2024 RTO Membership Analysis
Appendix 1

How are data center energy requirements impacting PJM load forecasts?

What transmission enhancements will continue to ensure PJM grid reliability under ongoing unprecedented change?

What steps is PJM taking to reduce transmission congestion?

What reforms are improving generation interconnection process efficiency?

How is PJM's regional planning process enabling states' renewable energy public policies?

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RTEP 2023

REGIONAL TRANSMISSION EXPANSION PLAN

MARCH 7, 2024

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1.0: Preface

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.

In 2023, PJM observed several ongoing trends, which are discussed throughout this report. These include the continuing shift in PJM's generation fuel mix, driven by new renewables and natural gas-fired resources and the deactivation of coal-fired plants.

- **Section 1 is a high-level summary of the 2023 RTEP process, activities and milestones, and includes a look toward the future of regional transmission planning.**
- **Section 2** includes an overview and detailed data from PJM's 2023 Load Forecast Report and PJM's Effective Load Carrying Capability methodology.
- **Section 3** provides highlights of system enhancements approved by the PJM Board in 2023, including those driven by generator deactivations, and summarizes the reevaluation of previously approved projects.
- **Section 4** summarizes 2023 market efficiency process activity, including input parameters, acceleration analysis results, reevaluation of previously approved market efficiency projects and the window progress.
- **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.

Planning Community

Request access at
https://pjm.force.com/planning/s/

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

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

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

- **Appendix 1** – Transmission Owner Zones and Locational Deliverability Areas
- **Glossary**
- **Topical Index**
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- **Appendix 5 –** RTEP Project Statistics

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Section 6: State Summaries

- Added Map 6.6: Northern Illinois Generation Deactivations (Dec. 31, 2023) and Table 6.8: Northen Illinois Generation Deactivations (Dec. 31, 2023) in Section 6.2.5 to include 2023 deactivation requests received in previous years, p. 110.
- Replaced Map 6.37: Ohio Generation Deactivations (Dec. 31, 2023) and updated Table 6.46: Ohio Generation Deactivations (Dec. 31, 2023) in Section 6.9.5 to include 2023 deactivation requests received in previous years, p. 186.
- Replaced Map 6.42: Pennsylvania Generation Deactivations (Dec. 31, 2023) and updated Table 6.52: Pennsylvania Generation Deactivations (Dec. 31, 2023) in Section 6.10.5 to include 2023 deactivation requests received in previous years, p. 210.
- Replaced Map 6.48: Virginia Generation Deactivations (Dec. 31, 2023) and updated Table 6.60: Virginia Generation Deactivations (Dec. 31, 2023) in Section 6.12.5 to include 2023 deactivation requests received in previous years, p. 233.
- Corrected project costs in Section 6.2.6 — Baseline Projects, Table 6.9: Northern Illinois Baseline Projects (Dec. 31, 2023), pp. 111–112.
- Corrected project cost in Section 6.3.5 — Baseline Projects, Table 6.15: Indiana Baseline Projects (Dec. 31, 2023), p. 122.
- Corrected project cost in Section 6.5.6 — Baseline Projects, Table 6.27: Maryland/District of Columbia Baseline Projects (Dec. 31, 2023), pp. 147–149.
- Corrected project cost and TO zones in Section 6.10.6 — Baseline Projects, Table 6.53: Pensylvania Baseline Projects (Dec. 31, 2023), pp. 211–213.

KEY 2023 HIGHLIGHTS

In 2023, PJM's RTEP process identified 48 new baseline projects at an estimated cost of around $6.6 billion to maintain fundamental grid reliability. Additionally, 93 new network transmission projects at an estimated cost of $180 million are required to enable the reliable delivery of generation seeking interconnection into PJM markets.

PJM and its stakeholders continue to work to identify challenges and craft solutions toward maintaining a reliable grid amid a historic energy transition marked by:

The retirement of large conventional steam-powered generators and an increase in interconnection requests from renewable resources whose operating characteristics differ from retiring generation

- In 2023, PJM received over 30 deactivation notifications totaling over 5.8 GW.
- Approximately 40% of new interconnection requests to the PJM grid are solar resources, and almost 11% are wind resources.
- In 2023, PJM issued a total of 240 System Impact and Facilities studies for a total of 17.6 GW.

The proliferation of new data centers, creating major pockets of significant, increasing demand

- The PJM Board approved baseline projects in 2023 totaling over $5 billion to address reliability criteria violations as part of 2022 RTEP Window No. 3. This includes transmission enhancements driven by 7,500 MW of data center load growth in the Dominion Energy and Allegheny Power (FirstEnergy) zones.

The electrification of the transportation, industrial and building sectors

- As a result, PJM now projects its RTO-wide summer normalized peak to grow 0.8% annually over the next 10 years, which is up 0.4% points from its 2022 forecast.

Additional milestones:

In 2023, PJM updated its analysis and models to reflect the approval of a new generator deliverability study process as well as block dispatch.

Throughout the year, PJM held a series of Long-Term Regional Transmission Planning Workshops in order to gather stakeholder feedback on proposed enhancements to PJM's long-term planning process.

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Section 1: 2023 Year in Review

1.0: Executive Summary

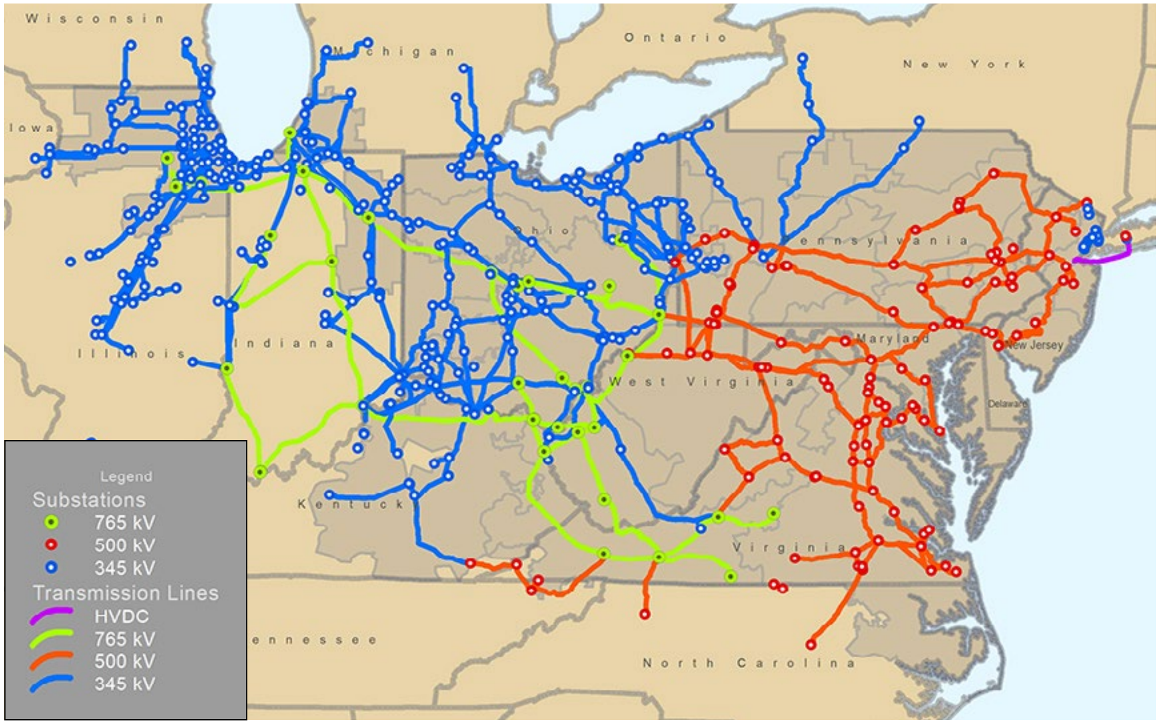
The PJM Regional Transmission Expansion Plan (RTEP) Report is published annually to convey planning study results throughout the year and to explain the rationale behind transmission system enhancement needs. The report also examines trends that continued throughout 2023 and will drive PJM's grid of the future, including the ongoing shift from fossil fuels to renewables and the impact of public policy.

1.0.1 — Regional Planning

PJM, a 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.

PJM's RTEP process identifies transmission system additions and improvements needed to serve more than 65 million people throughout 13 states and the District of Columbia. 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 183,000 MW of generation capacity over 88,000 miles of transmission lines.

Map 1.1: PJM Backbone Transmission System



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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, they formally become part of PJM's RTEP. PJM recommendations can also include the removal of, or change in scope to, previously approved projects. Forecast 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

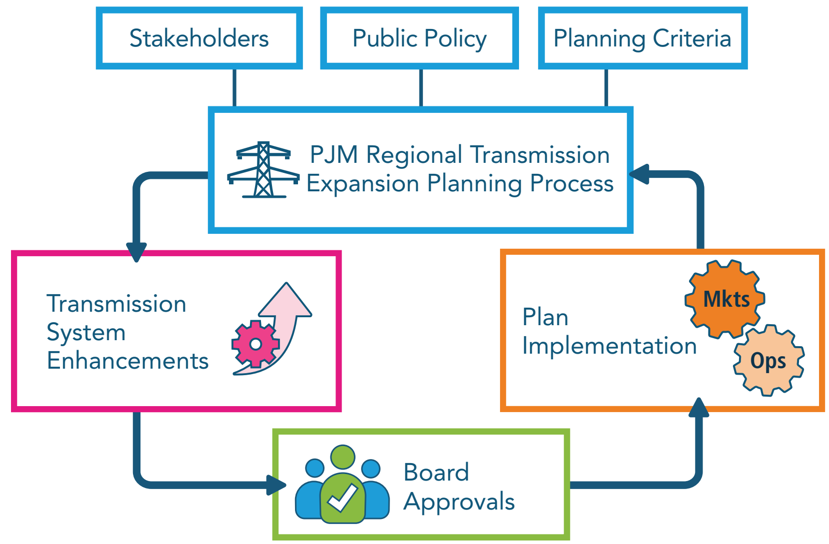
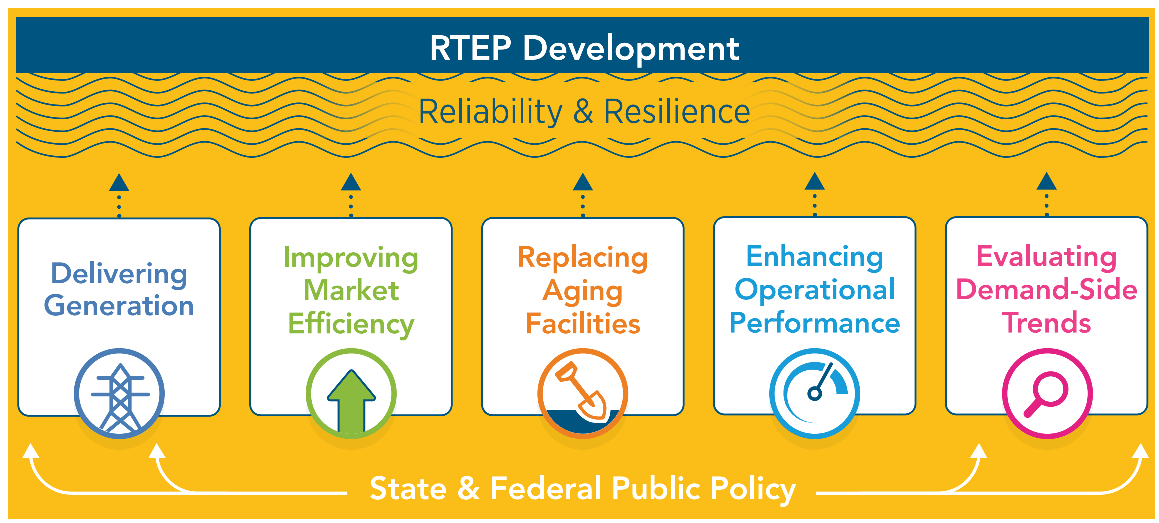


Figure 1.2: : System Enhancement Drivers



system compliance with the thermal, reactive, stability and short-circuit 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 2023 appear in **Section 3.** Details of specific large-scale projects are presented in **Section 6.**

1.0.2 — 2023 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 2023 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 48 new baseline projects during 2023 at an estimated $6.6 billion to ensure that fundamental system reliability criteria across the grid are met.
- The Board also approved the inclusion of 93 new network transmission projects at an estimated $180 million into the RTEP.

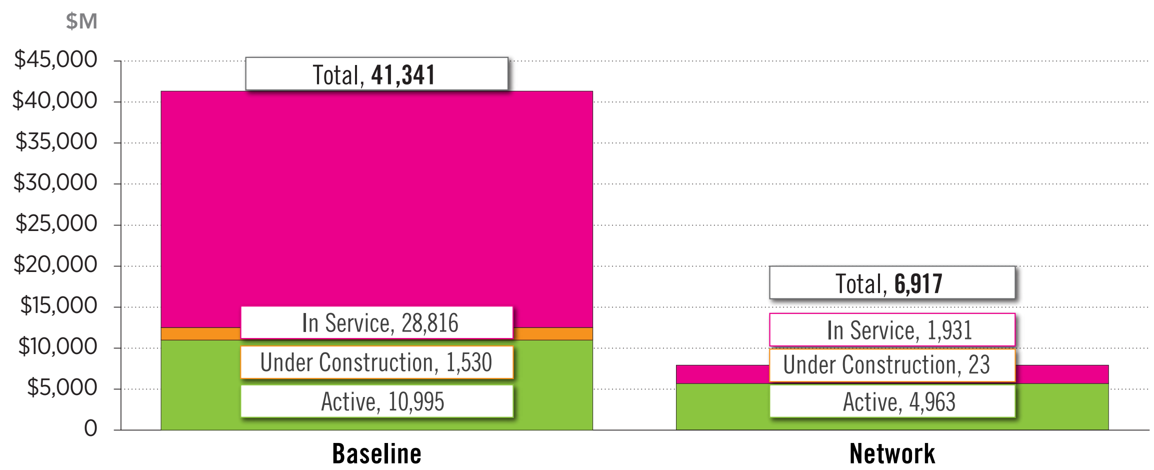
Since the RTEP process was implemented in 1997, the PJM Board has approved transmission system enhancements totaling approximately $48.3 billion. Of this, approximately $41.3 billion represents baseline projects to ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency congestion relief. An additional $6.9 billion represents network facilities to enable the reliable interconnection of new generation on the PJM system. A summary of projects by status as of Dec. 31, 2023, 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, 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 2023 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 Services 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

Figure 1.3: Board-Approved RTEP Projects as of Dec. 31, 2023



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 TO follow up.

RTO Annual Load Growth

PJM's 2023 RTEP baseline power flow model for study year 2028 was based on the 2023 PJM Load Forecast Report, summarized in **Section 2,** and shows a 10-year RTO summer, normalized peak growth rate of 0.8% per year. Average 10-year-annualized summer growth rates for individual PJM zones ranged from -0.7% to 5.0%. 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. However, in 2023, PJM also 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, 2023, renewable resources continue to represent a significant portion of PJM's New Services Requests, as discussed in **Section 1.1**.

Solar-powered resources total nearly 113,000 MW of Capacity Interconnection Rights (CIRs), or around 42%, of the nearly 266,000 MW of CIRs resources in PJM's New Services Requests, as shown in **Figure 1.5**. Solar generation has overtaken natural gas in PJM's New Services Requests. Natural gas plants total nearly 65,000 MW of CIRs and constitute around 24% of requested generation interconnections.

With respect to resource deactivation, i.e., supply exit, more than 42,000 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 2023, PJM continued to receive deactivation notifications (31 units totaling 5,844.8 MW), the impacts of which are discussed in **Section 3.3.**

1.1: Generation Landscape

PJM's 180,287 MW of RPM-eligible existing installed capacity reflects a fuel mix of 48.4% natural gas, 22.1% coal and 18.1% nuclear, as shown in **Figure 1.4.** Hydro, wind, solar, oil and waste fuels constitute the remaining 11.4%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility.

Totaling nearly 125,000 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM's interconnection process. Solar energy makes up 40% of the generation in PJM's interconnection New Services 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, under construction or as of Dec. 31, 2023.

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 Services Requests as of Dec. 31, 2023, for CIRs totaled around 21,088 MW of wind-powered generators that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 37,263 MW. Solar-powered generator requests for CIRs totaled 74,726 MW that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 106,070 MW.

Figure 1.4: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2023)

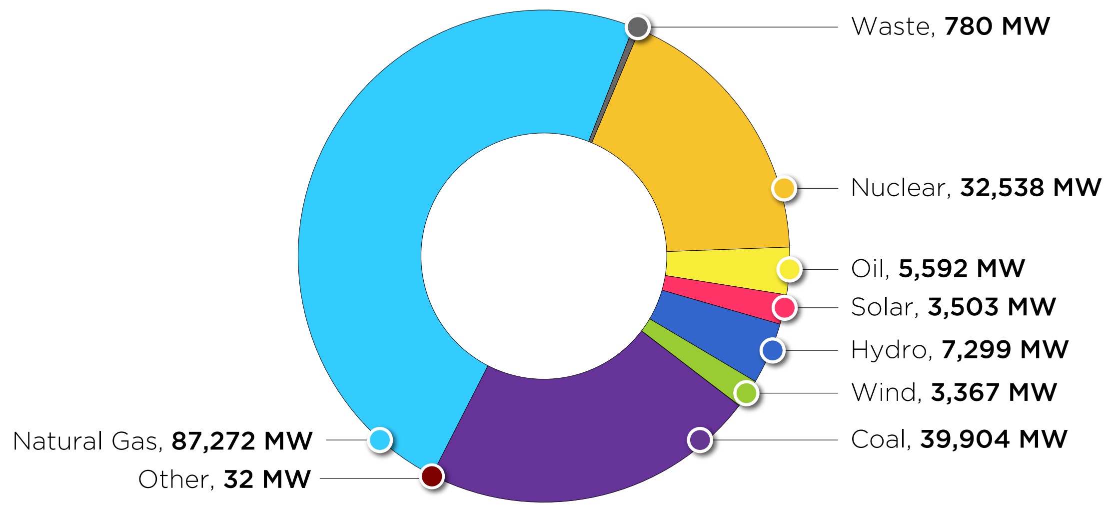
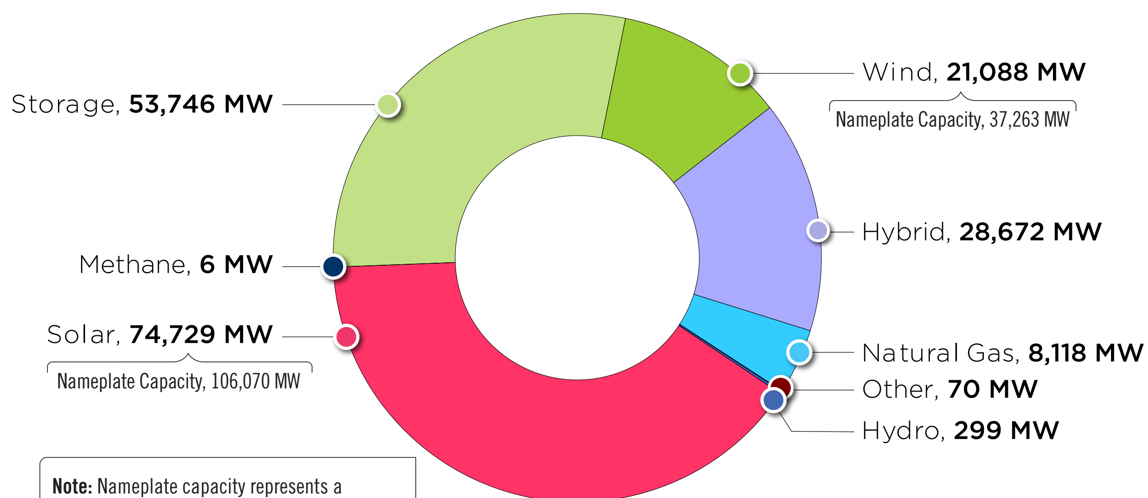


Figure 1.5: Interconnection Service Request Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2023)

		In Queue				Complete					
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	3	65.0	52	2,137.9	70	33,577.6	125	35,780.5
	Diesel	1	0.00	0	0.0	10	68.5	17	76.70	28	145.2
	Natural Gas	38	5,278.4	12	2,287.6	396	57,419.4	704	253,008.1	1,150	317,993.5
	Nuclear	0	0.0	1	44.0	46	3,940.2	24	9,038.0	71	13,022.2
	Oil	0	0.0	0	0.0	24	543.8	25	2,318.0	49	2,861.8
	Other	6	69.7	0	0.0	6	332.8	78	1,112.2	90	1,514.7
	Storage	626	53,644.2	26	799.2	30	32.0	362	11,439.6	1,044	65,915.0
Renewable	Biomass	0	0.0	0	0.0	8	153.8	40	896.9	48	1,050.7
	Hydro	7	299.3	3	35.0	32	1,155.9	53	2,440.9	95	3,931.0
	Methane	1	6.0	0	0.0	77	365.0	95	490.1	173	861.1
	Solar	1,904	98,470.6	296	10,926.4	291	3,613.2	2,008	44,743.0	4,499	157,753.2
	Wind	156	20,797.6	24	1,215.0	117	2,160.8	522	18,361.2	819	42,534.5
	Wood	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
	Grand Total	**2,739**	**178,565.7**	**365**	**15,372.2**	**1,091**	**71,977.2**	**4,002**	**377,655.2**	**8,197**	**643,570.3**

Note: Table does not include suspended projects, and hybrid resources are imbedded within the fuel type (e.g., solar + storage is captured under "Solar," wind + storage is captured under "Wind," and natural gas also includes some hybrid resources).

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 are 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 Services 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 Services Requests

Interconnection Activity

As part of the interconnection process, PJM performs Feasibility, System Impact and Facilities 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.

Table 1.2: Interconnection Service Study Requests (Dec. 31, 2023)

	Projects	Nameplate Capability (MW)	Capacity (MW)
Active	2,739	229,538	178,565.7
In Service	1,091	86,434	71,977.2
Under Construction	369	29,233	15,477.4
Withdrawn	4,001	495,586	377,655.2
Total	**8,200**	**840,791**	**643,675.5**

New Services Request Activity

Through 2023, PJM markets have attracted generation proposals totaling 643,676 MW, as shown in **Table 1.2**. Over 178,566 MW capacity of New Services Requests were actively under study, and over 15,477 MW capacity were under construction or suspended as of Dec. 31, 2023. 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.

Figure 1.6: Interconnection Service Study Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

15.8% Requested capacity megawatts

20.4% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	227	Interconnection Service Agreements	33,166 MW	42,636 MW
	390	Wholesale Market Participation Agreements	1,560 MW	3,140 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

Interconnection Progression History

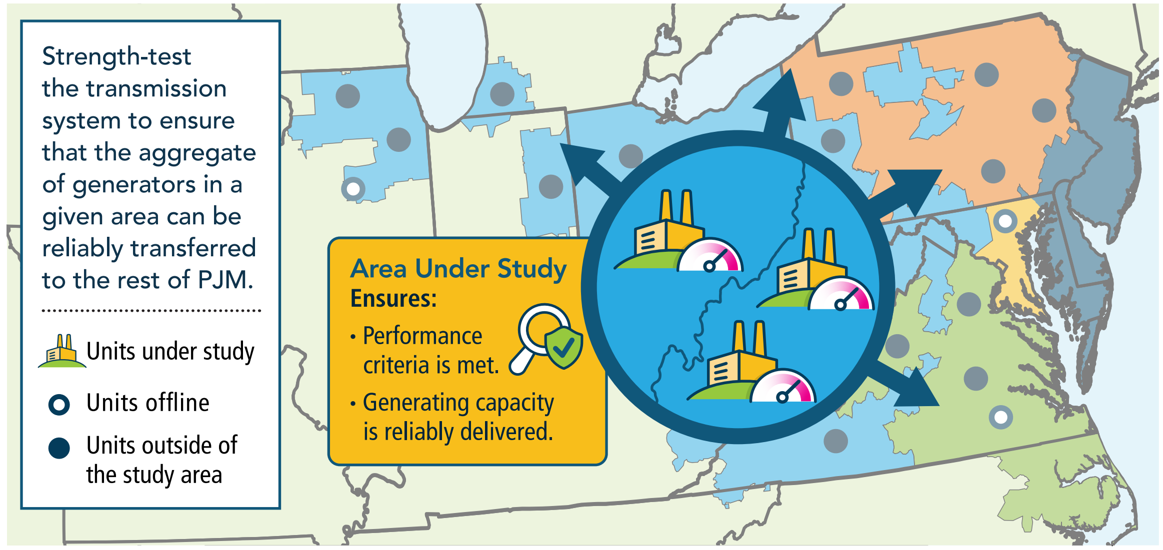
PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. **Figure 1.6** shows that for all generation (both new resources and existing plant uprates) submitted in Queue A (1999) through Dec. 31, 2023, 74,294 MW (or 15.8%) reached commercial operation. As **Figure 1.6** also shows, 33,166 MW (or 7%) of that accounts for withdrawals from the interconnection process after Interconnection Service Agreement (ISA) execution, and 1,560 MW (or 0.3%) represents withdrawals after wholesale market participant agreement (WMPA) execution, but before construction. Overall, 20.4% 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 Services 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 $6.9 billion since the inception of the RTEP process in 1997. The PJM Board approved the incorporation of 93 new network system enhancements totaling over $180 million into the RTEP in 2023 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.**

Figure 1.7: Generator Deliverability Concept



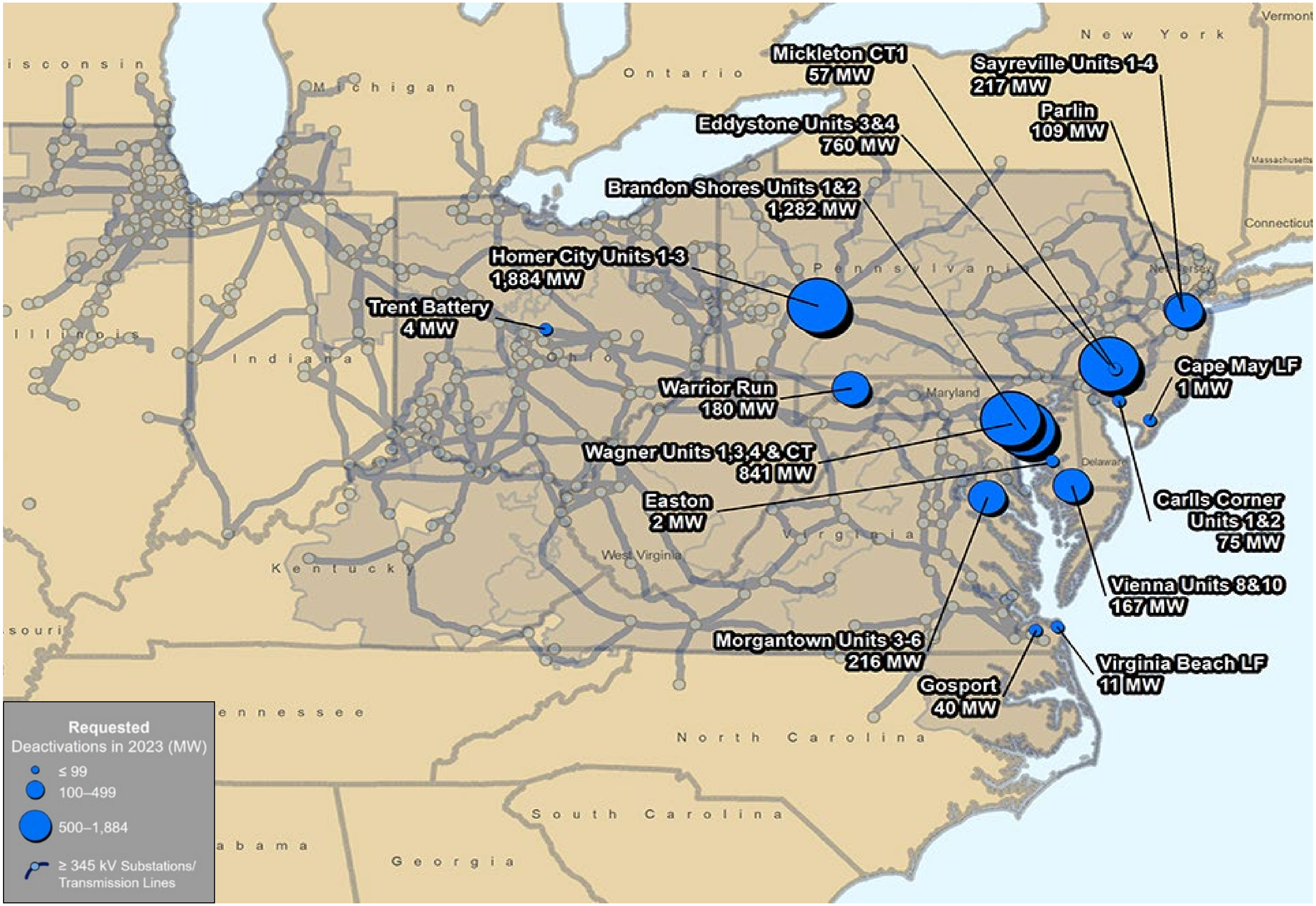
1.1.2 — Deactivations

PJM received 31 deactivation notifications in 2023 totaling 5,844.8 MW. **Map 1.2** shows the deactivation request locations received between Jan. 1, 2023, and Dec. 31, 2023.

Generator owners requested that the deactivation of these units takes place between October 2023 and June 2025. PJM maintains a list of formally submitted deactivation requests, which is available on the PJM website.

PJM has 60 days after the end of the quarter in which the notice was received, to respond to a generator owner with deactivation study results. 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 2023



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:

1. Individual generation resources larger than 20 MVA, or a generation plant with aggregate capacity greater than 75 MVA, that is connected via step-up transformer(s) to facilities operated at voltages of 100 kV or higher
2. Lines operated at voltages of 100 kV or higher
3. 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 P0 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.

- P0 – 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.

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

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 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:

1. A single protective relay
2. A single communication system associated with protective functions

3. A single-station dc supply associated with protective functions
4. 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:

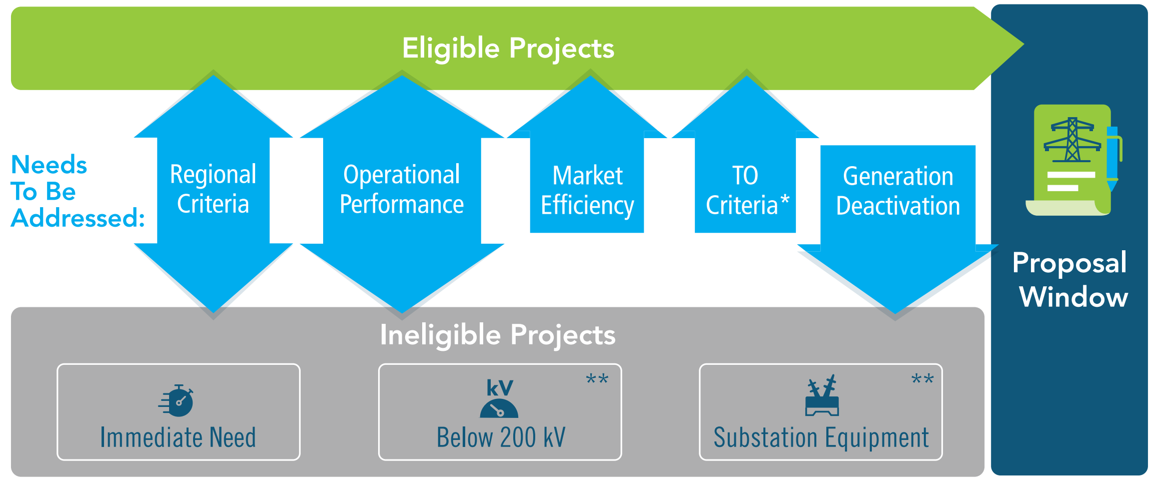
1. Selected known outage(s) of transmission facility(ies) or generation
2. The unavailability of major transmission equipment that has a lead time of one year or more in the near-term planning horizon

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.*

2023 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.

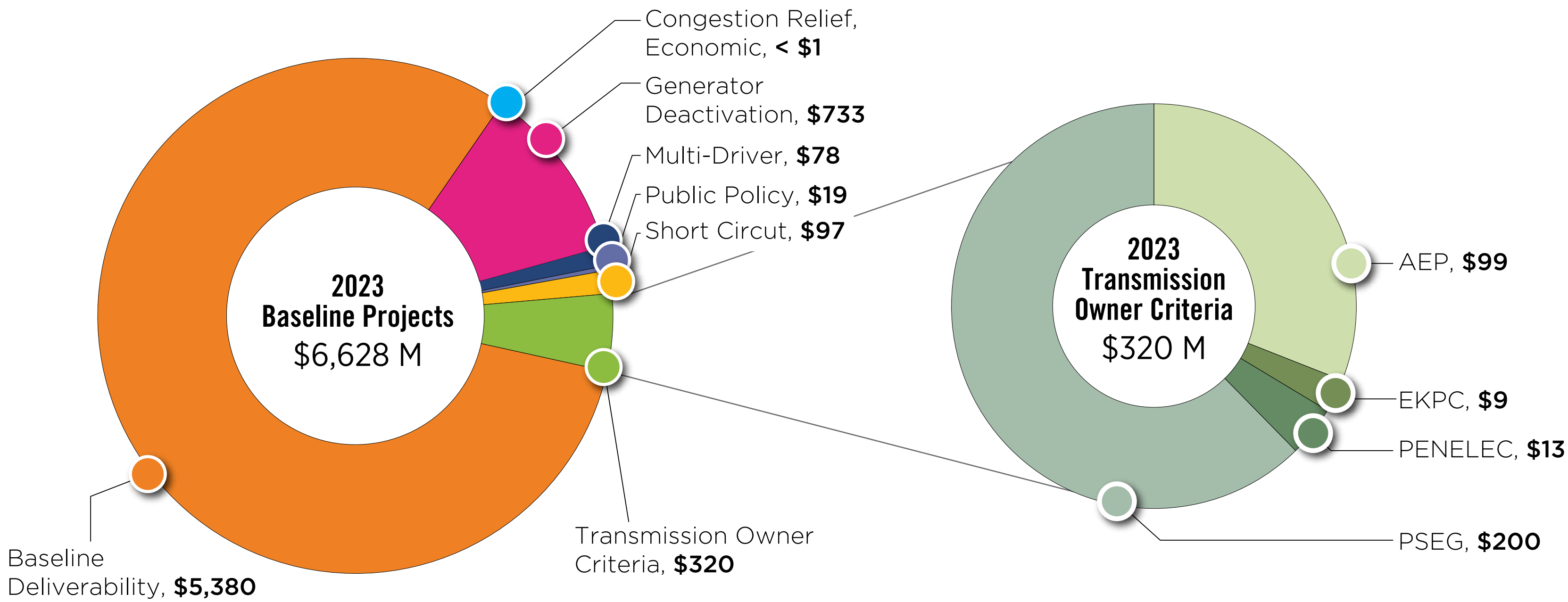
In other instances, TO criteria encompass local loss-of-load thresholds, particularly on radial facilities. The threshold for some is on a megawatt-mile basis, others on a megawatt-magnitude basis, to reduce the extent of load impacted under contingency or outage conditions.

Section 3.1 summarizes TO criteria-driven transmission projects with cost estimates greater than or equal to $10 million, as approved by the PJM Board in 2023.

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: 2023 RTEP Baseline Project Drivers ($ Million)



2023 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 in 2023 were no different, as discussed in later sections of this report and summarized in **Figure 1.9.** As the figure shows, baseline transmission investment, once primarily made up of projects driven by deliverability, now also includes projects driven by other factors, like public policy via the New Jersey State Agreement Approach.

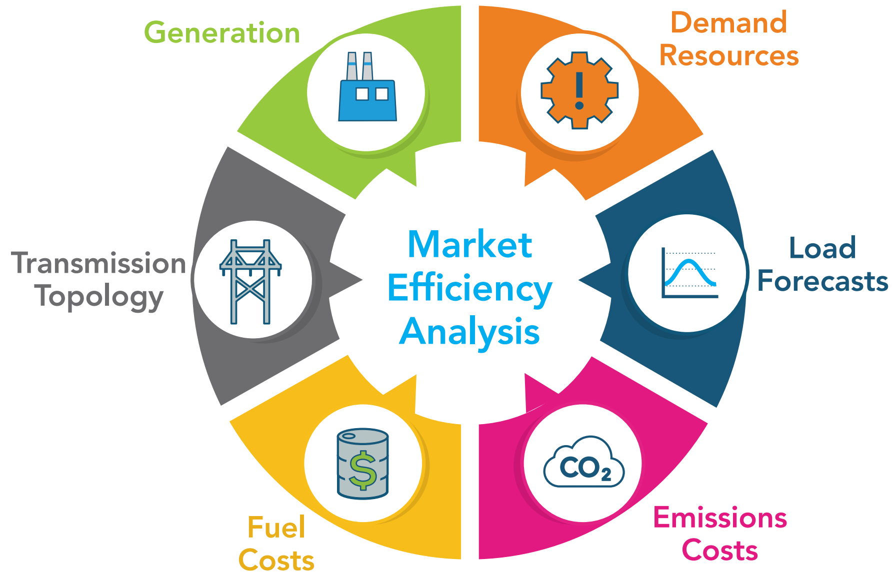
Market Efficiency

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: Future of Regional Transmission Planning

In 2023, PJM and its stakeholders continued to focus transmission planning efforts around the RTO's core challenge: maintaining a reliable grid amid the retirement of large conventional steam-powered generators, increasing demand for electricity, and additional renewable resources whose operating characteristics differ from retiring generation. The generation fueled by fossil fuels (mostly coal and natural gas) upon which PJM relies to balance the grid is retiring at a significant rate.

Overall, new generation is coming online slower than anticipated. Overall, generator retirements are outpacing that new generation that is replacing it. As a result, PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load. PJM could be at risk of facing resource adequacy challenges if these trends continue.

This situation is not unique to PJM. These challenges are emerging across the country and throughout the world. If current trends continue, PJM will experience an elevated risk of resource adequacy shortfalls later in this decade.

1.3.1 — Increasing Demand for Electricity

Load forecasting fundamentally helps PJM make decisions about how to plan and operate the bulk electric system in a reliable manner and how to administer competitive power markets effectively.

Impacts of Data Centers and Electrification

Although load growth has been relatively flat in recent years, PJM is now expecting the energy growth rate to increase significantly, driven by the electrification of transportation and the industrial and building sectors. In addition, PJM is also experiencing significant data center construction, creating major pockets of significant, increasing demand.

PJM's 2023 long-term load forecast shows an energy growth rate of 1.4% per year for the PJM footprint over the next 10 years. Due to the expansion of highly concentrated clusters of data centers, combined with overall electrification, certain individual zones exhibit more significant demand growth, as high as 7% annually, based on the 2023 PJM Load Forecast Report.

NOTE:

On February 24, 2023, PJM published the Energy Transition in PJM: Resource Retirements, Replacements & Risks report.

Section 1.3 describes a range of initiatives on which PJM is working with stakeholders.

Each sub-section includes milestones achieved in 2023 to show PJM's efforts towards maintaining a reliable transmission system amid a historic energy transition.

2023 MILESTONE: Increasing Demand for Electricity

Accounting for Data Centers and Electrification

As discussed later in **Sections 2.0** and **2.1**, PJM's 2023 Load Forecast Report addressed the impact of industry changes that are reshaping system hourly loads. As a result, the level and timing of coincident peak and non-coincident peak demands across PJM have begun to shift. Solar-power penetration, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are markedly increasing the complexity of PJM's load forecasting process.

Driven by discrete and localized load growth, like Data Center Alley in Loudoun County, Virginia, in 2022, PJM and stakeholders conducted a review of data center load growth and identified growth rates of over 300% in some instances. As a result, the 2023 PJM Load Forecast Report incorporates adjustments to specific zones for data center load growth and electrification, as shown in **Figure 1.11.**

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 variations in weather conditions, economic activity and technological changes (e.g., efficiency improvements, distributed resources).

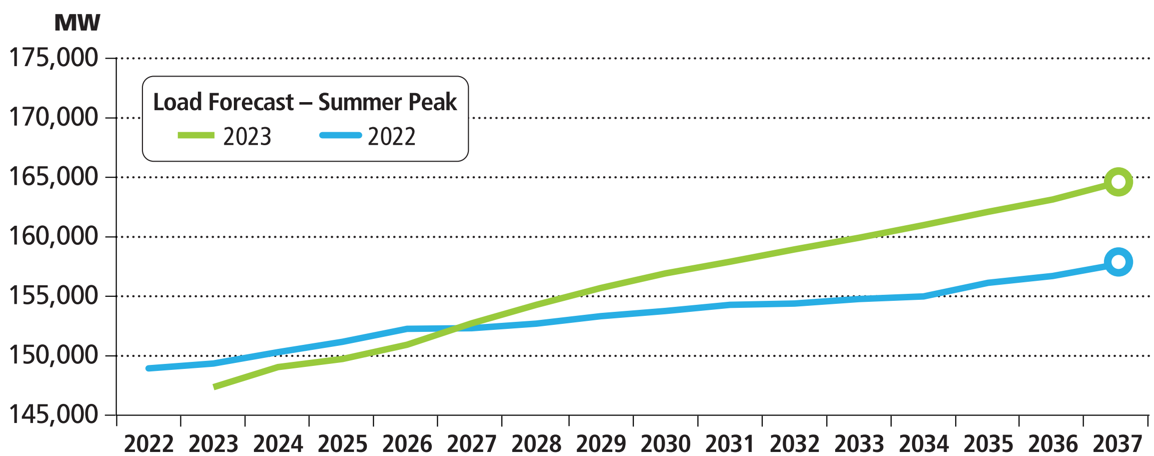
PJM implemented a number of changes to the 2023 load forecasting process to improve model accuracy including:

- **More granular data** – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heating, cooling and other non-weather-sensitive load.
- **Moving to an hourly framework** – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- **Longer-range load adjustment forecasts** – Higher expectations for data center loads now incorporate 15-year forecasts from impacted electric distribution companies (EDCs).

The 2024 Load Forecast Report is building on these changes with the assistance of vendor-supplied electric vehicle forecasts. PJM has also enhanced its load forecasting model to:

1. Include an additional cold weather variable that allows better forecast model calibration at colder temperatures.
2. Add more transparency and clarity around the large load adjustment process as reflected in PJM Manual 19: Load Forecasting and Analysis, Attachment B.

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



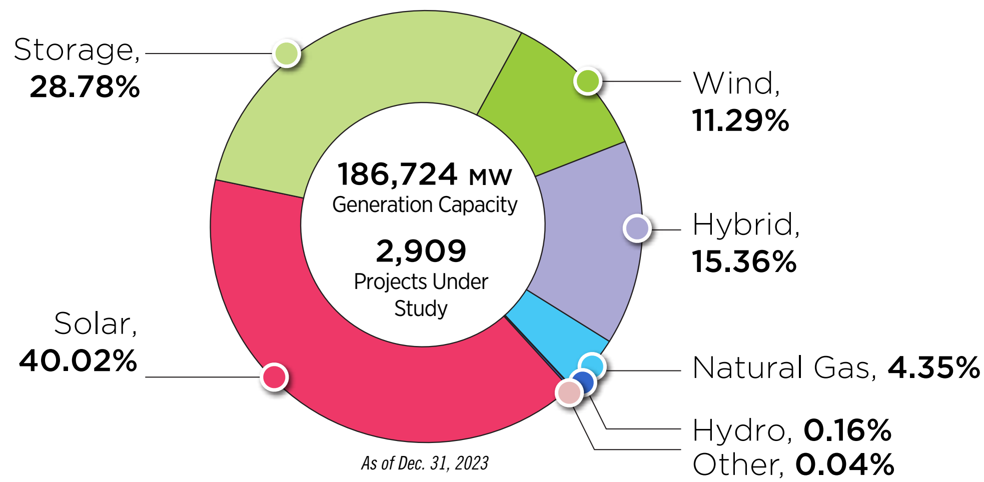
1.3.2 — Enabling the Energy Resource Transition

As with the entire U.S. electric grid, PJM is experiencing an accelerating transition toward intermittent renewable generation. Public policy, economics and consumer choices are shifting the grid away from dispatchable, carbon-emitting generation resources toward intermittent generation with little-to-no carbon emissions.

As generation retires, markets work to incentivize replacement generation. New requests to connect to the PJM grid are almost exclusively renewable resources and batteries – 96% – including 40% solar resources and 11% wind resources, as shown in **Figure 1.12**. An additional 29% of interconnection requests are from storage resources and 15% from hybrids of batteries co-located with renewables (primarily solar).

Looking out over the next eight to 10 years of the energy resource transition, maintaining an adequate level of generation resources with operational and physical characteristics that support reliability will be crucial for PJM's ability to serve electrical demand reliably. Observations from recent PJM analyses and reports have identified the trends below that, collectively and comprehensively, increase future challenges in procuring adequate levels of generation resources with the attributes needed to serve customers reliably.

Figure 1.12: Capacity Makeup of PJM Interconnection Request Process



Replacement Generation Impacts

Dispatchable generators, i.e., those generators that can quickly respond to directions from PJM operators regardless of weather, are retiring at a rapid, date-certain pace, driven in large part by state and federal environmental and other public policies. Although "dispatchable generators" today largely refer to fossil-fuel-powered resources, longer-duration batteries and potentially other technologies in the future could also serve in this role to the extent they can economically do so.

Growing levels of intermittent and limited-duration resources, such as wind, solar and battery storage, do not replace conventional large-scale generation installations megawatt-for-megawatt, but rather 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.

PJM has undertaken cross-functional initiatives to enhance its markets, operations and planning functions to properly accredit the relative risks of different types of generation resources for meeting winter and summer electricity demands and value those resources that present less outage risk to the system as a whole.

Future of Planning and the Need for an ELCC Methodology

PJM continues to witness extraordinary growth in energy storage and intermittent generating resources, such as wind, solar and other renewable resources. As a result, the manner in which PJM has historically evaluated the contribution of such resources toward resource capacity value has also evolved.

Prior to 2021, when the Effective Load Carrying Capability (ELCC) methodology was implemented, PJM calculated the resource capacity value of an intermittent resource (e.g., wind, solar and energy storage), and that which historically has been labeled as "limited duration," by a methodology independent of changes to the overall resource mix. This meant that a resource's capacity capability and its contribution toward meeting PJM's resource adequacy requirements would not have been impacted by the amount of renewables and energy storage within the RTO as a whole. This initially drew PJM's attention and concern in 2018, given that increasing amounts of intermittent and limited-duration resources impact PJM's hourly loss-of-load probability (LOLP) risk profile. Without recognizing this dynamic, PJM may have been overvaluing or undervaluing intermittent and limited-duration resource contribution to resource adequacy over time.

More specifically, prior to 2021, the capacity value of wind- and solar-powered resources was set at each resource's average output over a defined number of summer peak load hours. This approach has limitations, including:

1. Output is weighted over all hours equally, regardless of an individual hour's actual contribution to the annual loss-of-load risk.
2. Saturation effect as the amount of intermittent resources in PJM increases is not recognized.

To address these limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an ELCC methodology that encompasses the following:

- Measures the performance of each resource over all 8,760 hours of the year
- Recognizes the performance of the resource over the critical high-load, high-risk hours
- Recognizes the declining reliability value of wind, solar and storage resources as their penetration level increases

PJM and stakeholder efforts culminated in OATT and Reliability Assurance Agreement (RAA) changes that were filed with FERC on Oct. 30, 2020, based on a member-endorsed solution package. On July 30, 2021, FERC approved PJM's ELCC proposal to evaluate the contribution that intermittent and energy storage resources provide to PJM's resource adequacy. An ELCC study is run annually producing ELCC Class Ratings that serve as inputs to determine the accreditation that an intermittent or energy storage resource receives to participate in PJM's capacity market.

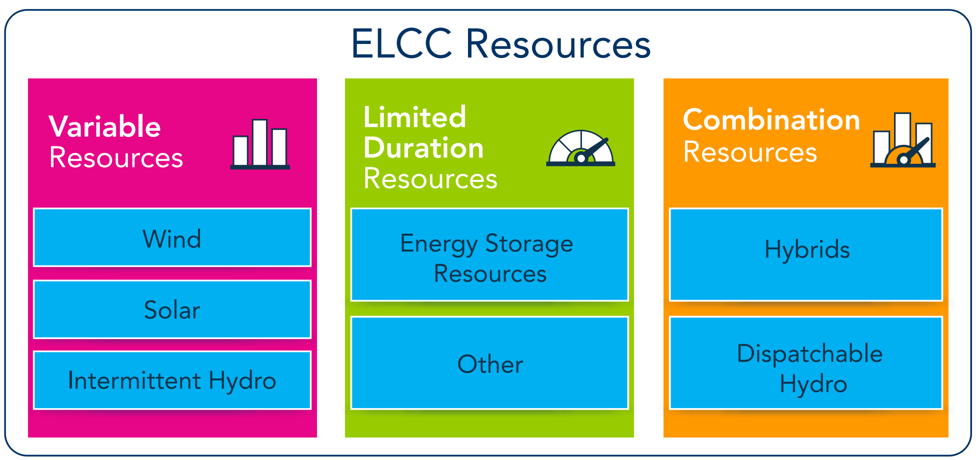
2023 MILESTONE: Enabling the Energy Resource Transition

ELCC Resource CIR Certainty

As discussed later in **Section 2.3**, the PJM Planning Committee (PC) recognized and initiated a stakeholder process in 2021 to review and modify existing CIR request and retention policies, with an emphasis on ELCC resources, to provide certainty around ELCC resource CIR values and unforced capacity (UCAP) valuation. More specifically, PJM and stakeholders developed a consensus package of reforms designed to more closely integrate CIRs into PJM's capacity accreditation process for generators that have been designated ELCC resources as shown in **Figure 1.13**.

- **Variable Resources:** Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run-of-river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of hydropower with non-pumped storage.
- **Limited Duration Resources:** Generation Capacity Resource that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.
- **Combination Resources:** Generation Capacity Resource that has a component that has the characteristics of a Limited Duration Resource combined with: (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource

Figure 1.13: ELCC Resources



PJM and stakeholder discussions throughout 2021 and 2022 led to stakeholder approval of a consensus package of reforms on Jan. 25, 2023, to more closely integrate CIRs into PJM's capacity accreditation process for ELCC resources.Implementation of the reforms will address the initial assignment of CIRs, the retention of CIRs through the implementation of appropriate testing procedures, the inclusion of CIRs in resource adequacy studies, and the role of CIRs in determining an ELCC resource's UCAP.

2023 MILESTONE: Enabling the Energy Resource Transition

ELCC Resource CIR Certainty (Continued)

Looking Forward

The PJM Board of Managers initiated the Critical Issue Fast Path (CIFP) stakeholder process by letter on Feb. 24, 2023, to address resource adequacy challenges in the PJM Reliability Pricing Model or capacity market. In the letter, the Board identified key topics as the focus of the initiative including the following with a bearing on the future of planning:

- **Enhanced risk modeling.** In particular, the Board asked to improve the way PJM accounts for winter risk and correlated outages in its reliability planning.
- **Evaluation of potential modifications to the Capacity Performance construct and alignment of permitted offers to the risk taken by suppliers.** The Board noted that it is appropriate to evaluate whether changes are needed to the Capacity Performance construct and to ensure that market sellers are able to reflect the risk of taking on a capacity obligation in their capacity market offers.
- **Improved accreditation.** The Board stated that it is necessary to enhance PJM's accreditation approach to ensure that the reliability contribution of each resource is accurately determined and aligned with compensation.
- **Synchronization between the RPM and Fixed Resource Requirement (FRR) rules.** The Board noted that it would like any changes in RPM rules to also be mapped to FRR rules to ensure that supply resources and consumers are held to comparable standards.

During most of 2023, as part of the CIFP-Resource Adequacy process, stakeholders and PJM staff developed and reviewed multiple solutions for the above topics, culminating with a set of capacity market reforms submitted to FERC in October 2023. Since then, FERC accepted several enhancements, including the adoption of enhanced risk modeling and improved accreditation in Docket No. ER24-99, and separately rejected other proposed capacity market reforms in Docket No. ER24-98.

Note:

FERC approved Docket No. ER24-99 on Jan. 30, 2024. The approved changes include moving to an hourly resource adequacy model, capturing all supply-side uncertainty in accreditation, as well as utilizing marginal resource accreditation for all resources.

2023 MILESTONE: Enabling the Energy Resource Transition

Modeling Operating Conditions More Closely

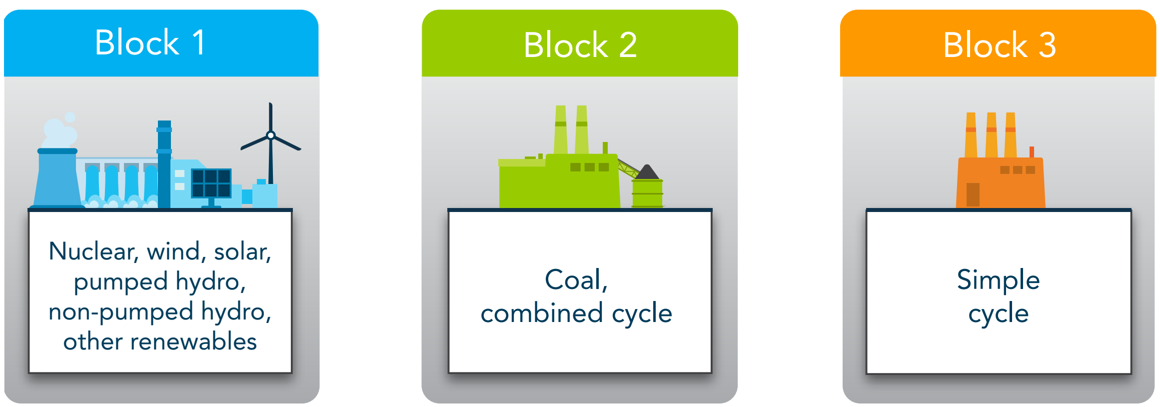
Generator Deliverability Process Modifications

As described in **Section 1.1.1,** 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.** PJM updated its testing methodology in 2023 to better account for expected higher variability in dispatches under increased renewable penetration. Doing so will ensure better planning alignment with operational experience and improve variable resource modeling in RTEP studies.

Prior to process modifications in 2023, PJM's generator deliverability test did not dispatch generation in the same way as PJM's real-time operations and therefore did not accurately reflect the behavior of PJM's rapidly evolving resource mix toward more intermittent generation. In short, instead of dispatching generation in merit order (i.e., by least cost), prior to 2023, the generator deliverability test relied on historic capacity factors to derate all generation.

The new testing approach better aligns with economic dispatch in actual operations. The modified process adds a new block dispatch approach to dispatch cases in which Locational Deliverability Area imports will be limited to their Capacity Emergency Transfer Objective (CETO) in the base case. Additionally, only firm interchange will be modeled in the base case with separate, simplified procedures for performing historical interchange sensitivity analysis.

Under this block dispatch approach, generating resources are grouped into three distinct categories based on economic considerations. Block 1 contains units expected to have the lowest offer prices, while Block 3 contains units expected to have the highest. Blocks are dispatched in successive order, as needed:



Doing so better matches how PJM will dispatch the system versus the prior approach that relied on flat dispatch for summer and historic conditions to dispatch the winter and light-load cases.

Transmission Facility Ratings: Light-Load Planning Studies

In 2023, PJM updated Manual 14B for the light-load period for planning studies. The published line and transformer daytime thermal ratings at ambient temperatures of 50° F (10° C) winter, 95° F (35° C) summer and 59° F (15° C) light load will be used as the default rating sets for all facilities. PJM will apply alternate transmission owner ambient temperature rating sets wherever variations exist. Doing so more closely models seasonal operating conditions.

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1.3.3 — Managing New Services Requests

PJM is responsible for evaluating requests from new generation seeking to interconnect to the regional PJM grid. Over the course of just a few years, PJM's interconnection queue transformed from one dominated by large natural gas projects to a queue dominated by many smaller, new renewable resources.

PJM's generation interconnection request activity reflects substantial development of renewable resources driven by public policy, corporate goals and customer interest. Delays in processing the volume of projects PJM is experiencing is the result of a queue filled with many instances of single developers submitting multiple, speculative, low-cost interconnection requests even though their intentions have been to build only one such project.

In October 2020, PJM and stakeholders began working together to create a plan that streamlines generation interconnection requests, improves project cost certainty, and significantly improves the process by which new and upgraded generation resources are introduced onto the electrical grid. PJM's Planning Committee held four workshops, and the Interconnection Process Reform Task Force held 21 meetings to work through solutions for these problems.

As discussed later in **Section 5**, this work culminated in a vote on a proposal for reform that received overwhelming stakeholder support. Specifically, the reforms included:

- Moving from a serial queue process to a clustered cycle process for both studies and cost allocation
- Implementing multiple decision points at which those seeking interconnection-related services must provide readiness deposits and meet other threshold requirements to move forward, thus allowing projects that are ready to proceed to do so while incentivizing those that are not ready to exit the interconnection process
- Implementing a transition mechanism to ensure a timely transition to the new "first-ready, first-served" cycle approach while providing an expedited process for projects in the existing interconnection queue that are close to completing that process (the "Expedited Process")
- Consolidating PJM's interconnection-related service agreements and forms that will be used for the Part VII transition process and the Part VIII New Rules as set forth in new Part IX of the Tariff

The interconnection reforms were approved in their entirety on Nov. 29, 2022, in Docket No. ER22-2110. Transition to the new rules began in July 2023 to clear the backlog of projects. In order to do so, PJM has invested significantly in tools and automation, in parallel with additional in-house staff expertise and outside contractors.

2023 MILESTONE: Managing New Services Requests

Interconnection Process Reform

PJM's reformed interconnection process was implemented on July 10, 2023, setting the stage for more than 260,000 MW of mostly renewable projects to be studied over the next three years. More than 95% of these projects are renewables or batteries, or a hybrid of both. By the end of 2024, PJM expects to have cleared about 62,000 MW for connection, another 100,000 MW by the end of 2025, and an additional 100,000 MW by the end of 2026. More specifically, 734 generation projects were eligible to be evaluated in the first step of the new process. Of those, 118 either dropped out of the process or did not post sufficient readiness requirements by the due date, clearing the queue of projects that were much less certain to be developed yet would have otherwise required PJM time and resources to process and study.

2023 MILESTONE: Managing New Services Requests

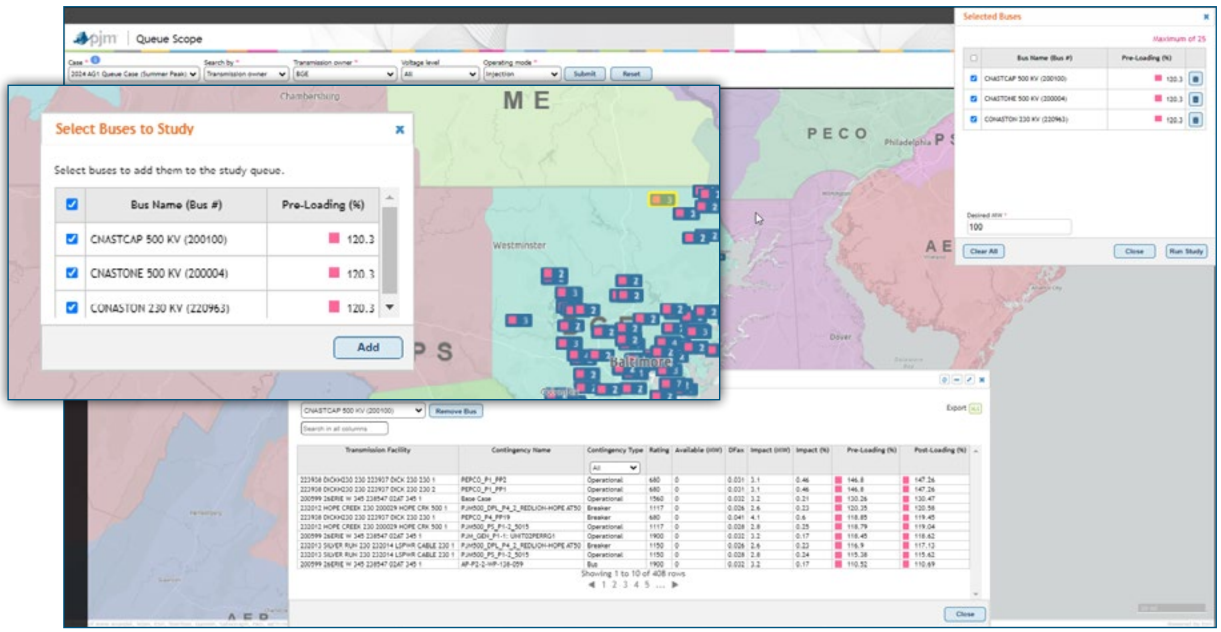
Queue Scope Grid Visualization Application

In December 2023, PJM launched an update to its public Queue Scope planning tool, which lets users, and generation developers in particular, visually evaluate the impacts of new generation on the power grid.

Integrated with PJM's system map, users can visualize how a generator impacts congestion on transmission lines as well as evaluate the potential transmission upgrades that would be needed to interconnect a generator without causing transmission line overloads or other reliability criteria violations.

The original version of Queue Scope, first made available in December 2022, relied on a tabular format alone to display information.

Queue Scope allows generation developers and other users to assess the location of future generators before they formally enter PJM's interconnection process. The tool screens potential points of interconnection (POI) on the PJM system by assessing grid impacts based on the amount of megawatt injection or withdrawal at a given POI by using RTEP power flow base cases and existing interconnection analysis study results.



The tool lets users overlay transmission lines, New Services Requests and generator deactivations within the map while reviewing POIs and running a generator evaluation. Queue Scope also includes a congestion overlay for the entire PJM footprint, which provides insight into the facility overloads by POI based on generation under study within the case. This overlay provides a visual representation of transmission headroom or the severity of facility overloads based on generation under study.

Queue Scope is one of a suite of modules that make up PJM's Planning Center, which is designed to facilitate data and information exchange as part of long-range planning studies.

NOTE:

Queue Scope is an informational tool and is not intended to be a substitute for actual interconnection studies conducted by PJM as part of its interconnection process. Queue Scope results are not reflective of current PJM system conditions and may not account for all study assumptions and considerations that would otherwise be considered in the formal study process.

1.3.4 — Supply Exit

PJM is undergoing a major transition in the resources needed to maintain grid reliability. Historically, thermal resources have provided the majority of the reliability services in PJM. Today, a confluence of unfolding industry events, including state and federal policy requirements, industry and corporate goals requiring clean energy, reduced costs and/or subsidies for clean resources, stringent environmental standards, age-related maintenance costs, and diminished energy revenues are hastening the decline in thermal resources.

A cross-functional energy transition study PJM completed in 2023 estimated anticipated retirements through 2030 by adding announced retirements with retirements likely as a result of various state and federal policies, and then with those at risk for retirement due to deteriorating unit economics. Potential policy-driven retirements, in this context, reflect resources that are subject to current and proposed federal and state environmental policies, in which it is conservatively assumed that the costs of mitigation and compliance could economically disadvantage these resources to the point of retirement.

As a result, PJM anticipates 40 GW of projected generation retirements by 2030, made up of the following:

- 12 GW of announced retirements
- 25 GW of potential policy-driven retirements
- 3 GW of potential economic retirements

Combined, this represents 21% of PJM's current installed capacity.

NOTE:
The grid implications of exiting generation are discussed in detail in the following PJM report: Energy Transition in PJM: Resource Retirements, Replacements & Risks, published on February 24, 2023.

2023 MILESTONE: Supply Exit

Streamlining CIR Transfers

Stakeholders at the June 6, 2023, Interconnection Process Subcommittee meeting approved an issue charge to examine how to enhance transfer of CIRs, which allow new generation to interconnect as a capacity resource, from deactivating resources to new generation. The goal is to develop a solution that both improves the efficiency of the process and clarifies that it applies to all energy-injecting capacity resource types.

The existing provisions in the PJM Tariff and related defined terms included in the Reliability Assurance Agreement (RAA) governing the CIR transfer process will be clarified to reduce confusion as to which capacity resource types the transfer process applies.

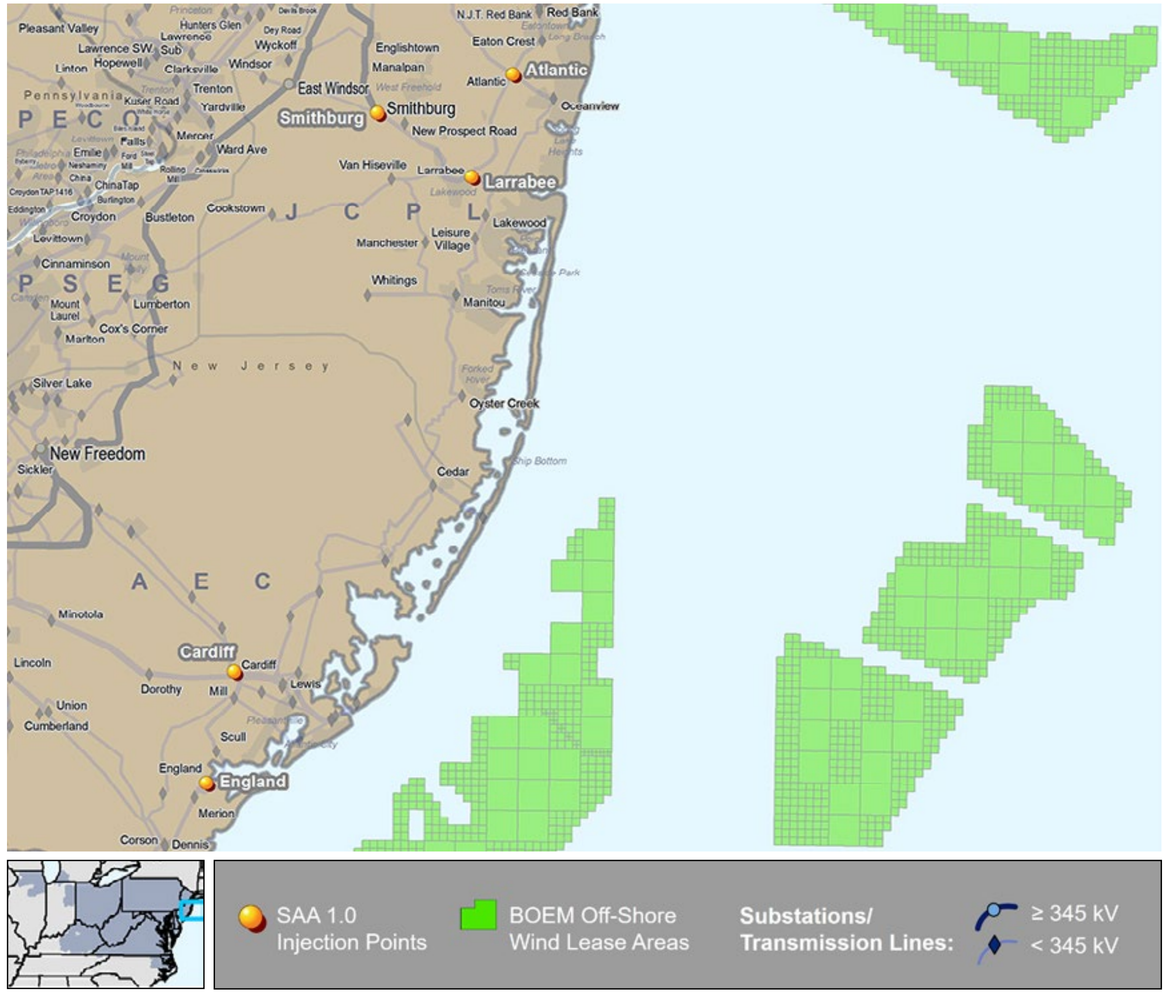
1.3.5 — State Agreement Approach – Enabling Offshore Wind

As part of baseline planning, PJM works with states to implement their public policy goals through various means, including what is called the State Agreement Approach (SAA). Under this approach, states that wish to build out the transmission system to meet state public policy initiatives, such as state-mandated offshore wind goals, can utilize the PJM planning process to efficiently develop and implement needed grid expansions.

New Jersey became the first state to implement the SAA process in November 2020 when the New Jersey Board of Public Utilities (NJBPU) issued an order formally requesting that PJM open a competitive proposal window to solicit project proposals to improve and/or expand the PJM transmission system to deliver up to 7,500 MW of offshore wind generation by 2035. This came to be known as the SAA 1.0 Request.

Over the course of 2022, PJM and the NJBPU engaged in review and analysis of the 80 proposals submitted by 13 developers (both incumbent transmission owners and non-incumbent transmission developers) in response to the SAA 1.0 Proposal Window, during which period PJM provided extensive reports to the NJBPU detailing all aspects of the submitted proposals. On Oct. 26, 2022, the NJBPU issued an order notifying PJM of its selection of the transmission project it would sponsor to achieve its offshore wind public policy goals. **Map 1.3** shows the onshore wind injection points to the local New Jersey grid at Atlantic, Smithburg, Larrabee, Cardiff and England substations.

Map 1.3: NJBPU Project SAA 1.0 Injection Points



NOTE:

Additional information describing NJBPU-Selected SAA Project and related RTEP study process by which it was selected can be found in the following PJM reports:

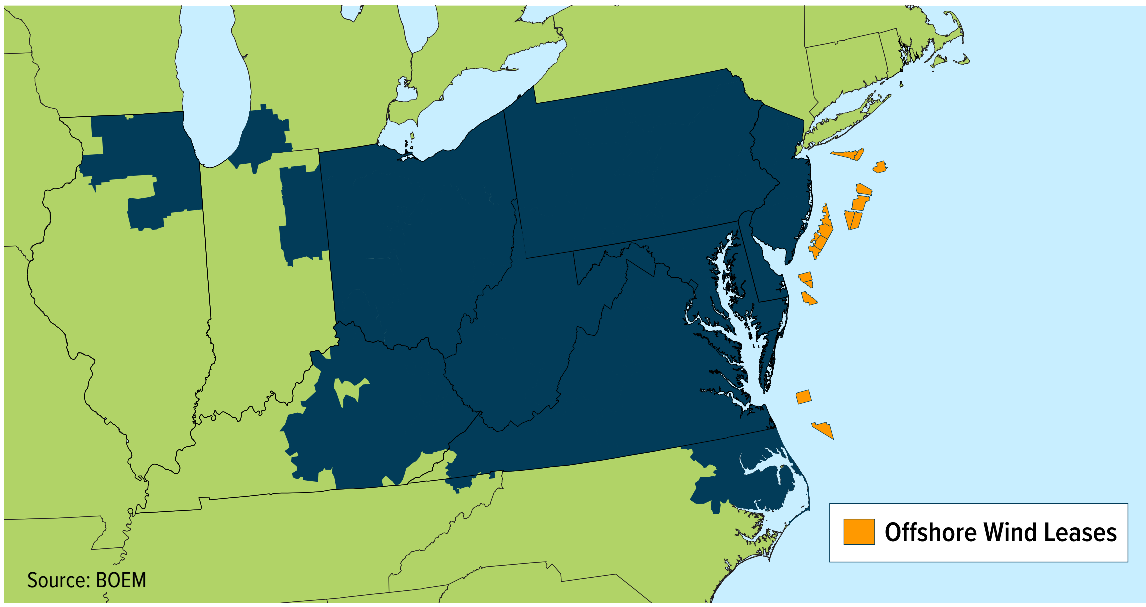
- November 15, 2022, report entitled, Summary Report for the NJBPU Selected Project 2021 SAA Proposal Window to Support NJ OSW
- 2022 RTEP Report, Section 3.1

2023 MILESTONE: State Agreement Approach – Enabling Offshore Wind

New Jersey Offshore Wind Solicitation SAA 2.0 Request

In October 2022, New Jersey increased the state's 7,500 MW by 2035 target to 11,000 MW by 2040. This came to be known as the "SAA 2.0 Request." The NJBPU issued an order on April 26, 2023, formally requesting that PJM open another competitive proposal window under the State Agreement Approach process to accommodate that increase. As with SAA 1.0, New Jersey is pursuing offshore wind facilities from lease areas noted on **Map 1.4**.

Map 1.4: Offshore Wind Leases



Throughout 2023, the NJBPU and PJM discussed and established the terms of the SAA 2.0 Study Agreement memorializing the understanding between PJM and the NJBPU regarding services to be performed under the SAA process, per PJM Operating Agreement, Schedule 6, Section 1.5.9:

1. The performance of planning studies to identify system improvements to interconnect and provide for the deliverability of the additional 3,500 MW of offshore wind to the state of New Jersey
2. The commencement of a competitive proposal window process to solicit project proposals that address the SAA 2.0 Request

Additionally, the SAA 2.0 Study Agreement provides notice to stakeholders that the SAA 2.0 Request will be included in the 2024 RTEP cycle and used as inputs for the development of the RTEP.

Note:

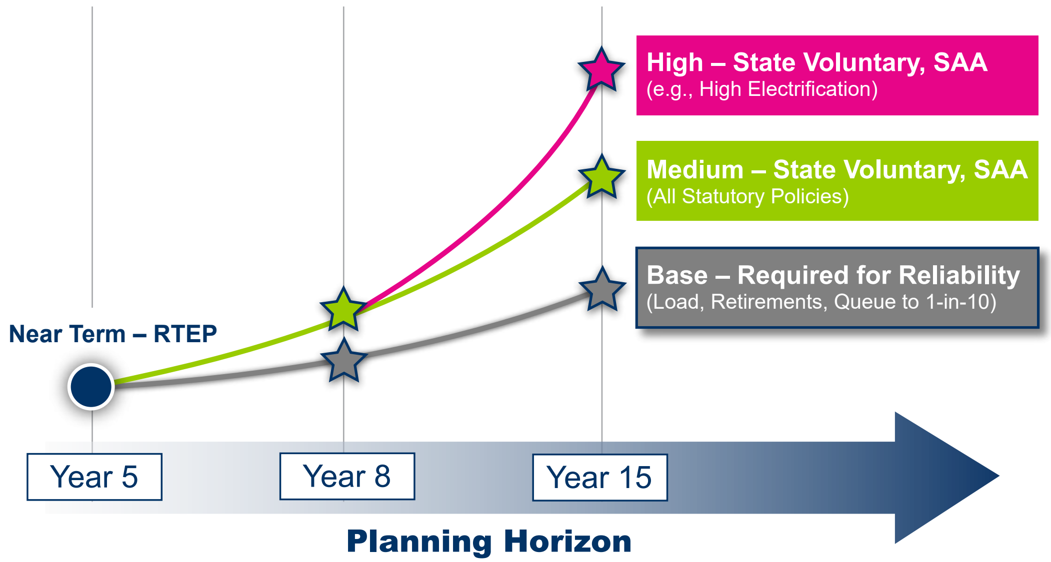
On February 2, 2024, PJM submitted for filing an executed SAA Study Agreement with the New Jersey Board of Public Utilities for its SAA 2.0 request:

Aside from the request to convene the SAA 2.0 Proposal Window and the request for studies as set forth in the Agreement, the Agreement does not consent to the selection of any projects, designated entities, or cost allocations, nor does it grant any rights. PJM and the NJBPU anticipate that such matters will be the subject of subsequent filings before the Commission, depending on the results of the competitive solicitation process, and New Jersey's future decisions after examining any proposals submitted with PJM.

1.3.6 — Long-Term Regional Transmission Planning

PJM continues to develop changes to existing long-term regional transmission planning (LTRTP) protocols in anticipation of FERC rule-making action in Docket No. RM21-17-000, Building for the Future through Electric Regional Planning. PJM's protocol changes encompass analysis of longer-term system needs under multiple future scenarios, as shown in **Figure 1.14.**

Figure 1.14: Implementing LTRTP Into Existing PJM RTEP Process



2023 MILESTONE: Long-Term Regional Transmission Planning

LTRTP Implementation

In 2023, PJM held a series of LTRTP workshops under the auspices of the PJM Planning Committee in order to gather stakeholder feedback on proposed enhancements to PJM's long-term planning process. PJM incorporated that feedback into the proposed framework. Implementation of this framework is currently under discussion and development in anticipation of 2024 Markets and Reliability Committee endorsement of the following provisions:

- The LTRTP process will evaluate system conditions in years six through 15 observing the same reliability criteria for the identification of required reinforcements as part of a 36-month planning cycle that begins in January of the first year and extends to December of the third year.
- LTRTP studies will be used to evaluate the need for more significant projects requiring a longer lead time to develop. These projects in addition to addressing reliability issues also generally provide a more regional benefit, such as in the form of production cost savings, capital investment savings and reduced loss of load.

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2023 MILESTONE: Long-term Regional Transmission Planning

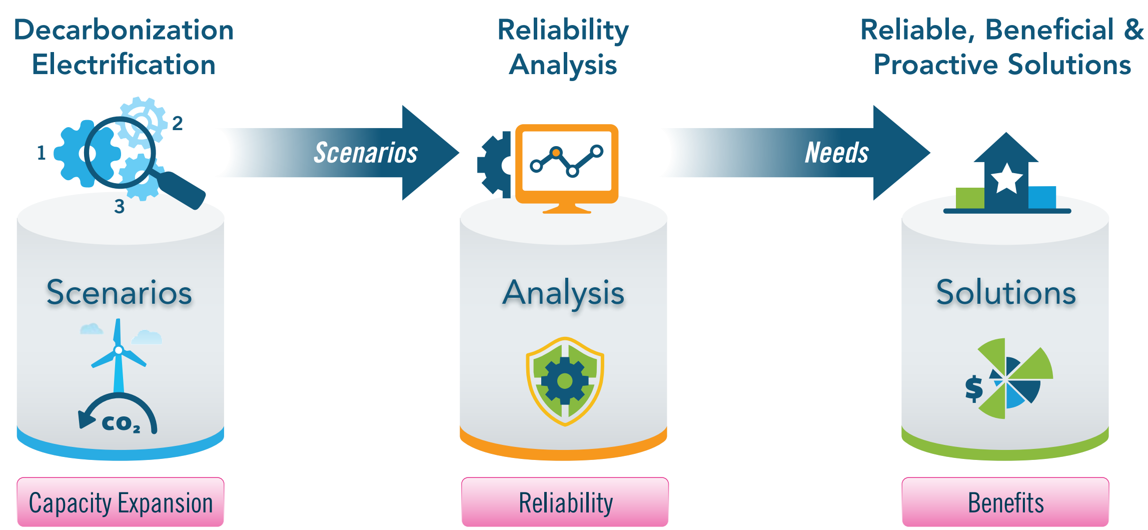
LTRTP Implementation (Continued)

- Load assumptions for the LTRTP process will start with the PJM load forecast employed as part of conventional near-term analysis but may also include additional assumptions regarding increased and new types of electrification.
- Generation additions will include those in the near-term models but may also include generation additions beyond those in the interconnection process, employing capacity expansion modeling that also leverages other sources of information on the economic potential of different assets at different locations to characterize possible future grid outcomes. Such models identify the economic resource fleet with consideration of, among other parameters, projected load, resource adequacy constructs, future technology costs and characteristics, fuel prices, and renewables' potentials at different locations, transmission headroom, and federal and state policies.
- Long-term power flow models will account for generation deactivations based on analysis of economics and federal and state public policy impacts over the planning horizon.
- At the beginning of the 36-month long-term planning cycle, PJM will work with the Transmission Expansion Advisory Committee (TEAC), Subregional RTEP Committees and Independent State Agencies Committee (ISAC) to identify public policies to be examined as part of long-term planning. This may include informational scenario and/or sensitivity studies to help states seeking to enter into a State Agreement Approach enhancement or expansion of the transmission system.

In order to ensure a reliable and cost-effective energy transition, PJM has proposed the following critical enhancements to the long-term planning process:

- A scenario-based planning approach that uses the interconnection process and fundamental modeling to understand capacity expansion and scenarios and sensitivities to identify needs and robust solutions
- Explicit modeling of 15-year-out cases, in addition to the eight-year-out cases, and linear interpolation to identify the timing of needs
- Parallel windows for the near-term planning process needs, long-term process reliability and State Agreement Approach needs to identify holistic transmission solution plans
- The use of secondary benefits to select solutions that address the reliability and State Agreement Approach needs and produce the most significant benefits

Figure 1.15: Long-Term Regional Transmission Planning Framework



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RTEP assumptions will be vetted with the ISAC, PJM stakeholders at TEAC, and Subregional RTEP Committees. PJM will make the final determination on all assumptions to be included in any scenario or sensitivity study and will share those assumptions with stakeholders at TEAC meetings.

LTRTP scenario studies will include single- and multiple-contingency analyses to identify reliability criteria violations that may require a solution with a lead time exceeding five years. Scenario study results may show the same violations in multiple LDAs or multiple or severe violations clustered in one area of the system, focusing primarily on the magnitude, concentration and kV level of the violations.

PJM worked with states and stakeholders in 2023 to refine the LTRTP process, which will be documented in PJM Manual 14B and Manual 14F. Additionally, PJM worked directly with states to develop a policy workbook, which will be used to document state public policy requirements for inclusion in scenario studies.

In order to make LTRTP a reality, in 2023, PJM created and staffed a new Scenario Analysis & Special Studies Department to lead long-term planning enhancement efforts. Those efforts have included engaging stakeholders, especially OPSI and ISAC state forums, to discuss a comprehensive LTRTP framework and related manual revisions, as summarized above. To that end, during 2023, PJM conducted a review of existing manual language and identified proposed revisions required to implement the LTRTP framework to address study assumptions, analysis and timelines.

1.3.7 — States: Facilitating Decarbonization Policies

The scale of the PJM system provides tremendous value for grid reliability. Electrons do not know state boundaries and travel across a vast network of interstate transmission. PJM plans for and operates this system in a manner that is both reliable and cost-effective. PJM has a diverse portfolio of resources and a footprint that spans multiple states and time zones. Operating the PJM region as one cohesive system gives operators the flexibility to rely on resources throughout the footprint and also allows the grid to better absorb abrupt system disturbances. Further, using competitive processes for the construction of transmission and competitive markets for the procurement of power, PJM is able to derive significant cost savings for consumers.

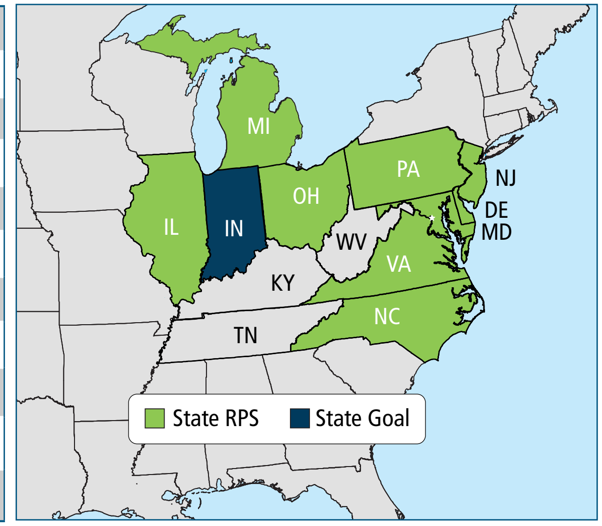
As with the entire U.S. electric grid, and as discussed previously, PJM is experiencing an accelerating transition toward intermittent renewable generation. State and federal policies, economics and consumer choices are shifting the grid away from dispatchable, emitting generation resources toward intermittent generation with little-to-no carbon emissions. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire.

More than ever, federal and state policies are poised to affect reliability and cost in the energy transition. PJM has been engaging states on how their policies can be achieved reliably and is working with federal officials to help inform their policies as well.

Figure 1.16: PJM State RPS Targets and Goals (as of January 2024)

State RPS Targets*

☼	**NJ:** 50% by 2030**
☼	**MD:** 50% by 2030**
☼	**DE:** 40% by 2035
☼	**DC:** 100% by 2032
☼	**PA:** 18% by 2021***
☼	**IL:** 50% by 2040
☼	**VA:** 100% by 2045/2050 (IOUs)
☼	**NC:** 12.5% by 2021 (IOUs)
	OH: 8.5% by 2026
	MI: 60% by 2035
	IN: 10% by 2025***



☼ Minimum solar requirement

* Targets may change over time; these are recent representative snapshot values

** Includes an additional 2.5% of Class II resources each year

*** Includes non-renewable "alternative" energy resources

Renewable Portfolio Standards

PJM's grid of the future will enable customer access to renewable power at much greater levels than today, driven by states' renewable portfolio standard (RPS) mandates. Ten states in the PJM footprint, plus the District of Columbia, have enacted these mandates as shown in **Figure 1.16**. These state RPS targets require that a certain percentage of a state's load is served by qualified renewable energy resources.

RPS policies have functioned as a significant driver of renewable resource development.

Across the nation, and in the PJM region, many states have increased their RPS targets in recent years in pursuit of accelerated decarbonization objectives. Since 2018, Delaware, the District of Columbia, Illinois, Maryland, New Jersey and Virginia have all established new RPS targets.

State RPS policies also vary by eligible resource technology, in-state resource carve-out requirements and required qualified resource location. Whether characterized as a goal or target, the majority of PJM states are moving toward a decarbonized grid over the course of the next 20–30 years. In addition, some in-state resource carve-outs are crafted as a percentage of energy, while others specify the minimum renewable capacity to be developed in state. Variability in policies has not been a hindrance to building new renewable generation and, in fact, has provided developers both direction and flexibility in siting planned renewable generators.

As a result, renewable generation is now the most prominent resource type in PJM's interconnection queue in each state, including those that have historically been more fossil-fuel intensive.

PJM continues to support state policies through creative and innovative solutions, such as cooperative planning between PJM and states to meet their public policy needs under PJM's SAA, or State Agreement Approach. For example, PJM recently planned targeted transmission projects with the state of New Jersey to support their offshore wind policy goals. PJM is also working with officials in Maryland and Delaware to study the prospect of offshore wind energy.

PJM incorporated the SAA, discussed in **Section 1.3.2**, into its Operating Agreement in 2013 as part of PJM's implementation of FERC Order 1000. With that order, FERC required regional grid operators to "provide for the consideration of transmission needs driven by public policy requirements in the regional transmission planning processes." The SAA may be used by any state, or combination of states, to advance state public policy goals, as long as the state (or states) agrees to pay all costs of the project's build-out included in the PJM Regional Transmission Expansion Plan.

2023 MILESTONE: States: Facilitating Decarbonization Policies

State-by-State Engagement

See **Section 6** for a current state-by-state summary of public policy impacts on transmission planning.

1.4: Optimizing Regional Transmission Infrastructure Investment

As discussed previously, PJM's RTEP process identifies transmission system additions and improvements needed to serve more than 65 million people spanning 13 states and the District of Columbia as shown in **Map 1.1**. Beginning 15 years in advance, 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 PJM 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.

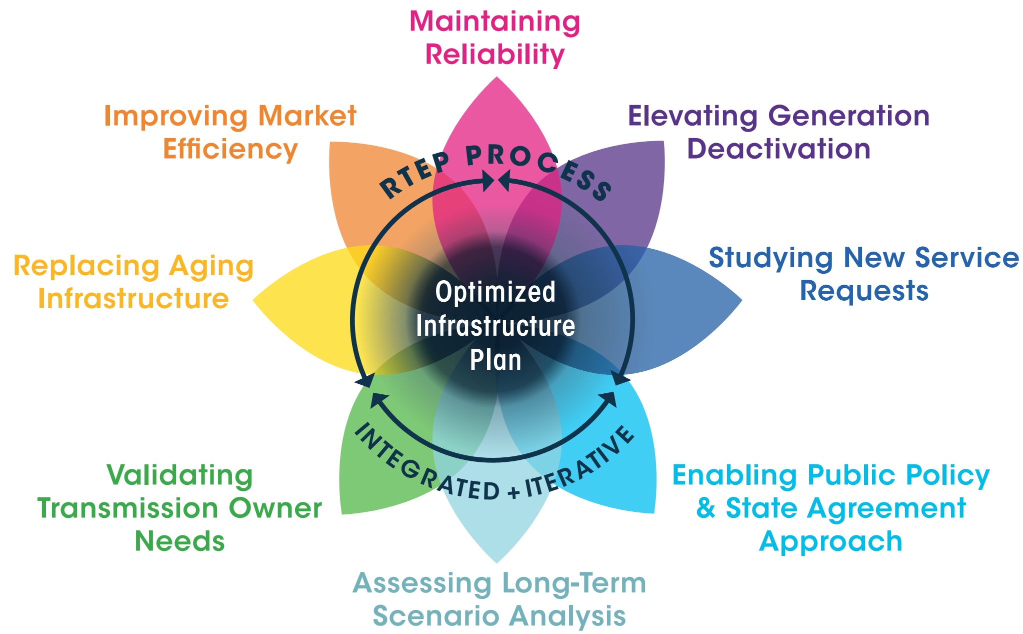
As **Figure 1.17** shows, PJM's comprehensive, regional transmission plan is the outcome of overlapping and interacting analytical processes, not siloed ones. PJM leverages opportunities to optimize regional transmission infrastructure investment under one plan by developing efficient solutions across 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 1.17: 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 generator interconnection request, the interconnection customer's incremental need(s) 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 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 in order to "lock down" the annual base case prior to commencing interconnection studies. This process provides a New Services 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 Process supplemental 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 Supplemental Project 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.

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.

Recent 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 during 2022 RTEP Window No. 1 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 during its 2021 RTEP Window 1 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 and also solves emerging OATT Attachment M-3 Process local supplemental projects to address identified aging infrastructure issues on including two transmission lines dating to 1939 with deteriorating wood-pole structures.

Section 2: Resource Adequacy Modeling

2.0: Power Flow Model Load

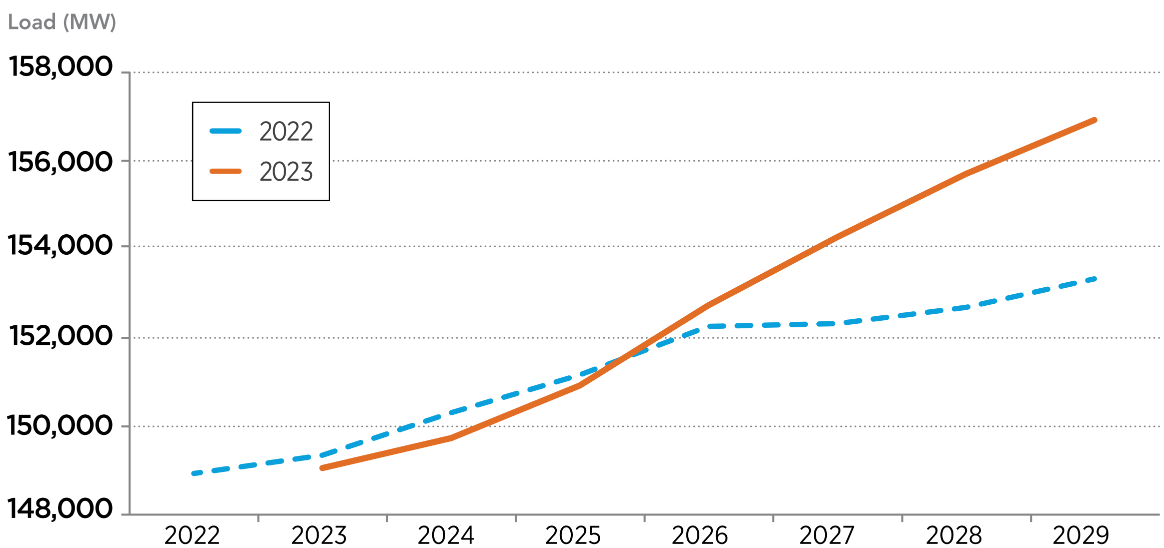
Fundamentally, PJM's planning process identifies future system transmission needs based on power flow studies that reveal reliability criteria violations. Power flow study models incorporate the effect of many system expansion drivers. Zonal load forecasts are the basis for power flow case bus loads. 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).

2023 RTEP Process Context

PJM's 2023 RTEP baseline power flow model for study year 2028 was based on an overall RTO summer peak load of 155,703 MW as published in the 2023 PJM Load Forecast Report. The Load Forecast Report, which covers the 2023 through 2038 planning horizon, states that PJM now projects its RTO-wide summer-normalized peak to grow 0.8% annually over the next 10 years, shown in **Figure 2.1**, which is up 0.4% points from the 2022 forecast.

Figure 2.1: Summer Peak Load Forecast 2023 vs. 2022

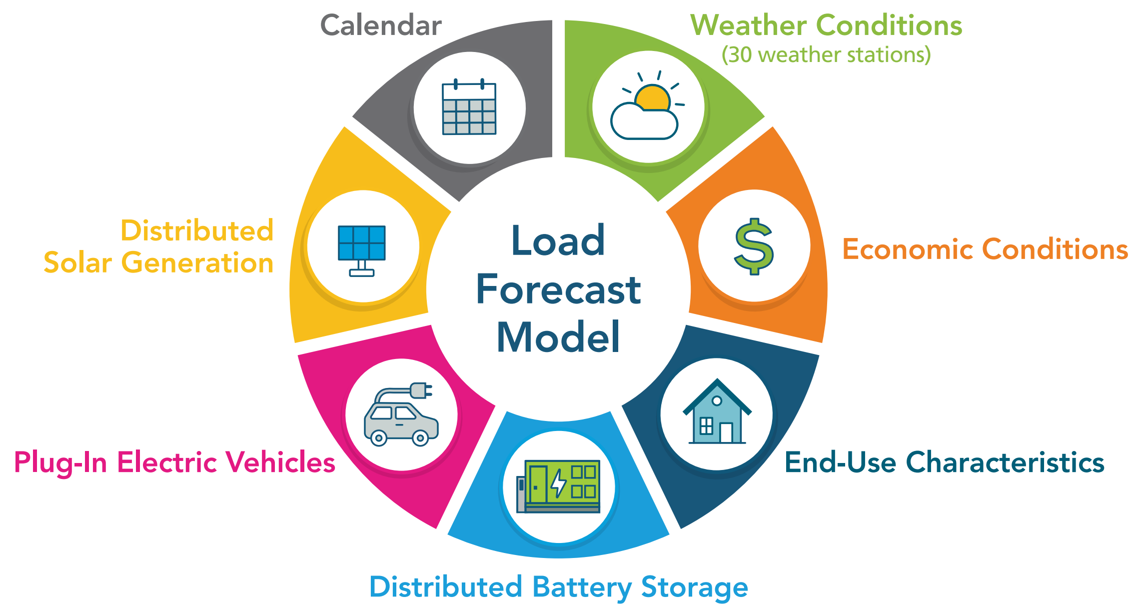


Significant load growth due to new construction of data centers is driving the need for additional sensitivity studies to assess the potential impacts of large localized load increases on transmission adequacy. PJM will continue to work closely with local transmission owner planners to ensure these load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

Load Forecasting Process

PJM's load forecast model produces a 15-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 forecast load, shown in **Figure 2.2**.

Figure 2.2: Load Forecast Model



Hourly Forecast Model Implementation

In 2022, PJM engaged with an independent consultant for guidance in establishing an hourly forecast model. Based on the guidance provided in the [consultant's report](), PJM implemented changes to its hourly forecast model through stakeholder engagement at its Load Analysis Subcommittee and Planning Committee meetings.

Starting with the 2023 Load Forecast, each zone in PJM has 24 hourly models. This granularity allows PJM to better incorporate the impacts of new technologies on the grid, such as distributed solar and electric vehicles. The 2023 forecast also uses monthly data to model residential, commercial and industrial sectors. Finally, the 2023 Load Forecast includes a longer forecast horizon for large load adjustments given the rapid growth in data centers in the PJM footprint.

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. Understanding trends in each of these categories is valuable to understanding 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, in order to better inform this understanding.

Weather Conditions

The impact on load driven by weather conditions across the RTO is accounted for through concepts such as temperature, humidity and wind speed. PJM obtains weather data from over 30 identified weather stations across the PJM footprint.

Calendar

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

Economic Conditions

The impact of economic conditions on load forecasting is accounted for by employing such factors as household electricity use, real personal income, population, working-age population and real output. This allows for localized treatment of economic effects within a zone. PJM has contracted with an outside economic services vendor to provide economic forecasts for all areas within the PJM footprint.

End-Use Characteristics

End-use characteristics are captured through three distinct variables designed to capture the various ways in which electricity is used: both weather-sensitive heating and 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 now also incorporates an explicit adjustment for plug-in electric vehicle (PEV) charging in peak megawatt demand and energy forecasts. Doing so ensures that PJM is accounting for their impact on reliability, as the share of PEVs on the road continues to grow.

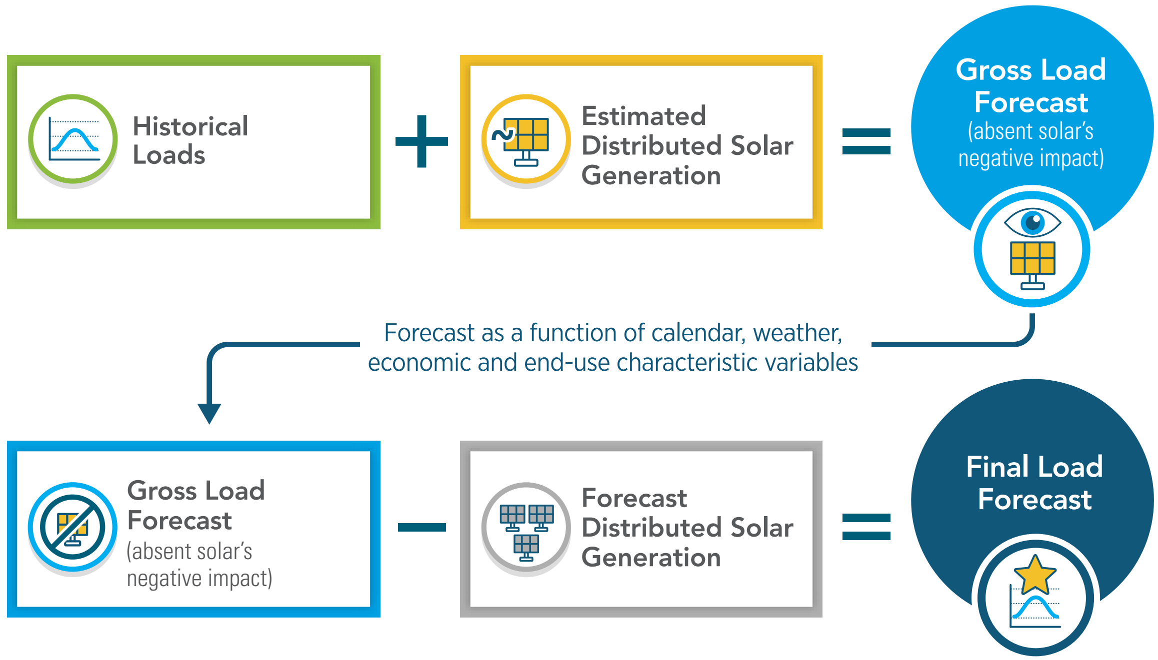
Distributed Solar and Battery Storage Generation

Distributed solar and battery storage generation acts to lower load from what it otherwise would be. Recent years have witnessed a significant ramp-up in behind-the-meter distributed solar resources: more than 6,500 MW since 1998, with more than 95% of installations since 2010. Though not a large amount from an RTO perspective, 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 update, 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.

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 forecast distributed solar and battery storage generation to obtain a final load forecast for each zone and for the RTO. Forecast distributed solar and battery storage generation is based on vendor-supplied, forecast distributed solar and battery capacity additions over the ensuing 15 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.

Figure 2.3: Accounting for Distributed Solar Generation



2.1: 2023 Load Forecast Report

The 2023 PJM Load Forecast Report, used in 2023 RTEP studies, includes forecast data for the 2023 through 2038 planning horizon and notes that PJM's 2028 RTO-wide summer peak is forecast to be 152,322 MW. Additional highlights from the forecast are summarized in this section.

Forecasting Trends

Table 2.1 summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2023 through 2033. 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. For most zones, lower load forecast trends over that period reflect broader trends in the U.S. economy and PJM model refinements to capture energy efficiency along with reflecting any peak hour shifting due to higher distributed solar penetration. A few zones have higher load forecast trends due to large load adjustments tied to data centers. These trends are subsequently reflected in RTEP process power flow models.

