RT
EP

02.29.2020

2019

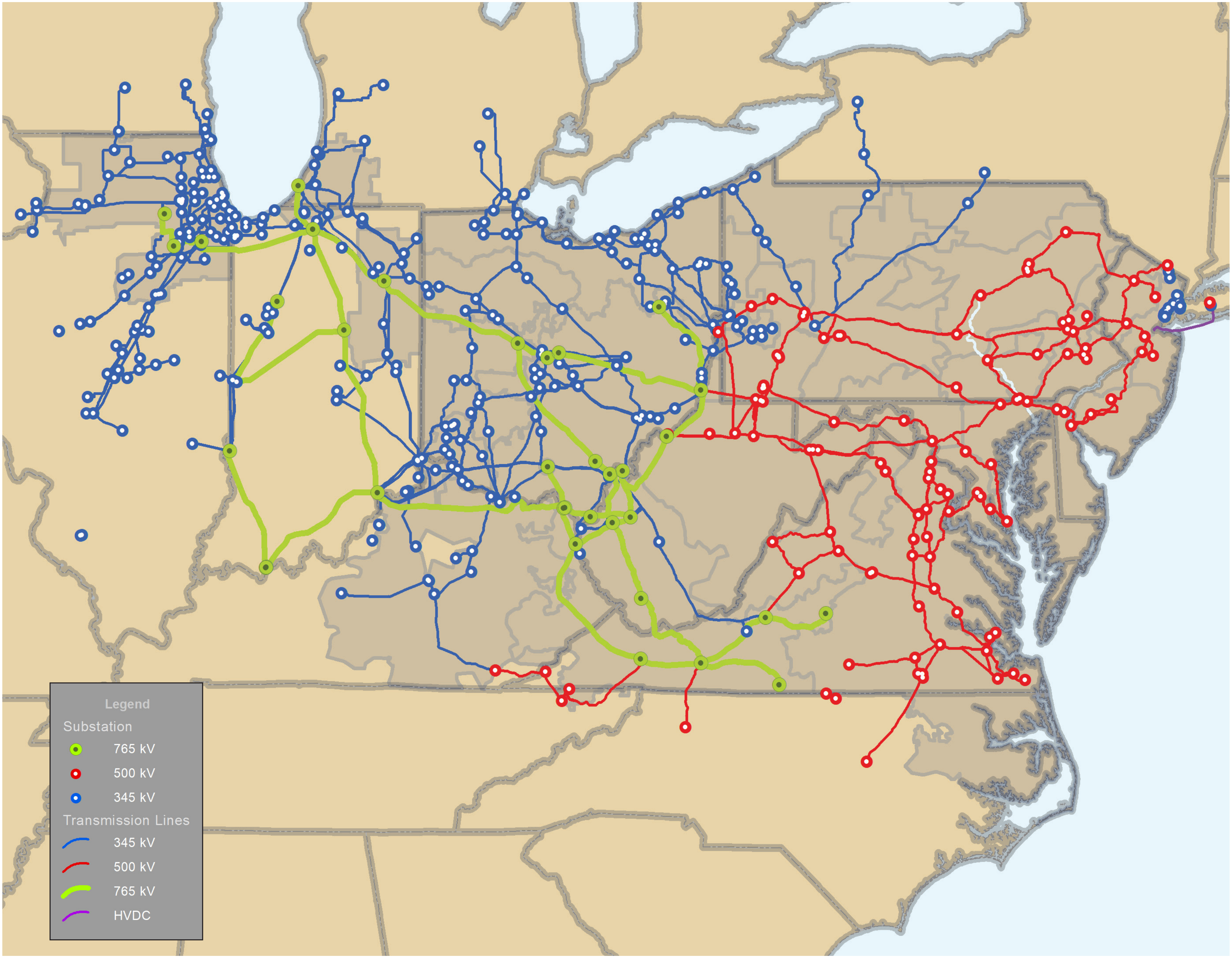
REGIONAL TRANSMISSION EXPANSION PLAN

TRANSPARENCY

BENEFIT

VALUE

STRATEGY


Legend
Substation
765 kV
500 kV
345 kV
Transmission Lines
345 kV
500 kV
765 kV
HVDC

Preface

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 need.

In 2019, PJM observed several trends continued that are discussed throughout this report, including the ongoing shifting dynamic of PJM's generation fuel mix, driven by new natural gas-fired plants and deactivation of coal-fired plants.

- **Section 1** is a high-level summary of the 2019 RTEP activities, including RTEP process improvements and a summary of projects organized by driver.
- **Section 2** includes an overview and detailed data of PJM's 2019 Load Forecast Report.
- **Section 3** provides 2019 RTEP project highlights, generator deactivations and re-evaluation of previously approved projects.
- **Section 4** summarizes the market efficiency process, including input assumptions, analysis and competitive windows.
- **Section 5** provides an overview of PJM's new service queue requests.
- **Section 6** includes state summaries, including a detailed breakdown of interconnection requests within each individual state in PJM, as well as transmission system enhancements identified as part of the RTEP analysis.
- **Appendix 1** – TO Zones and Locational Deliverability Areas
- Glossary
- Topical Index
- Key Maps, Tables and Figures

Planning ? Community

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

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

RTEP Process Description

The online resources below provide additional description of RTEP process business rules and methodologies:

- The Manual 14 series contains the specific business rules that govern the RTEP process. Specifically, Manual 14B describes the methodologies for conducting studies and developing solutions to solve planning criteria violations and market efficiency issues. PJM Manual 14B, Regional Planning Process, is available on the PJM website.
- Schedule 6 of the PJM Operating Agreement codifies the overall provisions under which PJM implements its Regional Transmission Expansion Planning protocol, more familiarly known (and used throughout this document) as the PJM RTEP process. The PJM Operating Agreement is available on the PJM website.
- The PJM Open Access Transmission Tariff (OATT) codifies provisions for generating resource interconnection, merchant/customer-funded transmission interconnection, long-term firm transmission service and other specific new service requests. The PJM OATT is available on the PJM website.
- The status of individual PJM Board-approved baseline and network RTEP projects, as well as that of Transmission Owner Supplemental Projects, is available on the PJM website.

Stakeholder Forums

The Planning Committee, established under the PJM Operating Agreement, has the responsibility to review and recommend system planning strategies and policies, as well as planning and engineering designs for the PJM bulk power supply system to assure the continued ability of the member companies to operate reliably and economically in a competitive market environment.

Additionally, the Planning Committee makes recommendations regarding generating capacity reserve requirements and demand-side valuation factors. Committee meeting materials and other resources are available on the PJM website.

The Transmission Expansion Advisory Committee (TEAC) and subregional RTEP committees continue to provide forums for PJM staff and stakeholders to exchange ideas, discuss study input assumptions and review results. Stakeholders are encouraged to participate in these ongoing committee activities. TEAC resources are available on the PJM website.

Each subregional RTEP committee provides a forum for stakeholders to discuss local planning concerns. Interested stakeholders can access subregional RTEP committee planning process information from the PJM website:

- PJM Mid-Atlantic Subregional RTEP
- PJM Western Subregional RTEP Committee
- PJM Southern Subregional RTEP Committee

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PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

Section 1: 2019 Executive Summary

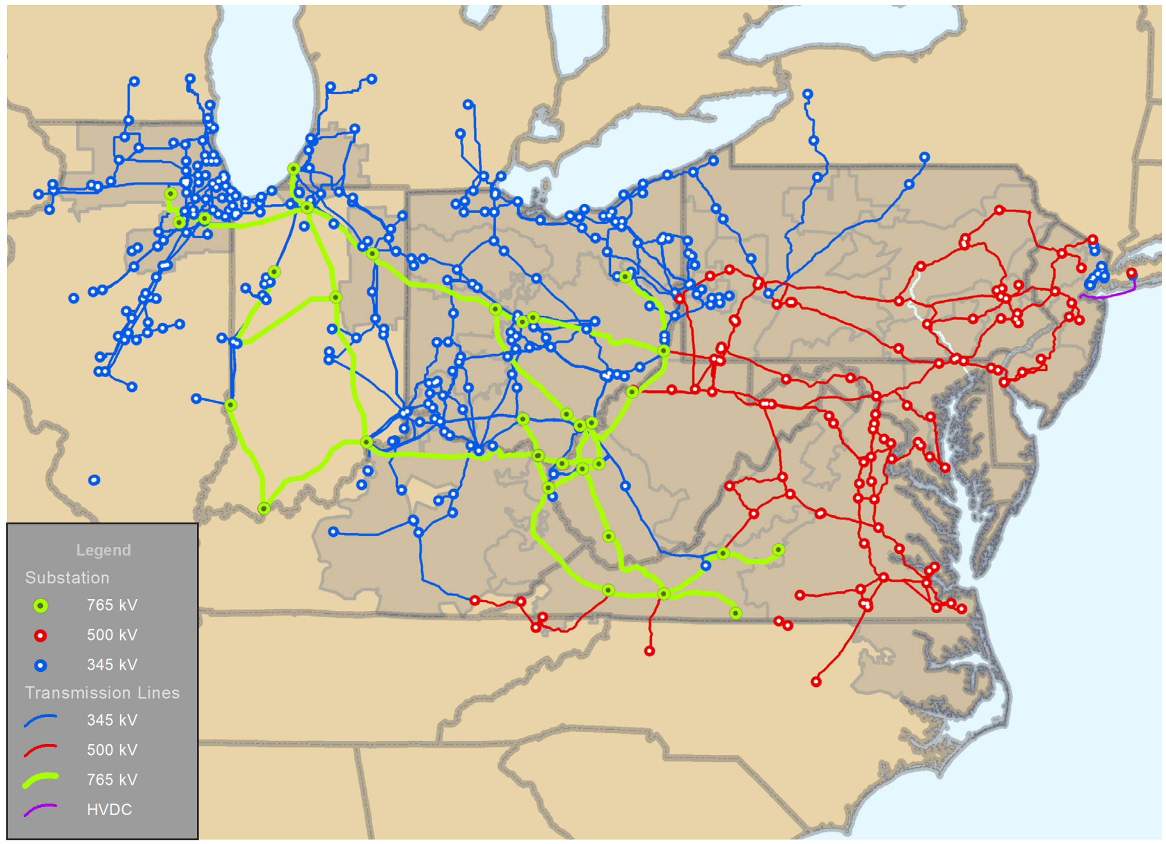
1.0: 2019 Executive Summary

Regional Scope

PJM, a FERC-approved 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 Illinois western border, including the metropolitan areas in and around Baltimore, Chicago, Columbus, Cleveland, Dayton, Newark and Northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond, Toledo and the District of Columbia.

PJM's Regional Transmission Expansion Plan (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 1,040 members, PJM dispatches more than 186,000 MW of generation capacity over 360,000 miles of transmission lines.

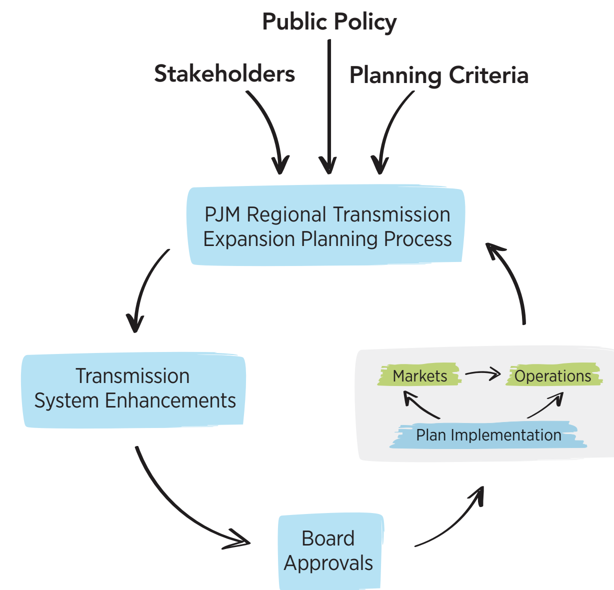
Map 1.1: PJM Backbone Transmission System



RTO Perspective

PJM's RTEP process spans state boundaries shown in **Map 1.1** and is a large part of the context of the RTO functions shown in **Figure 1.1**. Doing so 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 justified to meet local reliability requirements and deliver needed power to more distant load centers. Once the PJM Board 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. Expected system conditions can change such that justification for a project no longer exists or requires modification to capture scope changes.

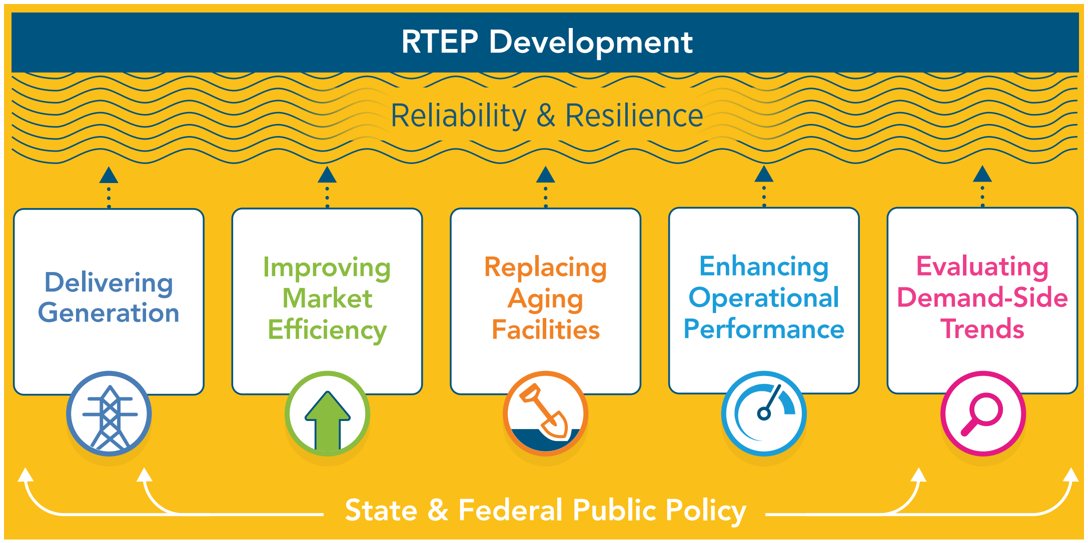
Figure 1.1: RTEP Process – RTO Perspective



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 of many drivers, including those arising out of public policy, market efficiency, aging infrastructure, operations performance and demand-side trends. Importantly though, as **Figure 1.2** shows, RTEP development considers all drivers through a reliability criteria and resilience lens. PJM's RTEP process encompasses a comprehensive assessment of system compliance with the thermal, reactive, stability and short-circuit North American Electric Reliability Corporation (NERC) Standard TPL-001-4 as described in **Section 1.2**.

Figure 1.2: System Enhancement Drivers



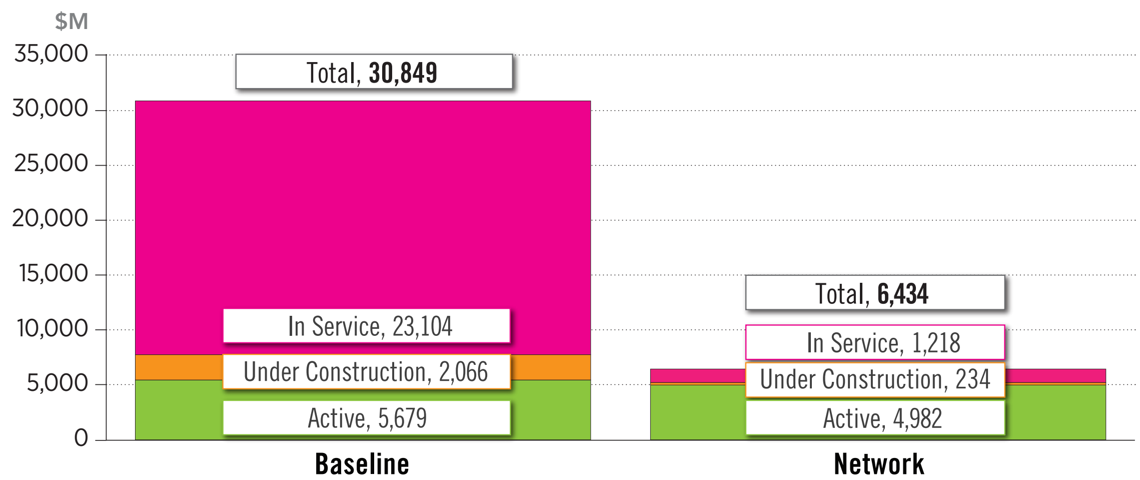
Highlights of projects identified and approved by the PJM Board during 2019 appear in **Section 3**. Details of specific large-scale projects – those greater than or equal to $10 million in scope – are presented in **Section 6**.

2019 PJM Board Approvals

Since 1999, the PJM Board has approved transmission system enhancements totaling approximately $37.3 billion. Of this, approximately $30 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 $6.4 billion represents network facilities to enable nearly 90,000 MW of new generation to interconnect reliably.

A summary of projects by status as of Dec. 31, 2019, appears in **Figure 1.3.** The numbers provide a snapshot of one point in time, as with an end-of-year balance sheet. The PJM Board approved 80 new baseline projects during 2019 at an estimated cost of $1.27 billion and 95 new network transmission projects at an estimated cost of over $100 million. These totals were offset by revised cost estimate changes and project cancellations for previously approved RTEP elements.

Figure 1.3: Board Approved RTEP Projects as of Dec. 31, 2019



PJM recommends canceling a network system enhancement from the RTEP when a queued project driving the need for the network project withdraws from the queue. 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.

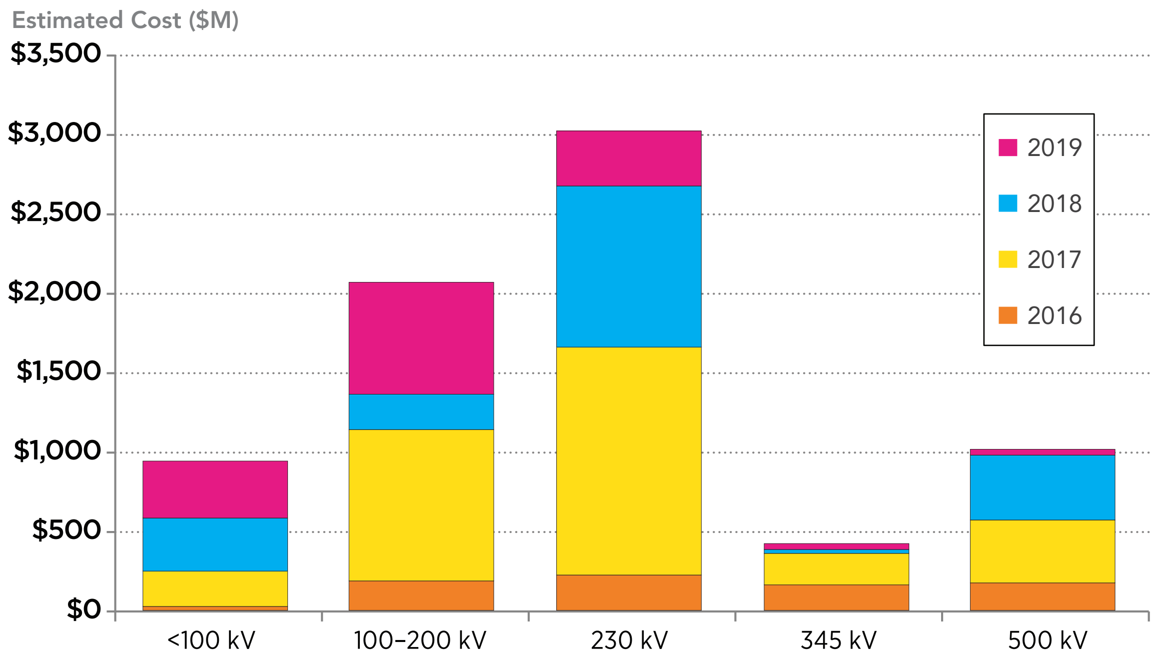
A discussion of supplemental projects, including summaries by driver greater than or equal to $10 million, is included in **Section 3.2**.

Supplemental projects are identified and developed by transmission owners to address local reliability needs, including customer service and load growth, equipment material condition, operational performance and risk, and infrastructure resilience. PJM reviews them to evaluate their impact on the regional transmission system.

Shifting RTEP Dynamics

The $1.27 billion of baseline transmission investment approved during 2019 continues to reflect the shifting dynamics driving transmission expansion. As **Figure 1.4** shows, new large-scale transmission projects (345 kV and above) have become more uncommon as RTO load growth has fallen below one-half of a percent. Aging infrastructure, grid resilience, shifting generation mix, and more localized reliability needs are now more frequently driving new system enhancements. Much of the new investment that is occurring at 500 kV is to address existing, aging transmission lines, many of which were constructed in the 1960s and 1970s.

Figure 1.4: Approved Baseline Projects by Voltage 2016–2019



No baseline projects at the 765 kV level have been identified for this time period.

Flat Load Growth

PJM's 2019 RTEP baseline power flow model for study year 2024 was based on the 2019 PJM Load Forecast Report, summarized in **Section 2**, showing a 10-year RTO summer, normalized peak growth rate of 0.3 percent. Average 10-year-annualized summer growth rates for individual PJM zones ranged from -0.3 percent to 0.9 percent. 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, roof-top solar installations.

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:

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

RPM-eligible, natural gas-fired generation capacity greatly exceeds that of coal. Natural gas plants totaling nearly 35,000 MW constitute 43 percent of the generation currently seeking capacity interconnection rights in PJM's new services queue. Solar generation has overtaken natural gas as the largest percentage of units seeking capacity interconnection rights. Solar interconnection requests have more than doubled, by megawatt, in the past year.

If formally submitted deactivation plans come to fruition, more than 27,000 MW of coal-fired generation will have deactivated between 2011 and 2020. 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. PJM continued to receive deactivation notifications throughout 2019. The impacts of deactivation notices received during 2019 are discussed in **Section 3.3**.

Distributed Energy Resources

Distributed energy resources have introduced another dynamic into PJM's RTEP process. The resources can remain behind-the-meter or participate in PJM markets. Distributed energy resources seeking to participate in PJM's capacity market must do so via PJM's RTEP new services queue process. This ensures that necessary transmission-level system improvements are in place to preserve reliability and market participation. Distributed energy devices like roof-top solar remain behind-the-meter and do not participate in the PJM capacity market. Nonetheless, they impact the demand side of PJM resource adequacy. These devices impact PJM's load forecast, both on a day-ahead and real-time basis, as well as for longer-term planning forecasts. For instance, distributed solar generation acts to offset load, making it lower than it otherwise would be.

Aging Infrastructure

Existing facilities at all voltage levels are reaching the end of their useful lives, requiring RTEP projects to ensure that reliability is maintained. PJM has observed that transmission owner aging infrastructure criteria are increasingly driving the need for investment. Condition assessments have identified deteriorating facilities built in the 1960s and earlier.

Planning for aging infrastructure is not new to PJM. Spare 500/230 kV transformers, 500 kV line rebuilds and a number of other transmission enhancements to mitigate potential equipment failure risk are already an important part of PJM's RTEP.

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

1.1: Generation in Transition

PJM's 184,173 MW of RPM-eligible existing installed capacity reflects a fuel mix comprising 42 percent natural gas, 29 percent coal and 18 percent nuclear, as shown in **Figure 1.5**. Hydro, wind, solar, oil and waste fuels constitute the remaining 11 percent. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility.

Both natural gas and solar fuels comprise 43 percent of the generation in PJM's interconnection queue, shown in **Figure 1.6**. Favorable fuel economics have emerged with the development of the Marcellus and Utica shale formations natural gas reserves, located in the middle of PJM's footprint. An increase in solar generation interconnection requests is attributable to state policies toward renewable generation. **Figure 1.6** shows PJM's fuel mix based on requested capacity interconnection rights for generation that was active, under construction or suspended as of Dec. 31, 2019.

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

Figure 1.5: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2019)

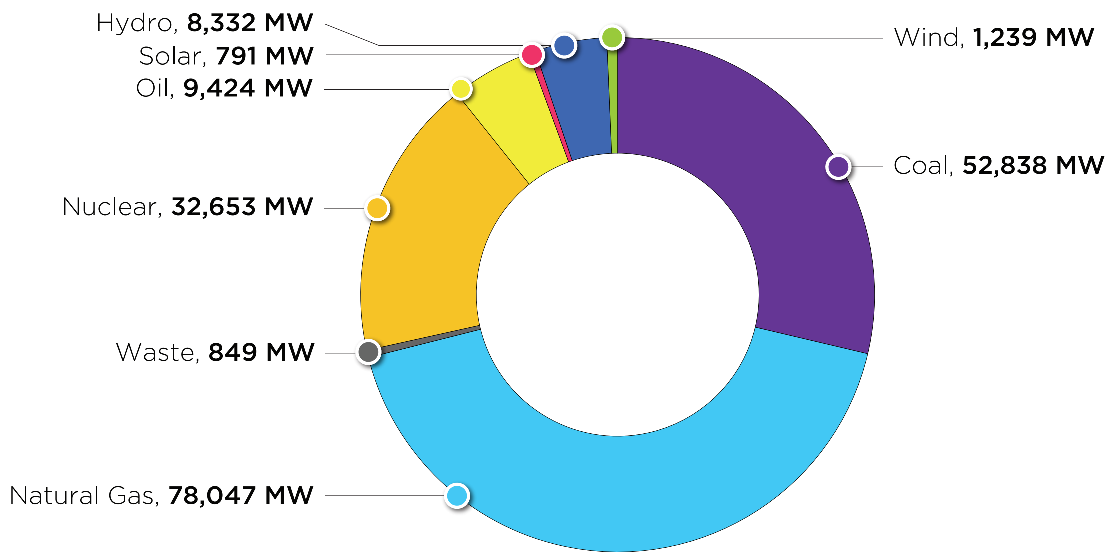


Figure 1.6: PJM Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2019)

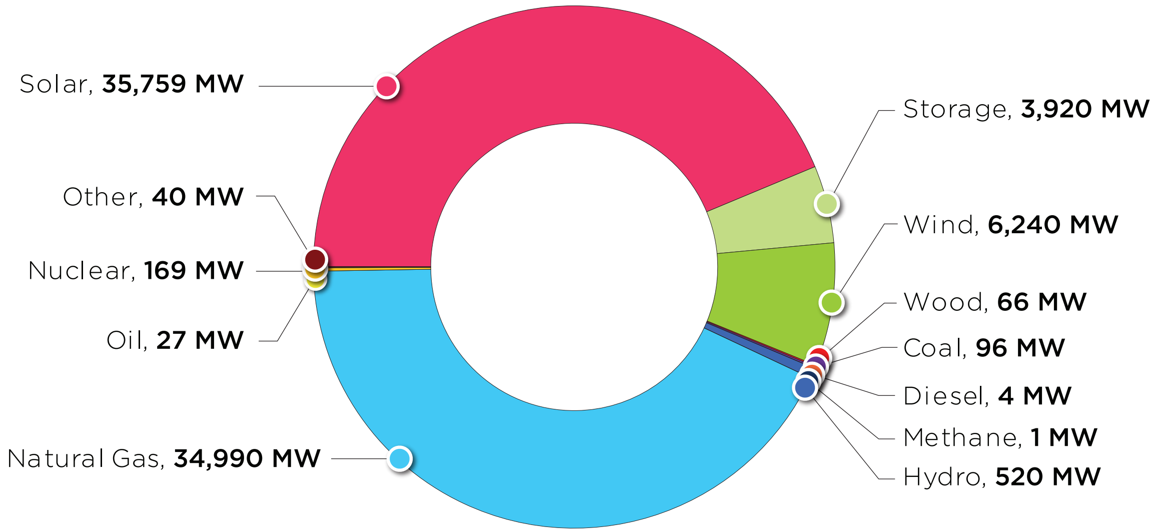


Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	3	40.0	0	0.0	2	56.0	56	2,176.9	69	33,537.6	130	35,810.5
	Diesel	0	0.0	0	0.0	1	4.1	10	72.4	16	76.7	27	153.2
	Natural Gas	87	16,834.7	14	5,927.8	45	12,227.2	321	46,853.5	636	234,316.1	1,103	316,159.3
	Nuclear	8	125.4	0	0.0	1	44.0	43	3,881.6	18	8,988.0	70	13,039.0
	Oil	9	27.0	0	0.0	0	0.0	18	539.8	22	2,300.0	49	2,866.8
	Other	1	40.0	0	00	0	0.0	6	356.5	76	858.8	83	1,255.3
	Storage	119	3,912.3	8	5.8	6	1.9	25	0.0	156	1,813.5	314	5,733.4
Renewable	Biomass	0	0.0	0	0.0	0	0.0	10	192.8	40	896.9	50	1,089.7
	Hydro	5	497.4	0	0.0	2	22.7	31	1,153.5	47	2,126.4	85	3,800.0
	Methane	1	0.8	0	0.0	00	0.0	86	421.0	95	490.1	182	911.8
	Solar	684	33,001.3	26	319.4	129	2,438.6	161	876.4	1,165	18,850.8	2,165	55,486.5
	Wind	86	5,655.3	9	130.4	24	453.9	91	1,716.1	458	13,578.9	668	21,534.6
	Wood	0	0.0	1	16.0	1	50.0	1	4.0	3	137.0	6	207.0
	Grand Total	**1,003**	**60,134.2**	**58**	**6,399.4**	**211**	**15,298.4**	**859**	**58,244.5**	**2,801**	**317,970.8**	**4,932**	**458,047.2**

Renewables

PJM's interconnection queue process continues to see renewable-powered generation growth. As **Figure 1.6** and **Table 1.1** show, queued requests as of Dec. 31, 2019, for Capacity Interconnection Rights (CIRs) totaled 6,240 MW of wind-powered generators that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 31,206 MW. Queued solar-powered generator requests for CIRs totaled 35,759 MW that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 61,488 MW.

Nameplate Capacity vs. Capacity Interconnection Rights

Nameplate capacity represents a generator's rated full power output capability. As **Table 1.2** 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 continually like conventional fossil-fueled power plants, other renewable resources operate intermittently, such as wind and solar.

Wind turbines can generate electricity only when wind speed is within a range consistent with turbine physical specifications. This presents challenges 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 request.

Generators powered by intermittent resources – such as wind – frequently require analytical studies unique to their particular characteristics. For example, wind-powered generator requests have clustered in remote 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.

The interconnection study process is described in PJM Manual 14A, New Services Request Process, available on the PJM website.

Table 1.2: Study Requests Queued Since 1999

Status	Number of Projects	Requested Capacity Interconnection Rights (MW)	Nameplate Capacity (MW)
Active	1,003	60,134.2	108,014
In Service	859	58,244.5	68,655
Suspended	58	6,399.4	7,781
Under Construction	211	15,298.4	20,557
Withdrawn	2,801	317,970.8	401,032
Grand Total	**4,932**	**458,047.2**	**606,040**

1.1.1 — New Services Queue Requests

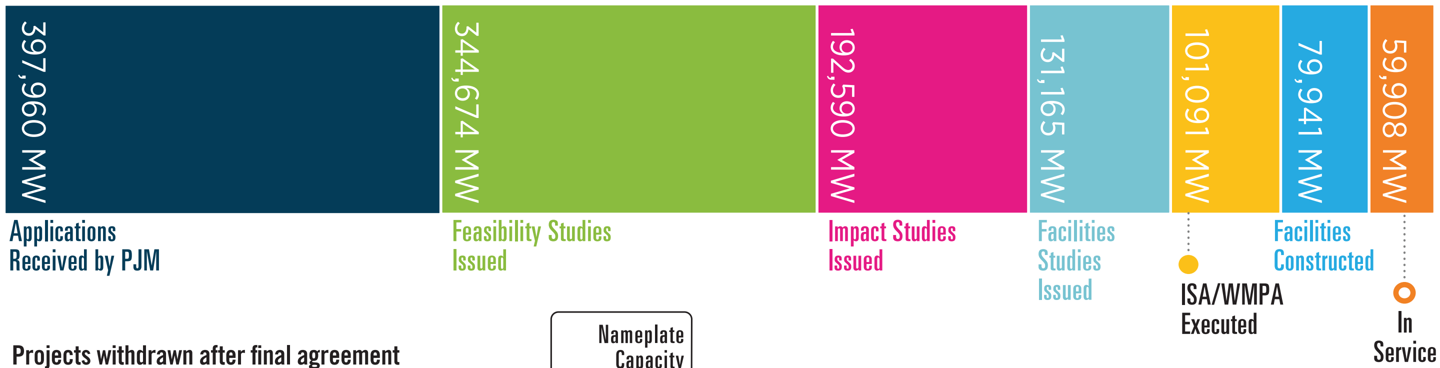
Interconnection Activity

The generation interconnection process has three study phases: 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.

Generation Queue Activity

PJM markets have attracted generation proposals totaling 458,047 MW, as shown in **Table 1.2**, and over 60,130 MW of interconnection requests were actively under study. Over 21,690 MW were under construction or suspended as of Dec. 31, 2019. PJM's queue-based 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, and regulatory, industry, economic and other competitive factors.

Figure 1.7: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2019)



Projects withdrawn after final agreement			Nameplate Capacity
155	Interconnection Service Agreements	20,516 MW	27,781 MW
268	Wholesale Market Participation Agreements	940 MW	1,972 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatts	23% Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

Queue Progression History

PJM reviews generation queue progression annually to understand overall developer trends and their impact on PJM's interconnection process. **Figure 1.7** shows that for generation submitted in Queue A (1999) through Dec. 31, 2019, only 59,908 MW – 15.1 percent – reached commercial operation. Note that **Figure 1.7** reflects requested capacity interconnection rights that are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants, as described earlier.

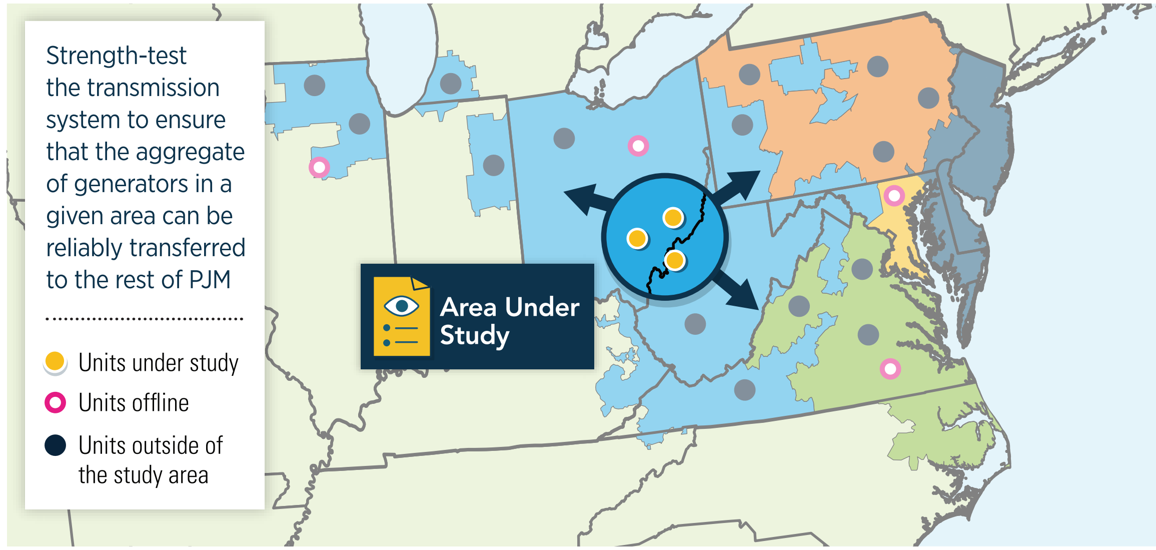
Following interconnection service agreement (ISA) or wholesale market participant agreement (WMPA) execution, 20,516 MW of capacity with ISAs and 940 MW of capacity with WMPAs withdrew from PJM's interconnection process. Overall, 23 percent of requests by project reach commercial operation, whereas only 15 percent of requests by megawatt reach commercial operation. This data shows that projects requesting fewer megawatts are more likely to reach commercial operation.

Interconnecting Reliably

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to resolve reliability criteria violations identified under prescribed deliverability tests. Since 1999, the PJM Board has approved network facility reinforcements totaling $6.4 billion to interconnect over 90,000 MW of new generating resources and satisfy other new service requests – merchant transmission interconnection, for example. The PJM Board approved 95 new network system enhancements totaling over $100 million in 2019 alone.

As described in **Section 1.2**, PJM tests for compliance with all reliability criteria imposed by the NERC and PJM regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies the system conditions to be evaluated that sufficiently stress the transmission system to ensure that the transmission system meets the performance criteria specified in the standards. 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 the rest of PJM load, as illustrated in **Figure 1.8**.

Figure 1.8: Generator Deliverability Concept



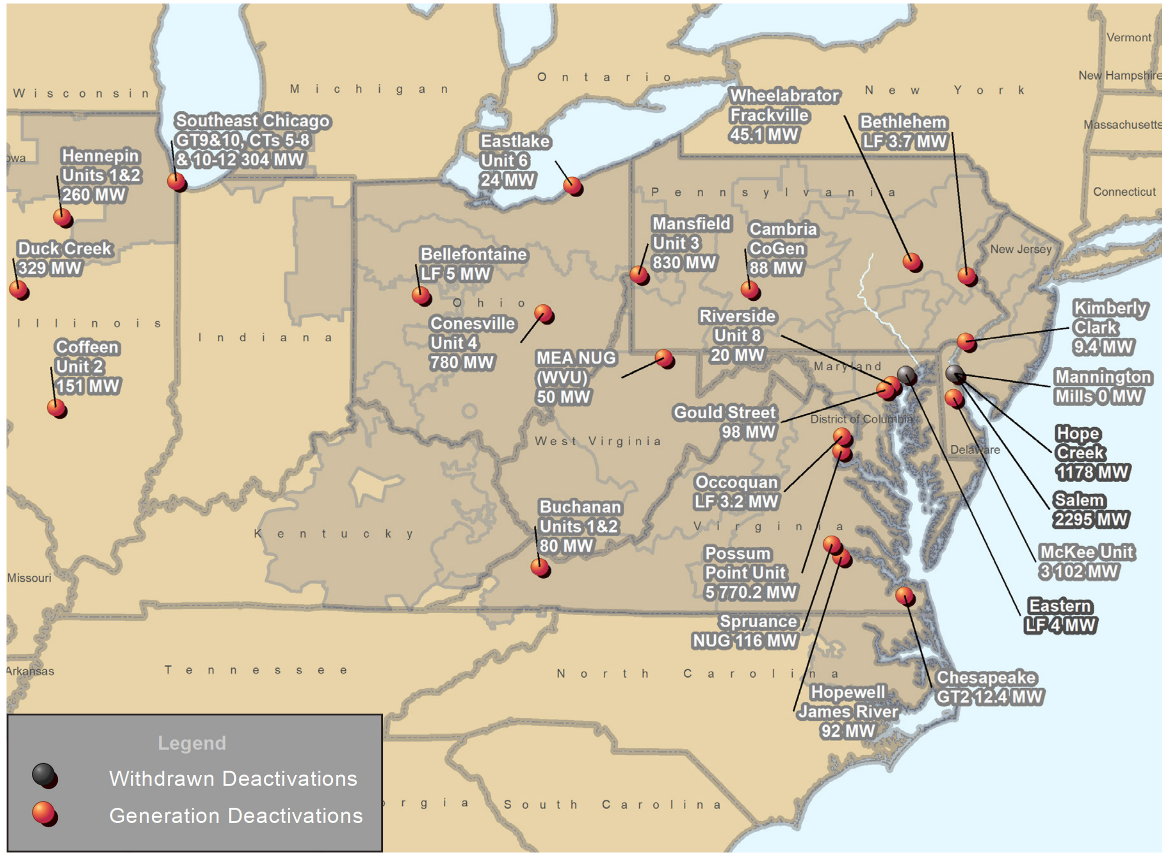
Deactivations

PJM received 36 deactivation notifications in 2019 totaling 7,650 MW. This was down from the previous seven years. **Map 1.2** shows the deactivation request locations received between Jan. 1, 2019, and Dec. 31, 2019.

Generator owners requested the deactivation of these units to take place between March 2020 and June 2023. PJM maintains a list of formally [submitted deactivation requests](), available on the PJM website.

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 undermine voltage support. Deactivation reliability studies are comprised of 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.

Map 1.2: PJM Generator Deactivation Notifications Received Jan. 1, 2019 through Dec. 31, 2019



PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

1.2: Baseline Project Drivers

NERC Criteria – RTEP Perspective

PJM's RTEP process rigorously applies NERC's Planning Standard TPL-001-4 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 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), which 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 BES definition, PJM conducts reliability analyses to ensure system compliance with NERC Standard TPL-001-4. If PJM identifies violations, it develops transmission expansion solutions to resolve them, as part of its RTEP window process.

NERC Reliability Standard TPL-001-4

Under NERC Reliability Standard TPL-001-4, "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 singles)
- 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 takes additional facilities out of service, then they are taken out of service as well. 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 is 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 event P1 – requires that BES facilities be tested for the loss of a single generator, transmission line or transformer. Likewise, bus voltages that exceed limits specified by PJM Manual 3 are also identified. Generator and load deliverability tests are also applied to event P1.

PJM N-1-1 analysis – mapped to planning events P3 and P6 – examines the impact of two successive N-1 events with re-dispatch 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 re-dispatch within applicable emergency thermal ratings and voltage limits after the second contingency as specified in PJM Manual 3.

PJM's N-2 multiple contingency and common mode analyses evaluate planning events P2, P4, P5 and P7 to look at the loss of multiple facilities that share a common element or system protection arrangement. These include bus faults, breaker failures, double-circuit tower line outages and stuck breaker events. N-2 analysis is conducted on the base case itself.

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
Base Case N-2 – Multiple Contingency Analysis	P2, P4, P5, P7
N-1-1 Analysis	P3, P6
Generator Deliverability	P0, P1
Common Mode Outage Procedure	P2, P4, P5, P7
Load Deliverability	P0, P1
Light-Load Reliability Criteria	P1, P2, P4, P5, P7

Common mode analysis is conducted within the context of PJM's deliverability testing methods, discussed in PJM Manual 14B, PJM Region Transmission Planning Process, available on the PJM website.

NERC Standard TPL-001-4 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 operation 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.

A key aspect of NERC Reliability Standard TPL-001-4 also calls for modeling the dynamic behavior of loads as part of stability analysis at peak load levels. Prior to TPL-001-4 standard implementation, stability analyses were conducted on static load models that may not necessarily have captured the dynamic nature of real and reactive components of system loads and energy-efficient loads. From an analytical perspective, this requirement enhances analysis of fault-induced, delayed voltage recovery or changes in load characteristics like that of more energy-efficient loads.

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. While transmission enhancements driven by TO criteria are considered RTEP baseline projects, they are assigned to the incumbent TO and are not eligible for proposal window consideration, as shown in **Figure 1.9**. Under the terms of the OATT, the costs of such projects are allocated 100 percent to the TO zone (starting Jan. 1, 2020, TO criteria projects will be included in PJMs competitive proposal process).

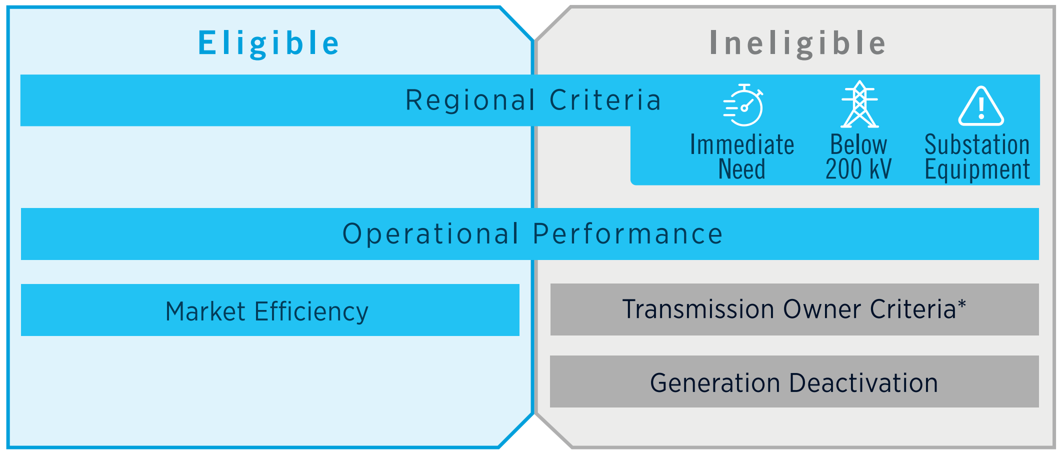
2019 Transmission Owner Criteria-Driven Projects

PJM has observed that TO aging infrastructure criteria are increasingly driving the need for baseline projects. Review of facilities built in the 1960s and earlier have revealed significant deterioration. Planning for aging infrastructure is not new to PJM. 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.

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 2019.

Figure 1.9: Window Eligibility



**Per FERC Order EL 19-61, PJM has eliminated the FERC 715 TO criteria exclusion as of Dec. 31, 2019.*

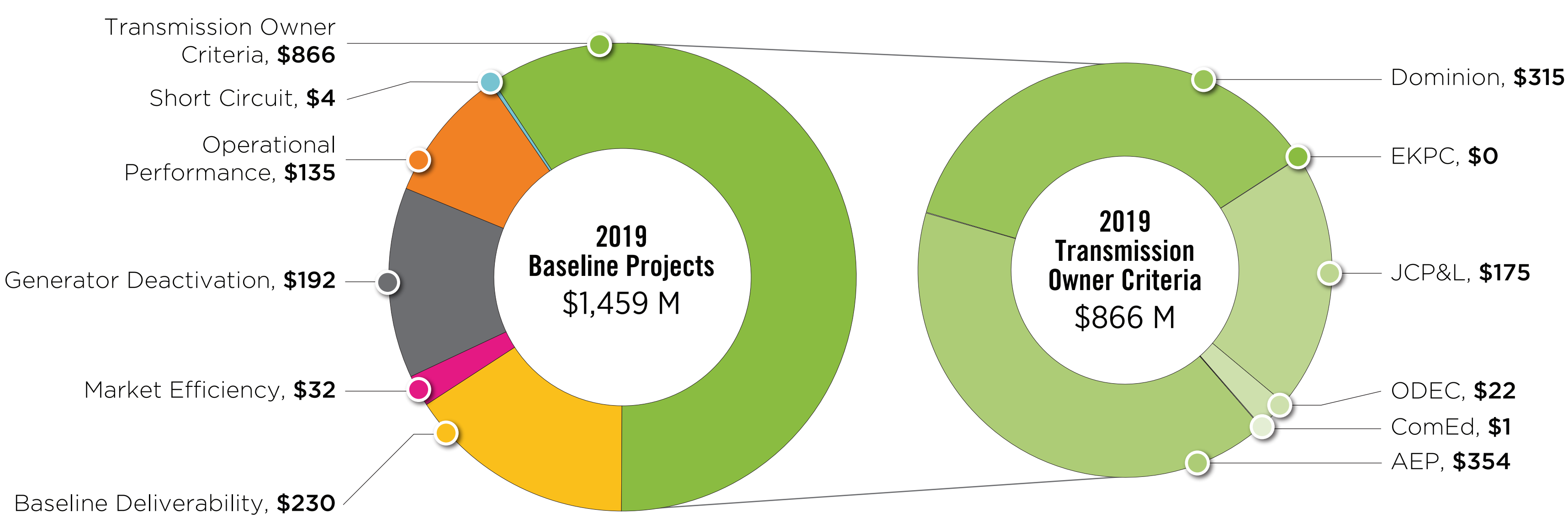
Developing Transmission Solutions

After PJM identifies a baseline transmission need, including market efficiency, PJM may open a competitive proposal window, depending on the required in-service date, voltage level and scope of likely projects. Window eligibility for project driver types is shown in **Figure 1.9**. 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 of our 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 project construction, ownership, operation, maintenance and financing.

2019 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 2019 were no different, as discussed in later sections of this report and summarized in **Figure 1.10**. As the figure shows, baseline transmission investment, once primarily comprising projects driven by deliverability, now also comprises projects driven by other factors, including transmission owner criteria.

Figure 1.10: 2019 RTEP Baseline Projects by Driver ($ Million)



Market Efficiency

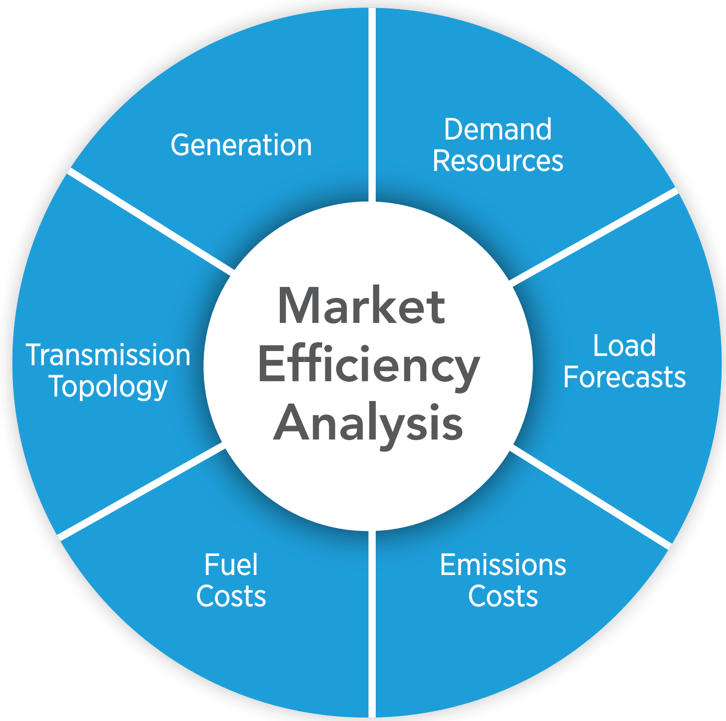
PJM's RTEP process includes a market efficiency analysis to accomplish the following goals:

- 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. 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 1.11: Market Efficiency Analysis Parameters



PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

1.3: RTEP Process Milestones

1.3.1 — 2019 Activities

PJM's RTEP process is continually evolving as the scope of system enhancement drivers it addresses evolves. Process improvements continued in 2019, milestones for which are discussed below.

Value of Transmission

In recent years, the question "What am I getting for my transmission investment dollars?" has been on the minds and agendas of state legislatures and utility commissions, consumers and other PJM Interconnection stakeholders. Today, transmission is constructed and improved for different reasons than 10 years ago. For most of the history of the transmission system, new projects were driven by two things: growth in the demand for electricity from consumers and requests from new generators to connect to the grid, which often require new transmission lines to reach load centers.

The benefits of the transmission system itself, and the dollars invested in it, extend well beyond delivering power over high-voltage transmission lines. To that end, PJM researched and published a white paper that demonstrated some of the benefits and drivers of new transmission:

- *Ensuring reliability* – keeping the lights on
- *Keeping costs low* – delivering the lowest cost energy to customers through wholesale markets
- *Supporting public policy* – helping bring to fruition state renewable mandates and federal emission mandates

Load is no longer growing at the one-percent to three-percent pace it once was. Now, load growth rates of 0.5 percent and lower are not unusual. Instead of load, transmission investment drivers now include shifting generation resources from coal to gas and renewables; aging infrastructure repair or replacement to maintain reliability; supporting public policy goals (environmental mandates, for example); and ensuring lower-cost energy flows to everyone in PJM by mitigating congestion.

Value of Transmission White Paper

PJM published a white paper on April 16, 2019, discussing the value of new and existing transmission equipment, lines and other assets for PJM Interconnection stakeholders and other engaged parties. The benefits discussed in the document were based on case studies, analysis and data from across PJM's Planning, Operations and Markets divisions. The Benefits of the PJM Transmission System White Paper provides readers with valuable insights and data to help value the reliability, economic and public policy goals that transmission enables.

While PJM's regional planning processes and transmission owner asset management processes are key to transmission development, they were not the focus of the paper, which was to demonstrate the benefit of the assets themselves. Information on these important processes is provided in the Appendix.

The paper offers observations that summarize transmission value. It does not, and is not intended to, take positions or draw conclusions on issues under discussion in the PJM stakeholder process, at the Federal Regulatory Energy Commission or in state legislatures and utility commissions.

PJM Manual 14B Updates

PJM's transmission planning performs deliverability analysis testing as part of the RTEP process. This testing consists of load and generation deliverability studies that help maintain reliability in a competitive capacity market, as detailed in PJM Manual 14B. These deliverability tests ensure that the PJM transmission system is adequate to deliver power from the aggregate of capacity resources to the aggregate of PJM load.

During its 2019 periodic annual review of Manual 14B, PJM continued a review and rewrite of these testing methodologies in order to make them more transparent and straightforward for PJM stakeholders. PJM revised Manual 14B by reorganizing and relabeling the sections related to load and generation deliverability methods, and added clarification to better describe how PJM implements these testing methodologies. PJM, in discussion with PJM stakeholders, proposed procedural changes, reorganization, clarifications and the restructuring of language within the load and generation deliverability methodology. This effort resulted in a revised Manual 14B that provides a more detailed and thorough understanding of load and generation deliverability testing methodologies that stakeholders can follow as part of the RTEP process.

Gas/Electric Coordination

The evaluation of extreme events required by TPL-001-4 includes the loss of large gas pipelines. Over the past several years, PJM has continued to expand its relationships with the interstate natural gas pipelines and local gas distribution companies that serve the natural gas generation fleet across the system. This effort supports the development of the gas pipeline and its related contingencies for near-term operational planning. PJM planning has coordinated with PJM operations to develop contingencies with future gas units modeled in the five-year-out winter RTEP case. During the interconnection request process, each future gas unit's geographic fuel supply data for the interstate pipelines and/or local gas distribution company infrastructure submitted by the generation project owners are reviewed.

CIP-014 Mitigation Projects Process

The CIP-014-2 standard requires transmission owners to identify and protect transmission stations and transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or cascading within an interconnection. The standard requires the implementation of a physical security plan for each identified CIP-014-2 substation. However, security protections do not eliminate the criticality of these substations, as damage to these substations may lead to the potential for long-term loss of load and associated loss of service to critical infrastructure. The very nature of the identified vulnerabilities implicate locations and risks that cannot be completely mitigated or resolved by physically protecting the substation. For this reason, on Aug. 12, 2019, the Transmission Owner Agreement-Administrative Committee (TOA-AC) issued a notice to stakeholders regarding the intent to file a new Tariff Attachment M-4, solely applicable to the planning of CIP-014 mitigation projects.

Achieving the removal of substations from the CIP-014 list may involve transmission projects that, under the Attachment M-3 (Additional Procedures for Planning of Supplemental Projects) process and state rules, would require public vetting. However, due to the criticality and vulnerabilities associated with these facilities, public vetting would be in violation of CIP-014-2 R2.4. The proposed Attachment M-4, CIP-014 mitigation projects process, provides a means for planning such projects, where the sole purpose is to reduce the criticality of these substations, so they can be removed from the CIP-014 list. There is currently no PJM criteria, mandate or requirement to reduce the criticality of these substations and thus remove them from the CIP-014 list. For this reason, CIP-014 mitigation projects can only be developed as supplemental projects. However, given the requirement to protect CIP-014 information, the Attachment M-3 process cannot be used.

The CIP-014 mitigation projects process in Attachment M-4, proposed by the TOA-AC, provides the necessary exception to the Attachment M-3 process, and therefore only applies to a small set of supplemental projects. The process also provides the necessary protection of sensitive and confidential CIP-014 information, and allows

NOTE:

The CIP mitigation process and associated stakeholder involvement is the subject of a PJM Planning Committee special session. Details of these discussions can be found on the PJM website.

for PJM's and the affected state's (as a proxy for stakeholders) input. The M-4 process does not affect existing cost allocation or existing planning authority, and is a temporary process that sunsets after five years, limiting the scope to only existing CIP-014 substations (for which there are fewer than twenty). After considering stakeholder feedback and input, the TOA-AC conducted a vote and filed the proposed Attachment M-4 with the Federal Energy Regulatory Commission.

Cost Containment

Since the first FERC Order 1000 competitive transmission proposal window was opened in 2013, over 800 proposals have been received, of which 150 have included some form of cost containment provision. PJM's examination of these provisions has been a part of its ongoing due diligence with respect to proposal evaluation. Beginning in May 2018, PJM engaged stakeholders under the auspices of the Markets and Reliability Committee to develop a more formalized comparative cost framework for PJM to use in evaluating cost containment provisions going forward.

One of the results of this effort was documentation of a new Comparative Cost Framework in PJM Manual 14F – PJM Competitive Planning Process. The main components of the framework include details of how proposals with or without cost containment are considered, project risk assessment, financial analysis and associated assumptions and communication to PJM stakeholders.

The manual language lists parameters that are anticipated to be part of cost containment provisions:

- Capital structure (debt to equity ratio)
- Caps on: initial capital costs (total costs associated with bringing the project into service)
- Annual revenue requirement
- Rate of return on equity
- Debt cost
- Total capital cost
- Allowance for funds used during construction
- Construction work in progress
- Abandonment costs
- Schedule guarantees

Note that a cost-commitment proposal may also exclude defined cost elements from the cost-commitment provision. This is not an exhaustive list, as PJM will evaluate and assess any submitted cost containment provision.

The framework documentation in PJM Manual 14F also describes the process of independent, detailed constructability studies to determine project-specific cost and risk, as well as the comparison to other competing projects and presentation to PJM stakeholders.

Market Efficiency Process Enhancement Task Force

The Market Efficiency Process Enhancement Task Force (MEPETF) was chartered in January 2018 under the auspices of the PJM Planning Committee. The mission of this group is to review, evaluate and discuss challenges and potential solutions necessary to improve the market efficiency process by doing the following:

- Provide educational material
- Evaluate benefit-to-cost calculation
- Evaluate facility service agreement modeling
- Evaluate the market efficiency re-evaluation process and mid-cycle assumption update
- Interregional market efficiency project selection
- Evaluate regional targeted market efficiency process
- Update market efficiency mid-cycle assumption and model

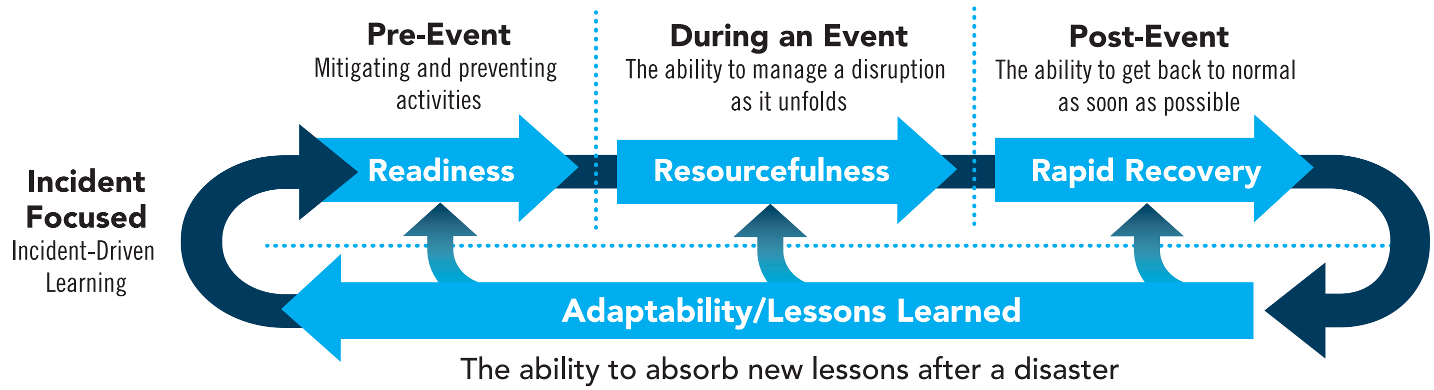
The reviews are being conducted in three phases. In April 2019, the work conducted under phase two was endorsed by PJM stakeholders, including the revisions to the Operating Agreement (OA), Manuals 14B and 14F regarding the market efficiency re-evaluation process, and the timing of the long-term window.

On Aug. 22, 2019, FERC accepted the revisions to the OA associated with these changes, and the changes became effective on Aug. 28, 2019.

Also in April 2019, the MEPETF started work on phase three, which entailed investigating a new Regional Targeted Market Efficiency Project process and looking into the separation of energy and capacity benefits in the benefit-to-cost calculations. Proposed package revisions are currently going through the stakeholder process.

More information can be accessed on the PJM website. Additional discussion on the MEPETF activities including those that continued into 2020 are included in **Section 4.6**.

Figure 1.12: Defining Resilience



1.3.2 — Looking Ahead

Capacity Treatment of Intermittent Resources

PJM began to re-examine the capacity treatment of intermittent resources (wind and solar) with the Planning Committee in 2019. The current treatment of intermittent resources sets their capacity value to the resources' average output over a defined number of summer peak load hours. This approach has two limitations. One, it weights the output over all hours equally, regardless of an individual hour's actual contribution to the annual loss of load risk, and, two, it fails to recognize the saturation effect as the amount of intermittent resources in PJM increases. To address these two limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an effective load carrying capability (ELCC) tool. This more robust methodology recognizes the full value of a resource's output over high-load risk hours and also accounts for the saturation effect. The assumptions and preliminary results of this ELCC study were presented at several Planning Committee meetings in 2019. Work on this issue will continue in 2020 and may result in a proposed alternate method to assign capacity credit values to intermittent resources.

Resilience

NERC defines infrastructure resilience as "the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from, a potentially disruptive event." To be resilient, PJM must prepare for, operate through, and recover from, such threats as depicted in **Figure 1.12**:

- **Pre-event – prepare** – anticipate, evaluate and cost-effectively mitigate risks
- **During an event – operate** – manage through a high-impact disruption
- **Post-event – recover** – regain essential functions as rapidly as possible

NOTE:

PJM anticipates proposing a Problem Statement and Issue Charge at the March 26, 2020, MRC meeting to develop an ELCC method for calculating the capability of limited energy resources (such as energy storage) and variable resources (such as wind and solar) in the capacity market. The Issue Charge proposes to form a senior task force under the MRC to pursue this initiative with the goal of submitting a FERC filing by Jan. 29, 2021.

PJM's operations, planning, markets, physical security and cybersecurity functions are part of ongoing collaborative, organization-wide efforts to establish processes, develop tools and enhance communication linkages to maximize grid resilience. **Figure 1.12** and **Figure 1.13** help illustrate PJM's resilience program objectives which fully integrate internal PJM work plans and initiatives across six focus areas: Operations, Planning, Markets, Security, Partnerships and System Restoration. PJM strives as an industry leader to align the input, goals and needs of PJM members and external stakeholders, and to design and implement a system capable of preparing for, operating through, and recovering from, severe events.

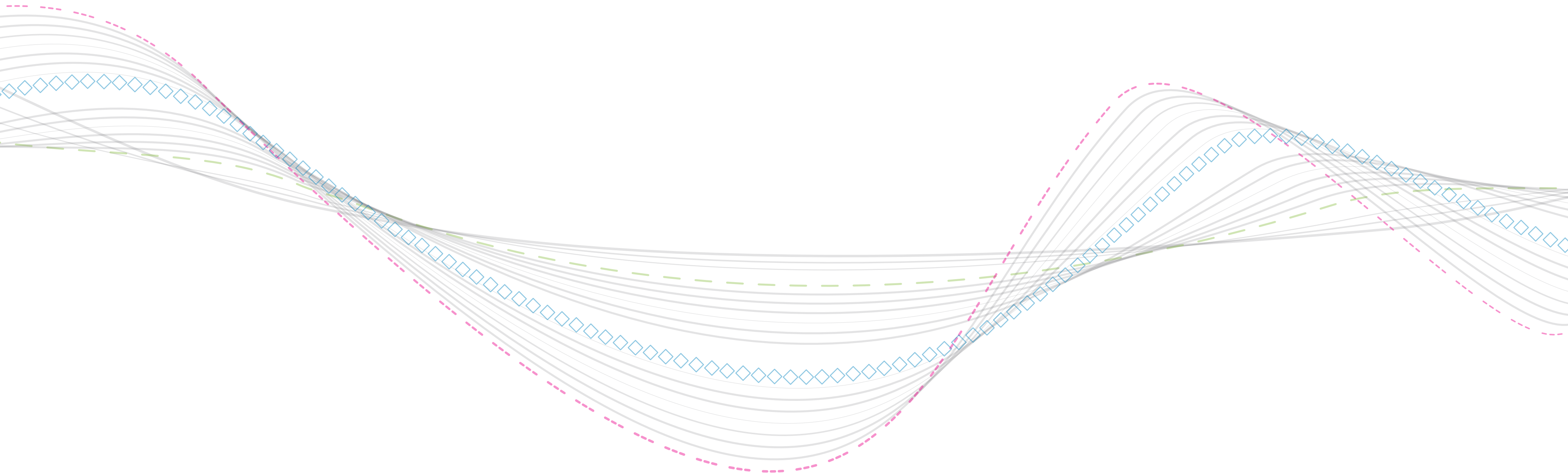
From a planning perspective, PJM established the Fuel Security Senior Task Force to determine what it means to be fuel/energy/resource secure and compare potential mechanisms to ensure and value fuel/energy/resource security in PJM. PJM also initiated efforts to implement RTEP process criteria and metrics to enhance grid resilience by virtue of compliance with NERC Standards TPL-001-4, TPL-007-1 and CIP-014.

PJM planning continues development of a new planning tool that uses a "cascading trees" event analysis, which complements existing studies by simulating and testing system resilience. The new methodology provides a way to simulate severe contingency events, such as the loss of a substation at extreme conditions, and to quantify the probability of a cascading system, the loss of load and generation, and to determine if the event is bounded, unbounded or unstable. Beyond extreme events, PJM could use this methodology to compare competing projects to measure which one increases or decreases the probability of cascading or resilience.

Figure 1.13: PJM's Resilience

Storage as a Transmission Asset

In 2018, PJM and its stakeholders worked to enhance PJM markets to further recognize and take advantage of the unique characteristics of energy storage resources. Moving into 2019, PJM continued to build an understanding of energy storage resources and their impacts to the grid. During 2019, PJM initiated an effort to determine how energy storage resources as a transmission asset could be utilized. PJM expects more discussions on this topic in 2020.



Section 2: Load Forecast Modeling

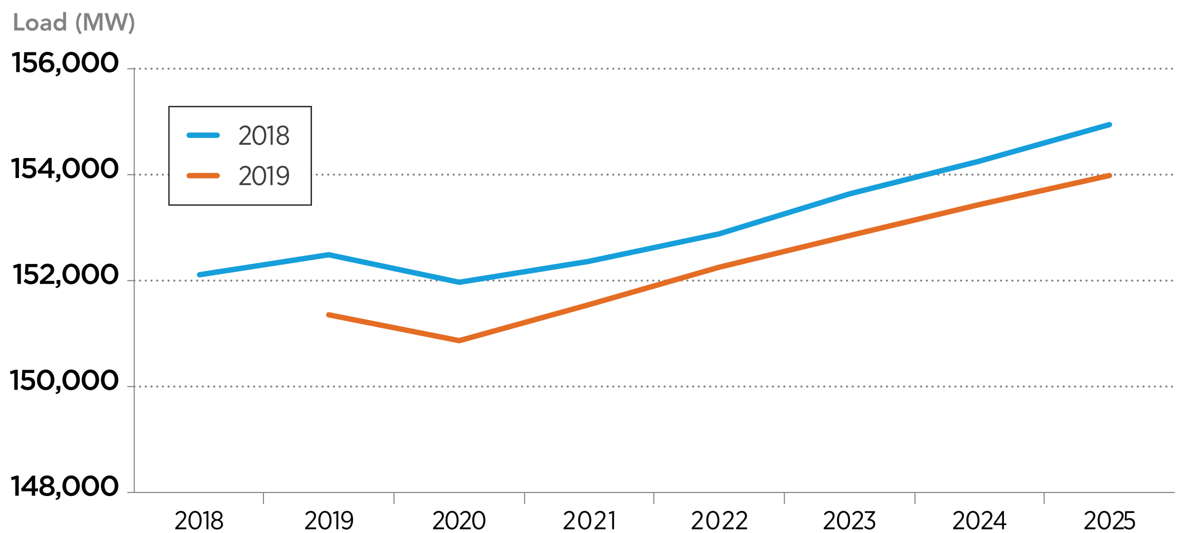
PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

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 economically efficient system operations.

As a starting point, in order to develop a power flow base case model, PJM assigns zonal load from its January 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 peak in different geographical areas 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).

Figure 2.1: Summer Peak Load Forecast 2019 vs. 2018



2019 RTEP Process Context

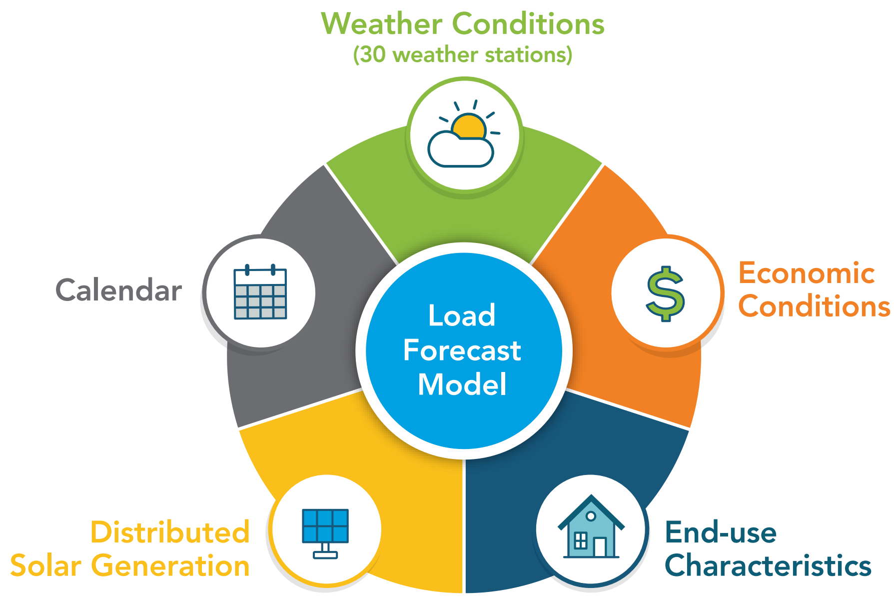
PJM's 2019 RTEP baseline power flow model for study year 2024 is based on the 2019 PJM Load Forecast Report. Summarized in the sections that follow, PJM's January 2019 load forecast covered the 2019 through 2034 planning horizon. From a power flow modeling perspective, the 2024 summer peak from that January 2019 forecast at an overall RTO demand of 153,435 MW was the basis for developing PJM's 2024 base case power flow model bus loads. Doing so will reflect that PJM now projects its RTO summer-normalized peak to grow 0.3 percent annually over the next 10 years, shown in **Figure 2.1** in terms of megawatt load level, which is down 0.1 percentage points from the 2018 forecast.

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), and distributed solar generation, and leverages those relationships to derive forecasted load, shown in **Figure 2.2**.

- Weather conditions across the RTO are accounted for by calculating a weighted average of temperature, humidity and wind speed. PJM obtains weather data from over 30 identified weather stations across the PJM region.
- Calendar effects are variables that represent the day of the week, month and holidays.
- The economic dimension of load forecasting employs an indexed variable that incorporates six economic measures (gross domestic product, gross metropolitan product, real personal income, population, households and non-manufacturing employment) into one measure. 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.
- Distributed solar 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.

Figure 2.2: Load Forecast Model



- 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 collection of different 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.
- Explicit treatment of end-use characteristics and distributed solar generation were new additions to the load forecast model in 2016 as reviewed with the Load Analysis Subcommittee. Previously, these characteristics were only captured to the extent to which they affected historical metered load.

PJM has updated its load forecast model to recognize the breakdown in the relationship between energy and economics. In large part, this reflects the continued evolution of a more service-driven economy and, consequently, a less energy-intensive economy as exacerbated by the accelerated proliferation of more energy-efficient electrical appliances and equipment.

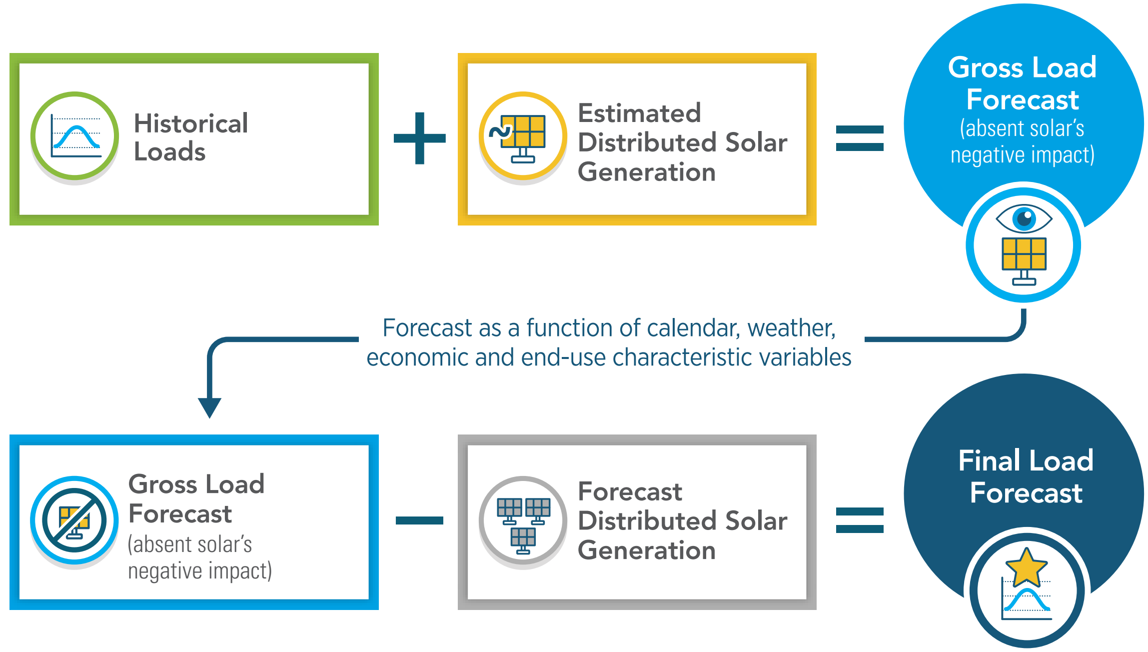
Distributed Solar Generation

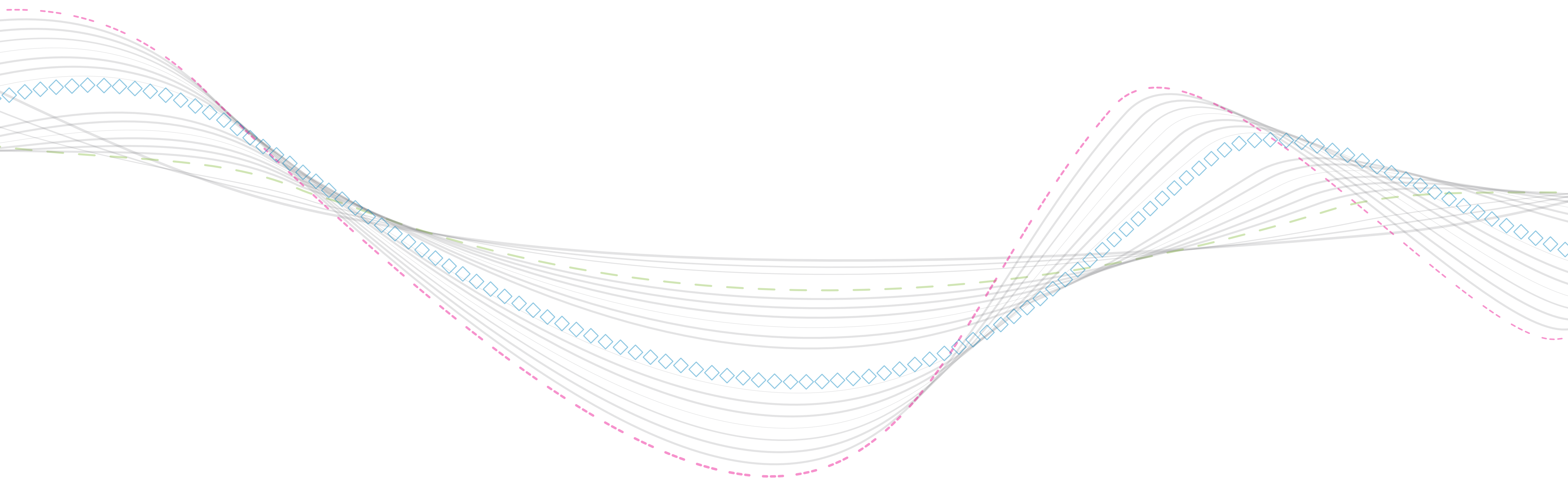
Recent years have witnessed a significant ramp-up in behind-the-meter distributed solar resources: more than 4,000 MW since 1998, with more than 95 percent of installations since 2010. Though not a large amount from an RTO perspective, the level of distributed solar is significant in certain areas of PJM and is expected to increase more in the years to come. Under PJM's model update, distributed solar generation impacts are reflected in its load forecast using the approach shown in **Figure 2.3** in order 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 forecasted, distributed solar generation to obtain a final load forecast for each zone and for the RTO. Forecasted distributed solar generation is based on vendor-supplied, forecasted, distributed solar 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. This forecast is discounted for: (1) expected panel degradation over time; and (2) solar energy production that does not align with the timing of PJM's peak load.

Figure 2.3: Accounting for Distributed Solar Generation





PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

2.1: January 2019 Forecast

PJM's January 2019 load forecast used in 2019 RTEP studies covered the 2019 through 2034 planning horizon, highlights of which are summarized in this section. The complete January 2019 PJM Load Forecast Report is accessible on the PJM website. As that report states, PJM's 2024 RTO summer peak is forecasted to be 153,435 MW.

Forecasting Trends

Table 2.1 summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2019 through 2029. All load forecasts in the table reflect adjustment for distributed solar generation. Adjustments to the summer, 10-year forecast are summarized in **Table 2.2**. Adjustments to the winter forecast 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. Lower load forecast trends over that period reflect broader trends in the U.S. economy and PJM model refinements to capture energy efficiency. These trends are subsequently reflected in RTEP process power flow models.

Table 2.1: 2019 Load Forecast Report

	Summer Peak (MW)			Winter Peak (MW)		
Transmission Owner	2019	2029	Growth Rate	2018/2019	2028/2029	Growth Rate
Atlantic City Electric Company	2,450	2,388	-0.3%	1,590	1,550	-0.3%
Baltimore Gas and Electric Company	6,697	6,663	-0.1%	5,872	5,907	0.1%
Delmarva Power & Light	3,933	3,962	0.1%	3,458	3,587	0.4%
Jersey Central Power & Light	5,914	5,912	0.0%	3,710	3,690	-0.1%
Met-Ed	2,986	3,157	0.6%	2,615	2,726	0.4%
PECO Energy Company	8,711	9,082	0.4%	6,753	6,936	0.3%
Pennsylvania Electric Company	2,897	2,908	0.0%	2,866	2,863	0.0%
PPL Electric Utilities	7,148	7,347	0.3%	7,259	7,371	0.2%
Potomac Electric Power Company	6,466	6,413	-0.1%	5,406	5,495	0.2%
PSEG	9,904	9,753	-0.2%	6,688	6,641	-0.1%
Rockland	404	402	0.0%	229	228	0.0%
UGI Utilities	189	188	-0.1%	193	189	-0.2%
Diversity – Mid-Atlantic	-1,213	-1,135		-644	-621	
Mid-Atlantic	**56,486**	**57,040**	**0.1%**	**45,995**	**46,562**	**0.1%**
American Electric Power	22,945	24,072	0.5%	22,485	23,541	0.5%
Allegheny Power	8,707	9,305	0.7%	8,721	9,413	0.8%
American Transmission Systems, Inc.	12,872	13,134	0.2%	10,601	10,729	0.1%
Commonwealth Edison Company	21,890	22,514	0.3%	15,515	15,806	0.2%
Dayton Power & Light	3,408	3,525	0.3%	2,864	2,945	0.3%
Duke Energy Corporation	5,480	5,742	0.5%	4,440	4,613	0.4%
Duquesne Light Company	2,862	2,887	0.1%	2,144	2,150	0.0%
East Kentucky Power Cooperative	1,989	2,072	0.4%	2,620	2,722	0.4%
Ohio Valley Electric Corporation	95	95	0.0%	125	125	0.0%
Diversity – Western	-1,612	-1,369		-1,476	-1,404	
Western	**78,636**	**81,977**	**0.4%**	**68,039**	**70,640**	**0.4%**
Dominion	19,391	21,238	0.9%	18,144	20,212	1.1%
Southern	**19,391**	**21,238**	**0.9%**	**18,144**	**20,212**	**1.1%**
Diversity – Total	-5,980	-6,070		-3,216	-3,261	
PJM RTO	**151,358**	**156,689**	**0.3%**	**131,082**	**136,178**	**0.4%**

Table 2.2: Distributed Solar Generation Adjusted to Summer Peak

	Distributed Solar Generation Adjustment to Summer Peak (MW)	
Transmission Owner	**2019**	**2029**
Atlantic City Electric Company	140	197
Baltimore Gas and Electric Company	128	210
Delmarva Power & Light	81	164
Jersey Central Power & Light	204	333
Met-Ed	21	38
PECO Energy Company	36	80
Pennsylvania Electric Company	6	26
PPL Electric Utilities	51	95
Potomac Electric Power Company	117	211
PSEG	313	570
Rockland	6	15
UGI Utilities	0	1
Mid-Atlantic	**1,103**	**1,940**
American Electric Power	39	186
Allegheny Power	54	121
American Transmission Systems, Inc.	41	104
Commonwealth Edison Company	29	142
Dayton Power & Light Company	10	27
Duke Energy Corporation	8	34
Duquesne Light Company	10	26
East Kentucky Power Cooperative	5	14
Western	**196**	**654**
Dominion	300	655
Southern	**300**	**655**
PJM RTO	**1,599**	**3,249**

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

Transmission Owner	2015 Load Forecast Report Summer Peak (MW)			2016 Load Forecast Report Summer Peak (MW)			2017 Load Forecast Report Summer Peak (MW)			2018 Load Forecast Report Summer Peak (MW)			2019 Load Forecast Report Summer Peak (MW)		
	2015	2025	Growth Rate	2016	2026	Growth Rate	2017	2027	Growth Rate	2018	2028	Growth Rate	2019	2029	Growth Rate
Atlantic City Electric Company	2,664	2,827	0.6%	2,524	2,502	-0.1%	2,495	2,445	-0.2%	2,460	2,409	-0.2%	2,450	2,388	-0.3%
Baltimore Gas and Electric Company	7,127	7,753	0.8%	6,945	7,220	0.4%	6,889	6,911		6,848	6,744	-0.2%	6,697	6,663	-0.1%
Delmarva Power & Light	4,177	4,557	0.9%	3,991	4,135	0.4%	4,028	3,983	-0.1%	3,937	4,018	0.2%	3,933	3,962	0.1%
Jersey Central Power & Light	6,269	6,851	0.9%	5,968	6,156	0.3%	6,056	6,108	0.1%	5,942	5,943		5,914	5,912	0.0%
Met-Ed	2,954	3,310	1.1%	2,940	3,176	0.8%	2,940	3,028	0.3%	2,974	3,115	0.5%	2,986	3,157	0.6%
PECO Energy Company	8,645	9,434	0.9%	8,547	9,122	0.7%	8,547	8,693	0.2%	8,642	8,979	0.4%	8,711	9,082	0.4%
Pennsylvania Electric Company	2,914	3,276	1.2%	2,890	2,919	0.1%	2,891	2,847	-0.2%	2,895	2,922	0.1%	2,897	2,908	0.0%
PPL Electric Utilities	7,162	7,759	0.8%	7,193	7,560	0.5%	7,132	7,186	0.1%	7,140	7,350	0.3%	7,148	7,347	0.3%
Potomac Electric Power Company	6,640	7,022	0.6%	6,563	6,813	0.4%	6,614	6,543	-0.1%	6,493	6,466		6,466	6,413	-0.1%
PSEG	10,306	10,907	0.6%	10,090	10,222	0.1%	10,057	10,012		9,903	9,876		9,904	9,753	-0.2%
Rockland	424	441	0.4%	407	410	0.1%	404	404		402	402		404	402	0.0%
UGI Utilities	197	212	0.7%	188	190	0.1%	191	185	-0.3%	190	188	-0.1%	189	188	-0.1%
Diversity – Mid-Atlantic	-578	-530		-1,072	-872		-1,080	-1,161		-1,225	-1,086		-1,213	-1,135	0.0%
Mid-Atlantic	**58,901**	**63,819**	**0.8%**	**57,174**	**59,553**	**0.4%**	**57,164**	**57,184**		**56,601**	**57,326**	**0.1%**	**56,486**	**57,040**	**0.1%**
American Electric Power	23,511	25,343	0.8%	23,006	24,891	0.8%	22,945	23,888	0.4%	22,876	24,018	0.5%	22,945	24,072	0.5%
Allegheny Power	8,734	9,701	1.1%	8,817	9,554	0.8%	8,802	9,087	0.3%	8,825	9,447	0.7%	8,707	9,305	0.7%
American Transmission Systems, Inc.	13,256	13,835	0.4%	12,921	13,413	0.4%	12,994	13,177	0.1%	12,952	13,309	0.3%	12,872	13,134	0.2%
Commonwealth Edison Company	22,914	25,953	1.3%	22,001	23,633	0.7%	22,296	22,872	0.3%	22,121	23,207	0.5%	21,890	22,514	0.3%
Dayton Power & Light Company	3,497	3,966	1.3%	3,403	3,647	0.7%	3,479	3,503	0.1%	3,459	3,508	0.1%	3,408	3,525	0.3%
Duke Energy Corporation	5,511	6,015	0.9%	5,436	5,853	0.7%	5,497	5,741	0.4%	5,523	5,860	0.6%	5,480	5,742	0.5%
Duquesne Light Company	2,969	3,161	0.6%	2,893	2,985	0.3%	2,884	2,882	0.0%	2,872	2,924	0.2%	2,862	2,887	0.1%
East Kentucky Power Cooperative	1,983	2,170	0.9%	1,924	2,041	0.6%	1,948	2,010	0.3%	1,960	2,033	0.4%	1,989	2,072	0.4%
Ohio Valley Electric Corporation													95	95	0.0%
Diversity – Western	-1,682	-1,997		-1,572	-1,574		-1,529	-1,468	0.0%	-1,540	-1,522		-1,612	-1,369	
Western	**80,693**	**88,147**	**0.9%**	**78,829**	**84,443**	**0.7%**	**79,316**	**81,692**	**0.3%**	**79,048**	**82,784**	**0.5%**	**78,636**	**81,977**	**0.4%**
Dominion	19,999	23,676	1.7%	19,531	22,041	1.2%	19,729	20,501	0.4%	19,596	21,161	0.8%	19,391	21,238	0.9%
Southern	**19,999**	**23,676**	**1.7%**	**19,531**	**22,041**	**1.2%**	**19,729**	**20,501**	**0.4%**	**19,596**	**21,161**	**0.8%**	**19,391**	**21,238**	**0.9%**
Diversity – RTO	-4,049	-4,062		-3,403	-4,146		-3,210	-3,604	0.0%	-3,137	-3,636		-5,980	-6,070	
PJM RTO	**155,544**	**171,580**	**1.0%**	**152,131**	**161,891**	**0.6%**	**152,999**	**155,773**	**0.2%**	**152,108**	**157,635**	**0.4%**	**151,358**	**156,689**	**0.3%**

2019 Forecast Summer Zonal Load Growth Rates

The PJM RTO weather-normalized summer peak is forecasted to grow at an average rate of 0.3 percent per year for the next 10 years. The PJM RTO summer peak is forecasted to be 156,689 MW in 2029, an increase of 5,331 MW over the 2019 peak of 151,358 MW. Individual geographic zone growth rates vary from -0.3 percent to 0.9 percent, as shown in **Figure 2.4** and **Figure 2.5**.

