	Other	3	33.4	0	0.0	0	0.0	0	0.0	1	135.0	4	168.4
	Storage	15	1,555.4	5	228.3	4	201.0	4	0.0	82	8,460.3	110	10,445.0
Renewable	Biomass	0	0.0	0	0.0	0	0.0	1	0.0	4	188.2	5	188.2
	Hybrid	21	1,762.9	0	0.0	1	56.0	1	1.3	40	3,008.4	63	4,828.6
	Hydro	0	0.0	0	0.0	0	0.0	1	112.0	8	76.2	9	188.2
	Methane	0	0.0	0	0.0	0	0.0	5	18.5	10	26.1	15	44.6
	Solar	107	5,243.5	15	541.9	47	2,977.8	47	2,709.6	309	12,507.7	525	23,980.5
	Wind	8	455.4	0	0.0	2	58.2	8	197.4	81	2,087.5	99	2,798.5
<b>Grand Total</b>		<b>164</b>	<b>10,957.0</b>	<b>20</b>	<b>770.2</b>	<b>58</b>	<b>3,729.5</b>	<b>120</b>	<b>11,724.6</b>	<b>593</b>	<b>52,657.8</b>	<b>955</b>	<b>79,839.1</b>

**Figure 6.43:** Ohio – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

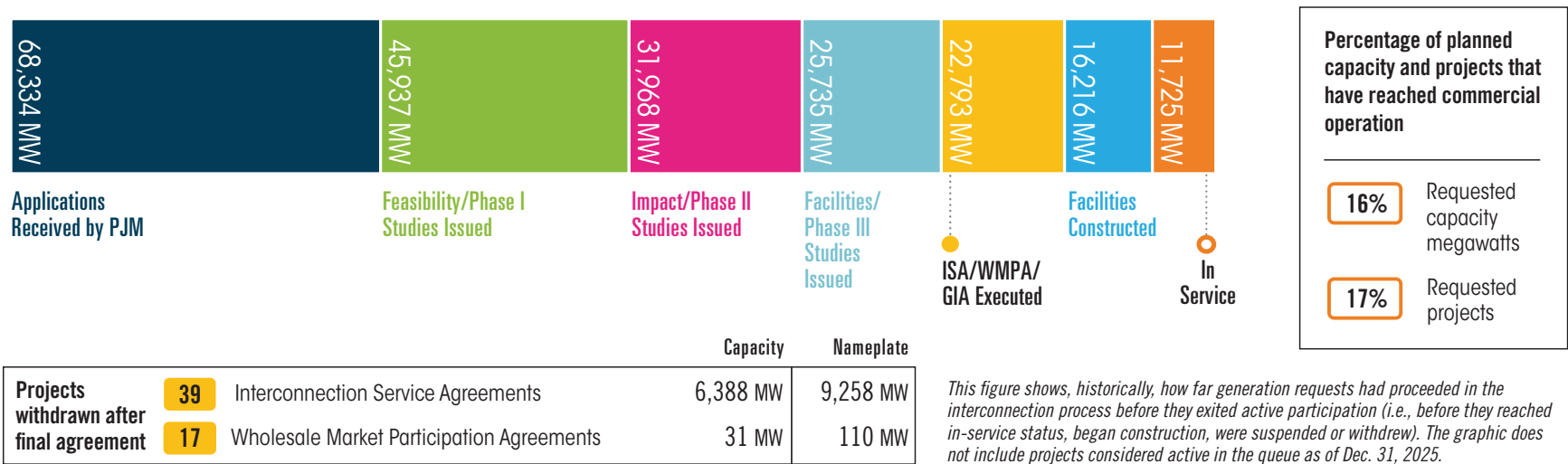


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**Figure 6.44:** Ohio Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.45:** Ohio Progression of Interconnection Requests (Dec. 31, 2025)

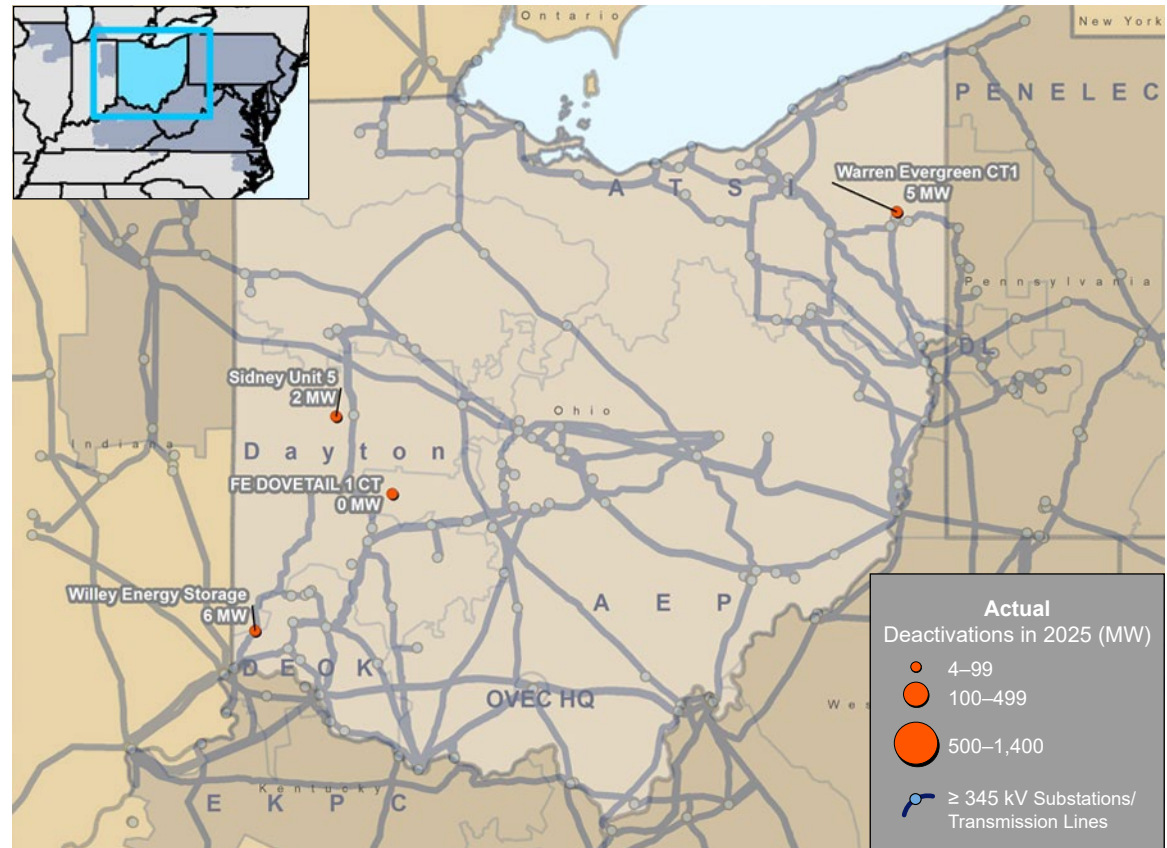


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### 6.9.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Ohio between Jan. 1, 2025, and Dec. 31, 2025, are summarized in **Map 6.36** and **Table 6.45**.

**Map 6.36:** Ohio Generation Deactivations (Dec. 31, 2025)



**Table 6.45:** Ohio Generation Deactivations (Dec. 31, 2025)

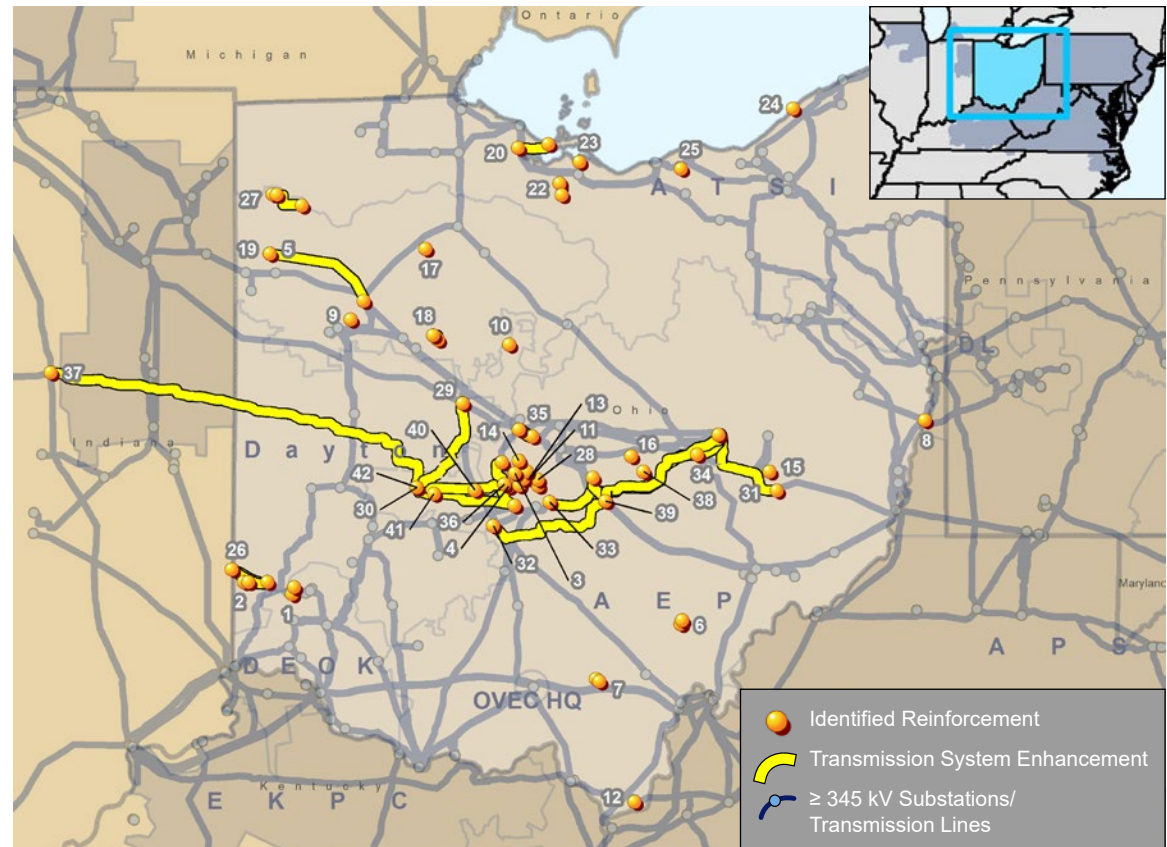
Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Sidney Unit 5	AES Ohio	Diesel	10/8/2025	10/8/2025	57	2
FirstEnergy Dovetail 1 CT	ATSI	Biomass	9/24/2025	9/24/2025	25	0
Warren Evergreen CT1	ATSI	Natural Gas	9/22/2025	10/1/2025	44	5
Willey Energy Storage	DEO&K	Battery	3/21/2025	9/2/2025	9	6

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**6.9.6 — Baseline Projects**

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in Ohio are summarized in **Map 6.37** and **Table 6.46**.

**Map 6.37:** Ohio Baseline Projects (Dec. 31, 2025)



**Table 6.46:** Ohio Baseline Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B3940.1	The 345 kV ring bus at Woodsdale substation will be reconfigured into a 345 kV breaker-and-half yard to improve substation reliability. Additionally, all 2000A equipment at Woodsdale substation will be upgraded to 3000A to increase substation capacity. Currently, two DEO&K supplemental projects that are planned at Woodsdale substation: S3447.1 & S3601.1. DEO&K will convert all of S3447.1 and parts of S3601.1 to address these reliability violations.	6/1/2030	\$36.82	DEO&K	1/6/2026	No	Baseline Load Growth Deliverability & Reliability

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Table 6.46: Ohio Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
2	B3944.1	Rebuild the McGuffey to Locust 69 kV line (~1.35 miles) with 954 ACSR rail conductor and OPGW. The 54 wood poles will be replaced with light-duty steel poles. The rebuild will take place in the existing right-of-way, and the distribution underbuilds will also be restored. Conductor drops going into McGuffey and Locust substations will be replaced with 954 AAC conductor.	6/1/2030	\$5.32	DEO&K	11/14/2025	No	TO Criteria Violation
3	B3955.1	Build ~0.8-mile 138 kV double-circuit extension from Roberts-Wilson 138 kV line into the Milepost 138 kV substation.	6/1/2030	\$8.33	AEP	11/14/2025	No	TO Criteria Violation
	B3955.2	Install additional 2-138 kV circuit breakers at Milepost substation to allow for the Robert-Wilson 138 kV line to come into the Milepost substation. DICM will need an expansion for additional relaying panels.	6/1/2030	\$3.84	AEP	11/14/2025	No	
	B4068.32	Roberts-Kenny 138 kV rebuild: Retire 3.18 miles of the Roberts-Kenny 138 kV underground line and install new underground cable for increased require ratings.	6/1/2030	\$66.36	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.33	Wilson-Fifth Avenue 138 kV line: Perform sag remediation on the Wilson-Fifth Avenue 138 kV line.	6/1/2030	\$18.25	AEP	1/6/2026	Yes (Reliability W1)	
4	B3956.1	Upgrade 336.4 ACSR 26/7 station conductor at Galloway 69 kV.	6/1/2030	\$0.18	AEP	11/14/2025	No	TO Criteria Violation
5	B3957.1	At Haviland substation, replace TR No. 4 with 138/69/12 kV 130 MVA bank, along with associated equipment such as the switch (600A), substation conductor 795 AAC 37 str., and substation conductor 300 MCM CU bus equipment.	12/1/2030	\$5.87	AEP	11/14/2025	No	TO Criteria Violation
	B3971.1	At Haviland, reconductor bus No. 1 substation conductor 500 MCM CU 37 str. toward Haviland bus No. 2 and reconductor Haviland bus No. 2 500 KCM CU, 37-str. and 795 KCM AAC, 37-structure (str.) toward Timber SW 138 kV.	12/1/2030	\$1.47	AEP	11/14/2025	No	Baseline Load Growth Deliverability & Reliability
6	B3958.1	Perform sag study mitigations on ~1.4 miles of line from str. 8 to str. 21 to bring conductor to full 142 MVA SE rating.	6/1/2030	\$0.36	AEP	11/14/2025	No	TO Criteria Violation
7	B3959.1	The line section overloading is roughly ~0.8 miles consisting of 336 ACSR 30/7 Oriole from structure 44 to Lick station. Reconductor limiting line conductor on the Lick-Ironman 69 kV circuit to match the rest of the line.	6/1/2030	\$1.10	AEP	11/14/2025	No	TO Criteria Violation
8	B3960.1	Replace 138 kV, 40 kA circuit breaker DD with higher fault-current-capable counterpart (63 kA). The new circuit breaker will have a larger footprint, which will require the shifting of nearby equipment.	6/1/2030	\$0.77	AEP	11/14/2025	No	Short Circuit
9	B3961.1	Replace station terminal equipment: South Side Lima 34.5 kV replace 4/0 AAC, 7-str. Replace 34.5 kV CB-L jumpers and 34.5 kV Sterling line riser.	12/1/2030	\$0.08	AEP	11/14/2025	No	TO Criteria Violation
10	B3962.1	Replace 138 kV circuit breakers CB-H014F2 and CB-H014F5 with 63 kA fault-current-capable breakers.	6/1/2030	\$0.85	AEP	11/14/2025	No	Short Circuit

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Table 6.46: Ohio Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
11	B3963.1	Replace 138 kV circuit breakers 102, 103 and circuit switcher XT4 with 63 kA fault-current-capable breakers.	6/1/2030	\$2.89	AEP	11/14/2025	No	Short Circuit
	B4068.35	Replace one 138 kV circuit breaker at OSU 138 kV station.	6/1/2030	\$0.50	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
12	B3964.1	Replaced the 138 kV circuit switcher XT3 with a 63 kA circuit breaker.	6/1/2030	\$0.94	AEP	11/14/2025	No	Short Circuit
13	B3965.1	Replace 138 kV circuit switchers XT1, XT3, XT2 and XT4 with 63 kA fault-current-capable counterpart.	6/1/2030	\$4.60	AEP	11/14/2025	No	Short Circuit
	B4068.36	Hess 138 kV substation scope: Replace one 138 kV circuit breaker to alleviate CT thermal limit.	6/1/2030	\$0.70	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
14	B3966.1	Replace 138 kV circuit breakers A, AA, D, E, F, XT1 and XT2 with 63 kA fault-current-capable counterpart. Reroute one line entrance in the station to make more room for the larger breakers.	9/30/2030	\$3.56	AEP	11/14/2025	No	Short Circuit
	B4068.34	Replace one 138 kV circuit breaker at Bethel 138 kV substation.	6/1/2030	\$0.50	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
15	B3967.1	Replace the existing Cambridge 34.5 kV circuit breaker F with a 3000A 40 kA unit.	6/1/2030	\$0.80	AEP	11/14/2025	No	TO Criteria Violation
16	B3968.1	Replace North Newark TR No. 1 with a 90 MVA bank. DICM expansion will be required. Replace motor operators on high-side switch "Z." Install two 138 kV disconnects on existing 138 kV lattice box bay. Install two 69 kV disconnects on existing 69 kV H-frame structure.	12/1/2030	\$6.33	AEP	11/14/2025	No	TO Criteria Violation
17	B3969.1	Replace Findlay Center transformer No. 1 with a 138/69/34.5 90 MVA unit. Replace the TR1 LS disconnect switch.	6/1/2030	\$3.94	AEP	11/14/2025	No	TO Criteria Violation
18	B3970.1	Rebuild ~2.87 miles Kenton-South Kenton 69 kV line.	6/1/2030	\$13.19	AEP	11/14/2025	No	TO Criteria Violation
	B4068.37	Replace line-side disconnect switches and bus tie switch on East Lima line at South Kenton 138 kV substation.	6/1/2030	\$0.11	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
19	B3972.1	Perform a ratings study and clearance mitigation on the ~5.55-mile section of sag derated 556.5 ACSR 26/7 DOVE conductor (East Lima-STR 28) between the East Lima-Haviland 138 kV circuit on the East Lima-West Lima 138 kV line.	4/15/2030	\$6.80	AEP	11/14/2025	No	Baseline Load Growth Deliverability & Reliability
20	B3978.1	Reconductor one span of transmission line outside Ottawa substation. Reconductor one span of transmission line outside Lakeview substation.	6/1/2030	\$1.09	ATSI	11/14/2025	No	Baseline Load Growth Deliverability & Reliability
	B3978.2	Replace limiting terminal equipment at Lakeview substation, which includes two thermal relays, two 138 kV disconnect switches and limiting substation conductor.	6/1/2030	\$0.32	ATSI	11/14/2025	No	

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**Table 6.46:** Ohio Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
21	B3979.1	Reconductor one span of transmission line between Johnson substation and Elyria Water P.C. 69 kV. Replace one 69 kV disconnect switch, upgrade one thermal relay, modify the Elyria Loop tap configuration and install one 69 kV disconnect switch.	6/1/2030	\$2.07	ATSI	11/14/2025	No	TO Criteria Violation
	B3979.2	Replace one 69 kV disconnect switch for Abbe-Johnson No. 1 69 kV line (Elyria Water P.C.-Spring Valley).	6/1/2030	\$0.71	ATSI	11/14/2025	No	
	B3979.3	Replace two 69 kV disconnect switches for Abbe-Johnson No. 1 69 kV line (Elyria Water P.C.-Spring Valley).	6/1/2030	\$0.44	ATSI	11/14/2025	No	
22	B3980.1	Rebuild 4 miles of the Bellevue-Groton 69 kV line.	6/1/2030	\$9.53	ATSI	11/14/2025	No	TO Criteria Violation
	B3980.2	Replace three 69 kV disconnect switches and limiting substation conductor at Bellevue substation. Also revise relay settings.	6/1/2030	\$0.47	ATSI	11/14/2025	No	
	B3980.3	Revise relay settings at Groton substation.	6/1/2030	\$0.10	ATSI	11/14/2025	No	
23	B3984.1	Replace Greenfield 69 kV circuit breakers: 501-B-24, 501-B-272, 501-B-274.	6/1/2030	\$1.53	ATSI	11/14/2025	No	TO Criteria Violation
24	B3985.2	Replace the following breakers at Eastlake substation with 3000A 80 kA circuit breakers (this will not affect the existing line ratings at the station): 46-B-18, 46-B-21, 46-B-24, 46-B-35, 46-B-36, 46-B-32, 46-B-33, 46-B-27, 46-B(795), 46-B-45, 46-B-54, 46-B-97.	6/1/2030	\$11.48	ATSI	11/14/2025	No	Short Circuit
25	B3985.4	At Johnson substation, replace 451-B-163 breaker with a 3000A 63 kA circuit breaker.	6/1/2030	\$0.96	ATSI	11/14/2025	No	Short Circuit

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Table 6.46: Ohio Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
26	B4003.1	Rebuild the College Corner (AEP)-Collinsville (DEO&K) 138 kV circuit from the OH/IN state line (tower 10P-X1-129) to Collinsville substation. AEP owns ~0.1 miles of the line from College Corner substation to the OH/IN state line. DEO&K owns the remaining 11.90 miles from the state line to Collinsville substation. The entire 11.90-mile section that DEO&K owns will be rebuilt with 954ACSS/TW conductor (@ 200C) and new double-circuit structures. The College Corner (AEP)-Trenton (DEO&K) line is on the other side of the double-circuit structure and will also be rebuilt. DEO&K will be doing a route survey to see if easement updates and/or additional structures are required.	6/1/2030	\$45.11	DEO&K	11/4/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4003.2	Rebuild parts of the College Corner (AEP)-Trenton (DEO&K) 138 kV circuit that shares a common structure with the College Corner (AEP)-Collinsville (DEO&K) circuit from the OH/IN state line (Tower 10P-X1-129) to Collinsville substation. AEP owns ~0.1 miles of the line from College Corner substation to the OH/IN state line. DEO&K owns the remaining 24.19 miles from the state line to Trenton substation. Only the 11.90-mile DEO&K section that shares a common structure with College Corner (AEP)-Collinsville (DEO&K) will be rebuilt with 954ACSS/TW conductor (@ 200C) and new double-circuit structures. The remaining sections from Collinsville-Trenton will be left untouched. DEO&K will be doing a route survey to see if easement updates and/or additional structures are required.	6/1/2030	\$13.24	DEO&K	11/4/2025	Yes (Reliability W1)	
	B4003.3	Relay settings at College Corner station needed due to Duke rebuilding their College Corner-Collinsville 138 kV line section.	6/1/2030	\$0.06	AEP	11/4/2025	Yes (Reliability W1)	
	B4003.4	Update relay settings for the College Corner-Collinsville line at DEO&K's Collinsville substation.	6/1/2030	\$0.03	DEO&K	11/4/2025	Yes (Reliability W1)	
	B4003.5	Update relay settings for the College Corner-Trenton line at DEO&K's Trenton substation.	6/1/2030	\$0.03	DEO&K	11/4/2025	Yes (Reliability W1)	
27	B4026.1	Rebuild ~3.5 miles of 69 kV line from Platter Creek to Sherwood station.	4/15/2030	\$7.17	AEP	12/8/2025	Yes (Reliability W1)	TO Criteria Violation
	B4026.2	Rebuild ~11.1 miles of 69 kV line from Sherwood to Auglaize station.	4/15/2030	\$21.51	AEP	12/8/2025	Yes (Reliability W1)	
28	B4028.1	Rebuild 2.3 miles of the Mound Street-St Clair Avenue 138 kV UG line with 5000 KCM XLPE cable.	6/1/2030	\$41.59	AEP	12/12/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability

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Table 6.46: Ohio Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
29	B4068.10	Add one 765 kV STATCOM at Marysville 765 kV substation.	6/1/2030	\$164.25	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.9	At Marysville 765 kV substation scope, create a new 765 kV line position. Install two 765 kV circuit breakers. Create a new 765 kV line position to relocate the existing 765 kV Sorenson line. Install one 765 kV circuit breaker. Add one 765/345 kV, 2250 MVA transformer.	6/1/2030	\$112.01	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.48	Add two 250 MVAR 345 kV capacitor banks at Marysville 765 kV substation.	6/1/2030	\$5.56	AEP	1/6/2026	Yes (Reliability W1)	
30	B4068.11	Construct a new 18.66-mile 345 kV single-circuit from Teddy-Beatty (FirstEnergy portion).	6/1/2030	\$50.19	GGOHLIC	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.12	Construct a new 13.34-mile 345 kV single-circuit from Teddy-Beatty (AEP portion).	6/1/2030	\$37.40	GGOHLIC	1/6/2026	Yes (Reliability W1)	
	B4068.13	At Teddy-Cole single-circuit 345 kV, construct a new 18.66-mile 345 kV line between the proposed Teddy 345 kV substation and existing Cole 345 kV substation on a shared structure with Teddy-Beatty single-circuit 345 kV (FirstEnergy portion). The total length of Teddy-Cole 345 kV circuit is 41.7 miles.	6/1/2030	\$50.19	GGOHLIC	1/6/2026	Yes (Reliability W1)	
	B4068.14	At Teddy-Cole single-circuit 345 kV, construct a new 13.34-mile 345 kV line between the proposed Teddy 345 kV substation and existing Cole 345 kV substation on a shared structure with Teddy-Beatty single-circuit 345 kV (AEP portion). The total length of Teddy-Cole 345 kV circuit is 41.7 miles.	6/1/2030	\$37.40	GGOHLIC	1/6/2026	Yes (Reliability W1)	
	B4068.15	At Teddy-Cole single-circuit 345 kV, install second circuit on the vacant side of the existing 9.7-mile 345 kV AC overhead transmission line between the existing Cole 345 kV substation and the existing Beatty 345 kV substation. The total length of Teddy-Cole 345 kV circuit is 41.7 miles.	6/1/2030	\$21.63	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.16	Create a new 345 kV line position to interconnect a new 345 kV Teddy line.	6/1/2030	\$1.00	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.17	At Beatty station, create a new 345 kV line position to interconnect the new 345 kV Teddy line. Install two 345 kV circuit breakers.	6/1/2030	\$3.86	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.47	At Beatty-Hayden structures, lower the existing Beatty-Hayden 345 kV line between structures 2 and 3 to facilitate crossing the proposed Teddy-Beatty 345 kV line.	6/1/2030	\$3.00	AEP	1/6/2026	Yes (Reliability W1)	

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Table 6.46: Ohio Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
31	B4068.18	At Guernsey 765 kV substation scope, create a new 765 kV line position to interconnect the new 765 kV Conesville line. Install one 765 kV circuit breaker.	6/1/2030	\$5.54	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.19	Construct a new 32-mile 765 kV single circuit from Guernsey-Conesville.	6/1/2030	\$166.17	GGOHLLC	1/6/2026	Yes (Reliability W1)	
	B4068.39	Upgrade the existing Conesville substation to include a 765 kV yard and expand the 345 kV yard. Install six 765 kV circuit breakers. Install one 765/345 kV, 2250 MVA transformer. Install one-circuit 345 kV circuit breaker. Replace wave trap and circuit switcher in 138 kV yard.	6/1/2030	\$140.97	AEP	1/6/2026	Yes (Reliability W1)	
32	B4068.20	For West Millersport Station upgrade, construct a new 765 kV West Millersport yard with four circuit breakers. Install one 765/345 kV, 2250 MVA transformer. Install one 345 kV circuit breaker.	6/1/2030	\$118.11	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.26	Construct a new 38-mile 765 kV single circuit from West Millersport-Adkins.	6/1/2030	\$201.83	GGOHLLC	1/6/2026	Yes (Reliability W1)	
	B4068.27	At West Millersport-Kirk 345 kV, rebuild 6.37-mile section of the double-circuit West Millersport-Kirk 345 kV circuit.	6/1/2030	\$24.30	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.41	Construct a 765 kV yard at Adkins substation. Install seven 765 kV circuit breakers. Install three 100 MVAR single-phase reactors on each 765 kV line.	6/1/2030	\$102.97	AEP	1/6/2026	Yes (Reliability W1)	
33	B4068.21	Retire a segment of the Bixby to Ohio Central 345 kV line and install ~3 miles of greenfield single-circuit 345 kV line from structure 284 to West Millersport substation.	6/1/2030	\$12.00	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.23	Wreck part of Ohio Center-Bixby 345 kV circuit around West Millersport 345 kV to facilitate the Conesville-West Millersport 765 kV line. Note: The cost for Conesville-West Millersport 765 kV is a different component.	6/1/2030	\$3.86	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.25	Install new relaying at Bixby station for new 345 kV tie to West Millersport.	6/1/2030	\$0.08	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.42	Install two new 138 kV circuit breakers at Ohio Central station.	6/1/2030	\$3.00	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.24	Extend existing Ohio Central 345 kV extension by one span to cut into the existing Conesville-Newark Center 138 kV line to loop the existing Conesville-Newark Center 138 kV line into Ohio Central station by installing four new three-pole steel pole structures.	6/1/2030	\$3.50	AEP	1/6/2026	Yes (Reliability W1)	
	B4068.44	At Ohio Central-Fostoria Central structure, remove structure 10 and replace with lower structure to lower the line.	6/1/2030	\$1.00	AEP	1/6/2026	Yes (Reliability W1)	
34	B4068.22	Wreck Ohio Center-Conesville 345 kV circuit to facilitate the Conesville-West Millersport 765 kV line. Note: The cost for Conesville-West Millersport 765 kV is a different component.	6/1/2030	\$1.46	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability

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Table 6.46: Ohio Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
35	B4068.28	Rebuild a 5.25-mile 345 kV single circuit from Hyatt-Maliszewski.	6/1/2030	\$17.06	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.49	Rebuild a 5.25-mile 345 kV single circuit from Hyatt-Maliszewski.	6/1/2030	\$17.06	AEP	1/6/2026	Yes (Reliability W1)	
36	B4068.29	At Hayden-Cole 345 kV, rebuild 7.8 miles of Beatty-Hayden 345 kV line.	6/1/2030	\$37.87	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
37	B4068.3	Construct a 49.92-mile 765 kV AC overhead transmission line between the existing Greentown 765 kV substation and the proposed Teddy 765 kV substation (AES Ohio Portion). The total line length is 137 miles of the Greentown to Teddy 765 kV line.	6/1/2030	\$230.94	GGOHLIC	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.4	Construct a 27.08-mile 765 kV AC overhead transmission line between the existing Greentown 765 kV substation and the proposed Teddy 765 kV substation (ATSI Portion). The total line length is 137 miles of the Greentown to Teddy 765 kV line.	6/1/2030	\$125.28	GGOHLIC	1/6/2026	Yes (Reliability W1)	
38	B4068.30	For Newark 138 kV Center station scope, replace wave trap and limiting bus conductor at Newark Center substation.	6/1/2030	\$0.70	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
39	B4068.40	At Conesville-West Millersport 765 kV, construct a new 49.1-mile single-circuit 765 kV AC overhead transmission line between the new Conesville 765 kV substation and the new West Millersport 765 kV substation.	6/1/2030	\$243.65	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
40	B4068.45	At Gavin-Marysville structures, raise the existing Gavin to Marysville 765 kV line between structures 358 and 359 to facilitate crossing the proposed Teddy to Beatty 345 kV line.	6/1/2030	\$3.00	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
41	B4068.46	At East Springfield-London structures, lower the existing First Energy East Springfield 138 kV line between structures 29 and 30 on the proposed Teddy-Beatty 345 kV line.	6/1/2030	\$1.00	ATSI	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
42	B4068.5	Construct a new 765/345 kV greenfield substation (Teddy) interconnecting the new 765 kV Marysville line and the new 765 kV Greentown line with three 100 MVAR single-phase reactors on each 765 kV line. Install nine 765 kV circuit breakers. Install two 765/345 kV, 2250 MVA transformers. Install nine 345 kV circuit breakers.	6/1/2030	\$222.77	ATSI	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4068.6	Install two 250 MVAR 345 kV capacitor banks at Teddy 765/345 kV substation.	6/1/2030	\$5.56	ATSI	1/6/2026	Yes (Reliability W1)	
	B4068.7	Construct a 35.4-mile 765 kV AC overhead transmission line between the proposed 765 kV Teddy substation and the existing 765 kV Marysville substation (FirstEnergy Portion).	6/1/2030	\$45.50	GGOHLIC	1/6/2026	Yes (Reliability W1)	
	B4068.8	Construct a 35.4-mile 765 kV AC overhead transmission line between the proposed 765 kV Teddy substation and the existing 765 kV Marysville substation (AEP Portion).	6/1/2030	\$130.96	GGOHLIC	1/6/2026	Yes (Reliability W1)	

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Table 6.46: Ohio Baseline Projects (Dec. 31, 2025) (Cont.)

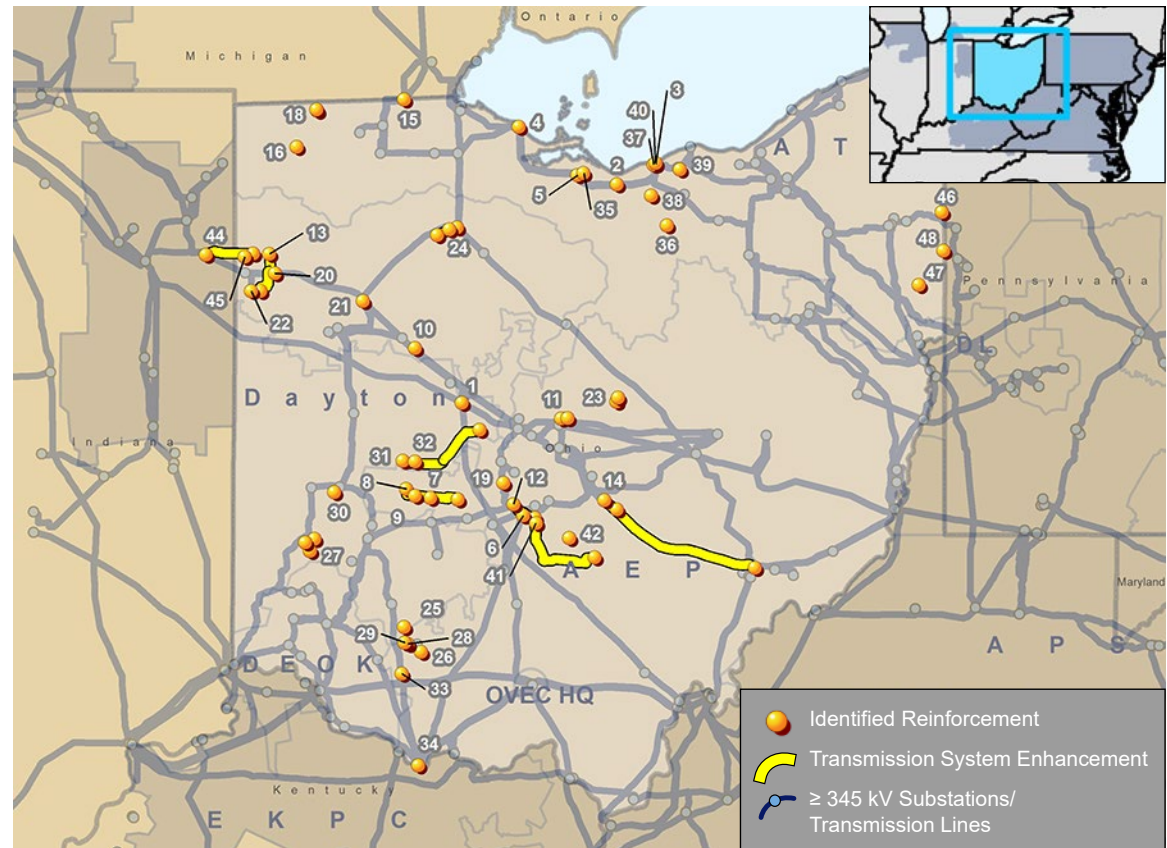
Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
CEII	B3936.1	For AEP zone 2024W1 P5 Solution No. 1, install battery chargers and associated equipment at AEP substation. Addresses the following flowglates: 2024-P5-AEP07, 2024-P5-AEP08.	6/1/2029	\$0.07	AEP	7/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B3936.2	For AEP zone 2024W1 P5 Solution No. 2, install battery chargers and associated equipment at AEP substation. Addresses the following flowglates: 2024-P5-AEP03, 2024-P5-AEP04.	6/1/2029	\$0.11	AEP	7/8/2025	No	
	B3936.3	For AEP zone 2024W1 P5 Solution No. 3, install battery chargers and associated equipment at AEP substation. Addresses the following flowglates: 2024-P5-AEP09, 2024-P5-AEP10, 2024-P5-AEP11, 2024-P5-AEP12.	6/1/2029	\$0.08	AEP	7/8/2025	No	
	B3936.6	For OVEC Zone 2024W1 P5 Solution No. 6, install battery chargers and associated equipment and upgrade protection equipment at OVEC substation. Addresses the following flowglates: 2024-P5-AEP02.	6/1/2029	\$0.58	AEP	7/8/2025	No	
	B4041.1	2024W1 P5: Install battery monitoring, DC panel, line panel and modify relay wiring. Addresses flowgate No. 2024-P5-ATSI15.	6/1/2029	\$1.23	ATSI	12/8/2025	No	Stability
	B4050.1	2024W1 P5: Modify relay wiring. Addresses flowgate No. 2024-P5-ATSI05.	6/1/2029	\$0.66	ATSI	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4051.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5-ATSI09.	6/1/2029	\$0.45	ATSI	12/8/2025	No	

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**6.9.7 — Network Projects**

Network projects in Ohio for 2025 are summarized in **Map 6.38** and **Table 6.47**.

**Map 6.38:** Ohio Network Projects (Dec. 31, 2025)



**Table 6.47:** Ohio Network Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	N3985	Replace three Marysville 765 kV wave traps on the Sorenson-Marysville 765 kV line.	AG1-302	1/15/2028	\$0.90	AEP	10/8/2025
2	N6005	Install attachment facility line and associated hardware to accept the interconnection customer generator lead line terminating at the AC2-103 interconnection substation.	AC2-103	12/31/2021	\$0.01	ATSI	10/8/2025
	N6006	Construct three-breaker 345 kV ring bus substation for future four-breaker expansion at AC2-103.	AC2-103	12/31/2021	\$9.47	ATSI	10/8/2025
	N6007	Construct a line tap to the proposed AC2-103 switching station. Construct one span from the proposed AC2-103 switching station to the customer Point of Interconnection (POI) at Beaver-Davis Besse (S-26) 345 kV line tap to customer POI.	AC2-103	12/31/2021	\$1.38	ATSI	10/8/2025

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Table 6.47: Ohio Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	N6008	Standard dual SEL421 panel with UPLC for pilot scheme and DTT for the AC2-103 line at Beaver substation.	AC2-103	12/31/2021	\$0.29	ATSI	10/8/2025
	N9006.0	Revise relay settings at Beaver substation.	AF2-005	4/1/2026	\$0.05		10/8/2025
4	N6009	Standard dual SEL421 panel with UPLC for pilot scheme and DTT for the AC2-103 line at Davis Bessie substation.	AC2-103	12/31/2021	\$0.29	ATSI	10/8/2025
5	N6010	Estimated MPLS router at AC2-103 substation to provide SCADA transport for new RTU. Next MPLS hops for SCADA backhaul are assumed to be at Avery substation and Hayes substation.	AC2-103	12/31/2021	\$0.19	ATSI	10/8/2025
6	N6263.3	Reconductor 5.5 miles of ACSR ~ 336.4 ~ 30/7 ~ ORIOLE Harrison-Zuber 138 kV line conductor with 795 ACSR or equivalent.	AF2-371	12/31/2023	\$8.25	AEP	10/8/2025
	N6263.4	Replace 800 amp wave trap at Harrison on the Harrison-Zuber 138 kV line.	AF2-371	12/31/2023	\$0.10	AEP	10/8/2025
7	N7339	AE2-217: Construct a new three-breaker ring bus on the 138 kV East Springfield-London line. This includes project management.	AE2-217	12/31/2021	\$5.59	ATSI	10/8/2025
	N7340	SCADA/fiber communication: Design, install and test/commission MPLS Equipment for SCADA transport.	AE2-217	12/31/2021	\$0.18	ATSI	10/8/2025
8	N7341	Estimated SCADA work at East Springfield and London substation to support relay installations, updated relay settings and wave trap installations. Estimated in-sub fiber run to customer-built fiber to support communications to AE2-217 substation.	AE2-217	12/31/2021	\$0.08	ATSI	10/8/2025
	N7343	Loop the East Springfield-London No. 1 138 kV line into the new AE2-217 substation between existing structures No. 5762 and No. 5763, ~8.44 miles from the London substation.	AE2-217	12/31/2021	\$1.36	ATSI	10/8/2025
	N7342	Install fiber from AE2-217 to North Titus for communication transport at AE2-217 to North Titus.	AE2-217	12/31/2021	\$0.88	ATSI	10/8/2025
	N7345	Upgrade line terminal at East Springfield.	AE2-217	12/31/2021	\$0.80	ATSI	10/8/2025
	N7346	Upgrade line terminal at London.	AE2-217	12/31/2021	\$1.01	ATSI	10/8/2025
9	N7344	At London-North Titus 138 kV line loop, transfer conductor and install dead-end hardware assemblies on the new three-pole structure.	AE2-217	12/31/2021	\$0.09	ATSI	10/8/2025
10	N7470	Expand Gunn Road 345 kV station, including the addition of one 345 kV circuit breaker, installation of associated protection and control equipment, 345 kV line risers, switches, jumpers and SCADA equipment.	AE2-306	9/30/2019	\$1.33	AEP	10/8/2025
11	N8199.1	Expand the station yard, fence and ground grid. Install one new 138 kV circuit breaker and one new line termination at the Centerburg 138 kV station.	AD2-067	2/28/2018	\$0.96	AEP	10/8/2025
	N8199.2	Reterminate the Centerburg-Trent 138 kV circuit to a different bay position at the Centerburg 138 kV station.	AD2-067	2/28/2018	\$0.38	AEP	10/8/2025
	N9278.0	Review and revise relay settings for AG1-024 at Centerburg 138 kV substation.	AG1-024	11/30/2028	\$0.06	AEP	10/8/2025
	N9279.0	Review and revise relay settings for AG1-034 at Centerburg 138 kV substation.	AG1-034	11/30/2028	\$0.06	AEP	10/8/2025
12	N8393	String 3.19 miles of 336.4 ACSR or equivalent conductor on the open side of the existing double-circuit structures (six-wire) at Beatty-Zuber 138 kV. Note, further engineering study will need to be performed to confirm this reinforcement can be performed on the existing lattice structures built in the 1950s.	AG1-351	12/31/2024	\$6.00	AEP	10/8/2025
13	N8434.1	Reconfigure the Haviland-West Van Wert 69 kV circuit.	AE1-245	6/30/2021	\$0.20	AEP	10/8/2025

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Table 6.47: Ohio Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
14	N8503.1	Construct the proposed AE2-048 345 kV breaker-and-a-half station, to be operated as a three-circuit breaker ring bus, initially expandable to six circuit breakers.	AE2-048	12/31/2028	\$14.26	AEP	10/8/2025
	N8503.2	Install two new fiber optic cable paths consisting of 0.5 miles of 144 count ADLT cable installed in new underground right-of-way and associated terminating equipment and devices (transceivers, multiplexors, routers) at Muskingum River-West Millersport 345 kV.	AE2-048	12/31/2028	\$0.18	AEP	10/8/2025
	N8503.3	New AE2-048 switching station tie-in at Muskingum River-West Millersport 345 kV line.	AE2-048	12/31/2028	\$1.82	AEP	10/8/2025
	N8503.5	Replace one wave trap and line tuner with two new one-phase wave traps and line tuners. Review and revise (as needed) the protective relay settings at Muskingum River 345 kV.	AE2-048	12/31/2028	\$0.17	AEP	10/8/2025
	N8503.6	Replace one wave trap and line tuner with two new one-phase wave traps and line tuners. Review and revise (as needed) the protective relay settings at West Millersport 345 kV.	AE2-048	12/31/2028	\$0.17	AEP	10/8/2025
	N8510	Review and revise the protective relay settings at the proposed AE2-048 345 kV station to account for the additional generation of AE2-136.	AE2-136	12/31/2028	\$0.06	AEP	10/8/2025
15	N8516	Review relay settings at Allen Junction substation.	AF1-206	5/31/2028	\$0.07	ATSI	10/8/2025
16	N8517	Review relay settings at Stryker substation.	AF1-206	5/31/2028	\$0.07	ATSI	10/8/2025
17	N8518	Reconfigure East Fayette substation from four-breaker ring bus to double-breaker, double-bus configuration.	AF1-206	5/31/2028	\$7.85	ATSI	10/8/2025
18	N8519	Reterminate the Arche Energy-East Fayette 138 kV line into the East Fayette substation.	AF1-206	5/31/2028	\$0.51	ATSI	10/8/2025
	N8520	Relocate and reterminate the East Fayette-Stryker 138 kV line into the expanded double-breaker double-bus East Fayette substation to accommodate the line exit for AF1-206.	AF1-206	5/31/2028	\$1.49	ATSI	10/8/2025
19	N8530	Review and revise the protective relay settings at Cole 345 kV.	AF1-275	12/31/2027	\$0.06	AEP	10/8/2025
20	N8644.0	Expand Maddox Creek 345 kV station for the interconnection of AF2-014.	AF2-014	12/31/2027	\$1.53	AEP	10/8/2025
21	N8645.0	Update protection and control settings at East Lima 345 kV.	AF2-014	12/31/2027	\$0.07	AEP	10/8/2025
22	N8646.0	Update protection and control settings at East Lima 345 kV.	AF2-014	12/31/2027	\$0.07	AEP	10/8/2025
23	N8705.0	Expand the existing Sharp Road station control house, replace the existing underhung-mounted capacitor disconnect switch, install associated structures, jumpers, bus work, insulators, grounding, cables, telecommunications, SCADA, fiber-optic relaying connectivity and equipment, and foundations.	AF2-149	1/31/2028	\$0.42	AEP	10/8/2025
	N8706.0	Replace the existing fence with 190 feet of new fencing and a new 24-foot gate.	AF2-149	1/31/2028	\$0.39	AEP	10/8/2025
	N8707.0	Relocate and replace structure No. 1 in the Commerce-Sharp Road 69 kV circuit.	AF2-149	1/31/2028	\$0.56	AEP	10/8/2025
24	N8783.0	Construct a new 138 kV ring bus station, initially populated with three circuit breakers, expandable to four breakers.	AF2-375	4/15/2027	\$9.96	AEP	10/8/2025
	N8784.0	New AF2-375 138 kV switching station tie-in.	AF2-375	4/15/2027	\$1.12	AEP	10/8/2025
	N8785.0	Review and revise protective relay settings at Eberonle 138 kV.	AF2-375	4/15/2027	\$0.45	AEP	10/8/2025
	N8786.0	Review and revise protective relay settings at Fostoria Central 138 kV.	AF2-375	4/15/2027	\$0.45	AEP	10/8/2025
	N8787.0	Install two new fiber optic cable paths consisting of 0.2 miles of 144 count ADLT cable.	AF2-375	4/15/2027	\$0.24	AEP	10/8/2025

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Table 6.47: Ohio Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
25	N8833.0	New 345 kV three-breaker ring bus switching station with control relaying, one drop in control module (DICM), six disconnect switch, one additional breaker string disconnect switch, three motor operated disconnect switch, two single-phase station Service Voltage Transformers (SSVT), six single-phase coupling capacitor voltage transformers (CCVT), two H-frame line exit structures, one single-phase line trap for line exit, one dual directional comparison blocking (DCB) for each line exit, one station battery and charger, one integrated communications optical network multiplexor (ICON MUX), associated conductors, telecom terminal equipment, insulators, arresters, foundations and structures.	AF2-440	12/31/2027	\$8.32	AEP	10/8/2025
	N8834.0	Transmission line tie-in: Remove one existing structure and install two new dead-end structure on concrete pier and anchor bolts, two new H-frame structure on concrete piers with anchor bolts, two new single-pole dead-end structure on concrete piers with anchor bolts four spans T-line conductor in an in-and-out arrangement, two shield wire.	AF2-440	12/31/2027	\$1.75	AEP	10/8/2025
	N8838.0	Install 0.3 mile of All Dielectric Loose Tube (ADLT) for two new extensions from the proposed IMTCo 138 kV station to the new 85-foot transmission line extension dead-ends and transition the extensions into two new OPGW splices.	AF2-440	12/31/2027	\$0.30	AEP	10/8/2025
26	N8835.0	Hillsboro upgrade 138: Replace/upgrade protective relay with ICON MUX diff relay, reconfigure existing ICON, remove existing line trap and tuner line to Hutchings 138 kV, replace existing one-phase CCVT with three-phase CCVT.	AF2-440	12/31/2027	\$0.44	AEP	10/8/2025
27	N8836.0	Review and revise protective relay settings at Hutchings 138 kV.	AF2-440	12/31/2027	\$0.60	AEP	10/8/2025
	N8929.0	Interconnection substation tie-in: Cut and loop the Hutchings-Crown 69 kV line into the new substation and reroute New Lebanon Tap 69 kV line.	AF2-298	3/31/2028	\$6.10	AES Ohio	10/8/2025
	N8930.0	New four-position ring bus switching station, expandable to six.	AF2-298	3/31/2028	\$10.69	AES Ohio	10/8/2025
	N8931.0	Remote end relaying at Crown substation.	AF2-298	3/31/2028	\$0.08	AES Ohio	10/8/2025
	N8932.0	Remote end relaying at Hutchings substation.	AF2-298	3/31/2028	\$0.08	AES Ohio	10/8/2025
	N8933.0	Remote end relaying at Lebanon substation.	AF2-298	3/31/2028	\$0.08	AES Ohio	10/8/2025
28	N8837.0	AC2-061 138 kV: Reconfigure the ICON at the AC2-061 138 kV station for fiber-optic communication connectivity with the proposed AF2-440 138 kV interconnection station.	AF2-440	12/31/2027	\$0.02	AEP	10/8/2025
29	N8839.0	New 138 kV substation: Review and revise protective relay settings to account for the additional generations.	AG1-107	12/31/2027	\$0.06	AEP	10/8/2025
30	N8887.0	Extend the existing Vandalia 69 kV south bus by one bay to accommodate a new disconnect switch and breaker. Procure and install new breakers, disconnect switches, structures and foundations.	AG1-207	10/1/2027	\$1.49	AES Ohio	10/8/2025
31	N8924.0	Interconnection substation tie-in: Cut and loop the Urbana-Darby 138 kV line into the new substation and reroute Givens Tap 138 kV line.	AE2-305	5/31/2029	\$5.97	AES Ohio	10/8/2025
	N8926.0	Remote end relaying at Urbana substation.	AE2-305	5/31/2029	\$0.68	AES Ohio	10/8/2025
	N8927.0	Remote end relaying at Darby substation.	AE2-305	5/31/2029	\$0.71	AES Ohio	10/8/2025

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Table 6.47: Ohio Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
32	N8925.0	New two-bay breaker and a half switching station.	AE2-305	5/31/2029	\$13.45	AES Ohio	10/8/2025
	N8928.0	Remote end relaying at Mutual substation.	AE2-305	5/31/2029	\$0.07	AES Ohio	10/8/2025
33	N8959.0	Upgrade Clay 345 kV substation to interconnect the AF1-282 generating facility. Remove existing rigid bus and install one 345 kV breaker and one 345 kV disconnect switch on existing stand in the fourth (future) position of the ring bus. Install rigid bus from the 345 kV ring to the new take-off structure location. Install three line PTs at the new take-off structure location, and add one new relay panel for line protection and metering of the AF1-282 generator tie line in the existing control enclosure. Also install rigid bus and two additional 345 kV disconnect switches on the north end of the ring to accommodate future expansion of the ring.	AF1-282	5/1/2030	\$2.94	AES Ohio	10/8/2025
	N8960.0	Review and update relay protection settings at Lynchburg substation.	AF1-282	5/1/2030	\$0.08	AES Ohio	10/8/2025
	N9270.0	Expand the Clay 345 kV substation to a five-breaker ring bus. Remove one 345 kV breaker, install two 345 kV breakers, four 345 kV disconnect switches, one take-off structure for the AF1-283 line terminal position, three line PTs, three arresters, one shield mast, new rigid bus and steel supports. One station service transformer will be relocated.	AF1-283	5/1/2030	\$8.56	AES Ohio	10/8/2025
	N9271.0	Review and update relay protection settings at Lynchburg substation.	AF1-283	5/1/2030	\$0.08	AES Ohio	10/8/2025
34	N8961.0	Review and update relay protection settings at Stuart substation.	AF1-282	5/1/2030	\$0.08	AES Ohio	10/8/2025
	N9272.0	Review and update relay protection settings at Stuart substation.	AF1-283	5/1/2030	\$0.08	AES Ohio	10/8/2025
35	N9007.0	Revise relay settings at NASA substation.	AF2-005	4/1/2026	\$0.05	ATSI	10/8/2025
36	N9008.0	Revise relay settings at Wellington substation.	AF2-005	4/1/2026	\$0.05	ATSI	10/8/2025
37	N9009.0	Revise relay settings at Ford substation.	AF2-005	4/1/2026	\$0.05	ATSI	10/8/2025
38	N9010.0	Revise relay settings at Henrietta substation.	AF2-005	4/1/2026	\$0.05	ATSI	10/8/2025
39	N9011.0	Revise relay settings at Johnson substation.	AF2-005	4/1/2026	\$0.05	ATSI	10/8/2025
40	N9012.0	Revise relay settings at Woodings substation	AF2-005	4/1/2026	\$0.10	AMPT	10/8/2025
41	N9039.0	Transmission tie the proposed 138 kV switching station into the proposed Lockbourne-Good Hope line.	AF2-371	1/31/2028	\$1.44	AEP	10/8/2025
	N9040.0	Review and revise (as needed) the protective relay settings at the Lockbourne 138 kV switching station.	AF2-371	1/31/2028	\$0.09	AEP	10/8/2025
42	N9041.0	Review and revise (as needed) the protective relay settings at the Lemaster 138 kV switching station.	AF2-371	1/31/2028	\$0.09	AEP	10/8/2025
	N9042.0	Install two new All Dielectric Loose Tube (ADLT) fiber-optic cable in new underground right-of-way and associated terminating equipment and devices (transceivers, multiplexors, routers).	AF2-371	1/31/2028	\$0.40	AEP	10/8/2025
	N9043.0	Review and revise (as needed) the protective relay settings at the new proposed 138 kV switching station.	AG1-351	1/31/2028	\$0.06	AEP	10/8/2025
43	N9047.0	Review and revise the protective relay settings at the College Corner 138 kV station.	AF1-071	2/24/2027	\$0.06	AEP	10/8/2025

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**Table 6.47:** Ohio Network Projects (Dec. 31, 2025) (Cont.)

