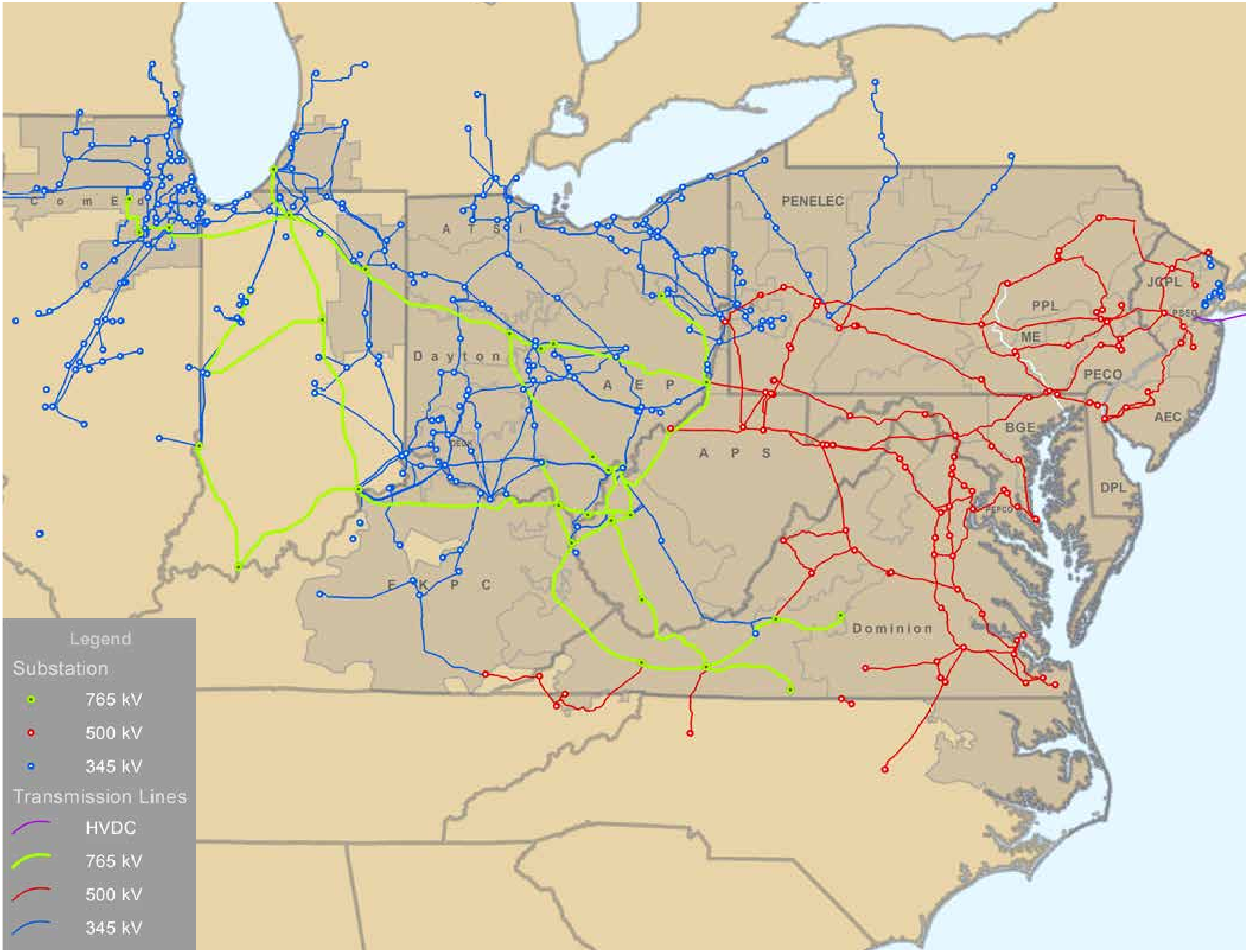
Regional Transmission Expansion Plan

February 28, 2019

2018


ComEd
ATSI
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DPL
PEPCO
Legend
Substation
765 kV
500 kV
345 kV
Transmission Lines
HVDC
765 kV
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1.0: Preface

The PJM Regional Transmission Expansion Plan (RTEP) Report is published annually to convey planning study results throughout the year, and to explain the rationale behind transmission system enhancement need.

In 2018, 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 a high-level summary of the 2018 RTEP activities including RTEP process improvements and a summary of projects organized by driver.