Figure 2.4: PJM Mid-Atlantic Summer Peak Load Growth 2019 – 2029

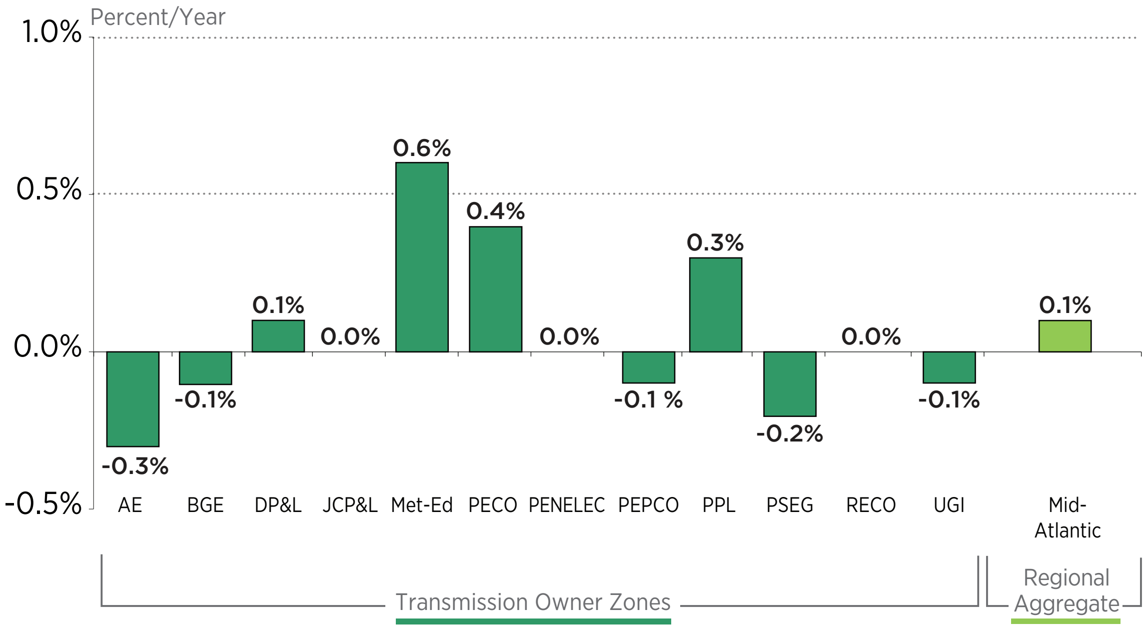
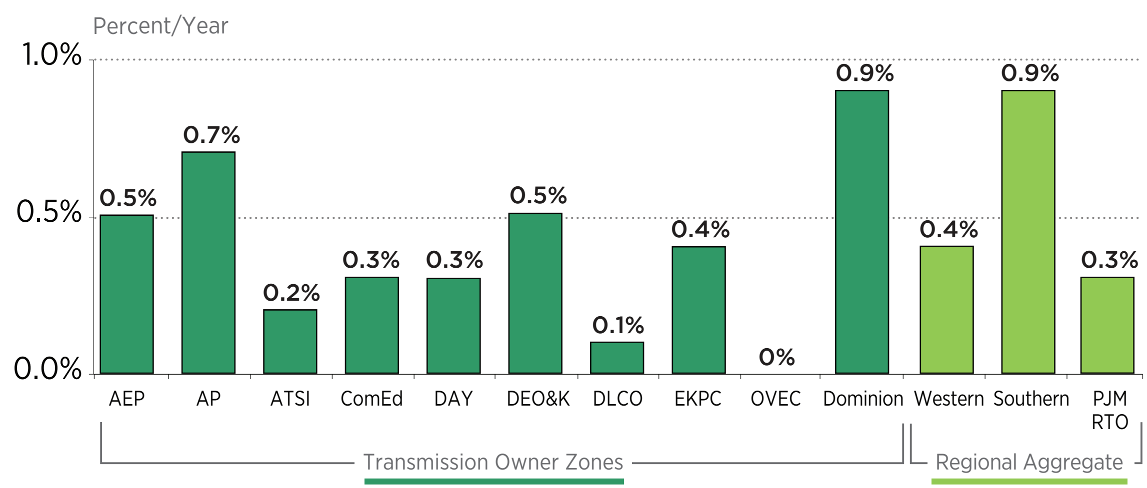


Figure 2.5: PJM Western and Southern Summer Peak Load Growth 2019 – 2029



2019 Forecast Winter Zonal Load Growth Rates

The PJM RTO weather-normalized winter peak is forecasted to grow at an average rate of 0.4 percent per year for the next 10 years. The PJM RTO winter peak is forecasted to be 136,178 MW in 2028/2029, an increase of 5,096 MW over the 2018/2019 peak of 131,082 MW. Individual geographic zone growth rates vary from -0.3 percent to 1.1 percent, as shown in **Figure 2.6** and **Figure 2.7**.

Figure 2.6: PJM Mid-Atlantic Winter Peak Load Growth 2019 – 2029

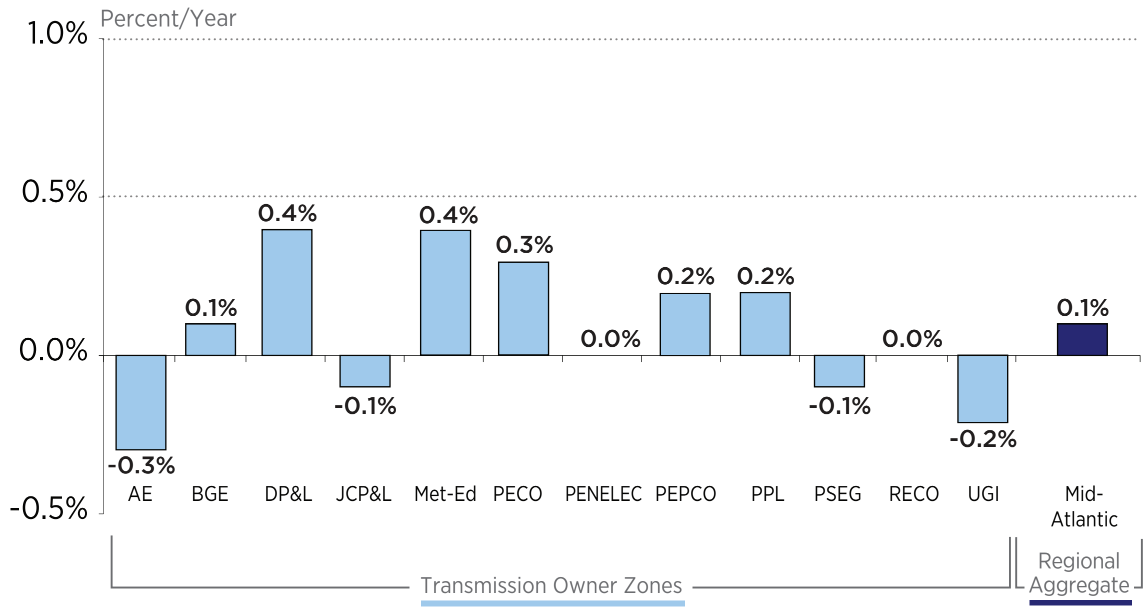
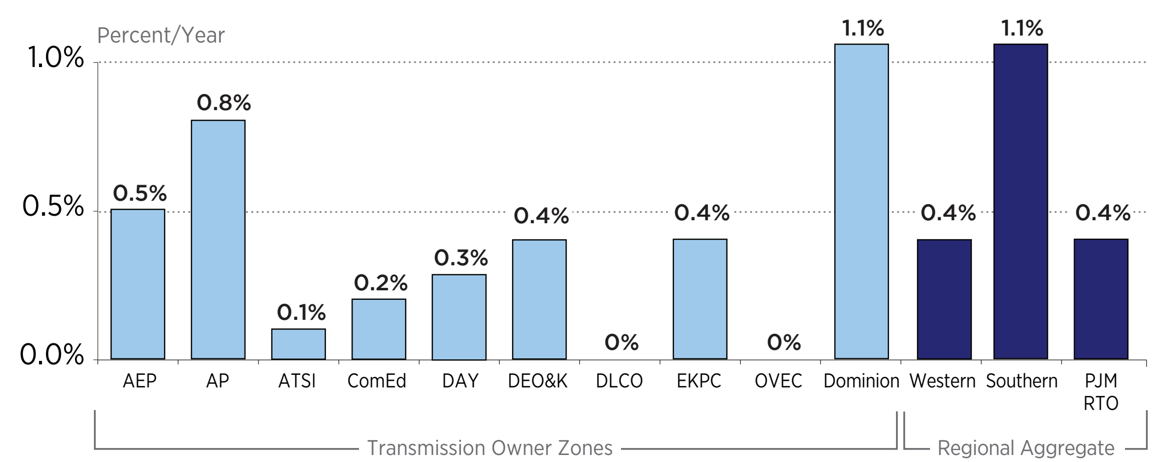


Figure 2.7: PJM Western and Southern Winter Peak Load Growth 2019 – 2029

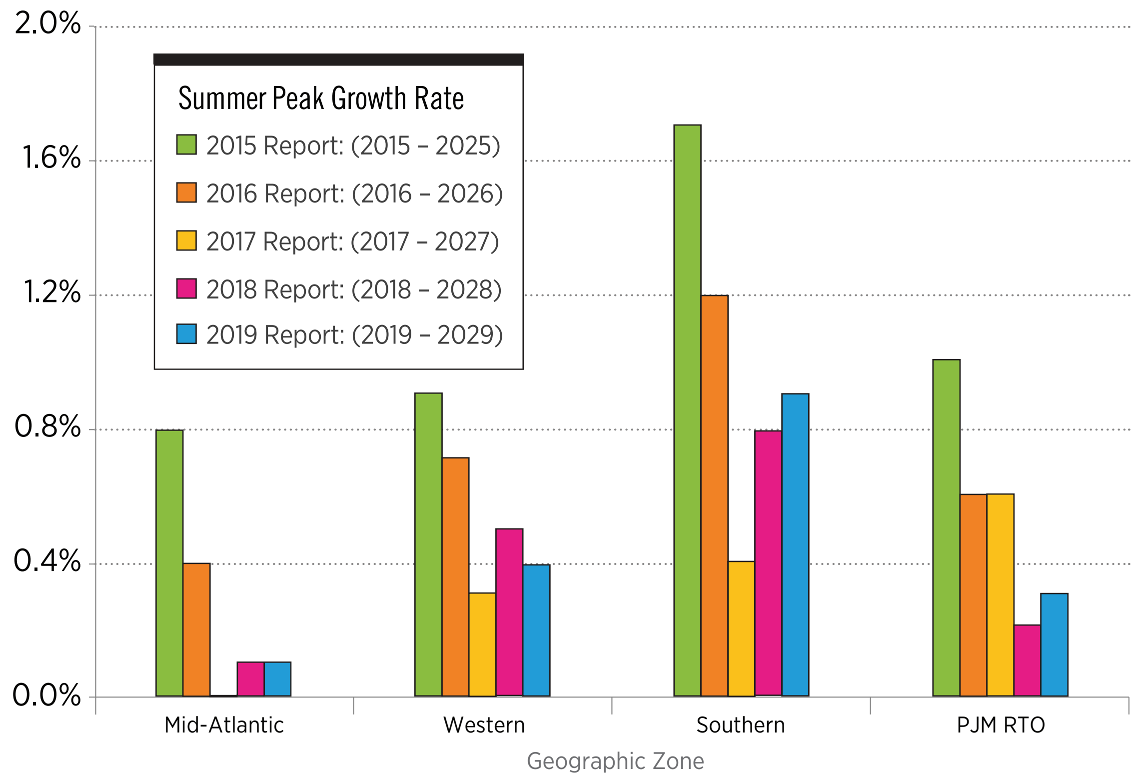


Subregional Forecast Trends

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 2015 through 2019, for the ensuing 10 years on a subregional basis. The trend reflects changes in the broader U.S. economic outlook and growing impact of energy efficiency and solar, looking forward in each of the five forecasts.

In particular, the 2019 report forecast load growth rate for the RTO decreased by 0.1 percentage points when compared to the 2018 report.

Figure 2.8: PJM 10-Year Summer Peak Load Growth Rate Comparison: 2015-2019 Load Forecast Reports



PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

2.2: Demand Resources and Peak Shaving

PJM accounts for demand resources by adjusting its base, unrestricted, peak load forecast by the amount that clears Reliability Pricing Model auctions. Those amounts, as reflected in the 2019 Load Forecast Report, are shown in **Table 2.4** for each transmission owner zone. The adjusted forecast is then used in RTEP power flow model studies that focus on summer peak capacity emergency conditions, where demand resources are assumed to be implemented. Consequently, demand resources can have a measurable impact on future system conditions and potential need for transmission system enhancements to serve load. Forecasted values for each zone are determined based on the following steps:

1. Compute the final amount of committed 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., duration, trigger, curtailed-load hourly profile), which PJM then uses to inform the load forecast. No peak shaving programs are included in this year's forecast used for the RTEP.

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:

- *Delivery year 2019:* Limited and extended summer demand resources are assumed to become base capacity demand resources. Annual demand resources are assumed to become Capacity Performance demand resources.
- *Delivery years 2020 and beyond:* Annual demand resources are assumed to become Capacity Performance demand resources and are based on actual cleared quantities of demand resource products in the 2020/2021 RPM Base Residual Auction.
- *Summer period demand resources:* Refers 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: 2019 Load Forecast Report Demand Resources

	Total Load Management	
Transmission Owner	**2019**	**2029**
Atlantic City Electric Company	106	66
Baltimore Gas and Electric Company	544	517
Delmarva Power & Light	319	288
Jersey Central Power & Light	106	144
Met-Ed	194	293
PECO Energy Company	264	392
Pennsylvania Electric Company	229	310
PPL Electric Utilities	504	596
Potomac Electric Power Company	495	436
PSEG	271	335
Rockland	2	4
UGI Utilities	0	0
Mid-Atlantic	**3,034**	**3,381**
American Electric Power	1,420	1,288
Allegheny Power	613	812
American Transmission Systems, Inc.	665	850
Commonwealth Edison Company	1,252	1,628
Dayton Power & Light	168	184
Duke Energy Corporation	180	174
Duquesne Light Company	118	136
East Kentucky Power Cooperative	128	143
Ohio Valley Electric Corporation	0	0
Western	**4,544**	**5,215**
Dominion	576	837
Southern	**576**	**837**
PJM RTO	**8,154**	**9,433**

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

2.3: Load Forecast Methodology Update

PJM is instituting several significant changes starting with the 2020 Load Forecast, aimed at providing a more accurate forecast that better aligns with ongoing load trends. These changes were implemented through significant stakeholder engagement at the Load Analysis Subcommittee and Planning Committee meetings.

Calibration

The new 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 load 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 the whole picture. 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.

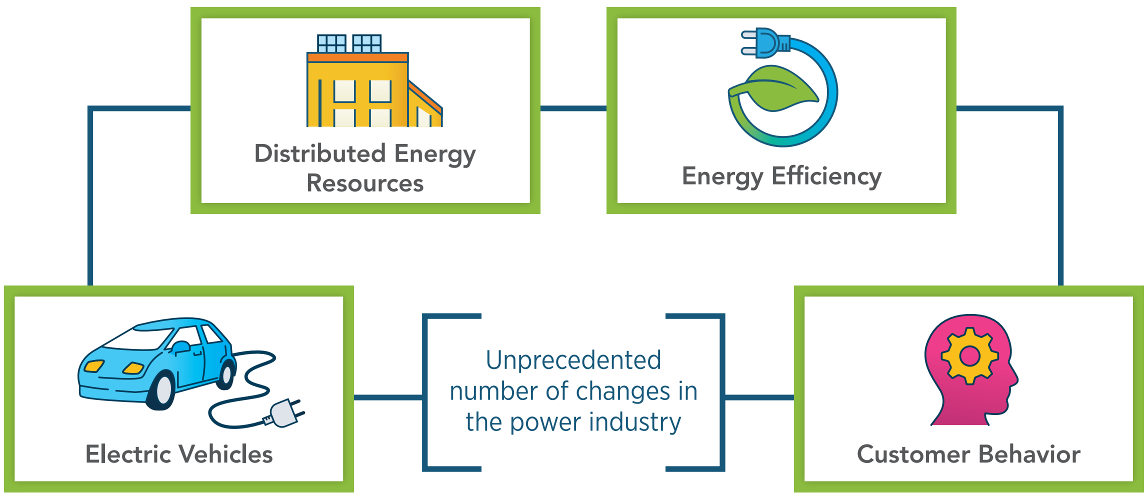
Distributed Solar Generation

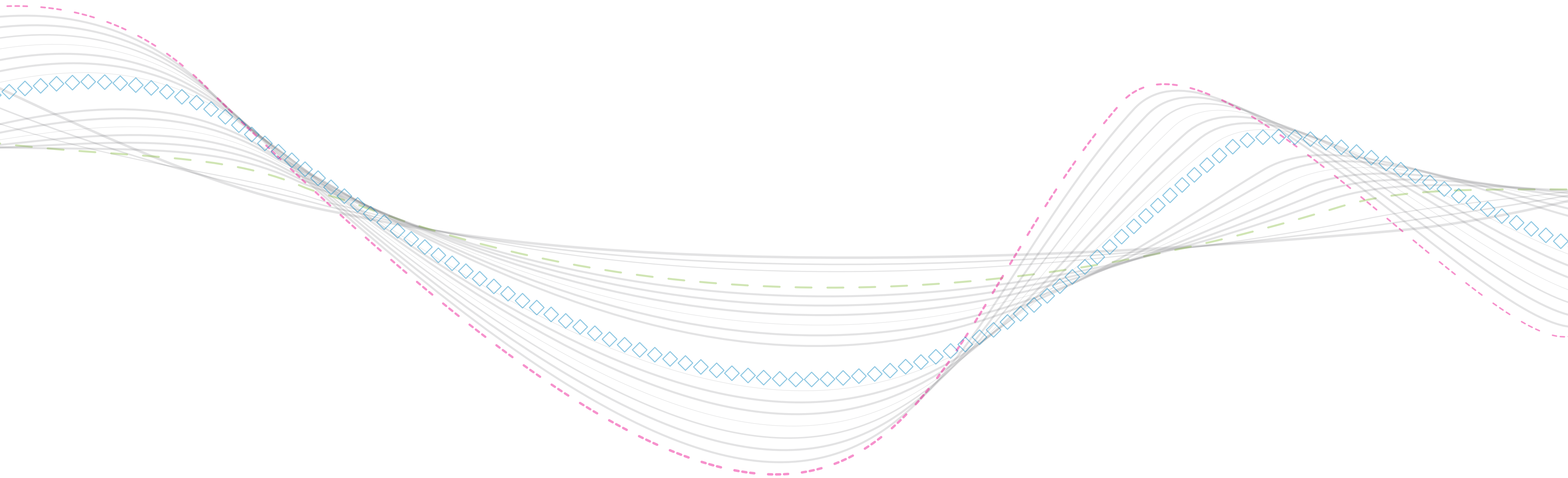
PJM is taking a more granular approach with modeling behind-the-meter solar load forecast impacts. The solar output by weather scenario varies in the same way that the weather related to the historical weather scenario in the weather simulation varies.

Plug-In Electric Vehicles

For the first time, PJM is incorporating an explicit adjustment for plug-in electric vehicle (PEV) charging in its peak and energy forecasts. PJM wants to ensure to account for PEVs to maintain reliability, as their share of overall number of vehicles on the road continues to grow.

Figure 2.9: Industry Trends





Section 3: Transmission Enhancements

3.0: 2019 RTEP Proposal Window No.1

R TEP Process Context

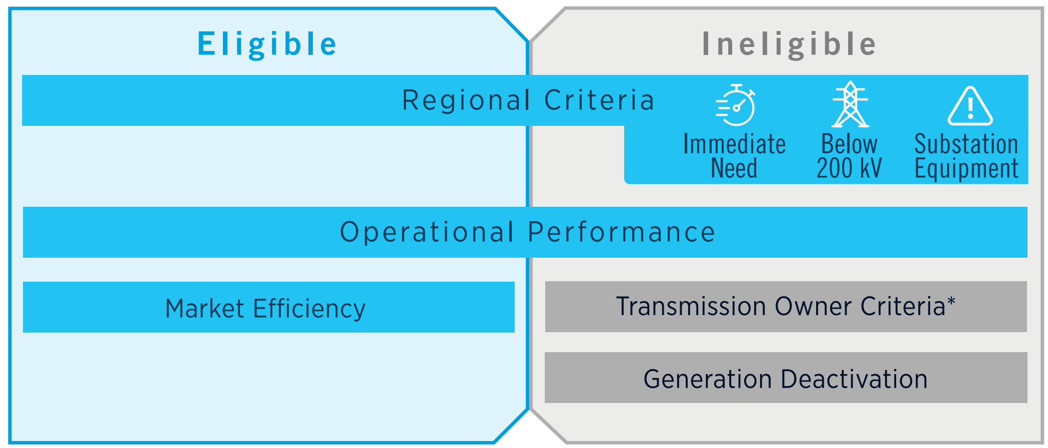
PJM seeks transmission proposals during each RTEP window to address one or more identified needs – reliability, market efficiency, operational performance and public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to PJM for consideration. Once a window closes, PJM proceeds with analytical, company, constructibility and financial evaluations to assess proposals for possible recommendation to the PJM Board. If selected, designated developers become responsible for project construction, ownership, operation, maintenance and financing.

PJM's Manual 14 series addresses the rules governing the RTEP process. In particular, Manual 14F describes PJM's competitive transmission process, including all aspects of analysis and evaluation pertaining to proposal windows. The manual provides one centralized source of business rules for stakeholders and PJM and is available on the PJM website.

Proposal Window Exemptions

The following definitions explain the basis for excluding flowgates (a combination of an overloaded facility and the event that caused the overload) and/or projects from the competitive planning process.

Figure 3.1: Window Eligibility



**Per FERC Order EL 19-61, PJM has eliminated the FERC 715 TO criteria exclusion as of Dec. 31, 2019.*

Exclusions are designated to the incumbent Transmission Owner (TO), as described in the PJM Operating Agreement, Schedule 6, Section 1.5.8.

These exemptions were developed with input from PJM stakeholders and have been approved by FERC:

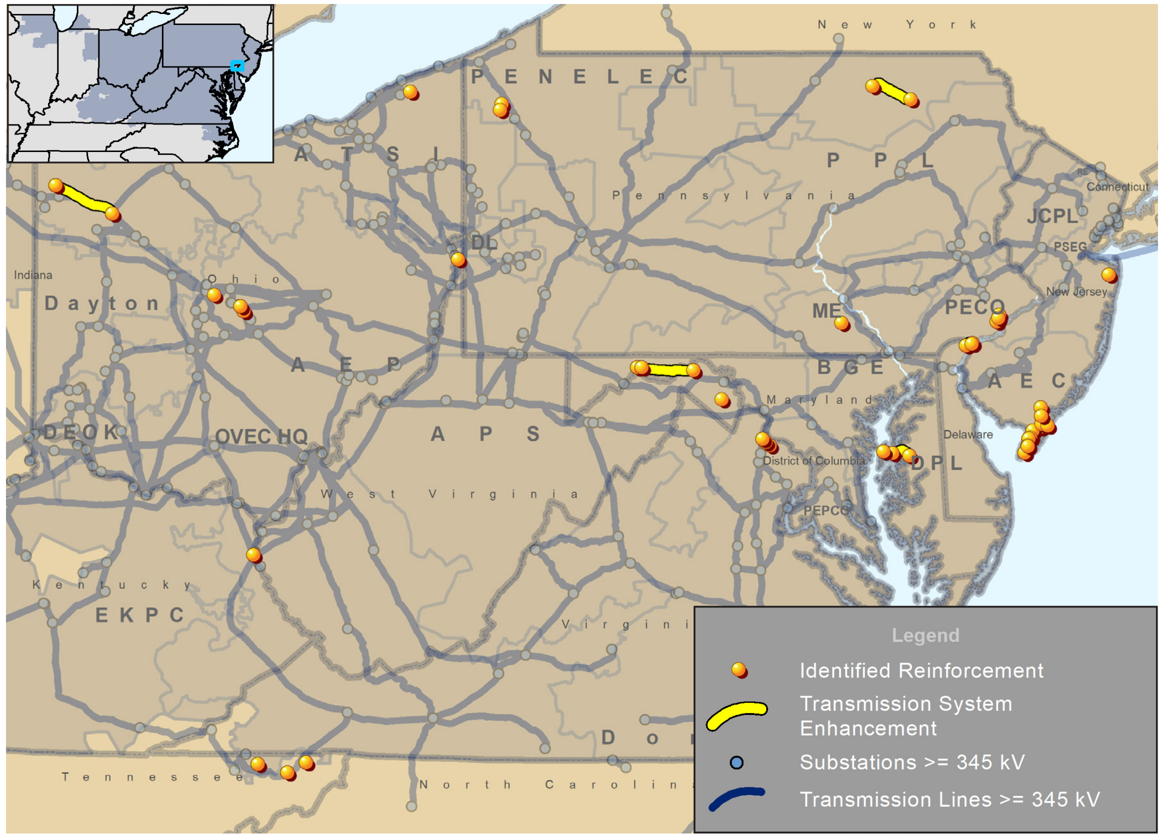
- *Immediate Need Exemption:* The required in-service date drives these projects, and they are exempted from the competitive process to ensure they can be completed in advance of the required in-service date.
- *Below 200 kV:* Given the high likelihood that the selected solution will be designated to the local TO, solutions below 200 kV are exempted from the competitive process.
- *FERC Form 715 (TO criteria):* As the need for this project results solely from the individual TO's FERC Form 715 reliability criteria, the designation is reserved for the incumbent TO.
- *Substation Equipment:* Due to identification of the limiting element(s) as substation equipment, these projects are designated to the local TO, and therefore exempted.

Proposal Window No. 1 Baseline Reliability Analysis Results

PJM's analysis of 2024 summer, winter and light load conditions identified 128 thermal and voltage criteria violations. Forty flowgates were impacted by a retool, described in **Section 3.4**.

A summary of the 128 violations is shown in **Map 3.1**.

Map 3.1: 2019 RTEP Baseline Thermal and Voltage Criteria Violations



Proposal Window No. 1 Proposals

Proposal Window No. 1 opened on July 3, 2019, and closed on Sept. 6, 2019. PJM received 15 proposals from four entities. All but one of the proposals were submitted by incumbent transmission owners. Five of the proposals included greenfield construction. The proposals are shown in **Map 3.2** and **Table 3.1**.

Subsequent power flow case retool analysis included the impact of the withdrawal of generation deactivation requests in western PJM: Davis Besse 1 (896 MW), Perry 1 (1,247 MW) and Sammis 5-7 (1,491 MW). The analysis revealed that the four flowgate violations that were the drivers for 11 of the window-submitted proposals – also in western PJM – no longer existed. Thus, those 11 proposals no longer required further evaluation.

Project No. 673

PJM evaluation of the window submittals in the DP&L zone identified Project No. 673 for recommendation to the PJM Board for approval, as summarized in **Table 3.1**, shown on the **Map 3.2** inset, and discussed at the Nov. 18, 2019, PJM Mid-Atlantic Sub Regional RTEP Committee Meeting.

Both summer and winter generation deliverability studies in the DP&L transmission zone identified a Naamans-Darley-Silver Side Rd. 69 kV line overload for the tower line outage loss of the Edge Moor-Claymont and Edge Moor-Linwood 230 kV lines. PJM evaluated the eight proposals in the DPL zone shown in **Table 3.1** to solve that reliability criteria violation and identified No. 673 as the most effective.

Map 3.2: 2019 RTEP Proposal Window No. 1 Submittals

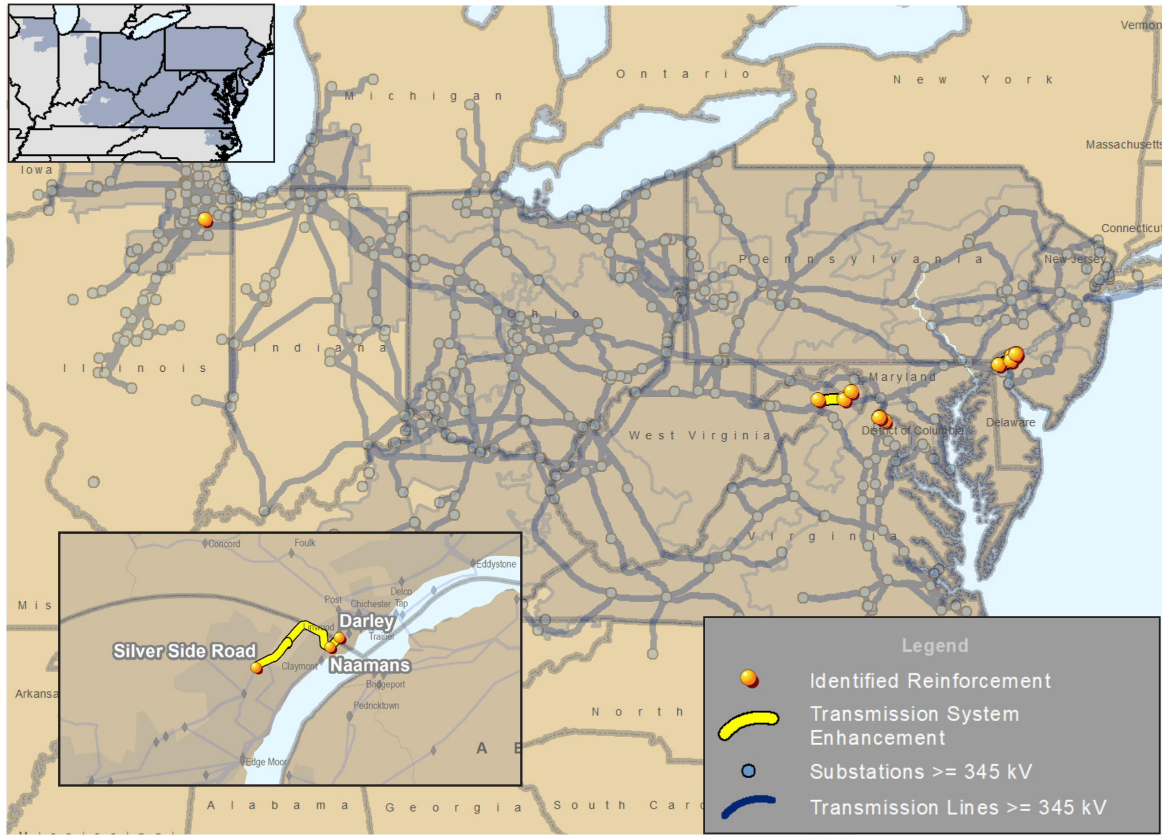


Table 3.1: 2019 RTEP Proposal Window No. 1 Proposals Submittals

PJM Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Upgrade	Cost Containment	Cost ($M)	Description
574	ComEd	765	Winter Generator Deliverability	Yes	Yes	No	$17.4	Install two 765 kV circuit breakers at Wilton Center substation and move the Collins-Wilton Center 765 kV line to a new bus position on the ring.
640	Dominion	230	Summer N-1 & N-1-1 Thermal and Gen. Deliverability	Yes	Yes	No	$7.0	Increase the maximum operating temperature of 230 kV line No. 227
800		230		Yes	Yes	No	$11.0	Reconductor 230 kV line No. 227 between Pleasant View Junction and Beaumeade, replacing the 1192.5 ACSS 45/7 conductor and the 1590 ACSR 45/7 conductor at Ashburn.
418		230		Yes	Yes	No	$13.9	Rebuild 230 kV line No. 227 by rebuilding the line between Cochran Mill DP-Pleasant View Junction and reconductoring between Pleasant View Junction-Beaumeade and Cochran Mill DP-Belmont.
174	DP&L	69	Summer/ Winter Generator Deliverability	Yes	No	No	$17.0	Construct a new 69 kV line between Edge Moor and Claymont substation. Create a new terminal position at Edge Moor substation and utilize an open terminal position at Claymont substation.
36		230		Yes	No	No	$36.6	Construct new 230 kV line from Edge Moor substation to new substations near Linwood substation (PECO). New substation will tie in to the Chichester-Linwood 230 kV line (PECO).
522		230		Yes	No	No	$37.9	Construct new 230 kV line from Edge Moor to Chichester substation and perform associated upgrades at substations to accommodate the new line.
839		230		Yes	No	No	$71.0	Construct new 230 kV line from Harmony to Chichester substation and perform associated upgrades at substations to accommodate the new line.
626		69		Yes	Yes	No	$1.0	Install a series reactor on the Silverside-Darley line.
820		69		Yes	Yes	No	$2.0	Install a SmartWire device in series with the Silverside-Darley line.
673		69		Yes	Yes	No	$5.5	Replace terminal equipment and implement reconductoring of the Silverside-Darley and Darley-Naamans lines to achieve ratings of 232 MVA normal and 239 MVA emergency (Silverside-Darley) and 174 MVA normal and 194 MVA emergency (Darley-Naamans).
637		230		Yes	Yes	No	$69.0	Construct new 230 kV line from Harmony substation to a new substation near Linwood Substation (PECO). The new substation will tie in to the Chichester-Linwood 230 kV line (PECO).
788	APS	500/ 138	Summer/Winter N-1-1 Voltage	No	No	Yes	$34.779	Build a greenfield 500/138 kV station (Woodside) cutting in Doubs-Bismark 500 kV circuit on the high side and Stonewall-Feagan's Mill and Stonewall-Inwood 138 kV circuits on the low side, with a 500/138 kV step-down transformer.
702		138		Yes	Yes	No	$13.298	Reconfigure Stonewall 138 kV substation from its current configuration to a six-breaker breaker-and-a-half layout and add two 36 MVAR capacitors with capacitor switchers.
620		138		Yes	Yes	No	$15.111	Reconfigure Hampshire 138 kV switching station from its current configuration to a 138 kV networked ring bus station. Install a 34.6 MVAR capacitor at Inwood 138 kV substation.

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

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 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. PJM applies TO criteria to all facilities included in the PJM Open Access Transmission Tariff (OATT) facility list.

Transmission enhancements driven by TO criteria are considered RTEP baseline projects. Projects are assigned to the incumbent TO and are not eligible for proposal window consideration as shown in **Figure 3.1**. Under the terms of the OATT, the costs of such projects are allocated 100 percent to the incumbent TO zone. The description and location of those projects with an estimated cost of $10 million or greater are shown in **Table 3.2** and **Map 3.3**. More detailed descriptions of these projects can be found in the TEAC PJM Board White Paper.

In situations where the TO is not able to complete construction by the required in-service date, PJM works to establish operating procedures to ensure that the system remains reliable until the reinforcement is in service.

3.1.2 — Aging Infrastructure

In recent years, TO reviews of existing infrastructure have identified the need to replace equipment and structures due to aging. Many 500 kV lines were constructed in the 1960s; 230 kV and 115 kV lines date to the 1950s and earlier. Some TOs have added aging infrastructure to their planning criteria as part of their respective FERC Form 715 filings. Planning for aging infrastructure is not new to PJM. Spare 500/230 kV transformers, 500 kV line rebuilds and a number of other transmission enhancements to mitigate potential equipment failure risk are already an important part of PJM's RTEP. The PJM Operating Agreement specifies that TO planning criteria are to be evaluated as a part of the RTEP process.

Dominion and PSEG have specific FERC Form 715 criteria to address end-of-life, as described in **Section 3.1.3** and **Section 3.1.4**.

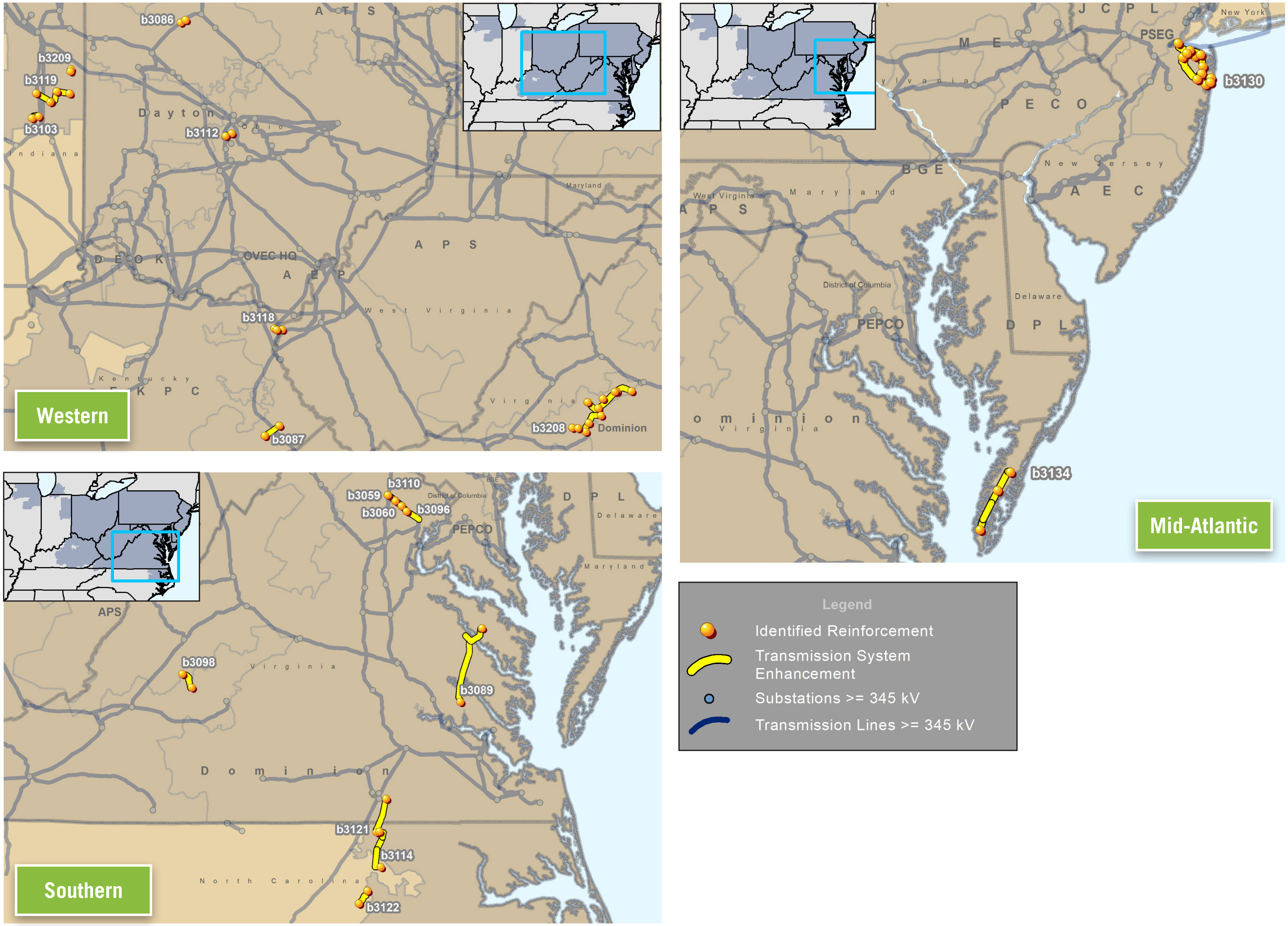
NOTE:

Per FERC Order EL19-61, PJM has eliminated the FERC Form 715 transmission owner criteria exclusion from the competitive proposal windows as of Jan. 1, 2020.

Table 3.2: Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million)

Upgrade ID	Description	TO Zone	Estimated Cost ($M)	Required In-Service	Projected In-service
B3059	Rebuild Loudoun-Elk Lick 230 kV line.	Dominion	$13.50	12/31/2022	12/31/2021
B3060	Rebuild the 4.6 mile Elk Lick-Bull Run 230 kV line No. 295 and 3.85 miles of the Clifton-Walney 230 kV line No. 265.	Dominion	$15.50	10/30/2018	12/31/2022
B3086	Rebuild 1.5 miles of the New Liberty-Findlay 34 kV line.	AEP	$13.02	6/1/2022	12/31/2021
B3087	Replace the Fords Branch substation with a new 138/34.5 kV substation consisting of two 30 MVA transformers and a four breaker ring bus.	AEP	$23.80	12/1/2018	9/30/2022
B3089	Rebuild 230 kV line No. 224 between Lanexa and Northern Neck with double circuit structures.	Dominion	$86.00	6/1/2018	12/31/2023
B3096	Rebuild Clifton-Ox 230 kV line No. 2063 and part of Clifton-Keene Mill line No. 2164 with double circuit steel structures.	Dominion	$22.00	6/1/2019	12/31/2024
B3098	Rebuild 9.8 miles of 115 kV line No. 141 between Balcony Falls and Skimmer and 3.8 miles of 115 kV line between Balcony Falls and Cushaw.	Dominion	$20.00	6/1/2019	12/31/2023
B3103	Install a 138/69 kV transformer at Royerton station. Install a 69 kV bus with one 69 kV breaker toward Bosman station. Rebuild the 138 kV portion into a ring bus configuration built for future breaker-and-a-half with four 138 kV breakers.	AEP	$70.75	6/1/2022	6/1/2022
B3110	Rebuild 230 kV line No. 2008 between Loudoun and Dulles Junction. Loop Clifton-Sully 230 kV line No. 265 into Bull Run substation and install three 230 kV breakers.	Dominion	$14.54	6/1/2019	12/31/2021
B3112	Build 3.5 miles of 138 kV line from Amlin to Dublin, convert Dublin station into a ring configuration, and re-terminate the Britton underground cable at Dublin station.	AEP	$39.29	6/1/2020	12/9/2021
B3114	Rebuild 18.6 miles of 115 kV line, including 1.7 miles of double circuit, with 230 kV line No. 2056.	Dominion	$25.00	6/1/2019	12/31/2025
B3118	Expand Chadwick substation by installing a second 138/69 kV transformer, building a new 138 kV bus and rebuilding the 69 kV bus into a four breaker ring.	AEP	$16.90	6/1/2022	10/1/2020
B3119	Rebuild the Jay-Pennville 138 kV line as double circuit 138/69 kV and build 9.8 miles of new single circuit 69 kV line from Pennville to North Portland substations.	AEP	$43.40	6/1/2022	6/1/2022
B3121	Rebuild Clubhouse-Lakeview 230 kV line No. 254.	Dominion	$27.00	6/1/2019	12/31/2024
B3122	Rebuild Hathaway-Rocky Mount (Duke Energy Progress) 230 kV line No. 2181 and line No. 2058 with double circuit steel structures.	Dominion	$13.00	6/1/2019	12/31/2024
B3130	Build 53.5 miles of 34.5 kV line creating seven new circuits; rebuild 5.5 miles of 34.5 kV line, consisting of two circuits; and install a second 115/34.5 kV transformer at Werner substation.	JCP&L	$175.00	6/1/2016	12/1/2025
B3134	Build 21 miles of 69 kV line from Kellam to the new Bayview substation and build a line terminal at Belle Haven delivery point	ODEC	$22.00	6/1/2019	6/1/2020
B3208	Retire ~38 miles of the Clifford-Scottsville 46 kV line. Build a new 138 kV line to two new distribution substations. Build 15 miles of 138 kV line between Joshua Falls, Riverville and Gladstone substations. Upgrade substations to accomodate the new 138 kV lines. Rebuild the fourmile Reusen-Monroe 69 kV line.	AEP	$85.00	12/1/2022	12/1/2022
B3209	Rebuild the 10.5 mile Berne-South Decatur 69 kV line.	AEP	$16.60	6/1/2022	6/1/2022

Map 3.3: Western, Mid-Atlantic and Southern Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million)



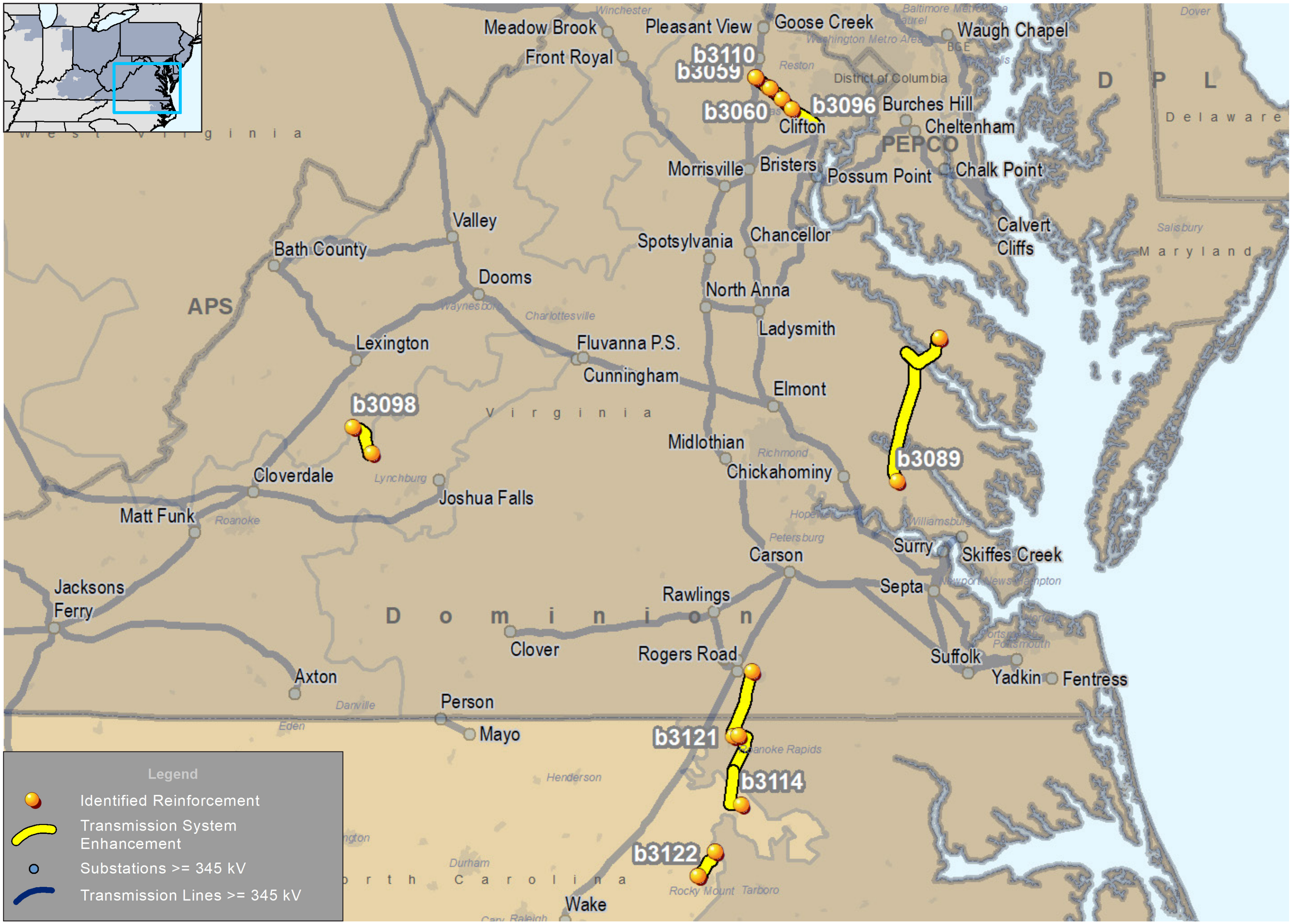
3.1.3 — Dominion End-of-Life Criteria

Several facilities in the Dominion transmission zone have been identified as violating their FERC Form 715 filed end-of-life criteria. In accordance with Section C.2.9 of Dominion's transmission planning criteria, age, condition and tower weakening were all identified as issues with a number of facilities. **Table 3.3** and **Map 3.4** describe and show the location of those facilities with a project upgrade cost estimate greater than or equal to $10 million.

Table 3.3: Dominion Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million)

Upgrade ID	Description	TO Zone	Cost ($M)	Required In-Service	Projected In-service
B3059	Rebuild 230 kV line No. 2173 from Loudoun to Elk Lick.	Dominion	$13.50	12/31/2022	12/31/2021
B3060	Rebuild the 4.6 mile Elk Lick-Bull Run 230 kV line No. 295 and 3.85 miles of the Clifton-Walney 230 kV line No. 265.	Dominion	$15.50	10/30/2018	12/31/2022
B3089	Rebuild 230 kV line No. 224 between Lanexa and Northern Neck with double circuit structures	Dominion	$86.00	6/1/2018	12/31/2023
B3096	Rebuild Clifton-Ox 230 kV line No. 2063 and part of Clifton-Keene Mill line No. 2164 with double circuit steel structures	Dominion	$22.00	6/1/2019	12/31/2024
B3098	Rebuild 9.8 miles of 115 kV line No. 141 between Balcony Falls and Skimmer and 3.8 miles of 115 kV line No. 28 between Balcony Falls and Cushaw.	Dominion	$20.00	6/1/2019	12/31/2023
B3110	Rebuild 230 kV line No. 2008 between Loudoun and Dulles Junction. Loop Clifton-Sully 230 kV line No. 265 into Bull Run substation and install three 230 kV breakers.	Dominion	$14.54	6/1/2019	12/31/2021
B3114	Rebuild 18.6 miles of 115 kV line No. 81, including 1.7 miles double circuit, with 230 kV line No. 2056.	Dominion	$25.00	6/1/2019	12/31/2025
B3121	Rebuild Clubhouse-Lakeview 230 kV line No. 254.	Dominion	$27.00	6/1/2019	12/31/2024
B3122	Rebuild Hathaway-Rocky Mount (Duke Energy Progress) 230 kV line No. 2181 and line No. 2058 with double circuit steel structures.	Dominion	$13.00	6/1/2019	12/31/2024

Map 3.4: Dominion Transmission Owner End-of-Life Criteria Projects (Greater Than or Equal to $10 Million)

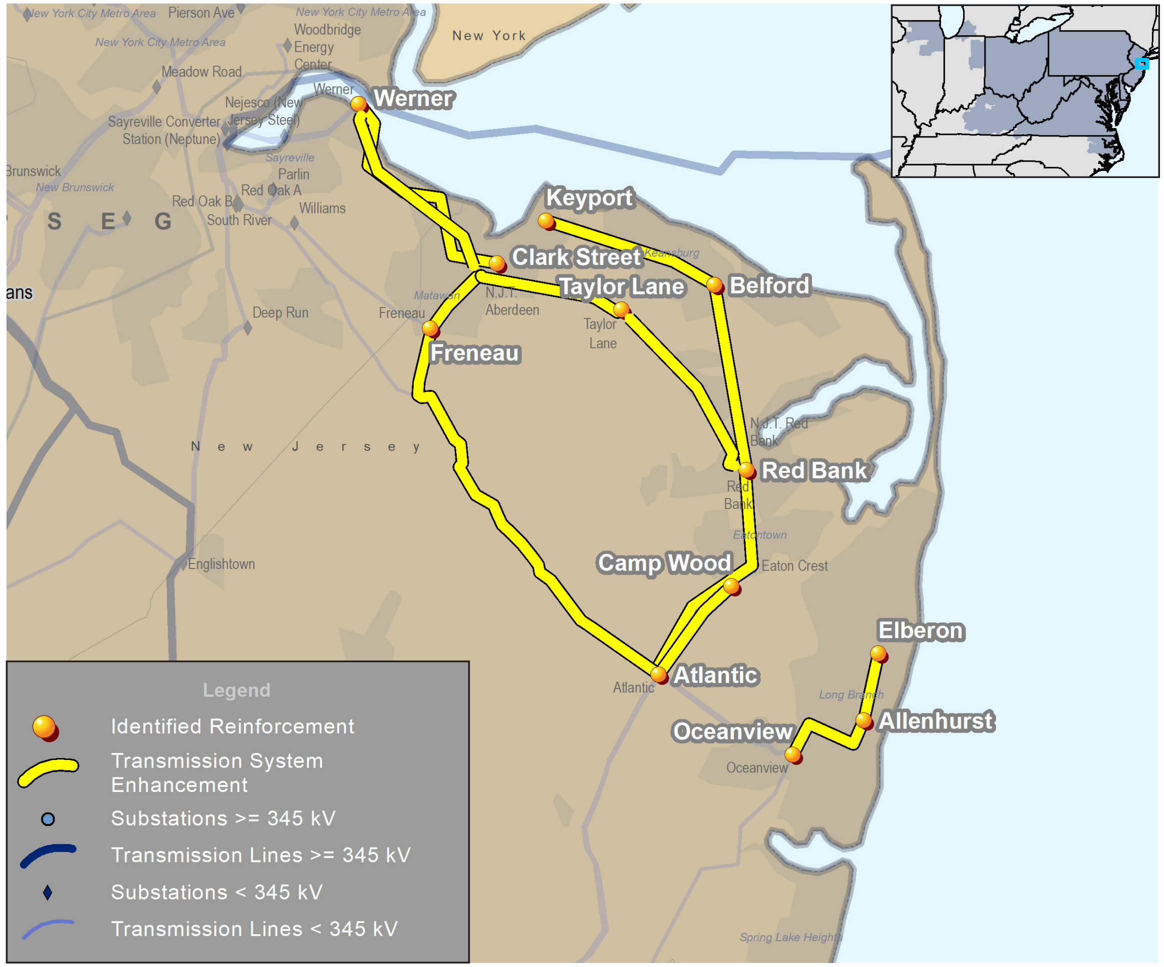


3.1.4 — Monmouth County Reliability Project in JCP&L

The Monmouth County Reliability Project was initially proposed in September 2011. Driving the upgrade was the potential collapse of the 34.5 kV system in Monmouth County due to the loss of both Atlantic-Red Bank 230 kV lines. The PJM Board approved the upgrade in October 2012 as baseline B1690: Project building a third 230 kV line along the existing right of way. As the design progressed, the cost and complexity of the project escalated due to changes in the route, site conditions and public policy requirements. In the second quarter of 2018, the New Jersey Board of Public Utilities denied the siting permit for the project. Subsequently, PJM and FirstEnergy studies confirmed that the reliability issues remained valid and began working collaboratively to develop alternative solutions. FirstEnergy met with federal, state and local stakeholders during the second and third quarters of 2019 to discuss these alternatives.

A consensus solution was presented at the August 2019 TEAC meeting. The new approach includes building 53.5 miles of new 34.5 kV line, rebuilding 5.5 miles of 34.5 kV line and installing a second 115/34.5 kV transformer at Werner substation. In October, the PJM Board approved the alternate solution as Baseline Project B3130. **Map 3.5** shows the location of new and upgraded facilities.

Map 3.5: Monmouth County Reliability Project Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million)



3.2: Supplemental Projects

Supplemental projects are not required for compliance with system reliability, operational performance or market efficiency economic criteria, as determined by PJM. They are 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 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.

While not subject to PJM Board approval, supplemental projects are included in PJM's RTEP models. FERC-approved Attachment M-3 of the PJM Tariff provides additional procedures that PJM and TOs follow for supplemental projects. PJM, in its role as a facilitator in the Attachment M3 process, is responsible for the following:

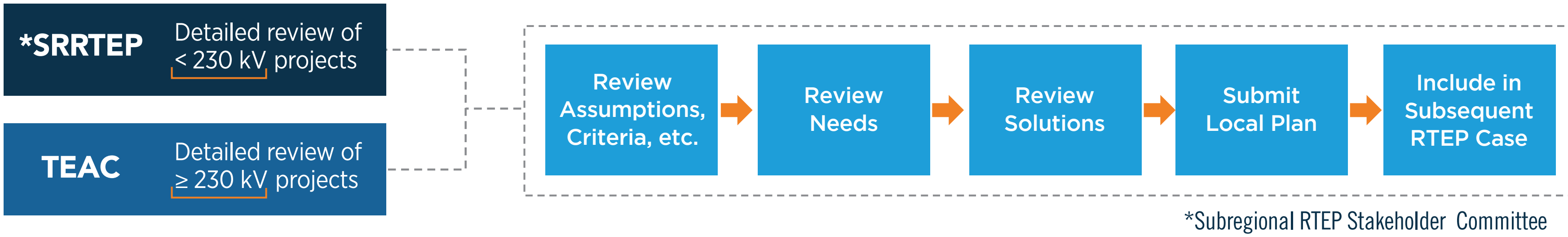
- *Provide necessary facilitation and logistical support* so that supplemental project planning meetings can be conducted as outlined in Attachment M-3 of the PJM Tariff.
- *Provide the applicable TO with modeling information* so that TOs can determine if a stakeholder-proposed project can address a 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 transmission owners and stakeholders to improve Attachment M3 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; 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 geo-magnetic disturbances.
Other	Meet objectives not included in other definitions such as, but not limited to, technological pilots, industry recommendations, environmental and saftey impacts, etc.

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 M3 process.

Figure 3.3: Attachment M3 Process for Supplemental Projects

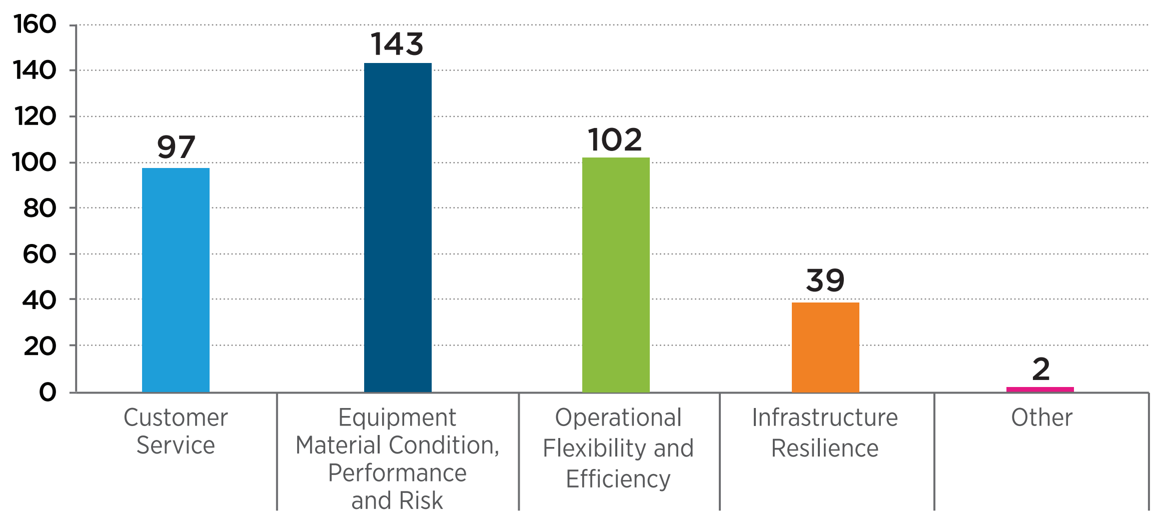


The M3 process leverages PJM's TEAC and subregional RTEP committees, which provides stakeholders a meaningful opportunity to participate and provide feedback, including written comments, throughout the transmission planning process for supplemental projects, as shown in **Figure 3.3**.

2019 Supplemental Projects

PJM evaluated approximately $3.5 billion of TO supplemental projects in 2019. **Figure 3.4** shows a breakdown of supplemental projects by driver over the past year and suggests that the largest driver is equipment material condition, performance and risk. In 2019, projects driven solely by equipment material condition, performance and risk add up to a total of $1.5 billion, while projects driven by customer service requests totaled approximately $940 million and $151 million respectively.

Figure 3.4: 2019 Supplemental Projects by Driver



PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

3.3: Generator Deactivations

PJM received 36 deactivation notices, including new requests and revisions to existing requests, totaling 7,650 MW during 2019. **Map 3.6** and **Table 3.4** show the 11 generators being deactivated with a capacity greater than or equal to 100 MW. The remaining 25 generators had a combined capacity of 900 MW. Deactivation notifications in 2019 included 12 coal unit deactivations for a total of 2,750 MW. PJM completed the required analysis to identify reliability criteria violations caused by deactivations. New baseline upgrades were required for several deactivations.

Other violations were solved with existing baseline transmission enhancements or had no reliability impacts identified. All units studied in 2019 can retire as requested; operational flexibility will allow PJM to bridge any delays with the completion of required transmission enhancements. On July 29, 2019, PJM received reinstatement notifications from FirstEnergy for the Davis Besse 1, Perry 1 and Sammis 5, 6 and 7 units totaling over 3,600 MW. These units will not be deactivating.

Map 3.6: Deactivations Notifications in 2019 Greater Than or Equal to 100 MW

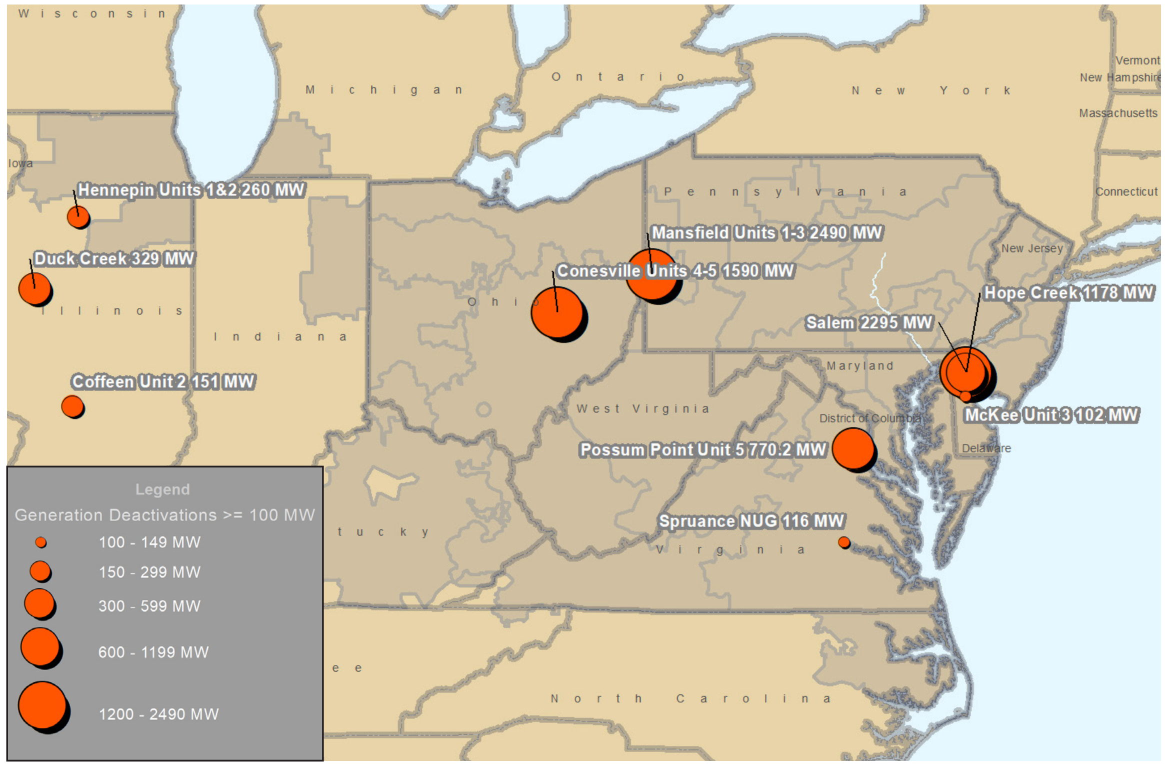


Table 3.4: PJM Generator Deactivations Greater Than or Equal to 100 MW Received Jan. 1, 2019 through Dec. 31, 2019

Unit	Capacity (MW)	TO Zone	Age	Fuel Type	Request Submittal Date	Actual or Projected Deactivation Date	Date Deactivation Request Withdrawn
Hennepin Power Station 2	200	MISO*	60	Coal	8/21/2019	10/29/2019	
Duck Creek 1	329	MISO*	43	Coal	8/21/2019	12/15/2019	
Coffeen 2	151	MISO*	47	Coal	8/21/2019	10/17/2019	
Salem 2	1,142	PSEG	38	Nuclear	4/16/2019	4/1/2020	4/19/2019
Salem 1	1153	PSEG	42	Nuclear	4/16/2019	10/1/2020	4/19/2019
Hope Creek 1	1,178	PSEG	33	Nuclear	4/16/2019	10/1/2019	4/19/2019
Possum Point 5	770	Dominion	29	Oil	3/27/2019	5/31/2021	
McKee 3	102	DP&L	44	Natural Gas	3/8/2019	6/1/2021	
Conesville 4	780	AEP	46	Coal	1/23/2019	6/1/2020	
Mansfield 3	830	ATSI	38	Coal	8/9/2019	11/7/2019	
Spruance NUG 1	116	Dominion	25	Coal	11/25/2019	1/12/2021	

*Consistent with established practices, PJM studies generator deactivations outside of PJM's footprint when they may have an impact on PJM facilities

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

3.4: 2019 Re-Evaluations

As part of each RTEP cycle, PJM evaluates how changing input assumptions impacts the results of analysis. Individual generator or load modeling changes are studied as a sensitivity to understand their impact to the transmission system. But, when a large set of input assumptions change, a full re-evaluation of these changing impact assumptions is required. This re-evaluation, known as a retool, allows for assumptions to be updated in the model used for analysis, and re-analyzed to understand their impacts.

As part of the 2019 RTEP, PJM performed a retool of the 2024 RTEP analysis, driven by the withdrawn deactivation of the Davis Besse 1, Perry 1 and Sammis 5, 6 and 7 units shown in **Map 3.7**, which had previously announced their intent to deactivate. This retool led to the cancellation of several baseline upgrades, previously identified for these units to deactivate without creating reliability criteria violations.

Additionally, retool analysis eliminated 40 flowgates identified in the 2019 Proposal Window No. 1, discussed in **Section 3.0**. Several other baseline upgrades are still required for other deactivations in these areas. A detailed description of the withdrawn deactivation analysis can be found on the PJM website.

Map 3.7: Withdrawn Deactivations Greater Than or Equal to 100 MW

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

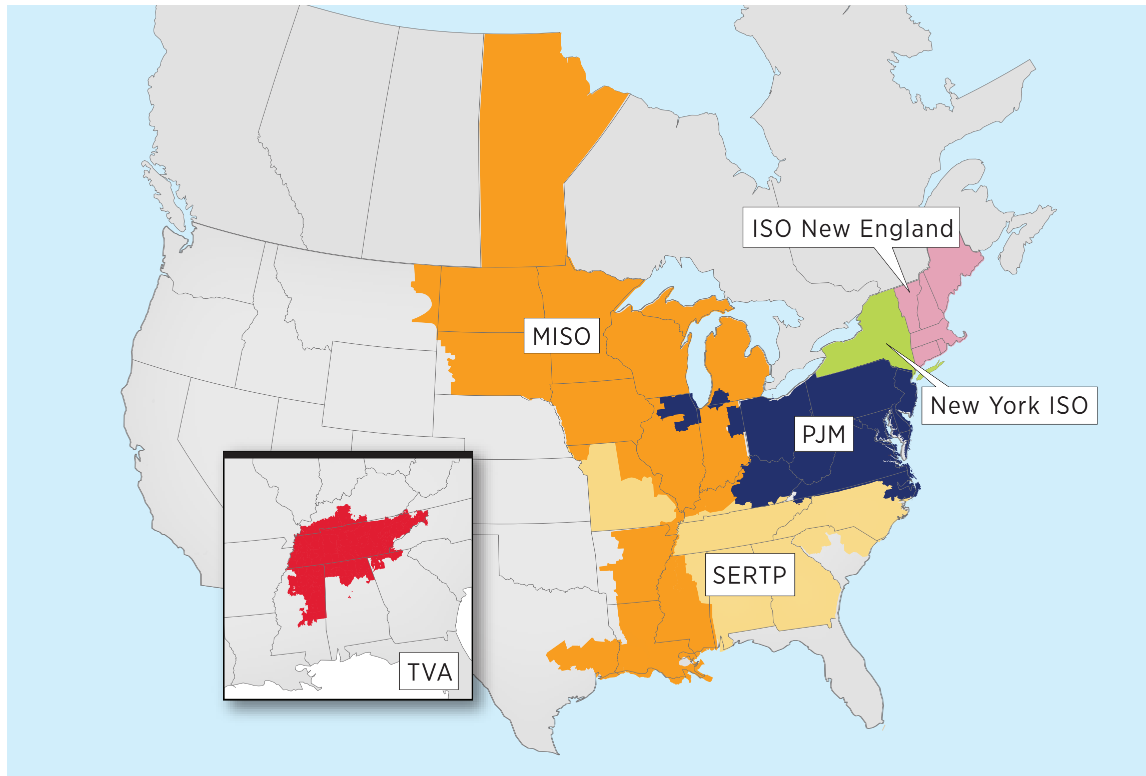
3.5: Interregional Planning

3.5.1 — Adjoining Systems

PJM's interregional planning activities continue to foster increased interregional coordination. The nature of these activities include 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 the Southeastern Regional Transmission Planning (SERTP), shown on **Map 3.8**.

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

Map 3.8: PJM Interregional Planning



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 queued generator 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

Each study is conducted in accordance with the PJM Tariff and respective interregional agreement. 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 and 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 2019 planning efforts under Article IX of the MISO/PJM joint operating agreement 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 3.4**. Throughout the year, stakeholder input and feedback to the interregional planning process were coordinated through the MISO/PJM Interregional Planning Stakeholder Advisory Committee (IPSAC).

Following the Annual Issues Review in the first quarter of 2019, PJM and MISO confirmed their commitment to complete a long-term Interregional Market Efficiency Project (IMEP) study, which began in mid-2018. Additionally, the interregional planning process sought to identify interregional reliability projects that were more efficient or cost effective than the alternative regional plans. No drivers for a potential interregional reliability project were identified in 2019.

Based on the annual issues review and stakeholder feedback, no significant drivers for other interregional studies were identified. No other interregional studies were conducted under the Coordinated System Plan (CSP) in 2019.

3.5.3 — PJM/MISO Interregional Market Efficiency Study

Periodically, the Joint RTO Planning Committee (JRPC), with input from IPSAC, may elect to perform a longer-term CSP study. After review of each RTO's transmission issues and regional solutions, the JRPC initiated a two-year IMEP study in 2018. This follows the CSP study process, including close coordination with PJM and MISO regional market efficiency analyses. For more information on PJM's regional market efficiency process, see **Section 4**.

During 2018, PJM and MISO each developed regional market analysis models to project future system conditions and identify eligible congestion drivers. PJM identified five eligible congestion drivers near the MISO seam. Of these, three were also identified by MISO as MISO regional constraints. Interregional market efficiency proposals were solicited through an open competitive window, which closed on March 15, 2019. Through the proposal window, PJM and MISO received ten eligible interregional proposals addressing at least one of the three mutually identified congestion drivers.

Throughout 2019, PJM & MISO worked closely together to review and evaluate these proposals. Consistent with currently effective interregional agreements, benefit determination was calculated independently by each region, following their unique regional process. PJM and MISO calculated their regional benefits and exchanged this information to determine the total project benefit. Based on the regional analysis and the total benefit to cost ratio, one interregional project was recommended by both RTOs. The Bosserman-Trail Creek project will address persistent historical congestion projected to continue on the NIPSCO/AEP seam.

Following review with the PJM TEAC and MISO PAC, the project was recommended for PJM and MISO board approval. See **Section 4.4** for full details on the Bosserman-Trail Creek project.

The Bosserman-Trail Creek project was approved by the PJM Board in December 2019, conditionally on MISO approval of the same project. MISO has not completed final approval of the project due to pending filings at FERC regarding regional cost allocation for interregional projects under 345 kV. Assuming a positive outcome from FERC, PJM expects MISO's final approval of this project in the first quarter of 2020.

3.5.4 — JOA Article 9 Revisions

In 2019, stakeholders at the IPSAC endorsed further changes to Article 9 of the Joint Operating Agreement. These changes centered on the cleanup of language which referred to a "joint model" no longer required following a 2016 FERC compliance directive. Additional changes removing the distribution factor threshold for interregional projects were also endorsed. Interregional projects must still meet the regional criteria of both PJM and MISO, but there will be no separate qualifying criteria in the JOA. These changes eliminate unnecessary burdens and increase the opportunities for development of beneficial interregional projects. The filing was made in October and was accepted by FERC in December 2019.

3.5.5 — New York ISO and ISO New England

PJM planning activities on its northern seam are conducted under the auspices of the Northeastern ISO/RTO Planning Coordination Protocol, a three-party agreement between PJM, NYISO and ISO-NE. Activities in 2019 were conducted in accordance with the protocol and ensured compliance with the provisions of FERC Order 1000. Stakeholder input continues to be coordinated through the activities of the IPSAC.

During 2019, PJM continued interconnection and transmission service coordination, data exchange and economic data updates necessary to complete the 2019 Northeast Coordinated System Plan (NCSP). This biennial report summarizes interregional planning activities, identified system needs and plans for meeting those needs.

PJM/NYISO/ISO-NE IPSAC review of regional analyses and transmission plans completed in 2019 did not identify any opportunities to pursue interregional transmission projects. Coordination activities will continue in 2020 as well as work on the 2019 NCSP, with a target to publish a draft document in the first quarter of 2020, and a final version in the first quarter of 2020.

3.5.6 — Adjoining Systems South of PJM

Interregional planning activities with entities south of PJM are conducted mainly under the auspices of the SERTP and SERC.

Southeastern Regional Transmission Planning

PJM and the SERTP, shown earlier on **Map 3.8**, continued interregional data exchange and interregional coordination during 2019. SERTP membership includes several entities under FERC jurisdiction and voluntary participation among six non-jurisdictional entities. The jurisdictional entities include Southern Company, Duke Energy (including Duke Energy Carolinas and Duke Energy Progress) and LGE/KU. Duke Energy, LGE/KU is directly connected to PJM. Of the non-jurisdictional entities, only TVA is directly connected to PJM. The remaining five SERTP participants are planning areas south and west of Duke Energy and TVA.

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

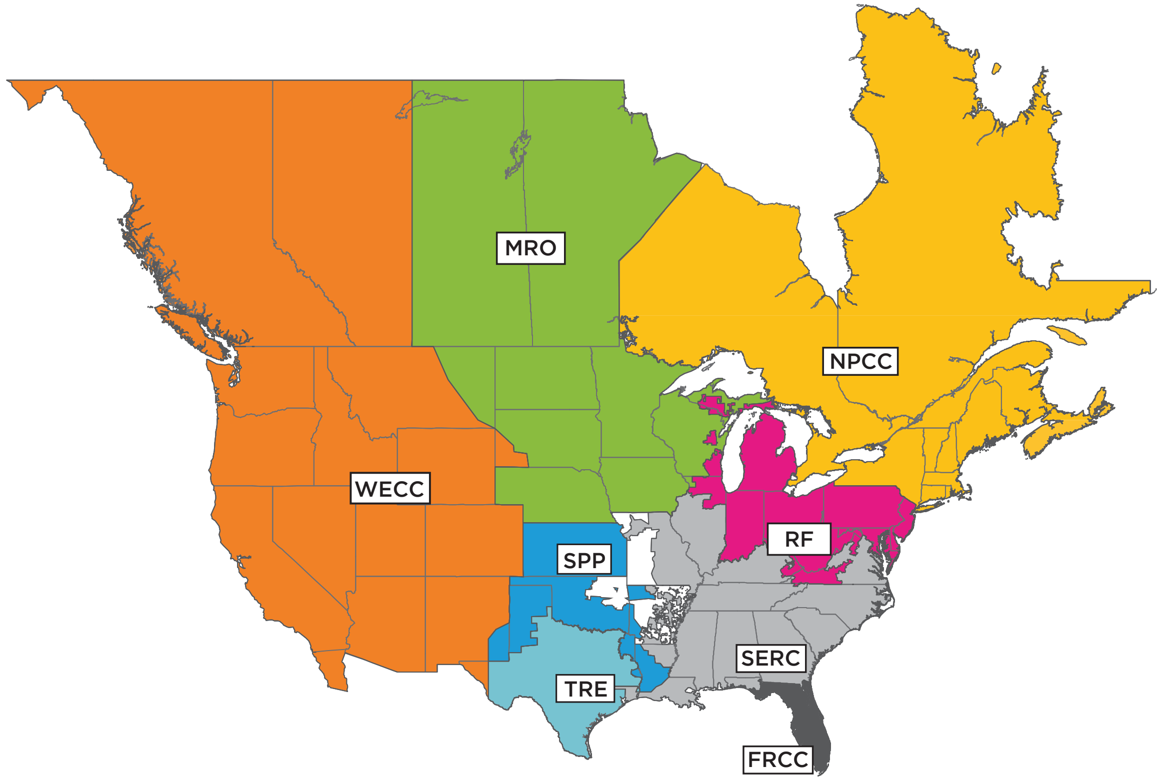
SERC Activities

PJM continues to support its members that are located within SERC – shown on **Map 3.9**. That support includes active participation in the Planning Coordination Subcommittee, the Long-Term Working Group, the Dynamics Working Group, the Short-Circuit Database Working Group, the Resource Adequacy Working Group and the Near-Term Working Group.

PJM actively contributed to SERC committee and working group activities to coordinate 2019 model development and study activities.

PJM Transmission Owners in the SERC region include Dominion and EKPC.

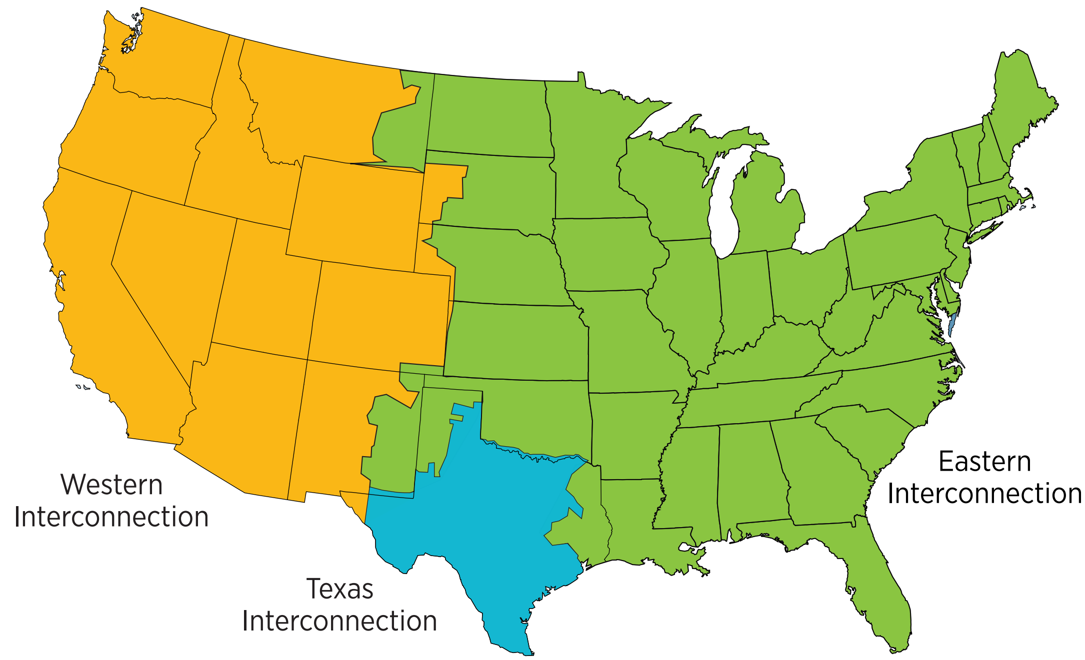
Map 3.9: NERC Areas



3.5.7 — 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 20 planning coordinators comprising approximately 95 percent 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 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.

Map 3.10: U. S. Interconnections



EIPC Activities

During 2019, EIPC continued to expand power system planning analysis activities, beyond the requirements of FERC Order 1000, including the following:

- The Frequency Response Working Group (FRWG) refined their study procedure and process based on experience from the 2018 study. The FRWG began developing a study case for a 2020 evaluation of the Eastern Interconnection's ability to maintain frequency following a disturbance during a low inertia period.
- The Transmission Analysis Working Group (TAWG) completed its analysis of a 'roll-up integration model'; 2028 summer and winter cases that combine individual plans of each Planning Coordinator (PC). The purpose of the analysis is to identify any potential impacts due to the integration of neighboring PCs' regional plans. No valid adverse effects to the PJM system were identified.
- The Production Cost Task Force (PCTF) developed and refined the scope for a potential study of a high renewables future. The study will be conducted in coordination by both the PCTF and the TAWG and utilize both load flow and production cost analysis to evaluate the impacts of a potential generation fleet comprising a high level of renewable generation.

PJM expects many of these activities to continue in 2020, including the low inertia frequency response study and the joint TAWG/PCTF high renewables impact study.