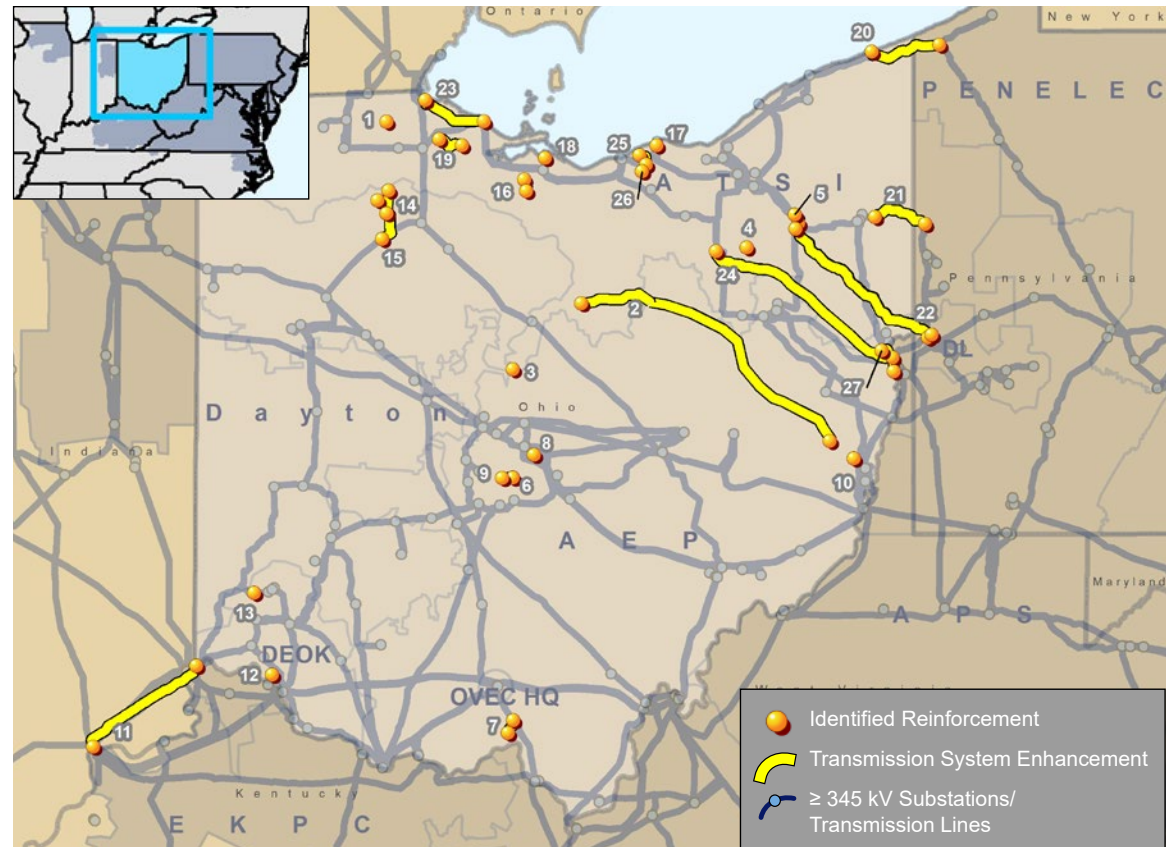
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
44	N9055	Reroute Allen-Timber Switch 138 kV circuit.	AG1-368	3/2/2028	\$1.00	AEP	10/8/2025
	N9056	Reconfigure the existing ICON and review and revise the protective relay settings.	AG1-368	3/2/2028	\$0.08	AEP	10/8/2025
45	N9300.0	Review and revise (as necessary) the protective relay settings at the Logtown 138 kV station, and replace current transformer on the line exit to AG1-369 generating facility at the Logtown 138 kV station.	AG1-369	3/17/2029	\$0.02	AEP	10/8/2025
	N9301.0	Review and revise (as necessary) the protective relay settings at the Logtown 138 kV station to account for the additional generation.	AF2-377	3/17/2029	\$0.06	AEP	10/8/2025
46	N8742.0	Review and update relay settings at Masury substation.	AG1-054	3/31/2026	\$0.05	ATSI	10/8/2025
47	N8743.0	Review and update relay settings at Columbiana substation.	AG1-054	3/31/2026	\$0.05	ATSI	10/8/2025
48	N8744.0	Review and update relay settings at Lowellville substation.	AG1-054	3/31/2026	\$0.05	ATSI	10/8/2025

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**6.9.8 — Supplemental Projects**

Supplemental projects included in the 2025 Local Plan in Ohio are summarized in **Map 6.39** and **Table 6.48**.

**Map 6.39:** Ohio Supplemental Projects (Dec. 31, 2025)



**Table 6.48:** Ohio Supplemental Projects (Dec. 31, 2025)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S3543.1	Expand Hawthorne station into a ring bus configuration. Build a four-breaker 138 kV ring bus.	3/14/2028	\$11.60	ATSI	8/16/2024
2	S3544.1	138 kV transmission line tap: Install two main-line SCADA-controlled switches. Install one tap-line SCADA-controlled switch. Construct 0.1 miles of 138 kV line extension. Adjust relay settings at Longview and Nottingham substations. Install revenue metering.	12/31/2027	\$1.50	ATSI	8/16/2024

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Table 6.48: Ohio Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	S3545.1	138 kV transmission line tap: Install two main-line SCADA-controlled switches. Install one tap-line SCADA-controlled switch. Construct 0.1 miles of 138 kV line extension. Install one breaker and associated equipment at Cardington substation. Adjust relay settings at Galion substation. Install revenue metering.	12/31/2027	\$2.80	ATSI	8/16/2024
4	S3546.1	Install new 138 kV breaker-and-a-half substation (Glenmount) adjacent to South Akron substation on existing FirstEnergy property. Install 11 new 138 kV breakers and associated equipment, including a new control house. Install one 138 kV capacitor switcher and capacitor bank. Rerterminate the existing 138 kV lines into the new switching station. The new lines will be the Glenmount-Firestone 138 kV line, Glenmount-Toronto 138 kV line, Glenmount-Lakemore 138 kV line and the Glenmount-Dale 138 kV line (lines were previously connected to South Akron substation). Install two new 138 kV lines from Glenmount switching station to South Akron substation (~0.2 miles each). Remove existing transmission equipment at South Akron substation (breakers and associated equipment, capacitor bank, etc.). Modify relay settings at four remote end substations (Dale substation, Lakemore substation, Toronto substation and Firestone substation). Install new MPLS equipment for SCADA transport at Glenmount switching station. Install ADSS from existing South Akron substation to Glenmount switching station.	12/31/2027	\$23.54	ATSI	9/20/2024
5	S3576.1	At Campbellsport-Ravenna No.1 69 kV line reconductor: Reconductor ~2.8 miles of the Campbellsport-Ravenna No.1 69 kV line using 556 kcmil 26/7 ACSR conductor. Upgrade A-115 switch with new 1200A units with SCADA control. Install vacuum bottle on A-408 switch. Install new 1200A switch with vacuum bottle and SCADA control at the Robson Tap. At Ravenna substation: Adjust relay settings. Upgrade D-15, and D-16 switches with new 1200A units with whips. Upgrade the SCCIR 477 kcmil ACSR substation conductor with 605 kcmil ACSR conductor. At Sumner substation: Upgrade A-9, A-10 and A-44 switches with new 1200A units with whips. Upgrade the SCCIR 477 kcmil ACSR substation conductor with 605 kcmil ACSR conductor. Install new 1200A switch with vacuum bottle and SCADA control.	12/31/2025	\$6.70	ATSI	1/17/2025
	S3718.1	At Campbellsport-Ravenna No. 2 69 kV line, rebuild 1.6 miles of noncontiguous 69 kV line sections. At Ravenna substation, replace bus transfer switch. Replace breaker disconnect switches. Upgrade substation conductors to exceed transmission line rating.	5/26/2026	\$6.77	ATSI	6/13/2025
6	S3577.1	At Bexley, work will be performed to address asset renewal concerns associated with the site and transmission equipment including work to allow for the retirement of the existing 40 kV yard at the station. This includes replacing 138 kV circuit breaker "106" with a 138 kV, 3000A 63 kA circuit breaker. Note that 138 kV breaker "105" that was identified in the original need statement failed in the field and has been subsequently replaced.	9/30/2026	\$4.42	AEP	10/18/2024
	S3577.2	Transmission line work will be completed outside Bexley to allow 40 kV circuits to bypass the station to accommodate the retirement of the 40 kV yard.	9/30/2026	\$2.19	AEP	10/18/2024
	S3577.3	Transmission line work will be completed to allow 40 kV circuits to bypass Etna Road station to accommodate the 40 kV equipment retirement at Etna Road.	9/30/2026	\$0.62	AEP	10/18/2024
7	S3589.1	Rebuild ~1.7 miles of 69 kV line from North Portsmouth to structure (str.) 13 on the North Portsmouth-Oertels Corner 69 kV line using ACSR 556 Dove. The remaining ~3.05 miles of the line is to be rebuilt under b3362.	5/1/2026	\$3.87	AEP	10/18/2024
8	S3590.1	Install four 138 kV, 4000A 90 kA circuit breakers at the proposed Kiber station (s3442.17) to accommodate the 138 kV line extensions to LRE's Groves Corner station.	1/2/2026	\$11.50	AEP	10/18/2024
	S3590.2	Install 12 kV customer metering.	1/2/2026	\$0.10	AEP	10/18/2024
	S3590.3	Construct a ~2.0-mile 138 kV double-circuit transmission line utilizing two-bundled ACSS 1033.5 MCM Curlew conductor SE rating (561 MVA) between Kiber and Licking REC's greenfield delivery point Groves Corner.	1/2/2026	\$20.69	AEP	10/18/2024
9	S3593.1	Construct a greenfield double-circuit 138 kV transmission line (~0.2 miles) from the existing Bexley-St. Clair Ave. 138 kV line cut in the new distribution delivery at the proposed Drew station.	11/30/2026	\$5.30	AEP	11/15/2024
	S3593.2	To accommodate the new distribution deliveries requested a new 138/13.8 kV station called Drew will be constructed. The station will be configured as a four-breaker ring utilizing 138 kV, 3000A 63 kA breakers to provide service to two new 138/13.8 kV distribution transformers.	11/30/2026	\$4.75	AEP	11/15/2024
	S3593.3	Remote end work will be performed at Bexley and St. Clair Ave. stations in or to coordinate with the newly proposed Drew station.	11/30/2026	\$0.75	AEP	11/15/2024

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Table 6.48: Ohio Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
10	S3596.1	At Summerhill station, replace the wood pole two-way 69 kV line switch with a new steel pole three-way switch with motor operators and SCADA functionality. Reconfigure the 69 kV transmission lines connected to the switch, based on the new switch location.	2/1/2027	\$2.03	AEP	12/13/2024
11	S3598.1	Retire the 138 kV feeder from Miami Fort (Duke Energy)-Clifty Creek (OVEC). This line is 93 years old, 47 miles long, and constructed of single-circuit lattice towers with 336 ACSR conductor. Near Petersburg, Kentucky a 2,000-foot section of static failed dropping onto the B phase conductor. The breaker at Clifty Creek opened due to the fault. The protection at Miami Fort failed to operate, which caused B phase to see 900 amps. The line is rated at 542 amps. After fifteen minutes, nine miles west of the initial static failure, a B phase conductor failed falling to the ground. Flexing of the towers snapped two statics. 3,700 feet of line is damaged at this location. An analysis of the failed conductor was performed. Visual inspection found extensive corrosion and pitting on the outer conductor. Rust was noted to various degrees on the steel core. Tensile testing on the core showed breaking strength ~26% lower than the ASTM requirement. Zinc coating was found to have an area density 15% lower than the required minimum. We believe these test results to be indicative of the condition of the remaining line.	12/31/2026	\$39.00	DE0&K	9/20/2024
12	S3599.1	Replace the two end-bus switches with 69 kV, 2000A, motorized switches. Install an automatic throw-over scheme. Replace an existing switch and add a second switch to the bus with 69 kV, 2000A, manually-operated switches so that each of the three bus sections and transformers can be isolated. Replace circuit breakers circuit breaker 677 and circuit breaker 684 with circuit switchers. Replace TB1 and Switchgear 1.	12/11/2026	\$1.08	DE0&K	3/14/2025
13	S3601.1	Supply the customer facility with two feeds from the directly adjacent Woodsdale 345 kV substation by expanding and modifying the Woodsdale ring bus into a breaker-and-a-half configuration. Seven new 345 kV circuit breakers with associated equipment will be required.	3/1/2026	\$36.20	DE0&K	9/13/2024
14	S3641.1	Rebuild the existing North Baltimore-Portage 34.5 kV line (~10 miles). There will be ~0.3 miles of greenfield line to support right-of-way efforts and outage constraints.	11/30/2028	\$23.17	AEP	10/18/2024
	S3641.2	Rebuild the ~1.7 mile 34.5 kV extension from Hammansburg Tap to Hoiles switch (Buckeye Pipeline and Cynet Pipeline).	11/30/2028	\$4.37	AEP	10/18/2024
	S3641.6	Install ~0.2 miles of greenfield 34.5 kV line between the proposed Portage switch and AMPT's proposed Greensburg 69/34.5 kV substation.	11/30/2028	\$0.45	AEP	10/18/2024
	S3641.8	AMPT will rebuild their Poe Road substation and reconfigure the 69 kV yard into a six-breaker ring bus configuration. To accommodate the station work, they will reterminate the existing three 69 kV circuits and two 69/12 kV transformers at the station along with establishing a position to accommodate the new Greensburg-Poe Road 69 kV circuit.	11/30/2028	\$13.30	AEP	10/18/2024
	S3641.9	AMPT will build a greenfield 69/34.5 kV station tentatively called "Greensburg." The station will initially accommodate one 69 kV breaker, one 34.5 kV breaker and one 69/34.5 kV, 50 MVA transformer. This station will terminate the new 69 kV circuit from Poe Road and connect to the end of the existing AEP 34.5 kV system near Portage switch.	11/30/2028	\$9.80	AEP	10/18/2024
	S3641.10	FirstEnergy will perform remote end relay work at Sandridge 69 kV substation to accommodate the reconfiguration of AMPT's Poe Road station.	11/30/2028	\$0.10	AEP	10/18/2024
	S3641.11	At Portage 34.5 kV tap, Install a new 69 kV, 1200A, three-way phase-over-phase switch to accommodate the new 34.5 kV connection to AMPT's Greensburg station.	11/30/2028	\$0.78	AEP	10/18/2024
	S3641.12	Replace existing Mungen hard tap with a new 69 kV, 1200A, three-way phase-over-phase switch.	11/30/2028	\$0.68	AEP	10/18/2024
	S3641.13	Replace existing Hammansburg hard tap with a 69 kV, 1200A, three-way phase-over-phase switch. Remove existing one-way line switch.	11/30/2028	\$0.87	AEP	10/18/2024

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Table 6.48: Ohio Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
15	S3641.3	Several spans of the 34.5 kV extension to the Henry Co-Op delivery will be rebuilt as part of the project. The delivery is currently served via the double-circuit section of the North Baltimore-Portage line directly out of North Baltimore.	11/30/2028	\$0.31	AEP	10/18/2024
	S3641.4	Retire North Baltimore-New Liberty from structures 179 to 11 (~6.81 miles). Remove conductors for the North Baltimore-New Liberty circuit on the New Liberty-West Melrose line from structure 11 to New Liberty (~0.43 miles).	11/30/2028	\$1.72	AEP	10/18/2024
	S3641.5	In order to accommodate the retirement of the ~6.81 miles of line on the North Baltimore-New Liberty 34.5 kV circuit, reconfiguration work will be performed to tie the remaining portion of the circuit into the nearby North Baltimore-North Findlay No. 2 34.5 kV circuit. This includes constructing ~1.1 miles of new transmission between the two existing lines and retiring ~1.85 miles of the North Baltimore-North Findlay No. 2 34.5 kV circuit north into North Baltimore.	11/30/2028	\$4.00	AEP	10/18/2024
	S3641.7	In order to provide a second source into the 34.5 kV network served from the North Baltimore-Portage 34.5 kV circuit, AMPT will be constructing ~7 miles of 69 kV circuit between Poe Road and the proposed Greensburg station. 3.5 miles of the line will be greenfield single circuit extending from right outside their existing Gypsy Lane station to a newly proposed Greensburg AMPT substation near Portage switch. To get the new circuit back to Poe Road station AMPT will be rebuilding the existing Gypsy Lane-Poe Road 69 kV line for ~3.5 miles from single-circuit to double-circuit tower arrangement utilizing the existing right-of-way.	11/30/2028	\$20.10	AEP	10/18/2024
	S3641.14	At North Baltimore 34.5 kV substation, in order to accommodate the reconfiguration and retirements of the 34.5 kV circuits to New Liberty and North Findlay, existing 34.5 kV circuit breaker "M" toward New Liberty substation will be retired. Additional relaying work will be performed at the station to accommodate the proposed work in the area.	11/30/2028	\$0.47	AEP	10/18/2024
	S3641.15	Work will be performed at New Liberty to accommodate the retirement of the 34.5 kV circuit to North Baltimore.	11/30/2028	\$0.09	AEP	10/18/2024
16	S3648.1	Rebuild 4 miles of the Bellevue-Groton 69 kV line with 556 kcmil ACSR conductor. The portion of Bellevue to Str 220-1b will be rebuilt. The portion of Groton to Str 220-1b will be reconducted. At Groton substation, revise relay settings. At Bellevue substation, replace six manual switches with two GOAB switches, replace switch A98. Revise relay settings and upgrade ACSR connections.	6/1/2026	\$10.10	ATSI	3/14/2025
17	S3659.1	Install revenue metering.	5/14/2026	\$0.10	ATSI	9/20/2024
18	S3660.1	Phase 1: 138 kV direct connection to New Departure: Adjust relay settings at New Departure substation.	5/25/2028	\$0.10	ATSI	9/13/2024
	S3660.2	Phase 2: 138 kV switching station: Rebuild New Departure substation as a new nine breaker, breaker-and-a-half, 138 kV switching station. Rereminate the lines from Ford substation and Greenfield substation into the New Departure substation. Loop the Greenfield-Nasa 138 kV line in and out of the new substation. Install two sets of revenue metering equipment. Upgrade relaying/adjust relay settings at Greenfield, Nasa and Ford substations.	5/25/2028	\$27.00	ATSI	9/13/2024
	S3660.3	Phase 3: 345 kV switching station: Build a new four-breaker 345 kV ring bus at New Departure substation. Add six new 138 kV breakers at New Departure substation and install two 345/138 kV transformers. Loop the Davis Besse-Hayes 345 kV line in and out of the new 345 kV ring bus by constructing two 345 kV lines, ~3.5 miles in length. Install two additional sets of revenue metering. Upgrade relaying/adjust relay settings at Davis Besse and Hayes substations.	5/25/2028	\$72.00	ATSI	9/13/2024
19	S3669.1	At Brush Wellman-Genoa 69 kV line, rebuild 11.4 miles of 69 kV line, replacing deteriorated wood pole construction. At Brush Wellman substation, replace circuit breakers B7226 and B7227. At Genoa substation, replace circuit breaker 6873. Replace associated disconnect switches.	6/1/2027	\$32.27	ATSI	5/16/2025
20	S3702.1	At Ashtabula-Erie West 345 kV line, rebuild the 7.2 mile, Penile section of the line. At Erie West, replace disconnect switches. At Ashtabula, revise relay settings.	5/31/2027	\$52.40	PENELEC	8/6/2024
21	S3714.1	At Niles-Shenango 345 kV line, rebuild the 12.4 mile wood pole section (total length 14.5 miles) from Structure 41946 to Structure 42033 an install new conductor. Reconductor ~2.1 miles from the Niles substation to Structure 41946. At Niles substation, replace five disconnect switches. replace line relaying. At Shenango substation, replace line relaying.	12/17/2027	\$73.92	ATSI	7/6/2025
22	S3715.1	At Beaver Valley-Hanna 345 kV line and Hanna-Mansfield 345 kV line, replace 33 steel structures from Structure 6270 to Structure 6632. Install new conductor on the Beaver Valley-Hanna line (~6.9 miles). Install new conductor on the Hanna-Mansfield line (~6.6 miles). At Beaver Valley, Mansfield and Hanna substations, adjust relay settings.	5/31/2028	\$53.35	ATSI	7/6/2025

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**Table 6.48:** Ohio Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
23	S3716.1	At Bayshore-Davis Besse 345 kV line, replace 17 deteriorated wood pole and phase-raised structures on the four-mile section from Structure 9 to Structure 25 and install new conductor. At Bayshore and Davis Besse substations, replace line relaying.	5/28/2028	\$21.12	ATSI	7/6/2025
24	S3717.1	At Sammis-Star 345 kV line, rebuild the existing Sammis-Star 345 kV line (~68.6 miles). At Sammis and Star substations, replace line relaying.	5/30/2031	\$343.70	ATSI	7/6/2025
25	S3719.1	Black River-Johnson West 69 kV line, retire and replace obsolete two-way line tap switches A-81 and A-82 at Oakwood Tap. Relocate new switches to mid-span structures and equip with SCADA controlled motor operators.	12/31/2026	\$1.66	ATSI	6/13/2025
26	S3720.1	At Gates substation, replace 138 kV breaker and associated disconnect switches. Install surge arresters and power communications monitor PCM-5350. Replace substation conductor. At Johnson substation, replace disconnect switches. Install power communications monitor PCM-5350.	12/29/2028	\$1.96	ATSI	6/13/2025
27	S3724.1	Rebuild ~0.95-mile section from structure No. 9 to structure No. 17 of the line asset as double-circuit with 556 ACSR. Additionally, rebuild 18.5-mile section from structure No. 17 to Hammondsville as single circuit with 556 ACSR.	3/16/2029	\$82.74	AEP	7/18/2025
	S3724.2	Install Croxton switch as a new 69 kV phase-over-phase switch to replace the existing switch as part of the line rebuild as the existing pole will be retired with the line work.	3/16/2029	\$1.42	AEP	7/18/2025

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## 6.10: Pennsylvania RTEP Summary

### 6.10.1 — RTEP Context

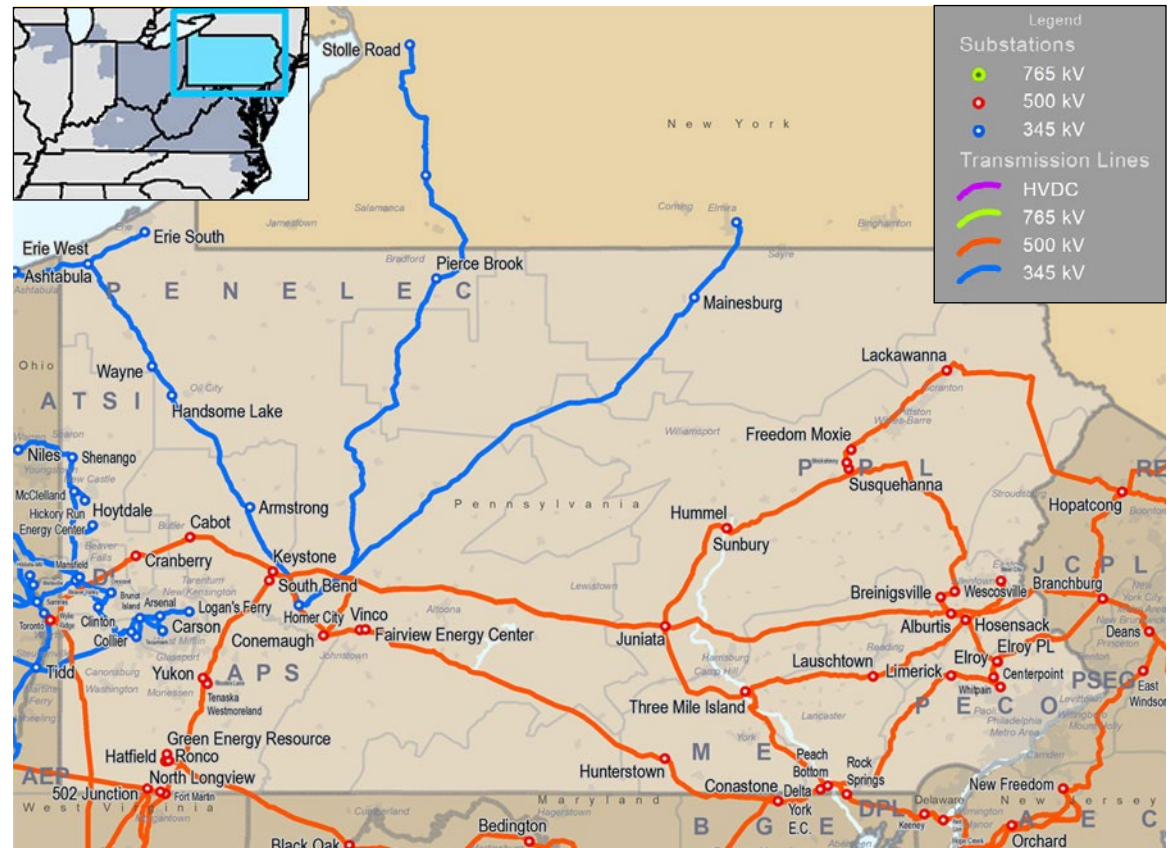
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Pennsylvania, including facilities owned and operated by Allegheny Power (FirstEnergy) (AP), Duquesne Light Company (DLCO), Met-Ed (METED), Pennsylvania Electric Company (PENELEC), PECO Energy Company (PECO), PPL Electric Utilities (PPL), UGI Utilities (UGI), Rock Springs and American Transmission Systems, Inc. (FirstEnergy) (ATSI) as shown on **Map 6.40**.

Pennsylvania's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

### **Renewable Portfolio Standards**

Pennsylvania has a mandatory alternative energy portfolio standard (AEPS) target of 8% Tier 1 resources and 10% Tier 2 resources. The AEPS includes a solar carve-out of 0.5%, and solar resources applying toward the AEPS must be located within Pennsylvania.

Map 6.40: PJM Service Area in Pennsylvania

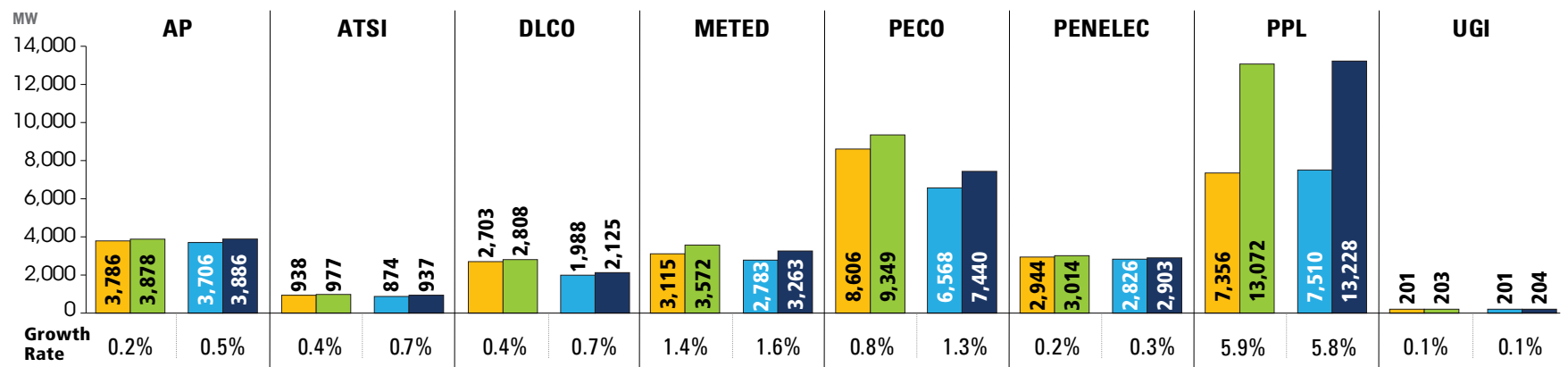


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### 6.10.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.46** summarizes the expected loads within the state of Pennsylvania and across the PJM region.

**Figure 6.46:** Pennsylvania – 2025 Long-Term Load Forecast



PJM RTO Summer Peak		PJM RTO Winter Peak	
2025	2035	2024/2025	2034/2035
154,144 MW	209,923 MW	136,127 MW	198,175 MW
Growth Rate 3.1%		Growth Rate 3.8%	

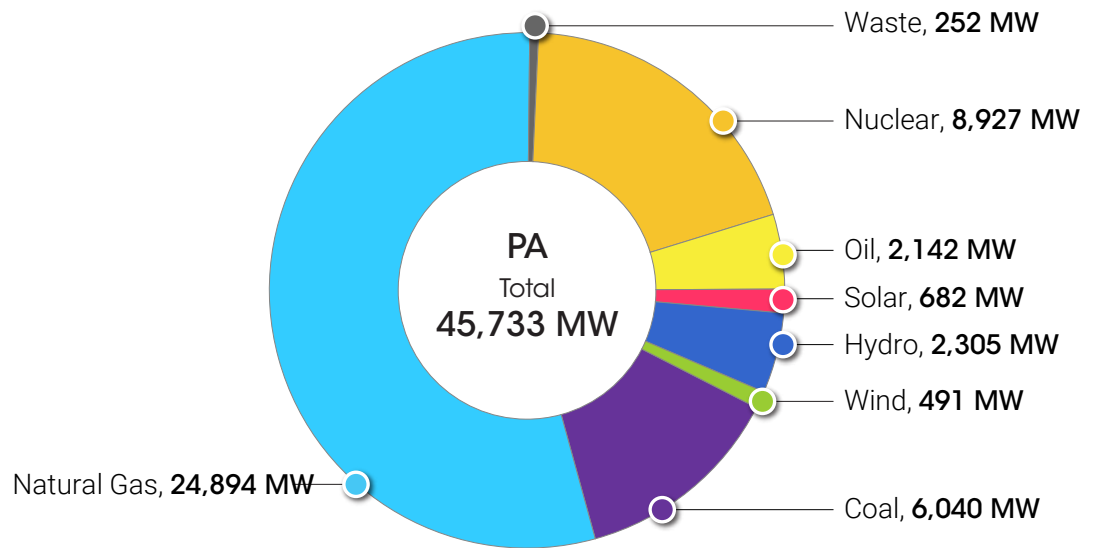
PJM notes that AP and ATSI serve load other than in Pennsylvania. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in Pennsylvania. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Pennsylvania over the past five years.

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**6.10.3 — Existing Generation**

Existing generation in Pennsylvania as of Dec. 31, 2025, is shown by fuel type in **Figure 6.47**.

**Figure 6.47:** Pennsylvania – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



**6.10.4 — Interconnection Requests**

In Pennsylvania, as of Dec. 31, 2025, 272 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.49**, **Table 6.50**, **Figure 6.48**, **Figure 6.49** and **Figure 6.50**.

**Table 6.49:** Pennsylvania – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

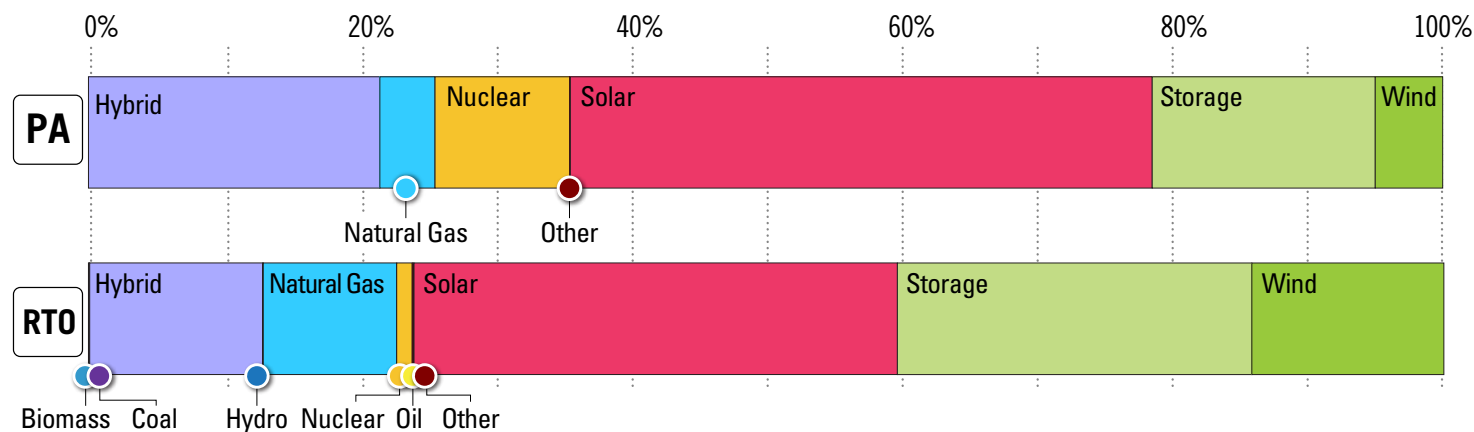
	Pennsylvania Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
<b>Biomass</b>	0.0	0.00%	10.0	0.01%
<b>Coal</b>	0.0	0.00%	14.0	0.01%
<b>Hybrid</b>	1,732.9	21.51%	14,332.3	12.76%
<b>Hydro</b>	0.0	0.00%	30.0	0.03%
<b>Natural Gas</b>	328.6	4.08%	11,082.0	9.87%
<b>Nuclear</b>	803.0	9.97%	1,305.9	1.16%
<b>Oil</b>	0.0	0.00%	50.0	0.04%
<b>Other</b>	2.9	0.04%	56.3	0.05%
<b>Solar</b>	3,462.9	42.97%	40,116.0	35.73%
<b>Storage</b>	1,326.6	16.46%	29,376.0	26.16%
<b>Wind</b>	401.0	4.98%	15,910.7	14.17%
<b>Grand Total</b>	<b>8,057.9</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

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**Table 6.50:** Pennsylvania – Interconnection Requests by Fuel Type (Dec. 31, 2025)

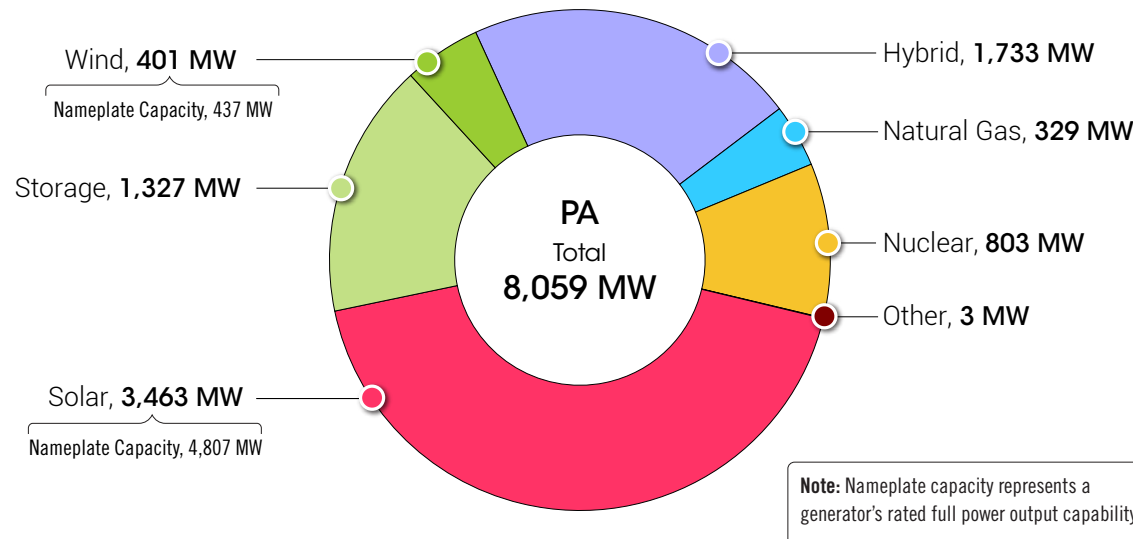
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	17	231.5	28	14,354.6	45	14,586.1
	Diesel	0	0.0	0	0.0	0	0.0	2	31.3	13	51.5	15	82.8
	Natural Gas	2	328.6	0	0.0	0	0.0	126	21,729.3	271	99,898.3	399	121,956.2
	Nuclear	1	803.0	0	0.0	0	0.0	15	2,609.0	15	1,731.0	31	5,143.0
	Oil	0	0.0	0	0.0	0	0.0	9	16.9	9	1,307.0	18	1,323.9
	Other	1	2.9	0	0.0	0	0.0	1	304.0	4	344.0	6	650.9
	Storage	14	1,177.6	3	133.0	2	16.0	4	0.0	119	4,060.7	142	5,387.3
Renewable	Biomass	0	0.0	0	0.0	0	0.0	1	6.4	4	36.5	5	42.9
	Hybrid	32	1,612.6	0	0.0	6	120.3	0	0.0	109	2,555.5	147	4,288.4
	Hydro	0	0.0	0	0.0	0	0.0	12	480.8	26	974.6	38	1,455.4
	Methane	0	0.0	0	0.0	0	0.0	22	120.2	37	201.3	59	321.5
	Solar	122	2,078.8	30	456.7	46	927.3	45	712.4	627	9,594.6	870	13,769.8
	Wind	12	380.4	0	0.0	1	20.5	40	281.4	142	1,819.2	195	2,501.5
	Wood	0	0.0	0	0.0	0	0.0	0	0.0	1	16.0	1	16.0
<b>Grand Total</b>		<b>184</b>	<b>6,384.0</b>	<b>33</b>	<b>589.7</b>	<b>55</b>	<b>1,084.1</b>	<b>294</b>	<b>26,523.1</b>	<b>1,405</b>	<b>136,944.7</b>	<b>1,971</b>	<b>171,525.7</b>

**Figure 6.48:** Pennsylvania – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

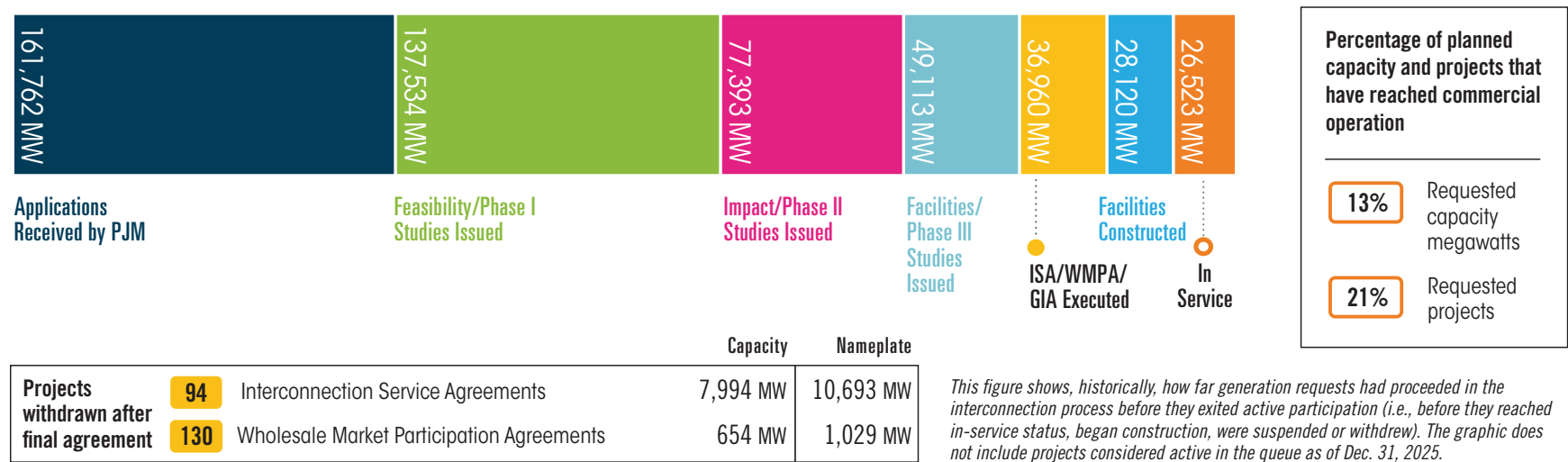


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**Figure 6.49:** Pennsylvania Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.50:** Pennsylvania Progression of Interconnection Requests (Dec. 31, 2025)

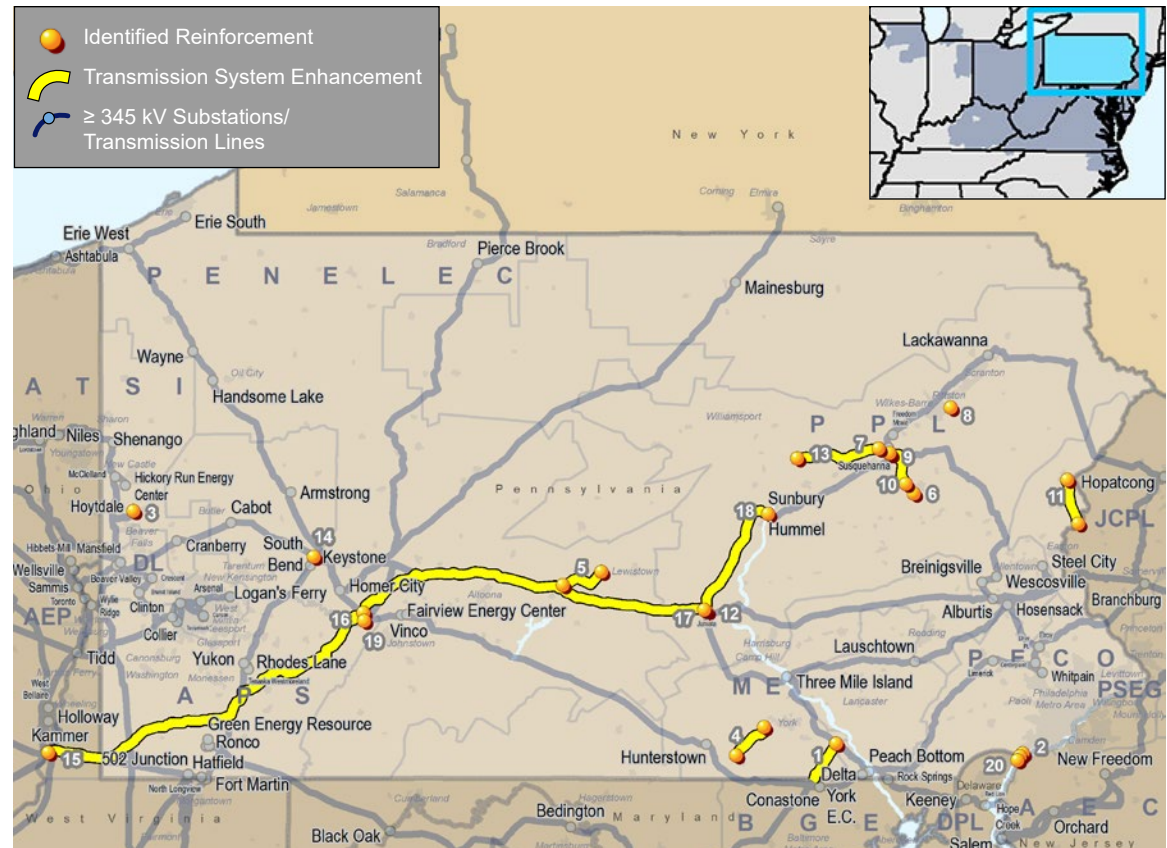


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**6.10.5 — Baseline Projects**

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in Pennsylvania are summarized in **Map 6.41** and **Table 6.51**.

**Map 6.41: Pennsylvania Baseline Projects (Dec. 31, 2025)**



**Table 6.51: Pennsylvania Baseline Projects (Dec. 31, 2025)**

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B3800.54	Perform final tie-ins and commissioning for Chanceford-Doubs 500 kV line energization upon completion of all transmission owner segments within PA and MD.	6/1/2027	\$0.20	PPL	7/8/2025	N/A - Scope Change	Baseline Load Growth Deliverability & Reliability
2	B3942.1	Replace existing and install new relays at Chichester 230 kV substation to increase the rating on Chichester-Trainer 230 kV circuit.	6/1/2030	\$0.69	PECO	11/4/2025	No	Baseline Load Growth Deliverability & Reliability

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Table 6.51: Pennsylvania Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
3	B3985.3	Replace 83-B-14, 83-B-18, 83-B-22 breakers with 3000A 63 kA circuit breakers at Hoytdale substation. This will not affect the Hoytdale-New Castle line ratings, which are currently rated at 435/500 SN/SE for circuit Z104 and 329/413 SN/SE for circuit Z110.	6/1/2030	\$2.87	ATSI	11/14/2025	No	Short Circuit
4	B4011.1	Install new 115 kV capacitor and replace limiting conductors, line relaying and disconnect switches at North Hanover on the Jackson terminal.	6/1/2030	\$3.56	METED	11/13/2025	No	Baseline Load Growth Deliverability & Reliability
	B4011.2	Replace limiting conductors, line relaying, circuit breaker and two 115 kV disconnect switches at Jackson on the North Hanover terminal.	6/1/2030	\$0.57	METED	11/13/2025	No	
	B4011.3	Rebuild the Jackson-North Hanover 115 kV 968 line as a double circuit, ~13.2 miles, using 954 ACSR 45/7. The line will be energized in a six-wire configuration.	6/1/2030	\$57.65	METED	11/13/2025	No	
5	B4012.1	Replace structures on the Belleville-Center Union 46 kV line and use 795 ACSR 26/7 conductor on spans D-356 through D-360.	6/1/2030	\$2.72	PENELEC	11/13/2025	No	TO Criteria Violation
6	B4029.1	Expand existing Slykerville 230 kV station to add a 500 kV yard. Build a new Kelayres 500 kV breaker-and-a-half substation. Add two 890 MVA, 500/230 kV transformers at Kelayres.	5/1/2030	\$72.92	PPL	12/2/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4029.2	Add one 500 kV, 4000A circuit breaker, two 500 kV, 4000A MODs and a Kelayres 890 MVA 500/230 kV T3 transformer.	5/1/2030	\$29.02	PPL	12/2/2025	Yes (Reliability W1)	
	B4029.3	Bifurcate the Sunbury-Susquehanna 500 kV line. From the bifurcation point, build a 13-mile extension to Kelayres, resulting in a Susquehanna-Kelayres 500 kV line.	5/1/2030	\$20.87	PPL	12/2/2025	Yes (Reliability W1)	
	B4029.4	Bifurcate the Sunbury-Susquehanna 500 kV line bringing both segments into a new Kelayres 500 kV station on separate towers. From the bifurcation point, build a 24-mile extension to Kelayres, resulting in a Sunbury-Kelayres 500 kV line.	5/1/2030	\$133.64	PPL	12/2/2025	Yes (Reliability W1)	
7	B4029.10	Replace ten 230 kV, 2000A MODs with 230 kV, 3000A MODs at Glen Brook 230/69 kV substation.	5/1/2030	\$2.50	PPL	12/2/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4029.13	Reconductor Glen Brook-Susquehanna T10 1 and 2 DCT line.	5/1/2030	\$2.63	PPL	12/2/2025	Yes (Reliability W1)	

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Table 6.51: Pennsylvania Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
8	B4029.11	Reterminate the Jenkins 230/69 kV T2 and T4 transformers at Jenkins 230/69 kV substation into bay positions in the 69 kV and 230 kV yards, respectively. Add one new 230 kV, 3000A circuit breaker, and two 230 kV, 3000A MODs to accommodate the retermination of the T4 transformer into the east bay position in the existing 230 kV breaker-and-a-half bay 2. Add two new 69 kV, 3000A circuit breakers and four 69 kV, 3000A switches to accommodate the retermination of the T2 transformer into a new 69 kV double-bus double-breaker bay 4.	5/1/2030	\$8.71	PPL	12/2/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4029.12	Reterminate high side of Jenkins T4 transformer into bay 2E of the 230 kV yard.	5/1/2030	\$1.46	PPL	12/2/2025	Yes (Reliability W1)	
9	B4029.14	Construct a new Susquehanna T10-Susquehanna 230 kV No. 3 line (~2.7 miles) using an ~75% brownfield route, with a short greenfield segment near the Susquehanna station.	5/1/2030	\$14.33	PPL	12/2/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4029.15	Construct a new breaker-and-a-half bay at Susquehanna T10 230 kV station and initially populate with two 230 kV, 3000A circuit breakers and four 230 kV, 3000A MODs, leaving a position for a future breaker to be added.	5/1/2030	\$6.62	PPL	12/2/2025	Yes (Reliability W1)	
	B4029.16	Reuse existing bay and upgrade to 3000A. Existing bay at Susquehanna vacated by the former Sunbury line. Inspect all facilities, refurbish and insure bay rating of 3000A.	5/1/2030	\$1.24	PPL	12/2/2025	Yes (Reliability W1)	
	B4029.18	Replace six 230 kV breakers at Susquehanna.	6/1/2030	\$4.50	PPL	1/6/2026	Yes (Reliability W1)	Short Circuit
10	B4029.5	Reconduct the Susquehanna-Tomhicken 230 kV 1 and 2 DCT circuits on the existing DCT tower with ACCC 1036/87/392 (2045 kcmil) conductor.	5/1/2030	\$29.73	PPL	12/2/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
11	B4029.6	Upgrade the existing Monroe 230/138 kV substation to a two-bay breaker and a half on the 230 kV side (with space to accommodate two future bays) and a double-bus double-breaker design on the 138 kV side.	5/1/2030	\$30.95	PPL	12/2/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4029.7	Perform retermination of the Monroe-Fox Hill and Monroe-Martins Creek 230 kV lines into their new locations in the upgraded 230 kV breaker-and-a-half yard.	5/1/2030	\$8.27	PPL	12/2/2025	Yes (Reliability W1)	
12	B4029.8	Address end-of-life concerns by rebuilding the existing 38-mile Juniata-Sunbury 500 kV line using single-circuit design.	5/1/2030	\$162.89	PPL	12/2/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability

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Table 6.51: Pennsylvania Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
13	B4029.9	The Montour-Glen Brook 230 kV 1 and 2 DCT line is 24.9 miles long. For this project, the developer will reconduct 0.70 miles of this route with ACCC 1036/87/392 (2045 kcmil) conductor. Another 5.2 miles of the route will be rebuilt with new steel pole structures and double-bundle 1590 ACSR conductor. The remaining 19 miles of the route is being rebuilt and reconducted as part of supplemental project s2373 to address end of life for CORTEN structures.	5/1/2030	\$37.15	PPL	12/2/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
14	B4036.1	Upgrade Keystone terminal of Keystone-South Bend 500 kV line.	6/1/2032	\$0.76	PENELEC	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4036.2	Upgrade South Bend terminal of Keystone-South Bend 500 kV line.	6/1/2032	\$0.76	AP	1/6/2026	Yes (Reliability W1)	
	B4036.21	Upgrade Keystone terminal of Keystone-Buttermilk Fall 500 kV line (formerly Keystone-Conemaugh).	6/1/2032	\$15.01	PENELEC	1/6/2026	Yes (Reliability W1)	
	B4036.3	Upgrade Keystone terminal of Keystone-Juniata 500 kV line.	6/1/2032	\$7.76	PENELEC	1/6/2026	Yes (Reliability W1)	
15	B4036.10	Construct a new single-circuit 765 kV transmission line between Kammer and proposed Buttermilk Falls substations (PENELEC Zone). The total length of the line is 114 miles.	6/1/2032	\$26.63	KJT	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4036.14	Complete 765/500 kV substation work at new Buttermilk station.	6/1/2032	\$170.29	KJT	1/6/2026	Yes (Reliability W1)	
	B4036.20	Perform transmission line work: Loop in Keystone-Conemaugh 500 kV into Buttermilk Falls. Establish Keystone-Buttermilk Falls.	6/1/2032	\$11.20	PENELEC	1/6/2026	Yes (Reliability W1)	
	B4036.22	Perform transmission line work: Loop in Keystone-Conemaugh 500 kV into Buttermilk Falls. Establish Conemaugh-Buttermilk Falls.	6/1/2032	\$11.20	PENELEC	1/6/2026	Yes (Reliability W1)	
	B4036.8	Construct a new single-circuit 765 kV transmission line between Kammer and proposed Buttermilk Falls substations (AEP Zone). The total length of the line is 114 miles.	6/1/2032	\$96.98	KJT	1/6/2026	Yes (Reliability W1)	
	B4036.9	Construct a new single-circuit 765 kV transmission line between Kammer and proposed Buttermilk Falls substations (AP Zone). The total length of the line is 114 miles.	6/1/2032	\$571.11	KJT	1/6/2026	Yes (Reliability W1)	

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Table 6.51: Pennsylvania Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
16	B4036.11	Construct a new single-circuit 765 kV transmission line between proposed Buttermilk Falls and proposed Mountain Stone substations (PENELEC Zone). The total length of the line is 108 miles.	6/1/2032	\$541.32	KJT	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4036.12	Construct a new single-circuit 765 kV transmission line between proposed Buttermilk Falls and proposed Mountain Stone substations (PPL Zone). The total length of the line is 108 miles.	6/1/2032	\$92.03	KJT	1/6/2026	Yes (Reliability W1)	
	B4036.13	Complete 765/500 kV substation work at new Mountain Stone.	6/1/2032	\$166.94	KJT	1/6/2026	Yes (Reliability W1)	
	B4036.18	Construct two new single-circuit 500 kV t-lines between proposed Mountain Stone substation and Juniata substation. The total length of the line is 0.6 miles.	6/1/2032	\$5.32	KJT	1/6/2026	Yes (Reliability W1)	
17	B4036.15	Install two new 500 kV circuit breakers at north and south bus to terminate the 765/500 kV transformers leads. Upgrade protection settings at Juniata (PPL work).	6/1/2032	\$9.95	PPL	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4036.16	Install two new 500 kV circuit breaker at north and south bus to terminate the 765/500 kV transformers leads. Upgrade protection settings at Juniata (NextEra work).	6/1/2032	\$0.00	NEET	1/6/2026	Yes (Reliability W1)	
	B4036.4	Upgrade Juniata terminal of Keystone-Juniata 500 kV line.	6/1/2032	\$0.00	PPL	1/6/2026	Yes (Reliability W1)	
18	B4036.17	Install two new 500 kV circuit breakers with 5000A 63 kA rating in transformer T24 and T25 bay. Both transformers will be in double-bus, double-breaker position after adding these two new breakers (Sunbury).	6/1/2032	\$4.98	PPL	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
19	B4036.19	Replace nine 500 kV circuit breakers Conemaugh 500 kV substation with new 5000A 63 kA breakers.	6/1/2032	\$22.24	PENELEC	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4036.23	Upgrade Conemaugh terminal of Conemaugh-Buttermilk Falls 500 kV line (formerly Keystone-Conemaugh).	6/1/2031	\$17.08	PENELEC	1/6/2026	Yes (Reliability W1)	
20	B4004.1	Upgrade existing 1590 ACSR stranded bus at Claymont substation to increase the rating on the Claymont-Linwood 230 kV circuit.	6/1/2030	\$0.03	DP&L	11/4/2025	No	Baseline Load Growth Deliverability & Reliability
CEII	B4008.1	2024W1 P5: Install open-battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5DYN-PN01.	6/1/2029	\$0.97	PENELEC	12/8/2025	No	Stability
	B4009.1	2024W1 P5: Modify relay wiring. Addresses flowgate No. 2024-P5-PN03.	6/1/2029	\$0.33	PENELEC	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4010.1	2024W1 P5: Install open-battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5DYN-PN05.	6/1/2029	\$0.97	PENELEC	12/8/2025	No	Stability
	B4037.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5-AP25.	6/1/2029	\$0.60	AP	12/8/2025	No	Baseline Load Growth Deliverability & Reliability

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Table 6.51: Pennsylvania Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
CELL	B4044.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5DYN-METED04.	6/1/2029	\$0.64	METED	12/8/2025	No	Stability
	B4048.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5DYN-METED02.	6/1/2029	\$0.97	METED	12/8/2025	No	
	B4054.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5DYN-METED03.	6/1/2029	\$0.33	METED	12/8/2025	No	
	B4055.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5DYN-PN04.	6/1/2029	\$0.40	PENELEC	12/8/2025	No	
	B4056.1	2024W1 P5: Move backup relaying DC supply to separate battery and modify relay wiring. Addresses flowgate No. 2024-P5DYN-PN02.	6/1/2029	\$0.48	PENELEC	12/8/2025	No	
	B4057.1	2024W1 P5: Install relay panel and modify relay wiring. Addresses flowgate No. 2024-P5-AP06.	6/1/2029	\$0.36	AP	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4058.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5-METED04.	6/1/2029	\$0.51	METED	12/8/2025	No	
	B4059.1	2024W1 P5: Install open-circuit battery monitoring, install relay panel, modify relay wiring. Addresses flowgate No. 2024-P5-METED05.	6/1/2029	\$0.69	METED	12/8/2025	No	
	B4061.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5-AP05.	6/1/2029	\$0.97	AP	12/8/2025	No	
	B4062.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5-AP08.	6/1/2029	\$0.64	AP	12/8/2025	No	Stability
	B4065.1	2024W1 P5: Install battery monitoring system and replace two 115 kV line protection schemes. Addresses flowgate No. 2024-P5-PN04.	6/1/2029	\$2.90	PENELEC	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4065.2	2024W1 P5: Install one relay panel at a confidential substation connected to the substation associated with b4065.1. Addresses flowgate No. 2024-P5-PN04.	6/1/2029	\$0.00	PENELEC	12/8/2025	No	
	B4066.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5-PN05.	6/1/2029	\$2.58	PENELEC	12/8/2025	No	
	B4070.1	2024W1 P5: Modify relay wiring. Addresses flowgate No. 2024-P5DYN-METED01.	6/1/2029	\$0.33	METED	12/8/2025	No	Stability

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Table 6.51: Pennsylvania Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
CELL	B4071.1	2024W1 P5: Separate DC supply to backup relaying and the second trip coils; modify relay wiring. Addresses flowgate No. 2024-P5DYN-PN03.	6/1/2029	\$0.66	PENELEC	12/8/2025	No	Stability
	B4072.1	2024W1 P5: Install open-circuit battery monitoring and modify relay wiring. Addresses flowgate No. 2024-P5-METED02.	6/1/2029	\$0.97	METED	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4074.1	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the control center. Addresses flowgate No. 2024-P5-PECO01.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.10	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO10.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.11	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO11.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.12	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO12.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.13	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO13.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.14	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO14.	6/1/2029	\$0.03	PECO	12/8/2025	No	

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Table 6.51: Pennsylvania Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
CEII	B4074.15	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO15.	6/1/2029	\$0.03	PECO	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4074.16	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO16.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.17	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO17.	6/1/2029	\$0.05	PECO	12/8/2025	No	
	B4074.18	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO18.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.19	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5DYN-PECO01.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.2	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO02.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.3	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PECO03.	6/1/2029	\$0.03	PECO	12/8/2025	No	

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Table 6.51: Pennsylvania Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
CEII	B4074.4	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PEC004.	6/1/2029	\$0.03	PECO	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4074.5	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PEC005.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.6	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PEC006.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.7	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PEC007.	6/1/2029	\$0.03	PECO	12/8/2025	No	
	B4074.8	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PEC008.	6/1/2029	\$0.05	PECO	12/8/2025	No	
	B4074.9	2024W1 P5: Replace existing battery charger; install auxiliary alarm relay board; install shunt enclosure; and connect alarm points to SCADA to monitor and report low-voltage and open-circuit conditions on the station DC supply to the Control Center. Addresses flowgate No. 2024-P5-PEC009.	6/1/2029	\$0.03	PECO	12/8/2025	No	

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6.10.6 — Network Projects

Network projects in Pennsylvania for 2025 are summarized in **Map 6.42** and **Table 6.52**.