Table 2.1: 2023 Load Forecast Report

	Summer Peak (MW)			Winter Peak (MW)		
Transmission Owner	2023	2033	Growth Rate	2022/23	2032/33	Growth Rate
Atlantic City Electric	2,549	2,418	-0.5%	1,590	1,561	-0.2%
Baltimore Gas and Electric	6,474	6,060	-0.7%	5,755	5,680	-0.1%
Delmarva Power	3,861	3,666	-0.5%	3,623	3,690	0.2%
Jersey Central Power & Light	6,072	5,830	-0.4%	3,740	3,864	0.3%
Met-Ed	3,040	3,112	0.2%	2,696	2,772	0.3%
PECO Energy Company	8,527	8,590	0.1%	6,459	6,530	0.1%
Pennsylvania Electric Company (Penelec)	2,871	2,792	-0.3%	2,823	2,751	-0.3%
PPL Electric Utilities	7,175	7,248	0.1%	7,334	7,407	0.1%
Potomac Electric Power Company (Pepco)	6,166	6,201	0.1%	5,381	5,531	0.3%
Public Service Electric & Gas Company (PSE&G)	9,904	9,499	-0.4%	6,530	6,393	-0.2%
Rockland Electric Company	414	416	0.0%	214	249	1.5%
UGI Utilities	195	189	-0.3%	198	192	-0.3%
Diversity – Mid-Atlantic	-1,512	-1,685		-868	-769	
Mid-Atlantic	**55,736**	**54,336**	**-0.3%**	**45,475**	**45,851**	**0.1%**
American Electric Power	22,453	22,637	0.1%	22,308	22,663	0.2%
Allegheny Power (FirstEnergy)	8,724	9,484	0.8%	8,993	10,077	1.1%
American Transmission Systems, Inc. (FirstEnergy)	11,962	11,593	-0.3%	9,883	9,629	-0.3%
Commonwealth Edison	20,417	19,595	-0.4%	14,305	14,573	0.2%
AES Ohio, formerly Dayton Power and Light	3,295	3,255	-0.1%	2,920	2,870	-0.2%
Duke Energy Ohio and Kentucky	5,249	5,126	-0.2%	4,479	4,380	-0.2%
Duquesne Light Company	2,712	2,687	-0.1%	1,996	1,962	-0.2%
East Kentucky Power Cooperative	2,027	2,084	0.3%	2,658	2,694	0.1%
Ohio Valley Electric Corporation	95	95	0.0%	110	110	0.0%
Diversity – Western	-1,581	-1,676		-1,797	-1,741	
Western	**75,353**	**74,880**	**-0.1%**	**65,855**	**67,217**	**0.2%**
Dominion Energy	21,920	35,789	5.0%	21,625	34,488	4.8%
Southern	**21,920**	**35,789**	**5.0%**	**21,625**	**34,488**	**4.8%**
Diversity – Total	-7,043	-7,395		-4,809	-5,074	
PJM RTO	**149,059**	**160,971**	**0.8%**	**130,811**	**144,992**	**1.0%**

Table 2.2: 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	
	2023	2033	2023	2033	2023	2033
Atlantic City Electric	136	97	5	38	1	16
Baltimore Gas and Electric	194	249	9	95	1	71
Delmarva Power	103	124	2	18	1	19
Jersey Central Power & Light	261	329	17	151	1	36
Met-Ed	46	74	1	6	0	5
PECO Energy Company	68	177	3	22	1	13
Pennsylvania Electric Company (Penelec)	19	77	1	6	0	6
PPL Electric Utilities	114	193	1	8	1	14
Potomac Electric Power Company (Pepco)	214	282	13	162	1	51
Public Service Electric & Gas Company (PSE&G)	392	365	14	129	3	72
Rockland Electric Company	13	25	3	28	0	2
UGI Utilities	1	3	0	0	0	0
American Electric Power	134	343	5	43	2	38
Allegheny Power (FirstEnergy)	86	169	3	30	1	29
American Transmission Systems, Inc. (FirstEnergy)	102	205	3	23	1	20
Commonwealth Edison	323	836	22	367	3	84
AES Ohio, formerly Dayton Power and Light Company	26	55	1	5	0	5
Duke Energy Ohio and Kentucky	23	67	1	7	0	7
Duquesne Light Company	20	54	1	5	0	5
East Kentucky Power Cooperative	5	14	0	3	0	1
Ohio Valley Electric Corporation	0	0	0	0	0	0
Dominion Energy	527	718	26	304	3	92
PJM RTO	**2,888**	**4,610**	**134**	**1,478**	**20**	**587**

Table 2.3: Comparison of 10-Year Summer Peak Load Growth Rates

	Load Forecast Report Summer Peak (MW)														
	2019			2020			2021			2022			2023		
Transmission Owner	2019	2029	Growth Rate	2020	2030	Growth Rate	2021	2031	Growth Rate	2022	2032	Growth Rate	2023	2033	Growth Rate
Atlantic City Electric	2,450	2,388	-0.3%	2,542	2,773	0.9%	2,470	2,605	0.5%	2,488	2,541	0.2%	2,549	2,418	-0.5%
Baltimore Gas and Electric	6,697	6,663	-0.1%	6,447	6,558	0.2%	6,582	6,652	0.1%	6,414	6,350	-0.1%	6,474	6,060	-0.7%
Delmarva Power	3,933	3,962	0.1%	3,979	4,327	0.8%	3,895	3,976	0.2%	3,873	3,854	0.0%	3,861	3,666	-0.5%
Jersey Central Power & Light	5,914	5,912	0.0%	5,842	6,122	0.5%	5,876	6,193	0.5%	5,831	5,868	0.1%	6,072	5,830	-0.4%
Met-Ed	2,986	3,157	0.6%	3,003	3,287	0.9%	3,060	3,255	0.6%	2,934	3,060	0.4%	3,040	3,112	0.2%
PECO Energy Company	8,711	9,082	0.4%	8,415	8,677	0.3%	8,389	8,691	0.4%	8,370	8,471	0.1%	8,527	8,590	0.1%
Pennsylvania Electric Company (Penelec)	2,897	2,908	0.0%	2,849	2,957	0.4%	2,894	3,164	0.9%	2,812	2,832	0.1%	2,871	2,792	-0.3%
PPL Electric Utilities	7,148	7,347	0.3%	7,069	7,792	1.0%	7,204	7,758	0.7%	7,024	7,237	0.3%	7,175	7,248	0.1%
Potomac Electric Power Company (Pepco)	6,466	6,413	-0.1%	6,109	5,794	-0.5%	5,924	5,248	-1.2%	5,902	5,766	-0.2%	6,166	6,201	0.1%
Public Service Electric & Gas Company (PSE&G)	9,904	9,753	-0.2%	9,792	10,597	0.8%	9,871	10,407	0.5%	9,543	9,857	0.3%	9,904	9,499	-0.4%
Rockland Electric Company	404	402	0.0%	395	420	0.6%	396	397	0.0%	391	388	-0.1%	414	416	0.0%
UGI Utilities	189	188	-0.1%	191	184	-0.4%	195	201	0.3%	193	191	-0.1%	195	189	-0.3%
Diversity – Mid-Atlantic	-1,213	-1,135	0.0%	-781	-948		-986	-810		-629	-875		-1,512	-1,685	
Mid-Atlantic	**56,486**	**57,040**	**0.1%**	**55,852**	**58,540**	**0.5%**	**55,770**	**57,737**	**0.3%**	**55,146**	**55,540**	**0.1%**	**55,736**	**54,336**	**-0.3%**
American Electric Power	22,945	24,072	0.5%	21,945	24,113	0.9%	22,609	23,471	0.4%	22,183	22,496	0.1%	22,453	22,637	0.1%
Allegheny Power (FirstEnergy)	8,707	9,305	0.7%	8,685	9,373	0.8%	8,859	9,140	0.3%	8,675	8,762	0.1%	8,724	9,484	0.8%
American Transmission Systems, Inc. (FirstEnergy)	12,872	13,134	0.2%	12,378	12,428	0.0%	12,525	12,842	0.3%	12,273	12,551	0.2%	11,962	11,593	-0.3%
Commonwealth Edison	21,890	22,514	0.3%	20,635	20,876	0.1%	20,421	19,433	-0.5%	20,787	20,121	-0.3%	20,417	19,595	-0.4%
AES Ohio, formerly Dayton Power and Light	3,408	3,525	0.3%	3,236	3,228	0.0%	3,415	3,550	0.4%	3,271	3,288	0.1%	3,295	3,255	-0.1%
Duke Energy Ohio and Kentucky	5,480	5,742	0.5%	5,280	5,650	0.7%	5,390	5,746	0.6%	5,239	5,427	0.4%	5,249	5,126	-0.2%
Duquesne Light Company	2,862	2,887	0.1%	2,759	2,855	0.3%	2,768	2,954	0.7%	2,742	2,837	0.3%	2,712	2,687	-0.1%
East Kentucky Power Cooperative	1,989	2,072	0.4%	2,004	2,334	1.5%	2,130	2,280	0.7%	2,091	2,228	0.6%	2,027	2,084	0.3%
Ohio Valley Electric Corporation	95	95	0.0%	95	95	0.0%	90	90	0.0%	90	90	0.0%	95	95	0.0%
Diversity – Western	-1,612	-1,369		-1,377	-1,311		-2,248	-2,224		-1,647	-1,674		-1,581	-1,676	
Western	**78,636**	**81,977**	**0.4%**	**75,640**	**79,641**	**0.5%**	**75,959**	**77,282**	**0.2%**	**75,704**	**76,126**	**0.1%**	**75,353**	**74,880**	**-0.1%**
Dominion Energy	19,391	21,238	0.9%	19,813	22,336	1.2%	20,150	21,269	0.5%	20,424	25,434	2.2%	21,920	35,789	5.0%
Southern	**19,391**	**21,238**	**0.9%**	**19,813**	**22,336**	**1.2%**	**20,150**	**21,269**	**0.5%**	**20,424**	**25,434**	**2.2%**	**21,920**	**35,789**	**5.0%**
Diversity – RTO	-5,980	-6,070		-5,371	-5,644		-5,889	-5,563		-4,612	-5,268		-7,043	-7,395	
PJM RTO	**151,358**	**156,689**	**0.3%**	**148,092**	**157,132**	**0.6%**	**149,224**	**153,759**	**0.3%**	**148,938**	**154,381**	**0.4%**	**149,059**	**160,971**	**0.8%**

2023 Forecast Summer Zonal Load Growth Rates

The PJM RTO weather-normalized summer peak is forecast to grow at an average rate of 0.8% per year for the next 10 years. The PJM RTO summer peak is forecast to be 160,971 MW in 2033, an increase of 11,912 MW over the 2023 peak of 149,059 MW. Individual geographic zone growth rates vary from -0.7% to 5.0%, as shown in **Figure 2.4** and **Figure 2.5**.

Figure 2.4: PJM Mid-Atlantic Summer Peak Load Growth 2023–2033

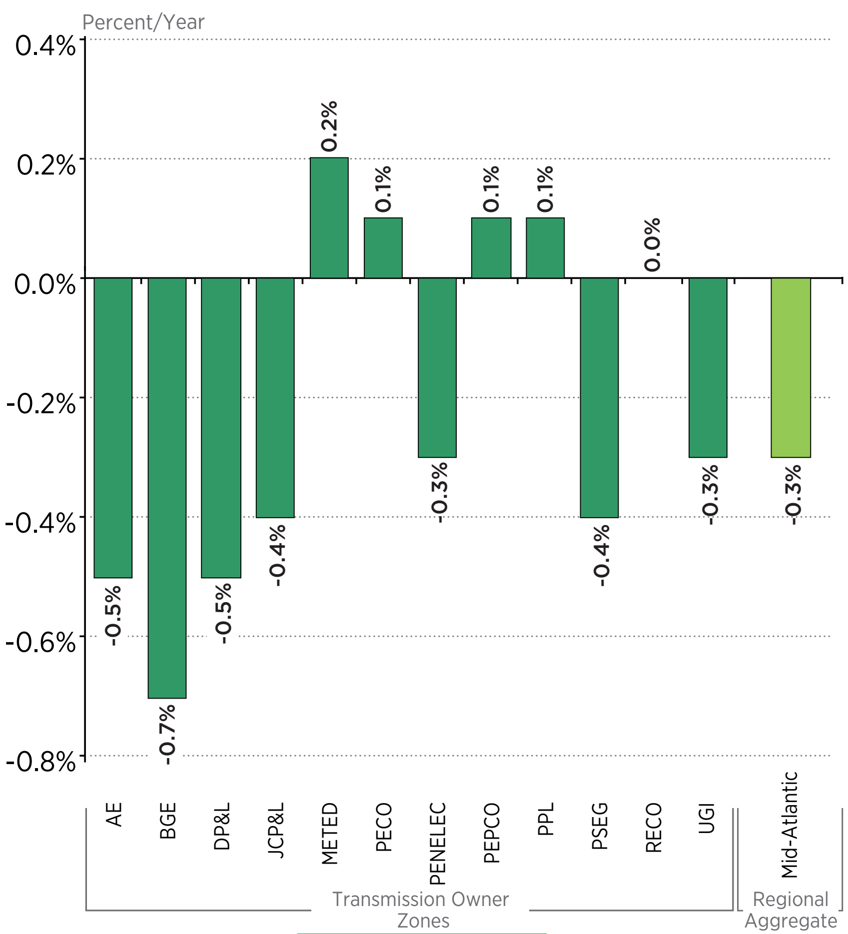
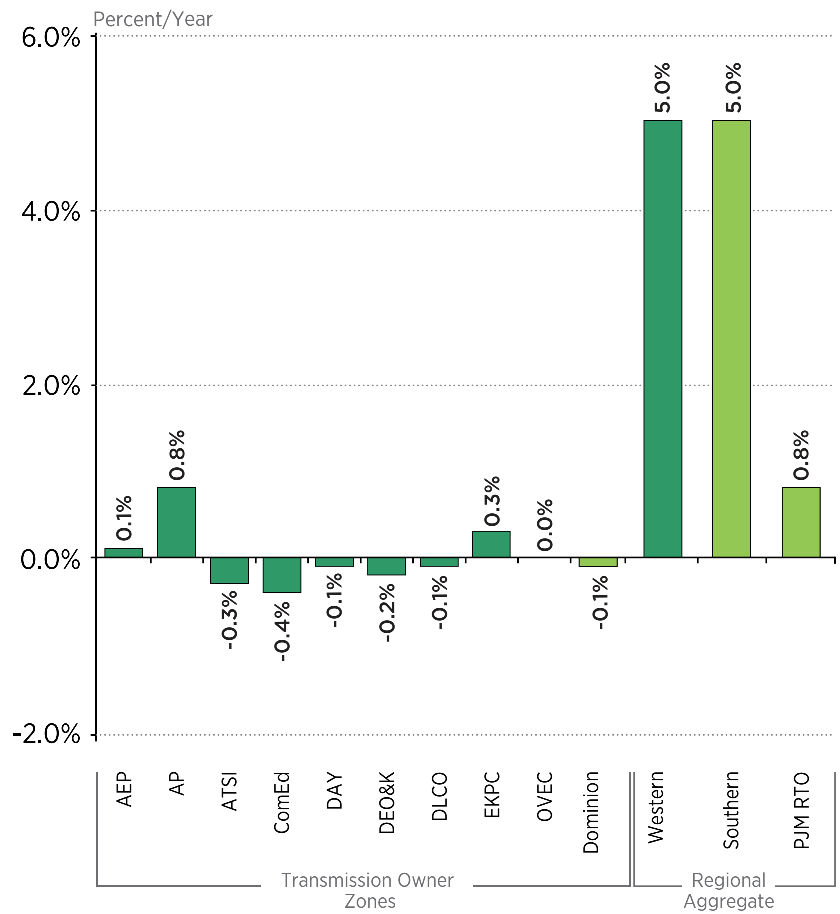


Figure 2.5: PJM Western and Southern Summer Peak Load Growth 2023–2033



2023 Forecast Winter Zonal Load Growth Rates

The PJM RTO weather-normalized winter peak is forecast to grow at an average rate of 1.0% per year for the next 10 years. The PJM RTO winter peak is forecast to be 144,992 MW in 2032/2033, an increase of 14,181 MW over the 2022/2023 peak of 130,811 MW. Individual geographic zone growth rates vary from -0.3% to 4.8%, as shown in **Figure 2.6** and **Figure 2.7**.

Figure 2.6: PJM Mid-Atlantic Winter Peak Load Growth 2023–2033

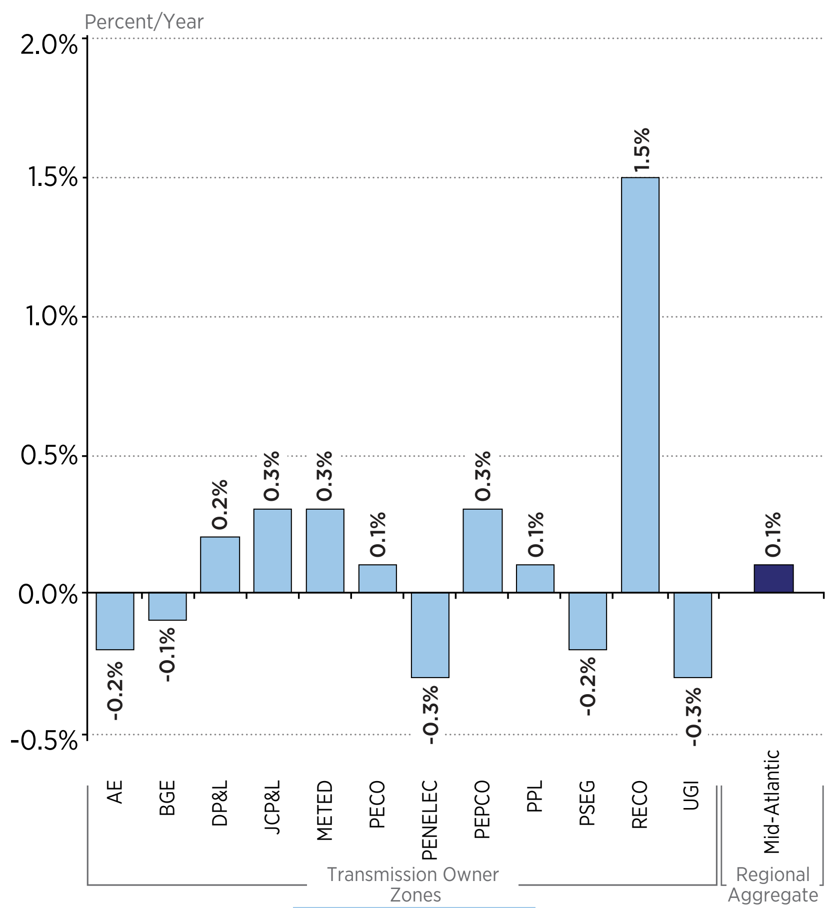
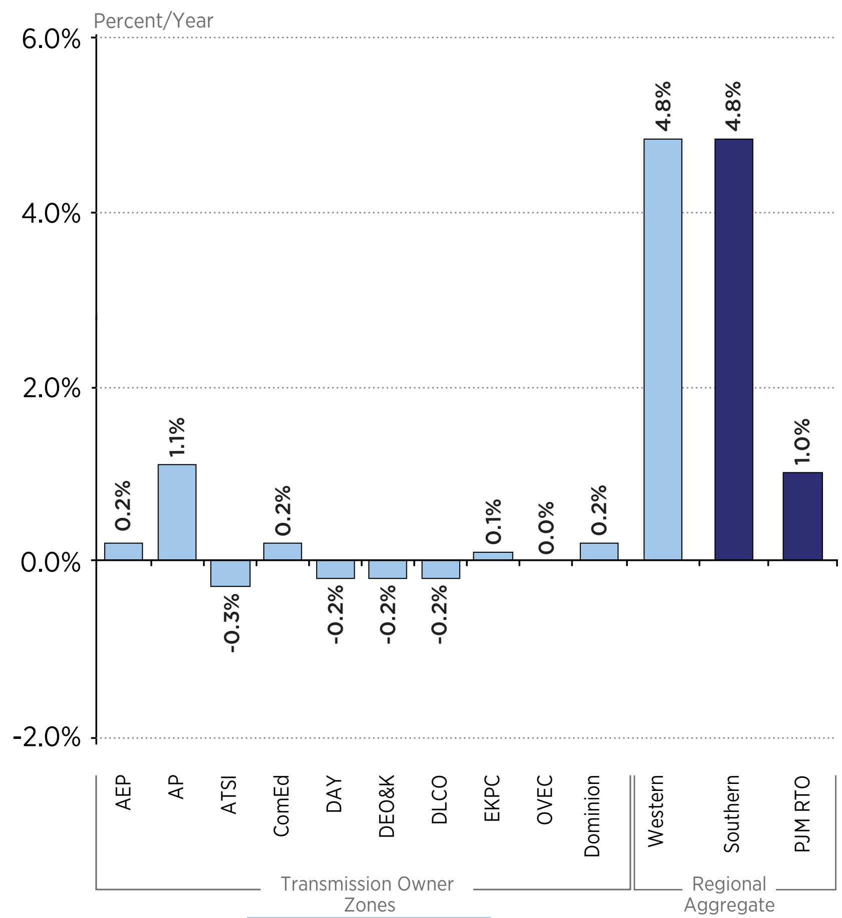


Figure 2.7: PJM Western and Southern Winter Peak Load Growth 2023–2033

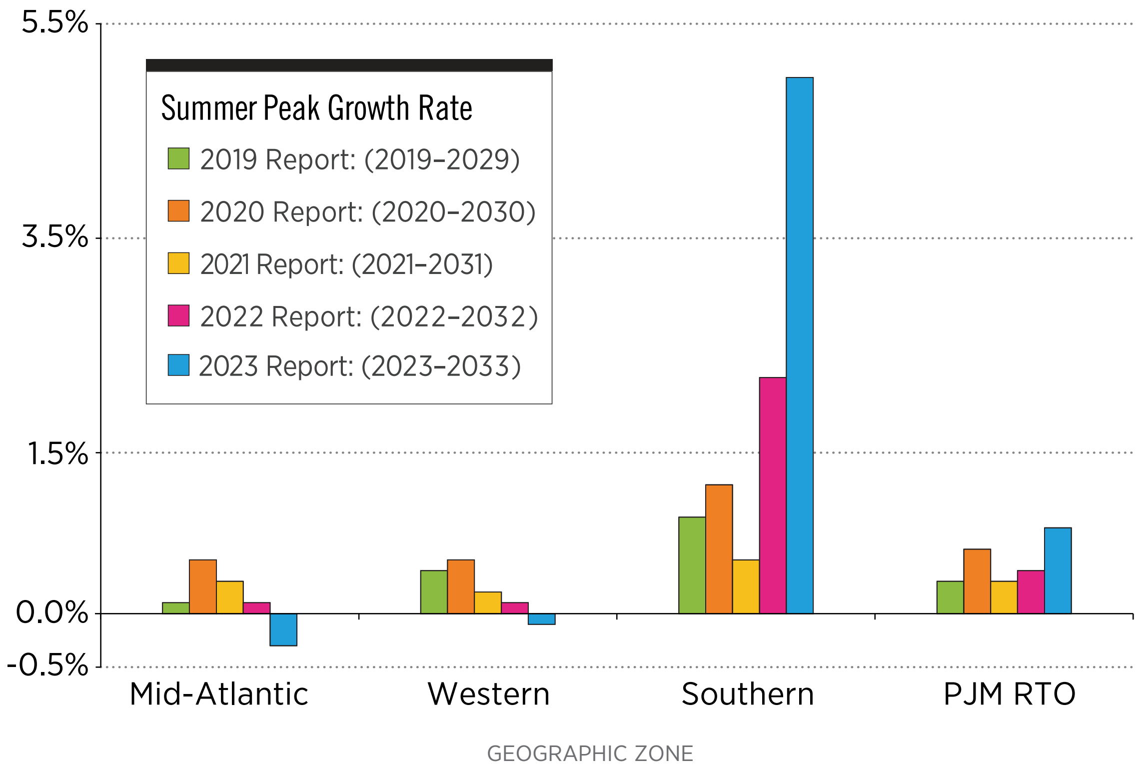


Subregional Forecast Trends

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 2019 through 2023, for the ensuing 10 years on a subregional basis. The trend reflects changes in the broader U.S. economic outlook and the growing impact of energy efficiency, solar generation and PEVs looking forward in each of the five s. Load forecasts for the Southern Region of PJM are growing at an increasing rate due to the large volume of data center activity in this area.

In particular, the 2023 report forecast that the load growth rate for the RTO increased by 0.4% points when compared to the 2022 report.

Figure 2.8: PJM 10-Year Summer Peak Load Growth Rate Comparison 2019–2023 Load Forecast Reports



Data Center Load Growth

PJM annually solicits information from its member Electric Distribution Companies (EDCs) for large load shifts (either positive or negative) that are known to the EDCs but may be unknown to PJM. 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.

In the 2023 Load Forecast Report, Dominion Energy requested that PJM consider a forecast adjustment to account for the growth of data centers in northern Virginia. This adjustment 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.

Dominion Energy has provided PJM with energy and peak information historical data for such facilities as well as expectations for new facilities through 2038. In addition to Dominion Energy, American Electric Power (AEP) and Allegheny Power (First Energy) (AP) have forecast adjustments to account for data center load.

2.2: Demand Resources and Peak Shaving

PJM accounts for demand resources by adjusting its base, unrestricted, peak load forecast by a forecast amount, which is calculated based on committed quantities in previous Reliability Pricing Model (RPM) auctions. Those amounts, as reflected in the 2023 Load Forecast Report, are shown in **Table 2.4** for each transmission zone. The adjusted forecast 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, demand resources can have a measurable impact on future system conditions and the potential need for transmission system enhancements to serve load. Forecast values for each zone are determined based on the following steps:

1. Compute the final amount of committed demand resources for each of the three most recent delivery years. Express the committed demand resource amount as a percentage of the zone's 50/50 forecast summer peak from the January load forecast report immediately preceding the respective delivery year.

2. Compute the most recent three-year-average committed demand resources percentage for each zone.

3. Multiply each zone's 50/50 forecast summer peak by the results from step two to obtain the demand resource 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 Load Forecast.

Capacity Performance Impacts

PJM's RPM transition to Capacity Performance in 2016 has required a transition in the treatment of demand resources as well. **Table 2.4** assumes the following:

- Annual demand resources are assumed to be Capacity Performance demand resources and are based on actual committed quantities of demand resource products in the 2020/2021, 2021/2022, 2022/2023 and actual cleared quantities in the 2021/2022, 2022/2023 and 2023/2024 RPM Base Residual Auctions for Price Responsive Demand.

- Summer period demand resources refer to demand resources that aggregate with winter-period resources to form a year-round commitment.

Both existing and planned demand resources 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 2.4: 2023 Load Forecast Report Demand Resources

Transmission Owner	Total Load Management 2023	Total Load Management 2033
Atlantic City Electric	47	45
Baltimore Gas and Electric	247	273
Delmarva Power	220	221
Jersey Central Power & Light	101	97
Met-Ed	166	169
PECO Energy Company	274	276
Pennsylvania Electric Company (Penelec)	230	224
PPL Electric Utilities	435	439
Potomac Electric Power Company (Pepco)	340	372
Public Service Electric & Gas Company (PSE&G)	206	198
Rockland Electric Company	2	2
UGI Utilities	0	0
Mid-Atlantic	**2,268**	**2,316**
American Electric Power	1,142	1,151
Allegheny Power (FirstEnergy)	543	590
American Transmission Systems, Inc. (FirstEnergy)	701	679
Commonwealth Edison	1,351	1,296
AES Ohio, formerly Dayton Power and Light	164	162
Duke Energy Ohio and Kentucky	153	149
Duquesne Light Company	88	88
East Kentucky Power Cooperative	174	179
Ohio Valley Electric Corporation	0	0
Western	**4,316**	**4,294**
Dominion Energy	704	1,148
Southern	**704**	**1,148**
PJM RTO	**7,288**	**7,758**

2.3: Effective Load Carrying Capability

Overview

PJM uses an Effective Load Carrying Capability (ELCC) methodology to evaluate the contribution that intermittent and energy storage resources provide to PJM's resource adequacy. The ELCC study is run annually producing ELCC Class Ratings that serve as inputs to determine the accreditation that an intermittent or energy storage resource receives to participate in the RPM.

2.3.1 — 2023 Study Results

As part of its annual RPM auction input parameters development, PJM develops ELCC Class Ratings. Completed in December 2023, those ratings for each class of ELCC generation enumerated in **Table 2.5** were calculated for each delivery year in the period 2024/2025–2033/2034. However, only the 2024/2025 values are final (the results for the rest of the delivery years are preliminary). Full study results can be found on the PJM website.

2.3.2 — Capacity Interconnection Rights for ELCC Resources

The PJM Planning Committee also initiated a separate stakeholder process in 2021 to review and modify existing Capacity Interconnection Rights (CIRs) request and retention policies, with an emphasis on ELCC resources, including the application of CIRs to the ELCC methodology and UCAP valuation. A number of special sessions of the Planning Committee took place in 2022 leading to PJM stakeholder approval, with implementation scheduled for the 2025/2026 Base Residual Auction.

Table 2.5: ELCC Class Ratings for 2024/2025 3IA

ELCC Class	ELCC Class Rating for: 2023/2024 3IA (% of Nameplate)
Onshore Wind	21%
Offshore Wind	47%
Solar Fixed Panel	33%
Solar Tracking Panel	50%
4-Hour Storage	92%
6-Hour Storage	100%
8-Hour Storage	100%
10-Hour Storage	100%
Solar Hybrid Open Loop – Storage Component	75%
Solar Hybrid Closed Loop – Storage Component	68%
Hydro Intermittent	36%
Landfill Gas Intermittent	61%
Hydro With Non-Pumped Storage*	95%

*PJM performs an ELCC analysis for each individual unit in this class. The value shown in the table is a representative value provided for informational purposes.

2.3.3 — Addressing RPM Resource Adequacy Challenges

The PJM Board of Managers initiated the Critical Issue Fast Path stakeholder process by letter on Feb. 24, 2023, to address resource adequacy challenges in the PJM Reliability Pricing Model or capacity market. In the letter, the Board identified some key capacity market topics as the focus of the Critical Issue Fast Path initiative: enhanced risk modeling, evaluation of potential modifications to the Capacity Performance construct and alignment of permitted offers to the risk taken by suppliers, improved accreditation, and synchronization between the RPM and Fixed Resource Requirement (FRR) rules. During most of 2023, as part of the CIFP-RA stakeholder process, stakeholders and PJM staff developed and reviewed multiple solution packages for the above capacity market topics, which culminated with PJM filing a set of capacity market reforms with FERC in mid-October 2023.

Section 3: Transmission Enhancements

3.0: 2023 RTEP Proposal Windows

3.0.1 — RTEP Process Context

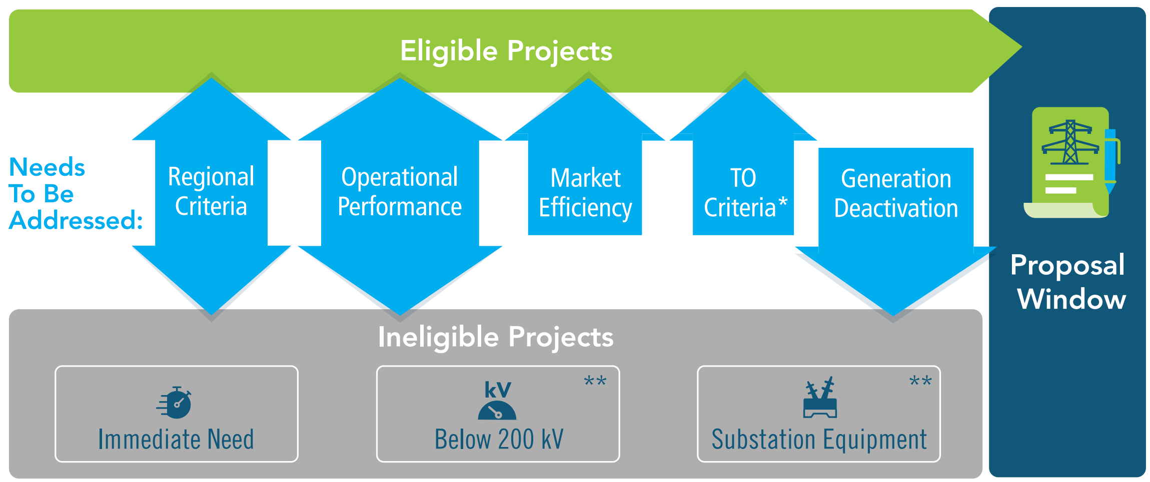
PJM seeks transmission proposals during each RTEP window to address one or more identified needs: reliability, market efficiency, operational performance and public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to 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 process, including all aspects of analysis and evaluation pertaining to proposal windows.

Proposal Window Exemptions

Certain flowgate violations are exempted 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.*

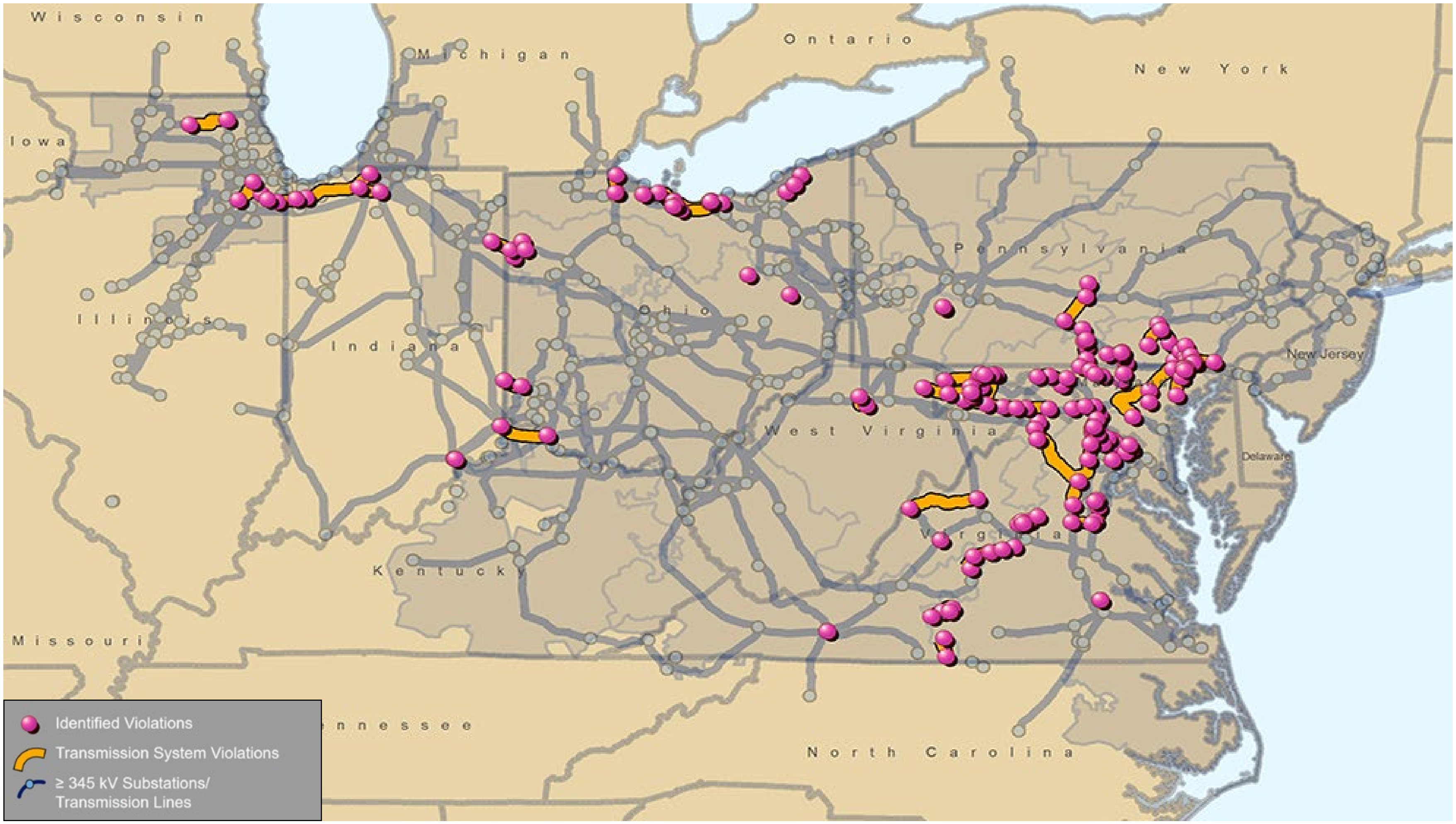
***Projects below 200 kV and substation equipment projects could become eligible for competition if multiple needs share common geography/contingency or if the project has multi-zonal cost allocation.*

- *Immediate-Need Exemption:* The required in-service date drives these projects, and they may be exempted from the competitive process to ensure they can be completed before the required in-service date.
- *Below 200 kV:* Solutions below 200 kV are exempted 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.

3.0.2 — 2023 RTEP Cycle Baseline Analysis Results

PJM's analysis of 2028 summer, winter and light load conditions identified 291 thermal and voltage criteria flowgate violations on the transmission system. One hundred and thirty of those were included in competitive windows, while 161 were excluded from competition. A summary of the 291 violations is shown in **Map 3.1**. These flowgate violations were addressed as part of RTEP Proposal Window No. 1. These flowgate violations were addressed as part of RTEP Proposal Window No. 1, described further in **Section 3.0.4**.

Map 3.1: 2023 RTEP Baseline Thermal and Voltage Criteria Violations



3.0.3 — 2022 RTEP Proposal Window No. 3

2022 RTEP Proposal Window No. 3 aimed to develop robust, holistic and expandable solutions that address the 2027-28 baseline violations associated with:

- Local constraints resulting from data center loads in the Allegheny Power (FirstEnergy) and Dominion Energy zones
- Regional constraints resulting from imports into load center areas
- Needed reactive power VAR reinforcements (both static and dynamic as necessary)
- The reliability impacts from the deactivation of 11 GW of generation

RTEP Proposal Window No. 3, which contained 1,054 flowgate violations with 997 open for competition, opened on Feb. 24, 2023, and closed on May 31, 2023. PJM received 72 proposals from 10 entities. Twenty-two proposals comprised upgrades to existing transmission infrastructure, while 50 proposals comprised greenfield projects. Forty-four projects included cost containment provisions. The proposals are shown in **Map 3.2** and **Table 3.1**. The solutions that were submitted aimed to address reliability issues in the area. One project was approved by the PJM Board totaling $5.142 billion to address the reliability criteria violations associated with this window. The Reliability Analysis Report and Constructability & Financial Analysis Report are accessible on the Transmission Expansion Advisory Committee webpage.

Map 3.2: 2022 RTEP Proposal Window No. 3 Submittals

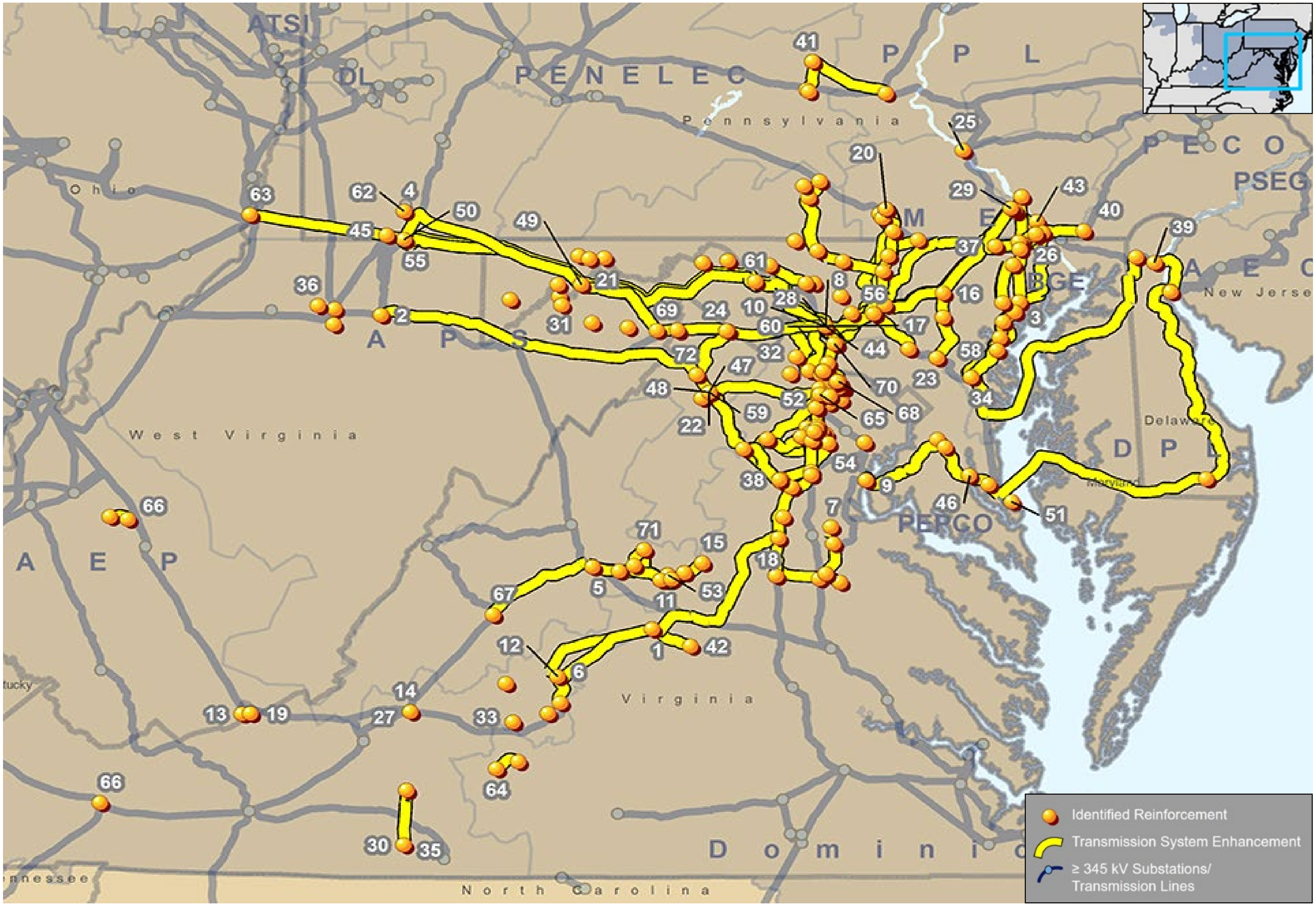


Table 3.1: 2022 RTEP Proposal Window No. 3 Submittals

Map ID	Proposal ID	Target Zone	kV	Incumbent TO	Project Type	Cost Containment	Cost Estimate ($M)	Description
1	9	AEP/Dominion	138	AEP	UPGRADE	No	$1.27	Scottsville-Bremo sag study
2	23	Dominion	500/230	FirstEnergy	GREENFIELD	No	$3,503.86	Data Center Reinforcement Proposal No. 2
3	24	MAAC	500	PSEG	GREENFIELD	Yes	$739.40	Proposal A - North Delta-New Raphael-Waugh Chapel 500 kV
4	28	Dominion	500/138	NextEra	GREENFIELD	Yes	$884.05	Hunterstown-Doubs-Goose Creek, Black Oak-Pike-Goose Creek, Pike SVC + Cap Banks
5	30	Dominion	230	Dominion	UPGRADE	No	$159.87	Rebuild Charlottesville-Hollymead line No. 2054.
6	55	AEP	138	AEP	UPGRADE	No	$104.88	Rebuild Boxwood-Scottsville 138 kV.
7	74	Dominion	230	Dominion	UPGRADE	No	$57.34	Rebuild line No. 2090 (Ladysmith CT-Fredericksburg).
8	116	Dominion	500/230	NextEra	GREENFIELD	Yes	$478.87	Hunterstown-Doubs-Gant solution
9	125	PSEG	500/230	PSEG	GREENFIELD	Yes	$313.34	Proposal B - North Delta-Northeast 230 kV
10	129	Dominion	500	Dominion	UPGRADE	No	$3,035.05	Dominion Aggregate 500 kV proposal
11	175	Dominion	500/230	NextEra	GREENFIELD	Yes	$2,530.65	Combination of PEBO 215A + WOP 1F + SOP 8E
12	181	AEP	138	AEP	UPGRADE	No	$4.26	Boxwood-Scottsville 138 kV sag study
13	196	AEP	138	AEP	UPGRADE	No	$21.89	Rebuild Glen Lyn-Peters Mountain.
14	202	AEP	500/345	AEP	UPGRADE	No	$57.29	Cloverdale Transformer addition
15	211	Dominion	500/230	Dominion	UPGRADE	No	$54.85	Rebuild Hollymead-Gordonsville line No. 2135.
16	217	Dominion	500/230	NextEra	GREENFIELD	Yes	$155.99	North Delta-Conastone solution
17	229	PSEG	500	PSEG	GREENFIELD	Yes	$529.11	Proposal C - Hunterstown-New Green Valley 500 kV
18	231	Dominion	500/230	Dominion	UPGRADE	No	$155.82	Reactive Power VAR reinforcements
19	234	AEP	138	AEP	UPGRADE	No	$0.80	Glen Lyn-Peters Mountain sag study
20	255	Dominion	500	NextEra	GREENFIELD	Yes	$411.61	Hunterstown-Doubs-Gant solution
21	279	Dominion	500/138	NextEra	GREENFIELD	Yes	$429.18	Black Oak - Woodside - Goose Creek, Woodside SVC + Cap Banks solution
22	325	PSEG	500/230	PSEG	GREENFIELD	Yes	$944.05	Proposal E - Brambleton-Hinsons Ford Rd 500 kV
23	344	PECO	500/230	PECO	GREENFIELD	Yes	$302.86	PECO Expansion Plan for DOM Window 2023
24	347	Dominion	500	NextEra	GREENFIELD	Yes	$483.83	Black Oak-Woodside-Gant, Woodside SVC + Cap Banks
25	374	PPL	500	PPL	GREENFIELD	Yes	$154.21	Otter Creek-Conastone 500 and 230 kV DCT line
26	385	Dominion	500/230	NextEra	GREENFIELD	Yes	$1,140.73	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation
27	410	AEP	765/500	AEP	UPGRADE	No	$11.59	Cloverdale breaker reconfiguration

Table 3.1: 2022 RTEP Proposal Window No. 3 Submittals (Cont.)

Map ID	Proposal ID	Target Zone	kV	Incumbent TO	Project Type	Cost Containment	Cost Estimate ($M)	Description
28	419	Dominion	500/230	NextEra	GREENFIELD	Yes	$548.75	Hunterstown-Doubs-Audobon-Goose Creek
29	445	Dominion	500/230	NextEra	GREENFIELD	Yes	$637.80	Muddy Creek / Delta - Conastone / Hunterstown - Doubs - Goose Creek Solution
30	477	AEP	138	AEP	UPGRADE	No	$74.89	Rebuild Fieldale-Franklin.
31	487	MAAC	230	AEP - Transource WV	GREENFIELD	Yes	$492.75	Maryland & Pennsylvania baseline reliability solution
32	516	Dominion	500/230	Dominion	GREENFIELD	No	$61.72	Interregional solution - Aspen-Doubs Second 500 kV line
33	524	AEP	138	AEP	UPGRADE	No	$8.86	Opossum Creek and New London Reactors
34	530	Dominion	500/230	NextEra	GREENFIELD	Yes	$166.74	Muddy Creek/North Delta-Conastone solution
35	537	AEP	138	AEP	UPGRADE	No	$30.19	Fieldale-Franklin sag study
36	548	Dominion	500/230	LSPower	GREENFIELD	Yes	$2,404.48	RTEP Window 3 solution
37	564	MAAC/Dominion	500/230	NextEra	GREENFIELD	Yes	$876.88	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation
38	577	Dominion	500/230	NextEra	GREENFIELD	Yes	$258.38	Front Royal-Racefield, Warrenton-Wheeler, North Anna-Lady Smith
39	598	Dominion	500/230	NextEra	GREENFIELD	Yes	$2,036.47	Combination of PEBO 220 + WOP 1F + SOP 8E
40	600	PECO	500	PECO	UPGRADE	Yes	$423.79	Exelon replacement upgrades
41	606	PPL	230	PPL	GREENFIELD	Yes	$141.16	Juniata-Lewistown 230 kV No. 2 line
42	629	AEP	138	AEP	UPGRADE	No	$31.31	Rebuild Scottsville-Bremo.
43	631	Dominion	500/230	NextEra	GREENFIELD	Yes	$184.47	Muddy Creek/North Delta-Conastone solution
44	637	PSEG/AP	500/230	PSEG	GREENFIELD	Yes	$684.22	Proposal D-Conastone-Doubs 500 kV
45	642	Dominion	500/138	NextEra	GREENFIELD	Yes	$747.31	502 Junction - Black Oak-Woodside - Gant, Woodside SVC + Cap Banks, Gant-Farmwell, Cochran Tap - Round Table
46	660	MAAC	500	PEPCO	GREENFIELD	Yes	$1,105.62	West Cooper BGE-PEPCO
47	663	Dominion	500/230	NextEra	GREENFIELD	Yes	$284.17	Front Royal-Racefield, Warrenton-Rixlew, Warrenton-Hourglass, Mars-Ocean Court-Davis Drive
48	671	Dominion	500/230	Dominion	UPGRADE	No	$299.03	Rebuild lines No. 541 (Front Royal to Morrisville).
49	676	Dominion	500/230	NextEra	GREENFIELD	Yes	$552.49	Black Oak-Stonewall-Gant, Stonewall SVC + Cap Banks, Gant-Farmwell, Cochran Tap - round table solution
50	685	Dominion	500/138	NextEra	GREENFIELD	Yes	$609.78	Ft. Martin-Black Oak-Woodside, Woodside SVC + Cap Banks solution
51	691	MAAC	500	PEPCO	GREENFIELD	No	$1,990.28	Mid-Atlantic Power Pathway (MAPP)
52	692	Dominion	500/230	Dominion	GREENFIELD	No	$1,058.45	Data Center Alley Local solution - New 500 kV/230 kV Aspen-Golden & Golden-Mars lines
53	704	Dominion	230	Dominion	UPGRADE	No	$36.89	Rebuild Hollymead-Gordonsville line No. 2135.

Table 3.1: 2022 RTEP Proposal Window No. 3 Submittals (Cont.)

Map ID	Proposal ID	Target Zone	kV	Incumbent TO	Project Type	Cost Containment	Cost Estimate ($M)	Description
54	711	Dominion	500	Dominion	GREENFIELD	No	$1,227.84	Regional Solution - 500 kV North Anna-Wishing Star upgrades
55	719	Dominion	500/138	NextEra	GREENFIELD	Yes	$600.90	Ft. Martin-Black Oak-Pike, Pike SVC + Cap Banks solution
56	728	Dominion	500	NextEra	GREENFIELD	Yes	$385.35	Barnhart Substation, Bartholow Substation, Barnhart - Bartholow - Goose Creek solution
57	731	Dominion	230/115	Dominion	UPGRADE	No	$7.14	Locks substation 230/115 kV transformer upgrade
58	741	MAAC	500	PSEG	GREENFIELD	Yes	$1,065.32	Proposal G - Peach Bottom-New Brandon Shores 500 kV; Peach Bottom-Doubs 500 kV
59	766	Dominion	500/230	NextEra	GREENFIELD	Yes	$239.59	Front Royal-Racefield, Warrenton-Wheeler
60	808	MAAC	500/230	PSEG	GREENFIELD	Yes	$1,150.80	Proposal F - Peach Bottom-New Raphael-Waugh Chapel 500 kV; Peach Bottom-Doubs 500 kV
61	837	AP	500 kV	FirstEnergy	GREENFIELD	No	$2,991.77	Data center reinforcement proposal No. 1
62	846	Dominion	500/138	NextEra	GREENFIELD	Yes	$892.94	Hunterstown-Doubs-Goose Creek, Black Oak-Woodside-Goose Creek, Stonewall SVC + Cap Banks
63	853	Dominion	500/138	NextEra	GREENFIELD	Yes	$683.55	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks
64	856	AEP	138	AEP	UPGRADE	No	$28.85	Rebuild Leesville-Altavista.
65	858	Dominion	500	AEP - Transource WV	GREENFIELD	Yes	$510.44	Stork-Flys 500 kV greenfield line and substations
66	904	AEP/Dominion	765	AEP - Transource WV	GREENFIELD	Yes	$1,048.10	Joshua Falls-Yeat 765 kV greenfield line and substation
67	923	Dominion	500	Dominion	GREENFIELD	No	$232.18	Second 500 kV line from Lexington to Dooms
68	948	Dominion	500/230	NextEra	GREENFIELD	Yes	$1,621.56	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation, and Keeney to Waugh Chapel tie-in.
69	951	Dominion	500/138	NextEra	GREENFIELD	Yes	$419.86	Black Oak-Gore-Goose Creek, Pike SVC + Cap Bank solution
70	962	MAAC/Dominion	500	PSEG	GREENFIELD	Yes	$977.71	Proposal H - Peach Bottom-Doubs 500 kV (Circuits No. 1 and No. 2)
71	967	Dominion	500/230	Dominion	UPGRADE	No	$183.48	Rebuild Charlottesville-Hollymead Line No. 2054.
72	977	Dominion	500/230	AEP - Transource WV	GREENFIELD	Yes	$232.14	Yeat 500/230 kV greenfield station

3.0.4 — 2023 RTEP Proposal Window No. 1

RTEP Proposal Window No. 1, which contained 291 flowgate violations with 130 open for competition, opened on July 24, 2023, and closed on Sept. 22, 2023. This window sought to address thermal and voltage violations identified as part of the 2023 RTEP as well as overlapping items in the 2022 Window 3. PJM received 20 proposals from nine entities. Five of the proposals included cost containment provisions, and five of the proposals included greenfield construction.
The proposals are shown in **Map 3.3** and **Table 3.2**.

Map 3.3: 2023 RTEP Proposal Window No. 1 Submittals

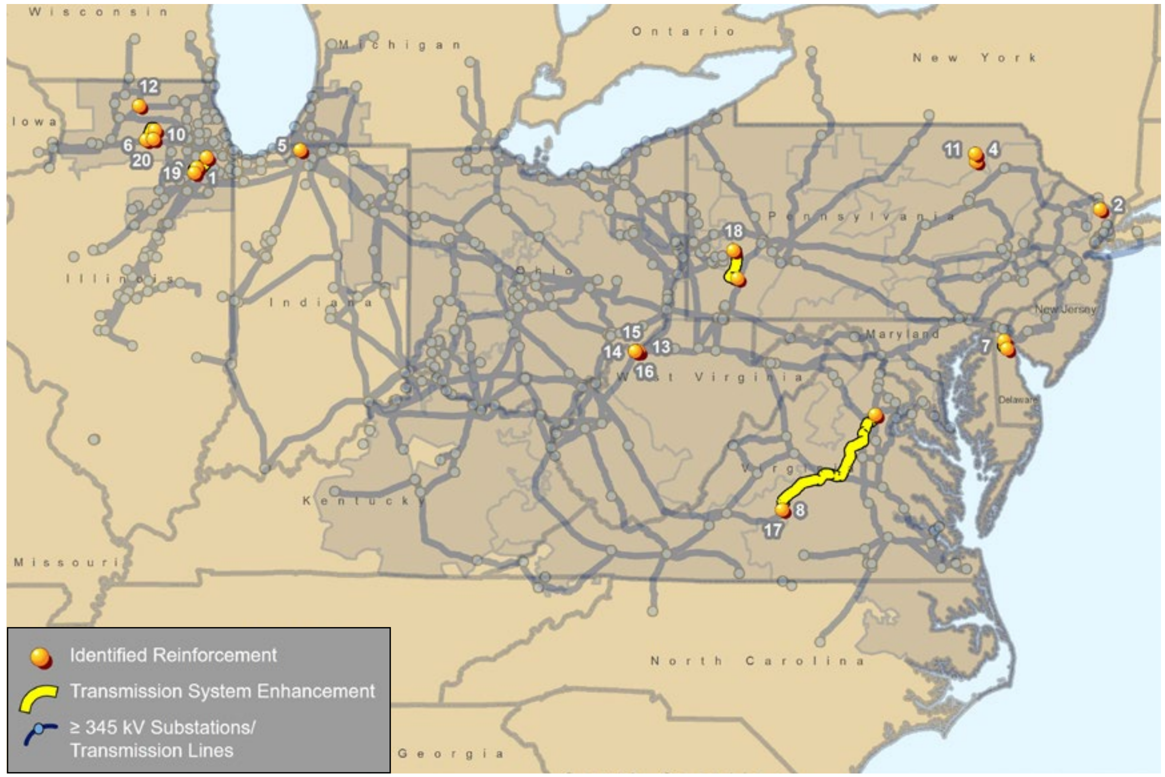


Table 3.2: 2022 RTEP Proposal Window No. 3 Submittals

Map ID	Proposal ID	Target Zone	kV	Incumbent TO	Project Type	Cost Containment	Cost Estimate ($M)	Description
1	35	ComEd	345	ComEd	UPGRADE	No	$61.84	Reconductor 345 kV lines 11620 & 11622 Elwood to Goodings Grove.
2	107	PSEG	230	PSEG	UPGRADE	No	$29.63	Waldwick Area Voltage upgrades
3	138	ComEd	345	ComEd	GREENFIELD	No	$97.50	Elwood-Joliet
4	158	PENELEC	115	MAIT	UPGRADE	No	$17.72	Rebuild North Meshoppen-Mehoopany No. 2 115 kV line.
5	384	AEP	345	AEP	UPGRADE	No	$1.08	Olive Breaker replacement

Table 3.2: 2022 RTEP Proposal Window No. 3 Submittals (Cont.)

Map ID	Proposal ID	Target Zone	kV	Incumbent TO	Project Type	Cost Containment	Cost Estimate ($M)	Description
6	500	ComEd	138	ComEd	GREENFIELD	No	$113.94	Haumesser Road-Glidden
7	573	DP&L	230	DP&L	GREENFIELD	No	$8.71	Reconductor Silver Run-Cedar Creek line.
8	605	AP	765	Transource	UPGRADE	Yes	$718.70	Joshua Falls-Yeat 765 kV line upgrade
9	663	ComED	345	Central Transmission, LLC	GREENFIELD	Yes	$29.37	Elwood-Joliet 345 kV transmission project
10	712	ComEd	138	ComEd	UPGRADE	No	$10.21	Reconductor 138 kV line 11323 from Haumesser Road to H-452 tap.
11	746	PENELEC	115	MAIT	UPGRADE	No	$17.40	Rebuild North Meshoppen-Mehoopany No. 1 115 kV line.
12	771	ComEd	345	ComEd	UPGRADE	No	$7.75	Cherry Valley circuit breakers
13	831	AP	765/500	Transource	UPGRADE	Yes	$125.69	Polecat Greenfield 765/500 kV substation.
14	850	AP	765/500	FirstEnergy	UPGRADE	No	$110.43	Install second 765/500 kV transformer at Belmont substation.
15	851	AP	765/500	Transource	UPGRADE	Yes	$53.36	Cork Greenfield 765 kV substation
16	903	AP	765/500	FirstEnergy	GREENFIELD	No	$37.49	Belmont 765/500 kV transformer No. 5 replacement
17	905	AP	765	Transource	UPGRADE	Yes	$1,089.45	Joshua Falls-Yeat 765 kV greenfield line and substation re-submittal
18	929	DLCO	138	DLCO	UPGRADE	No	$5.50	Reconductor Cheswick-Yukon.
19	937	ComEd	138	ComEd	UPGRADE	No	$8.52	Apply Conductor Coating Technology to Lines 11620 & 11622 Elwood-Goodings Grove
20	972	ComEd	138	ComEd	UPGRADE	No	$28.11	Install second circuit from Haumesser Road to H-452.

3.1: Transmission Owner Criteria

3.1.1 — 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 earlier in **Figure 3.1**. Under the terms of the OATT, the costs of such projects follow existing baseline reliability cost allocation rules.

3.1.2 — 2023 TO Criteria-Driven Projects

The 2023 RTEP included five TO criteria-driven projects for a total cost of over $28 million. The description and location of those projects are shown in **Table 3.3** and **Map 3.4**. More detailed descriptions of these projects can be found in TEAC PJM Board White Papers.

Map 3.4: 2023 Transmission Owner Criteria-Driven Projects

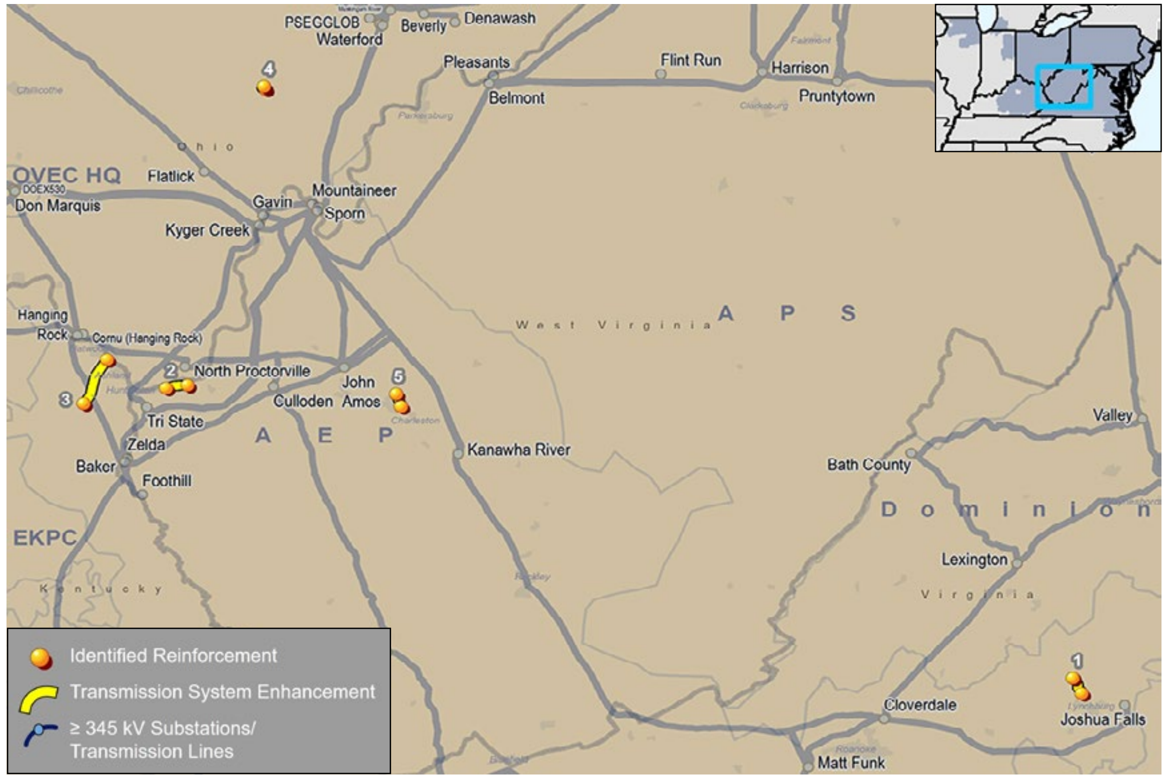


Table 3.3: 2023 Transmission Owner Criteria Driven Projects

Map ID	Upgrade ID	Description	TO Zone	Cost Estimate ($M)	Required In-Service	Projected In-Service
1	**B3786.1**	Rebuild ~4.5 miles of 69 kV line between Abert and Reusens substations. Update line settings at Reusens and Skimmer.	AEP	$14.40	6/1/2028	6/1/2028
2	**B3840.1**	Replace Structures 382-66 and 382-63 on Darrah-East Huntington 34.5 kV line to bypass 24th Street station. Retire structures 1 through 5 on Twenty Fourth Street 34.5 kV extension. Retire 24th Street station. Remove conductors from BASF Tap to BASF.	AEP	$1.80	6/1/2028	4/1/2024
3	**B3787.1**	Install a CCVT on 3 phase stand and remove the single phase existing CCVT on the 69 kV Coalton to Bellefonte line exit. The existing CCVT is mounted to lattice on a single phase CCVT stand, which will be replaced with the 3 phase CCVT stand. The line riser between line disconnect and line take off is being replaced. This remote end work changes the MLSE of the line section between Coalton-Princess 69 kV line section.	AEP	$0.00	12/1/2028	6/1/2026
4	**B3843.1**	Rebuild the underground portion of the Ohio University-West Clark 69 kV line, ~0.65 miles.	AEP	$4.60	6/1/2028	6/1/2028
5	**B3836.1**	Rebuild ~1.7 miles of line on the Chemical-Washington Street 46 kV circuit.	AEP	$7.60	6/1/2028	6/1/2028

3.2: Supplemental Projects

3.2.1 — Project Drivers

Supplemental projects are not required for compliance with system reliability, operational performance or market efficiency economic criteria. 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 (e.g., 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.

3.2.2 — OATT Attachment M-3 Process

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

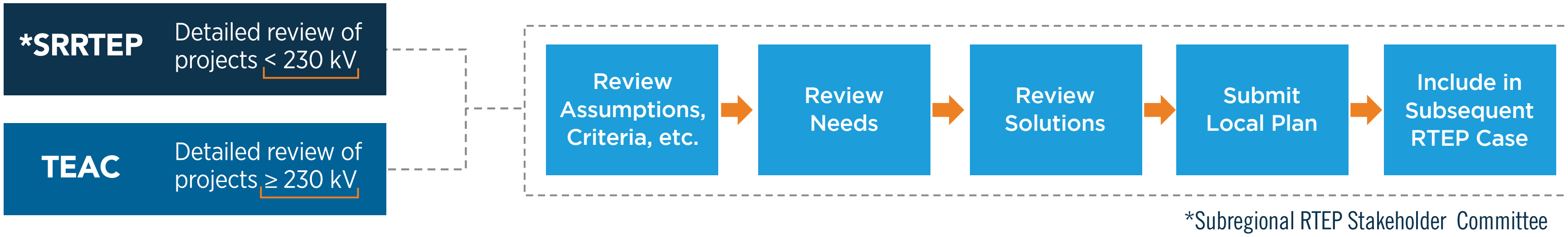
PJM, in its role as a facilitator in the OATT Attachment M-3 process, is responsible for the following:

- Provide necessary facilitation and logistical support so that supplemental project planning meetings can be conducted as outlined in 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.
- Work with TOs and stakeholders to improve OATT Attachment M-3 Process transparency.

Figure 3.2: Primary Supplemental Project Drivers

Customer Service	Provide service to new and existing customers; interconnect new customer load; address distribution load growth, customer outage exposure, equipment loading, etc.
Equipment Material Condition, Performance and Risk	Address degraded equipment performance, material condition, obsolescence; end of the useful life of equipment or a facility; equipment failure; employee and public safety; and environmental impact.
Operational Flexibility and Efficiency	Optimize system configuration, equipment duty cycles and restoration capability; minimize outages.
Infrastructure Resilience	Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather or geomagnetic disturbances.
Other	Meet objectives not included in other definitions such as, but not limited to, technological pilots, industry recommendations, and environmental and safety impacts.

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

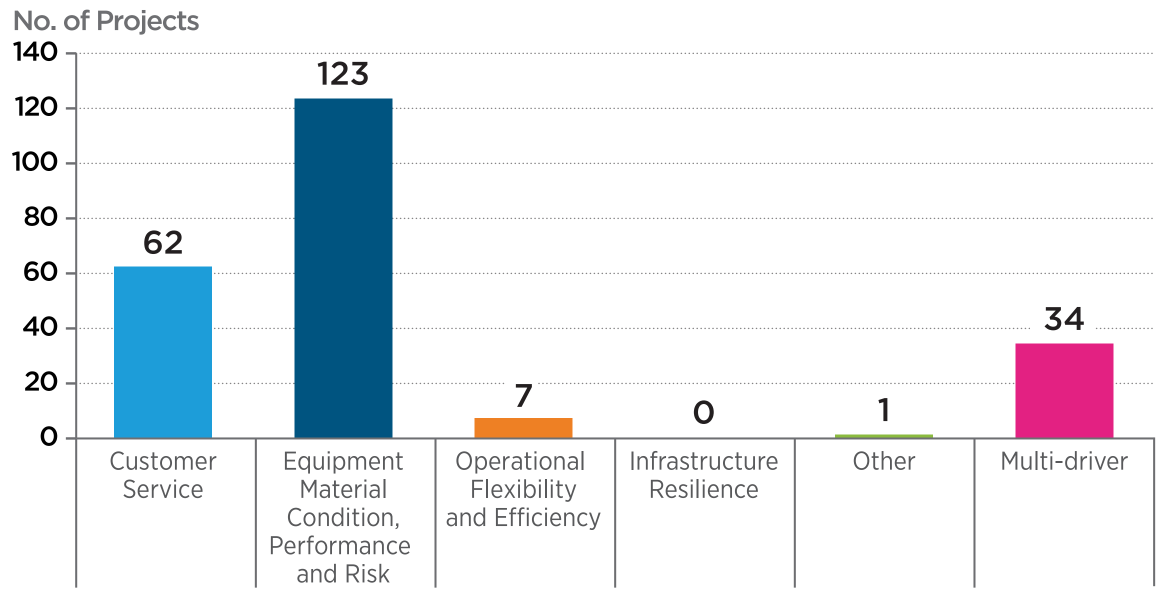


The OATT Attachment M-3 process provides stakeholders – via the PJM Transmission Expansion Advisory Committee (TEAC) and subregional RTEP committees – the meaningful opportunity to review supplemental projects and provide feedback, including written comments, as shown in **Figure 3.3**. Stakeholders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

3.2.3 — 2023 Supplemental Projects

PJM evaluated approximately $2.4 billion of TO supplemental projects in 2023. **Figure 3.4** shows a breakdown of supplemental solutions by driver, presented at TEAC and subregional RTEP committees over the past year. It suggests that the largest drivers are equipment material condition, performance and risk, and total approximately $1.27 billion. Projects driven by customer service requests and operational flexibility and efficiency totaled approximately $314.1 million and $62 million, respectively. The remaining $764.7 million are required by projects classified as "Other" or with more than one driver.

Figure 3.4: 2023 Supplemental Projects by Driver



3.3: Generator Deactivations

PJM received 31 deactivation notices totaling 5,844.8 MW in 2023. **Map 3.5** and **Table 3.4** show these generators' deactivation notifications.

Map 3.5: Deactivation Notifications Received in 2023

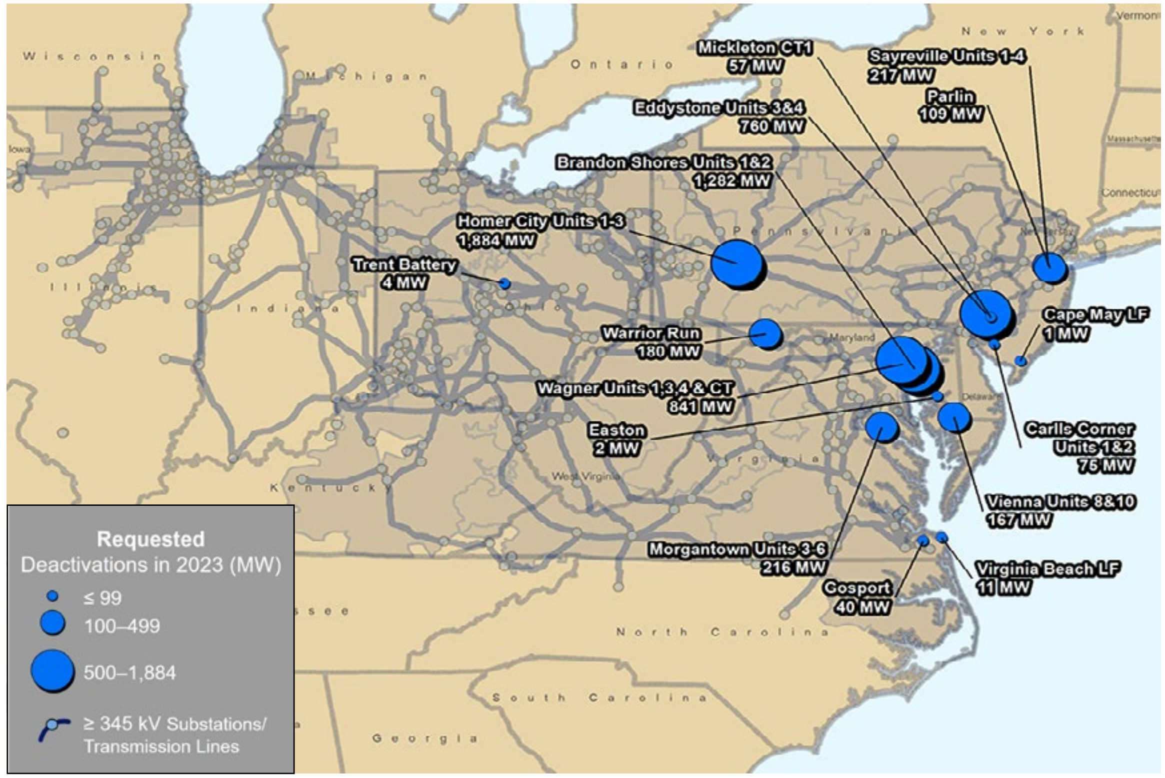


Table 3.4: Deactivation Notifications Received in 2023

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Requested Deactivation Date	Projected Deactivation Date
Homer City 3	650	PENELEC	46	Coal	7/1/2023	7/1/2023
Homer City 2	614	PENELEC	54	Coal	7/1/2023	7/1/2023
Homer City 1	620	PENELEC	54	Coal	7/1/2023	7/1/2023
Easton Unit No. 8	2	DP&L	9	Diesel	10/1/2023	10/1/2023
Cape May County MUA LF	0.6	AE	10	Methane	10/1/2023	3/1/2023
Parlin Nug	108.7	JCP&L	32	Natural Gas	10/31/2023	10/31/2023

Table 3.4: Deactivation Notifications Received in 2023 (Cont.)

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Requested Deactivation Date	Projected Deactivation Date
Trent 1 BT	4	AEP	10	Battery	1/1/2024	1/1/2024
Virginia Beach Landfill	11	Dominion	18	Methane	4/1/2024	4/1/2024
Sayreville C-4	48.5	JCP&L	51	Natural Gas	6/1/2024	6/1/2024
Sayreville C-3	54.6	JCP&L	51	Natural Gas	6/1/2024	6/1/2024
Sayreville C-2	56.7	JCP&L	51	Natural Gas	6/1/2024	6/1/2024
Sayreville C-1	57.1	JCP&L	51	Natural Gas	6/1/2024	6/1/2024
Morgantown CT 6	54	PEPCO	50	Oil	6/1/2024	6/1/2024
Morgantown CT 5	54	PEPCO	50	Oil	6/1/2024	6/1/2024
Morgantown CT 4	54	PEPCO	50	Oil	6/1/2024	6/1/2024
Morgantown CT 3	54	PEPCO	50	Oil	6/1/2024	6/1/2024
Mickleton 1 CT	57.2	AE	49	Natural Gas	6/1/2024	6/1/2024
Carlls Corner CT 2	38.2	AE	50	Natural Gas	6/1/2024	6/1/2024
Carlls Corner CT 1	36.3	AE	50	Natural Gas	6/1/2024	6/1/2024
Warrior GEN1	180	AP	21	Coal	6/1/2024	6/1/2024
VP Gosport 1 F	40	Dominion	36	Biomass	7/1/2024	7/1/2024
Eddystone E 4	380	PECO	53	Oil	5/31/2025	5/31/2025
Eddystone 3	380	PECO	53	Oil	5/31/2025	5/31/2025
Wagner CT 1	13	BGE	56	Diesel	6/1/2025	6/1/2025
Wagner 4	397	BGE	51	Oil	6/1/2025	6/1/2025
Wagner 3	305	BGE	64	Coal	6/1/2025	6/1/2025
Wagner 1	126	BGE	67	Natural Gas	6/1/2025	6/1/2025
Brandon Shores 2	642.7	BGE	32	Coal	6/1/2025	6/1/2025
Brandon Shores 1	638.9	BGE	39	Coal	6/1/2025	6/1/2025
Vienna 10	14.3	DP&L	55	Oil	6/1/2025	6/1/2025
Vienna 8	153	DP&L	51	Oil	6/1/2025	6/1/2025

Twenty-six generators totaling 6,830.2 MW deactivated in the PJM region during 2023, as shown in **Map 3.6** and **Table 3.5**. PJM completed the required analysis to identify reliability criteria violations caused by deactivations.

Map 3.6: Actual Generator Deactivations in 2023

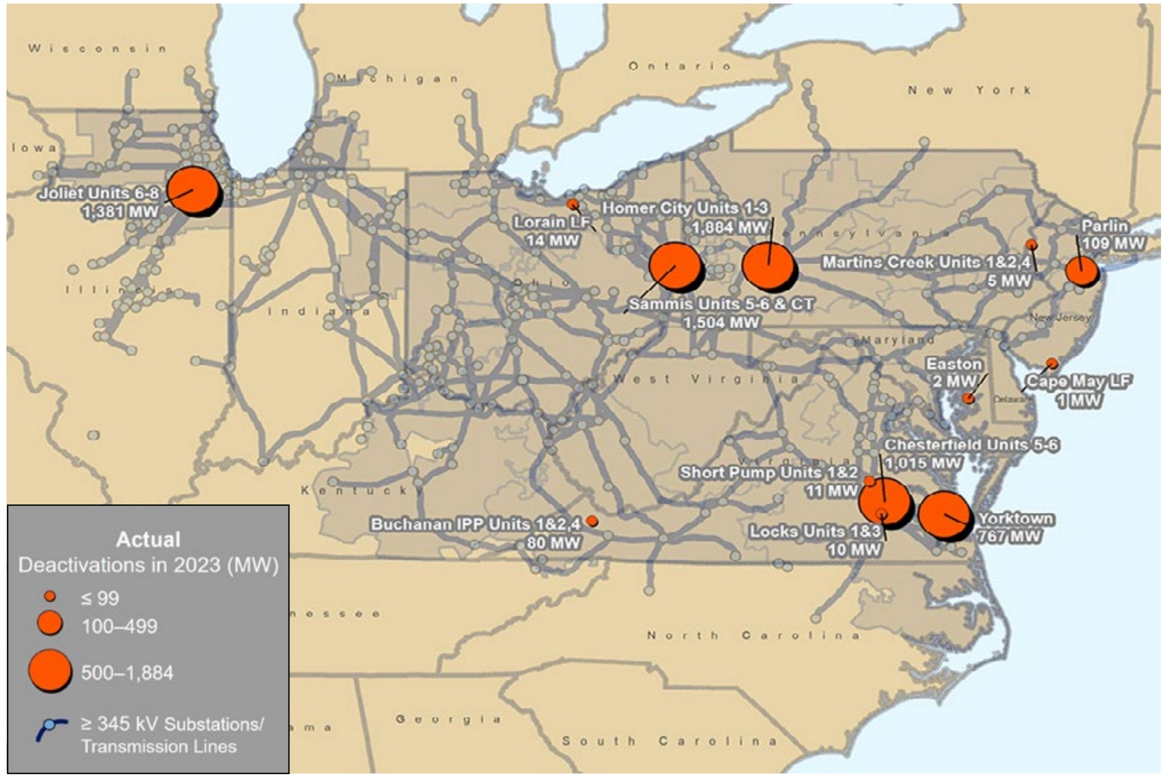


Table 3.5: Actual Deactivations in 2023

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Requested Deactivation Date	Projected Deactivation Date
Oberlin Lorain County 2 LF	14	ATSI	0	Methane	4/1/2023	4/1/2023
Yorktown 3	767.1	Dominion	48	Oil	6/1/2023	6/1/2023
Joliet 6	281	ComEd	63	Natural Gas	6/1/2023	6/1/2023
Sammis Diesel	13	ATSI	50	Coal	6/1/2023	5/3/2023
Sammis 7	600	ATSI	51	Coal	6/1/2023	5/3/2023
Sammis 6	600	ATSI	53	Coal	6/1/2023	5/3/2023

Table 3.5: Actual Deactivations in 2023 (Cont.)

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Requested Deactivation Date	Projected Deactivation Date
Sammis 5	291.3	ATSI	55	Coal	6/1/2023	5/3/2023
Martins Creek CT 2	17.3	PPL	50	Oil	6/1/2023	6/1/2023
Martins Creek CT 1	18	PPL	50	Oil	6/1/2023	6/1/2023
Martins Creek CT 4	17.3	PPL	50	Natural Gas	6/1/2023	6/1/2023
Rockville Diesel	4	Dominion	26	Diesel	6/1/2023	6/1/2023
Lanier Diesel	7	Dominion	21	Diesel	6/1/2023	6/1/2023
Weakley Diesel	7	Dominion	21	Diesel	6/1/2023	6/1/2023
Dinwiddle Diesel	3	Dominion	28	Diesel	6/1/2023	6/1/2023
Chesterfield 6	678.1	Dominion	51	Coal	6/1/2023	6/1/2023
Chesterfield 5	336.8	Dominion	56	Coal	6/1/2023	6/1/2023
Buchanco 2	40	AEP	17	Natural Gas	6/12/2023	6/12/2023
Buchanco 1	40	AEP	17	Natural Gas	6/12/2023	6/12/2023
Homer City 3	650	PENELEC	46	Coal	7/1/2023	7/1/2023
Homer City 2	614	PENELEC	54	Coal	7/1/2023	7/1/2023
Homer City 1	620	PENELEC	54	Coal	7/1/2023	7/1/2023
Joliet 8	550	ComEd	56	Natural Gas	9/1/2023	9/1/2023
Joliet 7	550	ComEd	57	Natural Gas	9/1/2023	9/1/2023
Easton Unit No. 8	2	DP&L	9	Diesel	10/1/2023	10/1/2023
Cape May County MUA LF	0.6	AE	10	Methane	10/1/2023	3/1/2023
Parlin Nug	108.7	JCP&L	32	Natural Gas	10/31/2023	10/31/2023

3.4: 2023 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 2023 for several projects are shown on **Map 3.7** and **Table 3.6**.

In the Pennsylvania Electric Company (Penelec) Zone, a retool study was conducted to assess the impact of the reconfiguration of a supplemental project S1729. This project was originally designed as an expansion the North Meshoppen 115 kV substation, but upon additional analysis, it was determined that a stuck breaker contingency would cause multiple 115 kV line outages in the area, and therefore an alternate solution was required. Project S1729 was redesigned as a stand-alone substation nearby to address these concerns. Retool study results revealed no reliability criteria violations. As a result, the supplemental project could move forward.

In the PPL Zone, a retool study was conducted to assess the impact of a topology change associated with supplemental project S0945.2. This project initially called for installing a second 69 kV circuit on existing poles, which were initially built to be double strung. After construction began, it was determined that additional work was required to replace existing poles along a 3.5-mile stretch. This work included acquiring six miles of greenfield right-of-way to create a tie between the McAlisterville and Walker substations. Retool study results revealed no reliability criteria violations. As a result, the supplemental project could move forward.

In the Public Service Electric & Gas Company (PSE&G) Zone, a retool study was conducted to assess the impact of a topology change associated with supplemental project S2491, which originally created a line between the Linden and Vauxhall substations. Siting challenges have resulted in solution refinements, which now include the creation of a new Elizabeth substation connected between Vauxhall and Roselle. Retool study results revealed no reliability criteria violations. As a result, the supplemental project could move forward.

Map 3.7: 2023 RTEP Cycle Retool Studies

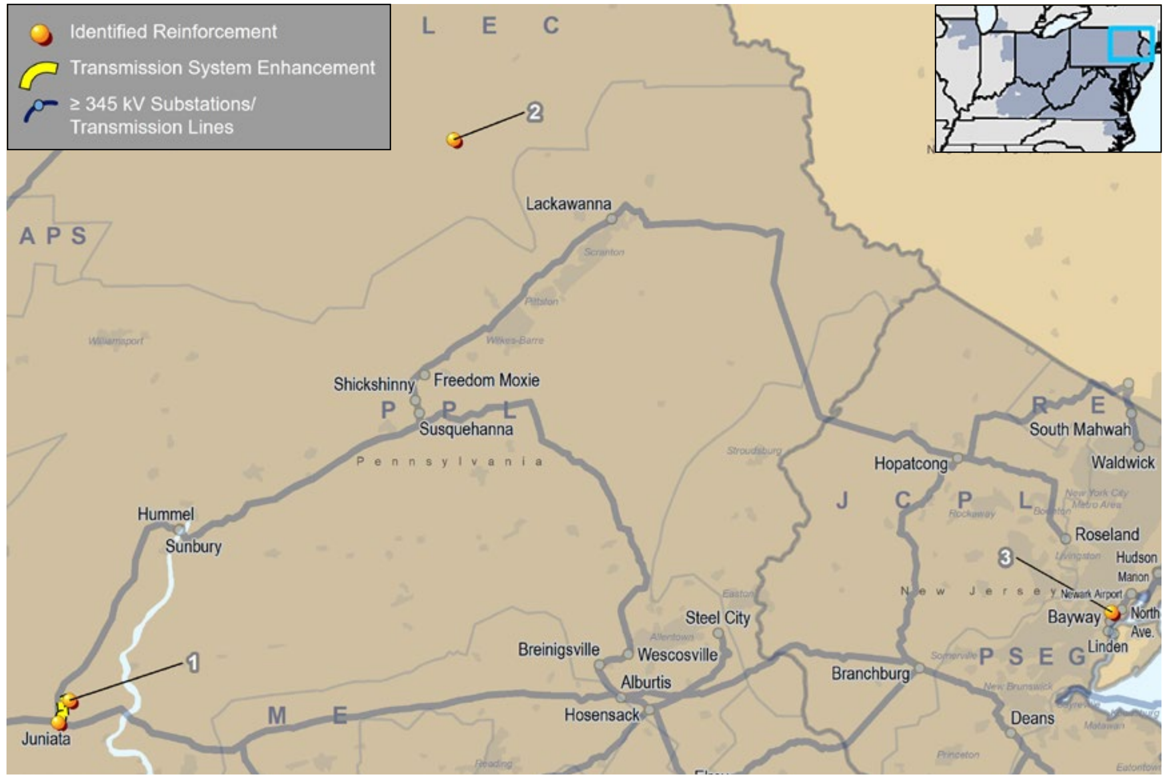


Table 3.6: Retool Impacts

Map ID	Projects	Description
1	S0945.2	Install fiber from Juniata to Newport (3.3 miles). Extend double circuit 69 kV on existing built for double circuit structures and add fiber from Newport to Thompsontown (9.3 Miles). Replace wood poles and install fiber on Walker tap (5 miles). Replace wood poles, install second circuit, and add fiber on the Mifflintown tap (3.5 miles). Rebuild from Thompsontown to Sunbury-Middleburg tie to single circuit future double circuit 69 kV (21 miles). Replace wood poles and add fiber to the McAlisterville tap (3.0 miles). Acquire new greenfield ROW for ~6 miles to create a tie between McAlisterville and Walker substations.
2	S1729	Expand the existing 115 kV yard to a breaker-and-a-half configuration at North Meshoppen substation.
3	S2491	Elizabeth substation is supplied by 26 kV circuits with increasing performance problems. Over the past decade, the four 26 kV supply circuits have seen 11 momentary and 36 extended outages, with total duration of 1,147 hours. Station equipment at Elizabeth has been in service since 1914 and needs to be addressed. Historical flooding has compromised some station structures. Elizabeth serves roughly 8,500 customers and 28.8 MVA of load.

3.5: Interregional Planning

3.5.1 — 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 process (SERTP), shown on **Map 3.8**.

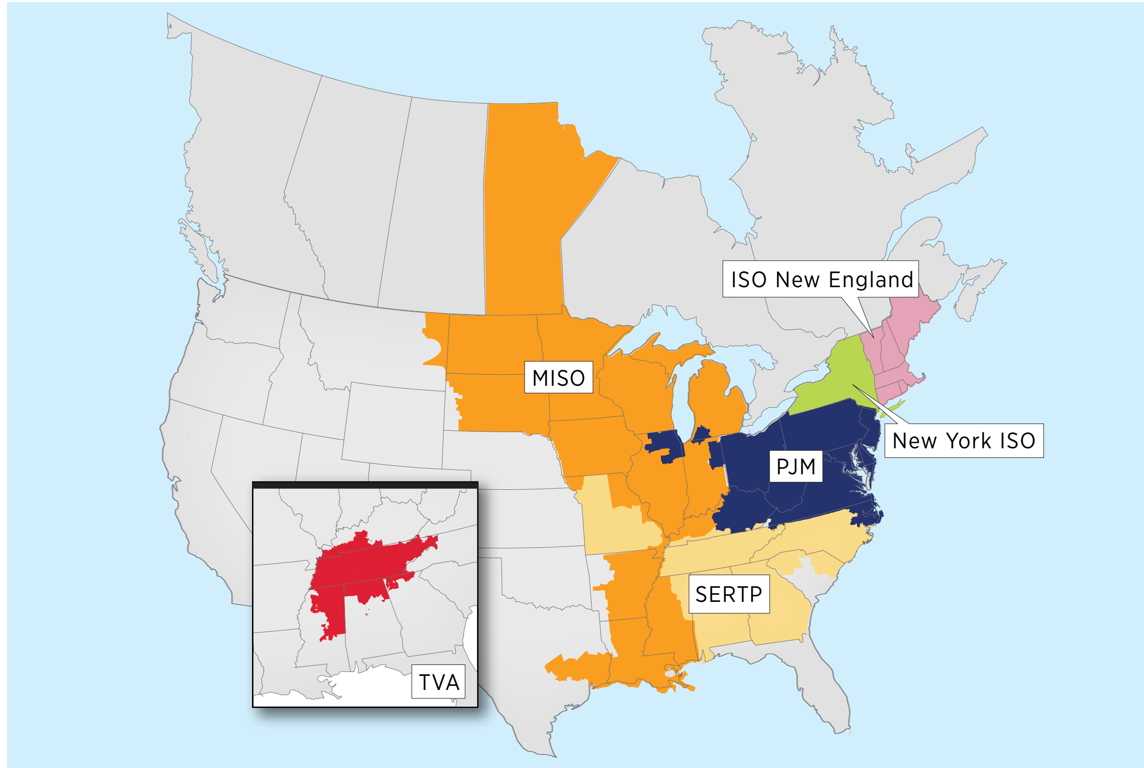
In addition, PJM actively participates in the Eastern Interconnection Planning Collaborative.

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 adversely impact 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
- 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 due to periodic exchange of power system modeling data and information

Map 3.8: PJM Interregional Planning



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, short circuit, 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.

3.5.2 — MISO

The 2023 planning efforts under Article IX of the MISO/PJM Joint Operating Agreement continued to ensure the coordination of regional reliability, market efficiency, 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).

2023 Coordinated System Plan Activities

As part of annual issues review process under Section 9.3.7.2 of the MISO/PJM Joint Operating Agreement, PJM and MISO reviewed:

1. Newly approved projects near the seam
2. New regional issues
3. Market-to-market historical congestion
4. Third-party issues

After rigorous review and analysis, the Joint Reliability Planning Committee (JRPC) determined that a CSP study would not be performed in 2023.

Previously, the TMEP study conducted in 2022 yielded results that recommended a Powerton Sub 138 kV wave trap project to mitigate congestion identified in the study. The project was approved by the PJM Board in February 2023. Additional detail regarding this project can be found in Section 3.6.2 of the 2022 RTEP Report.

3.5.3 — New York ISO and ISO New England

In 2023, PJM, New York ISO and ISO New England reviewed the status of their ongoing work plan and anticipated 2024 activities. The 2023 work included 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 group continues discussion on potential coordination/collaboration of an interregional offshore wind study. The group continues to seek opportunities for interregional transmission. The next Northeast Coordinated System Plan (NCSP23) is anticipated by the second quarter of 2024.

3.5.4 — Joint ISO/RTO Planning Committee (JIPC)

In March 2023, ISO New England wrote a letter to the JIPC requesting members of the JIPC perform a study to determine the feasibility of raising the minimum loss of source value for New England from an existing level of 1,200 MW to a proposed level of 2,000 MW. In August 2023, the JIPC posted a response accepting to collaboratively participate in the study. Study activities commenced in Q4 2023 with an anticipated duration of completion in 18–24 months.

3.5.5 — Adjoining Systems South of PJM

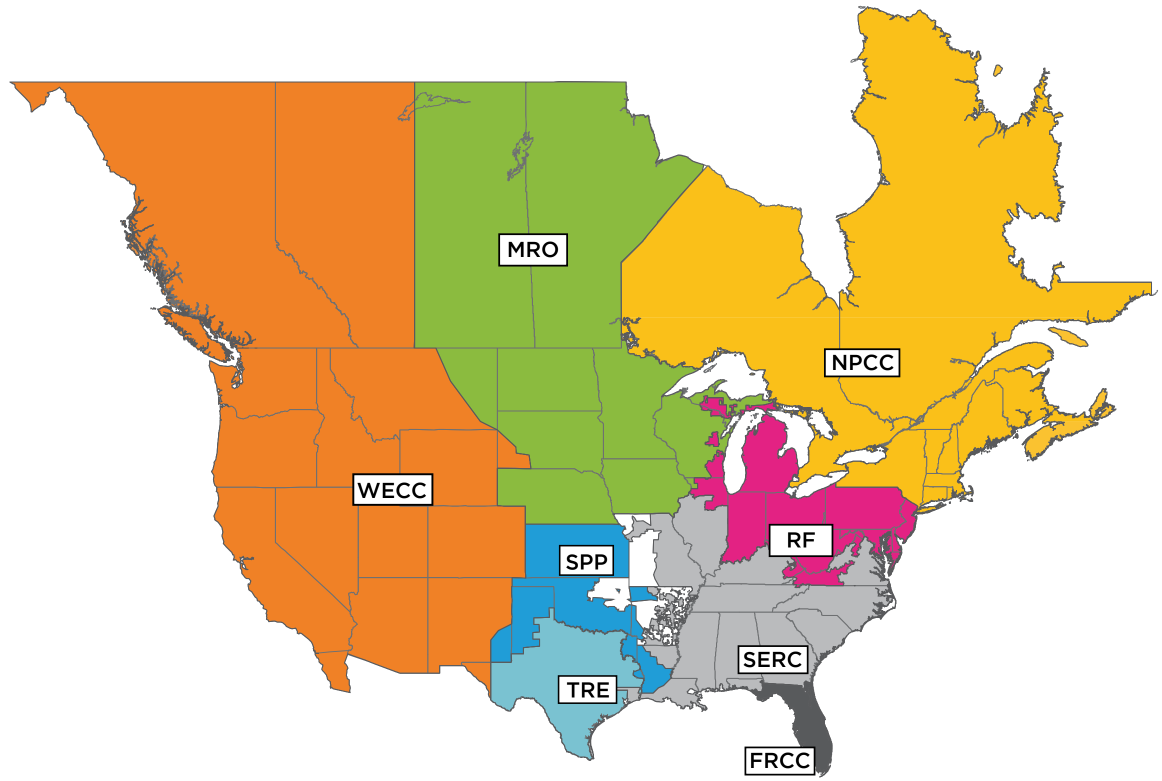
Interregional planning activities with entities south of PJM are conducted mainly under the auspices of the Southeastern Regional Transmission Planning (SERTP) process and SERC Reliability Corp.

Southeastern Regional Transmission Planning

PJM and the SERTP, shown earlier on **Map 3.8**, continued interregional data exchange and interregional coordination during 2023. 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 TEAC. The SERTP regional process itself can be followed at www.southeasternrtp.com.

Map 3.9: NERC Areas



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 3.9**. That support includes active participation in the Engineering Committee, Planning Coordination Subcommittee, the Long-Term Working Group, Dynamics Working Group, Short-Circuit Database Working Group, Resource Adequacy Working Group, and the Near-Term Working Group.

PJM actively contributed to SERC committee and working group activities to coordinate 2023 model development and study activities.

3.5.6 — Eastern Interconnection Planning Collaborative

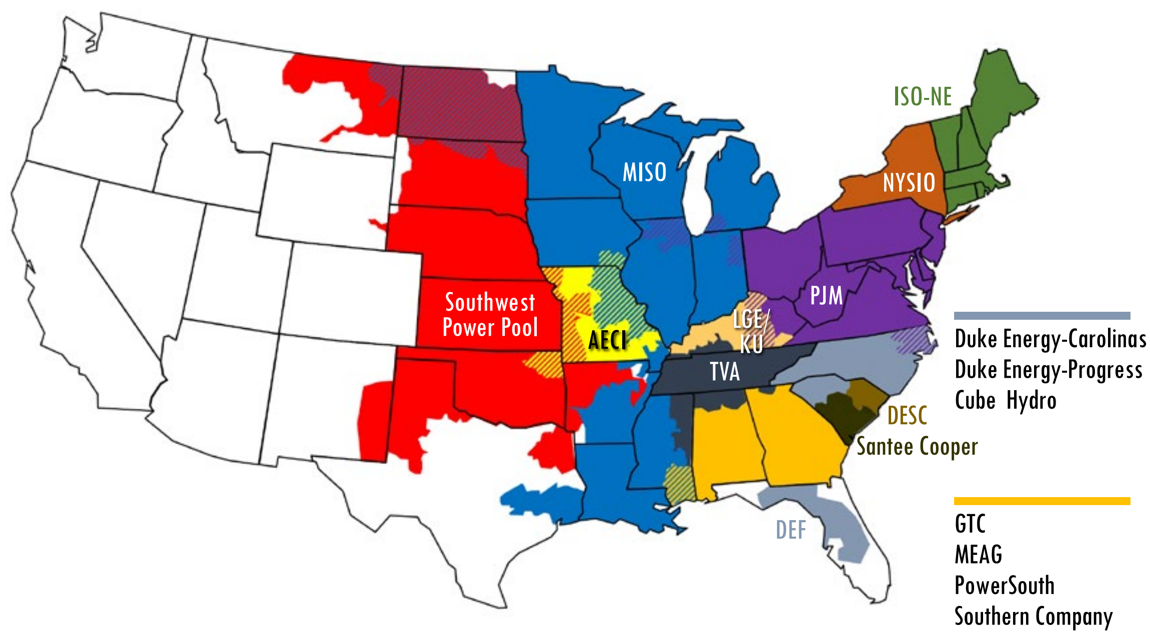
The Eastern Interconnection Planning Collaborative (EIPC) is an interconnection-wide transmission planning coordination effort among NERC planning authorities in the Eastern Interconnection, shown on **Map 3.10**. EIPC consists of 19 planning coordinators representing over 90% of the Eastern Interconnection load. EIPC coordinates analysis of regional transmission plans to ensure their coordination and provides resources to conduct analysis of emerging issues impacting the transmission grid. EIPC's work builds on, rather than replaces, existing regional and interregional transmission planning processes of participating planning authorities. EIPC's efforts are intended to inform regional planning processes.

EIPC Activities

During 2023, EIPC continued to engage power system planning analysis activities including the following:

- EIPC conducted a workshop on April 12, 2023, discussing both planning for DER (distributed energy resources) and resilience.
- EIPC participated in finalizing post-workshop comments to Docket No. AD23-3-000 entitled Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements.
- 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 3.10: Eastern Interconnection Planning Collaborative



3.6: 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. ARRs entitle the holder 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, Section 7.8, Schedule 1, 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 incremental ARRs 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.

Results: 2023/2024 Stage 1A ARR 10-Year Analysis

During 2023, PJM staff completed a 10-year simultaneous feasibility analysis for 2023/2024 Stage 1A ARR selections. The power flow case used in the 10-year feasibility analysis is the same one used in the 2023/2024 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 3.7** lists the facilities of concern and the previously approved baseline reliability solutions expected to address any violations identified in the analysis.

Table 3.7: 2023/2024 Stage 1A ARR 10-Year Feasibility Study: Reliability Criteria Violations

Facility Name	Upgrade Expected To Fix Infeasibility	Expected In-Service Date
Colora-Conowingo 230 kV	B3729: Increase the maximum operating temperature of DPL circuit 22088	2027
Conastone-Peach Bottom 500 kV	B3737.50: Constructing a new Peach Bottom-North Delta 500 kV line	2029
Lenox-North Meshoppen 115 kV	B3672: Upgrades East Towanda-North Meshoppen 115 kV line	2026
Linden-Minue St R 230 kV	B3737.38: Linden Subproject	2027
Various Dominion Constraints	2023 RTEP Proposal Window No. 3 Solutions part of the 2023 RTEP Process	To Be Determined

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 a 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 forecast 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 between 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 database provide key system information and trends to PJM stakeholders.

Go to Next Section >

24-Month Cycle

PJM's 2022/2023 24-month market efficiency timeline is shown in **Figure 4.1**. The 2023 market efficiency body of analysis is represented by the second year of the 24-month cycle and focused on the following:

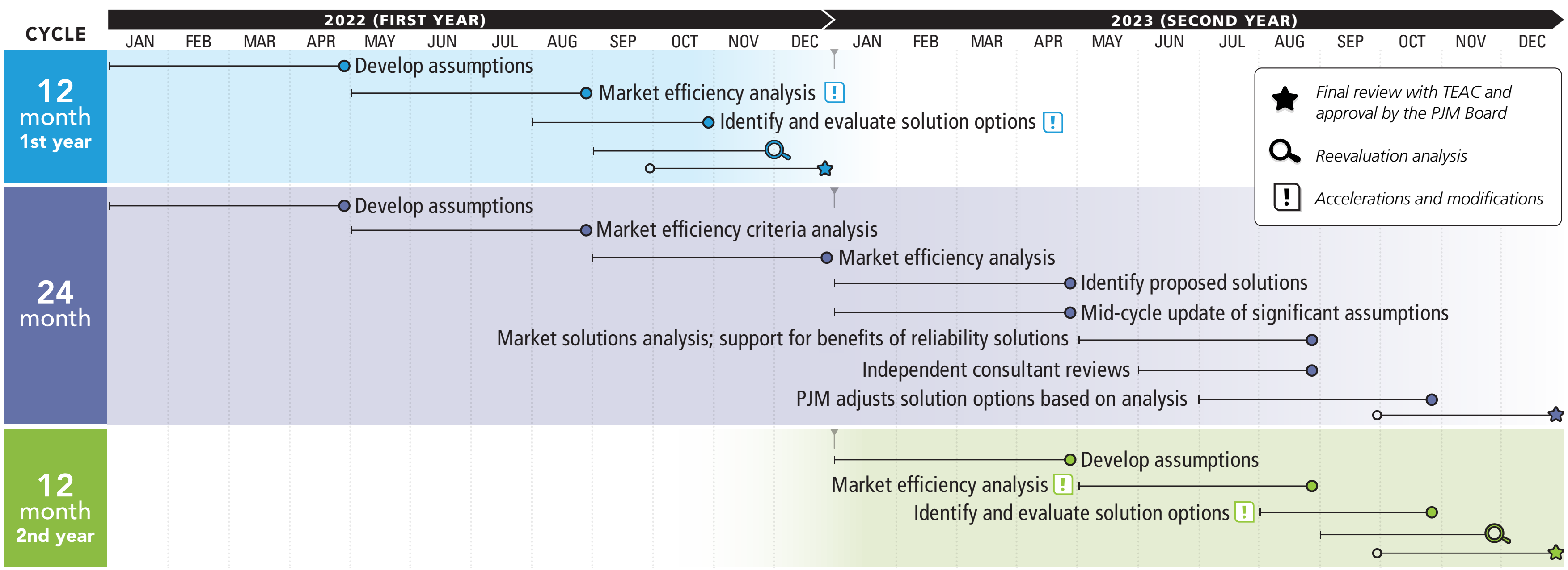
- Update of mid-cycle base case models
- Reevaluation of previously approved economic transmission projects
- Performing analysis considering the benefits of accelerating baseline projects previously approved for reliability but not yet built
- Identifying the congestion drivers associated with the 2022/23 market efficiency window

Market Efficiency Window Simulations

In order 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 five-year-out RTEP case (i.e., "as-planned" base case).

Market efficiency projects identified during the 2022/23 market efficiency window will be evaluated using the database initially developed during 2022. 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 for the mid-cycle update case is to ensure that potential projects are evaluated using an updated forecast of future conditions.

Figure 4.1: 2022/2023 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. Training material is available on PJM's website.

Project 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 2024 "as-is" simulation but not in the 2027 "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 perform the following:

- 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.

During 2023, 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 2024 and 2027 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 Convenience and 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 while maintaining 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

During 2023, PJM reevaluated a series of previously approved market efficiency transmission projects.

4.1: Input Parameters – 2023 Base Case

Overview

PJM licenses a commercially available database containing the necessary data elements to perform detailed PJM market simulations. This database is periodically updated permitting up-to-date representation of the Eastern Interconnection, and in particular, PJM. The PJM Transmission Expansion Advisory Committee (TEAC) reviews the key analysis input parameters, 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.

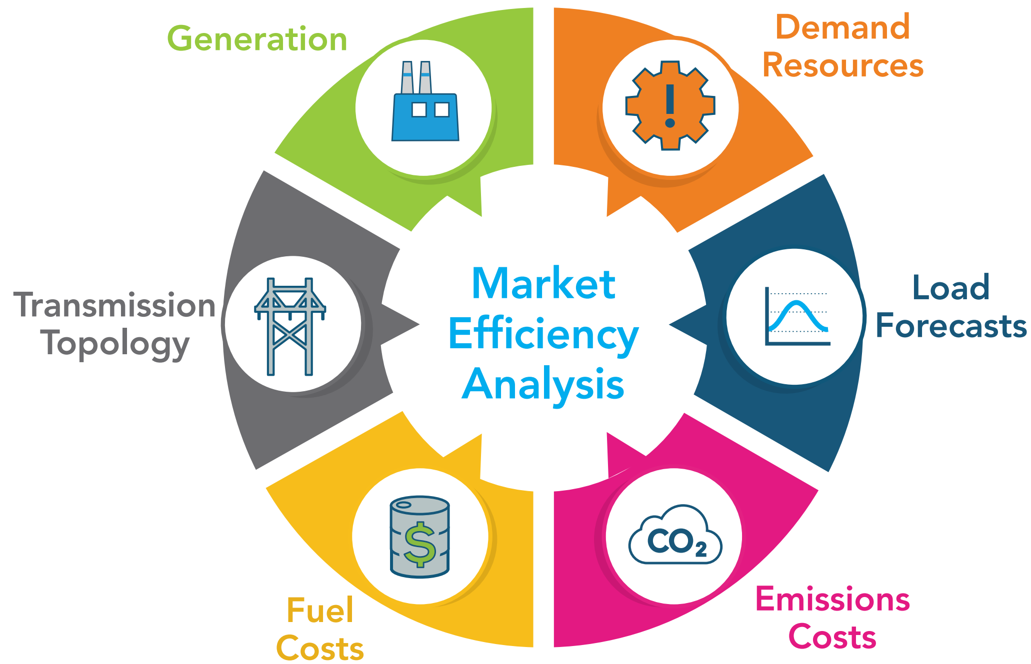
Transmission Topology

Market efficiency power flow models were developed to represent:

- The 2024 "as-is" transmission system topology
- The expected 2027 system topology for the five-year-out RTEP year

PJM derived the "as-is" system topology from its review of the Eastern Interconnection Reliability Assessment Group's Series 2022 Multi-Regional Modeling Working Group 2024 summer peak case. It included transmission enhancements expected to be in service by the summer of 2024. PJM derived system topologies for 2027 from the 2027 RTEP case and included several significant RTEP projects approved during the 2023 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 with at least an executed Interconnection Service Agreement (ISA), less planned generator deactivations that have given formal notification. The modeled generation provides enough capacity to meet PJM's installed reserve requirement through all study years, as shown in **Figure 4.3**.