Section 4: Market Efficiency Analysis

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

4.0: Scope

RTEP Process Context

PJM's Regional Transmission Expansion Plan (RTEP) process includes a 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. These simulations show the extent to which congestion is mitigated by a project for a specific study year's transmission and generation dispatch scenarios. Economic benefit is determined by comparing future-year simulations both with and without a proposed transmission enhancement.

The metrics and methods used to determine economic benefit are described in:

- PJM Manual 14B, Section 2.6
- PJM Operating Agreement, Schedule 6, Section 1.5.7

To conduct a market efficiency analysis, PJM uses a market simulation tool to model an hourly security-constrained generation commitment and economic dispatch. Several base case power flow models are developed and utilized by the market simulation tool. The primary difference between these cases is the transmission topology:

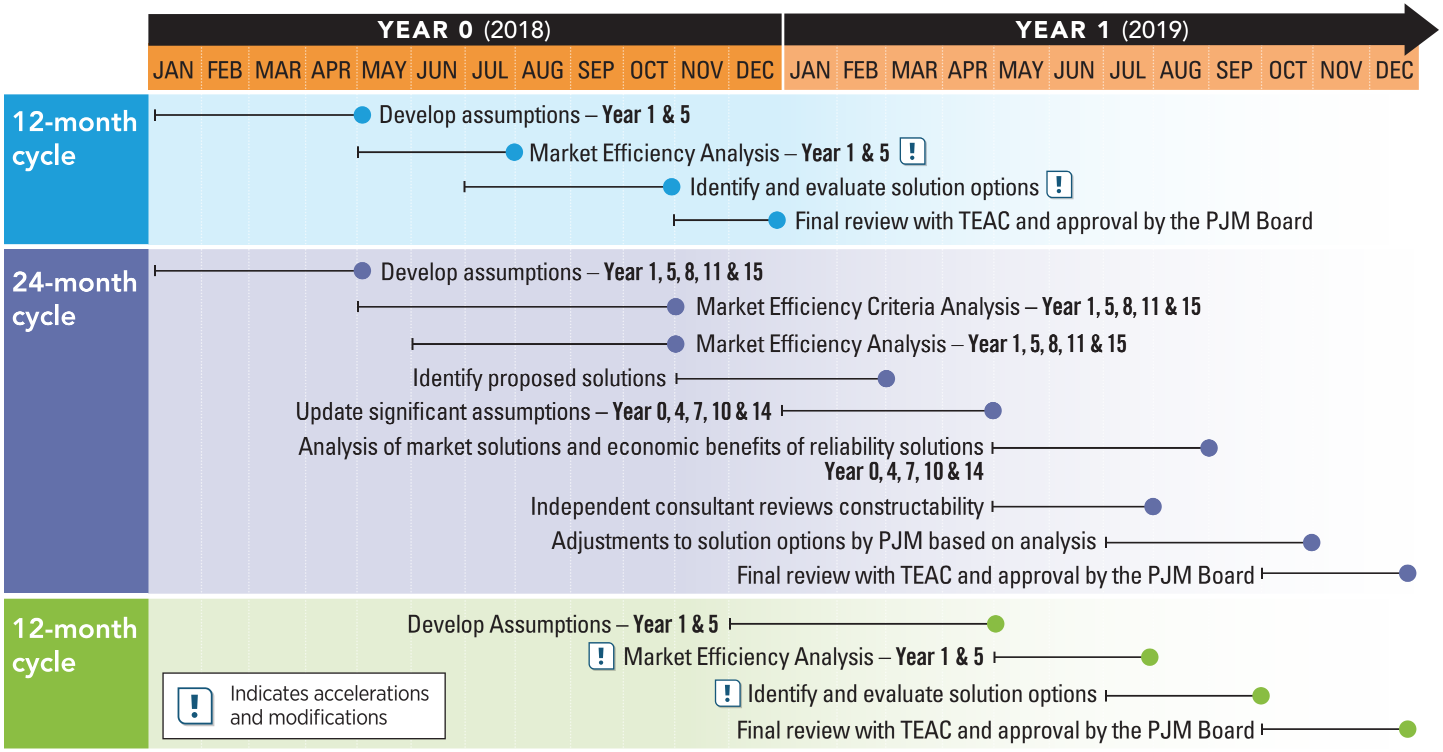
- An "as-is" base case power flow models a one-year-out, study-year transmission topology.
- An "as-planned" base case power flow models PJM Board-approved RTEP projects with required in-service dates by June 1 of the five-year-out study year.

PJM can determine the economic value of a transmission project by comparing the results of multiple simulations with the same input assumptions and operating constraints but different transmission topologies. Combined with benefit analysis, this allows PJM to do the following:

- Collectively value the approved RTEP portfolio of enhancements
- Evaluate reliability-based RTEP project acceleration or modification for potential economic benefit
- Evaluate the benefits of economic-based enhancements proposed during market efficiency competitive windows

Importantly, the simulated transmission congestion results provide important system information and trends to potential transmission developers and other PJM stakeholders.

Figure 4.1: Market Efficiency 24-Month Cycle



24-Month Cycle

The 24-month market efficiency timeline is shown in **Figure 4.1**. The 2019 market efficiency body of analysis is represented on the timeline as “Year 1” of the 24-month cycle. The 2019 analysis focused on:

- Mid-cycle update and validation of base case models and results
- Review of previously approved economic-based transmission projects
- Analysis to consider benefits of accelerating previously approved reliability-based projects not yet built
- Evaluation of economic-based enhancement proposals submitted in the 2018/2019 long-term window

Long-Term Window Simulations: 2019, 2023, 2026, 2029 Study Years

In order to quantify future, long-range transmission system market efficiency needs, PJM develops a simulation database for use as part of the long-term window study process. System modeling characteristics included in this database are described in **Section 4.1**.

Market efficiency projects identified for the 2018/2019 long-term proposal window as discussed in **Section 4.2** were initially evaluated using the base case model developed during the first nine months of 2018. During the 2019 project evaluation phase, PJM developed a 2019 mid-cycle update case that incorporates significant RTEP modeling changes approved through the 2018 RTEP cycle. The mid-cycle update case includes potentially significant forecasted changes in topology, generation, load and fuel costs. The purpose for the 2019 mid-cycle case is to ensure that potential projects are evaluated using an updated forecast of future system conditions.

Benefit-to-Cost Threshold Test

PJM calculates a benefit-to-cost threshold ratio to determine if market efficiency justification exists 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 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 undergo an independent, third-party cost review. Additional constructability reviews may be performed, as deemed appropriate, to evaluate competing proposals. This review is to help ensure consistent estimating practices and project-scope development.

PJM determines market efficiency benefits based on energy market simulations for the majority of proposed projects. Transmission projects that may impact PJM Reliability Pricing Market (RPM) auction activities may derive additional economic benefit as determined through separate capacity market simulations.

PJM's market efficiency study process and benefit-to-cost ratio methodology are detailed in Manual 14B, Section 2, PJM Region Transmission Planning Process, which is available on PJM's website.

Energy Benefit – Regional Facilities

Energy benefit calculation for regional facilities is weighted as follows:

- 50 percent to change in system production cost
- 50 percent to change in net-load energy payments for zones with a decrease in net-load payments as a result of the proposed project

The change in system production cost is the change in system generation variable costs (e.g., fuel costs, variable operating and maintenance costs, and emissions costs) associated with total PJM energy production.

The change in net-load energy payment is the change in gross-load payment as offset by the change in transmission rights credits. The net-load energy payment benefit is calculated only for zones in which the proposed project decreases net-load payments.

Energy Benefit – Lower-Voltage Facilities

Energy benefit calculation for lower voltage facilities is weighted 100 percent to zones with a decrease in net-load payments as a result of the proposed project. The change in net-load energy payment is the change in gross-load payment as offset by the change in transmission rights credits. The net-load payment benefit is only calculated for zones in which the proposed project decreases net-load payments.

Capacity Benefit – Regional Facilities

PJM's annual capacity benefit calculation for regional facilities is weighted as follows:

- 50 percent to change in total system capacity cost
- 50 percent to change in net-load capacity payments for zones with a decrease in net-load capacity payments as a result of the proposed project

The change in net-load capacity payment is the change in gross capacity payment as offset by the change in capacity transfer rights.

Capacity Benefit – Lower-Voltage Facilities

PJM's annual capacity benefit calculation for lower-voltage facilities is weighted 100 percent to zones with a decrease in net-load capacity payments as a result of the proposed project. The change in net-load capacity payment is the change in gross capacity payment offset by the change in capacity transfer rights.

RTEP Project Acceleration Analysis: 2020 and 2024 Study Years

PJM compares simulations of near-term topologies with those of planned topologies to assess the individual and collective economic impacts of baseline reliability RTEP projects not yet in service. PJM quantifies the transmission congestion reduction impact by comparing the simulation differences between the "as-is" base case model and the "as-planned" base case model for the 2020 and 2024 study years. Simulation comparisons help PJM to:

- Quantify the transmission congestion reduction due to 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

For example, if a constraint causes significant congestion in the 2020 "as-is" simulation, but not in the 2024 "as-planned" simulation, then a 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.

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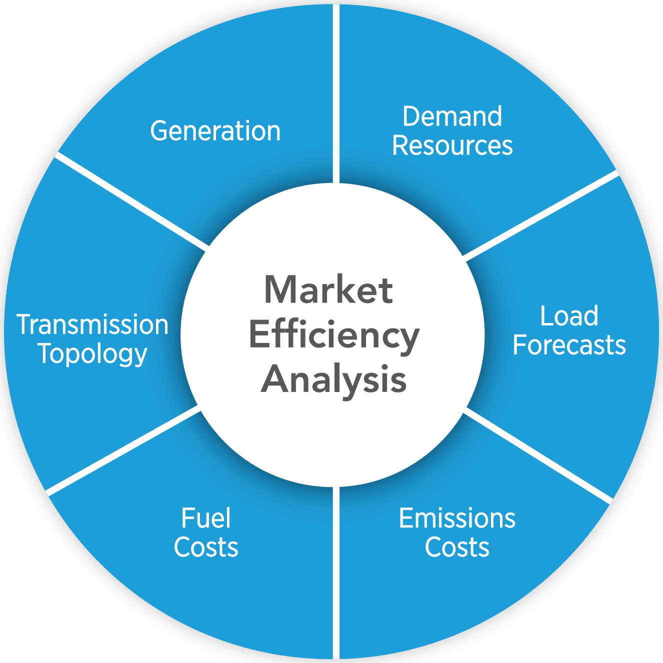
4.1: Input Parameters – 2019 Mid-Cycle Update

Overview

PJM licenses a commercially available database containing the necessary data elements to perform detailed PJM market simulations. This database includes a periodically updated representation of the Eastern Interconnection, and in particular, PJM markets. 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.

Figure 4.2: Market Efficiency Analysis Parameters



Transmission Topology

The market efficiency 2019 mid-cycle update base case power flow models were developed to represent:

- The 2020 "as-is" transmission system topology
- The "as-planned" 2024 system topology for the five-year-out RTEP study year

PJM derived the "as-is" transmission topology from its review of the Eastern Interconnection Reliability Assessment Group's Series 2019 Multi-Regional Modeling Working Group 2020 summer peak case. It included transmission enhancements expected to be in service by the summer of 2019. PJM derived system topologies for 2024 from the 2024 RTEP case and included RTEP projects approved during the 2018 RTEP cycle.

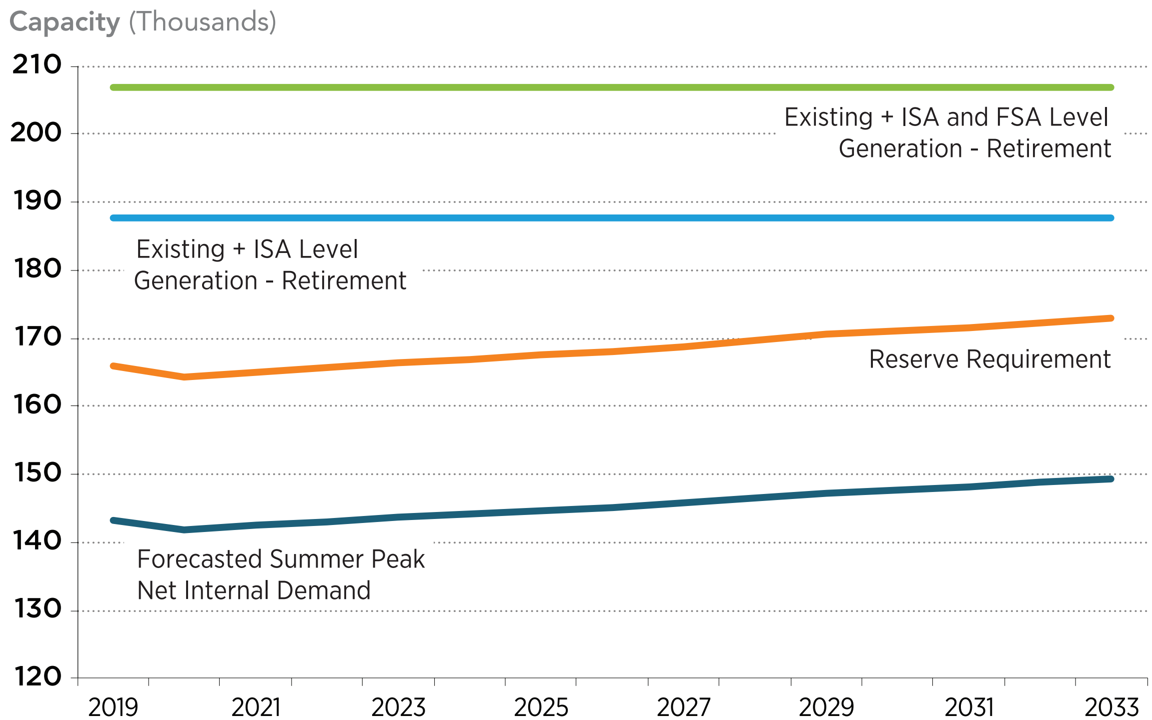
Monitored Constraints

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 and 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 base case simulations model existing in-service generation plus actively queued generation with an executed Interconnection Service Agreement (ISA). Generator deactivations that have given formal notification are removed from the model. The modeled generation provides enough capacity to meet PJM's installed reserve requirement through all study years, as shown in **Figure 4.3**. Additional sensitivities may be created by including queued generation at the Facility Study Agreement (FSA) level and suspended projects at the ISA level.

Figure 4.3: PJM Market Efficiency Reserve Margin



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 2019 Market Efficiency Analysis are represented in **Figure 4.4**.

Load and Energy Forecasts

PJM's 2019 Load Forecast Report provides the transmission zone peak load and energy data modeled in market efficiency simulations. **Table 4.1** summarizes the PJM peak load and energy values used in the 2019 market efficiency cases. The 2019 PJM Load Forecast can be accessed on the PJM website.

Figure 4.4: Fuel Price Assumptions

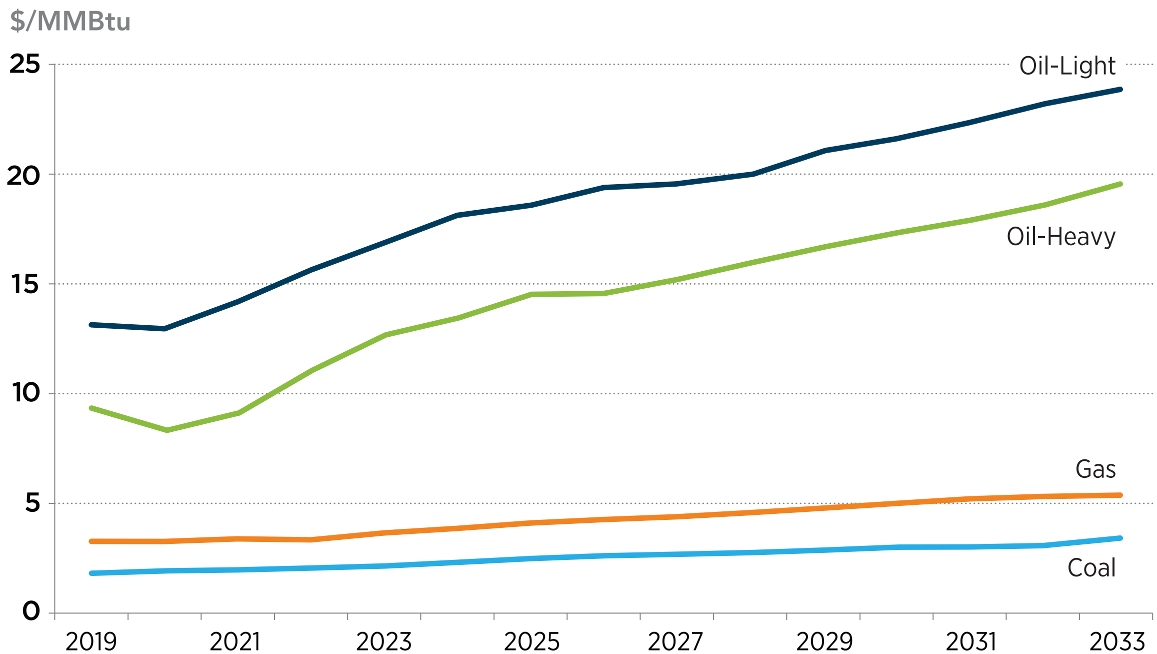


Table 4.1: 2019 PJM Peak Load and Energy Forecast

Load Forecast	2019	2023	2026	2029	2033
Peak (MW)	151,358	152,854	154,494	156,689	158,900
Energy (GWh)	801,724	813,283	823,826	836,489	847,956

Notes: 1. Peak and energy values from PJM Load Forecast Report, Table B-1 and Table E-1, respectively.
2. Model inputs are at the zonal level. To the extent zonal load shapes create different diversity, modeled PJM peak load may vary.

Demand Resources

The amount of demand resource modeled in each transmission zone is based on the 2019 PJM Load Forecast Report. **Table 4.2** summarizes PJM demand resource totals by year.

Emission Allowance Price Assumptions

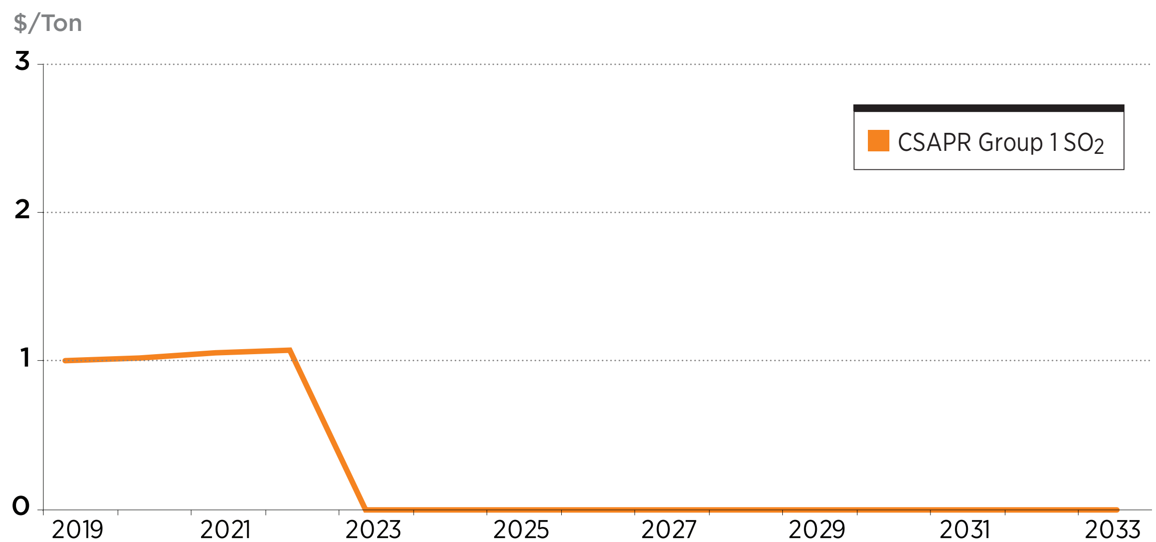
PJM currently models three major effluents – SO_2, NO_x and CO_2 – within its market efficiency simulations. SO_2 and NO_x emission price forecasts reflect implementation of the Cross-State Air Pollution Rule (CSAPR) and are shown in **Figure 4.5** and **Figure 4.6**, respectively.

Table 4.2: Demand Resource Forecast

Load Forecast	2019	2023	2026	2029	2033
Demand Resources (MW)	8,154	9,198	9,315	9,433	9,593

Note: Values from PJM Load Forecast Report, Table B-7.

Figure 4.5: SO_2 Emission Price Assumption



PJM unit CO_2 emissions are modeled as either part of the national CO_2 program or, for Maryland and Delaware units, as part of the Regional Greenhouse Gas Initiative (RGGI) program. The base emission price assumptions for both the national CO_2 and RGGI CO_2 program are shown in **Figure 4.7**.

Figure 4.6: NO_x Emission Price Assumptions

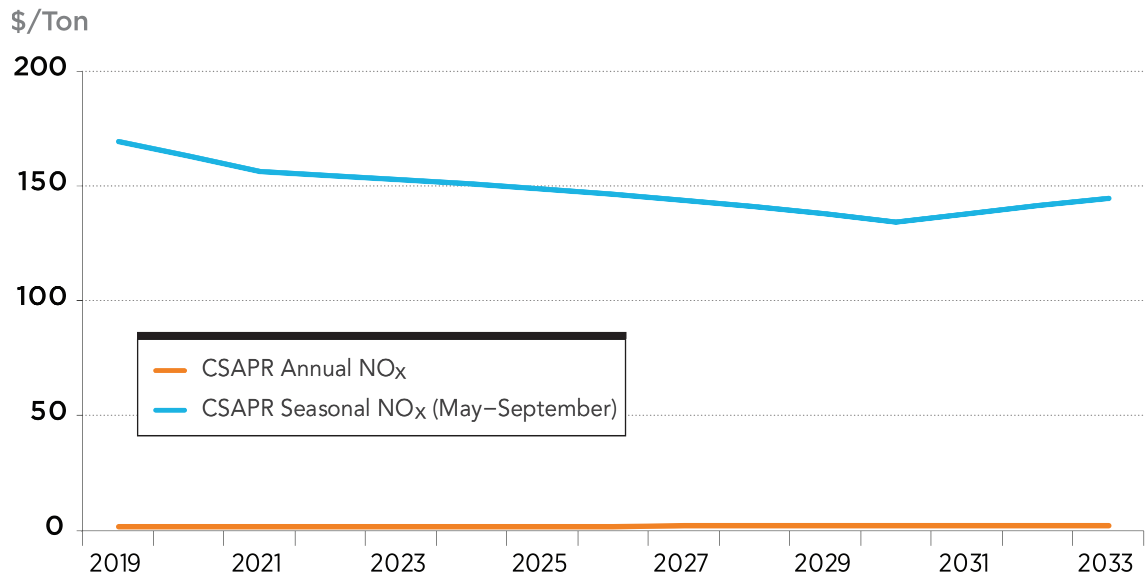
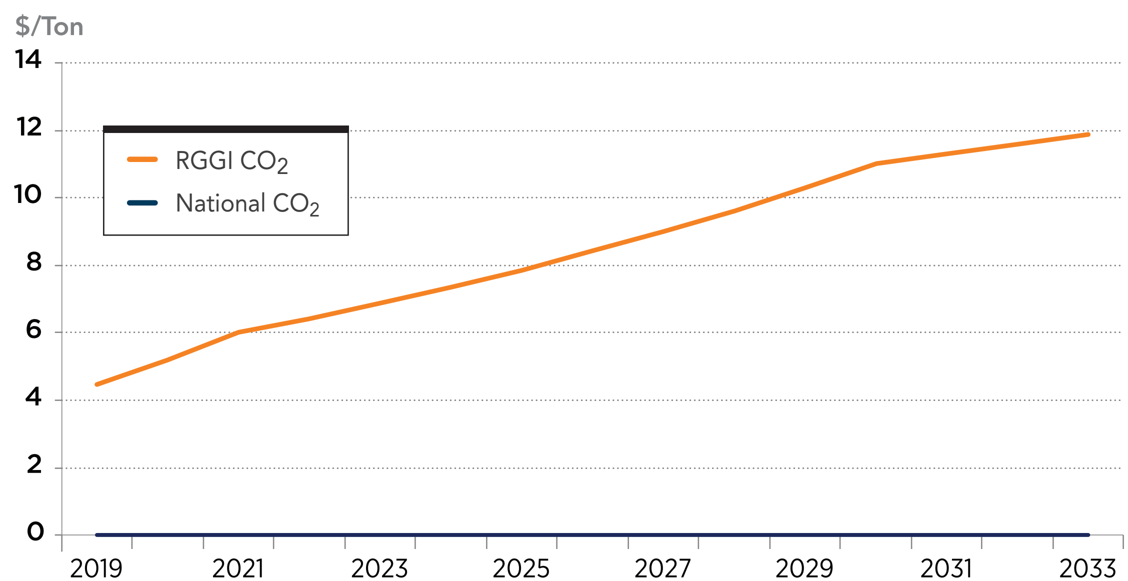


Figure 4.7: CO_2 Emission Price Assumptions



Carrying Charge Rate and Discount Rate

In order to determine and evaluate the potential economic benefit of RTEP projects, PJM performs market simulations and calculates a benefit-to-cost ratio for each candidate upgrade. The net present value of annual project benefits is calculated for a 15-year period starting with the RTEP year, compared to the net present value of the project revenue requirement for the same 15-year period. A discount rate and levelized carrying charge rate is developed using information contained in Attachment H of the transmission owner (TO) formula rate sheets, as posted on the PJM website.

The discount rate is a weighted-average, after-tax embedded cost of capital (average weighted by TO total transmission capitalization). The levelized, annual carrying charge rate is based on weighted-average, net-plant carrying charge (average weighted by TO total transmission capitalization), levelized over an assumed 45-year life of the project. PJM's 2019 market efficiency studies used a levelized annual carrying charge rate of 11.86 percent and a discount rate of 7.25 percent.

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4.2: 2018/2019 RTEP Long-Term Proposal Window – Market Efficiency Proposals

To identify and quantify long-term transmission system congestion, market simulations were conducted for study years 2019, 2023, 2026 and 2029. These simulations used the 2024 RTEP "as-planned" transmission system topology and included RTEP projects approved through the 2018 RTEP cycle.

Overall, congestion levels in PJM's 2019 market efficiency analyses remain low compared to previous RTEP cycles. This is due, in part, to:

- Low gas price assumptions coupled with generation portfolio shifts that include more high-efficiency, gas-fired generation
- Continued lower load forecast levels compared to previous forecasts
- RTEP transmission enhancements, which are improving or eliminating potential congestion-causing constraints

PJM solicited stakeholder proposals for market efficiency projects as part of an RTEP proposal window focusing on long-term analysis. The 2018/2019 RTEP long-term proposal window opened on Nov. 2, 2018, and closed on March 15, 2019. It sought solution alternatives to resolve or alleviate market efficiency congestion identified in the long-term simulations.

Table 4.3: 2018/2019 Long-Term Window Congestion Drivers

Constraint	Area	2023 Congestion (hours)	2023 Congestion ($M)	2026 Congestion (hours)	2026 Congestion ($M)
Hunterstown-Lincoln 115 kV line	Met-Ed (PJM)	1,720	$20.77	1,832	$29.62
Monroe Wayne 345 kV lines No. 1 and No. 2	MISO	45	$1.44	30	$0.61
Marblehead North Bus No. 1 161/138 kV transformer	MISO	195	$1.41	138	$1.18
Bosserman-Trail Creek 138 kV line	AEP-MISO	66	$1.47	89	$1.69

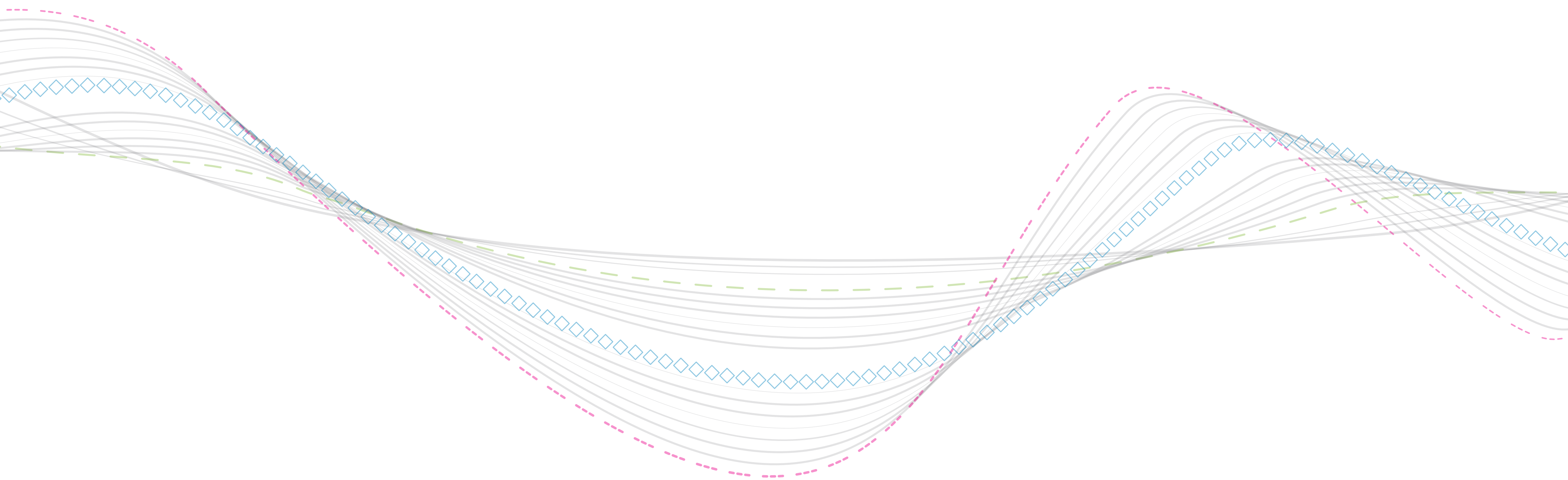
Table 4.4: Proposals by Type Submitted in the 2018/2019 Long-Term Proposal Window

Congestion Driver	Number of Proposals	Greenfield Proposals	TO Upgrade Proposals
Hunterstown-Lincoln 115 kV line	22	19	3
Bosserman-Trail Creek 138 kV line	5	4	1
Marblehead No. 1 161/138 kV transformer	2	1	1
Monroe Wayne 345 kV lines No. 1 and No. 2	3	0	3
No PJM Driver	2	1	1
Total	**34**	**25**	**9**

PJM posted a list of identified congestion drivers – facilities and their simulated congestion levels – as part of soliciting proposals during the window, as shown in **Table 4.3**.

Twelve parties submitted 34 proposals during the 2018/2019 RTEP long-term proposal window. Proposals ranged in cost from $0.1 million to $290.95 million and included transmission upgrades from transmission owners and greenfield projects from incumbent transmission owners and non-incumbent entities, as summarized in **Table 4.4**.

Market efficiency evaluation criteria is 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. Proposals with costs in excess of $50 million are also subject to an independent cost review. Other factors considered in selecting a successful project include risk assessment, model sensitivity evaluation, reliability impact and outage impact.



4.3: 2018/2019 Long-Term Window Results

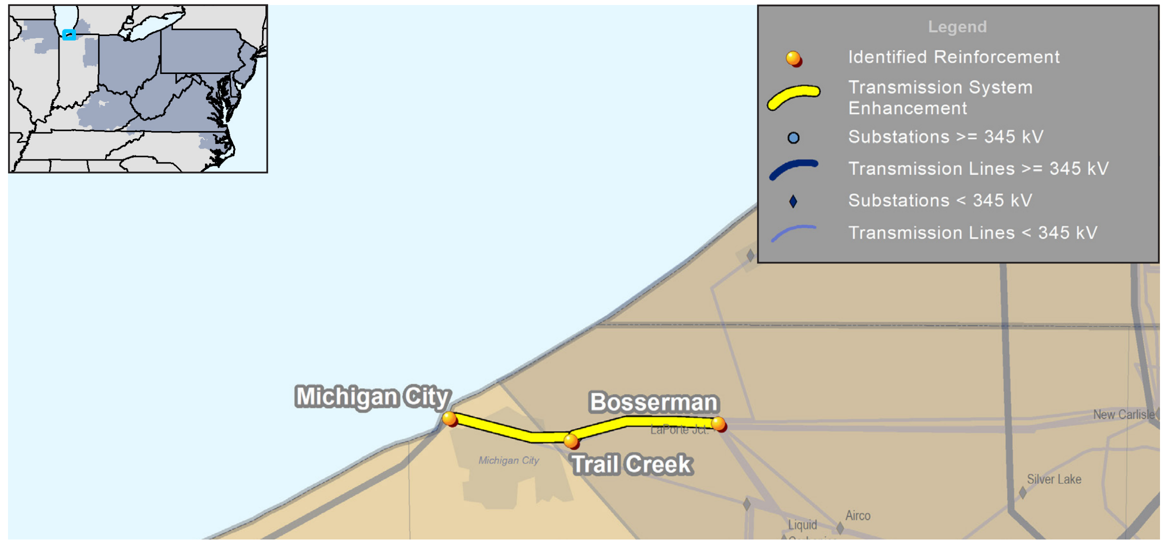
After the close of the 2018/2019 long-term window, PJM initiated the evaluation of two groups of projects. The Interregional Proposal Group included projects submitted to address the congestion drivers along the PJM-MISO border. The Hunterstown-Lincoln Group included projects submitted to address internal PJM congestion on the Hunterstown-Lincoln 115 kV line.

Interregional Proposal Group

PJM, working with MISO through the Interregional Planning Stakeholder Advisory Committee (IPSAC), completed a two-year Interregional Market Efficiency Project (IMEP) study in parallel with PJM's 2018/2019 long-term proposal window process. As part of the IMEP Study, PJM and MISO separately received project proposals that addressed at least one congestion driver identified in each region's respective planning process. Under the terms of the PJM-MISO Joint Operating Agreement, interregional proposals are separately submitted to, and evaluated by, PJM and MISO, and subject to each RTO's respective regional processes.

The congestion drivers associated with the MISO area in **Table 4.3** are interregional proposals. No projects were recommended for either the Marblehead North Transformer or Monroe-Wayne 345 kV line congestion drivers. Neither proposal addressing the Marblehead North Transformer congestion met the 1.25 benefit-to-cost ratio. None of the Monroe-Wayne proposals fully addressed the driver congestion. A project to address the Bosserman-Trail Creek 138 kV line congestion driver as approved by the PJM Board is discussed below.

Map 4.1: Baseline Project B3142: Bosserman-Trail Creek-Michigan City 138 kV Line



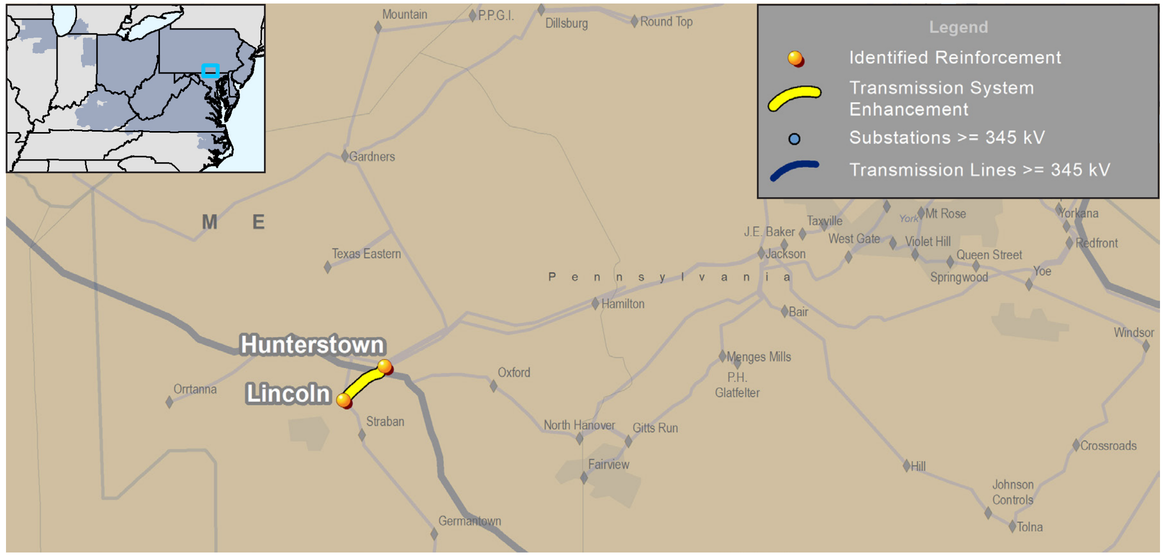
Interregional – Bosserman-Trail Creek 138 kV Line Evaluation

PJM received a cluster of five proposals (four greenfield proposals and one upgrade proposal) from five entities to address the Bosserman-Trail Creek congestion. The proposed project cost estimates ranged from $19 million to $266 million.

PJM evaluated each of the five proposals, out of which two exceeded the 1.25 benefit-to-cost ratio and fully mitigated congestion: (1) a rebuild of the Michigan City-Trail Creek-Bosserman 138 kV line; and (2) a new Kuchar substation and new Kuchar-Luchtman 138 kV line. PJM conducted further analysis on these two proposals to determine how the projects addressed the identified congestion and to evaluate project constructability risk. PJM selected the rebuild of the Michigan City-Trail Creek-Bosserman 138 kV line as the more efficient or cost-effective solution to the identified congestion driver. The project, which is identified as baseline project B3142 and shown on **Map 4.1,** offers the following:

- Benefit-to-cost ratio is 2.63
- Congestion driver is fully addressed
- Project is an upgrade and has lower constructability risk compared to the four greenfield proposals

Map 4.2: Baseline Project B3145: Hunterstown-Lincoln 115 kV Project



In addition to the market efficiency base case analysis for the recommended proposal, PJM also performed sensitivity analysis on key input variables: natural gas prices, PJM load forecasts, generation expansions and generator outage patterns. The benefit-to-cost ratio exceeded 1.25 in each instance. An RTEP process reliability analysis of the project did not identify any reliability criteria violations. PJM also conducted a constructability review of the components proposed by project and did not identify any significant issues.

The PJM Board provisionally approved the rebuild of the Michigan City-Trail Creek-Bosserman 138 kV line as an interregional baseline project, pending approval by the MISO Board as well. Both the PJM and MISO boards must approve the project in order for it to be included in each entity's regional transmission plan. This interregional baseline project is the first interregional proposal approved by the PJM Board through PJM's long-term proposal window for RTEP inclusion.

The estimated cost for the project is $24.69 million with a 2023 in-service date. Based on how project benefits accrue to PJM and MISO, 89.1 percent of the cost ($22 million) will be allocated to PJM.

Hunterstown-Lincoln 115 kV Evaluation

PJM received a cluster of 22 proposals (19 greenfield proposals and three upgrade proposals) from seven entities to address the Hunterstown-Lincoln congestion. The proposed project costs ranged from $4.65 million to $290.95 million.

PJM evaluated each proposal to determine which satisfied the market efficiency criteria of having a benefit-to-cost ratio greater than or equal to 1.25. PJM selected the top-five proposals with the highest benefit/cost ratios for further evaluation. Of these five solutions, three fully addressed the congestion driver. The three proposals included: (1) a rebuild of the Hunterstown-Lincoln 115 kV line; (2) placing a series SmartValve™ on the Hunterstown-Lincoln 115 kV line; and (3) building an additional Hunterstown-Lincoln 115kV line.

Once PJM identified the proposals that fully addressed the congestion driver, the three projects were analyzed to determine which addressed the identified congestion, the most efficient and cost-effective manner, while considering cost and constructability risk of each proposal. PJM identified several challenges associated with the SmartValve™ proposal compared to the upgrade proposal. See **Table 4.5**.

Based on the analysis performed, PJM selected the rebuild of the Hunterstown-Lincoln 115 kV line as the most efficient and cost effective solution to the identified congestion driver. The project, identified as RTEP baseline project B3145 and shown on **Map 4.2, offers the following**:

- Benefit-to-cost ratio is 76.41 – the highest across the proposals when using the PJM cost estimate
- Target congestion driver is fully addressed
- The project is an upgrade and has lower constructability risk compared to the other proposals

Table 4.5: Additional Comparison Criteria of Two Proposals to Address Hunterstown-Lincoln 115 kV Congestion

Criteria	Upgrade Solution	*SmartValve™ Solution
Constructability Risk	Upgrade, no additional property needed	Greenfield, permitting risk related to new property for substation due to location near historically sensitive area
PJM Operations and Markets	No changes needed to real-time operations procedures and practices	At this time, real-time operations would not be able to fully utilize the dynamic capabilities of this device without additional changes
Additional Integration Cost with Operations and Markets	No additional costs	May require updating day-ahead, real-time and/or SCADA systems to support full operational range of this type of device
Industry Experience	Established well known solution	Limited experience with SmartValve™ device
Additional System Capability/Flexibility**	Yes/No	No/Yes

*SmartValve is a Trademark of Smart Wires, Inc.
**Capability in terms of line ratings increase/Flexibility in terms of dynamic flow control

In addition to the market efficiency base case analysis for the recommended proposal, PJM also performed sensitivity analysis on key input variables: natural gas prices, PJM load forecasts, generation expansions, and generator outage patterns. A RTEP process reliability analysis of the project did not identify any reliability criteria violations. The estimated cost for the project is $7.21 million with a 2023 in-service date.

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4.4: Acceleration Results From 2019 Analysis

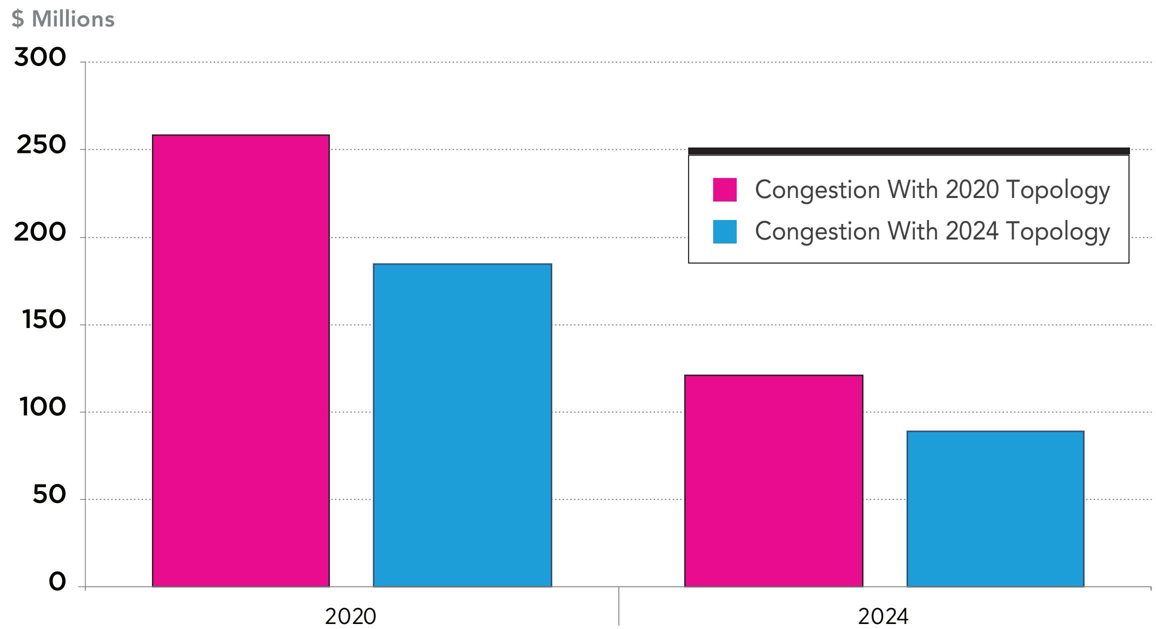
PJM's 2019 cycle of analysis included near-term simulations for study years 2020 and 2024. They identified collective and constraint-specific transmission system congestion due to the impacts of previously approved baseline reliability-based (RTEP) projects not yet in service. PJM conducted the simulations under two different transmission topologies:

1. 2020 "as-is" PJM transmission system topology
2. 2024 "as-planned" PJM RTEP transmission system topology

By comparing results of multiple simulations with the same 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. Collectively value the congestion benefits of approved RTEP upgrades.
2. Evaluate the congestion benefits of accelerating or modifying specific RTEP projects.

Figure 4.8: Simulated PJM Congestion Costs – 2020, 2024



PJM congestion costs from market simulations for study years 2020 and 2024 are shown in **Figure 4.8**. Annual congestion cost reductions of more than $73 million (29 percent) for 2020 and more than $32 million (27 percent) for 2024 using the 2024 RTEP topology were achieved. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

Table 4.6: RTEP Projects Reducing Specific Congestion Drivers: 2024 Analysis

Congestion Decreases Associated With Approved Reliability Projects – 2024 Study Year			2024 Study year				
			2020 Topology	2024 Topology			
Constraint Name	Area	Type	Year 2020 Congestion ($M)	Year 2024 Congestion ($M)	Congestion Savings ($M)	Upgrade Associated with Congestion Reduction	In-Service Date
Chemical-Capitol Hilll 138 kV	AEP	Line	$3.4	$0.0	$3.4	**B2834:** Reconductor and string open position as six-wire configuration 6.2 miles of the Chemical-Capitol Hill 138 kV circuit	2022
Tanners Creek-Miami Fort 345 kV	AEP/DEO&K	Line	$1.6	$0.0	$1.6	**B2831:** Upgrade/rebuild Tanners Creek-Miami Fort 345 kV line	2021

Note: The congestion savings for the 2024 study year are calculated as the difference in simulated congestion between with AS-IS topology and the RTEP topology.

Project-Specific Acceleration Analysis

PJM identified and evaluated specific RTEP enhancements that were most responsible for the congestion reductions identified in the acceleration simulations. **Table 4.6** identifies approved RTEP reliability projects and related congestion reductions considered as part of the 2024 study-year acceleration analysis.

The identified reliability enhancements, viewed within the context of the short-term analysis, will not be recommended for acceleration. These projects do not provide significant congestion benefits in the acceleration analysis, or are impractical to accelerate due to a near-term, in-service date or large project scope.

4.5: 2019 Re-Evaluation of Previously Approved Market Efficiency Projects

PJM's 2019 analysis included a re-evaluation of approved market efficiency projects from previous long-term window processes. The re-evaluation incorporated analysis of criteria changes implemented in 2019 through the Market Efficiency Process Enhancement Task Force (MEPETF) – discussed in **Section 4.6**.

Three previously approved upgrade projects with projected capital costs less than $20 million have yet to begin construction and are shown in **Table 4.7**. Each maintains a benefit-to-cost ratio greater than 1.25 with updated capital cost estimates.

Two previously approved projects with projected capital costs greater than $20 million have yet to begin construction or receive a Certificate of Public Convenience and Necessity (CPCN). These projects are identified as Project 9A and Project 5E, shown on **Map 4.3** and **Map 4.4**, respectively.

Map 4.3: Project 9A – RTEP Baseline Projects B2743 and B2752

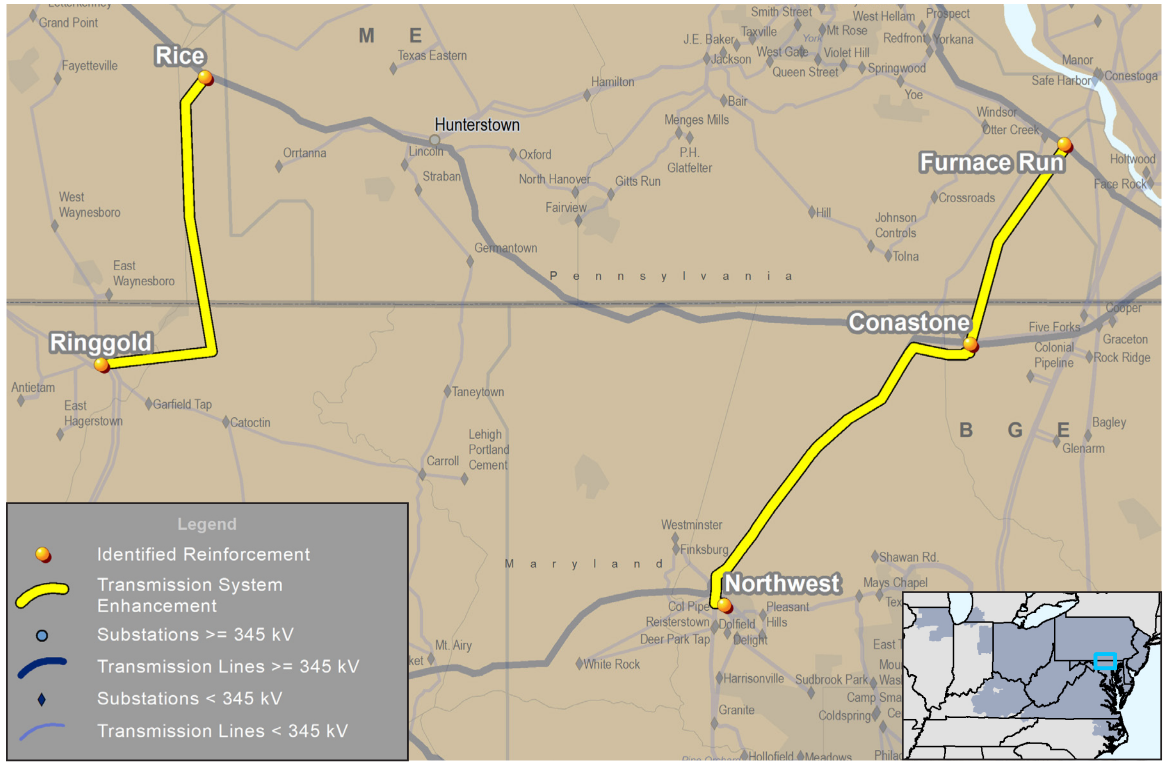


Table 4.7: Re-Evaluation of Projects Under $20 Million – Updated Cost

Project ID	Baseline ID	Type	Area	Constraint	Initial TEAC Date	Initial Benefit-to-Cost Ratio	Projected In-Service Date	2019 Re-Evaluation Benefit-to-Cost Ratio
201415_1-4I	B2697.1-2	Upgrade	AEP	Fieldale-Thornton 138 kV line	9/10/2015	101.19	1: 01/01/2019 2: 12/31/2019	28.11
201617_1A_RPM_DEOK	B2976	Upgrade	DEO&K	Tanners Creek-Dearborn 345 kV line	11/2/2017	151.61	6/1/2021	303.22
201617_1-3B	B2931	Upgrade	ComEd	Pontiac-Brokaw 345 kV line	8/10/2017	13.45	6/1/2021	13.45

All projects subject to re-evaluation are already included in the 2019 market efficiency base case as discussed earlier in **Section 4.0** and **Section 4.3**.

South-Central PA, Northern Maryland

Market efficiency analysis identified interaction between three projects providing congestion relief along the South-Central Pennsylvania and Northern Maryland border in PJM. The Hunterstown-Lincoln Project (B3145), Project 9A and Project 5E, each collectively support economic transfers between these areas. More information about these topics can be found in the December 2019 Baseline-Market Efficiency Recommendations document.

Table 4.8 shows the re-evaluation results for Projects 9A* and 5E.

Map 4.4: Project 5E – RTEP Baseline Project B2992

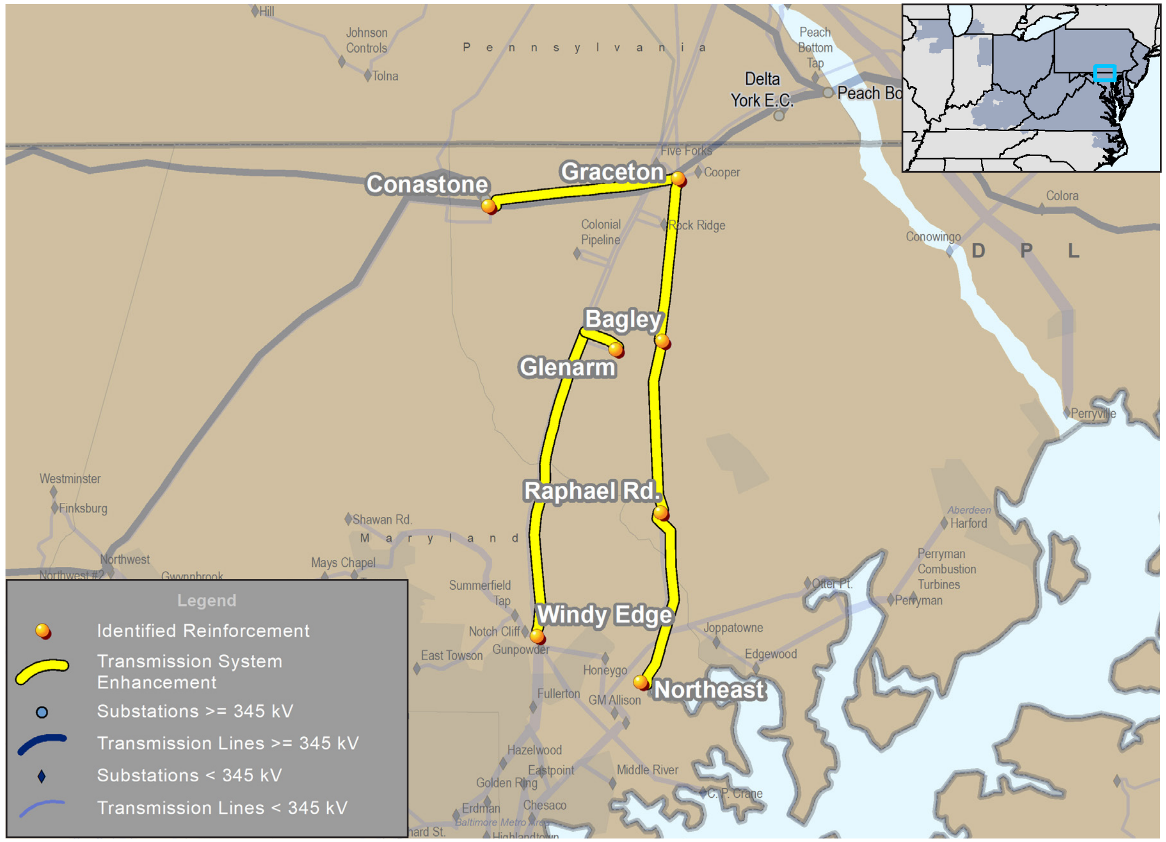


Table 4.8: Summary of 2019 Re-Evaluation – Project 9A, Project 5E

Re-Evaluation Analysis	Date Presented	Benefit-to-Cost Ratio
Project 9A*	10/17/2019	2.10
Project 5E	11/14/2019	**1.8

****Note:** Hunterstown-Lincoln Project (B3145) in the base case

***NOTE:**

Additionally, through ongoing siting proceedings in Pennsylvania and Maryland, several parties have filed a settlement that, if approved, offers an alternative configuration of the eastern portion of Project 9A.

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4.6: 2019 Market Efficiency Process Enhancements

The Market Efficiency Process Enhancement Task Force (MEPETF), chartered in January 2018, is under the auspices of the PJM Planning Committee. The mission of the task force is to review, evaluate and recommend any necessary solution(s) for the market efficiency process elements such as:

- Benefit-to-cost calculation
- Facility Service Agreement (FSA) modeling
- Market efficiency window
- Interregional Market Efficiency Project (IMEP) selection process
- Market efficiency re-evaluation process
- Regional Targeted Market Efficiency Project (TMEP)
- Market efficiency mid-cycle assumption update

To date, the task force has completed two phases of work. A third phase is ongoing with recommendations expected at the end of the first quarter 2020.

Phase 1

At the end of Phase 1, PJM filed revisions that:

1. Address generation assumptions that go into PJM's market efficiency analysis and
2. Modify the time period over which the benefit-to-cost analysis is performed.

PJM's first set of revisions changed the default treatment of generation with executed FSAs or executed ISAs under suspension by excluding those generation projects as a default in conducting market efficiency analysis. PJM's second set of revisions limited project evaluation to a 15-year period that begins with the RTEP year. In February 2019, FERC accepted PJM's Operating Agreement revisions.

Phase 2

As a result of the task force efforts completed during Phase 2, PJM filed revisions to the Operating Agreement, Schedule 6, Section 1.5.7(f). This section describes the criteria for market efficiency project re-evaluation. The revisions included specifying a time after which PJM would no longer be required to conduct an annual re-evaluation of previously approved market efficiency projects. The new re-evaluation criteria now include the following:

- Projects where construction activities have commenced at the project site, or that have a Certificate of Public Convenience and Necessity (CPCN), are no longer required to be re-evaluated.
- Projects not under construction, or without a CPCN with capital costs less than $20 million, will have projected costs updated, and using previously determined benefits should maintain a benefit-to-cost ratio greater than 1.25.
- Projects not under construction, or without a CPCN with capital costs greater than $20 million, will have projected costs updated and benefits re-evaluated. The project should maintain a benefit-to-cost ratio greater than 1.25.

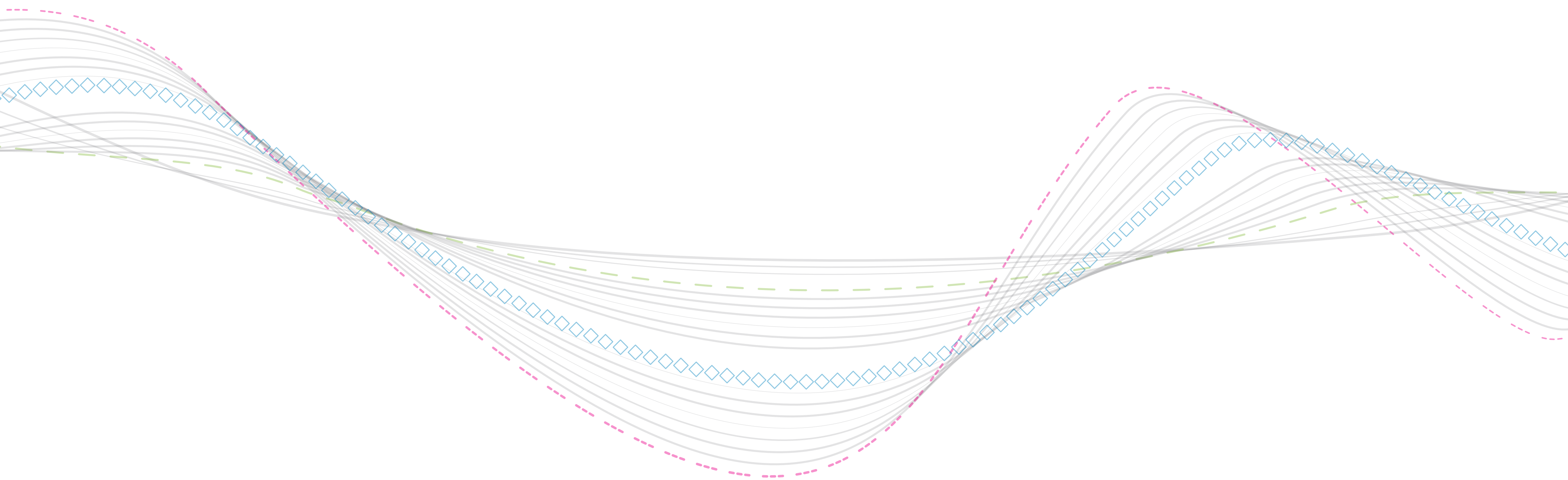
On Aug. 22, 2019, FERC accepted PJM's proposed OA revisions.

Phase 3

In June, 2019, the PJM Planning Committee endorsed amendments to the task force charter to add a third phase. The work is ongoing, with a projected first quarter 2020 conclusion. Key areas of review include:

- Concerns with benefit calculations using summation of energy and capacity benefits
- Regional Targeted Market Efficiency Projects (RTMEP)
- Two specific concerns raised by stakeholders on the benefit-to-cost calculation

Additional information can be accessed on the PJM website.



PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

4.7: Stage 1A ARR 10-Year Feasibility

4.7.1 — 2019–2020 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 IARRs so that all are simultaneously feasible for a 10-year period.

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

Table 4.9: 2019/2020 Stage 1A ARR 10-Year Infeasible Facilities

Facility Name	Facility Type	Upgrade Expected to Fix Infeasibility	Expected In-Service Date
Bellefonte 138 kV Transformer No. 3	Internal	**PJM RTEP B3118:** Expand existing Chadwick station and install a second 138/69 kV transformer at a new 138 kV bus tied into the Bellefonte-Grangston 138 kV circuit. The 69 kV bus will be reconfigured into a ring bus arrangement to tie the new transformer into the existing 69 kV yard via installation of four 3000A 63 kA 69 kV circuit breakers.	2020
Kilmer-Rariton River 230 kV line	Internal	**PJM RTEP B3042:** Replace substation conductor at Raritan River 230 kV substation on the Kilmer line terminal.	2023
Pleasant View 230 kV line	Internal	**PJM RTEP B3026:** Re-conductor the entire Pleasant View-Ashburn-Beaumeade 230 kV line No. 274 using a higher capacity conductor with an approximate rating of 1572 MVA.	2021
Tanners Creek-Miami Fort 345 kV loss of East Bend-Terminal 345 kV	Flowgate	**PJM RTEP B2968/2831:** Upgrade and/or rebuild the Tanners Creek-Miami Fort 345 kV line	2021
Eugene-Cayuga 345 kV loss of Rockport-Jefferson 765 kV	Flowgate	**PJM RTEP B2777:** Reconductor the entire Dequine-Eugene 345 kV circuit No. 1	2021

Results: 2019/2020 Stage 1A ARR 10-Year Analysis
During 2019, PJM market simulation staff completed a 10-year simultaneous feasibility analysis for 2019/2020 Stage 1A ARR selections. The power flow case used in the 10-year feasibility analysis is the same one used in the 2019/2020 annual ARR allocation, but without any modeled maintenance transmission outages. The results of the 10-year analysis identified violations on both PJM internal and MISO market-to-market coordinated flowgate facilities. PJM determined that the transmission solutions that will address the identified violations were already identified in one of the following processes:

- Planned projects as part of respective MISO or PJM regional planning processes
- Planned projects as part of the PJM/MISO interregional planning process

The list of infeasible facilities along with expected projects that will address the infeasibilities are provided in **Table 4.9**. Each of the violations is expected to be relieved by already planned PJM RTEP projects. Since a plan has been established to address these violations, no further immediate action is necessary.

Section 5: Facilitating Interconnection

5.0: New Services Queue Requests

Interconnection Activity

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.

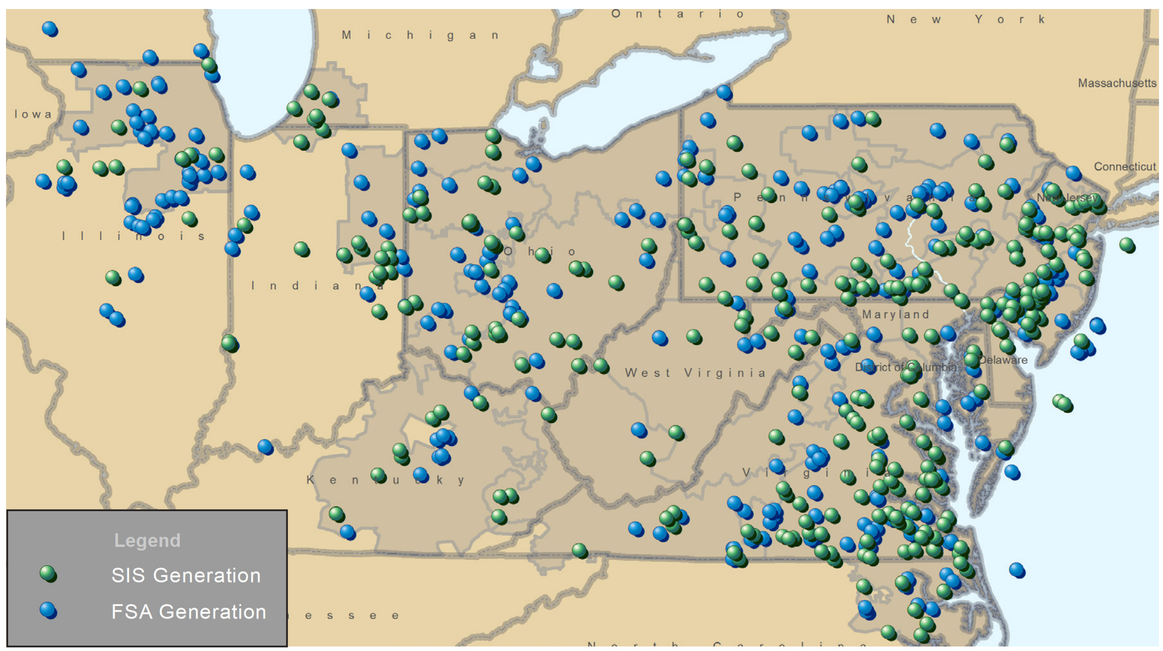
Generation Queue Activity

PJM markets have attracted generation proposals totaling 458,047 MW, as shown in **Table 5.1**. Over 60,130 MW of interconnection requests were actively under study during 2019. PJM analyzed and issued study reports for 550 feasibility studies and 379 system impact studies, as shown on **Map 5.1**. The unprecedented generator interconnection request volume appears to be driven by renewable fuel types, notably, offshore wind, as described later in this section. Over 21,600 MW of new generation was under construction or suspended as of Dec. 31, 2019, 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. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities.

Table 5.1: Study Requests Since 1999 (December 31, 2019)

	Number of Projects	Capacity (MW)	Nameplate Capability (MW)
Active	1,003	60,134	108,014
In Service	859	58,244	68,655
Suspended	58	6,399	7,781
Under Construction	211	15,298	20,557
Withdrawn	2,801	317,971	401,032
Grand Total	**4,932**	**458,047**	**606,040**

Map 5.1: Feasibility and System Impact Studies performed in 2019

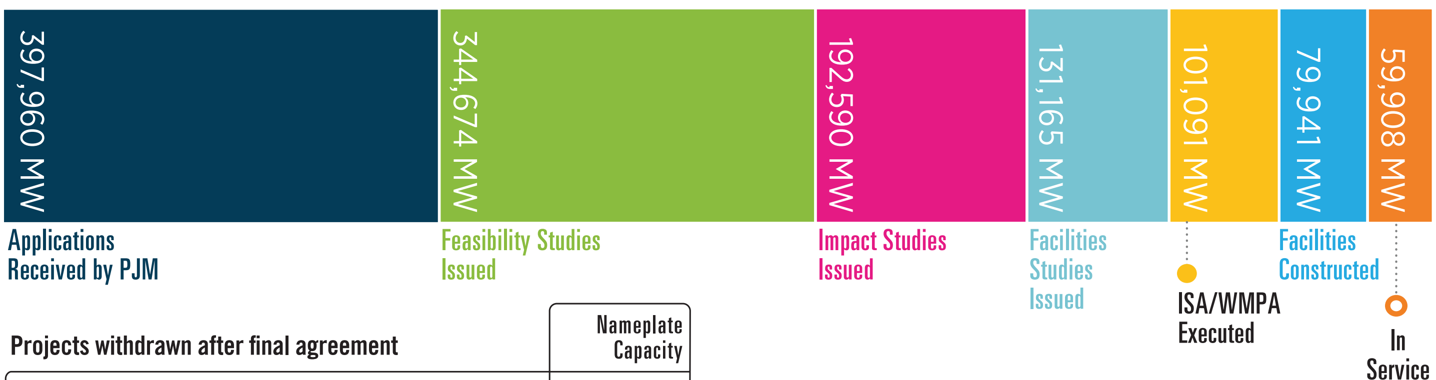


Queue Progression History

PJM reviews generation queue progression annually to understand overall developer trends more fully and their impact on PJM's interconnection process. **Figure 5.1** shows that for generation submitted in Queue A (1999) through Dec. 31, 2019, only 59,908 MW – 15.1 percent – reached commercial operation. Note that **Figure 5.1** reflects requested capacity interconnection rights which are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants, as described earlier.

Following interconnection service agreement (ISA) or wholesale market participant agreement (WMPA) execution, 20,516 MW of capacity with ISAs and 940 MW of capacity with WMPAs withdrew from PJM's interconnection process. Overall, 41.2 percent of projects that request uprates to existing capacity reach commercial operation. Only 14.6 percent of new generator requests reach commercial operation.

Figure 5.1: Queued Generation Progression



Projects withdrawn after final agreement

			Nameplate Capacity
155	Interconnection Service Agreements	**20,516 MW**	27,781 MW
268	Wholesale Market Participation Agreements	**940 MW**	1,972 MW

Percentage of planned capacity and projects that have reached commercial operation	**15%** Requested capacity megawatts	**23%** Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

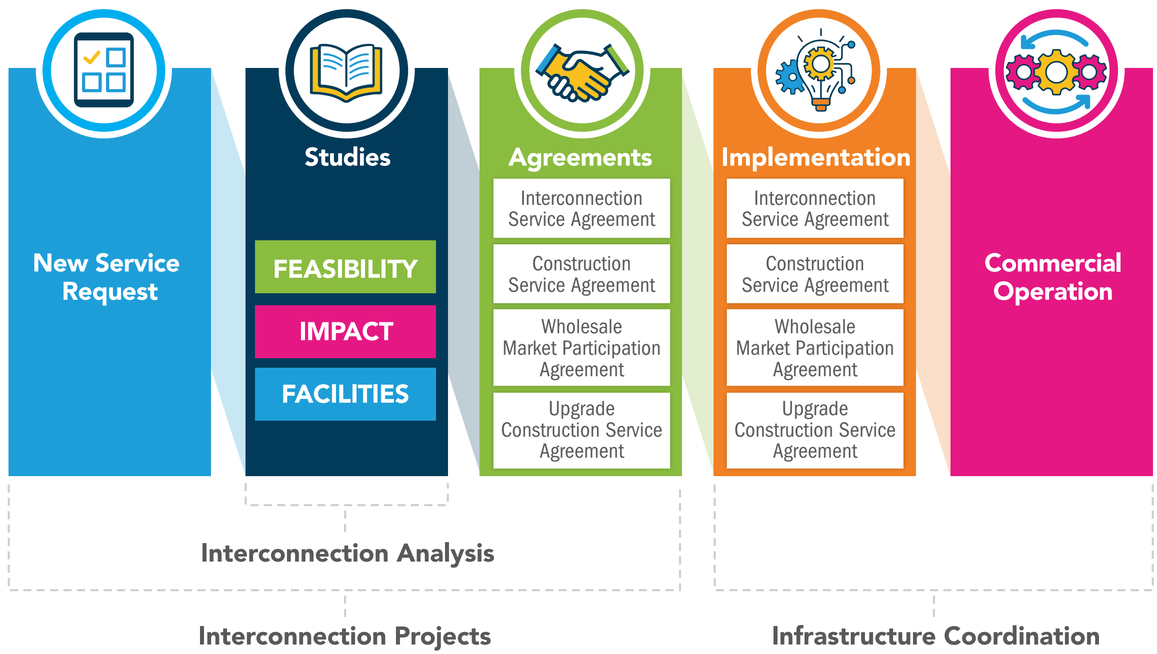
Interconnection Reliability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. Since 1999, the PJM Board has approved network facility reinforcements totaling $6.4 billion. The PJM Board approved 95 new network system enhancements totaling over $100 million in 2019 alone. As described in **Section 1.2**, PJM tests for compliance with all reliability criteria imposed by the NERC and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies the system conditions to be evaluated that sufficiently stress the transmission system to ensure that the transmission system meets the performance criteria specified in the standards. 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 the rest of PJM load. In addition to generator interconnection requests, PJM conducts this power flow test as part of baseline analysis under summer and winter peak load conditions, when capacity is most needed to serve load, as well as under light load conditions to ensure that a range of resource combinations and conditions is examined.

Queue Process Overview

PJM's interconnection queue process consists of five phases as shown in **Figure 5.2**. A new service queue request is submitted during the queue window, which is open from April to September and from October to March. During the feasibility study phase, the project is evaluated at a primary and a secondary (optional) point of interconnection.

Figure 5.2: Queue Process Overview



PJM targets to complete the feasibility study of a project within 120 days after the close of the queue window. During the impact study phase, the project elects one of the two points of interconnection, and the study is targeted to be completed 120 days after the start of the system impact study phase for the queue – or 120 days after the agreement is signed – whichever is later. During this phase, PJM coordinates with neighboring entities to conduct an affected system study, if applicable. The facilities study phase is completed in approximately six months after the Facilities Study Agreement has been executed. This study is conducted by the transmission owner. During the study phases, PJM performs power flow, short circuit and stability analysis to ensure the project's reliable interconnection to PJM's system. Once the study phases have been completed, the project signs agreements which grant it the rights to interconnect to the PJM system. The Interconnection Service Agreement and the Construction Service Agreement describe the milestones, point of interconnection, system upgrades, and construction responsibilities, that are associated with the project.

Offshore Wind

States within PJM have a variety of policies and regulations focused on environmental outcomes. PJM states on the East Coast are seeking to promote the development of offshore wind generation. The state policies of New Jersey mandate an incremental 7,500 MW of offshore wind generation by 2030. Other states such as Virginia and Maryland are also implementing policies that call for an increase in offshore wind generation. Driven by these policies, an increased number of offshore wind generation requests over the past few queue windows have been submitted to PJM. Twenty-four offshore wind projects are currently under study, 18 of which entered the PJM queue during the 2019 queue window. PJM studies these requests by continuously improving the evaluation criteria to ensure a reliable interconnection of the offshore wind generation to the PJM system.

FERC Order No. 845

On April 19, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 845. The purpose of this order was to enhance the interconnection process and provide more certainty to interconnection customers. On May 22, 2019, PJM submitted compliance filing for 10 reforms in FERC Order 845 and 845-A. Six of the 10 reforms were accepted by FERC on Dec. 17, 2019, including reforms to study deadline reporting and interconnection customer's Option to Build.

Study deadline reporting requires PJM to publish summary statistics on interconnection studies. PJM posts these statistics based on a six-month period, consistent with its six-month queue window.

Option to Build allows the interconnection customer the opportunity to construct required facilities to interconnect to the transmission owner's existing system, regardless of the transmission owner's ability to meet the interconnection customer's proposed schedule. PJM narrowed the applicability of Option to Build to attachment facilities and direct connection network upgrades. PJM also improved the Tariff definition of network upgrades to provide more clarity.

NOTE:

On Feb. 21, 2020, PJM submitted a compliance filing in response to FERC docket ER19-1958-002 to address changes with four reforms under FERC Order 845: Contingent Facilities, Provisional Interconnection Service, Surplus Interconnection Service, and Permissible Technological Advancements.

Section 6: State Summaries

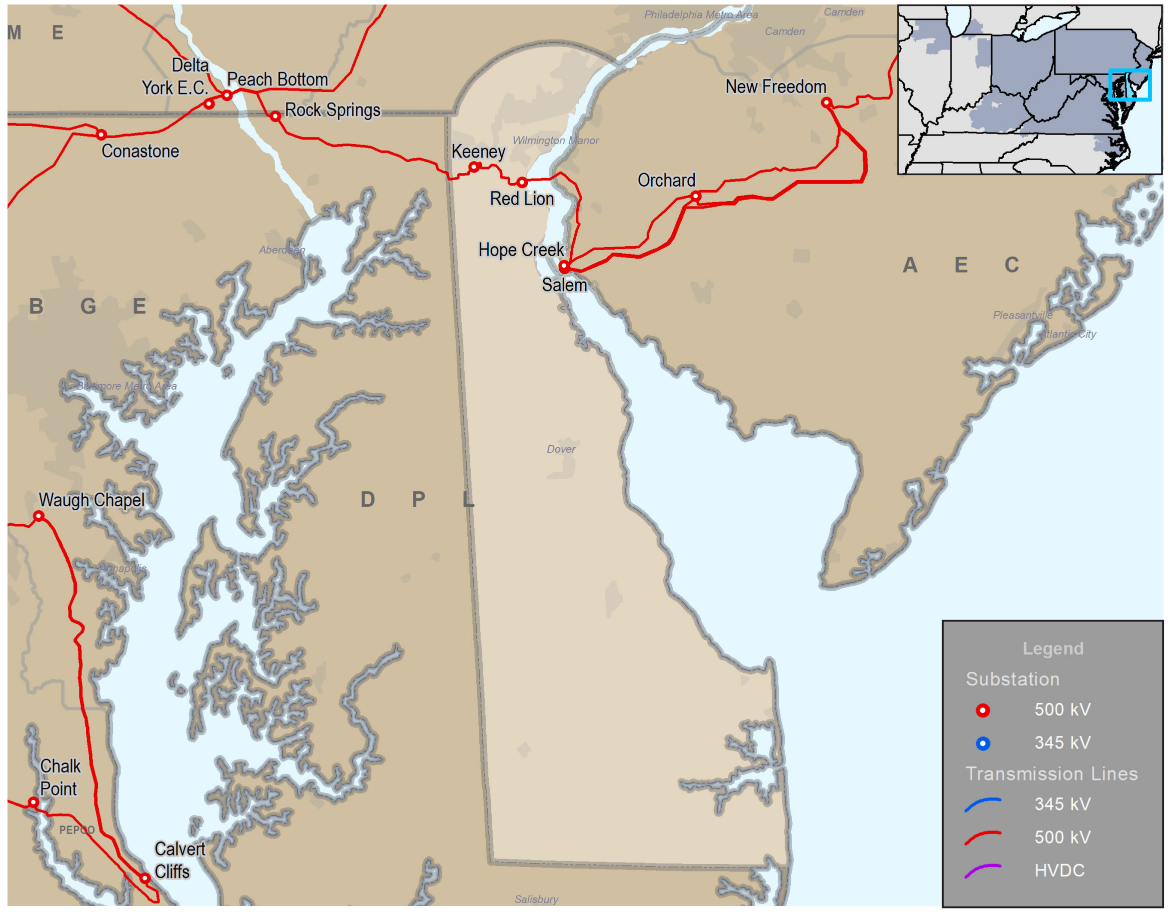
PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

6.0: Delaware RTEP Summary

6.0.1 — 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 & Light (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 PJM.

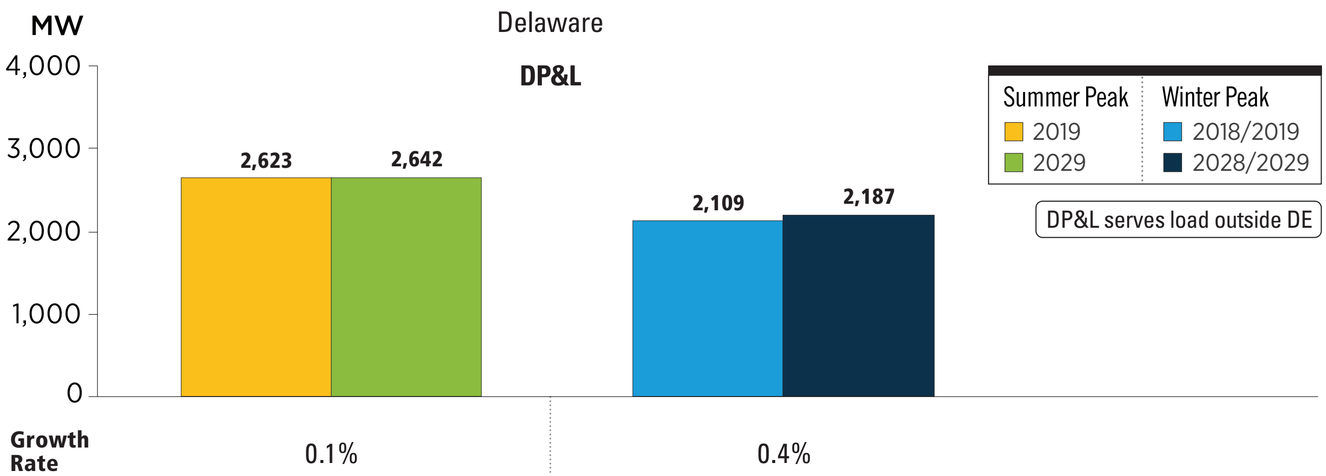
Map 6.1: PJM Service Area in Delaware



6.0.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.1** summarizes the expected loads within the state of Delaware and across PJM.

Figure 6.1: Delaware – 2019 Load Forecast Report



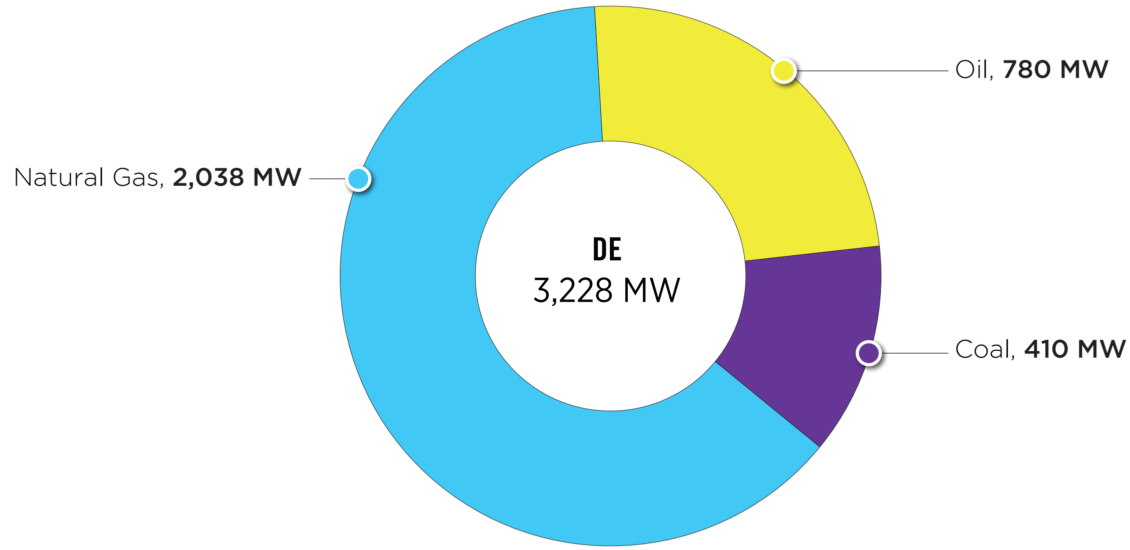
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156,689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. 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.

6.0.3 — Existing Generation

Existing generation in Delaware as of Dec. 31, 2019, is shown by fuel type in **Figure 6.2**.

Figure 6.2: Delaware – Existing Installed Capacity (MW) by Fuel Type (Dec.. 31, 2019)



6.0.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Delaware, 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.