Map 6.42: Pennsylvania Network Projects (Dec. 31, 2025)

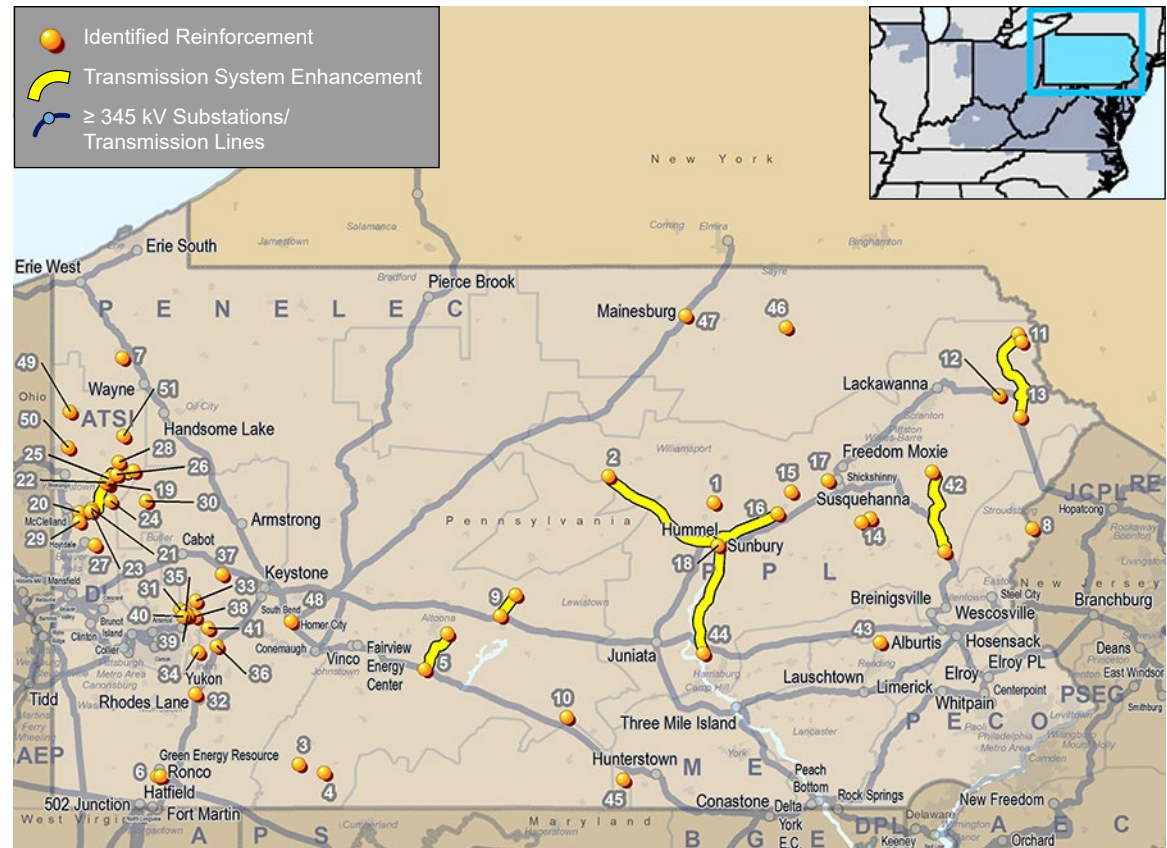


Table 6.52: Pennsylvania Network Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	N6490	Construct 69 kV attachment line from the Point of Interconnection to the Milton 230/69 kV substation.	AE2-042	6/30/2022	\$0.81	PPL	10/8/2025
	N6491	Modify the Milton 230/69 kV substation relays to accommodate the AE2-042 interconnection request.	AE2-042	6/30/2022	\$0.14	PPL	10/8/2025
	N6492	Remove the existing disconnect switches and install new disconnect switches and surge arrestors with support structures at the Milton 230/69 kV substation.	AE2-042	6/30/2022	\$0.40	PPL	10/8/2025

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Table 6.52: Pennsylvania Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
2	N8495.1	Construct transmission tap from the Point of Change in Ownership to the Sunbury-Lock Haven 69 kV line.	AF1-333	1/1/2027	\$0.90	PPL	10/8/2025
	N8495.2	Modify Sunbury-Lock Haven 69 kV line to tie in the new interconnection facilities.	AF1-333	1/1/2027	\$0.28	PPL	10/8/2025
	N8495.3	Modify relays at Lock Haven 69 kV substation.	AF1-333	1/1/2027	\$0.24	PPL	10/8/2025
	N8495.4	Modify relays at Sunbury 69 kV substation.	AF1-333	1/1/2027	\$0.24	PPL	10/8/2025
3	N8502.1	Review and revise relay settings as needed at Rockwood substation.	AF1-143	12/31/2027	\$0.06	MAIT	10/8/2025
4	N8502.2	Review and revise relay settings as needed at Bigby substation.	AF1-143	12/31/2027	\$0.06	MAIT	10/8/2025
	N8842.0	Design, install, test/commission MPLS equipment for SCADA at Hatfield substation (KATCo).	AG1-363	12/10/2029	\$0.24	AP	10/8/2025
	N8845.0	Install one line relaying panel at Hatfield substation (KATCo).	AG1-363	12/10/2029	\$0.68	AP	10/8/2025
5	N8533.1	Construct two line switches on the Claysburg-Hollidaysburg 46 kV line ~0.1 miles from Claysburg substation.	AG1-281	12/31/2027	\$0.86	MAIT	10/8/2025
	N8533.2	Revise relay settings at Hollidaysburg 46 kV substation.	AG1-281	12/31/2027	\$0.05	MAIT	10/8/2025
	N8533.3	Revise relay settings at Claysburg 46 kV substation.	AG1-281	12/31/2027	\$0.05	MAIT	10/8/2025
6	N8543	Revise relay settings at Ronco substation.	AF2-029	10/1/2027	\$0.06	AP	10/8/2025
	N8544	Revise relay settings at Hatfield substation.	AF2-029	10/1/2027	\$0.06	AP	10/8/2025
7	N8561	Morgan Street Substation: Replace 34.5 kV Mount Hope line relays and controls and install one 34.5 kV PT.	AG1-040	12/31/2026	\$0.64	PENELEC	10/8/2025
8	N8571	Relay setting changes at Portland substation.	AG1-511	5/31/2028	\$0.06	METED	10/8/2025
9	N8581	Install two SCADA-operated switches on the Miller REC-Warrior Ridge 46 kV line.	AG1-301	8/1/2027	\$0.61	PENELEC	10/8/2025
	N8582	Replace line relaying panel at Warrior Ridge substation.	AG1-301	8/1/2027	\$0.47	PENELEC	10/8/2025
10	N8586	Roxbury substation: Install new 23 kV PT on the Arco line. Revise relay settings for new customer tap. Replace existing 23 kV KRB ARCO relays with SEL-0351S line panel.	AF2-229	8/31/2027	\$2.82	PENELEC	10/8/2025
11	N8615.0	Modify Blooming Grove-West Damascus 69 kV line to tie in the new Transmission Owner Interconnection Facility.	AF2-417	12/31/2027	\$0.61	PPL	10/8/2025
12	N8616.0	Modify relays at Paupack 69 kV substation.	AF2-417	12/31/2027	\$0.14	PPL	10/8/2025
13	N8617.0	Modify relays at Blooming Grove 69 kV substation.	AF2-417	12/31/2027	\$0.14	PPL	10/8/2025
14	N8618.0	Modify Harwood-East Hazelton 69 kV line to tie in the new Transmission Owner Interconnection Facility.	AF2-417	3/1/2027	\$0.61	PPL	10/8/2025
	N8619.0	Modify relays at Harwood 69 kV substation.	AF2-417	3/1/2027	\$0.14	PPL	10/8/2025
15	N8634.0	Modify Scott Tap-Bowmans Mill Tap 69 kV line to tie in the new Transmission Owner Interconnection Facility.	AF2-086	12/31/2027	\$0.10	PPL	10/8/2025
16	N8635.0	Modify relays at Columbia 69 kV substation.	AF2-086	12/31/2027	\$0.14	PPL	10/8/2025
17	N8636.0	Modify relays at Glen Brook 69 kV substation.	AF2-086	12/31/2027	\$0.14	PPL	10/8/2025
18	N8691.0	Modify Sunbury-Columbia 69 kV line to tie in the new Transmission Owner Interconnection Facility.	AF2-433	5/1/2027	\$0.80	PPL	10/8/2025
	N8692.0	Modify relays at Columbia 69 kV substation.	AF2-433	12/31/2027	\$0.14	PPL	10/8/2025
	N8693.0	Relay modifications at Sunbury 69 kV substation.	AF2-433	12/31/2027	\$0.14	PPL	10/8/2025

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Table 6.52: Pennsylvania Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
19	N8729.0	TO construction scope of work at AG1-054 substation (includes security systems).	AG1-054	3/31/2026	\$1.33	ATSI	10/8/2025
	N8730.0	Design, install and test/commission Multi-Protocol Label Switching (MPLS) equipment for supervisory control and data acquisition (SCADA) transport at AG1-054 interconnection substation.	AG1-054	3/31/2026	\$0.31	ATSI	10/8/2025
20	N8731.0	Install 3.44 miles of ADSS to nearest splice point of OPGW on existing Campbell-Cedar Street line.	AG1-054	3/31/2026	\$1.33	ATSI	10/8/2025
	N8732.0	Loop the Campbell to Cedar Street 69 kV line into new interconnection substation ~10.2 miles from Campbell substation (between Potter and Harlan substations).	AG1-054	3/31/2026	\$0.77	ATSI	10/8/2025
	N8745.0	Update drawings and nameplates for line name change at Cedar Street substation. Review and update relay settings. Convert primary and back-up relays to POTT over fiber with step distance.	AG1-054	3/31/2026	\$0.07	ATSI	10/8/2025
	N8746.0	Update drawings and nameplates for line name change at Campbell substation. Review and update relay settings. Convert primary and back-up relays to POTT over fiber with step distance.	AG1-054	3/31/2026	\$0.07	ATSI	10/8/2025
	N9318.0	Change relay setting at the Cedar Street substation.	AE1-183	1/18/2027	\$0.05	ATSI	10/8/2025
	N9319.0	Change relay settings at the Campbell substation.	AE1-183	1/18/2027	\$0.05	ATSI	10/8/2025
21	N8733.0	Update drawings and nameplates for line name change at Frew Mill substation.	AG1-054	3/31/2026	\$0.03	ATSI	10/8/2025
22	N8734.0	Update drawings and nameplates for line name change at Potter substation.	AG1-054	3/31/2026	\$0.03	ATSI	10/8/2025
23	N8735.0	Update drawings and nameplates for line name change at Willowbrook substation.	AG1-054	3/31/2026	\$0.03	ATSI	10/8/2025
24	N8736.0	Update drawings and nameplates for line name change at Harlan substation.	AG1-054	3/31/2026	\$0.03	ATSI	10/8/2025
25	N8737.0	Update drawings and nameplates for line name change at Leesburg substation.	AG1-054	3/31/2026	\$0.03	ATSI	10/8/2025
26	N8738.0	Update drawings and nameplates for line name change at Veterans substation.	AG1-054	3/31/2026	\$0.03	ATSI	10/8/2025
27	N8739.0	Review and update relay settings at Frisco substation.	AG1-054	3/31/2026	\$0.05	ATSI	10/8/2025
28	N8740.0	Review and update relay settings at McDowell substation.	AG1-054	3/31/2026	\$0.05	ATSI	10/8/2025
	N9317.0	Change relay settings at the McDowell substation.	AE1-183	1/18/2027	\$0.05	ATSI	10/8/2025
29	N8741.0	Review and update relay settings at New Castle substation.	AG1-054	3/31/2026	\$0.05	ATSI	10/8/2025
30	N8747.0	Review and update relay settings at Keisters substation.	AG1-054	3/31/2026	\$0.05	AP	10/8/2025
31	N8749.0	Revise relay settings at Harwick substation.	AG1-514	6/1/2027	\$0.06	AP	10/8/2025
32	N8750.0	Revise relay settings at Yukon substation.	AG1-514	6/1/2027	\$0.06	AP	10/8/2025
33	N8751.0	Revise relay settings at Brackenridge substation.	AG1-514	6/1/2027	\$0.06	AP	10/8/2025
34	N8752.0	Revise relay settings at Huntingdon substation.	AG1-514	6/1/2027	\$0.06	AP	10/8/2025
35	N8753.0	Revise relay settings at Pittsburgh Mills substation.	AG1-514	6/1/2027	\$0.06	AP	10/8/2025
36	N8754.0	Revise relay settings at White Valley substation.	AG1-514	6/1/2027	\$0.06	AP	10/8/2025
37	N8755.0	Revise relay settings at All Dam 6 substation.	AG1-514	6/1/2027	\$0.06	AP	10/8/2025
38	N8756.0	Revise relay settings at Shaffers Corner substation.	AG1-514	6/1/2027	\$0.06	AP	10/8/2025
39	N8757.0	Revise relay settings at Springdale substation.	AG1-514	6/1/2027	\$0.06	AP	10/8/2025

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Table 6.52: Pennsylvania Network Projects (Dec. 31, 2025) (Cont.)

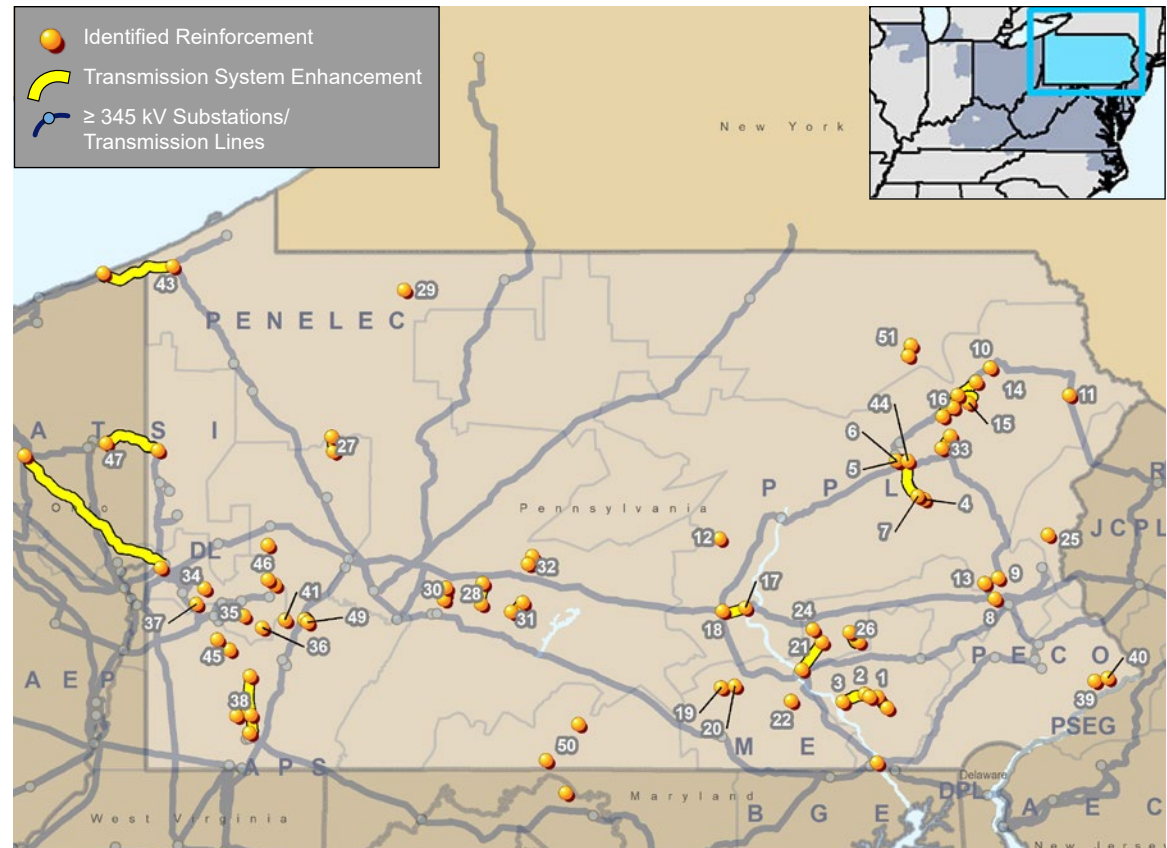
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
40	N8758.0	Revise relay settings at Cheswick substation.	AG1-514	6/1/2027	\$0.05	Duquesne Light (DL)	10/8/2025
41	N8759.0	Revise relay settings at Plum substation.	AG1-514	6/1/2027	\$0.05	Duquesne Light (DL)	10/8/2025
42	N8791.0	Modify Blooming East Palmerton-Acahela 69 kV line to tie in the new Transmission Owner Interconnection Facility.	AG1-156	12/31/2027	\$0.90	PPL	10/8/2025
	N8792.0	Modify relays at Acahela 69 kV substation.	AG1-156	12/31/2027	\$0.14	PPL	10/8/2025
	N8793.0	Modify relays at East Palmerton 69 kV substation.	AG1-156	12/31/2027	\$0.14	PPL	10/8/2025
43	N8870.0	Review and update relay settings for Ontelaunee substation.	AF2-030	11/30/2027	\$0.05	METED	10/8/2025
44	N8915.0	Modify Sunbury-Dauphin 69 kV line to tie in the new Transmission Owner Interconnection Facility.	AG1-259	12/31/2027	\$0.90	PPL	10/8/2025
	N8916.0	Modify relays at Sunbury 69 kV substation.	AG1-259	12/31/2027	\$0.14	PPL	10/8/2025
	N8917.0	Modify relays at Dauphin 69 kV substation.	AG1-259	12/31/2027	\$0.14	PPL	10/8/2025
45	N8962.0	Review and revise relay settings as required.	AG1-486	12/31/2027	\$0.06	MAIT	10/8/2025
46	N9085.0	East Towanda Substation: Install one 230 kV wave trap, line tuner and coax. Install one carrier panel containing two RFL GARD 8000 units, one PCM-5350 and one skewed hybrid. Review and revise relay settings as required.	NYISO-Q596	11/1/2026	\$0.53	PENELEC	10/8/2025
47	N9303.0	Upgrade line relaying equipment at Mainesburg terminal.	NYISO-Q1080	5/31/2027	\$0.96	PENELEC	10/8/2025
48	N9304.0	Upgrade line relaying equipment at Homer City terminal.	NYISO-Q1080	5/31/2027	\$0.95	PENELEC	10/8/2025
49	N9316.0	Change relay settings at the Maysville substation.	AE1-183	1/18/2027	\$0.06	ATSI	10/8/2025
50	N9320.0	Change relay settings at the Sharon substation.	AE1-183	1/18/2027	\$0.05	ATSI	10/8/2025
51	N9321.0	Change relay settings at the Dillworth substation.	AE1-183	1/18/2027	\$0.05	ATSI	10/8/2025

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### 6.10.7 — Supplemental Projects

Supplemental projects included in the 2025 Local Plan in Pennsylvania are summarized in **Map 6.43** and **Table 6.53**.

**Map 6.43:** Pennsylvania Supplemental Projects (Dec. 31, 2025)



[View state summaries:](#)

Table 6.53: Pennsylvania Supplemental Projects (Dec. 31, 2025)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S3547.1	Construct a new five-bay breaker-and-a-half 138 kV switchyard near the customer's facility.	6/1/2027	\$34.00	PPL	11/6/2024
	S3547.2	Bifurcate the South Akron-Prince No. 1 and No. 2 138 kV and terminate at the new Pitney 138 kV switchyard. Extend the 138 kV lines ~0.2 miles into the new Pitney 138 kV switchyard.	6/1/2027	\$3.00	PPL	11/6/2024
	S3547.3	Extend three 138 kV circuits for ~0.1 miles from the Pitney 138 kV switchyard to the customer's facility.	6/1/2027	\$3.50	PPL	11/6/2024
	S3547.4	Install a new 230/138 kV substation. Install a two-bay 230 kV breaker-and-a-half yard, two 230/138 kV 330 MVA transformers, and a two-bay breaker-and-a-half 138 kV yard.	6/1/2028	\$47.30	PPL	11/6/2024
	S3547.5	Bifurcate the Millwood-South Akron 230 kV line and terminate at the new Lampeter 230/138 kV substation.	6/1/2028	\$4.00	PPL	11/6/2024
	S3547.6	Rebuild 3.1 miles of the Strasburg No. 1 and No. 2 69 kV taps to double-circuit 138 kV operation from outside Lampeter to Strasburg substation. Extend two 138 kV circuits from the Lampeter 138 kV yard and tie into the rebuilt Strasburg 138 kV lines. Rebuild 3.3 miles of the Engleside-Greenland No. 1 and No. 2 69 kV line to double-circuit 138 kV operation from Strasburg Tap to the Greenland substation. Extend a new double-circuit 138 kV line for ~1.5 miles from the Engleside-Greenland No. 1 and No. 2 138 kV lines to Pitney 138 kV switchyard. Remove a 3.6 mile section of the Engleside-Greenland No. 1 and No. 2 69 kV line that will no longer be utilized.	6/1/2028	\$26.00	PPL	11/6/2024
2	S3548.1	Construct a new five-bay breaker-and-a-half 138 kV switchyard near the customer's facility.	6/1/2027	\$34.00	PPL	11/6/2024
	S3548.2	Bifurcate the West Hempfield-Prince No. 1 and No. 2 138 kV and terminate at the new North Lancaster 138 kV switchyard. Extend the 138 kV lines ~0.2 miles into the new North Lancaster 138 kV switchyard.	6/1/2027	\$3.00	PPL	11/6/2024
	S3548.3	Bifurcate the South Akron-Dillerville No. 1 and No. 2 138 kV and terminate at the new North Lancaster 138 kV switchyard. Extend the 138 kV lines ~0.2 miles into the new North Lancaster 138 kV switchyard.	6/1/2027	\$3.00	PPL	11/6/2024
	S3548.4	Extend three 138 kV circuits for ~0.1 miles from the North Lancaster 138 kV switchyard to the customer's facility.	6/1/2027	\$3.50	PPL	11/6/2024
3	S3548.5	Rebuild 8.1 miles the West Hempfield-Prince (NLAN) No. 1 and No. 2 138 kV lines from West Hempfield to new North Lancaster switchyard.	6/1/2028	\$24.00	PPL	11/6/2024
4	S3549.1	Bifurcate the Harwood-Tresckow No. 1 and No. 2 230 kV lines and terminate at the new Slykerville 230 kV switchyard. Extend lines ~0.2 miles into the new Slykerville 230 kV switchyard.	5/30/2027	\$4.00	PPL	11/6/2024
	S3549.2	Install a four-bay breaker-and-a-half 230 kV switchyard with a 125 MVAR capacitor bank.	5/30/2027	\$45.00	PPL	11/6/2024
	S3549.3	Install three 230 kV lead lines for ~0.1 miles from Slykerville 230 kV switchyard to the customer facility.	5/30/2027	\$4.00	PPL	11/6/2024
	S3555.1	Bifurcate the Harwood-Siegfried 230 kV and the Harwood-East Palmerton 230 kV lines and terminate at the new Tresckow 230 kV switchyard. Extend lines ~1 mile into the new Tresckow 230 kV switchyard.	5/31/2027	\$8.00	PPL	10/8/2024
	S3555.2	Install a four-bay breaker-and-a-half 230 kV switchyard with a 125 MVAR capacitor bank.	5/31/2027	\$45.00	PPL	10/8/2024
	S3555.3	Install three 230 kV lead lines for ~4 miles from Tresckow 230 kV switchyard to the customer facility.	5/31/2027	\$28.00	PPL	10/8/2024
5	S3549.4	Install 15 ohm series reactors on the Susquehanna-Harwood No. 1 and No. 2 230 kV line at Susquehanna 230 kV switchyard.	5/1/2028	\$8.00	PPL	11/6/2024
6	S3549.5	Reconductor the 2.7 miles of the Susquehanna T10-Susquehanna No. 1 and No. 2 230 kV lines. Replace three MODS at Susquehanna.	5/30/2028	\$8.10	PPL	11/6/2024
7	S3549.6	Replace four MODS on each of the Harwood-Slykerville No. 1 and No. 2 230 kV lines (eight total) at Harwood 230 kV yard.	5/30/2028	\$4.20	PPL	11/6/2024
8	S3550.1	Install new 250 MVA 500/230 kV transformers as an in-kind replacement for each of the three units of the current 500/230 kV Alburdis transformer No. 1 (750 MVA total).	12/31/2026	\$19.90	PPL	11/6/2024
9	S3551.1	Install a new 340 MVA, 500-138 kV transformer as an in-kind replacement of the existing 500/138 kV Wescosville transformer No. 3.	12/31/2026	\$15.50	PPL	11/6/2024
10	S3552.1	Install a new 170 MVA, 230-69 kV transformer as an in-kind replacement of the existing 230-69 kV Lackawanna transformer No. 2.	12/31/2026	\$6.30	PPL	11/6/2024

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Table 6.53: Pennsylvania Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
11	S3553.1	Install a new 170 MVA, 230-69 kV transformer as an in-kind replacement of the existing 230-69 kV Blooming Grove transformer No. 1.	12/31/2027	\$6.30	PPL	11/6/2024
12	S3554.1	Add second 69 kV circuit (556ACSR) on the existing single circuit, built for double-circuit SUNB-MIDD 69 kV line for ~6.4 miles.	5/31/2028	\$6.50	PPL	11/14/2024
	S3554.2	Rebuild the existing 9.1-mile single-circuit Beavertown 69 kV tap to double-circuit 69 kV. Conductor to be 556 ACSR.	5/31/2028	\$26.50	PPL	11/14/2024
13	S3556.1	Extend a new double-circuit 69/138 kV tap from the existing Breinigsville-ATTR 69/138 kV line to interconnect the new Tek Park 69-13.8 kV substation. Build 0.4 miles of new 69/138 kV double-circuit line using 795 ACSR conductor.	6/1/2026	\$1.50	PPL	9/19/2024
	S3556.2	Extend a new double-circuit 69/138 kV tap from the existing Breinigsville 500/138/69 kV substation to the new Tek Park 69/138 kV tap. Build 0.75 miles of new 69/138 kV double-circuit line using 795 ACSR conductor.	6/1/2027	\$4.00	PPL	9/19/2024
	S3556.3	Install two new line terminals in the Breinigsville 69/138 kV yard. Install two bays in initial DBDB future breaker-and-a-half arrangement.	6/1/2027	\$3.50	PPL	9/19/2024
14	S3557.1	Rebuild ~7 miles of the double-circuit Stanton-Summit No. 1 and No. 2 69 kV lines to double-circuit 69 kV with 556 ACSR conductor.	12/1/2027	\$17.50	PPL	9/19/2024
15	S3558.1	Rebuild 2 miles of the existing single-circuit Old Forge-Avoca 69 kV tie line as single-circuit 69 kV with 556 ACSR conductor.	12/1/2027	\$5.50	PPL	9/19/2024
16	S3559.1	Rebuild ~6 miles of the double-circuit Stanton-Swoyersville/Exeter 69 kV lines to double-circuit 69 kV. Rebuild ~1 mile of single-circuit 69 kV taps. All rebuilt sections to be 556 ACSR conductor.	12/1/2027	\$17.50	PPL	9/19/2024
17	S3571.1	Install a new 500-138 kV substation with a four-bay breaker-and-a-half 500 kV yard, four 500-138 kV Transformers, six-bay breaker-and-a-half 138 kV yard, and one 138 kV capacitor bank.	6/30/2027	\$148.00	PPL	1/7/2025
	S3571.2	Bifurcate the Juniata-Alburtis 500 kV line and terminate into the New Buffalo substation. Extend lines ~0.6 miles.	6/30/2027	\$8.00	PPL	1/7/2025
	S3571.4	Extend six 138 kV lines to the customer facility.	6/30/2027	\$3.00	PPL	1/7/2025
18	S3571.3	Rebuild the existing Juniata-Alburtis 500 kV line to double-circuit for 9.6 miles from Juniata substation to New Buffalo substation.	5/30/2028	\$83.00	PPL	1/7/2025
19	S3605.1	Convert Mountain substation into a six-breaker ring bus.	12/31/2026	\$11.00	METED	8/15/2024
20	S3605.2	At PPGI substation, replace Mountain circuit breaker.	12/31/2026	\$0.40	METED	8/15/2024
21	S3622.1	Rebuild ~9 miles of Campbelltown-Middletown Junction 69 kV line. At Middletown Junction, review and revise relaying. At Campbelltown substation, review and revise relaying.	12/21/2026	\$25.40	METED	3/13/2025
22	S3623.1	Construct a four-breaker 115 kV ring bus at Raintree substation. Remove existing temporary configuration connection at Raintree. Loop the Middletown Junction-Smith Street 115 kV 978 line into Raintree substation. Install one control house. Install four 115 kV circuit breakers and associated disconnect switches. Install two standard transmission line relay panels. At Middletown Junction substation, replace existing line relay panels. At Smith Street substation, replace one 115 kV circuit breaker and associated disconnect switches and existing line relay panels.	12/31/2026	\$12.50	METED	12/12/2024
23	S3624.1	Convert the 69 kV bus at North Hershey substation into a four-breaker ring bus. Install four 69 kV, 3000A circuit breakers and associated equipment. Install a second 230/69 kV transformer at North Hershey substation. Install one 230 kV, 3000 A circuit breaker and associated equipment.	12/17/2027	\$16.31	METED	11/6/2024
24	S3625.1	Construct a three breaker 69 kV ring bus by installing three 69 kV circuit breakers and associated disconnect switches. Install three standard transmission line relay panels. Reterminate the North Lebanon-West Lebanon 69 kV 94 line into Cleona.	6/8/2026	\$9.50	METED	12/12/2024
25	S3626.1	Construct a four breaker 115 kV ring bus. Install four 115 kV circuit breakers, disconnect switches, line traps and relaying. Update relaying at North Bangor and Glendon substations. Reterminate the North Bangor and Northwood 115 kV terminals at Belfast substation.	6/1/2028	\$14.30	METED	1/16/2025
26	S3627.1	Install one SCADA controlled transmission line switch. Relocate switch 9206 at/near str. 92-81. Construct ~1 to 2 spans of transmission line using from tap to customer. Install one 69 kV revenue metering package at customer substation. Modify relay settings at Alcoa and Broad Street substations.	11/24/2025	\$1.19	METED	8/15/2024

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Table 6.53: Pennsylvania Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
27	S3628.1	Complete the following for Piney substation: On the Burma line terminal, replace the circuit breaker, line trap, substation conductor, relays and associated disconnect switches. On the Grandview/Haynie line terminal, replace the circuit breaker, line trap, substation conductor, relays and associated disconnect switches. On the Timblin line terminal, replace circuit breaker and associated disconnect switches. On the Eclipse line terminal, replace line trap, substation conductor, disconnect switches and relays. Replace 115 kV bus tie breaker, 115 kV No. 3 transformer breaker, 115 kV No. 4 transformer breaker, relays and associated disconnect switches. Construct a new control building to house new equipment. At the Grandview substation, on the Piney/Haynie line terminal, replace the line trap, substation conductor, relays and associated disconnect switches. At the Eclipse substation, on the Piney line terminal, replace line trap, substation conductor and relays.	1/12/2026	\$11.40	PENELEC	8/15/2024
	S3542.1	At Burma, replace line trap, substation conductor and relays.	5/29/2026	\$1.90	AP	8/16/2024
28	S3629.1	Rebuild ~1.36 miles of existing line at SGC Tap-Summit 46 kV line.	5/29/2026	\$3.54	PENELEC	3/13/2025
29	S3631.1	Replace Glade substation control building with a new package control enclosure. Install new cable trench, replace four disconnect switches, and two 230 kV breakers. Replace substation conductor and line trap on the Lewis Run and Warren line terminals at Glade substation. Replace substation conductor on the Forest line terminal at Glade substation, and install new relaying and control equipment. At the Lewis Run substation, on the Glade line terminal, replace line trap. Install new relaying and control equipment. At the Warren substation, on the Glade line terminal, replace substation conductor. Install new relaying and control equipment. At the Forest substation, on the Glade line terminal, install new relaying and control equipment.	12/17/2027	\$12.00	PENELEC	3/4/2025
30	S3633.1	Relocate and replace obsolete and nonrepairable line switch Strongstown-Belsano A119. Upgrade switch to include SCADA controlled motor operators. Remove four-pole wood structure and replace with appropriate tap structure.	11/13/2026	\$0.93	PENELEC	2/13/2025
	S3633.2	Relocate and replace obsolete and non-repairable line switch Strongstown-Twin Rock A120. Upgrade switches to include SCADA-controlled motor operators. Remove four-pole wood structure and replace with appropriate tap structure.	11/13/2026	\$0.93	PENELEC	2/13/2025
31	S3634.1	Upgrade Altoona-Hollidaysburg 46 kV AH line terminal: Replace line relaying at Altoona and Hollidaysburg substations.	12/1/2027	\$2.21	PENELEC	4/10/2025
32	S3635.1	At Tyrone North-Tipton 46 kV line, upgrade line relaying and limiting substation conductor at Tyrone North substation. Upgrade protection and terminal equipment at Tipton substation.	12/31/2027	\$2.92	PENELEC	4/10/2025
33	S3640.1	Extend the Wright No. 1 and No. 2 69 kV taps ~0.5 miles to the connect the customer substation.	8/1/2025	\$1.75	PPL	10/17/2024
	S3640.2	Extend a new double-circuit 69 kV line from the existing Palooka 230/69 kV substation to the new Grand Landmark 69 kV taps. Build ~5 miles of new 69 kV double-circuit line using 795 ACSR conductor.	5/1/2028	\$12.50	PPL	10/17/2024
	S3640.3	Install two new line terminals in the Palooka 69 kV yard. Install two bays in initial DBDB, future breaker-and-a-half arrangement.	5/1/2028	\$3.50	PPL	10/17/2024
34	S3649.1	Replace one aged 138 kV breaker with a modern breaker at Neville substation.	12/31/2025	\$0.80	DL	3/14/2025
35	S3650.1	Replace two aged 138 kV oil breakers with modern breakers at Carson substation.	12/31/2025	\$1.60	DL	3/14/2025
36	S3651.1	Replace one aged 138 kV breaker with a modern breaker at Dravosburg substation.	12/31/2025	\$0.80	DL	3/14/2025
37	S3652.1	Replace one aged 138 kV breaker with a modern breaker at Findlay substation.	12/31/2025	\$0.80	DL	3/14/2025
38	S3657.1	At Charleroi substation, replace substation conductor, line trap, surge arresters, CVT and line relaying.	7/2/2029	\$2.06	AP	4/11/2025
	S3657.2	At Emerald substation, replace circuit switcher towards Brownsville Junction with a circuit breaker, replace bus tie circuit breaker, disconnect switches, substation conductor, line trap, CVTs and line relaying.	7/2/2029	\$2.06	AP	4/11/2025
	S3657.3	At Gates Hill substation, replace circuit switcher with circuit breaker, disconnect switches, line trap, line turner, COAX and line relaying.	7/2/2029	\$2.06	AP	4/11/2025
39	S3661.1	Install 6th Byberry 138/13 kV, 62 MVA transformer with high-side breaker.	6/1/2028	\$0.85	PECO	10/17/2024
	S3662.1	Replace Byberry circuit breaker No. 150. Existing rating is 1600A 42 kA. Proposed rating is 3000A 63 kA.	6/1/2028	\$0.55	PECO	10/17/2024

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Table 6.53: Pennsylvania Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
40	S3663.1	Rebuild Neshaminy 138 kV straight bus to a seven-breaker AIS ring bus configuration. Install two new 138 kV circuit breakers No. 705 and No. 905 with associated buses, switches and protection equipment. Remove the No. 175 138 kV circuit breaker and associated relay equipment. Remove specialized protection scheme upon completion of new ring bus.	12/31/2027	\$4.20	PECO	10/17/2024
41	S3665.1	Upgraded Peach Bottom circuit breaker 215 and circuit breaker 225 relays and metering equipment, along with corresponding CT tap changes. CT tap changes resulted in increasing the adjacent Peach Bottom 500 kV bus tie No. 2 ratings: Existing ratings are 2477/2860/2598/3022 (SN/SE/WN/WE). New ratings are 2598/3022/2598/3022 (SN/SE/WN/WE).	11/2/2024	\$0.84	PECO	2/4/2025
42	S3666.1	At Huntingdon substation, replace circuit breaker, disconnect switches, substation conductor, line trap, surge arresters, CVTs and relaying. At Springdale substation, replace disconnect switches, substation conductor, line trap, surge arresters, CVTs and relaying.	5/1/2028	\$4.71	AP	5/16/2025
43	S3702.1	At Ashtabula-Erie West 345 kV line, rebuild the 7.2 mile, Penile section of the line. At Erie West, replace disconnect switches. At Ashtabula, revise relay settings.	5/31/2027	\$52.40	PENELEC	8/6/2024
44	S3706.1	Install one new 230 kV breaker, 230 kV dead-end, and ancillary equipment in Bay 0 at Susquehanna 230 kV.	4/30/2026	\$1.50	PPL	5/6/2025
	S3706.2	Reterminate the Sunbury-Susquehanna No. 1 230 kV line from Bay No. 1 to Bay No. 0 at Susquehanna 230 kV.	4/30/2026	\$0.40	PPL	5/6/2025
	S3706.3	Extend a new 230 kV line (1590 ACSS) from Bay No. 1 at Susquehanna 230 kV yard to the customer substation dead-end (Customer Yard 1).	4/30/2026	\$6.05	PPL	5/6/2025
	S3706.4	Install one new 500 kV breaker, 500 kV dead-end, and ancillary equipment in Bay 2 at Susquehanna 500 kV.	4/30/2027	\$3.50	PPL	5/6/2025
	S3706.5	Extend a new 500 kV line from Bay No. 2 at Susquehanna 500 kV yard to the customer substation dead-end (Customer Yard 2).	4/30/2027	\$1.80	PPL	5/6/2025
	S3706.6	Install one new 230 kV breaker, 230 kV dead-end, and ancillary equipment in both Bay No. 1 and No. 3 at Susquehanna T10 230 kV yard.	5/30/2028	\$3.00	PPL	5/6/2025
	S3706.7	Extend two new 230 kV lines (1590 ACSS) from Bay No. 1 and Bay No. 3 at Susquehanna T10 230 kV yard to the customer substation dead-end (Customer Yard 3).	5/30/2028	\$3.15	PPL	5/6/2025
45	S3707.1	At Bethel Park substation, replace circuit breaker, disconnect switches, line turner and coax, CCVT, substation conductor, metering, line trap and relaying. At St. Clair substation, replace circuit breaker, disconnect switches, line turner and coax, CCVT, substation and bus conductors, line trap and relaying.	7/27/2029	\$4.50	AP	6/13/2025
46	S3709.1	At Harwick substation, replace circuit breaker, disconnect switches, line trap, line turner and coax, substation and bus conductors and relaying. At Houseville substation, replace disconnect switches, line trap, line turner and coax, CVT, substation conductor and relaying.	12/31/2027	\$3.40	AP	6/13/2025
47	S3714.1	At Niles-Shenango 345 kV line, rebuild the 12.4 mile wood pole section (total length 14.5 miles) from Structure 41946 to Structure 42033 an install new conductor. Reconductor ~2.1 miles from the Niles substation to Structure 41946. At Niles substation, replace five disconnect switches. replace line relaying. At Shenango substation, replace line relaying.	12/17/2027	\$73.92	ATSI	7/6/2025
48	S3715.1	At Beaver Valley-Hanna 345 kV line and Hanna-Mansfield 345 kV line, replace 33 steel structures from Structure 6270 to Structure 6632. Install new conductor on the Beaver Valley-Hanna line (~6.9 miles). Install new conductor on the Hanna-Mansfield line (~6.6 miles). At Beaver Valley, Mansfield and Hanna substations, adjust relay settings.	5/31/2028	\$53.35	ATSI	7/6/2025
49	S3575.1	At Harrison City-Penn 138 kV: At Harrison City substation, replace bus and line side breaker risers. At Penn substation, install one line breaker and one bus tie breaker. At North Oakford Tap, install new disconnect switches equipped with auto sectionalizing. At South Oakford Tap, install three switches with SCADA. At North Oakford substation, install full SCADA control on the existing switch. At Delmont substation, install full SCADA control on the existing switch. At Stony Springs Junction, install a three-breaker ring bus and associated relaying. At North Greensburg substation, replace circuit breaker. At Hempfield, replace line circuit breaker, disconnect switches and associated relaying. At Luxor substation, replace circuit breaker, substation conductor, breaker risers on both sides of breaker and relaying.	6/22/2027	\$13.66	AP	11/15/2024
50	S3708.1	At Cherry Run substation, replace circuit breaker, disconnect switches, line turner and coax, CVT, substation conductor and relaying. At Warfordsburg substation, replace disconnect switches, and relaying. At McConnellsburg substation, replace circuit breaker, disconnect switches, line turner, CCVT, substation conductor and relaying.	7/13/2029	\$2.50	AP	6/13/2025
51	S2834	Construct a 66 kV high-side bus at Hanover substation. Extend Hanover Tap 66 kV line to Loomis No. 2 66 kV bus (0.8 miles).	5/30/2023	\$8.00	UGI	8/18/2022

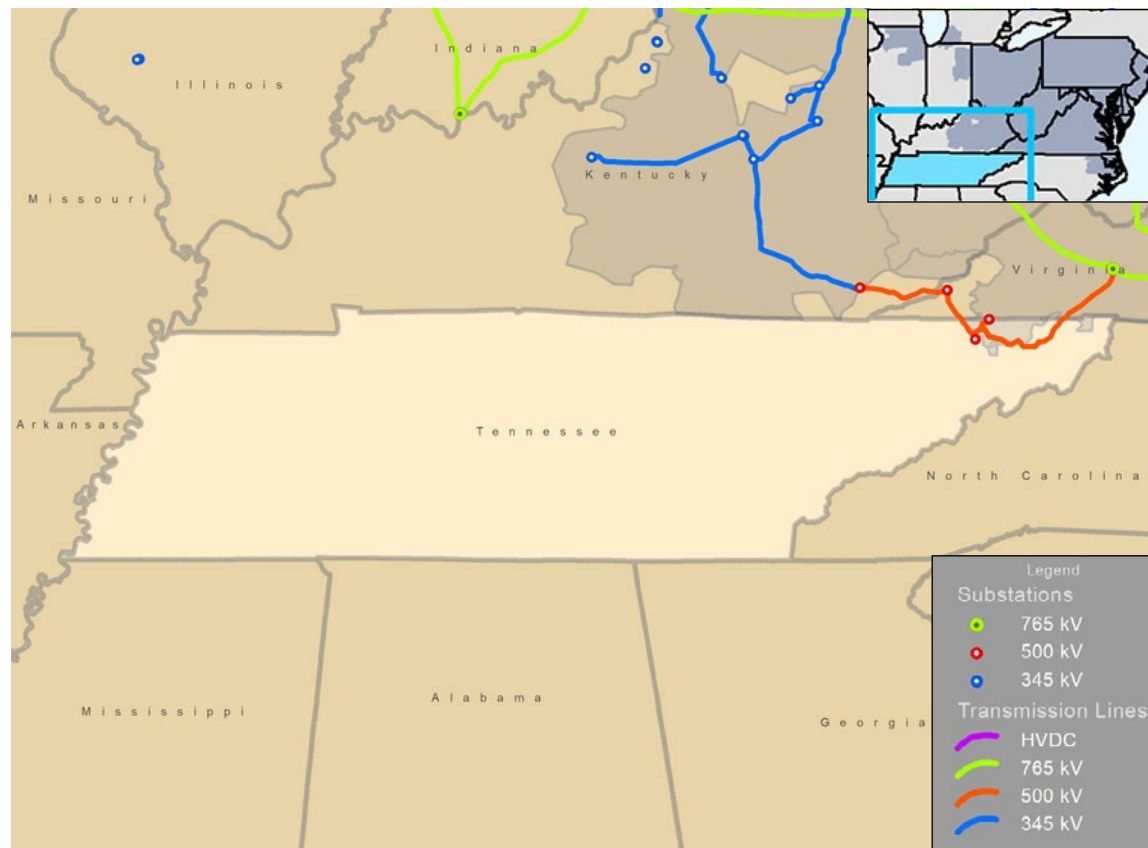
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## 6.11: Tennessee RTEP Summary

### 6.11.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Tennessee, including facilities owned and operated by American Electric Power (AEP) as shown on **Map 6.44**. Tennessee's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

Map 6.44: PJM Service Area in Tennessee

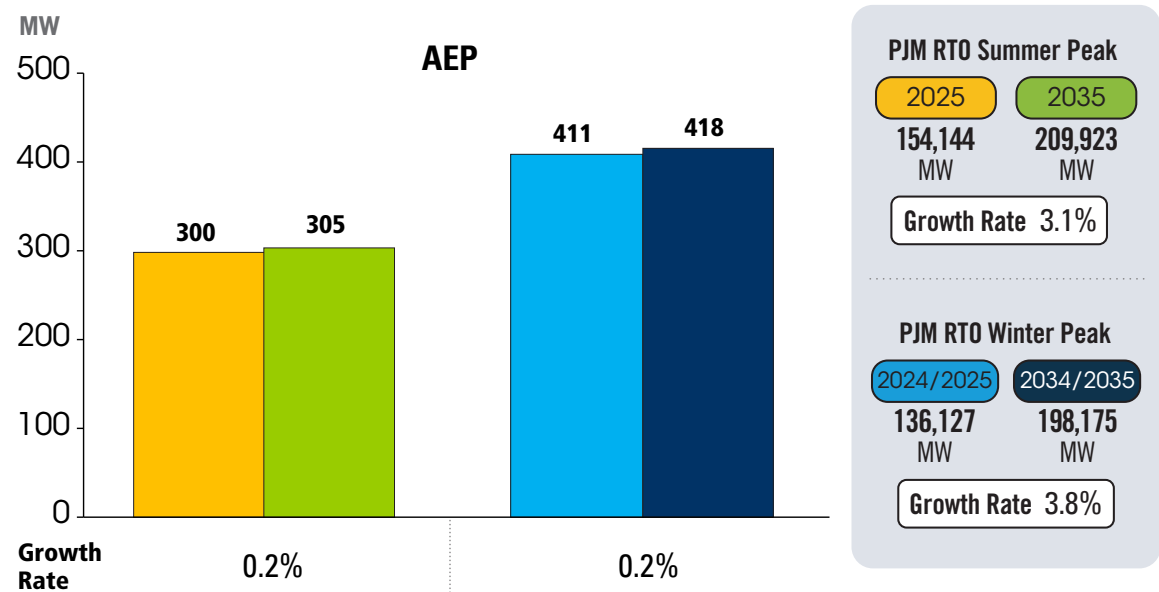


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### 6.11.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.51** summarizes the expected loads within the state of Tennessee and across the PJM region.

**Figure 6.51:** Tennessee – 2025 Long-Term Load Forecast



PJM notes that AEP serves load other than in Tennessee. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by AEP solely in Tennessee. Estimated amounts were calculated based on the average share of AEP's real-time summer and winter peak load located in Tennessee over the past five years.

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### 6.11.3 — Existing Generation

There is no existing generation in PJM's portion of Tennessee as of Dec. 31, 2025.

### 6.11.4 — Interconnection Requests

In Tennessee, as of Dec. 31, 2025, one project was actively under study as shown in the summaries presented in **Table 6.54**, **Table 6.55**, **Figure 6.52**, **Figure 6.53** and **Figure 6.54**.