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 2023 market efficiency analysis are represented in **Figure 4.4**.

Figure 4.3: PJM Market Efficiency Reserve Margin

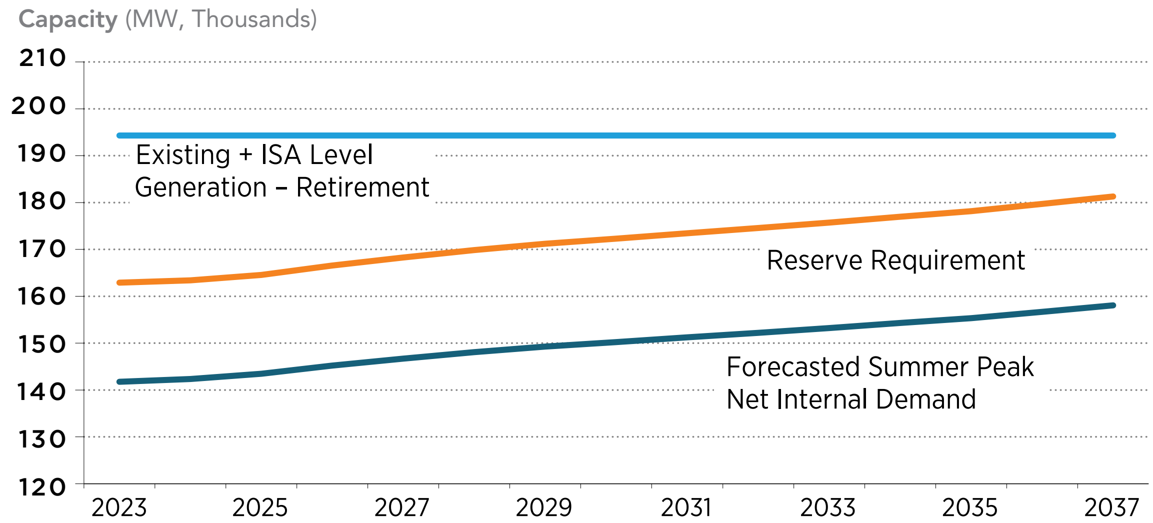
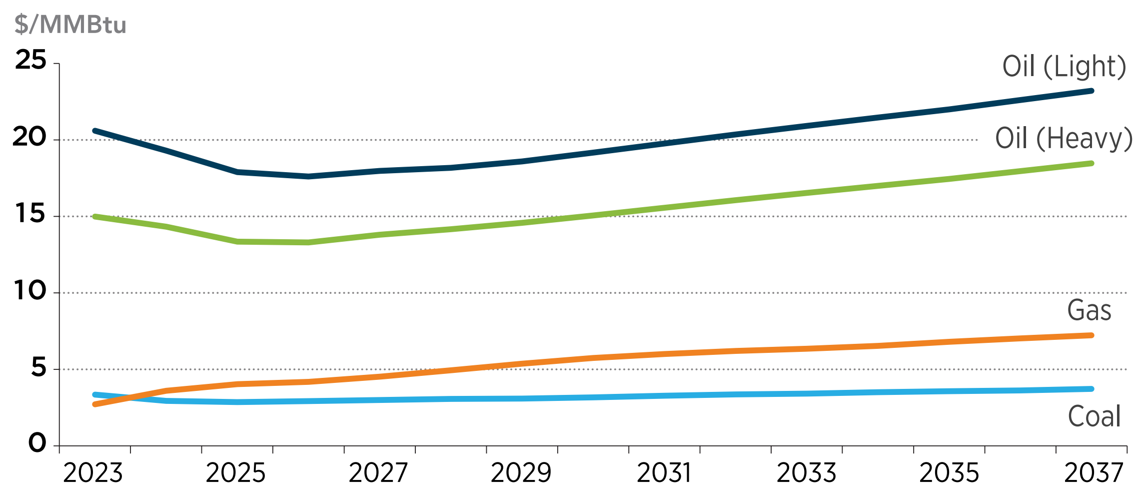


Figure 4.4: Fuel Price Assumptions



Load and Energy Forecasts

PJM's 2023 Load Forecast Report provides the transmission zone peak load and energy data to be modeled in market efficiency simulations. **Table 4.1** summarizes the PJM peak load and energy values to be used in the 2023 market efficiency cases.

Demand Resources

The amount of demand resources modeled in each transmission zone is based on the 2023 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_2, NO_x and CO_2 – within its market efficiency simulations. SO_2 and NO_x 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. Note that with the inclusion of the Good Neighbor Plan, the 2023 forecast for seasonal NO_x has increased significantly. PJM unit CO_2 emissions are modeled as either part of the national CO_2 program or the Regional Greenhouse Gas Initiative (RGGI) program. Currently, Maryland, Delaware, New Jersey, Virginia and Pennsylvania participate in the RGGI. The 2023 forecast has Pennsylvania starting the program in 2024 and Virginia leaving the program in 2024. The base emission price assumption for both the national CO_2 and RGGI CO_2 program is shown in **Figure 4.7**.

Table 4.1: 2023 PJM Peak Load and Energy Forecast

Load	2023	2027	2030	2033	2037
Peak (MW)	149,059	154,275	157,899	160,971	165,976
Energy (GWh)	788,050	841,514	878,461	909,622	949,166

Table 4.2: Demand Resource Forecast

Demand Resource	2023	2027	2030	2033	2037
Demand Resource (MW)	7,288	7,573	7,679	7,758	7,917

Figure 4.5: SO_2 Emission Price Assumption

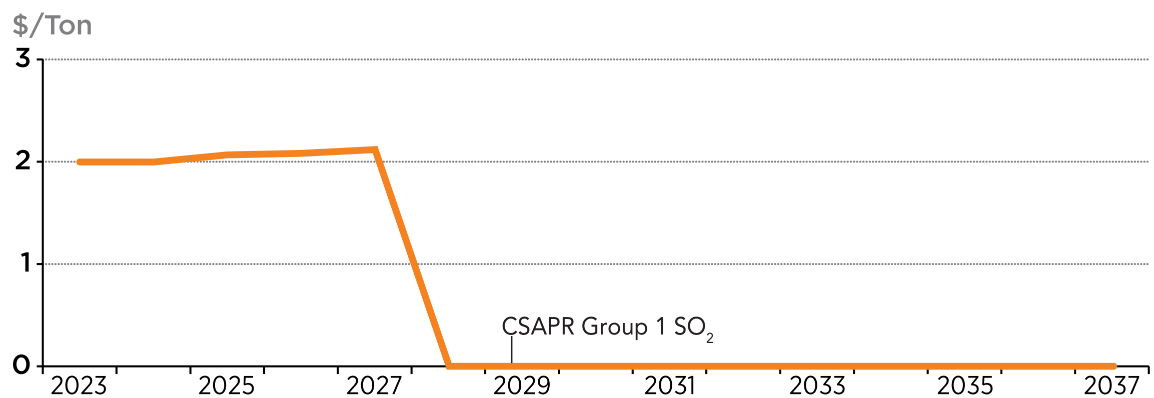
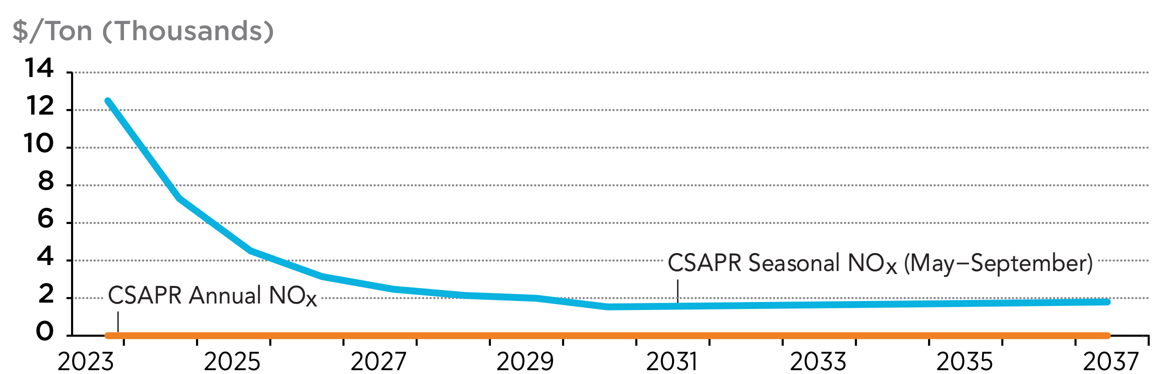


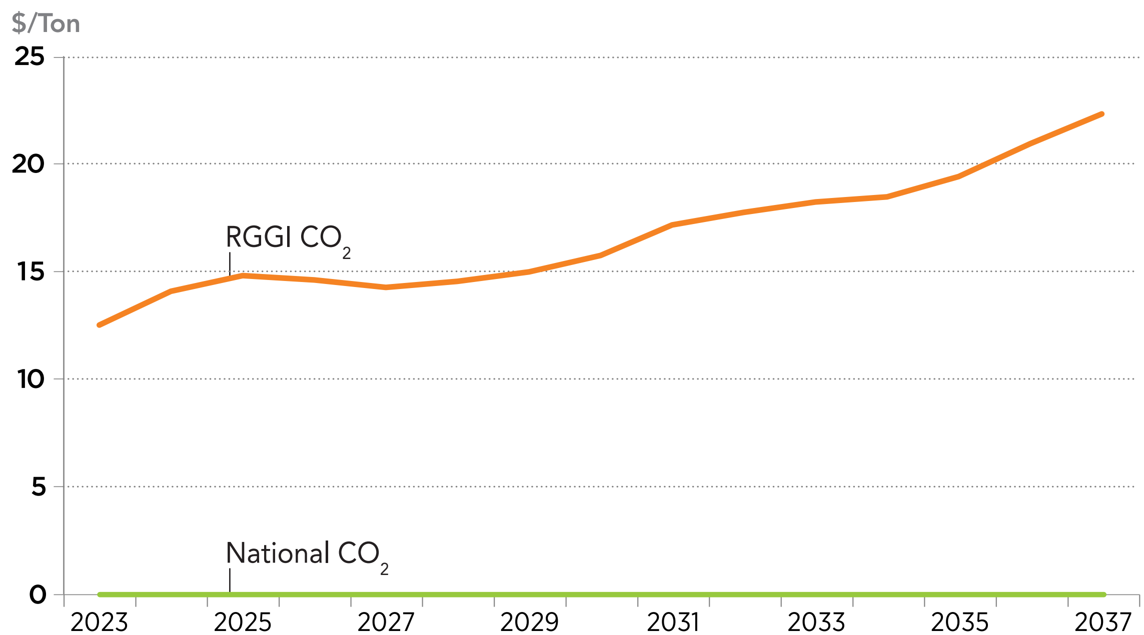
Figure 4.6: NO_x Emission Price Assumption



Carrying Charge Rate and Discount Rate

The evaluation of proposed market efficiency projects requires a benefit-to-cost analysis. As part of this evaluation, the present value of annual benefits projected for a 15-year period starting with the RTEP year 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 PJM's website. The annual carrying charge rate and discount rate for these analyses are 11.81% and 6.81%, respectively.

Figure 4.7: CO_2 Emission Price Assumption



4.2: 2023 Results From Project Acceleration Analysis

PJM's 2023 cycle of analysis included near-term simulations for study years 2024 and 2027. 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:

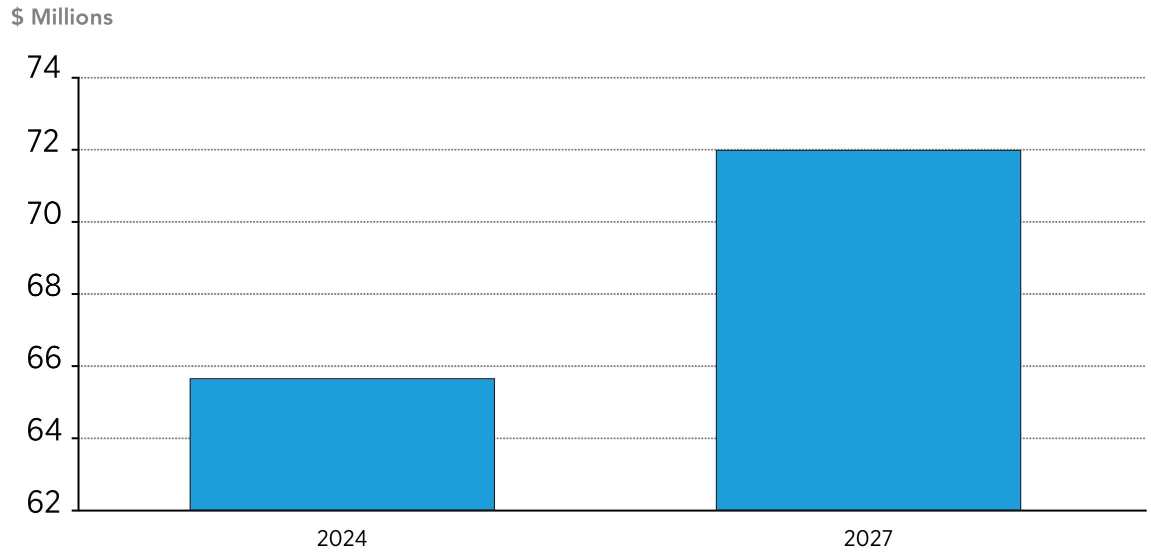
1. 2024 "as-is" PJM transmission system topology
2. 2027 "as-planned" RTEP PJM transmission system topology

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 from market simulations for study years 2024 and 2027 are shown in **Figure 4.8**. Annual congestion cost reductions of more than $65 million for 2024 and more than $72 million for 2027 using the 2027 RTEP topology are shown. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

Figure 4.8: Simulated PJM Congestion Cost Net Reduction: RTEP Topology Compared to "As-Is" Topology – 2024, 2027



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 majority of identified baseline reliability enhancements, viewed within the context of the short-term analysis, will not be recommended for acceleration. These projects provide neither significant congestion benefits in the acceleration analysis, nor are they practical to accelerate, because they have a near-term in-service date or because they are large projects.

Table 4.3 identifies specific RTEP reliability projects and related congestion reductions considered as part of the 2027 study year acceleration analysis.

Two specific projects will be accelerated as a result of the 2023 acceleration analysis.

- **Project B3729**: A $0.26 million project to increase the maximum operating temperature of DPL circuit 22088 (Colora-Conowingo 230 kV) will be accelerated to June 2026 at no additional cost.
- **Project B3694.8**: A $25.6 million project to rebuild 10.34 miles of 230 kV line No. 249 Carson-Locks will be accelerated to June 2025 at no additional cost.

Table 4.3: RTEP Projects Reducing Specific Congestion Drivers: 2027 Study Year Analysis

					2024 Topology	2027 Topology	
Constraint Name	Upgrade Associated With Congestion Reduction	Initial Year	Area	Type	2024 Congestion ($M)	2027 Congestion ($M)	Congestion Savings ($M)
Colora-Conowingo 230 kV	**B3729:** To increase the maximum operating temperature of DPL circuit 22088 (Colora-Conowingo 230 kV), install cable shunts on each phase, on each side of four dead-end structures and replace existing insulator bells.	2027	PECO/ DP&L	LINE	$0.80	$0.00	$0.80
Carson-Locks 230 kV	**B3694.8:** Partial wreck and rebuild 10.34 miles of 230 kV line No. 249 Carson-Locks to achieve a minimum summer emergency rating of 1047 MVA. Upgrade terminal equipment at Carson and Locks to not limit the new conductor rating.	2026	Dominion	LINE	$1.80	$0.00	$1.80

Note: The congestion savings for the 2027 study year are calculated as the difference in simulated congestion between the as-is topology and the RTEP topology.

4.3: Reevaluation of Previously Approved Market Efficiency Projects

PJM's 2023 analysis included 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 Convenience and Necessity (CPCN):
  - 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 while maintaining 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

Three previously approved market efficiency projects are in the engineering phase and have not yet begun construction. Cost estimates for these projects have not changed. **Table 4.4** shows a description of these projects and their reevaluation benefit-to-cost ratios.

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, includes RTEP baseline projects B2742 and B2752. 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.

On Nov. 21, 2023, PJM filed a request with FERC for a waiver of the timing requirement associated with the 2023 reevaluation analysis of Project 9A. This will permit PJM time to update the market efficiency model to include the Board-approved 2022 RTEP Window 3 projects associated with future reliability. PJM's waiver request was granted on Dec. 21, 2023, and it directs PJM to complete the 2023 reevaluation analysis of Project 9A by June 30, 2024.

Table 4.4: Market Efficiency Projects Not Under Construction With Cost Less Than $20 Million

Project ID	Baseline	Type	Area	Constraint	Status	In-Service Date	Cost ($M)	Benefit-to-Cost Ratio	Description
202021_1-704	**B3697**	Upgrade	PECO	Plymouth-Whitpain 230 kV	Engineering and Procurement Status	6/1/2025	0.62	75.3	Replace station equipment at Whitpain and Plymouth 230 kV.
202021_1-218	**B3698**	Upgrade	PPL	Juniata-Cumberland 230 kV		12/31/2023	8.99	11.28	Reconductor 14.2 miles of Juniata-Cumberland 230 kV.
202021_1-651	**B3702**	Upgrade	Dominion	Charlottesville-Proffit 230 kV		11/1/2023	11.38	16.05	Install series reactor on Charlottesville-Proffit 230 kV.

4.4: 2022/2023 RTEP Market Efficiency Window Progress

The 2022/2023 RTEP market efficiency window process uses study years 2023, 2027, 2030 and 2033 to identify and quantify transmission system congestion. These simulations will use the 2028 RTEP "as-planned" transmission system topology and include RTEP projects approved through the 2023 RTEP cycle.

Overall, congestion levels in PJM's market efficiency analysis have been increasing, particularly for the 5-, 7- and 10-year-out cases compared to recent RTEP cycles. This is due, in part, to:

- Higher gas-price assumptions coupled with generation portfolio shifts that include increased high-efficiency, gas-fired generation
- Increasing forecast load growth, particularly in the Dominion Energy and Allegheny Power (FirstEnergy) zones, coupled with generator deactivations that result in increased simulated regional flows into the area

PJM solicits stakeholder proposals for projects as part of an RTEP proposal window focusing on congestion identified in the market efficiency analysis. It seeks 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 delayed the decision to open the 2022/2023 market efficiency window until the reliability violations associated with the 2022 Window 3 are addressed. PJM intends to solicit stakeholder proposals for market efficiency projects as part of an RTEP proposal window focusing on congestion after the 2022 and 2023 reliability window solutions have been identified and studied. A determination regarding the holding of a 2022/2023 RTEP market efficiency window will be made in early in 2024.

NOTE: The market efficiency analyses supporting interregional activities are described in **Section 3.5** of this report.

Section 5: Facilitating Interconnection

5.0: Interconnection Reliability

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. The PJM Board has approved network transmission projects totaling $6.9 billion since the inception of the RTEP process in 1999. Approved network projects in 2023 have totaled $180 million. As described in **Section 1.2**, PJM tests for compliance with 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. In addition to generator interconnection requests, PJM conducts this power flow test as part of a 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.

Interconnection Process Overview

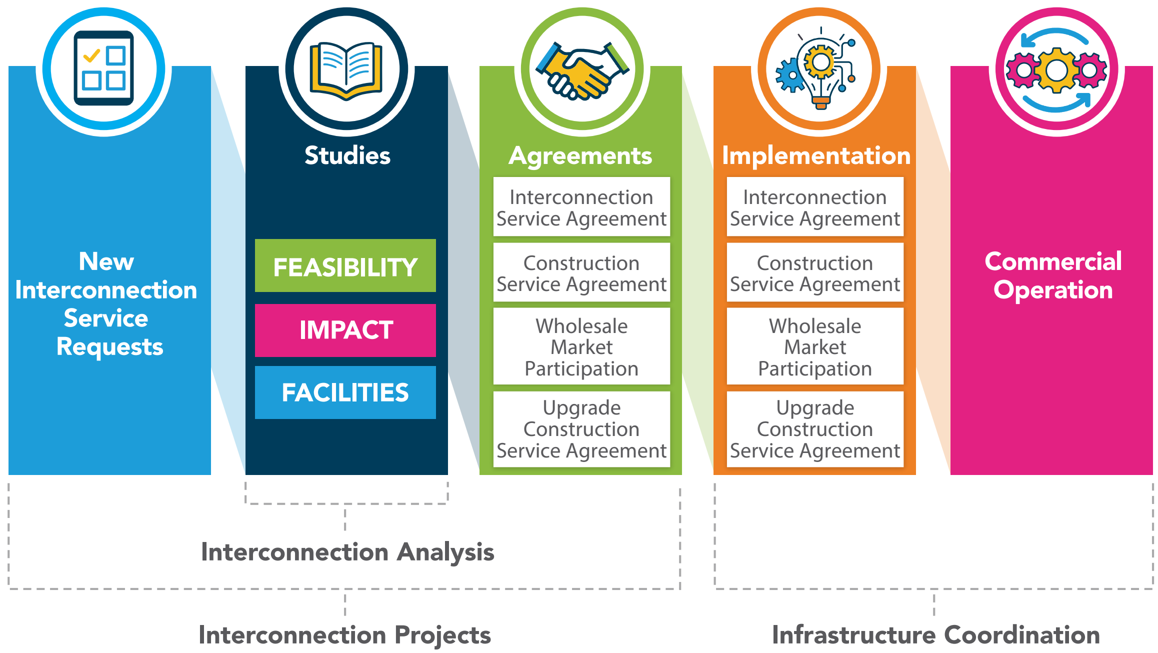
During 2022, interconnection activity was impacted by ongoing reforms. Older New Services Requests were prioritized for over a year in order to clear a backlog of requests in PJM's existing interconnection queue as well as to prepare for an enhanced interconnection process, which is described later in this section.

PJM's interconnection process as it existed prior to these reforms consisted of five phases as shown in **Figure 5.1**. Requests for generation interconnection could be submitted during one of two six-month queue windows: April through September and October through March.

As part of this process, PJM would perform Feasibility, System Impact and Facilities studies.

During a Feasibility study, PJM would perform an initial, high-level power flow analysis at the point of interconnection specified by the developer, who can also designate a secondary, optional point of interconnection to be evaluated.

Figure 5.1: Interconnection Process Prior to July 10, 2023



During a System Impact Study, the developer would elect one of the two points of interconnection it has requested. PJM would then perform power flow and short-circuit analyses and coordinate with neighboring entities to conduct an affected system study, if applicable.

During a Facilities Study, PJM would perform power flow, short-circuit and stability analyses to ensure the project's reliable interconnection to PJM's system.

Once these studies were completed, the project developer would sign an Interconnection Service Agreement (ISA) and Construction Service Agreement, which described the milestones, point of interconnection, system upgrades and construction responsibilities that are associated with the project. The ISA also conferred the rights associated with the interconnection of a generator as a capacity resource, including Capacity Interconnection Rights.

Section 5.2 discusses interconnection process initiatives in 2022 and beyond, including those arising out of the Interconnection Process Request Task Force stakeholder process and in compliance with FERC's recent Generation Interconnection Process NOPR.

5.1: Interconnection Process Reforms

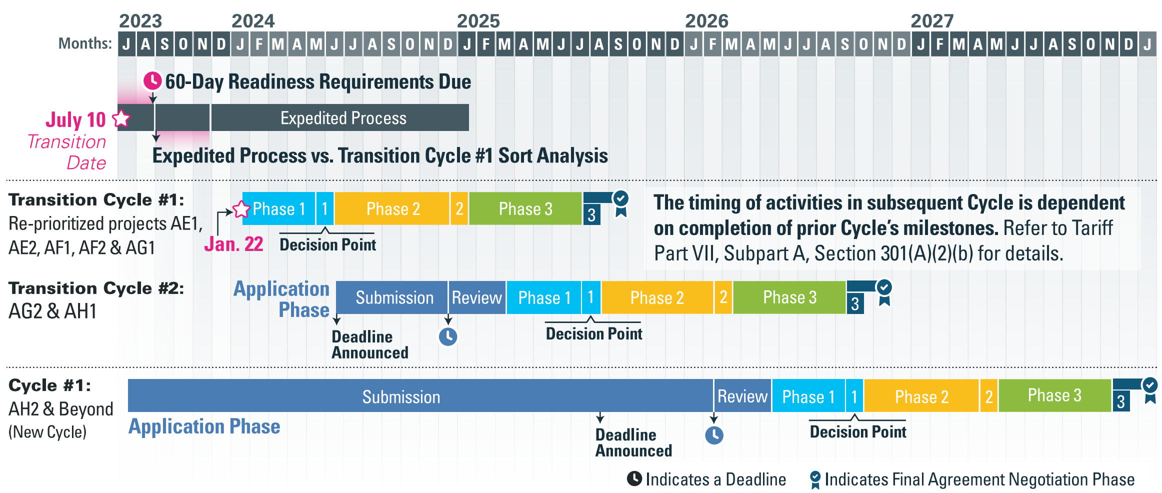
5.1.1 — Stakeholder Engagement

In 2021, the Interconnection Process Reform Task Force (IPRTF) was charged with developing improvements to the existing interconnection process in order to reduce a backlog of requests and increase efficiency. After months of stakeholder engagement through the IPRTF, PJM's new interconnection process package and proposal to transition to the new interconnection process were endorsed during the April 27, 2022, meeting of PJM's Members Committee, garnering the overwhelming support of PJM stakeholders.

First Ready, First Served

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

Figure 5.2: Interconnection Process Reform Timeline



The filing's reforms include:

- Moving from a serial queue process to a clustered Cycle process for both studies and cost allocation
- Implementing multiple decision points at which those seeking interconnection-related services must provide readiness deposits and meet other threshold requirements to move forward, thus allowing projects that are ready to proceed to do so while incentivizing those that are not ready to exit the interconnection process
- Implementing a transition mechanism to ensure a timely transition to the new "first-ready, first-served" Cycle approach while providing an Expedited Process for projects in the existing interconnection queue that are close to completing that process (the "Expedited Process")
- Consolidation of PJM's interconnection-related service agreements and forms that will be used for the Part VII Transition Process and the Part VIII New Rules set forth in new Part IX of the Tariff

The interconnection reforms are set forth in their entirety in FERC Docket No. ER22-2110.

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. 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 will be re-prioritized into Transition Cycle 1. The initial study phase of Transition Cycle 1 began Jan. 22, 2024. The application phase for Transition Cycle 2 is expected to open in 2024 for AG2 and AH1 projects that choose to reapply under the new interconnection process rules. The transition will continue to progress over the coming years, culminating in Cycle 1 of the new process, which is currently expected to occur in 2026.

Expanding Stakeholder Engagement

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

5.1.2 — 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 its forms of generator interconnection procedures and agreements. The Final Rule encompasses several reforms, including:

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

On Aug. 28, 2023, PJM filed a Request for Clarification and Rehearing of Order 2023 declaring that PJM has already developed and received approval of a process in November 2022 that meets the Commission's intent and substantially satisfies the requirements of the Final Rule. On Sept. 28, 2023, FERC essentially denied PJM's rehearing motion by operation of law and will issue a future order providing more detail related to the rehearing request. PJM is currently working on a compliance filing, which is due to FERC by April 3, 2024.

5.2: New Cycle-Based Process

5.2.1 — New Services Requests

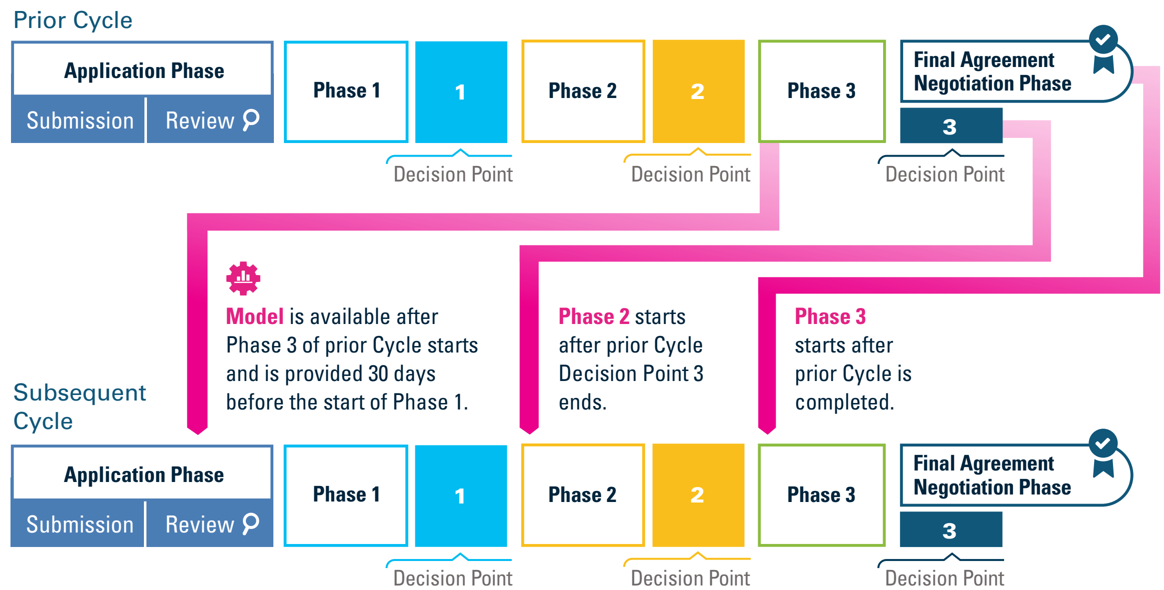
PJM has transitioned to a Cycle-based interconnection study approach for New Services as outlined in the new PJM Manual 14H. Project Developers with a Generation or Transmission Interconnection Request as well as Eligible Customers with Long-Term Firm Transmission Service Requests will follow the new Cycle Process. There are additional types of New Services Requests that are studied under a parallel process outside the Cycle Process. These include Upgrade Requests, Surplus Interconnection Requests, Affected System Study Requests, and requests to convert an existing two-party Interconnection Agreement to a PJM three-party Generator Interconnection Agreement (GIA).

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. Each Cycle consists of the:

- 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, shown in **Figure 5.3**, includes the submission of New Services Requests by the Project Developer or Eligible Customer and review and validation of the submission 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.

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 customer provides required data, evidence (such as permits, site control, etc.) and deposits, as specified in the PJM Tariff. The customer can also submit any modification as permitted by the PJM Tariff, and, if eligible, may accelerate to Final Agreement. PJM reviews the provided information, validates the customer's submission, and advances the customer to the subsequent phase.

After all study phases and prior to the start of the Final Agreement and Negotiation Phase, 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 Services Requests are withdrawn during Decision Point III, PJM will conduct a restudy and reissue updated draft agreements to the Project Developers with New Services Requests remaining in the Cycle.

Once the Project Developers in the Cycle receive the draft agreements, final negotiations will commence and continue until all agreements related to the New Services Requests are entirely executed. The Final Agreement Phase is then considered to be concluded, and the Cycle is officially closed once all required agreements have been fully executed.

A subsequent Cycle Process cannot begin until certain milestones in the prior Cycle have been achieved as described in Manual 14H, Section 1.3.2, "Cycle Process Overview."

Parallel Process

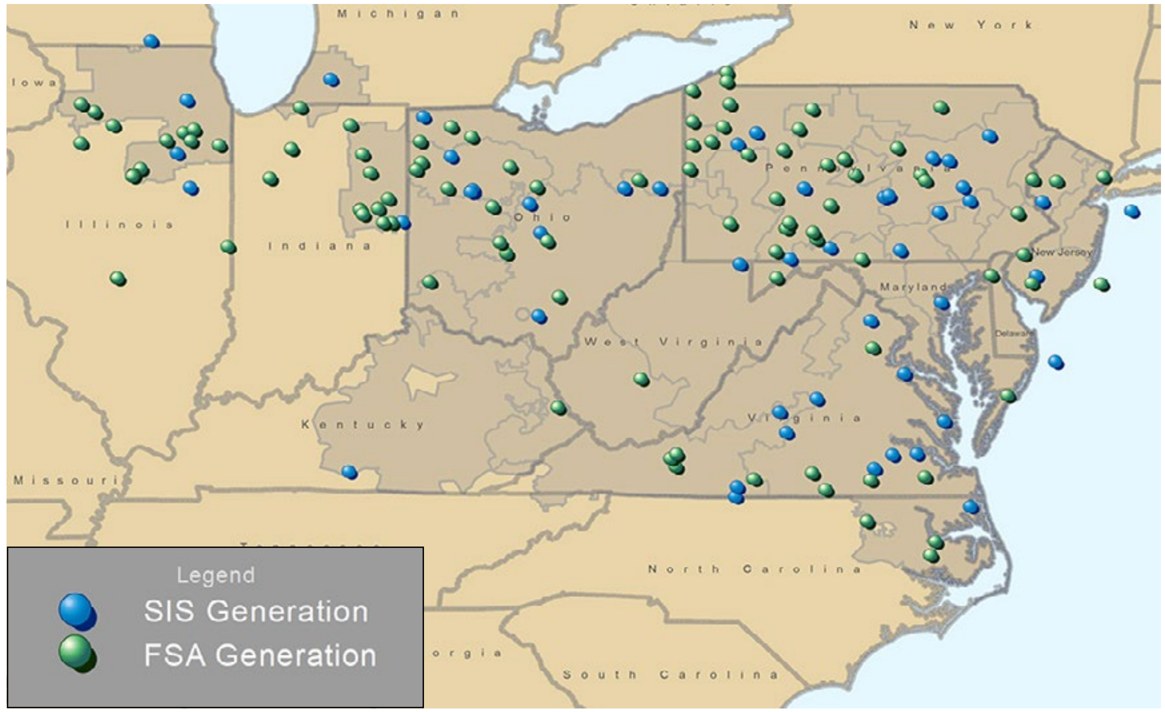
Details about each study under the parallel process are listed under Sections 11 through 14 of PJM Manual 14H.

5.3: New Services Request Activity

PJM markets have attracted generation proposals totaling 643,676 MW, as shown in **Table 5.1**. Over 178,566 MW capacity of New Services Requests were actively under study during 2023. PJM analyzed and issued reports for 114 System Impact Studies and 126 Facilities Studies, as shown on **Map 5.1**.

Over 15,477 MW capacity of new generation was under construction as of Dec. 31, 2023, across all fuel types. 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, regulatory, industry, economic and other competitive factors.

Map 5.1: Feasibility and System Impact Studies Performed in 2023



In 2023:

PJM received 486 New Services Requests representing

17,786 MW (energy) of generation and

32,226 MW of Capacity Interconnection Rights.

PJM issued agreements allowing construction activities to begin for

157 interconnection requests representing 10.7 GW.

PJM issued a total of

240 System Impact and Facilities studies for a total of 17.6 GW.

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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, 2023, only 74,294 MW, or 15.8%, reached commercial operation. Note that **Figure 5.4** reflects requested Capacity Interconnection Rights, which are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants.

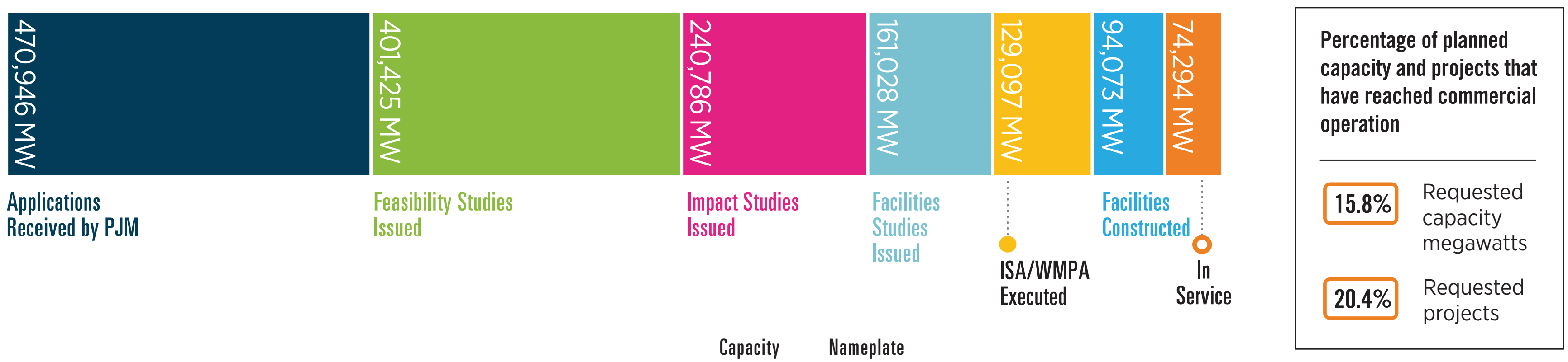
Following execution of an ISA or WMPA, 33,166 MW of capacity with ISAs and 1,560 MW of capacity with WMPAs withdrew from PJM's interconnection process.

Table 5.1: Interconnection Requests Studied in 2023

	Projects	Nameplate Capability (MW)	Capacity (MW)
Active	2,739	229,538	178,565.7
In Service	1,091	86,434	71,977.2
Under Construction	369	29,233	15,477.4
Withdrawn	4,001	495,586	377,655.2
Total	**8,200**	**840,791**	**643,675.5**

Overall, 50.9% of projects that requested uprates to existing capacity reached commercial operation. Only 12.9% of new generator requests, by megawatt, reached commercial operation.

Figure 5.4: New Service Request Progression



			Capacity	Nameplate
Projects withdrawn after final agreement	227	Interconnection Service Agreements	33,166 MW	42,636 MW
	390	Wholesale Market Participation Agreements	1,560 MW	3,140 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

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Section 6: State Summaries

This section contains state-specific information for Jan. 1, 2023, through Dec. 31, 2023, 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, that means that no deactivations or projects were approved between Jan. 1, 2023, and Dec. 31, 2023, for that state.

6.0: 2023 Development and Milestones

Load Growth

Load Forecast Accuracy Model Improvements

In 2023, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to 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).

The next 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.

PJM implemented a number of changes to the 2023 Load Forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heating load, cooling load and other non-weather-sensitive load.
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies (EDCs).

These are discussed further in **Section 1.3.5** and **Section 2.0**.

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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

Deliverability

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 the 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.

Interconnection Requests

PJM markets continue to attract generation proposals as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities.

The generation interconnection process has three study phases: Feasibility, System Impact and Facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria.

Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, 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 and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing.

The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process New Services Requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

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

Generation Deactivation

Deactivation Reliability Studies

PJM has 30 days in which to respond to a generator owner with deactivation study results. 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 comprise thermal and voltage analysis, including 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 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, 2023, and Dec. 31, 2023, as part of the 2023 RTEP.

The following states include information about **deactivation requests**:					
IL	MD/DC	NJ	OH	PA	VA

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 conducting Feasibility Studies and System Impact Studies for all proposed requests for generation and merchant transmission interconnection, and for long-term firm transmission service. This subsection will only appear in states with RTEP baseline system enhancements approved by the PJM Board in 2023.

This subsection will only appear in states with RTEP **baseline system enhancements** approved by the PJM Board in 2023.

The following states include information about **baseline projects**:								
DE	IL	IN	KY	MD/DC	NJ	OH	VA	WV

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 transmission system.

This topic will only appear in states with RTEP **network projects** approved by the PJM Board in 2023. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

The following states include information about **network projects**:				
DE	IL	IN	KY	
MD/DC	NJ	OH	NC	PA

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

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 2023 Local Plan.

The following states include information about **supplemental projects**:					
DE	IL	IN	KY	MD/DC	MI
NJ	NC	OH	PA	VA	WV

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, or 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 2023 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

The following states include information about merchant transmission requests:		
IL	IN	NJ

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

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 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 also includes a minimum solar carve-out of 10% by 2035.

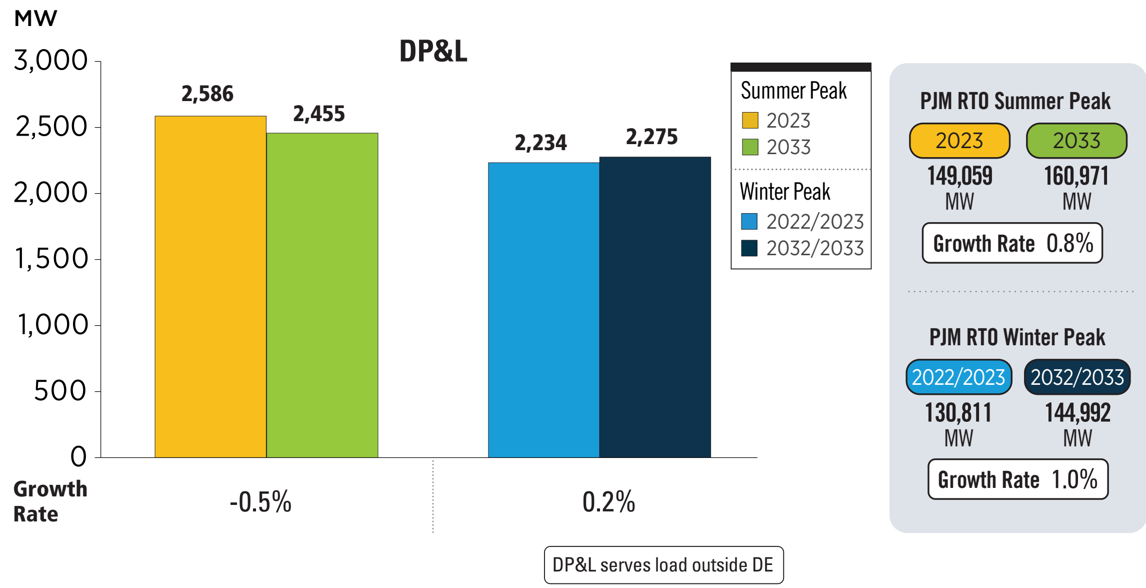
Map 6.1: PJM Service Area in Delaware

6.1.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.1** summarizes the expected loads within the state of Delaware and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.1: Delaware – 2023 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.1.3 — Existing Generation

Existing generation in Delaware as of Dec. 31, 2023, is shown by fuel type in **Figure 6.2**.

Read More
Changing Capacity Mix and Deliverability

6.1.4 — Interconnection Requests

In Delaware, as of Dec. 31, 2023, 39 projects were actively under study or under construction as shown in the summaries presented in **Table 6.1, Table 6.2, Figure 6.3, Figure 6.4** and **Figure 6.5**.

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.

Read More
Interconnection Requests

Figure 6.2: Delaware – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)

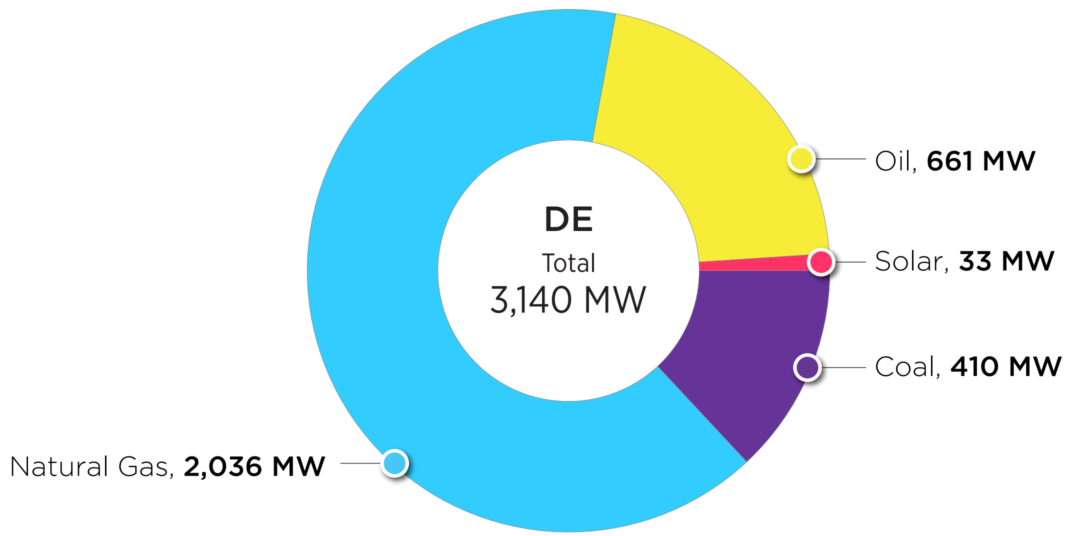


Table 6.1: Delaware – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Delaware Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	0	0.00%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	0	0.00%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	443	15.81%	98,471	55.15%
Storage	545	19.46%	53,644	30.04%
Wind	1,813	64.74%	20,798	11.65%
Grand Total	**2,801**	**100.00%**	**178,566**	**100.00%**

Table 6.2: Delaware – Interconnection Requests (Dec. 31, 2023)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	2	23.0	1	630.0	3	653.0
	Natural Gas	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	5	168.2	1	1.0	6	169.2
	Other	0	0.0	0	0.0	2	26.3	1	0.0	3	26.3
	Storage	5	545.0	0	0.0	0	0.0	8	119.7	13	664.7
Renewable	Biomass	0	0.0	0	0.0	1	0.0	4	24.0	5	24.0
	Methane	0	0.0	0	0.0	4	9.0	3	28.8	7	37.8
	Solar	13	442.8	9	62.3	1	37.6	35	407.6	58	950.3
	Wind	10	1,813.4	2	66.3	0	0.0	9	599.4	21	2,479.1
	Grand Total	28	2,801.2	11	128.6	33	1,545.2	82	7,817.9	154	12,292.9

Figure 6.3: Delaware – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

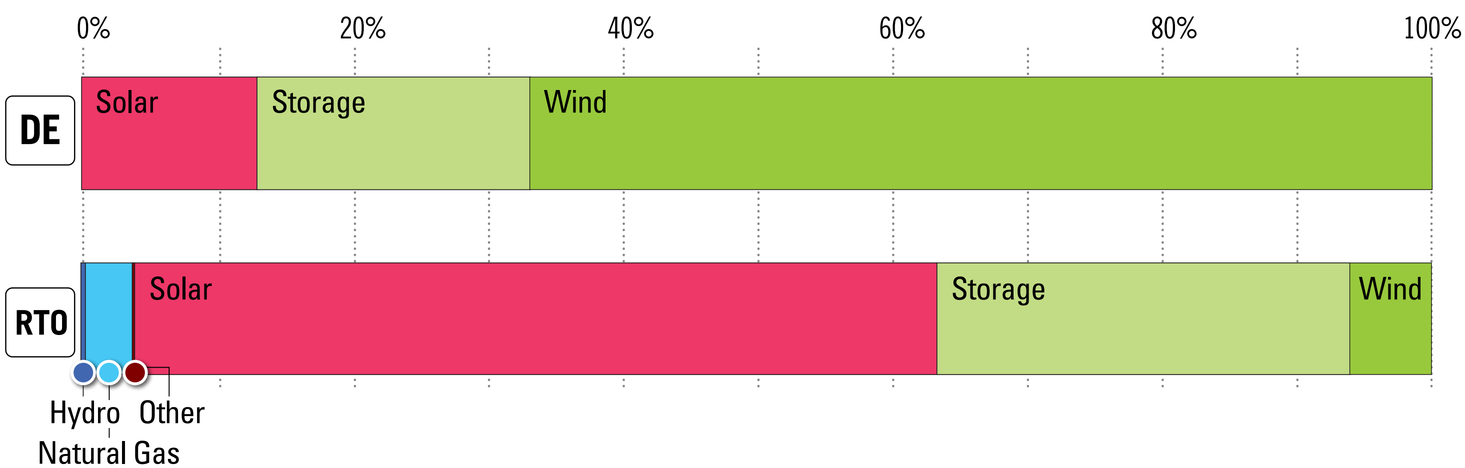
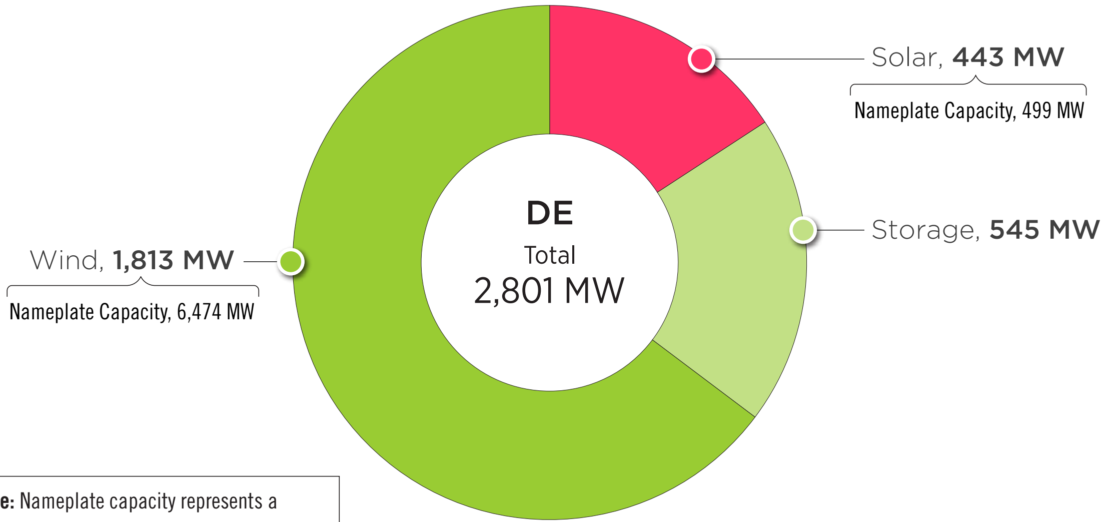


Figure 6.4: Delaware Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.5: Delaware Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

16.3% Requested capacity megawatts

26.2% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	4	Interconnection Service Agreements	871 MW	1,231 MW
	7	Wholesale Market Participation Agreements	18 MW	55 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.1.5 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in Delaware are summarized in **Map 6.2** and **Table 6.3**.

Read More
Baseline Projects

Map 6.2: Delaware Baseline Projects (Dec. 31, 2023)

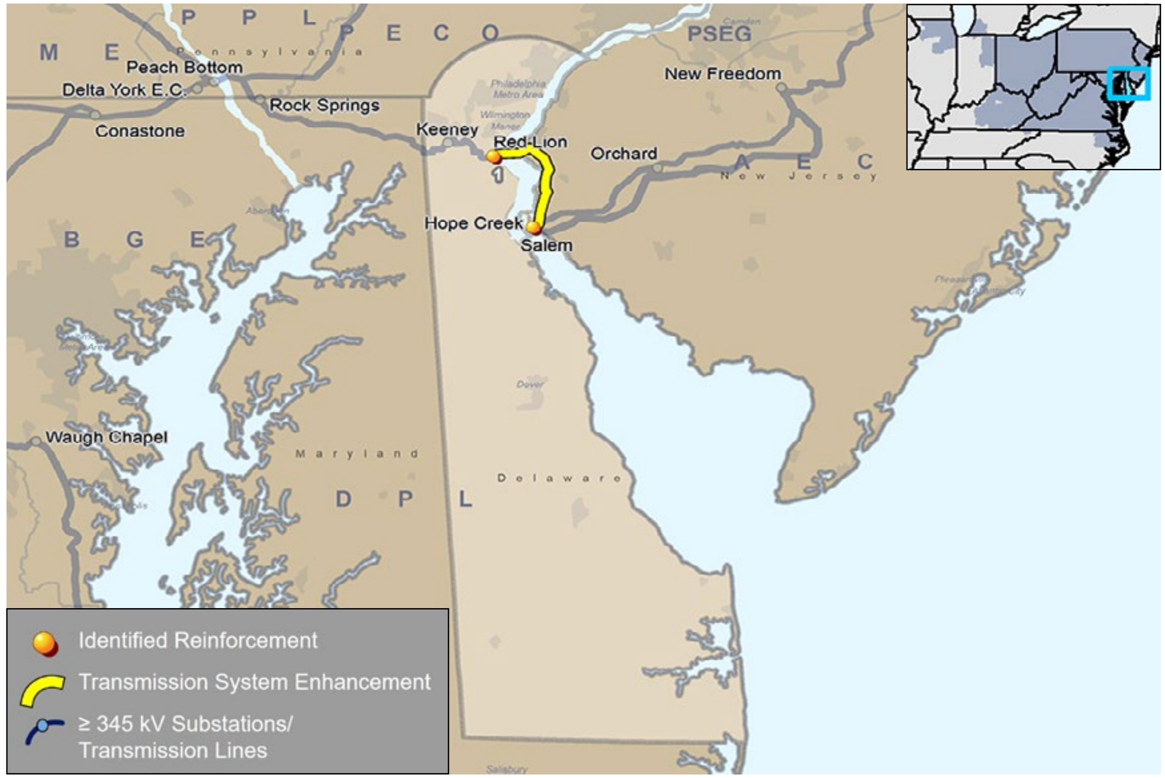


Table 6.3: Delaware Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3800	.39	Replace terminal equipment at Red Lion along the Red Lion-Hope Creek 500 kV.	6/1/2027	$4.00	DP&L	12/5/2023

6.1.6 — Network Projects

Network projects in Delaware for 2023 are summarized in **Map 6.3** and **Table 6.4**.

Read More
Network Projects

Map 6.3: Delaware Network Projects (Dec. 31, 2023)

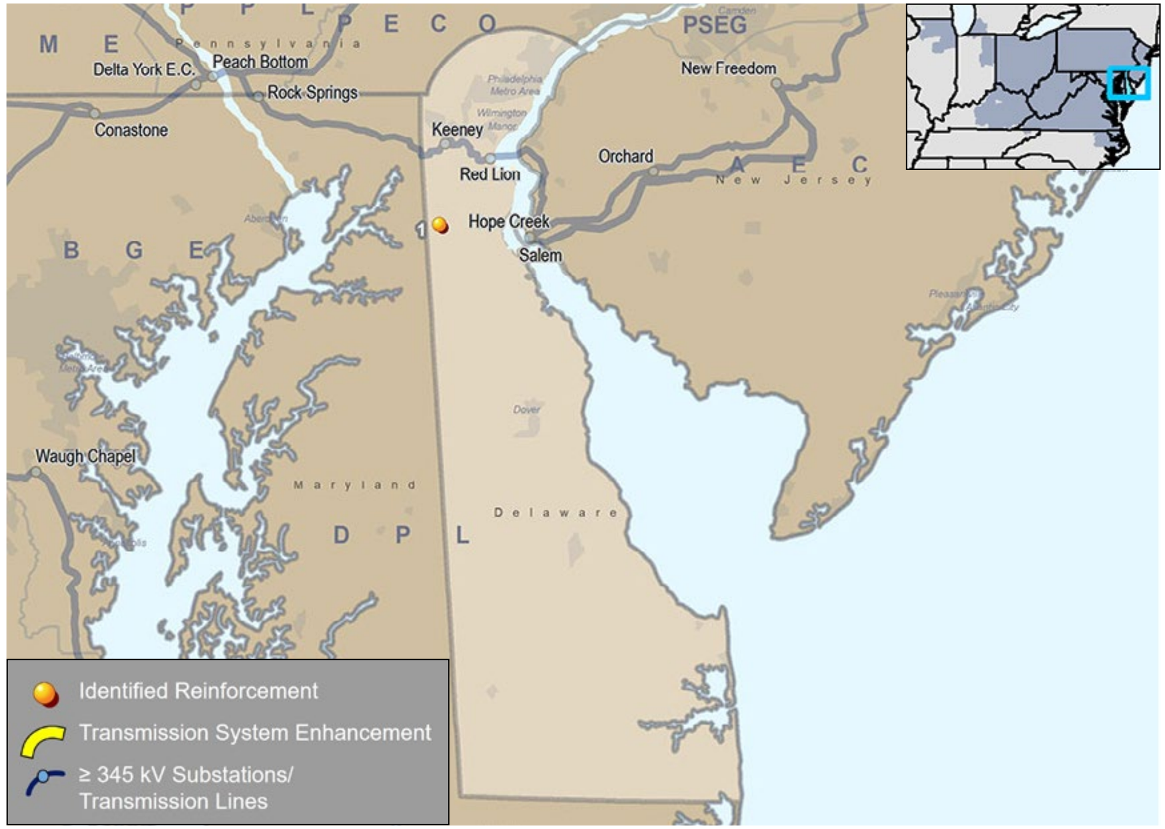


Table 6.4: Delaware Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N7753	Upgrade circuit breaker and associated current transformers and switches from 2000A to 3000A at Mt. Pleasant substation.	AG1-464	12/31/2021	$0.40	DP&L	10/3/2023

6.1.7 — Supplemental Projects

Supplemental projects received by PJM in 2023 in Delaware are summarized in **Map 6.4** and **Table 6.5**.

Read More
Supplemental Projects

Map 6.4: Delaware Supplemental Projects (Dec. 31, 2023)

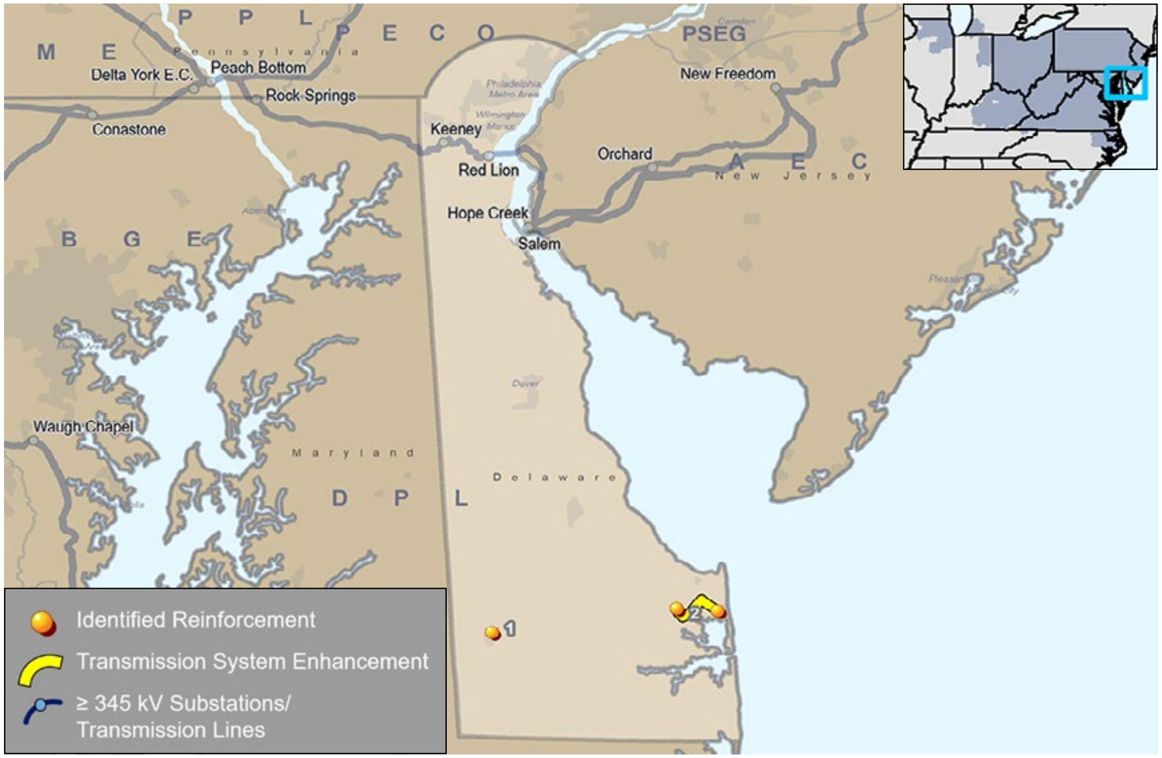


Table 6.5: Delaware Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2843		Replace N. Seaford 138/69 kV autotransformer No. 1.	5/31/2025	$8.00	DP&L	11/17/2022
2	S2947		Construct a new three-breaker ring bus substation tying to the Robinsonville-Rehoboth 138 kV line with a terminal position dedicated to the customer.	12/31/2026	$10.50		4/20/2023

6.2: Northern Illinois RTEP Summary

6.2.1 — RTEP Context

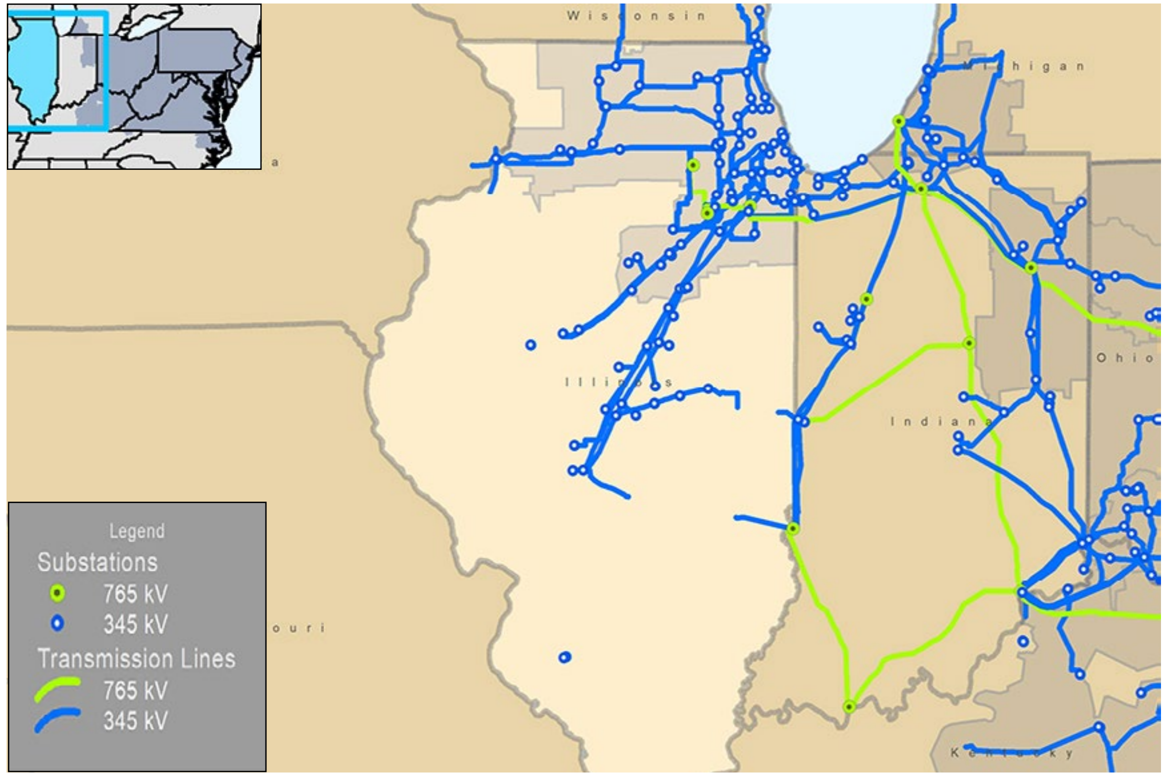
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in northern Illinois, including facilities owned and operated by Commonwealth Edison (ComEd) and the city of Rochelle as shown on **Map 6.5**. The transmission system in northern Illinois delivers power to customers from native 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. 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_2 emissions 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 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.

Map 6.5: PJM Service Area in Northern Illinois

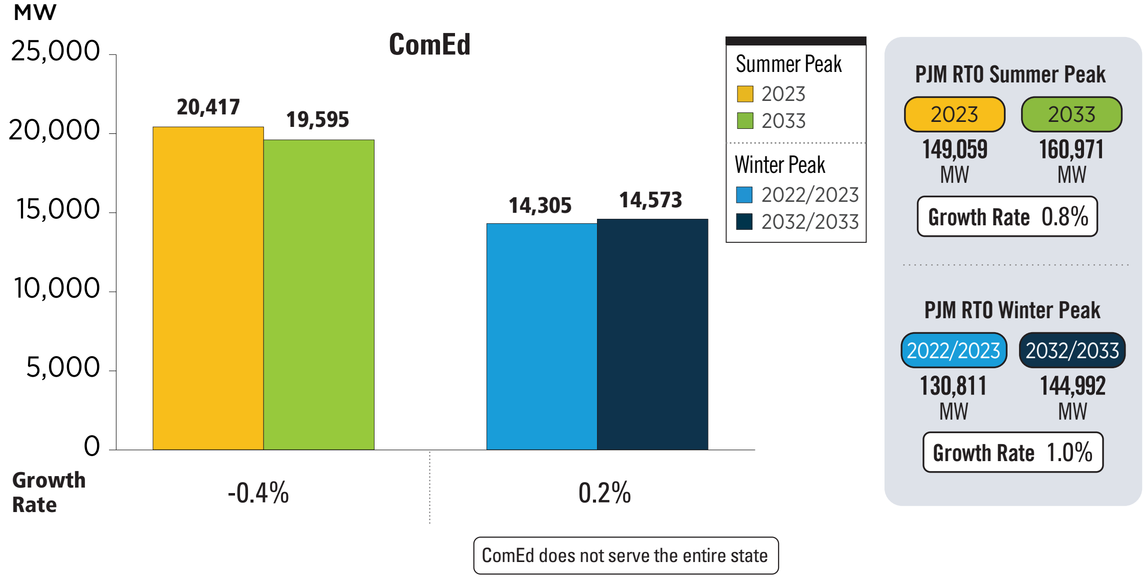


6.2.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.6** summarizes the expected loads within the state of Illinois and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.6: Northern Illinois – 2023 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.2.3 — Existing Generation

Existing generation in Illinois as of Dec. 31, 2023, is shown by fuel type in **Figure 6.7**.

Read More
Changing Capacity Mix and Deliverability

6.2.4 — Interconnection Requests

In Illinois, as of Dec. 31, 2023, 283 projects were actively under study or under construction as shown in the summaries presented in **Table 6.6, Table 6.7, Figure 6.8, Figure 6.9** and **Figure 6.10.**

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.

Read More
Interconnection Requests

Figure 6.7: Northern Illinois – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)

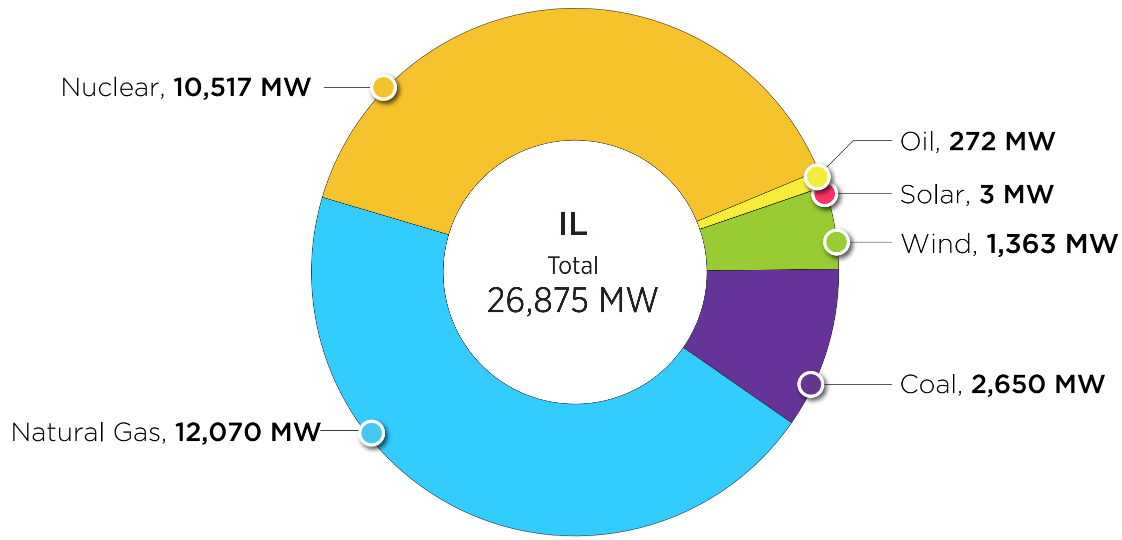


Table 6.6: Northern Illinois – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Illinois Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	0	0.00%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	140	0.59%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	10,871	45.85%	98,471	55.15%
Storage	9,643	40.67%	53,644	30.04%
Wind	3,057	12.89%	20,798	11.65%
Grand Total	**23,711**	**100.00%**	**178,566**	**100.00%**

Table 6.7: Northern Illinois – Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

		In Queue						Complete					
		Active		Suspended		Under Construction		In Service		Withdrawn		Grand Total	
		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	140	1	550.0	3	509.0	33	4,490.9	25	9,925.5	64	15,615.4
	Nuclear	0	0.0	0	0.0	0	0.0	10	385.8	5	782.0	15	1,167.8
	Other	0	0.0	0	0.0	0	0.0	0	0.0	3	0.0	3	0.0
	Storage	91	9,643.1	0	0.0	1	4.0	6	2.2	34	2,050.0	132	11,699.3
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	3	90.0	3	90.0
	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	127	10,871.2	4	54.1	6	261.8	3	45.4	82	3,478.5	222	14,711.0
	Wind	57	3,056.8	1	10.2	10	417.7	36	942.2	118	3,195.9	222	7,622.9
	Grand Total	**277**	**23,711.1**	**6**	**614.3**	**20**	**1,192.5**	**92**	**5,908.2**	**295**	**23,264.8**	**690**	**54,691.0**

Figure 6.8: Northern Illinois – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2023)

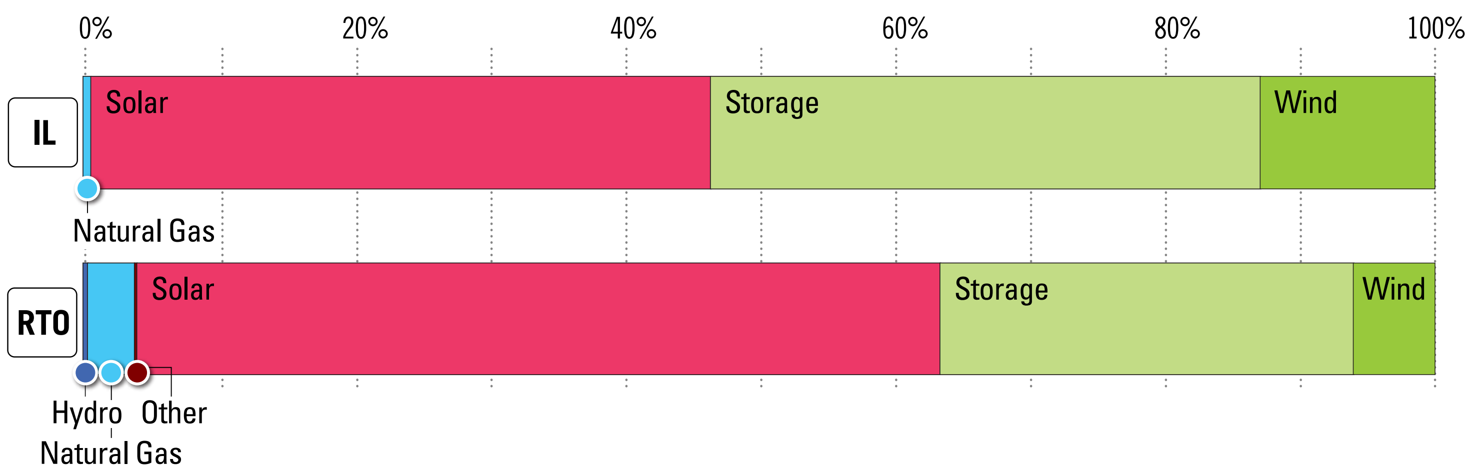
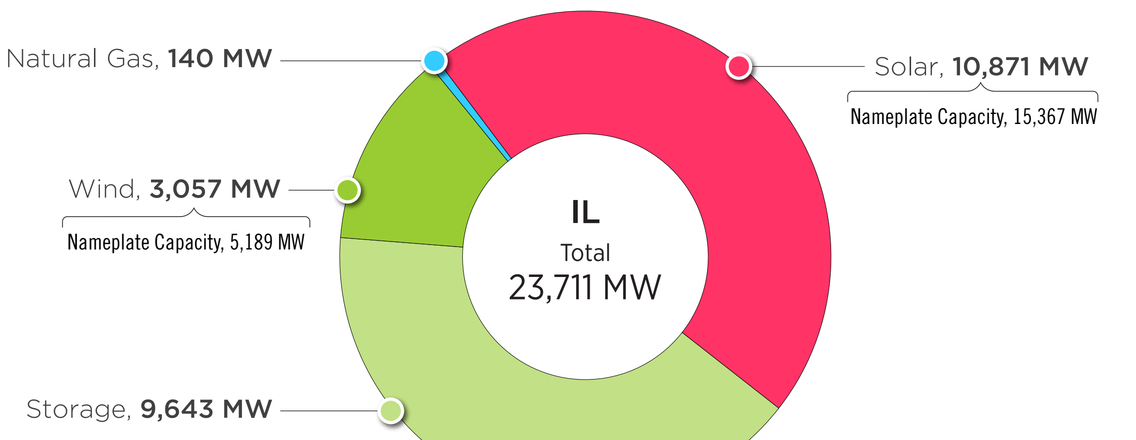


Figure 6.9: Northern Illinois Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.10: Northern Illinois Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

19.6% Requested capacity megawatts

23.1% Requested projects

Projects withdrawn after final agreement			Capacity	Nameplate
	11	Interconnection Service Agreements	836 MW	2,207 MW
	7	Wholesale Market Participation Agreements	27 MW	38 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.2.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Illinois between Jan. 1, 2023, and Dec. 31, 2023, are summarized in **Map 6.6** and **Table 6.8**.

Map 6.6: Northern Illinios Generation Deactivations (Dec. 31, 2023)

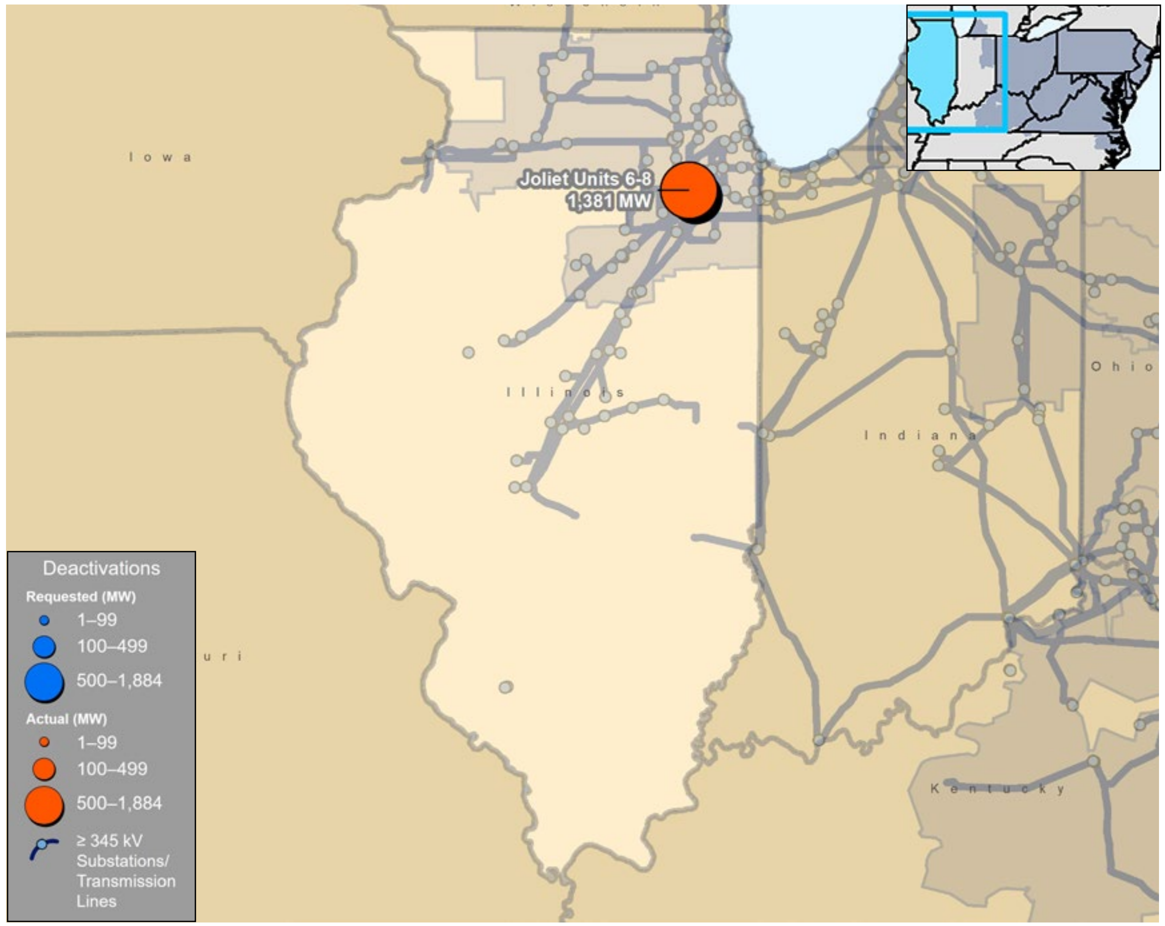


Table 6.8: Northern Illinois Generation Deactivations (Dec. 31, 2023)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Joliet 6	ComEd	Natural Gas	7/25/22	6/1/2023	63	281
Joliet 7				9/1/2023	57	550
Joliet 8				9/1/2023	56	550

6.2.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in northern Illinois are summarized in **Map 6.7** and **Table 6.9**.

Read More
Baseline Projects

Map 6.7: Northern Illinois Baseline Projects (Dec. 31, 2023)

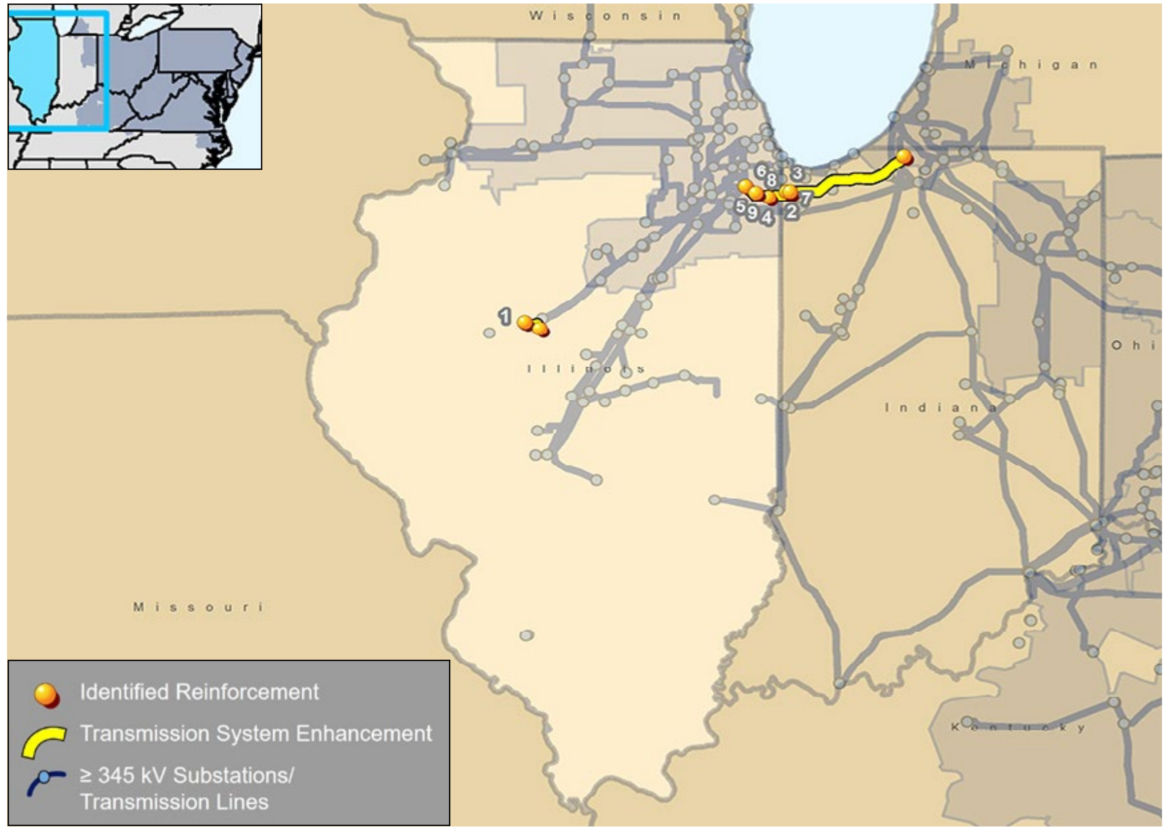


Table 6.9: Northern Illinois Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3760		Replace most limiting facility 800A wave trap with 2000A wave trap on the Powerton-Towerline 138 kV line terminal at Powerton substation.	6/1/2025	$0.20	ComEd	12/6/2022
2	B3775	.1	Swap the NIPSCO Green Acre tap towers from the St. John-Green Acres-Olive 345 kV line to the University Park N-Olive 345 kV line to create a University Park N-Green Acres-Olive and St. John-Olive 345 kV lines outside of the Green Acres substation.	12/1/2026	$71.66	NEET	1/10/2023
3		.2	Reconductor NEET's section of Crete(IN/IL border)-St. John 345 kV line (6.95 miles).				

Table 6.9: Northern Illinois Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	B3775 (Cont.)	.3	Rebuild ComEd's section of 345 kV double circuit in IL from St. John to Crete (5 miles) with twin bundled 1277 ACAR conductor.	12/1/2026	$71.66	ComEd	1/10/2023
5		.4	Rebuild 12.7 miles of 345 kV double circuit extending from Crete to E. Frankfort with twin bundled 1277 ACAR conductor.				
6		.5	Replace E. Frankfort 345 kV circuit breaker "9-14" with 3150A SF6 circuit breaker.				
7		.8	Upgrade the existing terminal equipment (substation conductor) at St. John on the existing Crete to St. John 345 kV line with bundled 2x1590 ACSR Lapwing.			NEET	
8		.9	Upgrade the existing terminal equipment (substation conductor) at Green Acres on the existing St. John to Green Acres 345 kV line with bundled 2x1590 ACSR Lapwing.				
9		.10	Perform a sag study on the Olive-University Park 345 kV line to increase the operating temperature to 225 F. Remediation work includes two tower replacements on the line.			AEP	

6.2.7 — Network Projects

Network projects in northern Illinois for 2023 are summarized in **Map 6.8** and **Table 6.10**.

Read More
Network Projects

Map 6.8: Northern Illinois Network Projects (Dec. 31, 2023)

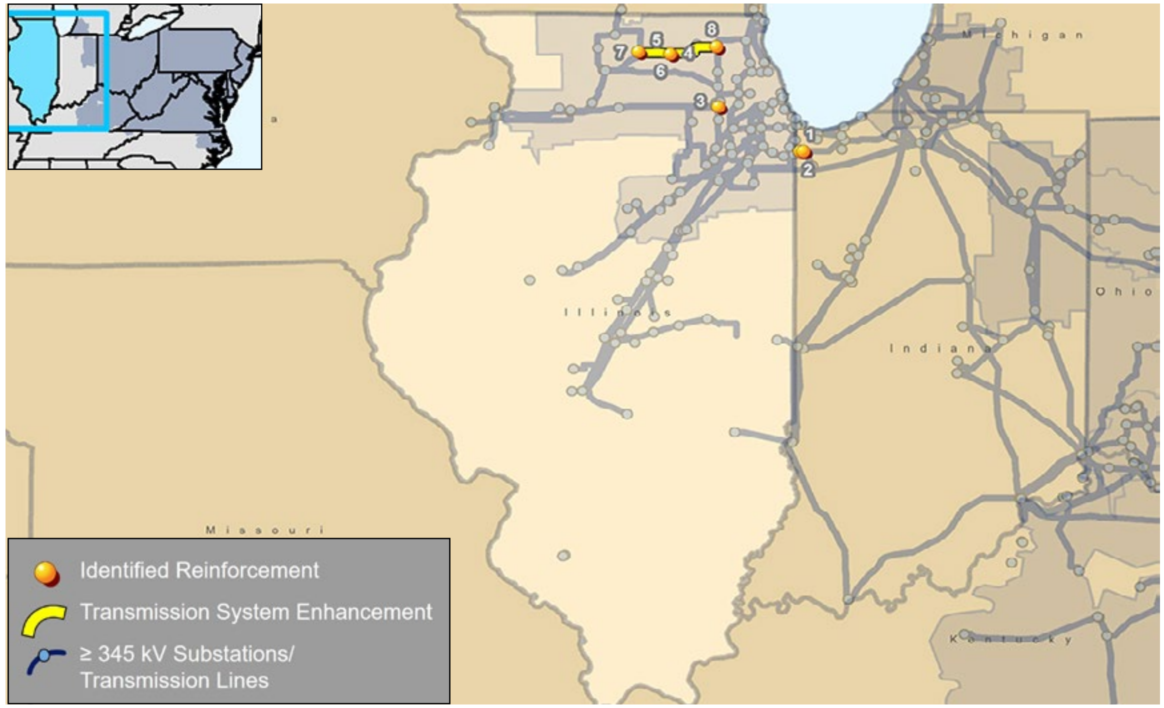


Table 6.10: Northern Illinois Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5833	Mitigate the sag on the St John 17-St John 345 kV line.	AD1-100	6/1/2021	$3.80	ComEd	10/3/2023
2	N5834	Mitigate the sag on the St John-Green Acre 345 kV line.			$3.80	AEP	
3	N6285	Modify breaker failure scheme to incorporate "A-Contact" logic to 138 kV blue bus to reduce total clearing times at TSS111 Electric Junction to nine cycles for fault on 345/138 kV transformer 81.	AC1-109	8/28/2023	$0.14	ComEd	
4	N6929	Construct new substation for AF2-349 interconnection.	AF2-349	12/26/2022	$15.00		
5	N6930	Cut circuit and loop into new AF2-349 substation.			$3.70		
6	N6931	Install communications equipment at new AF2-349 substation.			$2.90		
7	N6932	Update relays at Cherry Valley TSS 156 for AF2-349 interconnection.			$0.19		
8	N6933	Update relays at Silver Lake TSS 138 for AF2-349 interconnection.			$0.19		

6.2.8 — Supplemental Projects

Supplemental projects received by PJM in 2023 in northern Illinois are summarized in **Map 6.9** and **Table 6.11**.

Read More
Supplemental Projects

Map 6.9: Northern Illinois Supplemental Projects (Dec. 31, 2023)

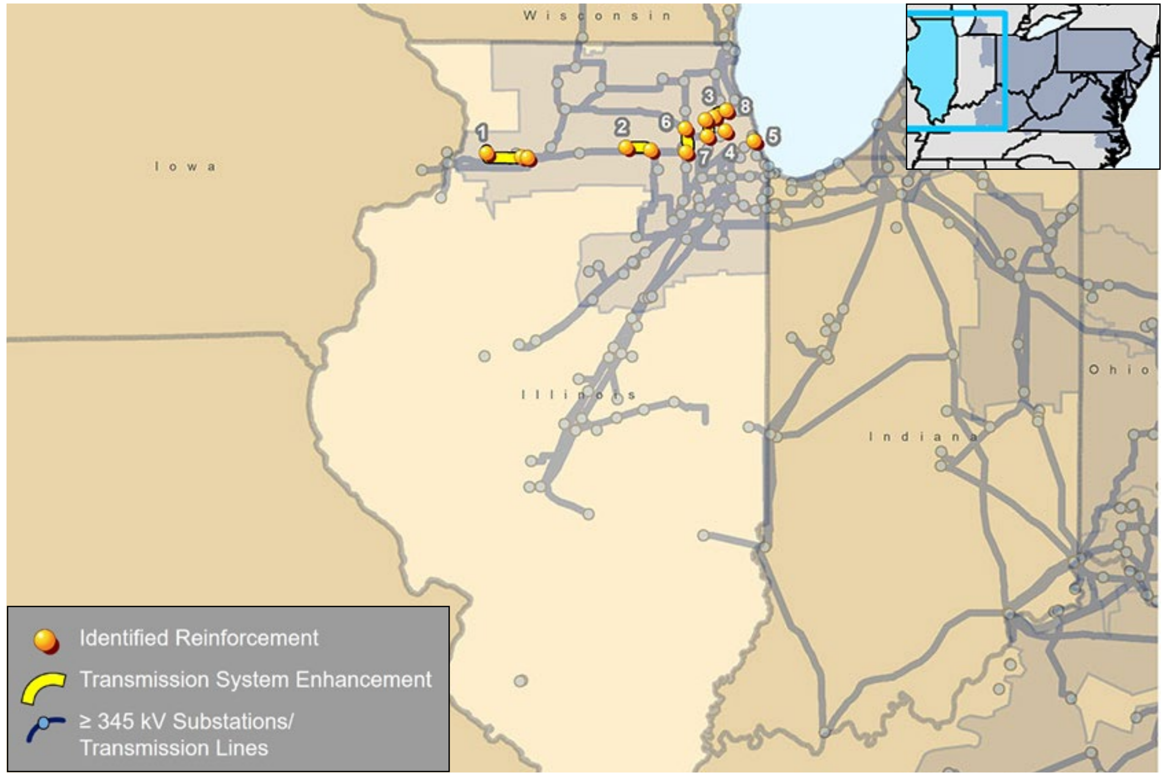


Table 6.11: Northern Illinois Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2870		Rebuild 23 miles of wood poles with 1,113 kcmil conductor on steel towers for the 138 kV L15518 (a three-terminal line between Rock Falls, Nelson and Garden Plain). Eliminate three-terminal line by extending 1,113 kcmil conductor from Rock Falls to the structure going to Garden Plain.	12/31/2026	$157.00	ComEd	10/14/2022
2	S2871		Expand 138 kV bus at Waterman and install 138-34 kV 60 MVA transformer. Reconfigure 138 kV bus at Waterman, and install 138 kV line circuit breakers on Waterman to Crego 138 kV line and Waterman to Haumesubstationer Road 138 kV line.	12/31/2025	$12.40	ComEd	10/14/2022
3	S2872		Tap 138 kV lines from Elk Grove to Tonne, and extend 0.12 miles to a new customer substation.	12/31/2024	$0.00	ComEd	11/18/2022
4	S2927		Install a new 138 kV circuit breaker at Franklin Park 138 kV between bus 4 and existing BT 2-4 to create a new bus 6.	12/31/2023	$3.90	ComEd	2/17/2023

Table 6.11: Northern Illinois Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	S2928		Install a new 138-12 kV transformer on bus 9 and move 138 kV Jefferson-Taylor line from bus 9 to bus 8. Install 138 kV line breaker on 138 kV Jefferson-Taylor line.	6/1/2023	$4.50	ComEd	2/17/2023
6	S2929		Move 345 kV line 11126 (Electric Junction-Wayne) to bus 6, and install 345 kV bus tie 5-6 circuit breaker.	12/31/2025	$10.00		4/11/2023
7	S3004		Serve new customer radially with two new 1-mile 138 kV lines from Itasca. Customer substation will be double ring bus configuration with four-138 kV to 34 kV transformers. Additionally, at Itasca, 138 kV line Itasca-Lombard will be moved from bus 1 to its own position on new bus 15. BT 3-4 circuit breaker will be installed at Itasca.	6/1/2026	$8.00		6/16/2023
8	S3005		Serve new customer radially with 2 new, 2-mile 138 kV lines from Elk Grove. Customer substation will be double ring bus configuration with 4-138 kV to 34 kV transformers. Expand Elk Grove to accommodate new line positions.	12/31/2025	$18.00		8/18/2023

6.2.9 — Merchant Transmission Project Requests

As of Dec. 31, 2023, PJM's queue contained one merchant transmission project request with a terminal in Illinois, as shown in **Map 6.10** and **Table 6.12**.

Read More
Merchant Transmission Projects

Map 6.10: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2023)

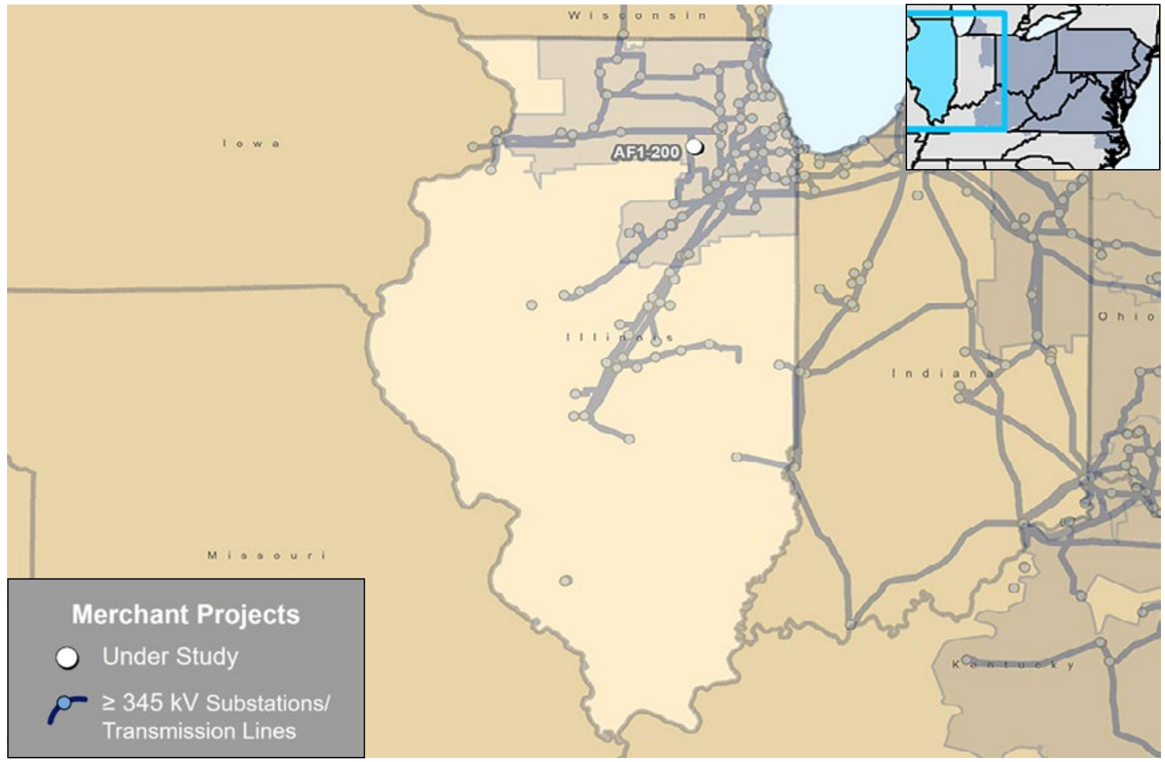


Table 6.12: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2023)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AF1-200	Plano 345 kV	ComEd	Active	1/31/2025	2,100

6.3: Indiana RTEP Summary

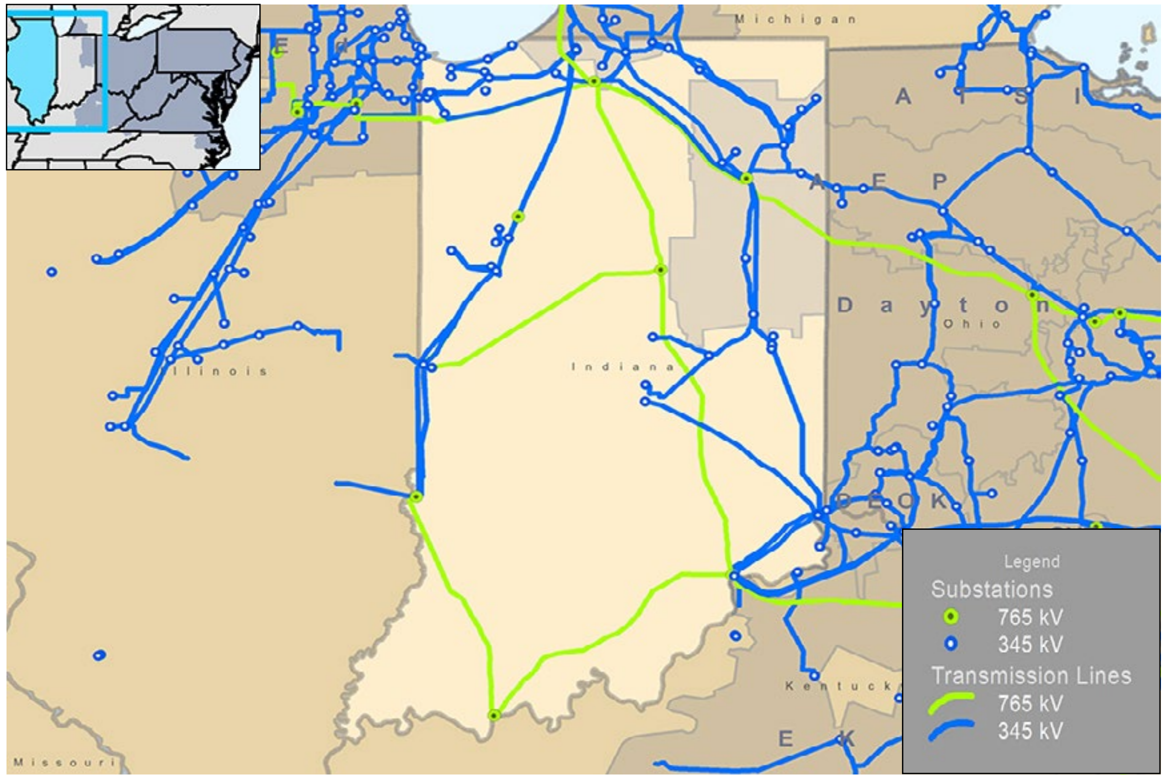
6.3.1 — RTEP Context

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 6.11** 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 6.11: PJM Service Area in Indiana

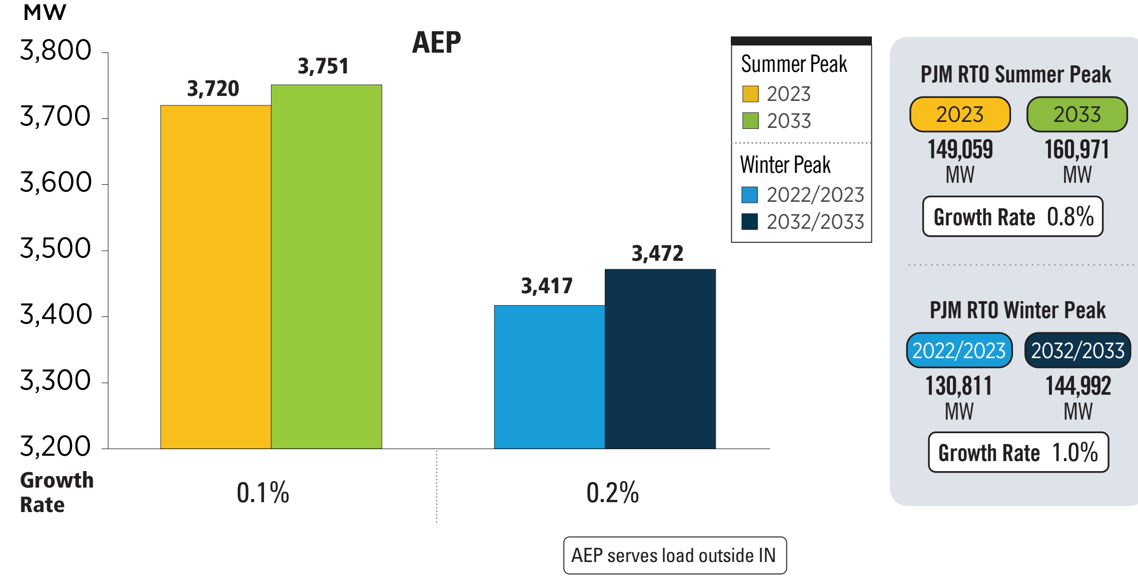


6.3.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.11** summarizes the expected loads within the state of Indiana and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.11: Indiana – 2023 Load Forecast Report



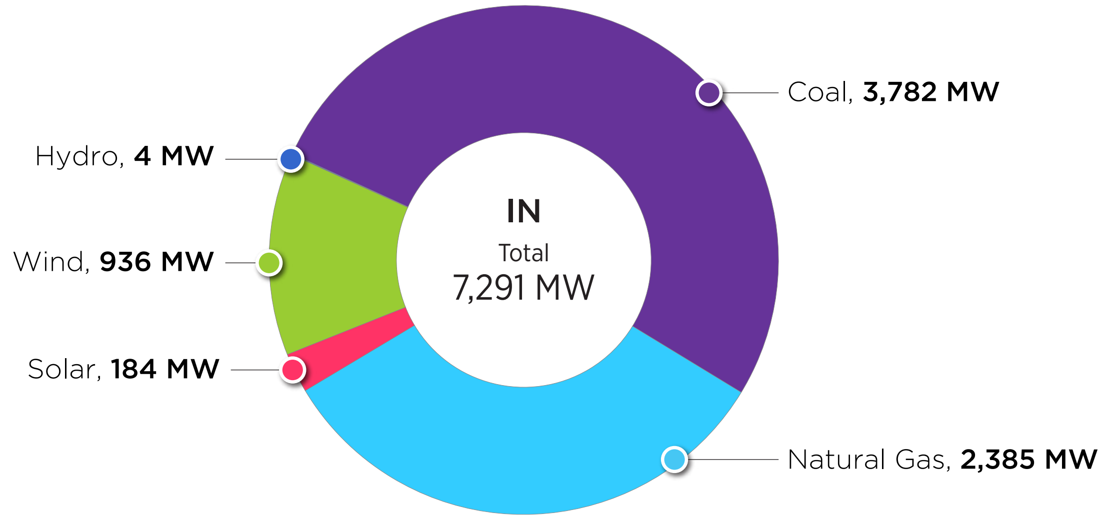
The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.3.3 — Existing Generation

Existing generation in Indiana as of Dec. 31, 2023, is shown by fuel type in **Figure 6.12**.

Read More
Changing Capacity Mix and Deliverability

Figure 6.12: Indiana – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)



6.3.4 — Interconnection Requests

In Indiana, as of Dec. 31, 2023, 268 projects were actively under study or under construction as shown in the summaries presented in **Table 6.13, Table 6.14, Figure 6.13, Figure 6.14** and **Figure 6.15**.

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.