Section 2 provides 2018 RTEP project highlights, generator deactivations and re-evaluation of previously approved projects

Section 3 summarizes the market efficiency process including input assumptions, analysis and competitive windows.

Section 4 includes on overview of the PJM interregional planning activities.

Section 5 provides the results of the PJM 2018/19 Stage 1A ARR analysis.

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.

Additional resources in this report include:

- **Appendix 1** – Load Forecast
- **Appendix 2** – TO Zones and Locational Deliverability Areas
- **Glossary**
- **Topical Index**
- Key Maps, Tables and Figures

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: http://www.pjm.com/~/media/documents/manuals/m14b.ashx

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/

- 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: http://www.pjm.com/media/documents/merged-tariffs/oa.pdf

- 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: http://www.pjm.com/media/documents/merged-tariffs/oatt.pdf

- 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: http://www.pjm.com/planning/rtep-upgrades-status.aspx

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 requirement and demand-side valuation factors. Committee meeting materials and other resources are available on the PJM website: http://www.pjm.com/committees-and-groups/committees/pc.aspx.

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: http://www.pjm.com/committees-and-groups/committees/teac.aspx.

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 Committee: http://www.pjm.com/committees-and-groups/committees/srrtep-ma.aspx

- PJM Western Subregional RTEP Committee: http://www.pjm.com/committees-and-groups/committees/srrtep-w.aspx

- PJM Southern Subregional RTEP Committee: http://www.pjm.com/committees-and-groups/committees/srrtep-s.aspx

The Independent State Agencies Committee (ISAC) is a voluntary, stand-alone committee comprising representatives from regulatory and other agencies in state jurisdictions within the PJM footprint. Through the activities of the ISAC, states have an opportunity to provide input on the assumptions and scenarios that PJM incorporates in the scope of its RTEP studies. Additional information is available on the PJM website: http://pjm.com/committees-and-groups/isac.aspx.

PJM Regional Transmission Expansion Plan – March 29, 2019 Errata

Errata – March 29, 2019

Section 1.1: Generation in Transition, p. 10

- In the sentence, *"Overall, 24 percent of projects requesting capacity uprates reach commercial operation whereas, only 11.7 percent of new generator requests reach commercial operation."* The reference to, 42 percent of projects requesting capacity uprates, has been corrected to 24 percent to reflect the correct percentage.

- In *Figure 1.9: Queued Generation Progression – Requested Capacity Rights,* the reference to 42 percent of requested projects has also been corrected to 24 percent.

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Section 1: 2018 Executive Summary