**NOTE:**

These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

**Table 6.54:** Tennessee – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

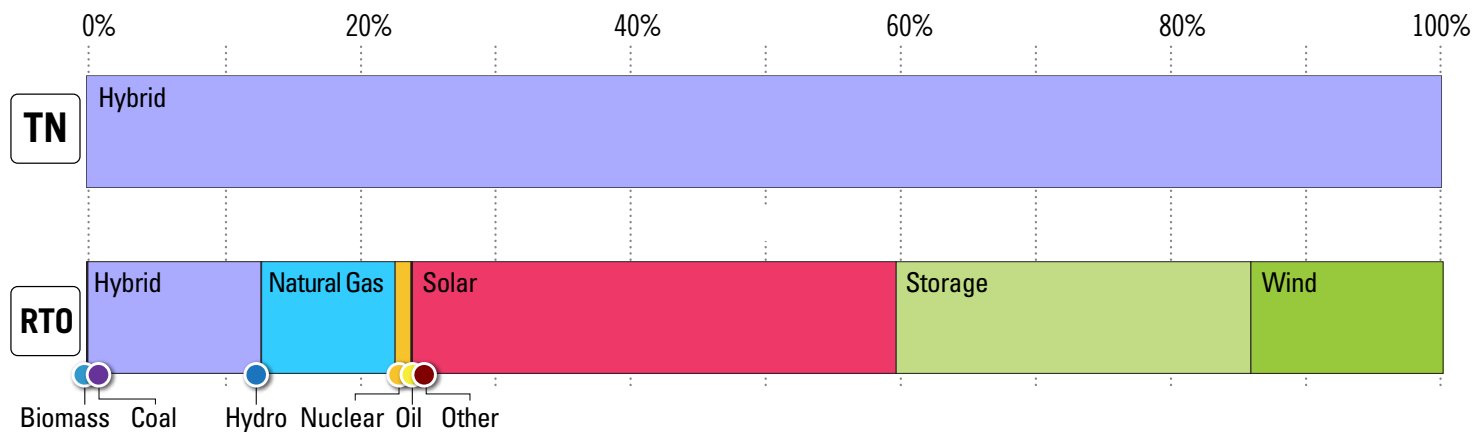
	Tennessee Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Biomass	0.0	0.00%	10.0	0.01%
Coal	0.0	0.00%	14.0	0.01%
Hybrid	40.0	100.00%	14,332.3	12.76%
Hydro	0.0	0.00%	30.0	0.03%
Natural Gas	0.0	0.00%	11,082.0	9.87%
Nuclear	0.0	0.00%	1,305.9	1.16%
Oil	0.0	0.00%	50.0	0.04%
Other	0.0	0.00%	56.3	0.05%
Solar	0.0	0.00%	40,116.0	35.73%
Storage	0.0	0.00%	29,376.0	26.16%
Wind	0.0	0.00%	15,910.7	14.17%
<b>Grand Total</b>	<b>40.0</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

**Table 6.55:** Tennessee – Interconnection Requests by Fuel Type (Dec. 31, 2025)

		In Queue		Complete		Grand Total	
		Active		Withdrawn		Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
<b>Non-Renewable</b>	Coal	0	0.0	1	75.0	1	75.0
<b>Renewable</b>	Hybrid	1	40.0	0	0.0	1	40.0
	Solar	0	0.0	1	13.6	1	13.6
	<b>Grand Total</b>	<b>1</b>	<b>40.0</b>	<b>2</b>	<b>88.6</b>	<b>3</b>	<b>128.6</b>

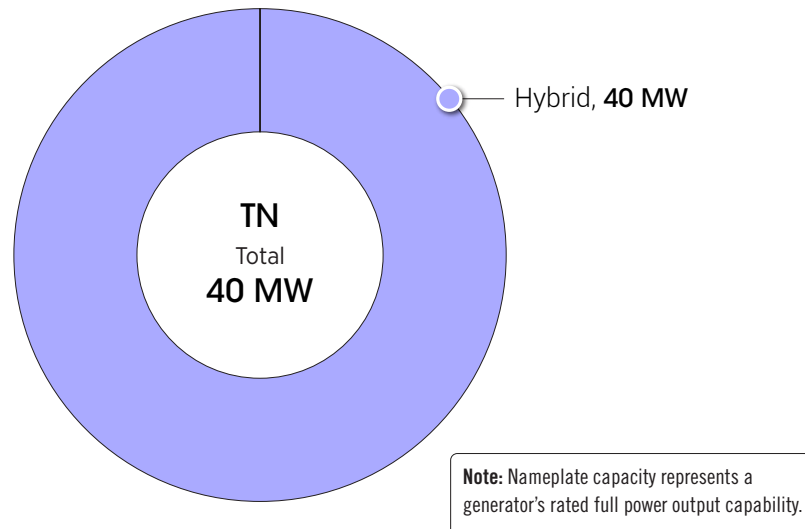
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**Figure 6.52:** Tennessee – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

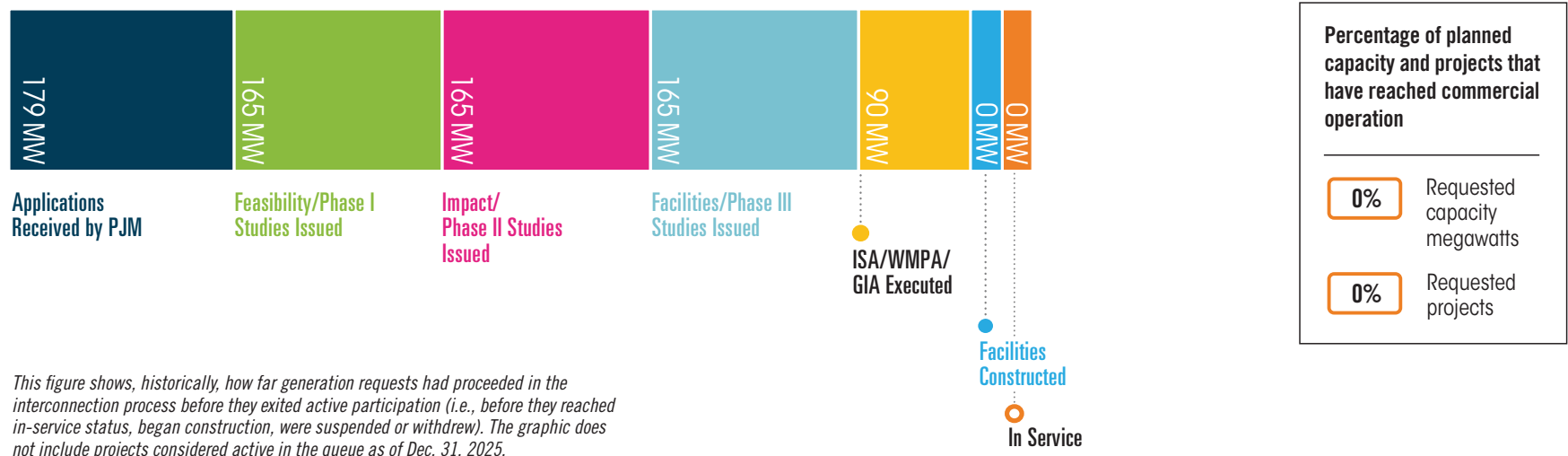


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**Figure 6.53:** Tennessee Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.54:** Tennessee Progression of Interconnection Requests (Dec. 31, 2025)



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## 6.12: Virginia RTEP Summary

### 6.12.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Virginia, including facilities owned and operated by Allegheny Power (FirstEnergy) (AP), American Electric Power (AEP), Delmarva Power (DP&L) and Dominion Energy as shown on **Map 6.45**. Virginia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

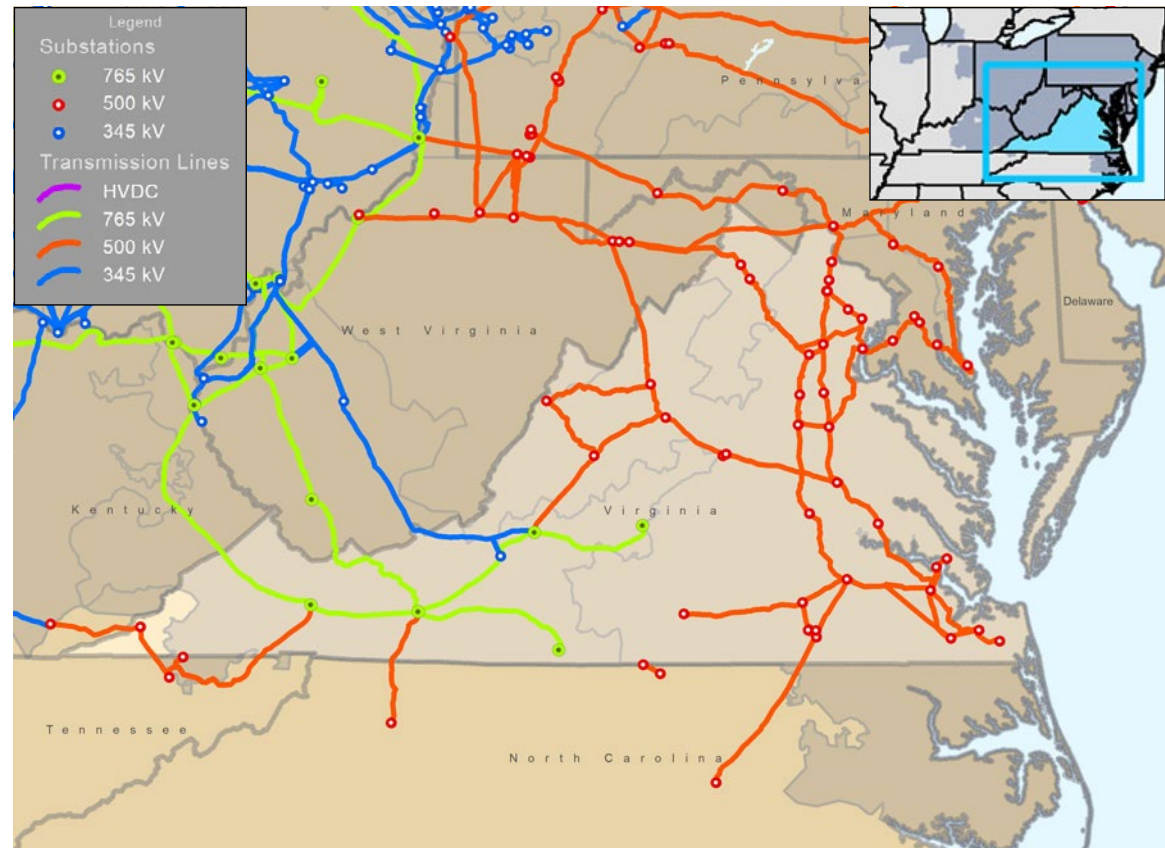
#### **Renewable Portfolio Standards**

Virginia has a mandatory renewable portfolio standard (RPS) target of 100% by 2045 or 2050, depending on the utility service territory. Virginia's RPS target is one of two in the PJM region set at 100%, with the other being the District of Columbia's.

The Virginia Clean Economy Act (VCEA) was enacted in 2020. In addition to mandating the 100% clean electricity target, the VCEA also called for renewable resource carve-outs to be developed within the commonwealth. For offshore wind, the VCEA specifically ordered the development of up to 5,200 MW by 2034. In 2020, the 12 MW Coastal Virginia Offshore Wind project became the first operational offshore wind facility in the PJM footprint.

The VCEA also directs Virginia utilities to develop, acquire or enter into agreements with 16,700 MW of solar or onshore wind capacity by 2035. Through the VCEA, Virginia is also looking to develop 3,100 MW of energy storage by 2035.

**Map 6.45:** PJM Service Area in Virginia

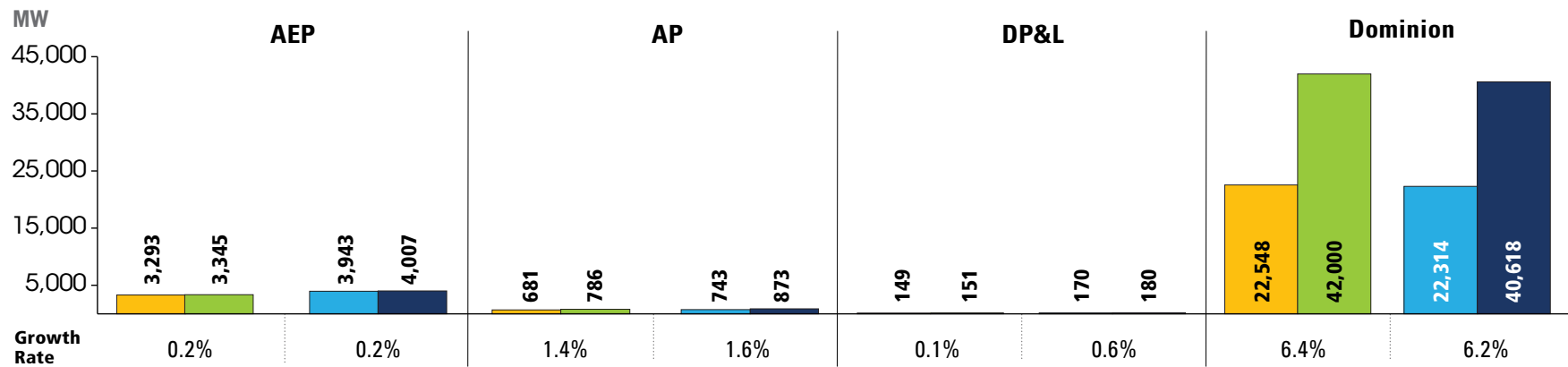


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### 6.12.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.55** summarizes the expected loads within the state of Virginia and across the PJM region.

**Figure 6.55:** Virginia – 2025 Long-Term Load Forecast



PJM RTO Summer Peak		PJM RTO Winter Peak	
2025	2035	2024/2025	2034/2035
154,144	209,923	136,127	198,175
MW	MW	MW	MW
Growth Rate 3.1%		Growth Rate 3.8%	

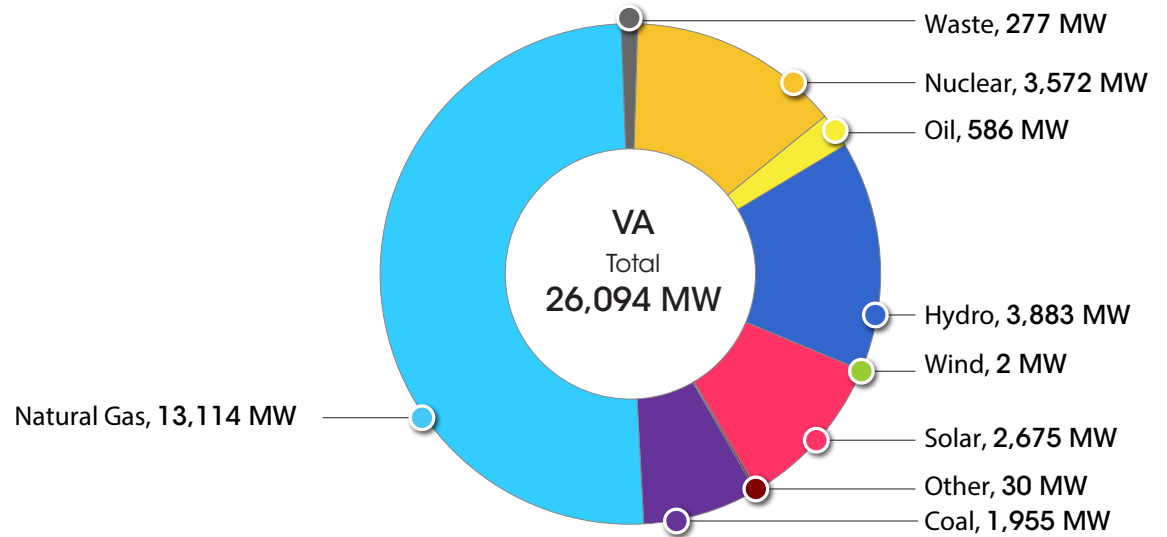
PJM notes that AEP, AP and DP&L serve load other than in Virginia. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in Virginia. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Virginia over the past five years.

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**6.12.3 — Existing Generation**

Existing generation in Virginia as of Dec. 31, 2025, is shown by fuel type in **Figure 6.56**.

**Figure 6.56:** Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



**6.12.4 — Interconnection Requests**

In Virginia, as of Dec. 31, 2025, 333 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.56**, **Table 6.57**, **Figure 6.57**, **Figure 6.58** and **Figure 6.59**.

**Table 6.56:** Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

**NOTE:**  
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

	Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
<b>Biomass</b>	0.0	0.00%	10.0	0.01%
<b>Coal</b>	0.0	0.00%	14.0	0.01%
<b>Hybrid</b>	2,376.8	10.22%	14,332.3	12.76%
<b>Hydro</b>	0.0	0.00%	30.0	0.03%
<b>Natural Gas</b>	1,785.8	7.68%	11,082.0	9.87%
<b>Nuclear</b>	0.0	0.00%	1,305.9	1.16%
<b>Oil</b>	0.0	0.00%	50.0	0.04%
<b>Other</b>	20.0	0.09%	56.3	0.05%
<b>Solar</b>	8,480.3	36.48%	40,116.0	35.73%
<b>Storage</b>	9,701.4	41.73%	29,376.0	26.16%
<b>Wind</b>	885.0	3.81%	15,910.7	14.17%
<b>Grand Total</b>	<b>23,249.3</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

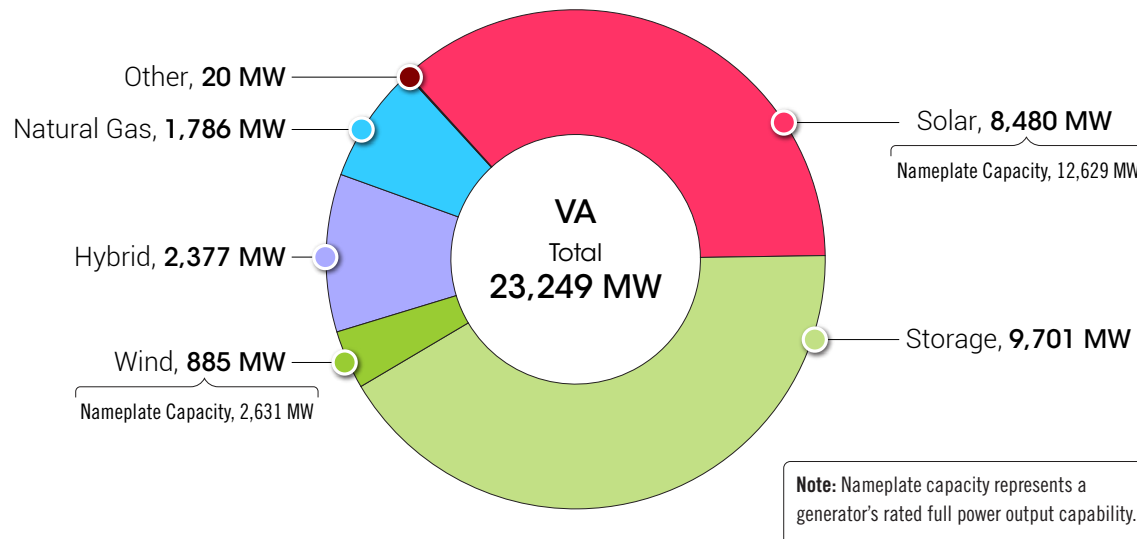
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**Table 6.57:** Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2025)

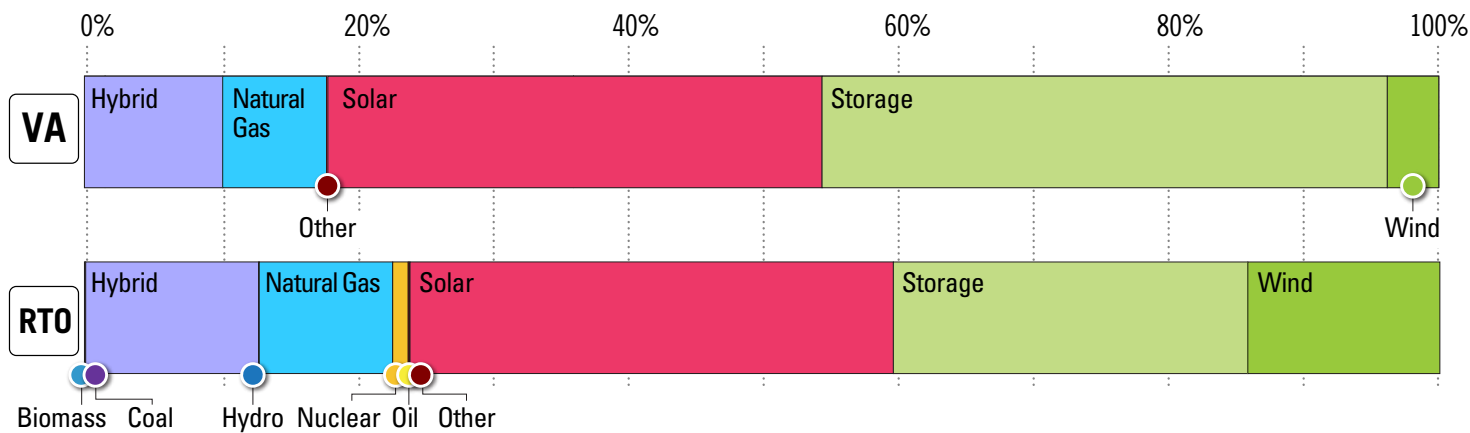
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	7	705.7	2	35.0	9	740.7
	Diesel	0	0.0	0	0.0	0	0.0	0	0.0	1	0.0	1	0.0
	Natural Gas	25	647.8	0	0.0	2	1,138.0	49	7,288.4	53	22,148.8	129	31,223.0
	Nuclear	0	0.0	0	0.0	0	0.0	8	350.0	1	1,570.0	9	1,920.0
	Oil	0	0.0	0	0.0	0	0.0	6	322.2	2	40.0	8	362.2
	Other	1	20.0	0	0.0	0	0.0	0	0.0	2	136.3	3	156.3
	Storage	93	9,039.1	1	9.0	11	653.3	3	35.7	226	14,291.5	334	24,028.6
Renewable	Biomass	0	0.0	0	0.0	0	0.0	5	125.4	5	77.1	10	202.5
	Hybrid	19	1,986.3	0	0.0	5	390.5	3	12.3	96	6,105.3	123	8,494.5
	Hydro	0	0.0	0	0.0	0	0.0	9	423.4	2	254.0	11	677.4
	Methane	0	0.0	0	0.0	0	0.0	15	85.3	12	87.8	27	173.1
	Solar	100	4,663.2	15	845.6	54	2,971.4	99	2,854.5	507	19,199.9	775	30,534.6
	Wind	2	109.0	0	0.0	5	776.0	1	1.5	37	1,405.1	45	2,291.6
	Wood	0	0.0	0	0.0	0	0.0	1	4.0	2	57.0	3	61.0
	<b>Grand Total</b>	<b>240</b>	<b>16,465.4</b>	<b>16</b>	<b>854.6</b>	<b>77</b>	<b>5,929.3</b>	<b>206</b>	<b>12,208.4</b>	<b>948</b>	<b>65,407.8</b>	<b>1,487</b>	<b>100,865.5</b>

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**Figure 6.58:** Virginia Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)

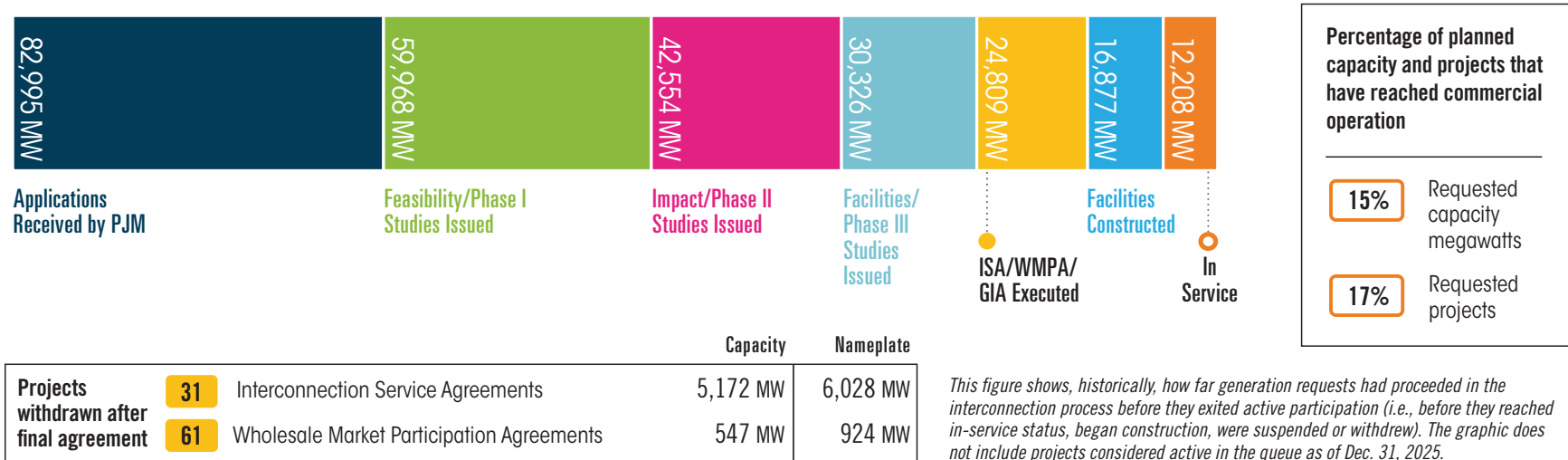


**Figure 6.57:** Virginia – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)



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**Figure 6.59: Virginia Progression of Interconnection Requests (Dec. 31, 2025)**

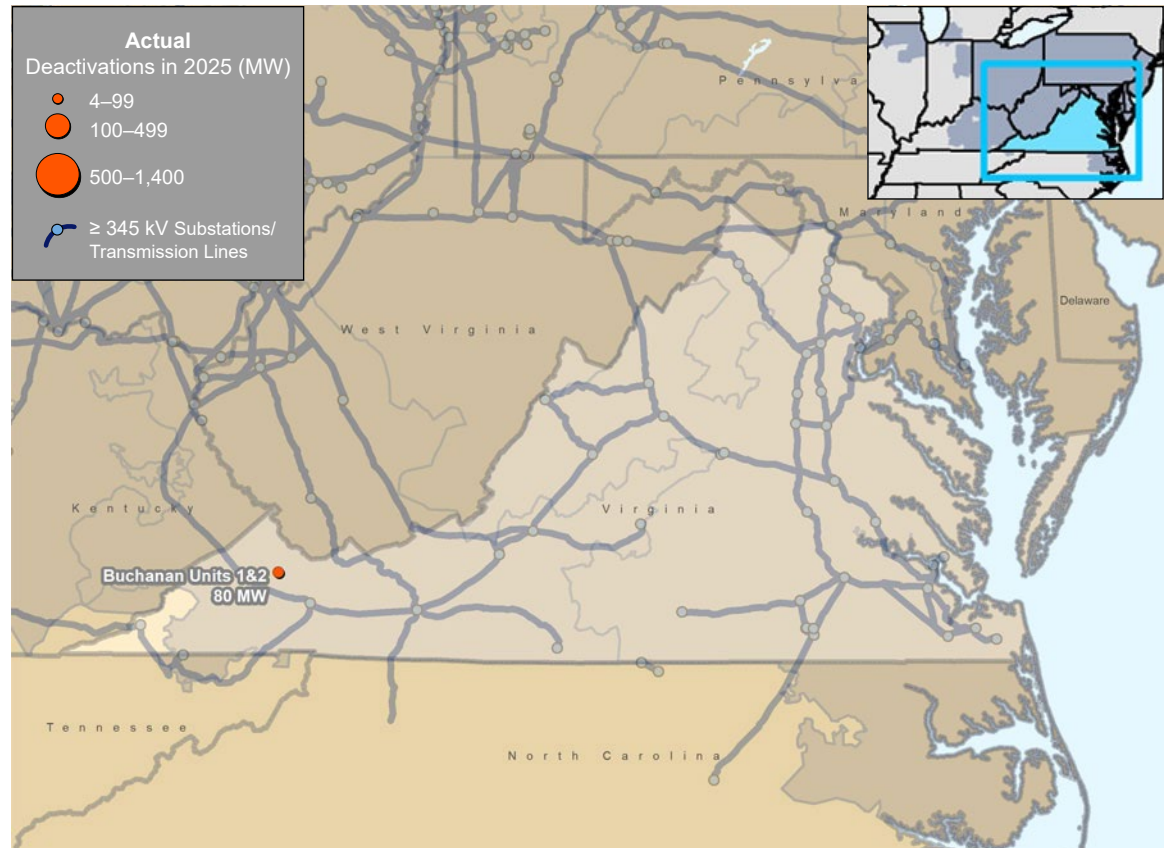


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**6.12.5 — Generation Deactivation**

Formal generator deactivations and requests received by PJM in Virginia between Jan. 1, 2025, and Dec. 31, 2025, are summarized in **Map 6.46** and **Table 6.58**.

**Map 6.46: Virginia Generation Deactivations (Dec. 31, 2025)**



**Table 6.58: Virginia Generation Deactivations (Dec. 31, 2025)**

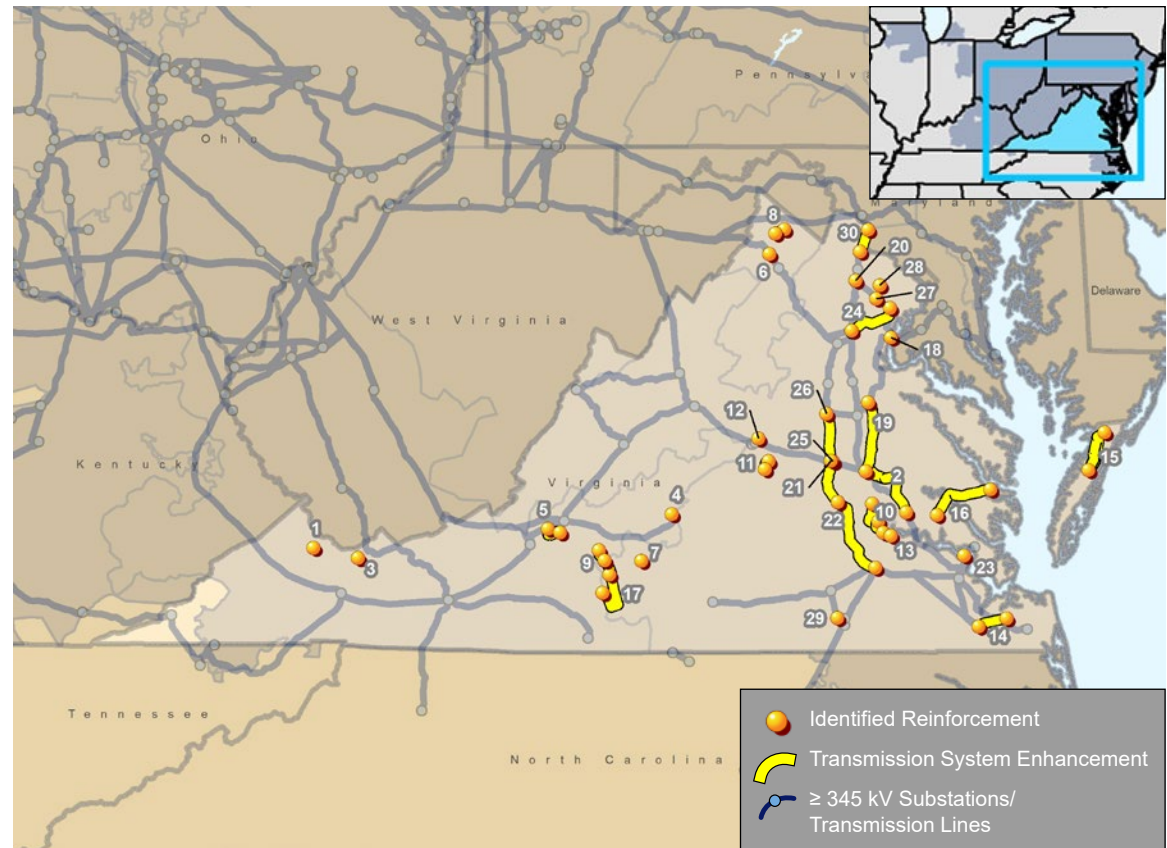
Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Buchanan Unit 1	AEP	Natural Gas	3/14/2025	7/2/2025	23	40
Buchanan Unit 2	AEP	Natural Gas	3/14/2025	7/2/2025	23	40

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**6.12.6 — Baseline Projects**

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in Virginia are summarized in **Map 6.47** and **Table 6.59**.

**Map 6.47: Virginia Baseline Projects (Dec. 31, 2025)**



**Table 6.59: Virginia Baseline Projects (Dec. 31, 2025)**

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B3333.14	Install ~2.6-mile greenfield 69 kV line from greenfield Mount Heron station to the existing Horn Mountain substation.	6/1/2023	\$18.02	AEP	7/18/2025	N/A - Scope Change	Generator Deactivation

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Table 6.59: Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
2	B3692.2	Switch to 5/2 H-frame structures and install ~27.7 miles of 230 kV transmission line (but not be terminated) from Elmont to Chickahominy. String up ~8 miles of new 230 kV conductor on the open arms of the structures of 230 kV line No. 2075 that runs parallel to 500 kV line No. 557.	6/1/2026	\$74.50	Dominion	5/6/2025	N/A - Scope Change	Baseline Load Growth Deliverability & Reliability
	B4053.21	Uprate 500 kV line No. 567 associated terminal equipment at Chickahominy to 5000A standards.	6/1/2032	\$0.03	Dominion	1/6/2026	Yes (Reliability W1)	
	B4053.32	Replace 230 kV, 63 kA breakers H592, L292, 203292, 207592, 28392-3, H692, L192 with 80 kA breakers at Elmont substation.	6/1/2030	\$7.00	Dominion	1/6/2026	Yes (Reliability W1)	Short Circuit
	B4053.9	Construct one new 500 kV line terminal position at the existing Elmont substation.	6/1/2032	\$6.04	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
3	B3950.1	Adjust existing Tazewell 138/34.5 kV transformer tap to 1:1 to help mitigate voltages on the 34.5 kV bus.	6/1/2030	\$0.10	AEP	11/14/2025	No	TO Criteria Violation
4	B3952.1	Replace 138 kV, 3000A circuit breakers H and H1 with 4000A circuit breakers.	6/1/2030	\$1.51	AEP	11/14/2025	No	Baseline Load Growth Deliverability & Reliability
5	B3975.1	Install a new 138/69 kV transformer at Catawba station with a high-side circuit switcher and a low-side circuit breaker.	12/1/2030	\$7.77	AEP	11/14/2025	No	TO Criteria Violation
	B3975.2	Upgrade one 69 kV breaker at Huntington Court.	6/1/2030	\$1.00	AEP	1/16/2026	Yes (Reliability W1)	Short Circuit
6	B3977.1	Install conduit and grounding for new equipment, one lot of cables and grounding for new equipment, and replace one 138 kV wave trap on the West Winchester line terminal at Meadow Brook substation.	6/1/2030	\$0.36	AP	11/14/2025	No	Baseline Load Growth Deliverability & Reliability
7	B4000.360	Replace two switches, a wave trap and leads to upgrade all related substation equipment to 2000A at Altavista 138 kV substation.	6/1/2029	\$1.00	Dominion	5/6/2025	N/A - Scope Change	Baseline Load Growth Deliverability & Reliability
8	B4001.1	Construct the McCanns Road 138 kV switching station and interconnect the existing Redbud-West Winchester 138 kV line and Bartonville-Stephenson 138 kV line.	6/1/2030	\$18.83	AP	11/4/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4001.2	Reconductor new Redbud McCanns Road 138 kV line with 795 kcmil 45/7 ACSS for 0.5 miles from Redbud 138 kV substation to str. 175 of the existing Redbud-West Winchester 138 kV line at ~coordinates (39.217478, -78.128621).	6/1/2030	\$5.04	AP	11/4/2025	Yes (Reliability W1)	

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Table 6.59: Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
9	B4027.1	Perform sag study the Smith Mountain-Moneta 138 kV line. ~14 structures will need to be added in existing rights-of-way to increase the sag along the existing centerline such that the higher requested ampacity can be achieved along the corridor and maintain safety clearances.	6/1/2030	\$9.60	AEP	12/8/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4027.2	Replace the 2" IPS Sch. 40 conductor with 4" IPS Sch. 40 conductor at Smith Mountain station on the Smith Mountain-Rock Castle branch allowing the branch to exceed a summer emergency rating of 1765A.	6/1/2030	\$0.28	AEP	12/8/2025	Yes (Reliability W1)	
10	B4030.1	Wreck and rebuild ~12.5 miles of Chesterfield-Basin 230 kV line.	6/1/2030	\$100.31	Dominion	12/8/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4030.2	Reconductor 230 kV lines No. 211 and No. 228 between the existing Chesterfield-Hopewell 230 kV substation. Each line reconductor is ~3 miles long.	6/1/2030	\$6.34	Dominion	12/8/2025	Yes (Reliability W1)	
	B4030.3	Replace all terminal equipment, line leads and bus at Basin 230 kV substation to be rated to 4000A.	6/1/2030	\$1.96	Dominion	12/8/2025	Yes (Reliability W1)	
	B4030.4	Replace all terminal equipment, line leads and bus at Chesterfield 230 kV substation to be rated to 4000A.	6/1/2030	\$3.51	Dominion	12/8/2025	Yes (Reliability W1)	
	B4030.5	Install a new 230 kV, 4000A 80 kA circuit breaker at Chesterfield 230 kV substation.	6/1/2030	\$1.50	Dominion	12/8/2025	Yes (Reliability W1)	

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Table 6.59: Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
11	B4030.9	Wreck and rebuild ~24 miles of Charlottesville-Fork Union 230 kV line.	6/1/2030	\$106.49	Dominion	12/8/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4030.10	Wreck and Rebuild ~1.74 miles of Fork Union-Bremo 230 kV line.	6/1/2030	\$10.81	Dominion	12/8/2025	Yes (Reliability W1)	
	B4030.11	Replace all terminal equipment at Charlottesville 230 kV substation to support the new line conductor ratings of the Charlottesville-Fork Union 230 kV rebuild.	6/1/2030	\$3.35	Dominion	12/8/2025	Yes (Reliability W1)	
	B4030.12	Replace all terminal equipment at Fork Union 230 kV substation to support the new line conductor ratings of the Charlottesville-Fork Union 230 kV rebuild.	6/1/2030	\$2.24	Dominion	12/8/2025	Yes (Reliability W1)	
	B4030.13	Replace all terminal equipment at Fork Union 230 kV substation to support the new conductor ratings of the Fork Union-Bremo 230 kV rebuild.	6/1/2030	\$1.60	Dominion	12/8/2025	Yes (Reliability W1)	
	B4030.14	Replace all terminal equipment at Bremo 230 kV substation to support the new conductor ratings of the Fork Union-Bremo 230 kV rebuild.	6/1/2030	\$1.80	Dominion	12/8/2025	Yes (Reliability W1)	
	B4031.1	Wreck and rebuild 115 kV line No. 5 using conductor with minimum summer rating of 393 MVA.	4/15/2030	\$5.00	Dominion	12/11/2025	No	
	B4031.2	Upgrade relevant equipment below 2000A, such as line leads, breakers, switches and CTs at Bremo substation to accommodate the upgraded 115 kV line 5.	4/15/2030	\$1.00	Dominion	12/11/2025	No	
	B4031.3	Upgrade relevant equipment below 2000A, such as line leads, breakers, switches and CTs at Fork Union substation to accommodate the upgraded 115 kV line 5.	4/15/2030	\$1.00	Dominion	12/11/2025	No	
12	B4030.15	Upgrade disconnect switches at Mt. Eagle tap 230 kV substation to 4000A.	6/1/2030	\$0.65	Dominion	12/8/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
13	B4030.16	Reset relays at Sycamore Springs 230 kV substation.	6/1/2030	\$0.04	Dominion	12/8/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
14	B4030.6	Rebuild ~13.2 miles of Suffolk-Yadkin 500 kV line.	6/1/2030	\$68.86	Dominion	12/8/2025	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4030.7	Replace all terminal equipment at Suffolk 500 kV substation to be rated to 5000A.	6/1/2030	\$5.23	Dominion	12/8/2025	Yes (Reliability W1)	
	B4030.8	Replace all terminal equipment at Yadkin 500 kV substation to be rated to 5000A.	6/1/2030	\$0.24	Dominion	12/8/2025	Yes (Reliability W1)	

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Table 6.59: Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
15	B4033.1	At Tasley substation 69 kV, replace one capacitor bank (14.4 MVAR) and install one new capacitor bank (7.2 MVAR).	12/31/2030	\$2.64	ODEC	11/13/2025	No	TO Criteria Violation
	B4033.10	Upgrade line relaying at Kellam Substation 69 kV.	12/31/2030	\$0.58	ODEC	11/13/2025	No	
	B4033.2	Convert Tasley substation 69 kV to breaker-and-a-half configuration with two new breaker bays in order to accommodate new Tasley-Oak Hall line and Tasley cap banks.	12/31/2030	\$18.83	ODEC	11/13/2025	No	
	B4033.3	Replace one capacitor bank (14.4 MVAR) at Kellam substation 69 kV and install one new capacity bank (7.2 MVAR).	12/31/2030	\$2.52	ODEC	11/13/2025	No	
	B4033.4	Install one new capacitor bank (3.6 MVAR) at At Cheriton substation 69 kV.	12/31/2030	\$1.19	ODEC	11/13/2025	No	
	B4033.5	Replace one capacitor bank (14.4 MVAR) at Belle Haven substation 69 kV.	12/31/2030	\$1.14	ODEC	11/13/2025	No	
	B4033.6	Rebuild Oak Hall substation 69 kV yard and upgrade to breaker-and-a-half configuration to accommodate new Tasley-Oak Hall line.	12/31/2030	\$32.46	ODEC	11/13/2025	No	
	B4033.7	Rebuild 69 kV line from Oak Hall-Hallwood-Tasley.	12/31/2030	\$29.81	ODEC	11/13/2025	No	
	B4033.8	Construct new 69 kV transmission line from Oak Hall-Tasley in existing right-of-way.	12/31/2030	\$41.74	ODEC	11/13/2025	No	
	B4033.9	Upgrade line relaying at Tasley substation 69 kV.	12/31/2030	\$1.11	ODEC	11/13/2025	No	
16	B4034.1	Cut the existing line 2016 in the corridor into the Goadlers Creek three-breaker ring bus station such that the remaining section of line going to Harmony Village will be renumbered to 2XX1.	1/1/2029	\$4.48	Dominion	12/8/2025	Yes (Market Efficiency W1)	Congestion Relief - Economic
	B4034.2	Install a new 230/115 kV TX No. 1 transformer using a 115 kV breaker and associated switches, as well as a new 230 kV line from Lanexa and Harmony Village with a 230 kV breaker and associated switches.	1/1/2029	\$17.33	Dominion	12/8/2025	Yes (Market Efficiency W1)	
	B4034.3	Reset relay reset only on line 2016 relays at Harmony Village substation.	1/1/2029	\$0.02	Dominion	12/8/2025	Yes (Market Efficiency W1)	
	B4034.4	Reset relay reset only on line 2016 relays at Lanexa substation.	1/1/2029	\$0.02	Dominion	12/8/2025	Yes (Market Efficiency W1)	
17	B4035.1	Reconductor one span of the Smith Mountain-Museville 138 kV line with 2-556 ACSR conductor.	1/1/2029	\$1.43	AEP	12/8/2025	Yes (Market Efficiency W1)	Congestion Relief - Economic
	B4035.2	Replace Smith Mountain 138 kV switches CS1, CS2 and C1S2 with 3000A switches and replace switch jumpers with 2-1272 AAC.	1/1/2029	\$0.37	AEP	12/8/2025	Yes (Market Efficiency W1)	

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Table 6.59: Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
18	B4053.1	Upgrade 500 kV line No. 560 terminal equipment at Possum Point substation so as not to limit the conductor rating.	6/1/2032	\$0.40	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4053.2	Rebuild ~0.19-mile segment of 500 kV line No. 560 from Possum Point substation (structure 560/1A) to Burches Interconnection (structure 560/1F) using 6000A conductor.	6/1/2032	\$3.49	Dominion	1/6/2026	Yes (Reliability W1)	
19	B4053.10	Construct one new 500 kV line terminal position at the proposed Kraken substation.	6/1/2032	\$8.61	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4053.8	Build a new 500 kV line from Elmont-Kraken (~31 miles). The new line will be constructed primarily of double-circuit 500 kV/230 kV monopole structures. The proposed route follows existing 230 kV line No. 2032 from Elmont-Hanover-Four Rivers and 230 kV line No. 256 from Four Rivers-Kings Dominion-St Johns-Kraken.	6/1/2032	\$147.85	Dominion	1/6/2026	Yes (Reliability W1)	
20	B4053.11	Cut and loop line No. 5008 into Mosby substation, which will result in two 500 kV lines: line No. 5008 Morrisville-Mosby and line No. 9573 Mosby-Wishing Star.	6/1/2032	\$6.69	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4053.12	Install two 500 kV breakers and all associated terminal equipment in the available bay adjacent to existing breaker XT590 to achieve a redundant breaker arrangement. Upgrade existing terminal equipment to 500 kV, 5000A 63 kAIC standards including breaker (XT590), disconnect switches (59078, X74), leads and bus work.	6/1/2032	\$9.56	Dominion	1/6/2026	Yes (Reliability W1)	
	B4053.5	Design and construct a new Voltage Source Converter (VSC) HVDC station at Mosby substation to support the new HVDC link.	6/1/2032	\$745.42	Dominion	1/6/2026	Yes (Reliability W1)	
21	B4053.13	Construct a new 765/500 kV Vontay switching station at the crossing of 500 kV line No. 553 Cunningham-Elmont and 765 kV line Joshua Falls-Yeat. Develop two 765 kV line terminal positions and three 500 kV line terminal positions. Install one 765/500 kV transformer with provisions for a future second transformer.	6/1/2032	\$217.76	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4053.14	Loop 500 kV line No. 553 into the new Vontay substation, which will result in two 500 kV lines: Cunningham-Vontay and Vontay-Elmont.	6/1/2032	\$6.69	Dominion	1/6/2026	Yes (Reliability W1)	
	B4053.15	Loop 500 kV line No. 576 into the new Vontay substation, which will result in two 500 kV lines: from North Anna-Vontay and Vontay-Midlothian.	6/1/2032	\$6.69	Dominion	1/6/2026	Yes (Reliability W1)	
	B4053.16	Loop 765 kV Joshua Falls-Yeat into the new Vontay substation, which will result in two 765 kV lines: from Joshua Falls-Vontay and Vontay-Yeat.	6/1/2032	\$8.36	Dominion	1/6/2026	Yes (Reliability W1)	
	B4053.28	Replace 500 kV circuit breakers (54265 and 553T564) and all associated equipment to line No. 553 including switches and CT with 5000A equipment at Cunningham substation.	6/1/2032	\$9.20	Dominion	1/6/2026	Yes (Reliability W1)	

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Table 6.59: Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
22	B4053.17	Replace equipment on the 500 kV side of Carson substation with 5000A equipment.	6/1/2032	\$12.44	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4053.18	Rebuild ~37.4 miles of 500 kV line No. 563 from Carson-Midlothian. The proposed structures to be installed are mainly 500/230 kV double-circuit V-string suspension towers. The 230 kV circuit position will be vacant at the completion of this project but serves to accommodate a future 230 kV line.	6/1/2032	\$228.48	Dominion	1/6/2026	Yes (Reliability W1)	
	B4053.19	Uprate 500 kV line No. 563 associated terminal equipment at Carson to 5000A standards.	6/1/2032	\$6.15	Dominion	1/6/2026	Yes (Reliability W1)	
	B4053.20	Uprate 500 kV line No. 563 associated terminal equipment at Midlothian to 5000A standards.	6/1/2032	\$2.43	Dominion	1/6/2026	Yes (Reliability W1)	
23	B4053.22	Uprate 500 kV line No. 567 associated terminal equipment at Surry to 5000A standards.	6/1/2032	\$2.46	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
24	B4053.23	Rebuild ~22 miles of 500 kV line No. 539 Yeat-Ox using 6000A conductor on double-circuit structures with the option of adding a 230 kV line at a later time.	6/1/2032	\$122.66	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4053.24	Upgrade 500 kV line No. 539 associated equipment at Ox substation to support the new conductor rating.	6/1/2032	\$2.25	Dominion	1/6/2026	Yes (Reliability W1)	
	B4053.25	Upgrade 500 kV line No. 539 associated equipment at Yeat substation to support the new conductor rating.	6/1/2032	\$0.33	Dominion	1/6/2026	Yes (Reliability W1)	
25	B4053.26	Rebuild 20 miles of 500 kV line No. 576 from Vontay substation to Midlothian substation using 6000A conductor.	6/1/2032	\$102.70	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4053.27	Upgrade/install 6000A equipment at Midlothian substation to support the new conductor termination from Vontay.	6/1/2032	\$2.16	Dominion	1/6/2026	Yes (Reliability W1)	
26	B4053.3	Construct a new bipolar +/- 525 kV HVDC link connecting Heritage and Mosby substations where the link has a capability of transmitting 3,000 MW. The HVDC link, ~185 miles in length, will be fully routed underground between the two new proposed converter stations, one at Heritage and one at Mosby.	6/1/2032	\$2,271.70	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4053.6	Rebuild 20 miles of 500 kV line No. 576 from North Anna substation to Vontay substation using 6000A conductor.	6/1/2032	\$102.70	Dominion	1/6/2026	Yes (Reliability W1)	
	B4053.7	Upgrade/install 6000A equipment at North Anna substation to support the new conductor termination.	6/1/2032	\$2.16	Dominion	1/6/2026	Yes (Reliability W1)	
27	B4053.30	Replace 230 kV, 63 kA breakers 205182, 2051T2063, 221282 with 80 kA breakers at Clifton substation.	6/1/2030	\$3.00	Dominion	1/6/2026	Yes (Reliability W1)	Short Circuit
	B4053.31	Replace 500 kV, 40 kA breakers H1T559 with 63 kA breakers at Clifton substation.	6/1/2030	\$1.00	Dominion	1/6/2026	Yes (Reliability W1)	

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Table 6.59: Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
28	B4053.33	Replace 230 kV, 63 kA breakers 213732, 226132 with 80 kA breakers at Celestial substation.	6/1/2030	\$2.00	Dominion	1/6/2026	Yes (Reliability W1)	Short Circuit
29	B4053.4	Design and construct a new Voltage Source Converter (VSC) HVDC station at Heritage substation to support the new HVDC link.	6/1/2032	\$773.73	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
30	B4052.6	Complete Aspen 500 kV remote work for Dickerson (new 500 kV)-Aspen line.	6/1/2032	\$0.00	Dominion	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
CEII	B3936.5	AEP Zone 2024W1 P5 Solution #5: Install battery chargers and associated equipment at AEP substation. Addresses the following flowglates: 2024-P5-AEP01.	6/1/2029	\$0.09	AEP	7/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B3937.1	2024W1 DVP P5 Solution #1 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP01.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.10	2024W1 DVP P5 Solution #10 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP10.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.11	2024W1 DVP P5 Solution #11 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP11.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.12	2024W1 DVP P5 Solution #12 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP12.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.13	2024W1 DVP P5 Solution #13 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP13.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.14	2024W1 DVP P5 Solution #14 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP14.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.15	2024W1 DVP P5 Solution #15 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP15.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.16	2024W1 DVP P5 Solution #16 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP16.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.17	2024W1 DVP P5 Solution #17 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP17.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.18	2024W1 DVP P5 Solution #18 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP18.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.19	2024W1 DVP P5 Solution #19 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP19.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.2	2024W1 DVP P5 Solution #2 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP02.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.20	2024W1 DVP P5 Solution #20 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP20.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
B3937.21	2024W1 DVP P5 Solution #21 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP21.	6/1/2029	\$0.02	Dominion	7/8/2025	No		

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Table 6.59: Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
CELL	B3937.22	2024W1 DVP P5 Solution #22 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP23.	6/1/2029	\$0.02	Dominion	7/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B3937.23	2024W1 DVP P5 Solution #23 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP24.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.24	2024W1 DVP P5 Solution #24 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP26.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.25	2024W1 DVP P5 Solution #25 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP27.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.26	2024W1 DVP P5 Solution #26 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP28.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.27	2024W1 DVP P5 Solution #27 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP29.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.29	2024W1 DVP P5 Solution #29 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP31.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.3	2024W1 DVP P5 Solution #3 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP03.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.30	2024W1 DVP P5 Solution #30 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP32.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.31	2024W1 DVP P5 Solution #31 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP33.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.32	2024W1 DVP P5 Solution #32 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP34.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.33	2024W1 DVP P5 Solution #33 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP35.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.34	2024W1 DVP P5 Solution #34 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP36.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.35	2024W1 DVP P5 Solution #35 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP37.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.36	2024W1 DVP P5 Solution #36 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP38.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.37	2024W1 DVP P5 Solution #37 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP39.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.38	2024W1 DVP P5 Solution #38 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP40.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.39	2024W1 DVP P5 Solution #39 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP41.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.4	2024W1 DVP P5 Solution #4 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP04.	6/1/2029	\$0.02	Dominion	7/8/2025	No	

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Table 6.59: Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

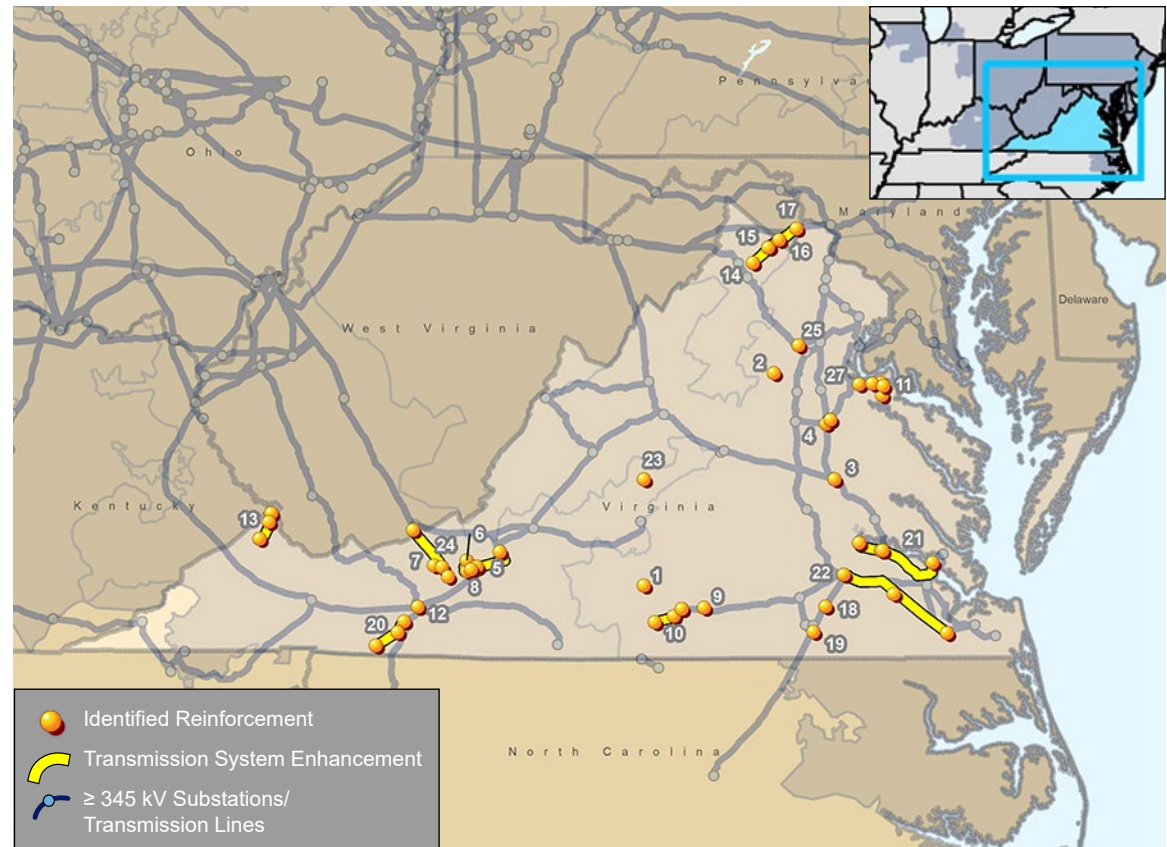
Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
CELL	B3937.5	2024W1 DVP P5 Solution #5 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP05.	6/1/2029	\$0.02	Dominion	7/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B3937.6	2024W1 DVP P5 Solution #6 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP06.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.8	2024W1 DVP P5 Solution #8 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP08.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.9	2024W1 DVP P5 Solution #9 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP09.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3938.1	2024W1 DVP P5 Solution No. 40 – Replace and upgrade relay and associated equipment at DVP substation. Addresses flowgate No. 2024-P5-DVP16.	6/1/2029	\$0.19	Dominion	7/8/2025	No	
	B3938.2	2024W1 DVP P5 Solution No. 41 – Replace and upgrade relay and associated equipment at DVP substation. Addresses flowgate No. 2024-P5-DVP23.	6/1/2029	\$0.11	Dominion	7/8/2025	No	
	B3938.3	2024W1 DVP P5 Solution No. 42 – Replace and upgrade relay and associated equipment at DVP substation. Addresses flowgate No. 2024-P5-DVP14.	6/1/2029	\$0.18	Dominion	7/8/2025	No	
	B3938.6	2024W1 DVP P5 Solution No. 45 – Replace and upgrade relay and associated equipment at DVP substation. Addresses flowgate No. 2024-P5-DVP03.	6/1/2029	\$0.20	Dominion	7/8/2025	No	
	B4076.5	2024W1 P5: Install open-circuit battery monitoring. Addresses flowgate No. 2024-P5-DP&L05.	6/1/2029	\$0.02	DP&L	12/8/2025	No	

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### 6.12.7 — Network Projects

Network projects in Virginia for 2025 are summarized in **Map 6.48** and **Table 6.60**.