Read More
Interconnection Requests

Table 6.13: Indiana – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Indiana Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	0	0.00%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	735	3.12%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	16,498	69.94%	98,471	55.15%
Storage	5,037	21.35%	53,644	30.04%
Wind	1,317	5.58%	20,798	11.65%
Grand Total	23,587	100.00%	178,566	100.00%

Table 6.14: Indiana – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		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	2	735.0	2	1,100.0	1	50.0	5	811.0	2	1,747.0	12	4,443.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	1	253.4	1	253.4
	Storage	50	5,037.0	0	0.0	1	40.0	0	0.0	16	750.5	67	5,827.5
Renewable	Methane	0	0.0	0	0.0	0	0.0	2	8.0	1	3.6	3	11.6
	Solar	177	16,497.8	2	84.1	13	925.3	7	184.6	35	4,279.0	234	21,970.8
	Wind	22	1,317.2	0	0.0	2	26.0	11	414.9	52	2,001.1	87	3,759.2
	Grand Total	**251**	**23,587.0**	**4**	**1,184.1**	**17**	**1,041.3**	**29**	**1,484.5**	**109**	**9,935.6**	**410**	**37,232.5**

Figure 6.13: Indiana – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

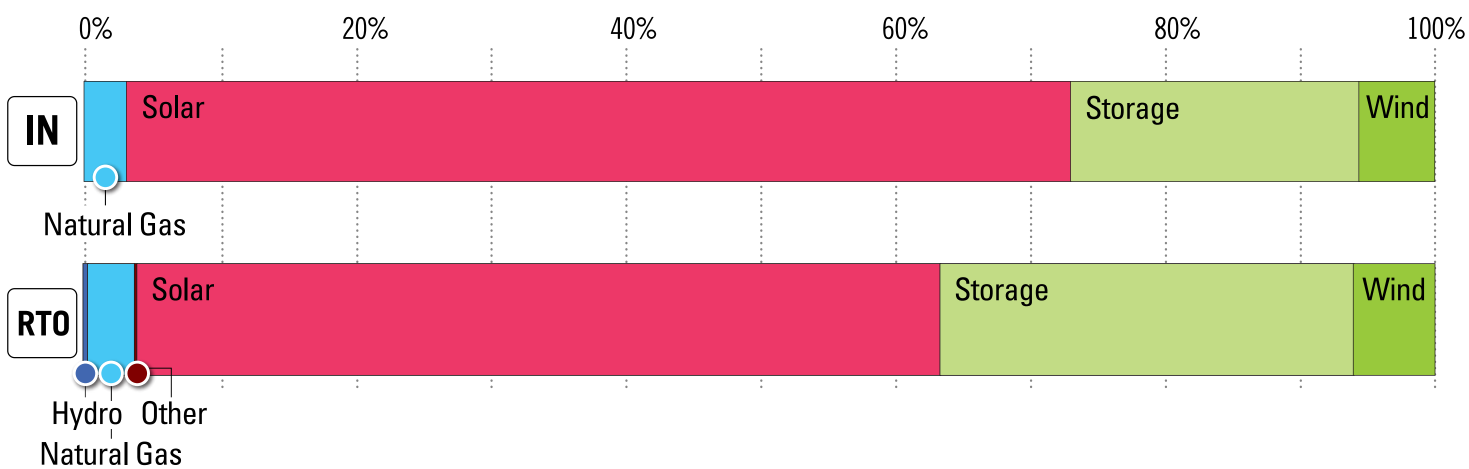


Figure 6.14: Indiana Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)

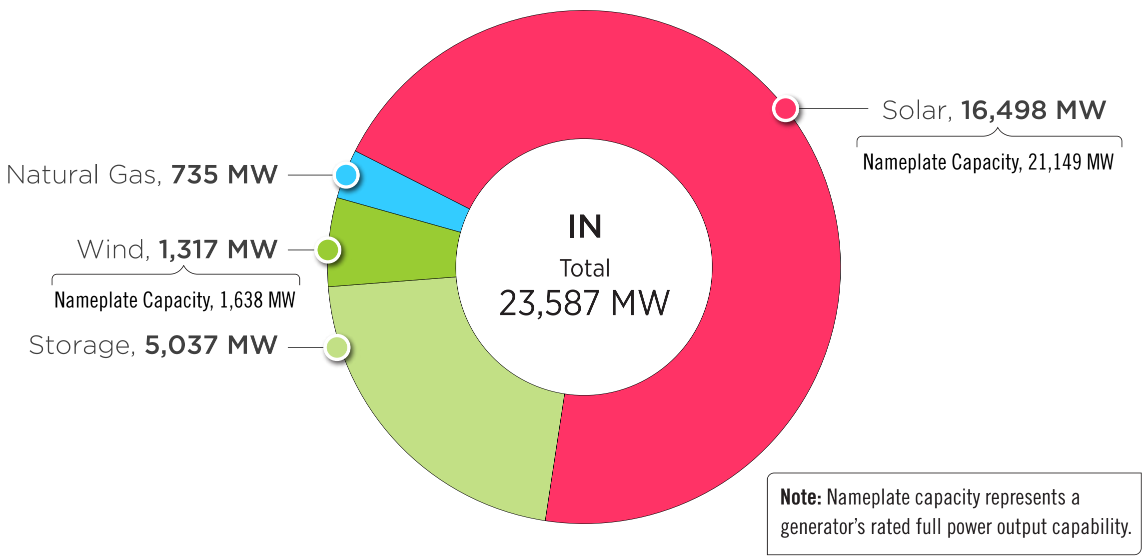


Figure 6.15: Indiana Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

11.2%	Requested capacity megawatts
18.9%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	3	Interconnection Service Agreements	71 MW	420 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.3.5 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in Indiana are summarized in **Map 6.12** and **Table 6.15**.

Read More
Baseline Projects

Map 6.12: Indiana Baseline Projects (Dec. 31, 2023)

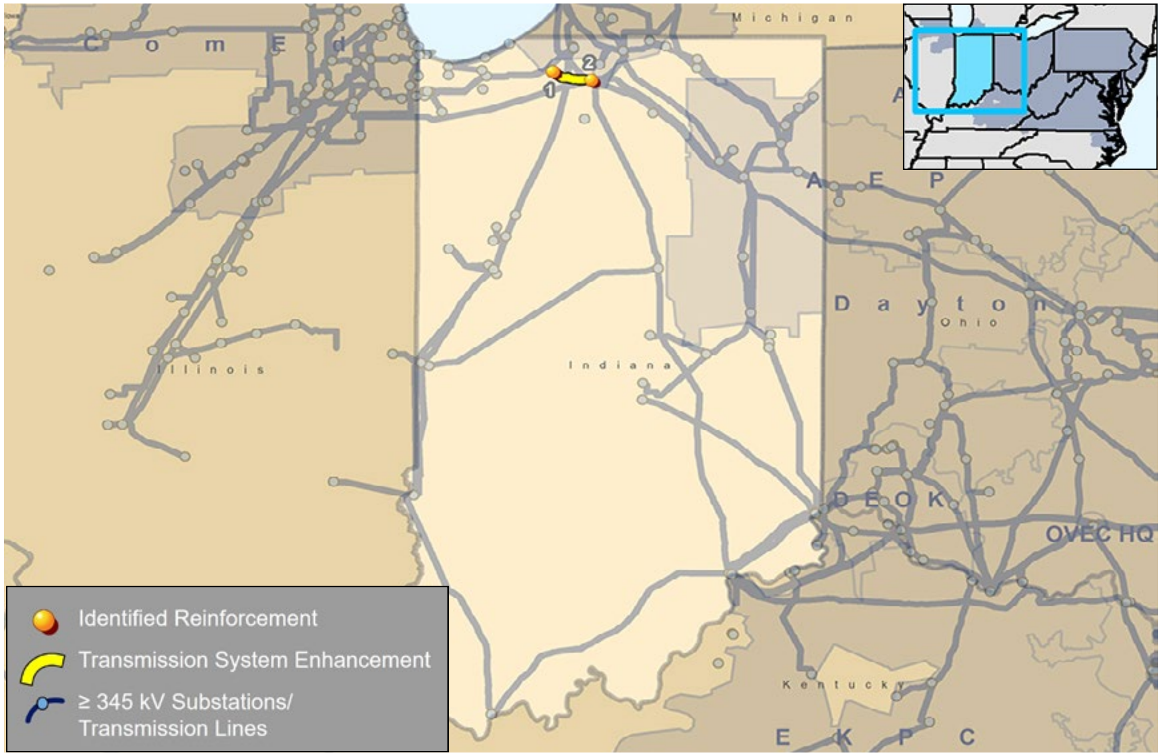


Table 6.15: Indiana Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3775	.6	Perform sag study mitigation work on the Dumont-Stillwell 345 kV line (remove a center-pivot irrigation system from under the line, allowing for the normal and emergency ratings of the line to increase, replace two structures and modify a third structure).	12/1/2026	$6.00	AEP	1/10/2023
2		.7	Upgrade the limiting element at Dumont substation to increase the rating of the Stillwell-Dumont 345 kV line to match conductor rating.				
		.11	Upgrade the limiting element at Stillwell substation to increase the rating of the Stillwell-Dumont 345 kV line to match conductor rating.				4/11/2023

6.3.6 — Network Projects

Network projects in Indiana for 2023 are summarized in **Map 6.13** and **Table 6.16**.

Read More
Network Projects

Map 6.13: Indiana Network Projects (Dec. 31, 2023)

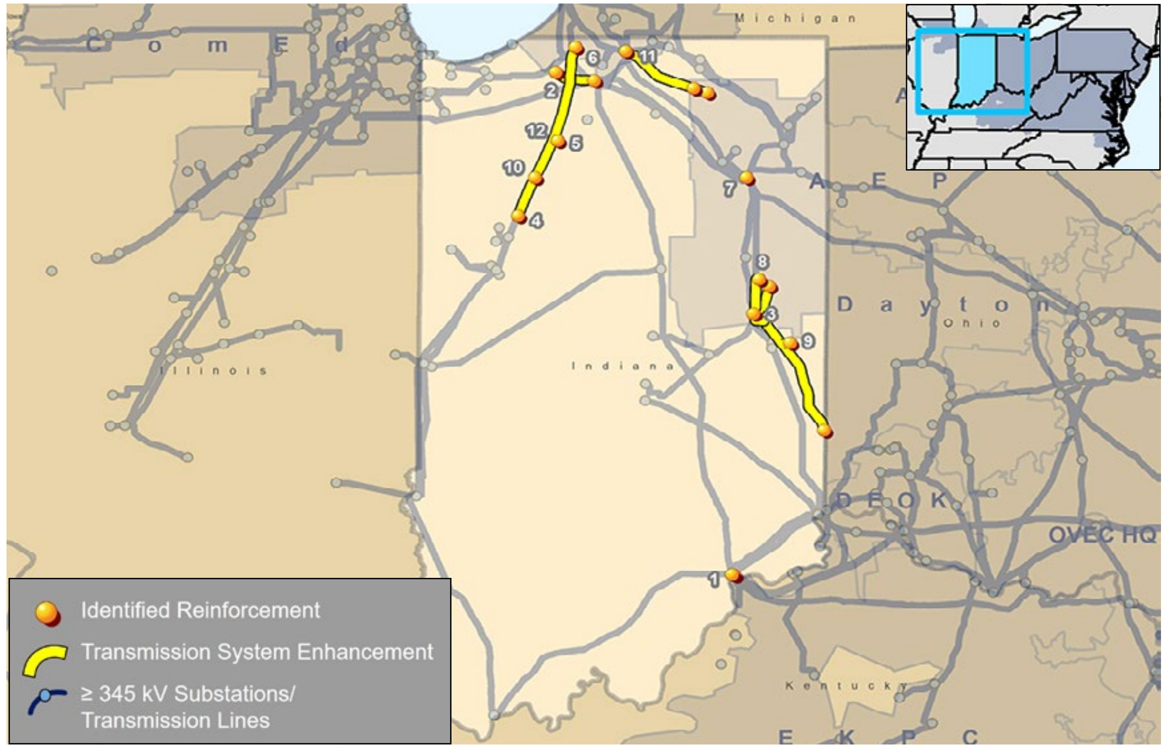


Table 6.16: Indiana Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N4106	Replace two switches at the Clifty Creek 345 kV station.	AF1-215	10/31/2023	$0.41	AEP	10/3/2023
	N4106.3	Perform Jefferson-Clifty 345 kV line sag study work: grading to remediate clearance between span 1 to 2; Extend one tower on the Jefferson-Clifty Creek (IKEC) 345 kV circuit.	AF1-215	12/31/2022	$0.41		
2	N5769.5	Replace four Dumont switches on the Stillwell-Dumont 345 kV line.	AG1-005	6/1/2020	$2.40		
	N5769.6	Adjust Dumont relay trip limit settings on the Stillwell-Dumont 345 kV line.			$0.60		
3	N6279.2	Perform a sag study on the Desoto-Jay 138 kV line.	AF1-173	12/31/2022	$0.05		

Table 6.16: Indiana Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	N7449	Install new 345 kV three-breaker ring bus station along the Olive-Reynolds 345 kV line.	AF1-215	5/31/2021	$0.35	AEP	10/3/2023
5	N7450	Install three structures, two spans of conductor; connect Ora Ora 345 kV station to existing transmission circuit.			$1.19		
6	N7451	Replace protective relays at Olive 345 kV station.			$0.61		
7	N7751	Replace 1600A switches at Sorenson 345 kV.	AG1-224	12/31/2021	$0.10		
8	N8029.1	Install attachment facility line and revenue metering at the new AF1-202 345 kV switching station.	AF1-202	12/31/2022	$1.08		
	N8029.2	Construct a new three-breaker 345 kV switching station for AF1-202 interconnection.			$17.44		
	N8029.3	Construct a new loop-in tap line at the Kerston-Desoto 345 kV line for AF1-202 interconnection.			$1.21		
	N8029.4	Modify relay settings at Desoto 345 kV substation.	AF1-202	12/31/2021	$0.05		
9	N8031.1	Install new 138 kV switching station (Wapahani switching station) to interconnect AD1-128 customer facility.	AD1-128	10/31/2021	$5.37		
	N8031.2	Loop in tap line to new AD1-128 switching station from College Corner-Desota 138 kV line.			$0.93		
10	N8083.1	Construct a new switching station for AF2-205 interconnection.	AF2-205	12/31/2022	$5.41		
	N8083.2	Cut in transmission line of Swingle 345 kV switching station and update remote end protection settings.			$0.71		
	N8083.3	Install two fiber-optic connections at Swingle-Tatertown 345 kV transmission line.			$0.56		
11	N8438.1	Construct three-breaker 138 kV station in a breaker-and-a-half configuration for AE2-323 interconnection.	AE2-323	4/4/2019	$6.36		
	N8438.2	Install two dead-end structures, two spans of conductor, two spans of OPGW shield wire; connect new 138 kV station to existing Twin Branch-Guardian transmission circuit and upgrade remote end relays.			$0.69		
12	N8445	Update protective relay settings at the proposed AF1-215 345 kV station.	AF2-134	3/16/2020	$0.05		

6.3.7 — Supplemental Projects

Supplemental projects received by PJM in 2023 in Indiana are summarized in **Map 6.14** and **Table 6.17.**

Read More
Supplemental Projects

Map 6.14: Indiana Supplemental Projects (Dec. 31, 2023)

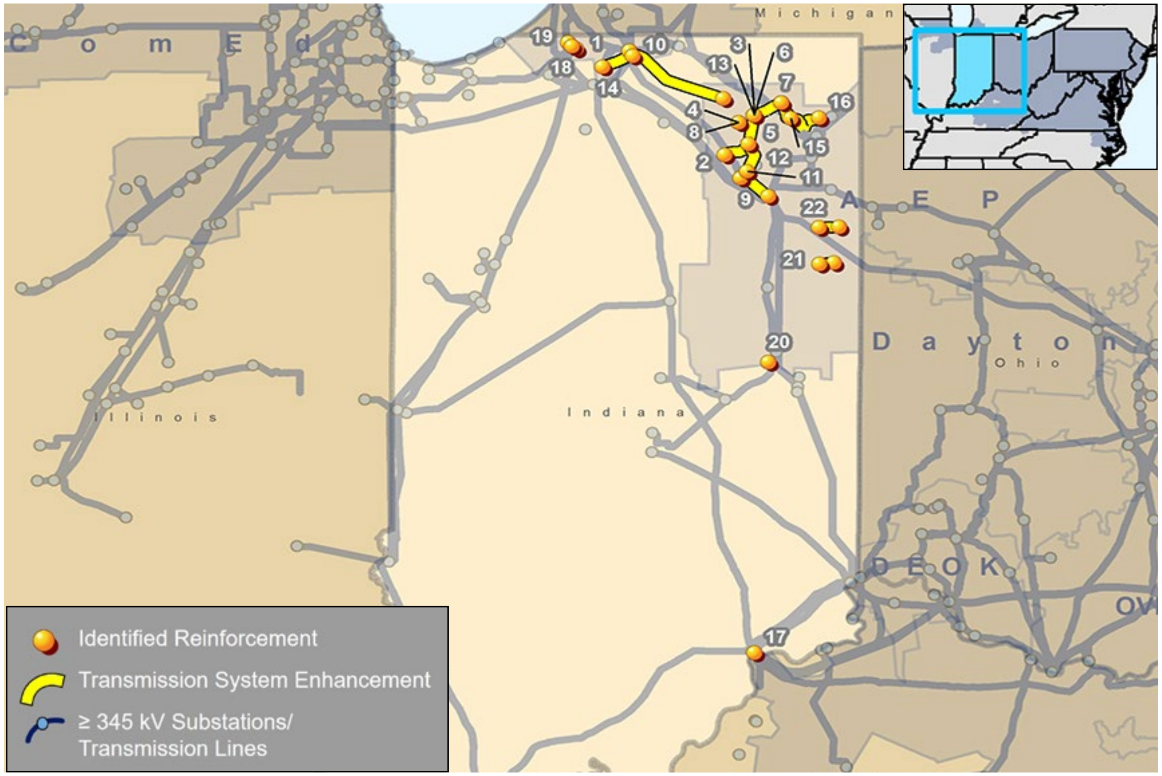


Table 6.17: Indiana Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2810		Replace 138 kV circuit breakers A, B and C with 3000A 40 kA breakers at Edison station.	3/31/2027	$1.18	AEP	8/19/2022
2	S2830	.1	Rebuild the ~8.7-mile line using double circuit 138 kV construction and 795 ACSR Drake construction at Richland-Ummel/Tri Lakes 69 kV line, but energize only one side at 69 kV.	11/3/2025	$180.10		10/14/2022
3		.2	Rebuild the ~8.5 mile Albion-Kendallville 138 kV circuit using 795 ACSR Drake.				

Table 6.17: Indiana Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	S2830 (Cont.)	.3	Rebuild the ~5.5-mile Wolf Lake tap as double circuit 138 kV using 795 ACSR Drake at Wolf Lake 69 kV tap. This line will be energized at 69 kV.	11/3/2025	$180.10	AEP	10/14/2022
5		.4	Replace 138 kV circuit breaker “F” and cap switcher “BB” at Albion 138/69 kV. In addition to this, this station had significant ancillary work needed, including foundation repairs, new control cable runs and DICM installation. Construction at this station will be aligned with B3248.				
6		.5	Reconnect Kuhns Sw to serve the currently hard tapped Albion REMC load at Kuhns/Albion REMC 69 kV.				
7		.6	Reterminate the line into Kuhns Sw 69 kV at Albion REMC 69 kV Radial tap.				
8		.7	Reterminate the line into Kuhns Sw 69 kV at Albion-Kendallville 69 kV line.				
9		.8	Replace the 138/69 kV transformer with a 90 MVA unit Kendallville 138/69 kV. This work will be aligned with S2431.				
		.9	Install a 69 kV phase-over-phase “Onion Bottom Bog” switch to serve Wolf Lake station at Onion Bottom Bog Sw/Wolf Lake 69 kV. This switch will be re-used from the “Whitford Sw” that was removed with S2431.				
		.10	Rebuild ~21 miles of the circuit from Sorenson to north of Columbia. Retire the remaining 44.1 miles of the line.	12/1/2032			
10		.11	Build a new ~7.5-mile double circuit extension from the Twin Branch-Guardian line to connect the existing Northeast station.				
11		.12	Build a new ~11.7-mile double circuit 138/69 kV line from Tri Lakes-Onion Bottom Bog Sw and reenergize the 138 kV circuit from Columbia-Albion.				
12		.13	Retire the ~7.8-mile Tri Lakes-Gateway 69 kV line.				
13		.14	Install a new 138 kV circuit breaker and a new 69 kV circuit breaker to connect the new lines at Albion station.				
14		.15	Reconnect Kline station to the Twin Branch-Jackson Rd. 138 kV line, and install a new 138 kV breaker.				
15	S2831	.1	Rebuild Noble 69/12 kV distribution station on neighboring property with a bus tie breaker and line Moab at Noble 69 kV station.	12/31/2024	$2.00		10/14/2022
16		.2	Reconnect the Auburn-Kendallville 69 kV line to the new station.				
17	S2832	.1	Replace 345 kV circuit breakers “R” and “S” Clifty Creek 345 kV with 5000A, 63 kA circuit breakers.	5/31/2024	$1.99		10/4/2022
18		.3	Replace the 1590 station conductor at Olive 138 kV station on the Olive-New Carlisle 138 kV line, and increase the CT thermal limit above 606 MVA WE.	12/31/2022			
19	S2851		Replace 138 kV circuit breaker A with a new 3000A 63 kA circuit breaker at New Carlisle 138 kV station.	10/28/2024	$0.35		11/18/2022
20	S2854	.1	Rebuild ~1.20 miles of 34.5 kV line with 556.5 ACSR 26/7 Dove Twenty Third Street-Blaine Street 34.5 kV.	10/15/2026	$12.36		12/16/2022
		.2	Replace the Twenty Third Street 138/34.5 kV transformer No. 1 and transformer at Twenty Third Street station. No. 2 with two 138/69/34.5 kV 90 MVA transformers.				
21	S2888		Replace ~4.9 miles of 69 kV line structures at Adams-Berne 69 kV. The following cost includes the structure replacements, structure removals, right-of-way acquisitions and station connections.	11/1/2026	$12.80		1/20/2023
22	S2943		Rebuild 5.88 miles of the 6.36-mile circuit from Magley-Decatur with 795 ACSR. The rebuild will consist of all 1957 and 1966 vintage poles, towers with failed strength requirements, as well as the 4/0 and 336 ACSR conductor.	8/1/2028	$12.48		4/21/2023

6.3.8 — Merchant Transmission Project Requests

As of Dec. 31, 2023, PJM's queue contained two merchant transmission project requests with a terminal in Indiana, as shown in **Map 6.15** and **Table 6.18**.

Read More
Merchant Transmission Projects

Map 6.15: Indiana Merchant Transmission Project Requests (Dec. 31, 2023)

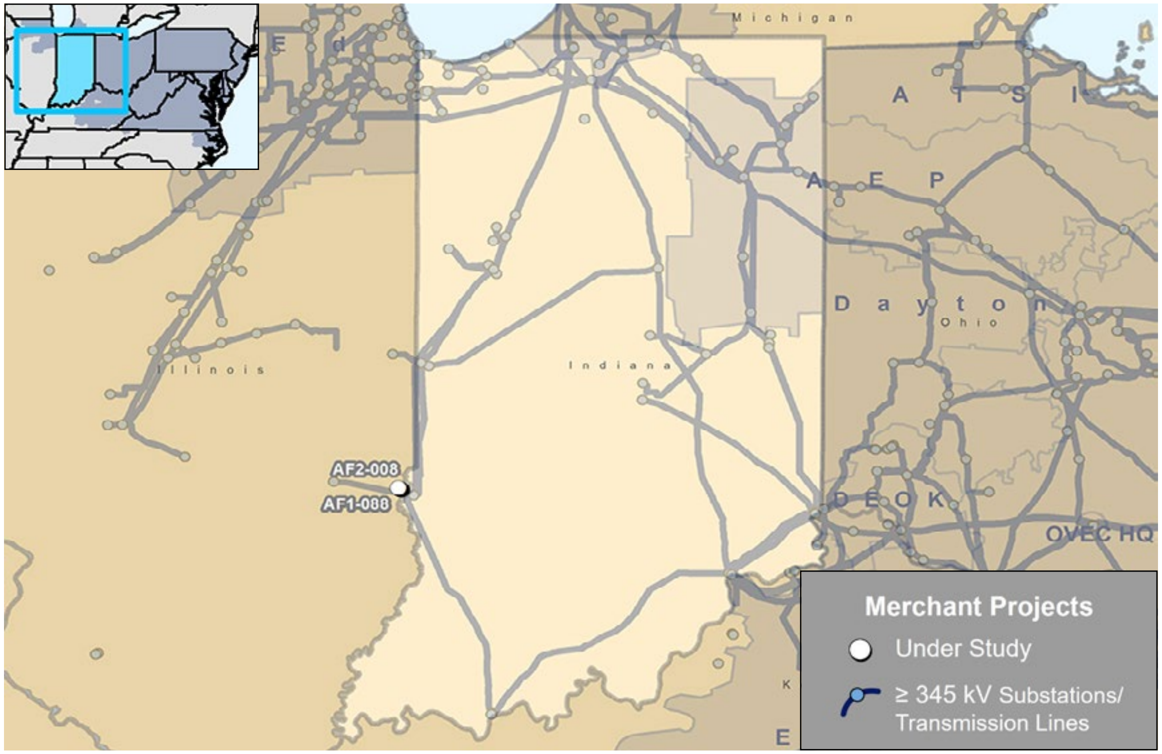


Table 6.18: Indiana Merchant Transmission Project Requests (Dec. 31, 2023)

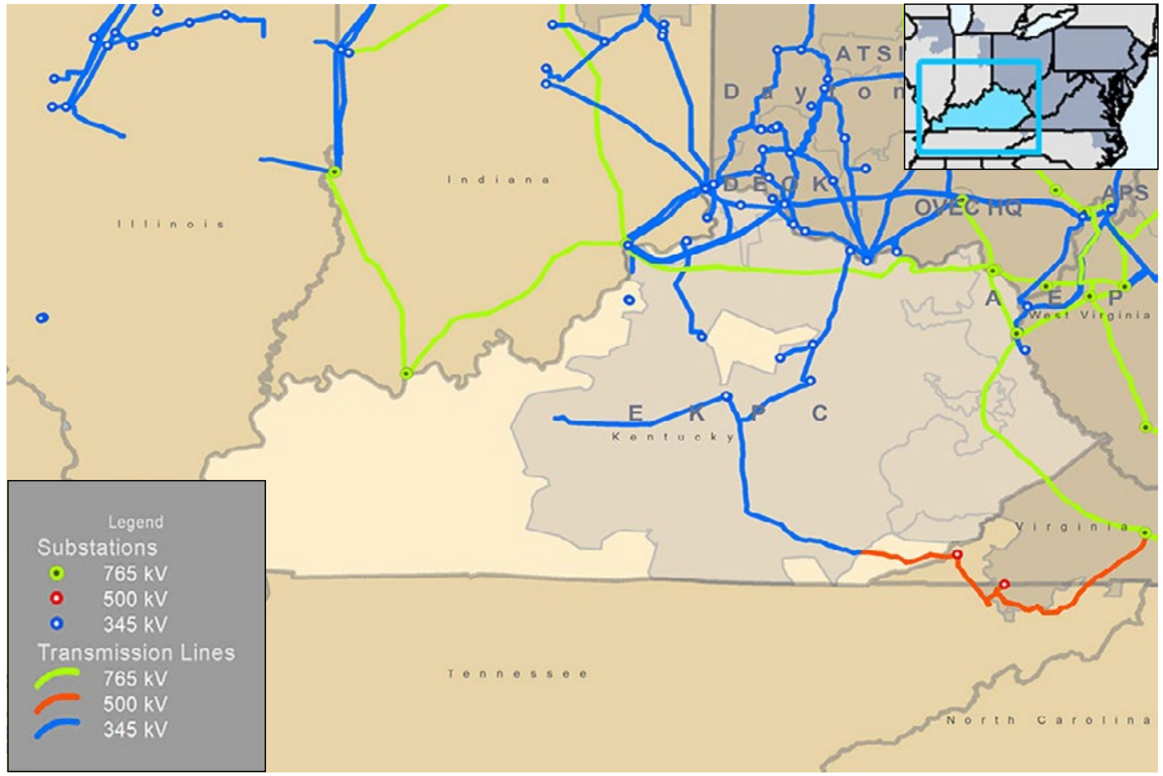
Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AF1-088	Sullivan 345 kV	AEP	Active	12/31/2025	1,000
AF2-008					2,000

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 6.16**. 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 6.16: PJM Service Area in Kentucky

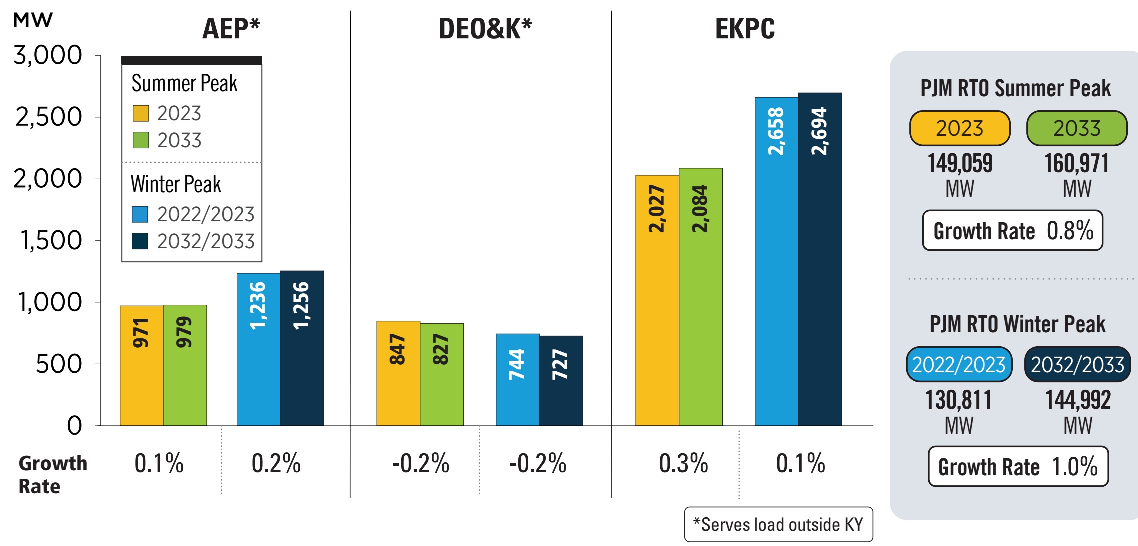


6.4.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.16** summarizes the expected loads within the state of Kentucky and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.16: Kentucky – 2023 Load Forecast Report



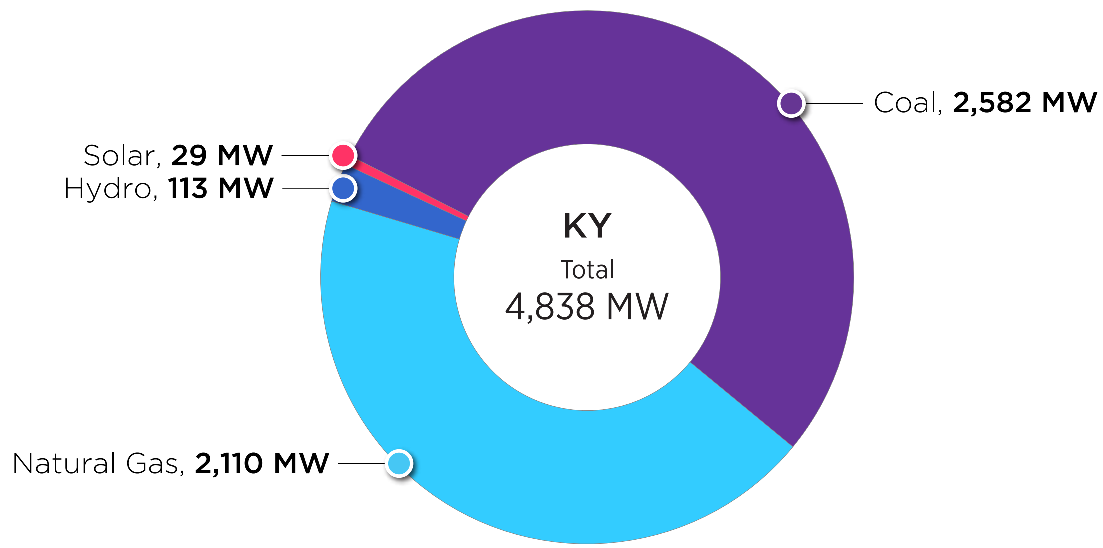
The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.4.3 — Existing Generation

Existing generation in Kentucky as of Dec. 31, 2023, is shown by fuel type in **Figure 6.17**.

Read More
Changing Capacity Mix and Deliverability

Figure 6.17: Kentucky – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)



6.4.4 — Interconnection Requests

In Kentucky, as of Dec. 31, 2023, 149 projects were actively under study or under construction as shown in the summaries presented in **Table 6.19, Table 6.20, Figure 6.18, Figure 6.19** and **Figure 6.20**.

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.

Read More
Interconnection Requests

Table 6.19: Kentucky – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Kentucky Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	0	0.00%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	0	0.00%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	8,729	94.56%	98,471	55.15%
Storage	502	5.44%	53,644	30.04%
Wind	0	0.00%	20,798	11.65%
Grand Total	**9,231**	**100.00%**	**178,566**	**100.00%**

Table 6.20: Kentucky – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		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	0	0.0	0	0.0	0	0.0	6	71.0	6	2,804.7	12	2,875.7
	Storage	11	502.0	0	0.0	0	0.0	0	0.0	3	106.2	14	608.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	5	198.5	5	198.5
	Hydro	0	0.0	0	0.0	0	0.0	0	0.0	1	70.0	1	70.0
	Solar	131	8,729.5	7	289.9	6	282.9	1	30.0	42	2,090.6	187	11,422.9
	Wind	0	0.0	0	0.0	0	0.0	0	0.0	2	27.3	2	27.3
	Grand Total	**142**	**9,231.5**	**7**	**289.9**	**6**	**282.9**	**7**	**101.0**	**65**	**8,266.4**	**227**	**18,171.7**

Figure 6.18: Kentucky – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

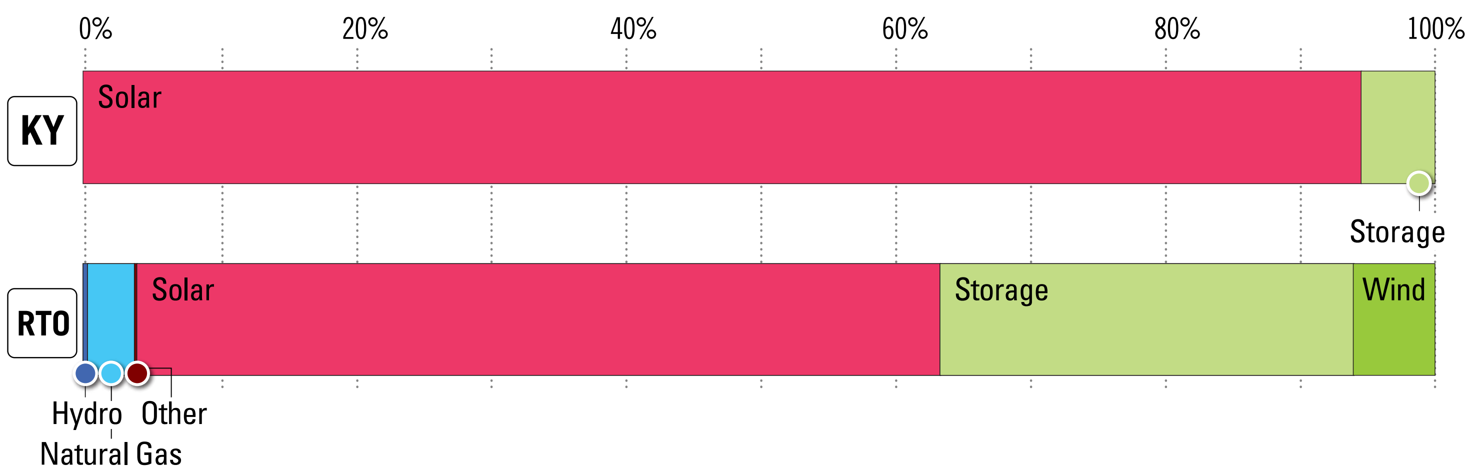
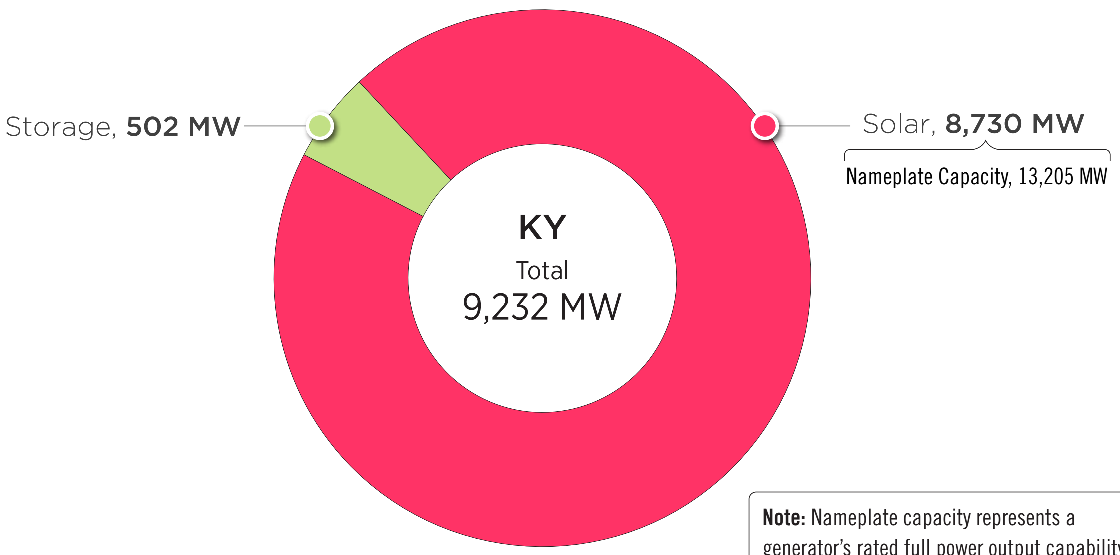


Figure 6.19: Kentucky Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.20: Kentucky Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

1.2% Requested capacity megawatts

8.3% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	**2**	Interconnection Service Agreements	1,180 MW	1,230 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.4.5 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in Kentucky are summarized in **Map 6.17** and **Table 6.21**.

Read More
Baseline Projects

Map 6.17: Kentucky Baseline Projects (Dec. 31, 2023)

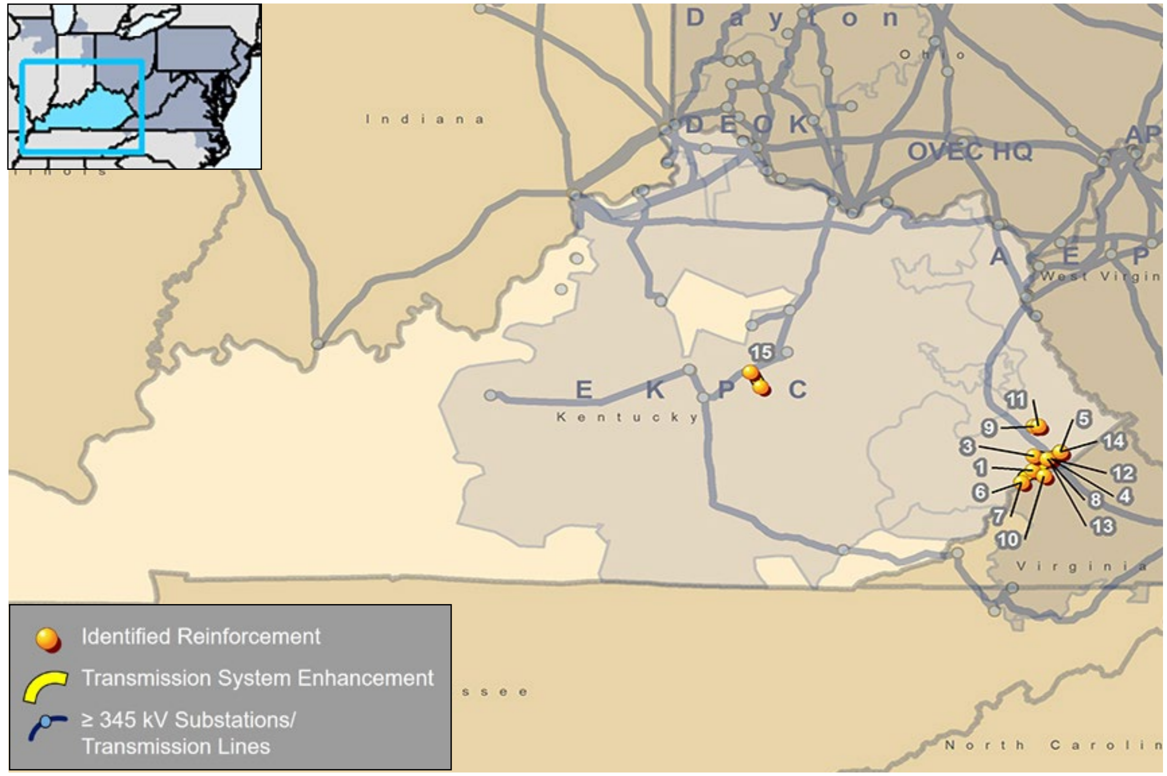


Table 6.21: Kentucky Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
		.1	Establish 69 kV bus and new 69 kV line circuit breaker at Dorton substation.				
1		.2	Reuse 72 kV breaker A as the new 69 kV line breaker at Breaks substation.				
	B3736	.3	Rebuild ~16.7-mile Dorton-Breaks 46 kV line to 69 kV.	12/1/2027	$83.09	AEP	11/18/2022
2		.4	Retire ~17.2-mile Cedar Creek-Elwood 46 kV circuit.				
3		.5	Retire ~ 6.2-mile Henry Clay-Elwood 46 kV line section.				

Table 6.21: Kentucky Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	B3736 (Cont.)	.6	Retire Henry Clay 46 kV substation and replace with Poor Bottom 69 kV station. Install a new 0.7-mile double circuit extension to Poor Bottom 69 kV.	12/1/2027	$83.09	AEP	11/18/2022
5		.7	Retire Draffin substation and replace with a new substation. Install a new 0.25-mile double circuit extension to New Draffin substation.				
6		.8	Perform remote end work at Jenkins substation.				
7		.9	Provide transition fiber to Dorton, Breaks, Poor Bottom, Jenkins and New Draffin substations.				
8		.10	Retire Henry Clay substation.				
9		.11	Perform Cedar Creek substation work.				
10		.12	Retire 46 kV equipment at Breaks substation.				
11		.13	Retire Pike 29 substation and Rob Fork substation.				
		.14	Serve Pike 29 and Rob Fork customers from nearby 34 kV distribution sources.				
12		.15	Install Poor Bottom substation.				
13		.16	Retire Henry Clay 46 kV substation.				
14		.17	Install new Draffin 69 kV substation.				
		.18	Retire Draffin 46 kV substation.				
15	B3762		Rebuild EKPC's Fawkes-Duncannon Lane tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR.	12/1/2026	$8.50	EKPC	12/16/2022

6.4.6 — Network Projects

Network projects in Kentucky for 2023 are summarized in **Map 6.18** and **Table 6.22**.

Read More
Network Projects

Map 6.18: Kentucky Network Projects (Dec. 31, 2023)

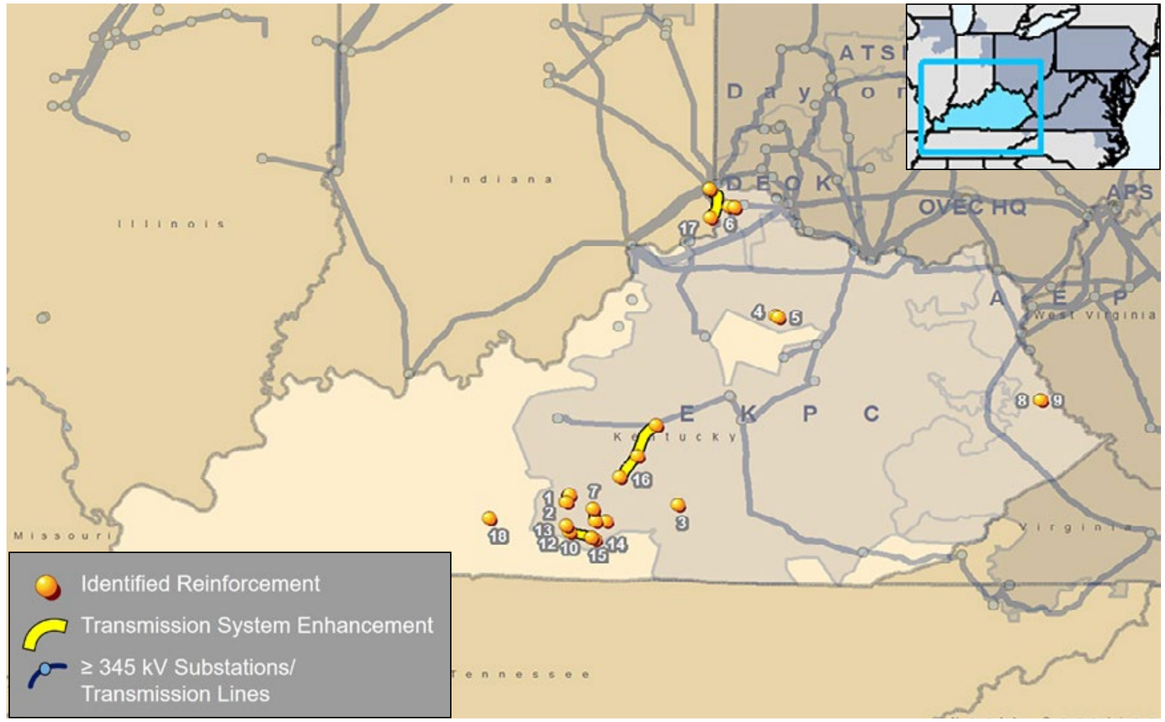


Table 6.22: Kentucky Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6197.1	Uprate CT associated with Barren Co-Horsecave Jct 69 kV line.	AG1-071	6/1/2022	$0.00	EKPC	10/3/2023
	N6197.2	Upgrade jumpers at Barren Co associated with Barren Co-Horsecave Jct 69 kV line.	AG1-472		$0.01		
2	N6198.2	Uprate high-side and two low-side CTs associated with Barren Co 161/69 kV auto to a minimum of 230 MVA summer emergency rating.	AE1-246		$0.00		
3	N6232	Upgrade the existing copper bus jumpers to larger jumpers. New rating after the upgrade will be 148 MVA.	AF1-038	12/31/2023	$0.25		

Table 6.22: Kentucky Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	N6274	Install an attachment facility line from the AC1-074 interconnection substation to the first structure located outside of the switchyard. Also, install revenue metering.	AC1-074	6/1/2019	$0.35	EKPC	10/3/2023
5	N6275	Install a new loop-in tap line to be constructed from EKPC's existing Jacksonville-Renaker 138 kV transmission line to the new switching station.			$0.52		
6	N6463.2	Upgrade bus and jumpers associated with Boone 138 kV bus using 2-500 MCM 37 CU conductor or equivalent on the Boone Co-Longbranch 138 kV line.	AE2-138	6/1/2022	$0.17		
	N6463.5	Replace the 750 MCM copper substation bus and jumpers at the Longbranch substation with bundled 500 MCM copper or equivalent equipment Boone Co-Longbranch 138 kV line.	AF1-256	1/31/2022	$0.19		
7	N6494	Increase the maximum operating temperature of the 266 MCM ACSR conductor in the Edmonton/JB Galloway Jct-Knob Lick 69 kV line section to 176 degrees F (5.7 miles).	AE2-071	12/31/2023	$0.31		
	N6494.1	Increase MOT (maximum operating temperature) of 266 MCM ACSR conductor to 212 degrees on the EDM-JBGAL J-Knob Lick 69 kV line.	AF1-203	12/31/2022	$0.29		
8	N7492	Install 138 kV metering at the Inez 138 kV station. Construct generator lead transmission line from the Inez 138 kV station to the point of interconnection. Install dual fiber telecommunications from the Inez 138 kV station to the Customer Facility collector station.	AF1-130	9/18/2019	$0.88	AEP	
9	N7493	Expand Inez 138 kV station, including the addition of a new string and two 138 kV circuit breakers and the installation of associated protection and control equipment, 138 kV line risers, switches, jumpers and SCADA equipment.	AF1-130	9/18/2019	$1.53		
10	N7847	Install necessary equipment by EKPC (a 69 kV isolation switch structure and associated switch plus interconnection metering, fiber-optic connection and telecommunications equipment, circuit breaker and associated switches, and relay panel) at the new Eighty Eight 69 kV switching station to accept the IC generator lead line/bus.	AE2-071	2/14/2019	$1.03	EKPC	
11	N7848	Construct a new 69 kV switching station built to 161 kV standards (Eighty Eight Switching) to facilitate connection of the Glover Creek Solar generation project.	AE2-071	12/31/2022	$3.74		
12	N7849	Construct facilities (~175 feet) to loop the existing Patton Road Junction-Summer Shade 69 kV line section into the new Eighty Eight switching substation.			$0.56		
13	N7850	Modify relay settings at Fox Hollow substation for existing line to Eighty Eight Switching station.			$0.05		
14	N7851	Modify relay settings at Summer Shade substation for existing line to Eighty Eight switching substation.			$0.05		
15	N7852	Install OPGW in the Summer Shade-Eighty Eight 69 kV line section (1.7 miles).			$0.50		
16	N8075.1	Construct a new switching station (North Taylor County switching station) to interconnect AF1-083 customer facility.	AF1-083	12/31/2022	$3.95		
	N8075.2	Loop in tap line to new AF1-083 switching station from Green Couonty-Marion County 161 kV line.			$0.34		
	N8075.3	Modify relay settings at Green County 161 kV substation.			$0.01		
	N8075.4	Modify relay settings at Marion County 161 kV substation.			$0.01		
	N8075.5	Install OPGW at Green County-North Taylor switching station.			$0.90		
17	N8319	Relocate the East Bend 345 kV line from the T bay to the R bay at the Tanners Creek 345 kV substation. This addresses the breaker failure contingency for the Tanners tie breaker.	AE2-297	12/31/2021	$3.10	AEP	
18	N8455.3	Install carrier equipment for anti-islanding at Bowling Green No. 2 69 kV.	AF1-064	3/31/2022	$0.47	APS	

6.4.7 — Supplemental Projects

Supplemental projects received by PJM in 2023 in Kentucky are summarized in **Map 6.19** and **Table 6.23**.

Read More
Supplemental Projects

Map 6.19: Kentucky Supplemental Projects (Dec. 31, 2023)

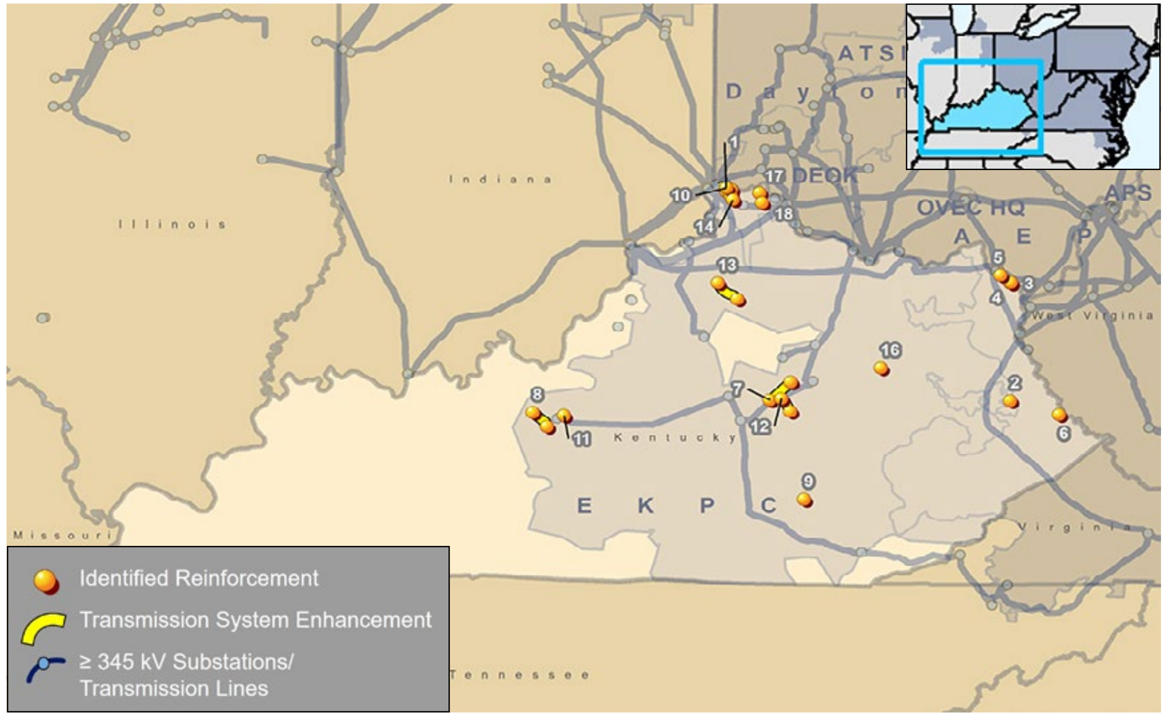


Table 6.23: Kentucky Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1782	.1	Expand the box structure and install two new 69 kV, 2000A breakers to create a four-position ring bus with individual positions for a circuit to Downing and a circuit to Oakbrook at Hebron substation. Retire a feeder section from Downing tap to structure HL-752 (0.67mi.). Construct a new section of feeder from Hebron to structure HL-752 with 954 ACSR on steel poles (1.75 mi). Raise two other circuits on shared structures in the corridor near the former Downing tap to allow the new feeder to pass under. At Levi, replace 500 MCM strain bus with 954 ACC conductor and remove bus tie switch SW4250. Replace drops into and out of Limaburg with 954 ACSR conductor. At Limaburg, replace 500 MCM strain bus with 954 ACC conductor, remove bus tie switch SW610, close normally open switch SW620 to complete the circuit to Oakbrook. Rebuild the section of feeder from Midvalley to Oakbrook with 954 ACSR on steel poles (1.5 mi.). Retire a feeder section from Oakbrook to Dixie tap (5.70 mi.). The ratings on the circuit from Hebron to Oakbrook will increase from 54/54 MVA to 133/133 MVA, S/N/E, and from 69/69 MVA to 166/166 MVA W/N/E.	4/22/2026	$32.00	DEO&K	10/17/2023
2	S2813	.1	Replace 138 kV circuit breaker B toward Thelma with new 138 kV 40 kA circuit breaker at Dewey substation. Provide new drop-in control module with new relays for all equipment at station so that existing control house can be removed. Upgrade station service.	12/1/2025	$2.98	AEP	8/19/2022

Table 6.23: Kentucky Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2813 (Cont.)	.2	Provide transition fiber via underground from the existing Control House to the new DICM at Dewey station. Retire existing fiber at Dewey substation	12/1/2025	$2.98	AEP	8/19/2022
		.3	Remote end relaying to replace line protection for breaker A toward (Dewey) to match upgrade at Dewey station. Provide MOS on existing 138 kV HS of transformer transformer No. 1 & No. 3 to provide additional control to stability system at Thelma substation.				
3	S2814	.1	Replace transformer No. 2 with a 200 MVA auto unit and retire transformer No. 1 and No. 5 at Bellefonte. The U/G feeder for transformer No. 3 69 kV riser is getting reconductored under B3349. Reconductor sections of 138 kV bus No. 1 and 138 kV bus No. 2. Replace remaining oil PTs connected to bus No. 1 and bus No. 2. Upgrade primary and backup station service. Replace 69 kV bus tie breaker H. Replace the hook stick disconnects switches for the tie breaker H and 69 kV tie breaker location will be relocated one bay south of the existing location and 69 kV buses will be reconfigured. Replace the hook stick disconnects switches for Raceland breaker D. Relocate the Raceland feeder to bus No. 1 after extending the 69 kV bus No. 1. The cap bank switcher/moab Mark 5 combo unit will get replaced with 69 kV breaker and set of breaker disconnects and relocated to bus No. 1. 69 kV breaker is needed instead of circuit switcher due to the high fault current. Relocate the cap bank to bus No. 1 after extending the 69 kV bus No. 1. 69 kV Air Products line MOABs will be replaced with 2000A SW. Replace hook-stick switches for oil circuit breaker-AB, JJ, I, G, Z, T and C. These breakers are replaced as part of B3350. Install 16'x48' DICM for 69 kV yard and a 16'x48' DICM for the 138 kV yard. Replace cable trench, single phase AC system and cable work, entire fence replacement and ground grid extension for 100'x10' expansion toward the Northwest of the 69 kV yard. Both 138 kV and 69 kV control house will be retired.	12/1/2025	$17.58	AEP	8/19/2022
		.2	The customer served out of 34.5 kV yard has plans for demolition of their facilities. Retire entire 34 kV yard, contingent on the timing of the customer being removed from service.				
		.3	Retire the Bellefonte 34.5 kV bus tie line that connects the Bellefonte 138 kV station to the Bellefonte 34 kV station. This removal involves removing three double circuit lattice towers, one triple circuit lattice towers and one single wood pole structure.				
4		.4	Retire the existing Bellefonte-Armco 34.5 kV operated line. The major removal work involves removing four lattice steel towers, one H-frame wood structure, and two single wood poles. The line being removed is ~0.55 miles long.				
5		.5	Perform remote end relaying at Raceland substation to install two new CCVTs on a custom two-phase single column stand for the Bellefonte 69 kV line exit. The existing CCVT mounted on a single phase CCVT stand will be reused and will remain as it is.				
		.6	Provide 0.2 miles of fiber from distribution structures outside the station to the new DICMs.				
6	S2815	.1	At Hatfield substation, expand the substation yard. Relocate 138/69/46kV transformer No. 1. Replace 138/69/46kV transformer No. 1 bushings, 138 kV 3 phase bus CCVTs, MOAB X1 and ground switch Z1 with a new 138 kV circuit switcher. Replace 138 kV Sprigg line metering, line switch "11" with a 138 kV circuit breaker. Replace and relocate 69 kV circuit breaker-B to standard bay position. Replace 69 kV circuit breaker-A and add three-phase CCVTs to John's Creek 69 kV line. Add 138 kV backup and 69 kV primary station service transformers and station service. Expand yard and install a 16'x27' base DICM. Remove 111 MVA 46/7.2 kV transformer No. 2 and associated equipment and 7.2 kV three-phase station service. Remove the control building.	8/1/2024	$5.45	AEP	8/19/2022
		.2	Remove existing guyed dead-end structure K357-29 and install a new single pole, single circuit, custom dead-end to remove the guy wires conflicting with station footprint plans on the Leslie No.1-Hatfield 69 kV circuit. The existing guy anchors would conflict with station expansion plans, and it is not feasible to span guy over top of proposed control house as the anchors would land in the proposed station drive path. The proposed custom dead-end structure will be placed 20' downhill from existing structure K357-29.	5/30/2025			
7	S2873		Rebuild 11.1-mile Dale-Newby line section as double-circuit 69 kV using 556 ACSR conductor.	12/31/2028	$12.60	EKPC	10/14/2022
8	S2874		Build a new 8.7-mile Stephensburg-Vertrees 69 kV line using 556 ACSR/TW conductor adjacent to the existing line section. Retire the existing line section.	6/1/2024	$0.00		11/18/2022
9	S2875		Build a new Dav Lane 4 breaker 69 kV switching station with a 69/12.47 kV, 12/16/20 MVA distribution substation, near the Laurel Co Industrial tap point.	6/1/2024	$3.80		11/18/2022

Table 6.23: Kentucky Supplemental Projects (Dec. 31, 2023) (Cont.)

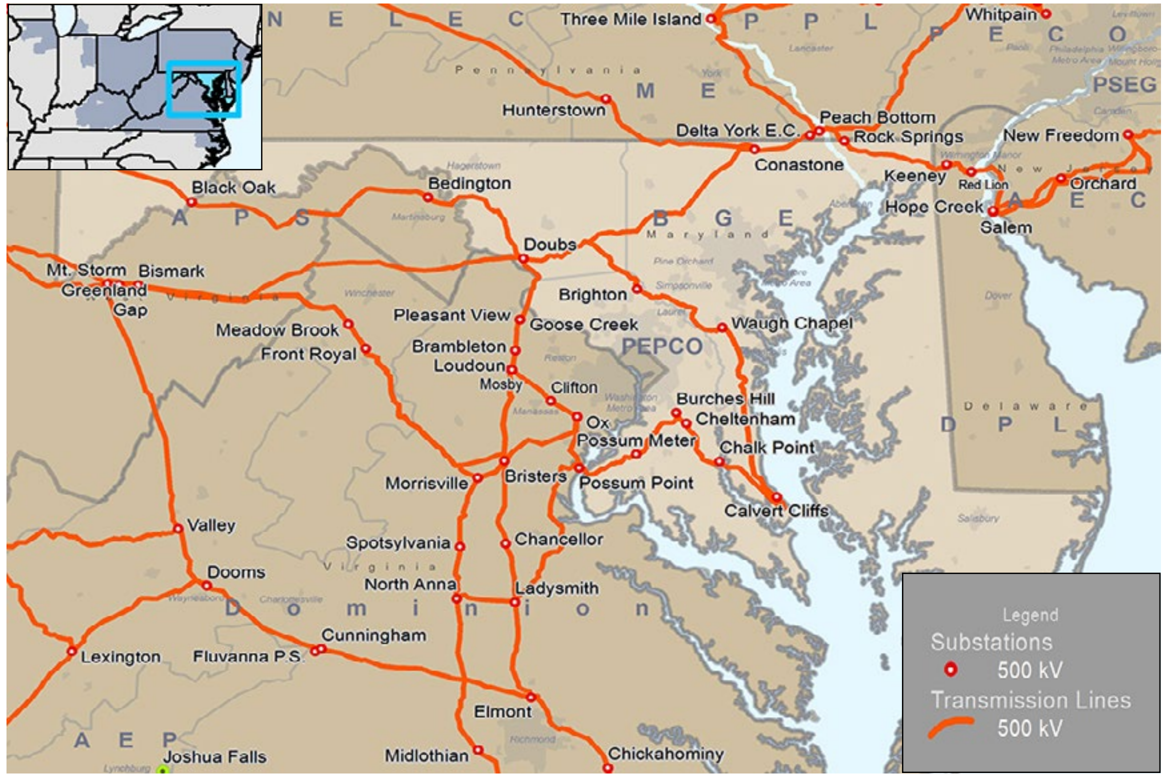
Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
10	S2876		Install a new 69 kV breaker at EKPC's Hebron substation, construct a new 7.6-mile 69 kV transmission line from EKPC's Hebron 69 kV substation to serve a new 69/13.2 kV, 12/16/20 MVA Mineola Pike distribution substation.	12/31/2024	$0.73	EKPC	11/18/2022
11	S2877		Build a new 69/13.2 kV 18/24/30 MVA distribution substation at Central Hardin.	12/31/2023	$0.00	EKPC	1/20/2023
12	S2878		Perform additional scope to modify the scope of (b3762) the Fawkes-Duncannon Lane tap (7.2 mile) single circuit 69 kV rebuild to rebuild this line as a double-circuit 138 kV and 69 kV line.	12/31/2024	$10.50	EKPC	1/20/2023
13	S2879		Install three 69 kV breakers and associated equipment at the Penn distribution substation. Operate the Keith-Penn 69 kV line section as normally closed.	5/1/2023	$3.70	EKPC	4/21/2023
14	S2910		Install a new 138/13 kV, 22 MVA transformer and 13 kV bus work for two feeder exits at Oakbrook. Roll the incoming 138 kV feeder phases to align with the transformer installation.	11/6/2025	$0.04	DEO&K	2/17/2023
15	S2919		Replace Wilder 138 kV circuit breaker 836, its bus and line disconnect switches, and drops from the switches to the breaker.	3/25/2024	$0.66	DEO&K	3/17/2023
16	S2977		Remove 10.8 MVAR capacitor bank at Frenchburg 69 kV.	12/31/2023	$0.00	EKPC	7/21/2023
17	S2979		Remove 138/69/34 kV transformer 2 at Wilder substation. Install a 138/69 kV, 150 MVA transformer to feed the 69 kV bus and a 138/34 kV, 33 MVA transformer to feed the 34 kV bus. Install a circuit switcher for the new high-side connection to the 138/34 kV transformer. Expand the substation and relocate transmission lines and structures to accommodate the new equipment.	5/8/2026	$10.99	DEO&K	7/21/2023
18	S2980		Retire Decoursey substation. Build Taylor Mill, a new substation on adjacent land. Install two H-frame take-off structures with motor operated line disconnect switches to loop through the 69 kV feeder, voltage sensors for an automatic throw over scheme (ATO), and 69 kV bus separated with a tie switch in the center.vInstall a circuit switcher to connect a new 69/13 kV, 22 MVA distribution transformer, and 13 kV bus, circuit breakers and regulators for two feeder exits.	11/22/2024	$2.99	DEO&K	7/21/2023

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.

Map 6.20: PJM Service Area in Maryland/District of Columbia



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.

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 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 that established an energy storage target of 3,000 MW by 2033.

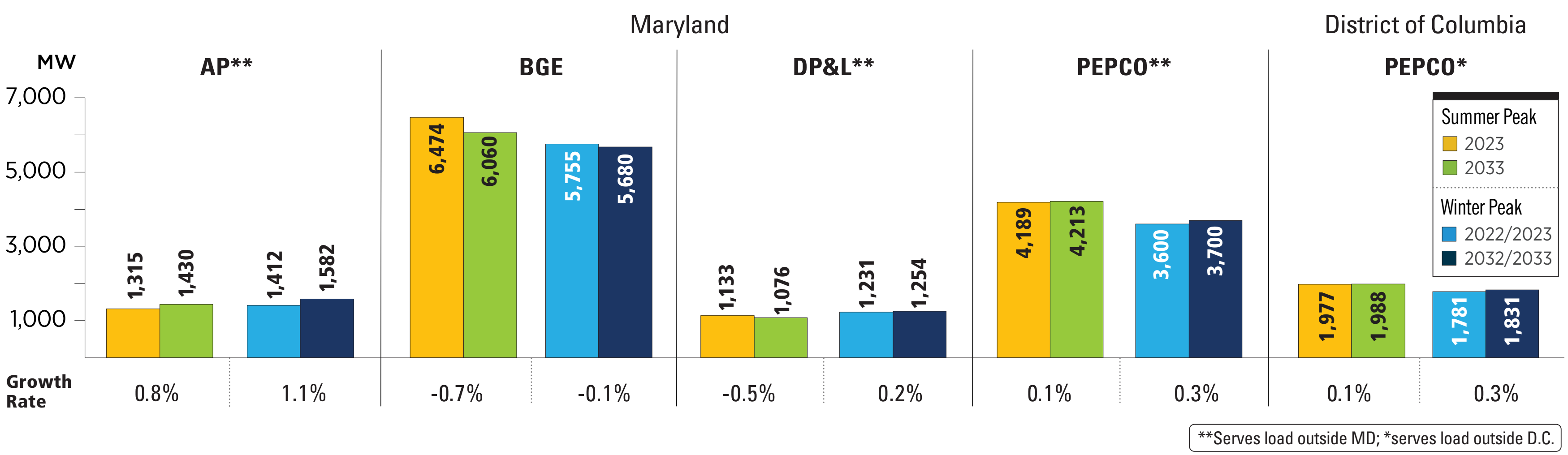
The District of Columbia has a mandatory RPS target of 100% by 2032. The resources serving D.C.'s RPS target must be located within the PJM region. The RPS target also includes a solar carve-out target of 5.5% by 2032 and 10% by 2041.

6.5.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.21** summarizes the expected loads within the state of Maryland and the District of Columbia, and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.21: Maryland/District of Columbia – 2023 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2023	2033	2022/2023	2032/2033
149,059 MW	160,971 MW	130,811 MW	144,992 MW
Growth Rate 0.8%		Growth Rate 1.0%	

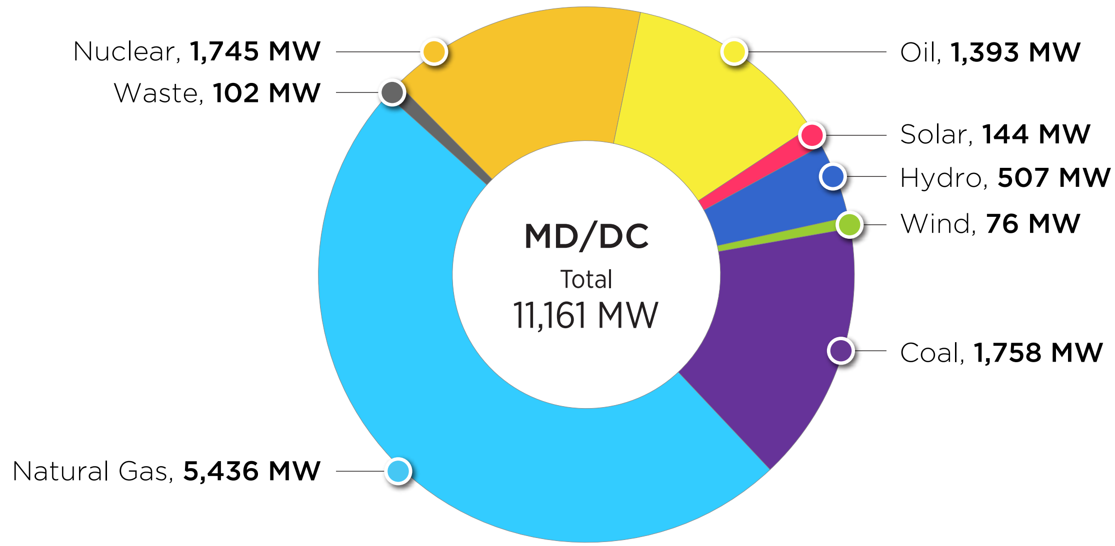
The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.5.3 — Existing Generation

Existing generation in Maryland and the District of Columbia as of Dec. 31, 2023, is shown by fuel type in **Figure 6.22**.

Read More
Changing Capacity Mix and Deliverability

Figure 6.22: Maryland/District of Columbia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)



6.5.4 — Interconnection Requests

In Maryland and the District of Columbia, as of Dec. 31, 2023, 125 projects were actively under study or under construction as shown in the summaries presented in **Table 6.24, Table 6.25, Figure 6.23, Figure 6.24** and **Figure 6.25**.

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.

Read More
Interconnection Requests

Table 6.24: Maryland/District of Columbia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Maryland/District of Columbia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	15	0.23%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	45	0.70%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	2,722	42.16%	98,471	55.15%
Storage	3,613	55.98%	53,644	30.04%
Wind	60	0.92%	20,798	11.65%
Grand Total	**6,455**	**100.00%**	**178,566**	**100.00%**

Table 6.25: Maryland/District of Columbia – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		In Queue						Complete					
		Active		Suspended		Under Construction		In Service		Withdrawn		Grand Total	
		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	1	45.0	0	0.0	0	0.0	36	3,834.2	72	33,060.4	109	36,939.6
	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	4	20.0	5	20.0
	Other	0	0.0	0	0.0	0	0.0	0.0	0.0	4	132.0	4	132.0
	Storage	27	3,613.5	0	0.0	5	1.9	0.0	0.0	43	534.5	75	4,149.9
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0.0	0.0	12	227.6	12	227.6
	Hydro	1	15.0	0	0.0	0	0.0	3	60.0	4	88.4	8	163.4
	Methane	0	0.0	0	0.0	0	0.0	5	14.5	6	18.3	11	32.8
	Solar	55	2,721.6	3	25.9	33	642.0	23	116.0	214	1,905.4	328	5,410.9
	Wind	3	59.7	0	0.0	0	0.0	6	66.2	10	265.6	19	391.5
	Grand Total	**87**	**6,454.7**	**3**	**25.9**	**38**	**643.9**	**80**	**4,138.3**	**374**	**41,212.2**	**582**	**52,475.0**

Figure 6.23: Maryland/District of Columbia – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

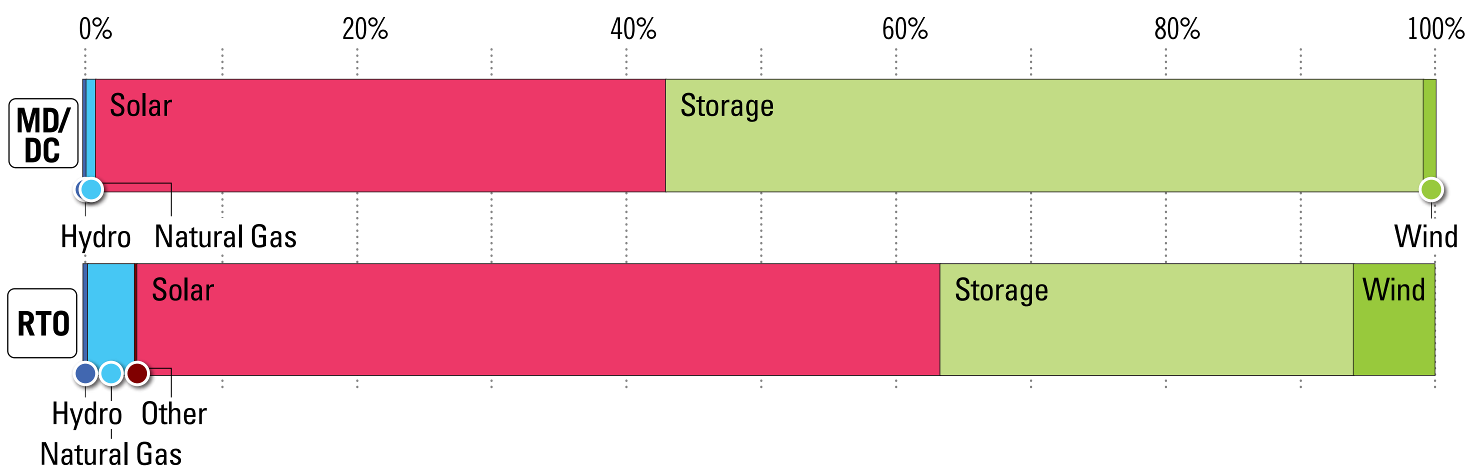


Figure 6.24: Maryland/District of Columbia Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)

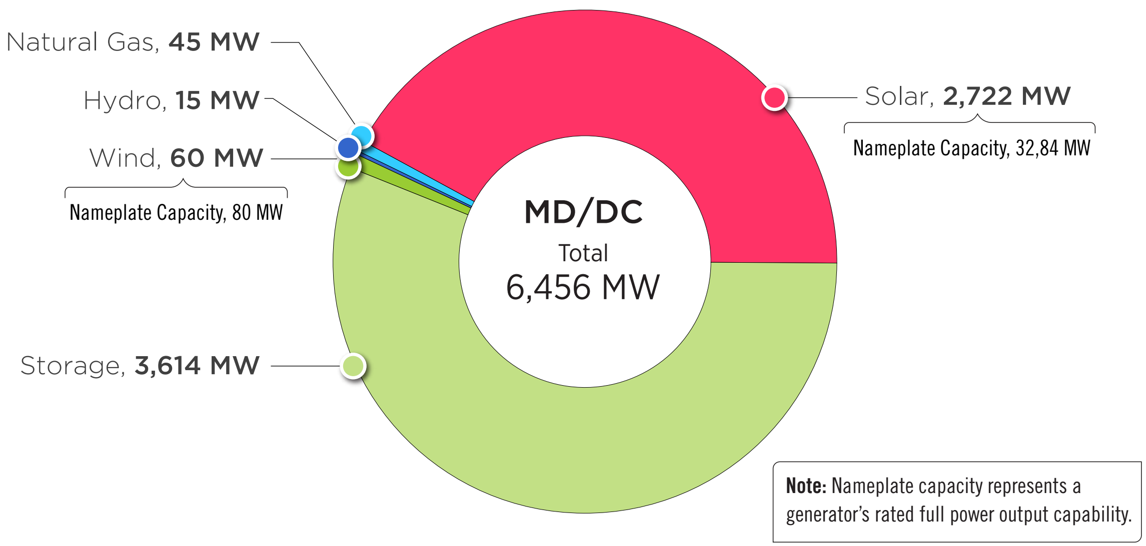


Figure 6.25: Maryland/District of Columbia Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

9.3%	Requested capacity megawatts
17.1%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	29	Interconnection Service Agreements	5,684 MW	6,184 MW
	54	Wholesale Market Participation Agreements	148 MW	290 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.5.5 — Generation Deactivation

Formal generator deactivation requests received by PJM in Maryland between Jan. 1, 2023, and Dec. 31, 2023, are summarized in **Map 6.21** and **Table 6.26**.

Read More
Generation Deactivation

Map 6.21: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2023)

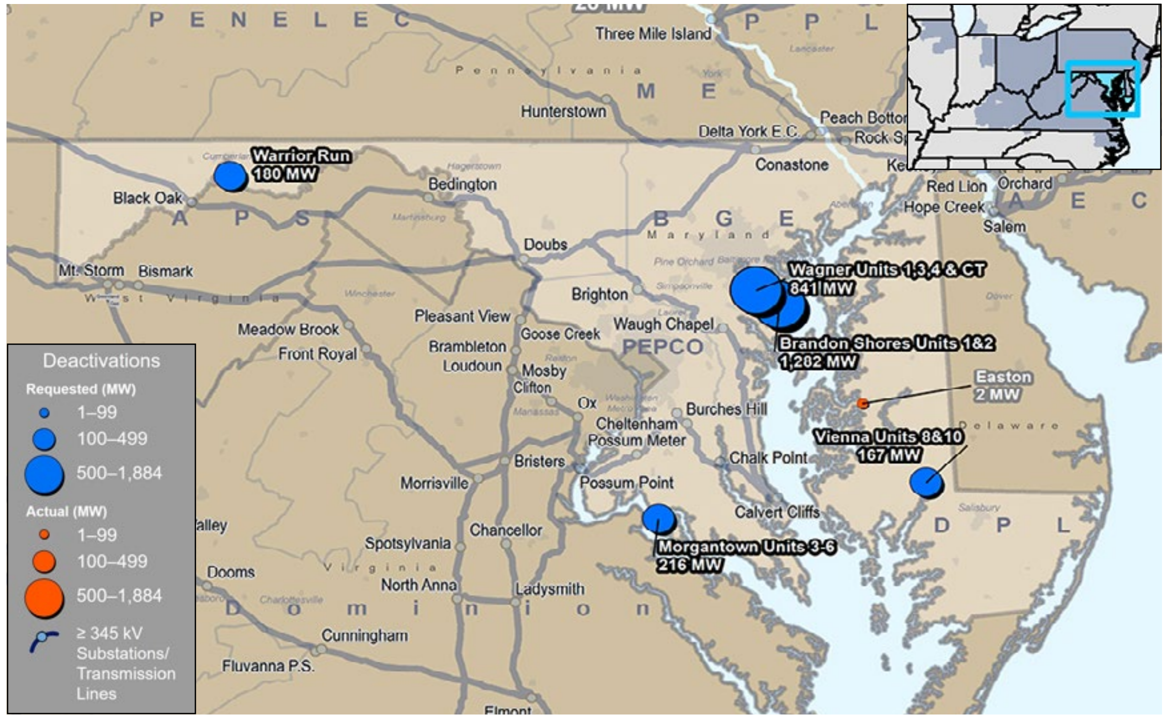


Table 6.26: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2023)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Morgantown CT 6	PEPCO	Oil	12/22/23	6/1/2024	50	54
Morgantown CT 5						
Morgantown CT 4						
Morgantown CT 3						

Table 6.26: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2023) (Cont.)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Wagner CT 1	BGE	Diesel	10/16/23	6/1/2025	56	13
Wagner 4	BGE	Oil	10/16/23	6/1/2025	51	397
Wagner 3	BGE	Coal	10/16/23	6/1/2025	64	305
Wagner 1	BGE	Natural Gas	10/16/23	6/1/2025	67	126
Warrior Run GEN1	AP	Coal	9/29/23	6/1/2024	21	180
Easton Diesel	DP&L	Diesel	6/9/23	10/1/2023	9	2
Brandon Shores 2	BGE	Coal	4/6/23	6/1/2025	32	643
Brandon Shores 1	BGE	Coal	4/6/23	6/1/2025	39	639
Vienna 10	DP&L	Oil	3/24/23	6/1/2025	55	14
Vienna 8	DP&L	Oil	3/24/23	6/1/2025	51	153

6.5.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in Maryland and the District of Columbia are summarized in **Map 6.22** and **Table 6.27**.

Read More
Baseline Projects

Map 6.22: Maryland/District of Columbia Baseline Projects (Dec. 31, 2023)

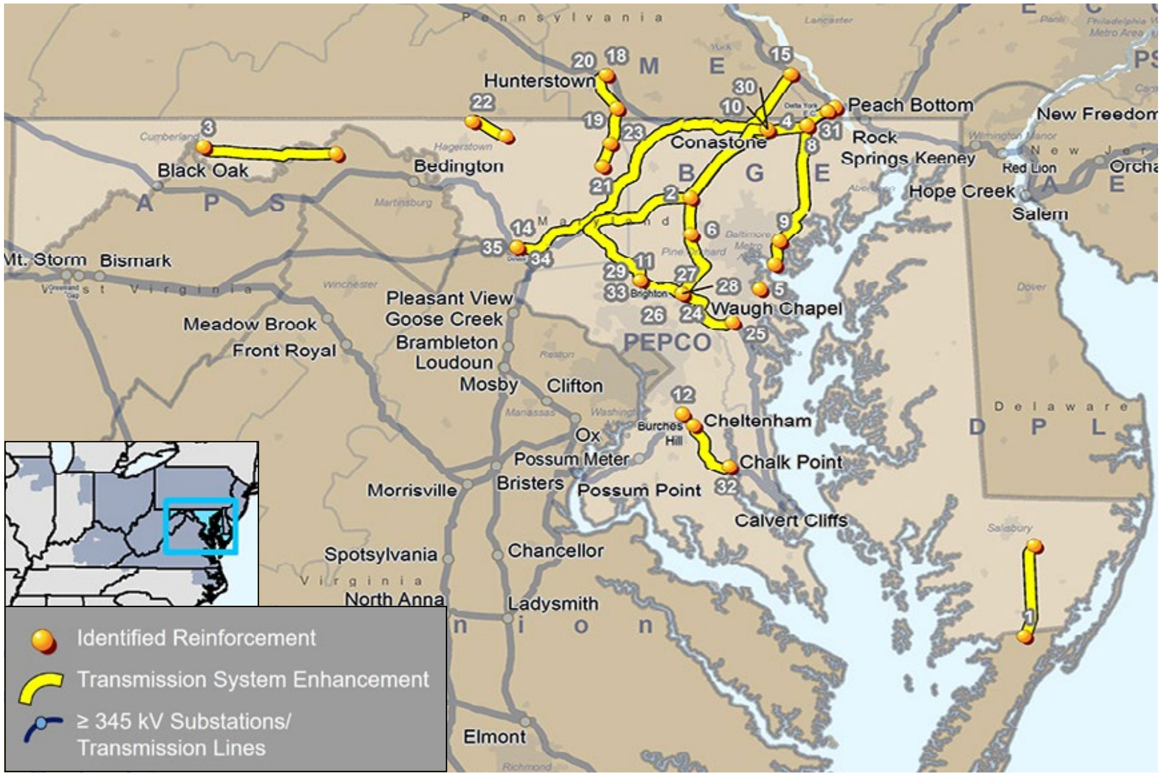


Table 6.27: Maryland/District of Columbia Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3749		Rebuild the New Church-Piney Grove 138 kV line.	6/1/2027	$63.00	DP&L	10/13/2022
2	B3771		Reconductor two 230 kV circuits from Conastone to Northwest #2.	6/1/2027	$37.76	BGE	12/6/2022
3	B3772		Reconductor 27.3 miles of the Messick Rd.-Morgan 138 kV line from 556 ACSR to 954 ACSR. At Messick Rd. substation, replace 138 kV wave trap, circuit breaker, CTs, disconnect switch, and substation conductor and upgrade relaying. At Morgan substation, upgrade relaying.	6/1/2027	$49.23	AP	12/6/2022

Table 6.27: Maryland/District of Columbia Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	B3780	.4	Perform transmission work at Peach Bottom to Graceton (BGE) – New rating: 4503 MVA SN/ 5022 MVA SE.	6/1/2025	$644.00	BGE	6/6/2023
5		.5	Build Solley Rd. substation + Statcom. New Statcom rating: 350 MVAR. Add four 230 kV breaker bays.				
6		.6	Build Granite substation + Statcom. New Statcom rating: 350 MVAR. Add four 230 kV breaker bays.				
7		.7	Build Batavia Rd. substation. Add four 230 kV breaker bays.				
8		.8	Perform Graceton 500 kV expansion: Add three 500 kV breaker bays, two 500/230 kV auto transformers, one 500 kV capacitor. New transformer rating: 1559 MVA SN / 1940 MVA SE. New capacitor rating: 250 MVAR.				
9		.9	Construct Graceton to Batavia Rd. 230 kV double circuit pole line. New rating: 1331 MVA SN/ 1594 MVA SE.				
10		.10	Install new Conastone capacitor. New capacitor rating: 350 MVAR.				
11		.11	Install Brighton Statcom and capacitor. New Statcom rating: 350 MVAR. New capacitor rating: 350 MVAR.			PEPCO	
12		.12	Install Burches Hill capacitor. New capacitor rating: 250 MVAR.				
13		.13	Construct Batavia Rd. to Riverside 230 kV reconductor; new rating: 1941 MVA SN / 2181 MVA SE.			BGE	
14	B3781		Replace line drops to Doubs transformer 3. New transformer rating: 721MVA SN /862 MVA SE.	12/31/2025	$0.80	AP	6/6/2023
15	B3800	.4	Rebuild and expand existing ~1.6 miles of Otter Creek-Conastone 230 kV line to become double-circuit 500 and 230 kV lines at New Otter Creek-Doubs 500 kV line (MD Border-PSEG demarcation point).	6/1/2027	$1,166.38	BGE	12/5/2023
16		.7	Construct 38 miles of 500 kV overhead AC line between the Conastone vicinity and the Doubs substations (BGE zone portion).			PSEG	10/31/2023
17		.8	Reconfigure Doubs 500 kV station and upgrade terminal equipment to terminate new line.			AP	12/5/2023
18		.9	Rebuild the existing Hunterstown-Carroll 115/138 kV corridor as double circuit using 230 kV construction standards. New circuit will be operated at 230 kV. Existing circuit to remain at 115/138 kV.				
19		.13	Rebuild the Germantown-Carroll 138 kV line to 230 kV double circuit construction (APS-PE Section).				
20		.15	Construct New 230 kV Hunterstown-Carroll line (APS-PE section).				
21		.16	Expand Carroll 230 kV substation to ring bus.				
		.17	Perform network upgrade at Caroll substation.				
22		.21	Replace line trap, substation conductor, breaker, relaying and CTs at Reid-Ringgold 138 kV.				
23		.25	Upgrade terminal at Taneytown substation.				
24		.26	Build High Ridge 500 kV substation – three-bay breaker-and-a-half configuration.			BGE	
25		.27	Construct High Ridge 500 kV substation (cut into Brighton-Waugh Chapel 500 kV line)–Waugh Chapel side.				
		.28	Construct High Ridge 500 kV substation (cut into Brighton-Waugh Chapel 500 kV line)–Brighton side.				
26		.29	Construct High Ridge termination for the North Delta-High Ridge 500 kV line.				
27		.30	Install two 500/230 kV transformers at High Ridge.				
28		.32	Build new North Delta-High Ridge 500 kV line (~59 miles).				

Table 6.27: Maryland/District of Columbia Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
29	B3800 (Cont.)	.33	Replace terminal equipment limitations at Brighton 500 kV on the existing Brighton-Waugh Chapel 500 kV (5053) or new Brighton-High Ridge 500 kV.	6/1/2027	$1,166.38	PEPCO	12/5/2023
30		.34	Rebuild 5012 (existing Peach Bottom-Conastone) (new Graceton-Conastone) 500 kV line on single circuit structures within existing right-of-way and cut into North Delta 500 kV and Gracetone 500 kV stations.			BGE	
		.36	Rebuild 5012 (existing Peach Bottom-Conastone) (new North Delta-Graceton BGE) 500 kV line on single circuit structures within existing right-of-way and cut into North Delta 500 kV and Gracetone 500 kV stations.				
31		.37	Replace terminal equipment limitations at Conastone 500 kV on the (existing Peach Bottom-Conastone) or (new Graceton-Conastone) 500 kV line.				
32		.38	Replace relay at Chalk Point 500 kV Chalk Point-Cheltanham 500 kV (5073).			PEPCO	
33		.40	Replace terminal equipment limitations at Brighton 500 kV Conastone-Brighton 500 kV (5011 circuit).				
		.41	Replace terminal equipment limitations at Conastone 500 kV Conastone-Brighton 500 kV (5011 circuit).			BGE	
34		.43	Construct 31.5 miles of 500 kV overhead AC line between the Conastone vicinity and the Doubs substations (APS zone portion).			PSEG	10/31/2023
35		.414	Replace Doubs 500 kV breaker DL-55 522LIN with a breakers rated at 60 kA.			AP	12/5/2023

6.5.7 — Network Projects

Network projects in Maryland and the District of Columbia received by PJM in 2023 are summarized in **Map 6.23** and **Table 6.28**.

Read More
Network Projects

Map 6.23: Maryland/District of Columbia Network Projects (Dec. 31, 2023)

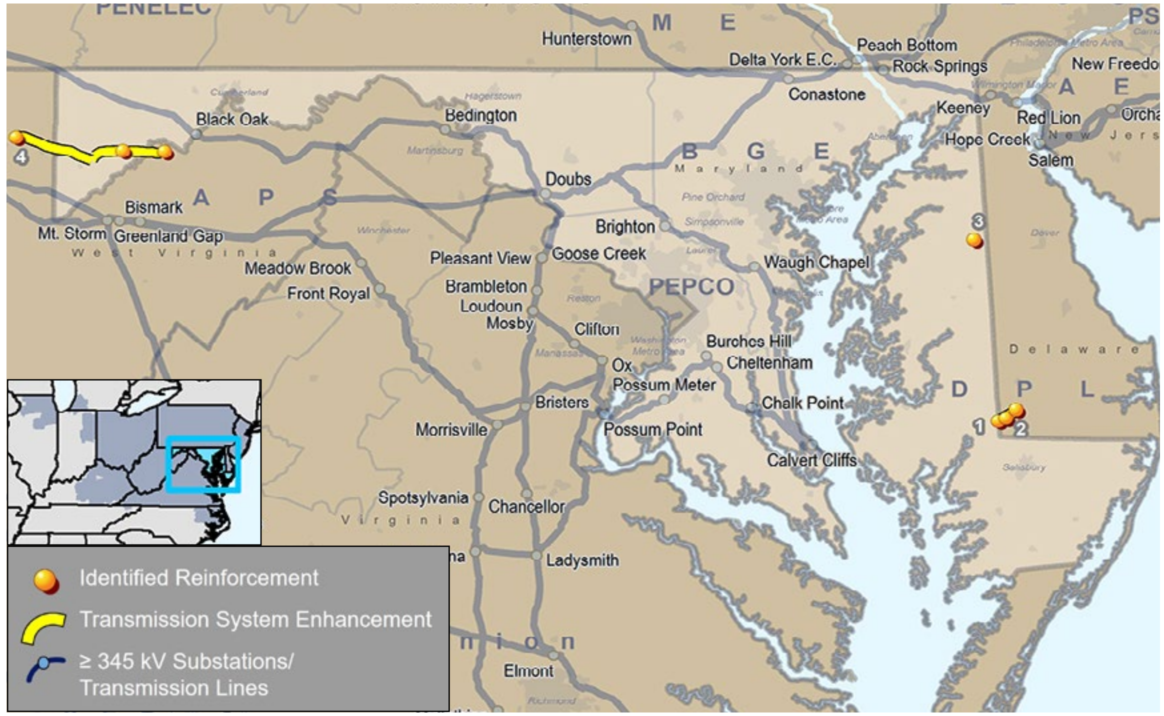


Table 6.28: Maryland/District of Columbia Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5879	Rebuild the 6705 Sharptown-AD2-088 TAP 69 kV line.	AC1-190	6/1/2020	$5.93	DP&L	10/3/2023
2	N5880	Rebuild the 6705 AD2-088 TAP-Laurel 69 kV line.			$5.09		
3	N6632	Construct a new 138 kV substation with a three-position ring bus for AB2-036 interconnection.	AB2-036	8/31/2024	$5.45		
4	N8211.1	Loop in and out the Albright-Cross School AFA 138 kV line to new three-breaker ring bus at Swanton 138 kV substation.	AF2-356	8/31/2025	$1.36	AP	
	N8211.4	Design, install and test/commission new licensed microwave link at Dan's Rock substation 138 kV.			$0.19		
	N8211.5	Design, install and test/commission MPLS equipment for SCADA transport at Swanton 138 KV substation.			$0.66		
	N8211.6	Install physical security camera system at AF2-356 interconnection substation (OTB).			$1.80		

6.5.8 — Supplemental Projects

Supplemental projects received by PJM in 2023 in Maryland and the District of Columbia are summarized in **Map 6.24** and **Table 6.29**.

Read More
Supplemental Projects

Map 6.24: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2023)

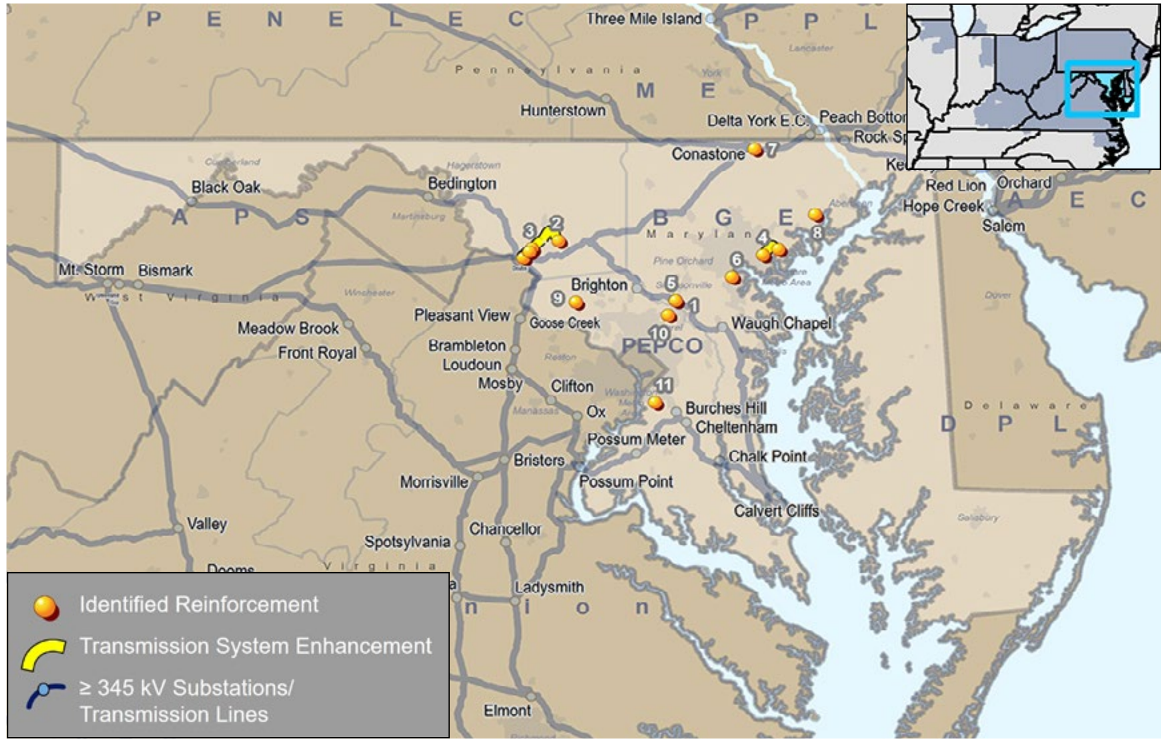


Table 6.29: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2839		Replace High Ridge 230-1 transformer and associated equipment.	6/1/2023	$7.40	BGE	10/4/2022
2	S2880		Install 230 kV circuit breaker and associated equipment (switch, relaying, etc.) to feed a new 230-34.5 kV transformer. Loop the Doubs-Monocacy 230 kV line into the new station.	11/1/2022	$4.90	AP	9/6/2022
3	S2881		Construct a new three-breaker 230 kV ring bus named Sage substation. Reterminate the Doubs-Eastalco No. 205 230 kV line at Doubs substation. Terminate the Doubs-Eastalco No. 205 230 kV line into the newly constructed Sage substation. Re-energize the Doubs-Eastalco No. 205 230 kV line. Install fiber from Doubs substation to the newly constructed Sage substation.	4/1/2024	$15.10	AP	9/6/2022
4	S2893		Replace 77 spans of 415 Hollow core Cu conductor with 421.9 kcmil ACCS on the 115 kV line (110580) between Chesaco Park and Middle River.	5/14/2024	$13.30	BGE	2/16/2023

Table 6.29: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	S2908		Replace High Ridge 115 kV circuit breaker B21.	6/7/2023	$1.30	BGE	3/16/2023
6	S2909		Replace Pumphrey 115 kV circuit breaker B8.	4/6/2023	$1.50	BGE	3/16/2023
6	S2959		Replace Pumphrey circuit breaker B27.	10/12/2023	$0.70	BGE	5/18/2023
6	S2960		Replace Pumphrey circuit breaker B30.	7/13/2023	$0.70	BGE	5/18/2023
6	S2961		Replace Pumphrey circuit breaker B31.	11/9/2023	$0.70	BGE	5/18/2023
6	S2962		Replace Pumphrey circuit breaker B32.	12/14/2023	$0.70	BGE	5/18/2023
7	S2965		Replace Conastone circuit breaker L.	11/14/2023	$2.35	BGE	6/6/2023
8	S2966		Replace Otter Point circuit breaker 50.	11/16/2023	$0.75	BGE	6/6/2023
8	S2967		Replace Otter Point circuit breaker 51.	10/11/2023	$0.75	BGE	6/6/2023
9	S2973		Replace the existing 230 kV oil circuit breaker 1A at Quince Orchard.	10/1/2024	$0.60	PEPCO	7/11/2023
9	S2974		Replace the existing 230 kV oil circuit breaker 6A at Quince Orchard.	10/1/2024	$0.60	PEPCO	7/11/2023
10	S2975		Replace the existing 230 kV oil circuit breaker 4B at Burtonsville.	9/1/2023	$0.60	PEPCO	7/11/2023
11	S2976		Replace the existing 230 kV oil circuit breaker 3C at Palmers Corner.	1/30/2024	$0.60	PEPCO	7/11/2023

6.6: Southwestern Michigan RTEP Summary

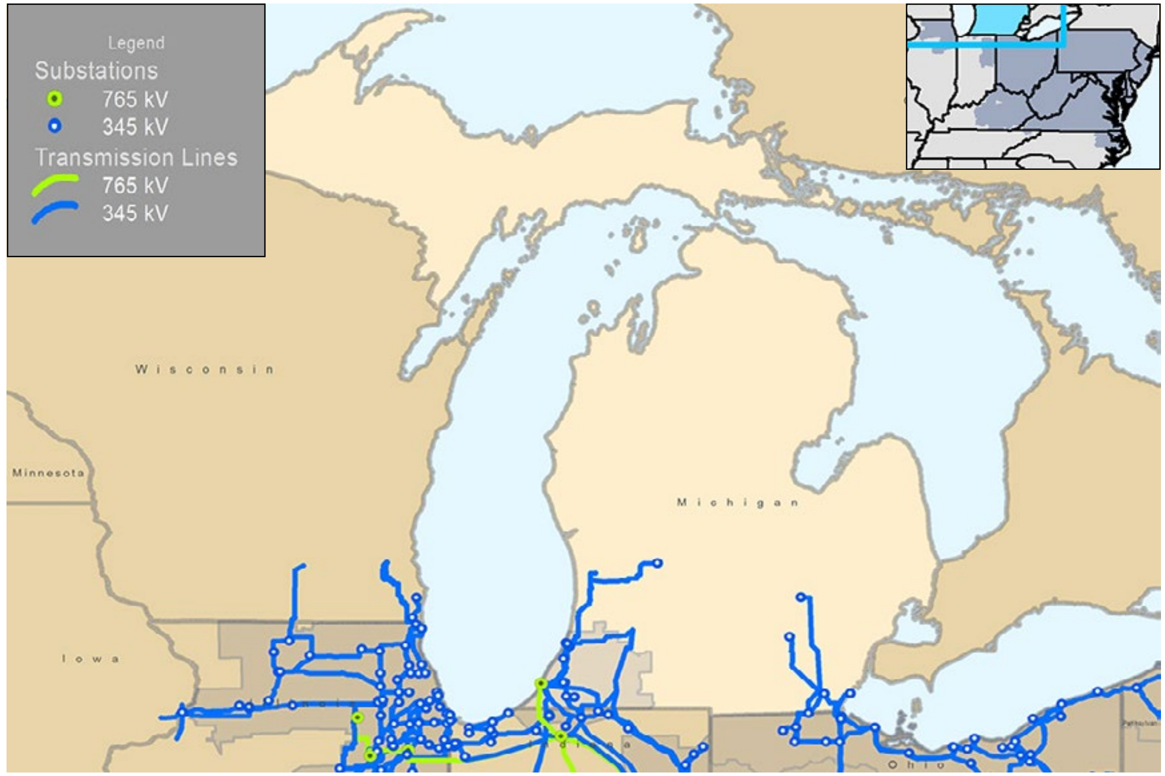
6.6.1 — RTEP Context

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 6.25**. 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 6.25: PJM Service Area in Southwestern Michigan

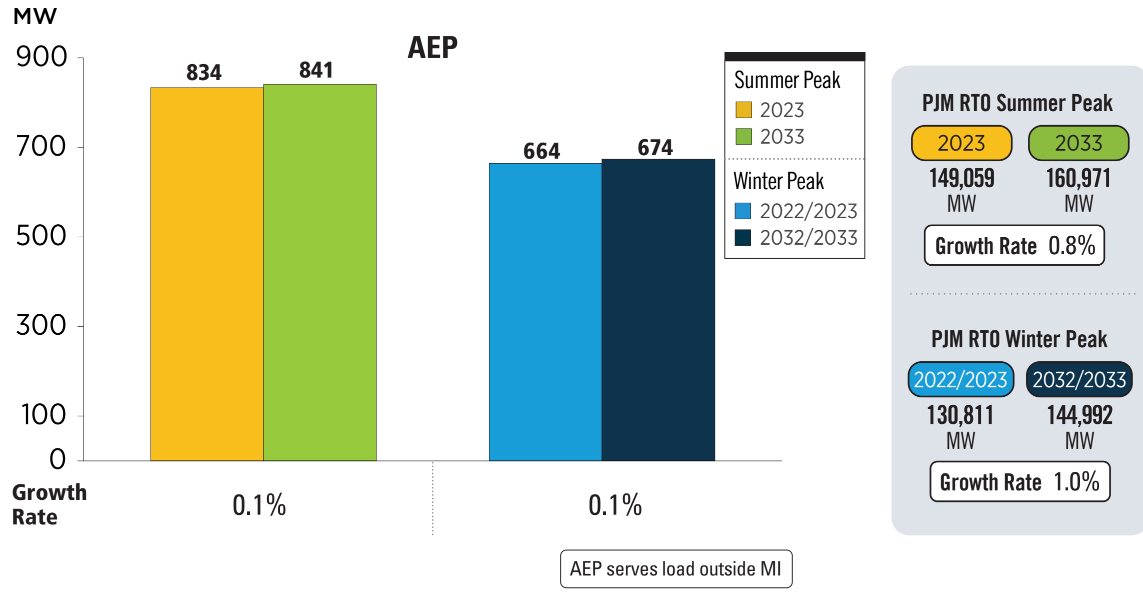


6.6.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.26** summarizes the expected loads within southwestern Michigan and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.26: Southwestern Michigan – 2023 Load Forecast Report



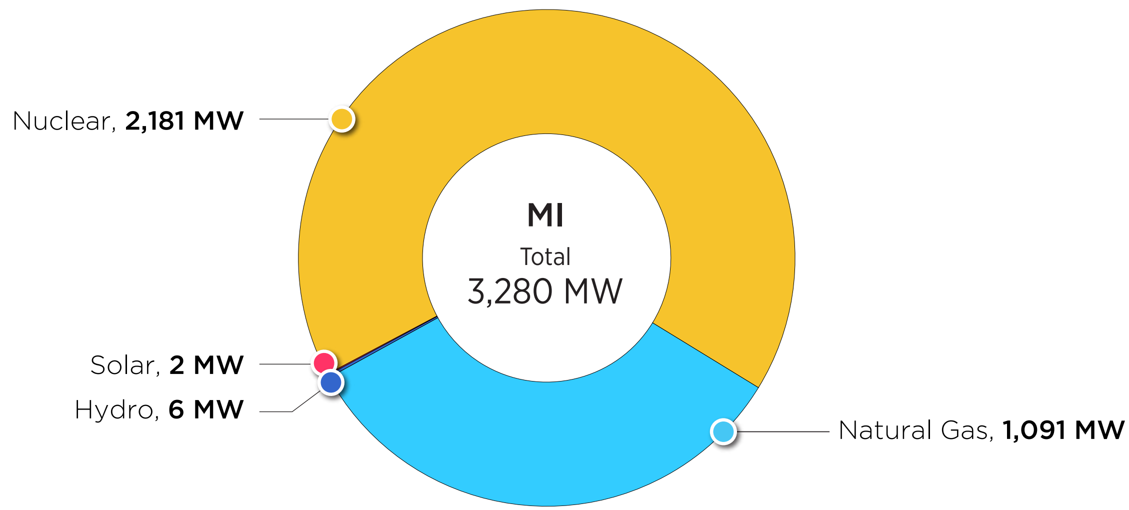
The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.6.3 — Existing Generation

Existing generation in southwestern Michigan as of Dec. 31, 2023, is shown by fuel type in **Figure 6.27**.