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

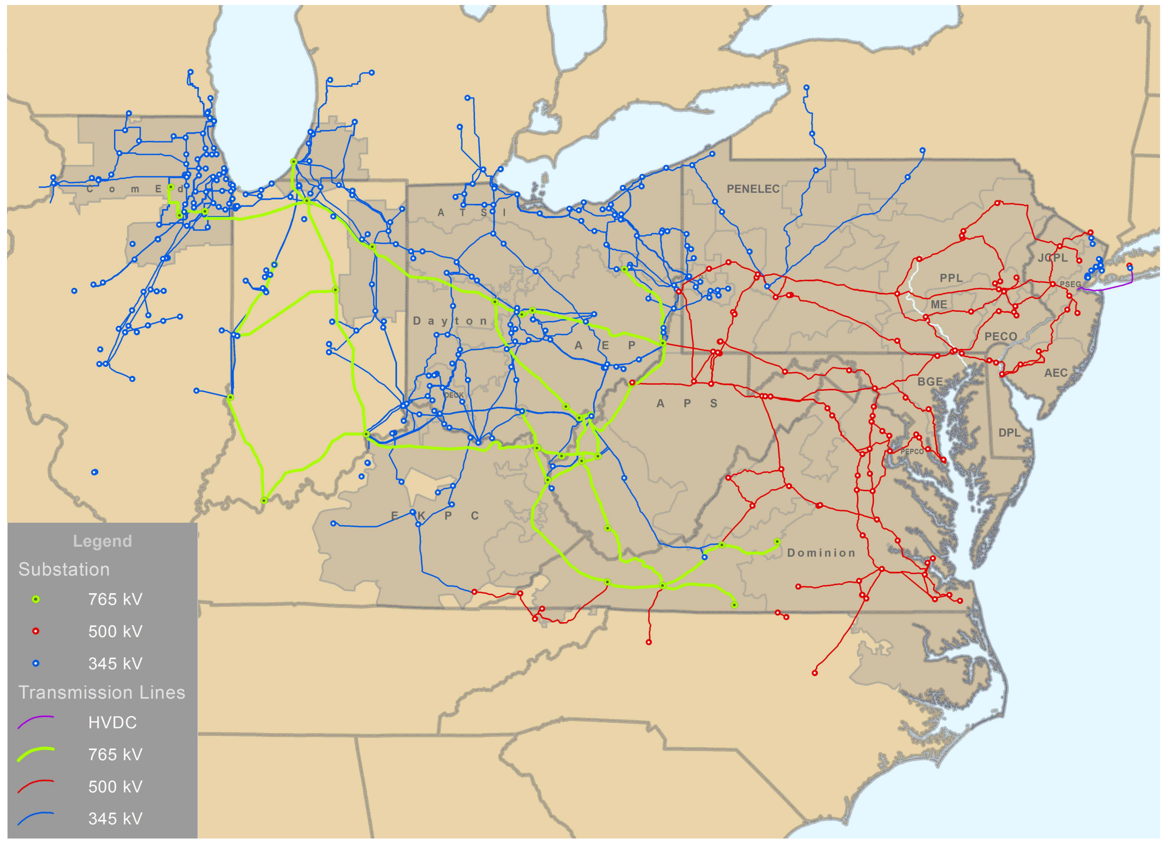
1.0: 2018 Executive Summary

1.0.1 — 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 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 1,010 members, PJM dispatches more than 180,080 MW of generation capacity over 84,040 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** in the broader 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 congestion 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 overall RTEP. The PJM Board approval obligates designated entities to implement those plans. PJM recommendations can also include removal of or change in scope to previously approved projects if expected system conditions have changed such that justification for a project no longer exists.

System Enhancement Drivers

A 15-year long-term planning horizon allows PJM to consider the aggregate effects of many factors, 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, interregional coordination and resilience. Importantly though, as **Figure 1.2** indicates, RTEP development considers all drivers through a reliability criteria 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 events P0 through P7 as described in **Section 1.2**.

Figure 1.1: RTEP Process – RTO Perspective

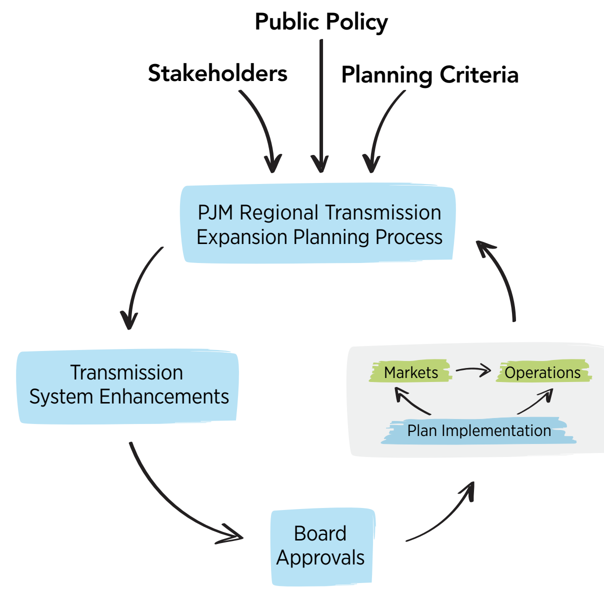
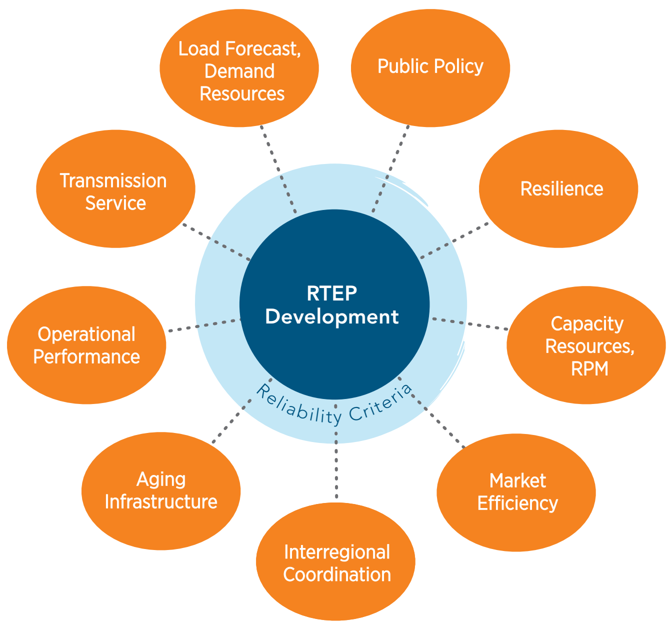