Specifically, in Delaware, as of Dec. 31, 2019, 23 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.1**, **Table 6.2**, **Figure 6.3**, **Figure 6.4** and **Figure 6.5**. 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 6.1: Delaware – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	Delaware Capacity (MW)	Percentage of Total Delaware Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	0	0.00%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	451	53.84%	34,990	42.76%
Nuclear	0	0.00%	169	0.21%
Oil	0	0.00%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	204	24.38%	35,759	43.70%
Storage	0	0.03%	3,920	4.79%
Wind	182	21.76%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**838**	**100.00%**	**81,832**	**100.00%**

Table 6.2: Delaware – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	2	23.0	1	630.0	3	653.0
	Natural Gas	0	0.0	1	451.0	0	0.0	19	1,097.1	19	5,556.4	39	7,104.5
	Oil	0	0.0	0	0.0	0	0.0	5	168.2	1	1.0	6	169.2
	Other	0	0.0	0	0.0	0	0.0	2	30.0	0	0.0	2	30.0
	Storage	1	0.2	0	0.0	0	0.0	0	0.0	4	45.0	5	45.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	1	0.0	4	24.0	5	24.0
	Methane	0	0.0	0	0.0	0	0.0	4	9.0	3	28.8	7	37.8
	Solar	14	162.4	0	0.0	2	41.8	0	0.0	18	190.5	34	394.7
	Wind	4	117.9	0	0.0	1	64.4	0	0.0	4	355.4	9	537.7
	Grand Total	**19**	**280.5**	**1**	**451.0**	**3**	**106.2**	**33**	**1,327.3**	**54**	**6,831.1**	**110**	**8,996.1**

Figure 6.3: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

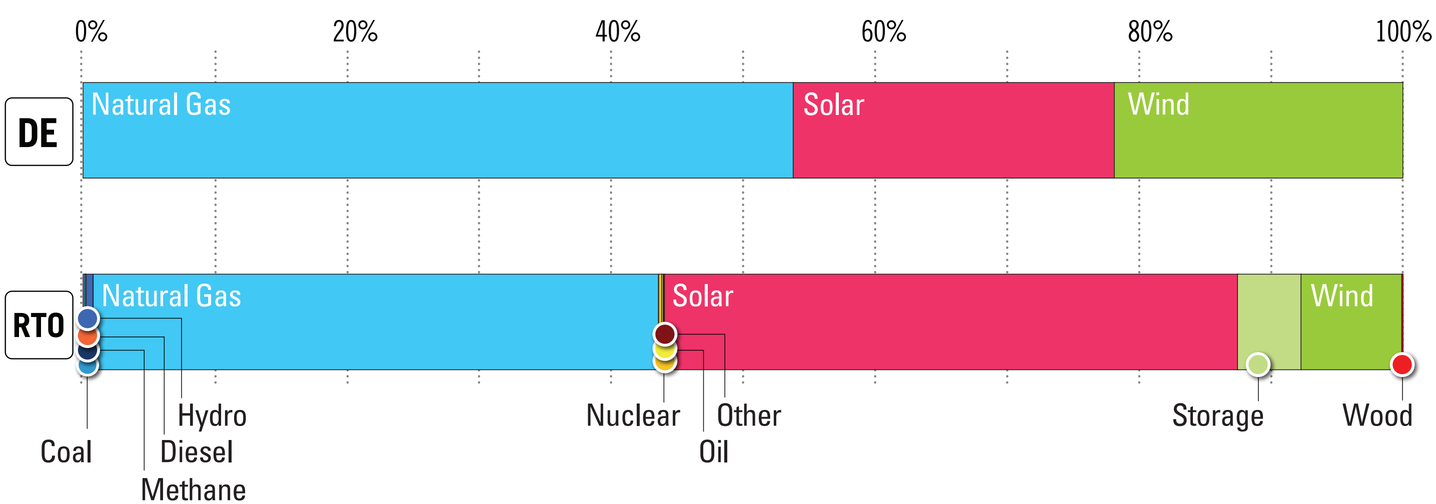


Figure 6.4: Delaware – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)

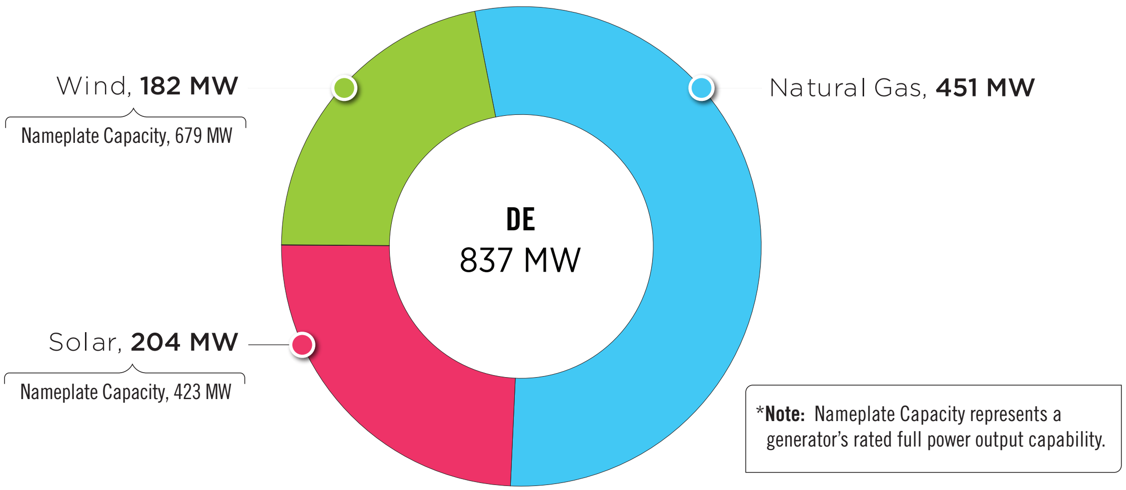
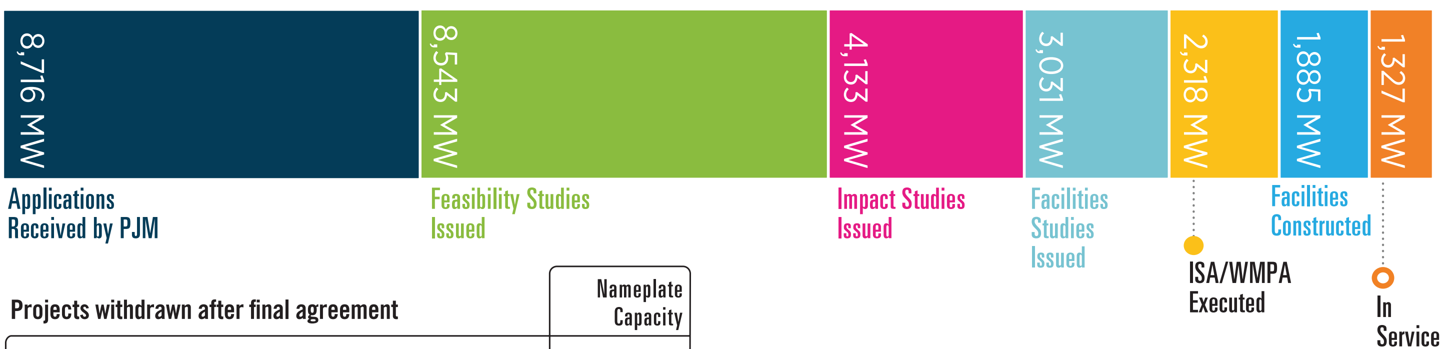


Figure 6.5: Delaware Progression History of Queue – Interconnection Requests (Dec. 31, 2019)



Projects withdrawn after final agreement

			Nameplate Capacity
3	Interconnection Service Agreements	420 MW	780 MW
4	Wholesale Market Participation Agreements	13 MW	47 MW

Percentage of planned capacity and projects that have reached commercial operation	**15%** Requested capacity megawatt	**36%** Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

6.0.5 — Generation Deactivation

Known generating unit deactivation requests in Delaware between Jan. 1, 2019, and Dec. 31, 2019, are summarized in **Table 6.3** and **Map 6.2**.

6.0.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in Delaware were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.0.7 — Network Projects

No network projects greater than or equal to $10 million in Delaware were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.2: Delaware Generation Deactivations (Dec. 31, 2019)

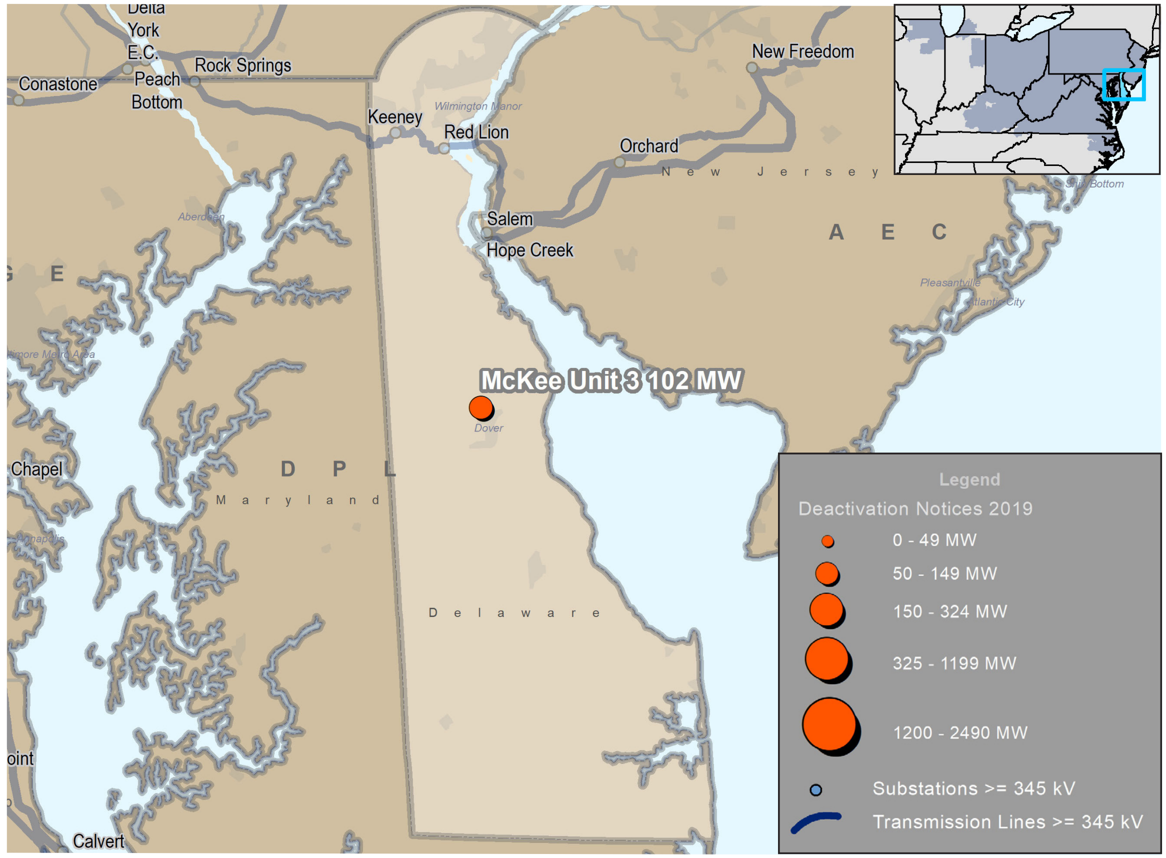


Table 6.3: Delaware Generation Deactivations (Dec. 31, 2019)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Status	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
McKee 3	DP&L	Natural Gas	3/8/2019	Pending	6/1/2021	44	102.00

6.0.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in Delaware are summarized in **Table 6.4** and **Map 6.3**.

6.0.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Delaware were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.3: Delaware Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

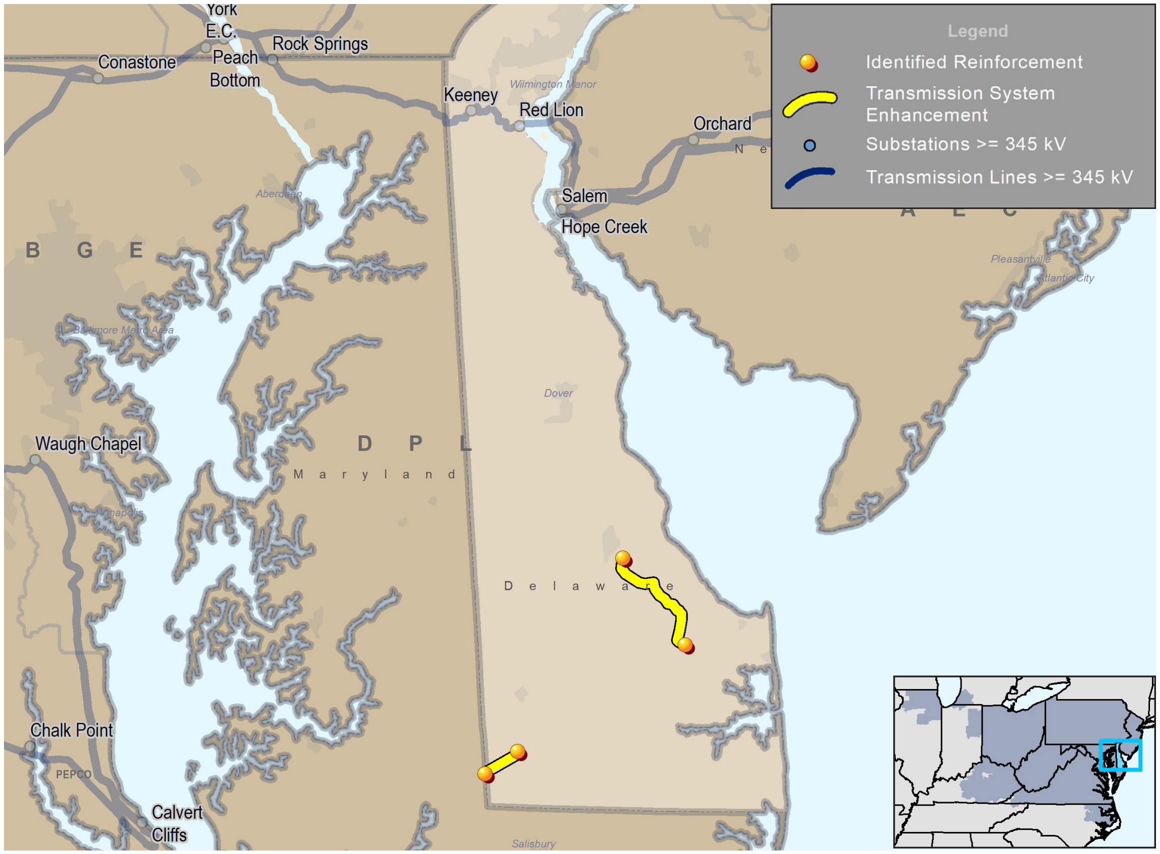


Table 6.4: Delaware Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

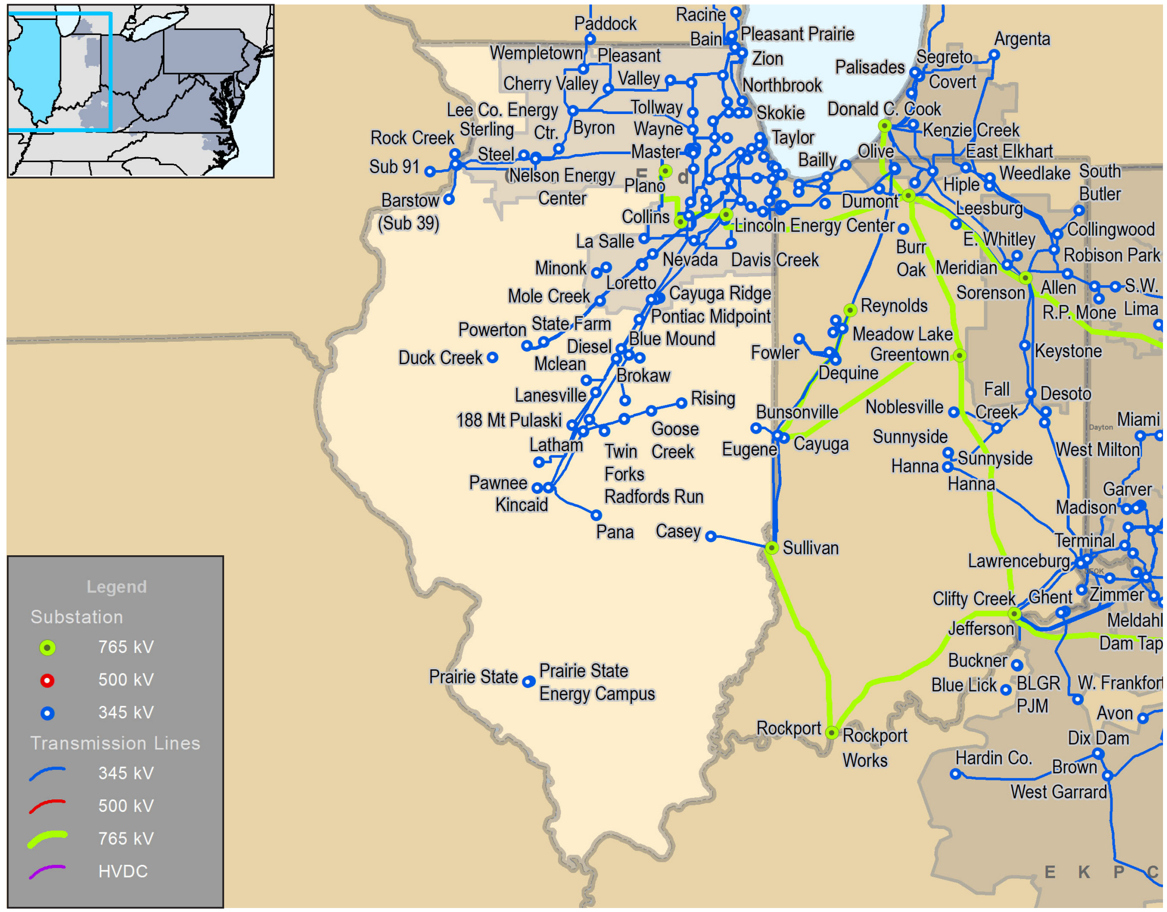
Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1871	Build a three-breaker ring 230 kV bus that would tie into the existing 23069 Milford-Cool Spring 230 kV line.	5/31/2022	$15.0	DP&L	2/22/2019
2	S2072	Rebuild 69 kV line from Sharptown-Laurel substations. All structures, conductor and static wire will be replaced with new steel poles, conductor and optical grounding wire communications.	5/31/2022	$11.0	DP&L	1/25/2019

6.1: Northern Illinois RTEP Summary

6.1.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Northern Illinois, including facilities owned and operated by Commonwealth Edison (ComEd) and the City of Rochelle as shown on **Map 6.4**. The Northern Illinois' 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 PJM.

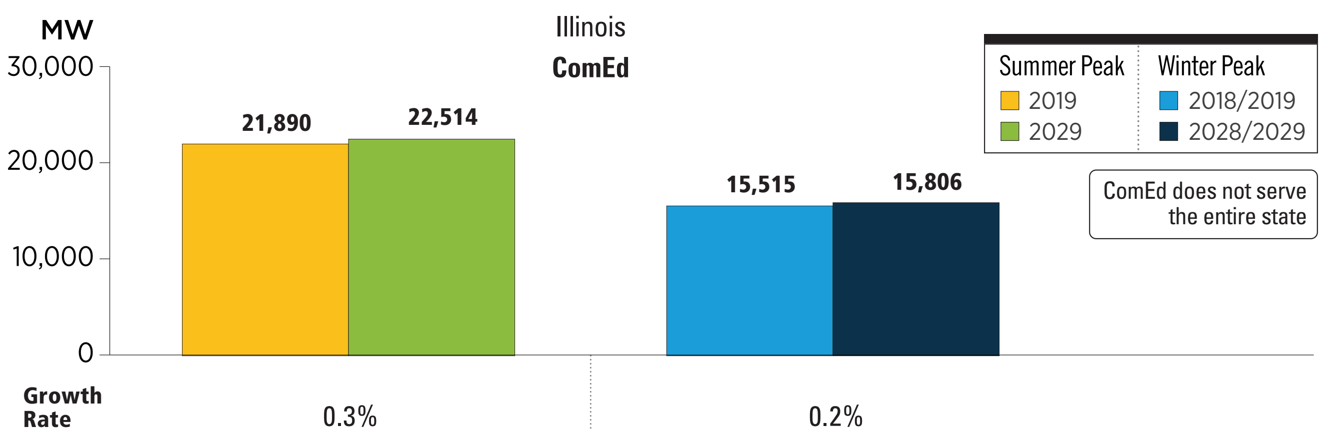
Map 6.4: PJM Service Area in Northern Illinois



6.1.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.6** summarizes the expected loads within the state of Northern Illinois and across all of PJM.

Figure 6.6: Northern Illinois – 2019 Load Forecast Report



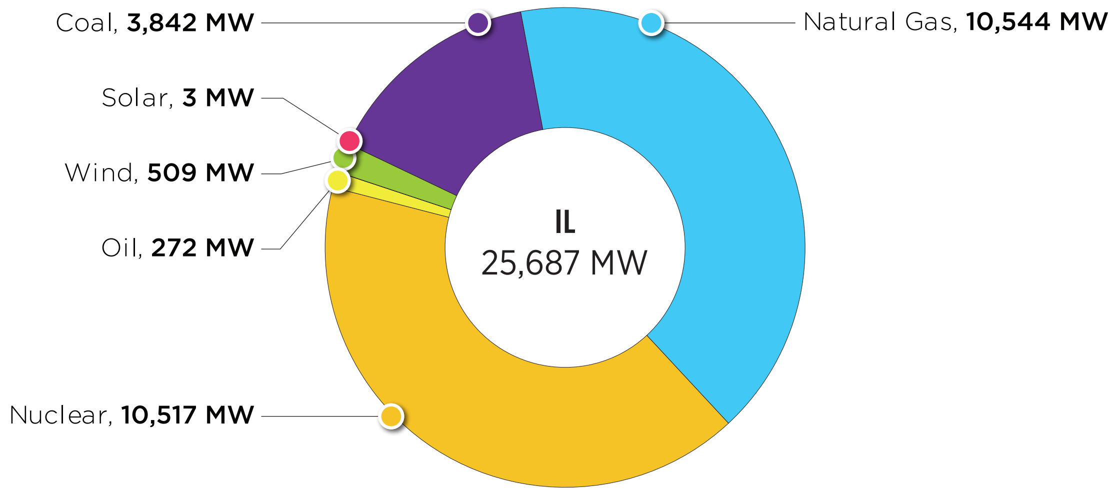
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156,689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the amount of forecasted load to be served by each transmission owner in the noted state. 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 Northern Illinois as of Dec. 31, 2019, is shown by fuel type in **Figure 6.7**.

Figure 6.7: Northern Illinois – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.1.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Northern Illinois, 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.

Specifically, in Northern Illinois, as of Dec. 31, 2019, 118 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.5**, **Table 6.6**, **Figure 6.8**, **Figure 6.9** and **Figure 6.10**. 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 6.5: Northern Illinois – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	Illinois Capacity (MW)	Percentage of Total Illinois State Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	23	0.24%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	4,990	52.98%	34,990	42.76%
Nuclear	0	0.00%	169	0.21%
Oil	0	0.00%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	2,615	27.77%	35,759	43.70%
Storage	307	3.26%	3,920	4.79%
Wind	1,483	15.74%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**9,419**	**100.00%**	**81,832**	**100.00%**

Table 6.6: Northern Illinois – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	5	3,652.0	5	3,652.0
	Diesel	0	0.0	0	0.0	2	22.0	0	0.0	2	22.0
	Natural Gas	22	3,780.3	3	1,209.9	16	1,435.6	21	8,908.3	62	15,334.1
	Nuclear	0	0.0	0	0.0	10	385.8	5	782.0	15	1,167.8
	Other	0	0.0	0	0.0	1	20.0	3	0	4	20.0
	Storage	15	307.4	1	0.0	5	0.0	18	421.6	39	729.0
Renewable	Biomass	0	0.0	0	0.0	0	0.0	3	90.0	3	90.0
	Hydro	0	0.0	2	22.7	0	0.0	2	4.3	4	27.0
	Methane	0	0.0	0	0.0	4	43.0	14	63.9	18	106.9
	Solar	40	2,615.4	0	0.0	1	3.4	38	1,175.0	79	3,793.8
	Wind	30	1,359.4	5	123.6	24	709.8	107	2,760.7	166	4,953.4
	Grand Total	**107**	**8,062.5**	**11**	**1,356.2**	**63**	**2,619.6**	**216**	**17,857.7**	**397**	**29,896.0**

Figure 6.8: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

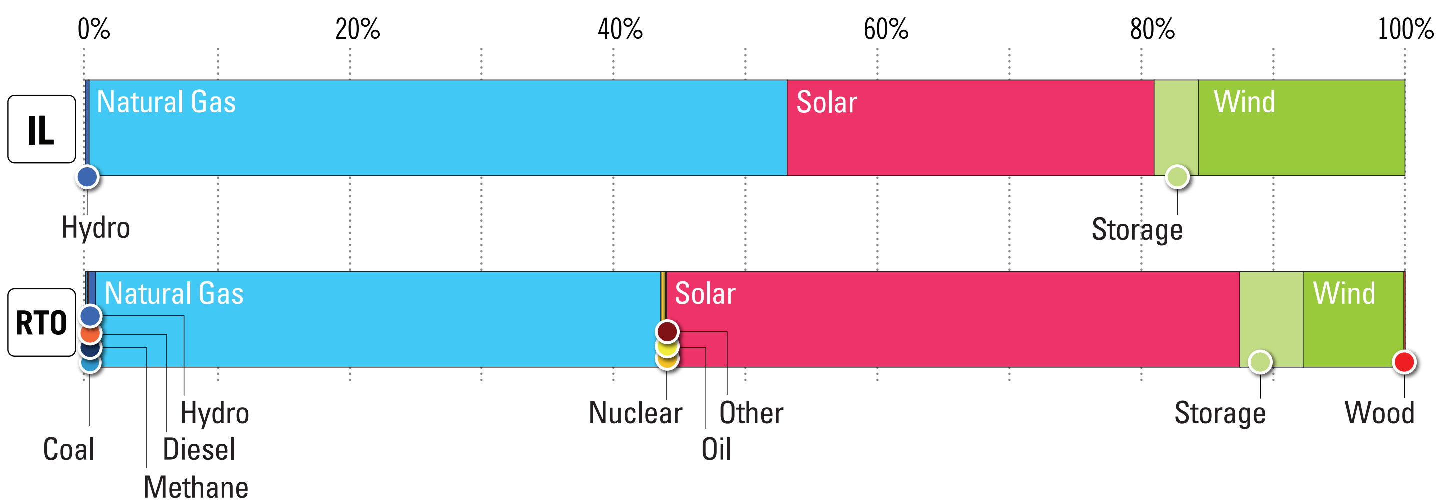
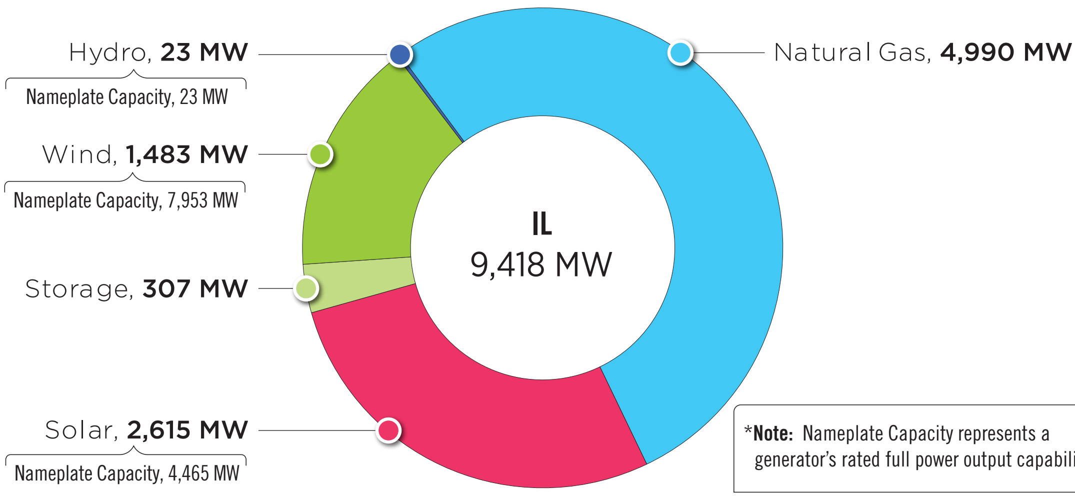


Figure 6.9: Northern Illinois – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)



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

Figure 6.10: Northern Illinois Progression History of Queue – Interconnection Requests (Dec. 31, 2019)

Projects withdrawn after final agreement			Nameplate Capacity
8	Interconnection Service Agreements	**376** MW	1,678 MW
4	Wholesale Market Participation Agreements	**4** MW	15 MW

Percentage of planned capacity and projects that have reached commercial operation		
	13% Requested capacity megawatt	**24%** Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

6.1.5 — Generation Deactivation

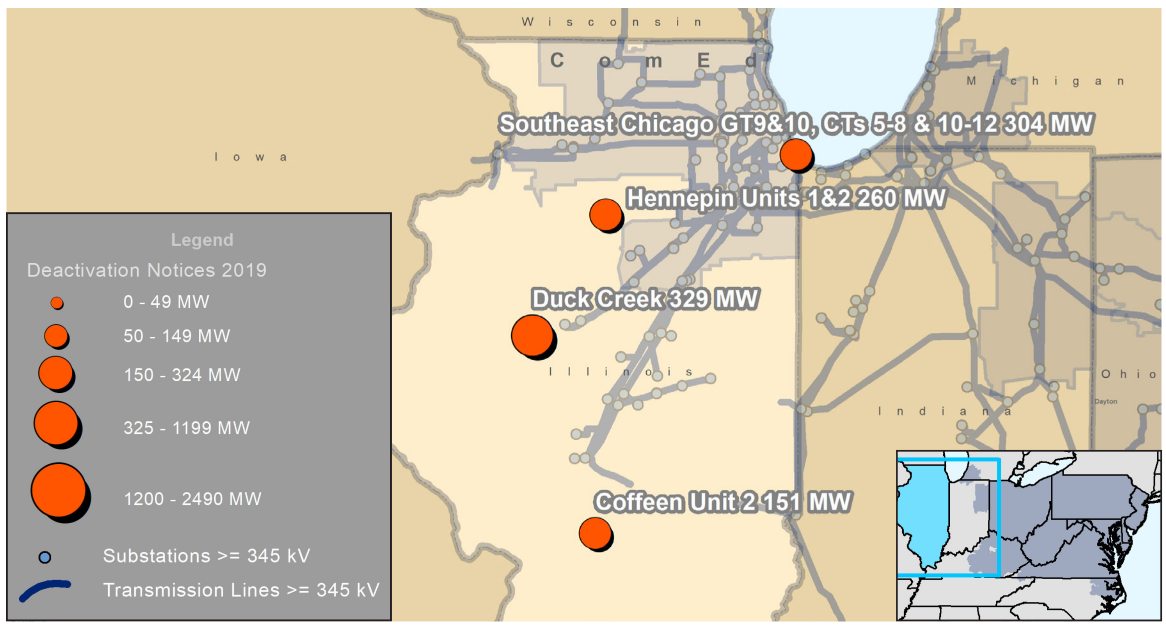
Known generating unit deactivation requests in Northern Illinois between Jan. 1, 2019, and Dec. 31, 2019, are summarized in **Table 6.7** and **Map 6.5**.

Table 6.7: Northern Illinois Generation Deactivations (Dec. 31, 2019)

Unit	TO Zone	Fuel Type	Actual Deactivation Date	Age (Years)	Capacity (MW)
Coffeen 2	MISO*	Coal	10/17/2019	47	151.0
Hennepin Power Station 1	MISO*	Coal	10/29/2019	66	60.0
Hennepin Power Station 2	MISO*	Coal	10/29/2019	60	200.0
Duck Creek 1	MISO*	Coal	12/15/2019	43	329.0
Southeast Chicago CT11	ComEd	Natural Gas	12/17/2019	16	38.0
Southeast Chicago CT12	ComEd	Natural Gas	12/17/2019	16	38.0
Southeast Chicago CT5	ComEd	Natural Gas	12/17/2019	16	38.0
Southeast Chicago CT6	ComEd	Natural Gas	12/17/2019	16	38.0
Southeast Chicago CT7	ComEd	Natural Gas	12/17/2019	16	38.0
Southeast Chicago CT8	ComEd	Natural Gas	12/17/2019	16	38.0
Southeast Chicago GT10	ComEd	Natural Gas	12/17/2019	16	38.0
Southeast Chicago GT9	ComEd	Natural Gas	12/17/2019	16	38.0

*Consistent with established practices, PJM studies generation deactivations outside of PJM's footprint when they may have an impact on PJM facilities.

Map 6.5: Northern Illinois Generation Deactivations (Dec. 31, 2019)



6.1.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in Northern Illinois were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.1.7 — Network Projects

RTEP network projects greater than or equal to $10 million in Northern Illinois are summarized in **Table 6.8** and **Map 6.6**.

Map 6.6: Northern Illinois Network Upgrades (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

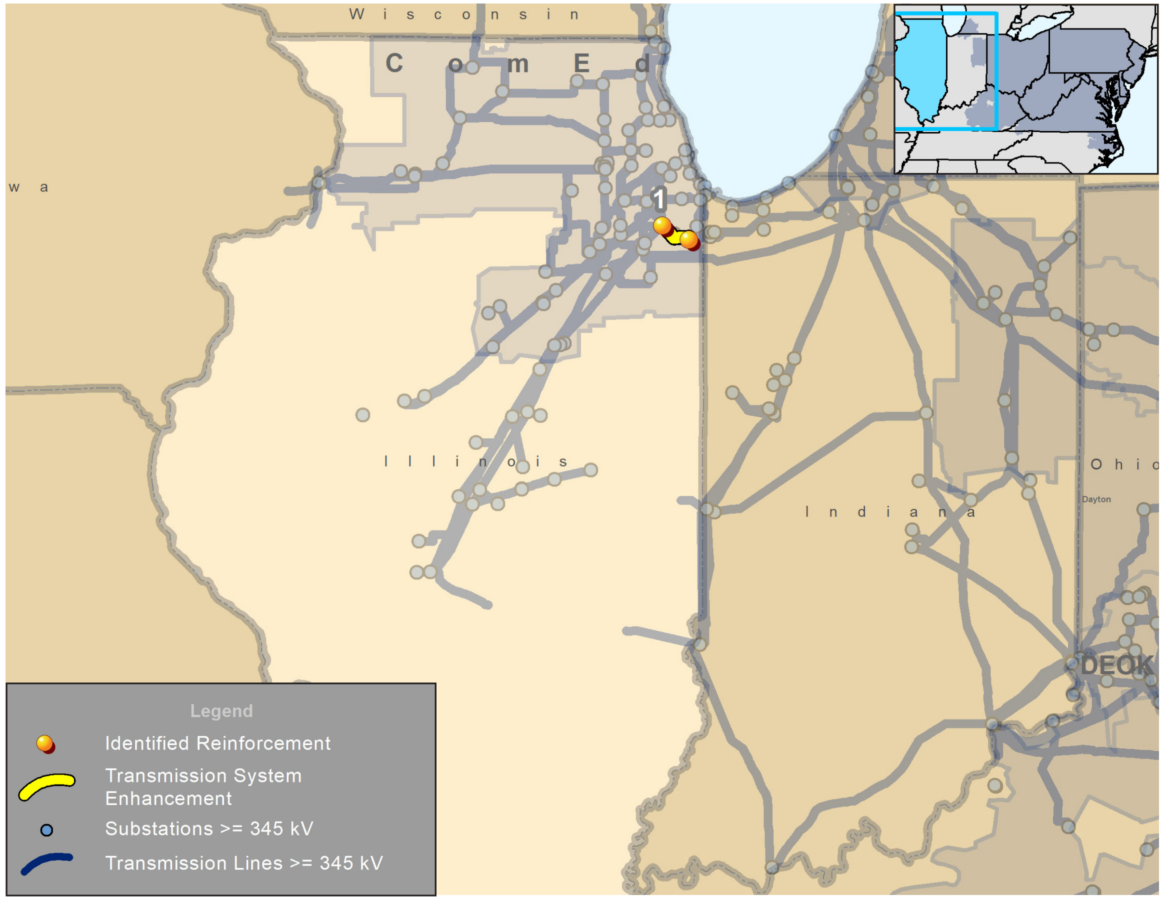


Table 6.8: Northern Illinois Network Upgrades Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Auction Revenue Requests	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N2089	Reconductor ~12.5 miles of 345 kV Line No. 6607 and upgrade terminal equipment to match same as B1773.	V3-052	12/31/2012	$10.0	ComEd	11/14/2019

6.1.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in Northern Illinois are summarized in **Table 6.9** and **Map 6.7.**

Map 6.7: Northern Illinois Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

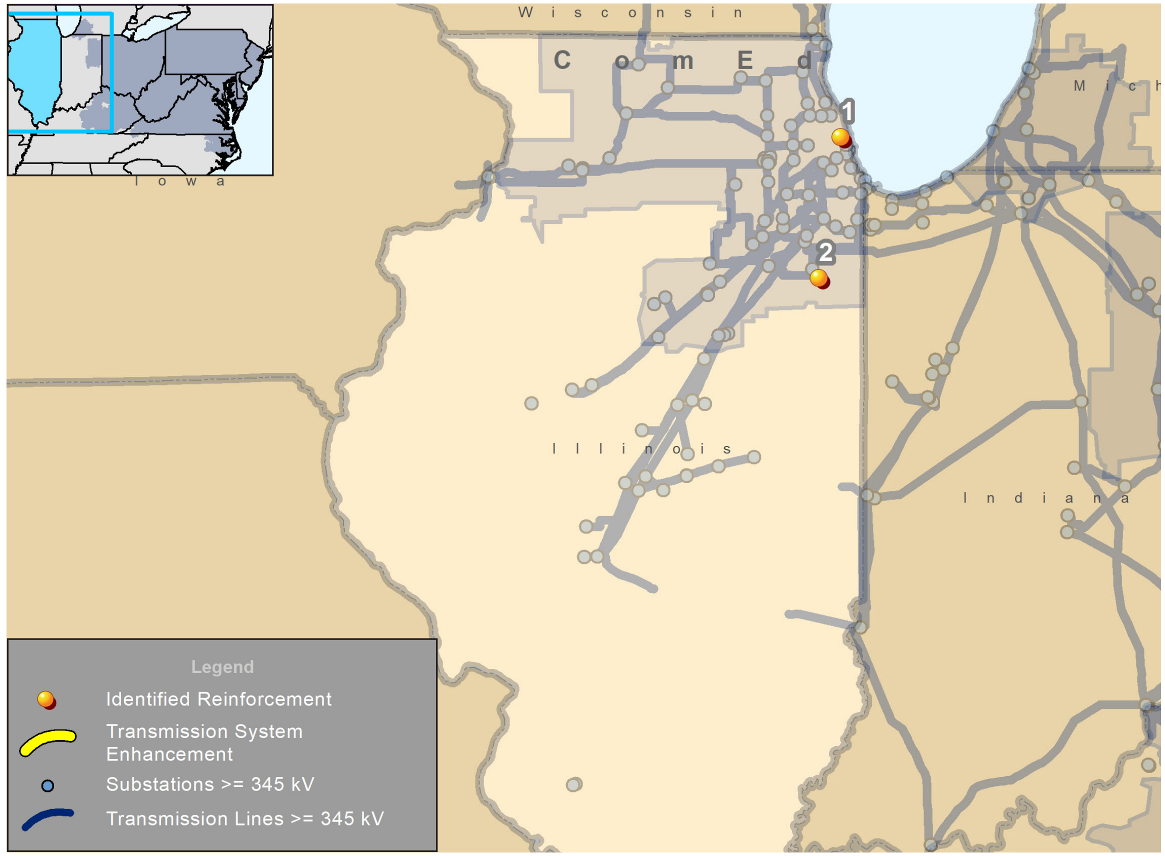


Table 6.9: Northern Illinois Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1793	Build a new superconducting cable that utilizes the second generation High Temperature Superconducting (HTS) wire to provide high transfer capacity between multiple 12 kV locations.	6/1/2026	$67.0	ComEd	3/25/2019
2	S1944	Build a double ring configuration substation near Bradley substation. Install two 138/12 kV transformers. Cut into existing Davis Creek-Kensington 138 kV lines No. 8603 & 8605.	5/31/2021	$16.0	ComEd	7/24/2019

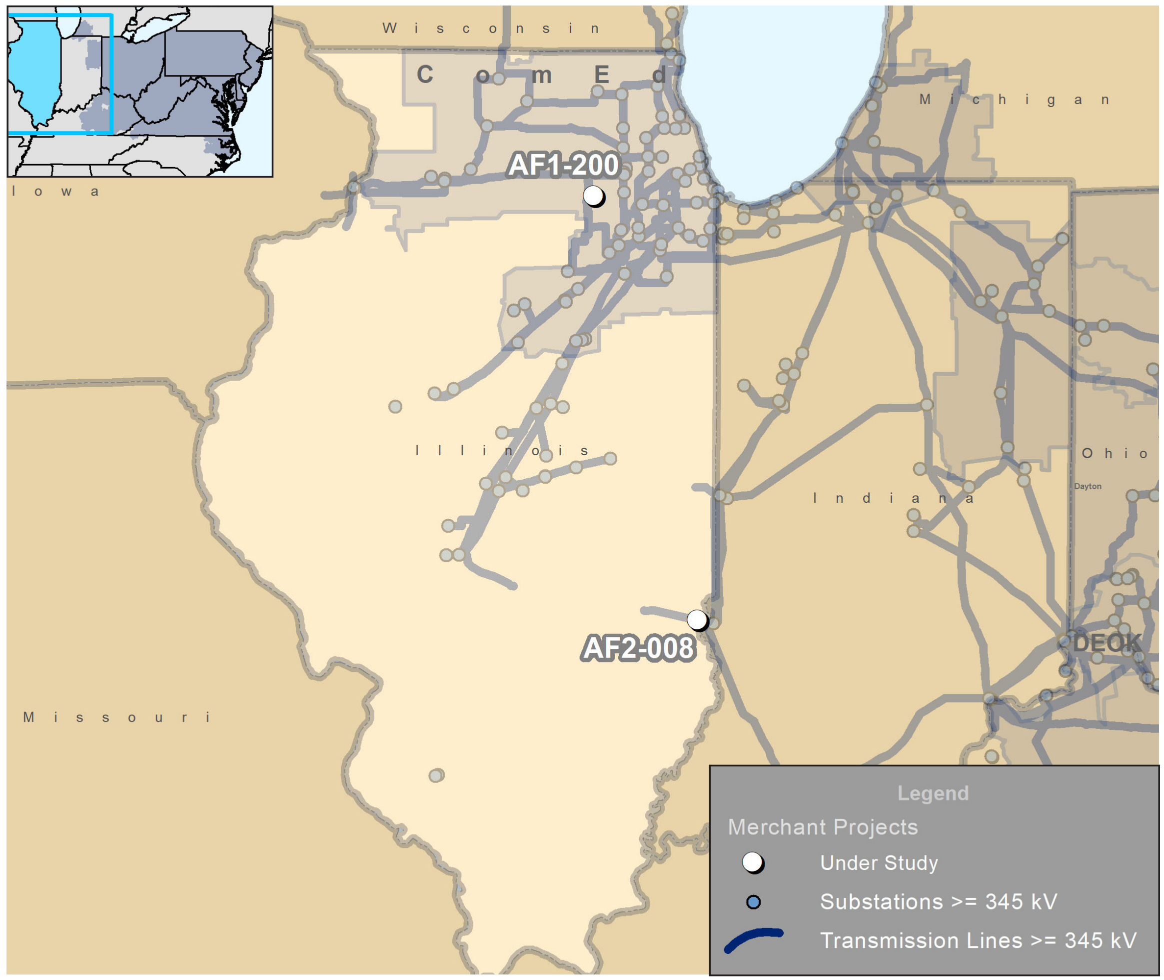
6.1.9 — Merchant Transmission Project Requests

As of Dec. 31, 2019, PJM's queue contained two merchant transmission project requests with a terminal in Northern Illinois, as shown in **Table 6.10** and **Map 6.8**.

Table 6.10: Northern Illinois Merchant Projects (Dec. 31, 2019)

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	2,035
AF2-008	Sullivan 345 kV	AEP	Active	12/31/2025	3,500

Map 6.8: Northern Illinois Merchant Projects (Dec. 31, 2019)

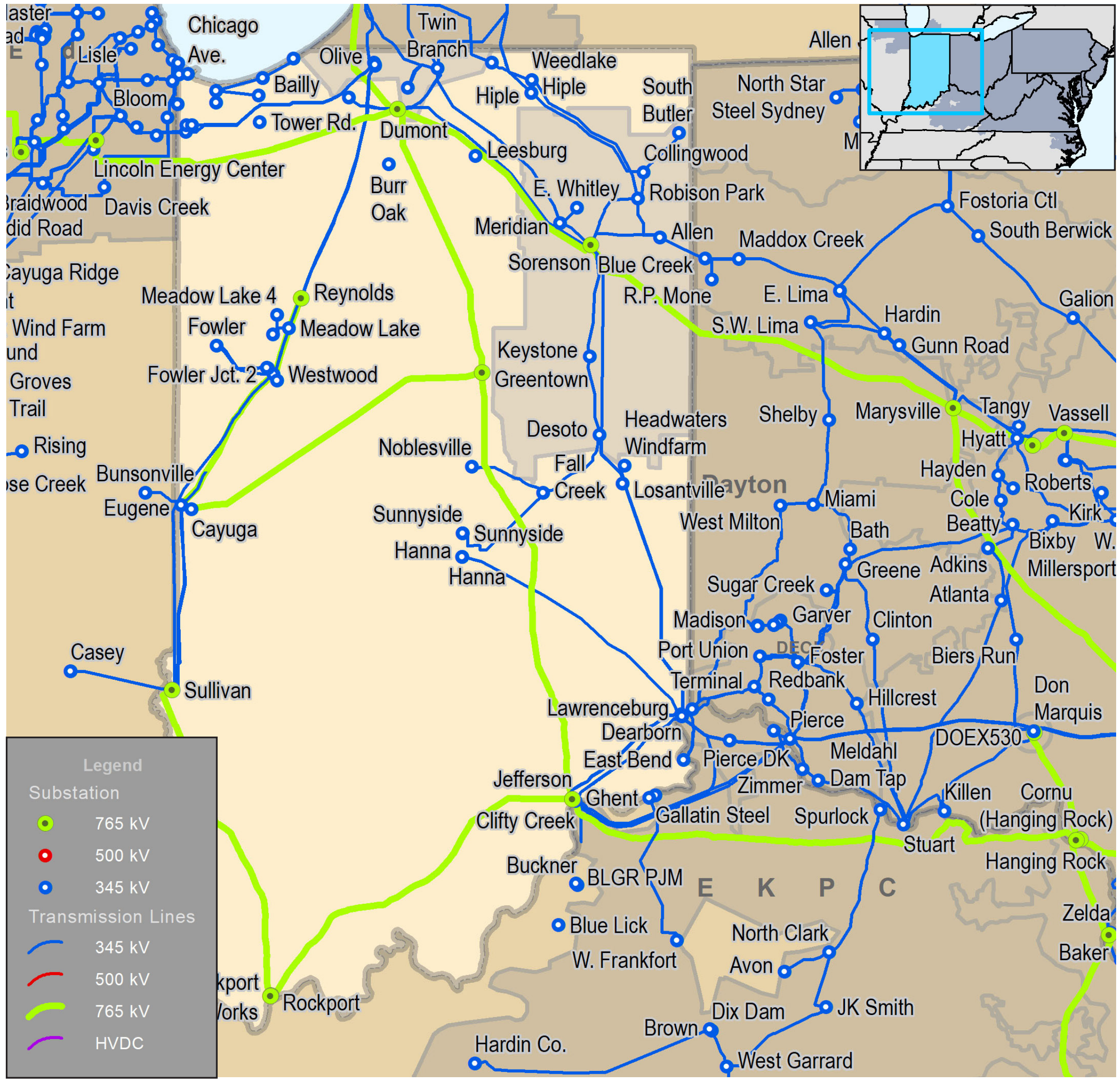


6.2: Indiana RTEP Summary

6.2.1 — RTEP Context

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

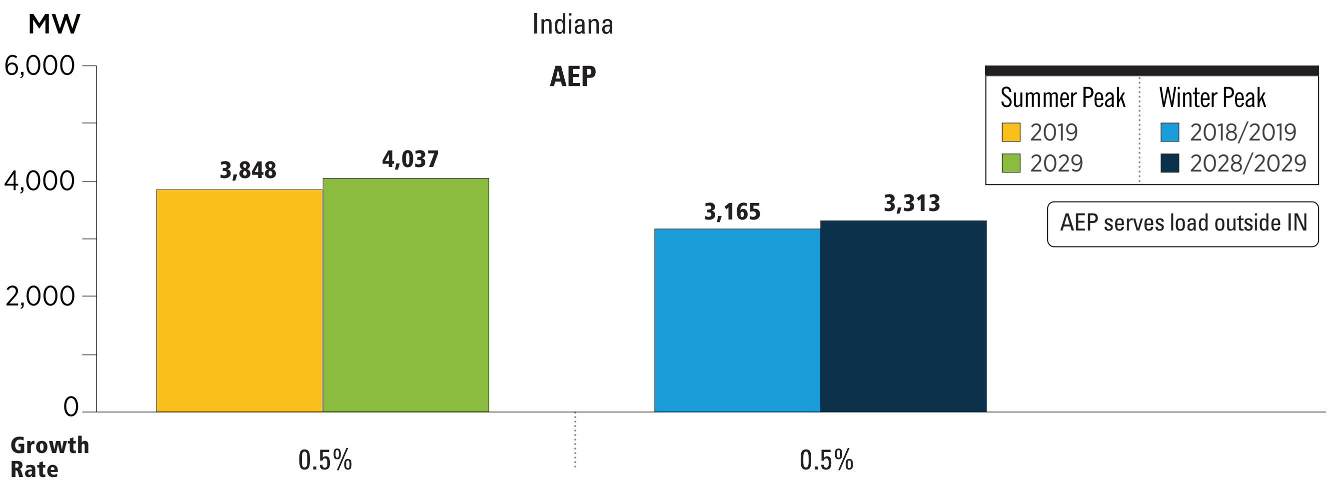
Map 6.9: PJM Service Area in Indiana



6.2.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.11** summarizes the expected loads within the state of Indiana and across all of PJM.

Figure 6.11: Indiana – 2019 Load Forecast Report



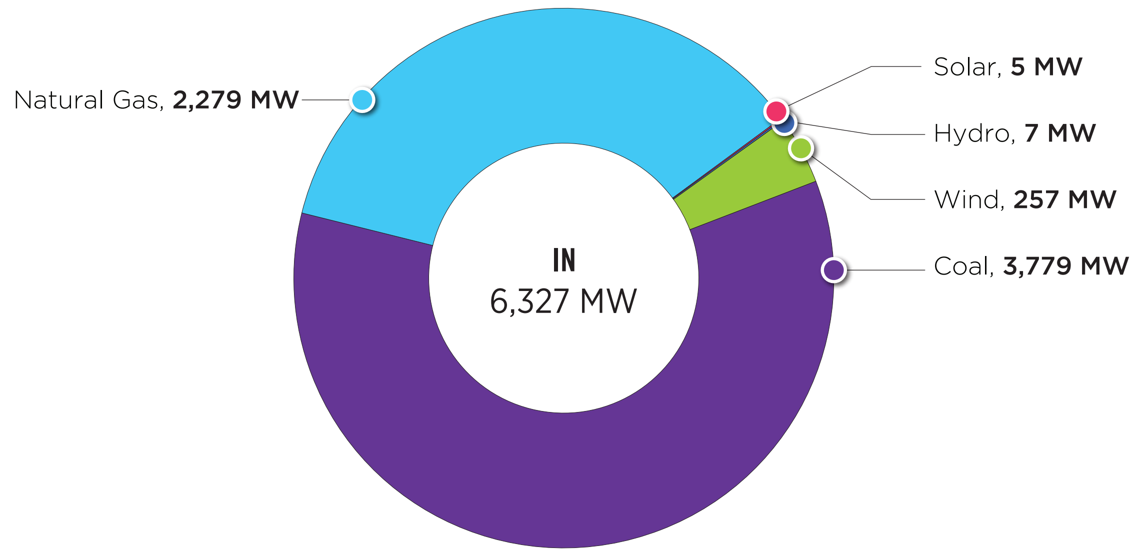
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156,689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. 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 Indiana as of Dec. 31, 2019, is shown by fuel type in **Figure 6.12**.

Figure 6.12: Indiana – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.2.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Indiana, 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.

Specifically, in Indiana, as of Dec. 31, 2019, 62 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.11**, **Table 6.12**, **Figure 6.13**, **Figure 6.14** and **Figure 6.15**. 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 6.11: Indiana – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	Indiana Capacity (MW)	Percentage of Total Indiana Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	0	0.00%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	1,200	22.65%	34,990	42.76%
Nuclear	0	0.00%	169	0.21%
Oil	0	0.00%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	3,315	62.56%	35,759	43.70%
Storage	334	6.31%	3,920	4.79%
Wind	449	8.48%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**5,299**	**100.00%**	**81,832**	**100.00%**

Table 6.12: Indiana – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	4	66.0	2	901.0	6	967.0
	Natural Gas	2	1,100.0	2	100.0	4	761.0	2	1,747.0	10	3,708.0
	Storage	8	334.3	0	0.0	0	0.0	6	232.1	14	566.5
Renewable	Methane	0	0.0	0	0.0	2	8.0	1	3.6	3	11.6
	Solar	36	3,315.0	0	0.0	3	5.1	13	2,005.0	52	5,325.0
	Wind	12	406.5	2	42.9	9	372.0	44	1,634.7	67	2,456.0
	Grand Total	**58**	**5,155.8**	**4**	**142.9**	**22**	**1,212.1**	**68**	**6,523.3**	**152**	**13,034.1**

Figure 6.13: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

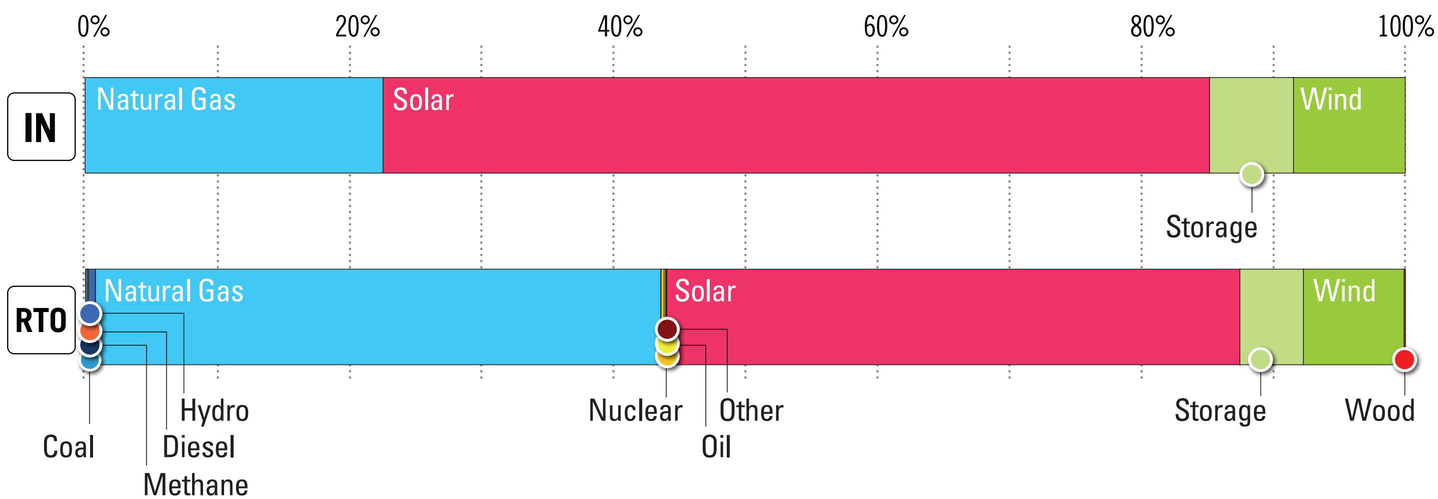
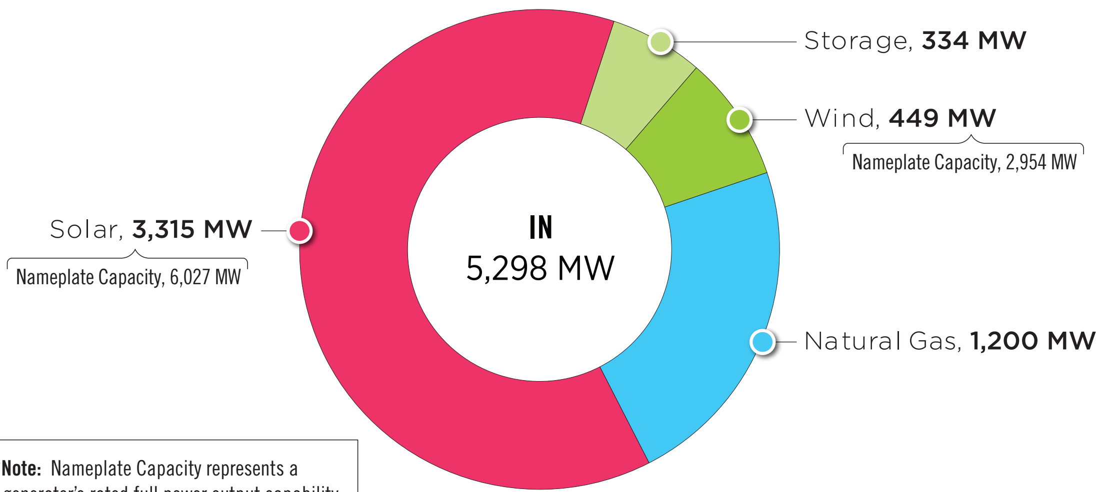


Figure 6.14: Indiana – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)



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

Figure 6.15: Indiana Progression History of Queue – Interconnection Requests (Dec. 31, 2019)

Projects withdrawn after final agreement

			Nameplate Capacity
3	Interconnection Service Agreements	71 MW	420 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatt	23% Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

6.2.5 — Generation Deactivations

No generating unit deactivation requests in Indiana between Jan. 1, 2019, and Dec. 31, 2019, were received as part of the 2019 RTEP.

6.2.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in Indiana are summarized in **Table 6.13** and **Map 6.10.**

Map 6.10: Indiana Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

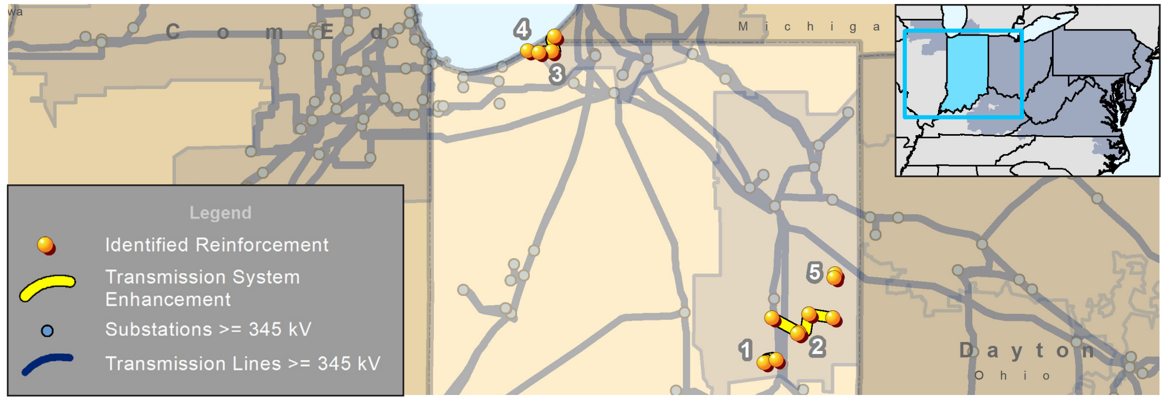


Table 6.13: Indiana Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3103	Install a 138/69 kV transformer at Royerton station. Install a 69 kV bus with one 69 kV breaker toward Bosman station. Rebuild the 138 kV portion into a ring bus configuration built for future breaker and a half with four 138 kV breakers.	6/1/2022	$70.8	AEP	1/11/2019
		Rebuild the Bosman/Strawboard station in the clear across the road to move it out of the flood plain and bring it up to 69 kV standards.				
		Retire 138 kV breaker L at Delaware station and re-purpose 138 kV breaker M for the Jay line.				
		Retire all 34.5 kV equipment at Hartford City station. Re-purpose breaker M for the Bosman line 69 kV exit.				
		Rebuild the 138 kV portion of Jay station as a six-breaker, breaker-and-a-half station re-using the existing breakers A, B and G. Rebuild the 69 kV portion of this station as a six-breaker ring bus re-using the two existing 69 kV breakers. Install a new 138/69 kV transformer.				
		Rebuild the 69 kV Hartford City-Armstrong Cork line, but instead of terminating it into Armstrong Cork, terminate it into Jay station.				
		Build a new 69 kV line from Armstrong Cork-Jay station.				
		Rebuild the 34.5 kV Delaware-Bosman line as the 69 kV Royerton-Strawboard line. Retire the line section from Royerton to Delaware stations.				
2	B3119	Rebuild the Jay-Pennville 138 kV line as double circuit 138/69 kV. Build a new 9.8 mile single circuit 69 kV line from near Pennville station to North Portland station.	6/1/2022	$43.4	AEP	5/20/2019
		Install three 69 kV breakers and add a low side breaker on Jay transformer No. 2.				
		Install two 69 kV breakers at North Portland station to complete the ring and allow for the new line.				
3	B3132	Rebuild 3.11 miles of the LaPorte Junction-New Buffalo 69 kV line with 795 ACSR.	6/1/2022	$12.3	AEP	6/17/2019
4	B3142	Rebuild Michigan City-Trail Creek-Bosserman 138 kV (10.7 miles).	1/1/2023	$24.7	NIPSCO	10/17/2019
5	B3209	Rebuild the 10.5 mile Berne-South Decatur 69 kV line using 556 ACSR in order to alleviate the overload and address a deteriorating asset.	6/1/2022	$16.6	AEP	4/23/2019

6.2.7 — Network Projects

No network projects greater than or equal to $10 million in Indiana were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.2.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in Indiana are summarized in **Table 6.14** and **Map 6.11**.

Map 6.11: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

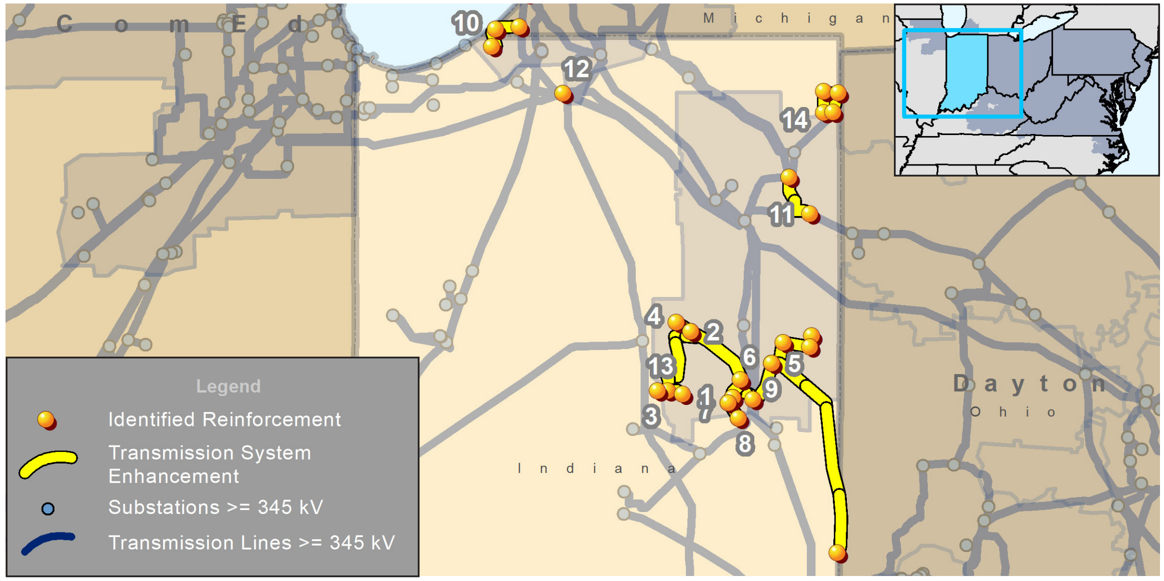


Table 6.14: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Projects	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1854	Medford Station	6/1/2022	$68.9	AEP	1/11/2019
		Install a new distribution transformer and bay at Arnold Hogan substation. Replace existing transformer and install a switcher on both transformers. Rebuild the 138 kV side as a breaker-and-a-half with three new 138 kV breakers. Rebuild the 34.5 kV voltage class as a ring bus with a new 28.8 MVAR cap bank.	6/1/2022			
		Retire Elmridge Station	6/1/2022			
		Rebuild the 34.5 kV voltage class 23rd Street substation as a six-breaker ring bus with five new 69 kV-rated breakers. Install three 138 kV breakers to form a ring bus on the high side. Retire the cap banks. Rebuild the underground line exits as overhead.	6/1/2022			
		Rebuild Medford station with a three breaker, 69 kV-rated ring bus on the 34.5 kV side. Rebuild the high side as a three breaker 138 kV ring bus. Replace the transformer with a 138/69/34.5 kV bank. Retire the cap bank.	6/1/2022			
		Retire Blaine Street station breaker E and construct a new 69 kV-rated bus with a new 69 kV-rated breaker and distribution bank.	6/1/2022			
		Build a new 138 kV Fuson station with a 138 kV bus tie breaker and two distribution banks to serve the Delco Battery site.	6/1/2022			
		Rebuild the Arnold Hogan-23rd Street 138 kV line from Arnold Hogan-STR 56 north of Utica using 556 ACSR.	6/1/2022			
		Build a new 138 kV line tapping the Arnold Hogan-23rd Street line toward the Fuson station site using 1033.5 ACSR.	6/1/2022			
		Retire the Elmridge tap line.	6/1/2022			

Table 6.14: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Projects	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S1855	Deer Creek-Delaware 138 kV line.	10/8/2021	$57.3	AEP	2/20/2019
		Rebuild ~19.8 miles of the Deer Creek-Delaware double circuit 138 kV line from structure 16 to structure 127.	10/8/2021			
		Install a 138 kV breaker at Gaston in the bus tie position (facing Desoto).	10/8/2021			
		Reterminate into the 138 kV breaker P at Delaware.	10/8/2021			
3	S2012	Retire the ~10.5 mile South Summitville-Jonesboro 34.5 kV line.	10/1/2021	$16.3	AEP	4/23/2019
		Retire Jonesboro 34.5 kV station.	10/1/2021			
		Build the new 69 kV Dean station with a single bus tie breaker to replace the Fairmount and Peacock 34.5 kV stations.	10/1/2021			
		Replace the 138/34.5 kV transformer No. 1 and the existing 34.5 kV breaker at South Elwood station with a 138/69 kV transformer and a 69 kV breaker.	10/1/2021			
		Build a three breaker 69 kV ring bus at Deer Creek 138/69/34.5 kV station in the clear to connect to the now 69 kV South Summitville line. Add a 138 kV breaker to the high side of transformer No. 1 to replace the motor-operated air break.	10/1/2021			
		Install a 138 kV bus tie breaker at Aladdin station to break up the four motor-operated air breaks in series.	10/1/2021			
		Rebuild Elwood 34.5 kV station in the clear as an in and out station with a bus tie breaker.	10/1/2021			
		Energize the Ohio Oil, South Summitville and Strawton stations and the lines connecting them to 69 kV. These stations and lines are already built to this standard.	10/1/2021			
4	S2013	Rebuild the 2.2 mile Grant-West End 34.5 kV line using 556.5 ACSR.	6/1/2022	$19.0	AEP	5/20/2019
		Retire the Deer Creek-Miller Ave 34.5 kV line.	6/1/2022			
		Rebuild the 3.5 mile Deer Creek-Marion Plant 34.5 kV line using 556.5 ACSR	6/1/2022			
		Retire the Deer Creek-East Tap 34.5 kV line.	6/1/2022			
		Re-route the Atlas Tap 34.5 kV line into West End station.	6/1/2022			
		Retire 34.5 kV breakers H, F, K and V and the 34.5 kV cap banks at Deer Creek 138/69/34.5 kV station. Re-use the 69 kV-rated breaker J toward South Side station. Re-use breakers A and E from South Summitville to replace breaker M and W at Deer Creek.	6/1/2022			
		Install a 69 kV breaker on Marion Plant line exit at South Side 34.5 kV station.	6/1/2022			
		Install a 14.4 MVAR138 kV cap bank and a 138 kV high side circuit switcher at Grant 138/34.5 kV station.	6/1/2022			
5	S2014	Rebuild the 62 mile College Corner-Jay 138 kV line as single circuit 138 kV. New conductor will be 795 ACSR.	12/1/2023	$113.5	AEP	5/20/2019
6	S2015	Retire the ~20 mile Delaware-Jay 34.5 kV line.	12/10/2021	$24.7	AEP	5/20/2019
		Rebuild the 2.5 miles of the Delaware-Haymond 34.5 kV line from Delaware to a point near Centennial Road using 556.5 ACSR (south of the road the line is newer construction).	12/10/2021			
		Reconfigure the Desoto-Jay 138 kV line to allow for the Perch Extension connection.	12/10/2021			
		Build a new ~1 mile 138 kV Perch extension to connect the new station to the Desoto-Jay 138 kV line.	12/10/2021			
		Rebuild the 34.5 kV bus at the Delaware 138/34.5 kV station as a 69 kV ring bus using three new breakers.	12/10/2021			
		Retire all 34.5 kV equipment at the Jay 138/69/34.5 kV station.	12/10/2021			
		Build a new in and out Perch 138 kV station with two motor-operated air breaks to allow retirements of the Delaware-Jay 34.5 kV line. Perch will pick up loads from retiring Sharon Road, Barley and Albany stations.	12/10/2021			

Table 6.14: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Projects	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
7	S2016	Arnold Hogan-Kenmore 34.5 kV (West Section): Rebuild 1.3 miles in the clear from structure 1 to structure 47 utilizing double circuit 34.5 kV line (69 kv-rated) with only the north side strung. New conductor will be 556.5 ACSR	6/1/2022	$15.7	AEP	5/20/2019
		Arnold Hogan-Kenmore 34.5 kV (East Section): Rebuild the 0.5 miles from STR 80 to Kenmore as underground construction.				
8	S2018	Rebuild the 3.3 mile Medford-Blaine Street 34.5 kV line to 69 kV using 795 Drake ACSR.	12/1/2022	$14.4	AEP	6/17/2019
		Retire the 3.7 mile Haymond-Blaine 34.5 kV line.				
		Retire the 3.3 mile Haymond-Medford 34.5 kV line portion south of 21st Street station.				
		Build a new 34.5 kV Blaine Street double circuit extension to facilitate the re-termination of the Haymond and 23rd Street lines into Blaine Street.				
		Retire the unused 34.5 kV breaker E at Haymond station.				
9	S2021	Rebuild the Antiville 69 kV station throughpath to allow for connection to the new Jay-North. Portland 69 kV line.	6/1/2022	$71.0	AEP	5/20/2019
		Retire the radial Antiville Tap 69 kV line.				
		Rebuild the ~38.5 mile Jay-Allen 138 kV line from Pennville to the juncture west of Allen station. This line is a single circuit 138 kV line using 795 ACSR.				
10	S2022	Rebuild 3.52 miles of the LaPorte-New Buffalo 69 kV line and re-terminate into Bosserman station.	12/15/2020	$15.7	AEP	6/17/2019
		At Bosserman station, install new 138/69 kV transformer, install 69 kV low side breaker on transformer No. 1, and 69 kV line breaker B towards Three Oaks Station.				
		Replace 69 kV line breakers C and B at Three Oaks station.				
		Replace 69 kV line breakers B, A and C at Bridgman station.				
		Retire Laporte Junction 69 kV Station.				
11	S2058	Rebuild 12 miles of the Allen-Robison Park double circuit 138 kV line using 795 ACSR Drake conductor.	10/15/2022	$34.9	AEP	8/29/2019
12	S2086	Replace Dumont 765/345 kV, 1500 MVA Transformer T2 with new 2250 and install associated protective equipment, including two 345 kV breakers.	11/1/2020	$27.8	AEP	10/17/2019
13	S2092	Rebuild 16.5 miles of the Deer Creek-Makahoy 138 kV line using 795 ACSR Drake conductor. Rebuild 3.9 miles of the Deer Creek-Makahoy 138 kV line as double circuit using 795 ACSR Drake conductor west from Deer Creek. Operate as double circuit to allow for bringing the Grant line into Deer Creek, eliminating the three terminal line.	10/1/2022	$47.1	AEP	10/25/2019
		Install a 138 kV circuit breaker at Deer Creek Station for the new line exit.				

Table 6.14: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Projects	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
14	S2098	Rebuild 0.15 miles Butler-Basket Factory 69 kV section and rebuild 7.2 miles Basket Factory-Hamilton 69 kV section with 556 ACSR.	6/22/2022	$42.8	AEP	10/25/2019
		Build 1.6 mile long greenfield line on the Hamilton-Muskrat SW 69 kV Section to loop Hamilton and replace roughly 0.8 miles of poles with woodpecker holes on the Hamilton-Muskrat SW 69 kV section with 556 ACSR.				
		Build 8.37 mile long greenfield line with 556 ACSR from Federal Sw to Muskrat Sw to provide two way service to University Tool, Hamilton and Dome Stations.				
		Build a 0.04 mile long greenfield line with 556 ACSR to eliminate the hard tap on the Butler-Hicksville Junction 138 kV Line.				
		Relocate the line entrance at Butler Station.				
		At Butler 69 kV station, install three 69 kV breakers and two cap banks to accommodate the line loops.				
		Install 69 kV phase over phase switch outside Universal Tool called Basket Factory Switch.				
		At Hamilton 69 kV station, install one line motor-operated air break and one line breaker.				
		Install 69 kV phase-over-phase switch outside Dome station called Muskrat switch.				
		Install 69 kV phase-over-phase switch outside Therma Tru called Federal switch.				
		Remove Metcalf tap from the Butler-North Hicksville 69 kV line and reconnect the throughpath.				
		Remote end relay upgrades at North Hicksville 69 kV.				

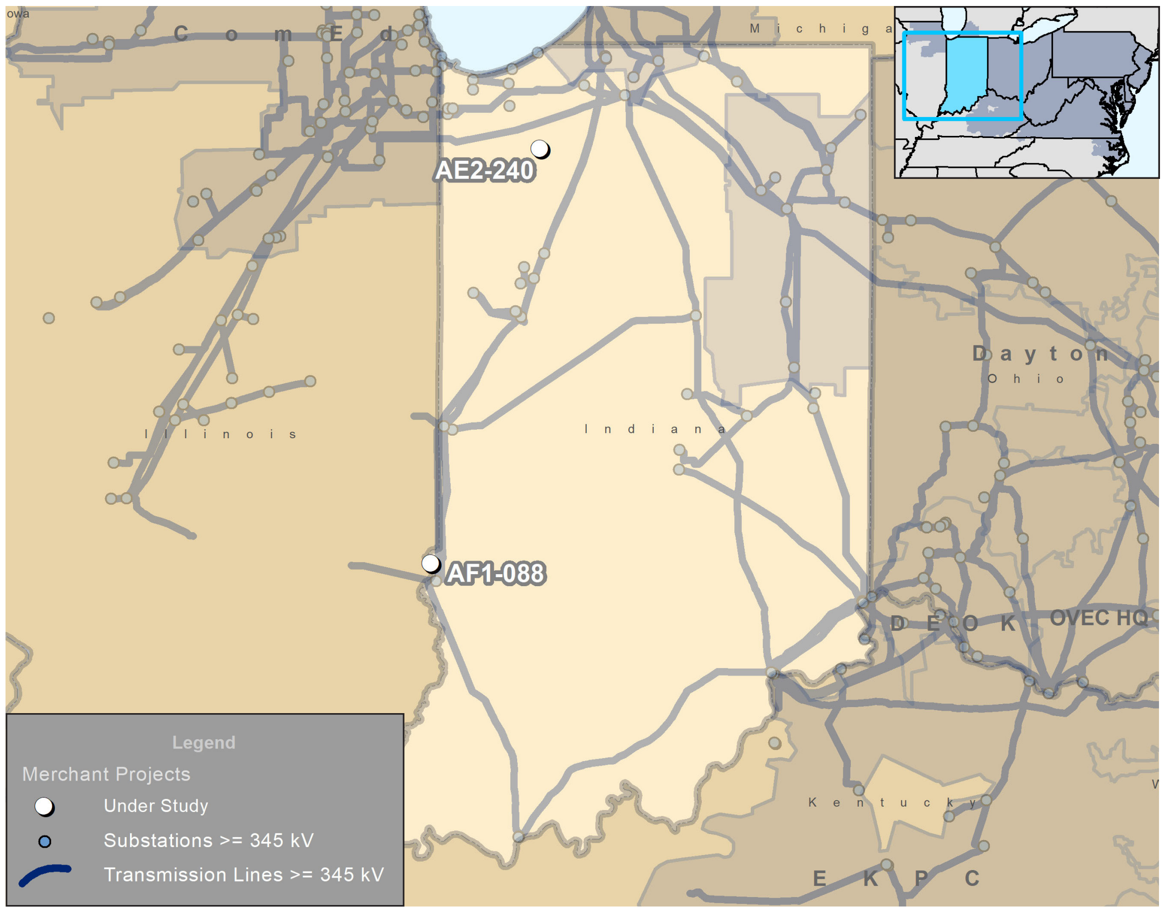
6.2.9 — Merchant Transmission Project Requests

As of Dec. 31, 2019, PJM's queue contained two merchant transmission project requests which include a terminal in Indiana as shown in **Table 6.15** and **Map 6.12.**

Table 6.15: Indiana Merchant Transmission Projects (Dec. 31, 2019)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AE2-240	Olive-Reynolds 345 kV No. 1 & 2	AEP	Active	6/1/2019	3,170
AF1-088	Sullivan 345 kV	AEP	Active	12/31/2025	1,000

Map 6.12: Indiana Merchant Transmission Projects (Dec. 31, 2019)

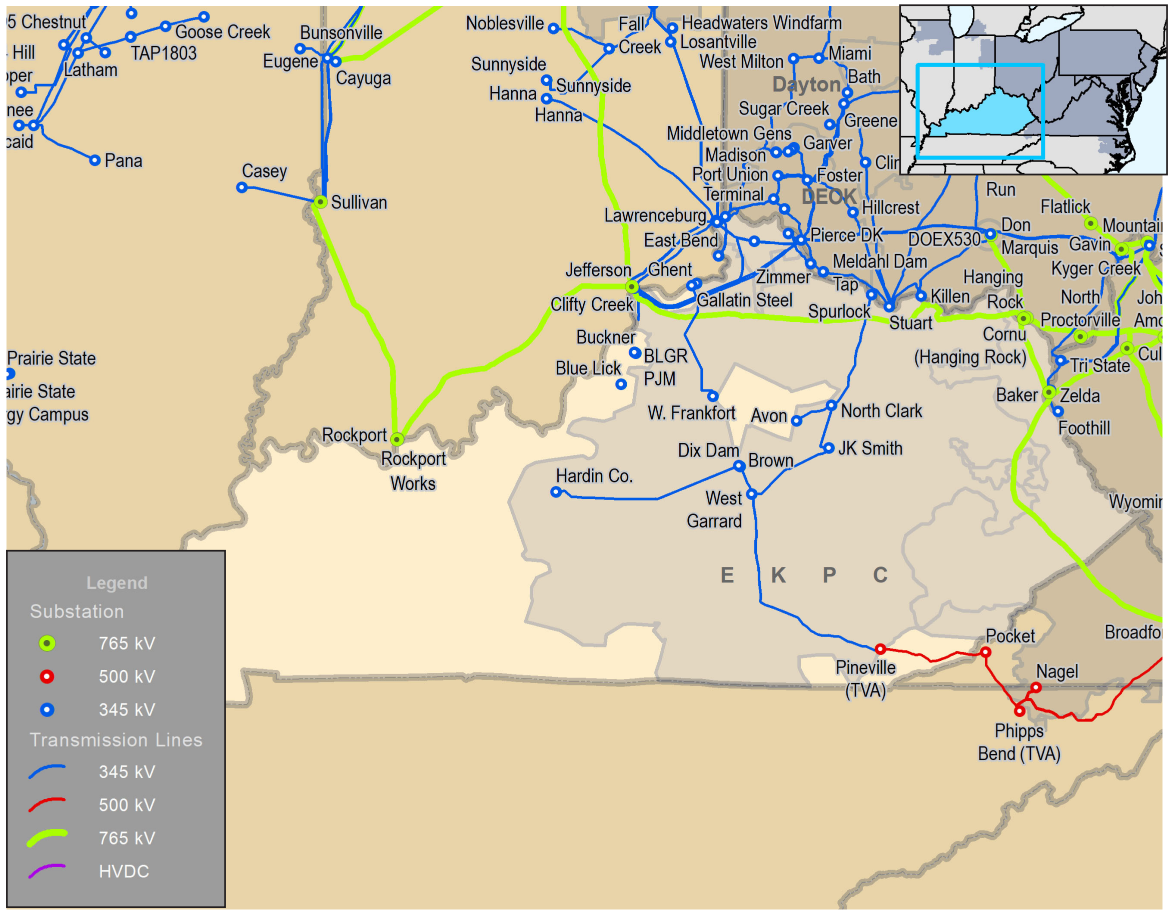


6.3: Kentucky RTEP Summary

6.3.1 — 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 6.13**. Duke Energy Ohio (DEO) 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 PJM.

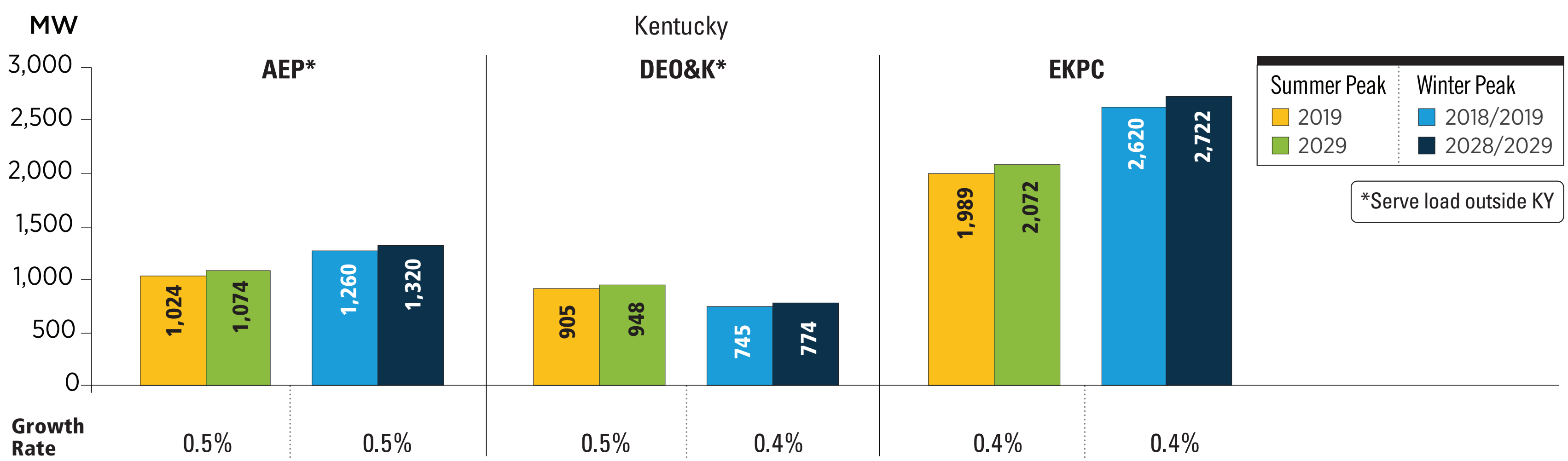
Map 6.13: PJM Service Area in Kentucky



6.3.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.16** summarizes the expected loads within the state of Kentucky and across all of PJM.

Figure 6.16: Kentucky – 2019 Load Forecast Report



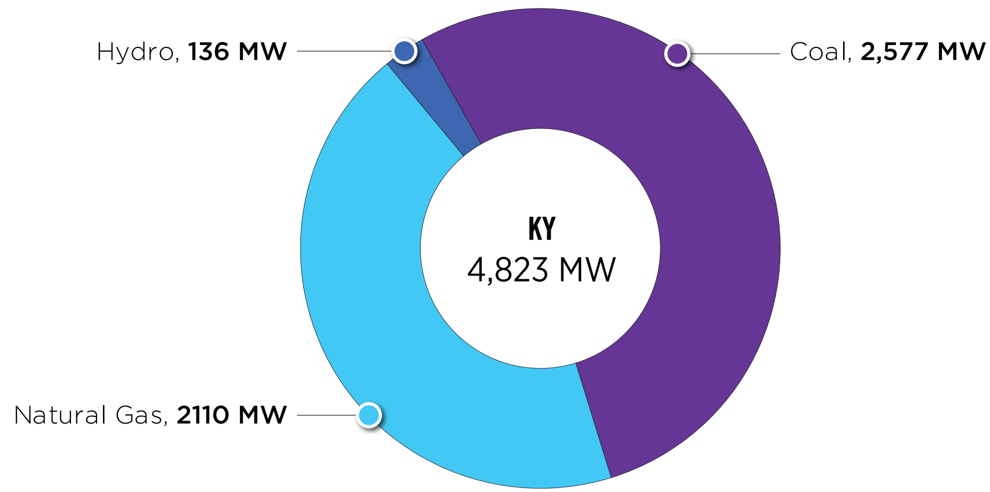
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156,689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. 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 Kentucky as of Dec. 31, 2019, is shown by fuel type in **Figure 6.17**.