Read More
Changing Capacity Mix and Deliverability

Figure 6.27: Southwestern Michigan – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)



6.6.4 — Interconnection Requests

In southwestern Michigan, as of Dec. 31, 2023, 30 projects were actively under study or under construction as shown in the summaries presented in **Table 6.30, Table 6.31, Figure 6.28, Figure 6.29** and **Figure 6.30**.

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.

Read More
Interconnection Requests

Table 6.30: Southwestern Michigan – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Michigan Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	0	0.00%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	0	0.00%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	1,629	87.57%	98,471	55.15%
Storage	231	12.43%	53,644	30.04%
Wind	0	0.00%	20,798	11.65%
Grand Total	**1,860**	**100.00%**	**178,566**	**100.00%**

Table 6.31: Southwestern Michigan – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		In Queue				Complete					
		Active		Under Construction		In Service		Withdrawn		Grand Total	
		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	4	2,140.0	2	1,265.0	6	3,405.0
	Nuclear	0	0.0	0	0.0	3	205.0	0	0.0	3	205.0
	Other	0	0.0	0	0.0	0	0.0	1	0.0	1	0.0
	Storage	4	231.3	0	0.0	0	0.0	1	75.0	5	306.3
Renewable	Methane	0	0.0	0	0.0	3	10.4	0	0.0	3	10.4
	Solar	24	1,629.1	2	124.9	1	2.3	5	237.8	32	1,994.1
	Wind	0	0.0	0	0.0	0	0.0	1	26.0	1	26.0
	Grand Total	**28**	**1,860.4**	**2**	**124.9**	**11**	**2,357.7**	**10**	**1,603.8**	**51**	**5,946.8**

Figure 6.28: Southwestern Michigan – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

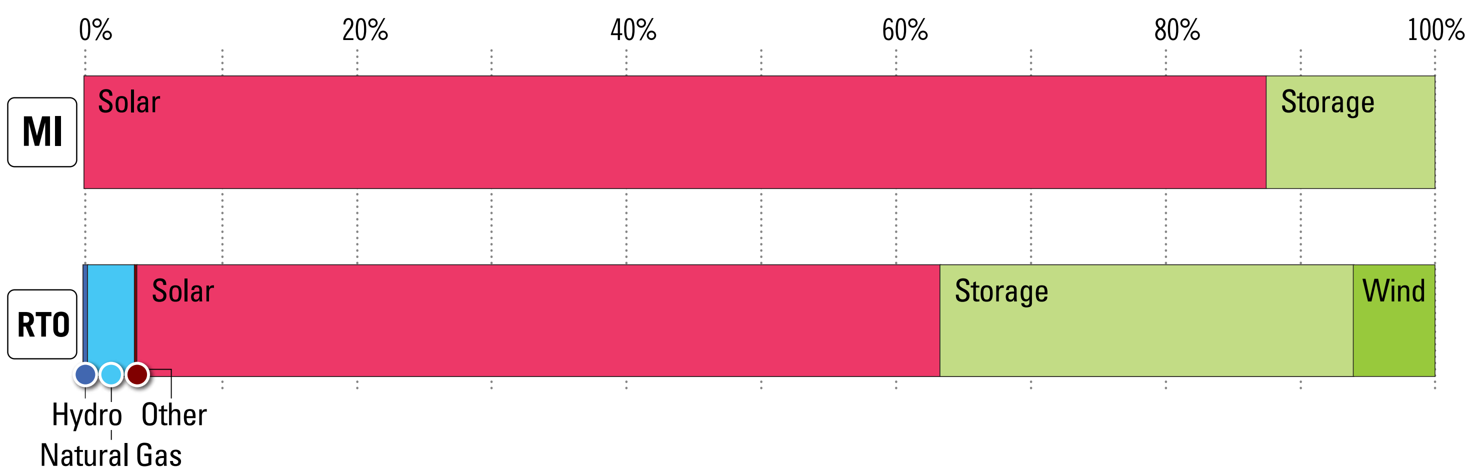
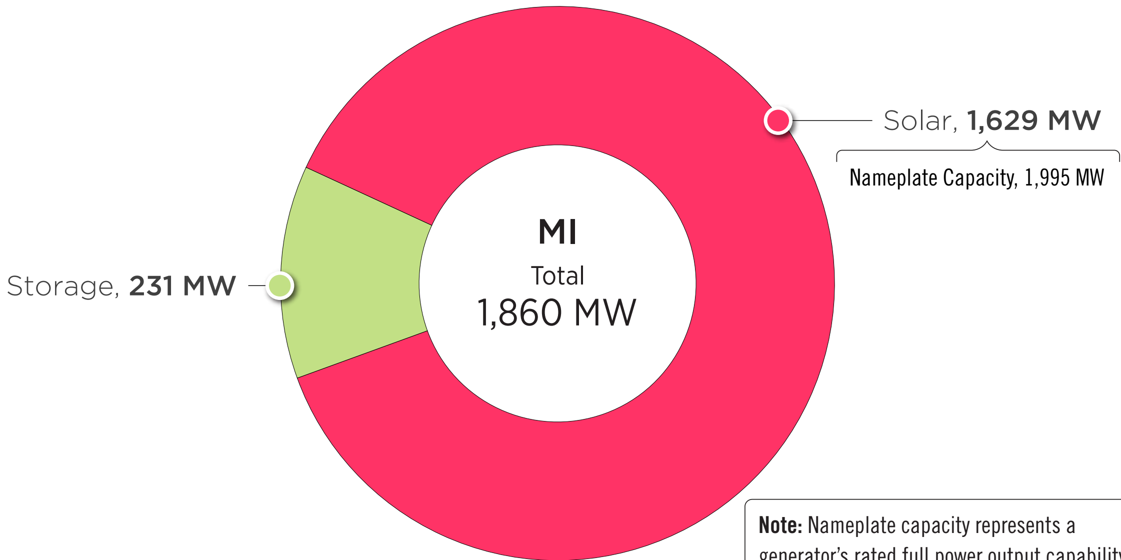
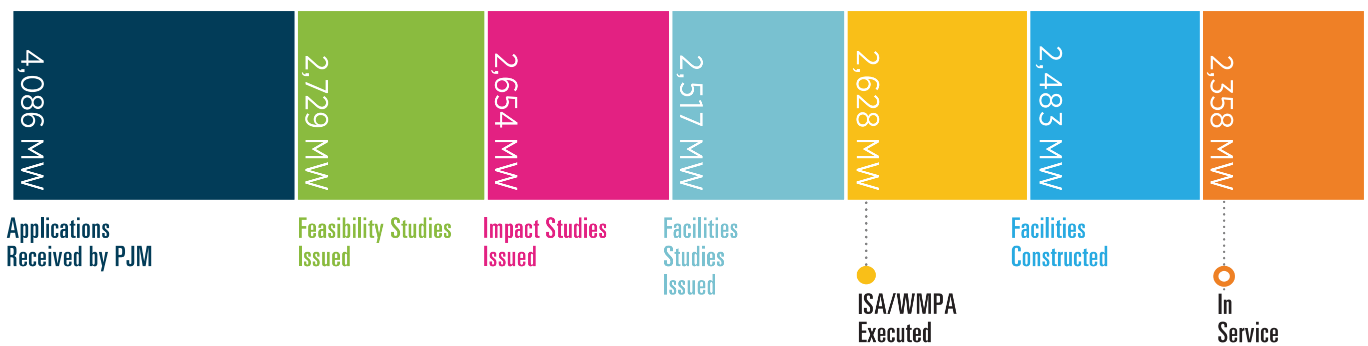


Figure 6.29: Southwestern Michigan Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.30: Southwestern Michigan Progression of Interconnection Requests (Dec. 31, 2023)



Percentage of planned capacity and projects that have reached commercial operation

57.7%	Requested capacity megawatts
47.8%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	1	Interconnection Service Agreements	145 MW	285 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.6.5 — Supplemental Projects

Supplemental projects in southwestern Michigan are summarized in **Map 6.26** and **Table 6.32**.

Read More
Supplemental Projects

Map 6.26: Southwestern Michigan Supplemental Projects (Dec. 31, 2023)

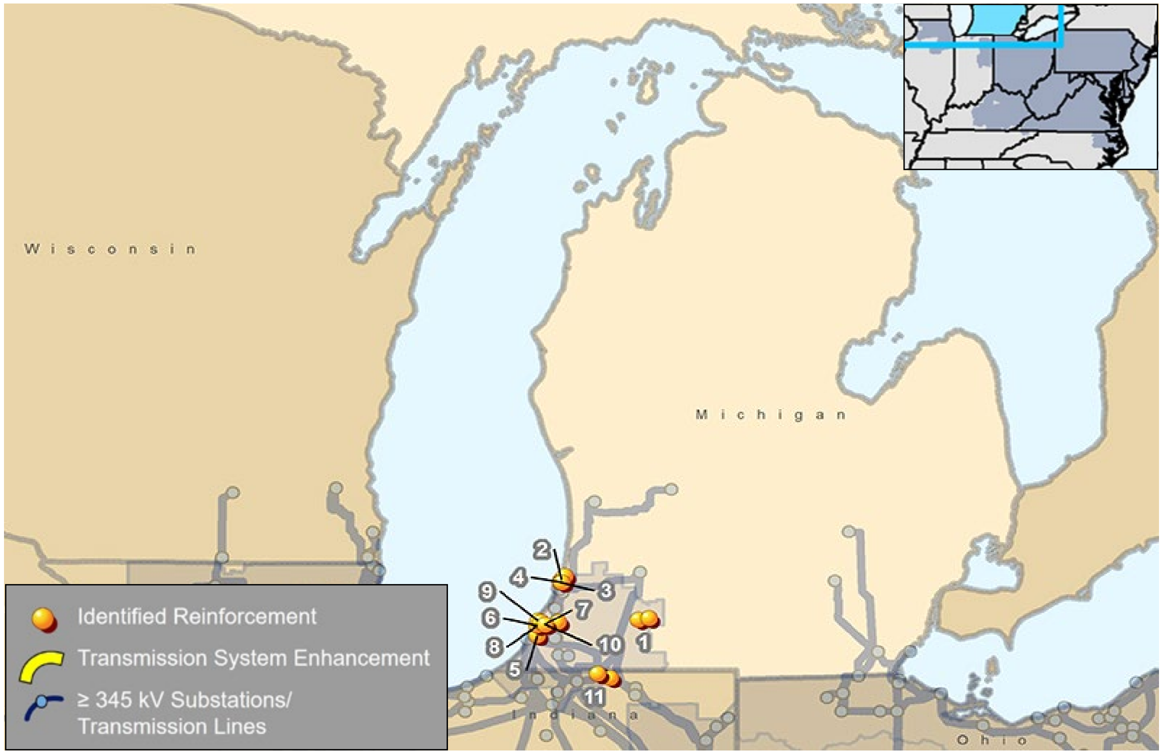


Table 6.32: Southwestern Michigan Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2821		Rebuild the 4.72 Kalamazoo-Vicksburg No. 1 69 kV line with 336 30/7 ACSR Oriole and eliminate line crossings with Kalamazoo-Vicksburg No. 2 69 kV.	11/2/2026	$8.45	AEP	9/16/2022
2	S2914	.1	Install a new 69 kV phase over phase switch on the South Haven-Phoenix Road tap 69 kV section of the Bangor-South Haven 69 kV circuit at Deerlick Creek switch 69 kV. Fiber Cable extension for the new switch.	5/26/2023	$1.88	AEP	2/17/2023
3		.2	Install ~0.06 mile of 69 kV single circuit with the conductor size 795 ACSR 26/7 Drake at Deerlick Creek switch-12th Avenue 69 kV (cost includes right-of-way).				
4		.3	Install metering and telecom upgrades at 12th Avenue station.				

Table 6.32: Southwestern Michigan Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	S2942	.1	Rebuild ~3.47 miles of the Derby-Main Street 138 kV circuit up to structure 125 at Main Street-Hickory Creek 138 kV line asset. Of that ~3.47 miles, the Main Street-Napier-Hickory Creek 34.5 kV circuit is double circuited with Derby-Main Street 138 kV circuit for ~2.84 miles, which will also be rebuilt and then energized to 69 kV. Both lines will utilize the 795 ACSR 26/7 Drake conductor.	5/7/2027	$19.30	AEP	4/21/2023
6		.2	Energize at 69 kV at Main Street-Hickory Creek 34.5 kV (via Pearl Street).				
7		.3	Energize circuit breakers J, K, and L to 69 kV at Main Street.				
8		.4	Retire 34.5 kV circuit breaker BG and remaining 34.5 kV equipment at Hickory Creek. Energize circuit breakers AQ, BE, and BH to 69 kV. Breaker BH will be used as a bus tie breaker.				
9		.5	Energize to 69 kV at Pearl Street, Langley and Napier.				
10		.6	Retire the 34.5 kV Ausco Radial.				
11	S2986	.1	Install a new 138 kV breaker string with 3 3000A 40 kA circuit breakers to accommodate two new feeds to the NIPSCO station at East Elkhart 138 kV. Relocate the 345/138 kV transformer No. 2 feed to the new string. Install metering on both exits out of East Elkhart toward NIPSCO'S Menges Ditch station.	12/1/2025	$0.00		5/19/2023
		.2	Install the first span and structure outside of East Elkhart, one exiting to the north and the other to the south, utilizing 2 bundle 795 ACSR 26/7 DRAKE conductor creating a new AEP-NIPSCO interconnection and PJM-MISO seam at East Elkhart-Menges Ditch 138 kV No. 1 and No. 2.				

6.7: New Jersey RTEP Summary

6.7.1 — RTEP Context

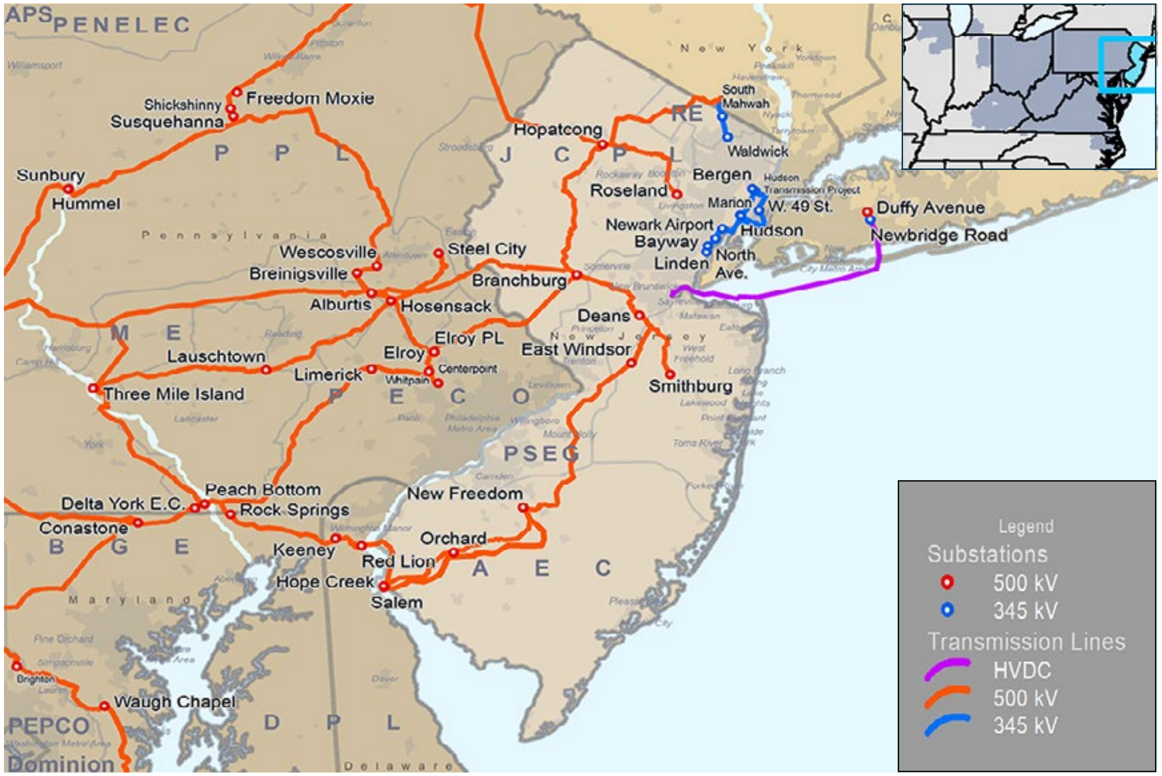
PJM, a FERC-approved RTO, operates and plans the bulk electric system in New Jersey, including facilities owned and operated by Atlantic City Electric (AE), Jersey Central Power & Light (JCP&L), Linden VFT (VFT), Neptune Regional Transmission System (Neptune RTS), Public Service Electric & Gas Company (PSE&G) 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 new solar incentive program that seeks up to 3,750 MW of new solar generation by 2026.

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, the state's offshore wind target was increased to 7,500 MW by 2035 through Gov. Phil Murphy's Executive Order No. 92. In 2022, that target was again increased to 11,000 MW by 2040 through Gov. Murphy's Executive Order No. 307. As of 2023, New Jersey has awarded offshore wind renewable energy credits (ORECs) to 3,757.6 MW of offshore wind projects.

Map 6.27: PJM Service Area in New Jersey



As discussed in **Section 1.3.5**, 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. In December 2023, the NJBPU approved a second SAA for PJM to solicit transmission solutions that would support the remaining 3,500 MW of its 11,000 MW target.

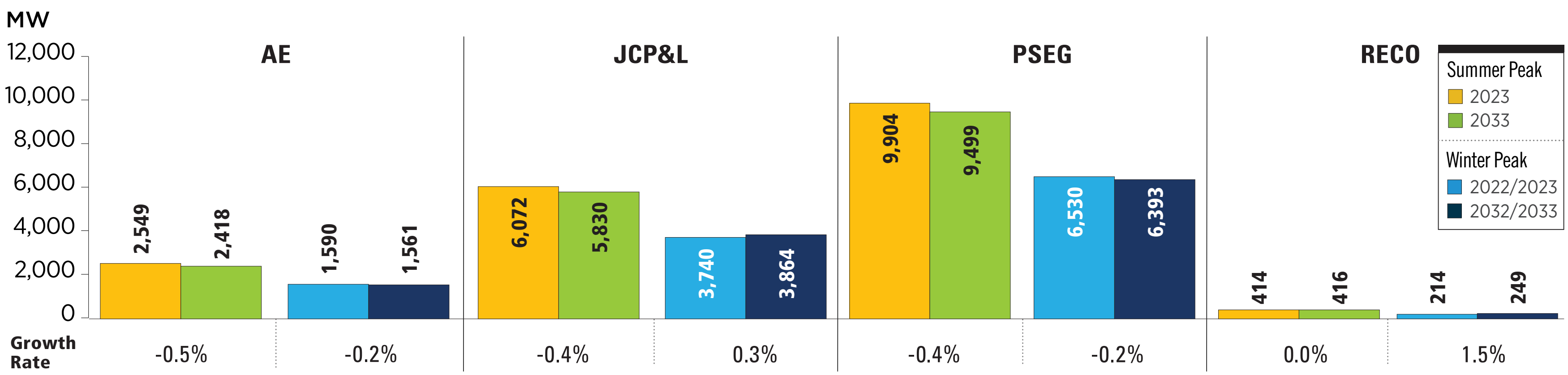
New Jersey is also pursuing decarbonization through additional efforts. In 2023, the New Jersey Department of Environmental Protection implemented CO_2 regulations for existing and proposed fossil fuel resources. New Jersey is also pursuing an energy storage target of 2,000 MW by 2030.

6.7.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.31** summarizes the expected loads within the state of New Jersey and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.31: New Jersey – 2023 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2023	2033	2022/2023	2032/2033
149,059 MW	160,971 MW	130,811 MW	144,992 MW
Growth Rate 0.8%		Growth Rate 1.0%	

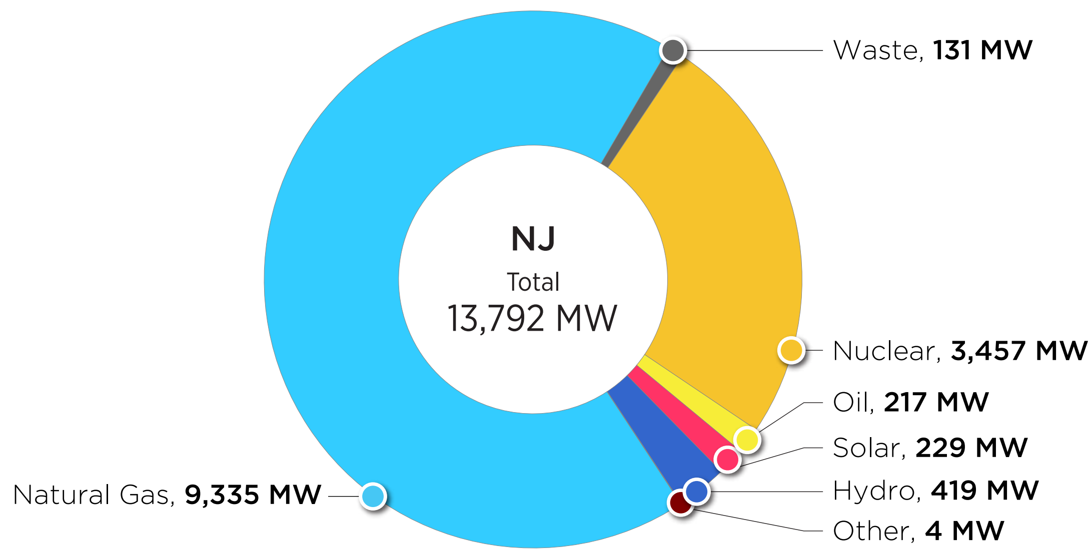
The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.7.3 — Existing Generation

Existing generation in New Jersey as of Dec. 31, 2023, is shown by fuel type in **Figure 6.32**.

Read More
Changing Capacity Mix and Deliverability

Figure 6.32: New Jersey – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)



6.7.4 — Interconnection Requests

In New Jersey, as of Dec. 31, 2023, 166 projects were actively under study or under construction 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.

Read More
Interconnection Requests

Table 6.33: New Jersey – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	New Jersey Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	30	0.18%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	98	0.60%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	773	4.71%	98,471	55.15%
Storage	3,801	23.18%	53,644	30.04%
Wind	11,701	71.33%	20,798	11.65%
Grand Total	16,403	100.00%	178,566	100.00%

Table 6.34: New Jersey – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		In Queue						Complete					
		Active		Suspended		Under Construction		In Service		Withdrawn		Grand Total	
		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	98.0	0	0.0	3	276.1	79	7,830.0	185	52,617.6	270	60,821.7
	Nuclear	0	0.0	0	0.0	0	0.0	6	381.0	0	0.0	6	381.0
	Oil	0	0.0	0	0.0	0	0.0	2	35.0	8	945.0	10	980.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	6	45.5	6	45.5
	Storage	41	3,801.3	2	12.0	6	0.0	10	4.0	76	1,441.3	135	5,258.6
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	3	17.3	3	17.3
	Hydro	1	30.0	0	0.0	0	0.0	2	20.5	2	1,001.1	5	1,051.6
	Methane	0	0.0	0	0.0	0	0.0	12	30.9	9	40.6	21	71.5
	Solar	70	772.6	3	75.6	18	187.7	127	275.3	530	2,019.6	748	3,330.7
	Wind	19	11,700.7	0	0.0	5	616.4	1	0.0	35	4,130.6	60	16,447.6
	Grand Total	**134**	**16,402.5**	**5**	**87.6**	**32**	**1,080.1**	**239**	**8,576.7**	**855**	**62,273.6**	**1,265**	**88,420.6**

Figure 6.33: New Jersey – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

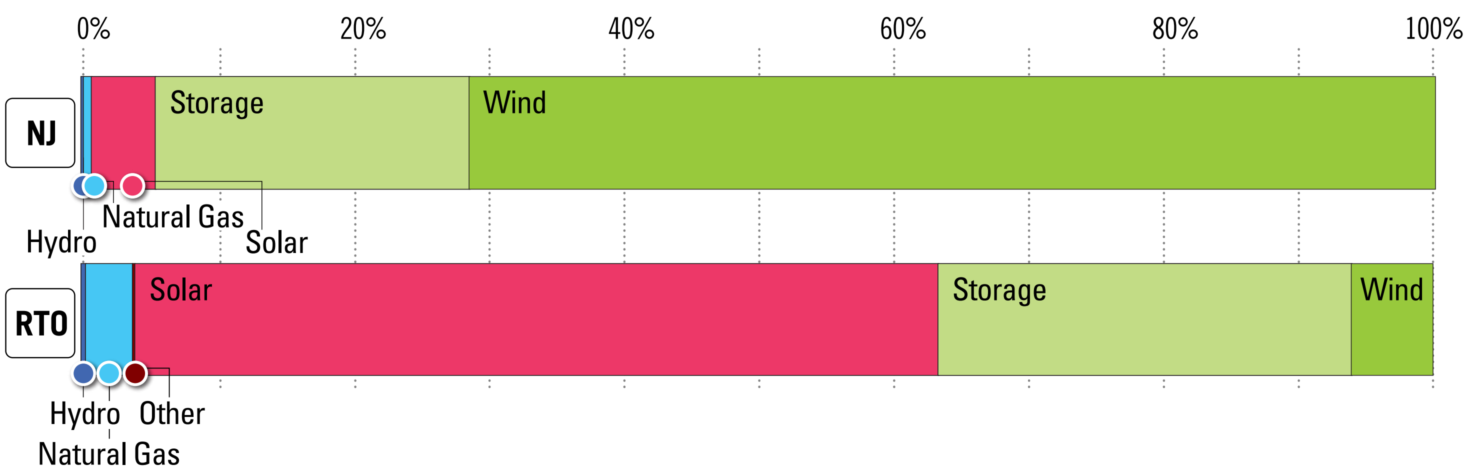
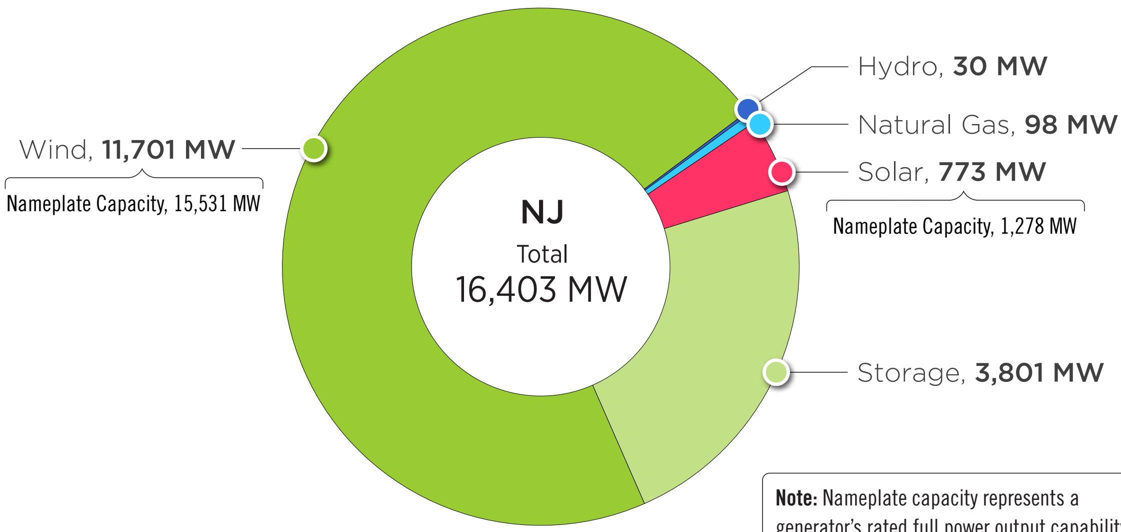


Figure 6.34: New Jersey Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.35: New Jersey Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

12.0%	Requested capacity megawatts
22.0%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	28	Interconnection Service Agreements	3,372 MW	3,817 MW
	157	Wholesale Market Participation Agreements	386 MW	1,102 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.7.5 — Generation Deactivation

Formal generator deactivation requests received by PJM in New Jersey between Jan. 1, 2023, and Dec. 31, 2023, are summarized in **Map 6.28** and **Table 6.35**.

Read More
Generation Deactivation

Map 6.28: New Jersey Generation Deativations (Dec. 31, 2023)

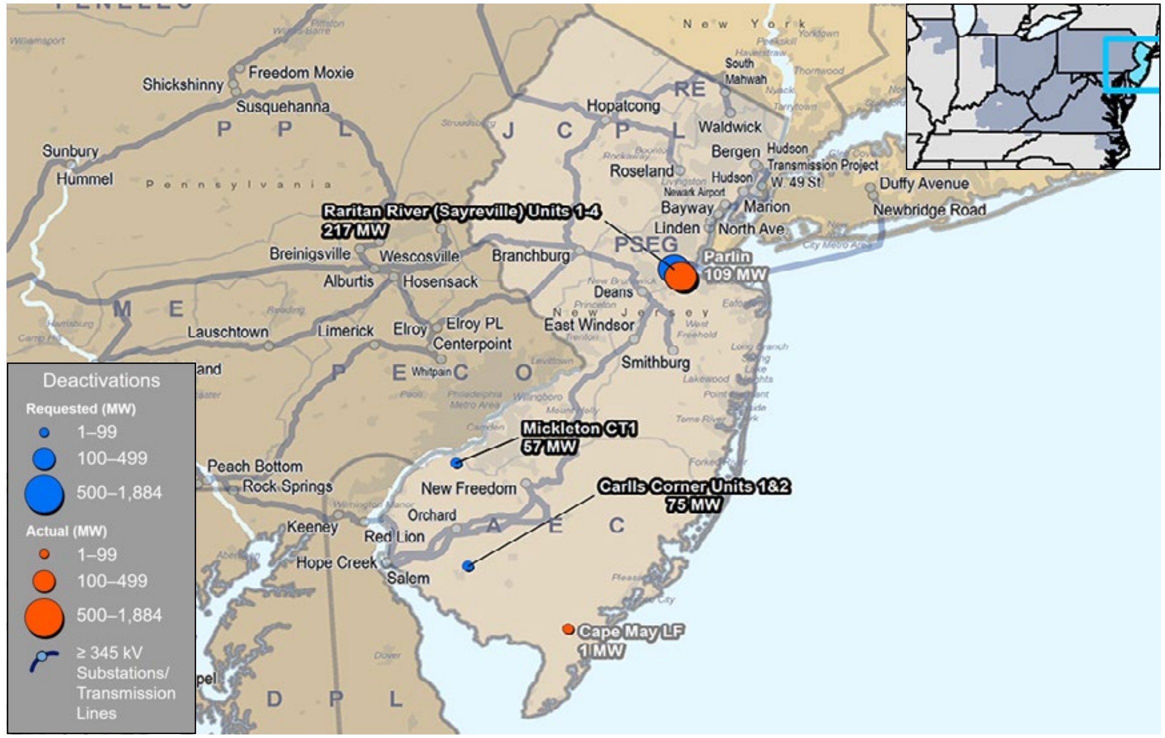


Table 6.35: New Jersey Generation Deactivations (Dec. 31, 2023)

<table>
<tr><th>Unit</th><th>TO Zone</th><th>Fuel Type</th><th>Request Received to Deactivate</th><th>Actual or Projected Deactivation Date</th><th>Age (Years)</th><th>Capacity (MW)</th></tr>
<tr><td>Sayreville C-4</td><td rowspan="5">JCP&L</td><td rowspan="5">Natural Gas</td><td rowspan="4">12/29/23</td><td rowspan="4">6/1/2024</td><td rowspan="4">51</td><td>49</td></tr>
<tr><td>Sayreville C-3</td><td>55</td></tr>
<tr><td>Sayreville C-2</td><td>57</td></tr>
<tr><td>Sayreville C-1</td><td>57</td></tr>
<tr><td>Parlin Nug</td><td>6/30/23</td><td>10/31/2023</td><td>32</td><td>109</td></tr>
</table>

Table 6.35: New Jersey Generation Deactivations (Dec. 31, 2023) (Cont.)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Cape May County LF	AE	Methane	4/5/23	3/1/2023	10	1
Mickleton 1 CT	AE	Natural Gas	1/30/23	6/1/2024	49	57
Carlls Corner CT 2	AE	Natural Gas	1/30/23	6/1/2024	50	38
Carlls Corner CT 1	AE	Natural Gas	1/30/23	6/1/2024	50	36

6.7.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in New Jersey are summarized in **Map 6.29** and **Table 6.36**.

Read More
Baseline Projects

Map 6.29: New Jersey Baseline Projects (Dec. 31, 2023)

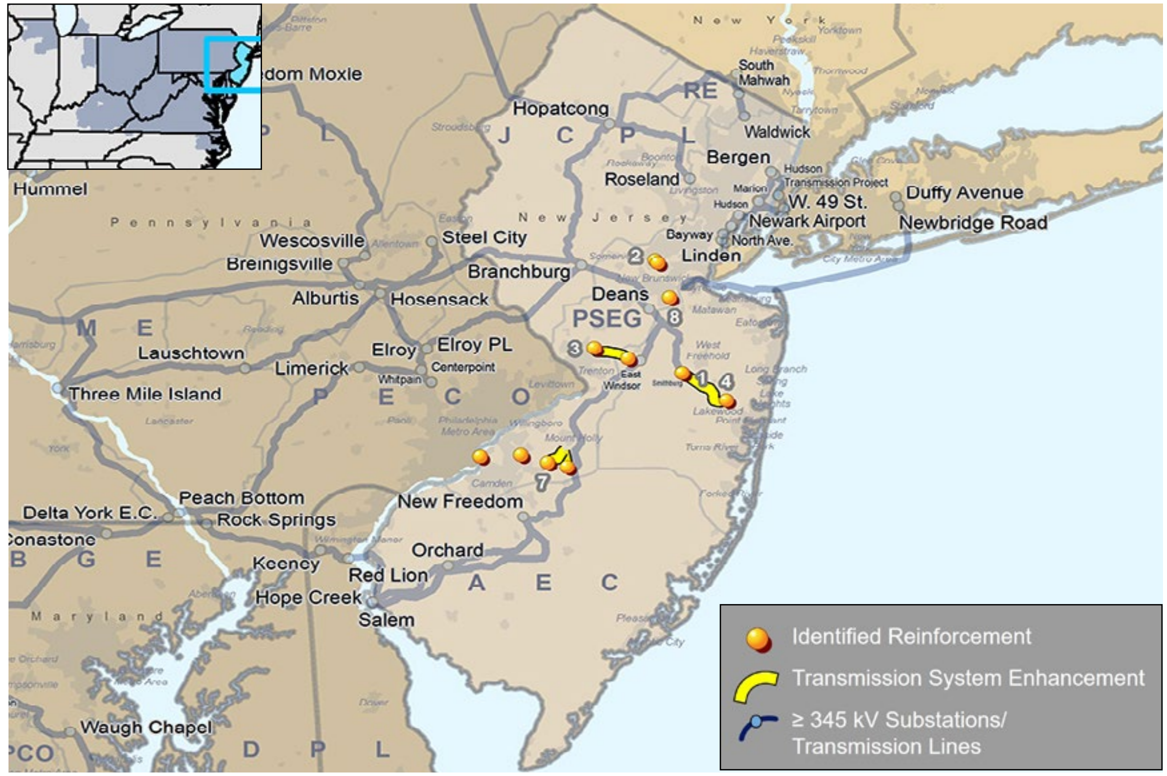


Table 6.36: New Jersey Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3737	.53	Remove the existing E83 line 115 kV (not in service) to accommodate the new 500 kV/230 kV lines (~7.7 miles).	12/31/2027	$19.34	JCP&L	5/9/2023
		.54	Remove the existing H2008 Larrabee-Smithburg No. 2 230 kV to accommodate the new 500 kV/230 kV lines.				
2		.55	Replace the 2000A circuit switcher at Middlesex switch point for the Lake Nelson I1023 230 kV exit at Middlesex substation 230 kV.	6/1/2029			
3		.59	Upgrade terminal equipment at Windsor 230 kV Windsor to Clarksville subproject.				
4		.60	Perform a pre-build infrastructure evaluation study in alignment with the NJBPU Solicitation Guidance Document requirements.			MAOD	

Table 6.36: New Jersey Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	B3755		Convert Locust Street 69 kV from a straight bus to a ring bus.	6/1/2027	$30.00	PSEG	10/13/2022
6	B3756		Convert Maple Shade 69 kV from a straight bus to a ring bus.	6/1/2027	$33.90	PSEG	10/13/2022
7	B3757		Convert existing Medford 69 kV straight bus to seven-breaker ring bus; construct a new 230/69 kV transformer at Cox's Corner and a new line from Cox's Corner to Medford.	6/1/2027	$101.50	PSEG	10/13/2022
8	B3758		Construct a new 69 kV line from 14th Street to Harts Lane.	6/1/2027	$34.40	PSEG	10/13/2022

6.7.7 — Network Projects

Network projects in New Jersey received by PJM in 2023 are summarized in **Map 6.30** and **Table 6.37**.

Read More
Network Projects

Map 6.30: New Jersey Network Projects (Dec. 31, 2023)

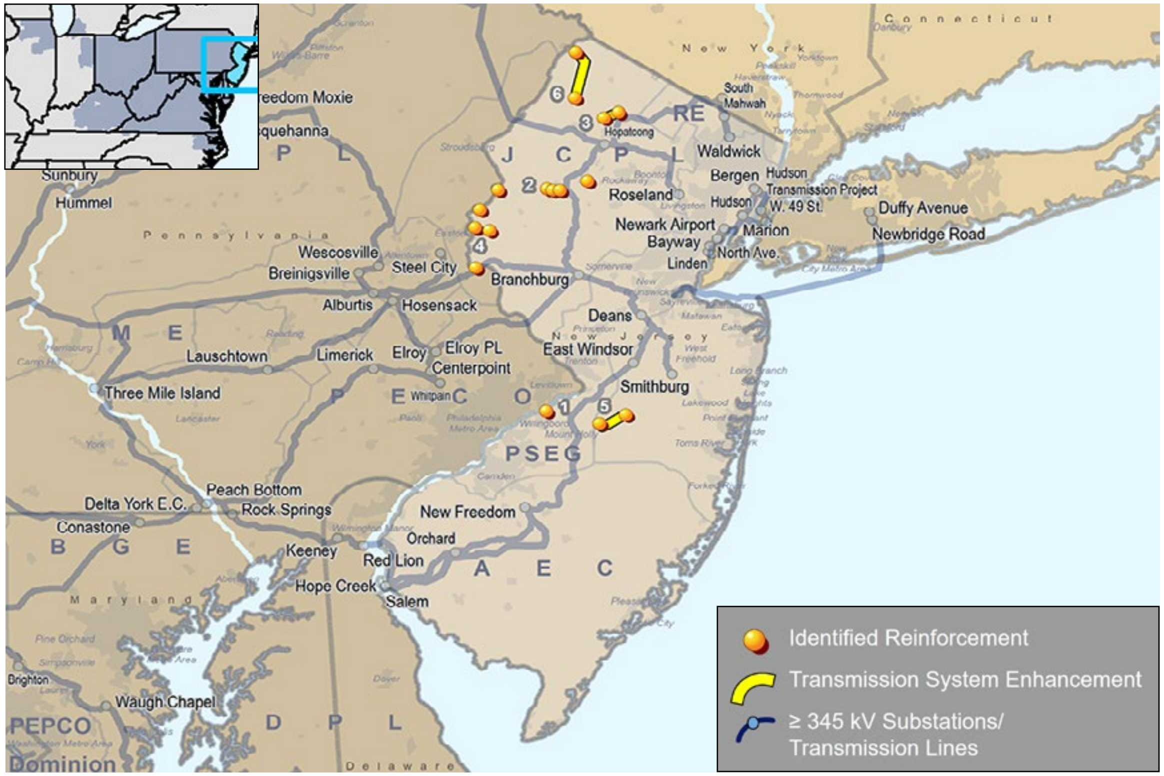


Table 6.37: New Jersey Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N7267	Extend the Burlington 26 kV P-120 circuit to the point of interconnection and install revenue-grade metering.	AG1-130	12/28/2022	$0.34	PSEG	10/3/2023
2	N8151.1	Tap the Hackettstown to Pohatcong 34.5 kV line to accommodate the AF1-328 interconnect project. This tap will take place at a location that is ~1.25 miles from the Pohatcong substation and 1.50 miles from the Hackettstown substation.	AF1-328	8/31/2021	$0.44	JCP&L	
	N8151.2	Revise relay settings for tap at Pohatcong 34.5 kV.			$0.04		
	N8151.3	Adjust relay settings at AF1-328 substation.			$0.07		

Table 6.37: New Jersey Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	N8160.1	Tap the Y701 Cozy Lake (Franklin) 34.5 kV line to interconnect to the new AF1-325 customer substation.	AF1-325	1/1/2026	$1.50	JCP&L	10/3/2023
	N8160.2	Revise relay settings at Franklin 34.5 kV.			$0.05		
4	N8166.1	Build a new 115 kV line to provide for the AF1-320 interconnection at the new Merrill Creek 115 kV substation.	AF1-320	12/1/2022	$6.36		
	N8166.2	Modify drawings, relay settings and nameplates for line name change at Flanders 115 kV.			$0.13		
	N8166.3	Modify drawings, relay settings and nameplates for line name change at Drakestown 115 kV.			$0.13		
	N8166.4	Replace one 115 kV wave trap, line tuner and coax for Gilbert line exit at Morris Park 115 kV.			$0.82		
	N8166.5	Change relay settings at Pequest River 115 kV.			$0.21		
	N8166.6	Review drawings, nameplates and relay settings Gilbert 115 kV.			$0.15		
	N8166.7	Install new three-breaker ring bus at Merrill Creek substation 115 kV.			$13.74		
	N8166.8	Install fiber from Merrill Creek to backbone for communication. Design, install and test/commission Multiprotocol Label Switching (MPLS) equipment for SCADA transport at Merrill Creek 115 kV.			$1.39		
	N8166.9	Design, install and test/commission MPLS equipment for SCADA transport at Merrill Creek 115 kV for SCADA/fiber communication.			$0.39		
5	N8198.1	Install three 34.5 kV load-break air switches with SCADA control on the Cookstown-New Lisbon (W75) 34.5 kV line ~0.3 miles from the Fort Dix W75 tap and 3.1 miles from the Hanover Solar tap (at structures 116 & 117).	AF2-254	12/31/2020	$0.36		
	N8198.2	Review Cookstown line relay settings as required for AF2-254 tap at New Lisbon 34.5 kV.			$0.04		
	N8198.3	Review New Lisbon line relay settings as required for AF2-254 tap at Cookstown 34.5 kV.			$0.04		
6	N8210.1	Tap the Branchville to Holiday Lakes 34.5 kV line to accommodate the customer facility. This tap will take place at a location that is ~1.50 miles from the Holiday Lakes substation and 10 miles from the Branchville substation.	AF1-019	3/1/2021	$1.42		
	N8210.2	Revise relay settings at Branchville substation 34.5 kV.			$0.05		

6.7.8 — Supplemental Projects

Supplemental projects received by PJM in 2023 in New Jersey are summarized in **Map 6.31** and **Table 6.38**.

Read More
Supplemental Projects

Map 6.31: New Jersey Supplemental Projects (Dec. 31, 2023)

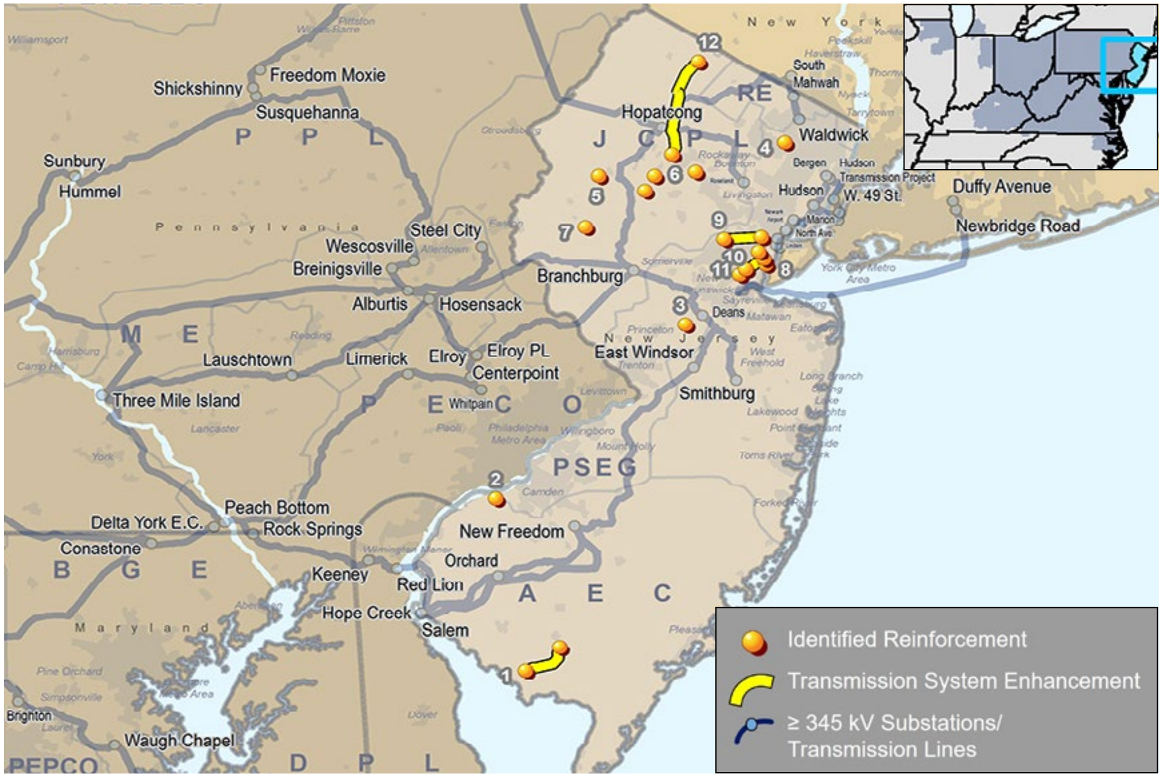


Table 6.38: New Jersey Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2823		Rebuild a 9.8-mile section of 69 kV line 0762 between Newport and South Millville. The conductor will be upgraded to 795 ACSR and the existing shield wire will be replaced with new OPGW.	12/31/2025	$40.00	AE	8/18/2022
2	S2889		Install a new 69 kV terminal position at Paulsboro substation and construct new 2.5-mile 69 kV line to service the customer.	6/30/2025	$3.20	AE	12/14/2022
3	S2904		Expand the existing Ridge Road substation to a full Class H substation. Install three 69 kV breakers at Ridge Road. Convert Ridge Road to Class H station; install two 69/13 kV transformers and sheltered aisled switchgear. Offload the Sand Hills station to the new Ridge Road Class H substation.	5/31/2027	$22.20	PSEG	3/16/2023
4	S2951		Construct new 69-13 kV substation with two transformers in acquired property in Prospect Park. Cut and loop Hinchmans-North Paterson and Hawthorne-Customer Sub 69 kV lines into the new 69 kV bus.	12/31/2027	$63.00	PSEG	4/20/2023

Table 6.38: New Jersey Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	S2952		Replace relaying, circuit breaker, wave trap and substation conductor at Pohatcong Mountain and West Wharton substations.	12/22/2023	$2.11	JCP&L	5/9/2023
6	S2953		Replace substation conductor and current transformer at Greystone and West Wharton substations.	5/8/2023	$2.36	JCP&L	5/9/2023
7	S2954		Replace substation conductor at Chester and Glen Gardner substations.	5/8/2023	$1.86	JCP&L	5/9/2023
9	S2955	.1	Install a 230 kV switching station with one 230/69 kV transformer and Cut and loop the Metuchen-Sewaren 230 kV line into the new 230 kV bus.	12/31/2027	$271.00	PSEG	5/9/2023
9	S2955	.2	Construct new 69-13 kV station (Rahway) on existing property. Install two 69-13 kV transformers and cut and loop the Front Street/Roselle line into the new substation.	12/31/2027	$271.00	PSEG	5/9/2023
10	S2955	.3	Build a new 69 kV line from Blair Road to Rahway.	12/31/2027	$271.00	PSEG	5/9/2023
11	S2956		Construct second half (230/13 kV) of Lafayette Road substation. Tap the 230 kV lines and bring them into the new substation. Install two new 230-13 kV transformers and associated equipment. Expand control house.	5/1/2027	$27.00	PSEG	5/9/2023
12	S2957		Replace substation conductor at Vernon and West Wharton substations.	5/18/2023	$1.14	JCP&L	5/18/2023

6.7.9 — Merchant Transmission Project Requests

As of Dec. 31, 2023, PJM's queue contained two merchant transmission project requests with a terminal in New Jersey, as shown in **Map 6.32** and **Table 6.39**.

Read More
Merchant Transmission Projects

Map 6.32: New Jersey Merchant Transmission Project Requests (Dec. 31, 2023)

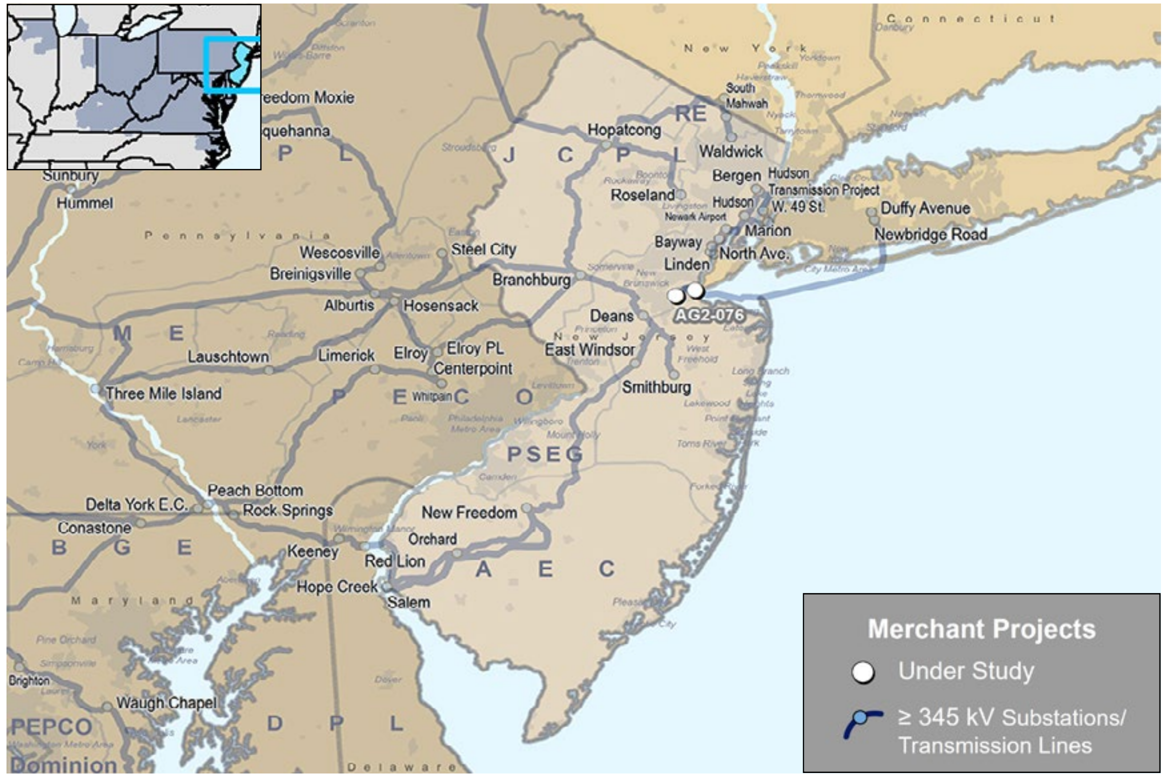


Table 6.39: New Jersey Merchant Transmission Project Requests (Dec. 31, 2023)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AG2-076	Raritan River 230 kV	JCP&L	Active	1/1/2024	0
AG2-146	Werner 230 kV-Ravenwood 345 kV			12/1/2026	

6.8: North Carolina RTEP Summary

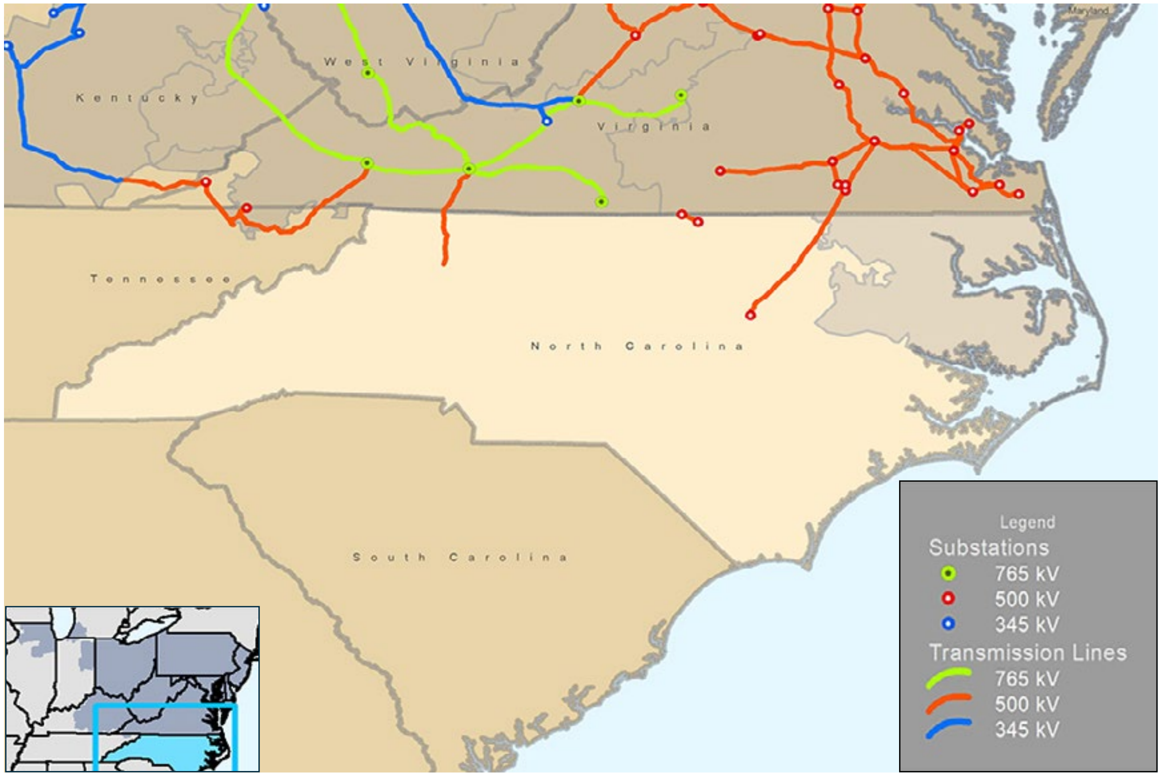
6.8.1 — RTEP Context

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 6.33**. 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 6.33: PJM Service Area in North Carolina

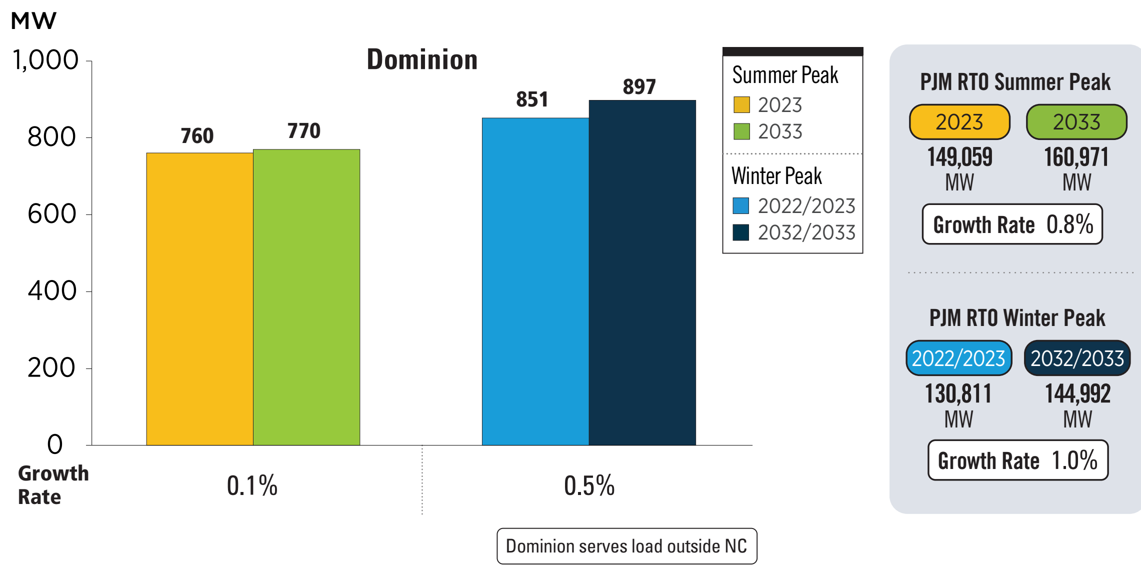


6.8.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.36** summarizes the expected loads within the state of North Carolina and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.36: North Carolina – 2023 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.8.3 — Existing Generation

Existing generation in North Carolina as of Dec. 31, 2023, is shown by fuel type in **Figure 6.37**.

Read More
Changing Capacity Mix and Deliverability

6.8.4 — Interconnection Requests

In North Carolina, as of Dec. 31, 2023, 70 projects were actively under study or under construction as shown in the summaries presented in **Table 6.40, Table 6.41, Figure 6.38, Figure 6.39** and **Figure 6.40**.

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.

Read More
Interconnection Requests

Figure 6.37: North Carolina – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)

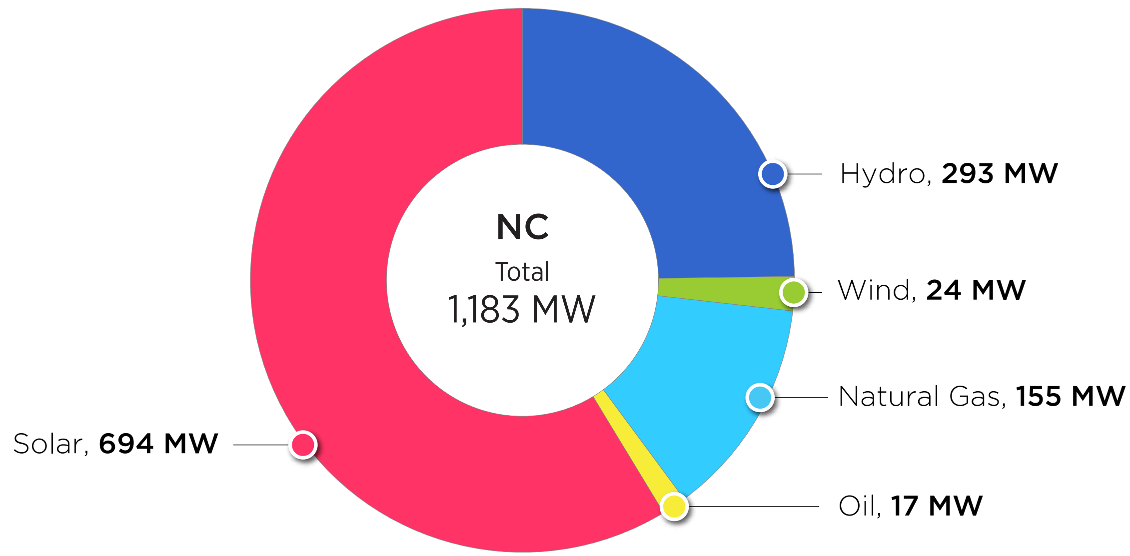


Table 6.40: North Carolina – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	North Carolina Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	0	0.00%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	0	0.00%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	1,953	85.15%	98,471	55.15%
Storage	284	12.40%	53,644	30.04%
Wind	56	2.46%	20,798	11.65%
Grand Total	**2,294**	**100.00%**	**178,566**	**100.00%**

Table 6.41: North Carolina – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		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	Storage	13	284.4	0	0.0	0	0.0	0	0.0	6	330.5	19	614.9
Renewable	Methane	0	0.0	0	0.0	0	0.0	0	0.0	1	12.0	1	12.0
	Solar	41	1,953.4	2	108.8	14	914.6	27	776.2	95	4,367.6	179	8,120.6
	Wind	1	56.4	0	0.0	1	24.5	1	27.0	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
	Grand Total	**55**	**2,294.2**	**2**	**108.8**	**15**	**939.1**	**29**	**853.2**	**112**	**4,985.4**	**213**	**9,180.6**

Figure 6.38: North Carolina – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

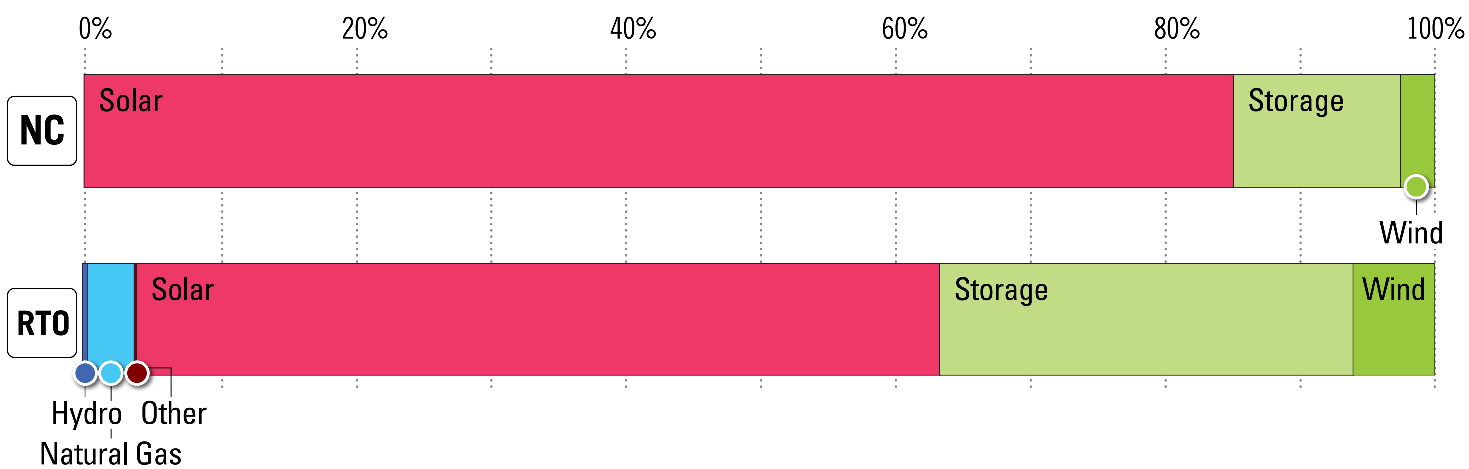
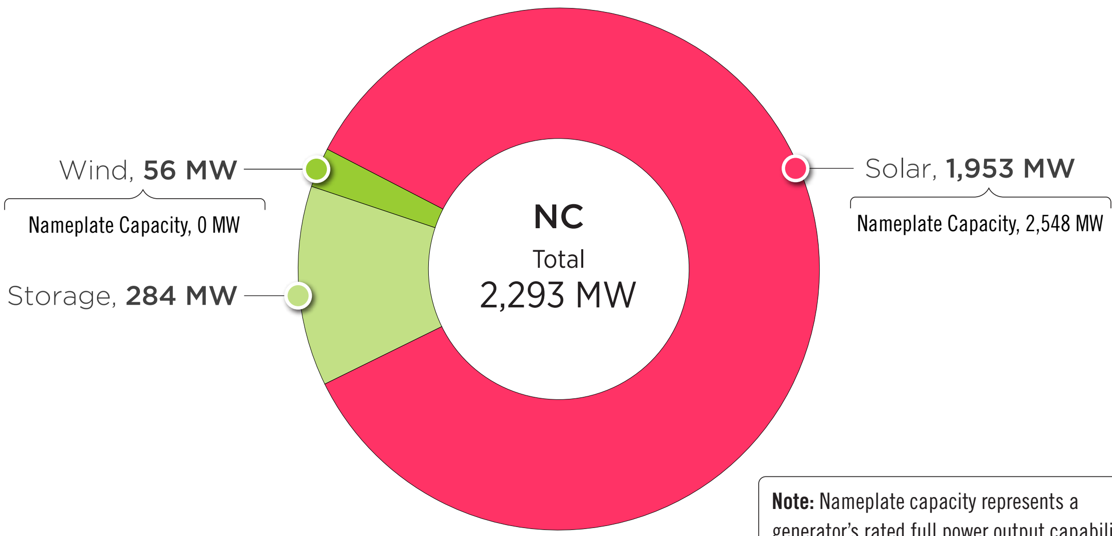


Figure 6.39: North Carolina Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.40: North Carolina Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

13.0%	Requested capacity megawatts
19.0%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	7	Interconnection Service Agreements	234.5 MW	744 MW
	5	Wholesale Market Participation Agreements	44.3 MW	65 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.8.5 — Network Projects

Network projects received by PJM in 2023 in North Carolina are summarized in **Map 6.34** and **Table 6.42**.

Read More
Network Projects

Map 6.34: North Carolina Network Projects (Dec. 31, 2023)

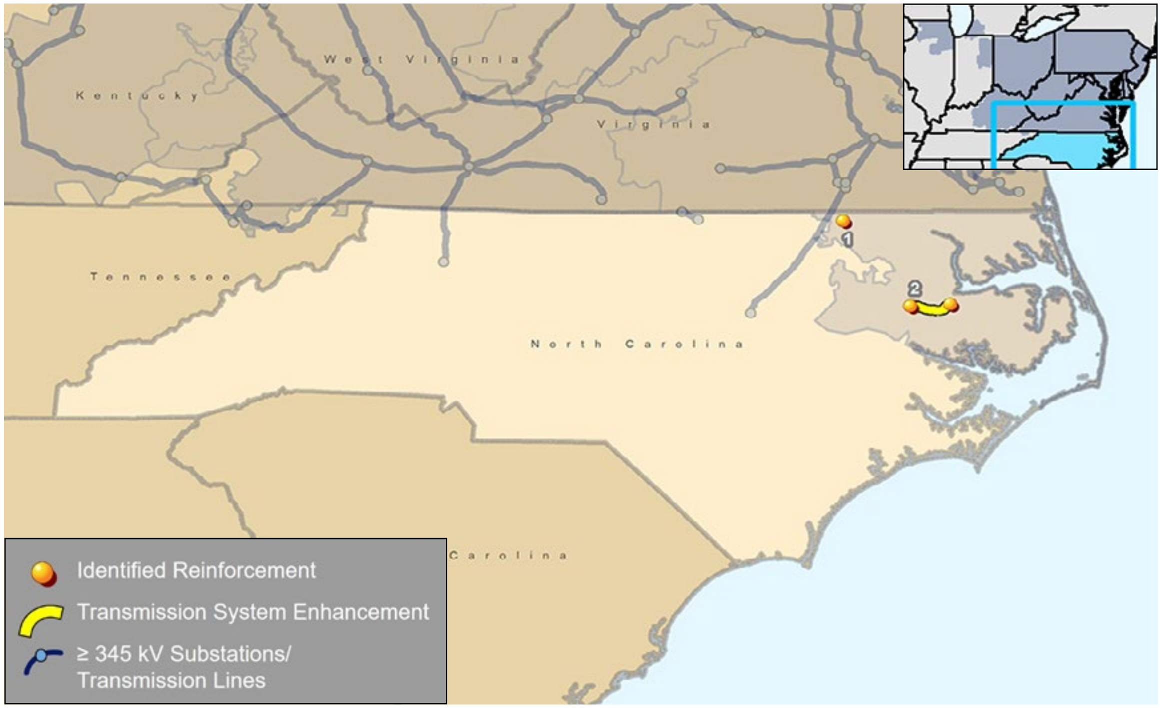


Table 6.42: North Carolina Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6220	Install a second back-to-back breaker between existing line positions No. 254 and No. 2141 at the Lakeview substation.	AC1-086	12/31/2017	$1.96	Dominion	10/3/2023
2	N8113	Reroute line No. 25 off of line No. 2034.	AD1-076	12/31/2022	$4.74		

6.8.6 — Supplemental Projects

Supplemental projects received by PJM in 2023 in North Carolina are summarized in **Map 6.35** and **Table 6.43**.

Read More
Supplemental Projects

Map 6.35: North Carolina Supplemental Projects (Dec. 31, 2023)

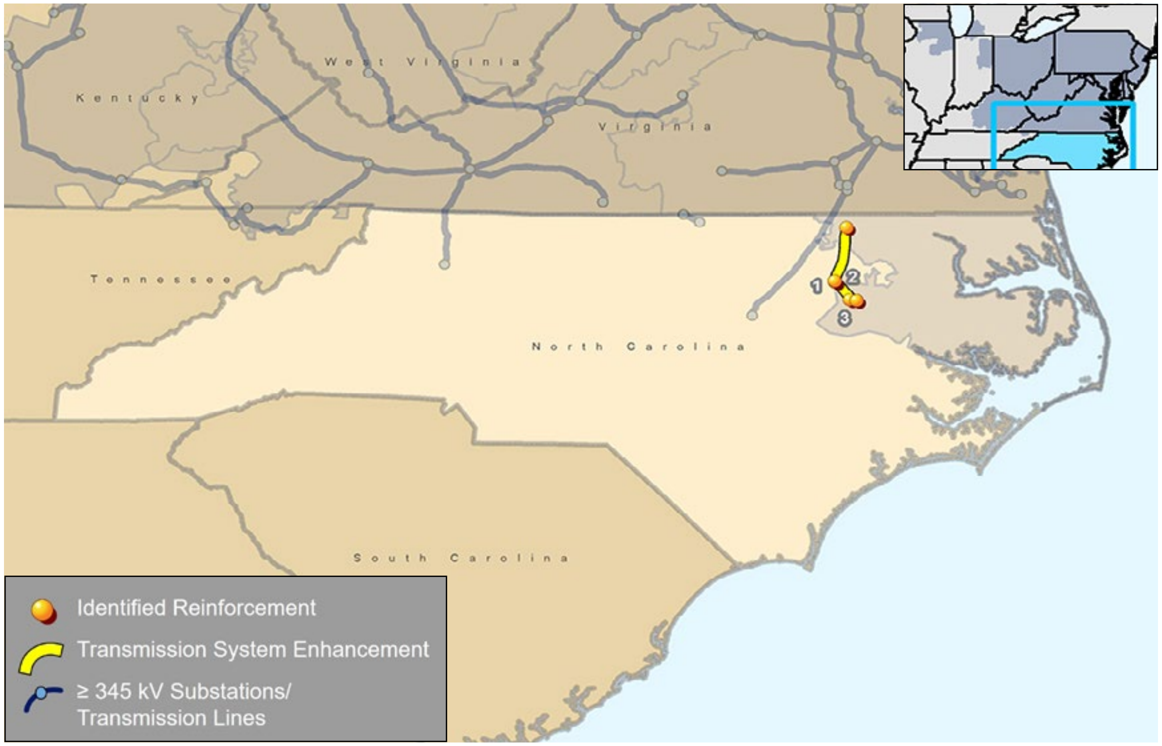


Table 6.43: North Carolina Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2824		Rebuild ~28.9 miles of 230 kV line No. 2056 Hornertown to Hathaway with current 230 kV standard construction practices. The new conductor will have a minimum normal summer rating of 1573 MVA. Terminal equipment will be upgraded as needed.	12/31/2026	$49.10	Dominion	7/12/2022
2	S2825	.1	Rebuild entire 230 kV line No. 2167 Edgecombe NUG-Hathaway (~0.73 miles) to current 230 kV standards with appropriate structures. The minimum normal summer conductor rating of this line will be 1573 MVA. Rebuild entire 230 kV line No. 229 Edgecombe NUG-Tarboro (~16.9 miles) to current 230 kV standards with appropriate structures. The minimum normal summer conductor rating of the line will be 1573 MVA.	12/31/2023	$43.00		8/9/2022
3		.2	Rebuild ~3 miles from Tarboro to Str 55/133 of 115 kV line No. 55 Tarboro-Harts Mill to current 115 kV standards with appropriate structures. The minimum normal summer conductor rating of the line will be 393 MVA. Terminal equipment will be upgraded as necessary.				

6.9: Ohio RTEP Summary

6.9.1 — RTEP Context

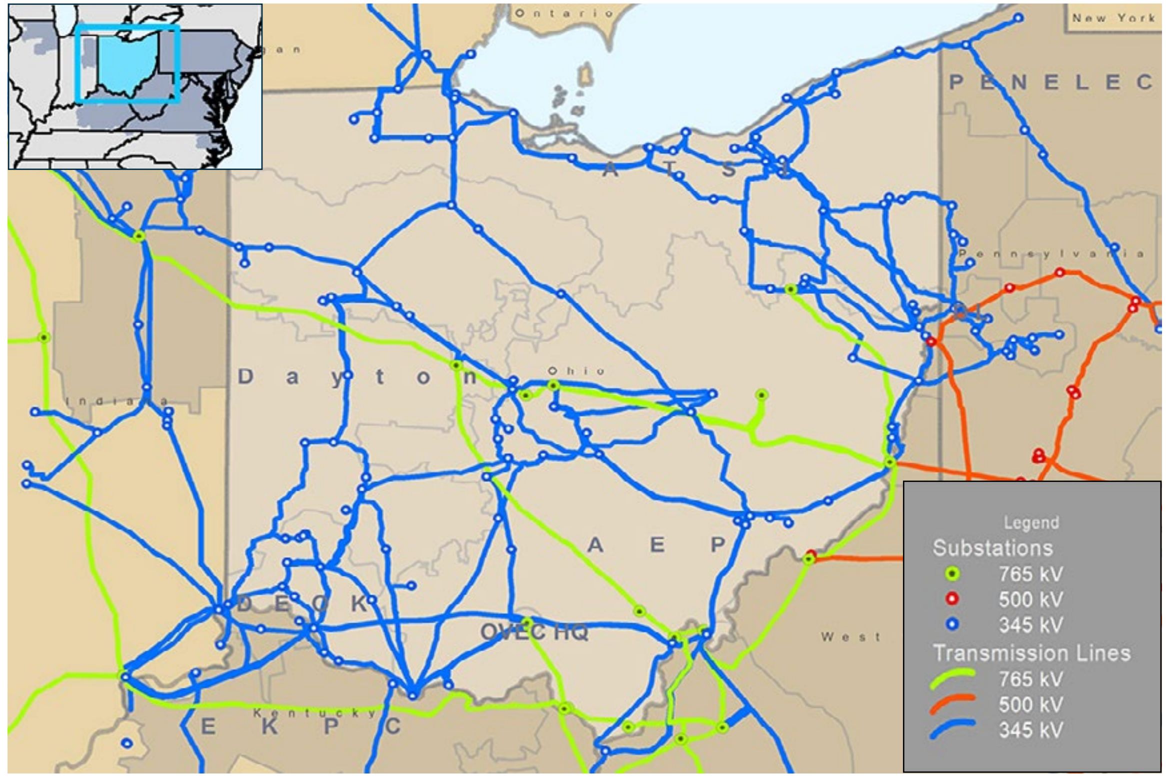
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Ohio, including facilities owned and operated by American Electric Power (AEP), AES Ohio, formerly Dayton Power and Light Company (DAY), American Transmission Systems, Inc. (FirstEnergy) (ATSI), Duke Energy Ohio and Kentucky (DEO&K), the city of Cleveland and the city of Hamilton as shown on **Map 6.36**.

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 6.36: PJM Service Area in Ohio

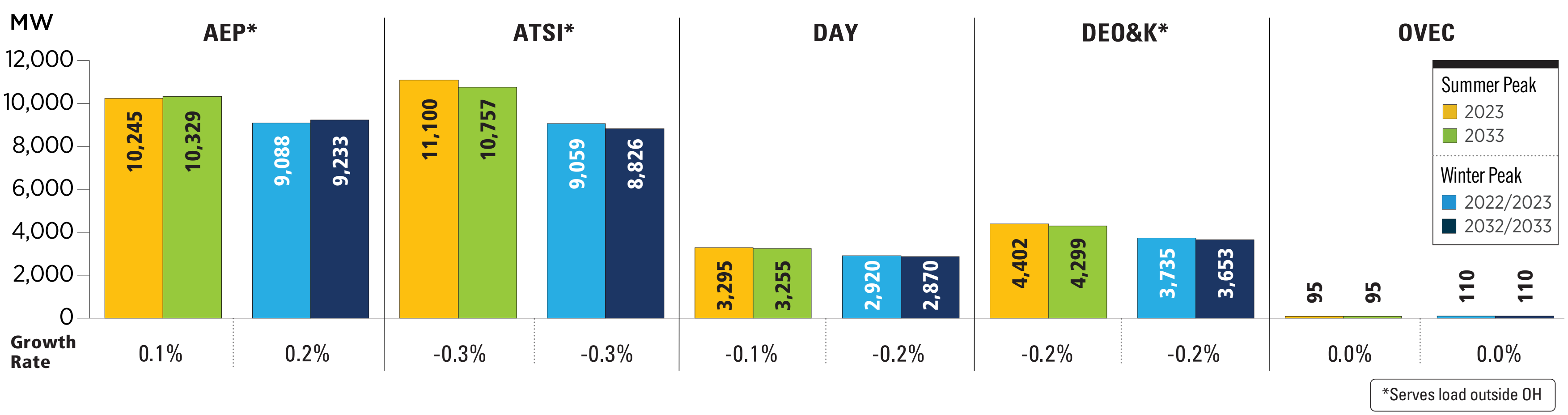


6.9.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.41** summarizes the expected loads within the state of Ohio and across PJM.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.41: Ohio – 2023 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2023	2033	2022/2023	2032/2033
149,059 MW	160,971 MW	130,811 MW	144,992 MW
Growth Rate 0.8%		Growth Rate 1.0%	

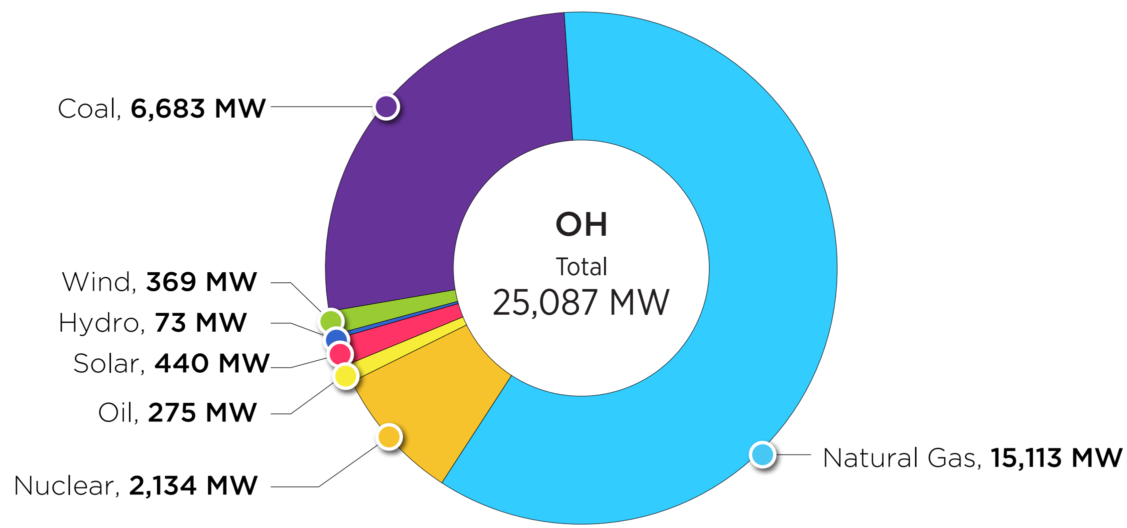
The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.9.3 — Existing Generation

Existing generation in Ohio as of Dec. 31, 2023, is shown by fuel type in **Figure 6.42**.

Read More
Changing Capacity Mix and Deliverability

Figure 6.42: Ohio – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)



6.9.4 — Interconnection Requests

In Ohio, as of Dec. 31, 2023, 466 projects were actively under study or under construction as shown in the summaries presented in **Table 6.44, Table 6.45, Figure 6.43, Figure 6.44** and **Figure 6.45**.

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 6.44: Ohio – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Ohio Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	0	0.00%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	596	2.37%	5,278	2.96%
Other	40	0.16%	70	0.04%
Solar	17,651	70.34%	98,471	55.15%
Storage	6,282	25.03%	53,644	30.04%
Wind	526	2.10%	20,798	11.65%
Grand Total	**25,094**	**100.00%**	**178,566**	**100.00%**

Read More
Interconnection Requests

Table 6.45: Ohio – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		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	2	29.0	11	230.0	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	7	595.5	0	0.0	1	850.0	36	7,552.3	40	15,695.4	84	24,693.2
	Nuclear	0	0.0	0	0.0	0	0.0	1	16	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	39.7	0	0.0	0	0.0	0	0.0	2	135.0	5	174.7
	Storage	57	6,282.0	0	0.0	6	308.3	5	0.0	35	1,448.7	103	8,039.0
Renewable	Biomass	0	0.0	0	0.0	0	0.0	1	0.0	3	185.0	4	185.0
	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	7	37.7	10	26.1	17	63.8
	Solar	321	17,651.0	19	851.5	58	3,387.6	12	414.8	177	7,139.1	587	29,444.1
	Wind	10	525.8	1	38.7	1	19.5	8	197.4	79	2,017.1	99	2,798.5
	Grand Total	**398**	**25,094.0**	**20**	**890.2**	**68**	**4,594.4**	**84**	**8,568.7**	**371**	**35,650.7**	**941**	**74,798.0**

Figure 6.43: Ohio – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

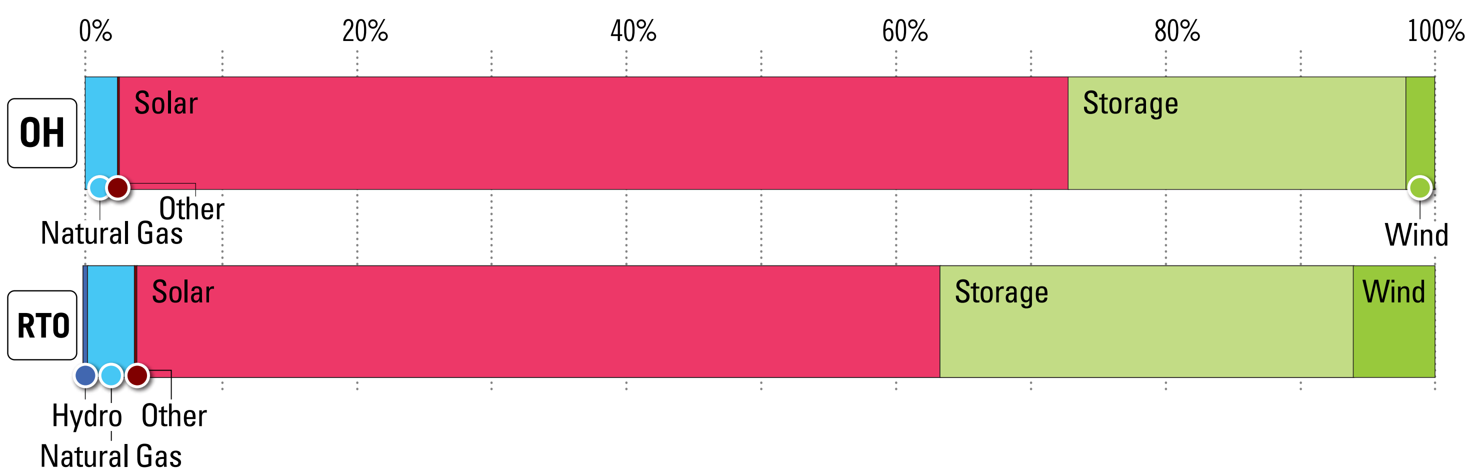
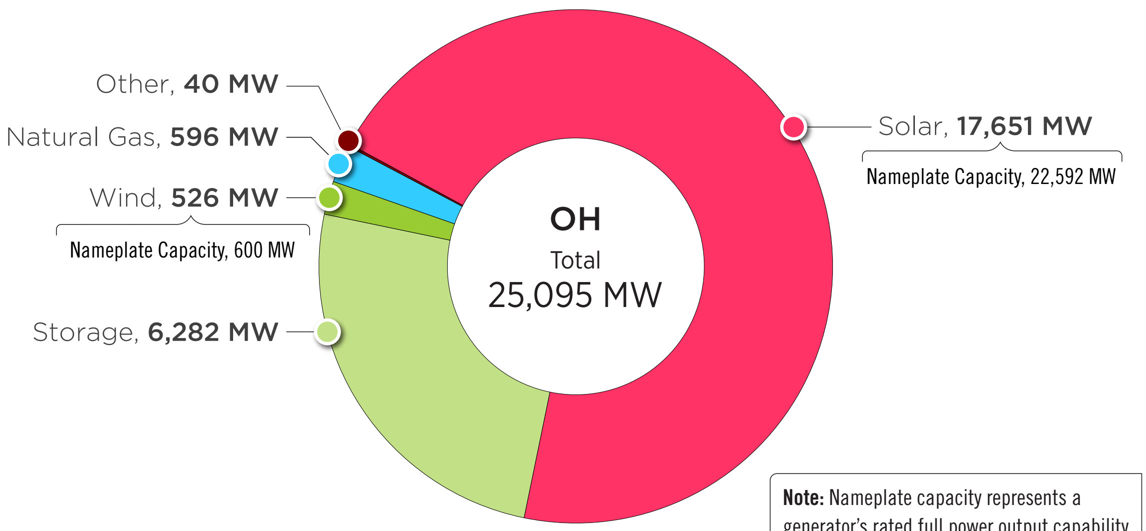


Figure 6.44: Ohio Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.45: Ohio Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

18.9%	Requested capacity megawatts
15.5%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	31	Interconnection Service Agreements	5,751 MW	8,250 MW
	15	Wholesale Market Participation Agreements	22 MW	88 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.9.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Ohio between Jan. 1, 2023, and Dec. 31, 2023, are summarized in **Map 6.37** and **Table 6.46**.

Read More
Generation Deactivation

Map 6.37: Ohio Generation Deactivations (Dec. 31, 2023)

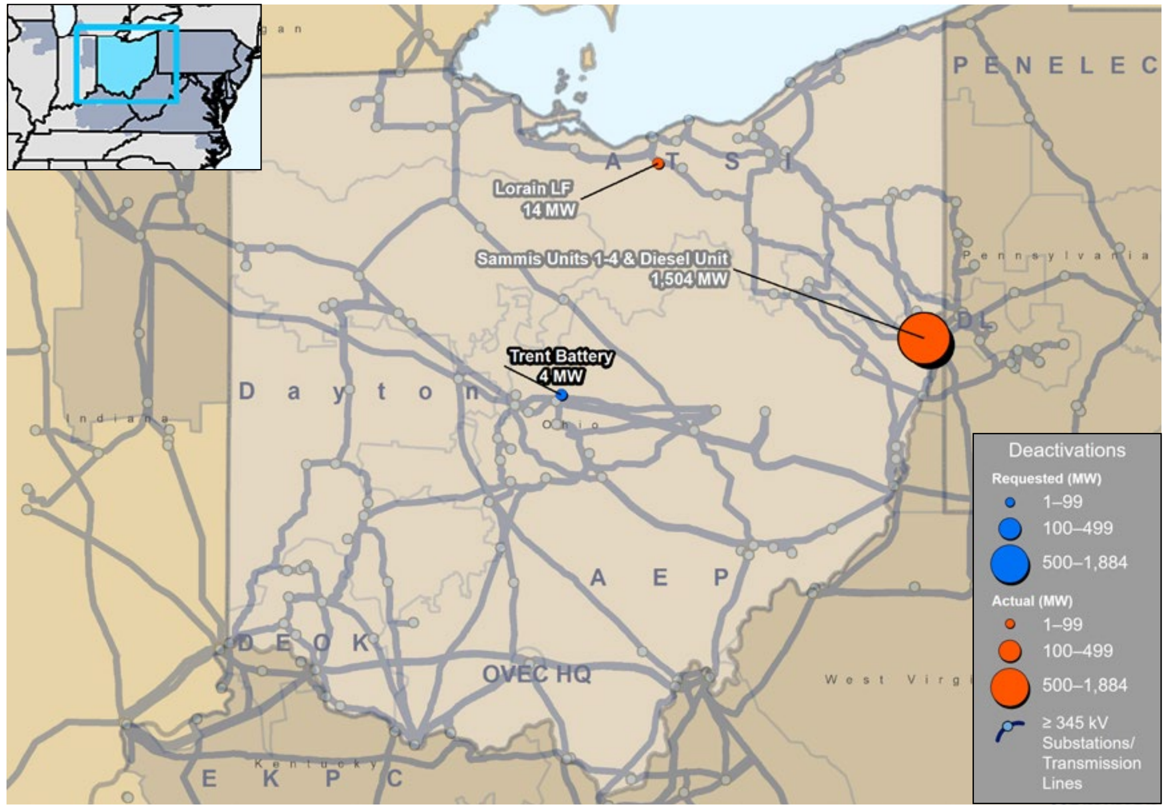


Table 6.46: Ohio Generation Deactivations (Dec. 31, 2023)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
TRENT 1 BT	AEP	Battery	9/22/23	1/1/2024	10	4
Sammis Diesel Units	ATSI	Diesel	3/14/22	5/3/2023	50	13
Sammis Unit 5		Coal			55	291.3
Sammis Unit 6					53	600
Sammis Unit 7					51	600
Lorain 1 LF		Methane	10/14/22	4/1/2023	21	14

6.9.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in Ohio are summarized in **Map 6.38** and **Table 6.47**.

Read More
Baseline Projects

Map 6.38: Ohio Baseline Projects (Dec. 31, 2023)

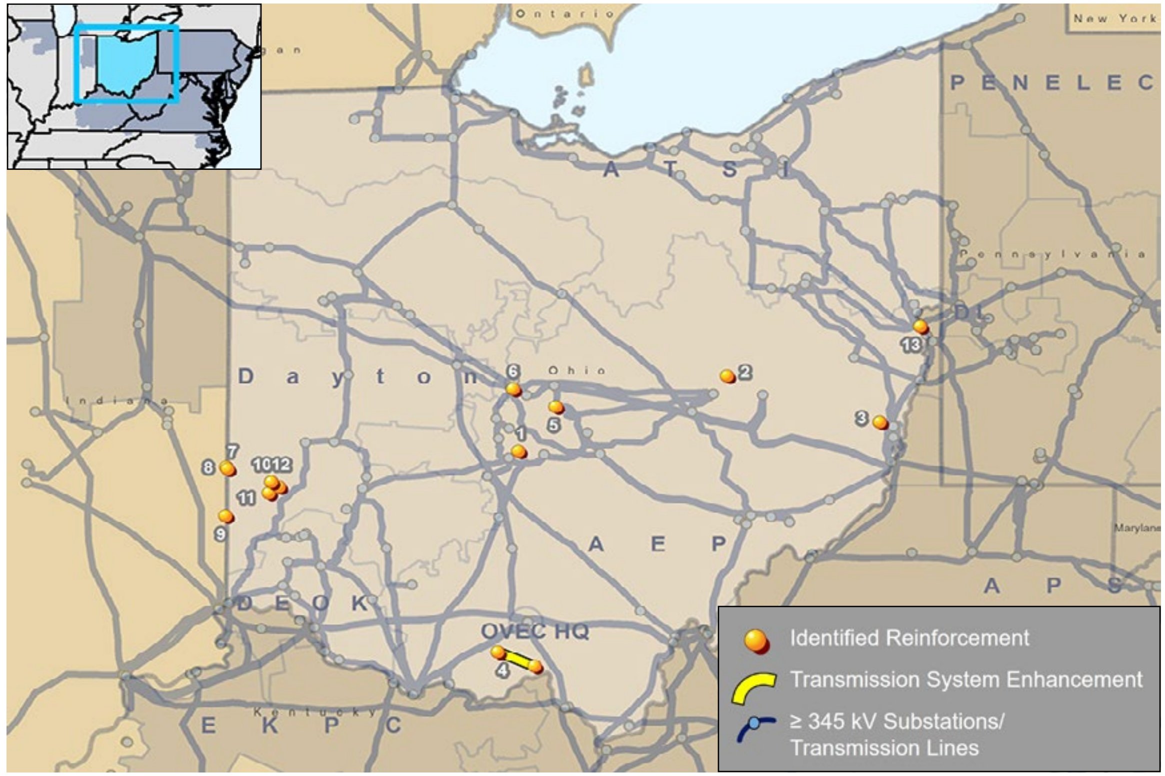


Table 6.47: Ohio Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3731		Replace 40 kV breaker J at McComb station with a new 3000A 40 kA breaker.		$0.50		
2	B3732		Install a 6 MVAR, 34.5 kV cap bank at Morgan Run station.	6/1/2027	$0.37	AEP	11/18/2022
3	B3733		Rebuild the 1.8-mile 69 kV T-line between Summerhill and Willow Grove Switch. Replace 4/0 ACSR conductor with 556 ACSR.		$5.10		

Table 6.47: Ohio Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	B3734		Install a 7.7 MVAR, 69 kV cap bank at both Otway station and Rosemount station.	6/1/2027	$1.73	AEP	11/18/2022
5	B3763		Replace the Jug Street 138 kV breakers M, N, BC, BF, BD, BE, D, H, J, L, BG, BH, BJ, BK with 80 kA breakers.	6/1/2024	$14.00		12/16/2022
6	B3764		Replace the Hyatt 138 kV breakers AB1 and AD1 with 63 kA breakers.		$2.00		
7	B3766	.1	Build ~0.19 miles of 138 kV line to the Indiana/Ohio state line to connect to AES's line portion of the Hayes-New Westville 138 kV line with the conductor size 795 ACSR26/7 Drake at Hayes-New Westville 138 kV line. The following cost includes the line construction and right-of-way.	6/1/2027	$38.64	AEP	12/6/2022
8		.2	Build ~0.05 miles of 138 kV line with the conductor size 795 ACSR26/7 Drake at Hayes-Hodgin 138 kV line. The following cost includes the line construction, right-of-way and fiber.				
9		.3	Build a new 4-138 kV circuit breaker ring bus at Hayes 138 kV. The following cost includes the new station construction, property purchase, metering, station fiber and the College Corner-Randolph 138 kV line connection.				
10		.4	Construct a 138 kV 1.86-mile single circuit transmission line at New Westville-AEP Hodgin 138 kV line. This transmission line will help loop the radial load served at New Westville as part of the overall effort to improve reliability in this area. Also, it provides a source to feed New Westville load while the 138 kV tie built back into the AES Ohio system.			DAY	
11		.5	Construct a new ~11-mile single circuit 138 kV line from New Westville to the Lewisburg tap off 6656 at New Westville-West Manchester 138 kV line. Convert a portion of 6656 West Manchester-Garage Rd. 69 kV line between West Manchester-Lewisburg to 138 kV operation (circuit is built to 138 kV). This will utilize part of the line already built to 138 kV and will take place of the 3302 that currently feeds New Westville. The 3302 line will be retired as part of this project.				
12		.6	Expand the West Manchester substation to a double-bus double-breaker design where AES Ohio will install one 138 kV circuit breaker, a 138/69 kV transformer, and eight new 69 kV circuit breakers. These improvements will help improve a non-standard bus arrangement where there is only one bus tie today and will improve the switching arrangement for the West Sonora Delivery Point.				
13	B3777		Disconnect and remove three 345 kV breakers, foundations and associated equipment from Sammis substation. Remove nine 345 kV CVTs. Remove two 345 kV disconnect switches. Install new 345 kV bus work and foundations. Install new fencing. Remove and adjust relaying at Sammis substation.	6/1/2023	$2.10	ATSI	5/9/2023

6.9.7 — Network Projects

Network projects in Ohio for 2023 are summarized in **Map 6.39** and **Table 6.48**.