**Map 6.48:** Virginia Network Projects (Dec. 31, 2025)



**Table 6.60:** Virginia Network Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	N6129	Remote protection and communication changes to allow for interconnection of the AC1-080 generating customer facility with the transmission system.	AC1-080	4/1/2021	0.85	Dominion	10/8/2025
2	N6334	Modify protection and communication work to support interconnection of new AC1-120 generator.	AC1-120	6/1/2019	0.25	Dominion	10/8/2025
	N6335	Build new structures to cut and loop the line No. 2 into AC1-120 115 kV substation.	AC1-120	6/1/2019	1.30	Dominion	10/8/2025
	N6336	Build a three-breaker 115 kV substation at the AC1-120 facility.	AC1-120	6/1/2019	5.30	Dominion	10/8/2025

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Table 6.60: Virginia Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	N6715	Build new structures to cut and loop the transmission line into AC1-191 115 kV substation.	AC1-191	12/31/2020	2.29	Dominion	10/8/2025
	N6716	Modify protection and communication work to support interconnection of new AC1-191 generator.	AC1-191	12/31/2020	0.17	Dominion	10/8/2025
4	N7049	Install a second 230 kV circuit of 3.94 miles from Ladysmith to Ladysmith CT (line 2089) with a 2000/2000/2300 MVA conductor. Add breakers at both stations.	AF2-013	10/1/2023	6.32	Dominion	10/8/2025
5	N7151.1	Perform a sag study on the 5 miles of ACSR 397.5 30/7 lark conductor on the Techdr-M Funk 138 kV line.	AF2-106	3/28/2022	0.02	AEP	10/8/2025
	N7151.2	Perform a sag study on the 14.5 miles of ACSR 556.5 26/7 dove conductor on the Techdr-M Funk 138 kV line.	AF2-106	3/28/2022	0.06	AEP	10/8/2025
6	N7152	Perform a sag study on the Edgemo-Vicker 138 kV line.	AF2-106	3/28/2022	0.02	AEP	10/8/2025
7	N7153	Rebuild 0.13 miles of 300 CU on the AF2-106 Tap-Glen Lyn 138 kV line.	AF2-106	3/28/2022	0.01	AEP	10/8/2025
	N7155	Perform a sag study on the AD2-179 Tap-AF2-105 Tap 138 kV line.	AF2-106	3/28/2022	0.01	AEP	10/8/2025
	N7155.1	Rebuild/reconductor 1.78 mi. 300 CU overhead conductor.	AF2-106	2/28/2028	2.67	AEP	10/8/2025
8	N7154	Perform a sag study on the Schiris-Techdr 138 kV line.	AF2-106	3/28/2022	0.02	AEP	10/8/2025
9	N7853.1	Rearrange line No. 1012 to loop into and out of the new three-breaker AD2-063 115 kV switching station. A new three-breaker ring bus substation will be installed between structures 2068/446 and 2068/447.	AD1-152	12/31/2024	1.20	Dominion	10/8/2025
10	N7853.2	Build a three-breaker AD1-152 230 kV switching station. AD1-152 provides for the initial construction of a new 230 kV three-breaker ring substation between transmission structures 2068/446 and 2068/447. The objective of this project is to build a 230 kV, three-breaker ring bus to support the new 80 MW solar farm built by Piney Creek Solar, LLC. The site is located along Dominion Energy's existing 230 kV, 2068 line from Clover substation to Sedge Hill substation. The cut line will consume two of the positions in the ring bus. The third position will be for the 230 kV feed from Piney Creek Solar, LLC collector station for the new 80 MW solar farm. The new 230 V three-breaker ring substation will share a common footprint and fence line with Piney Creek Solar, LLC collector station. The demarcation point between the two stations will be the 230 kV breaker disconnect switch four-hole pad in the Piney Creek Solar, LLC collector station by the common fence. The grounding systems for each station will be tied together. The developer will provide the	AD1-152	12/31/2024	7.60	Dominion	10/8/2025
	N7853.3	Remote protection and communications work at Clover 230 kV substation.	AD1-152	12/31/2024	0.06	Dominion	10/8/2025
	N7853.4	Remote drawing work at Sedge Hill 230 kV substation.	AD1-152	12/31/2024	0.02	Dominion	10/8/2025
11	N8444.1	Rearrange line No. 2076 to loop into and out of the new three-breaker AF1-114 230 kV switching station.	AF1-114	11/30/2021	2.70	Dominion	10/8/2025
	N8444.2	Remote protection and communication work.	AF1-114	11/30/2021	0.29	Dominion	10/8/2025
	N8444.3	Build a three-breaker AF1-114 230 kV switching station.	AF1-114	11/30/2021	8.39	Dominion	10/8/2025
12	N8546	Review and revise the protective relay settings at Jacksons Ferry 138 kV station.	AE2-326	6/15/2027	0.06	AEP	10/8/2025
13	N8587.0	Construct a new 69 kV ring bus station, initially populated with two circuit breakers, expandable to four circuit breakers.	AF2-382	9/30/2028	7.48	AEP	10/8/2025
	N8588.0	Connect the proposed 69 kV station to the existing Hurley-Looney Creek 69 kV.	AF2-382	9/30/2028	2.98	AEP	10/8/2025
	N8589.0	Remote end work at Looney Creek 69 kV station.	AF2-382	9/30/2028	1.85	AEP	10/8/2025

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Table 6.60: Virginia Network Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
14	N8641.0	Install carrier equipment at Double Toll Gate substation.	AG1-307	9/30/2029	0.53	AP	10/8/2025
	N8642.0	Replace line relaying panel at Kabletown substation.	AG1-307	9/30/2029	0.57	AP	10/8/2025
	N8643.0	Update nameplate/relay settings at Old Chapel substation.	AG1-307	9/30/2029	0.01	AP	10/8/2025
	N8860.0	Update relay settings at Double Toll Gate substation.	AG1-307	11/1/2027	0.06	AP	45938
	N8862.0	Update relay settings at AG1-182/AG1-186 substation.	AG1-307	11/1/2027	0.06	AP	45938
	N8668.0	Update relay settings at Double Toll Gate substation.	AG1-415	4/30/2027	0.04	AP	10/8/2025
15	N8665.0	Install security and communications infrastructure at AG1-415 interconnection substation.	AG1-415	4/30/2027	1.28	AP	10/8/2025
16	N8666.0	Install ~5.6 miles of new 48-count of OPGW/ADSS fiber solution between the planned AG1-307 interconnecting substation and the planned AG1-415 interconnecting substation.	AG1-415	4/30/2027	2.28	AP	10/8/2025
17	N8667.0	Cut and loop double toll Gate-Millville 138 kV line into new three-breaker ring bus for AG1-415 (~9.6 miles from Double Toll Gate and 0.2 miles from Old Chapel).	AG1-415	4/30/2027	1.33	AP	10/8/2025
	N8669.0	Update relay settings at Millville substation.	AG1-415	4/30/2027	0.04	AP	10/8/2025
	N8670.0	Update relay settings at AG1-307 substation.	AG1-415	4/30/2027	0.04	AP	10/8/2025
18	N8723.1	Build a three-breaker AE2-094 500 kV switching station.	AE2-094	6/1/2031	23.01	Dominion	10/8/2025
	N8723.2	Rearrange line No. 585 to loop into and out of the new three-breaker AE2-094 500 kV switching station.	AE2-094	6/1/2031	2.21	Dominion	10/8/2025
19	N8723.3	Remote protection and communication work at Carson and Rogers Road substations.	AE2-094	6/1/2031	0.19	Dominion	10/8/2025
20	N8775.0	Expand existing substation Independence 69 kV/Point Lookout 69 kV: install one new 16 ft. x 12 ft. DICM (Drop-In Control Module) non-mirrored control house expansion, review and revise (as necessary) the protective relay settings for the remainder of the Point Lookout 69 kV station.	AG1-508	12/7/2027	0.39	AEP	10/8/2025
	N8776.0	Upgrade Fries 69 kV substation: Review and revise (as necessary) the protective relay settings at the Fries 69 kV remote end station.	AG1-508	12/7/2027	0.06	AEP	10/8/2025
	N8777.0	Upgrade Jubal Early 69 kV substation: Review and revise (as necessary) the protective relay settings at the Fries 69 kV remote end station.	AG1-508	12/7/2027	0.06	AEP	10/8/2025
21	N8934.1	Three-breaker AF2-304 (AG1-000B) 230 kV switching station located along VEPCO's existing 230 kV line No. 240 from Wards Creek substation to Surry substation.	AF2-304	9/1/2028	12.57	Dominion	10/8/2025
	N8934.2	Rearrange line No. 240 to loop into and out of the new 230 kV switching station.	AF2-304	9/1/2028	3.97	Dominion	10/8/2025
	N8934.3	Remote protection and communication work at Wards Creek, Surry and Hopewell 230 kV substations.	AF2-304	9/1/2028	0.37	Dominion	10/8/2025
22	N8935.1	Build a new AE1-173 500 kV three-breaker ring switching station located along VEPCO's existing 500 kV, 544 line from Carson substation to Suffolk substation.	AE1-173	10/1/2029	22.90	Dominion	10/8/2025
	N8935.2	Rearrange line No. 544 to loop into and out of the new three-breaker AE1-173 500 kV switching station.	AE1-173	10/1/2029	5.66	Dominion	10/8/2025
	N8935.3	Remote protection and communication work at Carson and Suffolk 500 kV substations.	AE1-173	10/1/2029	0.19	Dominion	10/8/2025
23	N8986.0	Expansion of the Clifford 138 kV station ground grid (including yard and fence).	AF2-107	12/31/2027	1.58	AEP	10/8/2025

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Table 6.60: Virginia Network Projects (Dec. 31, 2025) (Cont.)

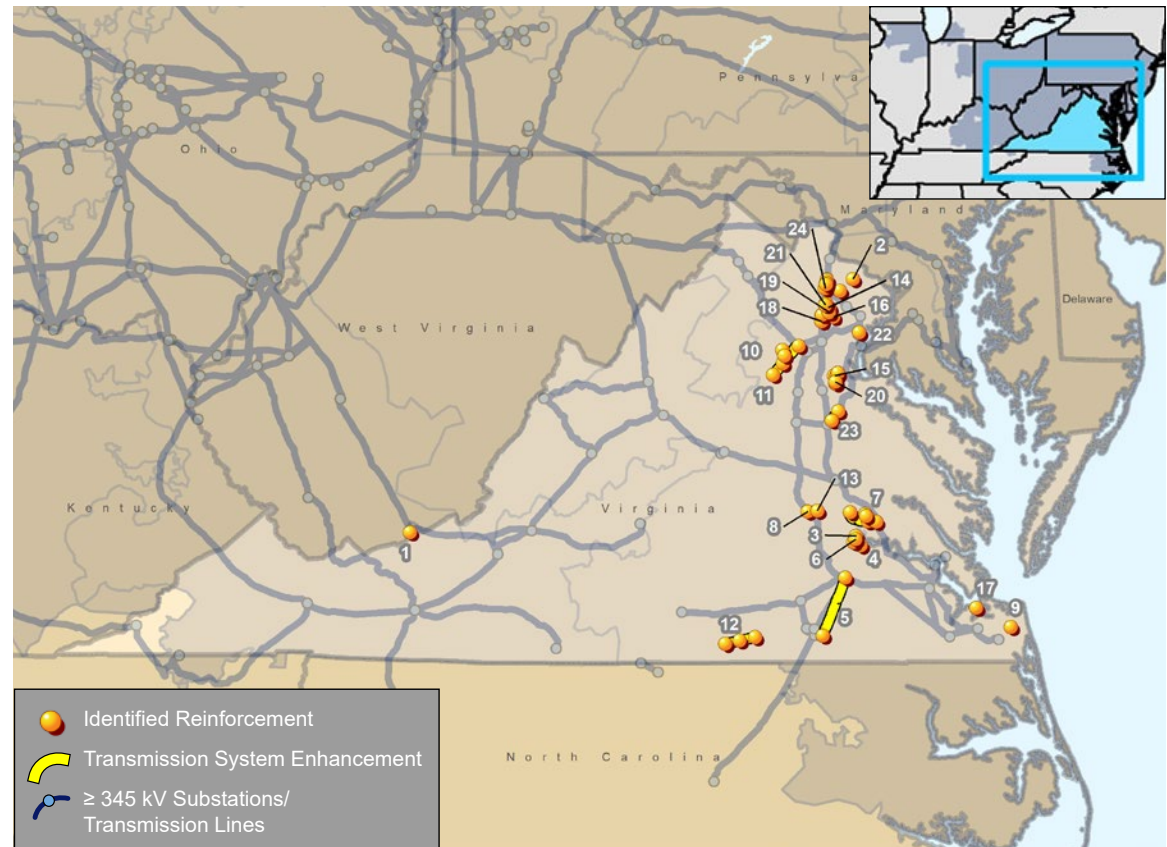
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
24	N8988.0	Tie the proposed AF2-106 138 kV switching station into the existing Glen Lyn-Claytor No. 1 138 kV circuit.	AF2-106	2/28/2028	6.72	AEP	10/8/2025
	N8989.0	Replace the protective relays, remove one wave trap and install a new ICON at Claytor 138 kV station.	AF2-106	2/28/2028	0.98	AEP	10/8/2025
	N8990.0	Review and revise the protective relay settings at the Glen Lyn 138 kV station.	AF2-106	2/28/2028	0.07	AEP	10/8/2025
	N8991.0	Install one new All Dielectric Loose Tube (ADLT) fiber-optic cable station exit transition and 0.2 miles of new ADLT fiber-optic cable to a new splice on existing fiber-cable at the Morgan's Cut 138 kV station.	AF2-106	2/28/2028	0.22	AEP	10/8/2025
	N9098.0	Construct a new 138 kV ring bus switching station initially populated with three-circuit breakers, expandable to four-circuit breakers on the Claytor-Glen Lyn No. 1 circuit.	AF2-106	2/28/2028	9.29	AEP	10/8/2025
25	N9290.0	Add new line position and two 230 kV breakers at Remington CT substation for AG1-152.	AG1-152	9/1/2029	13.26	Dominion	10/8/2025
26	N9296.0	Rearrange line No. 2145 to loop into and out of the new three-breaker AF2-013 230 kV switching station.	AF2-013	10/1/2029	3.02	Dominion	10/8/2025
27	N9297.0	Build a 230 kV three-breaker ring AF2-013 switching station.	AF2-013	10/1/2029	12.20	Dominion	10/8/2025
	N9298.0	Remote protection and communication work at Arnold's Corner 230 kV substation, Dahlgren 230 kV substation and Birchwood Nug 230 kV substation for AF2-013.	AF2-013	10/1/2029	0.52	Dominion	10/8/2025
	N9298.1	At Arnold's Corner 230 kV substation, project AF2-013 provides for drawing work, relay resets and field support necessary to change the line 2145 destination at Arnold's Corner substation.	AF2-013	10/1/2029	0.00	Dominion	10/8/2025
	N9298.2	At Dahlgren 230 kV substation, project AF2-013 provides for drawing work, islanding panel addition, relay resets and field support necessary to change line 2145 destination to AF2-013 generator interconnect.	AF2-013	10/1/2029	0.00	Dominion	10/8/2025
	N9298.3	At Birchwood Nug 230 kV substation, project AF2-013 provides for drawing work, islanding panel addition, relay resets and field support necessary to change line 2145 destination from Birchwood Nug to AF2-013 generator interconnect.	AF2-013	10/1/2029	0.00	Dominion	10/8/2025

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**6.12.8 — Supplemental Projects**

Supplemental projects included in the 2025 Local Plan in Virginia are summarized in **Map 6.49** and **Table 6.61**.

**Map 6.49: Virginia Supplemental Projects (Dec. 31, 2025)**



**Table 6.61: Virginia Supplemental Projects (Dec. 31, 2025)**

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S3607.3	Remote end work at Glen Lyn station to accommodate new breakers at Hinton station.	11/5/2029	\$0.90	AEP	3/14/2025
2	S3670.1	Interconnect the new substation by cutting and extending line No. 2043 (Reston-Park Center) to the proposed Towerview substation. Terminate both ends into a four-breaker ring arrangement to create a Towerview-Reston line and a Park Center-Towerview line. The customer will be paying excess facility cost for GIS substation.	11/30/2027	\$13.00	Dominion	11/6/2024

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Table 6.61: Virginia Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	S3671.1	Meadowville substation designed with six-breaker ring bus configuration.	1/1/2028	\$13.70	Dominion	12/3/2024
	S3671.2	Connect the new substation by extending new double-circuit 230 kV lines from future Sloan Drive substation.	1/1/2028	\$23.20	Dominion	12/3/2024
	S3672.1	Loop future 230 kV line connecting Sloan Drive and Meadowville substations in and out of White Mountain. Lines to terminate in a four-breaker ring bus arrangement.	1/1/2028	\$19.00	Dominion	12/3/2024
4	S3671.3	Reconductor line 211 from future Sycamore Springs switching station to Hopewell to achieve a normal summer rating of 1573 MVA.	12/31/2030	\$16.50	Dominion	12/3/2024
	S3671.4	Reconductor line 228 from future Sycamore Springs switching station to Hopewell to achieve a normal summer rating of 1573 MVA.	12/31/2030	\$16.50	Dominion	12/3/2024
	S3672.3	Construct new Sycamore Springs switching station. Tie lines 211, 228 and 2049 into Sycamore Springs.	12/31/2028	\$37.60	Dominion	12/3/2024
5	S3671.5	Reconductor line 238 from Carson to Clubhouse for a normal summer rating of 1573 MVA.	12/31/2030	\$84.00	Dominion	12/3/2024
6	S3672.2	Construct a new double-circuit 230 kV line from Meadowville substation to Enon substation.	12/31/2028	\$25.00	Dominion	12/3/2024
	S3672.4	Construct a new 230 kV line on DC structures with line 2049 from Sycamore Springs to Enon.	12/31/2028	\$30.00	Dominion	12/3/2024
	S3688.1	Add 84 MVA transformer No. 3.	3/1/2028	\$1.60	Dominion	4/1/2025
7	S3673.1	Cut and loop future 230 kV line 2294 (Chickahominy to White Oak) in and out of proposed Thicket substation. Line 2294 to terminate in a 230 kV six-breaker ring arrangement.	12/1/2027	\$25.00	Dominion	1/7/2025
	S3673.2	Reconductor line 286 from Techpark Place to Darbytown to achieve a minimum summer normal rating of 1573 MVA	12/1/2030	\$54.80	Dominion	1/7/2025
	S3673.3	Reconductor line 2050 from Chickahominy to Bermuda Hundred to achieve a normal summer rating of 1573 MVA.	12/1/2030	\$40.50	Dominion	1/7/2025
	S3673.4	Reconductor line 2075 from Chickahominy to future Thicket substation achieve a normal summer rating of 1573 MVA.	12/1/2030	\$19.50	Dominion	1/7/2025
	S3673.5	Reconductor line 2091 from Chickahominy to Elko to achieve a normal summer rating of 1573 MVA.	12/1/2030	\$20.25	Dominion	1/7/2025
	S3674.1	Extend two 230 kV lines from proposed Thicket substation to proposed Saltwood substation. Lines to terminate in a 230 kV six-breaker ring arrangement.	7/1/2027	\$40.00	Dominion	1/7/2025
	S3675.1	Cut and loop future 230 kV line between proposed Thicket substation and proposed Saltwood substation in and out of proposed Bunker substation. Lines to terminate in a 230 kV four-breaker ring arrangement.	12/1/2027	\$21.00	Dominion	1/7/2025
	S3676.1	Extend two 230 kV lines from proposed Saltwood substation to proposed Gray Bark substation. Cut and loop existing 230 kV line 2091 (Chickahominy to Portugee) into Gray Bark substation. Lines to terminate in a 230 kV six-breaker ring arrangement.	7/1/2027	\$40.00	Dominion	1/7/2025
S3698.1	Install a 230 kV circuit switcher, high-side switch, and any associated transmission equipment and bus work needed for new 230/34.5 kV transformer.	6/1/2026	\$5.00	Dominion	11/6/2024	
8	S3677.1	Lines to terminate in a 230 kV six-breaker ring arrangement.	1/1/2028	\$30.00	Dominion	2/4/2025
	S3677.2	Connect the new substation by extending four new 230 kV lines from Midlothian substation to proposed Duval substation.	1/1/2028	\$80.00	Dominion	2/4/2025
9	S3678.1	Replace Landstown transformer No. 1 with a new three-phase, 230/115/13.2 kV, 224 MVA unit. Include other ancillary equipment (high-side breaker, arresters, switches, relays, etc.) as needed.	12/31/2025	\$5.10	Dominion	2/4/2025
	S3679.1	Replace Landstown transformer No. 2 with a new three-phase, 230/115/13.2 kV, 224 MVA unit. Include other ancillary equipment (high-side breaker, arresters, switches, relays, etc.) as needed.	12/31/2026	\$4.76	Dominion	2/4/2025

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Table 6.61: Virginia Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
10	S3680.1	Build a new switching station Kyser next to the existing Mountain Run substation. Construct Kyser to accommodate a 230 kV breaker-and-a-half configuration with two rows initially installed, and three rows ultimately. Build new Cirrus switching station with 230 kV six-breaker ring arrangement with four breakers installed initially.	11/30/2027	\$38.00	Dominion	2/4/2025
	S3680.2	Wreck and rebuild ~five miles of existing double-circuit 115 kV line No. 2 and line No. 70 on the same structure (from 2/1201, 70/53 to 2/1253, 70/1), using 230 kV construction, from Mountain Run Junction to the new Kyser and Cirrus switching stations. Cut 230 kV line No. 2199 at Mountain Run Junction and feed the rebuilt double-circuit line to Kyser and Cirrus switching stations.	11/30/2027	\$22.00	Dominion	2/4/2025
	S3681.1	Construct a 230 kV six-breaker ring configuration at the new Palomino substation.	5/31/2028	\$14.30	Dominion	2/4/2025
	S3681.2	Connect the new substation Palomino by extending a new double-circuit 230 kV feed from future Cirrus substation.	5/31/2028	\$24.20	Dominion	2/4/2025
	S3682.1	Construct a 230 kV six-breaker ring at new substation.	5/31/2028	\$14.30	Dominion	2/4/2025
	S3682.2	Connect the new substation by extending a new double-circuit 230 kV feed from future Palomino substation.	5/31/2028	\$6.50	Dominion	2/4/2025
	S3683.1	Construct a 230 kV six-breaker ring at new substation.	5/31/2028	\$14.30	Dominion	2/4/2025
	S3683.2	Connect the new substation by extending a new double-circuit 230 kV feed from future Chandler substation.	5/31/2028	\$5.50	Dominion	2/4/2025
	S3684.1	Construct a 230 kV four-breaker ring at new substation.	5/31/2028	\$11.60	Dominion	2/4/2025
S3684.2	Connect the new substation by extending a new double-circuit 230 kV feed from future McDevitt substation.	5/31/2028	\$28.20	Dominion	2/4/2025	
11	S3684.3	The converted line No. 1065 is cut and one line is brought from Potato Run to McDevitt and other from Oak Green to Mt. Pony. The lines have a small greenfield component but is majorly colocated with the double-circuit lines going to Kyser substation.	5/15/2028	\$58.00	Dominion	2/4/2025
	S3684.4	Convert the 115 kV lines from Remington to Potato Run and Oak Green to Potato Run to 230 kV. No rebuild required.	5/15/2028	\$41.70	Dominion	2/4/2025
	S3684.5	Oak green is currently a 115 kV substation. When line No. 1065 is converted, we need to expand Oak Green. Due to space constraints at existing station, Oak Green is relocated.	5/15/2028	\$36.70	Dominion	2/4/2025
	S3684.6	Potato Run is a solar facility connected to the 115 kV line. When this line is converted, Potato Run must change their transformers and other equipment to interface with the new voltage.	5/15/2028	\$1.60	Dominion	2/4/2025
	S3684.7	For the conversion of line from 115 kV to 230 kV, a new breaker must be added at the 230 side in Remington station. Also, the 115 side of the line No. 70 should be removed.	5/15/2028	\$2.40	Dominion	2/4/2025
12	S3686.1	Cut, reroute ~0.9 mile and loop the future 230 kV line No. 2399 (Cloud to Raines) in and out of the proposed Nebula switching station.	11/1/2028	\$29.40	Dominion	5/6/2025
	S3686.2	Line No. 2399 and line No. 2402 to terminate into a 230 kV breaker-and-a-half configuration with fourteen 230 kV, 4000 amp breakers. Ten of these breakers will be paid for by the customer (cost not included here).	11/1/2028	\$19.20	Dominion	5/6/2025
13	S3687.1	Upgrade existing distribution transformer No. 1 to 84 MVA and add four-breaker 230 kV ring bus per DE Facility Interconnect Requirements.	1/1/2026	\$10.10	Dominion	4/1/2025

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Table 6.61: Virginia Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
14	S3693.1	Interconnect the new Devlin substation by cutting and extending line No. 2163 (Vint Hill-Dawkins Branch) to the proposed Devlin substation. Terminate both ends into a GIS 230 kV four-breaker arrangement expandable to an ultimate of nine 230 kV GIS breakers in a breaker-and-a-half scheme.	5/1/2026	\$42.00	Dominion	7/9/2024
	S3693.2	Construct two 230 kV transmission lines on a shared tower structure for ~2.9 miles from Devlin to Pegasus substation with a minimum summer normal conductor rating of 1572 MVA. Acquisition of new right-of-way will be required.	6/15/2029	\$73.00	Dominion	12/3/2024
	S3693.3	Install 230 kV breakers and associated equipment (i.e., switches, leads) at both Devlin and Pegasus substations to accommodate the termination of the lines.	6/15/2029	\$15.00	Dominion	12/3/2024
	S3699.3	String one 230 kV transmission line on shared tower structures for ~7.0 miles from Devlin to Vint Hill substation with a minimum summer normal conductor rating of 1573 MVA. The 230 kV circuit will be installed along the existing line No. 2161/No. 2346 corridor between Gainesville and Wheeler, and the existing line No. 2174 corridor between Wheeler and Vint Hill on the empty side of the double-circuit tower structures constructed under b4000.304 -310. Acquisition of ~0.25 miles of right-of-way will be required from Devlin to the existing line No. 2161/No. 2346 corridor.	6/1/2029	\$0.00	Dominion	12/3/2024
	S3699.4	Install 230 kV GIS breakers and associated equipment (i.e., switches, leads) at Vint Hill substation to accommodate the termination of the lines.	6/1/2029	\$0.00	Dominion	12/3/2024
	S3699.5	Install 230 kV GIS breakers and associated equipment (i.e., switches, leads) at Devlin to accommodate the termination of the lines.	6/1/2029	\$0.00	Dominion	12/3/2024
15	S3695.1	Construct Centreport 230 kV switching station with four-breaker ring bus configuration. Cut line No. 2104 (Spartan-Cranes Corner) and extend double-circuit 230 kV lines for ~2.5 miles to Centreport switching station.	7/1/2027	\$30.00	Dominion	8/6/2024
16	S3696.1	Install two 1200 amp, 50 kAIC circuit switchers and associated equipment (bus, relaying, etc.) to feed the new transformers at Cloverhill.	3/1/2027	\$1.00	Dominion	10/8/2024
17	S3697.1	Interconnect new NIT substation by tapping line No. 257 (Sewells Point-Churchland) near structure 257/56,2099/56 and extend a single-circuit 230 kV tap to NIT substation.	12/31/2024	\$5.70	Dominion	11/6/2024
18	S3699.1	Interconnect the proposed Bristow substation by extending two 230 kV tie lines between Hornbaker and Bristow. Due to being directly adjacent to Hornbaker substation, the termination of the 230 kV line between Nokesville and Hornbaker substations (DOM-2022-0045-DNH) will be reconfigured to terminate into Bristow. Lines to terminate into a 230 kV six-breaker ring arrangement.	4/30/2028	\$13.50	Dominion	12/3/2024
	S3699.2	Interconnect the proposed Bristow substation by extending two 230 kV tie lines between Hornbaker and Bristow. Due to being directly adjacent to Hornbaker substation, the termination of the 230 kV line between Nokesville and Hornbaker substations (DOM-2022-0045-DNH) will be reconfigured to terminate into Bristow. Lines to terminate into a 230 kV six-breaker ring arrangement.	4/30/2028	\$0.50	Dominion	12/3/2024
19	S3700.1	Interconnect the new substation by cutting and extending line No. 2187 (Liberty-Hornbaker) and line No. 9306 (Pioneer-Hornbaker) to the proposed site, terminating two 230 kV lines in and out of Pegasus substation. Lines to terminate into a six-breaker 230 kV breaker-and-a-half AIS configuration, expandable to an ultimate of nine breakers.	4/14/2027	\$25.00	Dominion	12/3/2024
	S3700.2	Interconnect the new substation by cutting and extending line No. 2187 (Liberty-Hornbaker) and line No. 9306 (Pioneer-Hornbaker) to the proposed site, terminating two 230 kV lines in and out of Pegasus substation. Lines to terminate into a six-breaker 230 kV breaker-and-a-half AIS configuration, expandable to an ultimate of nine breakers.	4/14/2027	\$3.50	Dominion	12/3/2024
20	S3701.1	Construct Allman switching station north of existing Fredericksburg substation, to accommodate ten, 230 kV line terminals (six north, four south) in five strings of a breaker-and-a-half arrangement. GIS equipment will be utilized due to limited space.	6/1/2029	\$60.00	Dominion	8/6/2024

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Table 6.61: Virginia Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
	S3701.2	Rebuild line No. 2157 ~4.5 miles, Allman to Cranes Corner, with double-circuit structures and a minimum summer conductor rating of 1573 MVA. Rebuild line No. 2083 ~0.7 miles, Allman to Hospital Junction, with double-circuit structures and a minimum summer conductor rating of 1573 MVA. Expand Cranes Corner substation to accommodate a new backbone for line realignment. Construct a second 230 kV double-circuit pole line ~12 miles, Aquia Harbour to Possum Point. ~41 lattice structures (~7.1 miles) of adjacent 500 kV line No. 568 will be replaced with monopole structures to accommodate the new 230 kV double-circuit structures in the corridor. Install two additional 230 kV lines in the corridor, with a minimum summer rating of 1573 MVA, by utilizing the vacant arm positions on the double-circuit structures that will be created by rebuilding the existing single-circuit structures from Fredericksburg to Aquia Harbour and the new double-circuit structures from Aquia Harbour to Possum Point. Reconfigure the 230 kV terminals at Possum Point to accommodate the two new line terminations.	6/1/2029	\$120.00	Dominion	8/6/2024
21	S3704.1	Interconnect the new substation by cutting and extending line No. 2176 (Heathcote-Gainesville) to the proposed Old Limb substation, directly adjacent to the existing Youngs Branch substation.	8/1/2027	\$35.00	Dominion	9/13/2024
22	S3705.1	Install two 1200 amp, 50 kAIC circuit switchers and associated equipment (bus, relaying, etc.) to feed the new transformers at Brickyard substation.	12/1/2026	\$1.00	Dominion	9/13/2024
23	S3721.1	Construct Tributary 230 kV switching station with a four-breaker ring bus configuration.	4/1/2027	\$11.70	Dominion	6/3/2025
	S3721.2	Cut line No. 2090 (New Post-Ladysmith CT) and extend double-circuit 230 kV lines for ~2.4 miles to Tributary Switching station.	4/1/2027	\$20.60	Dominion	6/3/2025
24	S3722.1	Interconnect the new substation by cutting and extending line No. 2094, (Racefield-Loudoun) ~0.2 mile to the proposed Reed Farm substation.	9/30/2026	\$7.00	Dominion	6/3/2025
	S3722.2	Potato Run is a solar facility connected to the 115 kV line. When this line is converted, Potato Run must change their transformers and other equipment to interface with the new voltage.	9/30/2026	\$12.00	Dominion	6/3/2025
	S3722.3	Install a new double-circuit consisting of two 230 kV transmission lines. Terminate both lines between Azalea Lane and Reed Farm (South Fork) substations. At Azalea Lane substation, install the remaining two breakers and any associated substation equipment required to build out the six-breaker ring ultimate arrangement. At Reed Farm (South Fork) substation, install the remaining two breakers and any associated substation equipment required to build out the six-breaker ring ultimate arrangement.	12/31/2029	\$20.00	Dominion	6/3/2025

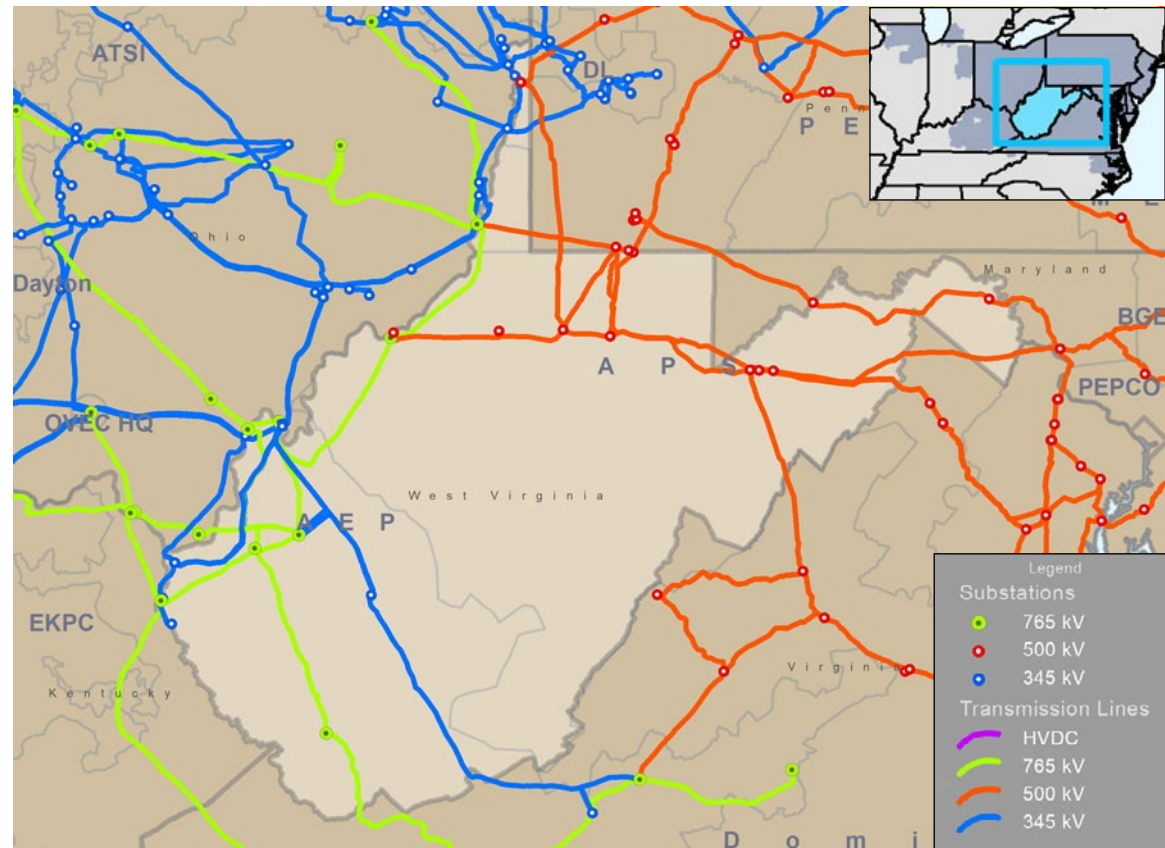
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## 6.13: West Virginia RTEP Summary

### 6.13.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in West Virginia, including facilities owned and operated by Allegheny Power (FirstEnergy) (AP) and American Electric Power (AEP) as shown on **Map 6.50**. West Virginia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of the PJM service area.

Map 6.50: PJM Service Area in West Virginia

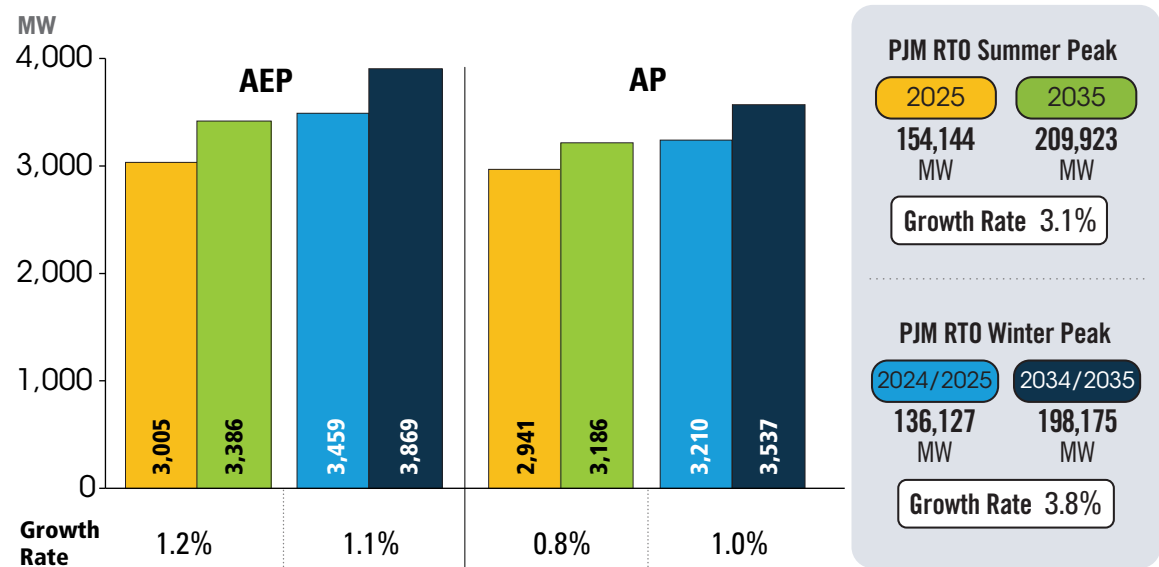


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### 6.13.2 — Load Growth

PJM's 2025 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2025 analyses. **Figure 6.60** summarizes the expected loads within the state of West Virginia and across the PJM region.

**Figure 6.60:** West Virginia – 2025 Long-Term Load Forecast



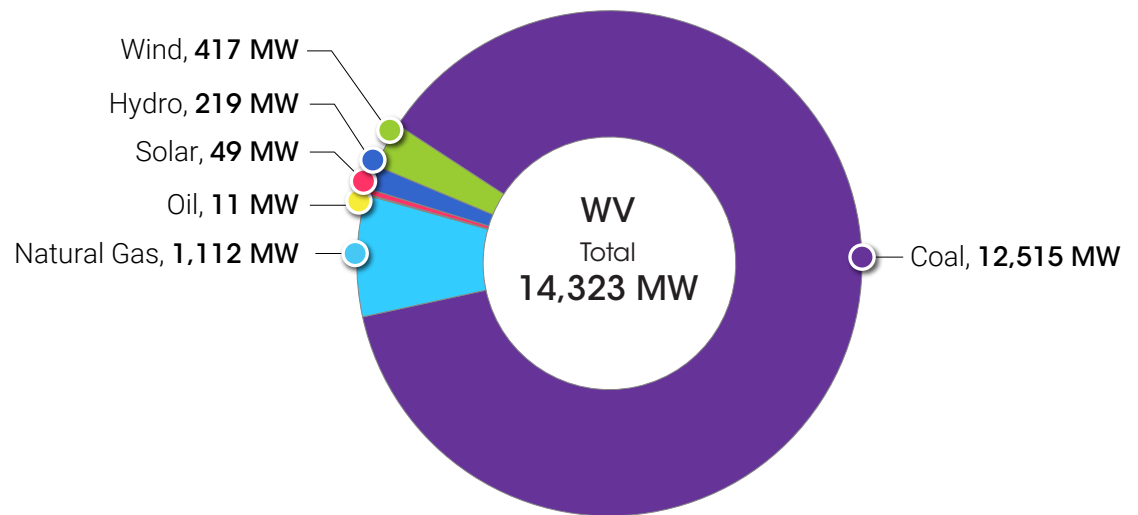
PJM notes that AEP and AP serve load other than in West Virginia. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in West Virginia. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in West Virginia over the past five years.

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### 6.13.3 — Existing Generation

Existing generation in West Virginia as of Dec. 31, 2025, is shown by fuel type in **Figure 6.61**.

**Figure 6.61:** West Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2025)



### 6.13.4 — Interconnection Requests

In West Virginia, as of Dec. 31, 2025, 56 projects were actively under study, under construction or suspended as shown in the summaries presented in **Table 6.62**, **Table 6.63**, **Figure 6.62**, **Figure 6.63** and **Figure 6.64**.

**Table 6.62:** West Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2025)

	West Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Biomass	0.0	0.00%	10.0	0.01%
Coal	14.0	0.21%	14.0	0.01%
Hybrid	1,136.2	16.95%	14,332.3	12.76%
Hydro	30.0	0.45%	30.0	0.03%
Natural Gas	3,950.0	58.94%	11,082.0	9.87%
Nuclear	0.0	0.00%	1,305.9	1.16%
Oil	50.0	0.75%	50.0	0.04%
Other	0.0	0.00%	56.3	0.05%
Solar	991.8	14.80%	40,116.0	35.73%
Storage	30.0	0.45%	29,376.0	26.16%
Wind	499.7	7.46%	15,910.7	14.17%
<b>Grand Total</b>	<b>6,701.6</b>	<b>100%</b>	<b>112,283.3</b>	<b>100%</b>

**NOTE:**

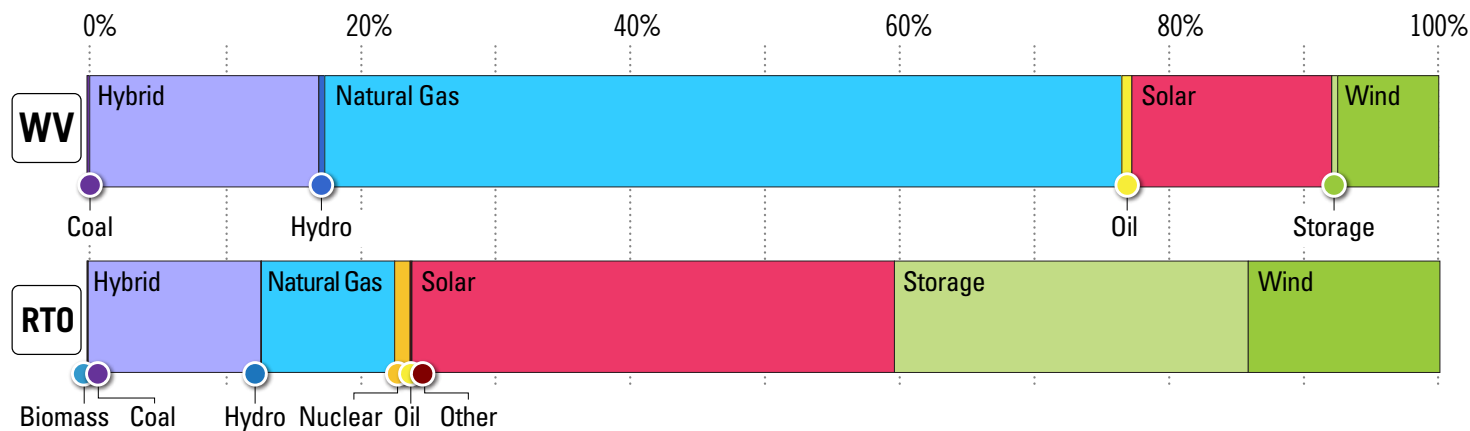
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in [Manual 21](#).

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**Table 6.63:** West Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2025)

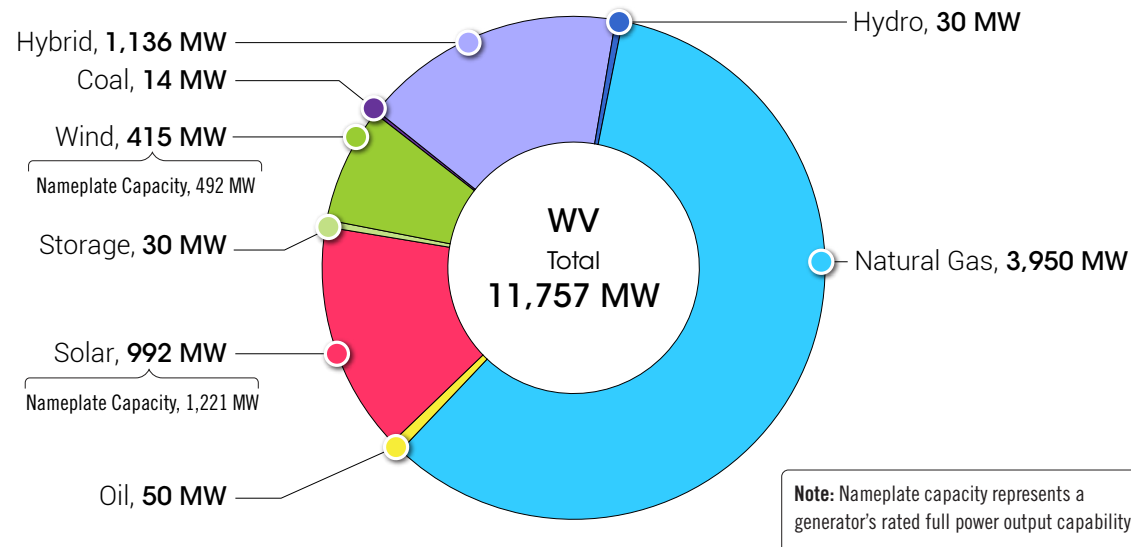
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	1	14.0	0	0.0	0	0.0	11	897.0	7	2,023.0	19	2,934.0
	Natural Gas	2	2,115.0	1	1,235.0	3	600.0	6	409.7	44	16,536.8	56	20,896.5
	Oil	0	0.0	0	0.0	1	50.0	0	0.0	0	0.0	1	50.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	2	66.0	2	66.0
	Storage	1	30.0	0	0.0	0	0.0	0	0.0	21	1,173.1	22	1,203.1
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	2	48.0	2	48.0
	Hybrid	6	1,080.2	0	0.0	1	56.0	1	37.2	18	1,321.5	26	2,494.8
	Hydro	0	0.0	0	0.0	1	30.0	5	59.2	13	208.8	19	298.0
	Methane	0	0.0	0	0.0	0	0.0	3	5.6	3	13.8	6	19.4
	Solar	20	622.4	2	112.3	4	257.1	2	49.1	44	2,194.4	72	3,235.3
	Wind	12	487.9	1	11.8	0	0.0	10	175.4	27	426.5	50	1,101.6
<b>Grand Total</b>		<b>42</b>	<b>4,349.5</b>	<b>4</b>	<b>1,359.1</b>	<b>10</b>	<b>993.1</b>	<b>38</b>	<b>1,633.2</b>	<b>181</b>	<b>24,011.8</b>	<b>275</b>	<b>32,346.7</b>

**Figure 6.62:** West Virginia – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2025)

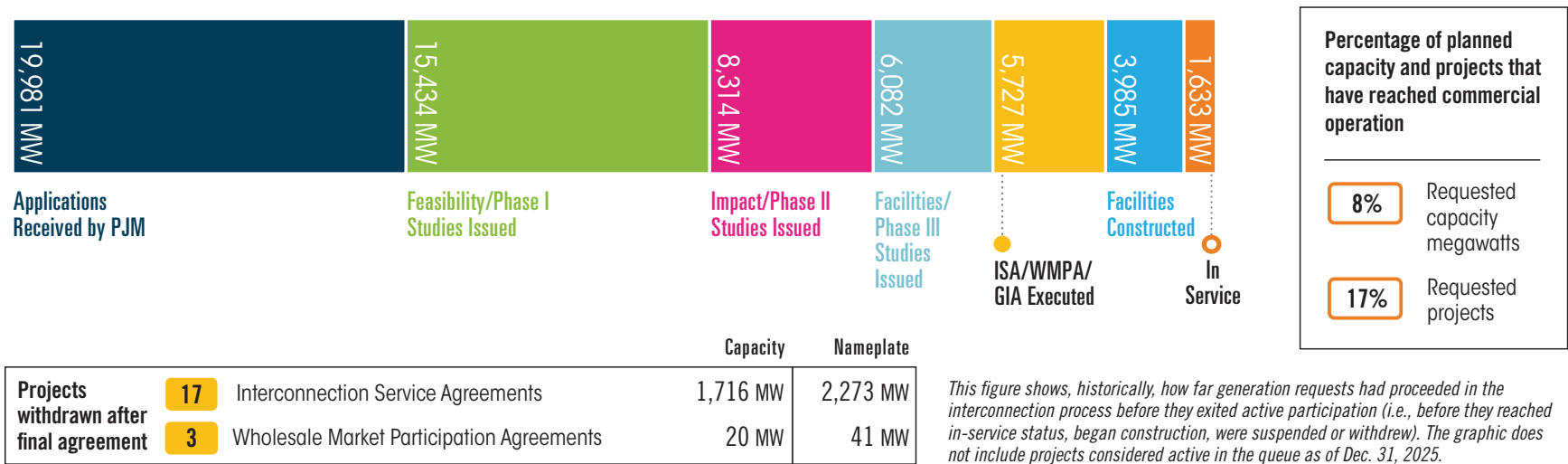


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**Figure 6.63:** West Virginia Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2025)



**Figure 6.64:** West Virginia Progression of Interconnection Requests (Dec. 31, 2025)

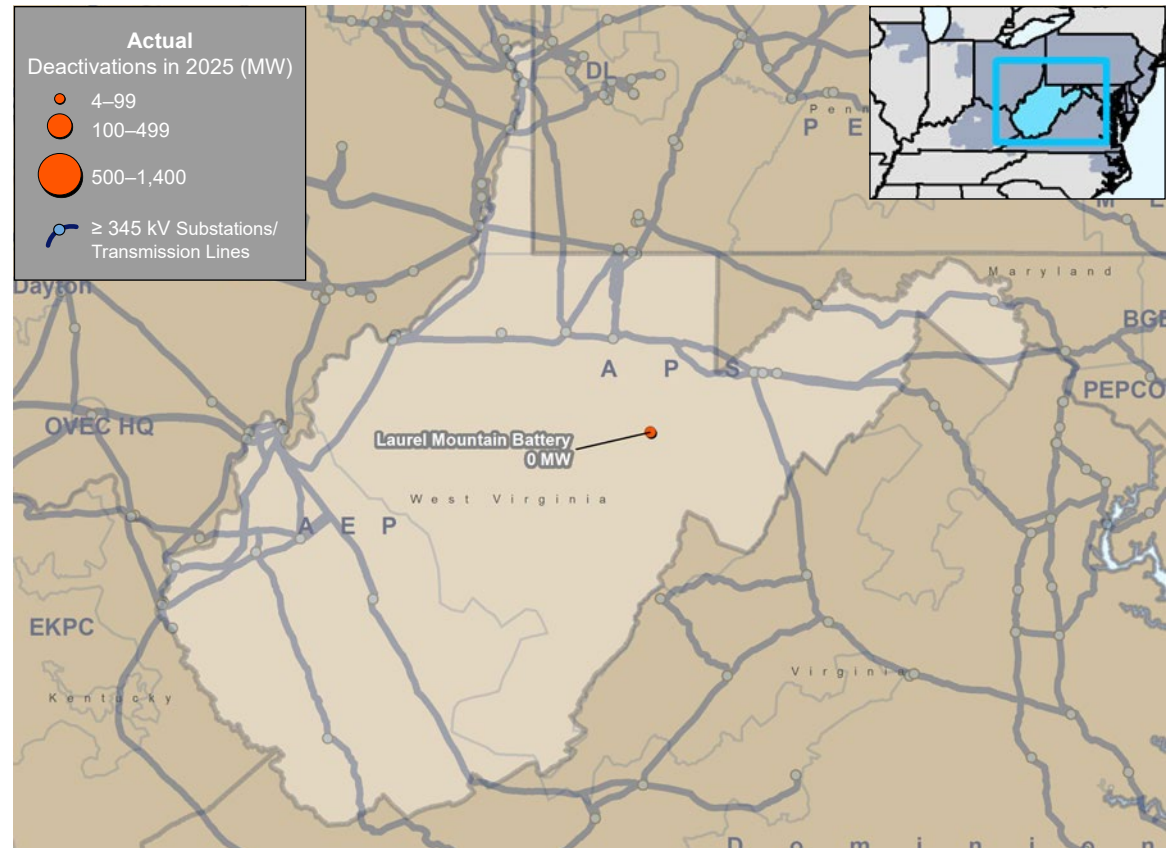


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**6.13.5 — Generation Deactivation**

Formal generator deactivations and requests received by PJM in West Virginia between Jan. 1, 2025, and Dec. 31, 2025, are summarized in **Map 6.51** and **Table 6.64**.