Figure 6.17: Kentucky – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.3.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Kentucky, 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.

Specifically, in Kentucky, as of Dec. 31, 2019, 39 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.16**, **Table 6.17**, **Figure 6.18**, **Figure 6.19** and **Figure 6.20**. 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 6.16: Kentucky – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	Kentucky Capacity (MW)	Percentage of Total Kentucky Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	0	0.00%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	1,100	32.19%	34,990	42.76%
Nuclear	0	0.00%	169	0.21%
Oil	0	0.00%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	2,233	65.33%	35,759	43.70%
Storage	85	2.49%	3,920	4.79%
Wind	0	0.00%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**3,418**	**100.00%**	**81,832**	**100.00%**

Table 6.17: Kentucky – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	0	0	0	0	0	0	6	2,969.0	6	2,969.0
	Natural Gas	0	0	1	1,100.0	6	71.0	5	1,704.7	12	2,875.7
	Storage	2	85.0	0	0	0	0	1	81.2	3	166.2
Renewable	Biomass	0	0	0	0	0	0	5	198.5	5	198.5
	Hydro	0	0	0	0	0	0	1	70.0	1	70.0
	Solar	36	2,232.7	0	0	0	0	11	605.1	47	2,837.8
	Grand Total	**38**	**2,317.7**	**1**	**1,100.0**	**6**	**71.0**	**31**	**5,655.8**	**76**	**9,144.5**

Figure 6.18: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

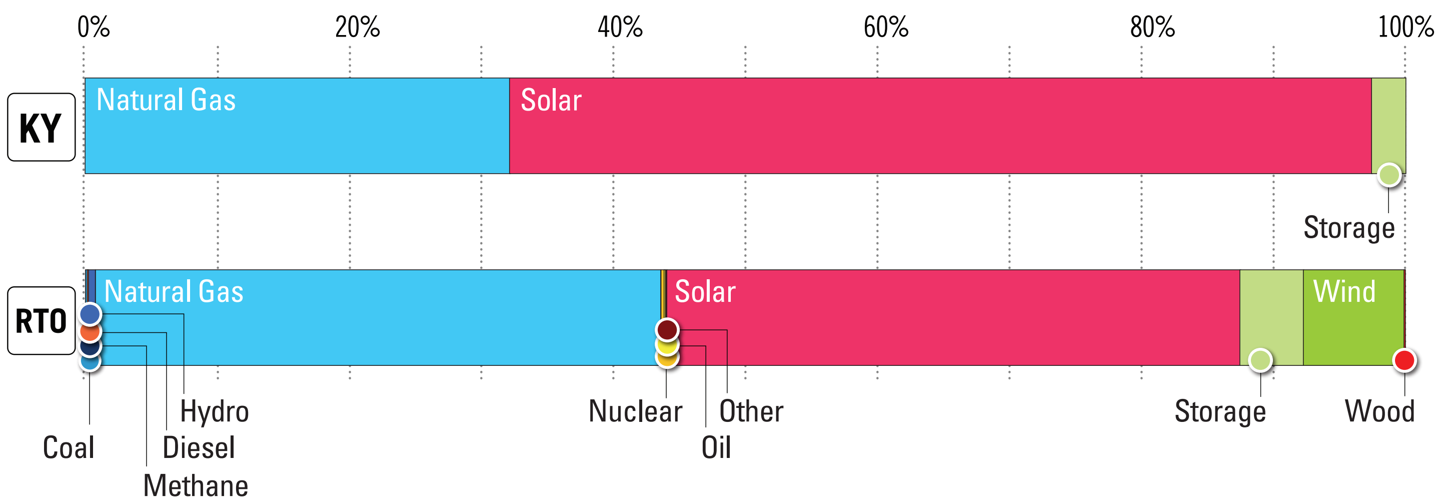


Figure 6.19: Kentucky – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)

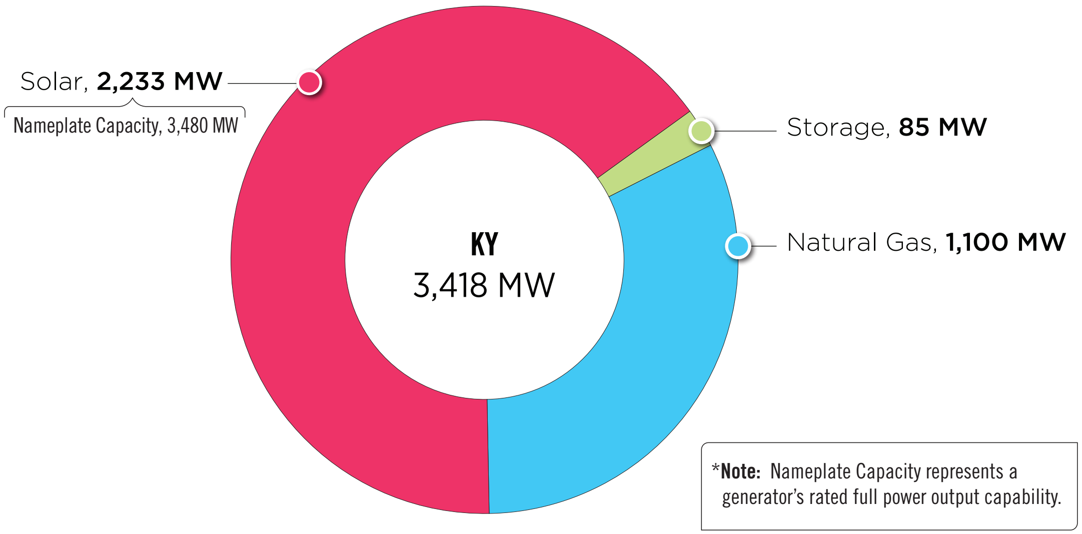


Figure 6.20: Kentucky Progression History of Queue – Interconnection Requests(Dec. 31, 2019)

Projects withdrawn after final agreement			Nameplate Capacity
1	Interconnection Service Agreements	**80 MW**	80 MW

Percentage of planned capacity and projects that have reached commercial operation	1%	16%
	Requested capacity megawatt	Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

6.3.5 — Generation Deactivation

No generating unit deactivation requests in Kentucky were received between Jan. 1, 2019, and Dec. 31, 2019, as part of the 2019 RTEP.

6.3.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in Kentucky are summarized in **Table 6.18** and **Map 6.14**.

6.3.7 — Network Projects

No network projects greater than or equal to $10 million in Kentucky were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.14: Kentucky Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

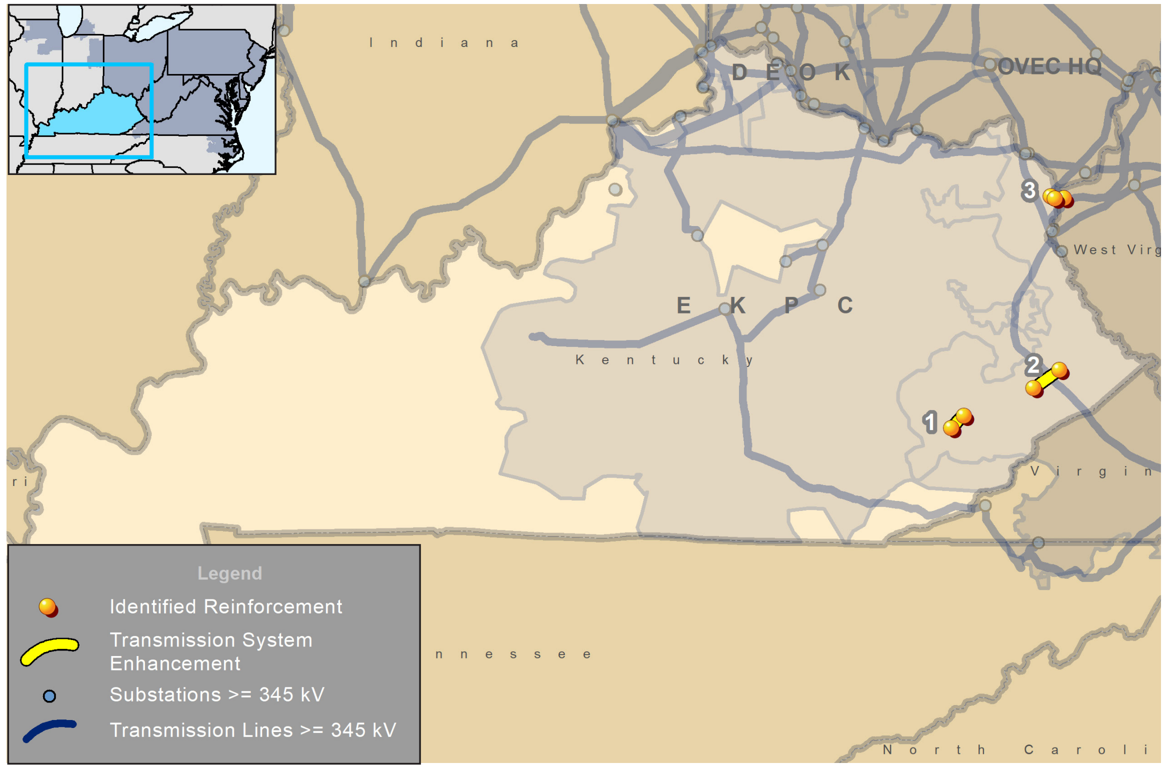


Table 6.18: Kentucky Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B2761	Replace and relocate the Hazard 161/138 kV transformer and circuit breaker M. Upgrade protection scheme on the new transformer including installation of low side breaker.	6/1/2021	$20.6	AEP	10/6/2016
		Rebuild the Hazard-Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating). Replace line relaying and associated termination equipment.				11/2/2017
2	B3087	Construct a new greenfield station to the west (~1.5 mi.) of the existing Fords Branch Station, potentially in/near the new Kentucky Enterprise Industrial Park. This new station will consist of four 138 kV breaker ring buses and two 30 MVA 138/34.5 kV transformers. The existing Fords Branch Station will be retired.	12/1/2023	$23.2	AEP	11/29/2018
		Construct ~5 miles of new double circuit 138 kV line in order to loop the new Fords Branch station into the existing Beaver Creek-Cedar Creek 138 kV circuit.				
		Remote end work will be required at Cedar Creek Station.				

Table 6.18: Kentucky Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019) (Cont.)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	B3118	Expand existing Chadwick station and install a second 138/69 kV transformer at a new 138 kV bus tied into the Bellefonte-Grangston 138 kV circuit. The 69 kV bus will be reconfigured into a ring bus arrangement to tie the new transformer into the existing 69 kV via installation of four 3000A 63 kA 69 kV circuit breakers.	6/1/2022	$16.9	AEP	2/20/2019
		Perform 138 kV remote end work at Grangston station.				
		Perform 138 kV remote end work at Bellefonte station.				
		Relocate the Chadwick-Leach 69 kV circuit within Chadwick station.				
		Terminate the Bellefonte-Grangston 138 kV circuit to the Chadwick 138 kV bus.				
		Chadwick-Tri-State No. 2 138 kV circuit will be reconfigured within the station to terminate into the newly established 138 kV bus No. 2 at Chadwick due to construction aspects.				
		Reconductor Chadwick-Leach and Chadwick-England Hill 69 kV lines with 795 ACSS conductor. Perform a LiDAR survey and a sag study to confirm that the reconductored circuits would maintain acceptable clearances.				
		Rebuild 336 ACSR portion of Leach-Miller Stainless Steel 69 kV line section (~0.3 miles) with 795 ACSS conductor.				
		Replace 69 kV line risers (towards Chadwick) at Leach station.				

6.3.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in Kentucky are summarized in **Table 6.19** and **Map 6.15**.

6.3.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Kentucky were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.15: Kentucky Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

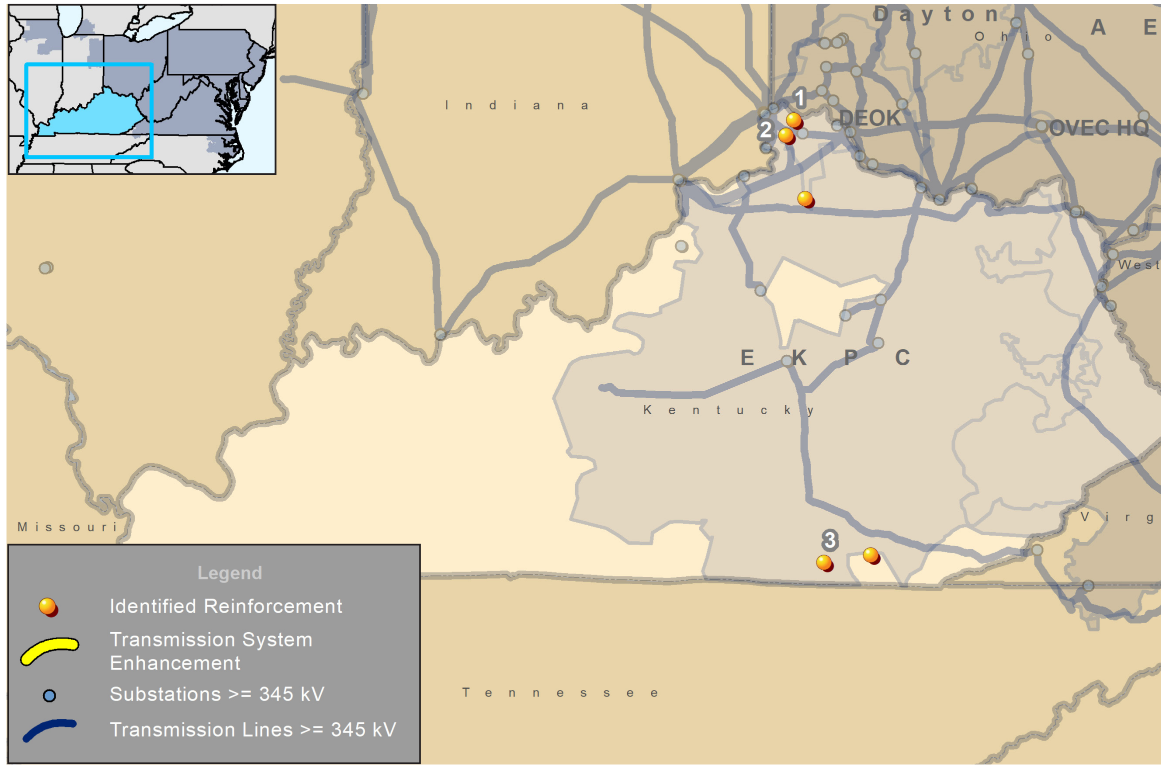


Table 6.19: Kentucky Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

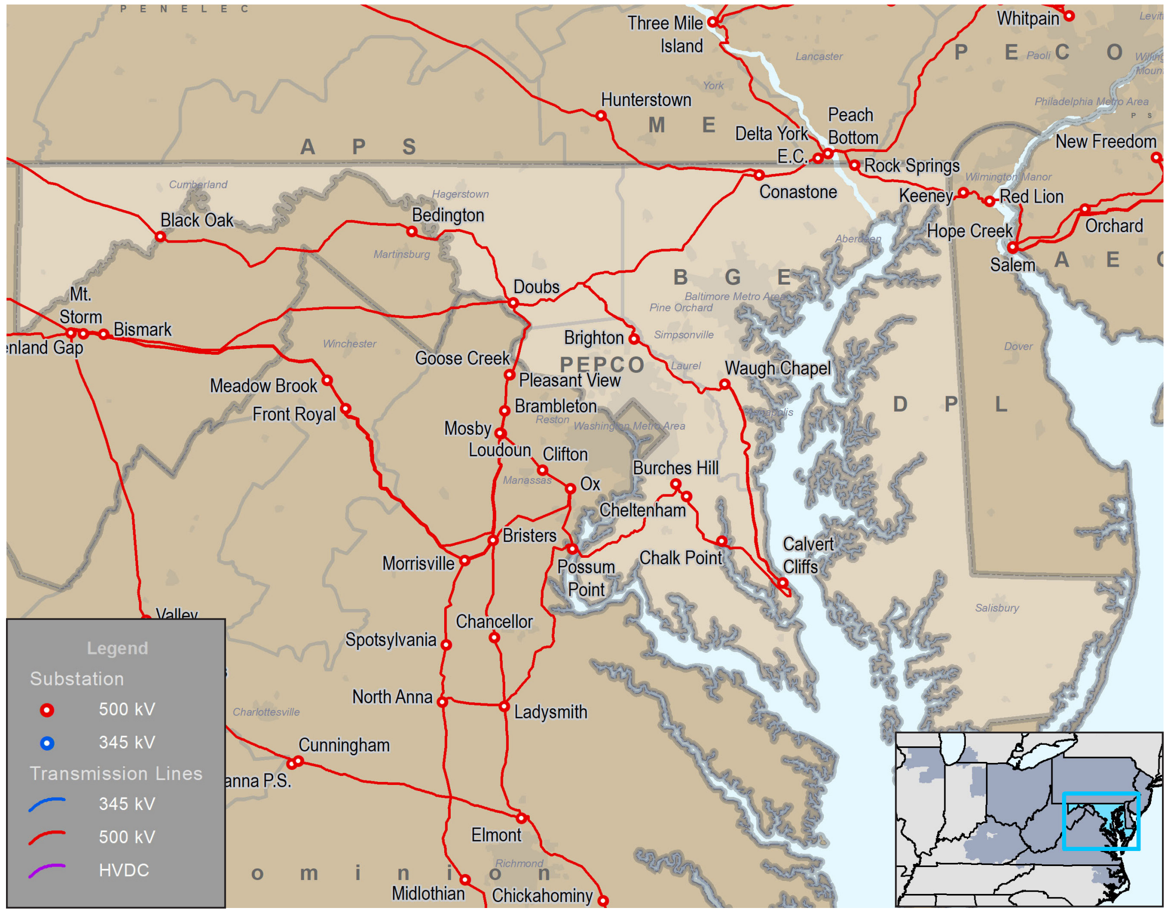
Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1782	Install a new 138 kV, three-breaker ring bus substation, Woodspoint. Install a new 138 kV, six-breaker ring bus, Aero, near Amazon Prime Hub. Install new 138 kV lines from Woodspoint to Aero, and from Aero to Oakbrook.	12/31/2020	$30.2	DEO&K	1/11/2019
2	S1940	Rebuild Boone County-Williamstown 69 kV line using 556.5 ACSR (28.5 miles).	12/1/2024	$15.8	EKPC	3/25/2019
3	S1941	Rebuild the KU Wofford-Whitley City 69 kV line using 556.5 ACSR conductor (20.7 miles)	12/31/2022	$13.0	EKPC	3/25/2019

6.4: Maryland/District of Columbia RTEP Summary

6.4.1 — 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 (AP), Baltimore Gas & Electric Company (BGE), Delmarva Power & Light (DP&L), Potomac Electric Power Company (PEPCO) and Southern Maryland Electric Cooperative (SMECO) as shown on **Map 6.16**. 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 PJM.

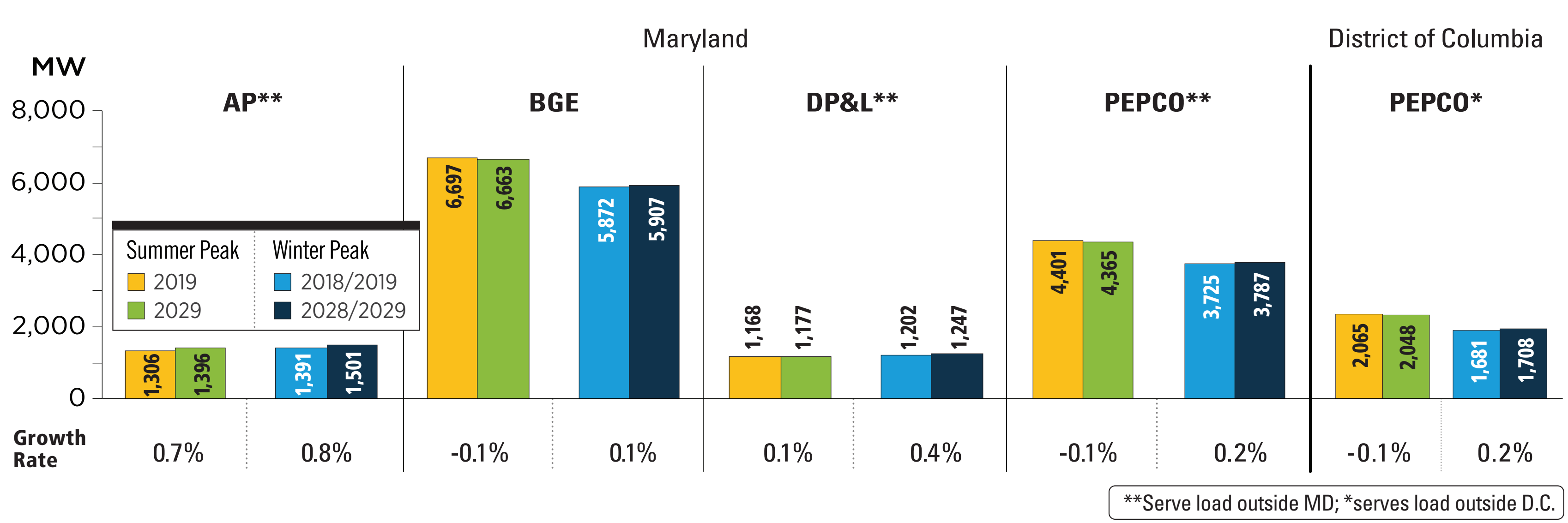
Map 6.16: PJM Service Area in Maryland and the District of Columbia



6.4.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.21** summarizes the expected loads within the state of Maryland and the District of Columbia and across all of PJM.

Figure 6.21: Maryland and the Washington, D.C. – 2019 Load Forecast Report



PJM RTO Summer Peak

2019	2029
151,358 MW	156, 689 MW

Growth Rate 0.3%

PJM RTO Winter Peak

2018/2019	2028/2029
131,082 MW	136,178 MW

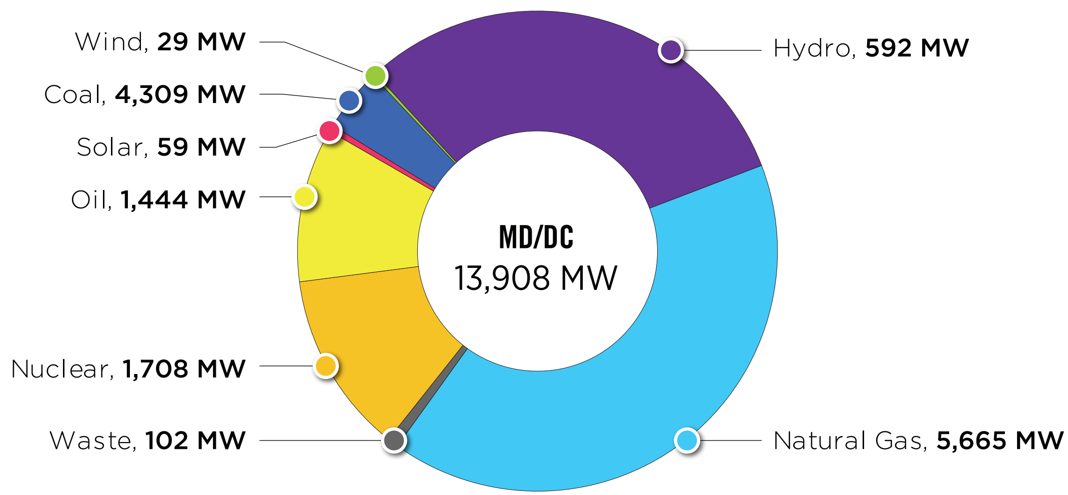
Growth Rate 0.4%

The summer and winter peak megawatt values reflect the estimated amount of forecasted 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 Maryland and the District of Columbia as of Dec. 31, 2019, is shown by fuel type in **Figure 6.22**.

Figure 6.22: Maryland and the District of Columbia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.4.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Maryland and the District of Columbia, 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.

Specifically, in Maryland and the District of Columbia, as of Dec. 31, 2019, 82 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.20**, **Table 6.21**, **Figure 6.23**, **Figure 6.24** and **Figure 6.25**. 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 6.20: Maryland and the District of Columbia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	Maryland/D.C. Capacity (MW)	Percentage of Total Maryland/D.C. Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	15	0.65%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	1,216	52.76%	34,990	42.76%
Nuclear	37	1.62%	169	0.21%
Oil	14	0.61%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	888	38.54%	35,759	43.70%
Storage	117	5.08%	3,920	4.79%
Wind	17	0.73%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**2,305**	**100.00%**	**81,832**	**100.00%**

Table 6.21: Maryland and the District of Columbia – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn		Grand Total	
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of 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	144.6	3	952.0	3	119.5	32	3,707.7	61	31,908.5	100	36,832.3
	Nuclear	3	37.4	0	0.0	0	0.0	1	0.0	4	4,955.0	8	4,992.4
	Oil	1	14.0	0	0.0	0	0.0	2	5.0	1	2.0	4	21.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	4	132.0	4	132.0
	Storage	5	117.2	0	0.0	0	0.0	0	0.0	30	60.0	35	177.2
Renewable	Biomass	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	3	73.4	7	148.4
	Methane	0	0.0	0	0.0	0	0.0	6	18.5	6	18.3	12	36.8
	Solar	38	663.9	9	84.8	16	139.7	11	38.5	161	848.9	235	1,775.8
	Wind	0	0.0	1	9.1	1	7.8	4	32.5	9	256.5	15	305.9
	Grand Total	**49**	**992.1**	**13**	**1,045.9**	**20**	**267.0**	**61**	**3,872.2**	**292**	**38,487.2**	**435**	**44,664.3**

Figure 6.23: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

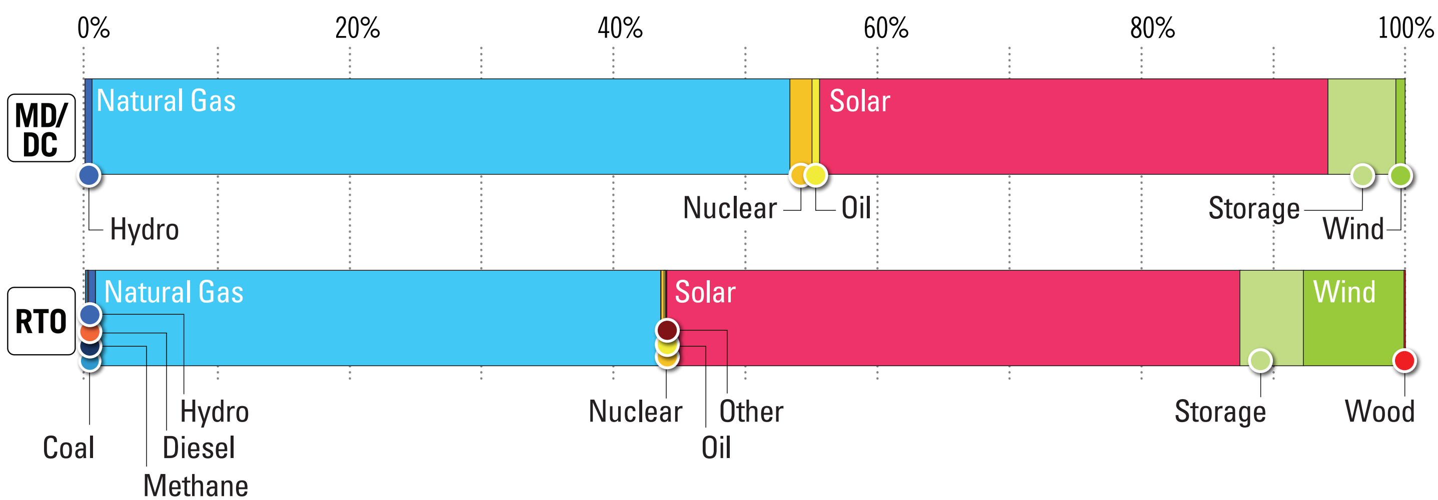


Figure 6.24: Maryland and the District of Columbia –Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)

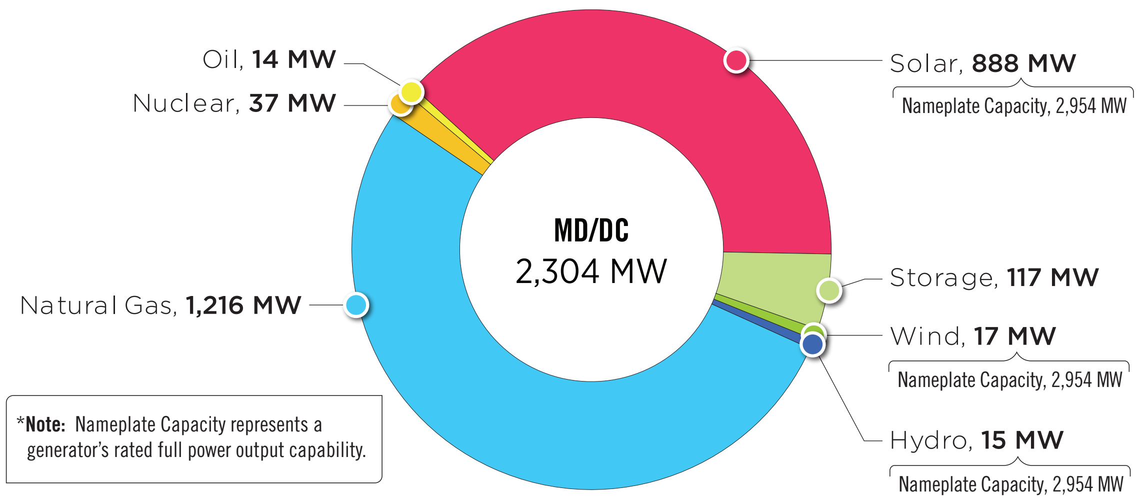


Figure 6.25: Maryland and the District of Columbia Progression history of Queue – Interconnection Requests (Dec. 31, 2019)

Projects withdrawn after final agreement			Nameplate Capacity
21	Interconnection Service Agreements	4,657 MW	4,941 MW
41	Wholesale Market Participation Agreements	73 MW	127 MW

Percentage of planned capacity and projects that have reached commercial operation	9% Requested capacity megawatt	17% Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

6.4.5 — Generation Deactivation

Known generating unit deactivation requests in Maryland and the District of Columbia between Jan. 1, 2019 and Dec. 31, 2019, are summarized in **Table 6.22** and **Map 6.17**.

Map 6.17: Maryland and the District of Columbia Generation Deactivations (Dec. 31, 2019)

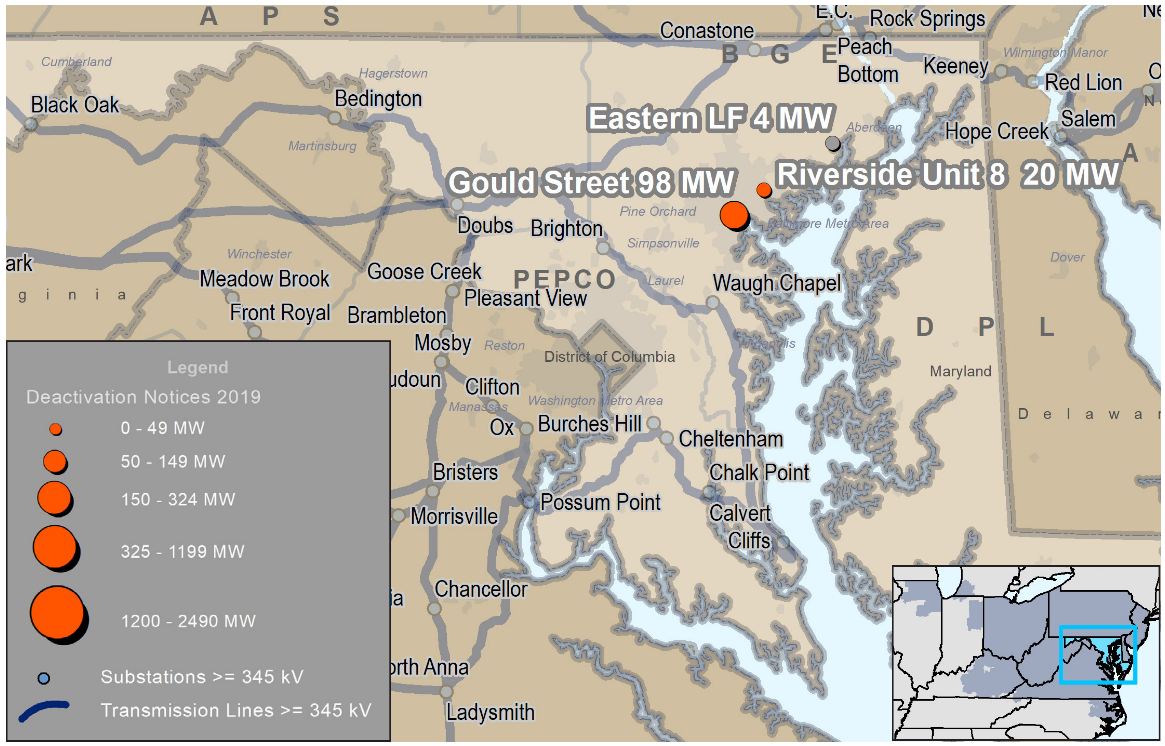


Table 6.22: Maryland and the District of Columbia Generation Deactivations (Dec. 31, 2019)

Unit	TO Zone	Fuel Type	Projected/Actual Deactivation Date	Withdrawn Deactivation Date	Age (Years)	Capacity (MW)
Gould Street Generation Station	BGE	Natural Gas	6/1/2019		66	98
Riverside 8	BGE	Oil	12/1/2019		48	20
Eastern Land Fill	BGE	Other Gas	9/30/2019	9/26/2019	12	4

6.4.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in Maryland and the District of Columbia are summarized in **Table 6.23** and **Map 6.18**.

6.4.7 — Network Projects

No network projects greater than or equal to $10 million in Maryland and the District of Columbia were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.18: Maryland and the District of Columbia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

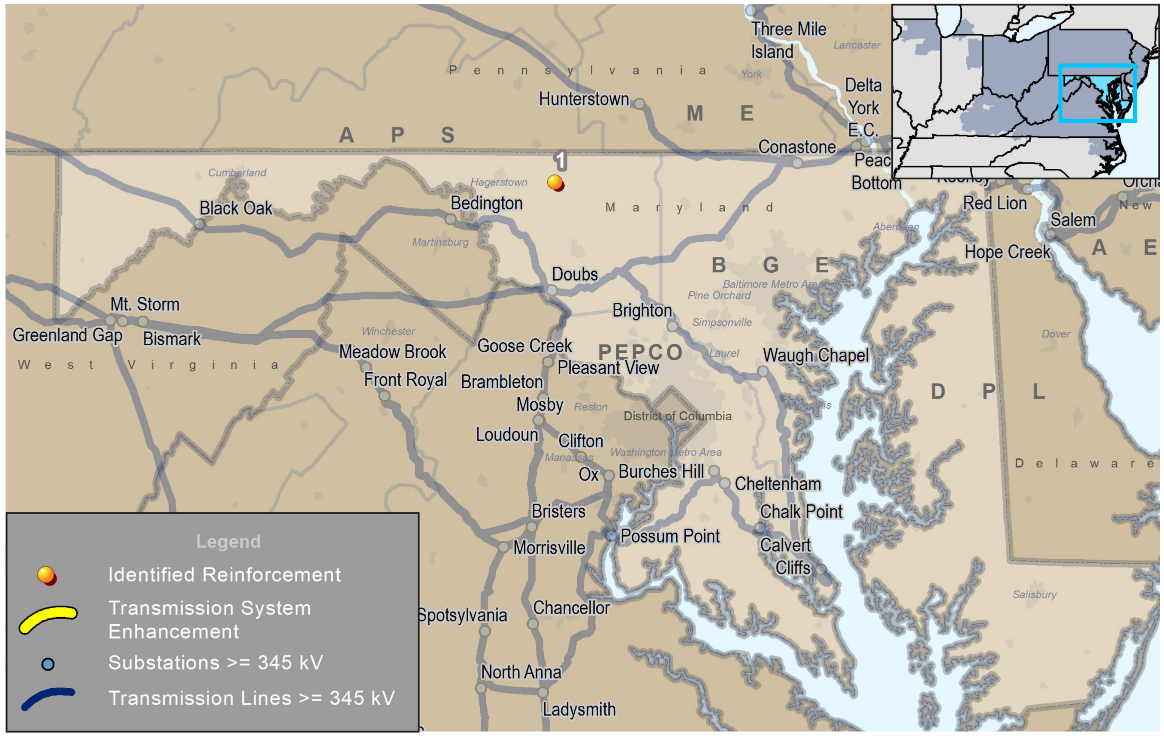


Table 6.23: Maryland and the District of Columbia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B2970	Convert Garfield 138/12.5 kV substation to 230/12.5 kV.	6/1/2020	$15.5	APS	5/16/2019

6.4.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in Maryland and the District of Columbia are summarized in **Table 6.24** and **Map 6.19**.

6.4.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Maryland and the District of Columbia were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.19: Maryland and the District of Columbia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

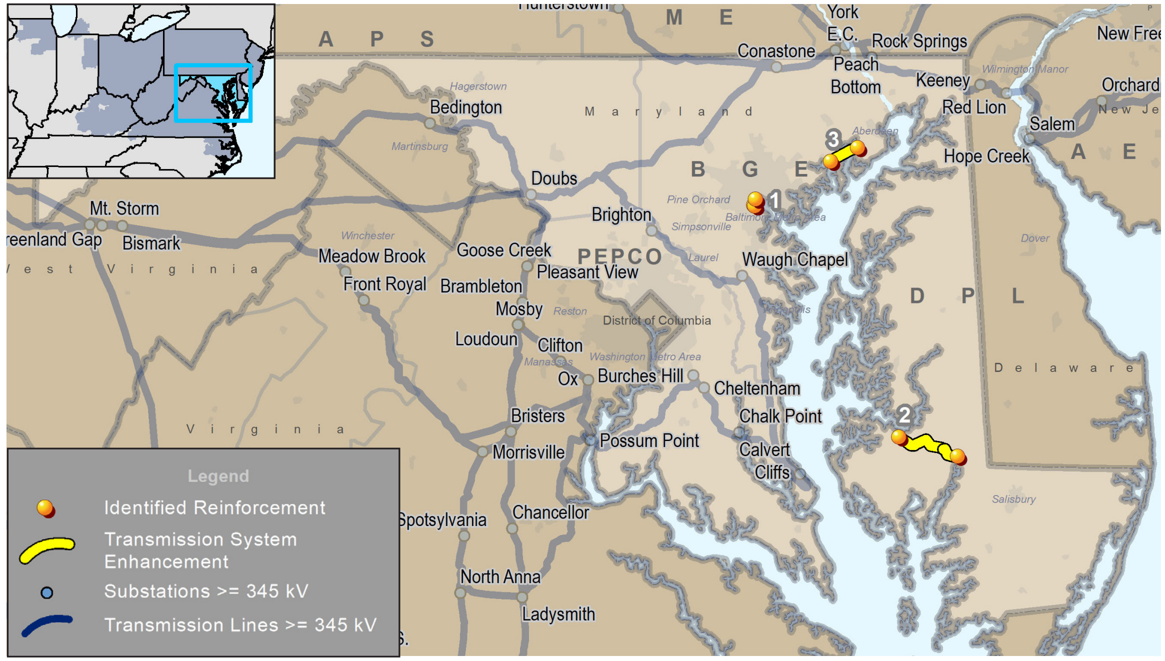
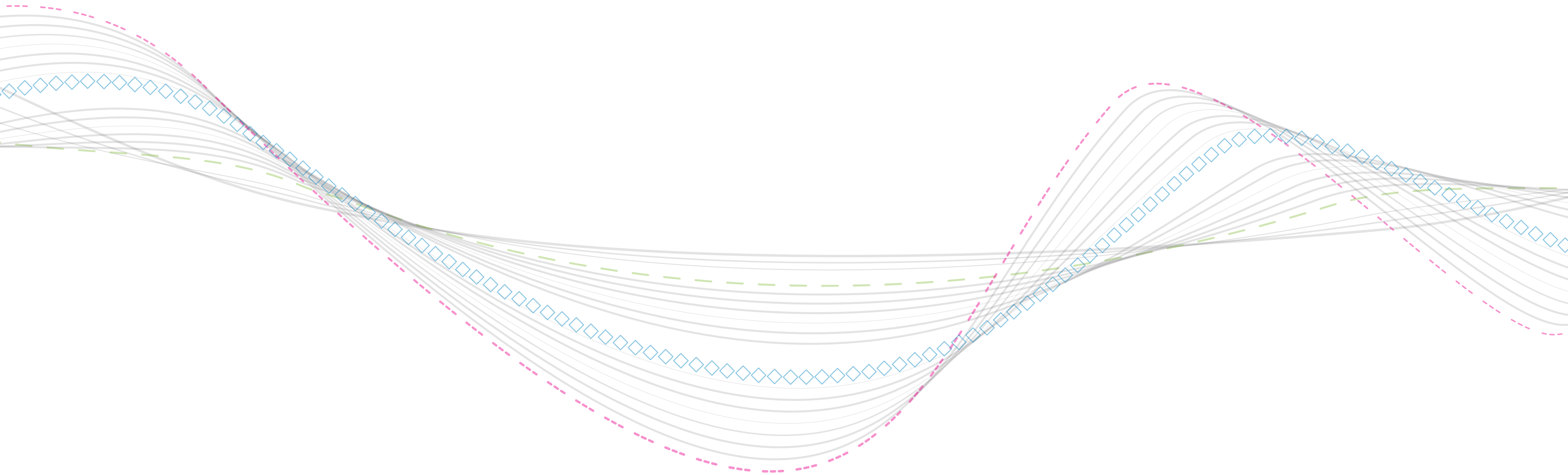


Table 6.24: Maryland and the District of Columbia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2025	Port Covington 115/13 kV Project.	12/1/2026	$105.0	BGE	3/25/2019
		Build a new Port Covington 115/13 kV station.				
		Expand existing Westport 115 kV station to accommodate new 115 kV underground circuits.				
		Build two 115 kV underground transmission lines from Westport to Port Covington.				
		Build two 115 kV underground transmission lines from Greene Street to Port Covington.				
2	S2073	Rebuild 69 kV line from Vienna-West Cambridge substations. All structures, conductor and static wire will be replaced with new steel poles, conductor and optical grand wire.	12/31/2022	$28.7	DP&L	1/25/2019
3	S2080	Edgewood-Perryman 115 kV circuits 110620, 110621: Replace existing three lattice towers and conductor with seven new double circuit monopole towers and conductor.	12/31/2022	$13.3	BGE	11/18/2019

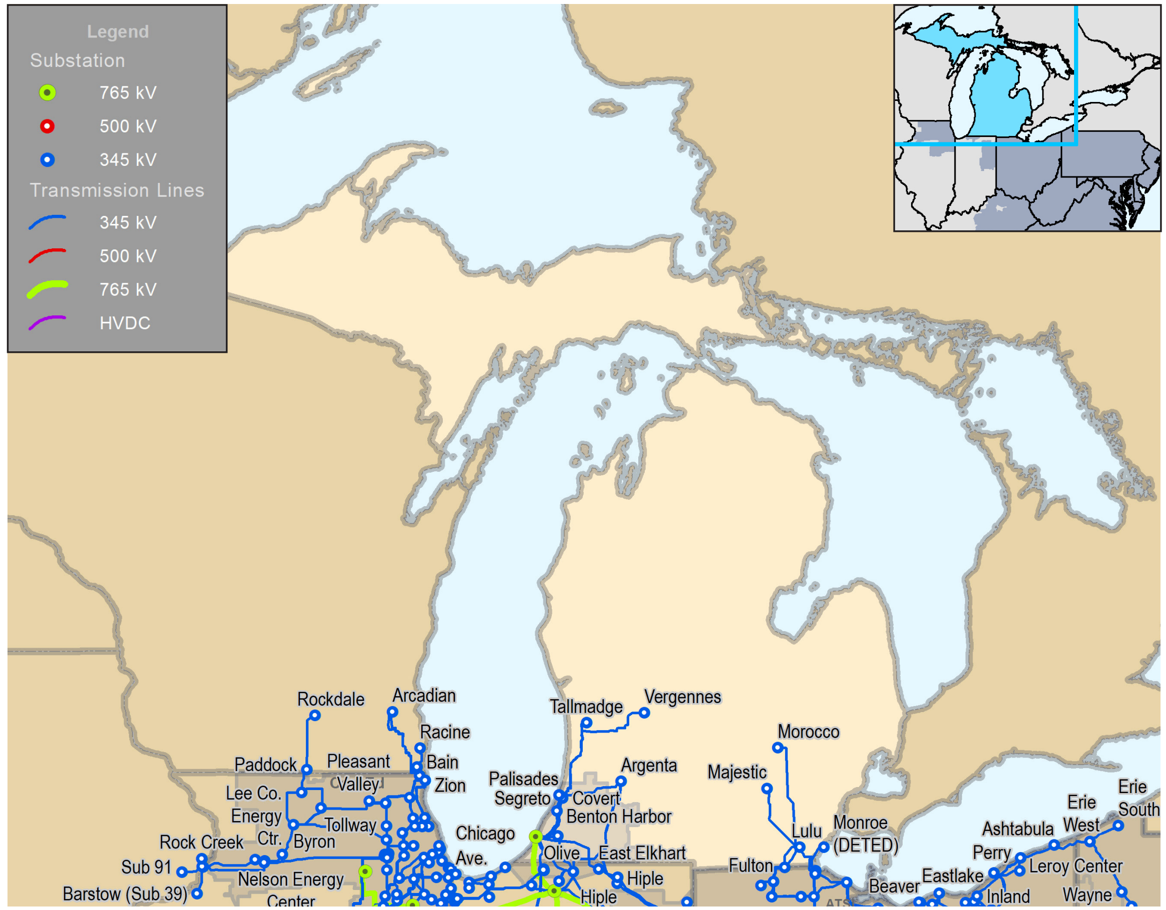


6.5: Southwestern Michigan RTEP Summary

6.5.1 — 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 as shown on **Map 6.20**. Southwestern Michigan'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 PJM.

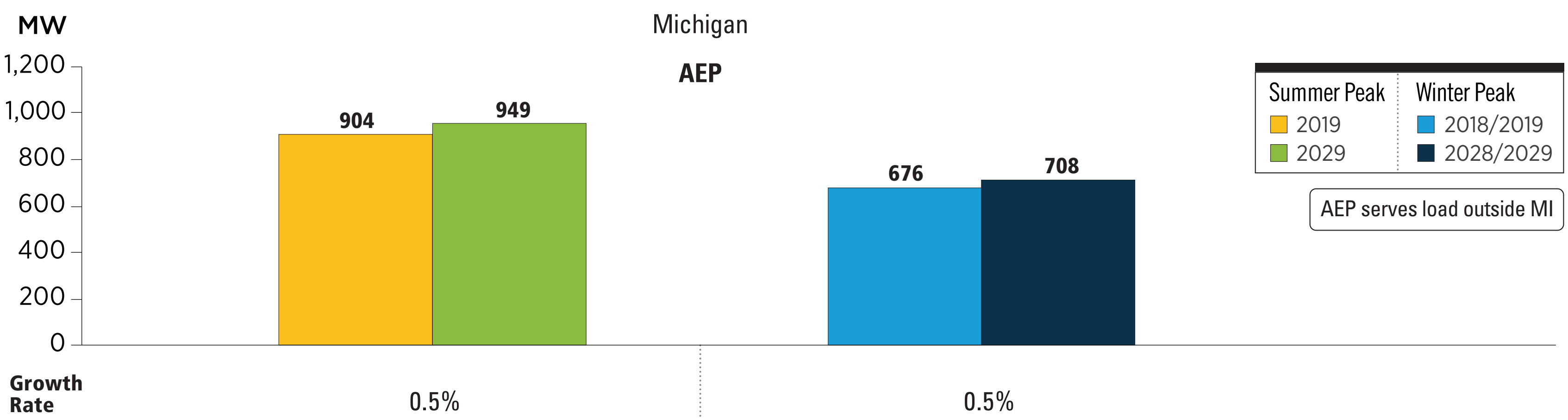
Map 6.20: PJM Service Area in Southwestern Michigan



6.5.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.26** summarizes the expected loads within the state of Michigan and across all of PJM.

Figure 6.26: Southwestern Michigan – 2019 Load Forecast Report



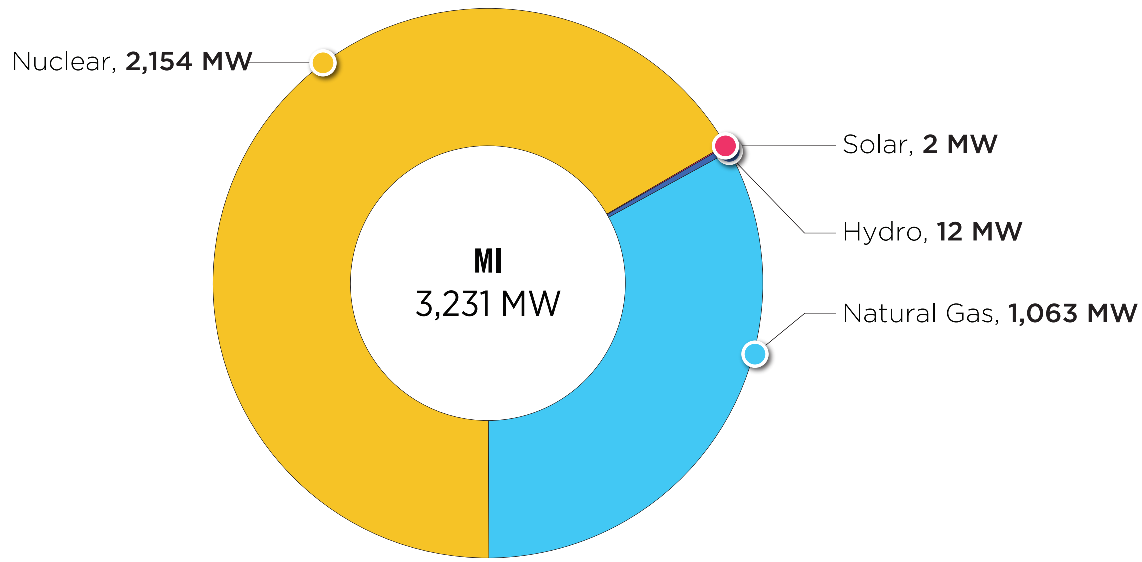
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156,689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. 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 Southwestern Michigan as of Dec. 31, 2019, is shown by fuel type in **Figure 6.27**.

Figure 6.27: Southwestern Michigan – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.5.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Southwestern Michigan, 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.

Specifically, in Southwestern Michigan, as of Dec. 31, 2019, 19 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.25**, **Table 6.26**, **Figure 6.28**, **Figure 6.29** and **Figure 6.30**. 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.

6.5.5 — Generation Deactivations

No generating unit deactivation requests in Southwestern Michigan between Jan. 1, 2019, and Dec. 31, 2019, were received as part of the 2019 RTEP.

Table 6.25: Southwestern Michigan – Percent MW Capacity by Fuel Type – Interconnection Requests

	Southwestern Michigan Capacity (MW)	Percentage of Total Southwestern Michigan Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	0	0.00%	520	0.64%
Methane	1	0.05%	1	0.00%
Natural Gas	1,230	70.90%	34,990	42.76%
Nuclear	38	2.19%	169	0.21%
Oil	0	0.00%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	335	19.30%	35,759	43.70%
Storage	131	7.57%	3,920	4.79%
Wind	0	0.00%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**1,735**	**100.00%**	**81,832**	**100.00%**

Table 6.26: Southwestern Michigan – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Natural Gas	1	145.0	2	1,085.0	2	1,055.0	1	1,120.0	6	3,405.0	5	88.0
	Nuclear	1	38.0	0	0.0	2	167.0	0	0.0	3	205.0	0	0.0
	Other	0	0.0	0	0.0	0	0.0	1	0.0	1	0.0	0	0.0
	Storage	3	131.3	0	0.0	0	0.0	0	0.0	3	131.3	0	0.0
Renewable	Methane	1	0.8	0	0.0	2	9.6	0	0.0	3	10.4	1	12.0
	Solar	4	334.8	0	0.0	1	2.3	3	177.8	8	514.8	126	5,481.3
	Wind	0	0.0	0	0.0	0	0.0	1	26.0	1	26.0	11	261.3
	Grand Total	**10**	**649.9**	**2**	**1,085.0**	**7**	**1,233.9**	**6**	**1,323.8**	**25**	**4,292.5**	**145**	**5,972.6**

Figure 6.28: Percentage of projects in Queue Fuel Type (Dec. 31, 2019)

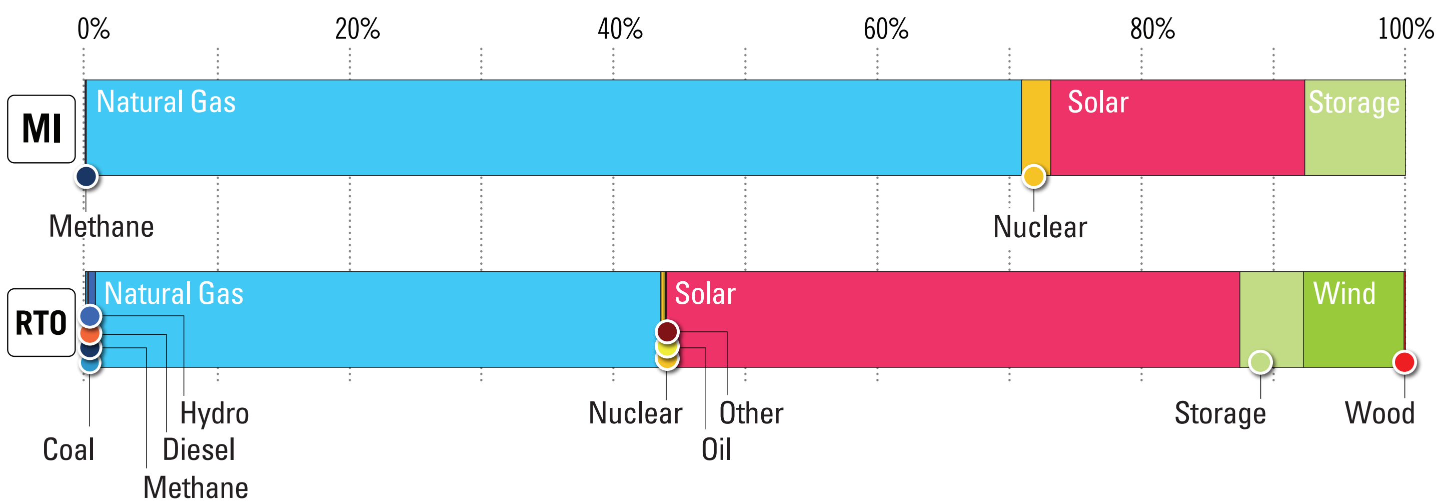


Figure 6.29: Southwestern Michigan – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)

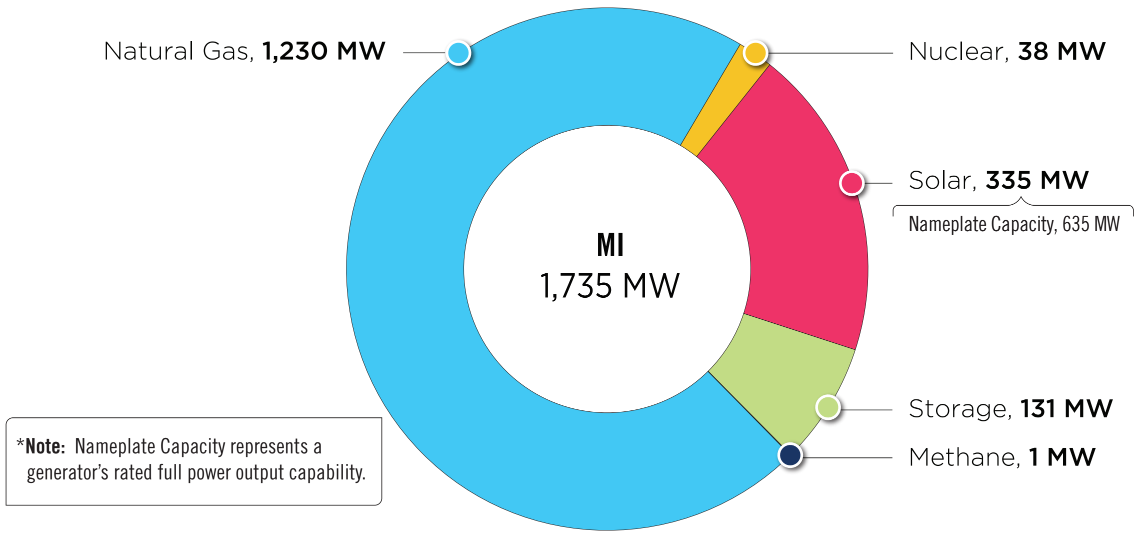


Figure 6.30: Southern Michigan Progression History of Queue – Interconnection Requests (Dec. 31, 2019)

Projects withdrawn after final agreement

0	Interconnection Service Agreements
0	Wholesale Market Participation Agreements

Percentage of planned capacity and projects that have reached commercial operation	**34%** Requested capacity megawatt	**47%** Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

6.5.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in Southernwestern Michigan are summarized in **Table 6.27** and **Map 6.21**.

6.5.7 — Network Projects

No network projects greater than or equal to $10 million in Southwestern Michigan were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.21: Southwestern Michigan Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

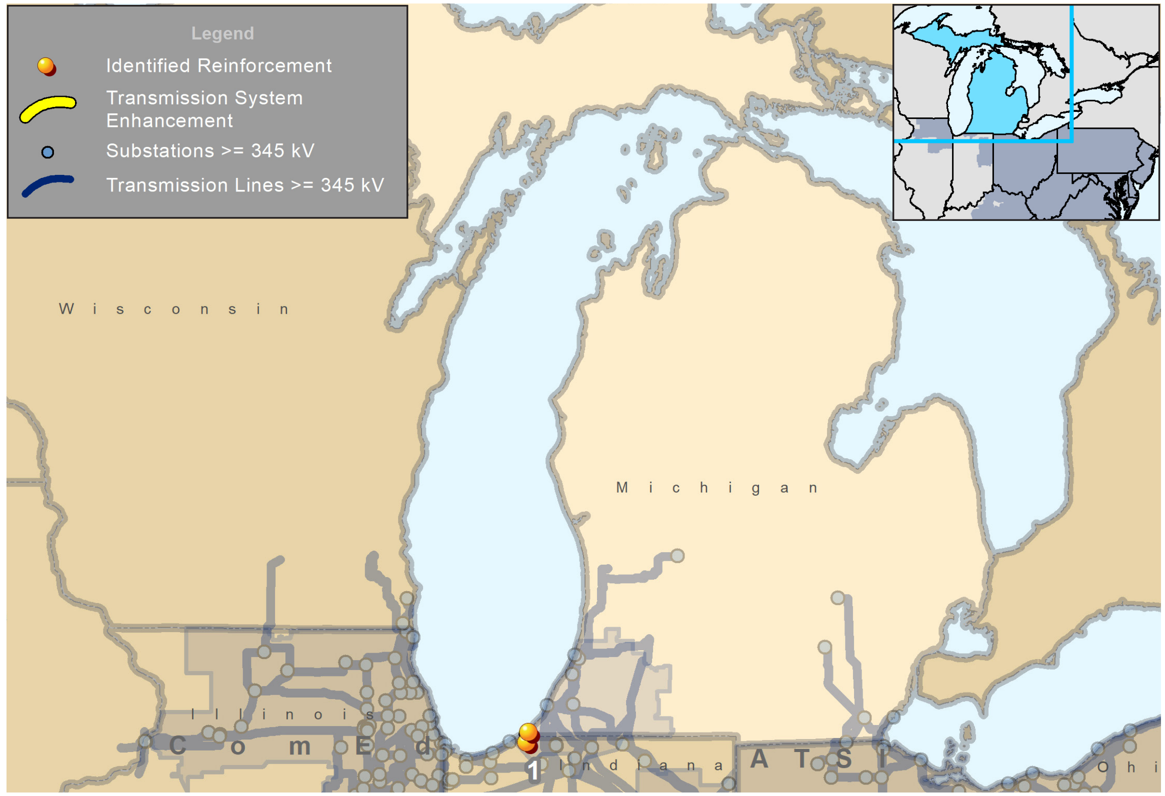


Table 6.27: Southwestern Michigan Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3132	Rebuild 3.11 miles of the LaPorte Junction-New Buffalo 69 kV line with 795 ACSR.	6/1/2022	$12.3	AEP	6/17/2019

6.5.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in Southwestern Michigan are summarized in **Table 6.28** and **Map 6.22**.

6.5.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Southwestern Michigan were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.22: Southwestern Michigan Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

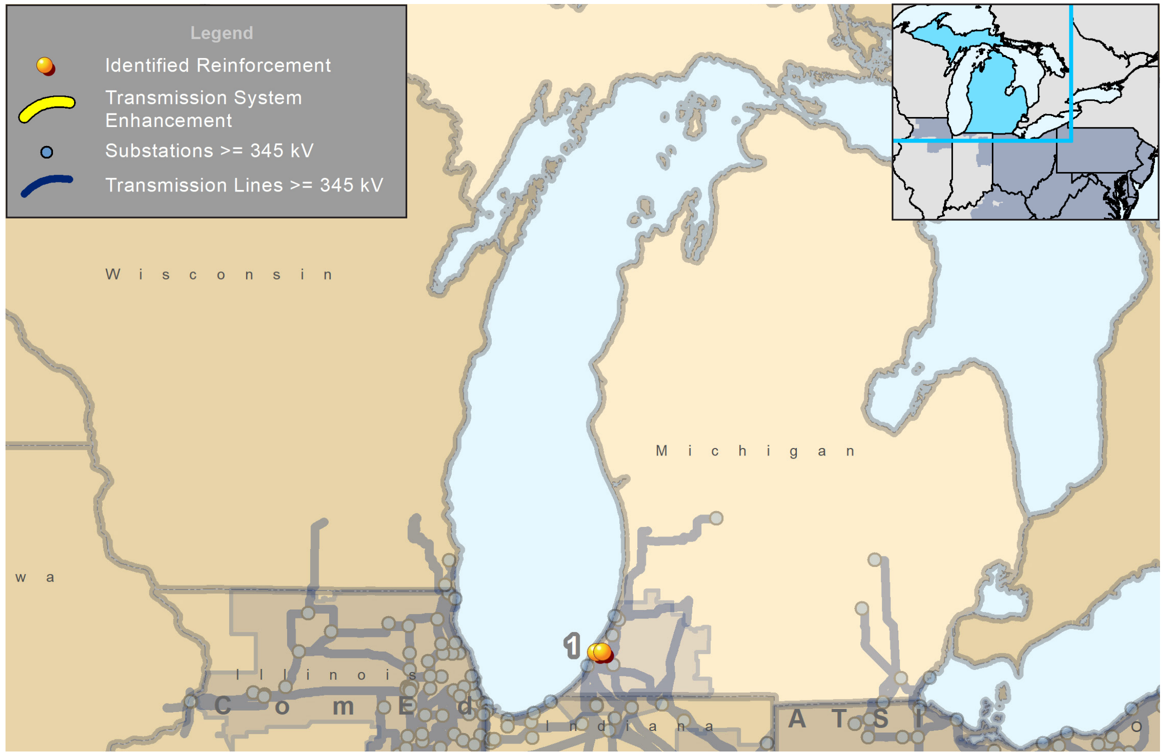


Table 6.28: Southwestern Michigan Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

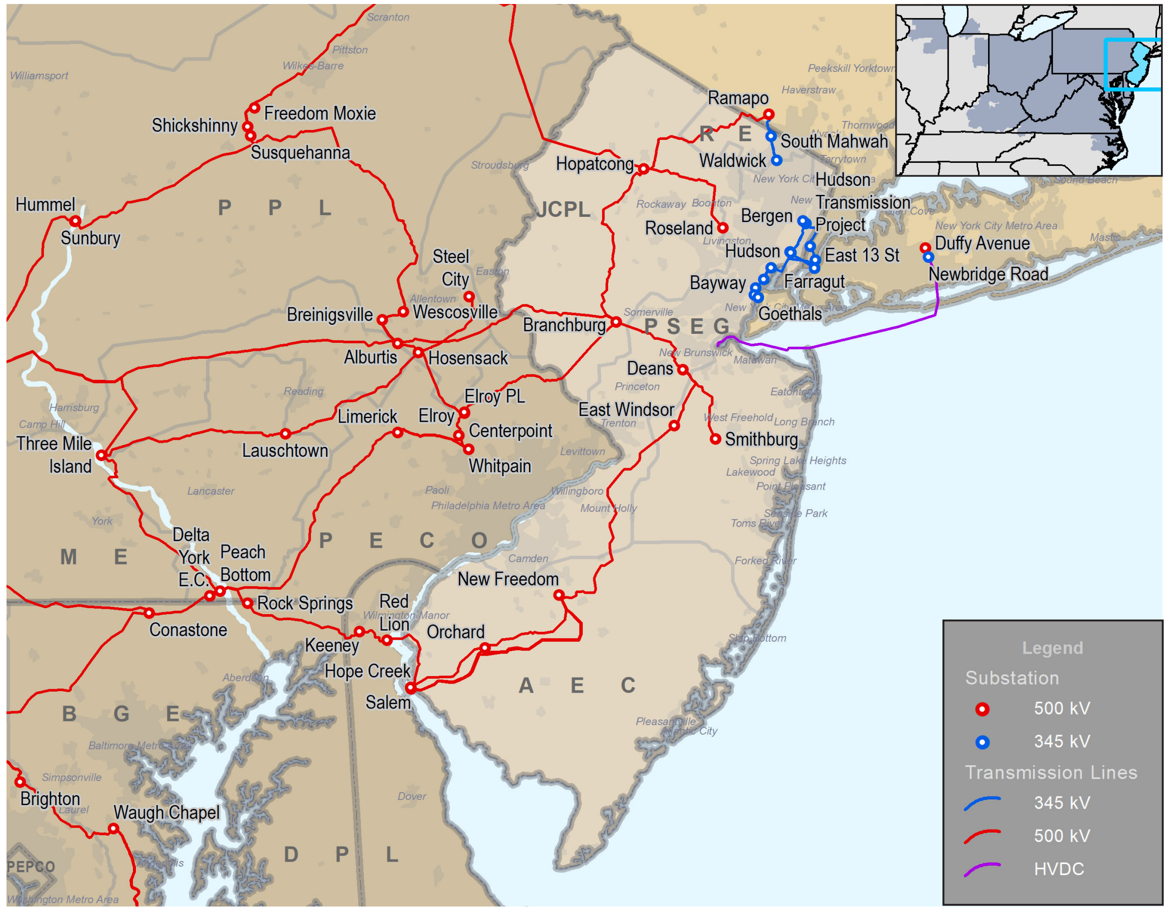
Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2090	Rebuild 6.7 miles of the 34.5 kV circuit Main Street-Hickory Creek circuit using 556 ACSR conductor.	2/3/2023	$22.5	AEP	10/25/2019
		Rebuild 0.5 miles of the Langley-Main Street 34.5 kV branch starting from the Langley station, using 556 ACSR conductor.				

6.6: New Jersey RTEP Summary

6.6.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in New Jersey, including facilities owned and operated by Atlantic City Electric Company (AE), Jersey Central Power & Light Company (JCP&L), Linden VFT (VFT), Neptune Regional Transmission System (neptune RTS), Public Service Electric and Gas Company (PSEG) and Rockland Electric Company (RECO), as shown on **Map 6.23**. 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 PJM.

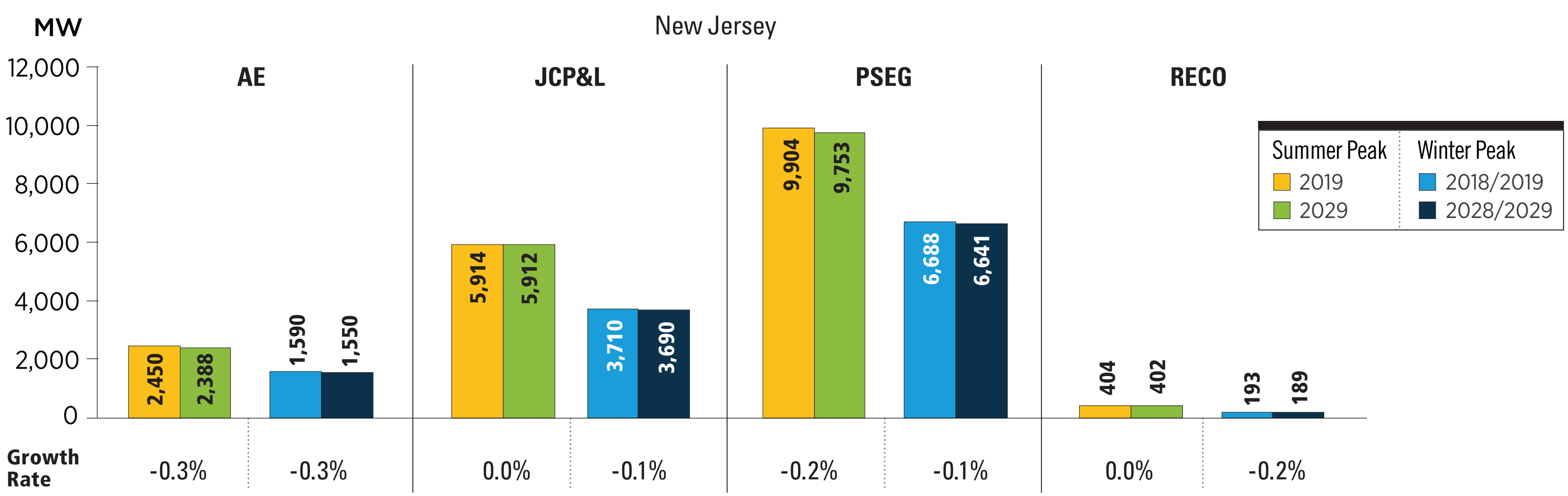
Map 6.23: PJM Service Area in New Jersey



6.6.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.31** summarizes the expected loads within the state of New Jersey and across all of PJM.

Figure 6.31: New Jersey – 2019 Load Forecast Report



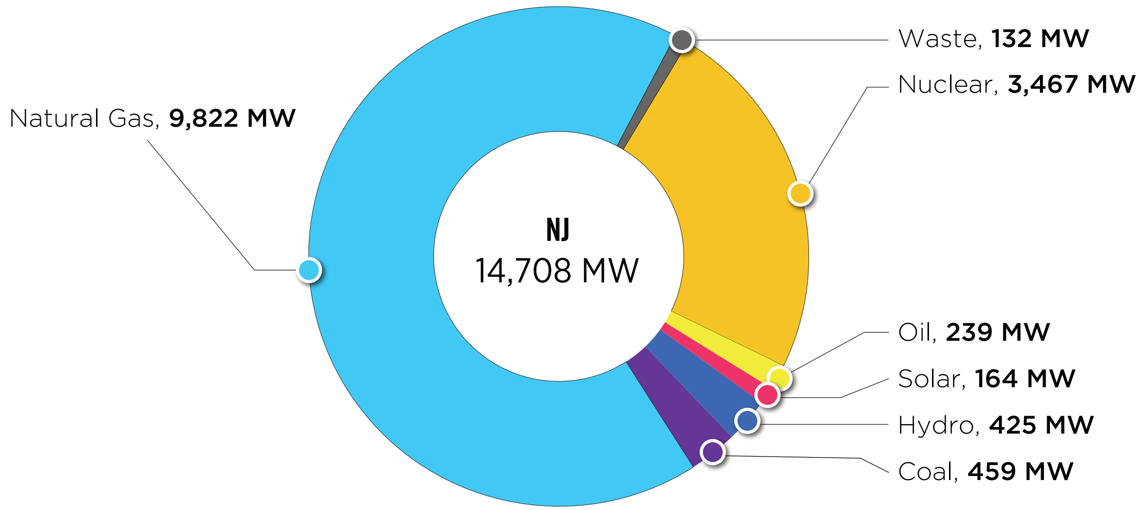
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156, 689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the amount of forecasted load to be served by each transmission owner in the noted state. 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 New Jersey as of Dec. 31, 2019, is shown by fuel type in **Figure 6.32**.

Figure 6.32: New Jersey – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.6.4 — Interconnection Requests

PJM markets continue to attract generation proposals in New Jersey, 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.

Specifically, in New Jersey, as of Dec. 31, 2019, 122 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.29**, **Table 6.30**, **Figure 6.33**, **Figure 6.34**, and **Figure 6.35**. 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 6.29: New Jersey – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	New Jersey Capacity (MW)	Percentage of Total New Jersey Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	0	0.00%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	2,655	45.32%	34,990	42.76%
Nuclear	0	0.00%	169	0.21%
Oil	0	0.00%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	631	10.77%	35,759	43.70%
Storage	650	11.10%	3,920	4.79%
Wind	1,922	32.81%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**5,859**	**100.00%**	**81,832**	**100.00%**

Table 6.30: New Jersey – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	0	0.0	1	15.0	1	15.0
	Diesel	0	0.0	0	0.0	0	0.0	1	8.0	0	0.0	1	8.0
	Natural Gas	9	1,650.2	2	275.0	3	730.2	76	7,796.9	176	50,434.3	266	60,886.6
	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	30	650.4	4	0.0	3	0.0	4	0.0	35	20.0	76	670.4
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	3	17.3	3	17.3
	Hydro	0	0.0	0	0.0	0	0.0	2	20.5	2	1,001.1	4	1,021.6
	Methane	0	0.0	0	0.0	0	0.0	16	45.3	9	40.6	25	85.9
	Solar	31	583.8	5	6.8	22	40.2	101	224.0	465	1,456.8	624	2,311.6
	Wind	13	1,922.4	0	0.0	0	0.0	1	0.0	19	605.0	33	2,527.4
	Grand Total	**83**	**4,806.9**	**11**	**281.8**	**28**	**770.4**	**209**	**8,510.7**	**724**	**54,580.6**	**1,055**	**68,950.4**

Figure 6.33: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

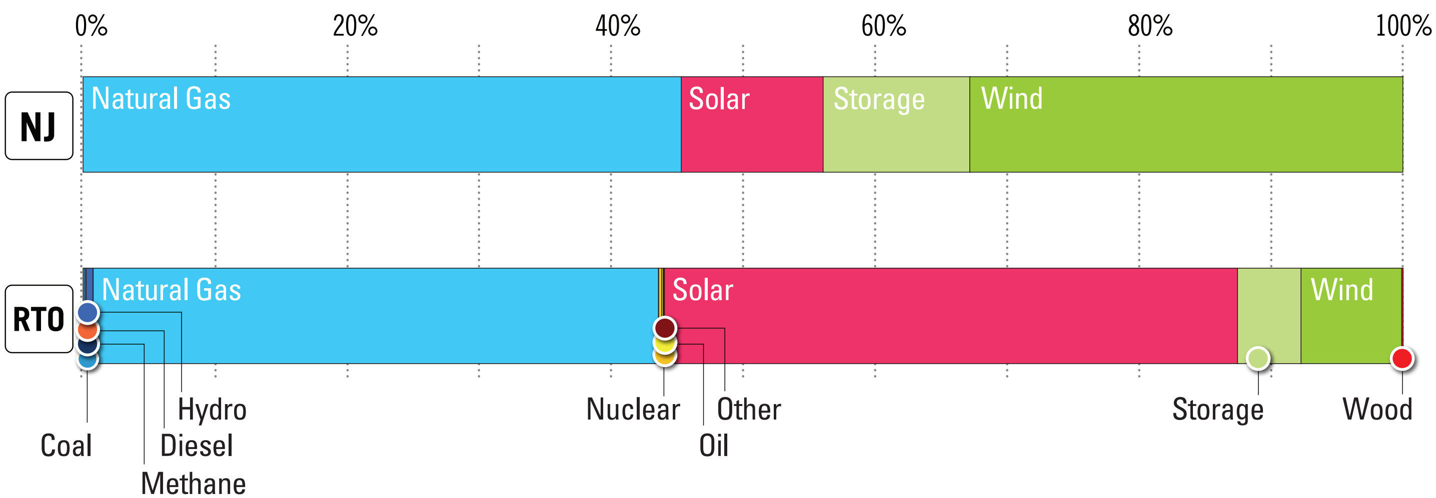


Figure 6.34: New Jersey – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)

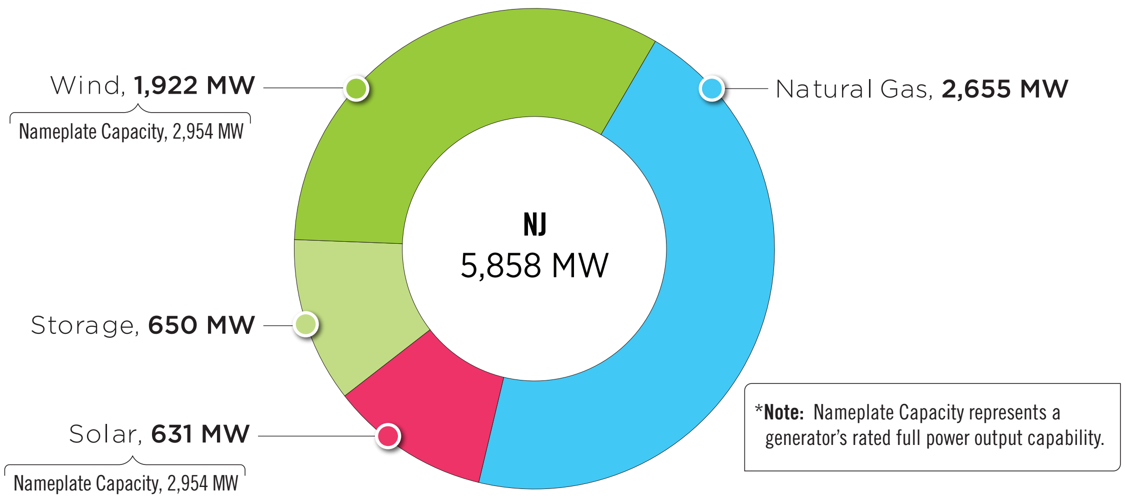
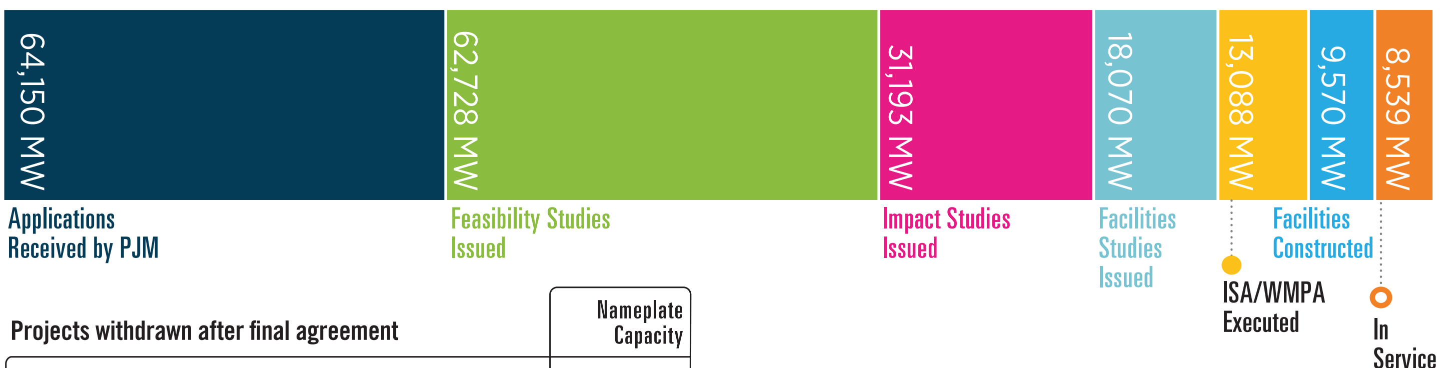


Figure 6.35: New Jersey Progression History of Queue – Interconnection Requests (Dec. 31, 2019)



Projects withdrawn after final agreement

			Nameplate Capacity
19	Interconnection Service Agreements	2,595 MW	3,003 MW
143	Wholesale Market Participation Agreements	370 MW	1,058 MW

Percentage of planned capacity and projects that have reached commercial operation	13% Requested capacity megawatt	23% Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

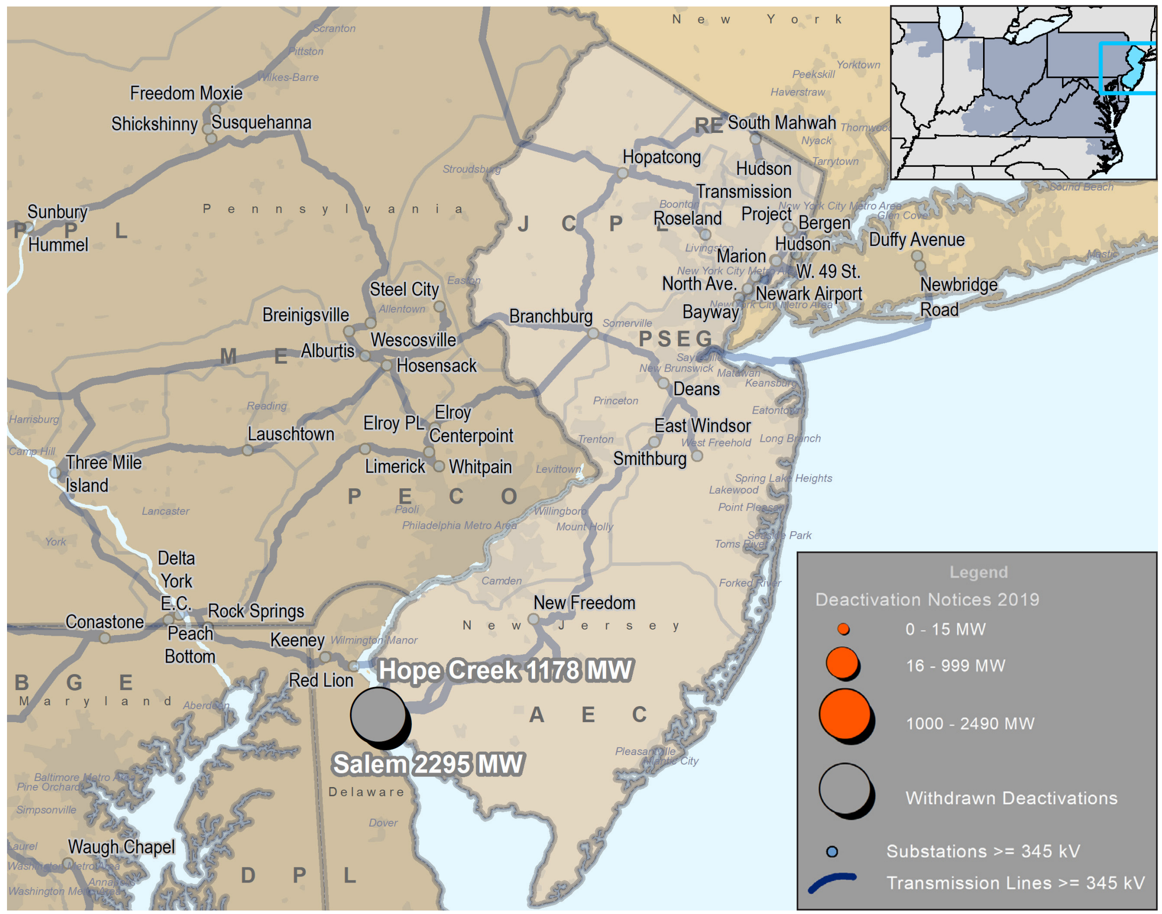
6.6.5 — Generation Deactivation

Known generating unit deactivation requests in New Jersey between Jan. 1, 2019, and Dec. 31, 2019, are summarized in **Table 6.31** and **Map 6.24**.