Read More
Network Projects

Map 6.39: Ohio Network Projects (Dec. 31, 2023)

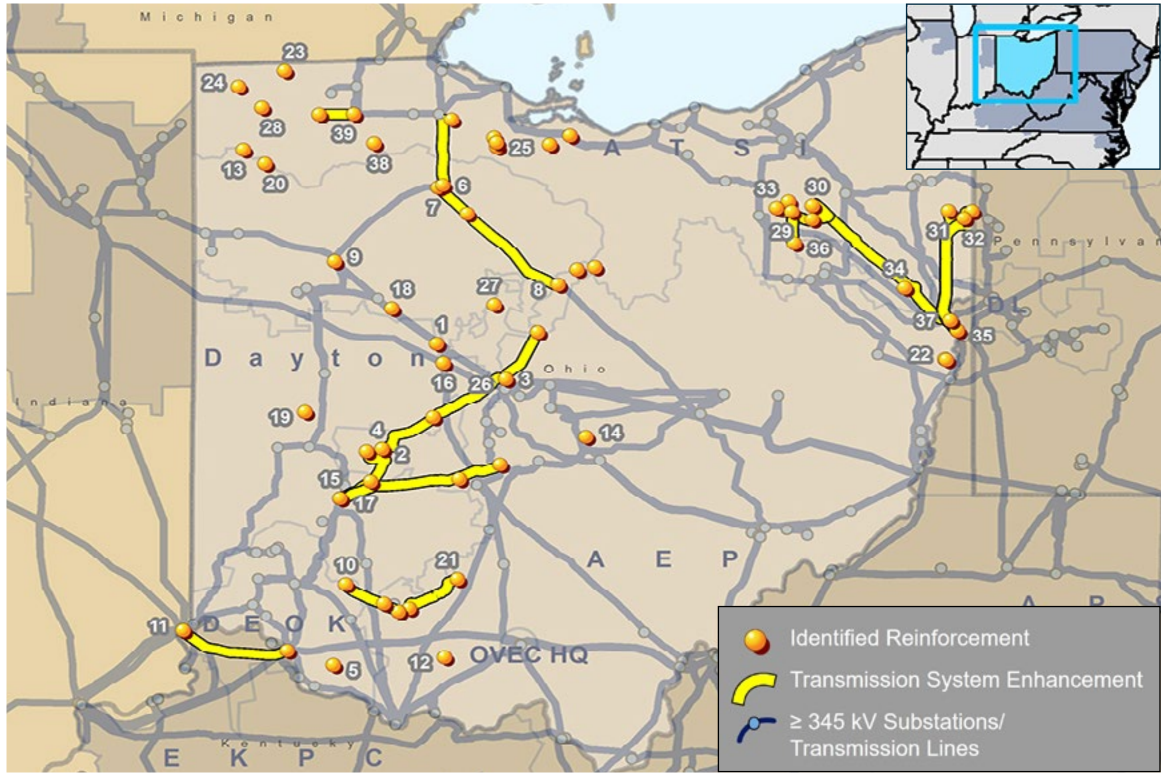


Table 6.48: Ohio Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5783	Reconductor the AC1-078 tap-London 138 kV line.	AF1-270	6/1/2020	$3.91	ATSI	10/3/2023
2	N5867	Cut the East-Springfield-Tangy 138 kV line and terminate the line inside the proposed AD2-163 ring bus in an in-out configuration at East Springfield-Tangy 138 kV line.	AD2-163	12/1/2021	$0.37		
3	N5868	Adjust remote, relaying and metering settings and replace 138 kV wave trap, line tuner and coax at Tangy 138 kV substation.			$0.12		

Table 6.48: Ohio Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	N5869	Adjust remote, relaying and metering settings and replace 138 kV wave trap, line tuner and coax. Also replace line and carrier relaying at East Springfield 138 kV substation.	AD2-163	12/1/2021	$0.27	ATSI	10/3/2023
5	N6239	Install metering and overhead conductors from the point of interconnection to the interconnection switching substation AC2-088/AD1-136.	AD1-136	6/30/2020	$0.42	DEO&K	10/3/2023
6	N6383	Perform required sag study on the 20-mile section and complete line reconductor/rebuild required.	J1969 (MISO)	10/1/2024	$0.08	AEP	10/3/2023
7	N6476	Perform a sag study on the 11.7 mile single circuit line between Fostoria Central and South Berwick.	AG1-319	6/1/2022	$0.07	AEP	10/3/2023
8	N6526.2	Perform required sag study on 18.3-mile line between South Berwick and Galion and rebuild/reconductor line segment.	AG1-411	9/25/2024	$0.73	AEP	10/3/2023
9	N6538.1	Replace five substation conductor 2156 ACSR 84/19 Std at E. Lima.	AG1-199	6/1/2023	$0.50	AEP	10/3/2023
9	N6538.2	Perform required sag study on 4-mile single circuit line between Fremont Center and Fremont with 1033 ACSR. Rebuild/reconductor the line with new ratings after the sag study S/N: 1409 MVA, S/E: 1887 MVA.	AG1-199	6/1/2023	$0.02	AEP	10/3/2023
9	N6538.3	Replace substation conductor 2870 MCM ACSR at E. Lima.	AG1-319	12/1/2022	$0.10	AEP	10/3/2023
10	N6634.10	Perform telecom upgrades at Highland 138 kV.	AC2-061	2/16/2017	$0.02	AEP	10/3/2023
10	N6634.11	Replace the wave trap on the feeder to Clinton County 138 kV station and make necessary relay settings changes at Warren 138 kV station.	AC2-061	2/16/2017	$0.12	DEO&K	10/3/2023
10	N6634.12	Replace the wave trap on the high side of TB1 at Clinton County 138 kV station.	AC2-061	2/16/2017	$0.10	DEO&K	10/3/2023
10	N6634.6	Install 138 kV revenue meter, generator lead transmission line span from the new Spickard 138 kV station to the point of interconnection, and extend dual fiber optic from the point of interconnection to the new Spickard 138 kV station control house.	AC2-061	2/16/2017	$0.57	AEP	10/3/2023
10	N6634.7	Install new Spickard 138 kV three-breaker ring bus station along the Hillsboro-Clinton County 138 kV line; install associated protection and control equipment, line risers, switches, jumpers and SCADA equipment.	AC2-061	2/16/2017	$4.92	AEP	10/3/2023
10	N6634.8	Modify Hillsboro-Clinton County 138 kV T-line and fiber cut-in for AC2-061 interconnection.	AC2-061	2/16/2017	$0.96	AEP	10/3/2023
10	N6634.9	Upgrade line protection and and fiber connectivity at Hillsboro 138 kV station for AC2-061 interconnection.	AC2-061	2/16/2017	$0.28	AEP	10/3/2023
11	N6759.1	Perform a sag study on the Deaborn-Pierce 345 kV line.	AE2-297	12/31/2021	$0.13	OVEC	10/3/2023
12	N7280	Build exit span and first structure to gen lead line at Adam 138 kV.	AB2-085	4/16/2016	$0.59	AEP	10/3/2023
12	N7281	Extend fiber-optic cables from the point of transition into the Adams 138 kV control house.	AB2-085	4/16/2016	$0.12	AEP	10/3/2023
13	N7289	Expand the Lockwood Road 138 kV substation: Install two additional 138 kV circuit breakers. Install associated protection and control equipment, 138 kV line risers and SCADA.	AF1-063	9/28/2017	$1.60	AEP	10/3/2023
14	N7297	Install one new 138 kV circuit breaker, associated equipment. Update protective relay settings at the Kirk 138 kV station.	AF2-122	2/28/2020	$1.00	AEP	10/3/2023
14	N7298	Install three dead-end structures, three spans of conductor, OPGW and Alumoweld shield wires from the Kirk 138 kV station to the point of interconnection.	AF2-122	2/28/2020	$1.65	AEP	10/3/2023
14	N7299	Install revenue metering at Kirk 138 substation.	AF2-122	2/28/2020	$0.31	AEP	10/3/2023
14	N7300	Install two fiber-optic cable paths from the Kirk 138 kV station to the fiber-optic cable points of interconnection.	AF2-122	2/28/2020	$0.27	AEP	10/3/2023
15	N7349	Oversee engineering and construction for a new three-breaker ring bus on the Greene-Clark 138 kV line for the AD1-140 interconnection; includes review of drawings, nameplates and relay settings for FirstEnergy standards and includes project management, environmental and right-of-way.	AD1-140	5/29/2020	$0.72	ATSI	10/3/2023

Table 6.48: Ohio Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
15 (Cont.)	N7350	Design, install and test/commission Multiprotocol Label Switching (MPLS) equipment for SCADA transport for AD1-140 (SCADA).	AD1-140	5/29/2020	$0.20	ATSI	10/3/2023
	N7351	Install fiber communication from AD1-140 Interconnection Switchyard control house to Greene-East Springfield line fiber and to developer-built fiber run to support communications and control to the generator site.			$0.08		
	N7352	Loop the Clark-Greene 138 kV circuit into the new AD1-140 Interconnection Switchyard. The proposed location of the new ring bus is near structure #5604; includes project management, environmental, forestry, real estate and right-of-way.			$0.41		
	N7353	Install two 138 kV wave traps and tuners at the Clark 138 kV substation. Update relay settings.			$0.13		
16	N7384	Install 345 kV metering at the Marysville 345 kV station. Construct line from the Marysville 345 kV station to the point of interconnection. Install dual fiber telecommunications from the Marysville 345 kV station to the customer facility collector station.	AD2-093	3/20/2018	$1.46	AEP	
	N7385	Modify and expand the existing Marysville 345 kV station including one 345 kV circuit breaker installation.			$1.28		
17	N7433	Construct a new three circuit breaker ring bus station named Chenoweth 345 kV.	AE2-148	6/1/2022	$10.47		
	N7434	Install 345 kV revenue meter, generator lead first span exiting the point of interconnection station, including the first structure outside the fence at the new AE2-148 switching station.			$1.60		
	N7435	Install a cut-in at Beatty Road-Greene 345 kV.			$1.43		
	N7436	Upgrade line protection and controls at the Beatty Road 345 kV station.			$0.60		
18	N7469	Install 345 kV metering at the Gunn Road 345 kV station. Construct line from the Gunn Road 345 kV station to the point of interconnection. Install dual fiber telecommunications from the Gunn Road 345 kV station to the customer facility collector station.	AE2-306	9/30/2019	$1.42		
19	N7475	Install a new 138 kV circuit breaker, physical structures, protection and control equipment, communications equipment, and associated facilities at the Eldean 138 kV substation.	AE2-218	12/31/2021	$0.85	DAY	
20	N7991	Install 69 kV revenue meter; generator lead transmission line span from the new 69 kV station to the point of interconnection, including the first structure outside the new 69 kV station. Extend fiber optic from the point of interconnection to the new 69 kV station control house.	AC1-167	10/31/2016	$0.69	AEP	
	N7992	Expand the Platter Creek 69 kV station, including the addition of one 69 kV circuit breaker, installation of associated protection and control equipment, 69 kV line risers and SCADA equipment.			$0.68		
21	N8035.1	Install 69 kV revenue meter; generator lead transmission line spans from the Buckskin 69 kV station to the point of interconnection, including the first two structures outside the Buckskin 69 kV station. Extend dual fiber-optic from the point of interconnection to the Buckskin 69 kV station control house.	AC2-060	2/16/2017	$1.03		
	N8035.2	Expand the Buckskin 69 kV station, including the addition of one 69 kV circuit breaker, installation of associated protection and control equipment, 69 kV line risers and SCADA equipment.			$0.71		
	N8035.3	Reterminiate Buckskin-Highland 69 kV T-line; external station associated work, including two structures, including one double circuit structure.			$0.82		
22	N8059.1	Construct one 69 kV generator lead transmission line from the Steubenville 69 kV station to the point of interconnection, install 69 kV revenue meter, extend dual fiber-optic cable from the point of interconnection to the Steubenville 69 kV station control house. Expand the Steubenville 69 kV station, including the addition of one 69 kV circuit breaker, installation of associated protection and control equipment, line risers, switches, jumpers and SCADA.	AD2-014	11/7/2017	$1.57		

Table 6.48: Ohio Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
22 (Cont.)	N8059.2	Install one additional 69 kV circuit breaker on the 69 kV side of the Steubenville 138/69/12 kV autotransformer.	AD2-014	11/7/2017	$0.37	AEP	10/3/2023
23	N8098.1	Establish a new line position within the East Fayette 138 kV substation by adding a new 138 kV circuit breaker and related equipment to connect the AE2-282 solar project with the Toledo Edison transmission system. A circuit breaker, three CCVTs, one 138 kV tubular steel H-frame dead end, and a relaying panel will be installed to accommodate the new line terminal.	AE2-282	9/15/2021	$1.03	ATSI	10/3/2023
23	N8098.2	Perform estimated SCADA work at East Fayette 138 kV substation to support breaker installation, relay installation and updated relay setting.	AE2-282	9/15/2021	$0.06	ATSI	10/3/2023
24	N8206	Extend the Snyder 69 kV bus. Install one 69 kV circuit breaker.	AE2-181	10/31/2021	$0.87	ATSI	10/3/2023
25	N8217.1	Expand existing Groton ring bus to a four-breaker ring bus at Groton substation 138 kV.	AE2-176	12/31/2021	$1.64	ATSI	10/3/2023
25	N8217.2	Modify relay setting at Hayes substation 138 kV.	AE2-176	12/31/2021	$0.13	ATSI	10/3/2023
25	N8217.3	Revise relay settings at West Fremont substation 138 kV.	AE2-176	12/31/2021	$0.13	ATSI	10/3/2023
26	N8221.1	Construct a new 69 kV three-breaker ring bus on the Cardington-Tangy 69 kV line.	AF1-122	11/30/2022	$5.78	ATSI	10/3/2023
26	N8221.2	Design, install and test/commission MPLS equipment for SCADA transport on the Cardington-Tangy 69 kV line.	AF1-122	11/30/2022	$0.26	ATSI	10/3/2023
26	N8221.3	Loop the Cardington-Tangy 69 kV line to create the interconnection for the new AF1-122 three-breaker ring bus ~1.1 miles from the Cardington substation. Install fiber from the new AF1-122 three-breaker ring bus to the Cardington substation.	AF1-122	11/30/2022	$1.14	ATSI	10/3/2023
26	N8221.4	Change relay settings, drawing updates and nameplates at Tangy 69 kV substation.	AF1-122	11/30/2022	$0.06	ATSI	10/3/2023
26	N8221.5	Upgrade line relaying at Cardington 69 kV substation.	AF1-122	11/30/2022	$0.56	ATSI	10/3/2023
27	N8337.1	Construct a new line exit out of the Galion substation by adding a new 138 kV breaker.	AF2-150	12/31/2023	$2.14	ATSI	10/3/2023
27	N8337.2	Modify relay settings at Roberts 138 kV.	AF2-150	12/31/2023	$0.10	ATSI	10/3/2023
27	N8337.3	Modify relay settings at Cardington 138 kV.	AF2-150	12/31/2023	$0.10	ATSI	10/3/2023
27	N8337.4	Modify relay settings at Leaside 138 kV.	AF2-150	12/31/2023	$0.10	ATSI	10/3/2023
27	N8337.5	Modify relay settings at Ontario 138 kV.	AF2-150	12/31/2023	$0.097	ATSI	10/3/2023
28	N8359.1	Upgrade existing Sullivan 138 kV (previoulsy named Napoleon Muni Northside) substation to a five-breaker ring bus substation.	AF1-205	11/1/2022	$2.94	AMPT	10/3/2023
28	N8359.2	Reterminate the Midway-Sullivan 138 kV line into the expanded substation to support new generation interconnection.	AF1-205	11/1/2022	$0.71	ATSI	10/3/2023
28	N8359.3	Revise relay settings at Striker 138 kV substation.	AF1-205	11/1/2022	$0.08	ATSI	10/3/2023
28	N8359.4	Perform end-to-end testing and revise relay settings at Midway 138 kV substation.	AF1-205	11/1/2022	$0.08	ATSI	10/3/2023
28	N8359.5	Integrate upgrades to the Sullivan 138 kV substation to the FirstEnergy transmission system.	AF1-205	11/1/2022	$0.08	ATSI	10/3/2023
29	N8451.1	Construct a new 138 kV three-breaker ring bus looping in the South Akron-Toronto 138 kV line to provide interconnection facilities for AE2-194.	AE2-194	5/1/2022	$6.38	ATSI	10/3/2023
30	N8451.10	Adjust relay settings for the Gilchrist-Lakemore 138 kV line.	AE2-194	5/1/2022	$0.09	ATSI	10/3/2023
30	N8451.12	Adjust relay settings for the Lakemore-South Akron 138 kV line.	AE2-194	5/1/2022	$0.19	ATSI	10/3/2023

Table 6.48: Ohio Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
31	N8451.13	Adjust relay settings for the Boardman-Toronto 138 kV line.	AE2-194	5/1/2022	$0.09	ATSI	10/3/2023
32	N8451.14	Adjust relay settings for the Lowellville-Dobbins 138 kV line.	AE2-194	5/1/2022	$0.09		
33	N8451.15	Adjust relay settings for the Urban-Firestone 138 kV line.			$0.19		
	N8451.16	Adjst relay settings for the Tusc-Urban 138 kV line.			$0.09		
34	N8451.2	Cut and loop the South Akron-Toronto 138 kV line into the new 138 kV interconnection substation. This cut will take place at a location that is ~21 miles from the Toronto substation. It is assumed that the interconnection substation will be located within one span (~0.1 mile) from the existing line.			$3.06		
	N8451.5	Change the 138 kV line relay setting for AE2-194 interconnection (South Akron).			$0.50		
	N8451.6	Install one 138 kV 2000A dual-frequency wave traps, line tuners and coax.			$0.17		
35	N8451.7	Adjust relay settings for the Dobbins-Toronoto 138 kV line.			$0.19		
36	N8451.8	Adjust relay settings for the Dale-South Akron 138 kV line.			$0.09		
37	N8451.9	Adjust relay settings for the Sammis-Toronoto 138 kV line.			$0.09		
38	N8455.1	Establish new 69 kV line position for AF1-064 at Sandridge substation.	AF1-064	3/31/2022	$1.56		
39	N8455.2	Install Carrier equipment for anti-islanding at Midway substation 69 kV.			$0.50		

6.9.8 — Supplemental Projects

Supplemental projects received by PJM in 2023 in Ohio are summarized in **Map 6.40** and **Table 6.49**.

Read More
Supplemental Projects

Map 6.40: Ohio Supplemental Projects (Dec. 31, 2023)

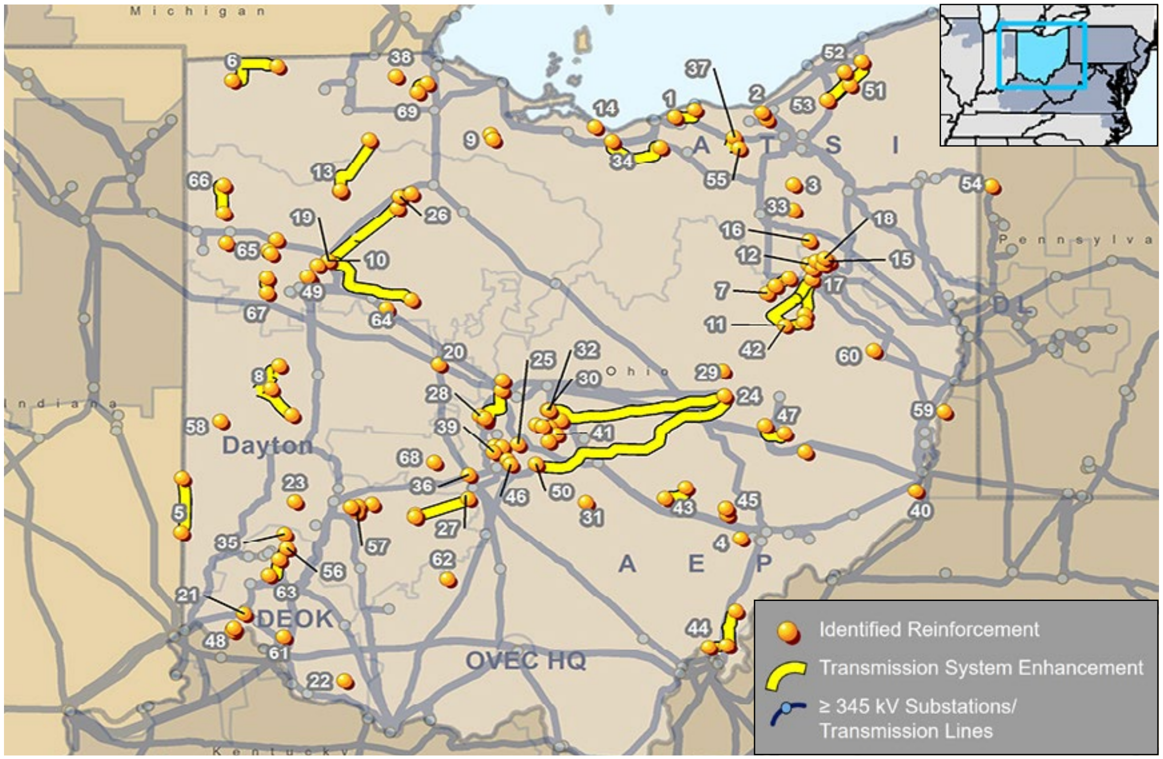


Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1873		Build ~8 miles of new 138 kV line from Black River to Astor substation with a rating of 435 MVA SN/500 MVA SE. Expand/build a new 138 kV four-breaker ring bus at Astor to network the following lines and existing transformer at Astor substation: Black River-Astor 138 kV line (new), Avon-Astor Q11 138 kV line, Astor-Fowles Q11 138 kV line and Astor Transformer No. 71 138/36 kV (existing). Build ~2 miles of new 138 kV line from Republic Vine to Charleston substation with a rating of 278 MVA SN/339 MVA SE. Expand the Charleston 138 kV four-breaker ring bus into five- (future six-) breaker ring bus to network the following lines at Charleston substation: Republic Vine-Charleston 138 kV line (new), Black River-Charleston 138 kV line, Charleston-Lorain 138 kV line, Charleston-Palm No.1 138 kV line, Charleston-Palm No.2 138 kV line.	12/31/2023	$24.50	ATSI	2/20/2019

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2183		Disconnect transformer No. 2 from the Harding-Jennings Q13 138 kV line. Reconnect transformer No. 2 to the Harding-Jennings Q11 138 kV line.	3/15/2020	$0.13	ATSI	11/22/2019
3	S2387	.2	Install two 138 kV CBs and associated equipment to separate AMPT's 138 kV facilities from FE's 138 kV ring bus at Valley 138/23.8 kV substation. Relocate two existing 138/23.8 kV transformers to accommodate the new 138 kV CBs. Install new panels in a new AMPT control house. ($6.3 M) Construct a greenfield 138/69/23 kV station called "Gaylord Grove," located next to FE's proposed Riverway 138 kV station and Cuyahoga Falls existing substation 5. Install two 138/69 kV 170 MVA transformers, two 138 kV CBs, five 69 kV CBs using 69 kV bus rated to 2000A. ($22.7 M) Install two 69/23 kV transformers, two 23 kV low-side transformer CBs and other associated equipment to connect from Gaylord Grove 69 kV yard to Cuyahoga Falls' substation 5 23 kV station (Cuyahoga Falls scope, $0.0 M). These facilities are distribution and not included in the overall project costs (AMPT identified scope, $29.0 M).	6/1/2025	$29.00	AMP	1/11/2019
4	S2401	.5	Remove the South Stockport switch.	6/3/2024	$0.07	AEP	2/17/2023
5	S2585	.11	Build ~0.19 miles of 138 kV line to the Indiana/Ohio state line to connect to AES's line portion of the Hayes-New Westville 138 kV line with the conductor size 795 ACSR26/7 Drake. The following cost includes the line construction and right-of-way.	12/31/2025	$9.04	AEP	11/18/2021
		.12	Build ~0.05 miles of 138 kV line with the conductor size 795 ACSR26/7 Drake. The following cost includes the line construction, right-of-way and fiber at Hayes-Hodgin 138 kV line.				
		.13	Build a new 4-138 kV circuit breaker ring bus at Hayes 138 kV. The following cost includes the new station construction, property purchase, metering, station fiber and the College Corner-Randolph 138 kV line connection.				
6	S2806		Construct a greenfield 69 kV single circuit line for ~3 miles using 795 26/7 ACSR conductor and break into the existing AMPT Pioneer tap off ATSI's East Fayette-Exit 2 69 kV line. Install one 69 kV three-way switch to accommodate the new tap to the existing AMPT line. Construct a new Kexon 69/12 kV substation. Install four (4) circuit breakers, 21.6 MVAR capacitor bank (split into three 7.2 MVAR blocks), and two 69 kV circuit switchers for two 69/12 kV transformers.	5/31/2025	$13.45	AMP	6/15/2022
		.1	Provide two 69 kV revenue metering equipment packages for the new Kexon Delivery Point. Revise relay settings at East Fayette and Snyder substations.			ATSI	
7	S2807	.1	Construct a greenfield 69 kV single circuit transmission line for ~5.5 miles using 795 26/7 ACSR conductor from AMPT's Brewster 69 kV substation to a structure outside of AEP's Alpine 69 kV ring bus station. Build a four circuit breaker 69 kV ring station at the existing Brewster substation location. The new ring bus will be used to reterminate the existing 69 kV Brewster-Harmon (FE) line, terminate the new 69 kV Alpine-Brewster (AEP) line, and tie with two existing terminals feeding the existing Brewster 69/12 kV transformation.	6/1/2025	$20.44	AMP	8/19/2022
		.2	Modify AEP's proposed Alpine 69 kV ring bus station (s2534.8) by adding an additional 69 kV circuit position to Brewster. Install one 69 kV circuit breaker, protective relaying and tie-line metering. Construct a 0.1-mile segment of 69 kV transmission line using 795 ACSR 26/7 conductor leaving Alpine station to connect to AMPT's transmission line toward Brewster.			AEP	
		.3	Provide fiber termination at FE's Harmon substation. AMPT is responsible for the fiber path on the Brewster-Harmon 69 kV line. At FE's Harmon 69 kV substation, replace two SEL-421s primary and backup relay with two SEL-411Ls and connect to the fiber; retain existing SEL-501 breaker failure relay. Adjust relay settings at Cloverdale.			ATSI	
8	S2809	.1	Rebuild and reconductor the 13-mile 69 kV line from Russia-Minster utilizing 1351 AAC conductor and ductile iron poles. This project will directly improve one of the worst-performing circuits in the AES Ohio footprint. This rebuild along with other area improvements will greatly reduce both permanent and momentary outages to the co-op delivery points along this line and will help improve the reliability area by reinforcing this important south to north 69 kV corridor on the AES Ohio system.	12/31/2026	$40.80	DAY	8/19/2022
		.2	Rebuild and reconductor the 14-mile 69 kV line from Russia-Covington. Like above, this project will reinforce a historically poor-performing circuit and reduce permanent and momentary outages to customers served in this area. Replacing the wood pole cross-arm and brace design with ductile iron poles will significantly improve reliability for the customers served from this line.	6/1/2027			
		.3	Replace five 1940s-era oil breakers, relaying and establish another 69 kV bus tie for operational flexibility at Covington substation. These breakers have experienced operational issues and should also be replaced at the time of the rebuild to ensure modern relaying is in place which will also help improve area reliability.				

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
9	S2811		Install a new 69 kV 3000A 40 kA breaker to replace breaker C and associated terminal equipment at Fremont on the line toward the City of Clyde. Install a new 138 kV 1200A MOAB switch to replace MOAB W toward West Fremont. Install new DICM. Station will need to be expanded to accomplish work.	6/1/2025	$3.48	AEP	8/19/2022
10	S2812	.1	The 41.3-mile long line will be rebuilt using double circuit 795 ACSR Drake conductor at Fostoria-East Lima 138. OPGW shield wire will be installed. Approximately one mile of line is being considered for greenfield construction to avoid encroachments and right-of-way challenges. The Boutwell, Flag City and Ebersole stations were installed recently, these line cut-ins will not be rebuilt.	9/15/2026	$95.98	AEP	8/19/2022
		.2	Modify the North Findlay-N Main and North Findlay-Findlay 69 kV lines for the Fostoria-East Lima 138 kV line crossing.				
11	S2820	.1	Rebuild the Philo-Torrey 138 kV transmission line between West Dover and South Canton stations (18.0 miles). The circuit affected is South Canton-West Dover 138 kV. Remove the existing lattice towers and supplement the right-of-way as needed.	12/1/2026	$89.58	AEP	9/16/2022
		.2	Rebuild the Philo-Canton 138 kV transmission line between North Intertie and South Canton (14.6 miles). The circuit affected is North Intertie-South Canton 138 kV. Remove the existing lattice towers and supplemental the right-of-way as needed.				
12	S2822	.1	Rebuild Gambrinus station as Nolan station ~0.2 miles away as a four-breaker 69 kV ring bus.	12/1/2025	$15.21	AEP	9/16/2022
		.2	Retire Gambrinus station, and remove all equipment.				
		.3	Extend the Gambrinus-Reedurban and Gambrinus-Torrey 69 kV transmission lines 0.2 mile northward to connect to Nolan station.				
		.4	Construct a span of 69 kV transmission line and a structure from Nolan station, for each of the two feeds to the customer. This will connect to the customer's 69 kV loop.				
		.5	Upgrade line relays to coordinate with Nolan station at the 69 kV remote-end of Torrey.				
		.6	Upgrade line relays to coordinate with Nolan and also replace the 69 kV oil-filled breaker "R" at the 69 kV remote-end of Reedurban. Convert the 69 kV pilot wire system to fiber. Eliminate the 138 kV 3-terminal configuration by installing two 138 kV breakers on the incoming 138 kV circuits.				
		.7	Reconfigure the South Canton-Reedurban-Miles Avenue 138 kV transmission line going into the station, to connect to the new breakers and bus at Reedurban station.				
		.8	Replace and relocate a structure on the Nolan 69 kV transmission line, to accommodate the station improvements and distribution scope at Reedurban station.				
13	S2827	.1	Construct a greenfield 69 kV single circuit transmission line for ~11.8 miles using 795 26/7 ACSR conductor from AMPT's Bremer 69 kV substation to a structure outside of ATSI's Weston 69 kV ring bus station. Install four 69 kV load break air switches in total on the existing Bremer tap. Install the switches on either side of the Keyser and Belmore co-op stations for sectionalizing. Install one load break air switch outside of ATSI's Weston 69 kV station on the new line between Bremer and Weston. Expand the existing Bremer 69 kV station to a new three-circuit breaker ring bus configuration to accommodate a second 69 kV circuit. Install a total of four new circuit breakers-including one 69 kV circuit breaker for the 69/12 kV transformer high-side protection.	8/1/2025	$37.41	AMP	10/14/2022
		.2	At AEP's East Leipsic station, extend the 69 kV bus and install a new 69 kV breaker. Install 69 kV To/To Metering. The station will need expanded to accommodate the work. Construct a new greenfield 0.55 miles long 69 kV single circuit line using 556 ACSR Dove from the new East Leipsic 69 kV breaker to the AEP / AMPT POI. Modify the East Leipsic Extension line. Modify the Yellow Creek-East Leipsic 69 kV line.			AEP	
		.3	Install one 69 kV circuit breaker and associated equipment at FE's Weston 69 kV substation. Install one span of conductor to a structure outside the FE Weston 69 kV substation. Install tie line interchange revenue metering at FE's Weston 69 kV substation.			ATSI	
14	S2828		Install a third 69/12 kV 25 MVA transformer at Rye Beach Road. Expand the distribution buses as necessary to accommodate the new transformer. The 69/12 kV transformer and associated 12 kV equipment costs are distribution costs. Related AMPT transmission work scope at Rye Beach Road will be completed under the AMPT-2021-001.	6/1/2025	$0.00	AMP	8/19/2022

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
15	S2829	.1	Construct a new Wagenhals 138-69 kV station on greenfield property owned by AEP to the south of the existing station. The 138 kV portion will be a breaker-and-a-half design, with a total of 17 breakers. The 69 kV will be a five-breaker ring bus. The existing 138-69 kV transformer No. 3 and 138 kV cap bank will be transferred, while the 138-69-23kV transformer No. 2 will be retired.	6/1/2025	$67.02	AEP	10/14/2022
		.2	Retire the existing 138-69-23kV station, including structures and control house.				
		.3	Relocate 8- 138 kV transmission lines and 4- 69 kV transmission lines to connect to the new station location.				
		.4	Perform required environmental remediation at the existing station property. Dispose of PCB-contaminated soils, drainage tile, legacy oil piping and storage tanks, and synchronous condenser system. Final abatement plan to be determined with EPA.				
16		.5	Perform remote end 138 kV relay upgrades at Wayview.				
17		.6	Perform remote end 69 kV relay upgrades at Sunnyside.				
18		.7	Perform remote end 69 kV relay upgrades at Stanley Court.				
19	S2832	.2	Replace 1000MCM, 1590 AAC bus and riser conductors on the B string and bus 2 with 2-2000 MCM AAC at East Lima 138 kV.	2/28/2025	$3.31		10/4/2022
20		.4	Replace two 345 kV 5000A 63 kA circuit breakers and associated sub conductor and switches on the H string to eliminate the lower-rated equipment at Marysville 345 kV station.	3/31/2022			
21	S2833		Remove the 13 kV switchgear at Elmwood substation. Demolish the switchgear building. Install new 13 kV bus with breakers for five feeder exits. Install a control building to house control and communications equipment. Demolish the existing 69 kV single-bay tower. Install a four-bay, 69 kV box structure with four 69 kV breakers to create a ring bus. Install two 138 kV breakers into an existing box structure to create a ring bus. Remove the 13 kV tertiary connection on TB6. Install one 138/13 kV and two 69/13 kV, 22 MVA transformers.	6/10/2026	$14.52	DEO&K	10/14/2022
22	S2846		Disconnect Brown TB1's 34 kV tertiary winding. Install a new 138 kV circuit breaker into the ring bus to create a new position. Connect a new 138/34 kV, 60 MVA transformer in this position. Feed the 34 kV distribution bus from the new transformer. Expand the substation to make room for the new transformer and equipment.	2/2/2026	$1.26		11/18/2022
23	S2847		Install an additional 69 kV breaker at Southtown substation to facilitate the installation of a third 69/12 kV transformer.	1/1/2024	$0.10	DAY	11/18/2022
24	S2849	.1	Construct 138 kV line ~200 feet from Conesville 138 kV yard to the Slate Customer's new station at Conesville-Slate (Customer) No. 1 138 kV line.	5/31/2023	$4.49	AEP	
		.2	Construct 138 kV line ~200 feet from Conesville 138 kV yard to the Slate Customer's new station Conesville-Slate (Customer) No. 2 138 kV line.				
		.3	Relocate the existing 138 kV line to the third string in Conesville station at Conesville-Centerburg 138 kV line.				
		.4	Relocate the existing Centerburg circuit to the third string in the breaker and half, installing 2-138 kV circuit breakers in the string to terminate the circuit at Conesville 138 kV station. Replace the existing Horizontal takeoff structures in the second string with vertical takeoff structures. Install associated protection equipment. Replace the existing 138 kV Cap Bank-BB with a 69.1 MVAR bank.				
25	S2850		Rebuild the 0.3-mile section between structures 2-7 from above ground to underground at Vine-City of Columbus West 138 kV line.	6/1/2023	$0.00		
26	S2852		Install a hard tap on the North Findlay-Ebersol circuit near the customer's station. Install in-line dead ends to support sectionalizing around this hard tap. From the hard tap structure install one span of radial 138 kV line to the customer's station.	3/17/2023	$0.00		12/16/2022

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
27	S2853	.1	The newly established Fayette substation will serve as the primary source for the Jeffersonville area and will step service down from 345 kV to 138 kV and 69 kV. This substation is located central to the largest developing load center in the AES Ohio area supporting the electric vehicle manufacturing industry developing in the area. The new substation called Fayette will have a breaker-and-half 345 kV design, two 345/138 kV 450 MVA transformers, a breaker-and-half 138 kV design, a 138/69 kV 200 MVA transformer, 138 kV capacitor, and 69 kV feed to a new Panther substation. A 0.25-mile 138 kV extension will span from AES's Fayette substation to a 138 kV delivery point to serve the first 140 MW development.	8/1/2024	$145.10	DAY	12/6/2022
		.2	AES will construct a 13-mile double circuit 345 kV line from Madison to Fayette substation utilizing bundled 1024.5 ACAR 30x7 conductor at Madison-Fayette 1 & 2 345 kV lines. The new 345 kV transmission lines will provide the primary feed into the new Fayette substation and Jeffersonville, Ohio region, which will be the primary load center between Dayton, Cincinnati, and Columbus, Ohio.				
		.3	AES will establish a new three-bay breaker-and-a-half 345 kV substation at Madison. Madison plays a critical role in sourcing the emerging load center while also improving reliability by looping present day radial loads at Cedarville, Jeffersonville and South Charleston. The Madison substation will have a single 345/69 kV transformer and will have 4-345 kV line exits.				
		.4	Jeffersonville 69 kV substation Relocation & Retirement: Retire the existing radial Jeffersonville substation that is located in floodplain and not conducive to further expansion for an additional 69 kV source. The retired substation will be replaced with a new 69 kV looped substation called Panther. The new Panther substation will have three 69/12kV 30MVA distribution transformers. The new Panther sub will be designed as a 69 kV breaker-and-a-half station.	12/31/2025			
		.5	Establish a new ~1.5-mile 69 kV transmission line from Fayette substation to Panther substation using 1351 AAC conductor. Reroute and upgrade to 1351 AAC conductor ~5.5 miles of line from Panther substation to Octa substation (6946 69 kV reroute and extension).				
28	S2855	.1	Build greenfield 138 kV breaker-and-a-half station configuration with four partial strings built initially due to physical arrangement of the station at Kileville 138 kV station. Seven 138 kV 4000A 63 kA circuit breakers will be installed initially.	7/31/2023	$15.85	AEP	12/16/2022
		.2	Cut in to the existing Amlin-Hyatt 138 kV circuit and construct ~0.15 miles of new double circuit line to the proposed Kileville station at Kileville Extension 138 kV. Extend the telecom fiber into Innovation station for relaying/communication.				
		.3	Connect two tie lines to the customer's facility at Kileville-Shire (Customer) 138 kV.				
		.4	Adjust remote end relay settings work at Amlin and Hyatt 138 kV stations.				
		.5	Install temporary customer power required at temporary Kileville Skid station.				
29	S2856		Rebuild the West Coshocton 138-69 kV station with a 138 kV three-breaker ring bus, a new 138-69 kV transformer (90 MVA nameplate), and a single 69 kV breaker. A new control building will also be installed. Remove the existing station facilities.	12/1/2025	$10.17		
30	S2857	.1	Construct a greenfield station with 19-138 kV, 90 kA 4000A circuit breakers in breaker-and-a-half bus configuration at Green Chapel 138 kV.	5/31/2024	$86.75		
		.2	Build out the remaining two breaker-and-a-half strings at the station and install four 138 kV, 4000A 80 kA circuit breakers at Innovation 138 kV.				
		.3	Construct ~2.1 miles of double circuit 138 kV transmission line from Innovation station to Green Chapel station utilizing two bundled ACSS Curlew 1033.5 (54/7) conductor SE rating 1123 MVA at Green Chapel-Innovation 138 kV.				
		.4	Construct ~2.6 miles of double circuit 138 kV transmission line extending from Jug-Corridor 138 kV line to Green Chapel station utilizing 2-bundled ACSR Falcon 1590 (54/19) conductor SE rating 1118 MVA to match the existing conductor on the Corridor-Jug line at Green Chapel Extension 138 kV.				

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
30	S2857 (Cont.)	.5	Additional structures and dead ends will be required on the existing Jug-Corridor double circuit line to accommodate the extension eastward to Green Chapel as the 138 kV circuit is on the west side of the structures at Jug-Corridor 138/345 kV.	5/31/2024	$86.75	AEP	12/16/2022
30	S2857 (Cont.)	.6	Modify the existing 345 kV line structures to enable appropriate height for the new line to Green Chapel station at Conesville-Corridor 345 kV.	5/31/2024	$86.75	AEP	12/16/2022
30	S2857 (Cont.)	.7	Install a second 675 MVA, 345/138 kV transformer to address overloading Jug Street 345/138 kV transformer under N-1-1 contingencies as a result of this customer load interconnection at Babbitt 345/138 kV.	5/31/2024	$86.75	AEP	12/16/2022
30	S2857 (Cont.)	.8	Replace 3000A breakers circuit breaker-104C and 104S with 4000A breakers at Corridor 138 kV. This addresses N-1-1 overloading on those breakers as a result of this customer load interconnection.	5/31/2024	$86.75	AEP	12/16/2022
31	S2857 (Cont.)	.9	Install high- and low-side sectionalizing on the two 138/69 kV transformers at West Lancaster 138 kV. This addresses, due to lack of sectionalizing, N-1-1 overloading on 69 kV lines as a result of this customer load interconnection.	5/31/2024	$86.75	AEP	12/16/2022
32	S2858		Install 1-138 kV, 80kA 4000A circuit breaker in the open F position on the ring bus to accommodate a new distribution transformer at Jug station 138 kV.	6/1/2024	$0.68	AEP	12/16/2022
33	S2859		Replace wave traps, line CCVTs, line and breaker failure relays, carrier sets, and line tuners for the South Akron 138 kV line exit at Firestone substation. At South Akron substation, replace wave traps, line drops, line CCVTs, line and breaker failure relays, carrier sets, and line tuners for the Firestone 138 kV line exit.	6/1/2023	$2.20	ATSI	10/14/2022
34	S2860	.1	Reroute and relocate the Shinrock-Oberlin Muni 69 kV line near structure 242 to the Oberlin Muni substation by building ~2.0 miles of new 69 kV line with 556 kcmil ACSR conductor in new right-of-way and on separate structures. Terminate new line and coordinate relay settings changes at Oberlin Muni substation. Revise relay settings at Shinrock substation.	12/31/2027	$46.90	ATSI	11/18/2022
34	S2860	.2	Rebuild the double circuit portion of Shinrock-Oberlin and Henrietta-Oberlin lines into a single circuit from Henrietta to Oberlin Muni using 556.6 kcmil ACSR conductor. Remove the Shinrock-Oberlin Muni portion of the double circuit. Coordinate relay setting changes at Oberlin Muni substation. Revise relay settings at Henrietta substation.	12/31/2027	$46.90	ATSI	11/18/2022
34	S2860	.3	Rebuild/rehab wood structures on Shinrock-Oberlin Muni 69 kV line from Shinrock to structure 201 including taps to Baird and Buckeye Pipeline and reconductor line with 556 kcmil ACSR conductor. Wood structures heading north at structure 201 were installed in 2019 and are not in need of replacement. Upgrade substation conductor at Wakeman to make TL the most limiting element. Upgrade switches A-74, A-73, A-14, A-16, A-65, and A-45. Revise relay settings at Shinrock and Oberlin Muni substations.	12/31/2027	$46.90	ATSI	11/18/2022
35	S2861		Migrate line relay communication to the SONET network, remove existing carrier schemes, install associated relay and communication equipment and remove the line wave trap (limiting element for winter ratings) at Pleasant Valley.	12/11/2023	$0.10	ATSI	11/18/2022
36	S2862		Migrate line relay communication to the SONET network, remove existing carrier schemes, install associated relay and communication equipment and remove the line wave trap (limiting element for winter emergency rating).	9/26/2023	$0.15	ATSI	11/18/2022
36	S2863		Migrate line relay communication to the SONET network, remove existing carrier schemes, install associated relay and communication equipment and remove the line wave trap (limiting element for winter emergency rating).	9/13/2023	$0.32	ATSI	11/18/2022
36	S2864		Migrate line relay communication to the SONET network, remove existing carrier schemes, install associated relay and communication equipment and remove the line wave trap (limiting element for winter emergency rating).	10/31/2023	$0.37	ATSI	11/18/2022
36	S2865		Migrate line relay communication to the SONET network, remove existing carrier schemes, install associated relay and communication equipment and remove the line wave trap (limiting element for summer emergency and winter ratings).	12/30/2023	$0.14	ATSI	11/18/2022

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
37	S2866		Upgrade Fowles substation's 138 kV No. 1 and No. 3 bus relaying with primary and backup protection scheme Replace one six-pole 138 kV switch (D304 and D305) with two 1200A manually operated GOAB switches. Remove linear couplers for several 138 kV breakers and install slip-over CTs. Replace and install new relaying equipment for bus No.1 and bus No.2 with a dual 487B relay panel. Replace limiting substation conductors.	12/31/2023	$0.62	ATSI	11/18/2022
38	S2867		Replace breakers 13301, 13303 and 13308. Breaker 13305 is to be replaced under supplemental project s1698. Replace line and bus disconnect switches. For the Angola terminal line, replace wave trap and tuner, replace limiting terminal conductor, CVT, and revise relay settings on the Angola PR relay. Replace 138 kV VTs with CVTs for both J and K bus. Replace J and K bus relays with a dual 487B relay panels.		$1.80		
39	S2882	.1	Install a new seven-breaker 138 kV ring bus utilizing 3000A 63 kA breakers to replace the existing Wilson Rd. ring bus. Retire the 40 kV equipment at Wilson Rd.	6/30/2025	$13.70	AEP	1/20/2023
		.2	Rebuild the existing 0.7 miles triple circuit line between structure 47 and Wilson Rd. as double circuit using 1033 ACSR conductor. The third circuit that creates a three-terminal point between Hall, Fisher and Wilson will be permanently retired. The Hall Road-Fisher 138 kV circuit will remain.				
		.3	Convert Phillipi station to 138 kV service to allow for the elimination of the 40kV system between McComb and Wilson Rd. stations. Majority of the station was originally built to 138 kV standards.				
		.4	Build a new 0.7-mile 138 kV double circuit line to serve Phillipi at 138 kV off the Beatty-Wilson circuit.				
		.5	Retire the 5.45-mile 40 kV circuit between Wilson and McComb.				
		.6	The 40 kV breakers at McComb station are no longer needed once Phillipi is converted to 138 kV and will be retired.				
40	S2883	.1	Upgrade the Natrium 138-69 kV station by completing the breaker-and-a-half design in the 138 kV and 69 kV portions of the station. Install a new control house in the 69 kV yard and expand the newer 138 kV control house. Remove the older control house and various 138 kV & 69 kV station structures. Install a 2nd 138 kV capacitor bank (46 MVAR).	12/1/2024	$22.07		
		.2	Construct a new 138 kV transmission line from Natrium to a customer station (0.5 mile), providing a second source to the customer.				
		.3	Perform remote end upgrades at Mobay 69 kV station to coordinate with the new fiber-based line relays at Natrium (two 69 kV circuits). A new transclosure will be installed to house the relays, RTU and metering equipment.				
41	S2884	.1	Rebuild the ~5.04 miles single circuit line with 795 kCM ACSR & install OPGW fiber on new line rebuild at Morse-Gahanna 138 kV line (Gahanna-Hap Cremean & Hap Cremean-Morse Road circuits).	6/1/2027	$29.68		
		.2	Rebuild the ~3.32 miles single circuit line with 795 kCM ACSR at Gahanna-Blacklick 138 kV line, and install OPGW fiber on new line rebuild.				
		.3	Partially rebuild the line from Blacklick to structure No. 11 ~0.71-mile single circuit line with 795 kCM ACSR at Blacklick Extension 138 kV line, and install OPGW fiber on new line rebuild.				
		.4	Perform telecom upgrades at Morse Road 138 kV station.				
		.5	Install remote end relay upgrades, CCVTs, telecom multiplexer, and remove wave trap at Hap Cremean 138 kV station.				
		.6	Install remote end relay upgrades, telecom multiplexer, and remove wave trap at Gahanna 138 kV station.				
		.7	Install remote end relay upgrades, CCVTs, telecom multiplexer, and remove wave trap Blacklick 138 kV station.				
		.8	Install remote end relay upgrades, telecom upgrades, CCVTs, and remove wave trap at East Broad Street 138 kV station.				

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
42	S2885	.1	Install a three-way motor-operated switch with SCADA functionality, to be called Purses switch at East Dover-West Dover tap.	6/1/2023	$2.87	AEP	1/20/2023
		.2	Extend a 0.4-mile radial 69 kV transmission line to reach the customer's substation.				
		.3	Modify the East Dover-West Dover 69 kV transmission line, to connect to the new three-way switch.				
43	S2886	.1	Install Buzzard Glory three-way phase-over-phase MOAB switch off Crooksville-New Lexington 69 kV line.	5/18/2023	$2.13		
		.2	Cut-in to the Crooksville-New Lexington 69 kV line and connect to the new phase over phase switch.				
		.3	Construct ~0.2 miles of greenfield single circuit 69 kV transmission line from new Buzzard Glory three-way phase-over-phase three-way MOAB switch to the customer's station.				
44	S2911	.1	Install an in-out station with an 2000A auto sectionalizing MOAB switch toward Coolville and a 3000A 40 kA circuit breaker toward Bryson at Guysville 69 kV.	6/1/2025	$94.15		2/17/2023
		.2	Construct a greenfield ~12.5-mile single circuit line using 556.5 ACSR (Dove) conductor (SE 142 MVA) at Bryson-Guysville 69 kV.				
		.3	Construct a greenfield ~10.5-mile single circuit line using 556.5 ACSR (Dove) conductor (SE 142 MVA) at Coolville-Guysville 69 kV.				
		.4	Upgrade to an in-out station with two 3000A 40 kA circuit breakers on the through path. Existing wood structures will be replaced with a new steel box bay to accommodate new breakers at Coolville 69 kV.				
		.5	Rebuild the existing single circuit ~12.6-mile line using 556.5 ACSR (Dove) conductor (SE 142 MVA) at Coolville-East Bashan 69 kV.				
		.6	Remove switch going to Hemlock at West Bashan 69 kV.				
		.7	Remove ~7.7 miles of single circuit line at Hemlock-West Bashan 69 kV.				
		.8	Remove the circuit breaker going to West Bashan (circuit breaker C) at Hemlock 69 kV.				
45	S2915	.1	Rebuild ~12.3 miles of line asset, the section between Grace-South Rokeby using 556 ACSR conductor, and install telecom fiber Grace-South Rokeby 69 kV line.	10/1/2026	$57.14		
		.2	Rebuild the whole ~8.4 mile-line asset using 556 ACSR conductor, and install telecom fiber at West Malta-North Muskingum 69 kV line.				
		.3	Rebuild the whole ~2.1-mile line asset using 556 ACSR conductor, and install telecom fiber at West Malta-North McConnelsville 69 kV line.				
		.4	Rebuild both ~0.05 miles (each) line assets using 556 ACSR conductor, and install telecom fiber at South Rokeby-Gould No.1 and No. 2 69 kV line.				
		.5	Rebuild ~0.25 miles on the South Rokeby-West Malta 69 kV circuit and install telecom fiber at South Rokeby-North McConnelsville 69 kV line.				
		.6	Install a new 69 kV, 1200A, three-way phase-over-phase switch outside the fence of North McConnelsville station, and install auto-sectionalizing at Buttermilk Hill switch 69 kV.				
		.7	Replace existing switch with 1200A, three-way switch, and install auto-sectionalizing Pennsville 69 kV phase-over-phase switch.				
46	S2916	.1	Close in the station ring bus with a vertical ring bus, install three-138 kV circuit breakers and associated relaying to accommodate new distribution source at the station at White Road 138 kV.	8/8/2023	$2.07		
		.2	Reterminate T-line 138 kV, install new 138 kV structure just west of existing Str. 29. Reterminate lines into new ring bus positions.				

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
47	S2917	.1	Reconfigure the existing East Cambridge-West Cambridge 69 kV circuit to add in a replacement switch pole for Cassell Junction Sw that is capable of adding MOAB operation on the throughpath. This replacement structure will be one span down from the existing switch in order to comply with current right-of-way standards.	12/31/2025	$2.23	AEP	2/17/2023
		.2	Install a new 138 kV three-way phase-over-phase switch named Cassell Junction switch to serve the Cassell Junction Co-op station.				
		.3	Construct ~ 0.12 miles of new 69 kV line between the new Cassell Junction switch and the Cassell Junction Co-op station using 556 ACSR conductor.				
		.4	Install new customer metering at Cassell Junction for Guernsey Muskingum Electric Cooperative.				
48	S2918		Disconnect the 69 kV feeder loop connecting Brighton substation. Demolish and remove Brighton. Build Camp Washington, a new three-breaker ring bus substation to serve area load formally served by Brighton. Install three 138/13 kV, 22 MVA transformers and switchgear for distribution feeders. Due to land constraints two of the ring positions in this small substation will also loop the South Fairmount-Metro Sewer 138 kV feeder through Camp Washington.	12/29/2025	$19.50	DEO&K	3/17/2023
49	S2920	.1	Replace breakers U and V with 3000A 40 kA breakers at East Lima 69 kV. The 69 kV disconnect switches and sub-conductors will be upgraded. A DICM will be installed to replace the old control structure. Relay and breaker control voltages will be standardized. Environmental remediation at the station will be completed per federal requirements. Remediation will include the disposal of PCB breaker-impacted soils, concrete and a legacy oil processing facility including associated oil piping and equipment.	12/1/2024	$12.10	AEP	
		.2	Upgrade relays at West Lima, Ford Lima, Yellow Creek and Woodlawn to coordinate with the new protection and communication scheme tied out of East Lima.				
50	S2921		Rebuild ~46.1 miles of the ~51.1 miles of line using 954 kCM ACSR bundled conductor, and install OPGW fiber on new line rebuild. Newer steel poles on the line will not be replaced at Conesville-Bixby 345 kV line (Bixby-Ohio Central and Ohio Central-Conesville Circuits).	9/1/2026	$154.53	AEP	2/7/2023
51	S2923	.1	Reconductor ~7.7 miles 138 kV line section from Mayfield to Pinegrove with 336 ACSS, insulators and cold end attachments will be replaced, as needed. Relay setting changes at Mayfield.	6/1/2024	$31.70	ATSI	3/17/2023
		.2	Reconductor ~8.1 miles 138 kV line section from Leroy Center to Pinegrove with 336 ACSS, insulators and cold end attachments will be replaced, as needed. Relay setting changes at Leroy Center.				
52	S2924		Reconductor ~7.7-mile 138 kV line section from Pawnee tap to Mayfield (Q1) with 336 ACSS. Replace tower structures, insulators and hardware as needed to address condition items and support new conductor. Revise relay settings at Mayfield, Leroy Center and Pawnee Leroy Center-Pawnee Q1 138 kV line section is being reconductored under baseline project RTEP B3152.	6/1/2026	$15.20		
53	S2925		Reconductor ~16.1 miles of the Leroy Center-Mayfield Q4 138 kV line with 336 ACSS. Replace tower structures, insulators and hardware as needed to address condition items and support new conductor. Revise relay settings at Mayfield, Leroy Center and Pinegrove.	3/1/2027	$33.50		
54	S2926		Update TR No. 1 and TR No. 2 Relaying at Shenango substation. TR No. 1 (345/138 kV): Replace 345/138 kV transformer grounding relay with SEL-587. Replace 138 kV disconnect switch D1, D3, D4, D5 & D7 and breaker B2 with 3000A equipment. Replace BFT relaying for breakers B2 and B6 with SEL-451. TR No. 2 (345/138 kV): Replace 345/138 kV transformer grounding relay with SEL-587. Replace 138 kV disconnect switch D63, D65, D66, D67 & D69 with 3000A equipment. Replace conductor from transformer bushing to disconnect switch. Modify relaying settings.	12/30/2023	$1.40		12/30/2023
55	S2937		Replace existing 500 Cu strain bus at Fowles 138 kV (Emily-Fox 138 kV line is routed through Fowles 138 kV station). Replace and upgrade seven wood pole structures on Emily-Fox 138 kV Q14 line. Replace damaged and worn insulators on ten additional structures.	12/31/2023	$1.10		4/21/2023
56	S2938		Build Greentree, a new 69 kV substation to serve the area load. Loop the Shaker Run-Red Lion feeder into/out of the substation. Greentree will have a straight bus design with line disconnects on each end controlled by an automatic throw-over scheme. A bus disconnect in series with a circuit switcher will connect a 69/13 kV, 22 MVA distribution transformer. Distribution bus work and breakers will be installed for two feeder exits.	12/13/2024	$3.10	DEO&K	

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
57	S2939	.1	Customer Delivery Point Extension: Establish a new 69 kV delivery point with auto sectionalizing motor operated air brake switches; extend a 0.4-mile 69 kV single circuit extension off the Xenia-Jasper 69 kV transmission line.	12/31/2023	$7.10	DAY	4/21/2023
		.2	Reconductor the 15.8-mile section of 2/0 conductor with 795 ACSR to improve capacity in the area at Jasper-Octa Reconductor.	12/31/2026			
58	S2940		Replace Greenville 69/12kV Bk-3 breaker.	12/31/2025	$0.35		
59	S2944		Replace the three-69 kV oil circuit breakers with new SF6 gas breakers at Warwood. Replace the electromechanical 69 kV line relays and bus differential relays with microprocessor-based relays.	10/1/2024	$1.49	AEP	
60	S2970		Remove the 69 kV cap bank and cap switcher at Scio. A new RTU will be added along with standard SCADA functionality for transmission and distribution equipment.	12/1/2024	$0.10		6/16/2023
61	S2971		Disconnect the 69 kV feeders from the substation at Aicholtz. Remove 69 kV bus, switches and the 69/13 kV transformers. Refeed the substation with the immediately adjacent Beckjord-Summerside 138 kV circuit. Expand the substation and install bus work with two 2000A air-break switches to create positions for three transformers. Install two 2000A motor operated line disconnects with an automatic throw over (ATO) scheme. Install two 138/13 kV, 22 MVA transformers connected with circuit switchers to the 138 kV bus. Install 13 kV switchgear to connect the existing distribution feeders.	3/6/2026	$6.70	DEO&K	5/19/2023
62	S2972		Replace two oil 69 kV breakers with gas breakers, convert the sub from a single bus to a double bus with redundant ties, requiring the addition of two new 69 kV breakers and reconfiguration of the bus at Greenfield substation expansion.	12/31/2026	$2.40	DAY	5/19/2023
63	S2978		Build Brewer, a new distribution substation. Brewer will have a straight bus configuration with positions for two distribution transformers. Install one 69/13 kV, 22 MVA transformer with a circuit switcher on the high side. The low side will be connected to 13 kV bus work with two feeder exits. Loop the Shaker Run-Liberty feeder into/out of the substation, switch connected with an automation throw over scheme (ATO).	12/18/2025	$2.40	DEO&K	7/21/2023
64	S2982	.1	Rebuild the 138 kV bay as a four-breaker ring bus using 3000A 40 kA breakers at South Kenton. Replace transformers two and three with a single 90 MVA unit. Install a DICM and replace the EM relays. Replace the 69 kV bus and breakers C and E.	6/1/2025	$21.68	AEP	
		.2	Reterminate the East Lima-SouRth Kenton 138 kV and South Kenton-Larue 138 kV circuits into the new South Kenton ring bus.				
		.3	Reterminate the South Kenton-Kenton No. 1 69 kV and South Kenton-Kenton No. 2 69 kV circuits into the station. Install fiber between South Kenton and Kenton, retire the pilot wire scheme E.				
		.4	Replace MOABS X,Z with 69 kV 3000A 40 kA breakers at Kenton station.				
		.5	Upgrade telecom equipment at Rangeline and Gunn Road stations.				
65	S2983	.1	Replace 69 kV circuit breakers A & C and Install DICM at North Delphos.	6/1/2026	$23.50		
		.2	Upgrade line relays at Van Wert.				
		.3	Rebuild 2.7 miles of 69 kV with 556 ACSR conductor at South Delphos-Delphos.				
		.4	Rebuild 4.33 miles of 69 kV with dove 556 ACSR at North Delphos-South Delphos. 1.1 miles will be double circuit (part of the in and out to North Delphos not covered under b3346), and 3.2 miles will be single circuit.				
66	S2984	.1	Rebuild the existing 10.73 mile-long line using 795 ACSR Drake conductor at Haviland-Paulding 69 kV.	1/1/2026	$21.17		
		.2	Perform remote end work at Paulding.				
		.3	Perform remote end work at Haviland.				
67	S2985	.1	Construct ~5 miles of 69 kV single circuit at Elgin-North Spencerville. Install ADSS.	12/1/2024	$12.94		
		.2	Install a DCIM expansion and new 69 kV circuit breaker at North Spencerville. Install bypass switch called West Spencerville.				

Table 6.49: Ohio Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
67	S2985 (Cont.)	.3	Install ~0.05 miles of 69 kV single circuit at Kossuth-E Delphos.	12/1/2024	$12.94	AEP	7/21/2023
68	S2999		Install one SCADA-controlled switch. Relocate one existing main-line SCADA controlled switch. Construct ~0.1 miles of 795 kcmil 26/7 ASCR transmission line. Adjust relay settings at London and Tangy substations.	6/1/2024	$0.80	ATSI	5/19/2023
69	S3000		Install three SCADA-controlled transmission line switches, Construct ~250 feet of transmission line using 954 45/7 ACSR from tap point to the customer substation.	10/1/2024	$0.90	APS	6/16/2023

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 6.41**.

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.

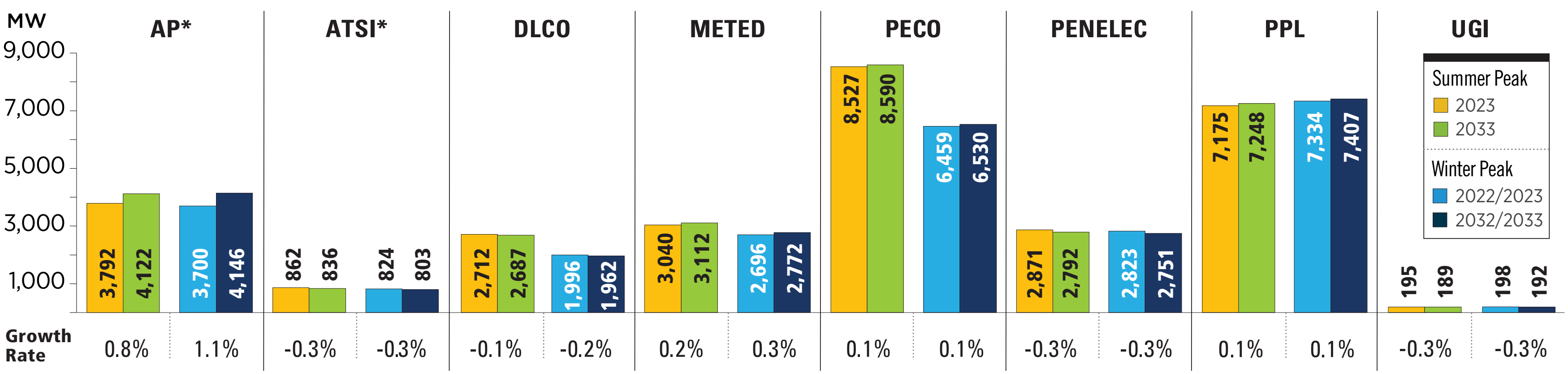
Map 6.41: PJM Service Area in Pennsylvania

6.10.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.46** summarizes the expected loads within the state of Pennsylvania and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.46: Pennsylvania – 2023 Load Forecast Report



*Serves load outside PA

PJM RTO Summer Peak		PJM RTO Winter Peak	
2023	2033	2022/2023	2032/2033
149,059 MW	160,971 MW	130,811 MW	144,992 MW
Growth Rate 0.8%		Growth Rate 1.0%	

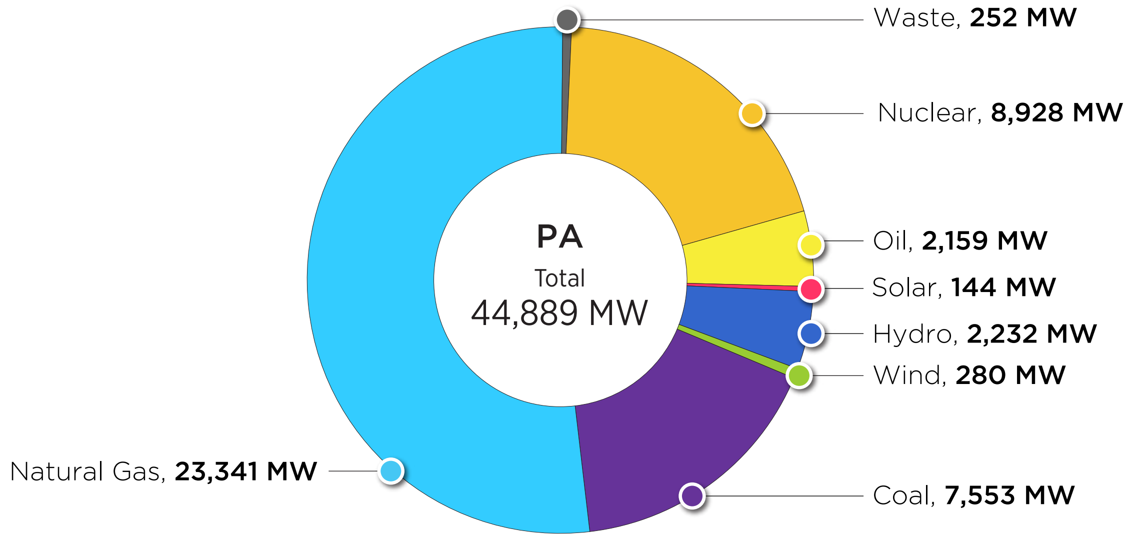
The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.10.3 — Existing Generation

Existing generation in Pennsylvania as of Dec. 31, 2023, is shown by fuel type in **Figure 6.47**.

Read More
Changing Capacity Mix and Deliverability

Figure 6.47: Pennsylvania – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)



6.10.4 — Interconnection Requests

In Pennsylvania, as of Dec. 31, 2023, 614 projects were actively under study or under constwruction as shown in the summaries presented in **Table 6.50, Table 6.51, Figure 6.48, Figure 6.49** and **Figure 6.50**.

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.

Read More
Interconnection Requests

Table 6.50: Pennsylvania – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Pennsylvania Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	224	1.49%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	95	0.63%	5,278	2.96%
Other	3	0.02%	70	0.04%
Solar	9,849	65.41%	98,471	55.15%
Storage	4,499	29.88%	53,644	30.04%
Wind	388	2.58%	20,798	11.65%
Grand Total	15,058	100.00%	178,566	100.00%

Table 6.51: Pennsylvania – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		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	16	229.0	28	14,354.6	44	14,583.6
	Diesel	1	0.0	0	0.0	0	0.0	4	37.4	13	51.5	18	88.9
	Natural Gas	3	95.0	0	0.0	1	2.5	124	21,710.8	260	92,554.5	388	114,362.8
	Nuclear	0	0.0	0	0.0	1	44.0	14	2,565.0	14	1,731.0	29	4,340.0
	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	2	306.5	6	344.0	9	653.4
	Storage	67	4,498.6	3	101.0	1	32.0	5	0.0	64	1,249.6	140	5,881.1
Renewable	Biomass	0	0.0	0	0.0	0	0.0	1	6.4	4	36.5	5	42.9
	Hydro	4	224.3	0	0.0	3	35.0	12	480.8	19	715.4	38	1,455.4
	Methane	0	0.0	0	0.0	0	0.0	23	125.9	37	201.3	60	327.2
	Solar	449	9,849.2	53	855.7	68	1,191.4	22	172.9	426	6,308.1	1,018	18,377.5
	Wind	13	387.7	0	0.0	2	34.5	40	299.0	140	1,791.9	195	2,513.1
	Wood	0	0.0	0	0.0	0	0.0	0	0	1	16.0	1	16.0
	Grand Total	**538**	**15,057.7**	**56**	**956.7**	**76**	**1,339.5**	**272**	**25,950.5**	**1,021**	**120,661.4**	**1,963**	**163,965.8**

Figure 6.48: Pennsylvania – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

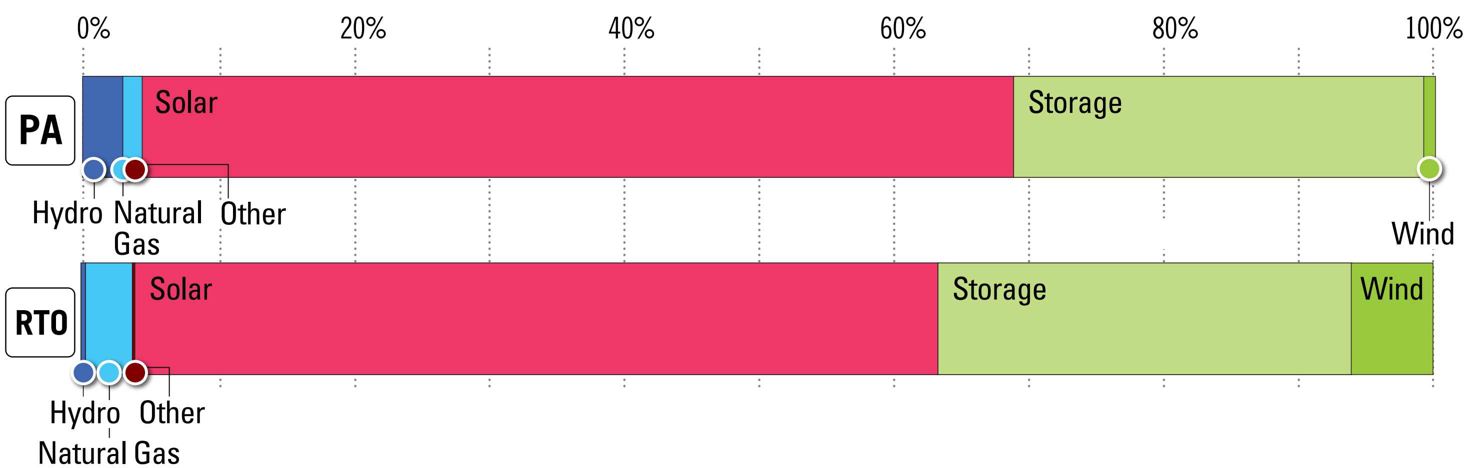
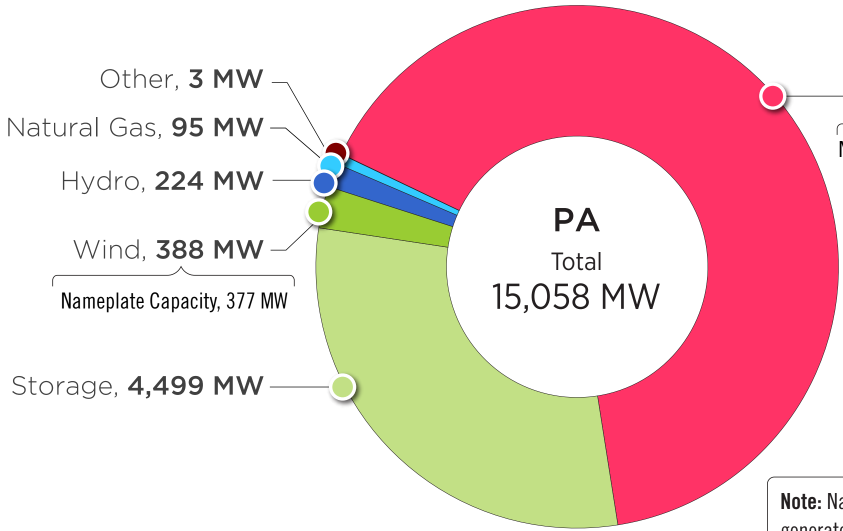


Figure 6.49: Pennsylvania Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.50: Pennsylvania Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

17.7% Requested capacity megawatts

20.4% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	75	Interconnection Service Agreements	8,767 MW	11,022 MW
	87	Wholesale Market Participation Agreements	406 MW	640 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.10.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Pennsylvania between Jan. 1, 2023, and Dec. 31, 2023, are summarized in **Map 6.42** and **Table 6.52**.

Read More
Generation Deactivation

Map 6.42: Pennsylvania Generation Deactivations (Dec. 31, 2023)

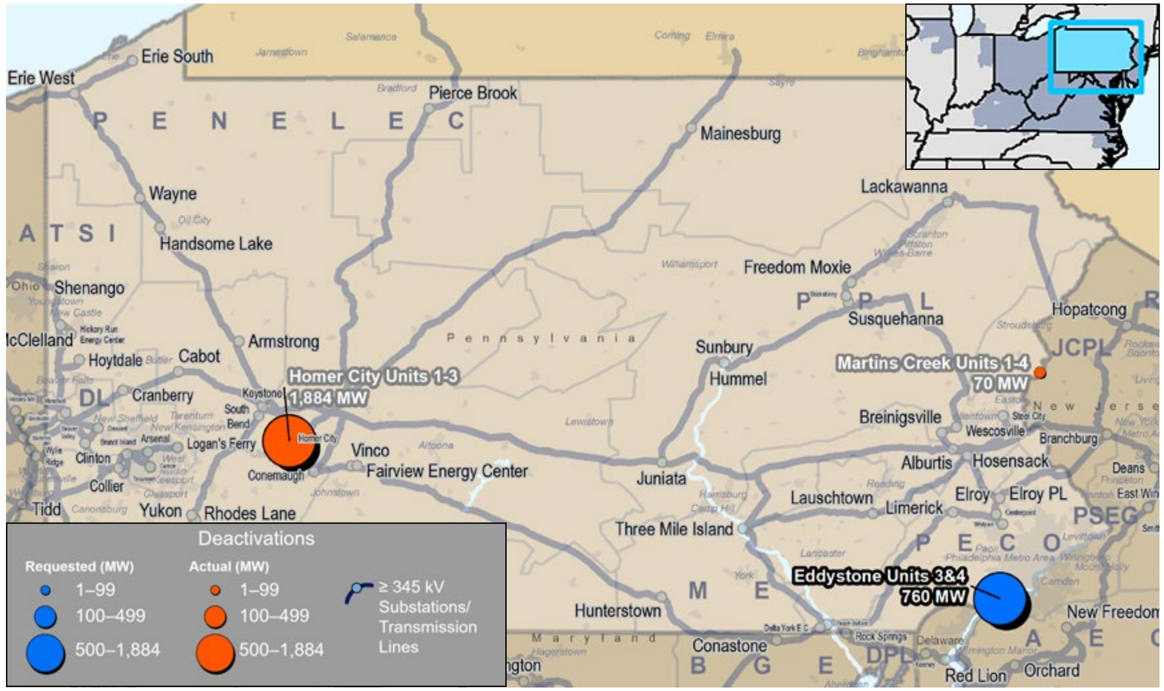


Table 6.52: Pennsylvania Generation Deactivations (Dec. 31, 2023)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
EDDYSTONE 4	PECO	Oil	12/1/23	5/31/2025	53	380
EDDYSTONE 3						380
HOMER CITY 3	PENELEC	Coal	3/31/23	7/1/2023	46	650
HOMER CITY 2					54	614
HOMER CITY 1						620
Martins Creek CT 1	PPL	Oil	2/10/2022	6/1/2023	50	18
Martins Creek CT 2						17.3
Martins Creek CT 4	PPL	Natural Gas				17.3

6.10.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in Pennsylvania are summarized in **Map 6.43** and **Table 6.53**.

Map 6.43: Pennsylvania Baseline Projects (Dec. 31, 2023)

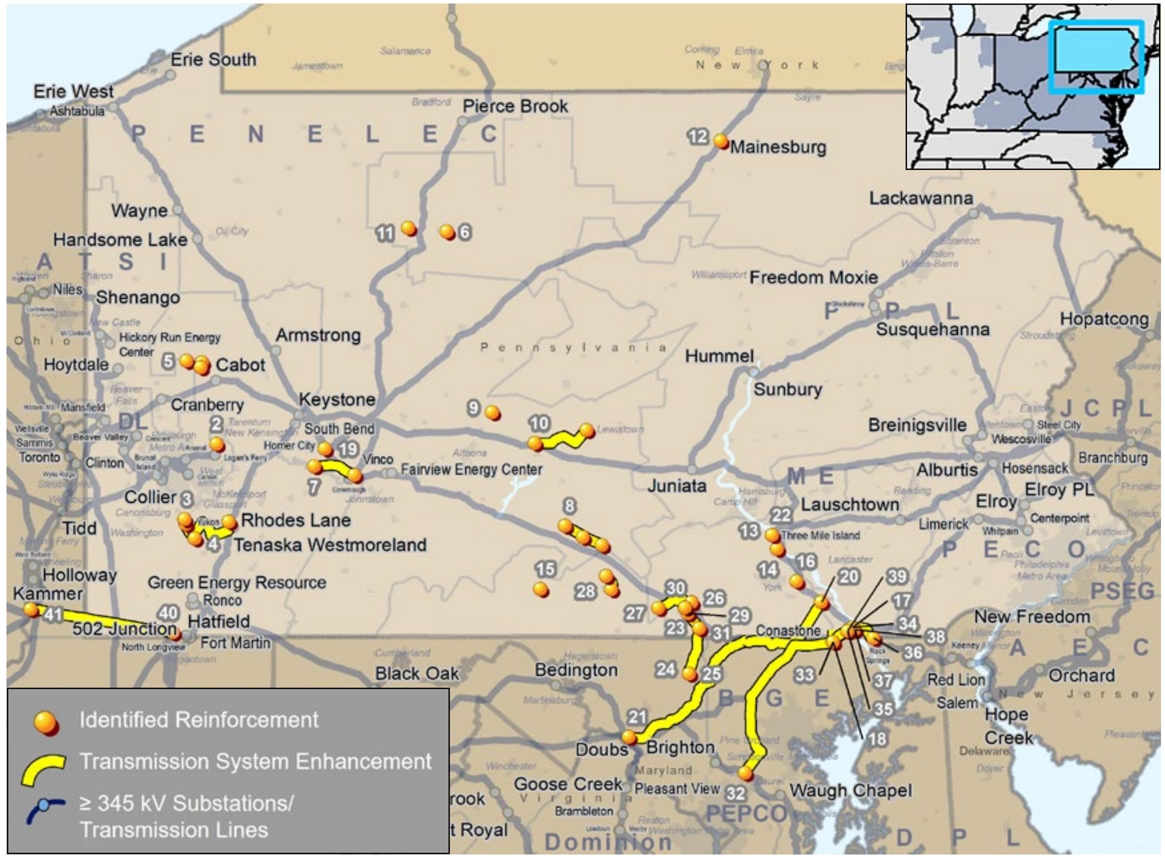


Table 6.53: Pennsylvania Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3717	.3	Perform relay work at Springdale 138 kV.	12/31/2024	$3.00	AP	4/11/2023
2		.4	Perform transmission line work – a new transmission structure and necessary tower work to handle the change in tension at Cheswick 138 kV.	1/1/2025			
3	B3738		Replace limiting terminal equipment at Charleroi-Dry Run 138 kV line.	6/1/2027	$0.38		11/18/2022

Table 6.53: Pennsylvania Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	B3739		Replace limiting terminal equipment at Dry Run-Mitchell 138 kV line.	6/1/2027	$0.40	AP	11/18/2022
4	B3741		Replace limiting terminal equipment at Yukon-Charleroi No. 1 138 kV line.	6/1/2027	$0.70	AP	11/18/2022
4	B3742		Replace limiting terminal equipment at Yukon-Charleroi No. 1 138 kV line.	6/1/2027	$0.70	AP	11/18/2022
5	B3744		Replace one span of 1272 ACSR from Krendale substation to structure 35 (~630 ft). Replace one span of 1272 ACSR from Shanor Manor to structure 21 (~148 ft). Replace 1272 ACSR risers at Krendale and Shanor Manor substations. Replace 1272 ACSR substation conductor at Krendale substation. Replace relaying at Krendale substation. Revise relay settings at Butler and Shanor Manor substations.	6/1/2027	$1.75	AP	11/18/2022
6	B3745		Install redundant relaying at Carbon Center substation.	6/1/2027	$0.57	AP	11/18/2022
7	B3750		Upgrade Seward terminal equipment of the Seward-Blairsville 115 kV line to increase the line rating such that the transmission line conductor is the limiting component.	6/1/2027	$0.43	PENELEC	10/13/2022
8	B3751		Rebuild 6.4 miles of the Roxbury-Shade Gap 115 kV line from Roxbury to the AE1-071 115 kV ring bus with single circuit 115 kV construction.	6/1/2027	$15.03	PENELEC	10/13/2022
	B3752		Rebuild 7.2 miles of the Shade Gap-AE1-071 115 kV line section of the Roxbury-Shade Gap 115 kV line.	6/1/2027	$17.43	PENELEC	10/13/2022
9	B3753		Replace the Tyrone North 115 /46 kV transformer with a new standard 75 MVA top-rated bank and upgrade the entire terminal to minimum 100 MVA capability for both SN and SE rating.	6/1/2027	$2.82	PENELEC	10/13/2022
10	B3754		Construct a new three-breaker ring bus to tie into the Warrior Ridge-Belleville 46 kV D line and the 1LK line at at Maclane tap.	6/1/2027	$10.09	PENELEC	10/13/2022
11	B3761		Install 138 kV breaker on the Ridgeway 138/46 kV No. 2 transformer.	6/1/2027	$1.10	AP	12/16/2022
12	B3765		Purchase one 80 MVAR 345 kV spare reactor to be located at the Mainesburg station.	12/1/2022	$6.44	PENELEC	11/4/2022
13	B3769		Install second TMI 500/230 kV transformer with additional 500 and 230 bus expansions.	6/1/2027	$30.19	METED	12/6/2022
14	B3770		Rebuild 1.4 miles of existing single circuit 230 kV tower line between BGE's Graceton substation to the Brunner Island PPL tie line at the MD/PA state line to double circuit steel pole line with one circuit installed to uprate 2303 circuit.	6/1/2027	$8.40	BGE	12/6/2022
15	B3773		Install 33 MVAR switched capacitor, 138 kV breaker and associated relaying at McConnellsburg 138 kV substation.	6/1/2027	$3.05	AP	12/6/2022
16	B3774		Upgrade terminal equipment at Brunner Island (on the Brunner Island-Yorkana 230 kV circuit).	6/1/2027	$2.50	PPL	12/6/2022
17	B3780	.1	Perform substation upgrade work at Peach Bottom North. Add three 500 kV breakers to form a breaker-and-a-half bay.	6/1/2027	$81.00	PECO	6/6/2023
18	B3780	.2	Add new 500 kV transmission line at Peach Bottom to Graceton (PECO). New rating: 4503 MVA SN/ 5022 MVA SE.	6/1/2027	$81.00	PECO	6/6/2023
19	B3783		Cut and remove the 345 kV and 230 kV generator lead lines at Homer City. Install new station service supply, separate AC station service, separate protection and controls schemes, and review and adjust relay protection settings.	6/1/2027	$2.25	PENELEC	9/5/2023
20	B3800	.1	Build New Otter Creek 500 kV (Collinsville) (switching station – two-bay three-breaker configuration).	6/1/2027	$313.35	PPL	12/5/2023
20	B3800	.2	Break the existing TMI-Peach Bottom 500 kV line and reterminate into adjacent Otter Creek 500 kV switchyard.	6/1/2027	$313.35	METED	12/5/2023
21	B3800	.3	Build New Otter Creek (Collinsville) to Doubs 500 kV line (Otter Creek 500 kV – MD Border). Rebuild and expand existing ~12 miles of Otter Creek-Conastone 230 kV line to become a double-circuit 500 and 230 kV lines.	6/1/2027	$313.35	PPL	12/5/2023
22	B3800	.5	Replace terminal equipment at Peach Bottom at Peach Bottom-TMI 500 kV.	6/1/2027	$313.35	PECO	12/5/2023
22	B3800	.6	Replace terminal equipment at TMI at Peach Bottom-TMI 500 kV.	6/1/2027	$313.35	METED	12/5/2023

Table 6.53: Pennsylvania Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
23	B3800 (Cont.)	.10	Rebuild the Germantown-Lincoln 115 kV line for 230 kV double circuit construction.	6/1/2027	$313.35	METED	12/5/2023
23	B3800 (Cont.)	.11	Rebuild the Hunterstown-Lincoln 115 kV line for 230 kV double circuit construction.	6/1/2027	$313.35	METED	12/5/2023
24	B3800 (Cont.)	.12	Rebuild the Germantown-Carroll 138 kV line for 230 kV double circuit construction (MAIT).	6/1/2027	$313.35	METED	12/5/2023
25	B3800 (Cont.)	.14	Construct new 230 kV Hunterstown-Carroll line (MAIT section).	6/1/2027	$313.35	METED	12/5/2023
26	B3800 (Cont.)	.18	Add a new 230 kV breaker at the Hunterstown 230 kV substation for the new Hunterstown-Carroll 230 kV termination.	6/1/2027	$313.35	METED	12/5/2023
27	B3800 (Cont.)	.19	Reconductor Lincoln-Orrtanna 115 kV line.	6/1/2027	$313.35	METED	12/5/2023
28	B3800 (Cont.)	.20	Replace line trap at Grand Point 138 kV at Fayetteville-Grand Point 138 kV.	6/1/2027	$313.35	AP	12/5/2023
29	B3800 (Cont.)	.22	Install DTT relaying at Straban substation.	6/1/2027	$313.35	METED	12/5/2023
30	B3800 (Cont.)	.23	Revise relay settings at Lincoln substation.	6/1/2027	$313.35	METED	12/5/2023
31	B3800 (Cont.)	.24	Revise relay settings at Germantown substation.	6/1/2027	$313.35	METED	12/5/2023
32	B3800 (Cont.)	.31	Build new North Delta-High Ridge 500 kV line.	6/1/2027	$313.35	PECO	12/5/2023
33	B3800 (Cont.)	.35	Rebuild 5012 (existing Peach Bottom-Conastone) (new North Delta-Graceton PECO) 500 kV line on single circuit structures within existing right of way and cut into North Delta 500 kV and Gracetone 500 kV stations.	6/1/2027	$313.35	PECO	12/5/2023
34	B3800 (Cont.)	.42	Replace 11 instances of strain bus conductor used for breaker drops or CT drops, seven 500 kV disconnect switches, seven free-tanding CTs, one 500 kV breaker, two breaker relays or meters for Peach Bottom North bus upgrade.	6/1/2027	$313.35	PECO	12/5/2023
35	B3800 (Cont.)	.44	Terminate North Delta for the North Delta-High Ridge 500 line (PECO work).	6/1/2027	$313.35	PECO	10/31/2023
36	B3800 (Cont.)	.45	Terminate North Delta 500 kV for the Rock Springs 500 kV line (5034/5014 line) (PECO work).	6/1/2027	$313.35	PECO	10/31/2023
37	B3800 (Cont.)	.46	Terminate North Delta 500 kV for the new Peach Bottom-North Delta 500 kV line (PECO work).	6/1/2027	$313.35	PECO	10/31/2023
38	B3800 (Cont.)	.47	Build new Peach Bottom South-North Delta 500 kV line – cut in to Peach Bottom tie No. 1 and extending line to North Delta (~1.25 miles new right of way).	6/1/2027	$313.35	PECO	10/31/2023
39	B3800 (Cont.)	.48	Terminate North Delta for the North Delta-High Ridge 500 line (Transource work).	6/1/2027	$313.35	Transource	10/31/2023
39	B3800 (Cont.)	.49	Terminate North Delta 500 kV for the Calpine generator (Calpine/Transource work).	6/1/2027	$313.35	Transource	10/31/2023
39	B3800 (Cont.)	.50	Terminate North Delta 500 kV for the Rock Springs 500 kV line (5034/5014 line) (Transource work).	6/1/2027	$313.35	Transource	10/31/2023
39	B3800 (Cont.)	.51	Terminate North Delta 500 kV for the new Peach Bottom-North Delta 500 kV line (Transource work).	6/1/2027	$313.35	Transource	10/31/2023
40	B3800 (Cont.)	.101	Expand 502 Junction substation with two 500 kV circuit breakers.	6/1/2027	$313.35	AP	12/5/2023
41	B3800 (Cont.)	.121	Conduct LIDAR Sag Study to assess SE rating and needed upgrades at Kammer to 502 Junction 500 kV line.	6/1/2027	$0.10	AEP	12/5/2023

6.10.7 — Network Projects

Network projects in Pennsylvania for 2023 are summarized in **Map 6.44** and **Table 6.54**.

Read More
Network Projects

Map 6.44: Pennsylvania Network Projects (Dec. 31, 2023)

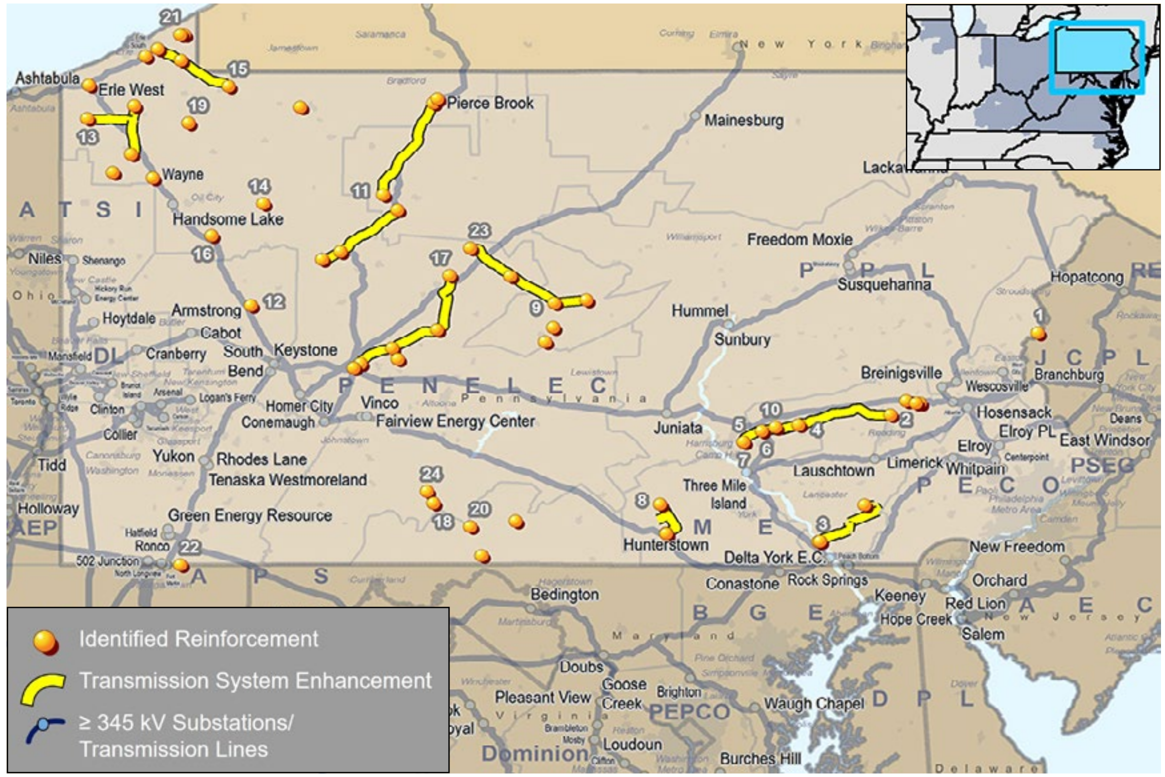


Table 6.54: Pennsylvania Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5806	Perform relay modification work to accommodate AD1-037.	AD1-037	5/1/2019	$0.03	PPL	
2	N5886	Install one span of attachment facility line from the point of interconnection to the tap point at or near MAIT structure No. 838-175 of the Lyons-Moselem 69 kV line.	AD2-115	4/1/2020	$0.21	METED	10/3/2023
	N5887	Install two switches at the tap point at or near MAIT structure No. 838-175 of the Lyons-Moselem 69 kV line.			$0.42		

Table 6.54: Pennsylvania Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2 (Cont.)	N5888	Perform estimated installation of 700 MHz radio system (70% penetration of FE territory) at AD2-115 to support the SCADA switch installations. Assumed SCADA work is included in this cost.	AD2-115	4/1/2020	$0.05	METED	10/3/2023
3	N6688	Construct 69 kV tap line, MOLBAB switch, poles, structure and foundations for AE1-226 interconnection at attachment facilities.	AE1-226	9/30/2020	$0.84	PPL	10/3/2023
3	N6689	Perform modifications to the Face Rock-Kinzer 69 kV line to tie in the AE1-226 attachment facilities.	AE1-226	9/30/2020	$0.09	PPL	10/3/2023
3	N6690	Perform relay modification scope of work at Face Rock substation.	AE1-226	9/30/2020	$0.21	PPL	10/3/2023
3	N8018	Design, install and test/commission MPLS equipment for SCADA transport at AE2-256 substation 230 kV.	AE1-226	6/30/2022	$0.30	METED	10/3/2023
4	N8019	Replace CVT and line/carrier relaying North Lebanon substation 230 kV.	AE1-226	6/30/2022	$0.67	METED	10/3/2023
5	N8020	Loop the 1094-1(Copperstone-North Lebanon) 230 kV line into a new substation, ~7.5 miles from the North Lebanon substation.	AE1-226	6/30/2022	$2.33	METED	10/3/2023
6	N8021	Install one steel pole strain structure on the existing North Hershey-North Temple 230 kV line to avoid clearance violations to new loop structures on the 1094-1 (Copperstone-North Lebanon) 230 kV line.	AE1-226	6/30/2022	$1.04	METED	10/3/2023
7	N8022	Replace CVT and line/carrier relaying at Copperstone substation (PPL 230 kV).	AE1-226	6/30/2022	$0.52	PPL	10/3/2023
8	N8072.1	Design, install and test/commission MPLS equipment for SCADA transport at the new AE2-345 substation.	AE2-345	4/9/2019	$0.26	METED	10/3/2023
8	N8072.2	Install fiber from AE2-345 interconnection to Hunterstown for relaying communication and MPLS transport (SCADA/fiber communication).	AE2-345	4/9/2019	$1.07	METED	10/3/2023
8	N8072.3	Loop existing L991 Gardners-Hunterstown 115 kV line into the new three-breaker ring bus ~4.2 miles from the Hunterstown substation.	AE2-345	4/9/2019	$0.77	METED	10/3/2023
8	N8072.4	Modify drawings, relay settings and nameplates for line name change at Gardeners 115 kV.	AE2-345	4/9/2019	$0.10	METED	10/3/2023
8	N8072.5	Modify drawings, relay settings and nameplates for line name change Hunterstown 115 kV.	AE2-345	4/9/2019	$0.10	METED	10/3/2023
8	N8072.6	Perform FirstEnergy work at new station built by developer (Security & Network), AE2-345 option to build.	AE2-345	4/9/2019	$1.57	METED	10/3/2023
9	N8097.1	Tap the existing Nittany-Zion 46 kV line and install two main line switches and one tap switch to interconnect queue project AE2-001. Tap and CTs/PTs mounted in the customer's station (AE2-001).	AE2-001	6/30/2025	$0.16	AP	10/3/2023
9	N8097.2	Replace Stone Junction 46 kV line relaying at Nittany for AE2-001 interconnection (Nittan 46 kV).	AE2-001	6/30/2025	$0.26	AP	10/3/2023
9	N8097.3	Replace Stone Junction 46 kV line relaying at Pleasant Gap for AE2-001 interconnection (Pleasant Gap 46 kV).	AE2-001	6/30/2025	$0.26	AP	10/3/2023
9	N8097.4	Replace Stone Junction 46 kV line relaying at Milesburg for AE2-001 interconnection (Milesburg 46 kV).	AE2-001	6/30/2025	$0.26	AP	10/3/2023
10	N8118	Construct a new three-breaker ring bus on the 230 kV (1094) line between Copperstone and North Lebanon (AE2-256 substation); includes project management, environmental, forestry, real estate and right-of-way.	AE2-256	6/30/2022	$6.14	METED	10/3/2023
10	N8119	Perform estimated in-sub fiber run to customer-built fiber run outside AE2-256 substation. Perform estimated SCADA work at North Lebanon substation to support relay installation and updated relay settings (AE2-256 substation).	AE2-256	6/30/2022	$0.05	METED	10/3/2023
11	N8187.1	Construct a loop from the Farmers Valley-Ridgway 115 kV line to the new substation, ~14.4 miles from Farmers Valley substation.	AE2-113	12/31/2020	$1.69	PENELEC	10/3/2023
11	N8187.2	Perform line terminal upgrade at Ridgway substation 115 kV.	AE2-113	12/31/2020	$0.19	PENELEC	10/3/2023
11	N8187.3	Perform line terminal upgrade at Farmers substation 115 kV.	AE2-113	12/31/2020	$0.30	PENELEC	10/3/2023

Table 6.54: Pennsylvania Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
11 (Cont.)	N8187.4	Perform line terminal upgrade at Pierce Brook substation 115 kV.	AE2-113	12/31/2020	$0.06	PENELEC	10/3/2023
12	N8188.1	Loop the Brookville-Squab Hollow 138 kV line into the new AE2-316 interconnection sub.	AE2-316	12/31/2020	$1.58	PENELEC	10/3/2023
12	N8188.2	Install new relays and modify relay settings at Brookville 138 kV.	AE2-316	12/31/2020	$0.24	PENELEC	10/3/2023
12	N8188.3	Install anti-islanding transmitter at Armstrong 138 kV.	AE2-316	12/31/2020	$0.19	PENELEC	10/3/2023
12	N8188.4	Install anti-islanding transmitter at Squab Hollow 138 kV.	AE2-316	12/31/2020	$0.21	PENELEC	10/3/2023
12	N8188.5	Install fiber from AE2-316 to Backbone for communication transport at AE2-316 Direct Connect-Squab Solar.	AE2-316	12/31/2020	$1.11	PENELEC	10/3/2023
12	N8188.6	Design, install and test/commission MPLS equipment for SCADA transport at AE2-316 interconnection substation (SCADA/Fiber Communication).	AE2-316	12/31/2020	$0.29	PENELEC	10/3/2023
13	N8193.1	Install fiber from AE2-344 interconnection substation to Edinboro South for communication transport.	AE2-344	3/31/2026	$0.40	PENELEC	10/3/2023
13	N8193.10	Perform line terminal upgrade at Morgan Street substation 115 kV.	AE2-344	3/31/2026	$0.59	PENELEC	10/3/2023
13	N8193.2	Design, install and test/commission MPLS equipment for SCADA transport at AE2-344 interconnection substation.	AE2-344	3/31/2026	$0.19	PENELEC	10/3/2023
13	N8193.3	Loop from the MF1/MFS (Edinboro South-Morgan Street-Springboro) 115 kV line to the new AE2-344 interconnection substation.	AE2-344	3/31/2026	$0.97	PENELEC	10/3/2023
13	N8193.4	Perform line terminal upgrade at Edinboro South 115 kV.	AE2-344	3/31/2026	$0.55	PENELEC	10/3/2023
13	N8193.5	Perform line terminal upgrade at Wayne substation 115 kV.	AE2-344	3/31/2026	$0.03	PENELEC	10/3/2023
13	N8193.6	Perform line terminal upgrade at Geneva substation 115 kV.	AE2-344	3/31/2026	$0.53	PENELEC	10/3/2023
13	N8193.7	Perform line terminal upgrade at Erie West substation 115 kV.	AE2-344	3/31/2026	$0.21	PENELEC	10/3/2023
13	N8193.8	Perform line terminal upgrade at Erie South substation 115 kV.	AE2-344	3/31/2026	$0.21	PENELEC	10/3/2023
13	N8193.9	Perform line terminal upgrade at Springboro substation 115 kV.	AE2-344	3/31/2026	$0.52	PENELEC	10/3/2023
14	N8207.1	Add new SCADA switch at the proposed tap point on the 34.5 kV Tionesta Jct./Crown distribution circuit.	AF2-130	6/30/2023	$0.11	PENELEC	10/3/2023
14	N8207.2	Integrate customer protection and controls to the FE transmission system at AF2-130 generation substation.	AF2-130	6/30/2023	$0.08	PENELEC	10/3/2023
14	N8207.3	Install 34.5 kV PT as well as SEL-351S at Crown substation.	AF2-130	6/30/2023	$0.63	PENELEC	10/3/2023
14	N8207.4	Revise relay settings at Tionesta substation 34.5 kV.	AF2-130	6/30/2023	$0.11	PENELEC	10/3/2023
15	N8312.1	Loop the Corry East-Four Mile Junction 115 kV line into the new substation, ~7.7 miles from Four Mile Junction substation.	AF1-098	8/30/2019	$0.96	PENELEC	10/3/2023
15	N8312.2	Provide interconnection facilities for PJM AF1-098 at Warren substation 115 kV.	AF1-098	8/30/2019	$0.59	PENELEC	10/3/2023
15	N8312.3	Provide interconnection facilities for PJM AF1-098 at Corry East substation 115 kV. Replace carrier equipment and relaying at Corry East.	AF1-098	8/30/2019	$0.89	PENELEC	10/3/2023
15	N8312.4	Provide interconnection facilities for PJM AF1-098 at Four Mile substation 115 kV. Replace carrier equipment and relaying at Four Mile Junction.	AF1-098	8/30/2019	$0.77	PENELEC	10/3/2023
15	N8312.5	Construct a new interconnection substation with three 115 kV breakers in a ring bus configuration at Four Mile 115 kV substation.	AF1-098	8/30/2019	$7.90	PENELEC	10/3/2023

Table 6.54: Pennsylvania Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
15 (Cont.)	N8312.6	Install fiber from AF1-098 to Four Mile Junction for communication transport at AF1-098.	AF1-098	8/30/2019	$4.70	PENELEC	10/3/2023
	N8312.7	Design, install and test/commission MPLS equipment for SCADA transport at AF1-098.			$0.29		
16	N8313.1	Install tap pole at Emlenton 34.5 kV.	AF2-166	3/17/2020	$0.02		
	N8313.2	Revise relay settings at Haynie 34.5 kV.			$0.27		
	N8313.3	Revise relay settings at Emlenton 34.5 kV.			$0.27		
17	N8314.1	Design, install and test/commission MPLS equipment for SCADA transport at the new AF1-086 interconnection substation (SCADA/fiber communication).	AF1-086	9/20/2019	$0.21	MAIT	
	N8314.2	Install fiber from AF1-086 interconnection substation to ADSS backbone for communication transport.			$1.26		
	N8314.3	Loop existing Garman Shawville 115 kV line into the new CPV Rogue's Wind interconnection substation.			$1.21		
	N8314.4	Modify drawings and nameplates for line name change Madera 115 kV.			$0.03		
	N8314.5	Modify drawings and nameplates for line name change at Westover 115 kV.			$0.03		
	N8314.6	Perform line terminal upgrade at Glory 115 kV.			$0.39		
	N8314.7	Perform line terminal upgrade at Shawville 115 kV.			$0.57		
	N8314.8	Perform line terminal upgrade at Garman 115 kV.			$0.81		
18	N8327	Replace existing 23 kV Bedford relaying with one SEL-351S and install one SATEC meter.	AF2-092	9/15/2022	$0.77	PENELEC	
19	N8370.1	Tap Cambridge Springs-Corry Central 34.5 kV line and convert ~three-quarters of a mile of 12 kV to 35 kV.	AF1-094	1/1/2023	$0.42		
	N8370.2	Update relay settings on 34.5 kV Cambridge Springs line.			$0.05		
	N8370.3	Install one 700 MHz radio system to support SCADA switch at AF1-094 tap location.			$0.06		
20	N8374.1	Replace existing McConnellsburg line relaying with one standard line relaying panel with two SEL-421 and one SEL-501 BFT at Warfordsburg substation.	AF1-136	3/28/2019	$0.19	AP	
	N8374.2	Install two main line switches on the existing Warfordsburg-Purcell Jct 34.5 kV line.			$0.12		
	N8374.3	Reconductor ~1.6 mi from Mercersburg-AD1-061 (Elk Hill 1) tap 34.5 kV line from Mercersburg substation to Pole PA406-WP47 with 795 ACSR conductor.			$1.32		
	N8374.4	Replace limiting conductors and revise relay settings at Mercersburg substation 34.5 kV.			$0.23		
	N8374.5	Revise relay settings at McConnellsburg substation 34.5 kV.			$0.13		
21	N8449.1	Install one 230 kV breaker and a new 230 kV line terminal position to create a five-breaker ring bus at Erie East substation.	AE2-299	6/1/2026	$2.91	PENELEC	
	N8449.2	Install anti-islanding (transfer trip) equipment at Four Mile Junction substation.			$0.63		
	N8449.3	Perform fiber connection and associated conduit to customer substation at Erie East substation.			$0.18		
22	N8450.5	Replace Panel No. 4 existing line relaying with new breaker control panel with one SEL451 and one SATEC meter at Lake Lynn substation 138 kV at Lake Lynn substation 138 kV.	AE1-106	9/30/2021	$0.33	AP	
23	N8457.1	Construct a new 230 kV three-breaker ring bus looping in the Moshannon-Milesburg 230 kV line to provide interconnection facilities for AE2-262/AE2-263.	AE2-262	6/30/2022	$11.43		

Table 6.54: Pennsylvania Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
23 (Cont.)	N8457.2	Design, install and test/commission MPLS equipment for SCADA transport at AE2-262/AE2-263 interconnection sub.	AE2-262	6/30/2022	$0.24	AP	10/3/2023
	N8457.3	Install fiber from AE2-262/AE2-263 new interconnection substation to fiber backbone for communication transport.			$0.15		
	N8457.4	Cut and loop the Moshannon-Milesburg 230 kV line into the new 230 kV interconnect substation. This cut will take place at a location that is ~16.3 miles from the Moshannon substation.			$1.72		
	N8457.5	Install anti-islanding and carrier equipment in existing relay panels at Moshannon 230 kV. Existing Milesburg line relaying will be replaced.			$0.69		
	N8457.6	Replace one existing 230 kV CVT, wave trap, line tuner and circuit breaker at Milesburg 230 kV. Anti-islanding will be installed. Existing Moshannon line relaying panel will be replaced.			$1.82		
	N8457.7	Install a new carrier relaying panel with anti-islanding for the Milesburg and Shingletown exits at Dale Summit 230 kV.			$0.57		
	N8457.8	Install a new carrier relaying panel with anti-islanding for the Dale Summit exit at Shingletown 230 kV.			$0.61		
24	N8458	Install one 23 kV line potential transformer and associated structure on Bedford North line. Replace 23 kV Bedford North line relays with one line relaying panel with one SEL351S and one SATEC Meter.	AG1-041	12/15/2022	$0.69	PENELEC	

6.10.8 — Supplemental Projects

Supplemental projects received by PJM in 2023 in Pennsylvania are summarized in **Map 6.45** and **Table 6.55**.