**Map 6.51:** West Virginia Generation Deactivations (Dec. 31, 2025)



**Table 6.64:** West Virginia Generation Deactivations (Dec. 31, 2025)

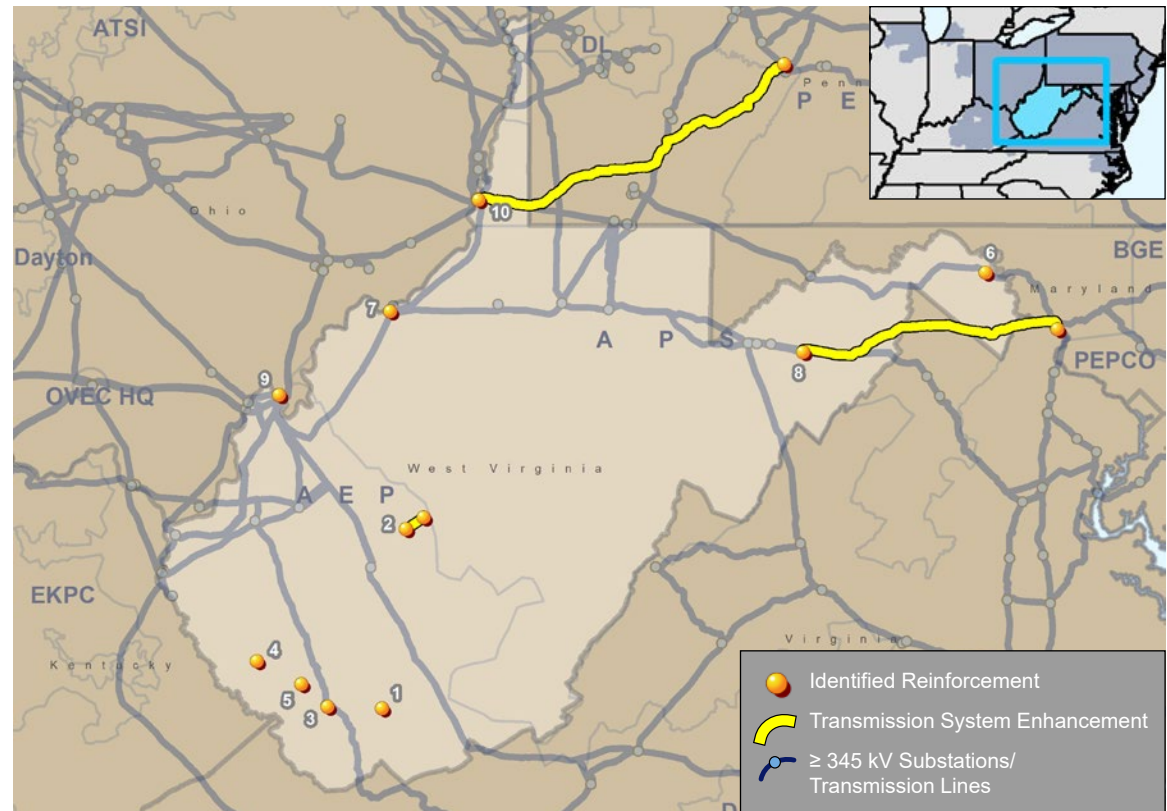
Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Laurel Mountain Battery	AP	Battery	4/1/2025	7/1/2025	14	0

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### 6.13.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2025 RTEP in West Virginia are summarized in **Map 6.52** and **Table 6.65**.

**Map 6.52:** West Virginia Baseline Projects (Dec. 31, 2025)



**Table 6.65:** West Virginia Baseline Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
1	B3945.1	Adjust Mullens 138 kV cap bank Vhi setting to 1.04. Adjust protection settings as needed at the station.	12/1/2030	\$0.10	AEP	11/14/2025	No	Baseline Load Growth Deliverability & Reliability
2	B3946.1	Adjust existing Jarrett 138/46 kV transformer tap to 1:1 to boost voltages on the sub-transmission network.	4/15/2030	\$0.10	AEP	11/14/2025	No	TO Criteria Violation
	B3946.2	Adjust the existing Hartland 46 kV cap bank Vhi setting to 1.04.	4/15/2030	\$0.10	AEP	11/14/2025	No	
3	B3947.1	Remove cans on existing Baileysville 46 kV cap bank to reduce it to 7.2 MVAR.	12/1/2030	\$0.10	AEP	11/14/2025	No	TO Criteria Violation

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Table 6.65: West Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
4	B3949.1	Change XF tap settings at Chauncey station to boost the sub-transmission voltage.	4/15/2030	\$0.10	AEP	11/14/2025	No	TO Criteria Violation
5	B3949.2	Change the XF tap settings at Huff Creek station to boost the sub-transmission voltage.	4/15/2030	\$0.10	AEP	11/14/2025	No	TO Criteria Violation
6	B3976.1	Install foundation, conduit and grounding for new equipment at Bedington substation. Install three 138 kV surge arresters. Replace one existing 138 kV CVT with three 138 kV CVTs, and replace one lot of limiting conductor while installing one lot of cables and grounding. Replace one existing 138 kV Eagle line terminal relay panel and breaker failure with one standard line relaying panel consisting of one SEL-421, one SEL-411L and one SEL-451.	6/1/2030	\$1.96	AP	11/14/2025	No	Baseline Load Growth Deliverability & Reliability
7	B3983.2	Belmont substation – Replace B-8 138 kV circuit breaker with a 63 kA, 3000A breaker. This will not affect the line ratings of the Belmont-Trissler 138 kV 604 line, which is currently rated at 176/229 SN/SE or the Belmont-Edgelawn 138 kV line, which is currently rated at 292/314 SN/SE.	6/1/2030	\$0.96	AP	11/14/2025	No	Short Circuit
	B4036.6	Upgrade Belmont terminal of Mountaineer-Belmont 765 kV line.	6/1/2032	\$0.00	AP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
8	B4000.15	Construct a new 86-mile Welton Spring to Rocky Point 765 kV line (Welton Spring to DVP local area, roughly 50 miles) (WV Portion).	6/1/2029	\$248.50	AP	6/5/2025	N/A - Scope Change	Baseline Load Growth Deliverability & Reliability
9	B4036.5	Upgrade Mountaineer terminal of Mountaineer-Belmont 765 kV line.	6/1/2032	\$1.03	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
10	B4036.7	Perform Kammer substation work for new Kammer-Buttermilk Falls 765 kV line termination.	6/1/2032	\$16.80	AEP	1/6/2026	Yes (Reliability W1)	Baseline Load Growth Deliverability & Reliability
	B4036.8	Construct a new single-circuit 765 kV transmission line between Kammer and proposed Buttermilk Falls substations (AEP Zone). The total length of the line is 114 miles.	6/1/2032	\$96.98	KJT	1/6/2026	Yes (Reliability W1)	
	B4036.9	Construct a new single-circuit 765 kV transmission line between Kammer and proposed Buttermilk Falls substations (AP Zone). The total length of the line is 114 miles.	6/1/2032	\$571.11	KJT	1/6/2026	Yes (Reliability W1)	
	B4036.10	Construct a new single-circuit 765 kV transmission line between Kammer and proposed Buttermilk Falls substations (PENELEC Zone). The total length of the line is 114 miles.	6/1/2032	\$26.63	KJT	1/6/2026	Yes (Reliability W1)	
	B4068.43	Kammer Dumont structures: Lower the existing Kammer to Dumont 765 kV line between structure 169 and 170 to facilitate crossing the proposed Conesville to Guernsey 765 kV line.	6/1/2030	\$2.00	AEP	1/6/2026	Yes (Reliability W1)	

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Table 6.65: West Virginia Baseline Projects (Dec. 31, 2025) (Cont.)

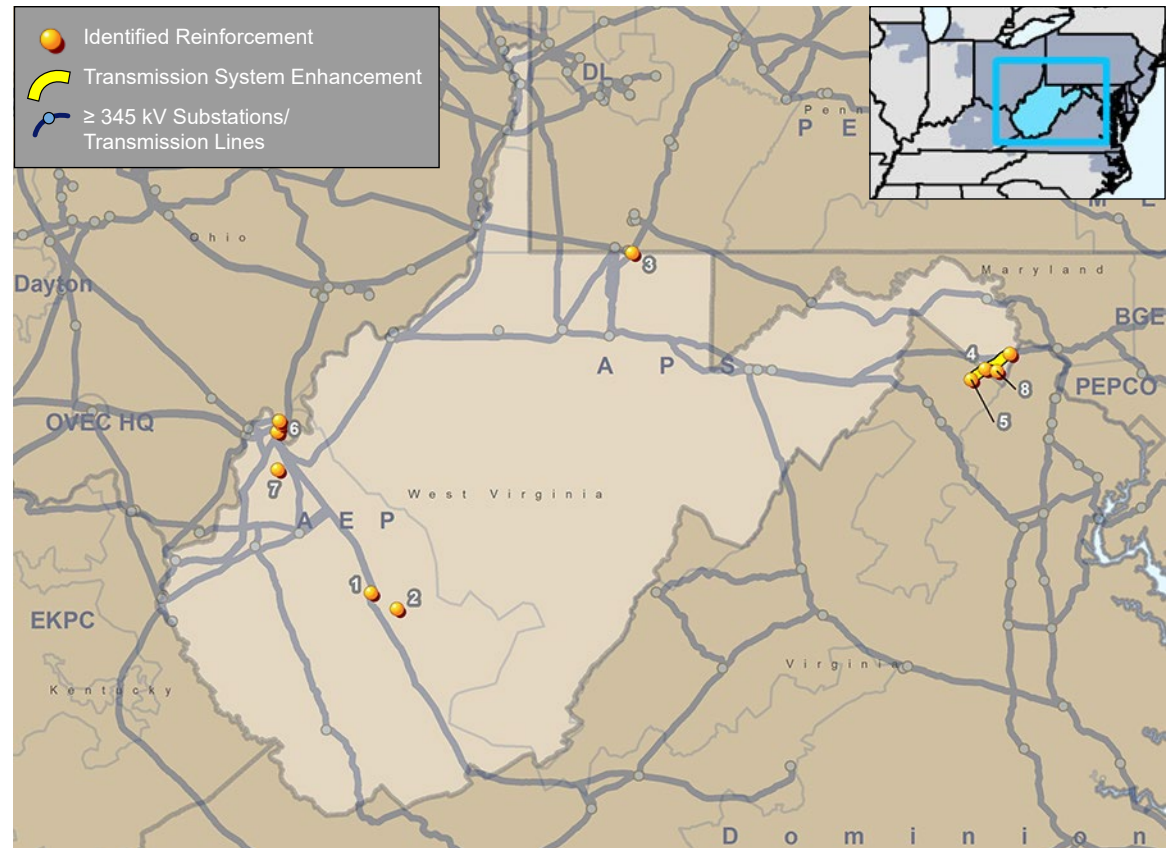
Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost (\$M)	TO	TEAC Date	Included in 2025 RTEP Window 1	Driver
CELL	B3936.7	AEP Zone 2024W1 P5 Solution #7: Install battery chargers & associated equipment at AEP substation. Addresses the following flowglates: 2024-P5-AEP06.	6/1/2029	\$0.15	AEP	7/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B3937.28	2024W1 DVP P5 Solution #28 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP30.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B3937.7	2024W1 DVP P5 Solution #7 – DC Supply Monitoring. Addresses flowgate # 2024-P5-DVP07.	6/1/2029	\$0.02	Dominion	7/8/2025	No	
	B4038.1	2024W1 P5: Modify relay wiring. Addresses flowgate No. 2024-P5-AP02.	6/1/2029	\$0.66	AP	12/8/2025	No	
	B4039.2	2024W1 P5: Replace one relay panel at a confidential substation connected to the substation associated with b4039.1. Addresses flowgate No. 2024-P5-AP24.	6/1/2029	\$0.00	AP	12/8/2025	No	
	B4039.4	2024W1 P5: Replace one relay panel at a confidential substation connected to the substation associated with b4039.1. Addresses flowgate No. 2024-P5-AP24.	6/1/2029	\$0.00	AP	12/8/2025	No	
	B4060.1	2024W1 P5: Install open-circuit battery monitoring, install relay panel, modify relay wiring. Addresses flowgate No. 2024-P5-AP01.	6/1/2029	\$1.14	AP	12/8/2025	No	Stability
	B4063.1	2024W1 P5: Install battery monitoring, DC panel(s); replace bus differential scheme and modify relay wiring. Addresses flowgate No. 2024-P5-AP22.	6/1/2029	\$1.29	AP	12/8/2025	No	Baseline Load Growth Deliverability & Reliability
	B4064.1	2024W1 P5: Install battery monitoring, relay panels; modify relay wiring. Addresses flowgate No. 2024-P5-AP23.	6/1/2029	\$1.94	AP	12/8/2025	No	

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**6.13.7 — Network Projects**

Network projects in West Virginia for 2025 are summarized in **Map 6.53** and **Table 6.66**.

**Map 6.53:** West Virginia Network Projects (Dec. 31, 2025)



**Table 6.66:** West Virginia Network Projects (Dec. 31, 2025)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	N8817.0	Expand Kanawha River 138 kV substation.	AE2-160	5/31/2028	\$0.54	AEP	10/8/2025
	N8431	Install CCVTs on the Alloy 138 kV line exit at Kanawha River station. Replace P&C relays.	AE2-160	10/1/2021	\$0.38	AEP	10/8/2025
2	N8437	Install 138 kV metering at Alloy 34.5 kV station.	AE2-160	10/1/2021	\$0.62	AEP	10/8/2025
	N8818.0	Install new revenue metering on a new structure inside Alloy 34.5 kV station.	AE2-160	5/31/2028	\$0.89	AEP	10/8/2025

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Table 6.66: West Virginia Network Projects (Dec. 31, 2025) (Cont.)

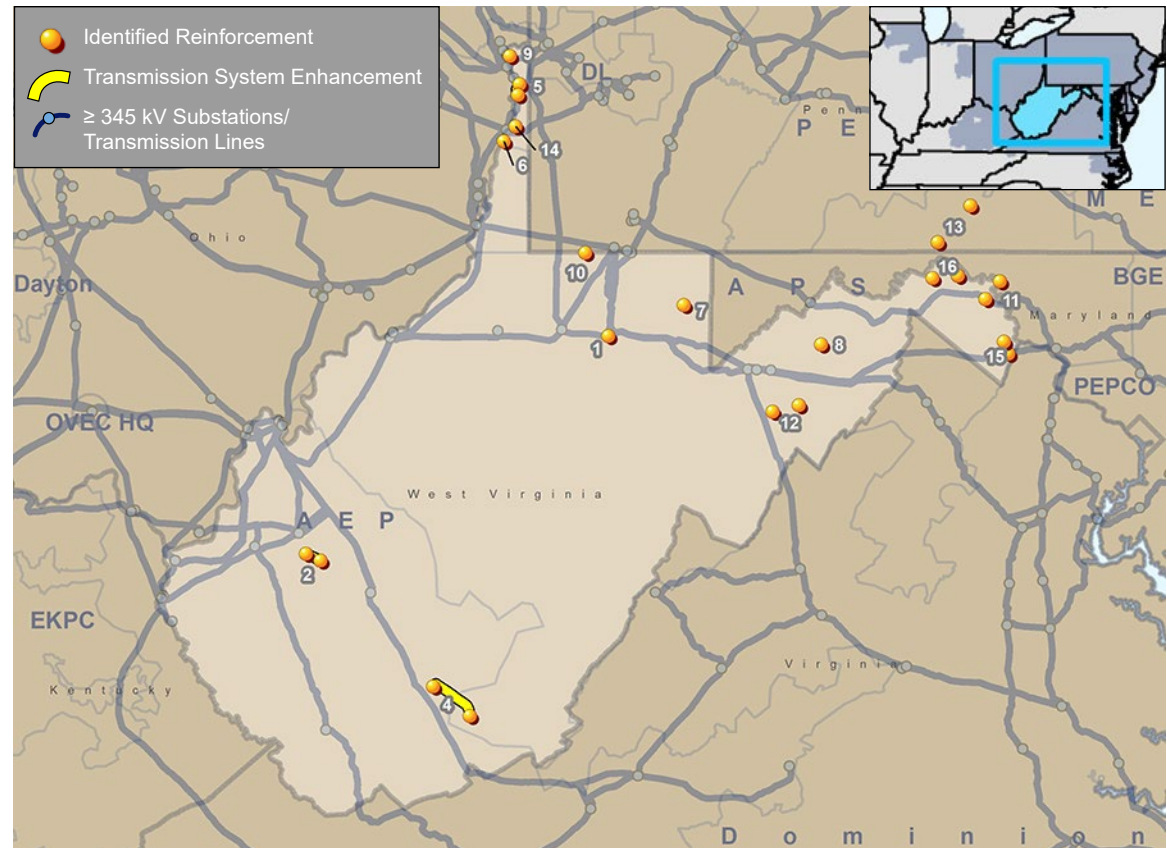
Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
3	N8545	Revise relay settings at Fort Martin substation.	AF2-029	10/1/2027	\$0.06	AP	10/8/2025
4	N8669.0	Update relay settings at Millville substation.	AG1-415	4/30/2027	\$0.04	AP	10/8/2025
	N8670.0	Update relay settings at AG1-307 substation.	AG1-415	4/30/2027	\$0.04	AP	10/8/2025
	N8669.0	Update relay settings at Millville substation.	AG1-415	4/30/2027	\$0.04	AP	10/8/2025
	N8857.0	Construct new three-breaker ring bus on the Millville-Old Chapel (Double Toll Gate) 138 kV line for AG1-307 Interconnection substation.	AG1-307	11/1/2027	\$9.52	AP	10/8/2025
	N8858.0	Design, installation, and testing/commissioning for MPLS equipment for SCADA transport at AG1-307 substation.	AG1-307	11/1/2027	\$0.23	AP	10/8/2025
	N8859.0	Cut and loop in the Millville-Old Chapel (Double Toll Gate) 138 kV line to the interconnection substation for AG1307, ~0.1 mile.	AG1-307	11/1/2027	\$0.84	AP	10/8/2025
	N8861.0	Update relay settings at Millville substation.	AG1-307	11/1/2027	\$0.05	AP	10/8/2025
5	N8860.0	Update relay settings at Double Toll Gate substation.	AG1-307	11/1/2027	\$0.06	AP	10/8/2025
6	N8992.0	Tie-in the proposed 138 kV station into existing Sporn South-Leon circuit (APCo).	AF2-291	3/31/2028	\$7.34	AEP	10/8/2025
	N8993.0	Replace existing protective relays with new fiber-based ICON MUX current differential relays at Sporn South 138 kV station (APCo).	AF2-291	3/31/2028	\$0.38	AEP	10/8/2025
	N8994.0	Reconfigure existing ICON with one new Small Form-Factor Pluggable (SFP) transceiver at Sporn 345 kV station (APCo).	AF2-291	3/31/2028	\$0.03	AEP	10/8/2025
	N8995.0	Reconfigure existing ICON with one new SFP transceiver at Mountaineer 765 kV station (APCo).	AF2-291	3/31/2028	\$0.03	AEP	10/8/2025
	N8997.0	Fiber installation in existing right-of-way for AF2-291 interconnection.	AF2-291	3/31/2028	\$0.31	AEP	10/8/2025
	N8998.0	Final tie in for fiber installation in new ROW for AF2-291 interconnection.	AF2-291	3/31/2028	\$0.07	AEP	10/8/2025
	N9000.0	New three, expandable to four, breaker 138 kV ring bus substation.	AF2-291	3/31/2028	\$7.10	AEP	10/8/2025
7	N8996.0	Review and revise (as needed) protective relay settings at Leon 138 kV station (APCo).	AF2-291	3/31/2028	\$0.03	AEP	10/8/2025
8	N9086.0	Install ~3.15 miles of new 48-count OPGW/ADSS fiber solution between the planned AE2-226 Kabletown interconnecting substation and the planned AG1-307 interconnecting substation.	AG1-307	11/1/2027	\$0.69	AP	10/8/2025

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**6.13.8 — Supplemental Projects**

Supplemental projects included in the 2025 Local Plan in West Virginia are summarized in **Map 6.54** and **Table 6.67**.

**Map 6.54:** West Virginia Supplemental Projects (Dec. 31, 2025)



**Table 6.67:** West Virginia Supplemental Projects (Dec. 31, 2025)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
1	S3574.1	At Pruntytown substation, replace the existing 500/138 kV transformer No. 3. Replace transformer conductor, circuit breakers, disconnect switches and relaying.	12/31/2029	\$15.77	AP	1/7/2025
	S3653.1	Replace No. 2 500/138 kV transformer at Pruntytown substation. Replace two 138 kV circuit breakers. Replace one 500 kV disconnect switch. Replace substation conductor.	12/13/2030	\$18.80	AP	4/1/2025
	S3655.1	Replace No. 1 500/138 kV transformer at Pruntytown substation. Replace one 500 kV disconnect switch.	6/13/2031	\$18.80	AP	4/1/2025

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Table 6.67: West Virginia Supplemental Projects (Dec. 31, 2025) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost (\$M)	TO Zone	TEAC Date
2	S3606.1	Rebuild existing Turner-Ward Hollow 46 kV line sections from Turner station to str. 359-213 (0.8 mi) and from str. 359-203 to str. 1189-24 (3.3 mi) and from str. 359-174 to str. 718-2 (1.8 mile double circuit). Higher than normal costs are driven by a river crossing and limited route options in a heavily congested industrial corridor on the double-circuit section.	8/1/2027	\$30.40	AEP	3/14/2025
	S3606.2	Replace existing 46 kV circuit breakers B, C and D with new 3000A 40 kA circuit breakers.	8/1/2027	\$2.70	AEP	3/14/2025
3	S3607.1	Replace existing 138 kV circuit breakers A, B, C, with three new 138 kV, 3000A 40 kA circuit breakers. Replace switch "W" on the FirstEnergy tie line with a new 138 kV, 3000 A 40 kA circuit breaker. 37 of the 40 relays are in need of replacement (28 EM, four static and five MP). Replace the existing RTU. Install a new DICM. Upgrade existing metering on tie with First Energy.	11/5/2029	\$6.30	AEP	3/14/2025
	S3607.2	Remote end work at Grandview station to accommodate the new breakers at Hinton station.	11/5/2029	\$0.60	AEP	3/14/2025
4	S3642.1	At Buckhannon, replace circuit breaker, disconnect switch, substation conductor, wave trap, line turner and coax, and relaying.	3/30/2029	\$3.55	AP	2/14/2025
	S3642.2	At French Creek, replace circuit breaker, disconnect switch, substation conductor, wave trap, line turner and coax, and relaying.	3/30/2029	\$3.55	AP	2/14/2025
5	S3643.1	At Weirton, replace circuit breaker, disconnect switches, wave trap, substation conductor, line turner and coax, and relaying.	4/27/2029	\$3.52	AP	2/14/2025
	S3643.2	At Wylie Ridge, replace circuit breaker, disconnect switches, wave trap, substation conductor, line turner and coax, and relaying.	4/27/2029	\$3.52	AP	2/14/2025
	S3654.1	Replace No. 7 500/345 kV transformer at Wylie Ridge substation. Replace one 500 kV disconnect switch. Replace one 345 kV disconnect switch.	12/13/2030	\$20.00	AP	4/1/2025
6	S3644.1	At Windsor, replace substation conductor, line turner and coax, and relaying.	11/20/2026	\$1.05	AP	2/14/2025
7	S3645.1	At Albright, replace circuit breaker, disconnect switches, wave trap and relaying.	8/20/2029	\$1.69	AP	2/14/2025
8	S3646.1	Rebuild ~22 miles of the Black Oak-Junction 138 kV line.	12/14/2029	16.27	AP	3/14/2025
9	S3646.3	At Junction substation, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying.	12/14/2029	\$16.27	AP	3/14/2025
10	S3647.1	Replace the obsolete line switch 1017 with 1200A rated switch and install motor operator. Replace two-pole structure 212-81 at Arroyo Junction.	5/9/2025	\$1.10	AP	3/14/2025
11	S3658.1	Replace the switch 1027 at Blacksville No. 1 Tap with a motor-operated, SCADA-controlled switch.	8/21/2026	\$1.30	AP	4/11/2025
12	S3667.1	At Marlowe substation, replace disconnect switches, substation conductor, line trap, surge arresters and relaying. At Bedington substation, replace circuit breakers, disconnect switches, substation conductor, line trap, surge arresters, CVT and relaying.	7/26/2029	\$4.00	AP	5/16/2025
13	S3668.1	At Hardy substation, replace circuit breaker, disconnect switches, substation conductor, line trap, surge arresters, CVT and relaying. At North Petersburg substation, replace disconnect switches, substation conductor, line trap, surge arresters, CVT and relaying.	7/27/2029	\$5.20	AP	5/16/2025
14	S3708.1	At Cherry Run substation, replace circuit breaker, disconnect switches, line turner and coax, CVT, substation conductor and relaying. At Warfordsburg substation, replace disconnect switches, and relaying. At McConnellsburg substation, replace circuit breaker, disconnect switches, line turner, CCVT, substation conductor and relaying.	7/13/2029	\$2.50	AP	6/13/2025
15	S3710.1	At Carnegie substation, replace disconnect switches, CVTs and relaying. At Weirton substation, replace wave trap, substation conductor, line turner and coax, CVT and relaying.	12/31/2029	\$1.90	AP	6/13/2025
16	S3711.1	At Sleepy Hollow, replace disconnect switches, line trap, line turner and coax, CCVT, metering, substation conductor and line relaying. At Millville, replace disconnect switches, line trap, line turner and coax, CCVT, substation conductor and line relaying.	1/31/2027	\$2.00	AP	7/18/2025
17	S3712.1	At Morgan, replace disconnect switches, line trap, substation conductor and line relaying. At Cherry Run, replace circuit breaker, line trap, substation conductor and line relaying.	7/21/2029	\$2.30	AP	7/18/2025

[View state summaries:](#)

# Appendix 1: TO Zones and Locational Deliverability Areas

## 1.0: TO Zones and Locational Deliverability Areas

The terms transmission owner zone and Locational Deliverability Area, as used in this report, are defined below and shown on **Map 1.1**. They are provided for the convenience of the reader based on definitions from other sources.

A transmission owner (TO) is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a TO. [Schedule 15](#) of the Reliability Assurance Agreement defines the distinct zones that the PJM control area comprises and is available on the PJM website.

A Locational Deliverability Area (LDA) is an electrically cohesive area defined by transmission zones, parts of zones or combination of zones. LDAs are used as part of PJM’s RTEP process load deliverability test. They are restated in **Table 1.1**.

Map 1.1: Locational Deliverability Areas

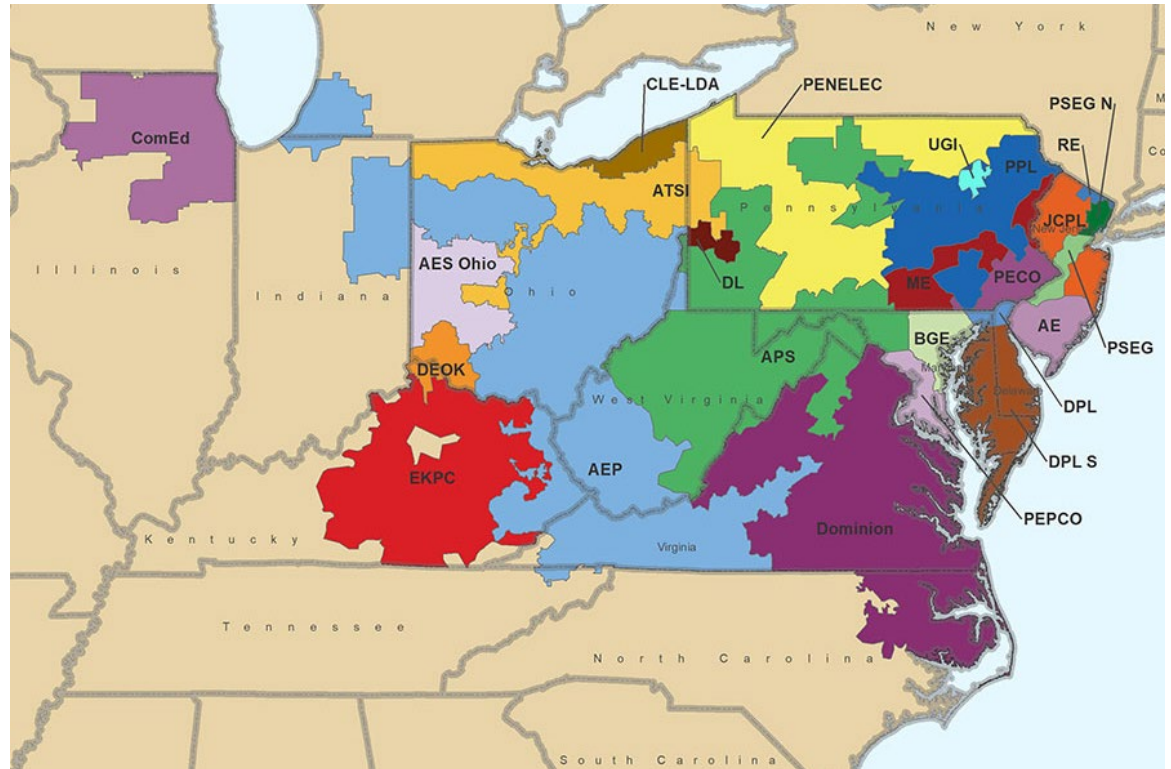


Table 1.1: Locational Deliverability Areas

Entity Name	TO Zone	LDA	Description
AE	▲	▲	Atlantic City Electric
AEP	▲	▲	American Electric Power
AP	▲	▲	Allegheny Power (FirstEnergy)
ATSI	▲	▲	American Transmission Systems, Inc. (FirstEnergy)
BGE	▲	▲	Baltimore Gas and Electric
Cleveland	n/a	▲	Cleveland Area
ComEd	▲	▲	Commonwealth Edison
AES Ohio	▲	▲	AES Ohio
DEO&K	▲	▲	Duke Energy Ohio and Kentucky
DLCO	▲	▲	Duquesne Light Company
Dominion	▲	▲	Dominion Energy
DP&L	▲	▲	Delmarva Power
Delmarva South	n/a	▲	Southern portion of Delmarva Power
Eastern Mid-Atlantic	n/a	▲	Global area: JCP&L, PECO, PSEG, AE, DP&L, RECO
EKPC	▲	▲	East Kentucky Power Cooperative
JCP&L	▲	▲	Jersey Central Power & Light
METED	▲	▲	Met-Ed
Mid-Atlantic	n/a	▲	Global area: PENELEC, METED, JCP&L, PPL, PECO, PSEG, BGE, PEPCO, AE, DP&L, RECO
PECO	▲	▲	PECO Energy Company
PENELEC	▲	▲	Pennsylvania Electric Company (Penelec)
PEPCO	▲	▲	Potomac Electric Power Company (Peppo)
PPL	▲	▲	PPL Electric Utilities
PSEG	▲	▲	Public Service Electric & Gas Company (PSEG)
PSEG North	n/a	▲	Northern portion of PSEG
Southern Mid-Atlantic	n/a	▲	Global area: BGE and PEPCO
Western Mid-Atlantic	n/a	▲	Global area: PENELEC, METED, PPL
Western PJM	n/a	▲	Global area: AP, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC, OVEC

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# Glossary

The terms and concepts in this glossary are provided for the convenience of the reader and are in large part based on definitions from other sources, as indicated in the “Reference” column for each term.

These references include the following:

- **Mxx:** [PJM Manual](#)
- **NERC:** [North American Electric Reliability Corporation](#)
- **OA:** [PJM Operating Agreement](#)
- **OATT:** [PJM Open Access Transmission Tariff](#)
- **RAA:** [Reliability Assurance Agreement](#)

Term	Reference	Acronym	Definition
<b>Adequacy</b>	NERC		Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency. “Resources” refers to a combination of electricity generation and transmission facilities, which produce and deliver electricity, and “demand response” programs, which reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
<b>Aluminum Conductor Steel Reinforced</b>		ACSR	This high-capacity, stranded conductor type is typically made with a core of steel (for its strength properties), surrounded by concentric layers of aluminum (for its conductive properties).
<b>Aluminum Conductor Steel Supported</b>		ACSS	This high capacity, stranded conductor type is made from annealed aluminum.
<b>All-Dielectric Loose Tube</b>		ADLT	This is a type of station that has fiber-optic cables installed that serve as a vital communication link for protection and control systems.
<b>All-Dielectric Self Supporting</b>		ADSS	This non-metallic, aerial fiber-optic cable supports its own weight, eliminating the need for messenger wires. The cable provides high-speed data communication and is typically installed in a single pass on overhead poles.
<b>Air-Insulated Substation</b>		AIS	An air-insulated substation is a high-voltage substation in which the major electrical components are contained within a sealed environment with air as the insulating medium.
<b>Ancillary Service</b>	OATT		Ancillary services are those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider’s transmission system.
<b>Annual Demand Resources</b>			Demand resources can be called on an unlimited number of times any day of the delivery year, unless on an approved maintenance outage. Product type ceases to exist following the commencement of Capacity Performance rules.
<b>Attachment Facilities</b>	OATT		Attachment facilities are necessary to physically connect a customer facility to the transmission system or interconnected distribution facilities.
<b>Auction Revenue Right</b>	OA	ARR	An auction revenue right is a financial instrument entitling its holder to auction revenue from financial transmission rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the annual FTR auction.
<b>Available Transfer Capability</b>	NERC	ATC	The available transfer capability is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
<b>Base Capacity Resource</b>	M18		Base capacity resources are capacity resources that are not capable of sustained, predictable operation throughout the entire delivery year. These resources will only be procured through the 2019/2020 Delivery Year, at which point all resources will be Capacity Performance resources starting with the 2020/2021 Delivery Year. See “Capacity Performance.”
<b>Baseline Upgrades</b>	M14B		In developing the RTEP, PJM tests the baseline adequacy of the transmission system to deliver energy and capacity resources to each load in the PJM region. The system (as planned to accommodate forecast demand, committed resources and commitments for firm transmission service for a specified time frame) is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, nuclear plant licensee requirements, PJM reliability standards and PJM design standards. Areas not in compliance with the standards are identified, and enhancement plans to achieve compliance are developed. Baseline expansion plans serve as the base system for conducting feasibility studies and system impact studies for all proposed requests for generation and merchant transmission interconnection, and for long-term firm transmission service.

Term	Reference	Acronym	Definition
<b>Behind-the-Meter Generation</b>	OATT	BTM	Behind-the-meter generation delivers energy to load without using the transmission system or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of PJM), provided, however, that behind-the-meter generation does not include (1) at any time, any portion of such generating unit's capacity that is designated as a capacity resource, or (2) in an hour, any portion of the output of such generating unit(s) sold to another entity for consumption at another electrical location or in to the PJM Interchange Energy Market.
<b>Bilateral Transaction</b>	OA		A bilateral transaction is a contractual arrangement between two entities (one or both being PJM members) for the sale and delivery of a service.
<b>Breaker-and-a-Half</b>		BAAH	This substation configuration type is typically composed of two main sections connected by element strings. Each element string is composed of circuit breakers, transformers or line elements.
<b>Bulk Electric System</b>	NERC, M14B	BES	ReliabilityFirst defines the bulk electric system as all individual generation resources larger than 20 MVA, or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher, lines operated at voltages of 100 kV or higher, associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment). The ReliabilityFirst BES definition excludes: (1) radial facilities connected to load-serving facilities or individual generation resources smaller than 20 MVA, or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher; (2) the balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and step-up transformer), which would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions; and (3) all other facilities operated at voltages below 100 kV.
<b>Coupling Capacitor Voltage Transformer/Capacitor Voltage Transformer</b>		CCVT/CVT	This type of transformer is used to step down high-voltage signals and provide a low-voltage signal for metering or protection devices.
<b>Capacity Emergency</b>	M13		A capacity emergency is a system condition where operating capacity plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet the total of its demand, firm sales and regulating requirements.
<b>Capacity Emergency Transfer Limit</b>	RAA, M14B, M18	CETL	The capacity emergency transfer limit is part of load deliverability analysis used to determine the maximum limit, expressed in megawatts, of a study area's import capability, under the conditions specified in the load deliverability criteria.
<b>Capacity Emergency Transfer Objective</b>	RAA, M14B, M18, M20	CETO	The CETO is the emergency import capability, expressed in megawatts, required of a PJM subregion area to satisfy established reliability criteria.
<b>Capacity Interconnection Rights</b>	OATT	CIRs	Capacity interconnection rights are rights to input generation as a capacity resource into the transmission system at the point of interconnection, where the generating facilities connect to the transmission system.
<b>Capacity Performance</b>			Capacity Performance is a set of rules governing resource participation in the Reliability Pricing Model (RPM). Following a series of transition auctions, Capacity Performance rules will be fully in place starting with the 2020/2021 Delivery Year. See "Base Capacity Resource" and "Capacity Performance Resource."
<b>Capacity Performance Resource</b>	M18		Capacity Performance resources are capable of sustained, predictable operation throughout the entire delivery year. All resources will be Capacity Performance resources starting with the 2020/2021 Delivery Year. See "Capacity Performance."
<b>Capacity Resource</b>	RAA, M14A, M14B		Capacity resources are megawatts of net capacity from existing or planned generation resources or load reduction capability provided by demand resources or interruptible load for reliability (ILR) in the region PJM serves.
<b>Carrier Ethernet Switch</b>		CES	A carrier Ethernet switch is a networking device used to deliver standardized, scalable and reliable data transport service that combines the flexibility of Ethernet with carrier-grade operational management and service protection.
<b>Certificate of Public Convenience and Necessity</b>		CPCN	This is a permit granted to a Transmission Owner that authorizes it to provide service to a new geographic area.
<b>Circuit Breaker</b>		CB	This automatic device is used to stop the flow of current in an electric circuit as a safety measure.
<b>Clean Air Interstate Rule</b>		CAIR	The Clean Air Interstate Rule is an Environmental Protection Agency (EPA) rule regarding the interstate transport of soot and smog.
<b>Clean Power Plan</b>		CPP	The Clean Power Plan is an EPA rule regarding carbon pollution from power plants.
<b>Coincident Peak</b>	M19		The coincident peak is a zone's contribution to the RTO or higher level locational deliverability area (LDA) peak load.

Term	Reference	Acronym	Definition
<b>Combined Cycle (Turbine)</b>		CC/CCT	This type of turbine is a generating unit facility that generally consists of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
<b>Combustion Turbine</b>		CT	A combustion turbine is a generating unit in which a combustion turbine engine is the prime mover.
<b>Consolidated Transmission Owners Agreement</b>	PJM.com	CTOA	The Consolidated Transmission Owners Agreement is an agreement between transmission owners, which PJM is a signatory to, establishing the rights and commitments of all parties involved.
<b>Contingency</b>			A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
<b>Coordinated System Plan</b>		CSP	A Coordinated System Plan (CSP) contains the results of coordinated PJM/MISO studies required to assure the reliable, efficient and effective operation of the transmission system. The CSP also includes the study results for interconnection requests and long-term firm transmission service requests. Further description of CSP development can be found in the PJM/MISO Joint Operating Agreement.
<b>Cost of New Entry</b>	M18	CONE	The cost of new entry is a Reliability Pricing Model (RPM) capacity market parameter defined as the levelized annual cost in installed capacity \$/MW-day of a reference combustion turbine to be built in a specific locational deliverability area.
<b>Cross-Linked Polyethylene</b>		XLPE	This is a type of plastic used to insulate power lines; benefits include resistance to temperature fluctuations and other environmental factors.
<b>Cross-State Air Pollution Rule</b>		CSAPR	The Cross-State Air Pollution Rule is an EPA rule regarding reduction in air pollution related to power plant emissions.
<b>Current Transformer</b>		CT	This type of transformer is used to measure electrical flows for purposes of telemetry.
<b>Cycle</b>	OATT		That period of time between the start of an Application phase and conclusion of the corresponding Final Agreement Negotiation Phase. The Cycle consists of the Application Phase, Phase I, Decision Point I, Phase II, Decision Point II, Phase III, Decision Point III, and the Final Agreement Negotiation Phase.
<b>Deactivation</b>	M14D		Deactivation encompasses retiring or mothballing a generating unit governed by the PJM Open Access Transmission Tariff. Any generator owner, or designated agent, who wishes to retire a unit from PJM operations must initiate a deactivation request in writing no less than 90 days in advance of the planned deactivation date.
<b>Decision Point I</b>	OATT		The time period that commences on the first Business Day immediately following Phase I of a Cycle, and shall end within 30 calendar days; however, if the 30th does not fall on a Business Day, this time period shall conclude on the next Business Day.
<b>Decision Point II</b>	OATT		The time period that commences on the first Business Day immediately following Phase II of a Cycle, and shall end within 30 calendar days; however, if the 30th does not fall on a Business Day, this time period shall conclude on the next Business Day.
<b>Decision Point III</b>	OATT		The time period that commences on the first Business Day immediately following Phase III of a Cycle, and shall end within 30 calendar days; however, if the 30th does not fall on a Business Day, this time period shall conclude on the next Business Day.
<b>Deliverability</b>	RAA, M14B, M18		Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver energy from generation facilities to wherever it is needed to ensure only that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) generation deliverability and (2) load deliverability.
<b>Demand Resource</b>	M18	DR	See "Load Management."
<b>Designated Entity</b>			A designated entity can be an existing transmission owner or non-incumbent transmission developer designated by PJM with the responsibility to construct, own, operate, maintain and finance immediate-need reliability projects, short-term projects, long-lead projects, or economic-based enhancements or expansions.
<b>Designated Entity Agreement</b>	OATT	DEA	When a project is designated as a greenfield project that is not reserved for the transmission owner, execution of a Designated Entity Agreement (DEA) is required. The DEA defines the terms, duties, accountabilities and obligations of each party, and relevant project information, including project milestones. Once construction is complete and the designated entity has met all DEA requirements, the agreement is no longer needed. The designated entity must execute the Consolidated Transmission Owners Agreement as a requirement for DEA termination. Once a project is energized, a designated entity that is not already a transmission owner must become a transmission owner, subject to the Consolidated Transmission Owners Agreement.
<b>Direct Transfer Trip</b>		DTT	This is a relay protection scheme that sends a signal from one substation to another to trip circuit breakers upon detecting severe faults, such as transformer failure, bus faults or breaker failure.
<b>Directional Comparison Blocking</b>		DCB	This is a high-speed protective relaying scheme for transmission lines. Dual DCB generally refers to an enhanced, redundant or dual-polarized blocking logic.

Term	Reference	Acronym	Definition
<b>Distributed Solar Generation</b>			Distributed solar generation is not connected to PJM and does not participate in PJM markets. These resources do not go through the full interconnection queue process. The output of these resources is netted directly with the load. PJM does not receive metered production data from any of these resources.
<b>Distribution Factor</b>		DFAX	A distribution factor is the portion of an imposed power transfer that flows across a specified transmission facility or interface.
<b>Diversity</b>	M18		Diversity is the number of megawatts that account for the difference between a transmission owner zone's forecasted peak load at the time of its own peak and its coincident load at the time of the PJM peak.
<b>Double-Breaker Double-Bus</b>		DBDB	This is a substation configuration that has two independent buses, where each circuit is connected to both buses through two dedicated circuit breakers.
<b>Drop-In Control Module</b>		DICM	This is a pre-manufactured, factory-tested, modular electrical control house designed for rapid, on-site installation at substations.
<b>Eastern Interconnection Planning Collaborative</b>		EIPC	The Eastern Interconnection Planning Collaborative (EIPC) represents an interconnection-wide transmission planning coordination effort among planning authorities in the Eastern Interconnection. EIPC consists of 20 planning coordinators comprising approximately 95% of the Eastern Interconnection electricity demand. EIPC coordinates analysis of regional transmission plans to ensure their coordination and also provides the resources to conduct analysis of emerging issues affecting the grid.
<b>Eastern Interconnection Reliability Assessment Group</b>		ERAG	The ERAG is a group whose purpose is to further augment the reliability of the bulk power system in the Eastern Interconnection through periodic studies of seasonal and longer-term transmission system conditions.
<b>Eastern MAAC</b>	M14B	EMAAC	Eastern MAAC is a term used in PJM deliverability analysis to refer to the portion of PJM that includes AE, DP&L, JCP&L, PECO, PSE&G and Rockland.
<b>Effective Forced Outage Rate on Demand</b>	M22	EFORd	EFORd is a measure of the probability that a generating unit will not be available due to forced outages or forced de-ratings when there is a demand on the unit to generate. See Manual 22: Generator Resource Performance Indices for the equation.
<b>Electrical Distribution Company</b>		EDC	An electrical distribution company owns and/or operates electrical distribution facilities for the delivery of electrical energy to end-use customers.
<b>End-Use Characteristics</b>	M19		End-use characteristics are the measures of electrical equipment and appliance efficiency used in residential and commercial settings. These are represented in forecast models as part of heating, cooling and other applications.
<b>Energy Efficiency Programs</b>		EE	Energy efficiency programs are incentives or requirements at the state or federal level, which promote energy conservation and wise use of energy resources.
<b>Energy Resource</b>	M14A, M14B		An energy resource is a generating facility that is not a capacity resource.
<b>Extended Summer Demand Resources</b>			Extended summer demand resources can be called on as many times as needed from 10 a.m. to 10 p.m., any day from June through October and during the following May of that delivery year. Product ceases to exist following the commencement of Capacity Performance rules.
<b>Extra High Voltage</b>		EHV	Extra high voltage transmission equipment operates at 230 kV and above.
<b>Facilities Study Agreement</b>	M14A	FSA	A facilities study agreement is an agreement made between the interconnection customer/developer and PJM to identify the scope of facility additions and upgrades to be included in the interconnection study.
<b>Fault</b>			A fault is a physical condition that results in the failure of a component or facility within the transmission system to transmit electrical power in the manner for which it was designed.
<b>Federal Energy Regulatory Commission</b>		FERC	FERC is an independent federal agency that regulates the interstate transmission of electricity, natural gas and oil.
<b>Financial Transmission Right</b>	M6	FTR	A financial transmission right is a financial instrument entitling the holder to receive revenues based on transmission congestion, measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
<b>Firm Transmission Service</b>	OATT		Firm transmission service is intended to be available at all times to the maximum extent practical. Service availability is subject to system emergency conditions, unanticipated facility failure or other unanticipated events and is governed by Part II of the OATT.
<b>Fixed Series Capacitor</b>		FSC	A fixed series capacitor is a grouping of capacitors used to reduce transfer reactances on bulk transmission corridors.
<b>Flexible Alternating Current Transmission System</b>		FACTS	FACTS is a system composed of static equipment used for the AC transmission of electrical energy, meant to enhance controllability and increase power transfer capability of the network. It is generally a power electronics-based system.
<b>Flowgate</b>			A flowgate is a specific combination of a monitored facility and a contingency that impacts that monitored facility.

Term	Reference	Acronym	Definition
<b>Gas-Insulated Substation</b>		GIS	This is a high-voltage substation in which the major electrical components are contained within a sealed environment with sulfur hexafluoride gas as the insulating medium.
<b>Generation Deliverability</b>	M14B		Generation deliverability is the ability of the transmission system to export capacity resources from one electrical area to the remainder of PJM. The generator deliverability test for reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the transmission system is capable of delivering the aggregate system generating capacity at peak load with all firm transmission uses modeled.
<b>Generator Step-up Transformer</b>		GSU	A GSU transformer “steps-up” generator power output voltage level to the suitable grid-level voltage for transmission of electricity to load centers.
<b>Geomagnetically Induced Current</b>		GIC	This is a manifestation at ground level of space weather; these currents impact the normal operation of electrical conductor systems.
<b>Good Utility Practice</b>	OATT		Good Utility Practice is any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be practices, methods or acts generally accepted in the region.
<b>Group/Gang-Operated Air Break</b>		GOAB	A group/gang operated air break is the portion of a circuit breaker that opens and closes to allow or block current to flow through or not. This particular type of break uses air as a dielectric medium, as opposed to others that use gas, oil or air contained within a vacuum. “Gang operated” refers to a mechanical linkage that opens and closes the disconnect.
<b>Horizontal Directional Drilling</b>		HDD	Horizontal directional drilling technology for laying transmission cable employs a long, flexible drill bit to bore horizontally underground. This is a trenchless method in which no surface excavation is required except for drill entry and exit points, which minimizes surface restoration, ecological disturbances and environmental impacts. By contrast, jet-plowing techniques affect the riverbed over the length of the installation.
<b>Integrated Communications Optical Network</b>		ICON	This is a system/platform that provides deterministic transport for critical protection relay traffic.
<b>Integrated Communications Optical Network Multiplexor</b>		ICON MUX	This is an industrial-hardened, modular multiplexer designed specifically for utility communications, providing deterministic transport for critical protection relay traffic.
<b>Independent State Agencies Committee</b>	PJM.com	ISAC	The ISAC is a voluntary, stand-alone committee that consists of members from regulatory and other state agencies representing all of the states and the District of Columbia within the service territory of PJM. The ISAC is an independent committee that is not controlled or directed by PJM, the PJM Board or PJM members. The purpose of the ISAC is to provide PJM with input and scenarios for transmission planning studies.
<b>Independent System Operator</b>		ISO	An independent system operator is an entity that is authorized to operate an electric transmission system and is independent of any influence from the owner(s) of that electric transmission system. See also “RTO.”
<b>Installed Capacity</b>		ICAP	Installed capacity is valued based on the summer net dependable rating of the unit as determined in accordance with PJM rules and procedures relating to the determination of generating capacity.
<b>Interconnected Reliability Operating Limit</b>	M14B	IROL	The interconnected reliability operating limit is a system operating limit that, if violated, could lead to instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk electric system.
<b>Interconnection Construction Service Agreement</b>	M14C	ICSA	The ICSA is a companion agreement to the ISA and is necessary for projects that require the construction of interconnection facilities as defined in the ISA. The ICSA details the project scope, construction responsibilities of the involved parties, ownership of transmission and customer interconnection facilities, and the schedule of major construction work.
<b>Interconnection Coordination Agreement</b>	OATT	ICA	An interconnection coordination agreement is made between transmission owners and/or transmission developers outlining the schedules and responsibilities of each party involved.
<b>Interconnection Process Reform Task Force</b>		IPRTF	A task force within PJM’s stakeholder process seeking to make improvements to the Interconnection Process
<b>Interconnection Service Agreement</b>	M14A	ISA	An interconnection service agreement is made among the transmission provider, an interconnection customer and an interconnected transmission owner regarding interconnection under Part IV and Part VI of the Tariff.
<b>Interregional Market Efficiency Project</b>		IMEP	Interregional proposals are designed to address congestion and its associated costs along the MISO/PJM border within the context of the MISO/PJM JOA as identified in long-term market efficiency simulation results.
<b>Joint RTO Planning Committee</b>		JRPC	The JRPC is the decision-making body for MISO/PJM coordinated system planning as governed by the MISO/PJM Joint Operating Agreement.

Term	Reference	Acronym	Definition
<b>Kilo-Ampere Interrupting Capacity</b>		kAIC	This is a rating that measures a circuit breaker or switch to interrupt high-level fault currents.
<b>Light Load Reliability Analysis</b>	M14B		Light load reliability analysis ensures that the transmission system is capable of delivering the system generating capacity during a light load situation (50% of 50/50 summer peak demand level).
<b>Limited Demand Resources</b>			Limited demand resources can be called on up to 10 times from noon to 8 p.m. on weekdays, other than NERC holidays, from June through September. Product type ceases to exist following the commencement of Capacity Performance rules.
<b>Load</b>			Load refers to demand for electricity at a given time, expressed in megawatts.
<b>Load Analysis Subcommittee</b>	M19	LAS	The Load Analysis Subcommittee is responsible for technical analysis and coordination of information related to the electric peak demand and energy forecasts, interruptible load resources for capacity, credit and weather, and peak load studies. The LAS reports to the Planning Committee.
<b>Load Deliverability</b>	M14B		Load deliverability is the ability of the transmission system to deliver energy from the aggregate of available capacity resources in one PJM electrical area and adjacent non-PJM areas to another PJM electrical area that is experiencing a capacity deficiency.
<b>Load Management</b>	M18	LM	Load management is the ability to interrupt retail customer load at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. Load management derives a demand resource or interruptible-load-for-reliability credit in RPM.
<b>Load Serving Entity</b>	RAA, OATT	LSE	Load serving entities (LSE) provide electricity to retail customers. LSEs include traditional distribution utilities.
<b>Local Distribution Company</b>		LDC	A local distribution company (LDC) is a regulated utility involved in the delivery of natural gas to consumers within a specific geographic area. While some large industrial, commercial and electric generation customers receive natural gas directly from high-capacity pipelines, most other users receive natural gas from their LDCs.
<b>Locational Deliverability Area</b>	M14B	LDA	Locational deliverability areas are electrically cohesive load areas, historically defined by transmission owner service territories and larger geographical zones comprising a number of those service areas.
<b>Locational Marginal Price</b>		LMP	The locational marginal price is the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.
<b>Loss-of-Load Expectation</b>	M14B	LOLE	Loss-of-load expectation defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, during only one day in 10 years.
<b>Market Participant</b>			A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met credit requirements as established by PJM. Market buyers are able to make purchases and market sellers are able to make sales in PJM energy and capacity markets.
<b>Maximum Facility Output</b>	M14A, M14G	MFO	This term refers to the maximum amount of power a generator is capable of producing.
<b>Megavolt-Ampere Reactive</b>	OA	MVAR	See “Reactive Power.”
<b>Merchant Transmission Facility</b>	OATT		Merchant transmission facilities are AC or DC transmission facilities that are interconnected with, or added to, the transmission system in accordance with the PJM Open Access Transmission Tariff. These facilities are not existing facilities within the transmission system, transmission facilities included in the rate base of a public utility on which a regulated return is earned, or transmission facilities included in previous RTEPs or customer interconnection facilities.
<b>Mercury and Air Toxins Standards</b>		MATS	MATS is an EPA rule limiting the emissions of toxic air pollutants like mercury, arsenic and metals from power plant emissions.
<b>Mid-Atlantic Subregion</b>	M14B	MAAC	The PJM Mid-Atlantic Subregion encompasses 12 transmission owner zones: Atlantic City Electric (AE), Baltimore Gas and Electric (BGE), Delmarva Power (DP&L), Jersey Central Power and Light (JCP&L), Metropolitan Edison (METED), Neptune, PECO, Pennsylvania Electric Company (PENELEC), Potomac Electric Power Company (PEPCO), PPL Electric Utilities (PPL), Public Service Electric & Gas (PSEG) and Rockland Electric (Rockland). The Neptune Regional Transmission System interconnects with the Mid-Atlantic PJM transmission system at Sayreville substation in Northern New Jersey.
<b>MISO Transmission Expansion Planning</b>		MTEP	MTEP is the Midcontinent Independent System Operator (MISO) plan for enhancing the future of the power grid in their area.
<b>Motor-Operated Air Break</b>		MOAB	A motor-operated air break is the portion of a circuit breaker that opens and closes to allow or block current. This particular type of break uses air as a dielectric medium, as opposed to others that use gas, oil or air contained within a vacuum. “Motor operated” refers to a remote-controlled motorized linkage that opens and closes the disconnect.
<b>Motor-Operated Disconnect</b>		MOD	This refers to a type of switch that allows for remote opening and closing of circuits.