Table 6.31: New Jersey Generation Deactivations (Dec. 31, 2019)

Unit	TO Zone	Fuel Type	Deactivation Notice	Projected/Actual Deactivation Date	Withdrawn Deactivation Date	Age (Years)	Capacity (MW)
Salem 2	PSEG	Nuclear	4/16/2019	4/1/2020	4/19/2019	38	1142.1
Salem 1	PSEG	Nuclear	4/16/2019	10/1/2020	4/19/2019	42	1153
Hope Creek 1	PSEG	Nuclear	4/16/2019	10/1/2019	4/19/2019	33	1178.3

Map 6.24: New Jersey Generation Deactivations (Dec. 31, 2019)



6.6.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in New Jersey are summarized in **Table 6.32** and **Map 6.25**.

6.6.7 — Network Projects

No network projects greater than or equal to $10 million in New Jersey were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.25: New Jersey Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

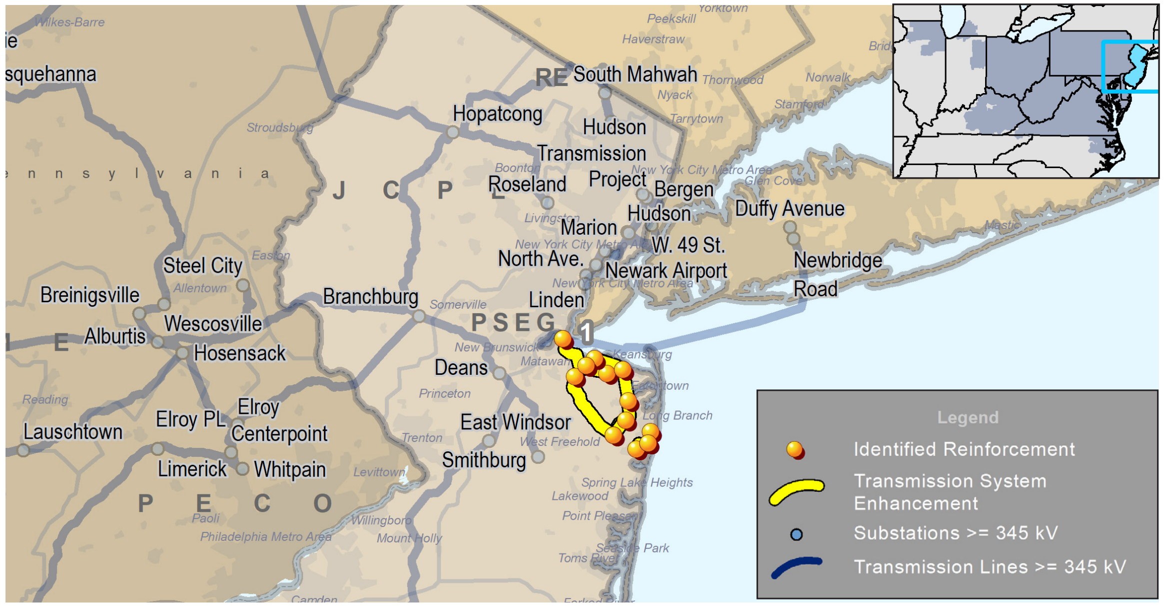


Table 6.32: New Jersey Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3130	Construct seven new 34.5 kV circuits on existing pole lines (total of 53.5 miles), rebuild/re-conductor two 34.5 kV circuits (total of 5.5 miles) and install a second 115/34.5 kV transformer (Werner).	6/1/2016	$175.0	JCP&L	8/3/2019
		Construct a new 34.5 kV circuit from Oceanview to Allenhurst 34.5 kV (4.0 miles).				
		Construct a new 34.5 kV circuit from Atlantic to Red Bank 34.5 kV (12.0 miles).				
		Construct a new 34.5 kV circuit from Freneau to Taylor Lane 34.5 kV (6.5 miles).				
		Construct a new 34.5 kV circuit from Keyport to Belford 34.5 kV (6.0 miles).				
		Construct a new 34.5 kV circuit from Red Bank to Belford 34.5 kV (5.0 miles).				
		Construct a new 34.5 kV circuit from Werner to Clark Street (7.0 miles).				
		Construct a new 34.5 kV circuit from Atlantic to Freneau (13.0 miles).				
		Rebuild/re-conductor the Atlantic-Camp Woods Switch Point (3.5 miles) 34.5 kV circuit.				
		Rebuild/re-conductor the Allenhurst-Elberon (2.0 miles) 34.5 kV circuit.				
		Install second 115/34.5 kV Transformer at Werner Substation.				

6.6.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in New Jersey are summarized in **Table 6.33** and **Map 6.26**.

Table 6.33: New Jersey Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1823	Build a new Walnut Avenue 69 kV substation. Eliminate Clark substation. Transfer load from nearby heavily loaded Aldene, Warinanco and Westfield substation to the new station.	4/30/2023	$143.0	PSEG	1/25/2019
		Purchase property to accommodate new construction of Walnut Ave 69 kV substation.	5/30/2023			
		Install a 69 kV bus with two 69/13 kV transformers at Walnut Aveww.				
		Construct a new 69 kV circuit between Vauxhall and the new Walnut Avenue station.				
		Loop the Front Street to Springfield Road 69 kV circuit into Walnut Avenue station.				
2	S1824	Build new 69 kV substation in North Brunswick. Transfer load from nearby heavily loaded Adams, Bennetts Lane and Brunswick to the new station.	4/30/2023	$129.0	PSEG	1/25/2019
		Purchase property to accommodate construction of the new 69 kV substation in North Brunswick.	3/30/2023			
		Install a 69 kV breaker-and-a-half bus with two 69/13 kV transformers at North Brunswick.				
		Loop the Bennetts Lane Brunswick 69 kV circuit into the new North Brunswick station.				
		Construct a new 69 kV circuit between the new North Brunswick station and the customer substation.				
3	S1825	Build a new 69 kV substation at Texas Avenue and transfer load from nearby heavily loaded Lawrence to the new station.	4/30/2023	$71.0	PSEG	1/25/2019
		Purchase neighboring property to accommodate construction of the new Texas Avenue 69 kV substation.				
		Install a 69 kV bus with two 69/13 kV transformers at the New Texas Ave 69 kV Substation.				
		Loop the Ewing Hamilton 69 kV circuit into the new Texas Avenue station.				
		Construct a new 69 kV circuit between Lawrence and the new Texas Avenue station.				
4	S1831	Build a new 230 kV substation in Mansfield: Install a 230 kV bus with two 230/13 kV transformers, cut and loop the Bustleton-Crosswicks 230 kV line into the 230 kV bus, Transfer load from nearby heavily loaded Bustleton and Crosswicks to the new station.	12/1/2023	$43.0	PSEG	2/22/2019
5	S2069	Rebuild 69 kV line from Moss Mill-Motts Farm substations. All structures, conductor and static wire will be replaced with new steel poles, conductor and OPGW.	5/31/2022	$27.4	AE	1/25/2019
6	S2070	Rebuild 69 kV line from Churchtown-Paulsboro substations. All structures, conductor and static wire will be replaced with new steel poles, conductor and optical grounding wire communications.	12/31/2023	$25.0	AE	1/25/2019
7	S2071	Rebuild 69 kV line from Mickleton-Valero-Paulsboro substations. All structures, conductor and static wire will be replaced with new steel poles, conductor and optical grounding wire communication.	12/31/2023	$10.0	AE	1/25/2019
8	S2077	Construct a new Echelon 230 kV bus by tapping the existing New Freedom-Marlton 230 kV circuit and install two 230/13 kV transformers at the Echelon substation.	6/1/2024	$39.0	PSEG	10/21/2019
9	S1806	Windsor and East Windsor related upgrade (JCPL-2018-001).	12/31/2020	$32.4	JCP&L	11/28/2018
		East Windsor-Windsor 230 kV: Convert 2.6 miles 1590 ACSR six-wire circuit to two three-wire circuits.				
		Expand Windsor 230 kV bus to an eight breaker-and-a-half 230 kV station.				

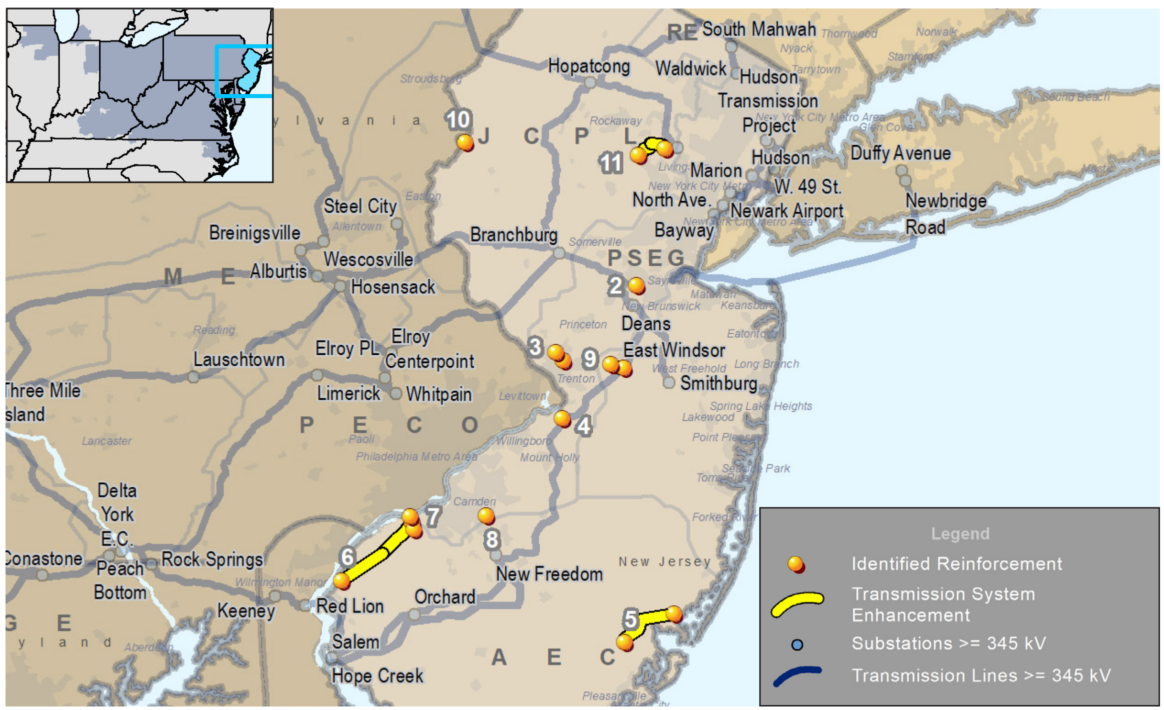
Table 6.33: New Jersey Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
9 (Cont.)	S1806	Install four new 34.5 kV breakers and one new 230-34.5 kV transformer at Windsor.	12/31/2020	$32.4	JCP&L	11/28/2018
		East Windsor Substation – Install one new 230 kV breaker.				
10	S1807	Pequest River 115 kV ring bus.	6/1/2020	$17.5	JCP&L	11/28/2018
		Expand Pequest River substation to a five breaker 115 kV ring bus.				
		Loop in the Gilbert-Pequest River-Flanders (S919) 115 kV line into the 115 kV ring bus.				
11	S1809	Morristown 230 & 34.5 kV Substation Reconfiguration.	6/1/2021	22.6	JCP&L	11/28/2018
		Construct a four breaker 230 kV ring bus at Morristown.				
		Construct a 34.5 kV breaker-and-a-half station with 18 breakers at Morristown.				
		Replace the Morristown No. 5 and No. 6 230-34.5 kV with 230-34.5 kV 168 MVA transformers.				
		Replace all overdutied breakers at Whippany 230 kV and 34 kV substations.				

6.6.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in New Jersey were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.26: New Jersey Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

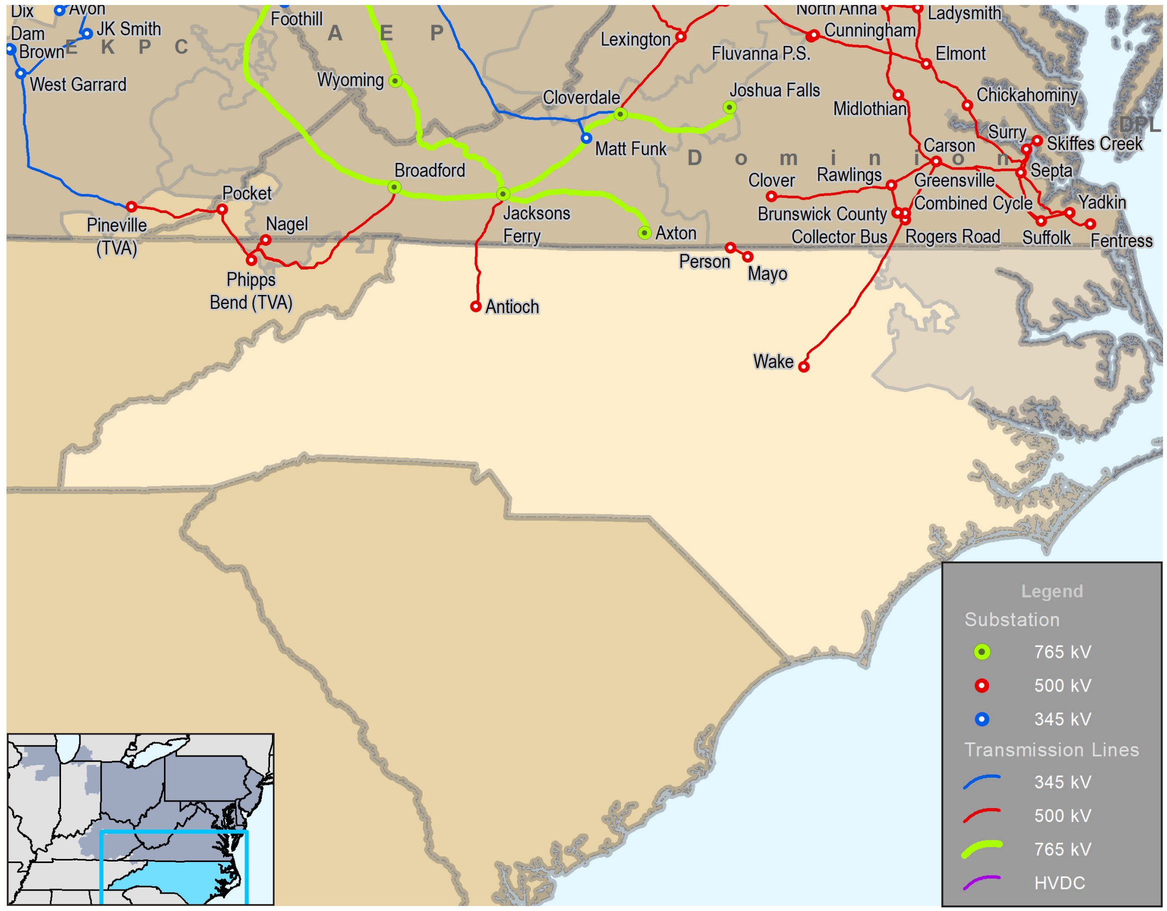


6.7: North Carolina RTEP Summary

6.7.1 — 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 North Carolina Power (DOM) as shown on **Map 6.27**. 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 PJM.

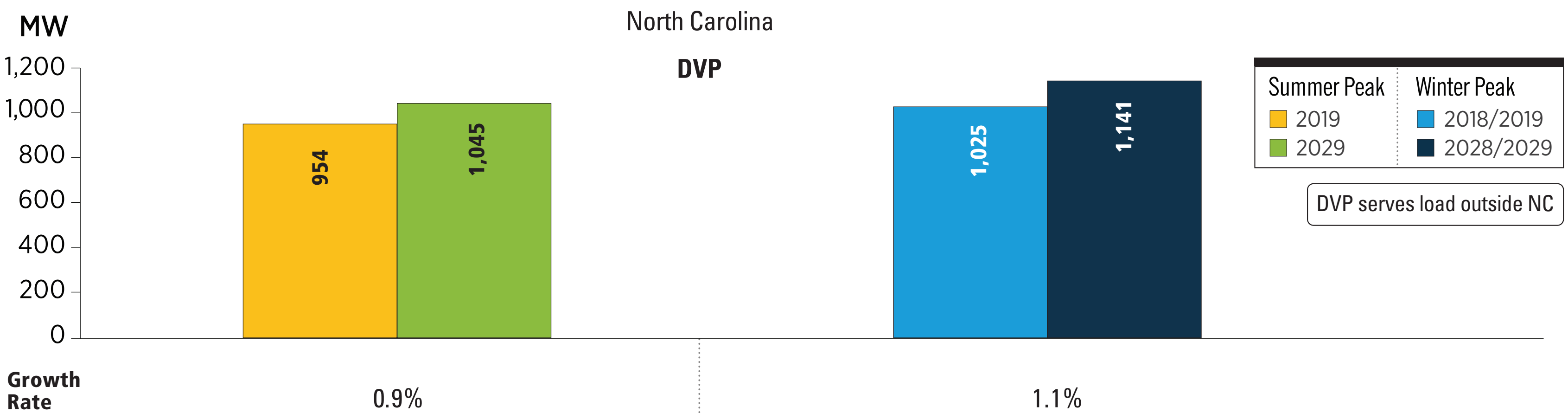
Map 6.27: PJM Service Area in North Carolina



6.7.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.36** summarizes the expected loads within the state of North Carolina and across all of PJM.

Figure 6.36: North Carolina – 2019 Load Forecast Report



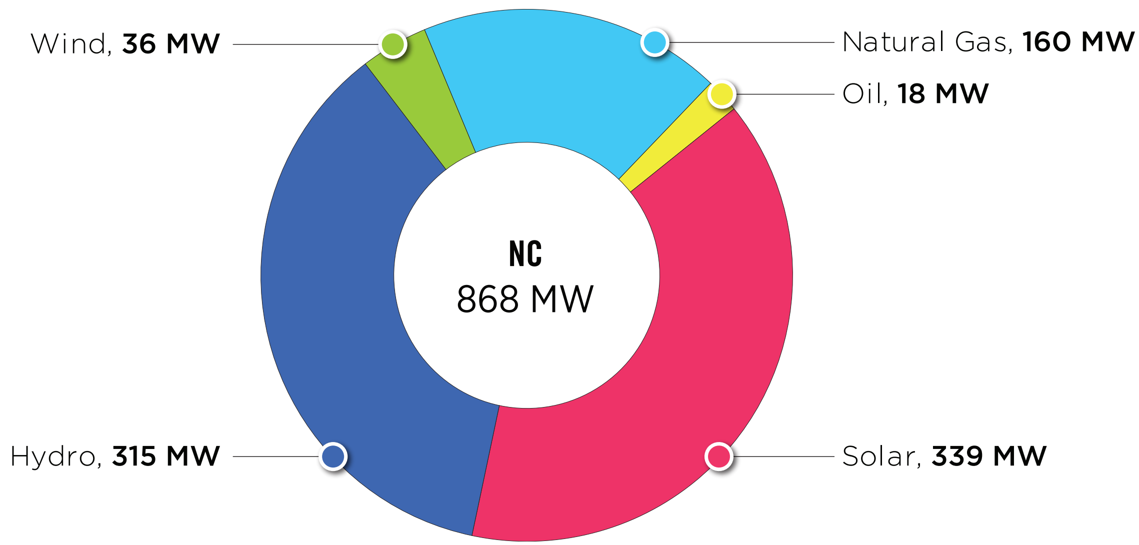
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156, 689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. 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 North Carolina as of Dec. 31, 2019, is shown by fuel type in **Figure 6.37**.

Figure 6.37: North Carolina – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.7.4 — Interconnection Requests

PJM markets continue to attract generation proposals in North Carolina, 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.

Specifically, in North Carolina, as of Dec. 31, 2019, 47 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.34**, **Table 6.35**, **Figure 6.38**, **Figure 6.39** and **Figure 6.40**. 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 6.34: North Carolina – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	North Carolina Capacity (MW)	Percentage of Total North Carolina Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	0	0.00%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	0	0.00%	34,990	42.76%
Nuclear	0	0.00%	169	0.21%
Oil	0	0.00%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	2,510	95.18%	35,759	43.70%
Storage	38	1.44%	3,920	4.79%
Wind	39	1.48%	6,240	7.62%
Wood	50	1.90%	66	0.08%
Grand Total	**2,637**	**100.00%**	**81,832**	**100.00%**

Table 6.35: North Carolina – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Storage	2	38.0	0	0.0	0	0.0	0	0.0	3	50.0	5	88.0
Renewable	Methane	0	0.0	0	0.0	0	0.0	0	0.0	1	12.0	1	12.0
	Solar	32	2,094.8	1	84.0	10	331.3	14	359.1	69	2,612.1	126	5,481.3
	Wind	0	0.0	0	0.0	1	39.0	1	27.0	9	195.3	11	261.3
	Wood	0	0.0	0	0.0	1	50.0	0	0.0	1	80.0	2	130.0
	Grand Total	**34**	**2,132.8**	**1**	**84.0**	**12**	**420.3**	**15**	**386.1**	**83**	**2,949.4**	**145**	**5,972.6**

Figure 6.38: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

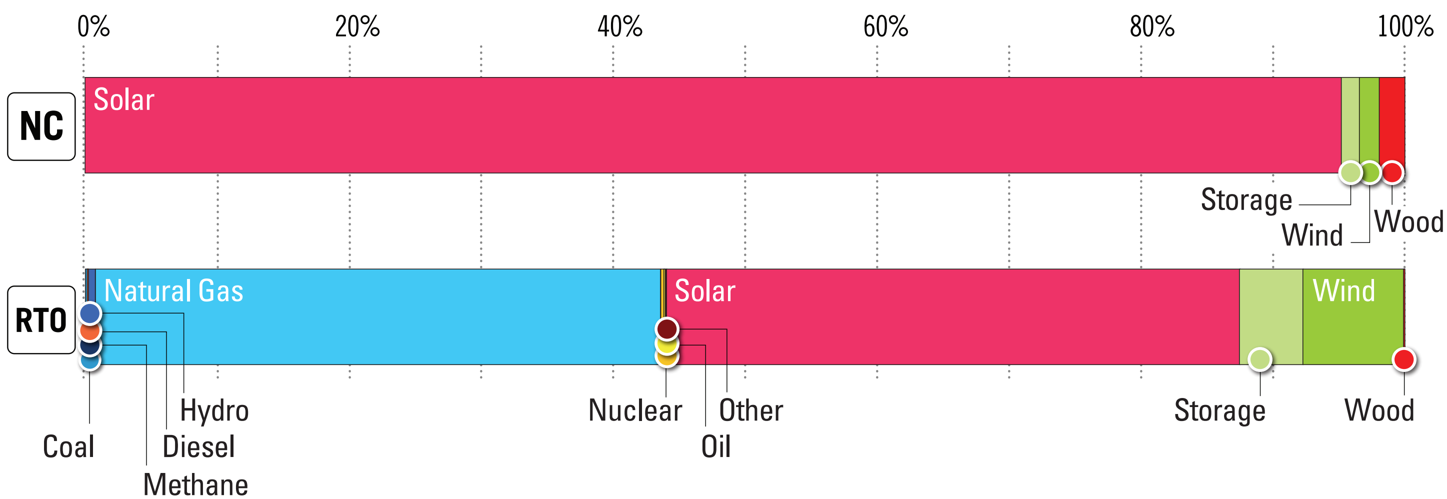
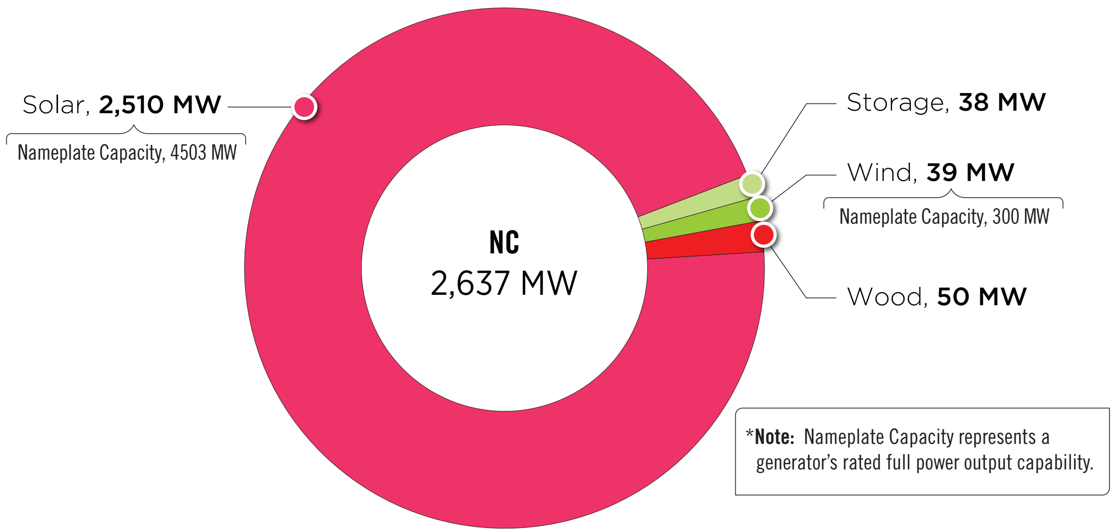
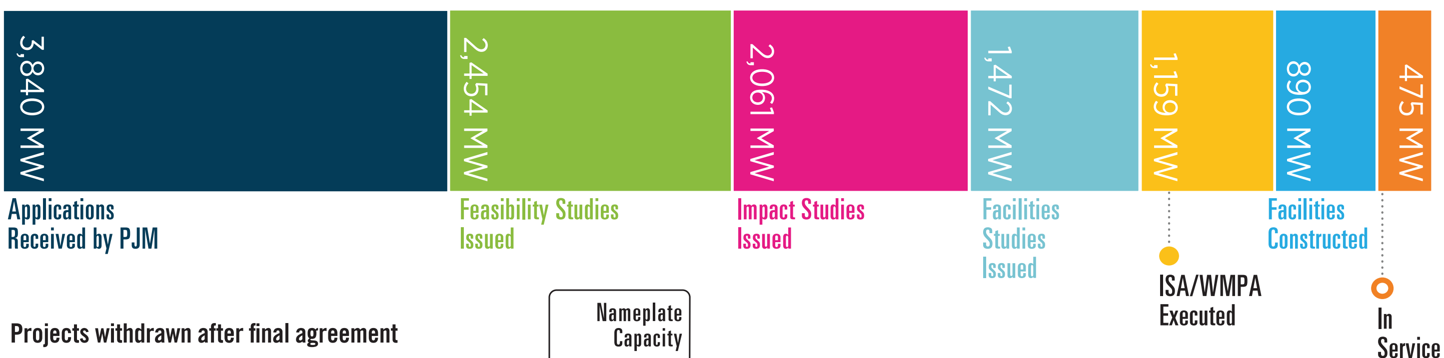


Figure 6.39: North Carolina – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)



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

Figure 6.40: North Carolina Progression History of Queue – Interconnection Requests (Dec. 31, 2019)



Projects withdrawn after final agreement

			Nameplate Capacity
7	Interconnection Service Agreements	234 MW	743 MW
3	Wholesale Market Participation Agreements	34 MW	50 MW

Percentage of planned capacity and projects that have reached commercial operation	12% Requested capacity megawatt	16% Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

6.7.5 — Generation Deactivation

There were no known generating unit deactivation requests in North Carolina between Jan. 1, 2019, and Dec. 31, 2019, as part of the 2019 RTEP.

6.7.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in North Carolina are summarized in **Table 6.36** and **Map 6.28**.

6.7.7 — Network Projects

No network projects greater than or equal to $10 million in North Carolina were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.7.8 — Supplemental Projects

No supplemental projects greater than or equal to $10 million in North Carolina were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.7.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in North Carolina were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.28: North Carolina Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

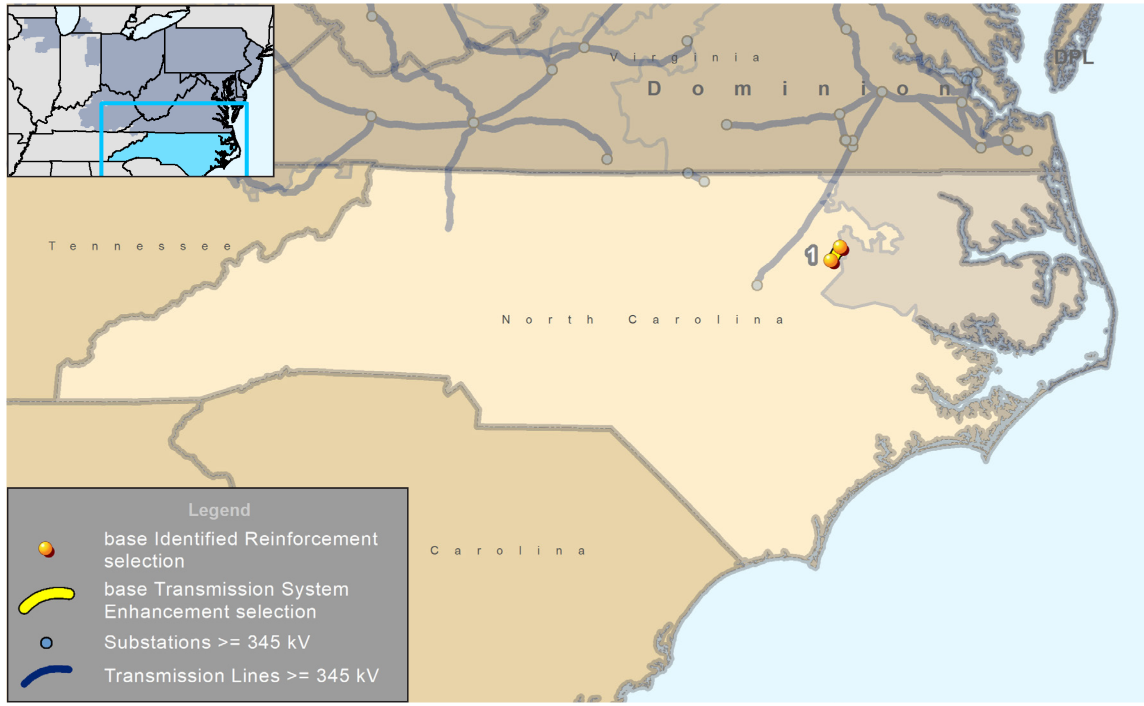
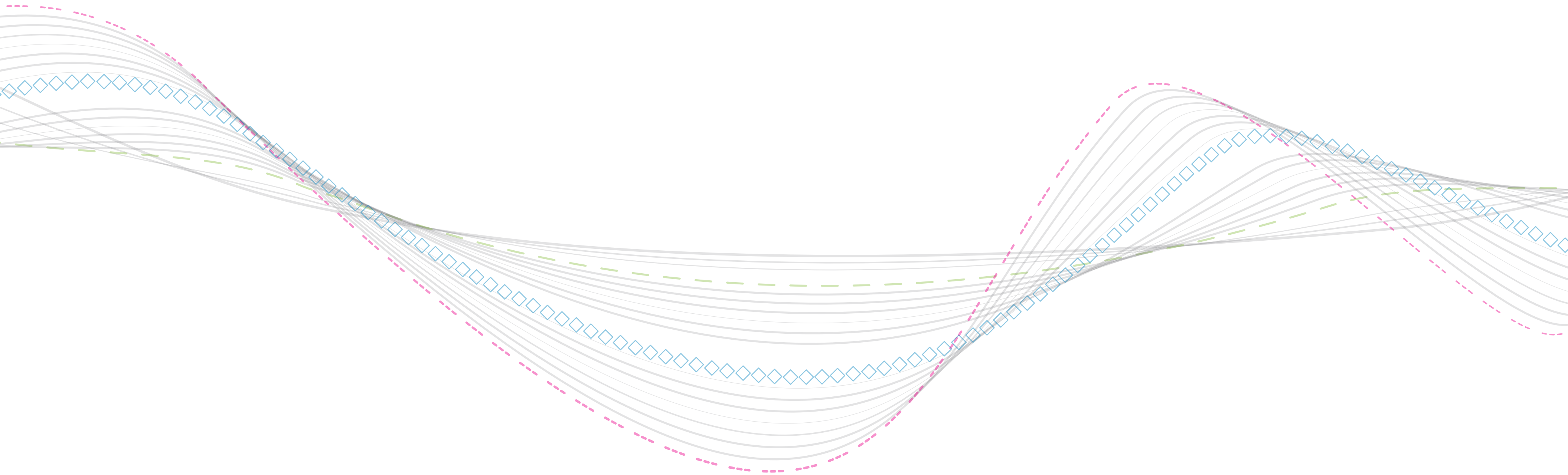


Table 6.36: North Carolina Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3122	Rebuild Hathaway-Rocky Mount (Duke Energy Progress) 230 kV Line No. 2181 and Line No. 2058 with double-circuit steel structures using double-circuit conductor at current 230 kV standards with a minimum rating of 1047 MVA.	6/1/2019	$13.0	Dominion	6/13/2019



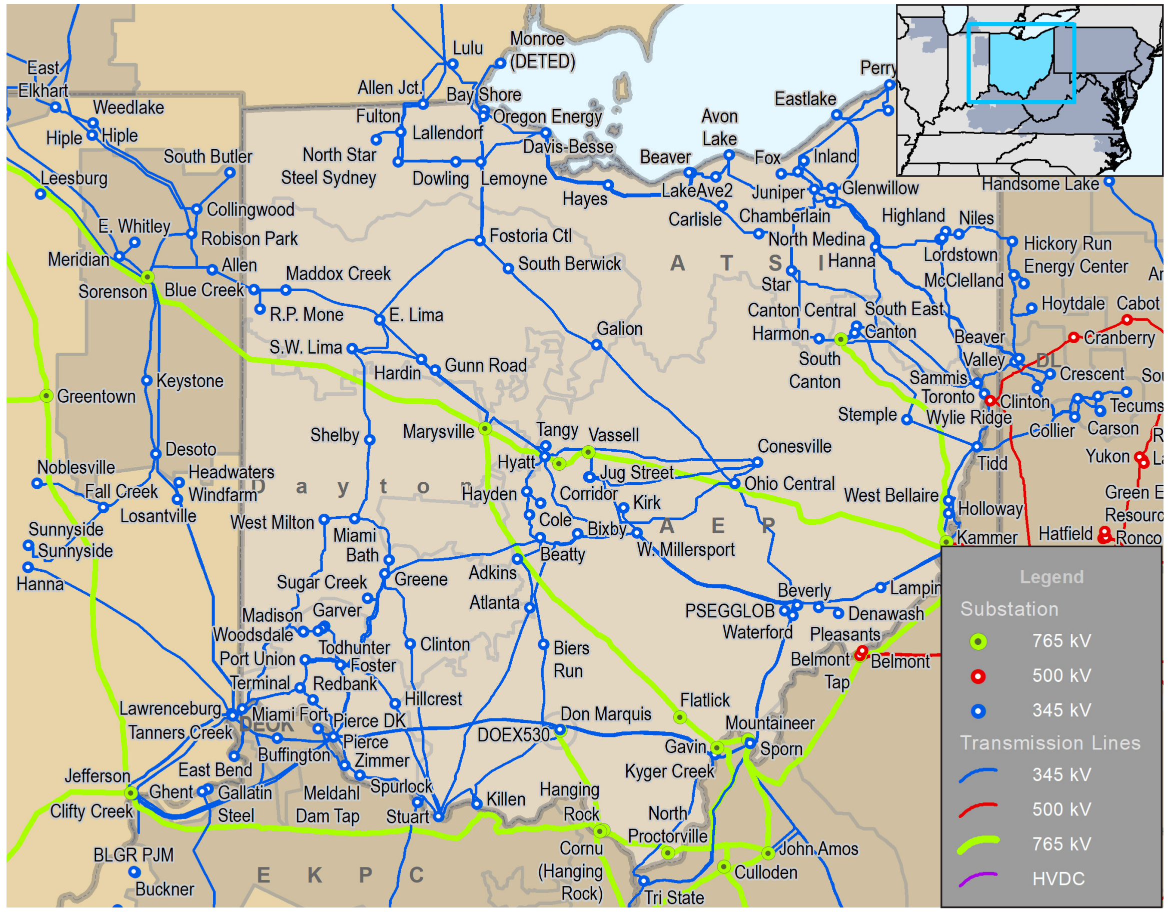
6.8: Ohio RTEP Summary

6.8.1 — 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), Dayton Power & Light (DAY), American Transmission Systems, Inc. (ATSI), Duke Energy Ohio & Kentucky (DEO&K), the City of Cleveland and the City of Hamilton as shown on **Map 6.29**.

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 PJM.

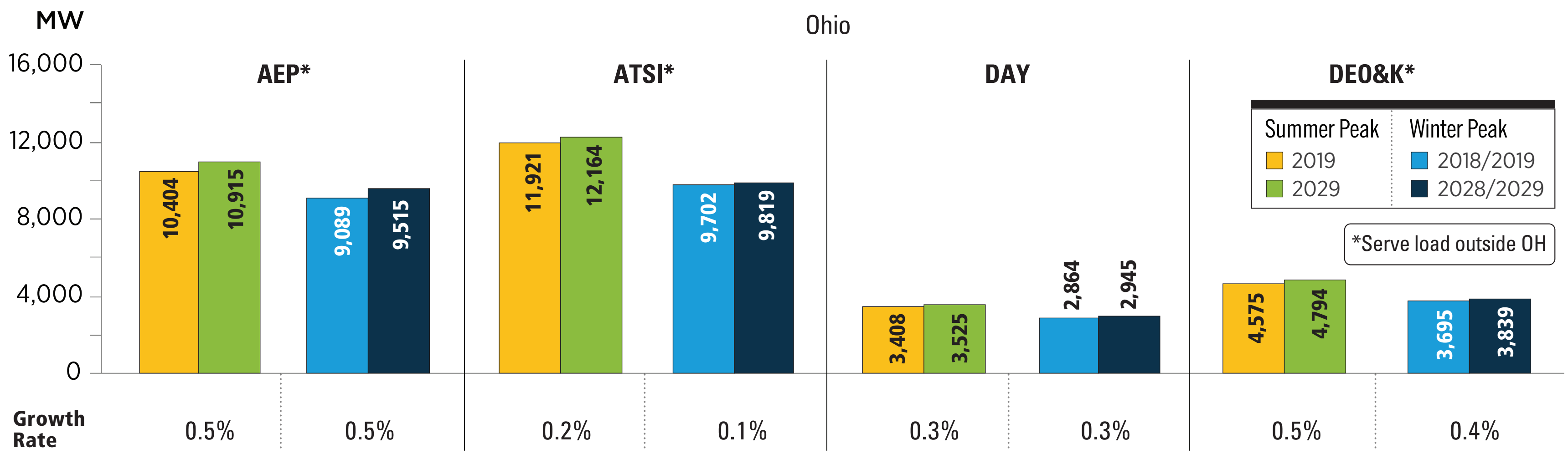
Map 6.29: PJM Service Area in Ohio



6.8.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.41** summarize the expected loads within the state of Ohio and across all of PJM.

Figure 6.41: Ohio – 2019 Load Forecast Report



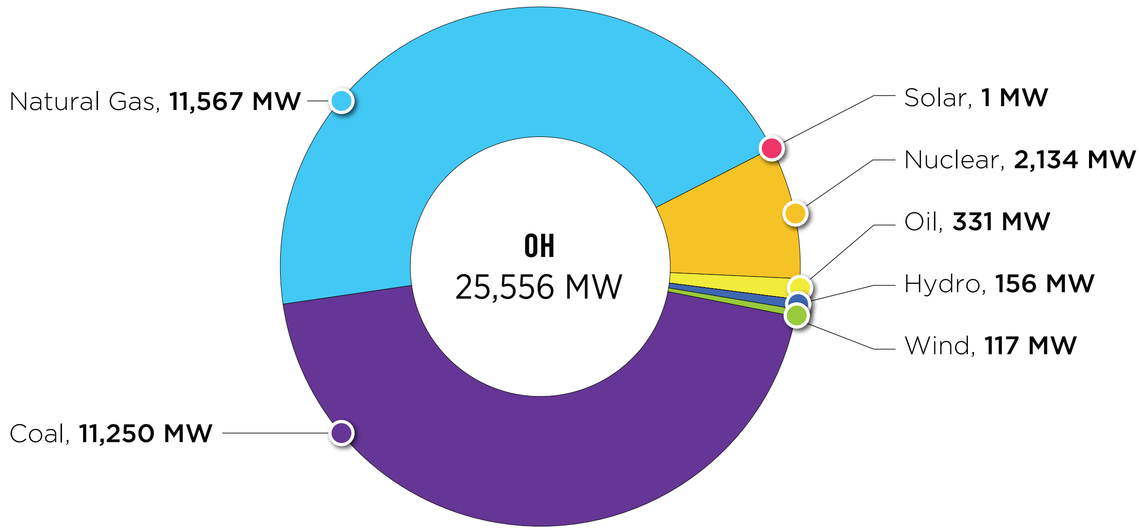
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156, 689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. 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 Ohio as of Dec. 31, 2019, is shown by fuel type in **Figure 6.42**.

Figure 6.42: Ohio – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.8.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Ohio, 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.

Specifically, in Ohio, as of Dec. 31, 2019, 180 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.37**, **Table 6.38**, **Figure 6.43**, **Figure 6.44** and **Figure 6.45**. 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 6.37: Ohio – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	Ohio Capacity (MW)	Percentage of Total Ohio Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	60	0.39%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	0	0.00%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	7,072	45.92%	34,990	42.76%
Nuclear	0	0.00%	169	0.21%
Oil	6	0.04%	27	0.03%
Other	40	0.26%	40	0.05%
Solar	7,234	46.97%	35,759	43.70%
Storage	507	3.29%	3,920	4.79%
Wind	484	3.14%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**15,401**	**100.00%**	**81,832**	**100.00%**

Table 6.38: Ohio – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	3	40.0	0	0.0	1	20.0	14	269.0	15	8,883.0	33	9,212.0
	Diesel	0	0.0	0	0.0	0	0	1	7.0	0	0.0	1	7.0
	Natural Gas	12	2,759.5	0	0.0	7	4,312.3	25	3,886.9	31	13,010.4	75	23,969.1
	Nuclear	0	0.0	0	0.0	0	0	1	16.0	0	0.0	1	16.0
	Oil	2	5.5	0	0.0	0	0	0	0.0	1	5.0	3	10.5
	Other	1	40.0	0	0.0	0	0	0	0.0	2	135.0	3	175.0
	Storage	13	504.8	0	0.0	1	1.9	8	0.0	20	548.0	42	1,054.7
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	9	50.9	9	26.1	18	77.0
	Solar	109	6,768.2	2	11.4	11	454.3	1	1.0	100	2,692.1	223	9,926.9
	Wind	11	333.2	2	45.5	5	104.9	5	125.0	66	1,671.5	89	2,280.0
	Grand Total	**151**	**10,451.2**	**4**	**56.9**	**25**	**4,893.4**	**66**	**4,467.7**	**255**	**27,232.3**	**501**	**47,101.5**

Figure 6.43: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

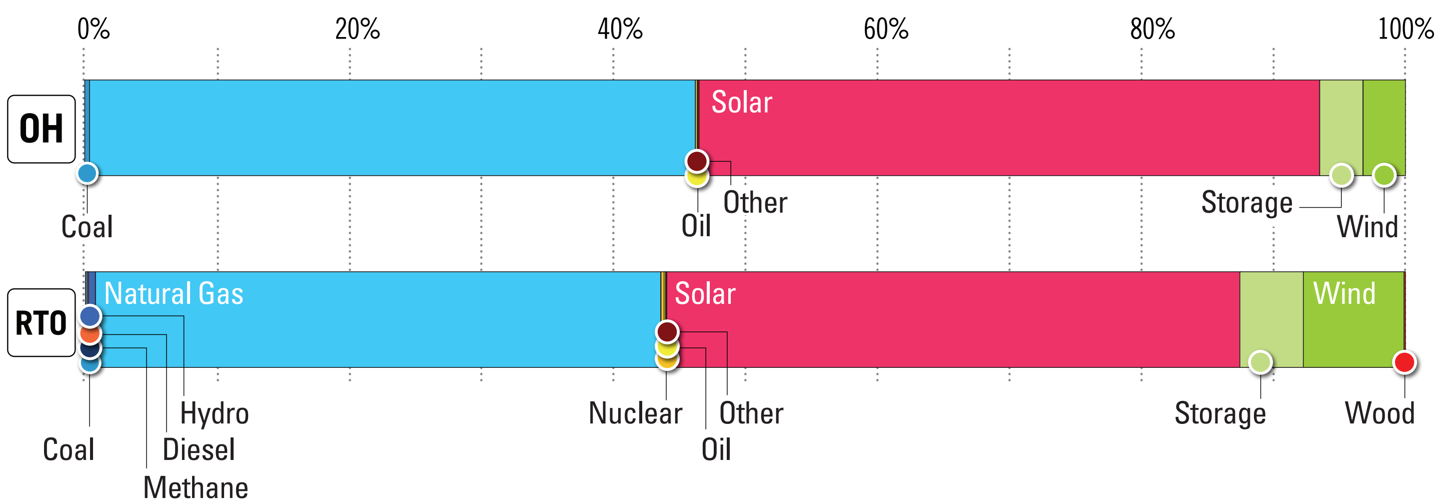
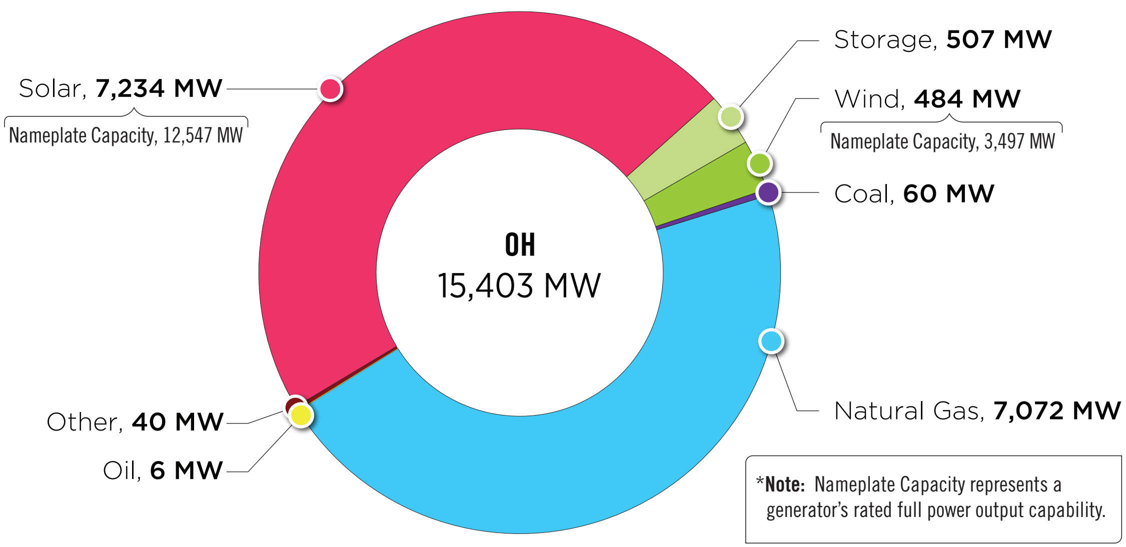
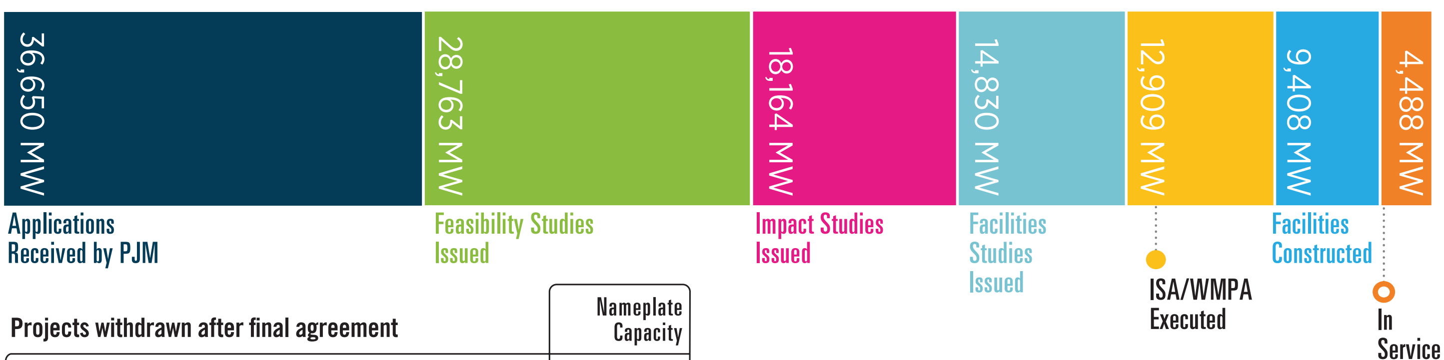


Figure 6.44: Ohio – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)



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

Figure 6.45: Ohio Progression History of Queue – Interconnection Requests (Dec. 31, 2019)



Projects withdrawn after final agreement

			Nameplate Capacity
20	Interconnection Service Agreements	3,530 MW	5,229 MW
10	Wholesale Market Participation Agreements	16 MW	52 MW

Percentage of planned capacity and projects that have reached commercial operation	12% Requested capacity megawatt	19% Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

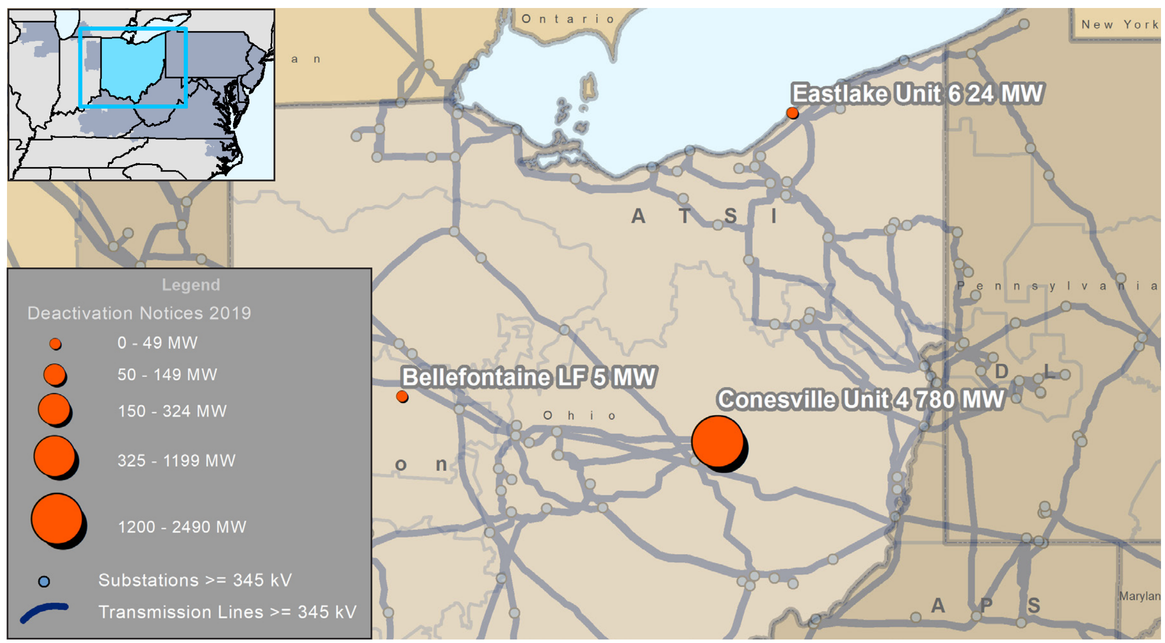
6.8.5 — Generation Deactivation

Known generating unit deactivation requests in Ohio between Jan. 1, 2019, and Dec. 31, 2019, are summarized in **Table 6.39** and **Map 6.30**.

Table 6.39: Ohio Generation Deactivations (Dec. 31, 2019)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Pending/Actual Deactivation Date	Age (Years)	Capacity (MW)
Bellefontaine Landfill Generating Station	DAY	Methane	11/20/2019	12/31/2019	10	5.0
Conesville 4	AEP	Coal	1/23/2019	6/1/2020	46	780.0
Eastlake 6	ATSI	Oil	11/20/2019	2/18/2020	45	24.0

Map 6.30: Ohio Generation Deactivations (Dec. 31, 2019)



6.8.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in Ohio are summarized in **Table 6.40** and **Map 6.31**.

6.8.7 — Network Projects

No network projects greater than or equal to $10 million in Ohio were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.31: Ohio Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

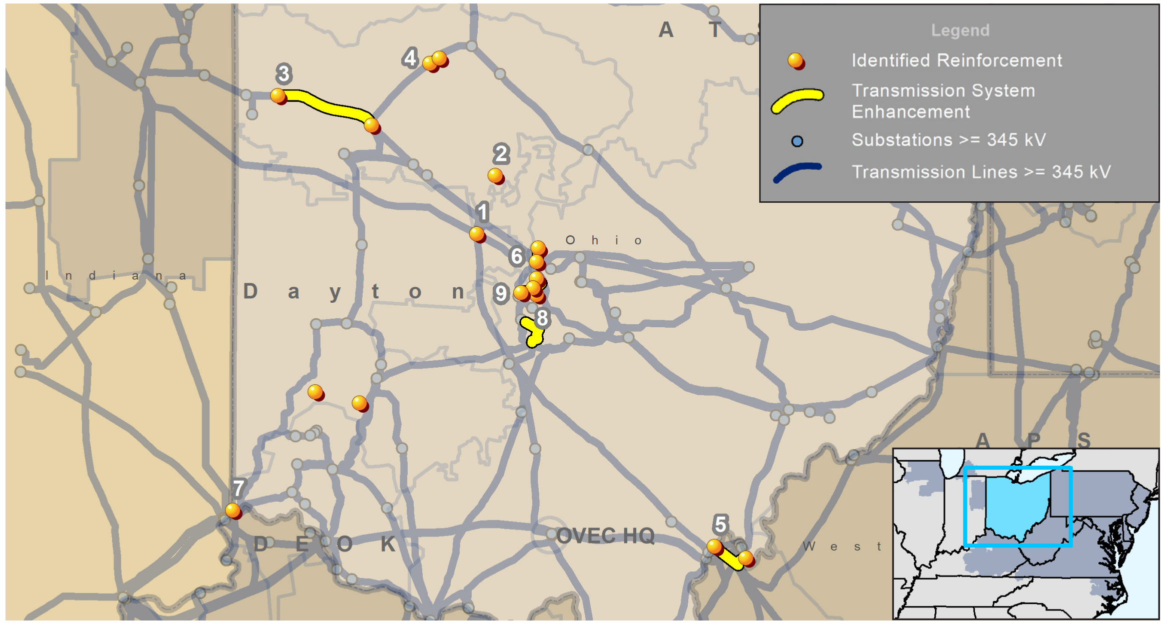


Table 6.40: Ohio Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B1570	Add a 345 kV breaker at Marysville station and a 0.1 mile 345 kV line extension from Marysville to the new 345/69 kV Dayton transformer.	6/1/2021	$20.1	AEP	4/11/2019
2	B2794	Construct a new 138/69/34 kV station and one 34 kV circuit (designed for 69 kV) from new station to Decliff station, ~5.5 miles, with 556 ACSR conductor (51 MVA rating).	6/1/2021	$28.9	AEP	5/31/2017
3	B2833	Re-conductor the Maddox Creek-East Lima 345 kV circuit with 2-954 ACSS Cardinal conductor.	12/1/2021	$30.5	AEP	1/12/2017
4	B3086	Rebuild New Liberty-Findlay 34 kV line structures 1–37 (1.5 miles), utilizing 795 26/7 ACSR conductor.	6/1/2022	$13.0	AEP	10/26/2018
		Rebuild New Liberty-North Baltimore 34 kV line structures 1–11 (0.5 miles), utilizing 795 26/7 ACSR conductor.				
		Rebuild West Melrose-Whirlpool 34 kV line structures 55–80 (1 mile), utilizing 795 26/7 ACSR conductor.				
		North Findlay Station: Install a 138 kV 3000 A 63 kA line breaker and low side 34.5 kV 2000 A 40 kA breaker, high side 138 kV circuit switcher on T1.				
		Ebersole Station: Install second 90 MVA 138/69/34 kV transformer. Install two low side (69 kV) 2000A 40kA breakers for T1 and T2.				
5	B3095	Rebuild Lakin-Racine Tap 69 kV line section (9.2 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor.	12/1/2022	$23.9	AEP	11/29/2018
6	B3105	Rebuild the Delaware-Hyatt 138 kV line (~4.3 miles) along with replacing conductors at both Hyatt and Delaware substations.	6/1/2020	$16.0	AEP	3/7/2019

Table 6.40: Ohio Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019) (Cont.)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
7	B3108	Install 100 MVAR reactor at Miami 138 kV substation.	6/1/2019	$15.0	DAY	3/7/2019
		Install 100 MVAR reactor at Sugarcreek 138 kV substation.				
		Install 100 MVAR reactor at Hutchings 138 kV substation.				
8	B3109	Rebuild 5.2 mile Bethel-Sawmill 138 kV line including.	6/1/2019	$34.5	AEP	2/20/2019
9	B3112	Construct a single circuit 138 kV line (~3.5 miles) from Amlin to Dublin using 1033 ACSR Curlew (296 MVA SN), convert Dublin station into a ring configuration, and re-terminate the Britton underground cable to Dublin station.	6/1/2020	$39.3	AEP	3/25/2019

6.8.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in Ohio are summarized in **Table 6.41** and **Map 6.32.**

Map 6.32: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

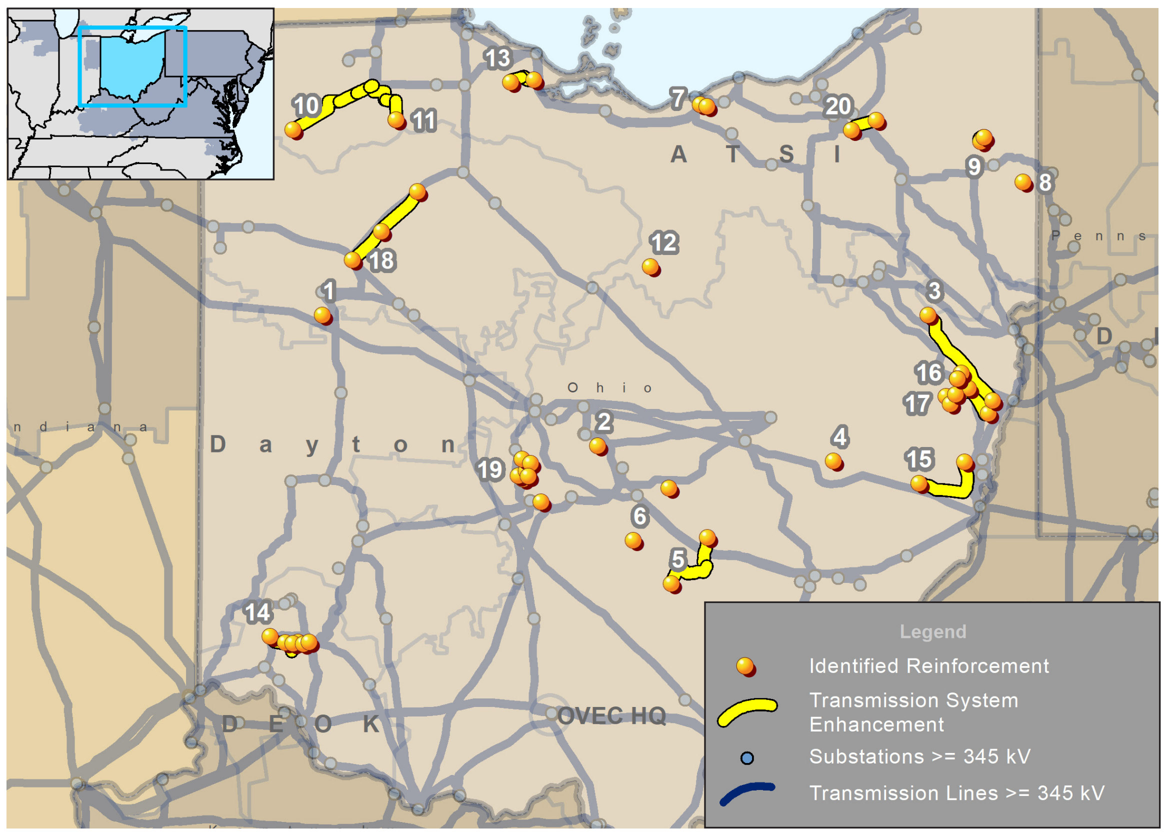


Table 6.41: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1856	Build a new 345/138 kV Gristmill station cutting into the Southwest Lima, Shelby 345 kV line. Build a new 138 kV Gemini station southeast of the City of Wapakoneta to serve the load request. Build a new 138 kV line connecting Gristmill and Gemini stations. Build a new 138 kV line from the new 138 kV Gemini station to existing West Moulton 138 kV Station. Rebuild the West Moulton 138 kV station as a four-breaker ring bus. Remove the existing City of St Marys hard tap off the Southwest Lima, West Moulton 138 kV line and bring it into West Moulton 138 kV station (~0.2 mi away).	12/31/2020	$132.4	AEP	1/11/2019
		Build a new 345/138 kV Gristmill station tapping the Southwest Lima-Shelby 345 kV line.				
		Build a new 138 kV Gemini station southeast of the City of Wapakoneta to serve the load request.				
		Build a new 138 kV Gristmill-Gemini line.				
		Build a new 138 kV Gemini-West Moulton line. Rebuild the 138 kV West Moulton station as a four breaker-ring bus.				
		Remove the existing City of St Marys hard tap off the Southwest Lima-West Moulton 138 kV line and terminate it at West Moulton 138 kV station (~0.2 mi).				
2	S1857	Customer 138 kV delivery request near Babbitt station.	2/1/2020	$47.6	AEP	2/20/2019
3	S1859	Rebuild the 29-mile Gable-Carrollton 138 kV circuit. Remove double circuit lattice towers with six-wired configuration . Install double-circuit steel poles with six-wired ACSS Yukon conductor.	11/1/2021	$42.1	AEP	1/11/2019
4	S1864	Rebuild East Cambridge station into a 69 kV, six-circuit-breaker ring bus with 69 kV 3000 A 40 kA breakers. Install a low side 34.5 kV 1200 A 25 kA circuit breaker on transformer No. 1. Build a new control house, bus work and install new line relaying. Re-terminate the transmission lines into the new station.	12/15/2019	$13.3	AEP	2/20/2019
5	S1866	Rebuild ~8.7 miles of the East Logan-New Lexington 69 kV circuit between New Lexington and Shawnee with 795 ASCR 26/7.	12/31/2021	$20.2	AEP	3/25/2019
		Replace the Shawnee 69 kV 1200 A MOABs with 2000 A switches.				
		Replace the New Lexington 69 kV line riser towards East Logan. Replace the New Lexington 600 A disconnects for circuit breaker "A" with 2000 A switches.				
6	S1867	Rebuild 18.4 miles of the Thornville-Lancaster 69 kV line utilizing 795 ACSR (26/7) conductor.	11/27/2019	$23.7	AEP	2/20/2019
7	S1876	Expand the Sugarcreek 138/69 kV substation by installing a new 138/69 kV 200 MVA transformer and a 69 kV ring bus. Build a new 69 kV line from Sugarcreek to Normandy substation connecting to the load center. These upgrades will provide a critical fourth source into the load center which will address shoulder peak loading concerns and will improve reliability of the three terminal 6610 Yankee-Caesars-Trebein 69 kV line that has historically been a poor performing circuit.	12/31/2021	$15.9	DAY	4/23/2019
		Replace the 138/12 kV transformer at Normandy substation with a 69/12 kV transformer. This will provide operations greater flexibility for switching loads through parallel distribution bank operation at Normandy.				
		Loop the Dayton Mall-Yankee-Normandy line No. 6671 in and out of the Yankee substation to eliminate a three terminal arrangement. Install one 69 kV breaker at Normandy to separate the bus. Install one 69 kV breaker at Yankee substation to eliminate the three terminal line.				
8	S1947	Lincoln Park-Riverbend 138 kV Line. Build a new 138 kV line from Riverbend to Lincoln Park substation (~5.7 miles). Convert the Riverbend substation into a four-breaker ring bus configuration by installing two 138 kV breakers. Expand the Lincoln Park 138 kV ring bus by installing one 138 kV breaker allowing for a new line terminal.	12/31/2022	$25.9	ATSI	3/25/2019
9	S1950	Elm 138 kV Ring Bus: Convert Ivanhoe 138 kV substation to a six-breaker ring bus configuration by installing two 138 kV breakers. Convert Elm 138 kV substation to a five breaker ring bus configuration (future six) by installing four 138 kV breakers. Build ~3 miles of 138 kV line from Ivanhoe to Elm.	6/1/2023	$12.1	ATSI	3/25/2019
10	S1952	Weldon 69 kV Ring Bus and Line Build. Construct a new four breaker ring bus (Weldon Substation) outside the existing Canfield Steel substation. Network the new four.breaker ring bus by completing the following: Loop the existing Canfield Steel radial 69 kV circuit into the new Weldon substation. Loop the existing Berlin Lake-Boardman 69 kV line into new Weldon substation by constructing ~0.6 miles of 69 kV line adjacent to existing Canfield Steel 69 kV radial circuit. Build new Weldon-Kimberly 69 kV line (~6.4 miles). Install new line exit switch and SCADA to the line exits at Kimberly. Install auto-sectionalizing scheme at Canfield substation.	6/1/2023	$17.4	ATSI	3/25/2019

Table 6.41: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
11	S1953	Richland-Weston 69 kV Line-Conversion from 34.5 kV. Richland Substation: Install one new 69 kV breaker and reconfigure the 69 kV yard to a three breaker ring bus with a new 69 kV line exit to Weston substation. Remove all 34.5 kV equipment post conversion (ex: Richland 138 - 34.5 kV transformer No. 1 and circuit breakers). Expand Weston substation to a four breaker, future six breaker ring bus with 69 kV line exits for the new Richland line, and the Midway and Tontogany 69 kV lines. Remove all 34.5 kV equipment post conversion (ex: Weston 69 - 34.5 kV transformer No. 3 and circuit breakers). New Richland-Weston 69 kV Line: Build new 5.6 mile 69 kV line to network Richland-Maroe and Weston-Malinta radial lines. Convert the existing Richland-Maroe 34.5 kV line to 69 kV (~19 miles); customers to upgrade existing substation equipment at Holgate and Maroe to 69 kV. Convert the existing Weston-Malinta 34.5 kV line to 69 kV (~13 miles); customers to upgrade existing substation.	12/31/2023	$50.0	ATSI	3/25/2019
12	S1963	Longview-Mohican 69 kV line (Longview-Coulter 69 kV line segment). Rebuild the Longview-Coulter 69 kV line segment (~15.8 miles of the 22.1 mile line), replace four line switches (A-10, A-19, A-23 and A-27) and add SCADA control. Terminal equipment at Longview substation to be upgraded under ATSI-2019-021, including: line relaying, substation conductor, and disconnect switches.	12/31/2022	$22.2	ATSI	3/25/2019
13	S1964	Brush Wellman-Ottawa 69 kV Line Rebuild the Brush Wellman-Ottawa 69 kV line (~7.3 miles) Replace four line switches; A-7240, A-7228, A-7235 and 7235 N.O Upgrade the terminal equipment at Brush Wellman substation including Substation conductors and relay communication equipment.	12/31/2022	$10.0	ATSI	3/25/2019
14	S1992	Rebuild Socialville and Simpson into three-breaker 138 kV ring buses. Rebuild Montgomery into a five-breaker ring bus. Extend the Montgomery tap 0.25 miles to connect at Socialville. Connect Cornell-Wards Corner that runs through Montgomery, at Montgomery. This configuration limits the 150 MW load loss to these maximums: 30 MW Port Union-Socialville, 34 MW Socialville-Simpson, 48 MW Simpson-Foster.	6/1/2023	$14.2	DEO&K	7/24/2019
15	S2003	Rebuild the Glencoe-Somerton 69 kV circuit (22 miles) with single-circuit 795 ACSR conductor.	6/1/2022	$61.5	AEP	7/24/2019
		Replace the Pipe Creek 69 kV hard tap with a 1200 A-rated three-way switch (Jacobsburg Switch).				
		Replace the Beallsville 69 kV hard tap with a 1200 A-rated three-way switch (Beallsville Switch).				
16	S2004	Rebuild the 9.3 mile, Dillonvale-Parlett 69 kV line using 795 ACSR conductors.	11/15/2022	$47.9	AEP	5/20/2019
		Rebuild 2.5 mile section of 69 kV line from Parletto Blackhawk using 795 ACSR conductors.				
		Rebuild ~2 mile section of the Blackhawk-North. Hopedale-Miller Switch 69 kV circuit using 795 ACSR conductors.				
		Retire the 0.12 mile radial 69 kV line from Rose Valley switch.				
		At Hopedale 69 kV station, install new H-frame for T-line termination and 69 kV line disconnect group/gang operated air breaks (40 kA, 1200 A).				
		At North Hopedale switch, replace the 69 kV switch with a new phase-over-phase switch (40 kA, 1200 A).				
		Retire the 69 kV switch at Rose Valley.				
17	S2007	Rebuild 9.65 miles of 69 kV Sparrow-Parlett-Cadiz line as single circuit using 795 ACSR conductor, energized at 69 kV. Install.	12/1/2020	$41.5	AEP	6/17/2019
		Retire 0.41 miles radial, de-energized 69 kV line that is routed west from Unionvale switch.				
		Retire Unionvale 69 kV switch.				
		Replace and re-locate East Cadiz 69 kV switch with a three-way phase-over-phase switch (2,000 A) with motor-operated air breaks on each side.				
		Modify 69 kV relaying at South Cadiz, Parlett and Sparrow.				

Table 6.41: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
18	S2060	Build a new Boutwell 138/69/34.5 kV station as a three breaker ring bus cutting into the East Lima-New Liberty 138 kV circuit. Install a 138/69/34.5 kV 90 MVA transformer. Install low side 69 kV bus and line breaker to feed line towards Lancers switch.	11/15/2022	$59.2	AEP	9/25/2019
		Cut in the East Lima-New Liberty 138 kV circuit and build to the new Boutwell station.				
		Construct a new 3.75 mile single circuit 69 kV (34.5 kV operated) line using 556 ACSR conductor connecting the Hancock Wood Airport delivery point with the new Boutwell Station.				
		Construct 1.5 miles of greenfield single circuit 69 kV (34.5 kV operated) line using 556 ACSR conductor from North Woodcock to the South Mt Cory-Woodcock Switch 69 kV line (34.5 kV Operated).				
		Rebuild the 1.7 mile, 34.5 kV line from Woodcock Switch Bluffton Airport as single circuit 69 kV (34.5 kV operated), using 556 ACSR conductor.				
		Rebuild 1.3 mile of existing 34.5 kV line as double circuit 69 kV line to loop Beaverdam station into the Dolahard-East Lima 69 kV circuit, using 556 ACSR conductor.				
		Retire portions of 34.5 kV line between Blue Lick & Beaverdam and Woodcock Switch & South Mt. Cory buses. (12.3 miles).				
		At North Woodcock station, replace 138/69/34.5 kV transformer No. 1 with a new 90 MVA bank. Install 138 kV circuit breakers (3000 A, 40 kA) on the line towards East Lima and the high side of transformer No. 1. Replace 69 kV circuit breaker A with a new 69 kV breaker (2000 A, 40 kA). Replace 34.5 kV circuit breaker E with a new 69 kV circuit breaker E (2000 A, 40 kA), operated at 34.5 kV. Install a new 69 kV circuit breaker (2000 A, 40 kA), operated at 34.5 kV, on the Morrical circuit. Replace the 34.5 kV grounding bank and retire the 34.5 kV cap bank.				
		Install 69 kV 1200 A phase-over-phase switch (Lancers Switch) at the airport delivery point.				
		Install 69 kV 1200 A phase-over-phase switch (Pirate Switch) at the hard tap.				
		Install 69 kV 1200 A phase-over-phase switch (Fliprock Switch) at National Lime & Stone hard tap.				
		Retire the 34.5 kV Woodcock switch.				

Table 6.41: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
19	S2063	Rebuild and relocate approx. 1.5 miles between Blair and Galloway to avoid a neighborhood along the existing line path.	5/31/2022	$50.1	AEP	9/25/2019
		Relocate Ballah-Madison 69 kV line exit to new Beatty 69 kV yard.				
		Connect 138/69 kV Cole station (new 69 kV yard) between Blair and Galloway.				
		At Beatty station, replace the 450 MVA 345/138 kV transformer with 675 MVA unit and retire the low side reactor. Replace 1-50 MVA 138/69 kV transformer with a 90 MVA unit and retire second 138/69 kV 50 MVA transformer. Replace 1-138 3,000 A 50 kA circuit breaker 6W with 4,000 A 63 kA. Install four 138 kV 3,000 A 63 kA circuit breakers. Rebuild 69 kV bus as ring bus, replacing three of four 69 kV 1,200A 20 kA circuit breakers with 2,000 A 40 kA circuit breakers. The fourth circuit breaker will be retired.				
		At Cole station, install a new 138/69 kV 90 MVA transformer. Install two 138 kV 3000 A 63 kA breakers with bus work to connect proposed 138/69 kV transformer. Install two 138 kV 3000 A 63 kA breakers with bus work to connect AEP-Ohio's requested 138/13 kV delivery point. Install three new 69 kV 2000 A 40 kA breakers in a ring configuration.				
		At Trabue station, install three 138 kV 3000 A 40 kA circuit breakers and associated relaying. Install a new 138 kV 14.4 MVAR capacitor with switcher.				
		At Hilliard station, upgrade 69 kV capacitor to 28.8 MVAR. Replace three 69 kV 1200 A 21 kA circuit breakers with 2000 A 40 kA circuit breakers. Replace two sets of high speed ground switch/motor-operated air breaks transformer protection with circuit switchers.				
		Perform 69 kV remote end relaying work at Galloway.				
		Perform 69 kV remote end relaying work at Roberts.				
		Perform 69 kV remote end relaying work at Fisher.				
		Perform 69 kV remote end relaying work at Blair.				
		Perform 69 kV remote end relaying work at Nautilus.				
20	S2079	Build ~5 miles of 69 kV line from Treat to Cantex to create the 69 kV Aurora-Chamberlin line No. 2. Operate the existing Aurora-Chamberlin 69 kV line radial out of Chamberlin. Serve Mantua 69 kV substation from Garrettsville. Add SCADA control switches at Treat and Cantex tap. Add an auto-sectionalizing scheme at Geauga substation.	8/14/2020	$11.0	ATSI	5/20/2019

6.8.9 — Merchant Transmission Project Requests

As of Dec. 31, 2019, PJM's queue contained two merchant transmission project requests which include a terminal in Ohio as shown in **Table 6.42** and **Map 6.33.**

Map 6.33: Ohio Merchant Transmission Project Requests (Dec. 31, 2019)

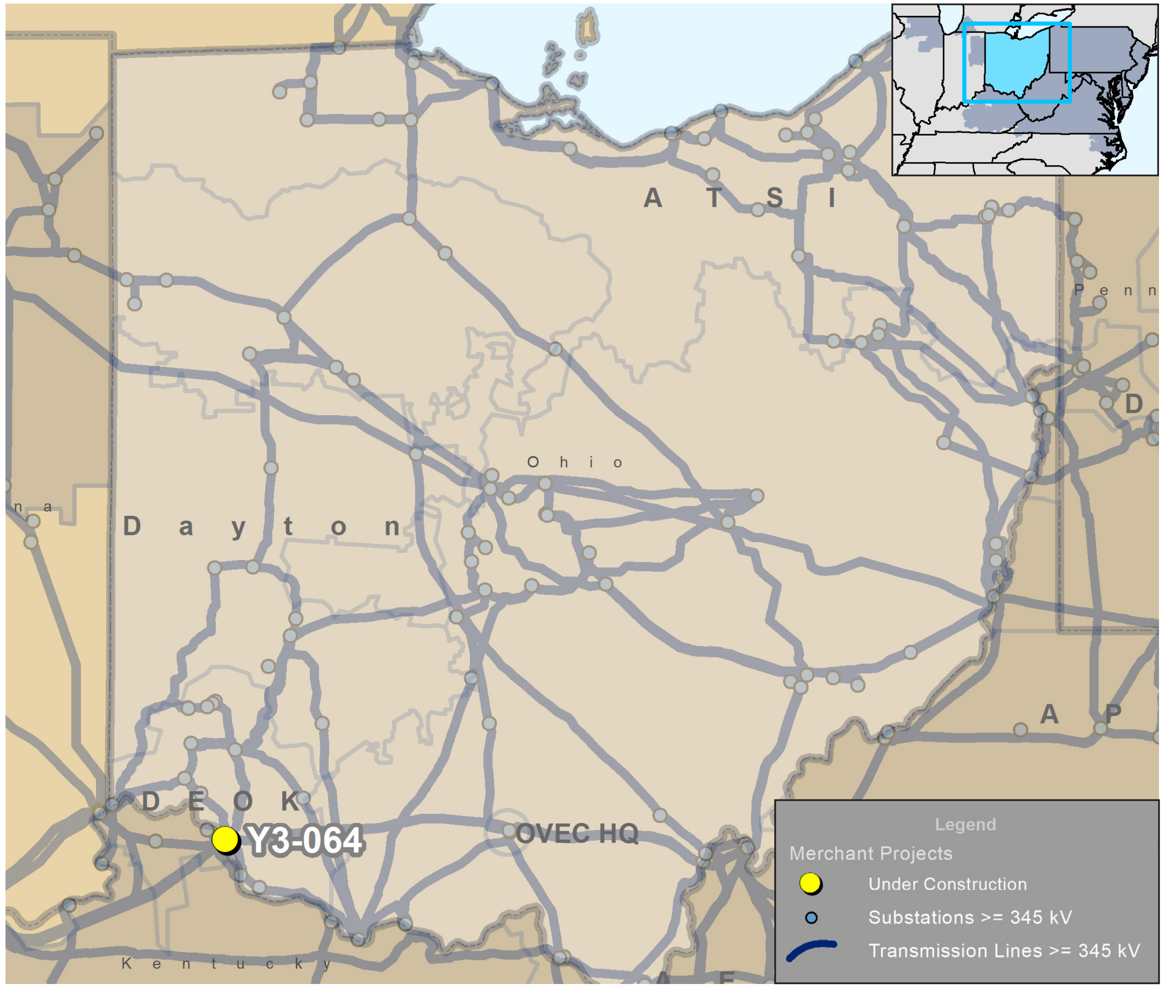


Table 6.42: Ohio Merchant Transmission Project Requests (Dec. 31, 2019)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
Y3-064	Pierce-Beckjord 138 kV	DEO&K	Under Construction	12/31/2019	160.0

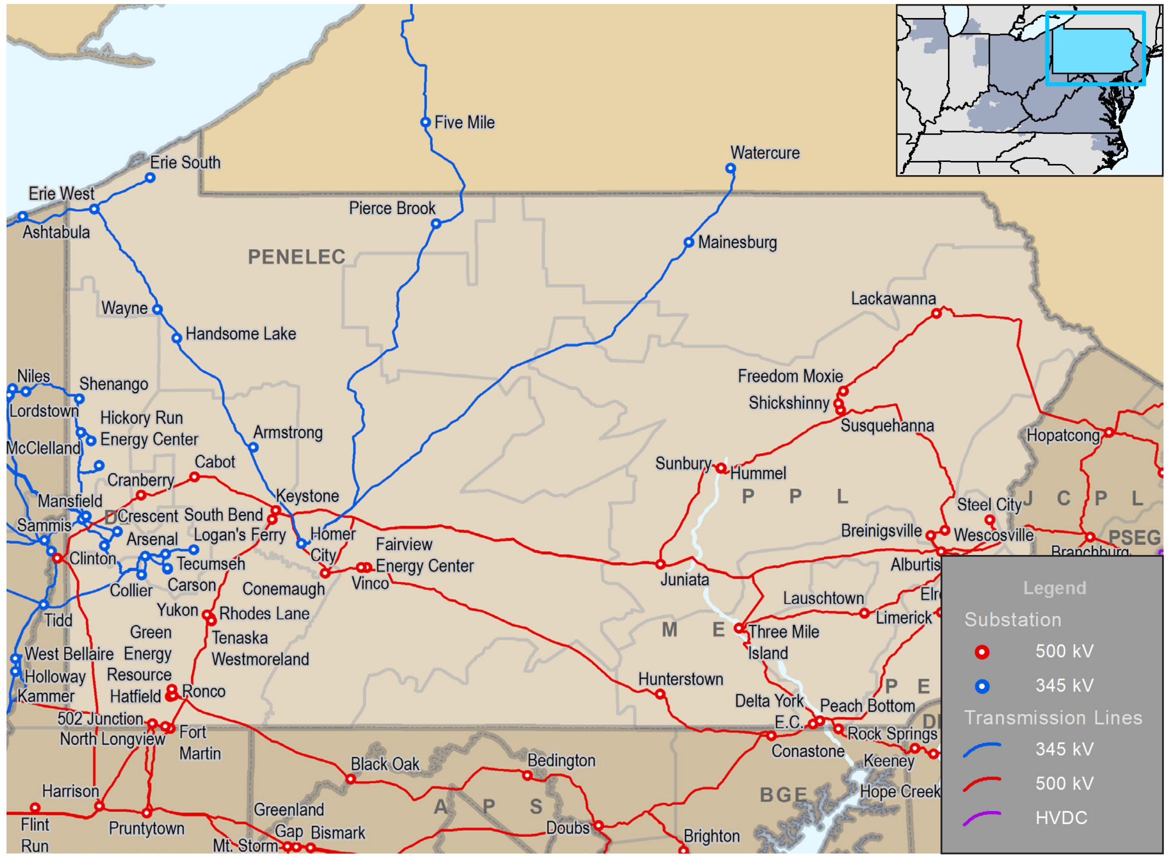
6.9: Pennsylvania RTEP Summary

6.9.1 — 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 (AP), Duquesne Light Company (DLCO), Metropolitan Edison Company (Met-Ed), Pennsylvania Electric Company (PENELEC), PECO Energy Company (PECO), PPL Electric Utilities Corporation (PPL), UGI Utilities, Inc. (UGI), Rock Springs and American Transmission Systems, Inc. (ATSI) as shown on **Map 6.34**.

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 PJM.

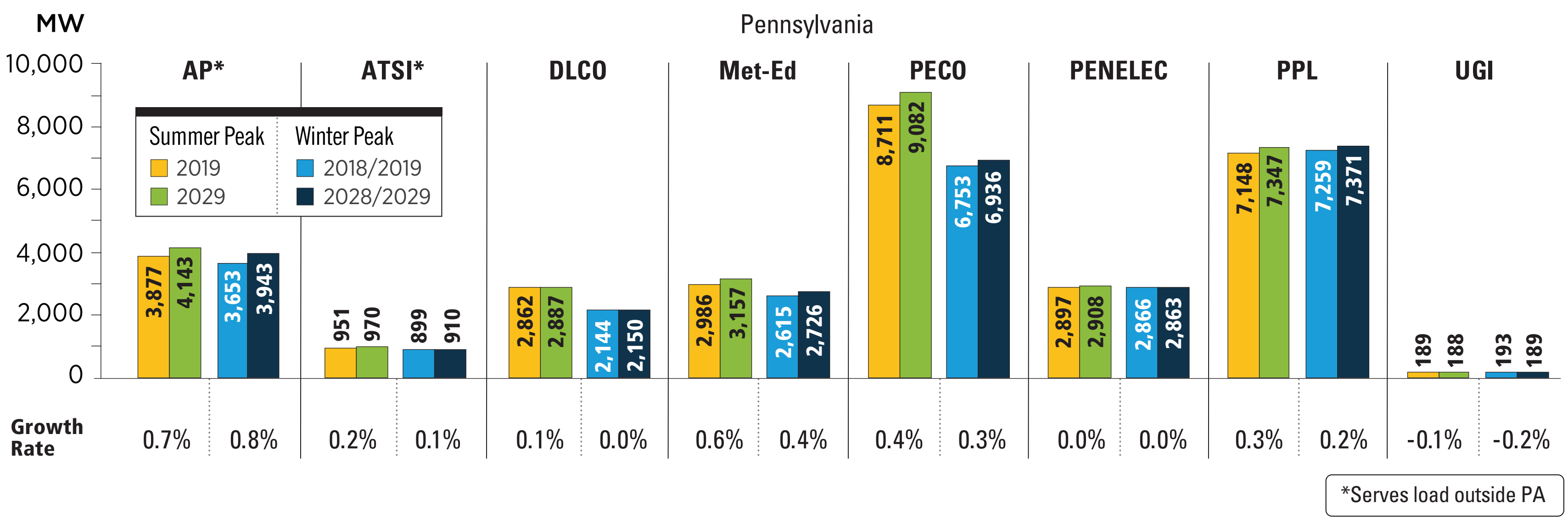
Map 6.34: PJM Service Area in Pennsylvania



6.9.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.46** summarize the expected loads within the state of Pennsylvania and across all of PJM.