Read More
Supplemental Projects

Map 6.45: Pennsylvania Supplemental Projects (Dec. 31, 2023)

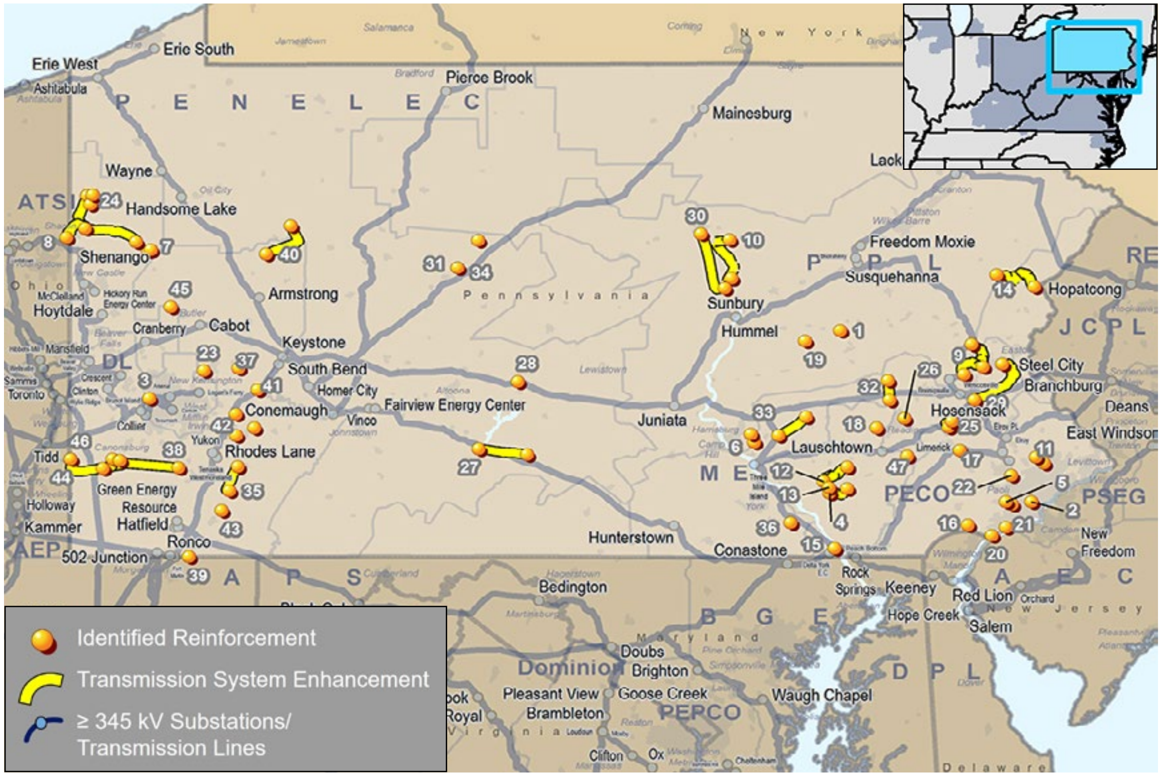


Table 6.55: Pennsylvania Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2753		Build a new breaker-and-a-half 230/69 kV substation next to the existing Frackville substation to address aging infrastructure and lack of operational flexibility.	12/31/2025	$60.00	PPL	5/10/2022
2	S2808		Install one 3000A 63 kA 230 kV breaker on the master straight bus to create a bus section for the third Master 230/13 kV transformer and install third master 230/13 kV 62 MVA transformer with high-side breaker.		$0.80	PECO	8/9/2022

Table 6.55: Pennsylvania Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2826		Replace the two Brunot Island 138/69 kV transformers.	12/31/2024	$3.25	DLCO	8/19/2022
4	S2837		Extend a new single 69 kV tap from the existing Engleside-Greenland No. 1 69 kV line to interconnect a new customer's 69-12.47 kV substation. Build 0.15 miles of new 69 kV single circuit line using 556 ACSR conductor.	10/11/2024	$1.00	PPL	9/15/2022
5	S2838		Replace 17 wood structures on a 1-mile stretch with steel structures on the 130-36 (Bryn-Llanerch) 138 kV circuit. New structures will use 795 ACSR conductor for the rebuild portion of the line. Replace the 477 ACSR OHT conductor to the UGT terminators at West Overbrook Terminal yard with 1000 kcmil 37 strand AAC.	11/2/2022	$6.78	PECO	
6	S2842		Extend a new double circuit 69 kV tap from the existing Hummelstown-Copperstone No. 1 and No. 2 69 kV lines to interconnect a new customer's 69-13.8 kV substation. Build 0.1 miles of new 69 kV double circuit line using 556 ACSR conductor.	1/31/2024	$1.50	PPL	11/17/2022
7	S2868		Replace 69 kV breakers B-16 and B-30 and associated line and bus disconnect switches. Replace the Campbell and Campbell tap relays with line relay panels and install SEL-421 primary/backup relays and SEL501 with LOR BF relays. Replace limiting substation conductors.	12/30/2023	$1.50	ATSI	11/18/2022
8	S2869		Replace relaying and controls at Sharon substation for the following lines: Sharon-Maysville Y-299/Y-81 69 kV line, Sharon-McDowell Y-300 69 kV line, Sharon-Maysville Y-301 69 kV line, Sharon-Masury Y-188/Y-303 69 kV line. Install a new 69 kV control building at Sharon substation. Adjust relay settings at Masury, Maysville and McDowell substations. Install a new standard large RTU panel and a new standard HMI pane.	6/1/2025	$20.80		
9	S2890	.1	Install in-line breakers on the Wescosville-Allentown No. 1 and No. 2 138 kV lines at the existing Sumner substation.	5/1/2024	$8.00	PPL	1/17/2023
		.2	Acquire new site and install in-line breaker yard on the Siegfried-Wescosville No. 1 and No. 2 138 kV.	12/31/2024			
10	S2891		Extend a new double circuit 69 kV tap from the existing Clinton-Milton No. 1 and No. 2 69 kV lines to interconnect a new Great Stream 69-12.47kV substation. Build 0.1 miles of new 69 kV double circuit line using 556 ACSR conductor.	5/1/2024	$1.50		
11	S2892		Upgrade relays, communication, metering and removal of wave trap on 220-51 (Heaton-Jarrett) line.	4/1/2023	$1.77	PECO	12/6/2022
12	S2894		Rebuild 11.3 miles of the 12.5 miles of the South Akron-Dillerville No. 1 and No. 2 138 kV lines with steel poles and 556 ACSR conductor. 1.2 miles of the line was rebuilt in 2013. If possible, any existing recently installed steel monopoles will be incorporated into the design.	12/31/2026	$31.50	PPL	3/16/2023
13	S2895		Rebuild 11 miles of the South Akron-Prince No. 1 and No. 2 138 kV lines with steel poles and 556 ACSR conductor. If possible, any existing recently installed steel monopoles will be incorporated into the design.	12/30/2025	$36.00		
14	S2896		Install in-line breakers on the Monroe-Jackson No. 1 and No. 2 138 kV lines at the existing North Stroudsburg substation. Install in-line breakers on the Siegfried-Jackson No. 1 and No. 2 138 kV lines at the existing Gilbert substation.	12/31/2024	$8.00		
15	S2899		Upgrade primary backup relays, communication, and replace No. 67 motor operated disconnect on Peach Bottom North Generating Unit No. 3.	11/3/2023	$1.04	PECO	3/7/2023
16	S2900		Replace Concord 230 kV circuit breaker No. 565.	11/11/2023	$0.85		
17	S2901		Replace Limerick 500 kV circuit breaker No. 355.	5/1/2023	$0.78		
18	S2902		Rebuild the 0.66 miles of the Laurel Pumping tap to Laurel Pumping 69 kV with steel poles and 556 ACSR conductor.	12/31/2024	$1.10	PPL	3/16/2023
19	S2903		Extend a new single circuit 69 kV tap from the existing Eldred-Cleveland 69 kV line to interconnect a new customer owned 69-4.16 kV substation. Build 0.1 miles of new 69 kV single circuit line using 556 ACSR conductor.	11/13/2024	$0.60		
20	S2905		Replace Marcus Hook 69 kV oil circuit breaker No. 200.	9/17/2023	$0.59	PECO	
21	S2906		Replace Eddystone 138 kV circuit breaker No. 55.	12/1/2023	$0.85		

Table 6.55: Pennsylvania Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
22	S2907		Upgrade line relays and communication on 138 kV line 130-37 (Plymouth Meeting-Cleveland Cliffs),and replace No. 375 Circuit Breaker at Plymouth Meeting.	11/5/2023	$0.65	PECO	3/16/2023
23	S2922		Extend the Gobain 138 kV bus to provide a connection for a new distribution transformer.	6/16/2023	$4.10	AP	3/17/2023
24	S2936		Remove switches A118 and A119 on the Maysville-Sharon Y-301 69 kV line. De-energize roughly 3.6 miles of the Maysville-Sharon 69 kV line from Maysville to the Camp Reynolds tap location. Remove switches A2153, A23, A2151, A260, A261 and A2152 at Greenville. Build ~3.0 miles of 69 kV line connecting the Camp Reynolds (near TY19) tap to the Canal tap (near TY104). Add 69 kV line switches with SCADA at Camp Reynolds tap, Greenville Metal tap, and Canal tap. Add one 69 kV line switch with SCADA at Trinity tap.	6/1/2025	$12.20	ATSI	4/21/2023
25	S2946	.1	Rebuild and reconductor North Boyertown-West Boyertown 69 kV line.	12/31/2027	$10.30	METED	4/20/2023
		.2	Replace substation conductor at North Boyertown 69 kV substation.				
		.3	Replace substation conductor at West Boyertown 69 kV substation.				
26	S2948		Rebuild McKnights Gap 69-13.2 kV substation and Install new 69 kV switches.	12/29/2023	$0.80		
27	S2949		Tap the Saxton-Shade Gap 115 kV line (Saxton-Three Springs 115 kV line segment) and construct ~8.64 miles of 115 kV line toward the customer. Install one 115 kV revenue metering package and three 1200A SCADA-controlled disconnect switches.	4/1/2025	$23.96	PENELEC	
28	S2950		Tap the Tyrone North-Warrior Ridge 46 kV line and construct 0.1 miles of 336 26/7 ACSR to the customer. Install three 1200A SCADA-controlled disconnect switches and Install one 46 kV revenue metering package	5/12/2023	$1.15		
29	S2958		Extend a new double circuit 69 kV tap from the existing Hosensack-Quarry No. 1 and No. 2 69 kV lines to interconnect the new Saucon Park 69-12.47 kV substation. Build 0.1 miles of new 69 kV double circuit line using 556 ACSR conductor. Initial loading of ~24 MVA. Alternatives considered.	5/1/2025	$1.10	PPL	5/18/2023
30	S2963		Remove 16.5 miles of the existing Lycoming-Lewisburg 69 kV line. Remaining 2 miles will be rebuilt as part of s0968.4 and will become part of the Milton-Lewisburg line.		$3.50		
31	S2964		Replace circuit breaker, wave trap and relaying at Shawville.	12/8/2023	$1.60	PENELEC	6/6/2023
32	S2968		Install three SCADA ntrolled transmission line switches. Construct ~0.1 miles of transmission line using 556 ACSR 26/7 from tap point to customer substation. Install one 69 kV revenue metering package at customer substation. Modify relay settings at Bernville and South Hamburg substations.	12/31/2024	$1.60	METED	6/15/2023
33	S2969		Install two SCADA controlled transmission line switches. Construct ~0.5 miles of transmission line using 556 ACSR 26/7 from tap point to customer substation . Install one 69 kV revenue metering package at customer substation. Modify relay settings at Campbelltown and North Lebanon substations	1/15/2024	$2.90		
34	S2987		Replace circuit breaker, wave trap and relaying at Shawville. Replace limiting substation conductor and relaying at Moshannon.	12/8/2023	$1.60	AP	6/6/2023
35	S2988		Replace limiting substation conductor, wave trap, and relaying at Connellsville 138 kV substation. Replace limiting substation conductor, wave trap, circuit breaker and relaying at King Farm 138 kV substation. Replace limiting substation conductor, wave trap, circuit breaker and relaying at Iron Bridge 138 kV substation.	12/15/2023	$1.90		5/19/2023
36	S2989		Replace line relaying, breaker, switches, substation conductor, line trap and current transformer at Cecil. Replace line relaying, breaker, switches, substation conductor and line trap at Windsor. Replace line relaying, breaker, switches, substation conductor, line trap at current transformer at Weirton.	11/17/2023	$4.11		6/16/2023
37	S2990		Replace line relaying, substation conductor and line trap at Kiski. Replace line relaying, breaker, switches, substation conductor, line trap and current transformers at Vandergrift.	12/15/2023	$2.99		
38	S2991		Replace line relaying, line trap and current transformer at Charleroi. Replace line relaying, breaker, switch, line trap and current transformer at Gordon.		$1.57		

Table 6.55: Pennsylvania Supplemental Projects (Dec. 31, 2023) (Cont.)

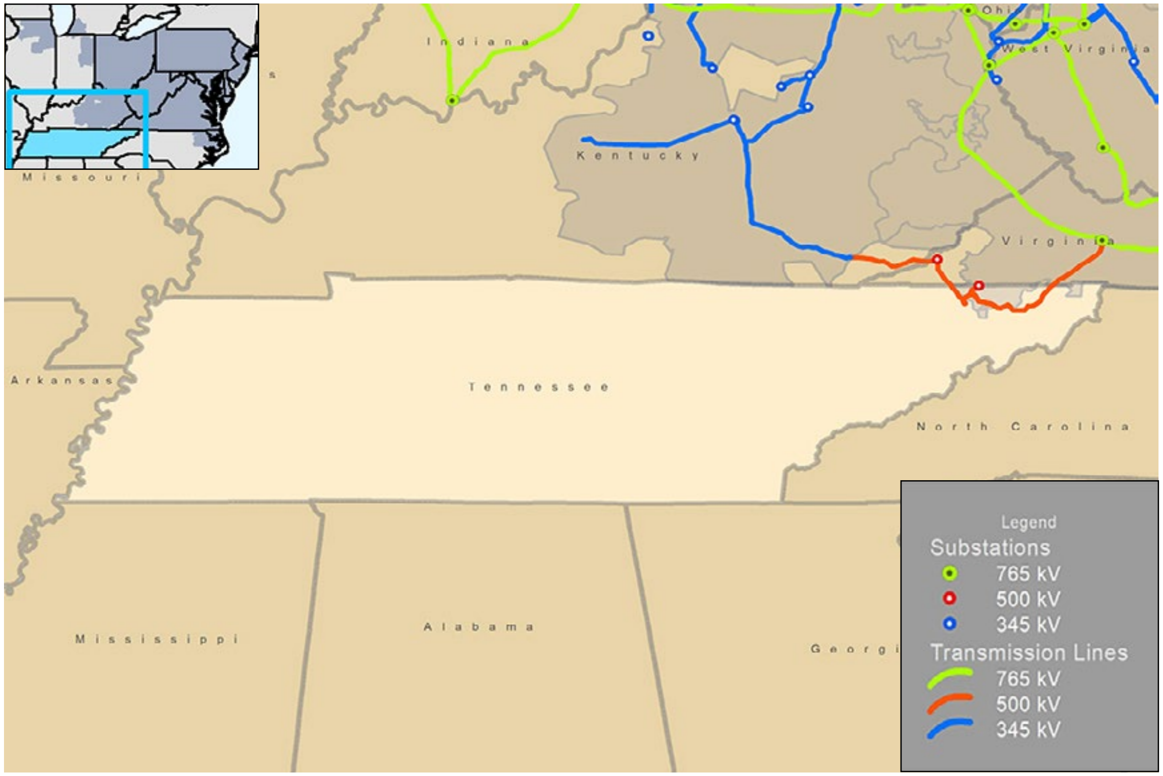
Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
39	S2992		Replace line relaying, substation conductor, current transformers at Lake Lynn. Replace line relaying, breakers, switch, substation conductor, line trap, current transformers at Pierpont.	11/15/2023	$2.33	AP	6/16/2023
40	S2993		Replace line relay, breaker, switches, substation conductor, line trap and current transformer at Burma. Replace substation conductor at Clairion. Replace line relaying, breaker, switches, substation conductor, line trap and current transformer at Ridgway.	11/17/2023	$2.64	AP	6/16/2023
41	S2994		Replace line relaying, breakers, switches, line trap, current transformers at Saltsburg. Replace line relaying, breaker, switches, substation conductor, line trap, current transformer at Social Hall.	11/4/2023	$2.98	AP	6/16/2023
42	S2995		Replace line relaying, substation conductor and current transformer at Harrison City. Replace line relaying, breaker, switch, substation conductor, current transformer at Hempfield. Replace line relaying, breaker, switch, substation conductor, current transformer at Luxor.	12/29/2023	$4.90	AP	6/16/2023
43	S2996		Replace line relaying, breaker, switch, substation conductor, line trap and current transformer at Bethelboro. Replace line relaying, breaker, switch, substation conductor, line trap and current transformer at Lake Lynn.	12/15/2023	$3.32	AP	6/16/2023
44	S2997		Create the Vankirk substation. Construct a new 10-breaker 138 kV breaker-and-a-half substation, loop in the Dutch Fork, Washington 138 kV line, loop in the Gordon, Lagonda 138 kV line, loop in the Gordon, Charleroi 138 kV line. Replace limiting substation conductor and wave trap at Washington. Replace limiting substation conductor at Dutch Fork. Replace limiting substation conductor, relaying and wave trap at Gordon. Replace limiting substation conductor at Claysville. Replace limiting substation conductor and wave trap at Charleroi.	12/31/2025	$31.70	AP	6/16/2023
45	S2998		Install three SCADA controlled-transmission line switches. Construct 0.1 miles of 954 ACSR 48/7 transmission line. Adjust relay settings at Maple substation. Install tie line interchange revenue metering at Krendale	6/1/2024	$1.70	ATSI	5/19/2023
46	S3001		Install three SCADA-controlled transmission line switches. Construct ~1.0 mile of transmission line using 1024.5 24/13 ACAR from tap point to customer substation. Install one 138 kV revenue metering package at customer substation. Adjust relay settings at remote end substations Dutch Fork and Washington.	7/10/2024	$7.10	AP	5/19/2023
47	S3003		Extend a new single circuit 69 kV tap from the existing Twin Valley tap No. 1 69 kV line to interconnect a new customer owned 69-12.47 kV substation. Build 0.2 miles of new 69 kV single circuit line using 556 ACSR conductor.	6/30/2024	$0.75	PPL	7/20/2023

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 6.46**. 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 6.46: PJM Service Area in Tennessee

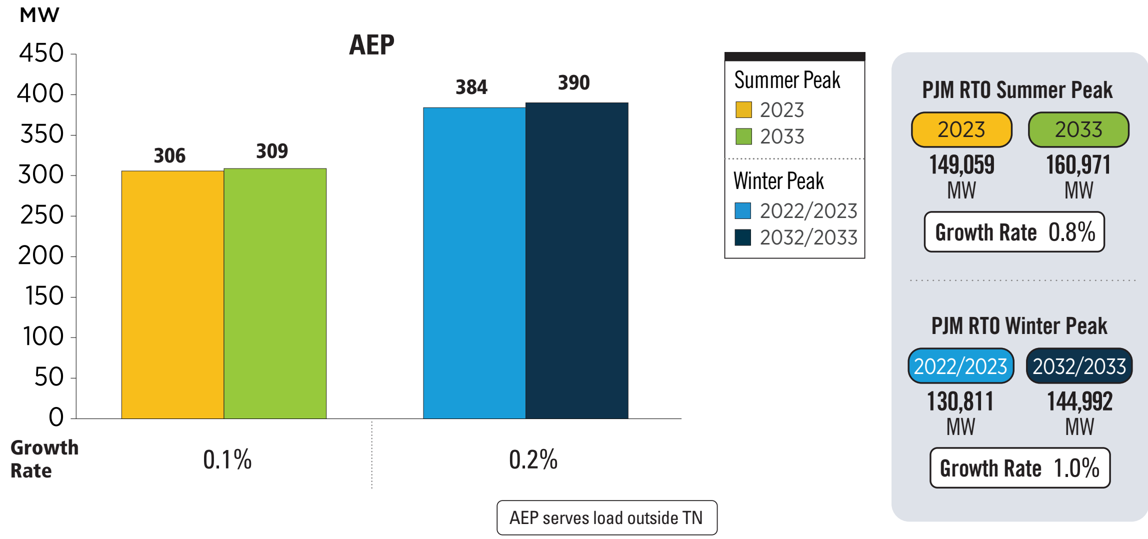


6.11.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.51** summarizes the expected loads within the state of Tennessee and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.51: Tennessee – 2023 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.11.3 — Existing Generation

There is no existing generation in PJM's portion of Tennessee as of Dec. 31, 2023.

6.11.4 — Interconnection Requests

In Tennessee, as of Dec. 31, 2023, one project was actively under study or under construction as shown in the summaries presented in **Table 6.56, Table 6.57, 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.

Read More
Interconnection Requests

Table 6.56: Tennessee – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Tennessee Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	0	0.00%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	0	0.00%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	94	100.00%	98,471	55.15%
Storage	0	0.00%	53,644	30.04%
Wind	0	0.00%	20,798	11.65%
Grand Total	**94**	**100.00%**	**178,566**	**100.00%**

Table 6.57: Tennessee – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		In Queue		Complete		Grand Total	
		Active		Withdrawn		Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	1	75.0	1	75.0
Renewable	Solar	2	93.8	0	0.0	2	93.8
	Grand Total	**2**	**93.8**	**1**	**75.0**	**3**	**168.8**

Figure 6.52: Tennessee – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

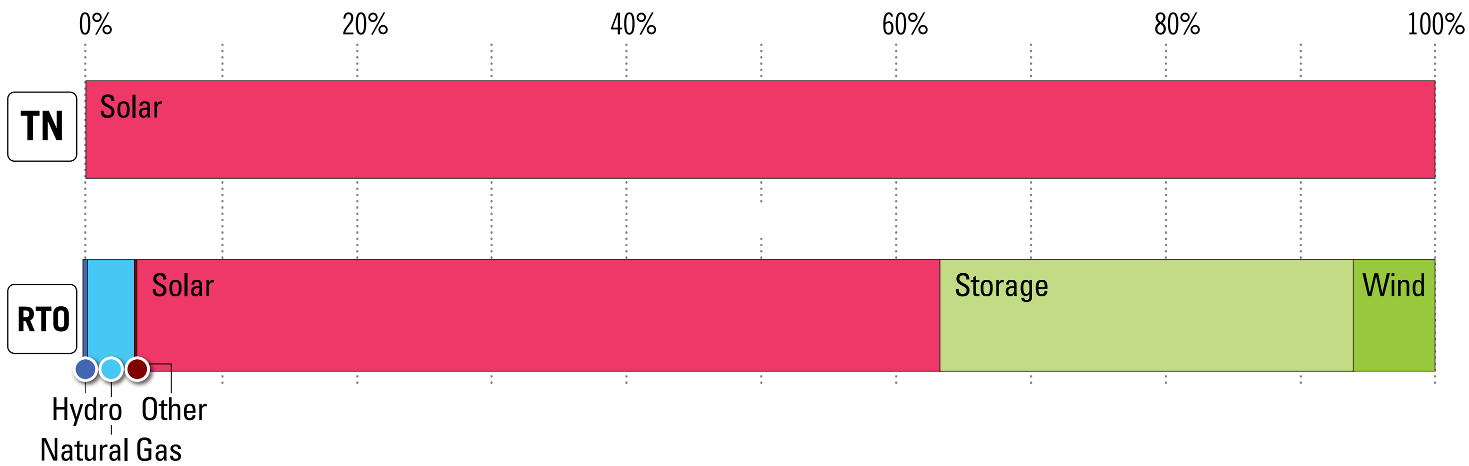
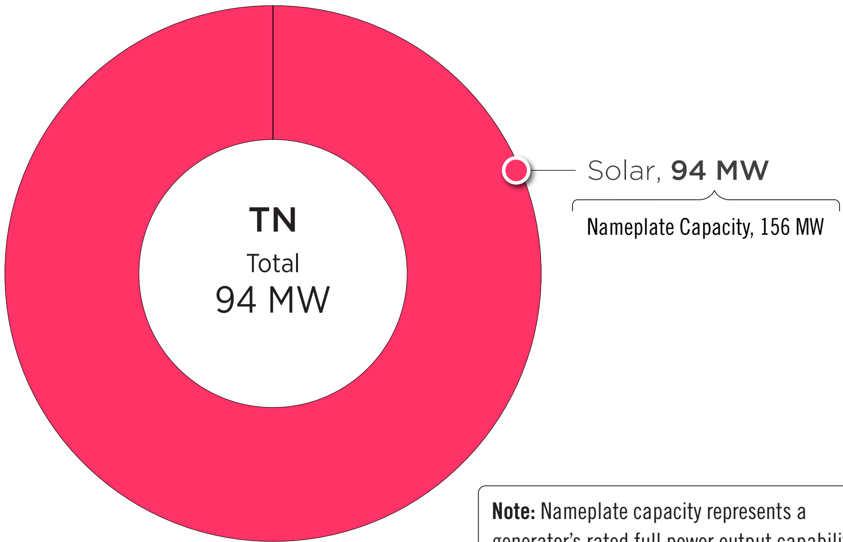
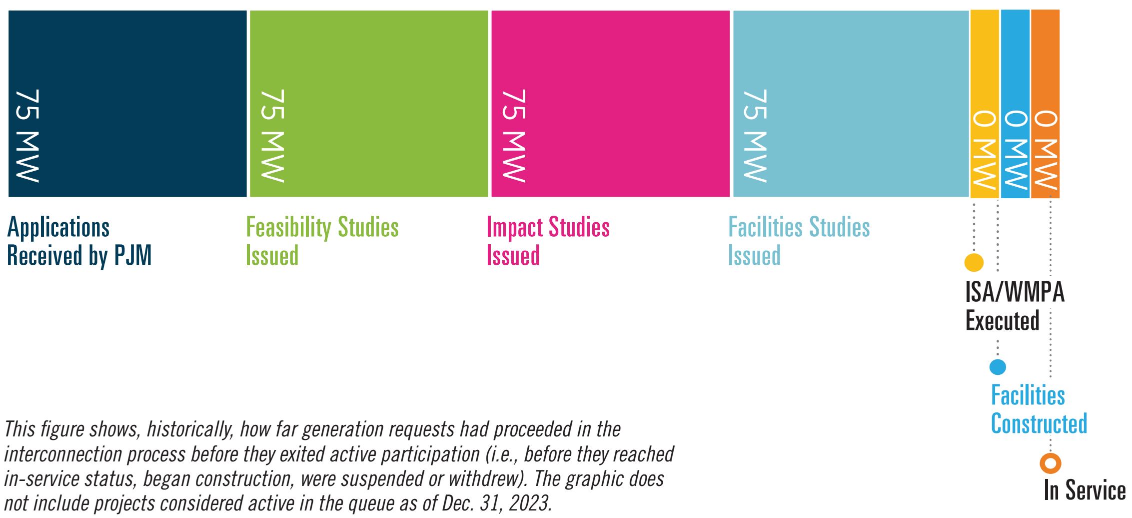


Figure 6.53: Tennessee Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.54: Tennessee Progression of Interconnection Requests (Dec. 31, 2023)



This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

Percentage of planned capacity and projects that have reached commercial operation

0%	Requested capacity megawatts
0%	Requested projects

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 6.47**. 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.

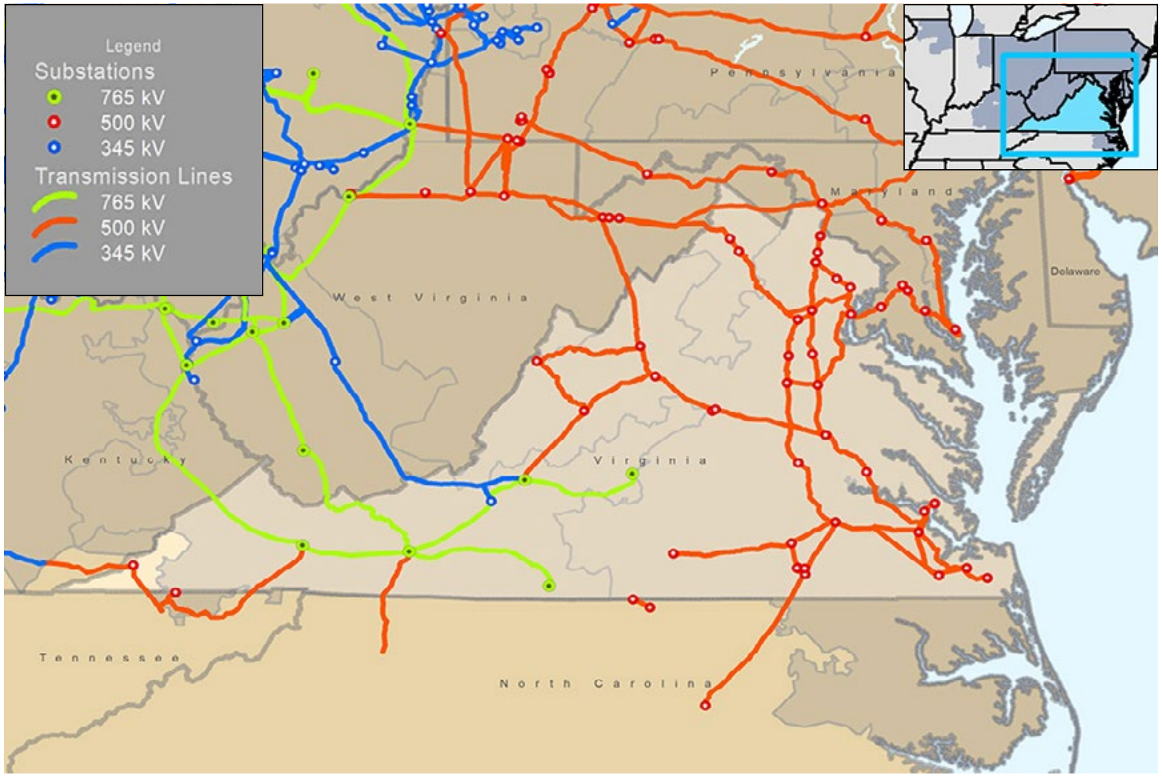
Renewable Portfolio Standards

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 PJM.

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 6.47: PJM Service Area in Virginia



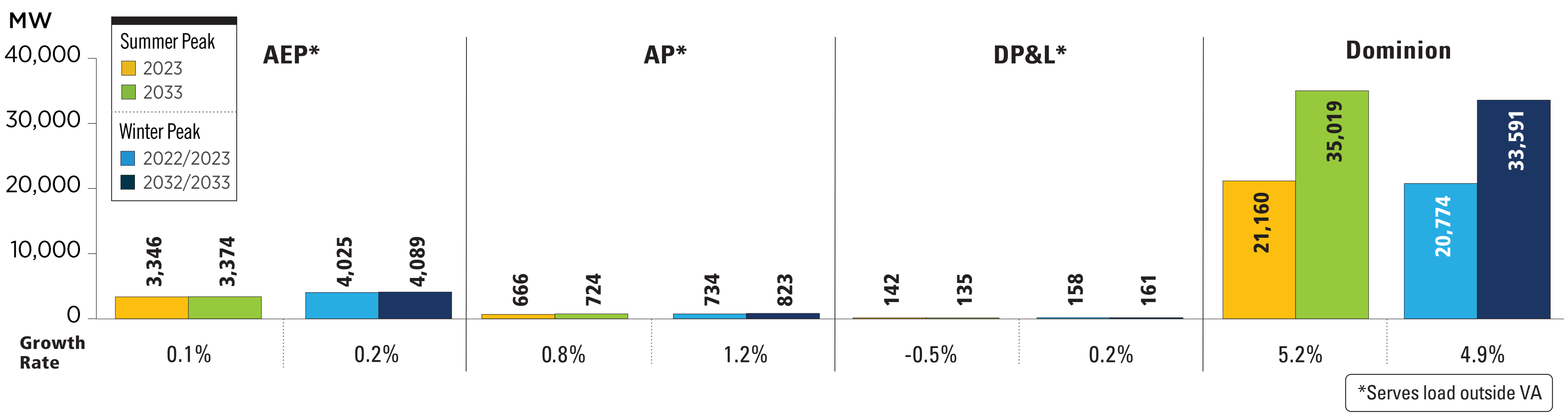
6.12.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.55** summarizes the expected loads within the state of Virginia and across the PJM region.

As part of the 2023 RTEP, PJM continues work to address an increase of 7.5 GW of load in an area known as "Data Center Alley" in the Loudon County area of Virginia. The PJM Board approved a $627 million project to construct a new substation called Wishing Star, interconnecting into existing Brambleton-Mosby 500 kV lines. Analysis will continue into 2023 as PJM opens a competitive proposal window seeking solutions to reliability criteria violations that were not addressed by the Wishing Star project.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.55: Virginia – 2023 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2023	2033	2022/2023	2032/2033
149,059 MW	160,971 MW	130,811 MW	144,992 MW
Growth Rate 0.8%		Growth Rate 1.0%	

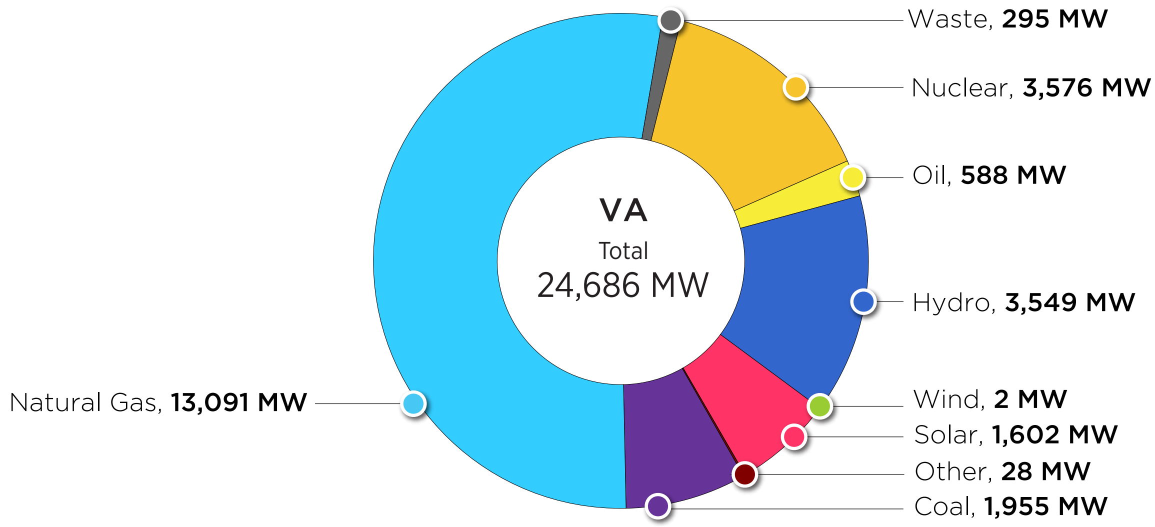
The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.12.3 — Existing Generation

Existing generation in Virginia as of Dec. 31, 2023, is shown by fuel type in **Figure 6.56**.

Read More
Changing Capacity Mix and Deliverability

Figure 6.56: Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)



6.12.4 — Interconnection Requests

In Virginia, as of Dec. 31, 2023, 749 projects were actively under study or under construction as shown in the summaries presented in **Table 6.58, Table 6.59, Figure 6.57, Figure 6.58** and **Figure 6.59**.

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.

Read More
Interconnection Requests

Table 6.58: Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	0	0.00%	299	0.17%
Methane	6	0.01%	6	0.00%
Natural Gas	1,380	3.27%	5,278	2.96%
Other	27	0.06%	70	0.04%
Solar	21,247	50.31%	98,471	55.15%
Storage	18,178	43.05%	53,644	30.04%
Wind	1,392	3.30%	20,798	11.65%
Grand Total	**42,229**	**100.00%**	**178,566**	**100.00%**

Table 6.59: Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		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	8	718.9	2	35.0	10	753.9
	Diesel	0	0.0	0	0.0	0	0.0	2	2.1	2	20.2	4	22.3
	Natural Gas	17	1,379.9	0	0.0	0	0.0	49	7,288.4	46	20,389.8	112	29,058.1
	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	2	27.1	0	0.0	0	0.0	1	0.0	2	136.3	5	163.4
	Storage	247	18,177.8	1	15.7	6	413.0	2	20.0	69	3,255.6	325	21,882.1
Renewable	Biomass	0	0.0	0	0.0	0	0.0	5	147.4	4	70.0	9	217.4
	Hydro	0	0.0	0	0.0	0	0.0	9	423.4	2	254.0	11	677.4
	Methane	1	6.0	0	0.0	0	0.0	16	103.3	11	81.8	28	191.1
	Solar	402	21,246.7	26	1,098.2	64	2,731.9	67	1,558.1	344	11,972.4	903	38,607.3
	Wind	9	1,391.5	0	0.0	1	10.1	1	1.5	34	934.4	45	2,337.5
	Wood	0	0.0	0	0.0	0	0.0	1	4.0	2	57.0	3	61.0
	Grand Total	**678**	**42,229.0**	**27**	**1,113.9**	**71**	**3,155.0**	**175**	**10,939.4**	**521**	**38,816.5**	**1,472**	**96,253.7**

Figure 6.57: Virginia – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

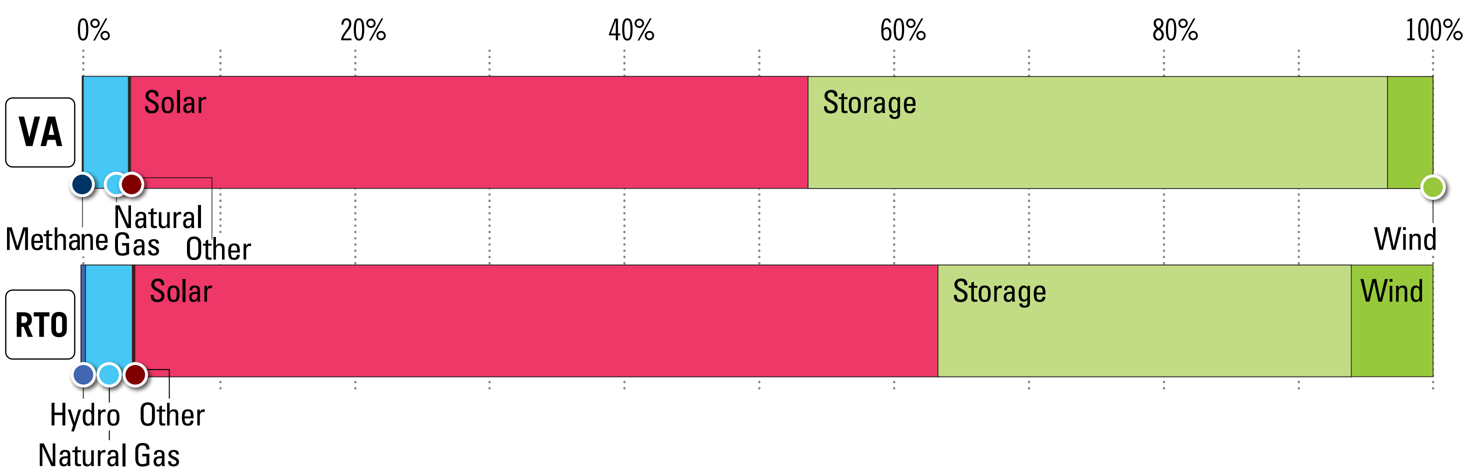
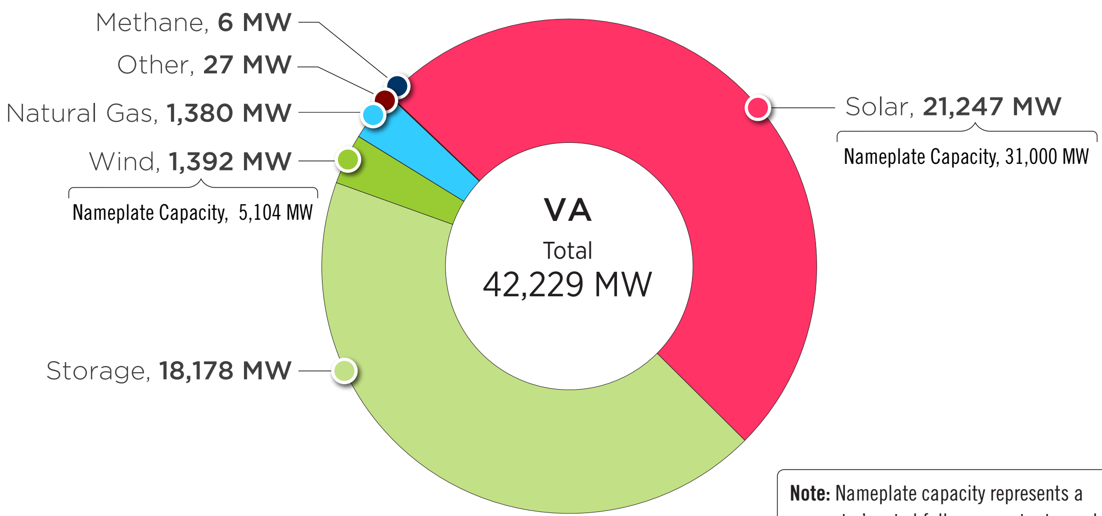


Figure 6.58: Virginia Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.59: Virginia Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

21.4%	Requested capacity megawatts
23.3%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	22	Interconnection Service Agreements	4,746 MW	5,275 MW
	55	Wholesale Market Participation Agreements	490 MW	819 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.12.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Virginia between Jan. 1, 2023, and Dec. 31, 2023, are summarized in **Map 6.48** and **Table 6.60**.

Read More
Generation Deactivation

6.12.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in Virginia are summarized in **Map 6.49** and **Table 6.61**.

Read More
Baseline Projects

Map 6.48: Virginia Generation Deactivations (Dec. 31, 2023)

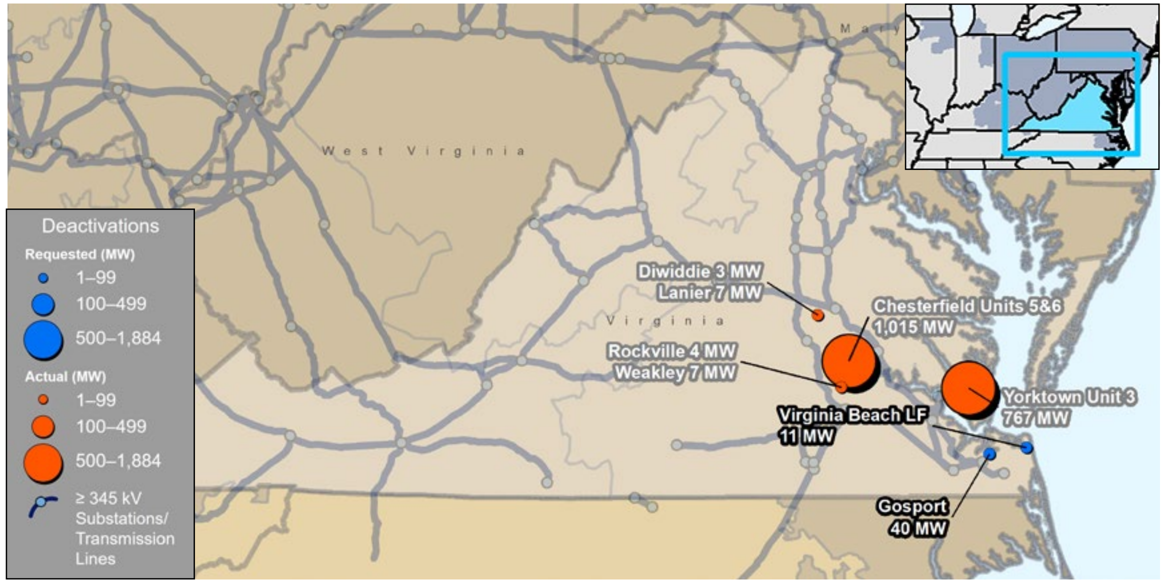
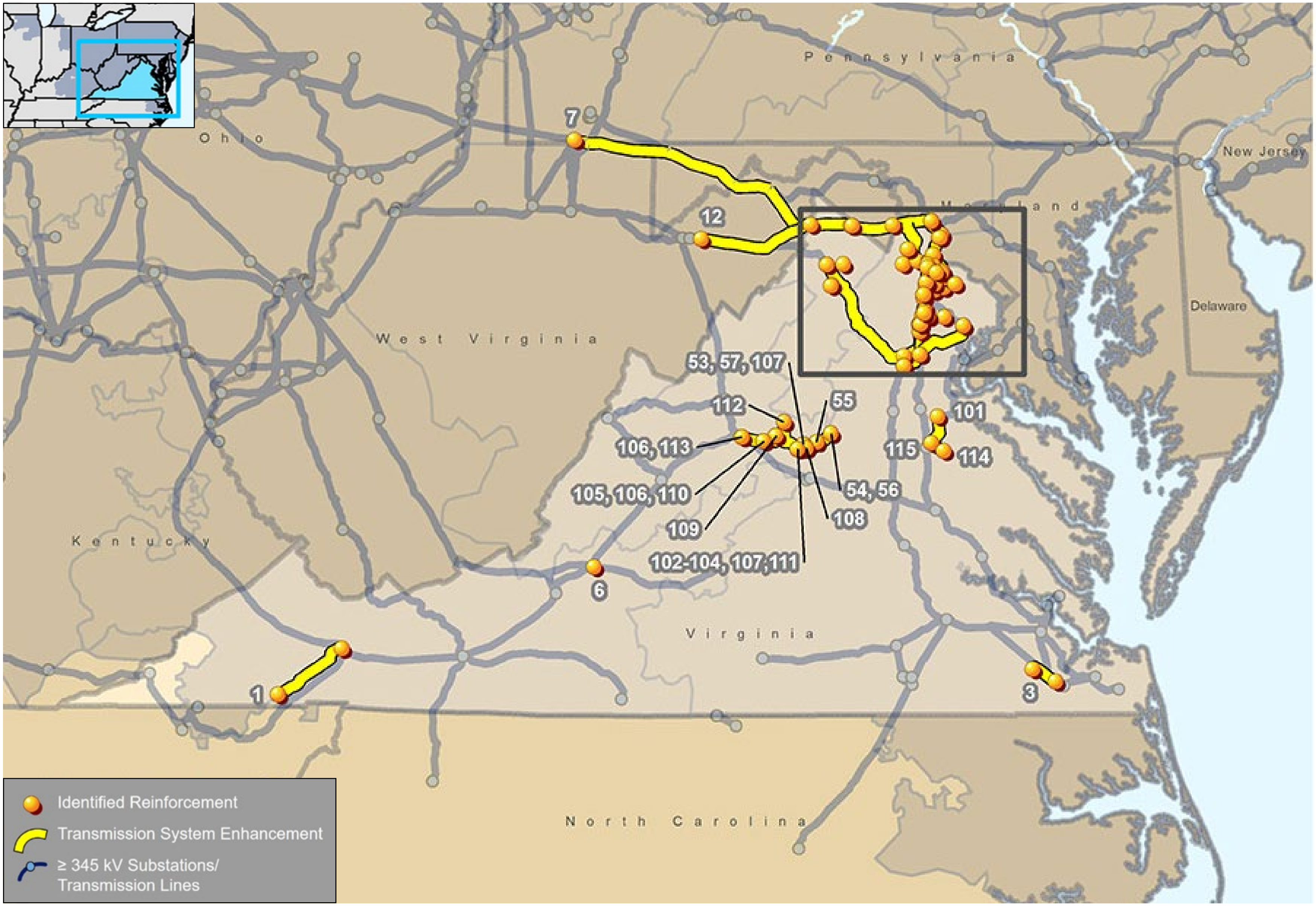


Table 6.60: Virginia Generation Deactivations (Dec. 31, 2023)

<table>
<tr><th>Unit</th><th>TO Zone</th><th>Fuel Type</th><th>Request Received to Deactivate</th><th>Actual or Projected Deactivation Date</th><th>Age (Years)</th><th>Capacity (MW)</th></tr>
<tr><td>VIRGINIA BEACH LANDFILL</td><td rowspan="9">Dominion</td><td>Methane</td><td>12/8/23</td><td>4/1/2024</td><td>18</td><td>11</td></tr>
<tr><td>GOSPORT 1 F</td><td>Biomass</td><td>2/15/23</td><td>7/1/2024</td><td>36</td><td>40</td></tr>
<tr><td>Chesterfield 5</td><td rowspan="2">Coal</td><td rowspan="2">2/20/2020</td><td rowspan="7">6/1/2023</td><td>56</td><td>336.8</td></tr>
<tr><td>Chesterfield 6</td><td>51</td><td>678.1</td></tr>
<tr><td>DINWIDDIE 1 CT</td><td rowspan="4">Diesel</td><td rowspan="4">9/29/2021</td><td>28</td><td>3</td></tr>
<tr><td>Lanier 1 CT</td><td>21</td><td>7</td></tr>
<tr><td>Rockville CT</td><td>26</td><td>4</td></tr>
<tr><td>Weakley CT</td><td>21</td><td>7</td></tr>
<tr><td>Yorktown 3</td><td>Oil</td><td>12/20/2022</td><td>48</td><td>767.1</td></tr>
</table>

Map 6.49: Virginia Baseline Projects (Dec. 31, 2023)



Map 6.48: Virginia Baseline Projects (Northern Virginia) (Dec. 31, 2023) (Cont.)

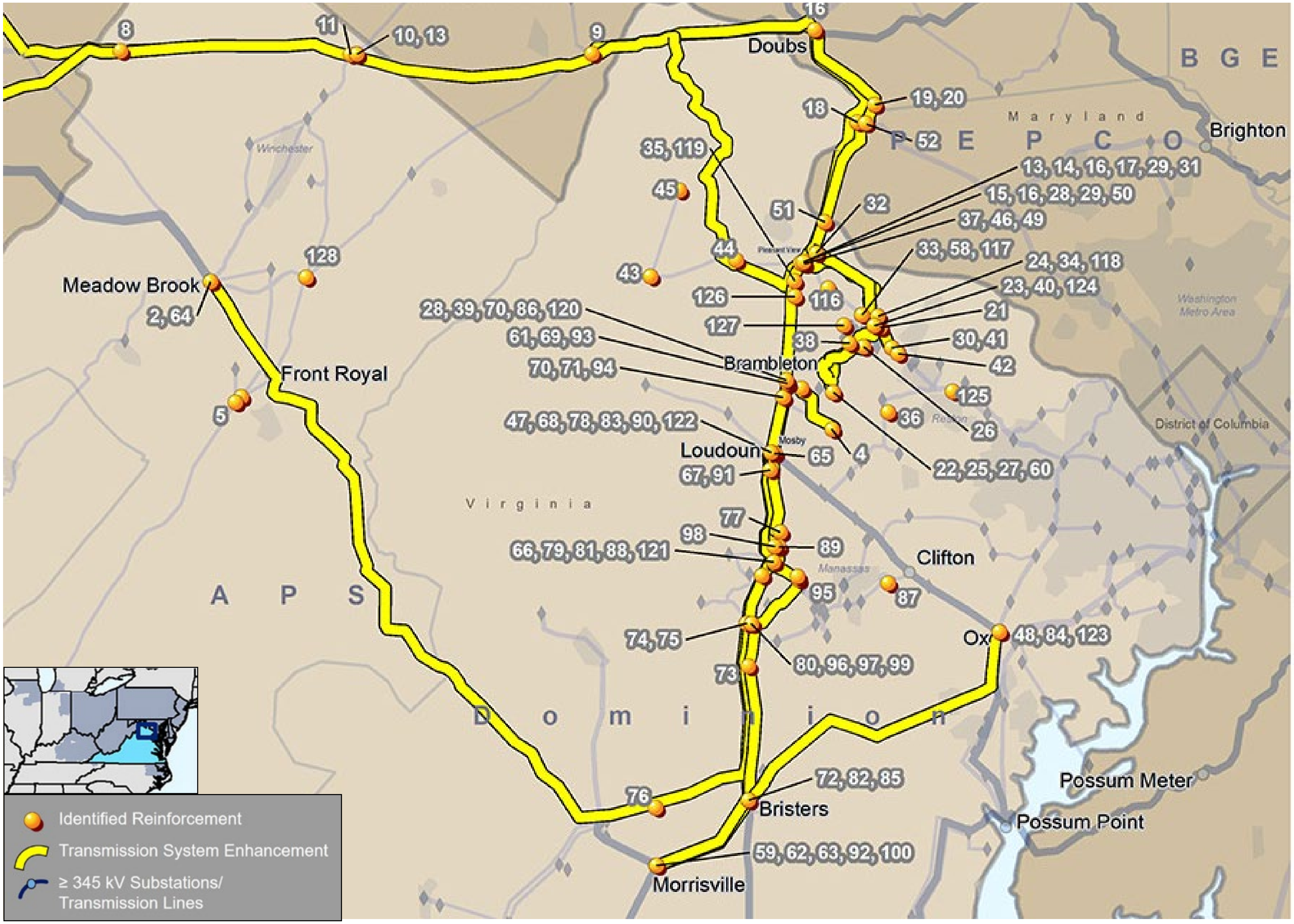


Table 6.61: Virginia Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3735		Terminate the existing Broadford-Wolf Hills No. 1 138 kV line into Abingdon 138 kV station. This line currently bypasses the existing Abingdon 138 kV station; install two new 138 kV circuit breakers on each new line exit toward Broadford and toward Wolf Hills No. 1; install one new 138 kV circuit breaker on line exit toward South Abingdon for standard bus sectionalizing.	6/1/2027	$8.48	AEP	11/18/2022
2	B3746		Install redundant relaying at Meadow Brook substation.		$0.21	AP	
3	B3759		Reconductor ~10.5 miles of 115 kV line No. 23 segment from Oak Ridge to AC2-079 tap to minimum emergency ratings of 393 MVA summer/412 MVA winter.		$23.50	Dominion	10/13/2022
4	B3779		Cut existing 230 kV line No. 2183 and extend from Poland Rd. substation to Evergreen Mills substation. ~0.59 miles of new line will be built from the cut-in to the Evergreen Mills substation. Cut and extend the existing 230 kV line No. 2183 creating a new line No. 2210 from Brambleton substation to be terminated at Evergreen Mills substation. ~0.59 miles of new line will be built from the cut-in to the Evergreen Mills substation.		$7.71		4/11/2023
5	B3782		Adjust relay settings at Riverton substation on the Riverton-Bethel tap 138 kV line.	6/1/2025	$0.08	AP	9/5/2023
6	B3800	.100	Establish a new 500 kV breaker position for the low side of the existing 765/500 kV transformer at Cloverdale station. The new position will be between two new 500 kV circuit breakers located in a new breaker string, electrically converting the 500 kV yard to double-bus double-breaker configuration.	6/1/2027	$3,522.24	AEP	12/5/2023
7		.102	Construct new 500 kV line from existing 502 Junction substation to Woodside 500 kV substation (bypass Black Oak) (NEET portion).			NEET	
8		.103	Rebuild ~16 miles of the Gore-Stonewall 138 kV line with 500 kV overbuild (502 Jct to Woodside 500 kV line section).			AP	
9		.105	Rebuild ~6 miles of the Millville-Doubs 138 kV line with 500 kV overbuild (502 Jct to Woodside 500 kV line section).				
10		.106	Construct Woodside 500 kV substation (except terminations, transformer, cap banks and Statcom).			NEET	
		.107	Terminate line at Woodside 500 kV for 502 Jct to Woodside 500 kV line.				
		.108	Terminate line at Woodside 500 kV for Woodside to Aspen 500 kV line.				
		.109	Perform termination work for two 500/138 kV transformers at Woodside 500 kV substation.				
		.110	Install two 500/138 kV transformers at Woodside 500 kV substation.				
11		.111	Construct the Woodside-Stonewall 138 kV No. 1 line.			AP	
		.112	Construct the Woodside-Stonewall 138 kV No. 2 line.				
		.113	Install two 150 MVAR cap banks and one +500/-300 MVAR Statcom at Woodside 500 kV substation.			NEET	
		.114	Construct Stonewall 138 kV substation two 138 kV breaker expansion.			AP	
12		.115	Perform line work for terminating Doubs to Bismark line for Doubs side for Woodside 500 kV substation (NEET portion).			NEET	
		.116	Perform line work for terminating Doubs to Bismark line for Doubs side for Woodside 500 kV substation (FE portion).			AP	
		.117	Perform line work for terminating Doubs to Bismark line for Bismark side for Woodside 500 kV substation (NEET portion).			NEET	
		.118	Perform line work for terminating Doubs to Bismark line into Woodside 500 kV substation (Dominion portion).			Dominion	
13		.119	Construct new 500 kV transmission line from Woodside substation to Aspen substation (in Dominion zone) (NEET portion).			NEET	
14		.120	Perform Aspen substation work to terminate new NextEra 500 kV line. Include Aspen 500 kV substation portion build.			Dominion	

Table 6.61: Virginia Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
15	B3800 (Cont.)	.122	Rebuild 500 kV line No. 514 from Doubs-Goose Creek 500 kV line. The Doubs-Goose Creek 500 kV line will be rebuilt (AP portion).	6/1/2027	$3,522.24	AP	12/5/2023
16		.123	Perform Doubs substation work – Reterminate the rebuilt Doubs-Goose Creek 500 kV line in its existing bay; terminate the new Doubs-Aspen 500 kV line in the open bay at Doubs; replace three 500 kV breakers; replace 500 kV terminal equipment including disconnect switches, CTs and substation conductor; replace relaying (APS portion).				
17		.124	Construct new Doubs to Aspen 500 kV line – Aspen substation is not yet constructed but is a component in Dominion's proposal 2022-W3-692 (APS portion).				
18		.125	Rebuild the Doubs-Dickerson 230 kV line. This will be underbuilt on the new Doubs-Goose Creek 500 kV line (AP portion).				
19		.126	Rebuild the Doubs-Aqueduct 230 kV line. This will be underbuilt on the new Doubs-Aspen 500 kV line (AP portion).				
20		.127	Rebuild the Dickerson-Aqueduct 230 kV line. This will be underbuilt on the new Doubs-Aspen 500 kV line (AP portion).				
21		.200	Build a new 500 kV line from Aspen-Golden on 500/230kV double circuit structures with substation upgrades at Aspen and Golden. New conductor to have a minimum summer normal rating of 4357 MVA.			Dominion	10/31/2023
		.201	Install two 500-230 kV transformer banks at Golden substation.				
		.202	Install one 500-230 kV transformer bank at Aspen substation.				
22		.203	Install a second 500-230 kV 1440 MVA transformer at Mars substation.				
23		.204	Reconductor 0.5-mile section of 230 kV line No. 2150 Golden-Paragon Park circuit 1 to achieve a summer rating of 1573 MVA.				
		.205	Reconductor 0.5-mile-section of 230 kV line No. 2081 Golden-Paragon Park circuit 2 to achieve a summer rating of 1573 MVA.				
24		.206	Upgrade Paragon Park substation line conductors to 4000A continuous current rating for 230 kV lines No. 2081 and line No. 2150.				
		.207	Reconductor 230 kV line No. 2207 Paragon Park-Beco to achieve a summer rating of 1573 MVA.				
		.208	Upgrade Paragon Park substation conductor and line leads to 4000A continuous current rating for 230 kV line No. 2207.				
		.209	Upgrade BECO substation equipment to 4000A continuous current rating for 230 kV line No. 2207.				
25		.210	Build a new 230 kV line from Mars-Lockridge on 500/230 kV double circuit structures to achieve a summer rating of 1573 MVA. Install 230 kV equipment at Mars and Lockridge.				
26		.211	Build a new 230 kV line from Lockridge-Golden on 500/230 kV double circuit structures to achieve a summer rating of 1573 MVA. Install 230 kV equipment at Golden and Lockridge.				
27		.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.				
28		.213	Cut 500 kV line No. 558 Brambleton-Goose Creek into Aspen substation. Upgrade 500 kV terminal equipment at Aspen and Goose Creek to 5000A continuous rating current. At Goose Creek, replace circuit breakers 59582 and 55882 and associated disconnect switches, breaker leads, bus and line risers to accommodate 5000A rating.				
29		.214	Build a new 500 kV line from Aspen-Goose Creek to achieve a summer rating of 4357 MVA. Install new 500 kV terminal equipment at Aspen.				
30		.215	Cut 230 kV line No. 2150 Sterling Park-Paragon Park circuit 1 into Golden substation and install 230 kV equipment at Golden. Upgrade relay settings at Golden substation for upgrading 230 kV line No. 2150 to 4000A continuous current rating.				

Table 6.61: Virginia Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
30	B3800 (Cont.)	.216	Cut 230 kV line No. 2081 Sterling Park-Paragon Park circuit 2 into Golden substation and install 230 kV equipment at Golden. Upgrade relay settings at Golden substation for upgrading 230 kV line No. 2081 to 4000A continuous current rating.	6/1/2027	$3,522.24	Dominion	10/31/2023
31		.217	Build a new 230 kV line from Aspen-Sycolin Creek on 500/230kV double circuit structures to achieve a summer rating of 1573 MVA. Install 230 kV equipment at Golden and Sycolin Creek.				
32		.218	Build a new 230 kV line from Sycolin Creek-Golden on 500/230 kV double circuit structures to achieve a summer rating of 1573 MVA. Install 230 kV equipment at Golden and Sycolin Creek.				
33		.219	Replace seven overdutied 230 kV breakers at Beaumeade substation with 80 kA breakers.				
34		.220	Replace four overdutied 230 kV breakers at BECO substation with 80 kA breakers.				
35		.221	Replace four overdutied 230 kV breakers at Belmont substation with 80 kA breakers.				
36		.222	Replace one overdutied 230 kV breaker at Discovery substation with 80 kA breaker.				
37		.223	Replace one overdutied 230 kV breaker at Pleasant View substation with 80 kA breaker.				
38		.224	Replace two overdutied 230 kV breakers at Shellhorn substation with 80 kA breakers.				
39		.225	Change 500 kV line No. 558 destination at Brambleton to Aspen substation and upgrade line protection relays.				
40		.226	Change 230 kV lines No. 2081 and 2150 at Paragon Park substation destination to Golden substation and upgrade line protection relays.				
41		.227	Change 230 kV lines No. 2081 and 2150 at Sterling Park substation destination to Golden Substation and upgrade line protection relays.				
41		.228	Reconductor 1.47 miles of 230 kV circuits 2081 and 2150 from Sterling Park to Golden substation. Upgrade terminal equipment at Sterling Park to 4000A continuous current.				
42		.229	Reconductor 0.67 miles of 230 kV circuits 2194 and 9231 from Davis Drive to Sterling Park substation. Terminal equipment at remote end substations will be installed or upgraded to 4000A continuous current rating to support new conductor ratings.				
43		.230	Reset relays at Breezy Knoll for the revised current rating of 230 kV line No. 2098 Plesant View-Hamilton.				
44		.231	Reset relays at Dry Mill for the revised current rating of 230 kV line No. 2098 Plesant View-Hamilton.				
45		.232	Reset relays at Hamilton for the revised current rating of 230 kV line No. 2098 Plesant View-Hamilton.				
46		.233	Upgrade equipment to 4000A continuous current rating at Pleasant View substation in support of 230 kV line No. 2098 wreck and rebuild. Replace circuit breakers 274T2098 & 2098T2180 and associated disconnect switches, breaker leads, bus and line risers to accommodate 4000A rating.				
46		.234	Wreck and rebuild ~1 mile of 230 kV line No. 2098 between Pleasant View and structure 2098/9 where line No. 2098 turns toward Hamilton substation.				
47		.235	Replace five overdutied 230 kV breakers at Loudoun substation with 80 kA breakers.				
48		.236	Replace two overdutied 500 kV breakers at Ox substation with 63 kA breakers.				
49		.237	Replace one overdutied 500 kV breaker at Pleasant View substation with a 63 kA breaker.				

Table 6.61: Virginia Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
49 (Cont.)	B3800 (Cont.)	.238	Upgrade equipment to 4000A continuous current rating at Pleasant View substation in support of 230 kV line No. 203 rebuild. Replace circuit breakers 203T274 & L3T203 and associated disconnect switches, breaker leads, bus and line risers to accommodate 4000A rating.	6/1/2027	$3,522.24	Dominion	10/31/2023
		.239	Wreck and rebuild 230 kV line No. 203 between Pleasant View and structure 203/15 using double circuit 500/230 kV structures. The 500 kV line is from Aspen-Doubs.				
		.240	Build a new 500 kV line from Aspen-Doubs using double circuit 500/230 kV structures. The 230 kV line is from Pleasant View – structure 203/15. Install terminal equipment at Aspen for a 5000A line to Doubs (First Energy). This includes GIS breakers, GIS-to-AIS transition equipment, and metering CCVTs and CTs for the tie line.				
50		.241	Rebuild 500 kV line No. 514 from Goose Creek-Doubs using 500/230 kV double circuit structures. The new double circuit towers will accommodate 230 kV line No. 2098 between Pleasant View substation and structure 2098/9. Upgrade equipment at Goose Creek to 5000A continuous current rating in support of line No. 514 wreck and rebuild. Replace circuit breakers 514T595 & 51482 and associated disconnect switches, breaker leads, bus and line risers to accommodate 5000A rating.				
51		.242	Upgrade switches 20366M and 20369M and line leads to 4000A continuous current rating of 230 kV line No. 203 at Edwards Ferry substation.				
52		.243	Rebuild 7.26 miles of existing 500 kV circuit from Dickerson Station H to Ed's Ferry area to accommodate the new 500 kV circuit between Doubs and Aspen (the 500 kV portion of the work).			PEPCO	
		.244	Rebuild 7.26 miles of existing 230 kV circuit from Dickerson Station H to Ed's Ferry area to accommodate the new 500 kV circuit between Doubs and Aspen (the 230 kV portion of the project).				
		.245	Reconfigure Dickerson H 230 kV substation and upgrade terminal equipment.				
53		.300	Rebuild 230 kV line No. 2135 Hollymeade Junction-Cash's Corner using double circuit-capable 500/230 kV poles. New conductor has a summer rating of 1573 MVA (the 500 kV circuit will not be wired as part of this project).			Dominion	
54		.301	Rebuild 230 kV line #2135 Cash's Corner-Gordonsville using double circuit-capable 500/230 kV poles. New conductor has a summer rating of 1573 MVA (the 500 kV circuit will not be wired as part of this project).				
55		.302	Upgrade Cash's Corner switches 213576 and 213579 and line leads to 4000A continuous current rating of 230 kV line No. 2135.				
56		.303	Upgrade Gordonsville substation line leads to 4000A continuous current rating of 230 kV line No. 2135.				
57		.304	Upgrade Hollymeade substation switch 213549 and line leads to 4000A continuous current rating of 230 kV line No. 2135.				
58		.305	Install one 300 MVAR Statcom and associated equipment at Beaumeade substation.				
59		.306	Install one 500 kV, 150 MVAR shunt capacitor bank and associated equipment at Morrisville substation. This addition will require a control house expansion to accommodate for two new panels.				
60		.307	Install one 500 kV, 300 MVAR Statcom and associated equipment at Mars substation.				
		.308	Install one 230 kV, 150 MVAR shunt capacitor bank and associated equipment at Mars substation.				
61		.309	Install one 230 kV, 150 MVAR shunt capacitor bank and associated equipment at Wishing Star substation.				
		.310	Install one 500 kV, 293.8 MVAR shunt capacitor bank and associated equipment at Wishing Star substation.				
62		.311	Rebuild 500 kV line No. 545 Bristers-Morrisville as a single circuit monopole line to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 4357 MVA.				

Table 6.61: Virginia Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
63	B3800 (Cont.)	.312	Rebuild 500 kV line No. 569 Loudoun-Morrisville to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 4357 MVA.	6/1/2027	$3,522.24	Dominion	10/31/2023
64		.313	Rebuild ~10.29-mile line segment of line No. 535 (Meadow Brook to Loudoun) to accommodate the new 500 kV line in the existing right-of-way.				
65		.314	Rebuild ~4.83 miles of 500 kV line No. 546 Mosby-Wishing Star to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 4357 MVA. Upgrade and install equipment at Mosby substation to upgrade terminal equipment to be rated for 5000A for 500 kV lines No. 546.				
65		.315	Rebuild ~4.59 miles of 500 kV line #590 Mosby-Wishing Star to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 4357 MVA. Upgrade and install equipment at Mosby substation to upgrade terminal equipment to be rated for 5000A for 500 kV lines No. 590.				
66		.316	Rebuild ~6.17 miles of 230 kV line No. 2030 Gainesville-Mint Springs to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
67		.317	Rebuild ~1.58 miles of 230 kV line No. 2030 Mint Springs-Loudoun to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
68		.318	Rebuild ~4.2 miles of 230 kV line No. 2045 Loudoun-North Star to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
69		.319	Rebuild ~0.88 miles of 230 kV line No. 2045 North Star-Brambleton to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
70		.320	Rebuild ~1.22 miles of 230 kV line No. 2227 Brambleton-Racefield to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
71		.321	Rebuild ~3.69 miles of 230 kV line No. 2094 Racefield-Loudoun to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
72		.322	Rebuild ~9.16 miles of 230 kV line No. 2101 Bristers-Nokesville to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
73		.323	Rebuild ~2.89 miles of 230 kV line No. 2101 Nokesville-Vint Hill TP to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
74		.324	Rebuild ~0.33 miles of 230 kV line No. 2101 Vint Hill TP-Vint Hill to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
75		.325	Rebuild ~3.32 miles of 230 kV line No. 2114 Rollins Ford-Vint Hill to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
76		.326	Rebuild ~10.09 miles of 230 kV line No. 2114 Vint Hill-Elk Run to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
77		.327	Rebuild ~4.43 miles of 230 kV line No. 2140 Heathcote-Catharpin to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
78		.328	Rebuild ~2.88 miles of 230 kV line No. 2140 Catharpin-Loudoun to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
79		.329	Rebuild ~0.25 miles of 230 kV line No. 2151 Railroad DP-Gainesville to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				

Table 6.61: Virginia Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
80	B3800 (Cont.)	.330	Rebuild ~4.14 miles of 230 kV line No. 2163 Vint Hill-Liberty to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.	6/1/2027	$3,522.24	Dominion	10/31/2023
81		.331	Rebuild ~0.48 miles of line No. 2176 Heathcote-Gainesville to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
		.332	Rebuild ~1.11 miles of line No. 2222 Rollins Ford-Gainesville to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
82		.333	Rebuild ~1.65 miles of line No. 183 Bristers-Ox to accommodate the new 500 kV line in the existing right-of-way. New conductor to have a summer rating of 1573 MVA.				
83		.334	Replace four overdutied 230 kV breakers at Loudoun substation with 80 kA breakers.				
84		.335	Replace one overdutied 500 kV breaker at Ox substation with a 63 kA breaker.				
85		.336	Upgrade and install equipment at Bristers substation to support the new conductor 5000A rating for 500 kV line No. 545.				
86		.337	Upgrade and install equipment at Brambleton substation to support the new conductor termination. All terminal equipment for 230 kV lines No. 2045 and No. 2094 to be rated for 4000A continuous current rating.				
87		.338	Revise relay settings at Dawkins Branch.				
88		.339	Upgrade and install equipment at Gainesville substation to support the new conductor termination. All terminal equipment for 230 kV line No. 2030 to be rated for 4000A continuous current rating.				
89		.340	Revise relay settings at Heathcote.				
90		.341	Upgrade and install equipment at Loudoun substation for 230 kV line No. 2094 Loudoun-Racefield to be rated for 4000A continuous current rating.				
		.342	Upgrade and install equipment at Loudoun substation for 230 kV line No. 2045 Loudoun-North Star to be rated for 4000A continuous current rating.				
		.343	Upgrade and install equipment at Loudoun substation for 230 kV line No. 2030 Loudoun-Mint Springs to be rated for 4000A continuous current rating.				
		.344	Upgrade and install equipment at Loudoun substation to support the new conductor 5000A rating for 500 kV line No. 569 Loudoun-Morrisville.				
91		.345	Revise relay settings at Mint Springs.				
92		.346	Upgrade and install equipment at Morrisville substation to support the new 500 kV conductor termination. All terminal equipment to be rated for 5000A for 500 kV line No. 545 and #569. Upgrade 500 kV bus 2 to 5000A.				
93		.347	Revise relay settings at North Star.				
94		.348	Revise relay settings at Racefield.				
95		.349	Revise relay settings at Railroad.				
96		.350	Install terminal equipment at Vint Hill substation to support a 5000A line to Morrisville. Update relay settings for 230 kV lines No. 2101, No. 2163 and 500 kV line No. 535.				
		.351	Update relay settings at Vint Hill for 230 kV line No. 2101 Vint Hill-Bristers.				

Table 6.61: Virginia Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
96	B3800 (Cont.)	.352	Update relay settings at Vint Hill for 230 kV line No. 2163 Vint Hill-Liberty.	6/1/2027	$3,522.24	Dominion	10/31/2023
96		.353	Update relay settings at Vint Hill for 500 kV line No. 535 Vint Hill-Loudoun.				
97		.354	Install terminal equipment at Wishing Star substation to support a 5000A line to Vint Hill. Update relay settings for 500 kV lines No. 546 and No. 590.				
98		.355	Revise relay settings at Youngs Branch.				
99		.356	Build a new 500 kV line from Vint Hill to Wishing Star. The line will be supported on single circuit monopoles. New conductor to have a summer rating of 4357 MVA. Line length is ~16.59 miles.				
100		.357	Build a new 500 kV line from Morrisville to Vint Hill. New conductor to have a summer rating of 4357 MVA. Line length is ~19.71 miles.				
		.358	Replace single unit Locks 230/115 kV 168 MVA transformer No. 7 with new single-unit transformer with a rating of 224 MVA. Lead lines at the 115 kV level will be upgraded to 2000A.				
101		.359	Wreck and rebuild line No. 2090 Ladysmith CT-Summit D.P. segment as a double circuit 230 kV line to achieve a summer rating of 1573 MVA. Only one circuit will be wired at this stage. Upgrade circuit breaker leads, switches and line leads at Ladysmith CT to 4000A.				
102		.360	Rebuild 230 kV line No. 2054 Charlottesville-Proffit DP using double circuit-capable 500/230 kV poles (the 500 kV circuit will not be wired as part of this project).				
103		.361	Rebuild 230 kV line No. 233 Charlottesville-Hydraulic Rd.-Barracks Rd.-Crozet-Dooms.				
104		.362	Rebuild 230 kV line No. 291 segment from Charlottesville-Barracks Rd.				
105		.363	Rebuild 230 kV line No. 291 segment from Barracks Rd.-Crozet.				
106		.364	Rebuild 230 kV line No. 291 segment Crozet-Dooms.				
107		.365	Perform Hollymeade substation relay revision for 230 kV line No. 2054 Charlottsville-Hollymeade.				
		.366	Upgrade the terminal equipment at Charlottesville to 4000A for 230 kV line No. 2054 (Charlottsville-Hollymeade).				
108		.367	Perform Proffit DP substation relay revision for 230 kV line No. 2054 Charlottesville-Hollymeade.				
109		.368	Perform Barracks Rd. substation relay reset to accommodate the rebuilt 230 kV lines No. 233 and No. 291.				
110		.369	Perform Crozet substation relay reset to accommodate the rebuilt 230 kV lines No. 233 and No. 291.				
111		.370	Perform Charlottesville substation terminal equipment upgrade for 230 kV lines No. 233 and No. 291 rebuild.				
112		.371	Upgrade Hydraulic Rd. substation equipment for 230 kV line No. 233 and No. 291 rebuild.				
113		.372	Perform Dooms substation terminal equipment upgrade for 230 kV line No. 233 and No. 291 rebuild.				
114		.373	Wreck and rebuild ~7.14 miles of 230 kV line No. 256 from St. Johns to structure 256/108 to achieve a summer rating of 1573 MVA. Line switch 25666 at St. Johns to be upgraded to 4000A.	6/1/2028			
115		.374	Reconductor ~5.30 miles of 230 kV line No. 256 from Ladysmith CT to structure 256/107 to achieve a summer rating of 1573 MVA. Terminal equipment at remote end substations will be upgraded to 4000A.				
116		.401	Replace Ashburn 230 kV breaker SC432 with a breakers rated at 63 kA.	6/1/2027			12/5/2023

Table 6.61: Virginia Baseline Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
117	B3800 (Cont.)	.402	Replace Beaumeade 230 kV breaker 227T2152 with a breakers rated at 80 kA.	6/1/2027	$3,522.24	Dominion	12/5/2023
118		.403	Replace BECO 230 kV breakers 215012 and H12T2150 with breakers rated at 63 kA.				
119		.404	Replace Belmont 230 kV breaker 227T2180 with a breakers rated at 80 kA.				
120		.405	Replace Brambleton 230 kV breakers 20102, 20602, 204502, 209402, 201T2045, 206T2094 with breakers rated at 80 kA.				
121		.406	Replace Gainesville 230 kV breaker 216192 with a breakers rated at 80 kA.				
122		.407	Replace Loudoun 230 kV breakers 204552, 217352 with breakers rated at 80 kA.				
123		.408	Replace Ox 230 kV breakers 22042, 24342, 24842, 220T2063, 243T2097, 248T2013, H342 with breakers rated at 80 kA.				
124		.409	Replace Paragon Park 230 kV breakers 208132, 215032, 2081T2206, 2150T2207 with breakers rated at 80 kA.				
125		.410	Replace Reston 230 kV breaker 264T2015 with a breakers rated at 63 kA.				
126		.411	Replace Stonewater 230 kV breakers 20662-1, 20662-2, 217862-1, 217862-2 with breakers rated at 80 kA.				
127		.412	Replace Waxpool 230 kV breakers 214922-5, 214922-6, 216622-5, 216622-6 with breakers rated at 63 kA.				
128		.413	Replace Double Toll Gate 138 kV breaker MDT 138 OCB with a breakers rated at 40 kA.			AP	

6.12.7 — Network Projects

Network projects in Virginia for 2023 are summarized in **Map 6.50** and **Table 6.62**.

Read More
Network Projects

Map 6.50: Virginia Network Projects (Dec. 31, 2023)

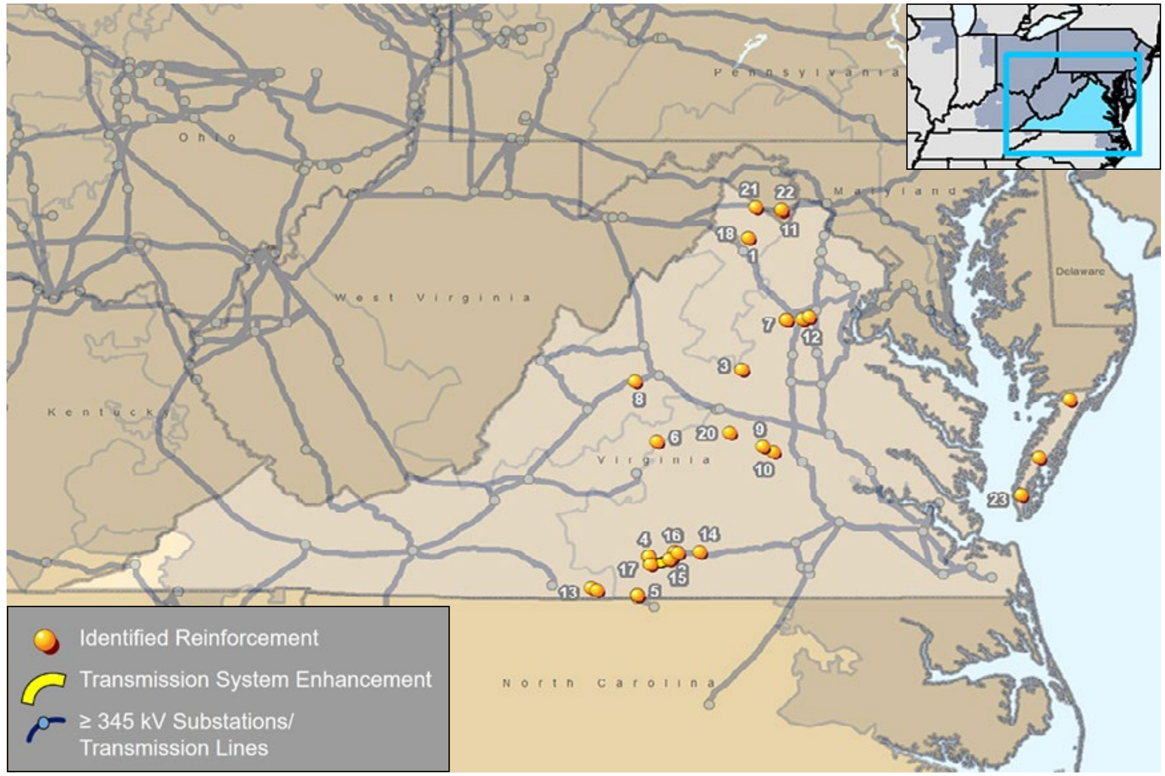


Table 6.62: Virginia Network Projects (Dec. 31, 2023)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6081	Upgrade carrier and line relaying and wave trap at Double Toll Gate 138 kV substation.	AD2-158	9/1/2020	$0.55	AP	10/3/2023
2	N6134	Build a new three-breaker 230 kV ring bus cutting the Clover-Sedge Hill 230 kV line.	AD1-087	9/2/2019	$6.12	Dominion	
	N6135	Install new structures to cut and loop the line into AD1-087 switching station.			$1.28		
	N6136	Perform protection and communication work to support interconnection of new AD1-087 generator.			$0.16		

Table 6.61: Virginia Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	N6235	Build a three-breaker ring bus at the new AC1-043 substation.	AC1-043	10/2/2019	$5.47	Dominion	10/3/2023
3	N6237	Modify protection and communication work to support interconnection of new AC1-105 generator.	AC1-043	10/2/2019	$0.18	Dominion	10/3/2023
4	N6331	Modify protection and communication work to support interconnection of new AC1-222 generator.	AC1-222	1/31/2019	$0.18	Dominion	10/3/2023
4	N6332	Build new structures to cut and loop the line No. 1016 into AC1-222 115 kV substation.	AC1-222	1/31/2019	$0.68	Dominion	10/3/2023
4	N6333	Build a three-breaker 115 kV substation at the AC1-222 facility.	AC1-222	1/31/2019	$5.10	Dominion	10/3/2023
5	N6355	Modify protection and communication work to support interconnection of new AC1-221 generator.	AC1-221	9/30/2018	$0.07	Dominion	10/3/2023
5	N6356	Build new structures to cut and loop the line No. 1016 into AC1-221 230 kV substation.	AC1-221	9/30/2018	$0.61	Dominion	10/3/2023
5	N6357	Build a three-breaker 230 kV substation at the AC1-221 facility.	AC1-221	9/30/2018	$5.80	Dominion	10/3/2023
6	N6457.1	The sag study was completed under the AE1-130 project and determined that no violations occur on this line when operating at Maximum Operating Temperature.	AG1-124	9/1/2024	$0.00	AEP	10/3/2023
7	N6648	Build a three-breaker 115 kV substation at the AC1-143 facility.	AC1-143	6/30/2018	$5.30	Dominion	10/3/2023
7	N6649	Build new structures to cut and loop the transmission line into AC1-143 115 kV substation.	AC1-143	6/30/2018	$1.80	Dominion	10/3/2023
7	N6650	Modify protection and communication work to support interconnection of new AC1-143 generator.	AC1-143	6/30/2018	$0.15	Dominion	10/3/2023
8	N6764	Build a three-breaker 115 kV substation at the AE1-084 facility.	AE1-084	11/30/2020	$5.60	Dominion	10/3/2023
8	N6765	Build new structures to cut and loop the transmission line into AE1-084 115 kV substation.	AE1-084	11/30/2020	$0.80	Dominion	10/3/2023
8	N6766	Modify protection and communication work to support interconnection of new AE1-084 generator.	AE1-084	11/30/2020	$0.27	Dominion	10/3/2023
9	N6770	Build a three-breaker 230 kV substation at the AC2-165 facility.	AC2-165	10/1/2019	$6.30	Dominion	10/3/2023
10	N6771	Build new structures to cut and loop the transmission line into the Powhatan 230 kV substation.	AC2-165	10/1/2019	$1.00	Dominion	10/3/2023
10	N6772	Modify protection and communication work to support interconnection of new Powhatan generator.	AC2-165	10/1/2019	$0.19	Dominion	10/3/2023
11	N7279	Modify substation nameplates and high voltage circuit diagram at Old Chapel 138 kV substation.	AD2-158	9/1/2020	$0.06	AP	10/3/2023
12	N7422	Construct line between Morrisville substation and AE1-044 Transition station.	AE1-044	11/2/2020	$1.71	Dominion	10/3/2023
13	N7754.1	Replace substation conductor at Danville2 138 kV station.	AD1-152	11/30/2022	$0.00	AEP	10/3/2023
13	N7754.2	Replace substation conductor at East Danville 138 kV station.	AD1-152	11/30/2022	$0.00	AEP	10/3/2023
14	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	10/3/2023
15	N7853.2	Build a three-breaker AD1-152 230 kV switching station.	AD1-152	12/31/2024	$7.60	Dominion	10/3/2023
16	N7853.3	Perform remote protection and communications work at Clover 230 kV substation.	AD1-152	12/31/2024	$0.06	Dominion	10/3/2023
17	N7853.4	Perform remote drawing work at Sedge Hill 230 kV substation.	AD1-152	12/31/2024	$0.02	Dominion	10/3/2023
18	N7966	Adjust relay setttings and update drawings and nameplates at Double Toll Gate 138 kV.	AE2-226	12/1/2022	$0.05	AP	10/3/2023
19	N7967	Modify SCADA RTU and update drawings and nameplates at Old Chapel 138 kV.	AE2-226	12/1/2022	$0.05	AP	10/3/2023

Table 6.61: Virginia Network Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
20	N8157	Update 138 kV line relaying at the Bremo 138 kV station.	AE1-108	9/12/2018	$0.18	Dominion	10/3/2023
21	N8159.4	Perform line terminal upgrade at Stonewall substation.	AF1-290	11/15/2023	$0.66	AP	10/3/2023
22	N8159.5	Modify drawings and nameplates for line name change at Feagans Mill substation.	AF1-290	11/15/2023	$0.03	AP	10/3/2023
23	N8443.1	Build a new 69 kV IC substation with a three-breaker ring bus. Two of the positions on the ring bus will be transmission line terminals for the tie-in of the Kellam-Cheriton 69 kV line (line 6750) to the substation. The other position will be a terminal configured for AF2-055 with a disconnect switch.	AF2-055	6/1/2027	$5.00	ODEC	10/3/2023
23	N8443.2	Rebuild ~20 miles of Cheriton/Bayview-Kellam 69 kV. Install reverse power relay at Cheriton station to trip the generator tie if power flow is greater that 0.15 MW toward AF2-055.	AF2-055	6/1/2027	$20.00	ODEC	10/3/2023
23	N8443.3	Install dynamic VAR compensation at Kellam-Chriton 69 kV substation.	AF2-055	6/1/2027	$5.00	ODEC	10/3/2023
23	N8443.4	Perform communication network upgrades for Island detection at Oakhall 69 kV substation.	AF2-055	6/1/2027	$0.50	ODEC	10/3/2023
23	N8443.5	Perform communication network upgrades for Island detection at Oakhall 69 kV substation.	AF2-055	6/1/2027	$0.50	DP&L	10/3/2023

6.12.8 — Supplemental Projects

Supplemental projects received by PJM in 2023 in Virginia are summarized in **Map 6.51** and **Table 6.63**.

Read More
Supplemental Projects

Map 6.51: Virginia Supplemental Projects (Dec. 31, 2023)

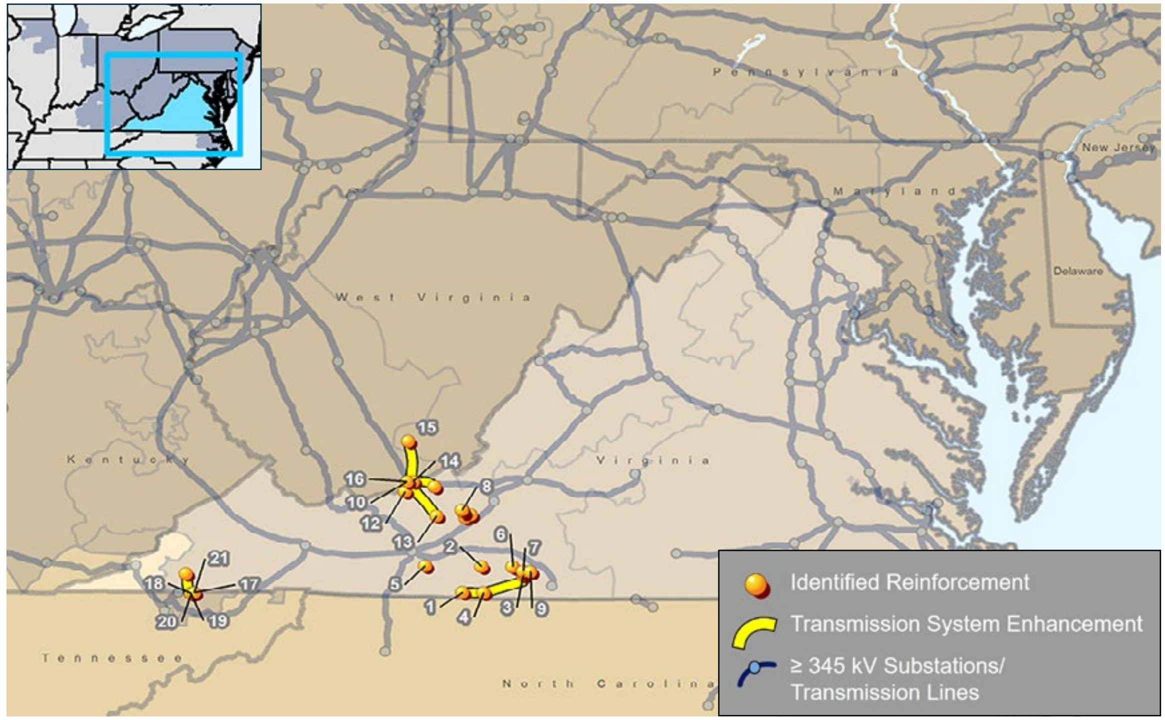


Table 6.63: Virginia Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2179	.35	Construct ~11.4 miles of 138 kV line from Claudville to Mayo River.	11/1/2027	$121.62	AEP	2/17/2023
2		.36	Remove ~0.4 miles of 69 kV line from Woolwine “in and out” loop.				

Table 6.63: Virginia Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2179 (Cont.)	.37	Construct ~9.5 miles 138 kV from Stoneleigh station site to proposed Patrick Henry site.	11/1/2027	$121.62	AEP	2/17/2023
		.38	Construct ~4.1 miles of double circuit 138 kV from Stoneleigh station site to Smith River.				
		.39	Construct ~1.8 miles of 138 kV from Fieldale to Stoneleigh tap structure.				
4		.40	Construct ~11 miles 138 kV from Mayo River to Proposed Patrick Henry Site.				
5		.41	Remove circuit breaker “C” bypass switch and Install CCVT with wave trap on Willis Gap line at Huffman station.				
6		.42	Retire West Bassett station.				
7		.43	Establish new 138 kV tap station, install three-way MOAB switch, install 138/12 kV transformer and associated feeders at Stoneleigh station.				
8	S2817	.1	Rebuild the Midway-South Christiansburg 69 kV line from Midway station to Str. 466-9 (0.45 miles). Rebuild the Midway-South Christiansburg 69 kV line from Str. 466-28B to Str. 466-98 (3.8 miles). At Str. 466-98 build new 69 kV line to the existing Tech Drive station (0.35 miles). The cost per mile is due to the need for matted access roads to minimize property damage in the urban environment. 50 permanent encroachments have been identified within the existing right-of-way and require a greater number of line structures than normal to reroute the line. Also, due to numerous encroachments on the existing centerline, the rebuild will consist of 1.8 miles rebuilt on existing centerline and 2.8 miles near centerline or greenfield.	6/1/2027	$26.35		8/19/2022
		.2	Remove the Midway-South Christiansburg 69 kV circuit from Midway station to Str. 466-9 (0.45 miles). Remove the Midway-South Christiansburg 69 kV circuit from Str. 466-28B to Str. 466-98 (3.4 miles). Retire the Midway-South Christiansburg 69 kV circuit from South Christiansburg station to Str. 466-98 (0.7 miles).				
		.3	Remove the existing 138/69 kV transformer and 69 kV circuit breaker at South Christiansburg station.				
		.4	Build four fiber station transitions using OPGW at Midway, Hans Meadow, Tech Drive and South Christiansburg. Retire 4.3 miles of ADSS fiber currently on the Midway-South Christiansburg 69 kV circuit. Build 4.6 miles of OPGW on the new Midway-Tech Drive 69 kV line.				
		.5	Replace the MOAB switch facing Cambria station with a 69 kV circuit breaker at Hans meadow station.				
		.6	Replace existing 69 kV line CCVTs, bus conductors, and pass-through riser connectors on both line exits to match the 69 kV line capacity at Cambria station.				
		.7	Replace existing risers to support the 69 kV line rebuild at Midway station.				
		.8	Replace the manual switch facing South Christiansburg station with a 138 kV circuit breaker, and remove the 138 kV bus tie switch at Tech Drive station. Install a 138 kV circuit switcher and a 90 MVA 138/69 kV transformer. Add a 69 kV circuit breaker to the 69 kV side of the transformer.				
9	S2848		Establish new distribution station at Patrick Henry station, which will be designed at 138 kV and operated at 69 kV until the area conversion project converts the high-side to 138 kV as part of s2179 (Stuart Area Improvements). The new station will consist of two 138 kV motor operated air-break switches (MOABs), high-side circuit switcher, 138 (69) kV/34.5 kV 30 MVA transformer, 34.5 kV low-side circuit breaker and 2-34.5 kV distribution feeder circuit breakers.	12/2/2025	$0.00		11/18/2022
10	S2887	.1	Construct a new brownfield, breaker and a half Glen Lyn station next to the existing station. The new station will contain eleven 138 kV breakers with seven 138 kV line exits creating four breaker and half strings. Two 138 kV capacitor banks with circuit switchers. One 138/34.5 kV distribution bank with high side circuit switcher and four 34.5 kV breakers. The high station cost is due to the need to raise the new station nearly 10 feet to relieve the flooding concern. Environmental cost is anticipated to be high to remove station equipment, asbestos abatement, building demolition, disposal of soils/TCI conduit/concrete/underground piping/underground transformer vaults. Remove the existing 138 and 34.5 kV yards.	6/1/2026	$48.18		1/20/2023

Table 6.63: Virginia Supplemental Projects (Dec. 31, 2023) (Cont.)

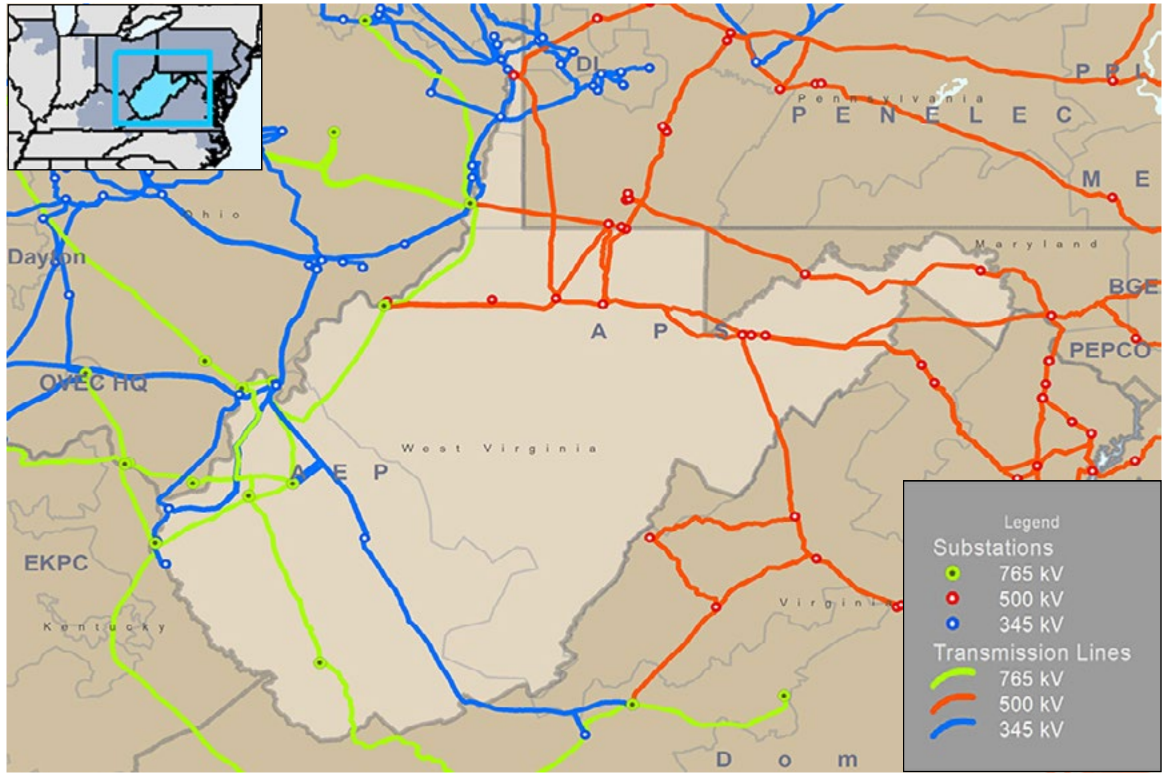
Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
11	S2887 (Cont.)	.2	Remove the line trap at Hinton station. Install bus CCVTs and line arresters on the 138 kV line to Glen Lyn. Upgrade relaying to coordinate to the new breakers.	6/1/2026	$48.18	AEP	1/20/2023
12		.3	Extend the Glen Lyn-Progress Park circuit ~0.4 miles of install to reconnect the circuit to the new Glen Lyn station.				
13		.4	Extend the Glen Lyn-Morgans Cut and Glen Lyn-Hazel Hollow lines (double circuit construction) ~0.15 miles to reconnect the lines to the new Glen Lyn station.				
14		.5	Extend the Glen Lyn-Kimballton and Glen Lyn-Peters Mountain lines (double circuit construction) ~0.25 miles to reconnect the lines to the new Glen Lyn station.				
15		.6	Extend the Glen Lyn-Hinton circuit ~0.1 miles to reconnect the line to the new Glen Lyn station.				
16		.7	Perform required work to connect the New Glen Lyn station to the existing fiber network.				
17	S2913	.1	Retire existing Kyle Hill station.	7/1/2026	$4.31		2/17/2023
18		.2	Build new 0.07-mile double circuit in/out line from the Fort Robinson-Hill 69 kV line to the new Kyle Hill 69 kV station (Kyle Hill Extension).				
19		.3	Build a new Kyle Hill station behind the existing station. Establish a 69 kV bus to allow a 69 kV in/out from Fort Robinson-Hill 69 kV line. Install one 1200A 69 kV rated line MOAB switches toward Hill station. Install one 1200A 69 kV rated line switches toward Fort Robinson station. Replace Ground MOAB with a high-side circuit switcher. Replace existing 34.5/12 kV transformer No. 1 with 69/12 kV transformer. Install new 12 kV bus. Reuse existing Kyle Hill 12 kV breakers. Install 16x19 DICM.				
20		.4	Retire ~3.41 miles of the Fort Robinson-Lovedale 34.5 kV line.				
		.5	Perform remote end and removal of circuit Breaker J at Fort Robinson substation.				
		.6	Perform remote end and removal of circuit breaker G at Lovedale substation.				
21		.7	Retire 34.5 kV Echo switch.				
		.8	Provide transition fiber for Kyle Hill station.				

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 6.52**. 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 6.52: PJM Service Area in West Virginia

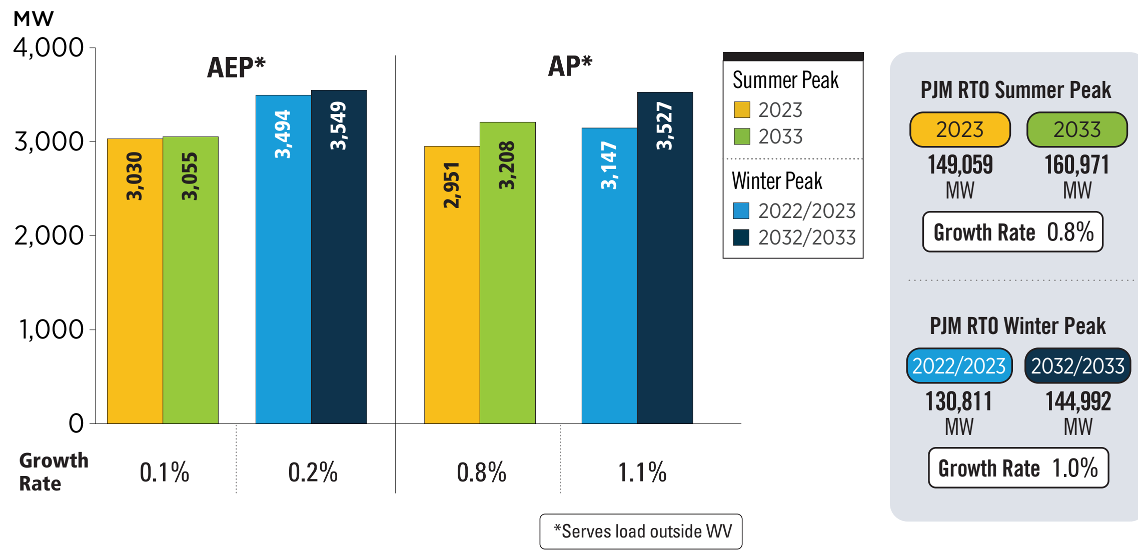


6.13.2 — Load Growth

PJM's 2023 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2023 analyses. **Figure 6.60** summarizes the expected loads within the state of West Virginia and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.60: West Virginia – 2023 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.13.3 — Existing Generation

Existing generation in West Virginia as of Dec. 31, 2023, is shown by fuel type in **Figure 6.61**.

Read More
Changing Capacity Mix and Deliverability

6.13.4 — Interconnection Requests

In West Virginia, as of Dec. 31, 2023, 118 projects were actively under study or under construction as shown in the summaries presented in **Table 6.64, Table 6.65, Figure 6.62, Figure 6.63** and **Figure 6.64**.

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.

Read More
Interconnection Requests

Figure 6.61: West Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2023)

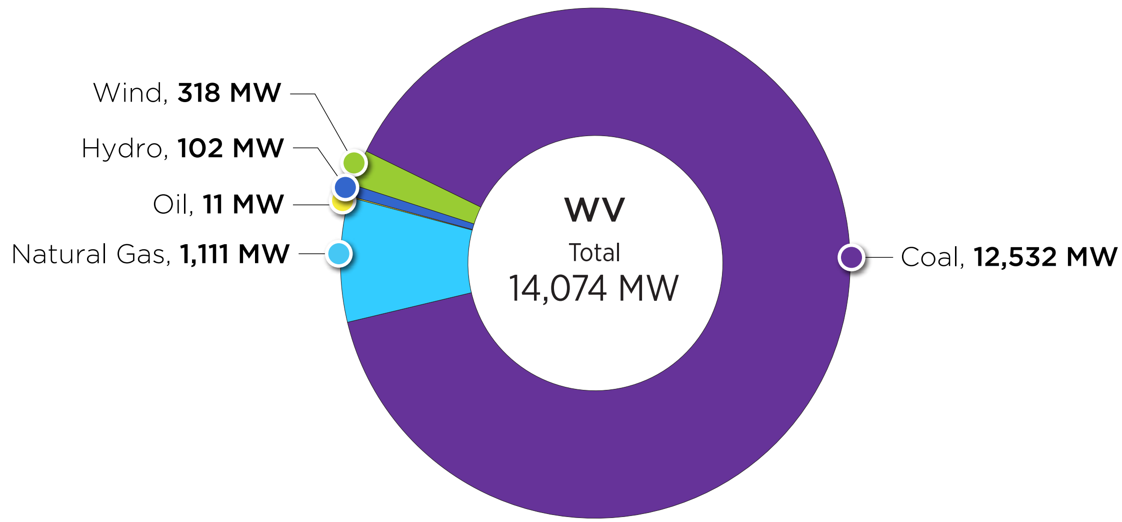


Table 6.64: West Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2023)

	West Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Diesel	0	0.00%	0	0.00%
Hydro	30	0.31%	299	0.17%
Methane	0	0.00%	6	0.00%
Natural Gas	2,190	22.46%	5,278	2.96%
Other	0	0.00%	70	0.04%
Solar	6,012	61.67%	98,471	55.15%
Storage	1,028	10.55%	53,644	30.04%
Wind	488	5.01%	20,798	11.65%
Grand Total	**9,749**	**100.00%**	**178,566**	**100.00%**

Table 6.65: West Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2023)

		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	1	36.0	10	861.0	7	2,023.0	18	2,920.0
	Natural Gas	3	2,190.0	1	1,235.0	3	600.0	6	409.7	43	16,140.8	56	20,575.5
	Other	0	0.0	0	0.0	0	0.0	0	0.0	2	66.0	2	66.0
	Storage	13	1,028.2	0	0.0	0	0.0	2	5.8	7	78.0	22	1,112.0
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	2	48.0	2	48.0
	Hydro	1	30.0	0	0.0	0	0.0	5	59.2	12	208.8	18	298.0
	Methane	0	0.0	0	0.0	0	0.0	3	5.6	3	13.8	6	19.4
	Solar	80	6,011.9	1	53.3	5	214.0	0	0.0	13	398.7	99	6,678.0
	Wind	12	488.4	1	11.8	0	0.0	11	212.6	27	426.5	51	1,139.3
	Grand Total	**109**	**9,748.5**	**3**	**1,300.1**	**9**	**850.0**	**37**	**1,553.9**	**116**	**19,403.7**	**274**	**32,856.1**

Figure 6.62: West Virginia – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2023)

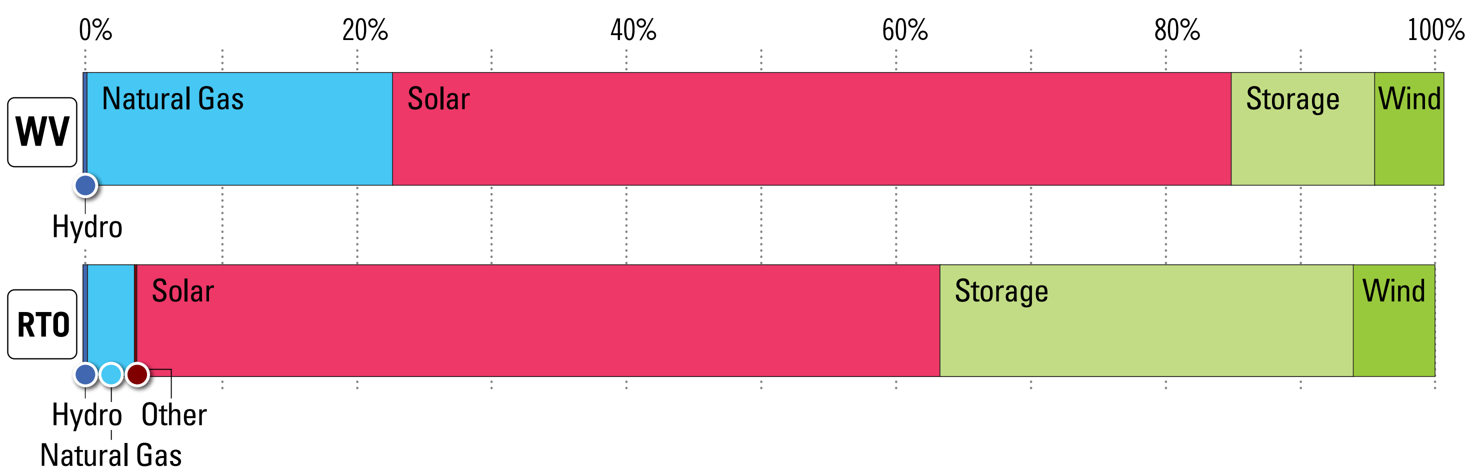
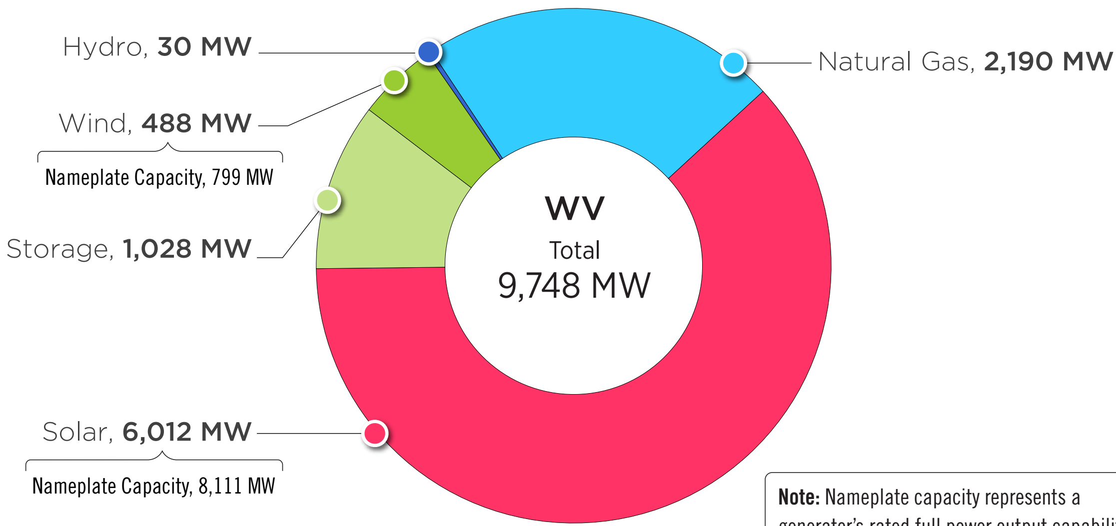


Figure 6.63: West Virginia Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.64: West Virginia Progression of Interconnection Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

7.1%	Requested capacity megawatts
23.6%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	14	Interconnection Service Agreements	1,509 MW	1,971 MW
	3	Wholesale Market Participation Agreements	20 MW	41 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

6.13.5 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2023 in West Virginia are summarized in **Map 6.53** and **Table 6.66**.