Term	Reference	Acronym	Definition
<b>Multiregional Model Working Group</b>		MMWG	The Multiregional Model Working Group reports to the ERAG and is responsible for developing all Eastern Interconnection power flow and dynamic base case models, including seasonal updates to summer and winter power flow study cases.
<b>National Renewable Energy Laboratory</b>		NREL	The NREL, part of the Department of Energy, is a federal laboratory dedicated to the research, development, commercialization and deployment of renewable energy and energy efficiency technologies.
<b>Network Reinforcements</b>	OATT		Network reinforcements are modifications or additions to transmission-related facilities that are integrated with and support the transmission provider's overall transmission system for the general benefit of all users of such transmission system.
<b>New Service Request(s)</b>	M14a		A general term describing all requests to PJM for generation or transmission service and/or rights (Formerly known as the "queue")
<b>Non-Coincident Peak</b>	M19	NCP	The non-coincident peak is a zone's individual peak load.
<b>North American Electric Reliability Corporation</b>	NERC	NERC	NERC is a FERC-appointed body whose mission is to ensure the reliability of the bulk power system.
<b>Open Access Same-Time Information System</b>		OASIS	The Open Access Same-Time Information System (OASIS) provides information by electronic means about available transmission capability for point-to-point service and a process for requesting transmission service on a non-discriminatory basis. OASIS enables transmission providers and transmission customers to communicate requests and responses to buy and sell available transmission capacity offered under the PJM Open Access Transmission Tariff.
<b>Open Access Transmission Tariff</b>	OATT	OATT	The OATT is a FERC-filed tariff specifying the terms and conditions under which PJM provides transmission service and carries out its generation and merchant transmission interconnection process.
<b>Optical Grounding Wire Communications</b>		OPGW	This is a type of fiber optic cable that is used in the construction of electric power transmission and distribution lines and that combines the functions of grounding and communications.
<b>Optimal Power Flow</b>		OPF	Optimal power flow is a tool used to determine optimal dispatch, subject to transmission constraints. Optimal often means most economical but may also mean "minimum control change."
<b>Organization of PJM States, Inc.</b>		OPSI	OPSI refers to an organization of statutory regulatory agencies in the 13 states and the District of Columbia within which PJM Interconnection operates. OPSI Member Regulatory Agencies' activities include, but are not limited to, coordinating activities such as data collection, issues analyses and policy formulation related to PJM, its operations, its market monitor and matters related to the FERC, as well as their individual roles as statutory regulators within their respective state boundaries.
<b>Phase I</b>	OATT		Starts on the first Business Day immediately after the close of the Application Phase of a Cycle, but no earlier than 30 calendar days following the distribution of the Phase I System Impact Study Base Case Data. During Phase I, Transmission Provider shall conduct the Phase I System Impact Study.
<b>Phase II</b>	OATT		Starts on the first Business Day immediately after the close of Decision Point I Phase unless the Decision Point III of the immediately preceding Cycle is still open. In no event, shall Phase II of a Cycle commence before the conclusion of Decision Point III of the immediately preceding Cycle. During Phase II, Transmission Provider shall conduct the Phase II System Impact Study.
<b>Phase III</b>	OATT		Starts on the first Business Day immediately after the close of Decision Point II, unless the Final Agreement Negotiation Phase of the immediately preceding Cycle is still open. In no event shall Phase III of a Cycle commence before the conclusion of the Final Agreement Negotiation Phase of the immediately preceding Cycle. During Phase III, Transmission Provider shall conduct the Phase III System Impact Study.
<b>PJM Manuals</b>			PJM Manuals contain the instructions, rules, procedures and guidelines established by PJM for the operation, planning and accounting requirements of the region PJM serves and the PJM Interchange Energy Market.
<b>PJM Member</b>	OA, M33		A PJM member is any entity that has satisfied PJM requirements to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
<b>Planning Committee</b>	OA	PC	The Planning Committee was established under the Operating Agreement to review and recommend system planning strategies and policies, as well as planning and engineering designs for the PJM bulk power supply system.
<b>Planning Cycle</b>	M14B		The planning cycle is the annual RTEP process, including a series of studies, analysis, assessments and related supporting functions.
<b>Planning Horizon</b>	M14B		The planning horizon is the future time period over which system transmission expansion plans are developed based on forecasted conditions.
<b>Probabilistic Risk Assessment</b>	M14B	PRA	PJM assesses risk exposure using a Probabilistic Risk Assessment (PRA) risk management tool. The goal of the PRA model is to minimize asset service cost. PJM's PRA method integrates the economics of facility loss with the likelihood of that loss occurring.
<b>Queue</b>	M14A		See New Service Request(s)

Term	Reference	Acronym	Definition
<b>Reactive Power (expressed in MVAR)</b>	M14A		Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is usually expressed as megavolt-ampere reactive (MVAR).
<b>Regional Greenhouse Gas Initiative</b>		RGGI	States and provinces in the northeastern United States and eastern Canada adopted the Regional Greenhouse Gas Initiative to reduce greenhouse gas emissions.
<b>Regional RTEP Project</b>	M14B, OA		A regional RTEP project is a transmission expansion or enhancement at a voltage level of 100 kV or higher.
<b>Regional Transmission Expansion Plan</b>	M14B	RTEP	The Regional Transmission Expansion Plan (RTEP) is prepared by PJM pursuant to Schedule 6 of the PJM Operating Agreement for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the region PJM serves.
<b>Regional Transmission Organization</b>	FERC	RTO	A regional transmission organization is an independent, FERC-approved organization of sufficient regional scope, which coordinates the interstate movement of electricity under FERC-approved tariffs by operating the transmission system and competitive wholesale electricity markets, and ensures reliability and efficiency through expansion planning and interregional coordination.
<b>Reliability</b>	NERC		A reliable bulk power system is one that is able to meet the electricity needs of end-use customers, even when unexpected equipment failures or other factors reduce the amount of available electricity.
<b>Reliability Assurance Agreement</b>	RAA	RAA	The Reliability Assurance Agreement (RAA) among load-serving entities in the region PJM serves is intended to ensure that adequate capacity resources will be planned and made available to provide reliable service to loads within PJM, to assist other parties during emergencies and to coordinate planning of capacity resources consistent with the reliability principles and standards.
<b>Reliability Must Run</b>		RMR	A reliability must run (RMR) generating unit is one slated to be retired by its owners but is needed to be available to maintain reliability. Typically, it is requested to remain operational beyond its proposed retirement date until required transmission enhancements are completed.
<b>Reliability Pricing Model</b>		RPM	The Reliability Pricing Model (RPM) is PJM's resource adequacy construct. The purpose of RPM is to develop a long-term pricing signal for capacity resources and load serving entity obligations that is consistent with the PJM RTEP process. RPM adds stability and a locational nature to the pricing signal for capacity.
<b>ReliabilityFirst Corporation</b>		RFC	ReliabilityFirst is a not-for-profit company incorporated in the state of Delaware, whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. ReliabilityFirst was approved by the North American Electric Reliability Corporation (NERC) to become one of eight Regional Reliability Councils in North America and began operations on Jan. 1, 2006. ReliabilityFirst is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council, the East Central Area Coordination Agreement and the Mid-American Interconnected Network.
<b>Remote Terminal Unit</b>		TRU	These are ruggedized, microprocessor-based substation devices that bridge physical field equipment with SCADA systems for data acquisition and control.
<b>Renewable Integration Study</b>		RIS	The RIS is an ongoing study to examine the reliability and market impacts of high wind and solar penetration in the PJM system to meet objectives of state policies regarding renewable resource production.
<b>Renewable Portfolio Standard</b>		RPS	The Renewable Portfolio Standard is a set of guidelines or requirements at the state or federal level requiring energy suppliers to provide specified amounts of electric energy from eligible renewable energy resources.
<b>Right of First Refusal</b>		ROFR or RFR	The right of first refusal is a contractual right that gives the holder the option to enter a business transaction with the owner of an asset, according to specified terms, before the owner is entitled to enter into that transaction with a third party.
<b>Right-of-Way</b>		ROW	A right-of-way is a corridor of land on which electric lines may be located. The transmission owner may own the land in fee; own an easement; or have certain franchise, prescription or license rights to construct and maintain lines.
<b>Security</b>	NERC		The ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by physical or cyberattacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.
<b>Security Constrained Optimal Power Flow</b>		SCOPF	The optimal power flow determines the ideal dispatch, subject to transmission constraints. Optimal usually means "least cost" (or most economical), but may also mean "minimum control change." Security-constrained OPF, or SCOPF, adds contingencies. The SCOPF will seek a single dispatch that does not cause any overloads in the base case, nor any overloads during any of the contingencies.
<b>Small Form-Factor Pluggable</b>		SFP	This is a type of transceiver used in network switches, routers and fiber-optic equipment to convert electrical signals to optical signals (or vice versa).

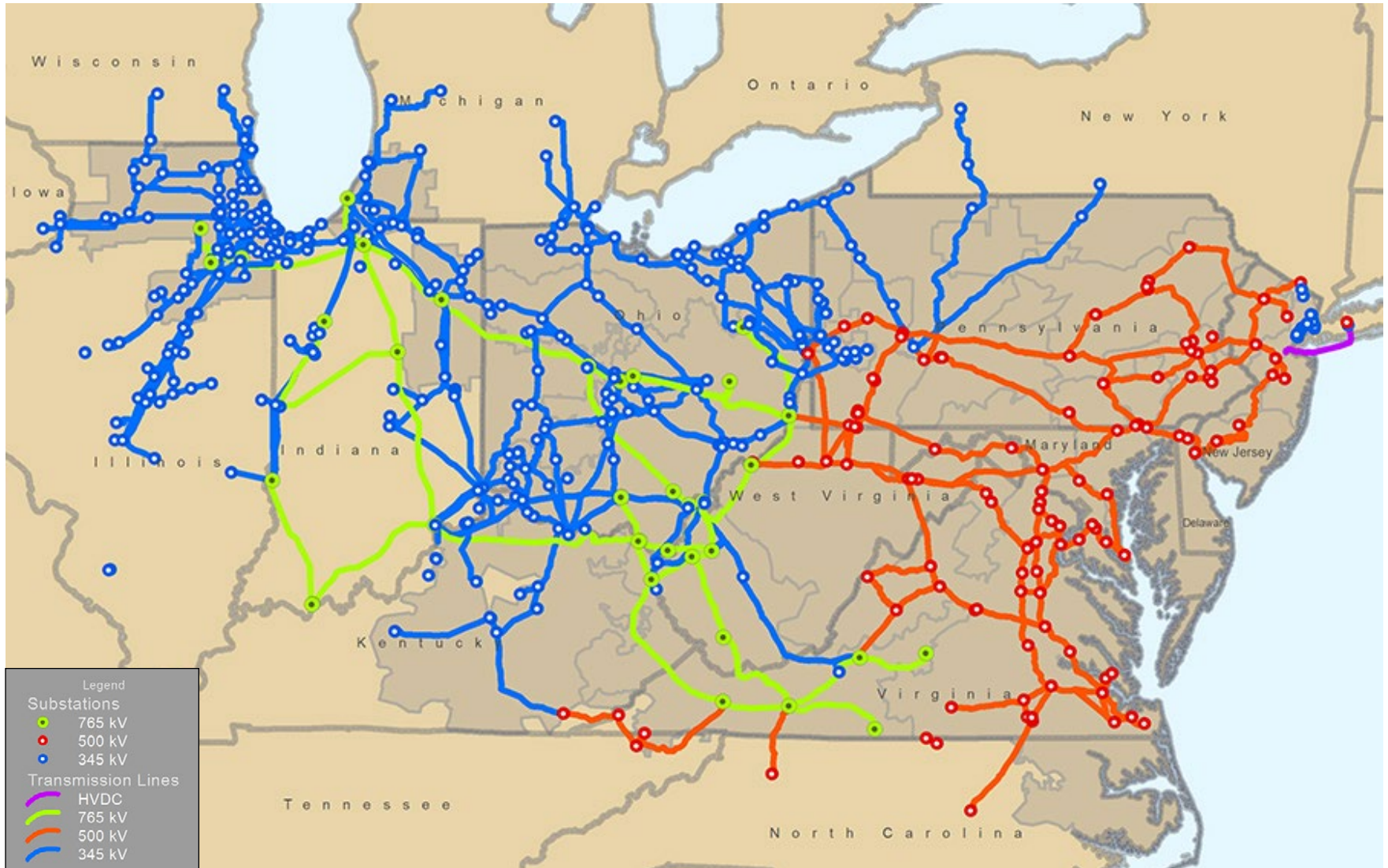
Term	Reference	Acronym	Definition
<b>Southern Subregion</b>	M14B		The PJM Southern Subregion comprises one transmission owner zone – Dominion Energy Virginia and North Carolina.
<b>Special Protection System</b>	M03	SPS	A Special Protection System (SPS) also known as a remedial action scheme, includes an assembly of protection devices designed to detect and initiate automatic action in response to abnormal or predefined system conditions. The intent of these schemes is generally to protect equipment from thermal overload or to protect against system instability following subsequent contingencies on the electric system. Redundant assemblies may be applied for the above functions on an individual facility – in such cases, each assembly is considered a separate protection system. An SPS consists of protection devices such as relays, current transformers, potential transformers, communication interface equipment, communication links, breaker trip and close coils, switch gear auxiliary switches and all associated connections.
<b>State Agreement Approach</b>	OA, M14B	SAA	A provision in PJM's Operating Agreement that enables a state to propose a transmission project for inclusion in PJM's Regional Transmission Expansion Plan that advances that state's Public Policy Requirements, as long as the state agrees to assume the cost of the project's build-out.
<b>Static Synchronous Compensator</b>		STATCOM	A shunt device of the Flexible AC Transmission System (FACTS) family that uses power electronics to control power flow and improve transient stability on power grids.
<b>Static Var Compensation</b>		SVC	An SVC device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system transmission and distribution performance.
<b>Station Service Voltage Transformer</b>		SSVT	This is a high-voltage, single-phase transformer that allows direct transformation from 69 kV to 550 kV down to low-voltage auxiliary power.
<b>Storage as a Transmission Asset</b>		SATA	A storage device that can be utilized on the transmission system to address reliability issues
<b>Subregional RTEP Committee</b>	M14B, OA		This PJM committee that facilitates the development and review of the subregional RTEP projects. The Subregional RTEP Committee is responsible for the initial review of the subregional RTEP projects and for providing recommendations to the Transmission Expansion Advisory Committee concerning the subregional RTEP projects.
<b>Subregional RTEP Project</b>	M14B, OA		A subregional RTEP project is defined in the PJM Operating Agreement as a transmission expansion or enhancement rated below 230 kV.
<b>Sub-Synchronous Resonance</b>		SSR	Power system sub-synchronous resonance (SSR) is the buildup of mechanical oscillations in a turbine shaft arising from the electro-mechanical interaction between the turbine generator and the rest of the power system. This can lead to turbine shaft damage, or even catastrophic loss. The term "sub-synchronous" refers to the fact that the oscillations a shaft can experience occur at levels below 60 Hz (cycles per second).
<b>Supervisory Control and Data Acquisition</b>		SCADA	A system of software and hardware that control industrial processes locally or at remote locations.
<b>Supplemental Project</b>	M14B, OA		"Supplemental Project" replaces the term "Transmission Owner Initiated or TOI Project" and refers to a regional RTEP project or a subregional RTEP project that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.
<b>Surge Impedance Loading</b>		SIL	The megawatt loading of a transmission line at which a natural reactive power balance occurs. A line loaded below its SIL supplies reactive power to the system; a line above its SIL absorbs reactive power.
<b>System Operating Limit</b>	M14B	SOL	The value (such as MW, MVAR, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System operating limits are based upon certain operating criteria.
<b>System Stability</b>			Stability studies examine the grid's ability to return to a stable operating point following a system fault or similar disturbance. Such contingencies can cause a nearby generator's rotor position to change in relation to the stator's magnetic field, affecting the generator's ability to maintain synchronism with the grid. Power system engineers measure this stability in terms of generator bus voltage and maximum observed angular displacement between a generator's rotor axis and the stator magnetic field. Stability in actual operations is affected by machine megawatt, system voltage, machine voltage, duration of the disturbance and system impedance. Transient stability examines this phenomenon over the first several seconds following a system disturbance.
<b>Targeted Market Efficiency Project</b>		TMEP	TMEP interregional projects address historical congestion on reciprocal coordinated flowgates – a set of specific flowgates subject to joint and common market congestion management.
<b>Temperature-Humidity Index</b>	M19	THI	The temperature-humidity index (THI) gives a single numerical value in the general range of 70 to 80, reflecting the outdoor atmospheric conditions of temperature and humidity during warm weather. The THI is defined as follows: $THI = T_d - (0.55 - 0.55RH) * (T_d - 58)$ , where $T_d$ is the dry-bulb temperature and RH is the percentage of relative humidity, when $T_d$ is greater than or equal to 58.
<b>Thyristor Controlled Series Compensator</b>		TCSC	A thyristor controlled series compensator is a series capacitor bank that is shunted by a thyristor controlled reactor.

Term	Reference	Acronym	Definition
<b>Topology</b>	M14B		Topology is a geographically based or other diagrammatic representation of the physical features of an electrical system or portion of an electrical system – including transmission lines, transformers, substations, capacitors and other power system elements – that in aggregate constitute a transmission system model for power flow and economic analysis.
<b>Transmission Customer</b>	M14A, M14B, M2, OATT		A transmission customer is any eligible customer, or its designated agent, that (1) executes a service agreement or (2) requests in writing that PJM file with FERC, a proposed, unexecuted service agreement to receive transmission service under Part II of the PJM OATT.
<b>Transmission Expansion Advisory Committee</b>	M14B	TEAC	The Transmission Expansion Advisory Committee was established by PJM to provide advice and recommendations to aid in the development of the RTEP.
<b>Transmission Loading Relief</b>	M03	TLR	Transmission loading relief is a NERC procedure developed for the Eastern Interconnection to mitigate overloads on the transmission system by allowing reliability coordinators to request the curtailment of transactions that are causing parallel flows through their system.
<b>Transmission Owner</b>	M14B, OATT	TO	A transmission owner is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a transmission owner.
<b>Transmission Owner Initiated</b>		TOI	See “Supplemental Project.”
<b>Transmission Owner Upgrade</b>	OA		A transmission owner upgrade is an improvement to, addition to, or replacement of part of a transmission owner's existing facility and is not an entirely new transmission facility.
<b>Transmission Provider</b>	M14B, OATT		The transmission provider is PJM for all purposes in accordance with the PJM OATT.
<b>Transmission Service Request</b>	M02	TSR	A transmission service request is a request submitted by a PJM market participant for transmission service over PJM-designated facilities. Typically, the request is for either short-term or long-term service, over a specific path for a specific megawatt amount. PJM evaluates each request and determines if it can be accommodated and, if the requestor so chooses, pursues needed upgrades to accommodate the request.
<b>Transmission Substation</b>		TSS	This is a term that a TO may append at the beginning of a substation name to indicate that it is a transmission substation instead of a distribution substation.
<b>Transmission System</b>	OATT		The transmission system comprises the transmission facilities operated by PJM used to provide transmission services. These facilities that transmit electricity are within the PJM footprint, meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities, and have been demonstrated to the satisfaction of PJM to be integrated with the transmission system of PJM and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.
<b>Unforced Capacity</b>	RAA	UCAP	Unforced capacity is an entitlement to a specified number of summer-rated MW of capacity from a specific resource, on average, not experiencing a forced outage or de-rating, for the purpose of satisfying capacity obligations imposed under the RAA.
<b>Upgrade</b>	OA		See “Transmission Owner Upgrade.”
<b>Upgrade Construction Service Agreement</b>		UCSA	The terms and conditions of a UCSA govern the construction activities associated with the upgrade of capability along an existing PJM bulk electric system circuit in order to accommodate a merchant transmission interconnection request. Facilities constructed under a UCSA are not owned by a developer. All ownership rights of the physical facilities are retained by the respective transmission owner following the completion of construction. PJM and the developer execute a separate UCSA with each impacted transmission owner. A developer retains the right, but not the obligation (option to build), to design, procure, construct and install all or any portion of the direct assignment facilities and/or customer-funded upgrades.
<b>Violation</b>	M14B		A violation is a PJM planning study result that shows a specific system condition that is not in compliance with established NERC, ReliabilityFirst, SERC or PJM reliability criteria.
<b>Voltage Source Converter</b>		VSC	This is a power electronics device that converts DC voltage to AC (or vice versa) with constant DC polarity.
<b>Weather Normalized Peak</b>	M19		The weather normalized peak is an estimate of the seasonal peak load at normal peak-day weather conditions.
<b>Western Subregion</b>	M14B, OA		The PJM Western Subregion comprises five transmission owner zones: Allegheny Power (AP), American Electric Power (AEP), American Transmission Systems, Inc. (ATSI), Commonwealth Edison (ComEd), AES Ohio – formerly Dayton Power & Light (DAY), Duke Energy Ohio and Kentucky (DEO&K), Duquesne Light Company (DLCO) and Eastern Kentucky Power Cooperative (EKPC).
<b>Wheel</b>			A wheel is the contracted, third-party use of electrical facilities to transmit power whose origin and destination are outside the entity transmitting the power.

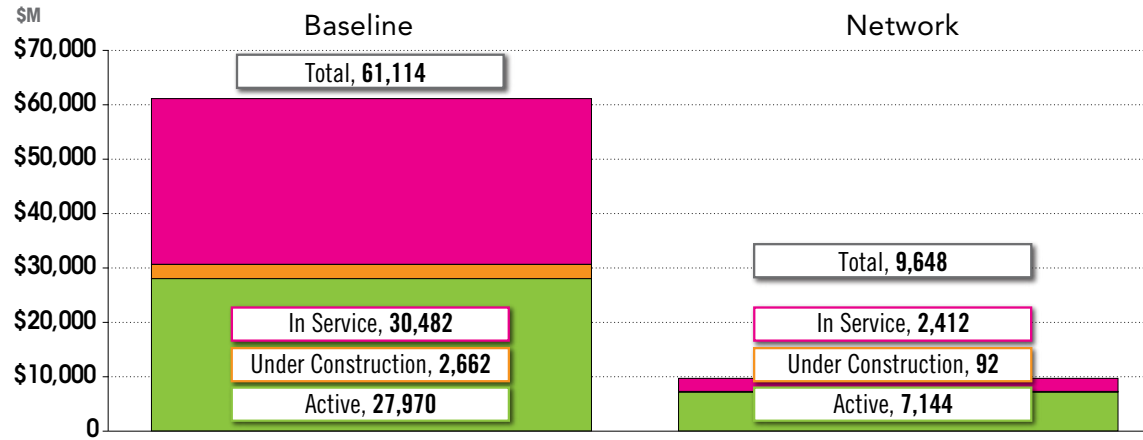
Term	Reference	Acronym	Definition
<b>Wholesale Market Participation Agreement</b>	M14C	WMPA	A contractual agreement required for generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market.
<b>X-Effective Forced Outage Rate on Demand</b>		XEFORd	XEFORd is a statistic that results from excluding events outside management control (outages deemed not to be preventable by the operator) from the EFORd calculation. See "Effective Forced Outage Rate on Demand (EFORd)."
<b>Zone/Control Zone</b>	M14B		A zone/control zone is an area within the PJM control area, as set forth in the PJM OATT and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

# Key Maps, Tables and Figures

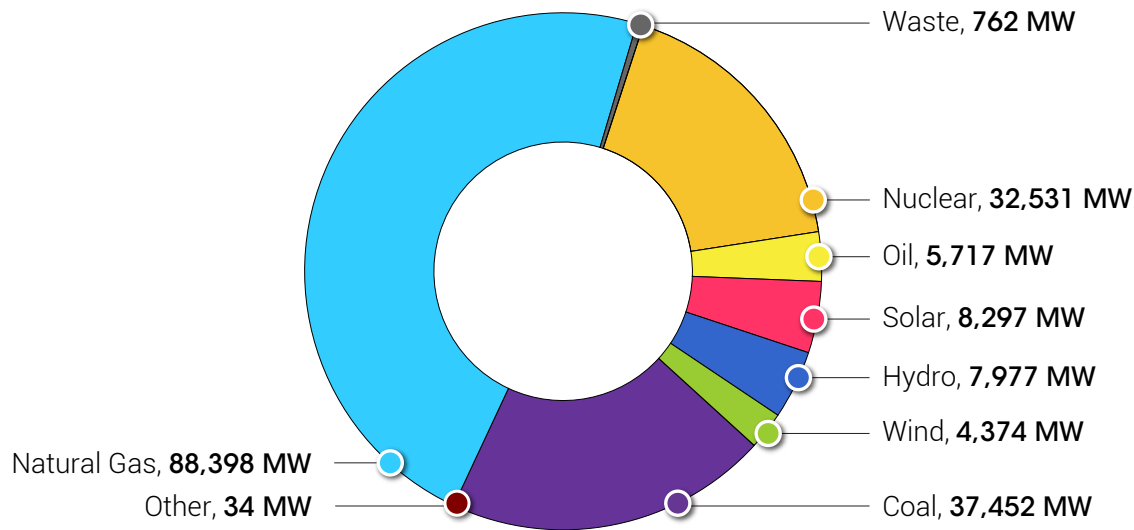
Map 1.1: PJM Backbone Transmission System



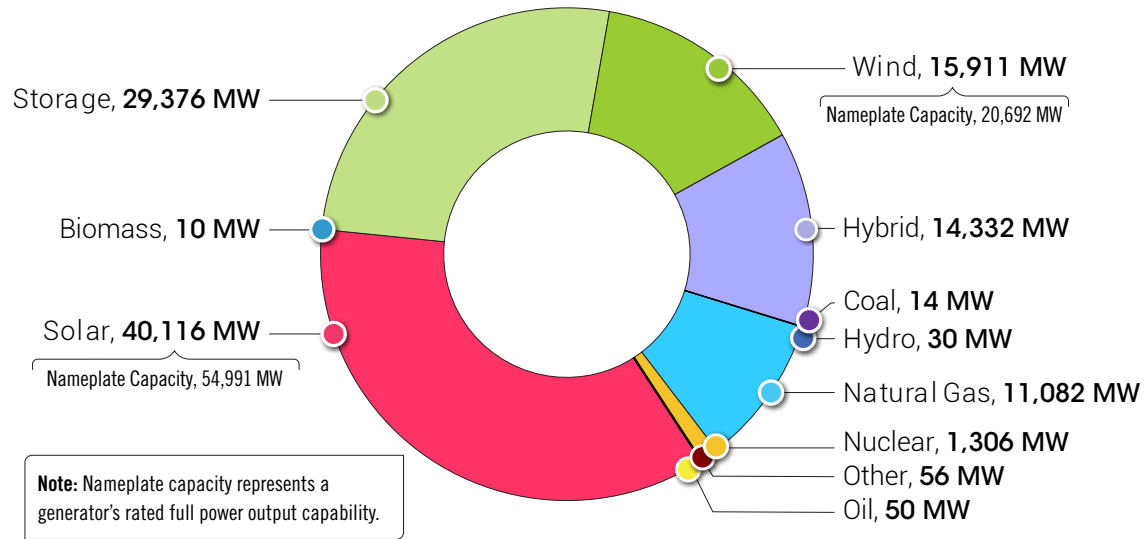
**Figure 1.3:** Board-Approved RTEP Projects as of Dec. 31, 2025



**Figure 1.4:** PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2025)



**Figure 1.5:** Interconnection Service Request Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2025)



**Table 1.1:** Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2025)

		In Cycle						Complete				Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
<b>Non-Renewable</b>	Coal	1	14.0	0	0.0	0	0.0	54	2,174.2	70	33,577.6	125	35,765.8
	Diesel	0	0.0	0	0.0	0	0.0	6	60.3	16	56.5	22	116.8
	Natural Gas	50	6,572.5	1	1,235.0	11	3,274.5	398	58,422.0	731	266,681.6	1,191	336,185.6
	Nuclear	5	1,305.9	0	0.0	0	0.0	47	3,984.2	25	9,038.0	77	14,328.1
	Oil	0	0.0	0	0.0	1	50.0	23	525.8	23	2,314.0	47	2,889.8
	Other	5	56.3	0	0.0	0	0.0	5	330.3	14	1,112.2	24	1,498.8
	Storage	240	26,703.4	11	414.3	37	2,258.3	30	40.4	771	43,595.2	1,089	7,3011.7
<b>Renewable</b>	Biomass	1	10.0	0	0.0	0	0.0	8	131.8	41	899.9	50	1,041.7
	Hybrid	133	12,741.5	1	115.0	27	1,475.8	12	53.9	396	21,776.0	569	36,162.2
	Hydro	0	0.0	0	0.0	2	30.0	32	1,155.9	63	2,744.1	97	3,930.0
	Methane	0	0.0	0	0.0	0	0.0	72	311.7	95	485.8	167	797.5
	Solar	595	25,405.8	94	3,054.5	227	11,655.8	415	8,889.7	2,739	72,257.2	4,070	12,1263.0
	Wind	101	14,109.0	9	499.0	19	1,302.7	120	2,175.8	576	25,905.4	825	43,991.9
	Wood	0	0.0	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
	<b>Total</b>	<b>1,131</b>	<b>86,918.4</b>	<b>116</b>	<b>5,317.7</b>	<b>324</b>	<b>20,047.2</b>	<b>1,224</b>	<b>78,310.0</b>	<b>5,564</b>	<b>480,596.6</b>	<b>8,359</b>	<b>671,189.8</b>

Figure 1.6: Interconnection Service Study Requests (Dec. 31, 2025)

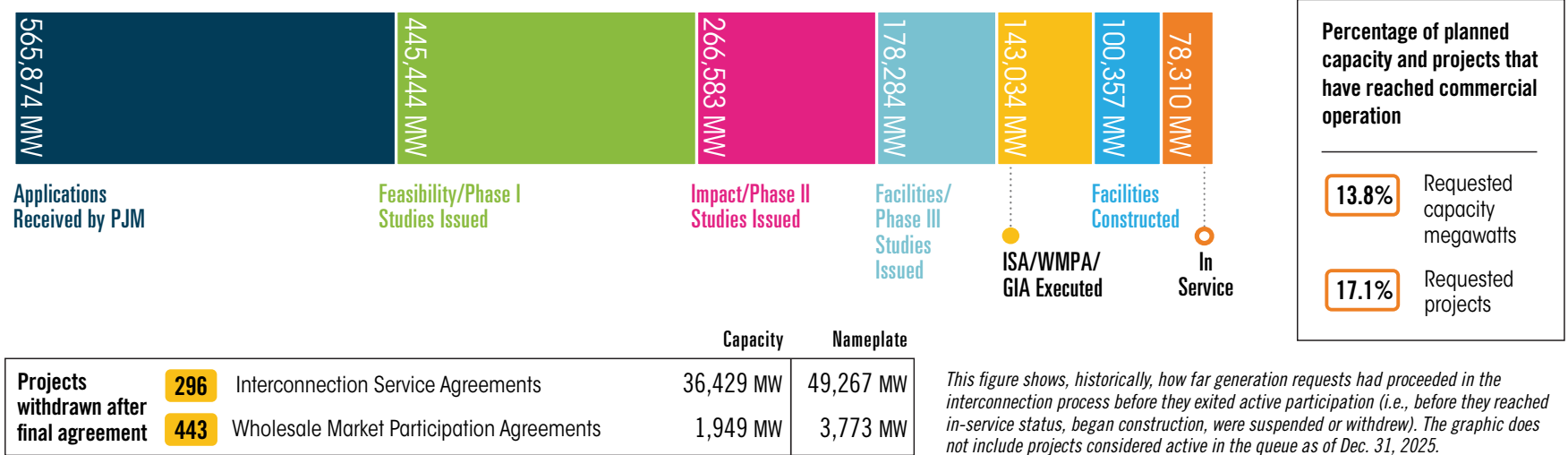


Figure 1.9: 2025 RTEP Baseline Project Drivers (\$Million)

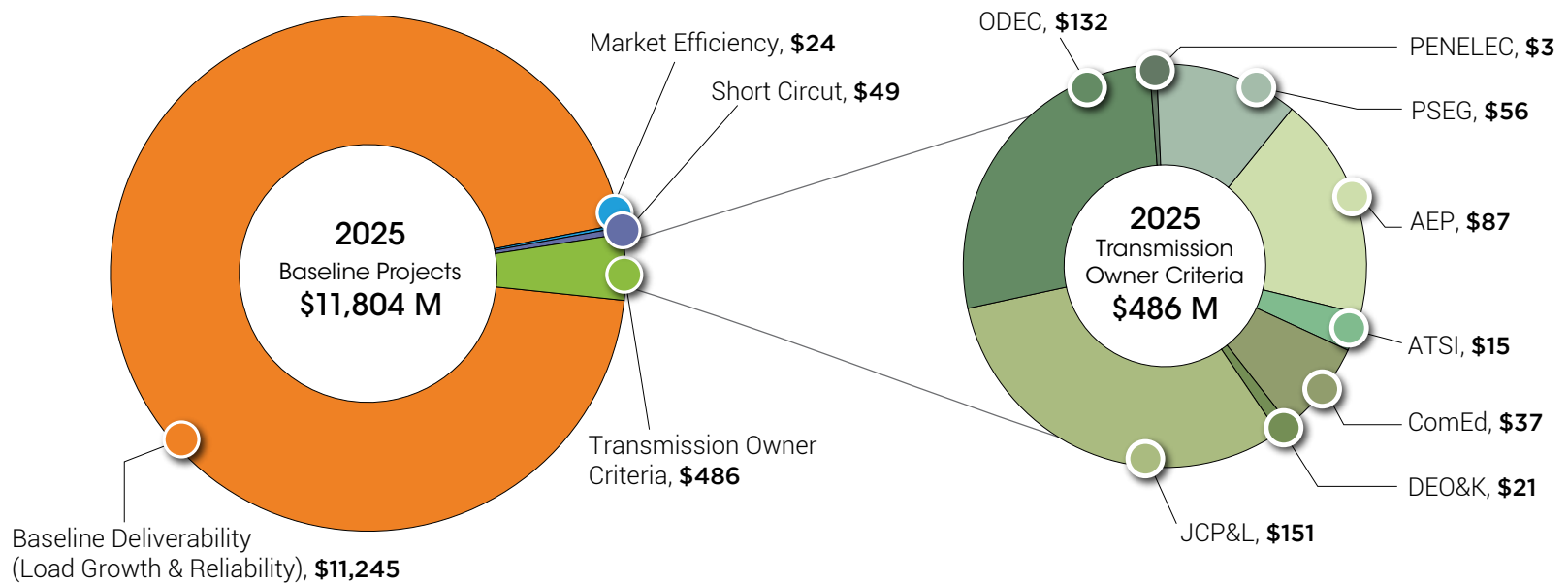


Figure 1.11: Impact of Electrification and Data Center Load on Forecasts

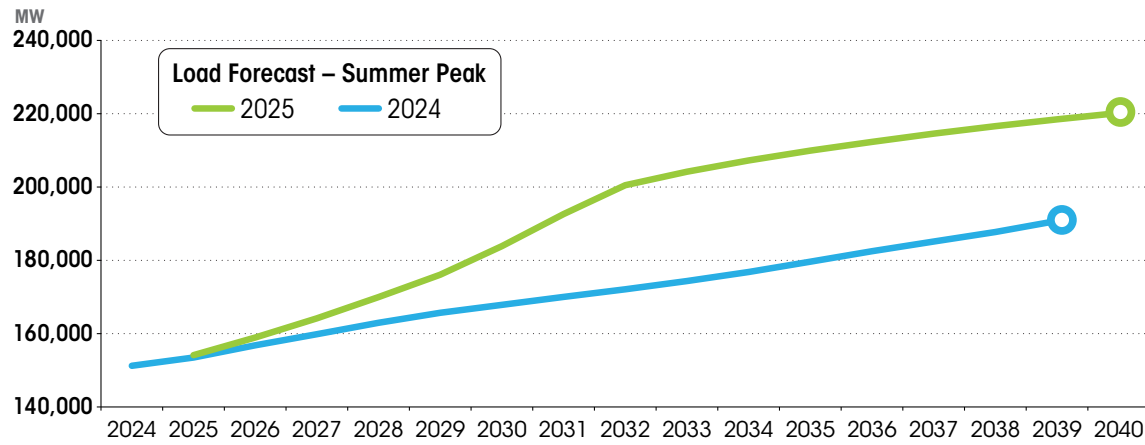
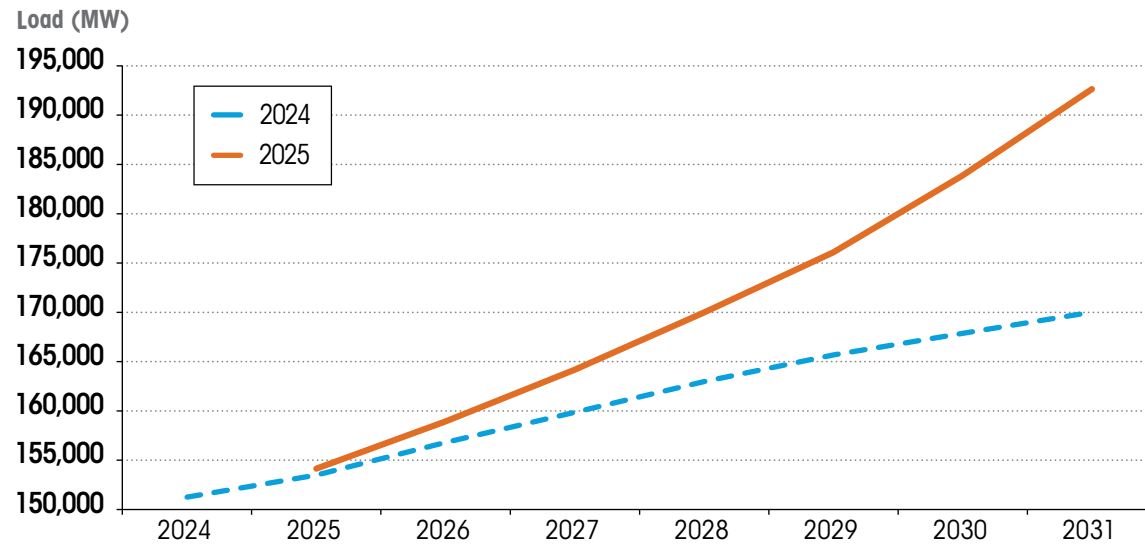


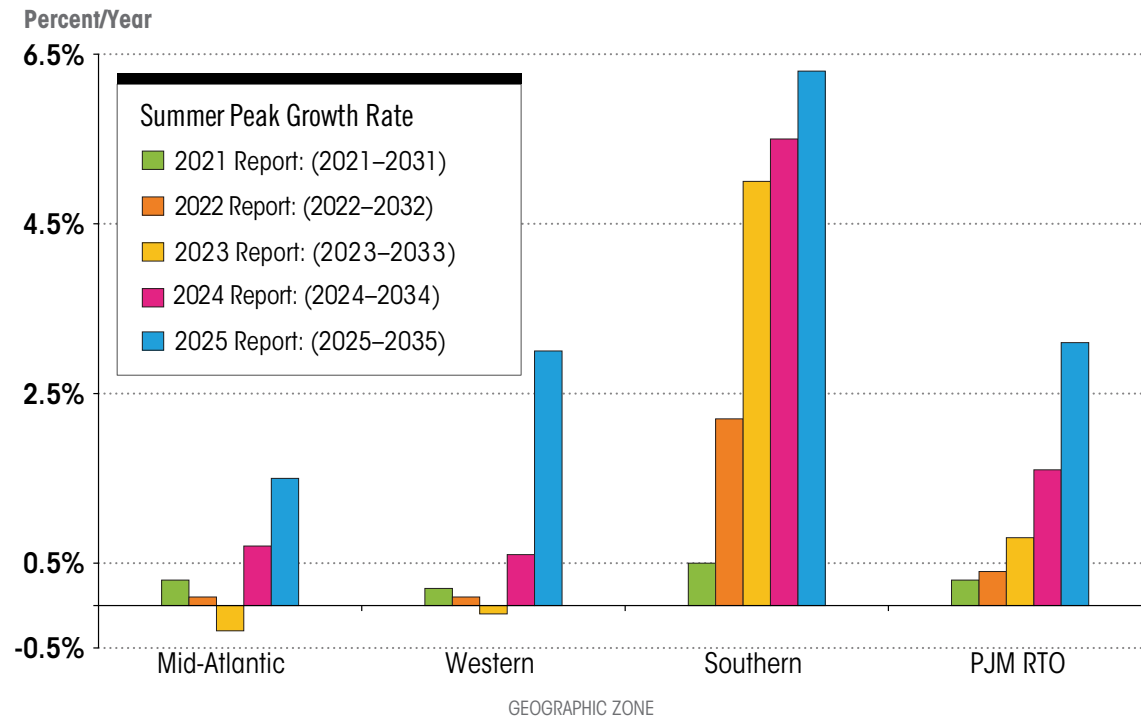
Figure 2.1: Summer Peak Load Forecast 2025 vs. 2024



**Table 2.1:** 2025 Long-Term Load Forecast Report: Summer and Winter Peaks

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2025	2035	Growth Rate	2024/25	2034/35	Growth Rate
Atlantic City Electric	2,584	2,619	0.1%	1,645	2,082	2.4%
Baltimore Gas and Electric	6,544	6,993	0.7%	5,897	6,508	1.0%
Delmarva Power	4,005	4,074	0.2%	3,731	3,956	0.6%
Jersey Central Power & Light	6,096	6,397	0.5%	3,995	5,885	3.9%
METED	3,115	3,572	1.4%	2,783	3,263	1.6%
PECO Energy Company	8,606	9,349	0.8%	6,568	7,440	1.3%
Pennsylvania Electric Company (Penelec)	2,944	3,014	0.2%	2,826	2,903	0.3%
PPL Electric Utilities	7,356	13,072	5.9%	7,510	13,228	5.8%
Potomac Electric Power Company (Pepco)	6,069	6,311	0.4%	5,389	5,702	0.6%
Public Service Electric & Gas Company (PSE&G)	10,341	11,785	1.3%	7,329	10,833	4.0%
Rockland Electric Company	415	420	0.1%	231	300	2.6%
UGI Utilities	201	203	0.1%	201	204	0.1%
Diversity – Mid-Atlantic	-1,454	-1,618		-892	-682	
<b>Mid-Atlantic</b>	<b>56,822</b>	<b>66,191</b>	<b>1.5%</b>	<b>47,213</b>	<b>61,622</b>	<b>2.7%</b>
American Electric Power	23,592	40,190	5.5%	22,727	40,379	5.9%
Allegheny Power (FirstEnergy)	8,707	11,151	2.5%	9,074	11,719	2.6%
American Transmission Systems, Inc. (FirstEnergy)	12,847	16,112	2.3%	10,662	14,186	2.9%
Commonwealth Edison	20,565	24,069	1.6%	14,875	19,876	2.9%
AES Ohio	3,348	3,757	1.2%	2,940	3,339	1.3%
Duke Energy Ohio and Kentucky	5,370	5,760	0.7%	4,563	4,976	0.9%
Duquesne Light Company	2,703	2,808	0.4%	1,988	2,125	0.7%
East Kentucky Power Cooperative	2,117	2,192	0.3%	2,761	2,843	0.3%
Ohio Valley Electric Corporation	85	85	0.0%	100	100	0.0%
Diversity – Western	-1,619	-1,803		-1,757	-1,789	
<b>Western</b>	<b>77,715</b>	<b>104,321</b>	<b>3.0%</b>	<b>67,933</b>	<b>97,754</b>	<b>3.7%</b>
Dominion Energy	23,351	42,846	6.3%	23,127	41,480	6.0%
<b>Southern</b>	<b>23,351</b>	<b>42,846</b>	<b>6.3%</b>	<b>23,127</b>	<b>41,480</b>	<b>6.0%</b>
Diversity – Total	-6,817	-6,856		-4,795	-5,152	
<b>PJM RTO</b>	<b>154,144</b>	<b>209,923</b>	<b>3.1%</b>	<b>136,127</b>	<b>198,175</b>	<b>3.8%</b>

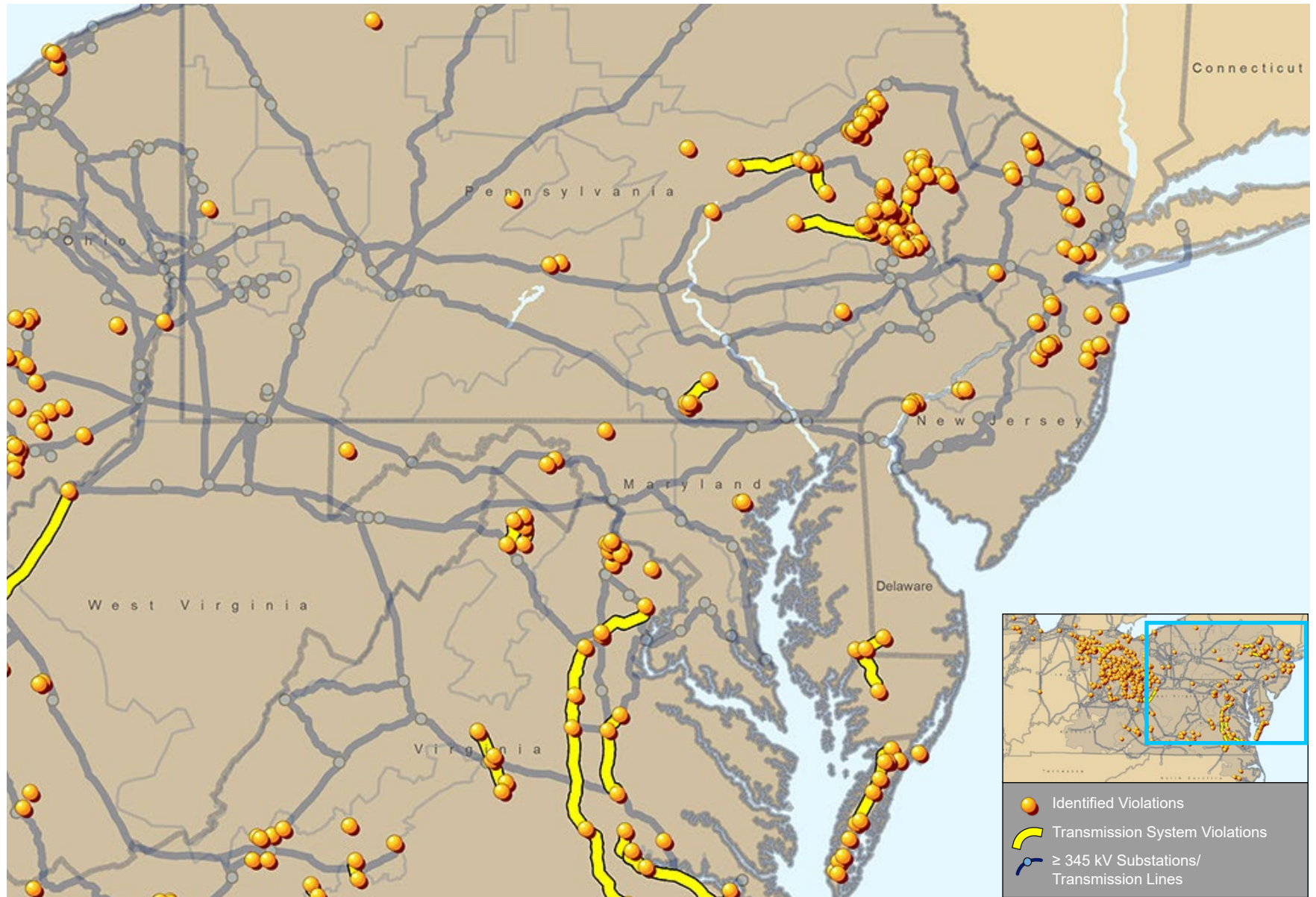
**Figure 2.8:** PJM 10-Year Summer Peak Load Growth Rate Comparison 2021–2025 Long-Term Load Forecast Reports



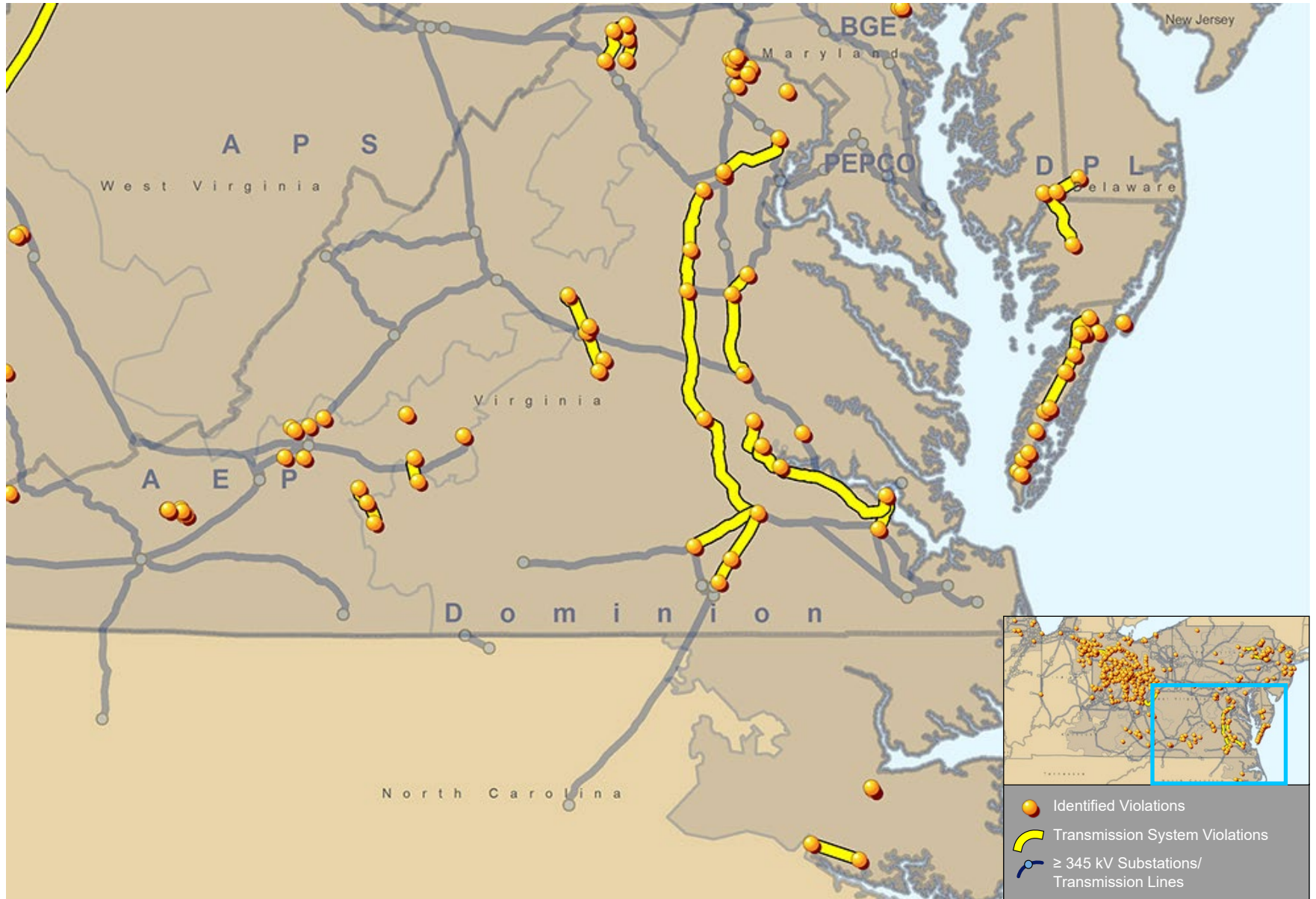
**Table 2.4:** 2025 Long-Term Load Forecast Report: Large Load Adjustments in 2025 and 2035

Transmission Owner	Total Load Associated With Adjustments to Summer Peak Load (MW) for Each PJM Zone	
	2025	2035
Atlantic City Electric	0	0
Baltimore Gas and Electric	12	318
Delmarva Power	0	0
Jersey Central Power & Light	0	0
METED	0	0
PECO Energy Company	0	427
Pennsylvania Electric Company (Penelec)	0	0
PPL Electric Utilities	93	5,528
Potomac Electric Power Company (Pepco)	0	0
Public Service Electric & Gas Company (PSE&G)	289	1,235
Rockland Electric Company	0	0
UGI Utilities	0	0
<b>Mid-Atlantic</b>		
American Electric Power	1,761	18,017
Allegheny Power (FirstEnergy) (AP)	8	2,239
American Transmission Systems, Inc. (FirstEnergy) (ATSI)	56	2,792
Commonwealth Edison	546	4,822
AES Ohio	0	334
Duke Energy Ohio and Kentucky	0	243
Duquesne Light Company	0	0
East Kentucky Power Cooperative	0	0
Ohio Valley Electric Corporation	0	0
<b>Western</b>		
Dominion Energy	4,970	23,464
<b>PJM RTO</b>	<b>7,735</b>	<b>59,419</b>