Figure 6.46: Pennsylvania – 2019 Load Forecast Report



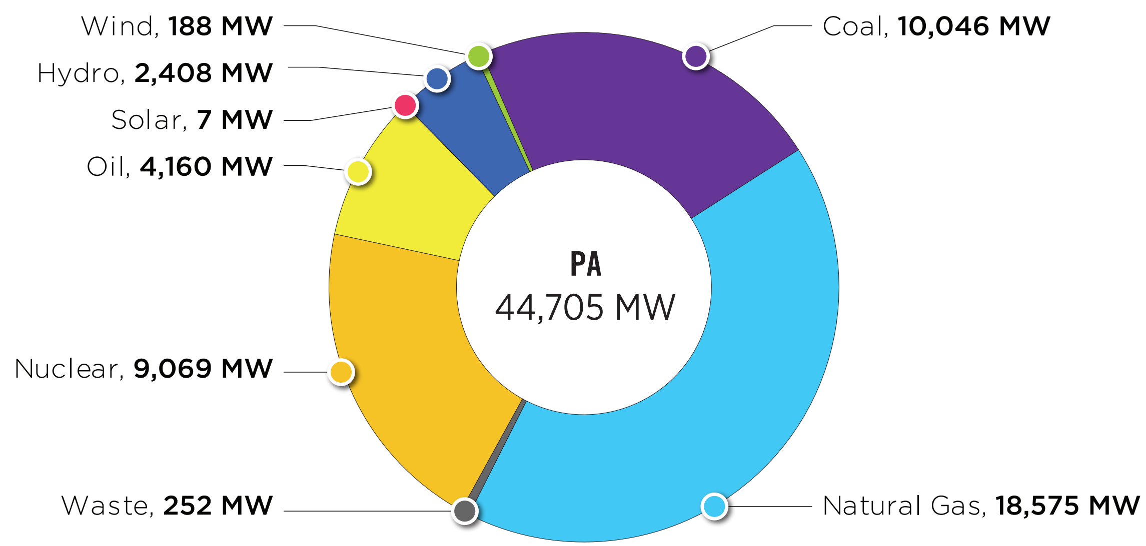
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156, 689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. 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 Pennsylvania as of Dec. 31, 2019, is shown by fuel type in **Figure 6.47**.

Figure 6.47: Pennsylvania – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.9.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Pennsylvania, 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.

Specifically, in Pennsylvania, as of Dec. 31, 2019, 265 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.43**, **Table 6.44**, **Figure 6.48**, **Figure 6.49** and **Figure 6.50**. 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 6.43: Pennsylvania – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	Pennsylvania Capacity (MW)	Percentage of Total Pennsylvania Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	4	0.03%	4	0.01%
Hydro	450	3.59%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	7,067	56.40%	34,990	42.76%
Nuclear	94	0.75%	169	0.21%
Oil	8	0.06%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	4,443	35.46%	35,759	43.70%
Storage	271	2.16%	3,920	4.79%
Wind	177	1.41%	6,240	7.62%
Wood	16	0.13%	66	0.08%
Grand Total	**12,530**	**100.00%**	**81,832**	**100.00%**

Table 6.44: Pennsylvania – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	0	0	0	0.0	0	0	17	229.0	28	14,354.6	45	14,583.6
	Diesel	0	0	0	0.0	1	4.1	3	33.3	12	51.5	16	88.9
	Natural Gas	30	3,393.5	3	989.8	18	2,683.7	92	19,411.1	237	87,763.2	380	114,241.3
	Nuclear	4	50.0	0	0.0	1	44.0	15	2,581.8	8	1,681.0	28	4,356.8
	Oil	6	7.5	0	0.0	0	0.0	3	9.4	9	1,307.0	18	1,323.9
	Other	0	0	0	0.0	0	0.0	2	306.5	6	344.0	8	650.5
	Storage	13	270.8	1	0.0	1	0.0	5	0.0	27	282.1	47	552.9
Renewable	Biomass	0	0	0	0.0	0	0.0	2	15.4	4	36.5	6	51.9
	Hydro	2	450.0	0	0.0	0	0.0	12	480.8	16	438.6	30	1,369.4
	Methane	0	0	0	0.0	0	0.0	25	130.7	37	201.3	62	332.0
	Solar	158	4,377.0	3	22.0	10	44.3	4	11.9	123	1,629.4	298	6,084.7
	Wind	5	87.8	3	34.4	5	54.9	39	259.6	133	1,716.3	185	2,153.0
	Wood	0	0.0	1	16.0	0	0.0	0	0.0	0	0.0	1	16.0
	Grand Total	**218**	**8,636.6**	**11**	**1,062.2**	**36**	**2,831.0**	**219**	**23,469.5**	**640**	**109,805.5**	**1,124**	**145,804.9**

Figure 6.48: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

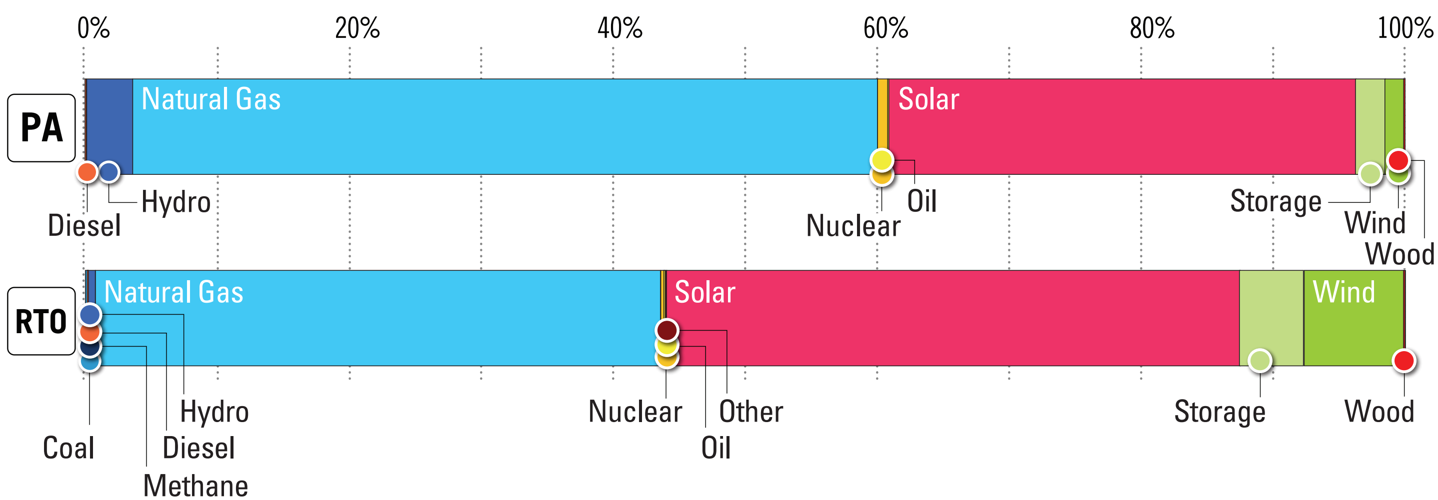


Figure 6.49: Pennsylvania – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)

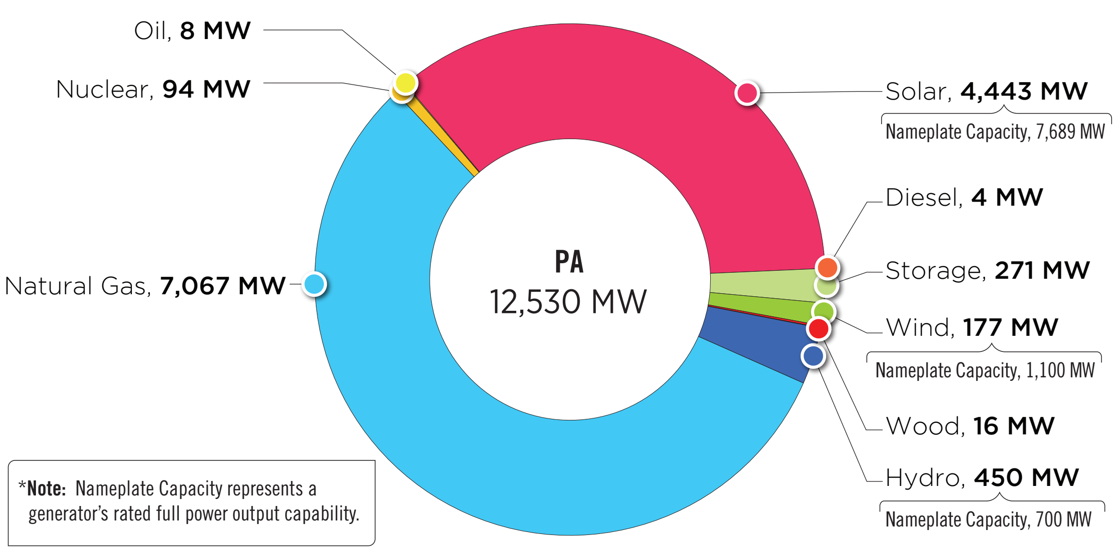
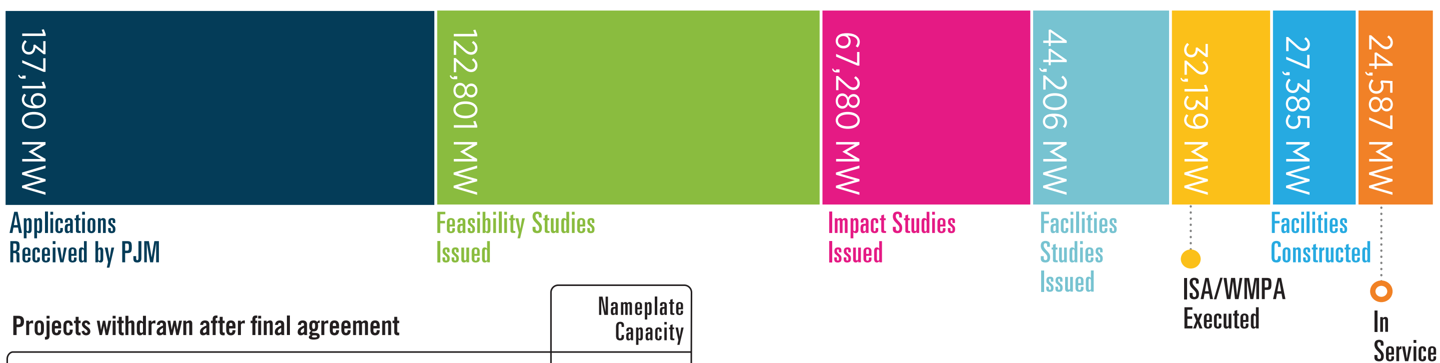


Figure 6.50: Pennsylvania Progression History of Queue – Interconnection Requests (Dec. 31, 2019)



Projects withdrawn after final agreement			Nameplate Capacity
50	Interconnection Service Agreements	5,972 MW	7,661 MW
47	Wholesale Market Participation Agreements	287 MW	400 MW

Percentage of planned capacity and projects that have reached commercial operation	18%	26%
	Requested capacity megawatt	Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

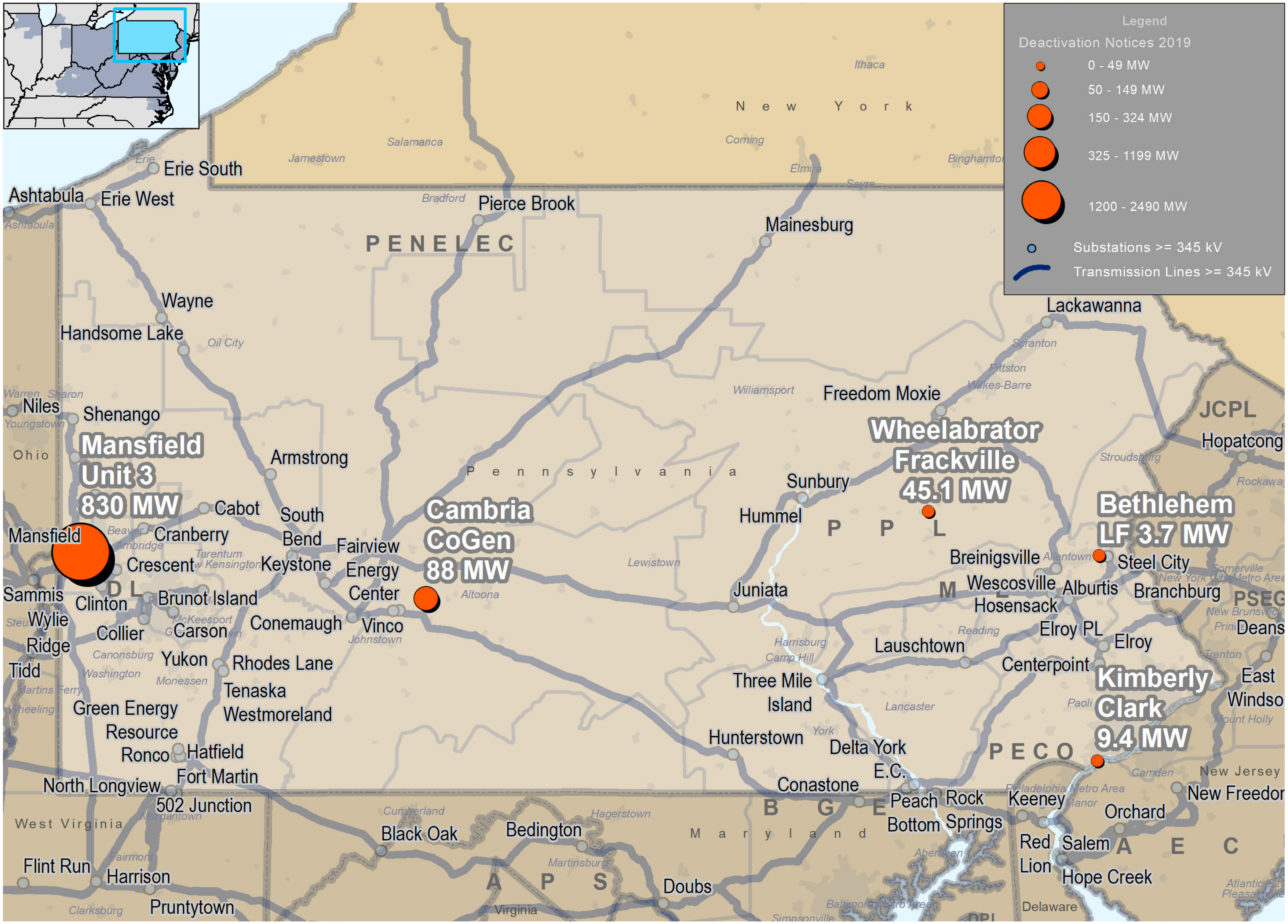
6.9.5 — Generation Deactivations

Known generating unit deactivation requests in Pennsylvania between Jan. 1, 2019, and Dec. 31, 2019, are summarized in **Table 6.45** and **Map 6.35**.

Table 6.45: Pennsylvania Generation Deactivations (Dec. 31, 2019)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Pending/Actual Deactivation Date	Age (Years)	Capacity (MW)
Frackville Wheelabrator 1	PPL	Coal	9/3/2019	3/1/2020	31	45.1
Cambria CoGen	MAIT	Coal	3/7/2019	9/17/2019	28	88
Bethlehem Renewable Energy Generator (Landfill)	PPL	Methane	2/25/2019	8/31/2019	10	3.7
Kimberly Clark Generator	PECO	Coal	8/28/2019	9/4/2019	32	9.4
Mansfield 3	ATSI	Coal	8/9/2019	11/7/2019	38	830

Map 6.35: Pennsylvania Generation Deactivations (Dec. 31, 2019)



6.9.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in Pennsylvania are summarized in **Table 6.46** and **Map 6.36**.

Map 6.36: Pennsylvania Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

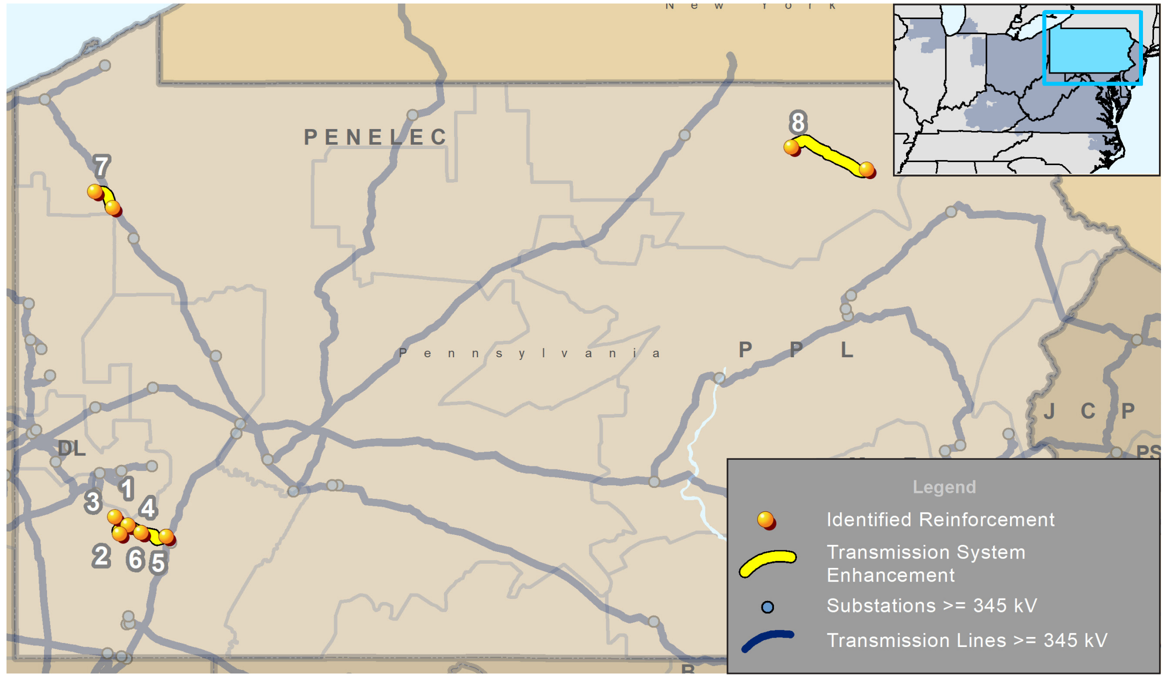


Table 6.46: Pennsylvania Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3011	Replace the line terminal equipment and line breaker No. 85 at Dravosburg 138 kV substation in the Elwyn Z-70 line position/bay, with the breaker duty as 63 kA.	6/1/2021	$28.5	DLCO	2/20/2019
2	B3012	Construct two new 138 kV ties with the single structure from Allegheny Power's new substation to Duquesne's new substation. The estimated line length is ~4.7 miles. The line is planned to use multiple ACSS conductors per phase.	6/1/2021	$46.8	AP	6/7/2018
		Construct two new ties from a new First Energy substation to a new Duquesne substation by using two separate structures in the Duquesne portion.			DLCO	
		Construct a new Elrama-Route 51 138 kV line No. 3: reconductor 4.7 miles of the existing line, and construct 1.5 miles of a new line to the reconductored portion. Install a new line terminal at Allegheny Power's Route 51 substation.	6/1/2020		AP	5/16/2019
		Establish the new tie line in place of the existing Elarama-Mitchell 138 kV line.	6/1/2021		DLCO	5/16/2019
3	B3064	Expand Elrama 138 kV substation to loop in the existing USS Steel Clariton-Piney Fork 138 kV line.	6/1/2021	$13.1	DLCO	11/8/2018
		Replace the West Mifflin 138 kV breakers Z-94, Z-74, Z14, and Z-13 with 63 kA breakers.				5/20/2019

Table 6.46: Pennsylvania Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	B3070	Reconductor the Yukon-Route 51 138 kV No. 1 line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV.	6/1/2022	$10.0	AP	11/8/2018
5	B3071	Reconductor the Yukon-Route 51 138 kV No. 2 line (8 miles) and replace relays at Yukon 138 kV.	6/1/2022	$10.0	AP	11/8/2018
6	B3072	Reconductor the Yukon-Route 51 138 kV No. 3 line (8 miles) and replace relays at Yukon 138 kV.	6/1/2022	$10.0	AP	11/8/2018
7	B3077	Reconductor the Franklin Pike-Wayne 115 kV line (6.78 miles).	6/1/2022	$15.0	PENELEC	11/8/2018
8	B3137	Rebuild 20 miles of the East Towanda-North Meshoppen 115 kV line.	6/1/2024	$58.6	PENELEC	9/24/2019

6.9.7 — Network Projects

RTEP network projects greater than or equal to $10 million in Pennsylvania are summarized in **Table 6.47** and **Map 6.37**.

Map 6.37: Pennsylvania Network Projects (Greater than $10 M) (Dec. 31, 2019)

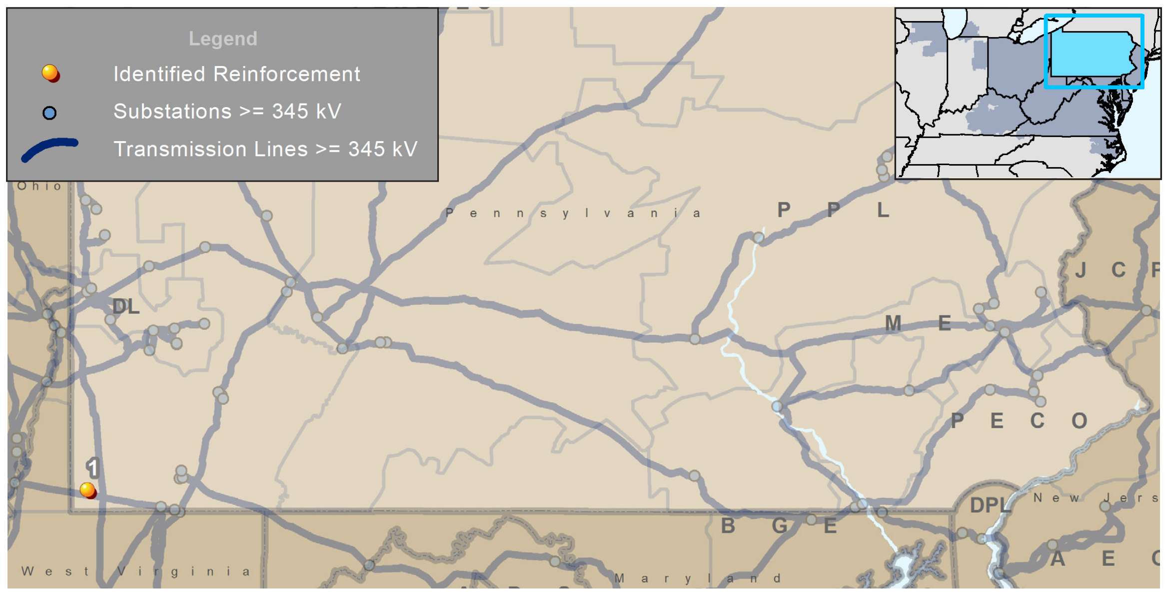


Table 6.47: Pennsylvania Network Upgrades (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5934	Construct 500 kV three-breaker ring bus substation. Cut and loop in the 500 kV Wylie Ridge-Harrison line and install new tie line to new generation at Strope Road substation.	AB1-069	7/1/2019	$14.7	AP	11/14/2019

6.9.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in Pennsylvania are summarized in **Table 6.48** and **Map 6.38**.

Map 6.38: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

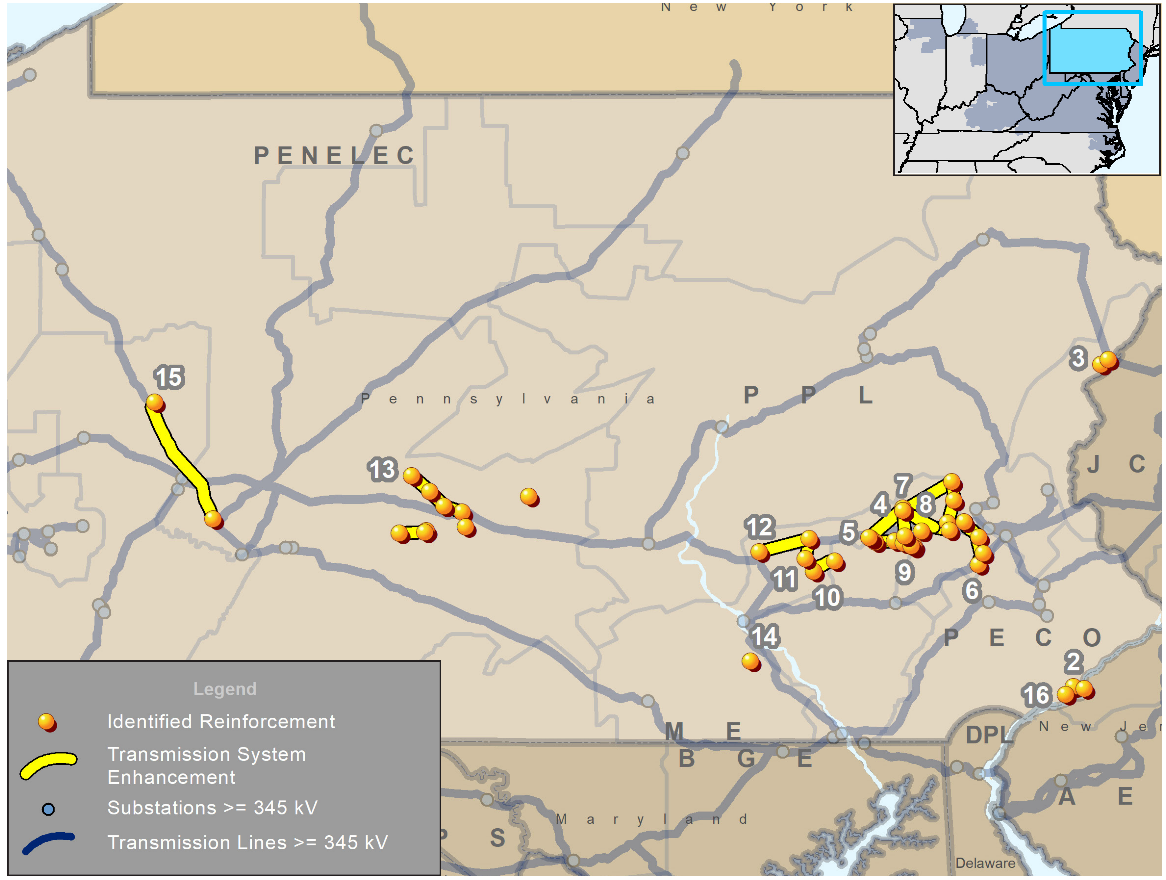


Table 6.48: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1849	Build a new Upland 230/13 kV station.	6/1/2021	$27.0	PECO	2/22/2019
		Purchase property to accommodate construction of Upland 230/13 kV substation.				
		Construct tap from existing 230 kV Bala-Parrish line to feed new Upland substation.				
		Install 230 kV bus and two 230/13 kV transformers in the Upland station.				

Table 6.48: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S1850	Build a new Civic 69/13 kV distribution substation.	12/31/2023	$89.0	PECO	4/26/2019
		Install a new Civic 69 kV bus (breaker-and-a-half configuration).	6/30/2022			
		Tap existing 69 kV Schuylkill-Angora, Schuylkill-Island Road, and Schuylkill-University lines-feed new Civic substation. Retire portions of the Schuylkill-Island Road and Schuylkill-University lines under the Schuylkill river.	6/30/2022			
		Relocate north connection point of Schuylkill North-Central bus tie to open terminal position of retired Island Road to Schuylkill line.	6/30/2022			
		Rebuild Passyunk-Southwark 69 kV line.	6/30/2022			
		Install two 69/13 kV transformers at Civic station.	12/31/2023			
3	S1880	Construct a new 69 kV transmission line from Shawnee to Walker substations (~31.1 miles).	12/31/2023	$60.0	Met-Ed	1/25/2019
		Expand Shawnee 230 kV bus into a six breaker ring bus.				
		Install a new 230/69 kV 100/134/168 MVA transformer and associated equipment at Shawnee station.				
		Build new 69 kV delivery point at Birchwood Lakes.				
		Install a new 69 kV 9.6 MVAR capacitor at Birchwood Lakes.				
		Build new 69 kV delivery point at Bushkill Falls.				
		Install a new 69 kV 9.6 MVAR capacitor at Bushkill Falls.				
		Expand Walker 69 kV bus into a three breaker ring bus.				
4	S1893	Rehab/rebuild Baldy-South Hamburg 69 kV line.	12/31/2019	$12.3	Met-Ed	4/26/2019
		Rehab/rebuild Baldy-South Hamburg (~29.3 miles) 69 kV line.				
		Replace line relaying and substation conductoron the Weisenberg 69 kV line exit at the at Baldy substation.				
		Replace substation conductor on the Lynnville 69 kV line exit at the South Hamburg substation.				
5	S1894	Rehab/rebuild the North Temple-Northkill 69 kV line.	6/1/2020	$14.2	Met-Ed	4/26/2019
		Rehab/rebuild North Temple-Berkley Tap-Cambridge Lee-Bern Church-Northkill 69 kV line. Reconductor ~5.8 miles on Cambridge Lee-Bern Church section.				
		Replace substation conductor on the Berkley Tap 69 kV line exit at the North Temple substation.				
6	S1896	Rehab/rebuild the East Topton-North Boyertown 69 kV line.	12/31/2019	$36.4	Met-Ed	4/26/2019
		Rehab/rebuild East Topton-Huffs Church-Barto-North Boyertown 69 kV line.				
		Replace line relaying and substation conductoron the Huffs Church 69 kV line exit at East Topton substation.				
7	S1898	Rehab/rebuild Bernville-State Street-South Hamburg 69 kV line.	6/1/2020	$14.9	Met-Ed	4/26/2019
		Reconductor Bernville-State Street 69 kV line section.				
		Replace substation conductor and relays on the State Street 69 kV line exit at South Hamburg substation.				
		Replace substation conductor on the State Street 69 kV line exit at Bernville station.				

Table 6.48: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
8	S1900	Rehab/rebuild Allentown-Lyons-South Hamburg 69 kV line.	12/31/2021	$15.7	Met-Ed	4/26/2019
		Rehab/rebuild Allentown-Lyons-South Hamburg 69 kV line. Reconductor 15.2 miles of the circuit.				
		Replace substation conductor at South Hamburg 69 kV station.				
		Replace substation conductor at Moselem 69 kV station.				
		Replace substation conductor at Lyons 69 kV station.				
9	S1901	Rehab/rebuild the North Temple-South Hamburg 69 kV line.	12/31/2021	$13.8	Met-Ed	4/26/2019
		Rehab/rebuild North Temple-Royal Green Tap-Berkley Tap-Leesport-South Hamburg 69 kV line. Reconductor ~11.86 miles.				
		Replace substation conductor and switches at North Temple 69 kV station.				
		Replace switches at Royal Green Tap 69 kV station.				
		Replace substation conductor at South Hamburg 69 kV station.				
10	S1907	Replacement 230/69 kV transformers No. 1 and No. 2 and 230 kV ring bus at South Lebanon substation.	12/31/2021	$13.9	Met-Ed	4/26/2019
		Replace the South Lebanon 230/69 kV 60/80/100 MVA transformer No. 1 and associated equipment with a new 230/69 kV 100/134/168 MVA transformer.				
		Replace the South Lebanon 230/69 kV 60/80/100 MVA transformer No. 2 and associated equipment with a new 230/69 kV 100/134/168 MVA transformer.				
		Expand the South Lebanon 230 kV bus into a five-breaker ring bus.				
11	S1909	Rehab/rebuild the South Lebanon-Bayer Labs-Myerstown 69 kV line.	12/31/2021	$10.4	Met-Ed	4/26/2019
		Rehab/rebuild South Lebanon-Bayer Labs-Myerstown 69 kV line. Reconductor ~7 miles.				
		Replace substation conductor on the Bayer Labs 69 kV line exit at South Lebanon substation.				
12	S1910	Rehab/rebuild North Lebanon-Fredericksburg Tap-Lickdale-Indiantown Gap-Turf Club 69 kV line.	12/31/2021	$21.1	Met-Ed	4/26/2019
		Reconductor approximately 18.5 miles of Frystown-Fredericksburg Tap-Lickdale-Indiantown Gap-Turf Club 69 kV line.				
		Replace switches on the Fredericksburg Tap 69 kV line exit at North Lebanon substation.				

Table 6.48: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
13	S1923	Warrior Ridge 46 kV project.	12/1/2021	$26.4	PENELEC	5/31/2019
		Build a 46 kV breaker-and-a-half substation at Warrior Ridge.				
		Replace disconnect switch on Warrior Ridge 46 kV line exit with motor operated disconnect switch with whip at the Center Union substation.				
		Replace disconnect switch on Center Union 46 kV line exit with motor operated disconnect switch with vacuum bottles at Belleville substation.				
		Replace disconnect switch on Belleville 46 kV line exit with motor operated disconnect switch with vacuum bottles at the New Holland station.				
		Replace line relaying, substation conductor, disconnect switches on the Warrior Ridge 46 kV line exit at the Huntingdon substation.				
		Replace line relaying, disconnect switches on the Williamsburg 46 kV line exit at the Altoona substation.				
		Rebuild ~0.9 miles of the Altoona-Williamsburg 46 kV line.				
		Replace line relaying, disconnect switches and substation conductor on the Altoona 46 kV line exit at the Williamsburg substation.				
		Replace disconnect switches with motor operated disconnect switches with whips on the Williamsburg 46 kV line exit at the Williamsburg REC substation.				
		Rebuild ~0.5 miles of Williamsburg-Williamsburg REC 46 kV line.				
		Eliminate ABW Tap via a line loop and rebuild ~7.5 miles of Williamsburg REC-Warrior Ridge 46 kV line.				
		Rebuild the Alexandria-Warrior Ridge 46 kV line.				
		Replace disconnect switch on the Warrior Ridge 46 kV line exit with motor operated disconnect switch with whip at the Alexandria substation.				
		Replace disconnect switches with motor operated disconnect switches with vacuum bottles on Pemberton and Alexandria 46 kV line exits at the Water Street substation.				
		Replace disconnect switch on the Sinking Valley REC 46 kV line exit with a motor operated disconnect switch with vacuum bottles at the Pemberton station.				
		Replace substation conductor on Sinking Valley REC and Tyrone North 46 kV line exits at the Birmingham substation.				
		Replace line relaying and substation conductor Birmingham 46 kV line exit at the Tyrone North substation.				
14	S2037	Expand Pleasureville 115 kV substation into a breaker-and-a-half configuration (eight breakers).	12/31/2022	$10.0	Met-Ed	7/31/2019
15	S2054	Rebuild and reconductor ~33.0 miles of the Armstrong-Homer City 345 kV line, of wood pole construction.	12/31/2023	$138.0	PENELEC	8/8/2019
16	S2076	Construct new 230/13 kV substation at Navy Yard.	6/1/2023	$71.0	PECO	10/21/2019

6.9.9 — Merchant Transmission Project Requests

As of Dec. 31, 2019, PJM's queue contained two merchant transmission project requests which include a terminal in Pennsylvania, as shown in **Table 6.49** and **Map 6.39**.

Map 6.39: Pennsylvania Merchant Transmission Project Requests (Dec. 31, 2019)

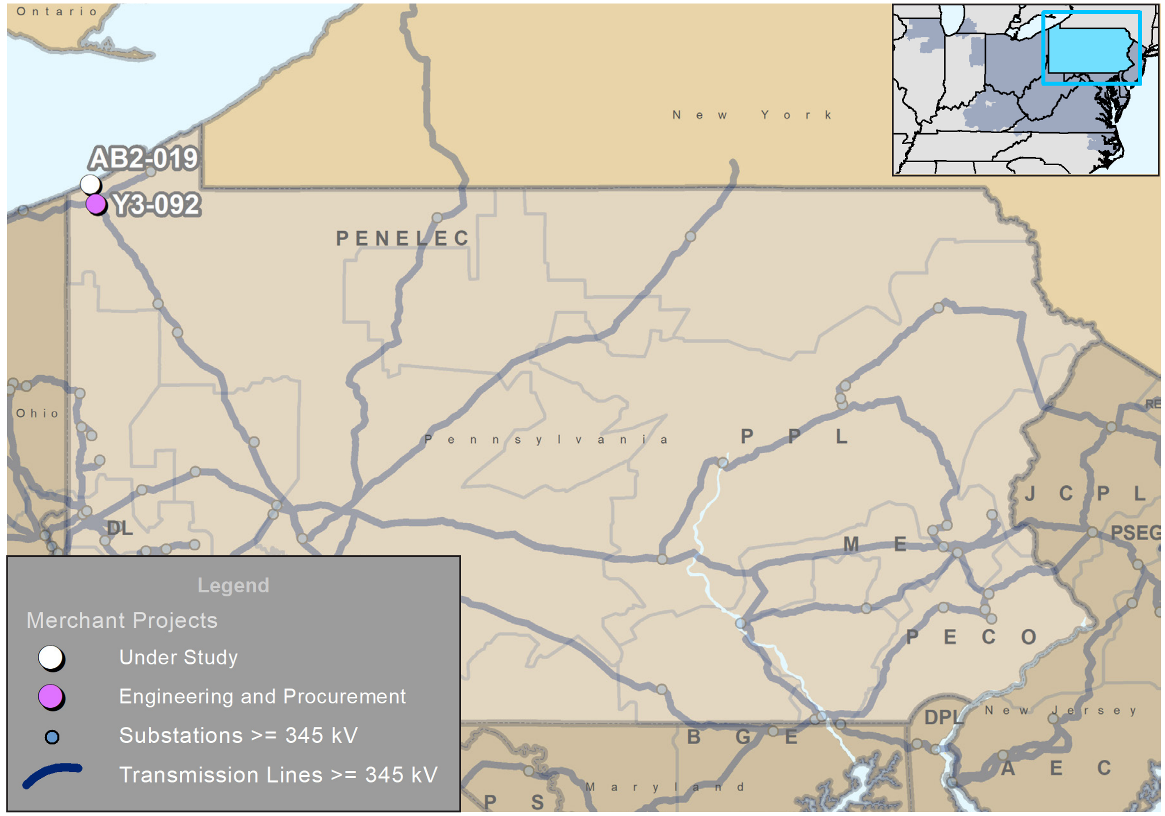


Table 6.49: Pennsylvania Merchant Transmission Project Requests (Dec. 31, 2019)

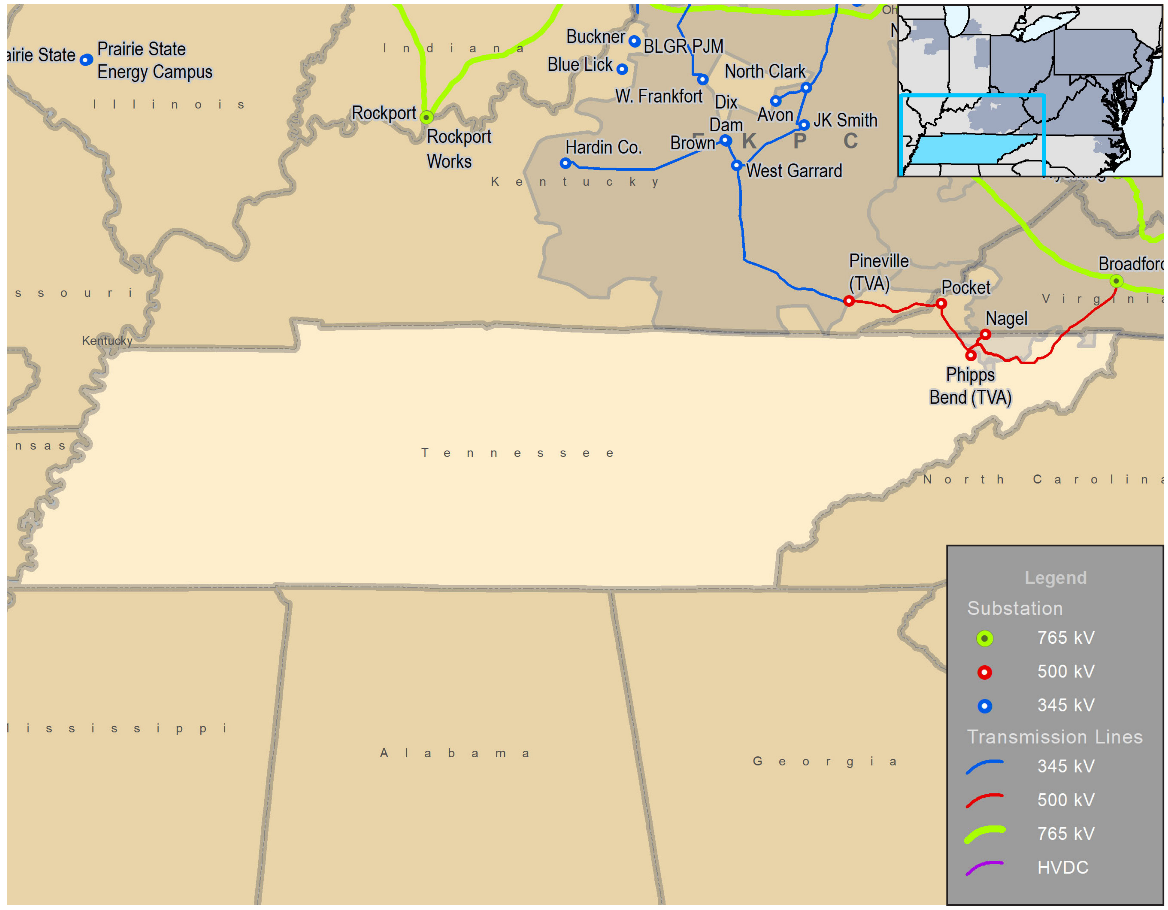
Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
Y3-092	Erie West 345 kV	PENELEC	Under Construction	3/31/2024	1,000.0
AB2-019	Erie West 345 kV	PENELEC	Active	3/31/2024	28.0

6.10: Tennessee RTEP Summary

6.10.1 — 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 6.40**. 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 PJM.

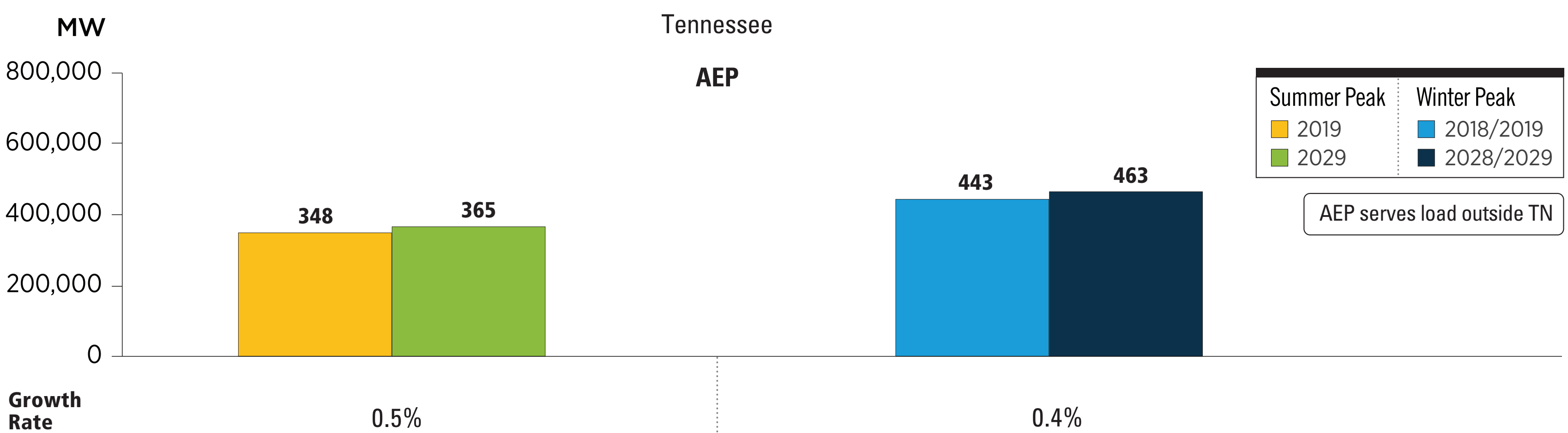
Map 6.40: PJM Service Area in Tennessee



6.10.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.51** summarizes the expected loads within the state of Tennessee and across all of PJM.

Figure 6.51: 2019 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156, 689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. 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 Tennessee as of Dec. 31, 2019, is shown by fuel type in **Figure 6.53**.

6.10.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Tennessee, 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

Figure 6.53: Tennessee – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)

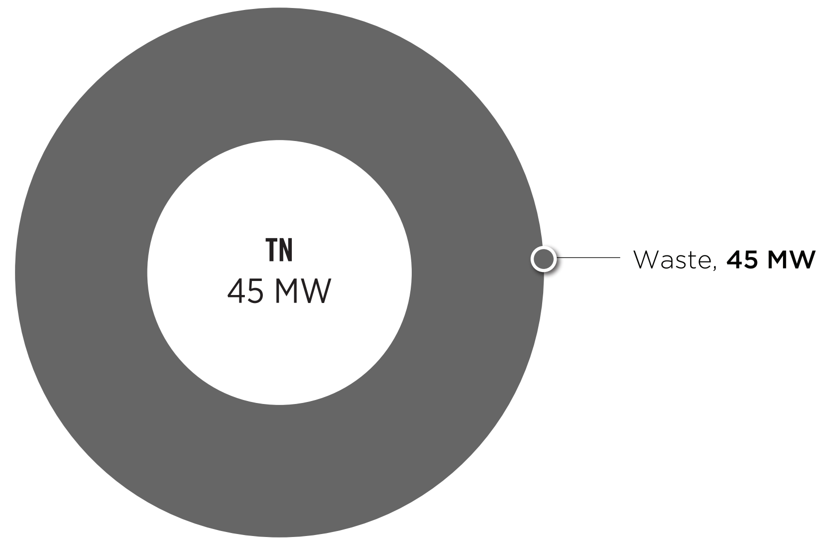


Figure 6.52: Tennessee Progression History of Queue – Interconnection Requests (Dec. 31, 2019)

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

Percentage of planned capacity and projects that have reached commercial operation	55% Requested capacity megawatt	67% Requested projects

Table 6.50: Tennessee – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		Complete				Grand Total	
		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	1	75.0	1	75.0
Renewable	Biomass	2	90.0	0	0.0	2	90.0
	Grand Total	**2**	**90.0**	**1**	**75.0**	**3**	**165.0**

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.

Specifically, in Tennessee, as of Dec. 31, 2019, two queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Figure 6.52** and **Table 6.50.** 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.

6.10.5 — Generation Deactivation

No generating unit deactivation requests in Tennessee between Jan. 1, 2019, and Dec. 31, 2019, were received as part of the 2019 RTEP.

6.10.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in Tennessee were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.10.7 — Network Projects

No network projects greater than or equal to $10 million in Tennessee were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.10.8 — Supplemental Projects

No supplemental projects greater than or equal to $10 million in Tennessee were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.10.9 — Merchant Transmission Project Requests

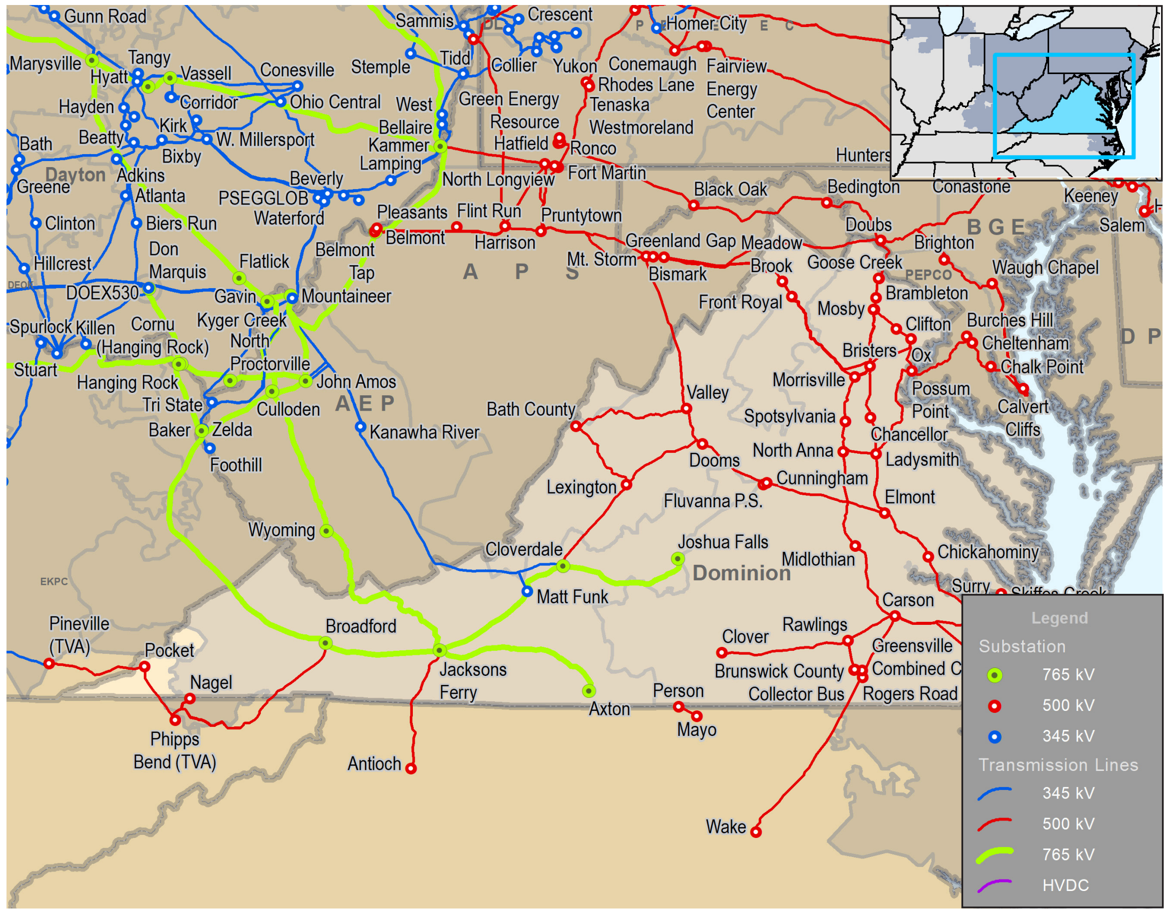
No merchant transmission project requests greater than or equal to $10 million in Tennessee were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.11: Virginia RTEP Summary

6.11.1 — 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 (AP), American Electric Power (AEP), Delmarva Power & Light (DP&L) and Dominion Virginia Power (DVP) as shown on **Map 6.41**. 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 PJM.

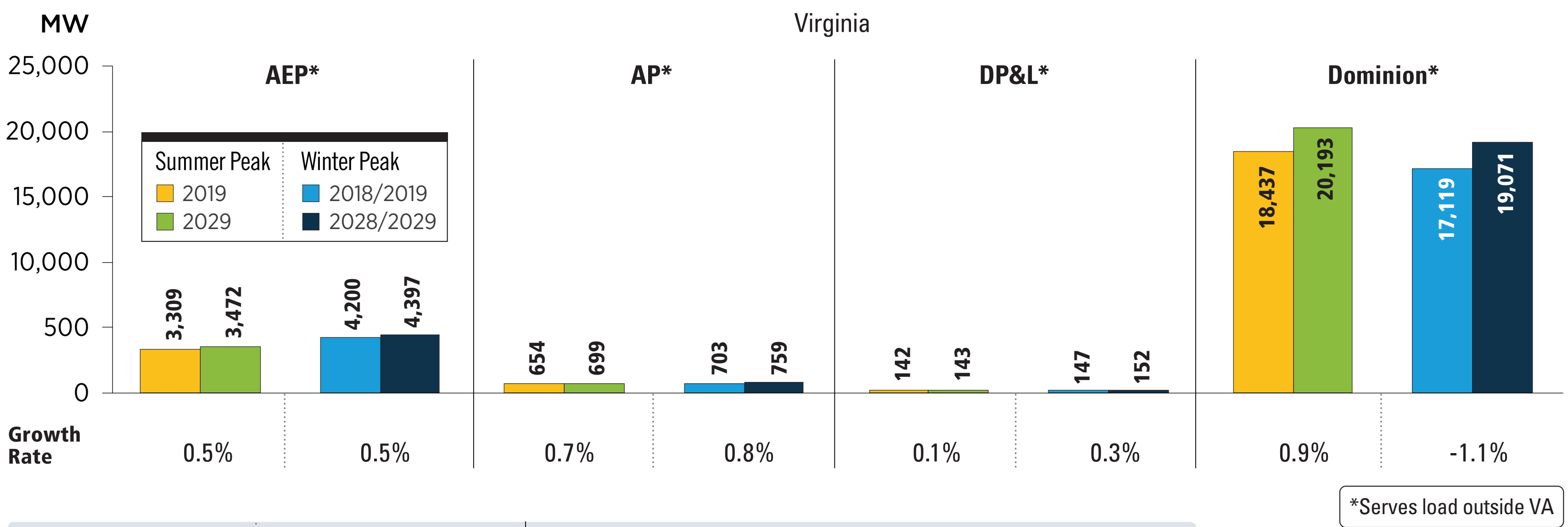
Map 6.41: PJM Service Area in Virginia



6.11.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.54** summarizes the expected loads within the state of Virginia and across all of PJM.

Figure 6.54: Virginia – 2019 Load Forecast Report



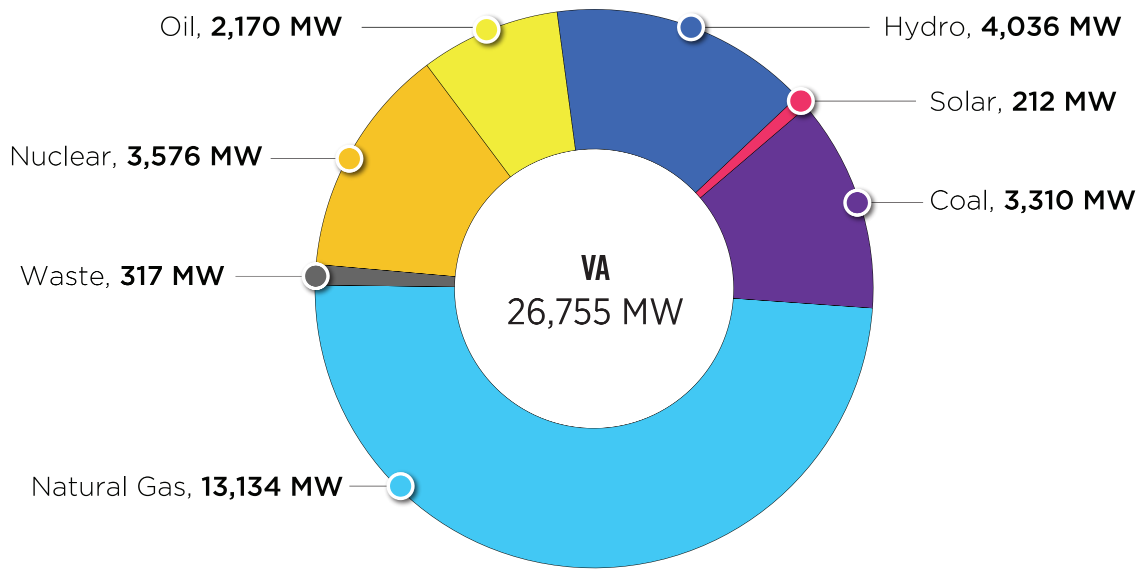
PJM RTO Summer Peak		PJM RTO Winter Peak	
2019	2029	2018/2019	2028/2029
151,358 MW	156,689 MW	131,082 MW	136,178 MW
Growth Rate 0.3%		Growth Rate 0.4%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. 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

Existing generation in Virginia as of Dec. 31, 2019, is shown by fuel type in **Figure 6.55**.

Figure 6.55: Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.11.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Virginia, 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.

Specifically, in Virginia, as of Dec. 31, 2019, 270 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.51**, **Table 6.52**, **Figure 6.56**, **Figure 6.57** and **Figure 6.58**. 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 6.51: Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	Virginia Capacity (MW)	Percentage of Total Virginia Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	0	0.00%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	2	0.01%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	5,324	29.36%	34,990	42.76%
Nuclear	0	0.00%	169	0.21%
Oil	0	0.00%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	10,335	56.99%	35,759	43.70%
Storage	1,221	6.73%	3,920	4.79%
Wind	1,253	6.91%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**18,136**	**100.00%**	**81,832**	**100.00%**

Table 6.52: Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of 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	7	2,607.6	2	2,660.0	3	56.6	44	7,239.5	40	16,052.5	96	28,616.2
	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	0	0.0	0	0.0	0	0.0	1	0.0	2	136.3	3	136.3
	Storage	19	1,221.3	1	0.0	0	0.0	1	0.0	7	55.5	28	1,276.8
Renewable	Biomass	0	0.0	0	0.0	0	0.0	4	87.4	4	70.0	8	157.4
	Hydro	1	2.4	0	0.0	0	0.0	8	421.0	2	254.0	11	677.4
	Methane	0	0.0	0	0.0	0	0.0	15	100.4	11	81.8	26	182.2
	Solar	162	8,837.4	6	110.4	58	1,387.0	25	231.1	140	4,820.4	391	15,386.3
	Wind	7	1,224.6	2	19.3	2	9.1	0	0.0	30	878.6	41	2,131.5
	Wood	0	0.0	0	0.0	0	0.0	1	4.0	2	57.0	3	61.0
	Grand Total	**196**	**13,893.3**	**11**	**2,789.7**	**63**	**1,452.7**	**123**	**9,476.7**	**245**	**24,071.2**	**638**	**51,683.5**

Figure 6.56: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

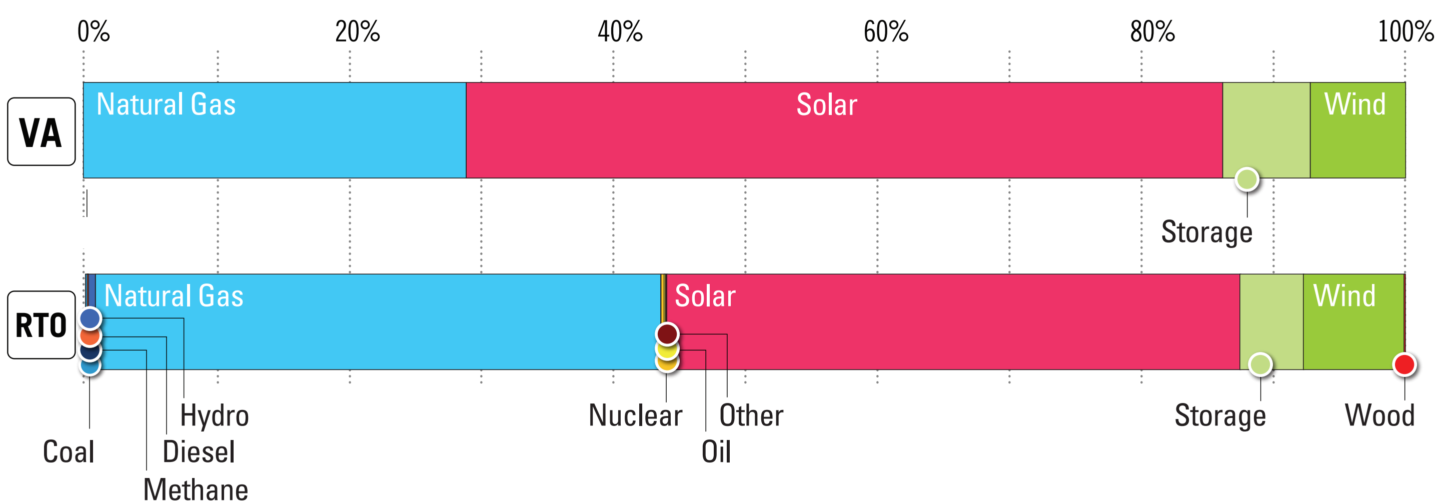
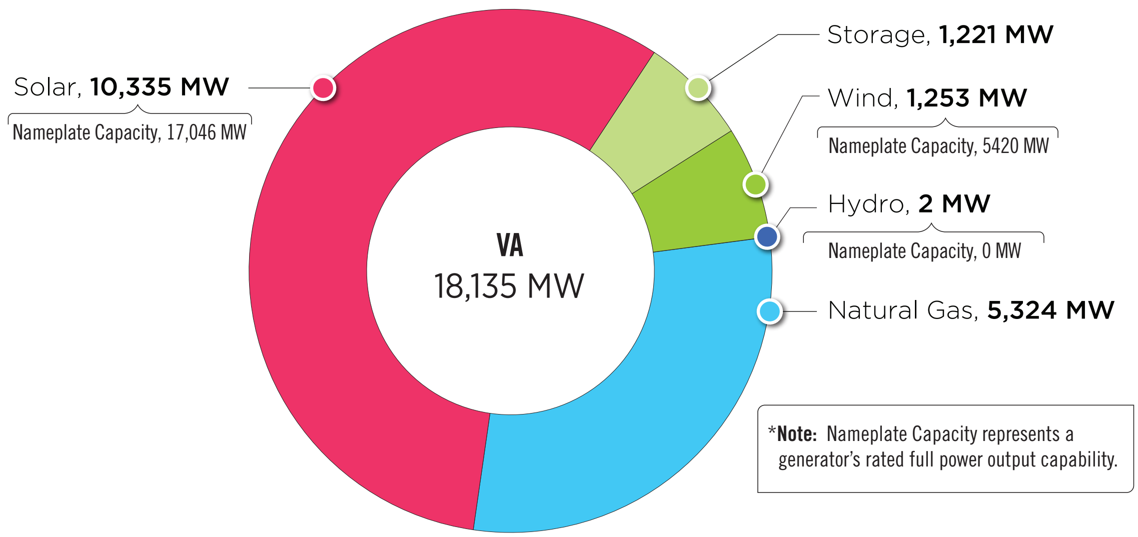


Figure 6.57: Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)



*__Note:__ Nameplate Capacity represents a generator's rated full power output capability.

Figure 6.58: Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2019)

Projects withdrawn after final agreement			Nameplate Capacity
15	Interconnection Service Agreements	1,934 MW	2,275 MW
14	Wholesale Market Participation Agreements	136 MW	211 MW

Percentage of planned capacity and projects that have reached commercial operation	25% Requested capacity megawatt	28% Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

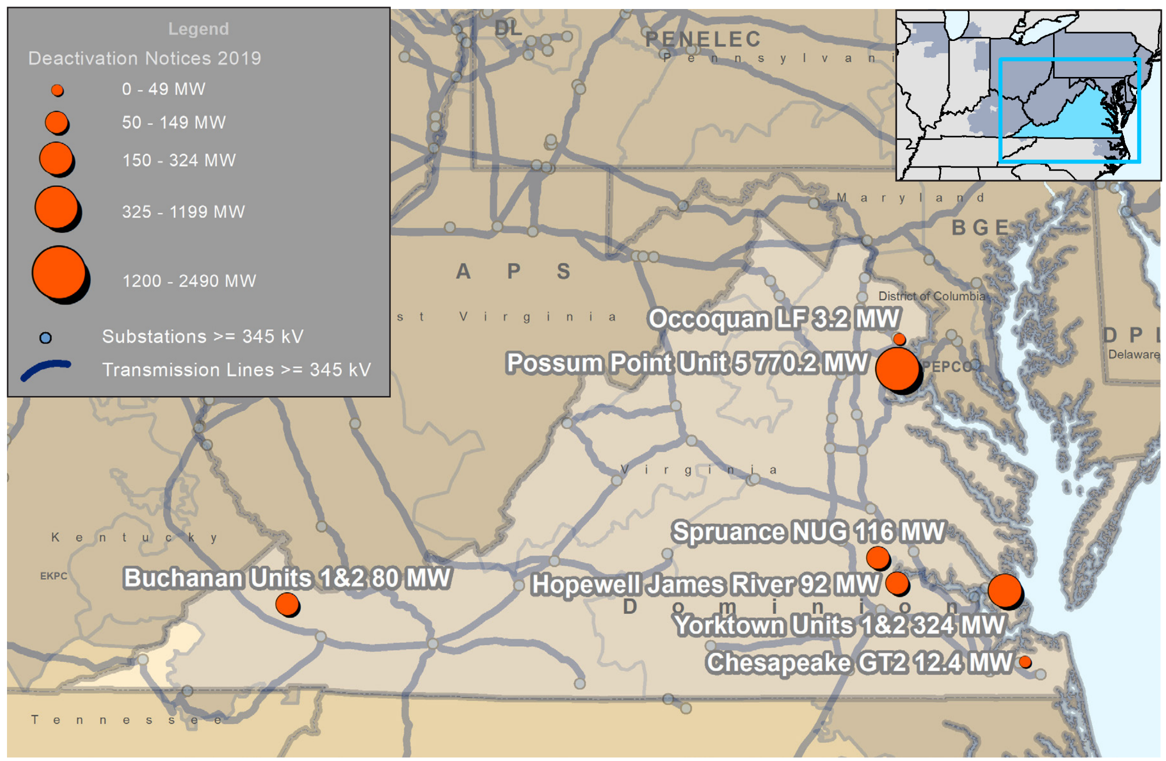
6.11.5 — Generation Deactivation

Known generating unit deactivation requests in Virginia between Jan. 1, 2019, and Dec. 31, 2019, are summarized in **Table 6.53** and **Map 6.42**.

Table 6.53: Virginia Generation Deactivations (Dec. 31, 2019)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Pending/Actual Deactivation Date	Age (Years)	Capacity (MW)
Chesapeake GT2	Dominion	Oil	4/18/2019	5/31/2019	0	12.4
Hopewell James River Cogeneration	Dominion	Coal	3/4/2019	6/25/2019	28	92.0
Occoquan 1 LF	Dominion	Methane	8/9/2019	11/7/2019	27	3.2
Possum Point 5	Dominion	Oil	3/26/2019	5/31/2021	29	770.2
Buchanan 1	AEP	Natural Gas	8/30/2019	6/1/2023	17	40.0
Buchanan 2	AEP	Natural Gas	8/30/2019	6/1/2023	17	40.0
Spruance NUG 1	Dominion	Coal	11/25/2019	1/12/2021	25	116.0

Map 6.42: Virginia Generation Deactivations (Dec. 31, 2019)



6.11.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in Virginia are summarized in **Table 6.54** and **Map 6.43**.

6.11.7 — Network Projects

No network projects greater than or equal to $10 million in Virginia were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.43: Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

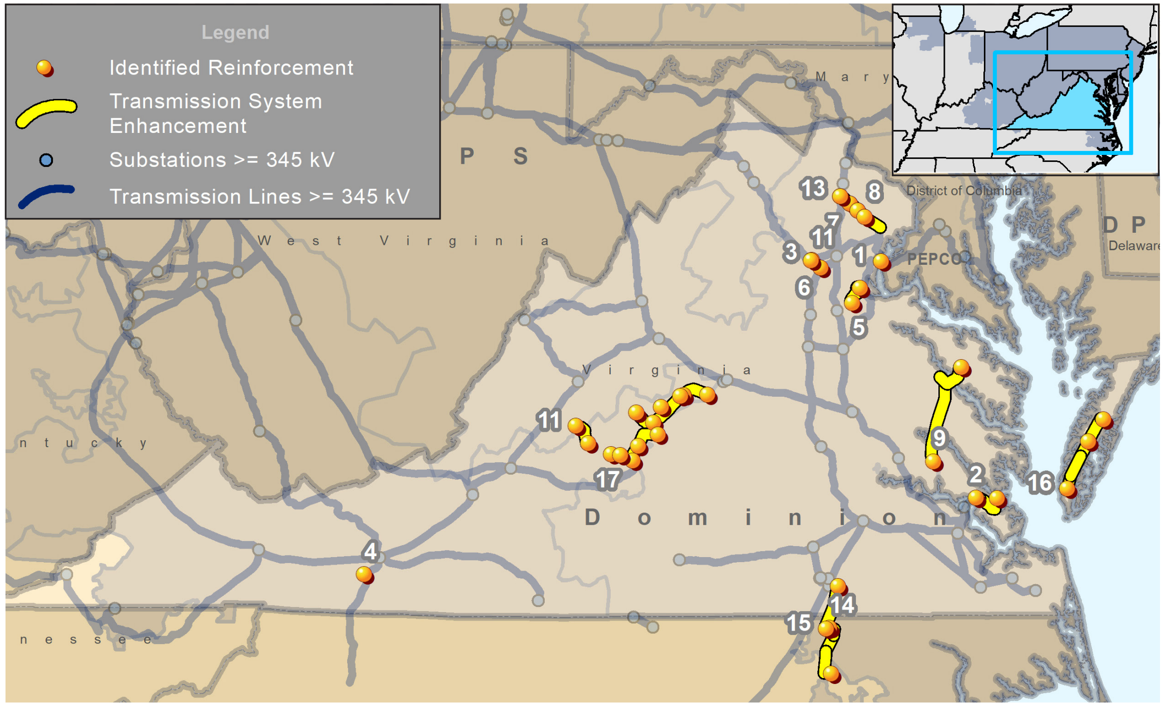


Table 6.54: Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B2443	Install a second 500/230 kV transformer at Possum Point substation and replace bus work and associated equipment as needed.	6/1/2023	$338.8	Dominion	1/10/2019
		Replace 19-63 kA 230 kV breakers with 19-80 kA 230 kV breakers.				
2	B2626	Rebuild the Skiffes Creek-Yorktown 115 kV line No. 34 and the double circuit portion of 115 kV line No. 61 to current standards with a summer emergency rating of 353 MVA at 115 kV. Rebuild the 2.5 mile tap line to Fort Eustis as Double Circuit line to loop line No. 34 in and out of Fort Eustis station to current standard with a summer emergency rating of 393 MVA at 115 kV. Install a 115 kV breaker in line No. 34 at Fort Eustis station.	12/31/2018	$35.7	Dominion	3/9/2015
3	B2686	Replace the Remington CT 230 kV breaker 2114T2155 with a 63 kA breaker.	6/1/2019	$104.0	Dominion	5/16/2019
4	B2889	Install one 138/69 kV (90 MVA) transformer, one 138 kV circuit switcher, two 138 kV (40 kA 3000A) breakers, establish a 69 kV bus and install three 69 kV(40 kA 3000A) breakers at Jubal Early station.	6/1/2021	$37.0	AEP	
		Extend the existing double circuit Cliffview 69 kV line 0.5 mile to the new Wolf Glade Station.				

Table 6.54: Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019) (Cont.)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	B2981	Rebuild 115 kV line No. 29 segment between Fredericksburg and Aquia Harbor to current 230 kV standards (operating at 115 kV) utilizing steel H-frame structures with 2-636 ACSR to provide a normal continuous summer rating of 524 MVA at 115 kV (1047 MVA at 230 kV).	12/31/2022	$20.0	Dominion	12/18/2017
6	B3019	Update the nameplate for Morrisville 500 kV breaker H1T594 to be 50 kA.	6/1/2018	$64.7	Dominion	12/13/2018
		Update the nameplate for Morrisville 500 kV breaker H1T545 to be 50 kA.				
7	B3059	Rebuild Loudoun-Elklick line No. 2173.	12/31/2022	$13.5	Dominion	9/13/2018
8	B3060	Rebuild 4.6 mile Elk Lick-Bull Run 230 kV line No. 295 and the portion (3.85 miles) of the Clifton-Walney 230 kV line No. 265 which shares structures with line No. 295.	10/30/2018	$15.5	Dominion	9/13/2018
9	B3089	Rebuild 230 kV line No. 224 between Lanexa and Northern Neck, utilizing double circuit structures to current 230 kV standards. Only one circuit is to be installed on the structures with this project with a minimum summer emergency rating of 1047 MVA.	6/1/2018	$86.0	Dominion	12/13/2018
10	B3090	Convert the overhead portion (~1,500 Feet) of 230 kV lines No. 248 & No. 2023 to underground and convert Glebe substation to a gas insulated substation.	1/1/2021	$120.0	Dominion	12/13/2018
11	B3096	Rebuild Clifton-Ox 230 kV line No.2063 and part of Clifton-Keene Mill 230 kV line No. 2164 (with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1,200 MVA.	6/1/2019	$22.0	Dominion	4/11/2019
12	B3098	Rebuild 9.8 miles of 115 kV line No. 141 between Balcony Falls and Skimmer and 3.8 miles of 115 kV line No. 28 between Balcony Falls and Cushaw to current standards with a minimum rating of 261 MVA.	6/1/2019	$20.0	Dominion	2/20/2019
13	B3110	Rebuild line No. 2008 between Loudoun to Dulles Junction using single circuit conductor at current 230 kV northern Virginia standards with minimum summer ratings of 1200 MVA. Cut and loop Clifton-Sully line No. 265 into Bull Run substation. Add three 230 kV breakers at Bull Run to accommodate the new line and upgrade the substation.	6/1/2019	$14.5	Dominion	3/7/2019
		Replace the Bull Run 230 kV breakers 200T244 and 200T295 with 50 kA breakers.				5/16/2019
14	B3114	Rebuild the 18.6 mile section of 115 kV line No. 81 which includes 1.7 miles of double circuit line No. 81 and 230 kV line No. 2056. This segment of line of No. 81 will be rebuilt to current standards with a minimum rating of 261 MVA. Line No. 2056 rating will not change.	6/1/2019	$25.0	Dominion	3/28/2019
15	B3121	Rebuild Clubhouse-Lakeview 230 kV line No. 254 with single-circuit wood pole equivalent structures at the current 230 kV standard with a minimum rating of 1,047 MVA.	6/1/2019	$27.0	Dominion	6/13/2019
16	B3134	Build a new single circuit 69 kV overhead from Kellam sub to new Bayview substation (21 miles) and create a line terminal at Belle Haven delivery point (three-breaker ring bus).	6/1/2019	$22.0	ODEC	5/31/2019
		Reconfigure the Belle Haven 69 kV bus to three-breaker ring bus and create a line terminal for the new 69 kV circuit to Bayview.				
		Build a new single circuit 69 kV overhead from Kellam sub to new Bayview Substation (21 miles).				
17	B3208	Retire ~38 miles of the 44 mile Clifford-Scottsville 46 kV circuit. Build new 138 kV in-and-out to two new distribution stations to serve the load formerly served by Phoenix, Shipman, Schuyler (AEP) and Rockfish stations. Construct new 138 kV lines from Joshua Falls-Riverville (~10 mi.) and Riverville-Gladstone (~5 mi.). Install required station upgrades at Joshua Falls, Riverville and Gladstone stations to accommodate the new 138 kV circuits. Rebuild Reusen-Monroe 69 kV (~4 mi.).	12/1/2022	$85.0	AEP	2/20/2019

6.11.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in Virginia are summarized in **Table 6.55** and **Map 6.44**.

6.11.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Virginia were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.44: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

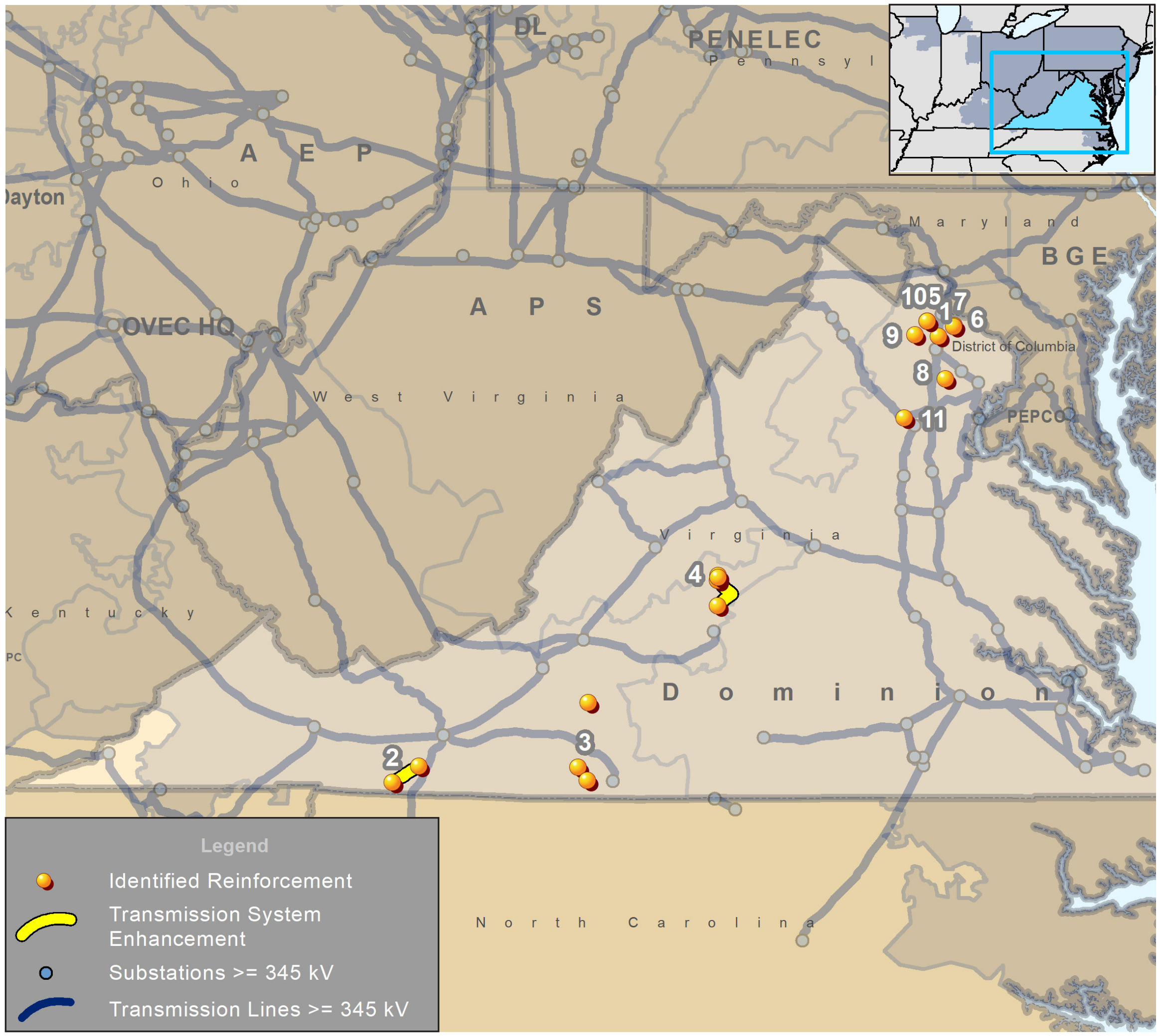


Table 6.55: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

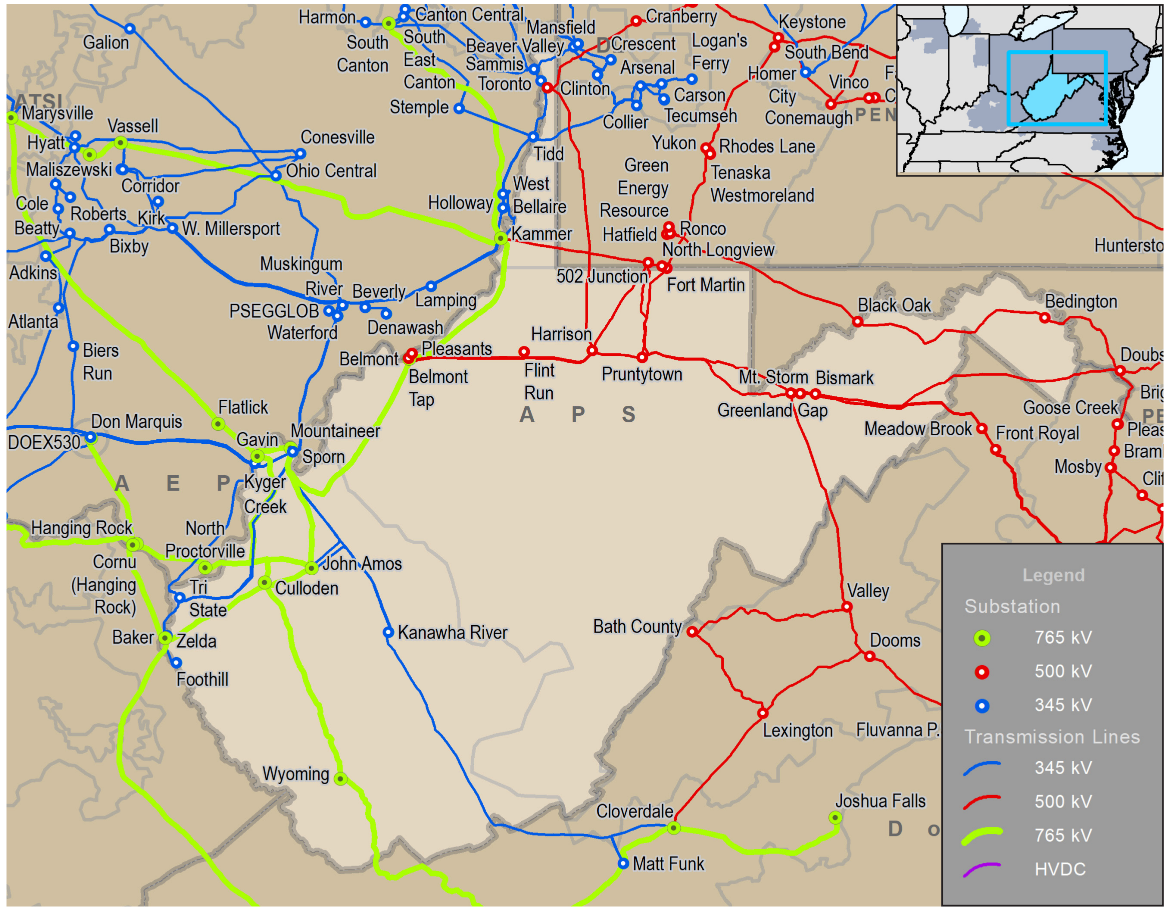
Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1838	Re-conductor 230 kV line No. 227 Cochran Mill-Ashburn and Ashburn-Beaumeade line segments using a higher capacity conductor as well as upgrade the terminal equipment to achieve a rating of 1,572 MVA.	6/1/2023	$15.8	Dominion	8/8/2019
2	S1851	Build a new Jubal Early-Independence 69 kV line (~15 miles). Install one 69 kV circuit breaker at Jubal Early Station and two 69 kV circuit breakers at Independence station.	6/1/2022	$32.5	AEP	1/11/2019
3	S1852	At Fieldale station, replace synchronous condenser with two units (-50/+100 MVAR). Replace 138 kV circuit breakers AC and AB with new 3,000 A, 40 kA breakers. Replace 138 kV circuit switchers EE"& DD with new 3,000 A, 40 kA units. Replace 69 kV circuit breaker F with new 72.5 kV, 3,000 A, 40 kA circuit breaker. Retire 34.5 kV equipment including circuit breaker T, 7.2 MVAR capacitor bank and circuit cwitcher AA. Move 69 kV Fieldcrest Mills load to 12 kV service and retire radial 69 kV line to Fieldcrest Mills and Fieldcrest Mills Station.	12/1/2022	$57.0	AEP	2/20/2019
		Retire three 69 kV breakers A, B and C and replace with two line MOABs at DuPont Station.				
		Replace 138 kV S&C Mark V circuit switcher AA at Blaine Station.				
		Reconfigure existing 69 kV capacitor bank from a 15.6 MVAR to 10.8 MVAR at Morris Novelty station. Replace 34.5 kV FK oil-filled breakers F and E.				
		Add high side 69 kV circuit switcher to Rich Acres transformer No. 1.				
4	S2000	Rebuild Monroe-Amherst 69 kV line section (~7.9 mi.).	10/1/2022	$39.0	AEP	5/20/2019
		Rebuild Esmont-Scottsville 46 kV line section (~6.0 mi.).				
5	S2100	Interconnect the new Nimbus substation by cutting and extending 230 kV line No. 2152 (Buttermilk-Beaumeade). Terminate both ends into a four-breaker ring arrangement to create a Buttermilk-Nimbus line and a Nimbus-Beaumeade line.	11/15/2022	$20.0	Dominion	5/16/2019
6	S2101	Interconnect the new DTC substation by cutting and extending 230 kV line No. 2143 (Beaumeade-BECO) ~1.5 miles to the proposed DTC Substation. Terminate both ends into a six-breaker ring bus arrangement with four breakers installed to create a Beaumeade-DTC line and a BECO-DTC line. Install two 230 kV circuit switchers and any necessary high side switches and bus work for the new transformers.	11/15/2021	$25.0	Dominion	5/16/2019
7	S2104	Interconnect the new Buttermilk substation by cutting and looping both Cumulus-Beaumeade 230 kV line No. 2152 and Roundtable-Pacific 230 kV line No. 2170. Buttermilk substation will have a six-breaker 230 kV breaker and a half bus configuration. Install line switches, two 230 kV circuit switchers and high side switches, and necessary bus work for the new transformers.	12/30/2020	$11.0	Dominion	3/7/2019
8	S2108	Interconnect the new Lockridge substation by cutting the existing 230 kV line between Roundtable and Buttermilk substations. Construct a 1.8 mile 230 kV loop to Lockridge substation. At Lockridge, install four 230 kV breakers (station arranged as six breaker ring) to terminate the two lines. Install two 230 kV circuit switchers and any necessary high side switches and bus work for two initial transformers (five ultimate).	7/31/2022	$35.0	Dominion	8/8/2019
9	S2111	Interconnect the new Global Plaza substation by constructing two 230 kV lines ~1.0 mile from Pacific substation. At Pacific, install two 230 kV breakers (completing the six-breaker ring) to terminate the two lines. At Global Plaza, install four 230 kV breakers (station arranged as breaker-and-a-half) to terminate the two lines. Install two 230 kV circuit switchers and any necessary high side switches and bus work for two initial transformers (five ultimate).	12/15/2021	$40.0	Dominion	5/16/2019
10	S2113	Interconnect Paragon Park substation by cutting and terminating both BECO-Sterling Park 230 kV line No. 2081 and Beaumeade-Sterling Park 230 kV line No. 2150 into a six-breaker 230 kV ring bus. Install two 230 kV circuit switchers and any necessary high side switches and bus work for the new transformers.	7/15/2021	$10.0	Dominion	5/16/2019
11	S2117	Replace the Peninusla transformer No. 4 224 MVA 230/115 kV transformer with a new 224 MVA 230/115 kV transformer. Build a 230 kV three-breaker ring bus to connect Peninsula-Yorktown 230 kV lines No. 288 , Peninsula-Shellbank 230 kV line No. 2004 and the 230/115 kV transformer.	4/30/2021	$16.1	Dominion	4/11/2019

6.12: West Virginia RTEP Summary

6.12.1 — 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 (AP) and American Electric Power (AEP) as shown on **Map 6.45**. 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 PJM.