Read More
Baseline Projects

Map 6.53: West Virginia Baseline Projects (Dec. 31, 2023)

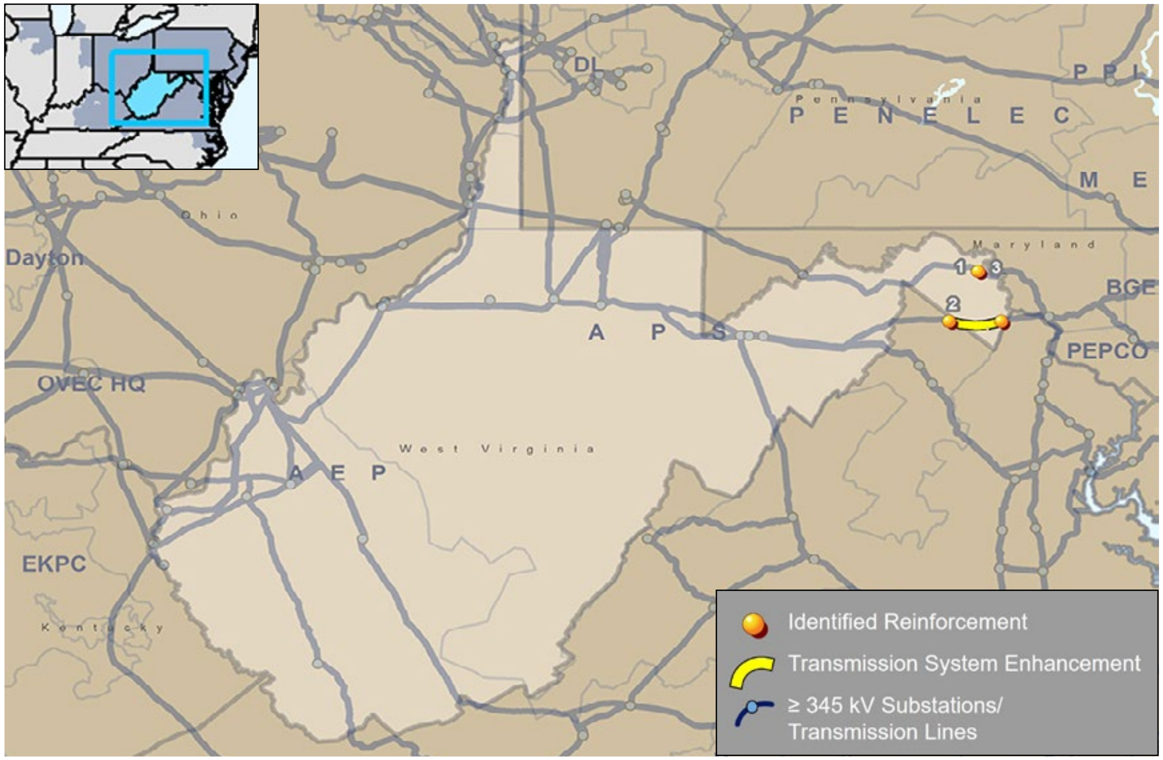


Table 6.66: West Virginia Baseline Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3743		Replace substation conductor, wave trap, CTs and upgrade relaying at Bedington substation. Replace substation conductor, wave trap, CTs, disconnect switches, circuit breaker and upgrade relaying at Cherry Run substation. Replace substation conductor, wave trap, CTs and upgrade relaying at Marlowe.	6/1/2027	$4.60	AP	11/18/2022
	B3747		Install redundant relaying at Bedington substation.		$0.28		
2	B3740		Replace limiting terminal equipment at Glen Falls-Bridgeport 138 kV line.		$1.88		
3	B3800	.104	Rebuild ~15 miles of the Stonewall-Millville 138 kV line with 500 kV overbuild (502 Jct to Woodside 500 kV line section).		$136.93		12/5/2023

6.13.6 — Supplemental Projects

Supplemental projects received by PJM in 2023 in West Virginia are summarized in **Map 6.54** and **Table 6.67**.

Read More
Supplemental Projects

Map 6.54: West Virginia Supplemental Projects (Dec. 31, 2023)

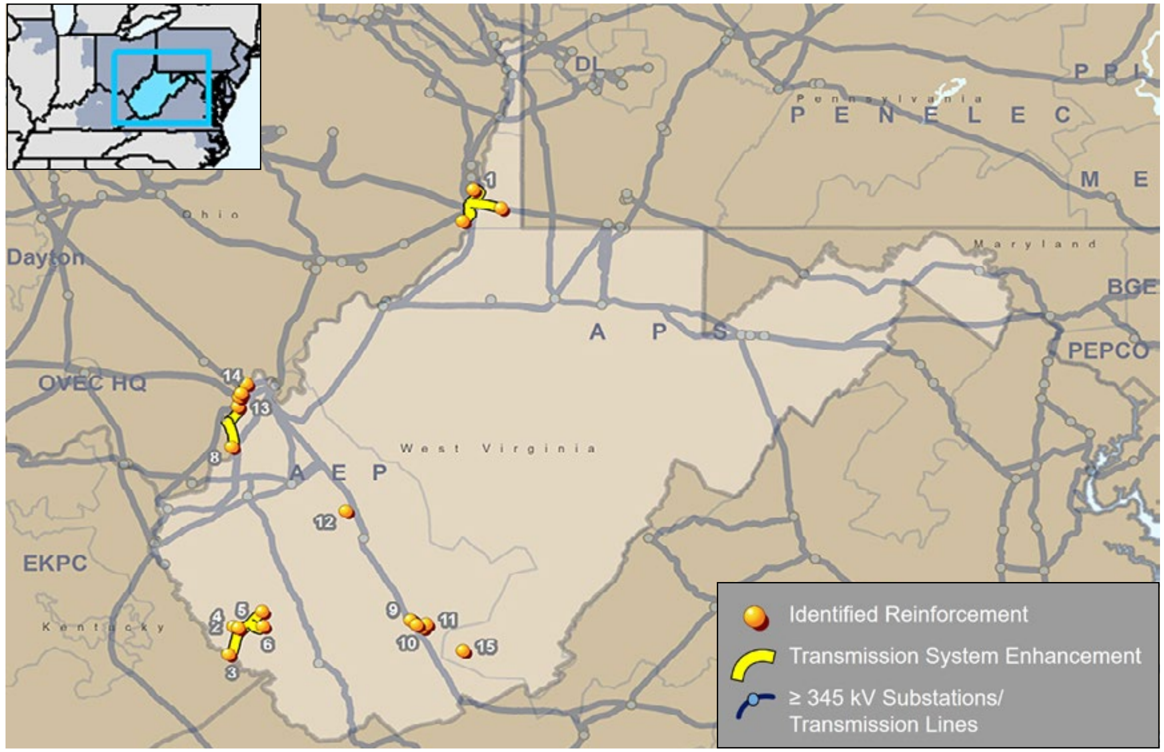


Table 6.67: West Virginia Supplemental Projects (Dec. 31, 2023)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2270	.8	Cut into the George Washington-Natrium 138 kV circuit and extend an 8.6-mile double-circuit 138 kV loop east to Nauvoo Ridge.	6/21/2024	$46.64	AEP	5/12/2020
		.9	Modify the George Washington-Natrium 138 kV line, which is part of a double-circuit lattice tower line.				
		.10	Rebuild the Kammer-Natrium 138 kV double-circuit line (9.3 miles). The circuit's limiting ratings are currently set by the T-line conductor (556 ACSR). The rebuilt circuit will utilize 795 ACSS high-temperature conductor to optimize the new structure sizing and cost.	12/1/2025			9/16/2022

Table 6.67: West Virginia Supplemental Projects (Dec. 31, 2023) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2816	.1	Construct a new greenfield station (Holden) with a 138/12 kV 25 MVA transformer and high-side circuit switcher. There will be two 12 kV feeders from the station. The 138 kV side will be a straight bus with one 138 kV circuit breaker facing Ragland and one 138 kV MOAB switch facing Tin Branch. The intent of the greenfield station is to support the business-ready site, and the 138 kV circuit breaker will provide added protection for sensitive industrial customers. The existing Pine Creek station will be retired.	6/1/2024	$14.10	AEP	8/19/2022
3		.2	Tap the Logan-Sprigg No. 2 138 kV line and build 3.5 miles of greenfield double circuit 138 kV line to serve Holden station. The higher estimated cost is due to a large amount of new access roads and environmental studies that are required for this greenfield line that will be built through mountainous terrain.				
4		.3	Build 0.6 miles of 96 ADSS Telecom underbuilt cable to connect Holden station to the existing fiber network.				
5		.4	Remove 1.85 mile long Pine Creek 138 kV tap.				
6	S2818	.1	Add two additional 138 kV circuit breakers to the already proposed and approved Tin Branch station (b3348), transforming the designed station from a 138 kV two-breaker straight station to a four-breaker ring bus station.	3/1/2027	$7.50		
7		.2	Disconnect the Chauncey hard tap from the Logan-Sprigg circuit and build 1.5 miles of greenfield 138 kV line to connect the Chauncey 138 kV tap into the new Tin Branch station. The higher estimated cost is due to the difficult mountainous terrain, expensive access roads and required environmental studies.				
8	S2819	.1	Rebuild existing Apple Grove-Point Pleasant 69 kV line to 138 kV standards (approx. 17.3 miles).	4/1/2025	$57.00		9/16/2022
		.2	Replace existing 69 kV circuit breaker-L with a new 69 kV, 3000A 40 kA circuit breaker at Apple Grove station. Replace existing 138/69 kV transformer No. 1 with a new 138/69 kV 90 MVA transformer and install new high-side circuit switcher. Add 138 kV circuit breaker on 138 kV bus increasing sectionalizing by separating existing customer facilities from AEP facilities. Upgrade metering at station. Install new DICM. Replace existing 69/12 kV transformer No. 2 with a new 138/12 kV transformer E.				
9	S2912	.1	Cut in/out of the existing Cherry Creek-Clifftop 138 kV and construct a new 4-mile double circuit 138 kV line to a new 138/12 kV station at Raleigh County Airport (RCA).	3/14/2024	$17.10		2/17/2023
10		.2	Install two 138 kV circuit breakers and a 138/12 kV 25 MVA transformer at the new Raleigh County Airport (RCA) station.				
11		.3	Perform remote end relaying work required at Grandview station.				
12	S2941		Install one new 138/12 kV transformer and one new 138 kV circuit breaker at the existing Coco station.	11/22/2023	$0.90		4/21/2023
13	S2981	.1	Cut in/out of the existing Lakin-Lock Lane 69 kV line and construct a new double circuit 69 kV line in/out to the new Mason County Industrial Park station (approx. 0.25 mile).	5/1/2024	$2.10		7/21/2023
14		.2	Install two 69 kV circuit breakers and a 69/12 kV 25 MVA transformer at the new Mason County Industrial Park station (York station).				

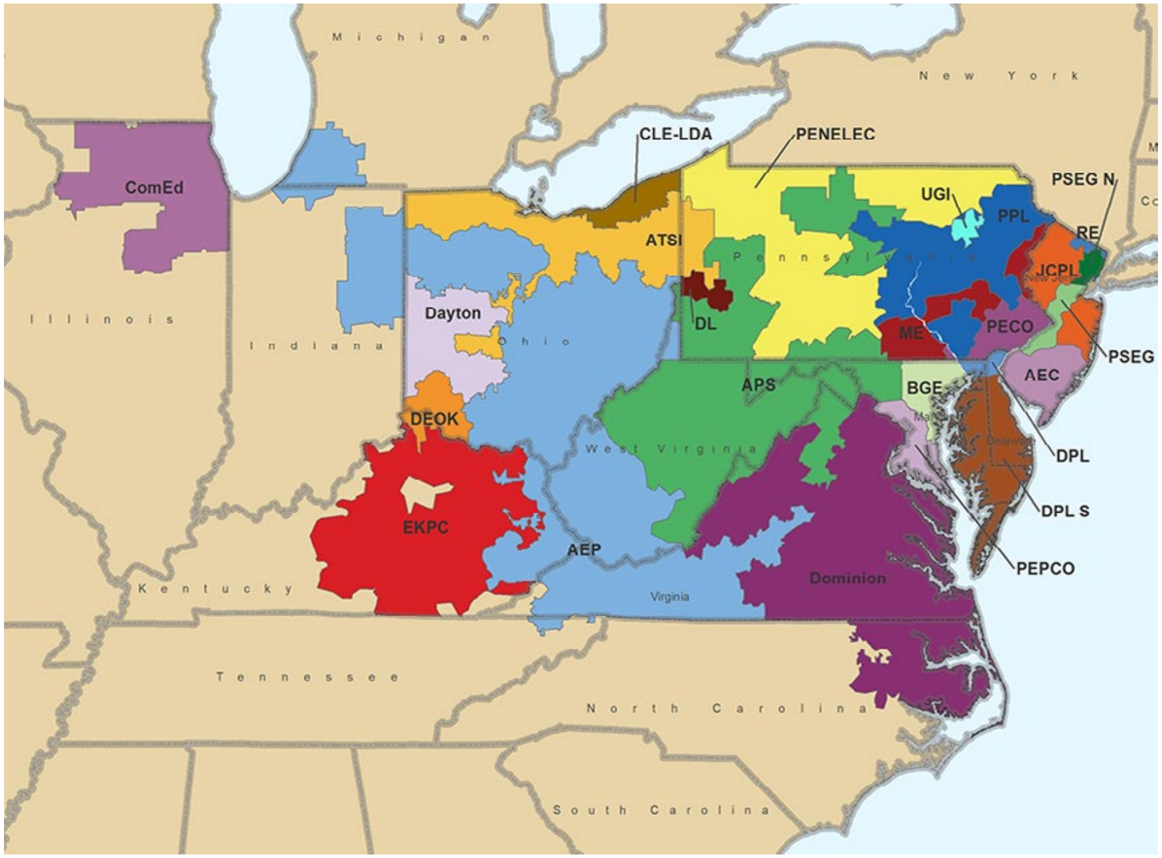
1.0: TO Zones and Locational Deliverability Areas

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



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TOC

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
DAY	▲	▲	AES Ohio, formerly Dayton Power and Light Company
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 (Pepco)
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
Adequacy	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.
Aluminum Conductor Steel Reinforced		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).
Aluminum Conductor Steel Supported		ACSS	This high-capacity, stranded conductor type is made from annealed aluminum.
Ancillary Service	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.
Annual Demand Resources			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.
Attachment Facilities	OATT		Attachment facilities are necessary to physically connect a customer facility to the transmission system or interconnected distribution facilities.
Auction Revenue Right	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.
Available Transfer Capability	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.
Base Capacity Resource	M18		Base capacity resources are capacity resources that are not capable of sustained, predictable operation throughout the entire delivery year. These resources were only procured through the 2019/2020 Delivery Year. Starting with the 2020/2021 Delivery Year, all resources are Capacity Performance Resources. See "Capacity Performance."
Baseline Upgrades	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.
Behind-the-Meter Generation	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.
Bilateral Transaction	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.

Term	Reference	Acronym	Definition
Breaker-and-a-Half		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.
Bulk Electric System	NERC, M14B	BES	ReliabilityFirst defines the bulk electric system as all individual generation resources that are: (1) larger than 20 MVA, or (2) a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to: (A) facilities operated at voltages of 100 kV or higher, or (B) lines operated at voltages of 100 kV or higher with 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.
Capacitor Voltage Transformer		CCVT	This type of transformer is used to step down high voltage signals and provide a low voltage signal for metering or protection devices.
Capacity Emergency	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.
Capacity Emergency Transfer Limit	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.
Capacity Emergency Transfer Objective	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.
Capacity Interconnection Rights	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.
Capacity Performance			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 were fully in place starting with the 2020/2021 Delivery Year. See "Base Capacity Resource" and "Capacity Performance Resource."
Capacity Performance Resource	M18		Capacity Performance Resources are capable of sustained, predictable operation throughout the entire delivery year. Starting with the 2020/2021 Delivery Year, all resources are Capacity Performance Resources. See "Capacity Performance."
Capacity Resource	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.
Certificate of Public Convenience and Necessity		CPCN	A permit granted to a transmission owner that authorizes it to a provide service to a new geographic area.
Circuit Breaker		CB	This automatic device is used to stop the flow of current in an electric circuit as a safety measure.
Clean Air Interstate Rule		CAIR	The Clean Air Interstate Rule is an Environmental Protection Agency (EPA) rule regarding the interstate transport of soot and smog.
Clean Power Plan		CPP	The Clean Power Plan is an EPA rule regarding carbon pollution from power plants.
Coincident Peak	M19		The coincident peak is a zone's contribution to the RTO or higher level locational deliverability area (LDA) peak load.
Combined Cycle (Turbine)		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.
Combustion Turbine		CT	A combustion turbine is a generating unit in which a combustion turbine engine is the prime mover.
Consolidated Transmission Owners Agreement	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.
Contingency			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.
Coordinated System Plan		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.

Term	Reference	Acronym	Definition
Cost of New Entry	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.
Cross-Linked Polyethylene		XLPE	A type of plastic used to insulate power lines; the benefits of cross-linked polyethylene include resistance to temperature fluctuations and other environmental factors.
Cross-State Air Pollution Rule		CSAPR	The Cross-State Air Pollution Rule is an EPA rule regarding reduction in air pollution related to power plant emissions.
Current Transformer		CT	This type of transformer is used to measure electrical flows for purposes of telemetry.
Deactivation	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.
Deliverability	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.
Demand Resource	M18	DR	See "Load Management."
Designated Entity			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.
Designated Entity Agreement	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.
Distributed Solar Generation			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.
Distribution Factor		DFAX	A distribution factor is the portion of an imposed power transfer that flows across a specified transmission facility or interface.
Diversity	M18		Diversity is the number of megawatts that account for the difference between a transmission owner zone's forecast peak load at the time of its own peak and its coincident load at the time of the PJM peak.
Eastern Interconnection Planning Collaborative		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.
Eastern Interconnection Reliability Assessment Group		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.
Eastern MAAC	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, PSEG and Rockland.
Effective Forced Outage Rate on Demand	M22	EFORd	EFORd is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. See Manual 22: Generator Resource Performance Indices for the equation.
Electrical Distribution Company		EDC	An electrical distribution company owns and/or operates electrical distribution facilities for the delivery of electrical energy to end-use customers.
End-Use Characteristics	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.
Energy Efficiency Programs		EE	Energy efficiency programs are incentives or requirements at the state or federal level, which promote energy conservation and wise use of energy resources.
Energy Resource	M14A, M14B		An energy resource is a generating facility that is not a capacity resource.
Extended Summer Demand Resources			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.

Term	Reference	Acronym	Definition
Extra High Voltage		EHV	Extra high voltage transmission equipment operates at 230 kV and above.
Facilities Study Agreement	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.
Fault			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.
Federal Energy Regulatory Commission		FERC	FERC is an independent federal agency that regulates the interstate transmission of electricity, natural gas and oil.
Financial Transmission Right	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.
Firm Transmission Service	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.
Fixed Series Capacitor		FSC	A fixed series capacitor is a grouping of capacitors used to reduce transfer reactances on bulk transmission corridors.
Flexible Alternating Current Transmission System		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.
Flowgate			A flowgate is a specific combination of a monitored facility and a contingency that impacts that monitored facility.
Gas Insulated Substation		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.
Generation Deliverability	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.
Generator Step-up Transformer		GSU	A GSU transformer “steps-up” generator power output voltage level to the suitable grid-level voltage for transmission of electricity to load centers.
Geomagnetically Induced Current		GIC	This is a manifestation at ground level of space weather; these currents impact the normal operation of electrical conductor systems.
Good Utility Practice	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.
Group/Gang Operated Air Break		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.
Horizontal Directional Drilling		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.
Independent State Agencies Committee	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.
Independent System Operator		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.”
Installed Capacity		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.
Interconnected Reliability Operating Limit	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.

Term	Reference	Acronym	Definition
Interconnection Construction Service Agreement	M14C	ICSA	The Interconnection Construction Service Agreement 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.
Interconnection Coordination Agreement	OATT	ICA	An Interconnection Coordination Agreement is made between transmission owners and/or transmission developers outlining the schedules and responsibilities of each party involved.
Interconnection Process Reform Task Force		IPRTF	The Interconnection Process Reform Task Force is a task force within PJM's stakeholder process seeking to make improvements to the interconnection process.
Interconnection Service Agreement	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.
Interregional Market Efficiency Project		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.
Joint RTO Planning Committee		JRPC	The JRPC is the decision-making body for MISO/PJM coordinated system planning as governed by the MISO/PJM Joint Operating Agreement.
Light Load Reliability Analysis	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).
Limited Demand Resources			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.
Load			Load refers to demand for electricity at a given time, expressed in megawatts.
Load Analysis Subcommittee	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.
Load Deliverability	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.
Load Management	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.
Load Serving Entity	RAA, OATT	LSE	Load serving entities (LSE) provide electricity to retail customers. LSEs include traditional distribution utilities.
Local Distribution Company		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.
Locational Deliverability Area	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.
Locational Marginal Price		LMP	The locational marginal price is the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.
Loss-of-Load Expectation	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.
Market Participant			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.
Maximum Facility Output	M14A, M14G	MFO	This term refers to the maximum amount of power a generator is capable of producing.
Megavolt-Ampere Reactive	OA	MVAR	See "Reactive Power."
Merchant Transmission Facility	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.
Mercury and Air Toxins Standards		MATS	MATS is an EPA rule limiting the emissions of toxic air pollutants like mercury, arsenic and metals from power plant emissions.

Term	Reference	Acronym	Definition
Mid-Atlantic Subregion	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 & Light (JCP&L), Met-Ed (METED), Neptune Regional Transmission System (Neptune RTS), PECO Energy Company (PECO), Pennsylvania Electric Company (Penelec), Potomac Electric Power Company (Pepco), PPL Electric Utilities (PPL), Public Service Electric & Gas Company (PSE&G) and Rockland Electric Company (RECO). The Neptune Regional Transmission System interconnects with the Mid-Atlantic PJM transmission system at Sayreville substation in Northern New Jersey.
MISO Transmission Expansion Planning		MTEP	MTEP is the Midcontinent Independent System Operator (MISO) plan for enhancing the future of the power grid in their area.
Motor-Operated Air Break		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.
Multiregional Model Working Group		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.
National Renewable Energy Laboratory		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.
Network Reinforcements	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.
New Services Request(s)	M14A		A New Services Request is a general term describing all requests to PJM for generation or transmission service and/or rights (formerly known as the "queue").
Non-Coincident Peak	M19	NCP	The non-coincident peak is a zone's individual peak load.
North American Electric Reliability Corporation	NERC	NERC	NERC is a FERC-appointed body whose mission is to ensure the reliability of the bulk power system.
Open Access Same-Time Information System		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.
Open Access Transmission Tariff	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.
Optical Grounding Wire Communications		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.
Optimal Power Flow		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."
Organization of PJM States, Inc.		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 FERC, as well as their individual roles as statutory regulators within their respective state boundaries.
PJM Manuals			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.
PJM Member	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.
Planning Committee	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.
Planning Cycle	M14B		The planning cycle is the annual RTEP process, including a series of studies, analysis, assessments and related supporting functions.
Planning Horizon	M14B		The planning horizon is the future time period over which system transmission expansion plans are developed based on forecast conditions.
Probabilistic Risk Assessment	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.

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Term	Reference	Acronym	Definition
Queue	M14A		See New Services Request(s).
Reactive Power (expressed in MVAR)	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).
Regional Greenhouse Gas Initiative		RGGI	States and provinces in the northeastern United States and eastern Canada adopted the Regional Greenhouse Gas Initiative to reduce greenhouse gas emissions.
Regional RTEP Project	M14B, OA		A regional RTEP project is a transmission expansion or enhancement at a voltage level of 100 kV or higher.
Regional Transmission Expansion Plan	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.
Regional Transmission Organization	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.
Reliability	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.
Reliability Assurance Agreement	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.
Reliability Must Run		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.
Reliability Pricing Model		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.
ReliabilityFirst Corporation		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.
Renewable Portfolio Standard		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.
Right of First Refusal		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.
Right-of-Way		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.
Security	NERC		Security is 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.
Security Constrained Optimal Power Flow		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.
Southern Subregion	M14B		The PJM Southern Subregion comprises one transmission owner zone – Dominion Energy.

Term	Reference	Acronym	Definition
Special Protection System	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.
Static Synchronous Compensator		STATCOM	This is 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.
Static Var Compensation		SVC	A static var compensation device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system transmission and distribution performance.
Storage as a Transmission Asset		SATA	This a storage device that can be utilized on the transmission system to address reliability issues.
Subregional RTEP Committee	M14B, OA		This PJM committee 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.
Subregional RTEP Project	M14B, OA		A subregional RTEP project is defined in the PJM Operating Agreement as a transmission expansion or enhancement rated below 230 kV.
Sub-Synchronous Resonance		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).
Supervisory Control and Data Acquisition		SCADA	A system of software and hardware that controls industrial processes locally or at remote locations.
Supplemental Project	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.
Surge Impedance Loading		SIL	This is 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.
System Operating Limit	M14B	SOL	This is 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.
System Stability			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.
Targeted Market Efficiency Project		TMEP	These interregional projects address historical congestion on reciprocal coordinated flowgates – a set of specific flowgates subject to joint and common market congestion management.
Temperature-Humidity Index	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 = Td – (0.55 – 0.55RH) * (Td - 58), where Td is the dry-bulb temperature and RH is the percentage of relative humidity, when Td is greater than or equal to 58.
Thyristor Controlled Series Compensator		TCSC	A thyristor controlled series compensator is a series capacitor bank that is shunted by a thyristor controlled reactor.
Topology	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.
Transmission Customer	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.

Term	Reference	Acronym	Definition
Transmission Expansion Advisory Committee	M14B	TEAC	The Transmission Expansion Advisory Committee was established by PJM to provide advice and recommendations to aid in the development of the RTEP.
Transmission Loading Relief	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.
Transmission Owner	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.
Transmission Owner Initiated		TOI	See "Supplemental Project."
Transmission Owner Upgrade	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.
Transmission Provider	M14B, OATT		The transmission provider is PJM for all purposes in accordance with the PJM OATT.
Transmission Service Request	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.
Transmission System	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.
Unforced Capacity	RAA	UCAP	Unforced capacity is an entitlement to a specified number of summer-rated megawatts 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.
Upgrade	OA		See "Transmission Owner Upgrade."
Upgrade Construction Service Agreement		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.
Violation	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.
Weather Normalized Peak	M19		The weather normalized peak is an estimate of the seasonal peak load at normal peak-day weather conditions.
Western Subregion	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 East Kentucky Power Cooperative (EKPC).
Wheel			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.
Wholesale Market Participation Agreement	M14C	WMPA	This is 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.
X-Effective Forced Outage Rate on Demand		XEFORd	This 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)."
Zone/Control Zone	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.

Figure 1.1: Board-Approved RTEP Projects as of Dec. 31, 2023

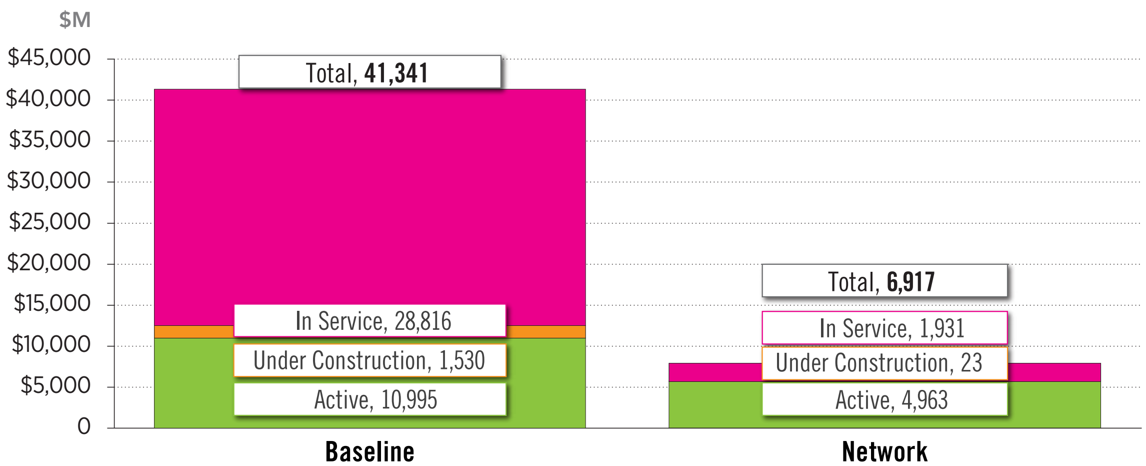


Figure 1.2: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2023)

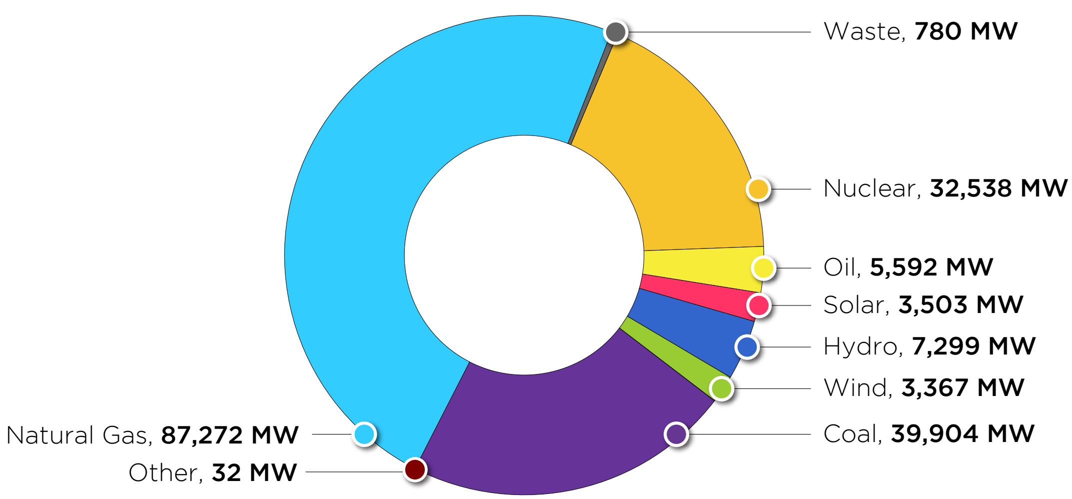
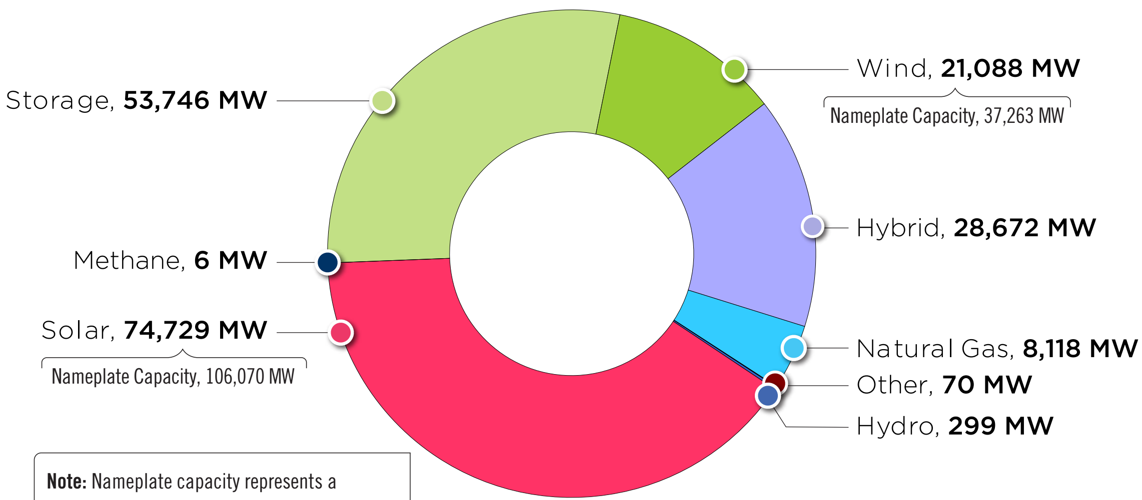


Figure 1.3: Interconnection Service Request Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2023)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 1.4: Interconnection Service Study Requests (Dec. 31, 2023)

Percentage of planned capacity and projects that have reached commercial operation

15.8% Requested capacity megawatts

20.4% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	227	Interconnection Service Agreements	33,166 MW	42,636 MW
	390	Wholesale Market Participation Agreements	1,560 MW	3,140 MW

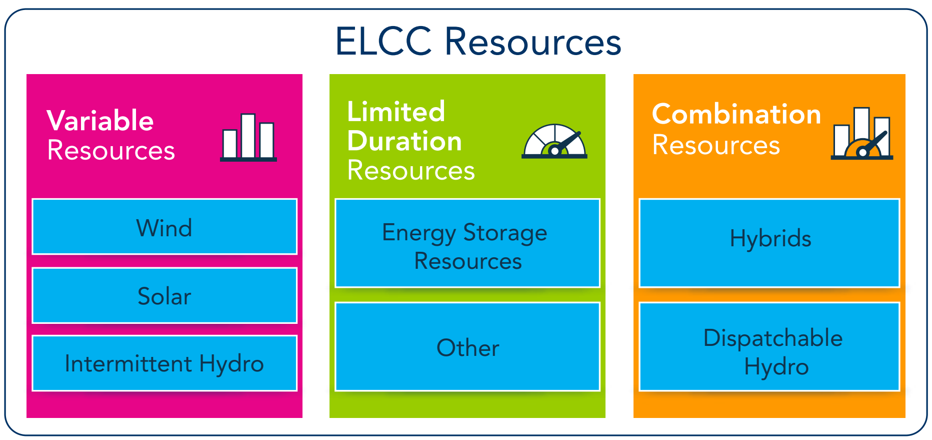
This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2023.

Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2023)

		In Queue				Complete					
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	3	65.0	52	2,137.9	70	33,577.6	125	35,780.5
	Diesel	1	0.00	0	0.0	10	68.5	17	76.70	28	145.2
	Natural Gas	38	5,278.4	12	2,287.6	396	57,419.4	704	253,008.1	1,150	317,993.5
	Nuclear	0	0.0	1	44.0	46	3,940.2	24	9,038.0	71	13,022.2
	Oil	0	0.0	0	0.0	24	543.8	25	2,318.0	49	2,861.8
	Other	6	69.7	0	0.0	6	332.8	78	1,112.2	90	1,514.7
	Storage	626	53,644.2	26	799.2	30	32.0	362	11,439.6	1,044	65,915.0
Renewable	Biomass	0	0.0	0	0.0	8	153.8	40	896.9	48	1,050.7
	Hydro	7	299.3	3	35.0	32	1,155.9	53	2,440.9	95	3,931.0
	Methane	1	6.0	0	0.0	77	365.0	95	490.1	173	861.1
	Solar	1,904	98,470.6	296	10,926.4	291	3,613.2	2,008	44,743.0	4,499	157,753.2
	Wind	156	20,797.6	24	1,215.0	117	2,160.8	522	18,361.2	819	42,534.5
	Wood	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
	Grand Total	**2,739**	**178,565.7**	**365**	**15,372.2**	**1,091**	**71,977.2**	**4,002**	**377,655.2**	**8,197**	**643,570.3**

Note: Table does not include suspended projects, and hybrid resources are imbedded within the fuel type (e.g., solar + storage is captured under "Solar," wind + storage is captured under "Wind," and natural gas also includes some hybrid resources)

Figure 1.5: ELCC Resources



Map 1.1: NJBPU Project SAA 1.0 Injection Points

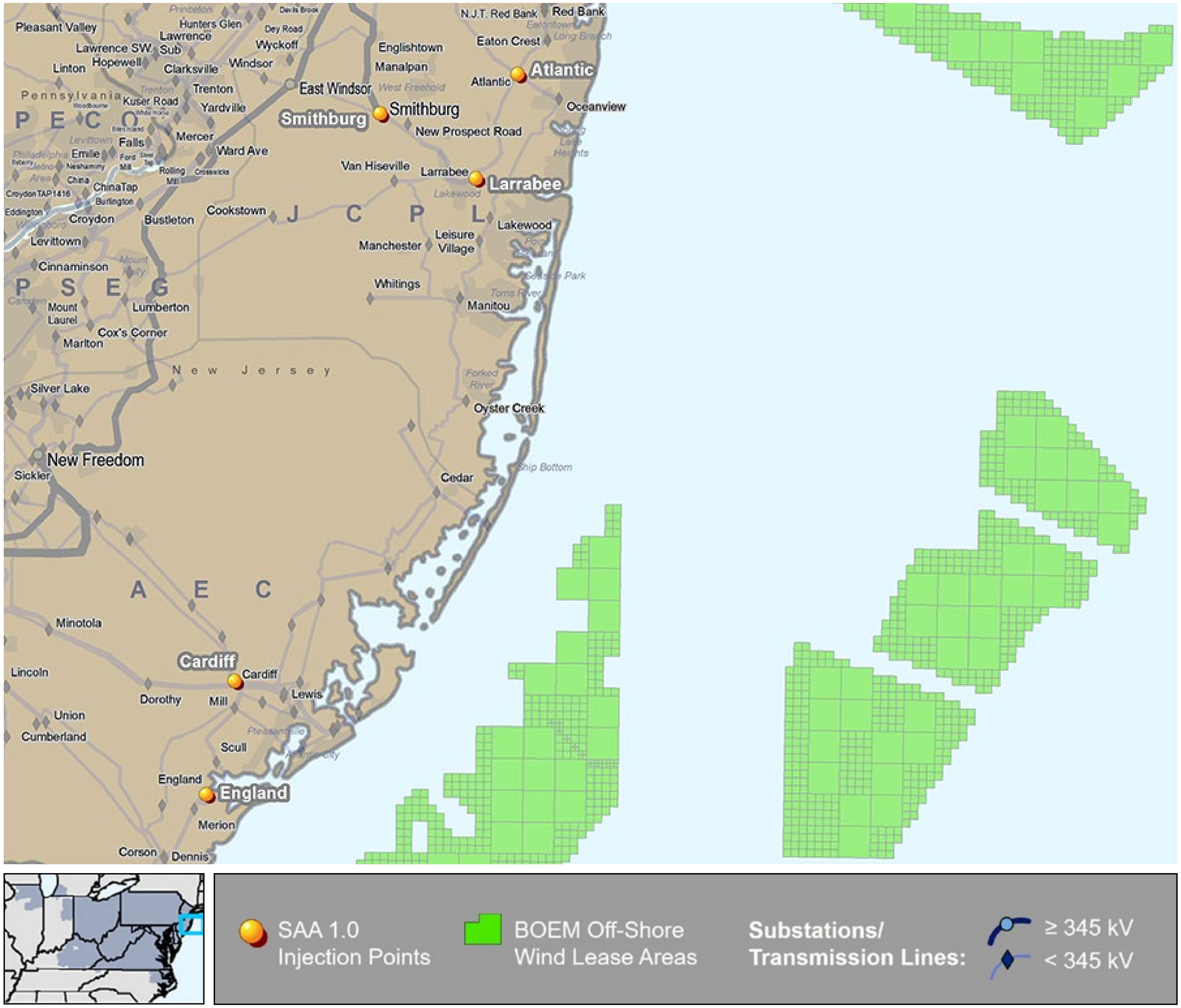


Figure 1.6: Implementing LTRTP Into Existing PJM RTEP Process

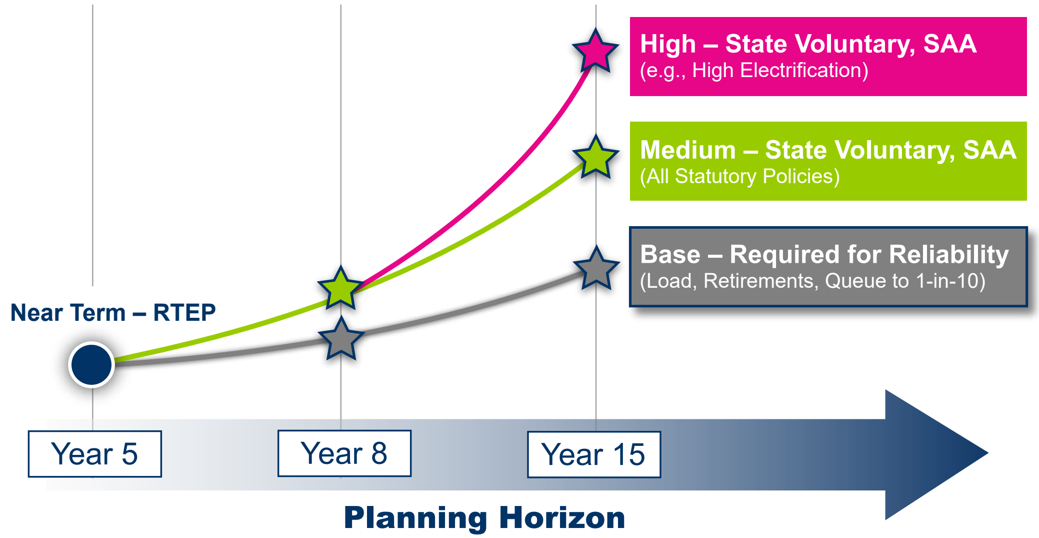


Figure 1.7: Long-Term Regional Transmission Planning Framework

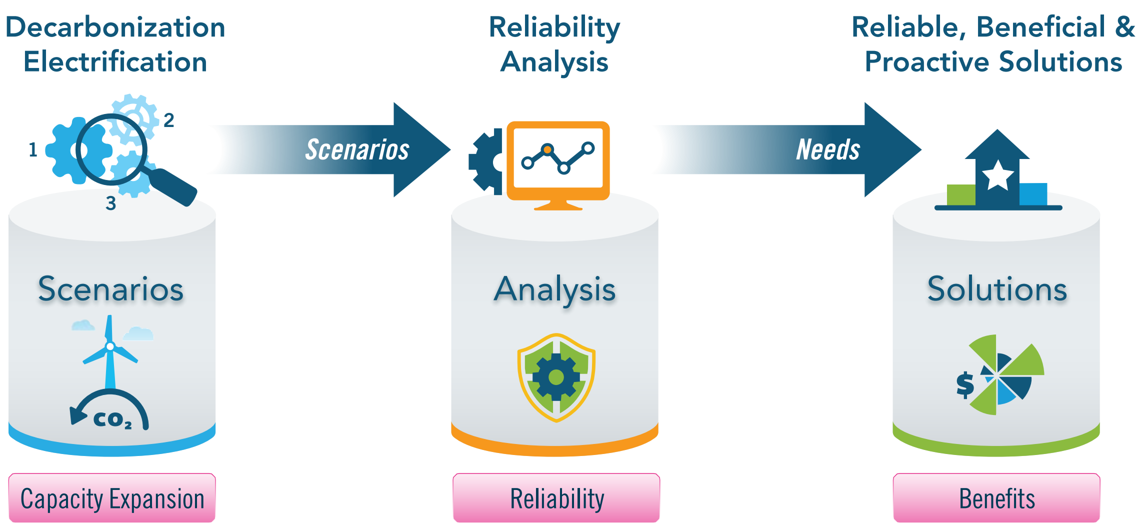
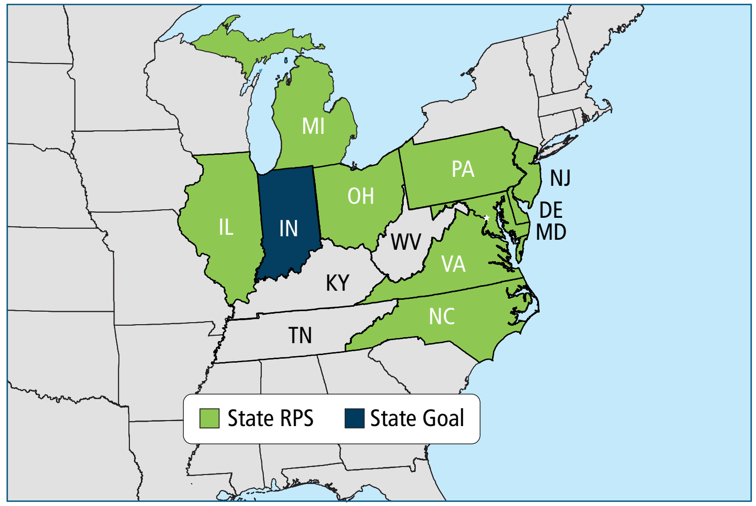


Figure 1.8: PJM State RPS Targets and Goals (as of January 2024)

State RPS Targets*

☼	**NJ:** 50% by 2030**
☼	**MD:** 50% by 2030**
☼	**DE:** 40% by 2035
☼	**DC:** 100% by 2032
☼	**PA:** 18% by 2021***
☼	**IL:** 50% by 2040
☼	**VA:** 100% by 2045/2050 (IOUs)
☼	**NC:** 12.5% by 2021 (IOUs)
	OH: 8.5% by 2026
	MI: 60% by 2035
	IN: 10% by 2025***



☼ Minimum solar requirement

* Targets may change over time; these are recent representative snapshot values

** Includes an additional 2.5% of Class II resources each year

*** Includes non-renewable "alternative" energy resources

Figure 1.9: Accounting for Distributed Solar Generation

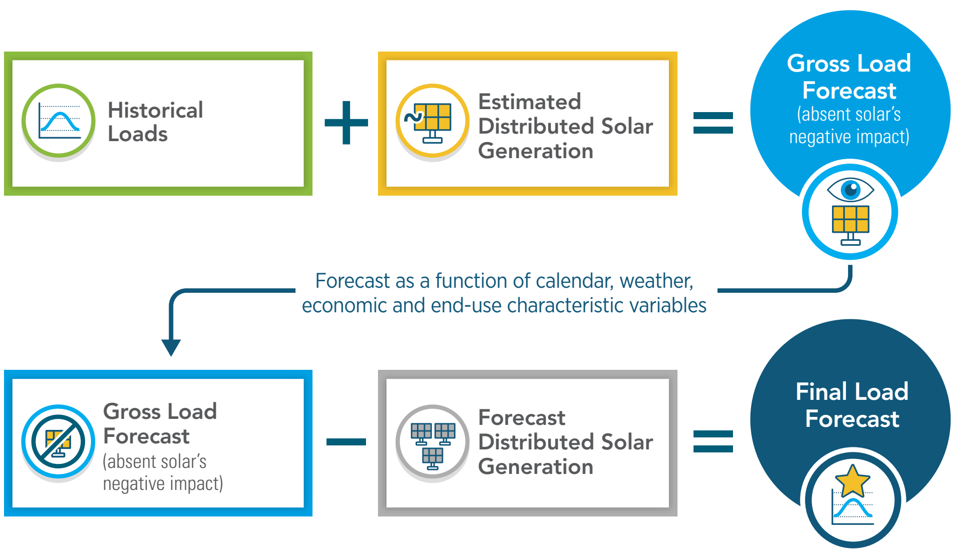


Figure 1.10: Load Forecast Model

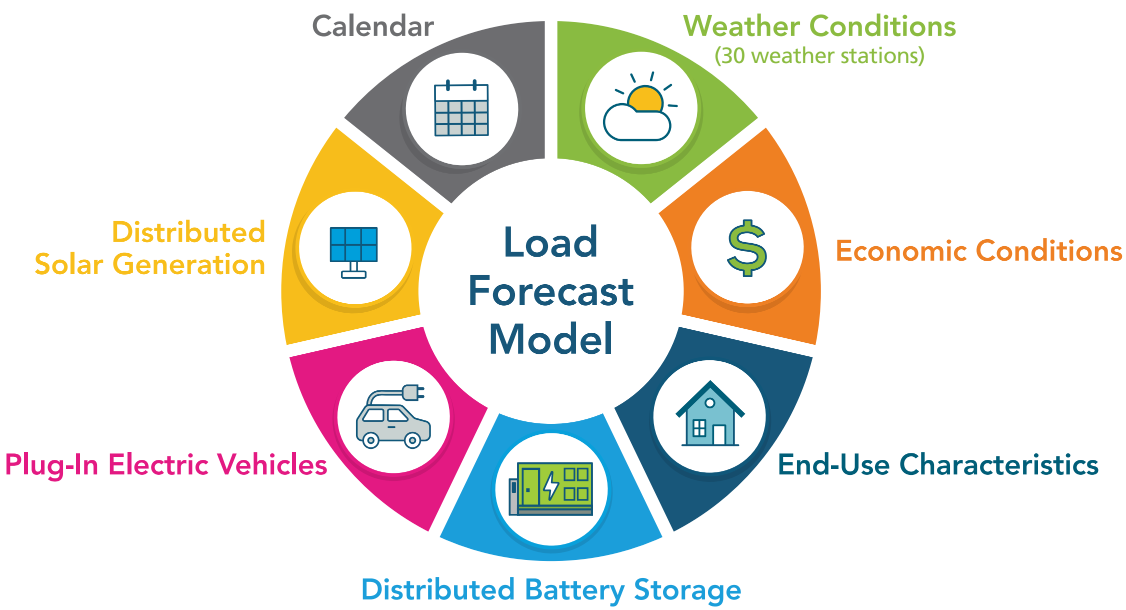


Table 1.2: 2023 Load Forecast Report

Transmission Owner	Summer Peak (MW) 2023	Summer Peak (MW) 2033	Summer Peak (MW) Growth Rate	Winter Peak (MW) 2022/23	Winter Peak (MW) 2032/33	Winter Peak (MW) Growth Rate
Atlantic City Electric	2,549	2,418	-0.5%	1,590	1,561	-0.2%
Baltimore Gas and Electric	6,474	6,060	-0.7%	5,755	5,680	-0.1%
Delmarva Power	3,861	3,666	-0.5%	3,623	3,690	0.2%
Jersey Central Power & Light	6,072	5,830	-0.4%	3,740	3,864	0.3%
Met-Ed	3,040	3,112	0.2%	2,696	2,772	0.3%
PECO Energy Company	8,527	8,590	0.1%	6,459	6,530	0.1%
Pennsylvania Electric Company (Penelec)	2,871	2,792	-0.3%	2,823	2,751	-0.3%
PPL Electric Utilities	7,175	7,248	0.1%	7,334	7,407	0.1%
Potomac Electric Power Company (Pepco)	6,166	6,201	0.1%	5,381	5,531	0.3%
Public Service Electric & Gas Company (PSE&G)	9,904	9,499	-0.4%	6,530	6,393	-0.2%
Rockland Electric Company	414	416	0.0%	214	249	1.5%
UGI Utilities	195	189	-0.3%	198	192	-0.3%
Diversity – Mid-Atlantic	-1,512	-1,685		-868	-769	
Mid-Atlantic	**55,736**	**54,336**	**-0.3%**	**45,475**	**45,851**	**0.1%**
American Electric Power	22,453	22,637	0.1%	22,308	22,663	0.2%
Allegheny Power (FirstEnergy)	8,724	9,484	0.8%	8,993	10,077	1.1%
American Transmission Systems, Inc. (FirstEnergy)	11,962	11,593	-0.3%	9,883	9,629	-0.3%
Commonwealth Edison	20,417	19,595	-0.4%	14,305	14,573	0.2%
AES Ohio, formerly Dayton Power and Light	3,295	3,255	-0.1%	2,920	2,870	-0.2%
Duke Energy Ohio and Kentucky	5,249	5,126	-0.2%	4,479	4,380	-0.2%
Duquesne Light Company	2,712	2,687	-0.1%	1,996	1,962	-0.2%
East Kentucky Power Cooperative	2,027	2,084	0.3%	2,658	2,694	0.1%
Ohio Valley Electric Corporation	95	95	0.0%	110	110	0.0%
Diversity – Western	-1,581	-1,676		-1,797	-1,741	
Western	**75,353**	**74,880**	**-0.1%**	**65,855**	**67,217**	**0.2%**
Dominion Energy	21,920	35,789	5.0%	21,625	34,488	4.8%
Southern	**21,920**	**35,789**	**5.0%**	**21,625**	**34,488**	**4.8%**
Diversity – Total	-7,043	-7,395		-4,809	-5,074	
PJM RTO	**149,059**	**160,971**	**0.8%**	**130,811**	**144,992**	**1.0%**

Go to Next Section >

Table 1.3: ELCC Class Ratings for 2024/2025 3IA

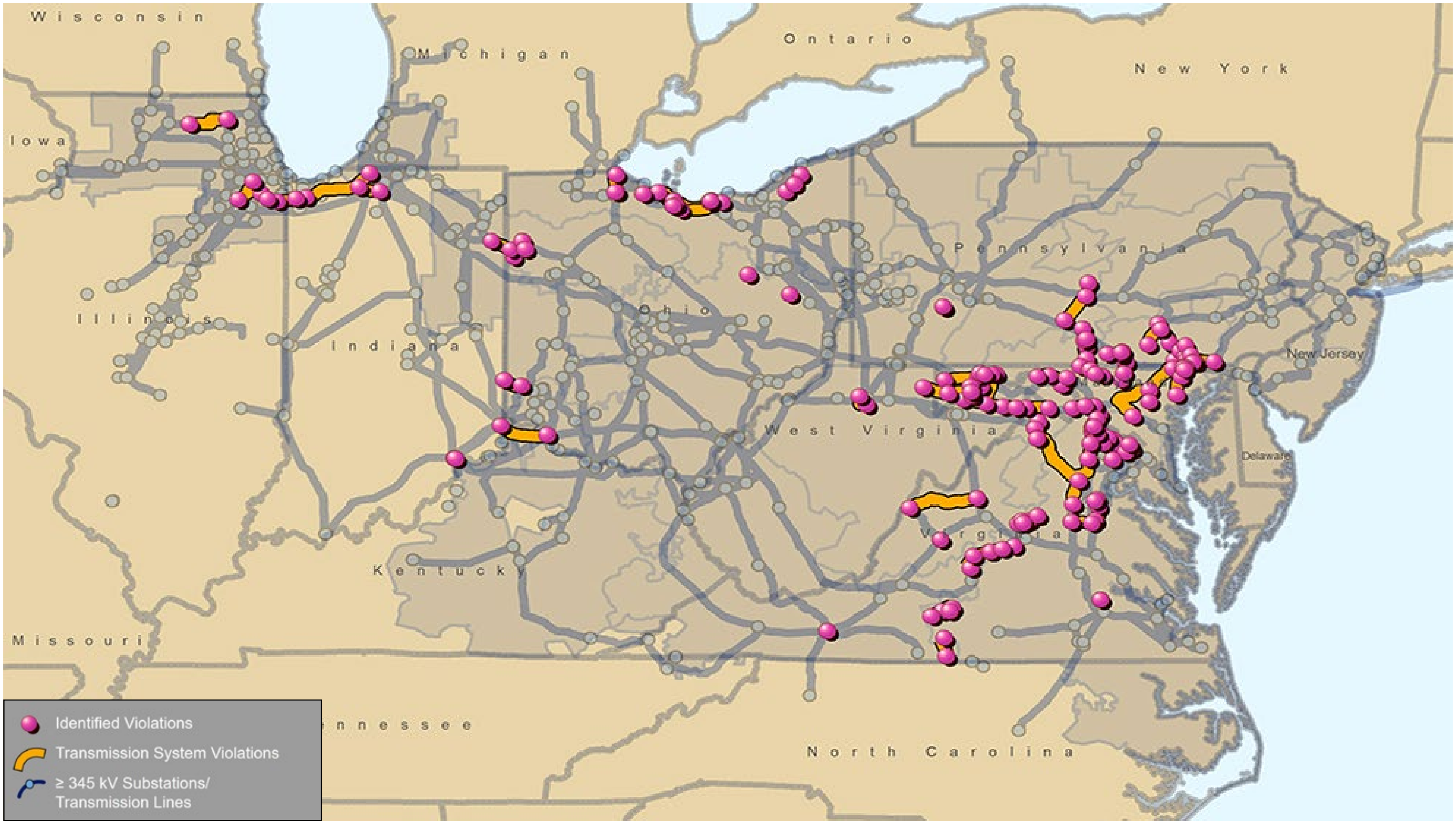
ELCC Class	ELCC Class Rating for: 2023/2024 3IA (% of Nameplate)
Onshore Wind	21%
Offshore Wind	47%
Solar Fixed Panel	33%
Solar Tracking Panel	50%
4-Hour Storage	92%
6-Hour Storage	100%
8-Hour Storage	100%
10-Hour Storage	100%
Solar Hybrid Open Loop – Storage Component	75%
Solar Hybrid Closed Loop – Storage Component	68%
Hydro Intermittent	36%
Landfill Gas Intermittent	61%
Hydro With Non-Pumped Storage*	95%

*PJM performs an ELCC analysis for each individual unit in this class. The value shown in the table is a representative value provided for informational purposes.

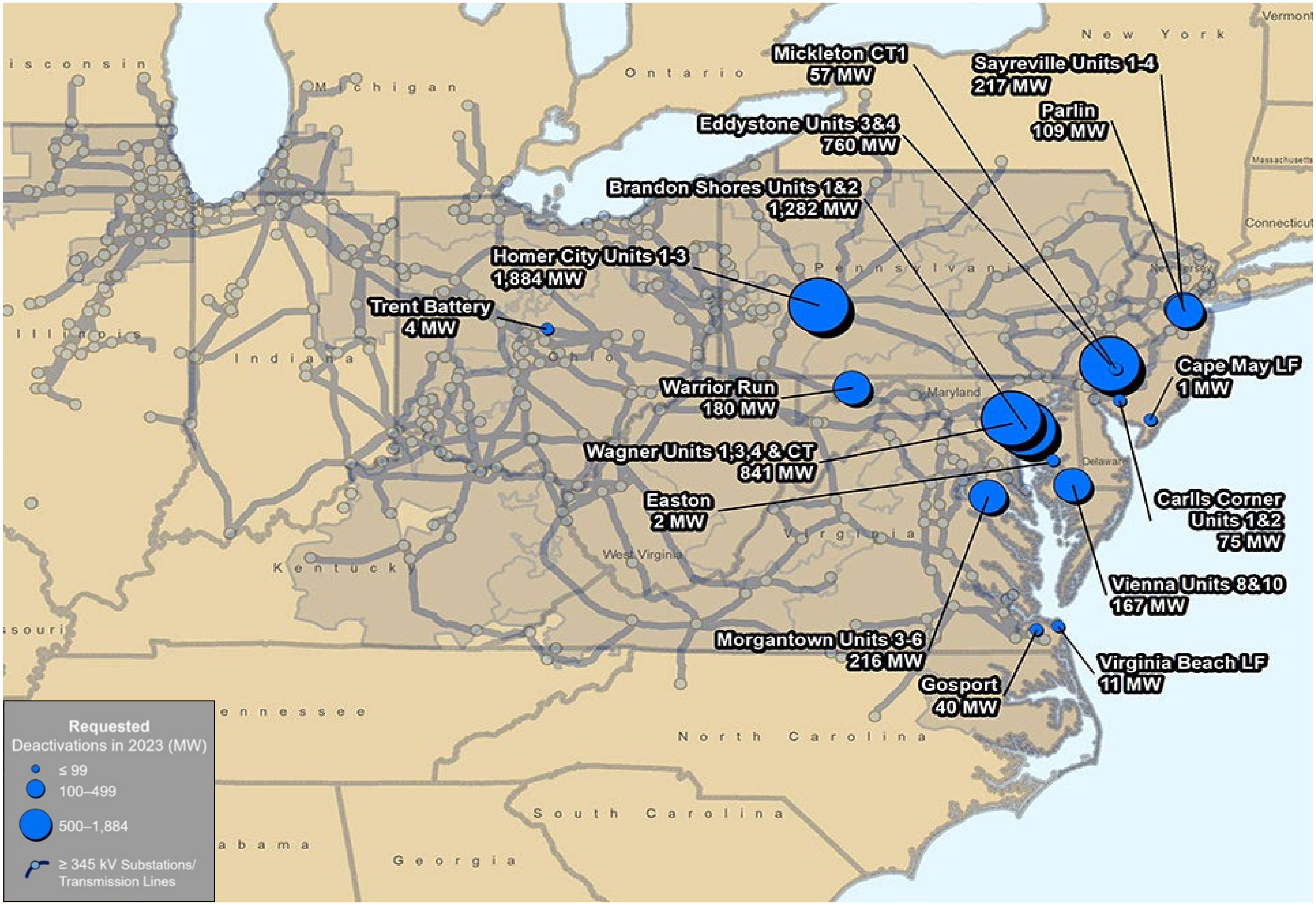
Table 1.4: 2023/2024 Stage 1A ARR 10-Year Feasibility Study: Reliability Criteria Violations

Facility Name	Upgrade Expected to Fix Infeasibility	Expected In-Service Date
Colora-Conowingo 230 kV	B3729: Increase the maximum operating temperature of DPL circuit 22088	2027
Conastone-Peach Bottom 500 kV	B3737.50: Constructing a new Peach Bottom-North Delta 500 kV line	2029
Lenox-North Meshoppen 115 kV	B3672: Upgrades East Towanda-North Meshoppen 115 kV line	2026
Linden-Minue St R 230 kV	B3737.38: Linden Subproject	2027
Various Dominion Constraints	2023 RTEP Proposal Window No. 3 Solutions part of the 2023 RTEP Process	To Be Determined

Map 1.2: 2023 RTEP Baseline Thermal and Voltage Criteria Violations



Map 1.3: Deactivation Notifications Received in 2023



Map 1.4: Actual Generator Deactivations in 2023

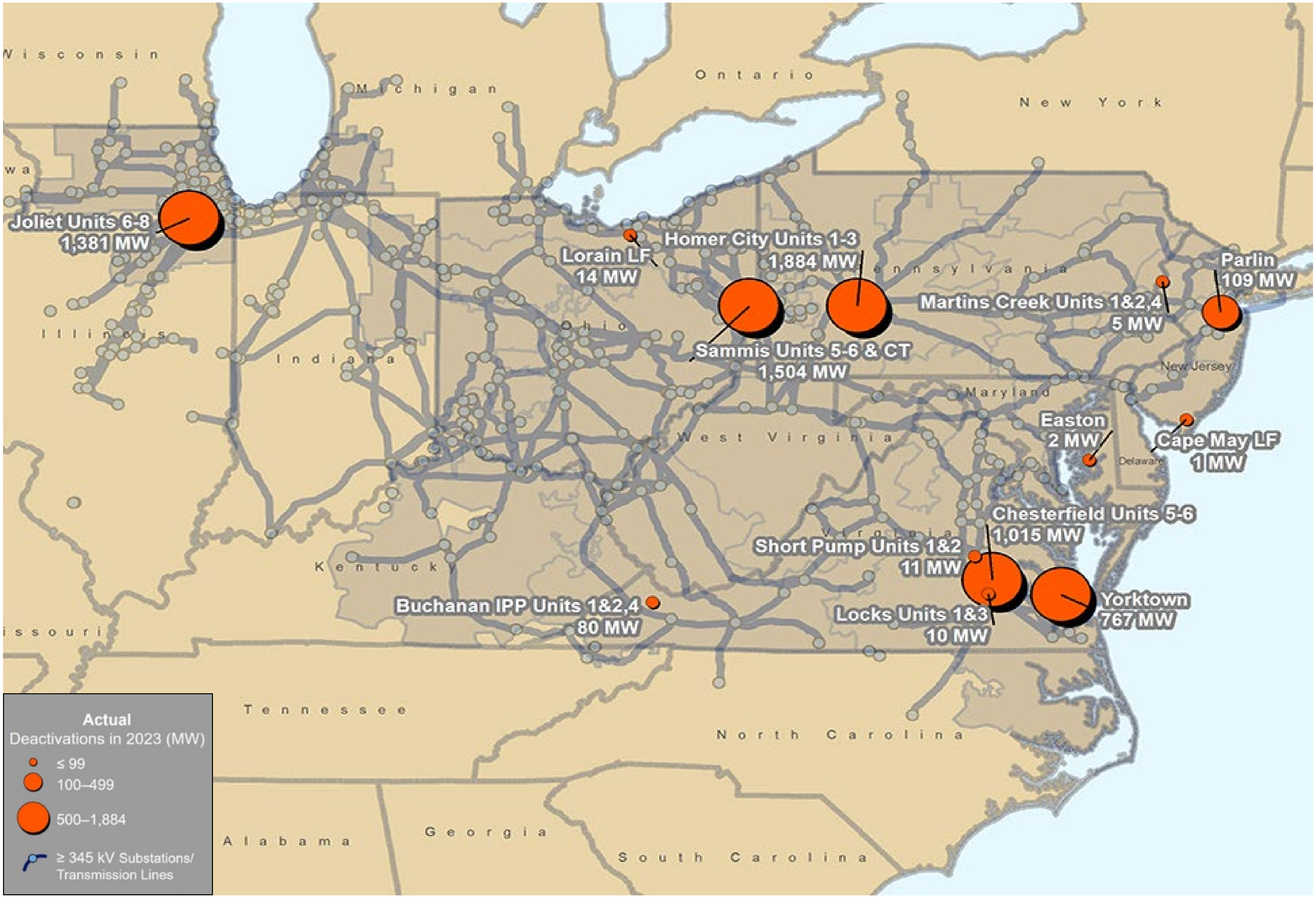


Figure 1.11: Primary Supplemental Project Drivers

Customer Service	Provide service to new and existing customers; interconnect new customer load; address distribution load growth, customer outage exposure, equipment loading, etc.
Equipment Material Condition, Performance and Risk	Address degraded equipment performance, material condition, obsolescence; end of the useful life of equipment or a facility; equipment failure; employee and public safety; and environmental impact.
Operational Flexibility and Efficiency	Optimize system configuration, equipment duty cycles and restoration capability; minimize outages.
Infrastructure Resilience	Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather or geomagnetic disturbances.
Other	Meet objectives not included in other definitions such as, but not limited to, technological pilots, industry recommendations, and environmental and safety impacts.

Figure 1.12: Market Efficiency Analysis Parameters

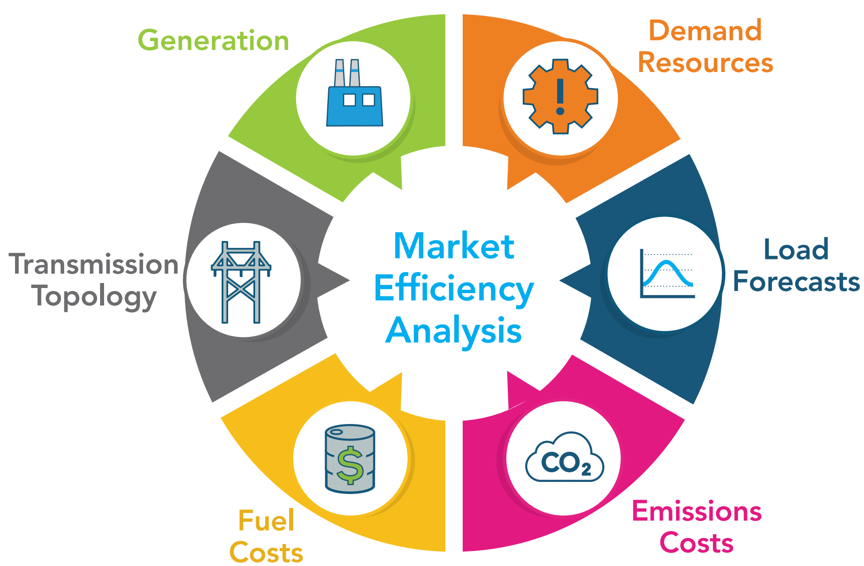


Figure 1.13: 2022/2023 Market Efficiency 24-Month Cycle

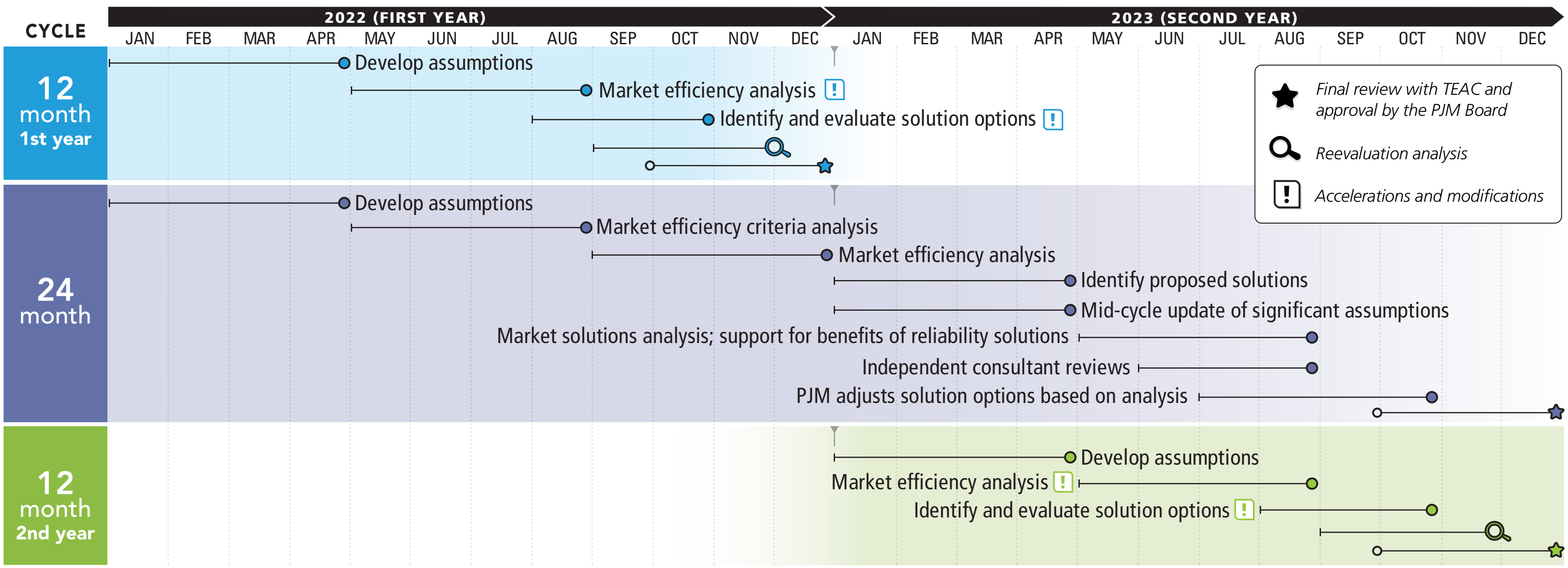


Figure 1.14: Interconnection Process Reform Timeline

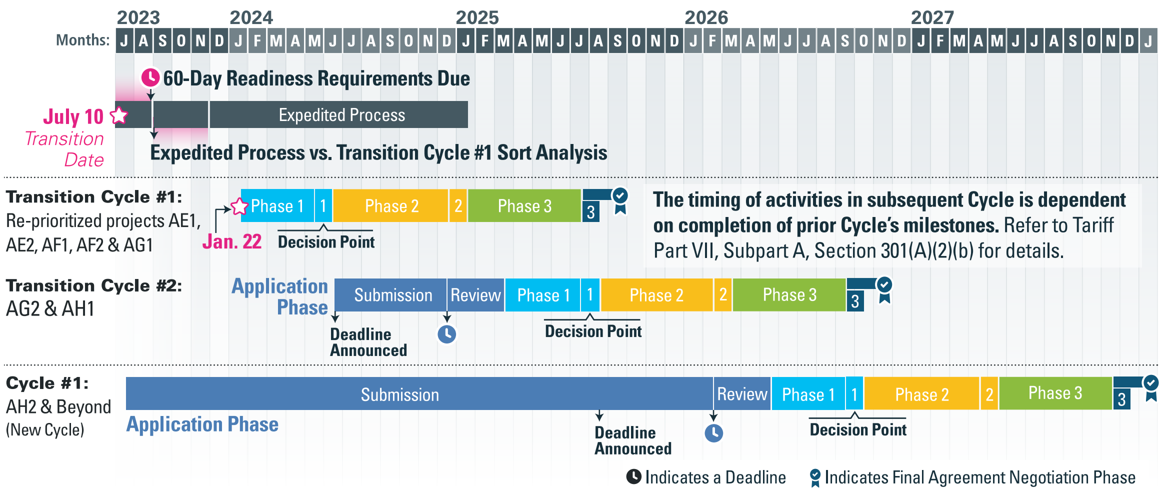
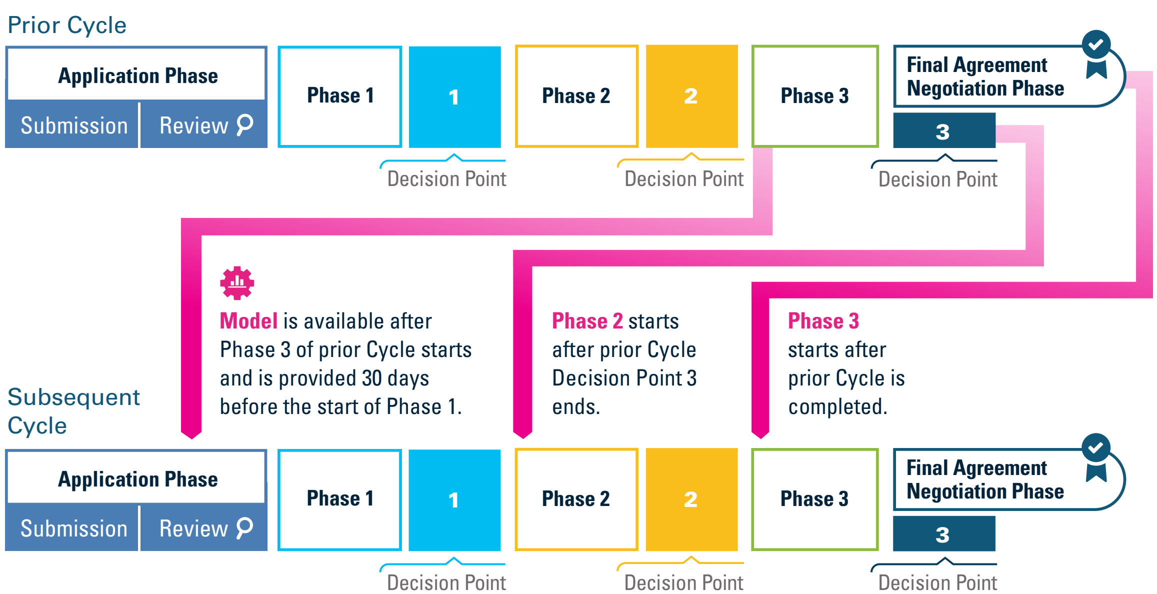


Figure 1.15: New Interconnection Request Cycles



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 2023 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 2013 to 2022 (2.48%).
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 2024 to 2028.

Figure 5.1: Project Status as of Dec. 31, 2023

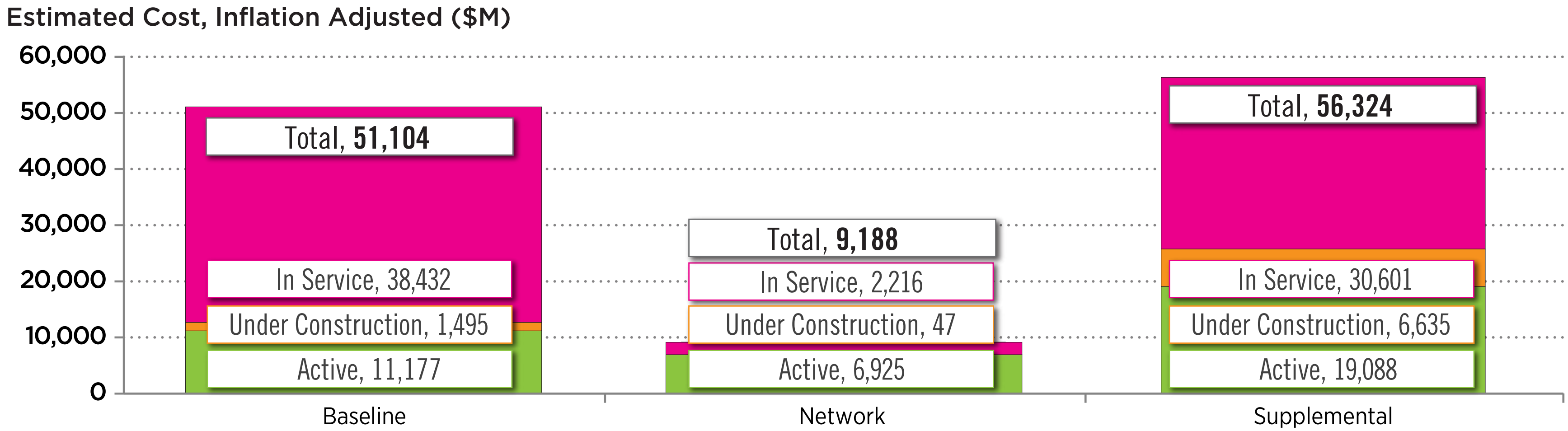


Figure 5.2: Baseline and Supplemental Proects by Year

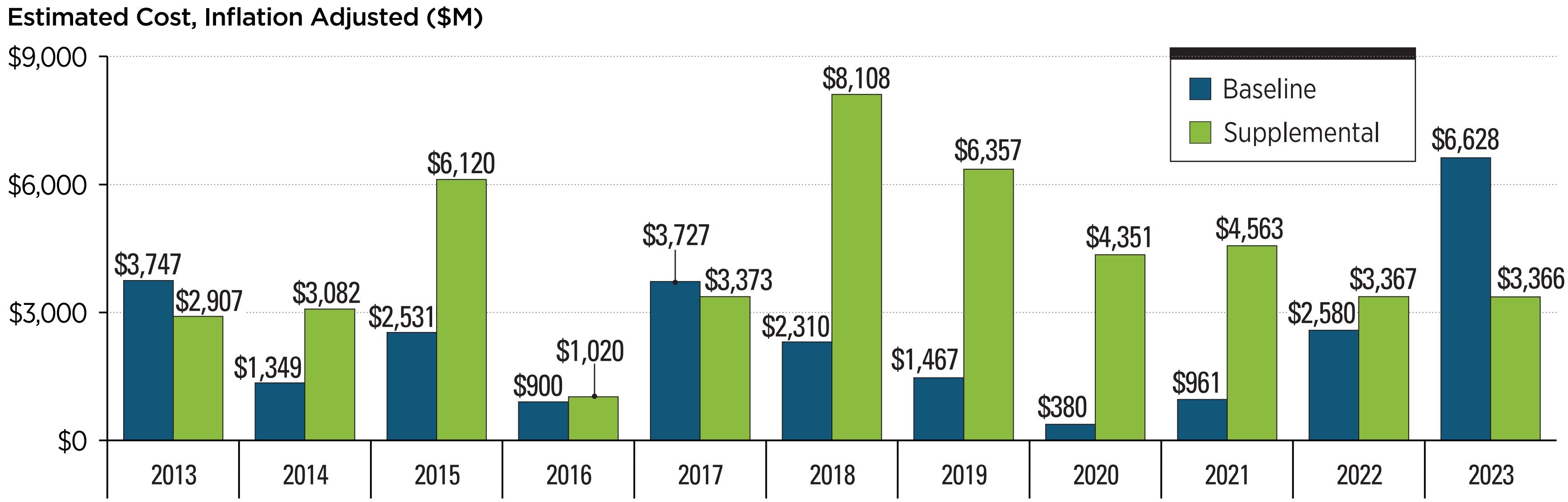


Figure 5.3: PJM Baseline Projects by Criteria

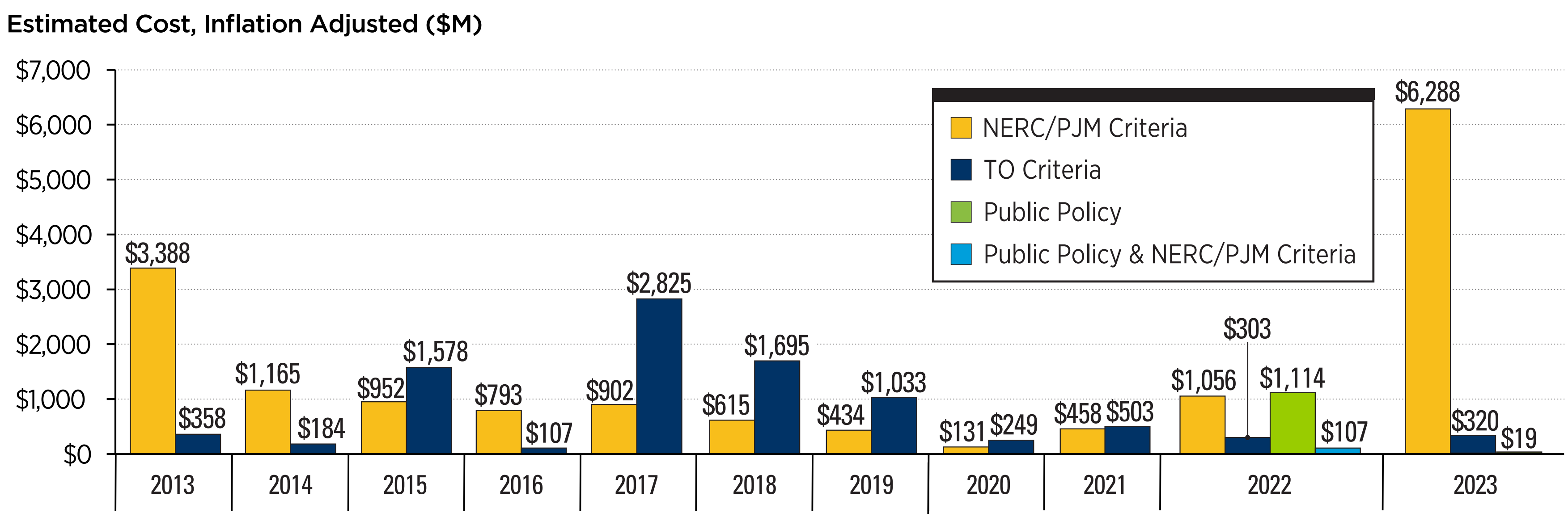


Figure 5.4: Baseline Projects by Voltage

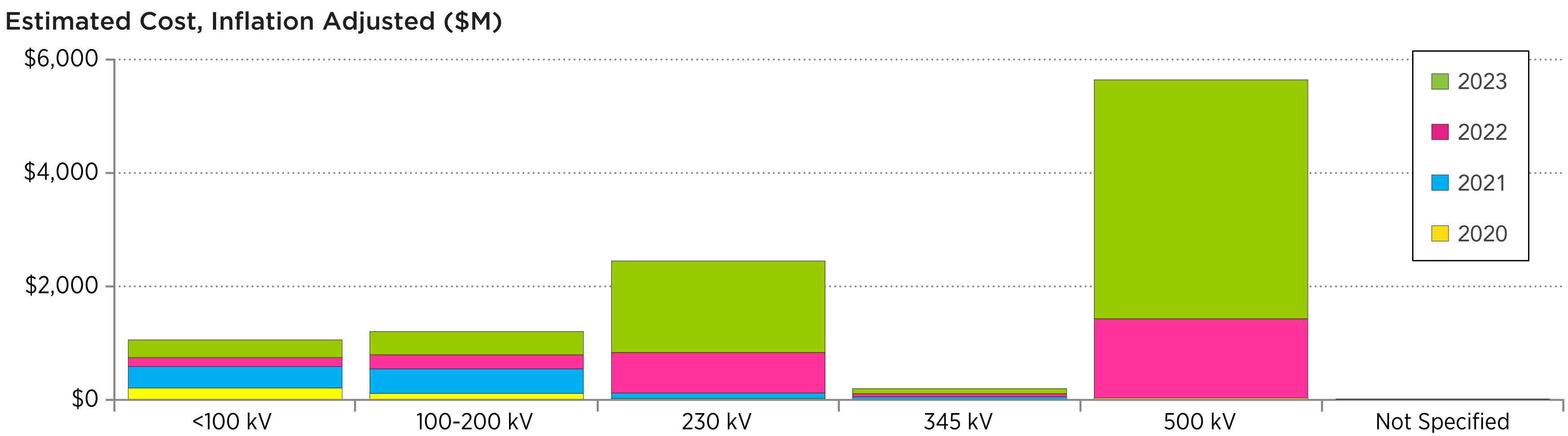


Figure 5.5: Supplemental Projects by Voltage

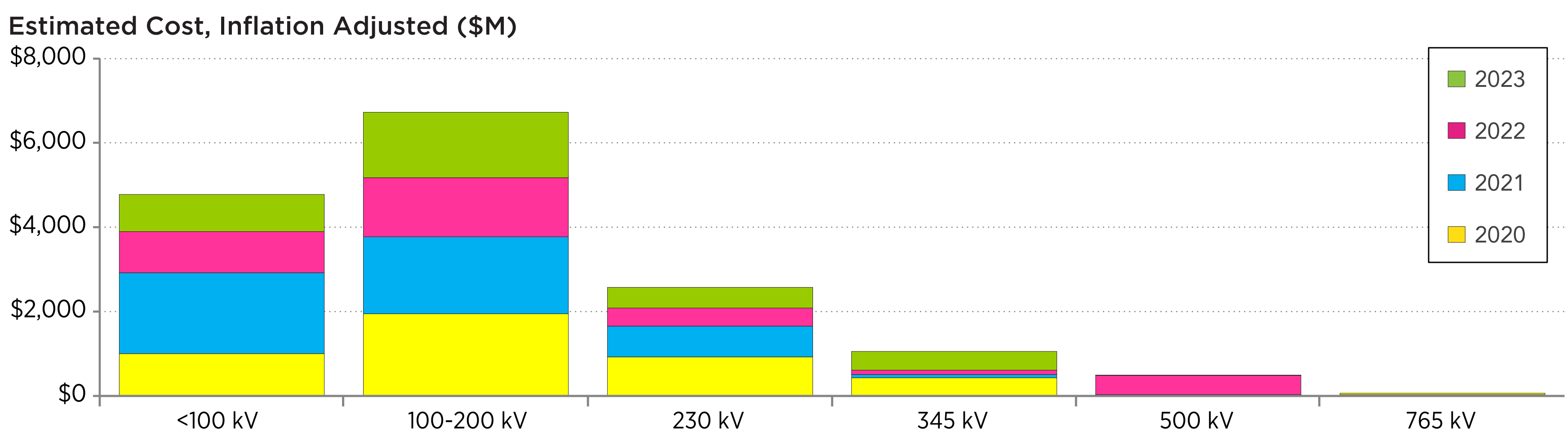


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2013

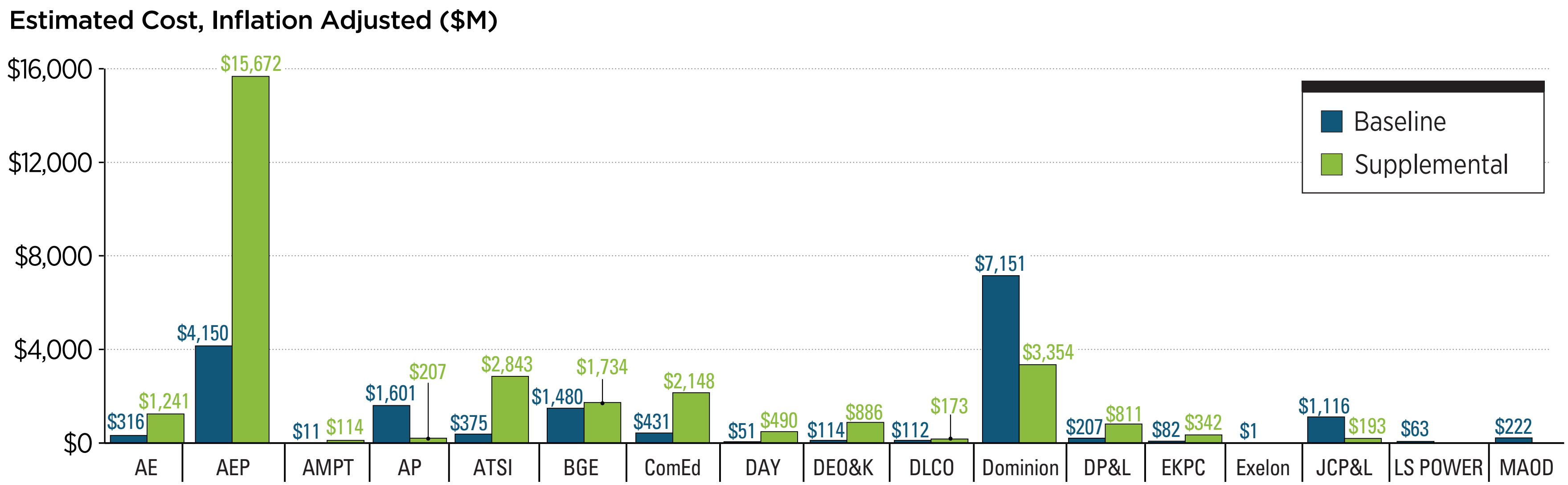


Figure A.6: Baseline and Supplemental Projects by Designated Entity Since 2013 (Cont.)

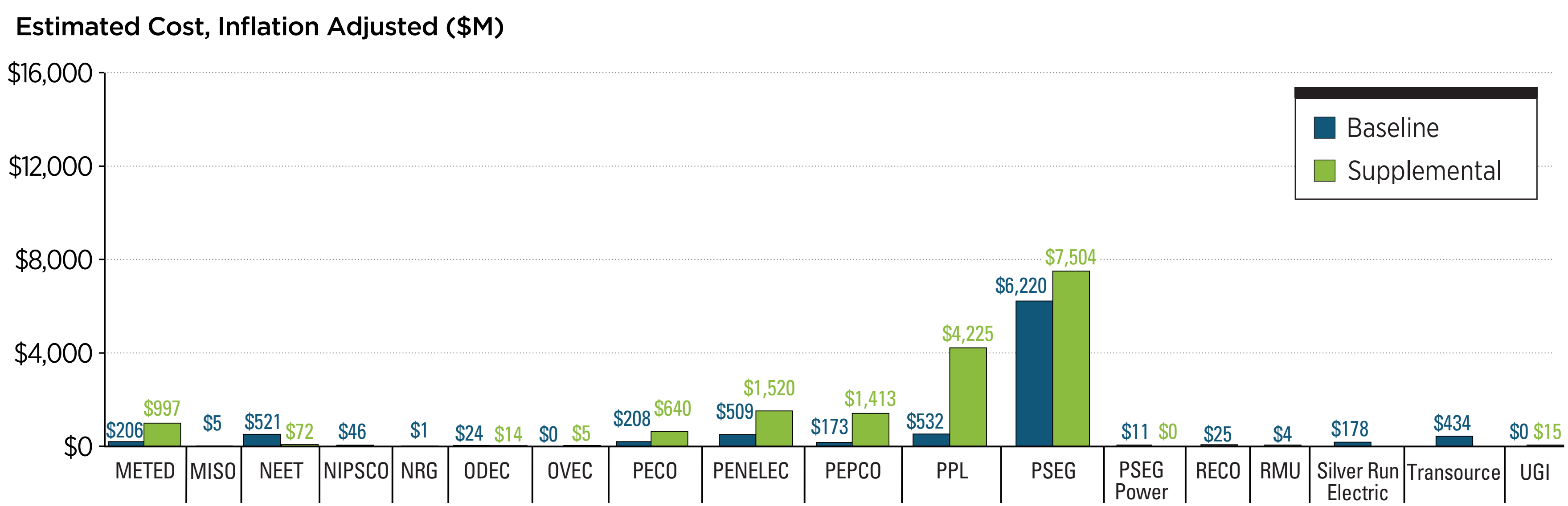


Figure 5.7: 2023 Baseline and Supplemental Projects by Designated Entity

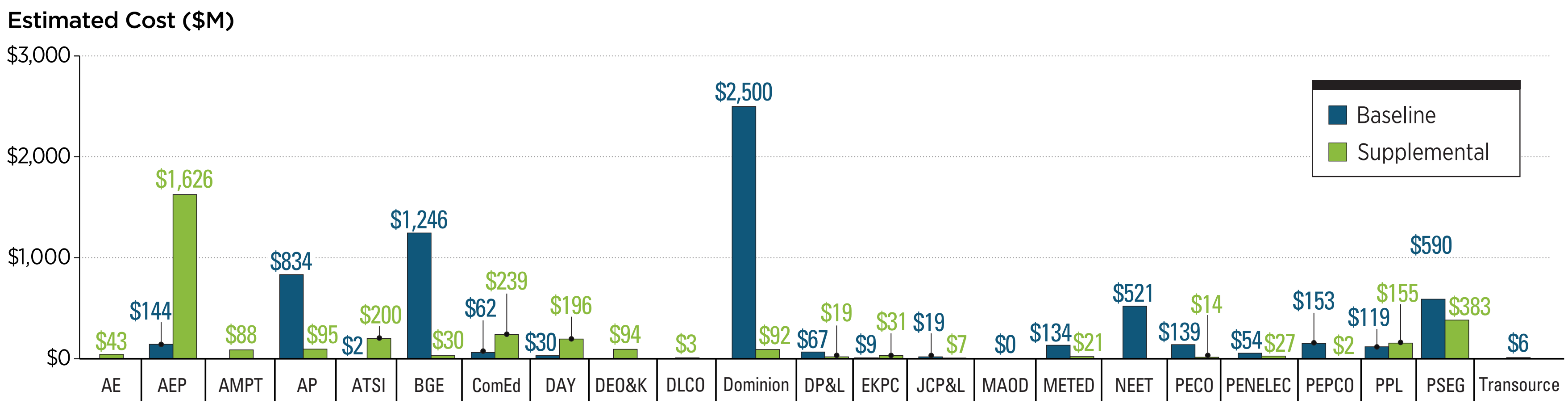


Figure 5.8: Baseline and Supplemental Projects Adjusted by Peak Load Since 2013

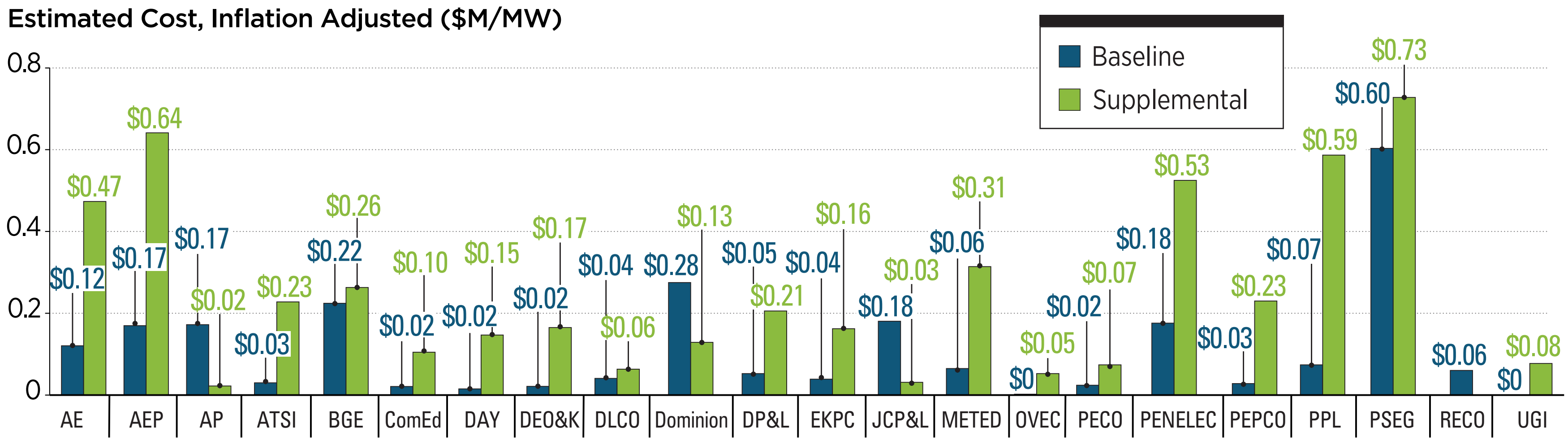


Figure 5.9: 2023 Baseline and Supplemental Projects Adjusted by Peak Load

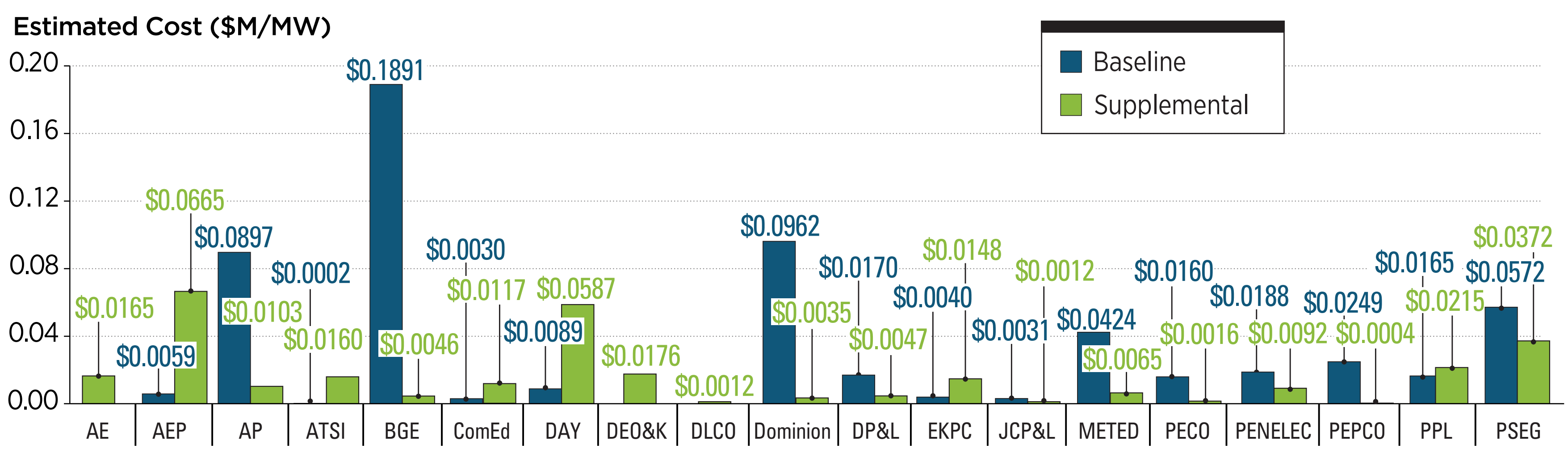


Figure 5.10: Baseline and Supplemental Projects Adjusted by Circuit Miles Since 2013

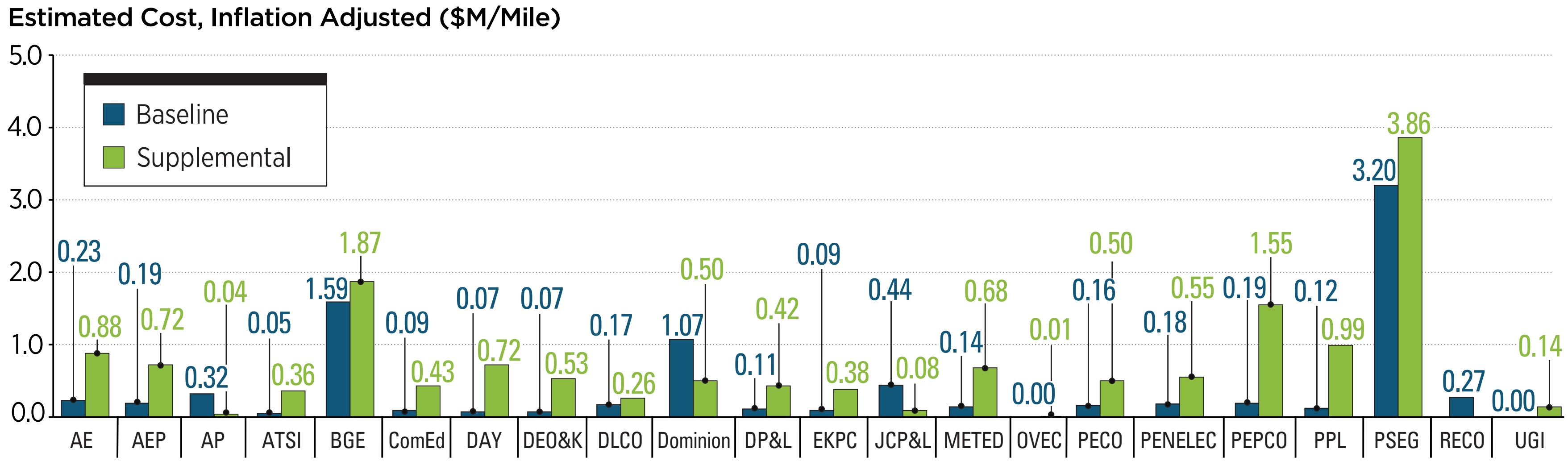


Figure 5.11: 2023 Baseline and Supplemental Projects Adjusted by Circuit Miles