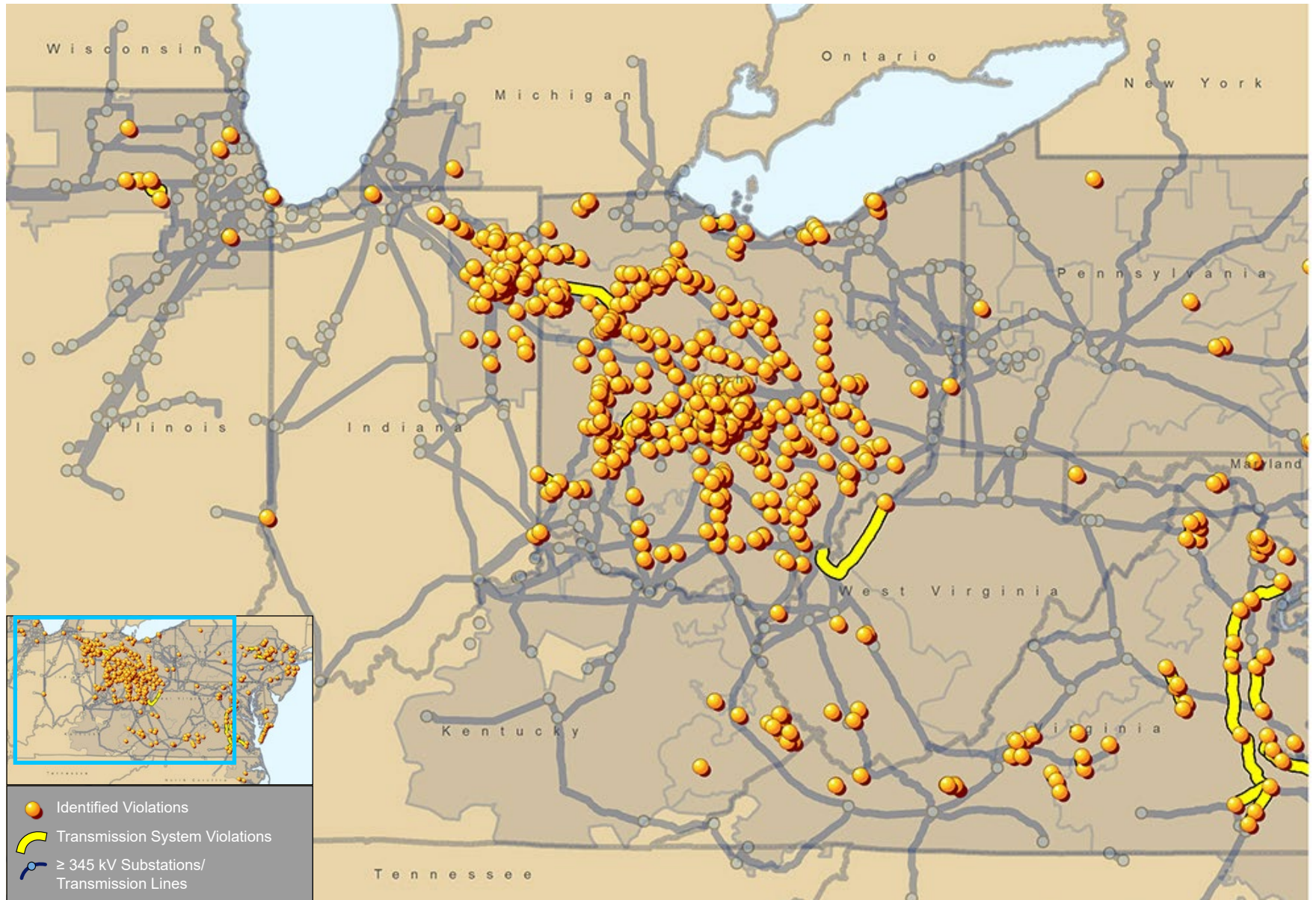
**Map 3.2: 2025 RTEP Baseline Thermal and Voltage Criteria Violations – Mid-Atlantic – Study Years 2030 and 2032**



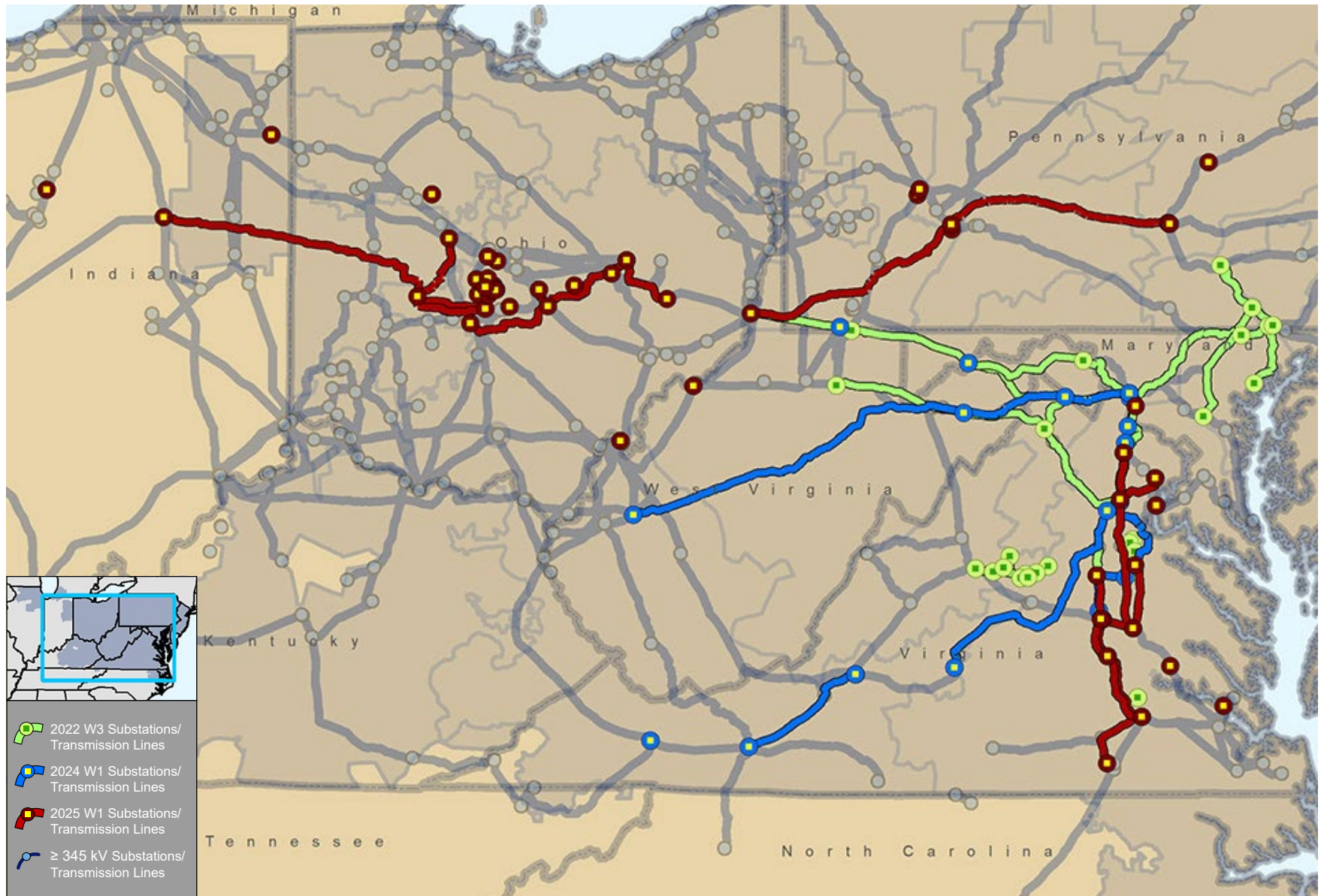
**Map 3.3: 2025 RTEP Baseline Thermal and Voltage Criteria Violations – South – Study Years 2030 and 2032**



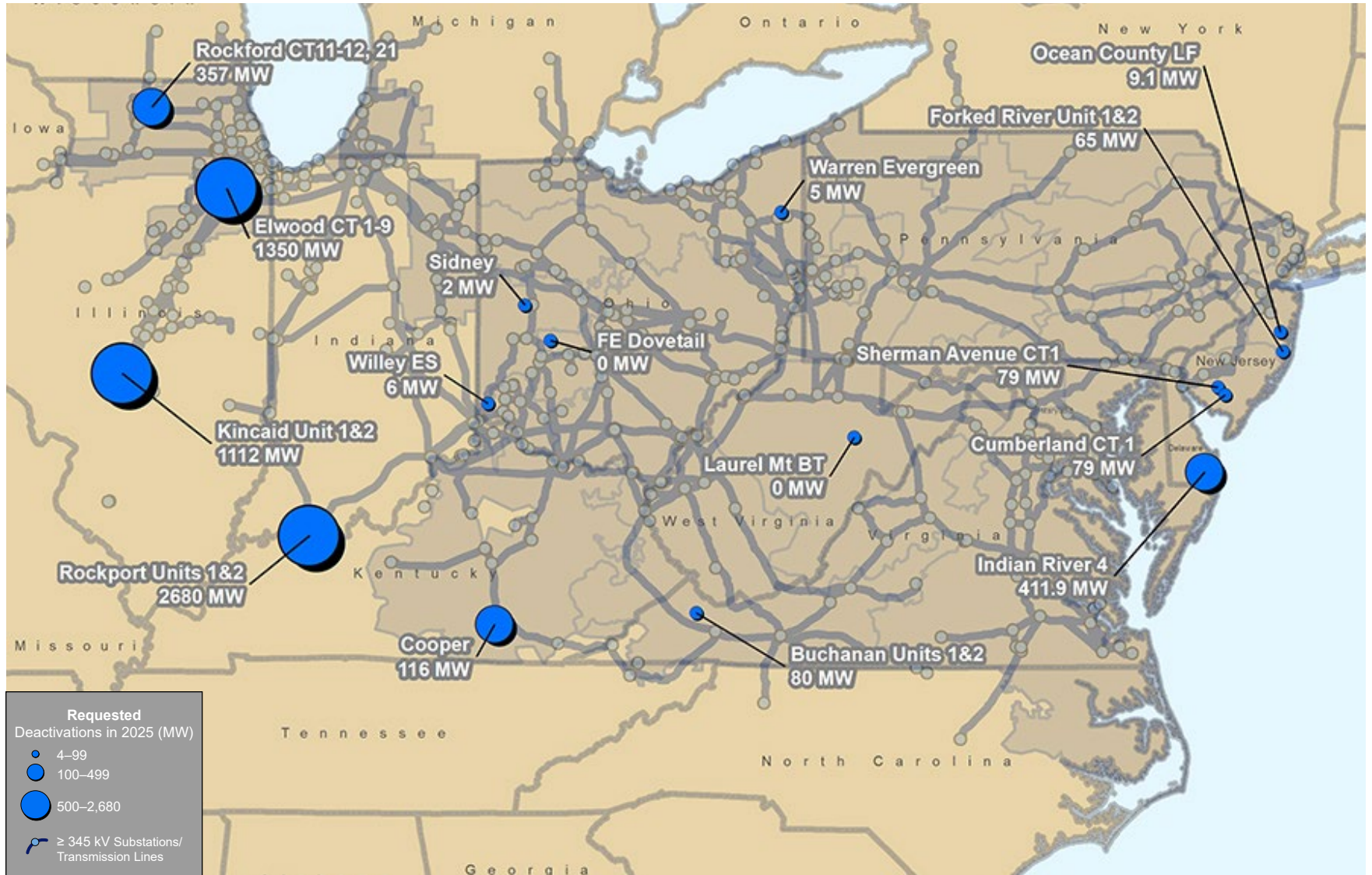
**Map 3.4:** 2025 RTEP Baseline Thermal and Voltage Criteria Violations – West – Study Years 2030 and 2032



**Map 3.9:** 500 kV and Above Projects from 2025 RTEP Window 1, 2024 RTEP Window 1 and 2022 RTEP Window 3



Map 3.10: Deactivation Notifications Received in 2025



Map 3.11: Actual Generator Deactivations in 2025

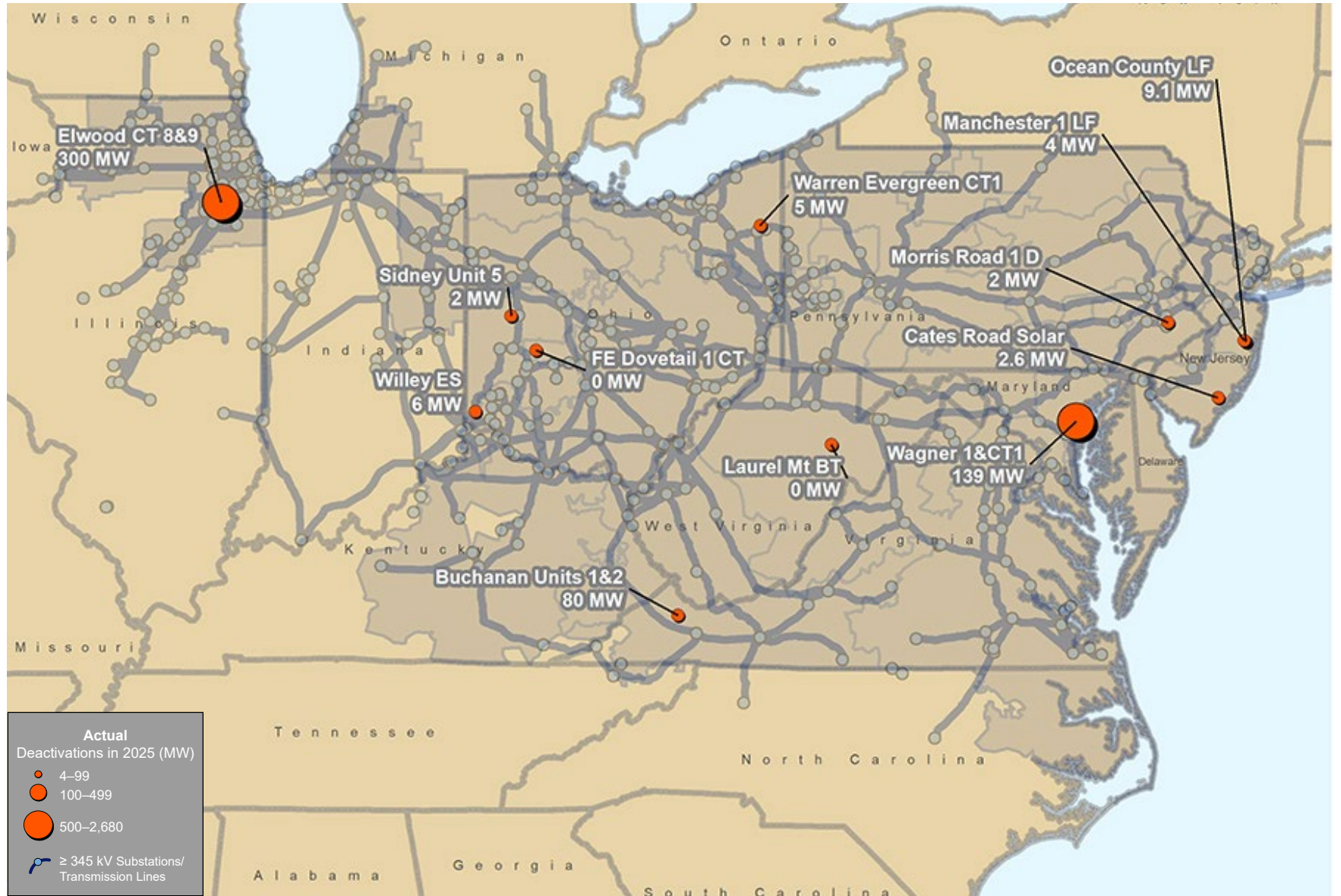


Figure 3.6: Economic Capacity Expansion

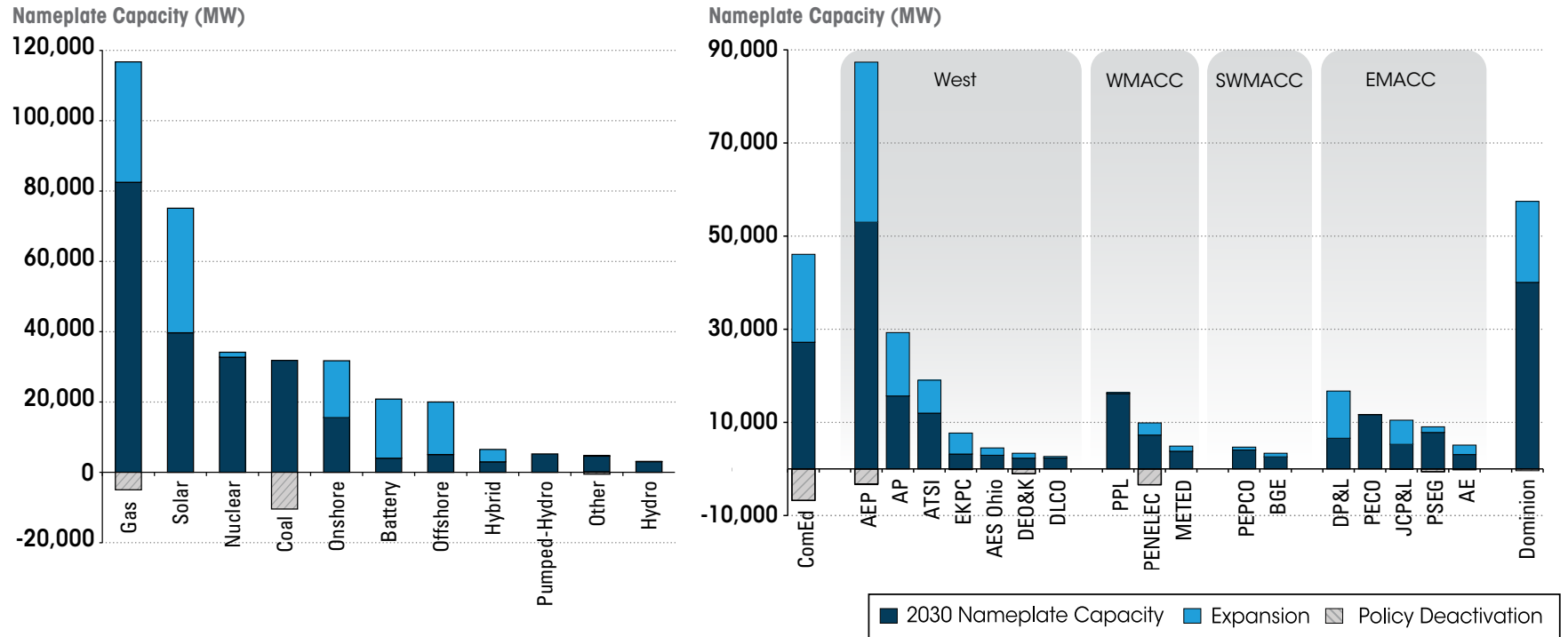
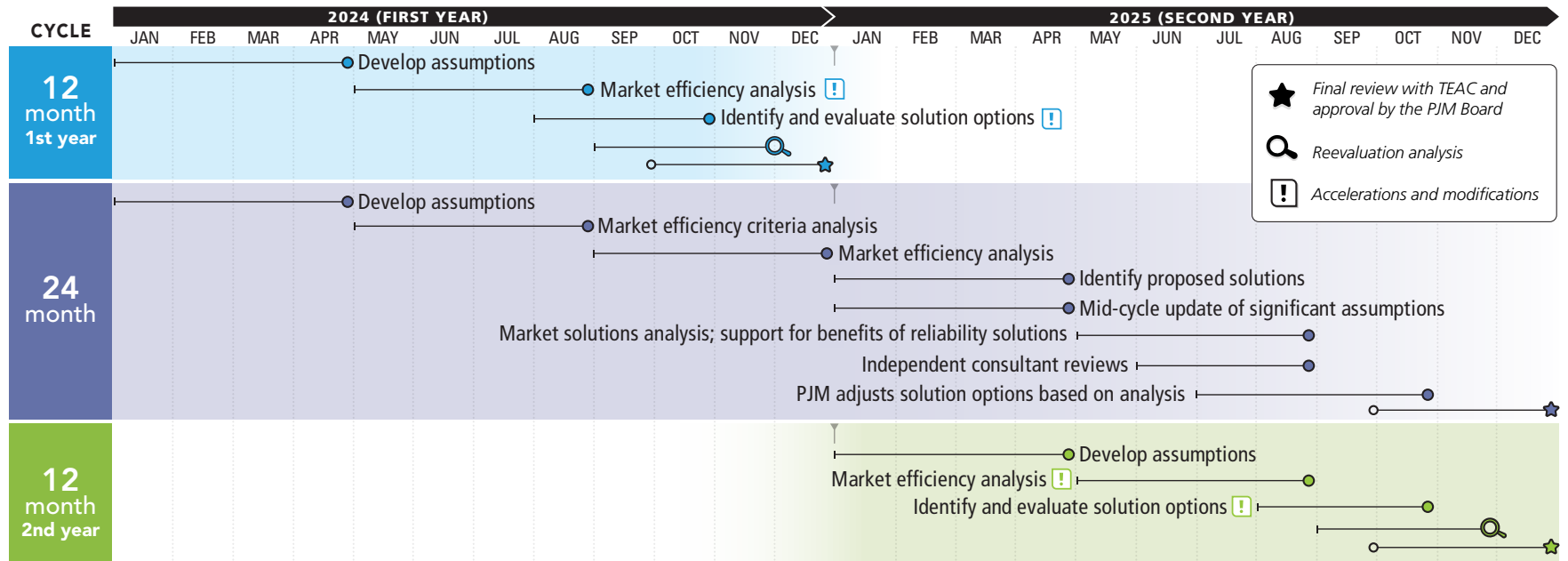


Figure 4.1: 2024/2025 Market Efficiency 24-Month Cycle



Map 4.1: Project 9A – RTEP Baseline Project B2743 and B2752

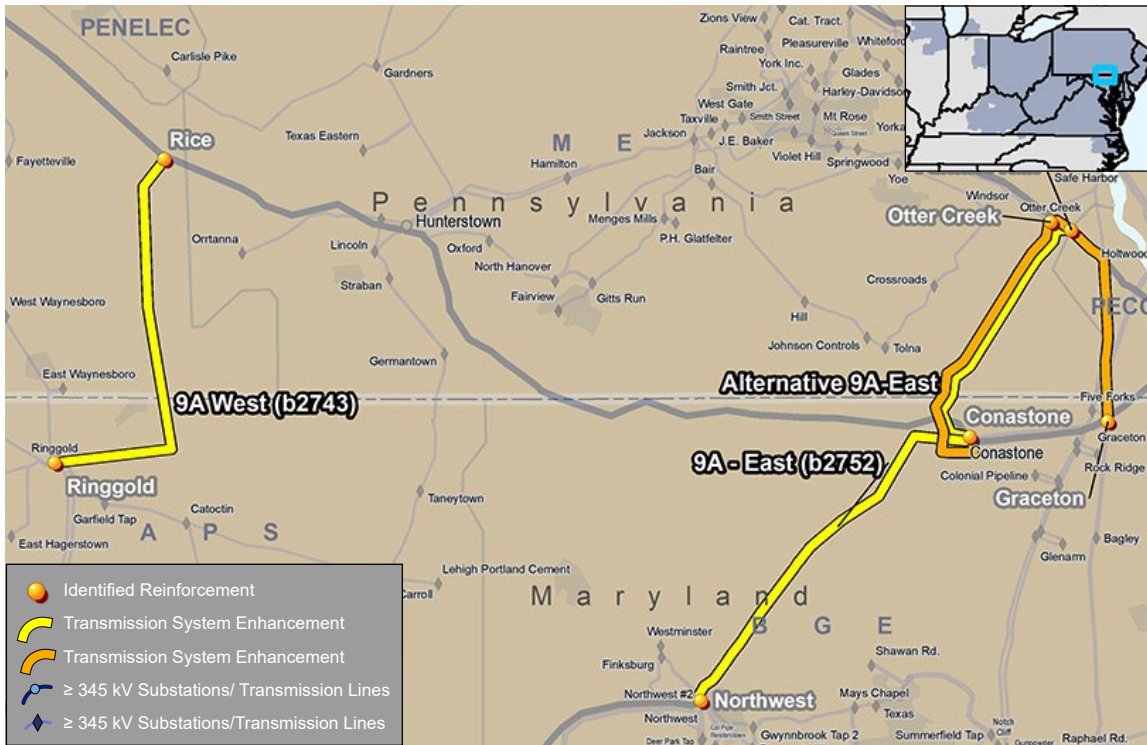


Table 4.4: 2025 Project 9A Reevaluation

Reevaluation	Base Case Ratio	Cost (\$M)
Original 9A (9A West + 9A East)	3.74	\$430.41
Alternate 9A (9A West + Alt 9A East)	3.42	\$584.57
9A West Only	3.85	\$264.61

**Table 4.5** 2024/2025 Long-Term Market Efficiency Window Congestion Drivers

Constraint	Area	Base Simulation Annual Congestion (\$M)	
		2029	2032
Musville-Smith Mountain 138 kV	AEP	\$11.4	\$24.9
West Point-Lanexa 115 kV	Dominion	\$2.0	\$1.7
Garrett-Garrett Tap 115 kV	PN-AP	\$1.8	\$2.1

**Figure 5.2:** Interconnection Process Reform Timeline (as of March 18, 2026, 10:21 a.m. EPT)

Phase	Transition Cycle 1			Transition Cycle 2			Cycle 1		
	Start Date	End Date	Duration	Start Date	End Date	Duration	Start Date	End Date	Duration
<b>Fast Lane End Date</b> <i>executed by Developer &amp; TO or filed unexecuted</i>	12/15/2023	4/18/2025							
<b>Application Deadline</b>	N/A	N/A	N/A	12/17/2024	12/17/2024	0	4/27/2026	4/27/2026	0
<b>Application Review</b>	N/A	N/A	N/A	12/18/2024	7/6/2025	201	4/28/2026	7/27/2026	91
<b>Model Posting</b>	2/1/2024	2/1/2024	0	6/6/2025	6/6/2025	0	6/26/2026	6/26/2026	0
<b>Phase I</b>	1/22/2024	5/20/2024	120	7/7/2025	10/31/2025	117	7/28/2026	11/24/2026	120
<b>Decision Point I</b>	5/21/2024	6/20/2024	31	11/3/2025	12/2/2025	30	11/25/2026	12/24/2026	30
<b>Phase II</b>	6/21/2024	12/20/2024	183	12/3/2025	6/1/2026	181	1/28/2027	7/26/2027	180
<b>Decision Point II</b>	12/23/2024	1/21/2025	30	6/2/2026	7/1/2026	30	7/27/2027	8/25/2027	30
<b>Phase III</b>	4/21/2025	9/19/2025	152	7/2/2026	12/28/2026	180	8/26/2027	2/22/2028	181
<b>Decision Point III</b>	9/22/2025	10/21/2025	30	12/29/2026	1/27/2027	30	2/23/2028	3/23/2028	30
<b>Final Agreement Negotiation</b>	9/22/2025	11/20/2025	60	12/29/2026	2/26/2027	60	2/23/2028	4/24/2028	62

**Notes:**

- **Transition Cycle 2 Phase III** start date is dependent on Transition Cycle 1 GIAs executed or withdrawn.
- **Cycle 1 Phase I** start date is dependent on Transition Cycle 2 Decision Point II close, Cycle 1 Review completion and Cycle 1 Model being posted for 30 days.
- **Cycle 1 Phase II** start date is dependent on Transition Cycle 2 Decision Point III close.
- **Cycle 1 Phase III** start date is dependent on the conclusion of the Transition Cycle 2 Final Agreement Negotiation Phase.

Legend
Actual date
Projected date

# Appendix 5: RTEP Project Statistics

## 5.0: RTEP Project Statistics

This set of figures and tables summarizes the estimated costs for projects presented at the Transmission Expansion Advisory Committee or Subregional TEAC meetings. It is intended to visually represent and consolidate materials presented elsewhere in this report to allow stakeholders to view trends in the identification of violations over time, and by voltage class. Where historical costs are used in the comparison of a graph, the costs have been adjusted for inflation to have a common representation of 2025 dollars.

***These figures are developed using the following assumptions:***

- 1 Baseline project was approved by the PJM Board.
- 2 Supplemental project was presented at the TEAC or Subregional TEAC meetings.
- 3 Costs are provided by the designated entity or transmission owners. Cost estimation methods may vary by company. Estimated costs in this document may include cost caps or cost containment, even though it is not specifically noted.
- 4 Cost estimates may change over time as new information is incorporated into the estimate by the project sponsor. This document reflects the current estimates that are provided to PJM.
- 5 Estimated project costs are adjusted by average inflation rate from 2015 to 2024 (2.88%).
- 6 Transmission line mileage is based on FERC Form 1 filed in 2019.
- 7 TO peak load is the average of forecast summer peak load from 2026 to 2030.

Figure 5.1: Project Status as of Dec. 31, 2025

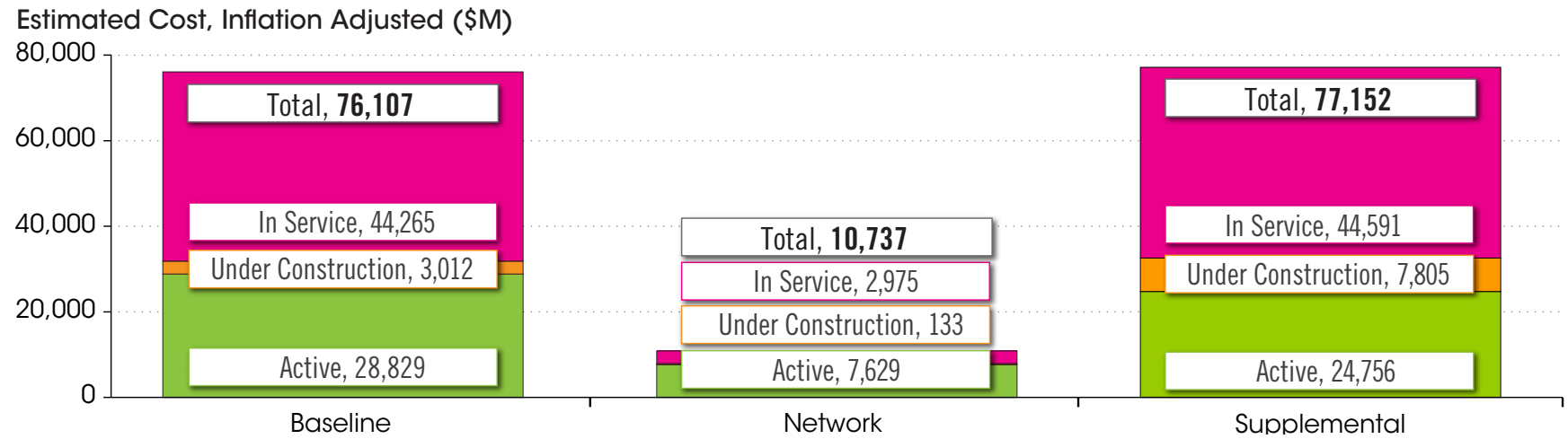


Figure 5.2: Baseline and Supplemental Projects by Year

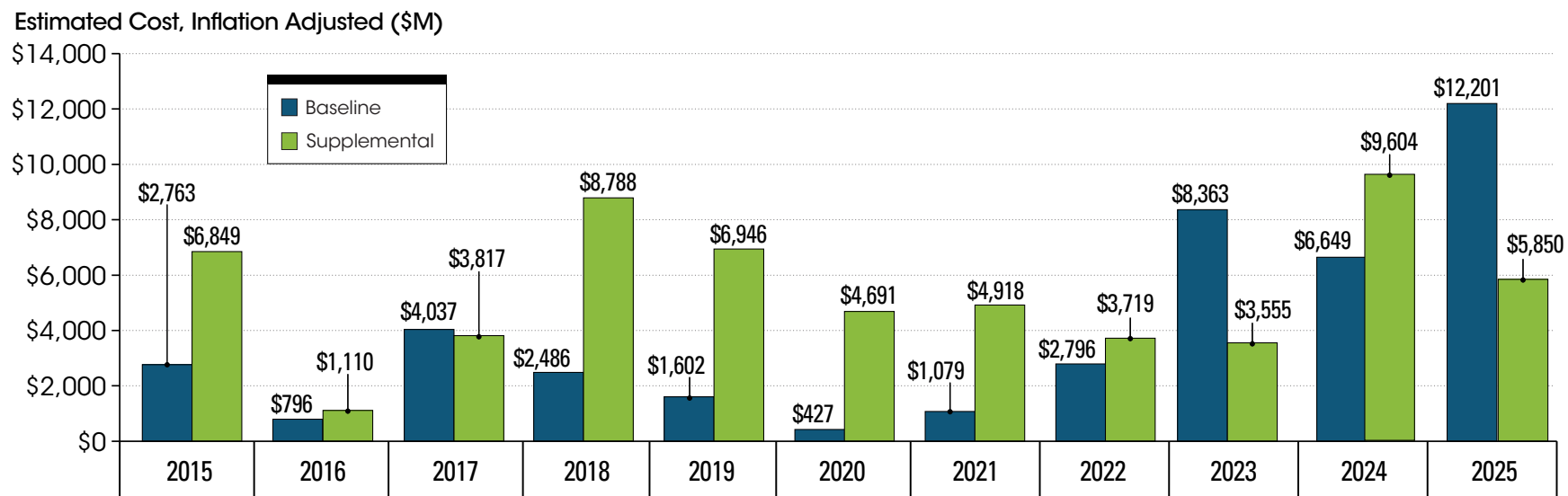


Figure 5.3: PJM Baseline Projects by Criteria

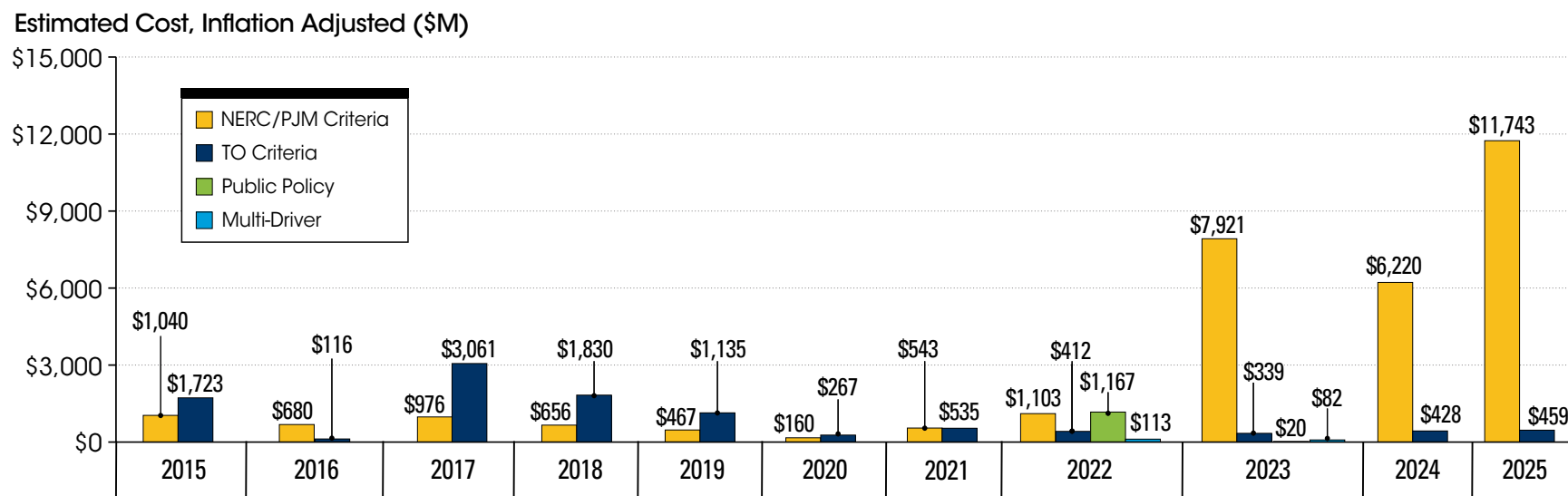


Figure 5.4: Baseline Projects by Voltage

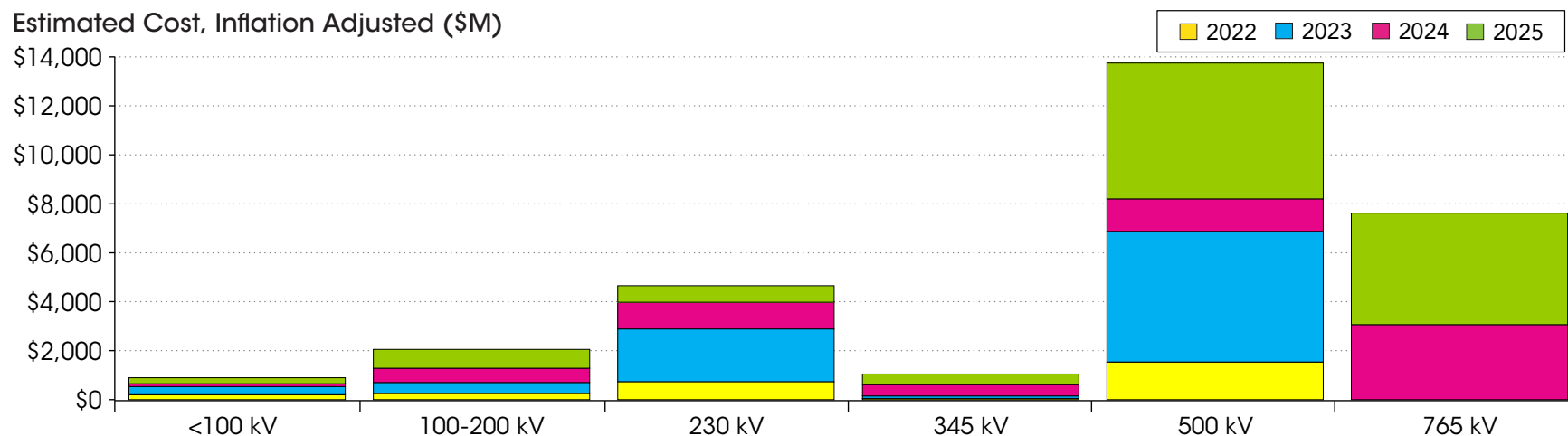


Figure 5.5: Supplemental Projects by Voltage

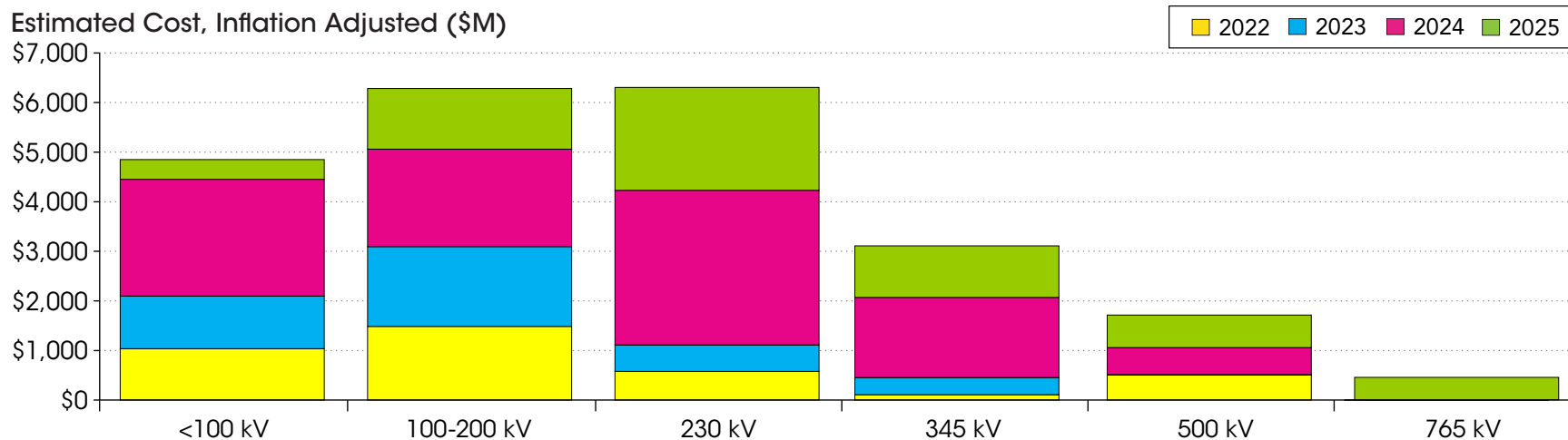


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2015

Estimated Cost, Inflation Adjusted (\$M)

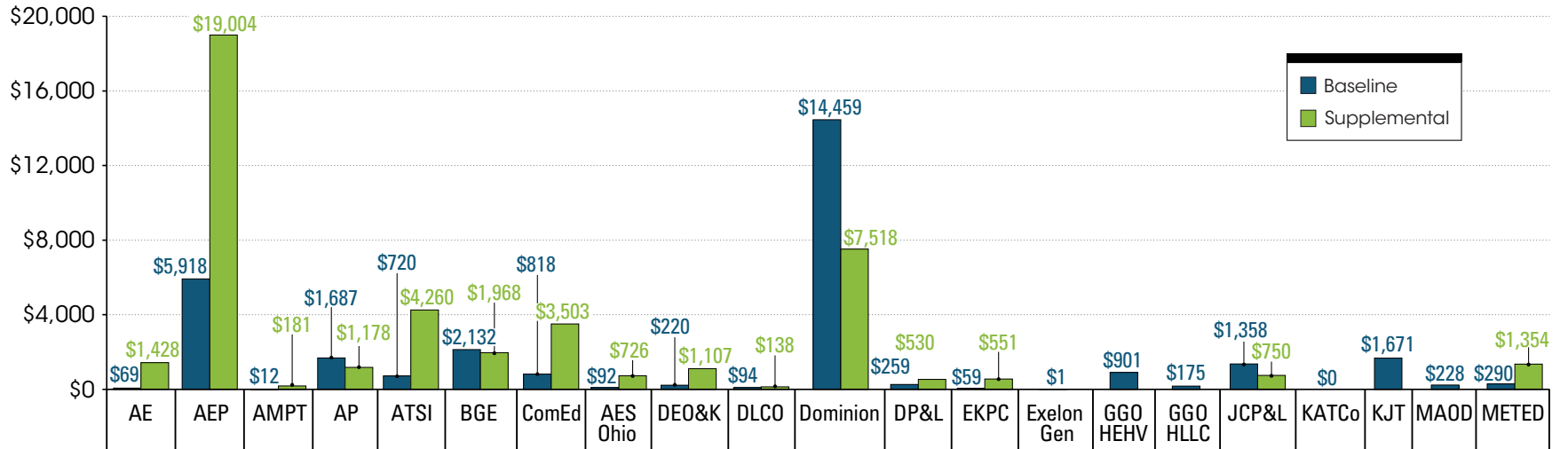
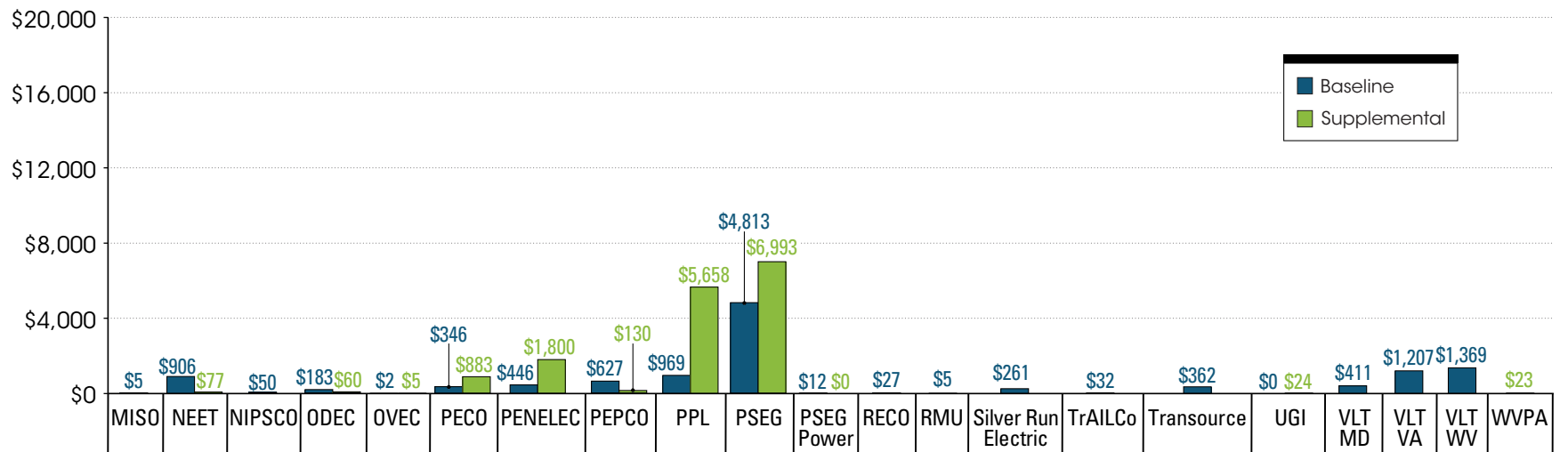


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2015 (Cont.)

Estimated Cost, Inflation Adjusted (\$M)



**Figure 5.7:** 2025 Baseline and Supplemental Projects by Designated Entity

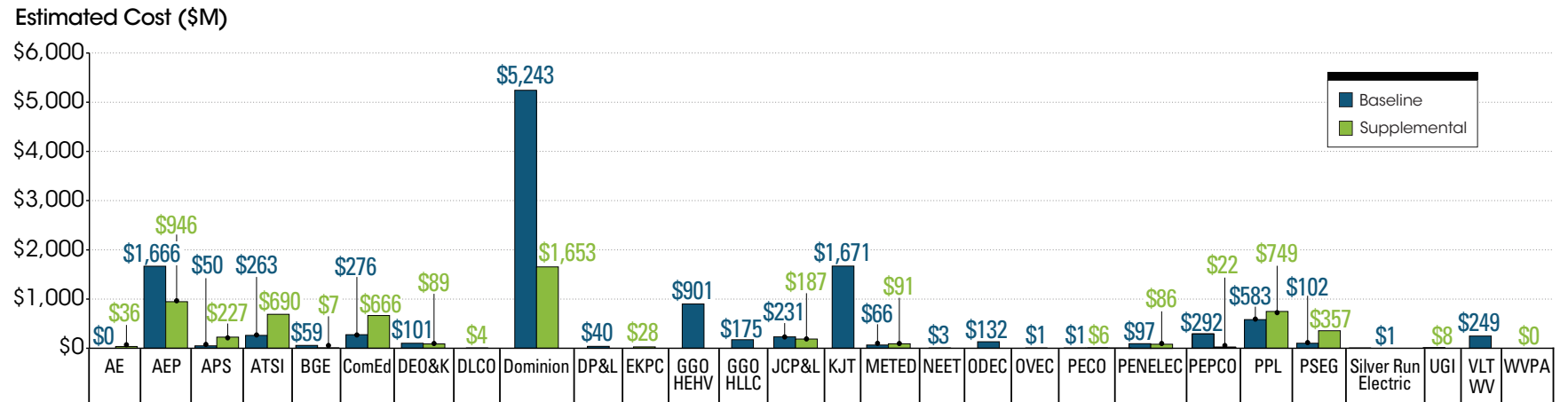


Figure 5.8: Baseline and Supplemental Projects Adjusted by Peak Load Since 2015

Estimated Cost, Inflation Adjusted (\$M/MW)

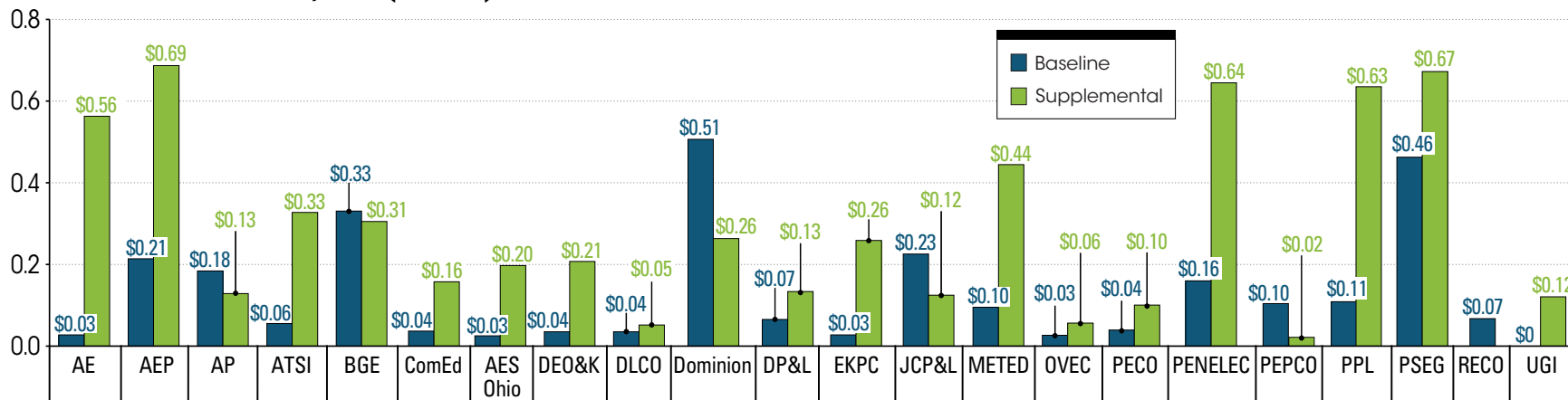


Figure 5.9: 2025 Baseline and Supplemental Projects Adjusted by Peak Load

Estimated Cost (\$M/MW)

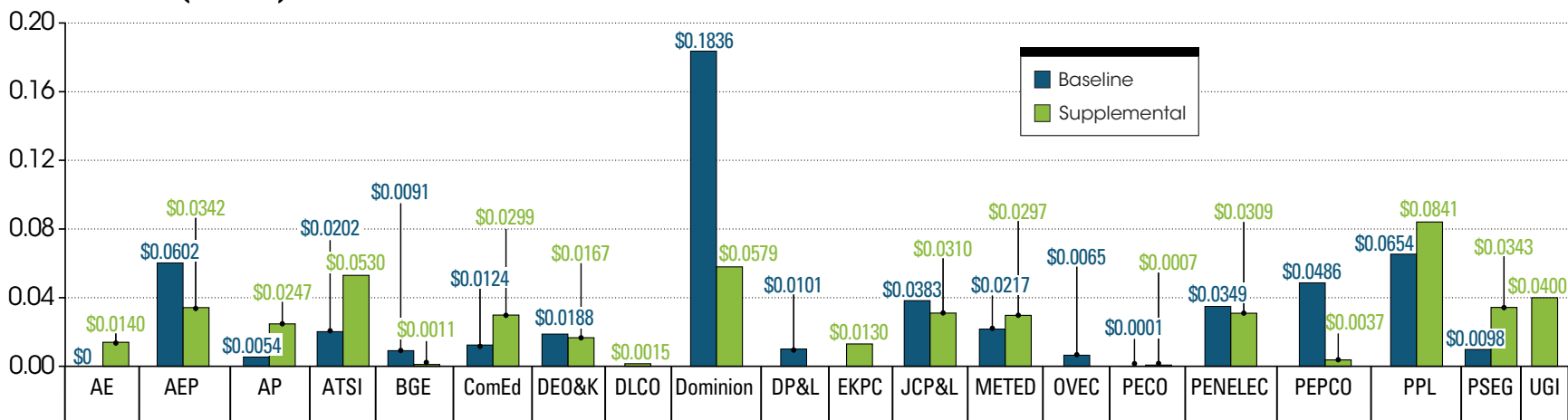


Figure 5.10: Baseline and Supplemental Projects Adjusted by Circuit Miles Since 2015

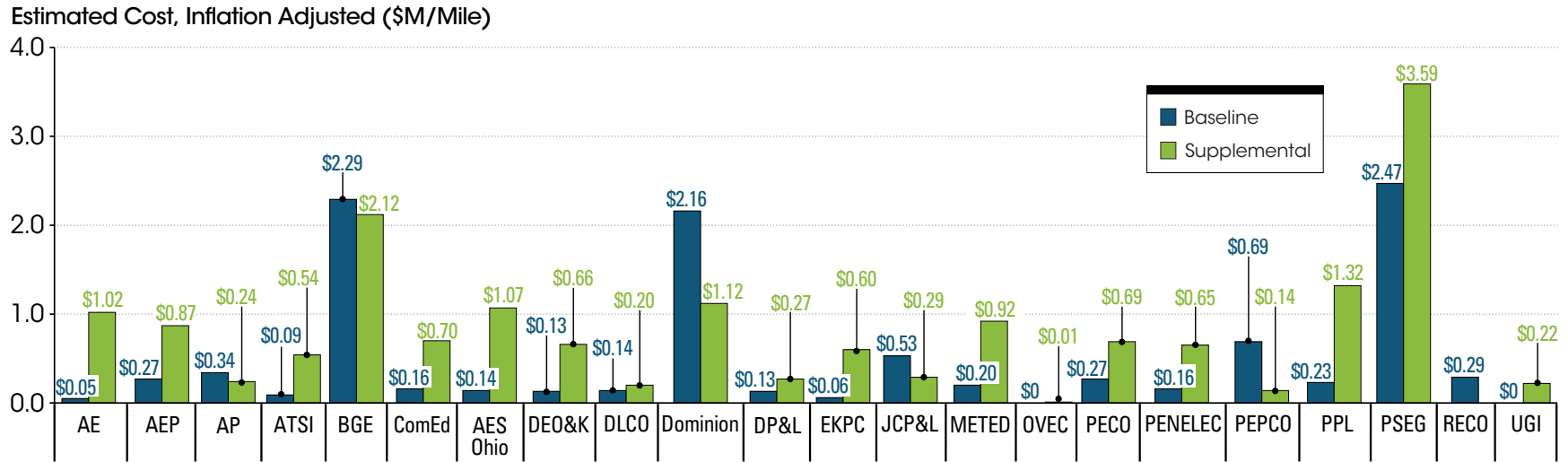


Figure 5.11: 2025 Baseline and Supplemental Projects Adjusted by Circuit Miles