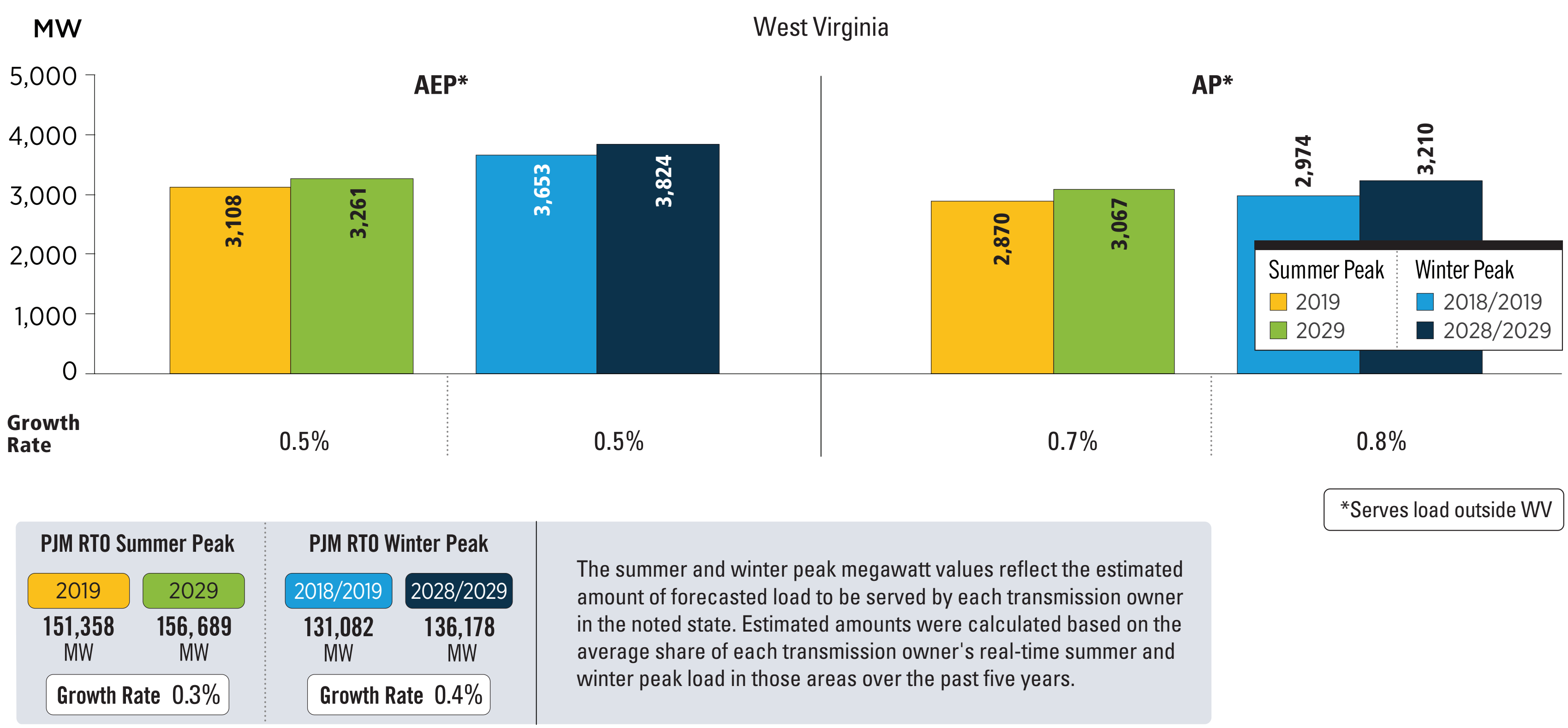
Map 6.45: PJM Service Area in West Virginia



6.12.2 — Load Growth

PJM's 2019 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2019 analyses. **Figure 6.59** summarizes the expected loads within the state of West Virgina and across all of PJM.

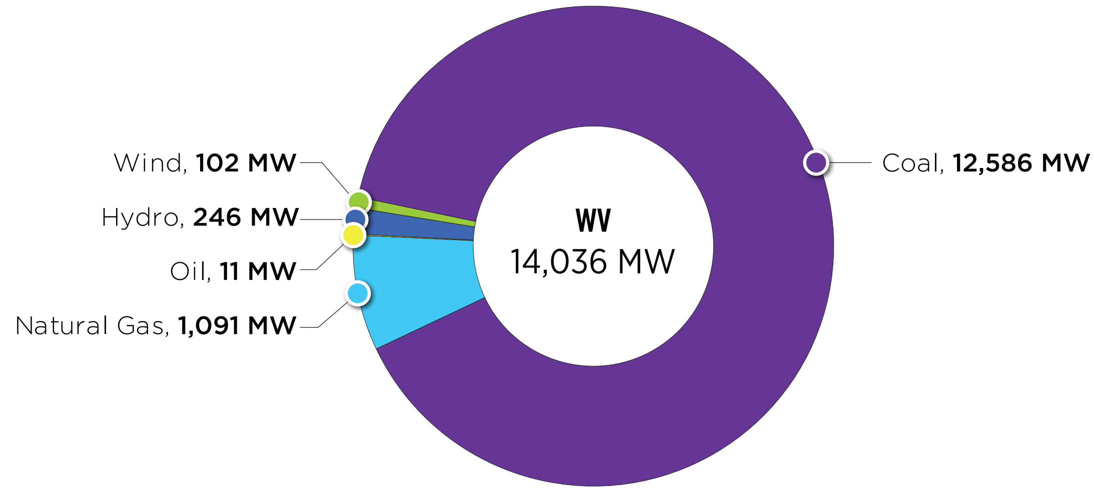
Figure 6.59: West Virginia – 2019 Load Forecast Report



6.12.3 — Existing Generation

Existing generation in West Virginia as of Dec. 31, 2019, is shown by fuel type in **Figure 6.60**.

Figure 6.60: West Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2019)



6.12.4 — Interconnection Requests

PJM markets continue to attract generation proposals in West Virginia, 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.

Specifically, in West Virginia, as of Dec. 31, 2019, 28 queued projects were actively under study, under construction or in suspension as shown in the summaries presented in **Table 6.56**, **Figure 6.61**, **Table 6.57**, **Figure 6.62** and **Figure 6.63**. 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 6.56: West Virginia – Percent MW Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2019)

	West Virginia Capacity (MW)	Percentage of Total West Virginia Capacity	PJM RTO Capacity (MW)	Percentage of Total PJM RTO Capacity
Coal	36	1.14%	96	0.12%
Diesel	0	0.00%	4	0.01%
Hydro	30	0.95%	520	0.64%
Methane	0	0.00%	1	0.00%
Natural Gas	2,684	84.97%	34,990	42.76%
Nuclear	0	0.00%	169	0.21%
Oil	0	0.00%	27	0.03%
Other	0	0.00%	40	0.05%
Solar	340	10.77%	35,759	43.70%
Storage	16	0.50%	3,920	4.79%
Wind	53	1.68%	6,240	7.62%
Wood	0	0.00%	66	0.08%
Grand Total	**3,159**	**100.00%**	**81,832**	**100.00%**

Figure 6.61: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2019)

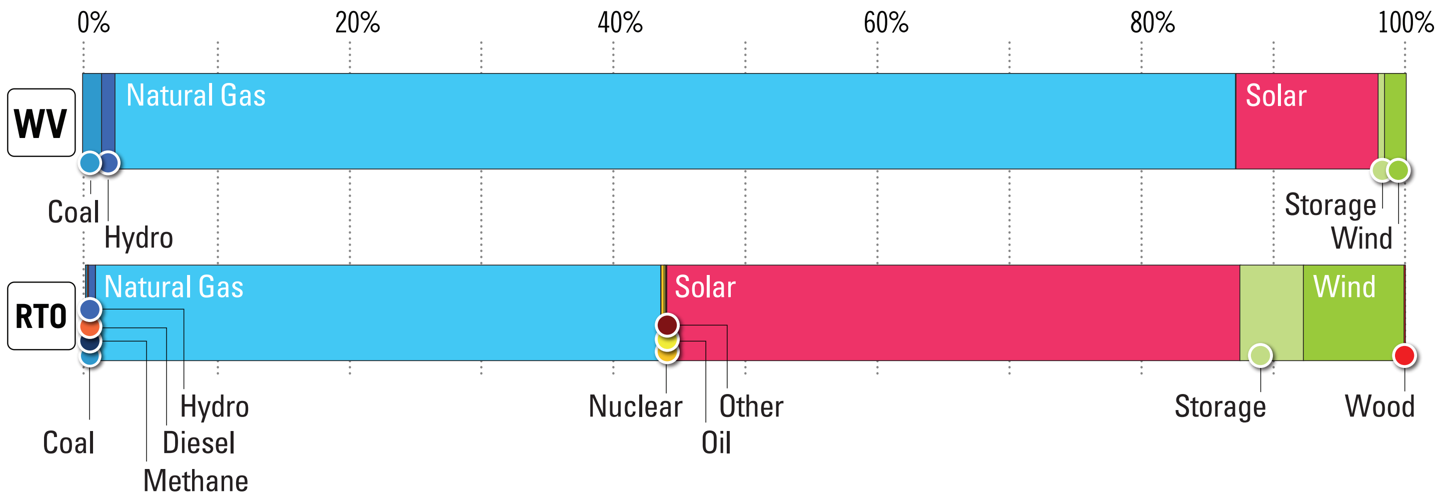


Table 6.57: West Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2019)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Non-Renewable	Coal	0	0	0	0	1	36.0	10	861.0	7	2,023.0	18	2,920.0
	Natural Gas	3	1,254.0	3	600.0	3	830.0	5	391.7	39	15,310.8	53	18,386.5
	Other	0	0	0	0	0	0	0	0	2	66.0	2	66.0
	Storage	2	10.0	2	5.8	0	0	2	0.0	2	18.0	8	33.8
Renewable	Biomass	0	0	0	0	0	0	0	0	2	48.0	2	48.0
	Hydro	1	30.0	0	0	0	0	5	59.2	12	208.8	18	298.0
	Methane	0	0	0	0	0	0	3	5.6	3	13.8	6	19.4
	Solar	8	340.1	0	0	0	0	0	0	4	44.2	12	384.3
	Wind	2	23.5	1	22.1	2	7.3	8	190.2	25	392.7	38	635.8
	Grand Total	**16**	**1,657.6**	**6**	**627.9**	**6**	**873.3**	**33**	**1,507.7**	**96**	**18,125.3**	**157**	**22,791.8**

Figure 6.62: West Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2019)

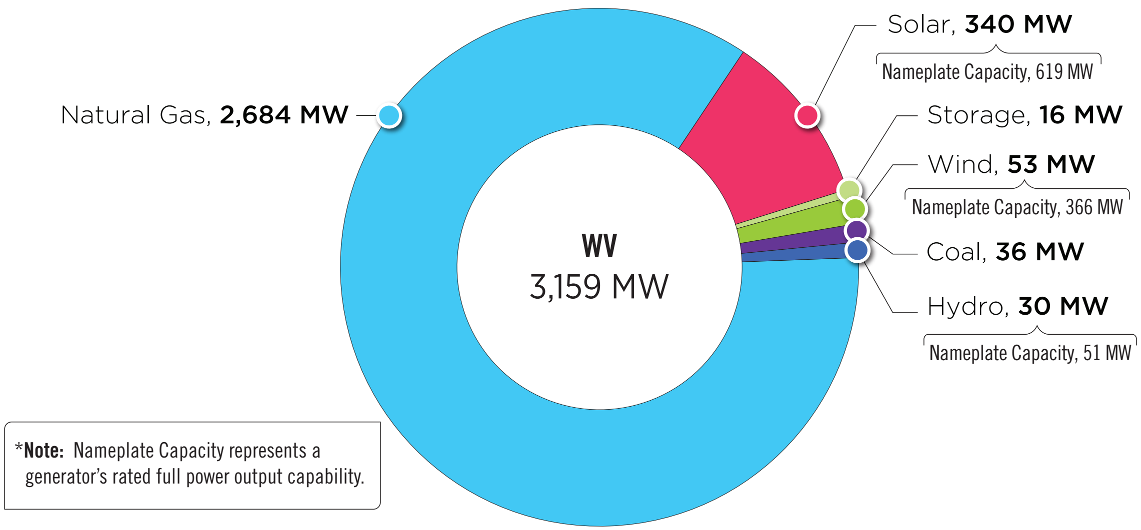


Figure 6.63: West Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2019)

Projects withdrawn after final agreement			Nameplate Capacity
8	Interconnection Service Agreements	647 MW	971 MW
2	Wholesale Market Participation Agreements	6 MW	11 MW

Percentage of planned capacity and projects that have reached commercial operation	7% Requested capacity megawatt	23% Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

6.12.5 — Generation Deactivation

Known generating unit deactivation requests in West Virginia between Jan. 1, 2019, and Dec. 31, 2019, are summarized in **Table 6.58** and **Map 6.46**.

Map 6.46: West Virginia Generation Deactivations (Dec. 31, 2019)

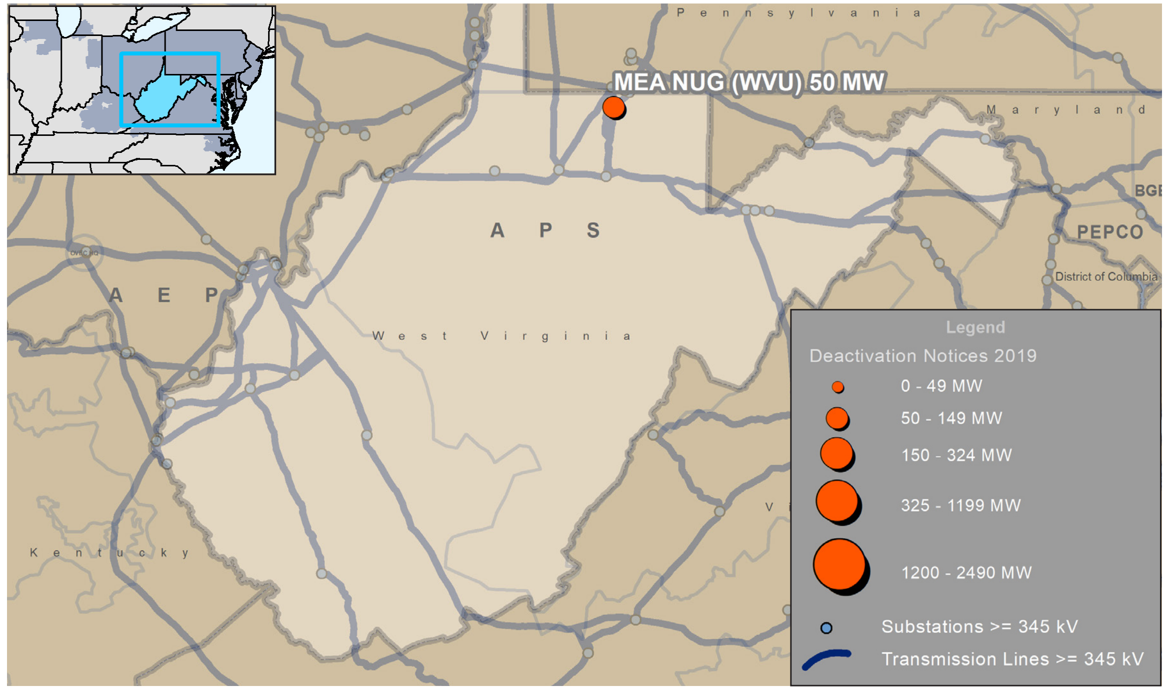


Table 6.58: West Virginia Generation Deactivations (Dec. 31, 2019)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Pending/Actual Deactivation Date	Age (Years)	Capacity (MW)
MEA NUG (WVU)	APS	Coal	10/4/2019	12/30/2019	28	50.00

6.12.6 — Baseline Projects

RTEP baseline projects greater than or equal to $10 million in West Virginia are summarized in **Table 6.59** and **Map 6.47**.

Map 6.47: West Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

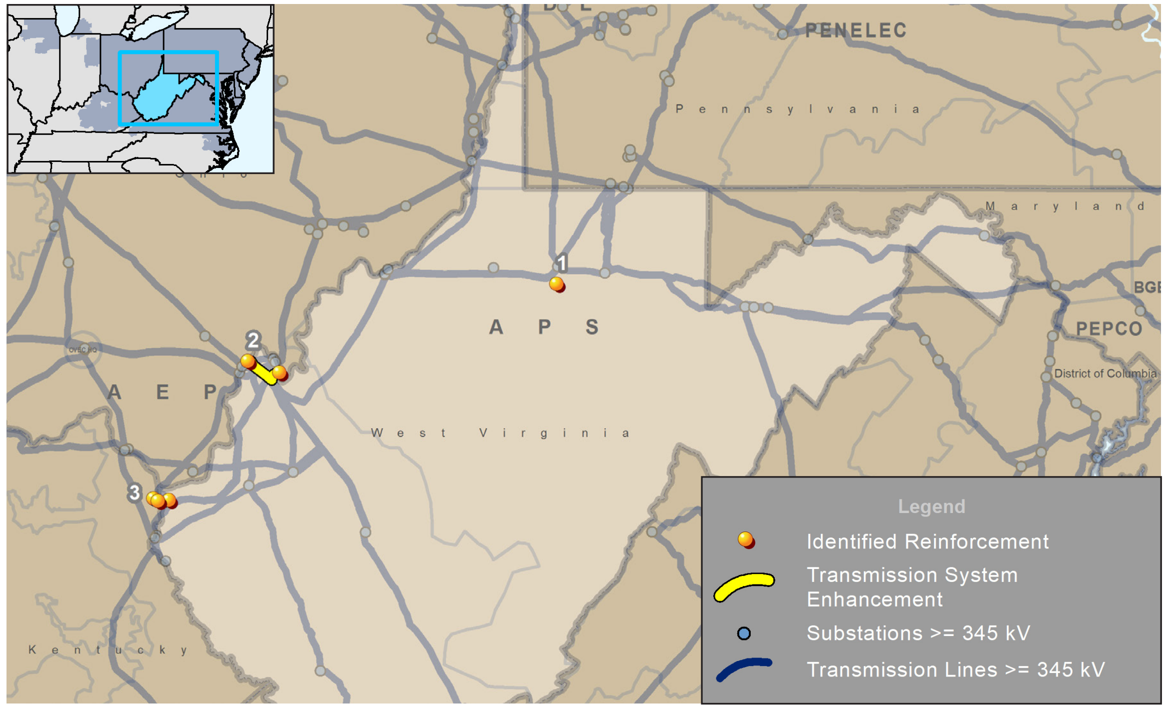


Table 6.59: West Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B2996	Upgrade two existing 138 kV breakers (Rider 50 and No. 1/4 transformer breaker) at Glen Falls with 63 kA, 3000 A units.	5/31/2020	$40.6	APS	6/17/2019
2	B3095	Rebuild 9.2 miles of Lakin-Racine Tap 69 kV line section to 69 kV standards, utilizing 795 26/7 ACSR conductor.	12/1/2022	$23.9	AEP	11/29/2018
3	B3118	Chadwick-Tri-State No. 2 138 kV circuit will be reconfigured within the station to terminate into the newly established 138 kV bus No. 2 at Chadwick due to construability aspects. Replace 20 kA 69 kV circuit breaker F at South Neal station with a new 3000A 40 kA 69 kV circuit breaker. Replace line risers towards Leach station.	6/1/2022	$16.9	AEP	2/20/2019

6.12.7 — Network Projects

No network projects greater than or equal to $10 million in West Virginia were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.12.8 — Supplemental Projects

RTEP supplemental projects greater than or equal to $10 million in West Virginia are summarized in **Map 6.48** and **Table 6.60**.

6.12.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in West Virginia were identified as part of the 2019 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.48: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

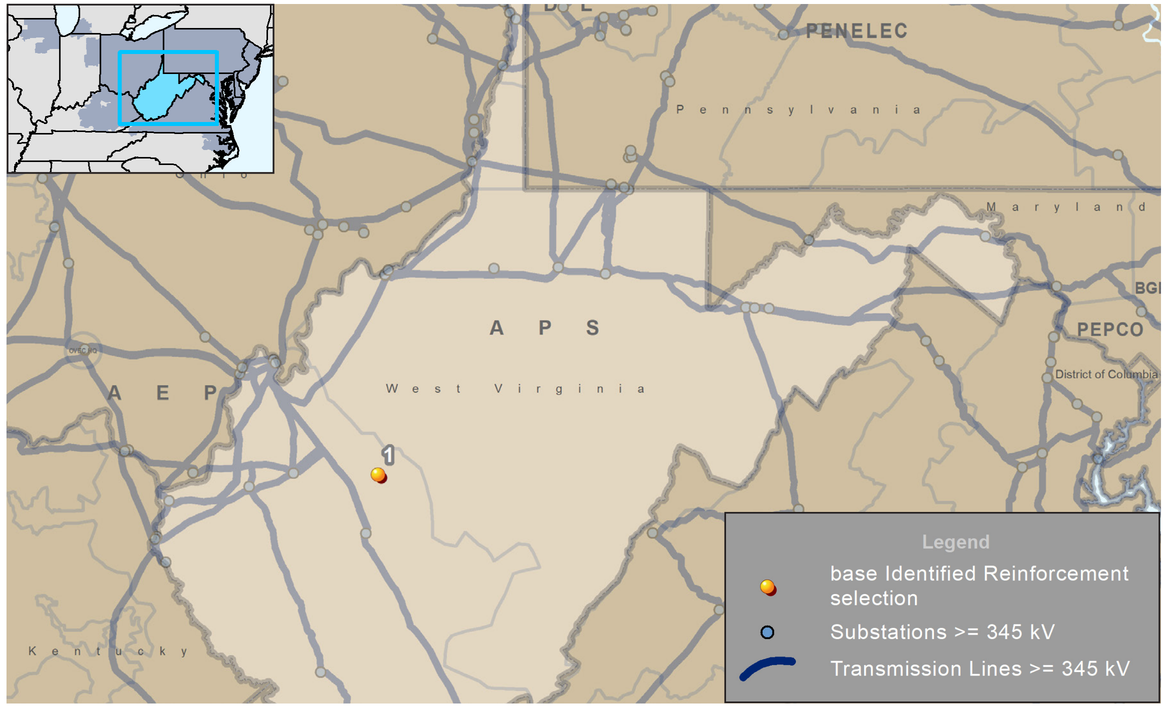


Table 6.60: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2019)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1996	Replace the existing Clendenin station with the new Jarrett station, ~0.2 miles away from Clendenin station, located outside of the flood plain. Install a new 138/46 kV 90 MVA transformer, with a high side circuit switcher. Install two 138 kV 40 kA circuit breakers and three 46 kV 40 kA circuit breakers. Install a 9.6 MVAR capacitor bank. Re-route the existing 138 kV and 46 kV transmission lines into the new station.	8/26/2021	$21.3	AEP	5/20/2019

Appendix: TO Zones and Locational Deliverability Areas

1.0: TO Zones and Locational Deliverability Areas

The terms *Transmission Owner Zone* and *Locational Deliverability Area* as used in this report are defined below and shown on **Map 1.1**. They are provided for the convenience of the reader based on definitions from other sources.

A transmission owner (TO) is a PJM member that owns transmission facilities or leases transmission facilities with rights equivalent to ownership. 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 a combination of zones. LDAs are used as part of PJM's RTEP process load deliverability test. They are restated in **Table 1.1**, below, for ease of reference.

Map 1.1: Locational Deliverability Areas

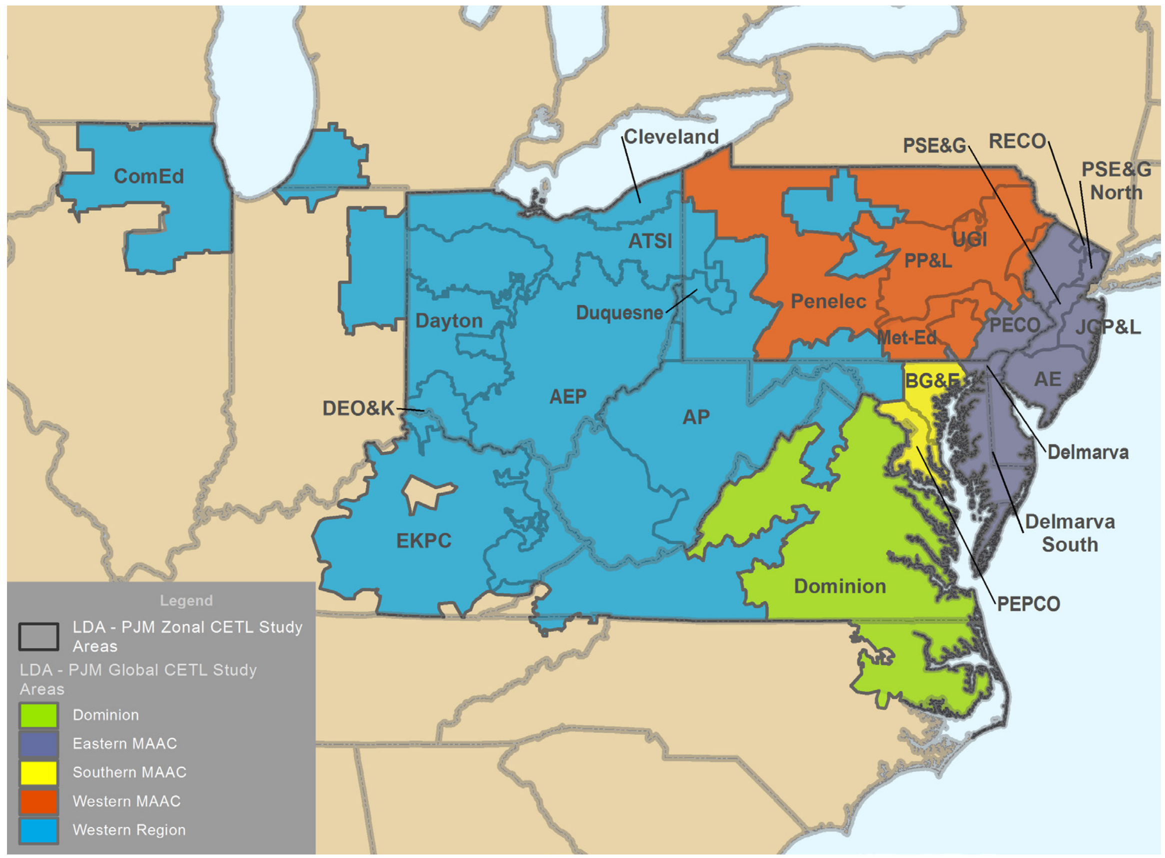


Table 1.1: Locational Deliverability Areas

Entity Name	TO Zone	LDA	Description
AE	▲	▲	Atlantic City Electric Company
AEP	▲	▲	American Electric Power
AP	▲	▲	Allegheny Power
ATSI	▲	▲	American Transmission Systems, Inc.
BGE	▲	▲	Baltimore Gas and Electric Company
Cleveland	n/a	▲	Cleveland Area
ComEd	▲	▲	Commonwealth Edison Company
DAY	▲	▲	Dayton Power & Light Company
DEO&K	▲	▲	Duke Energy Corporation
DLCO	▲	▲	Duquesne Light Company
Dominion	▲	▲	Dominion Energy
DP&L	▲	▲	Delmarva Power & Light
Delmarva South	n/a	▲	Southern Portion of DP&L
Eastern Mid-Atlantic	n/a	▲	Global area – JCP&L, PECO, PSEG, AE, DP&L, Rockland
EKPC	▲	▲	East Kentucky Power Cooperative
JCP&L	▲	▲	Jersey Central Power Light
Met-Ed	▲	▲	Met-Ed
Mid-Atlantic	n/a	▲	Global Area – PENELEC, Met-Ed, JCP&L, PPL, PECO, PSEG, BGE, PEPCO, AE, DP&L, Rockland
PECO	▲	▲	PECO
PENELEC	▲	▲	Pennsylvania Electric Company
PEPCO	▲	▲	Potomac Electric Power Company
PPL	▲	▲	PPL Electric Utilities
PSEG	▲	▲	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, Met-Ed, PPL
Western PJM	n/a	▲	Global Area – AP, AEP, DAY, DLCO, ComEd, ATSI, DEO&K, EKPC, OVEC

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Glossary

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

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
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.
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.
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 will only be procured through the 2019/2020 Delivery Year, at which point all resources will be Capacity Performance resources starting with the 2020/2021 Delivery Year. See "Capacity Performance."
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.

Term	Reference	Acronym	Definition
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 (i) at any time, any portion of such generating unit's capacity that is designated as a capacity resource, or (ii) in an hour, any portion of the output of such generating unit(s) that is 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.
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 larger than 20 MVA, or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher, lines operated at voltages of 100 kV or higher, associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment). The ReliabilityFirst BES definition excludes: (1) Radial facilities connected to load-serving facilities or individual generation resources smaller than 20 MVA, or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher; (2) the balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and step-up transformer), which would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions; and (3) all other facilities operated at voltages below 100 kV.
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 will be 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. All resources will be Capacity Performance resources starting with the 2020/2021 Delivery Year. 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.
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.

Term	Reference	Acronym	Definition
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.
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-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.
Cross Linked Polyethylene		XLPE	Type of plastic used to insulate power lines; benefits include resistance to temperature fluctuations and other environmental factors.
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 forecasted 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 percent 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, DPL, JCP&L, PECO, PSE&G 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 de-ratings 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.

Term	Reference	Acronym	Definition
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.
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 which 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.
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.
Fixed Series Capacitor		FSC	A fixed series capacitor is a grouping of capacitors used to reduce transfer reactances on bulk transmission corridors.
Flowgate			A flowgate is a specific combination of a monitored facility and a contingency which 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 which 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.

Term	Reference	Acronym	Definition
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.
Interconnection Construction Service Agreement	M14C	ICSA	The ICSA is a companion agreement to the ISA and is necessary for projects that require the construction of interconnection facilities as defined in the ISA. The ICSA details the project scope, construction responsibilities of the involved parties, ownership of transmission and customer interconnection facilities and the schedule of major construction work.
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 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 percent 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.

Term	Reference	Acronym	Definition
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.
Mid-Atlantic Subregion	M14B	MAAC	The PJM Mid-Atlantic Subregion encompasses 12 transmission owner zones: Atlantic Electric Company (AE), Baltimore Gas and Electric (BGE), Delmarva Power and Light (DP&L), Jersey Central Power and Light (JCP&L), Metropolitan Edison Company (Met-Ed), Neptune, PECO Energy (PECO), Pennsylvania Electric Company (PENELEC), PEPCO, PPL Electric Utilities Corporation (PPL), Public Service Electric and Gas (PSEG) and Rockland Electric (Rockland). The Neptune Regional Transmission System interconnects with the Mid-Atlantic PJM transmission system at Sayreville substation in Northern New Jersey.
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.
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 the FERC, as well as their individual roles as statutory regulators within their respective state boundaries.

Term	Reference	Acronym	Definition
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 forecasted 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.
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 Integration Study		RIS	The RIS is an ongoing study to examine the reliability and market impacts of high wind and solar penetration in the PJM system to meet objectives of state policies regarding renewable resource production.
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.

Term	Reference	Acronym	Definition
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		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 Virginia Power.
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 pre-defined 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	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.
System Operating Limit	M14B	SOL	The value (such as MW, MVAR, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System operating limits are based upon certain operating criteria.
Static Var Compensation		SVC	An SVC device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system transmission and distribution performance.
Subregional RTEP Committee	M14B, OA		This PJM committee that facilitates the development and review of the subregional RTEP projects. The Subregional RTEP Committee is responsible for the initial review of the subregional RTEP projects, and for providing recommendations to the Transmission Expansion Advisory Committee concerning the subregional RTEP projects.
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 build-up 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).
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	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 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	TMEP 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.

Term	Reference	Acronym	Definition
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 (i) executes a service agreement or (ii) requests in writing that PJM file with FERC, a proposed, unexecuted service agreement to receive transmission service under Part II of the PJM OATT.
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 MW of capacity from a specific resource, on average, not experiencing a forced outage or de-rating, for the purpose of satisfying capacity obligations imposed under the RAA.
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 Incorporated (ATSI), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Duke Energy Ohio and Kentucky (DEO&K), Duquesne Light Company (DLCO) and Eastern 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	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.

Term	Reference	Acronym	Definition
X-Effective Forced Outage Rate on Demand		XEFORd	XEFORd is a statistic that results from excluding events outside management control (outages deemed not to be preventable by the operator) from the EFORd calculation. See "Effective Forced Outage Rate on Demand (EFORd)."
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.

Key Maps, Tables and Figures

PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

Map 1.1: PJM Backbone Transmission System

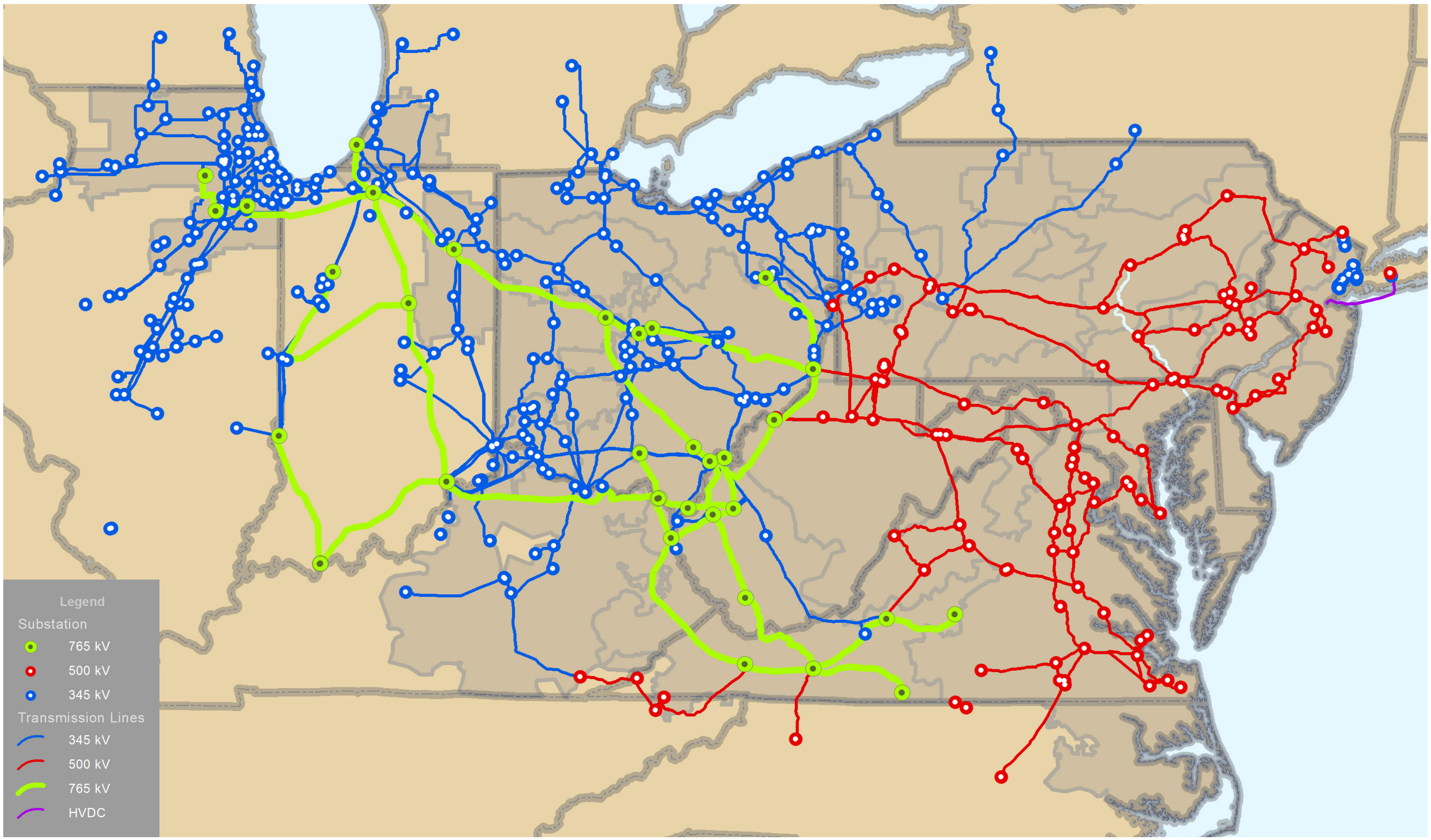


Figure 1.1: RTEP Process – RTO Perspective

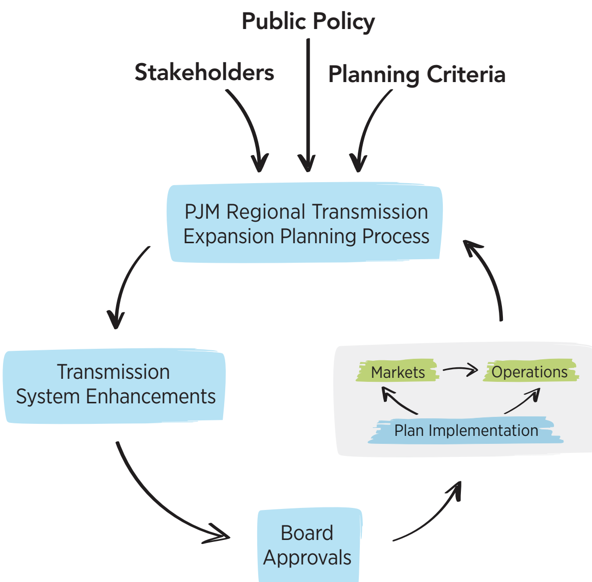


Figure 1.2: System Enhancement Drivers

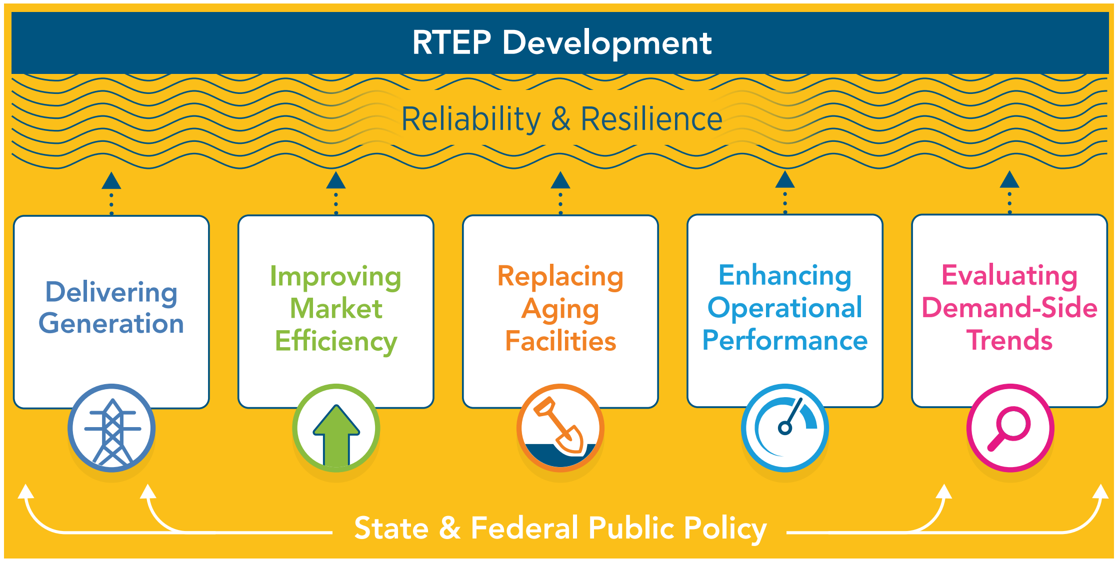


Figure 1.3: Board Approved RTEP Projects as of Dec. 31, 2019

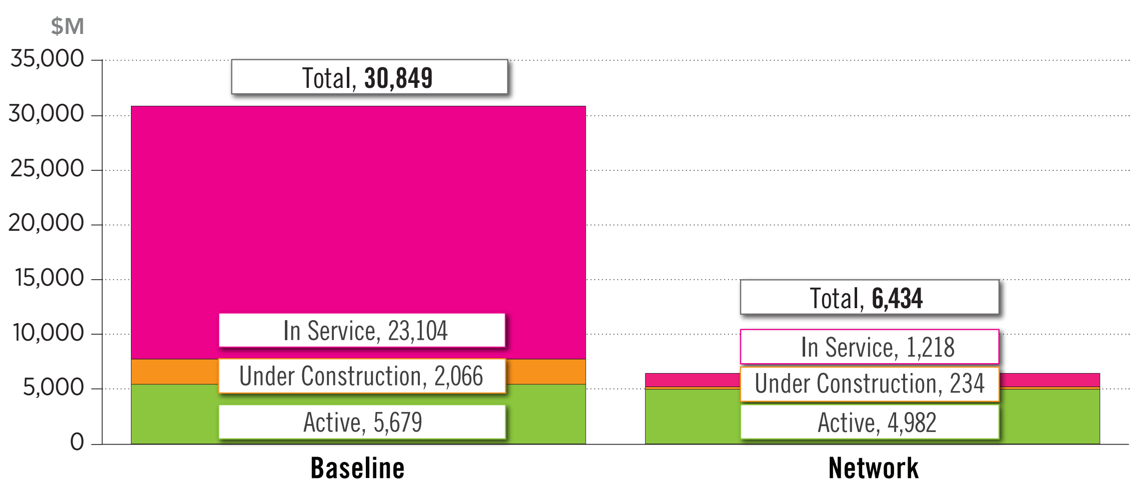
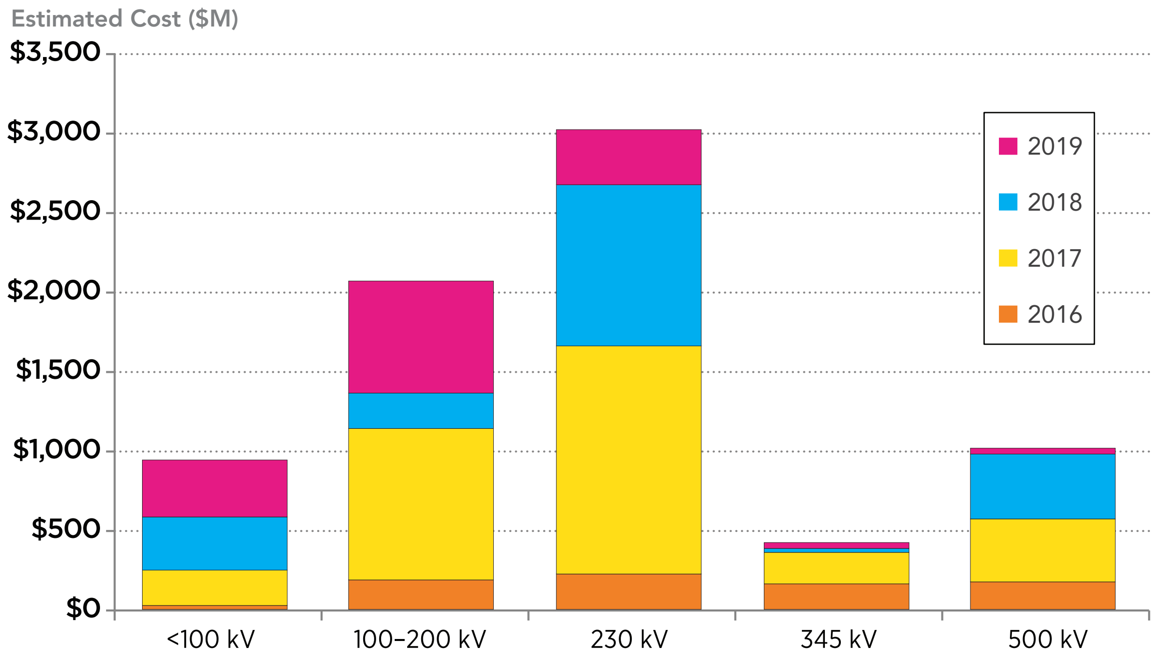


Figure 1.4: Approved Baseline Projects by Voltage 2016–2019



No baseline projects at the 765 kV level have been identified for this time period.

Figure 1.5: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2019)

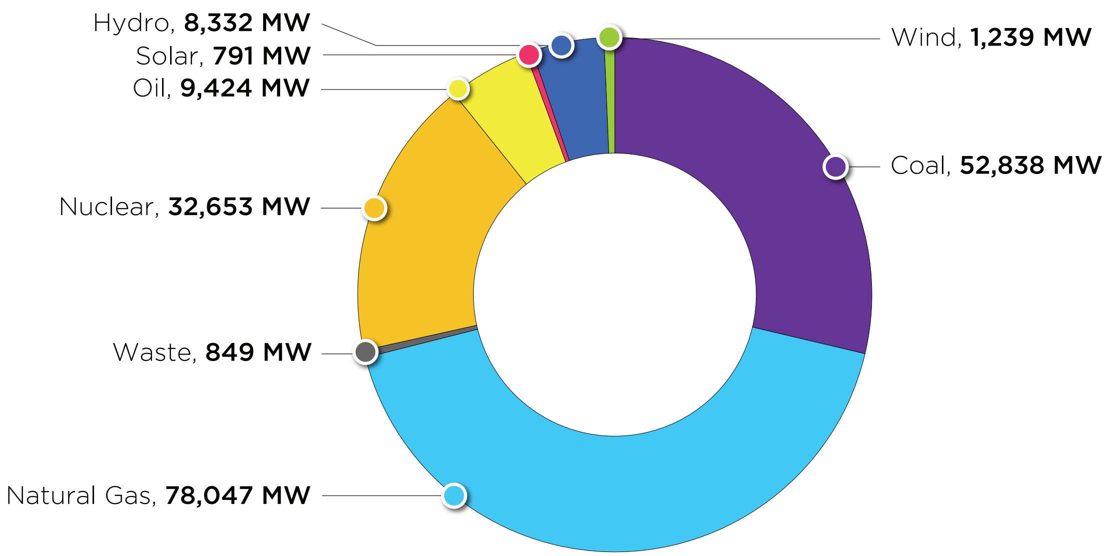


Figure 1.6: PJM Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2019)

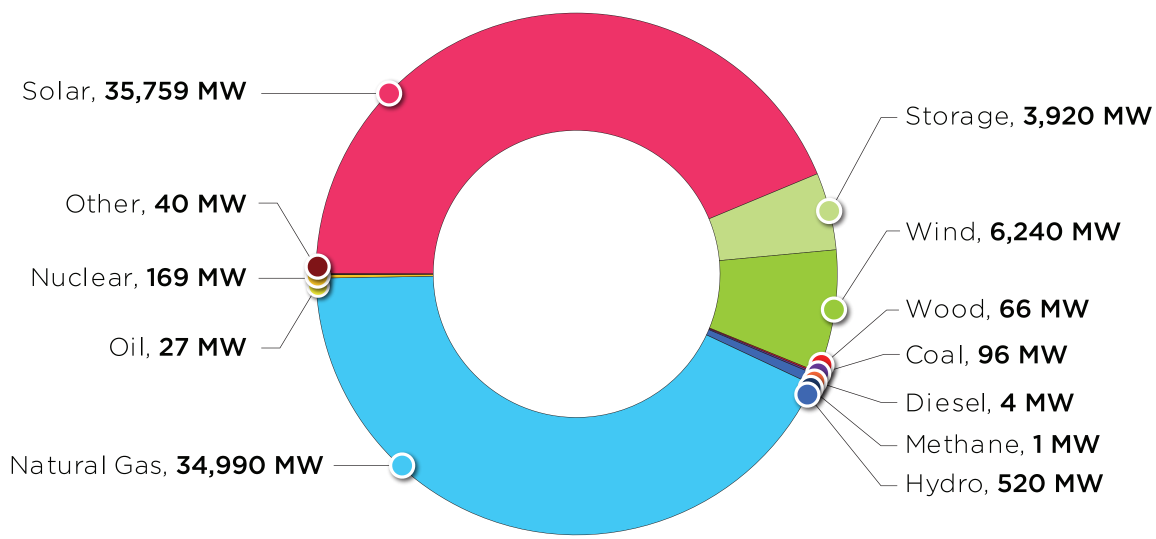


Figure 1.7: Generator Deliverability Concept

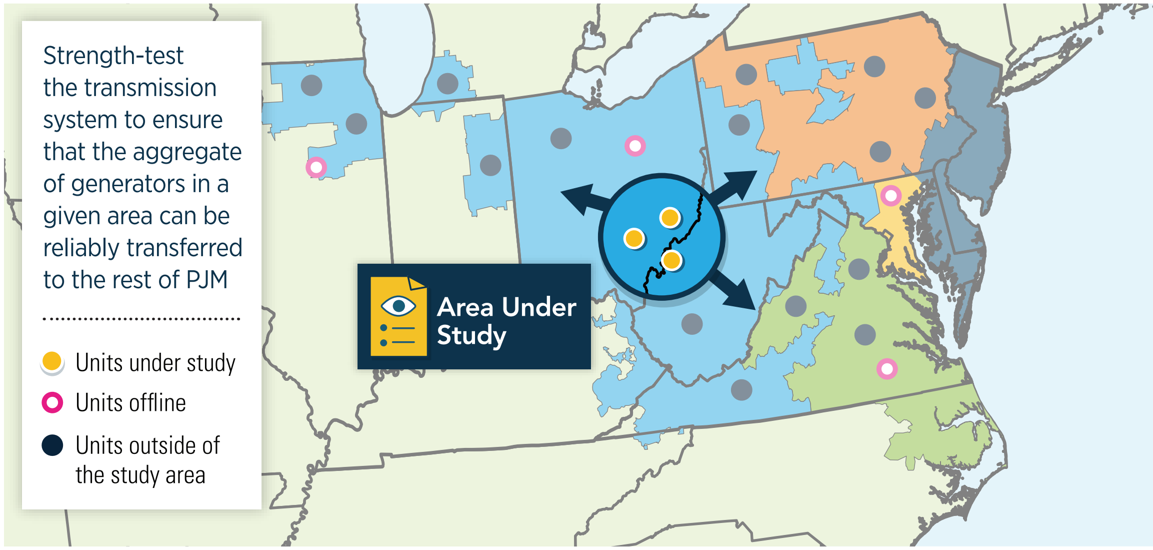
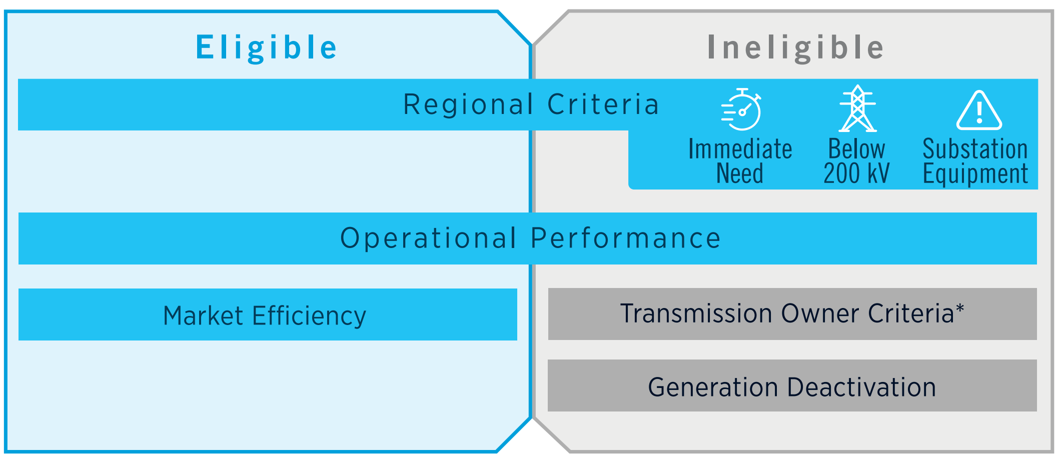
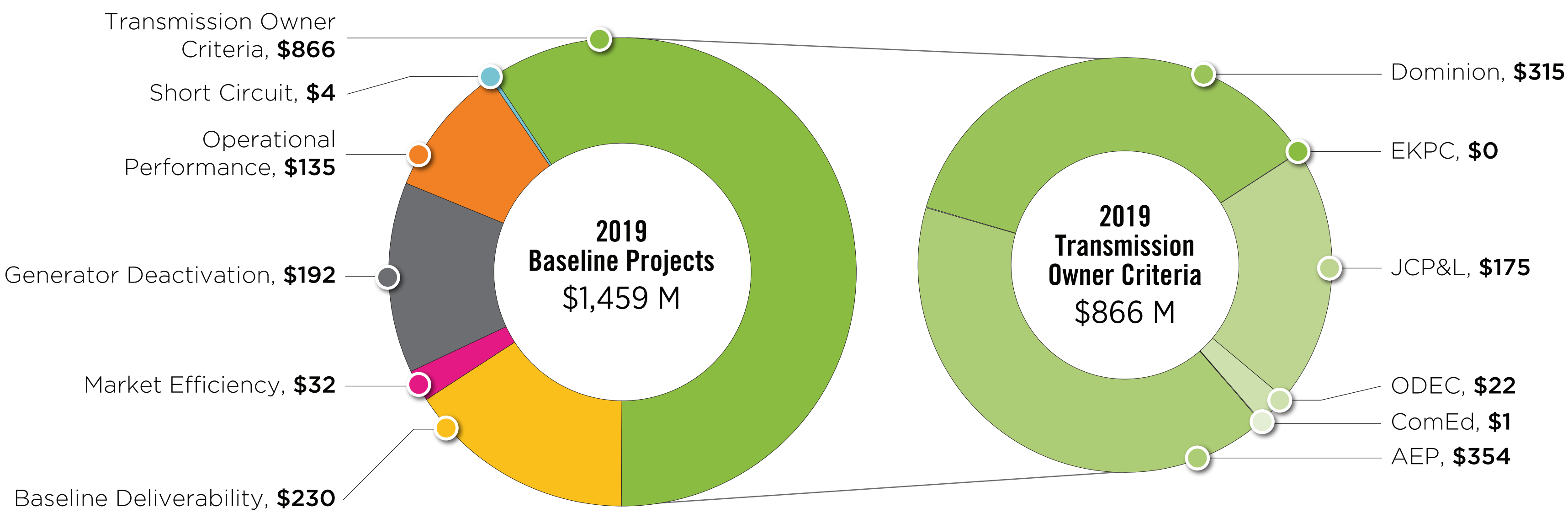


Figure 1.8: Window Eligibility



**Per FERC Order EL 19-61, PJM has eliminated the FERC 715 TO criteria exclusion as of Dec. 31, 2019.*

Figure 1.9: 2019 RTEP Baseline Projects by Driver ($ Million)



Map 1.2: PJM Generator Deactivation Notifications Received Jan. 1, 2019 through Dec. 31, 2019

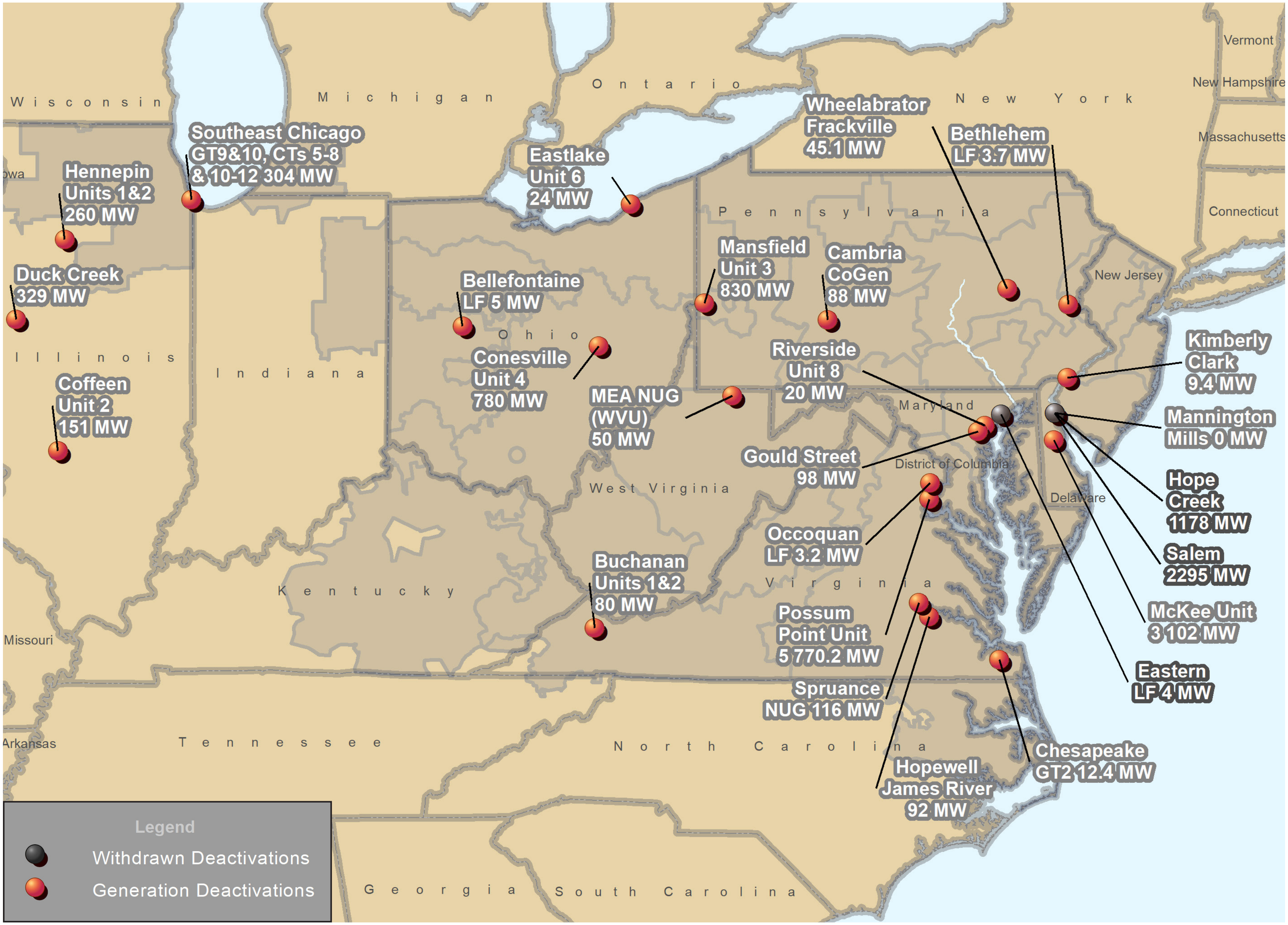


Figure 1.10: Accounting for Distributed Solar Generation

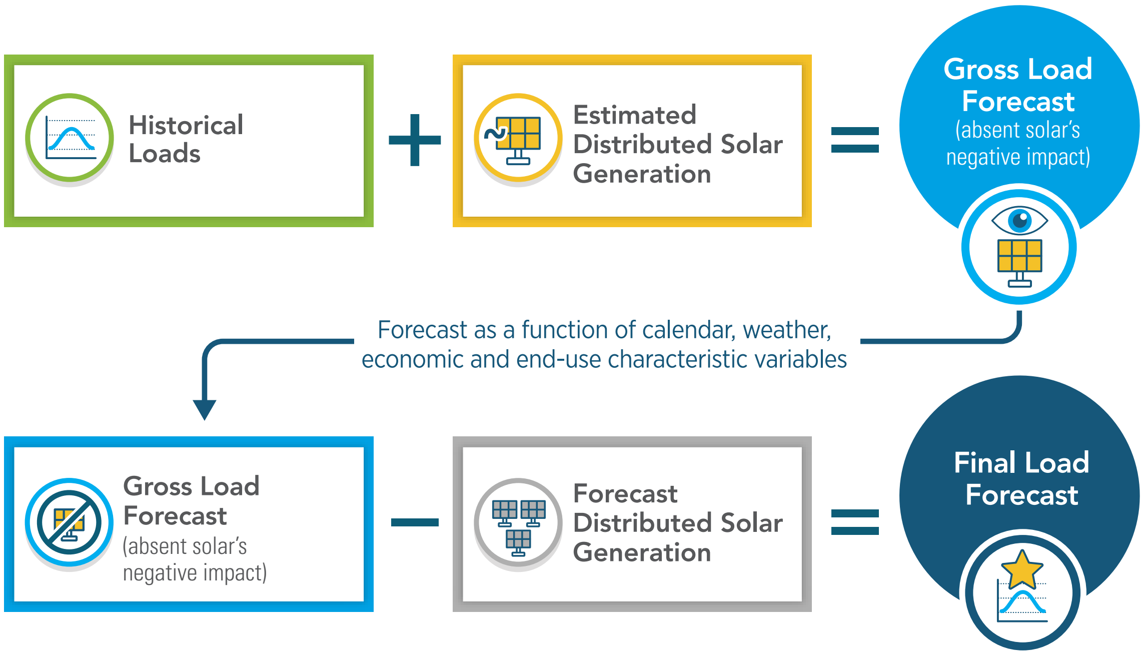


Table 1.1: 2019 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2019	2029	Growth Rate	2018/2019	2028/2029	Growth Rate
Atlantic City Electric Company	2,450	2,388	-0.3%	1,590	1,550	-0.3%
Baltimore Gas and Electric Company	6,697	6,663	-0.1%	5,872	5,907	0.1%
Delmarva Power & Light	3,933	3,962	0.1%	3,458	3,587	0.4%
Jersey Central Power & Light	5,914	5,912	0.0%	3,710	3,690	-0.1%
Met-Ed	2,986	3,157	0.6%	2,615	2,726	0.4%
PECO Energy Company	8,711	9,082	0.4%	6,753	6,936	0.3%
Pennsylvania Electric Company	2,897	2,908	0.0%	2,866	2,863	0.0%
PPL Electric Utilities	7,148	7,347	0.3%	7,259	7,371	0.2%
Potomac Electric Power Company	6,466	6,413	-0.1%	5,406	5,495	0.2%
PSEG	9,904	9,753	-0.2%	6,688	6,641	-0.1%
Rockland	404	402	0.0%	229	228	0.0%
UGI Utilities	189	188	-0.1%	193	189	-0.2%
Diversity – Mid-Atlantic	-1,213	-1,135		-644	-621	
Mid-Atlantic	**56,486**	**57,040**	**0.1%**	**45,995**	**46,562**	**0.1%**
American Electric Power	22,945	24,072	0.5%	22,485	23,541	0.5%
Allegheny Power	8,707	9,305	0.7%	8,721	9,413	0.8%
American Transmission Systems, Inc.	12,872	13,134	0.2%	10,601	10,729	0.1%
Commonwealth Edison Company	21,890	22,514	0.3%	15,515	15,806	0.2%
Dayton Power & Light	3,408	3,525	0.3%	2,864	2,945	0.3%
Duke Energy Corporation	5,480	5,742	0.5%	4,440	4,613	0.4%
Duquesne Light Company	2,862	2,887	0.1%	2,144	2,150	0.0%
East Kentucky Power Cooperative	1,989	2,072	0.4%	2,620	2,722	0.4%
Ohio Valley Electric Corporation	95	95	0.0%	125	125	0.0%
Diversity – Western	-1,612	-1,369		-1,476	-1,404	
Western	**78,636**	**81,977**	**0.4%**	**68,039**	**70,640**	**0.4%**
Dominion	19,391	21,238	0.9%	18,144	20,212	1.1%
Southern	**19,391**	**21,238**	**0.9%**	**18,144**	**20,212**	**1.1%**
Diversity – Total	-5,980	-6,070		-3,216	-3,261	
PJM RTO	**151,358**	**156,689**	**0.3%**	**131,082**	**136,178**	**0.4%**

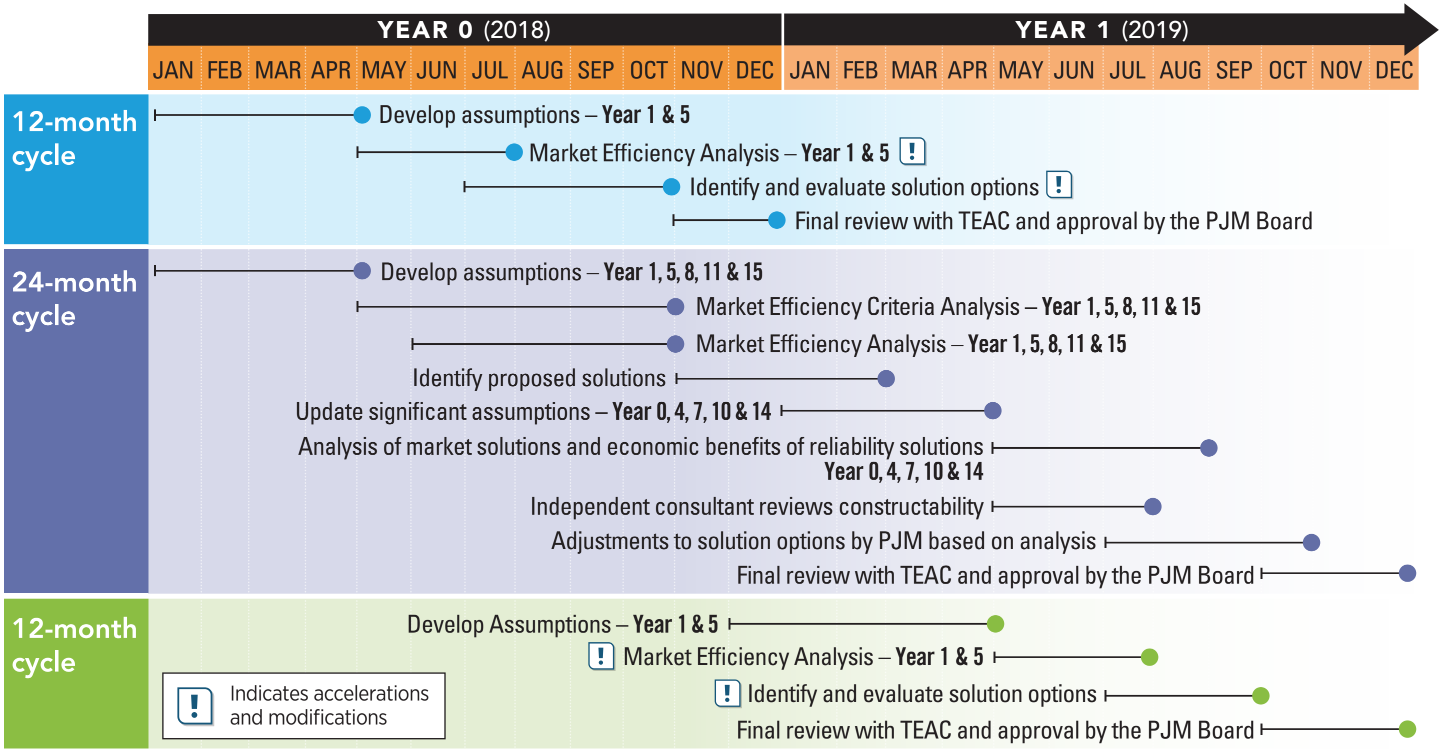
Figure 1.11: Primary Supplemental Project Drivers

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; 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 geo-magnetic disturbances.
Other	Meet objectives not included in other definitions such as, but not limited to, technological pilots, industry recommendations, environmental and saftey impacts, etc.

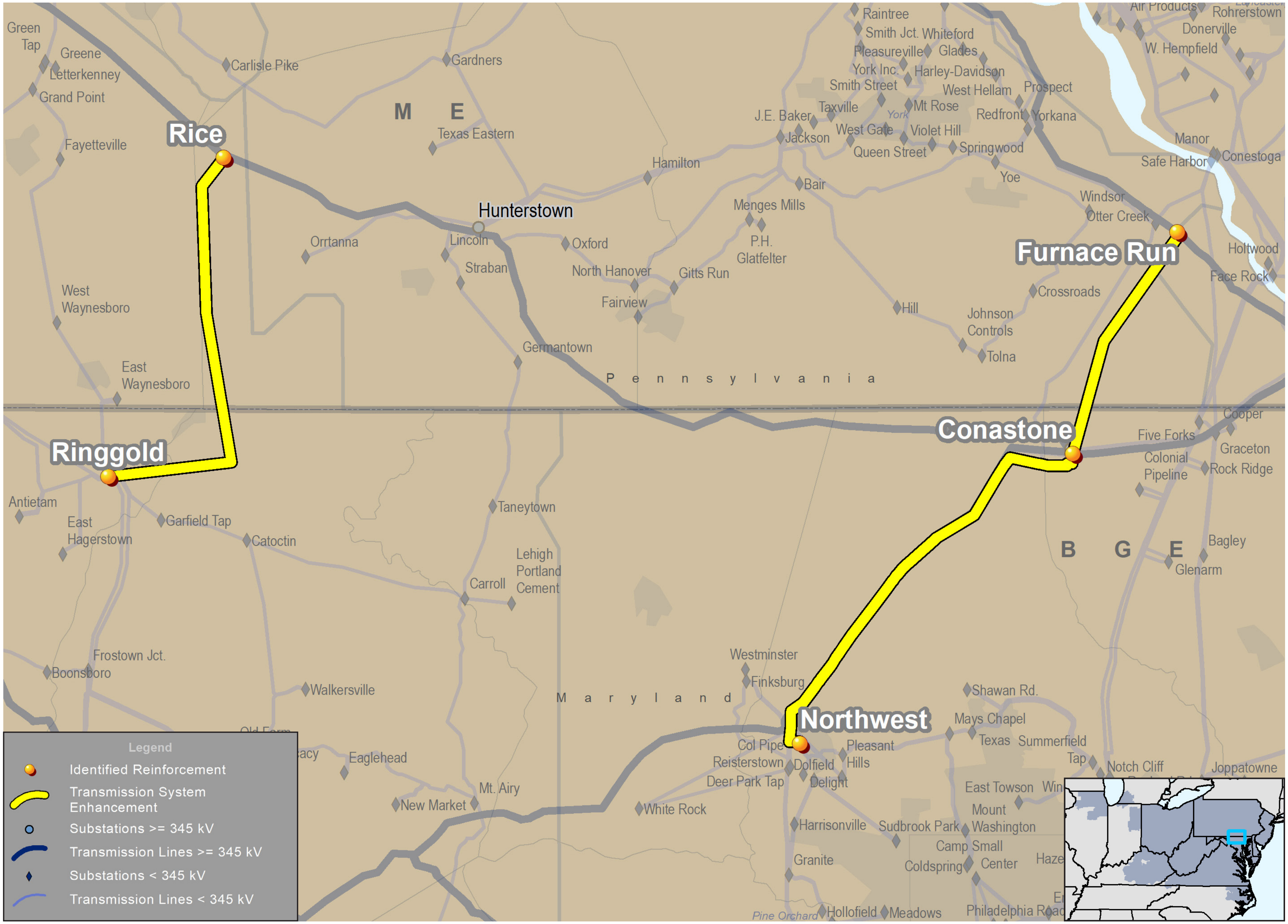
Figure 1.12: Attachment M3 Process for Supplemental Projects

*Subregional RTEP Stakeholder Committee

Figure 1.13: Market Efficiency 24-Month Cycle



Map 1.3: Project 9A – RTEP Baseline Projects B2743 and B2752



Map 1.4: Project 5E – RTEP Baseline Project B2992

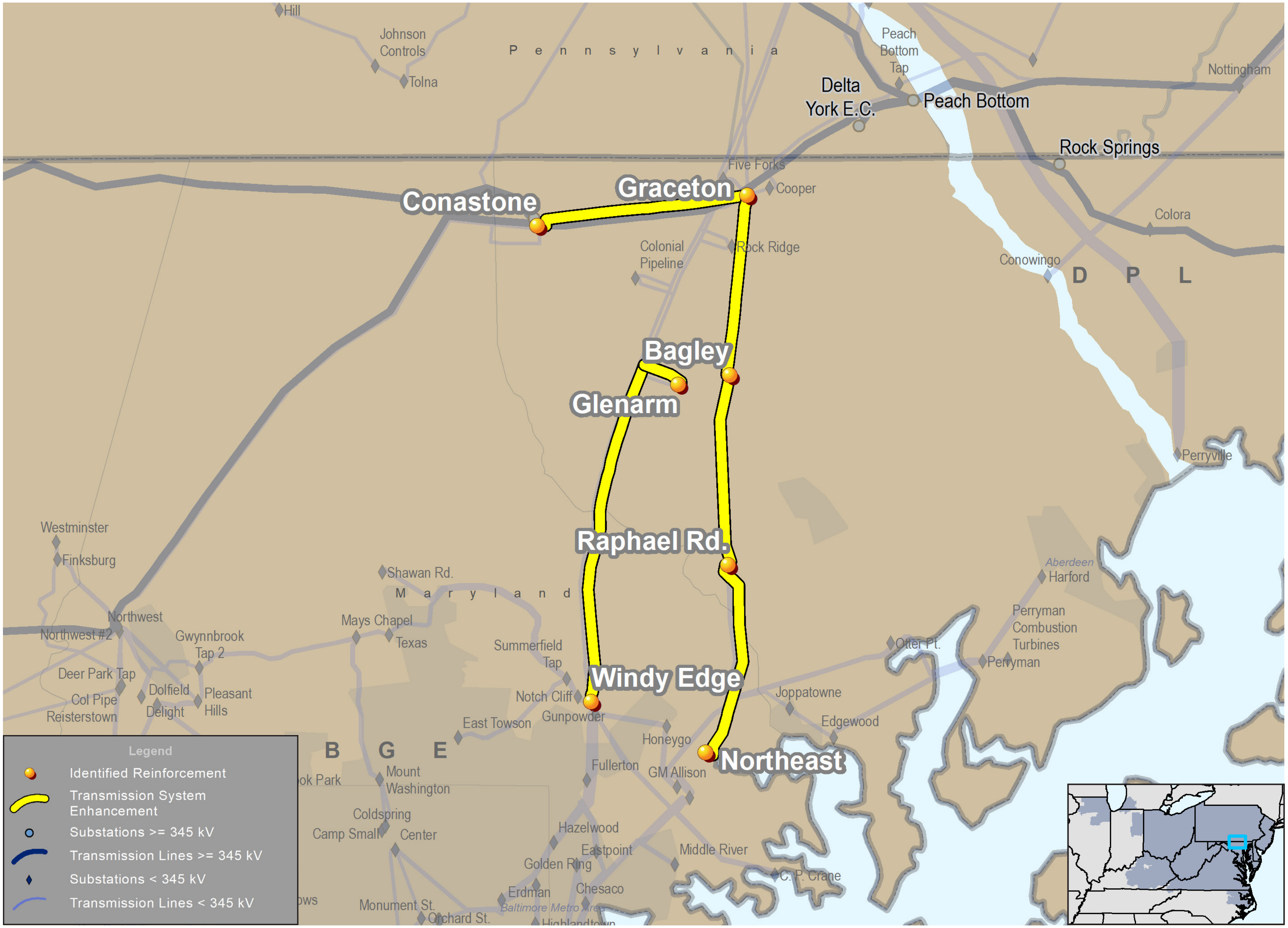
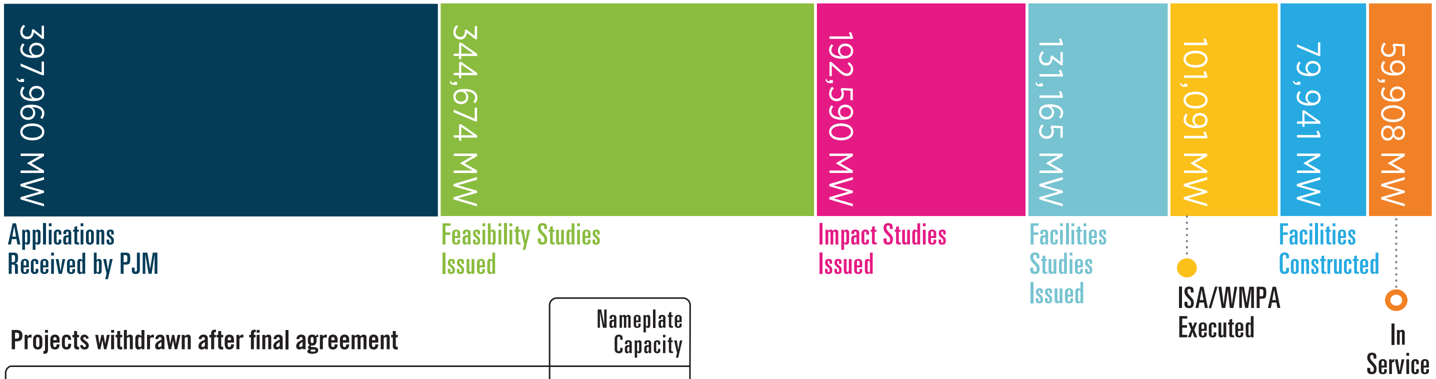


Figure 1.14: Queued Generation Progression



Projects withdrawn after final agreement

			Nameplate Capacity
155	Interconnection Service Agreements	**20,516** MW	27,781 MW
268	Wholesale Market Participation Agreements	**940** MW	1,972 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatts	23% Requested projects

This graphic shows the final state of generation submitted in all PJM queues that reached in-service operation, began construction, or was suspended or withdrawn as of Dec. 31, 2019.

Map 1.5: Feasibility and System Impact Studies performed in 2019

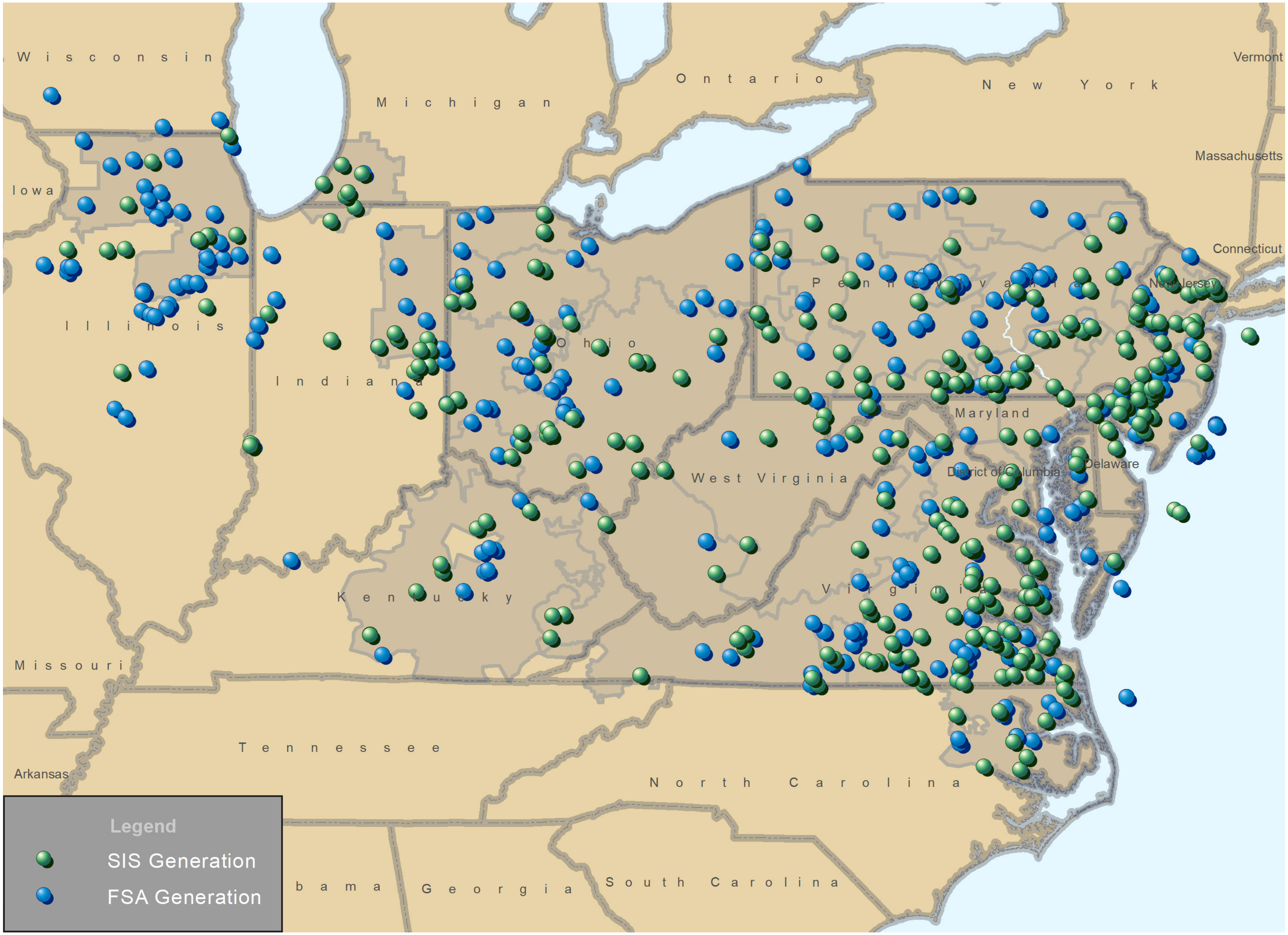


Figure 1.15: Queue Process Overview