Figure 1.2: System Enhancement Drivers



Highlights of projects identified and approved by the PJM Board during 2018 appear in **Section 2**. Details of specific large-scale projects – those greater than $10 million in scope – are presented in **Section 6**.

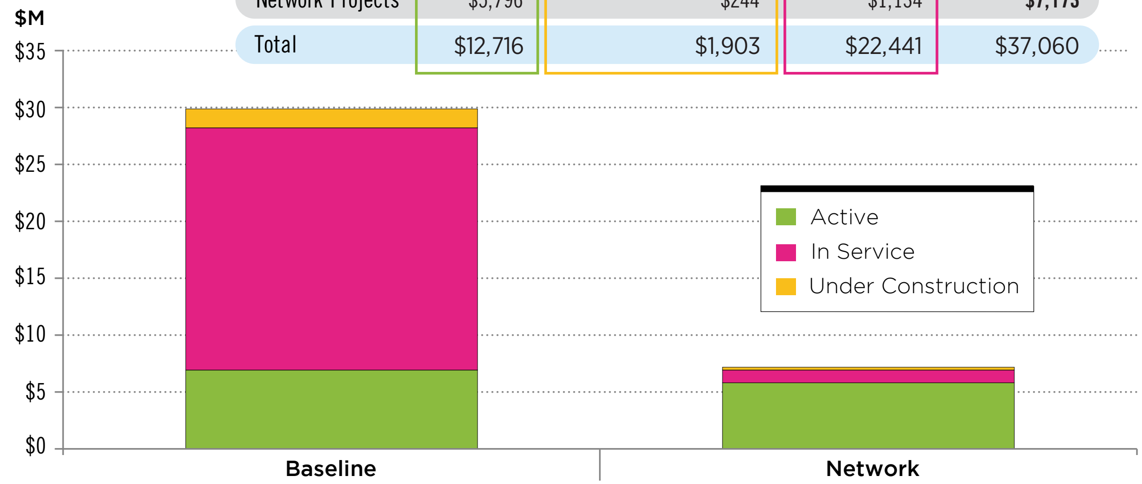
2018 PJM Board Approvals

Since 1999, the PJM Board has approved transmission system enhancements totaling $37.1 billion. Of this, $29.9 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 $7.2 billion represents network facilities to enable more than 85,000 MW of new generation to interconnect reliably.

A summary of projects by status as of December 31, 2018, appears in **Figure 1.3**. The numbers provide a snapshot of one point in time, as with an end-of-year balance sheet. The $37.1 billion total reflects a net $2 billion increase over December 31, 2017. The year-over-year differentials are detailed in **Table 1.1** and graphically portrayed in the **Figure 1.4** and **Figure 1.5** waterfall diagrams for RTEP baseline and network projects. The PJM Board approved 139 new baseline projects at an estimated cost of $2.1 billion and 251 new network transmission projects at an estimated cost of nearly $1 billion. 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 December 31, 2018

($M)	Active	Under Construction	In Service	Grand Total
Baseline Projects	$6,920	$1,659	$21,307	**$29,887**
Network Projects	$5,796	$244	$1,134	**$7,173**
Total	$12,716	$1,903	$22,441	$37,060



PJM recommends canceling a network system enhancements from the RTEP when the queue 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 and voltage greater than $10 million is included in **Section 2.3.**

Table 1.1: RTEP Project Cost Differentials – December 31, 2017 vs. December 31, 2018

	Baseline Projects ($M)	Network Projects ($M)
Value at the end of 2017 (start)	2,7882.6	7227.9
Cost of new projects (new)	2,065.45	986.33
Cost changes to existing projects (change)	55.08	1,404.95
Cost of canceled projects (canceled)	-142.56	-1,137.19
Value at the end of 2018 (end)	**29,860.57**	**8,481.99**

Figure 1.4: Baseline Project Differentials – 2018

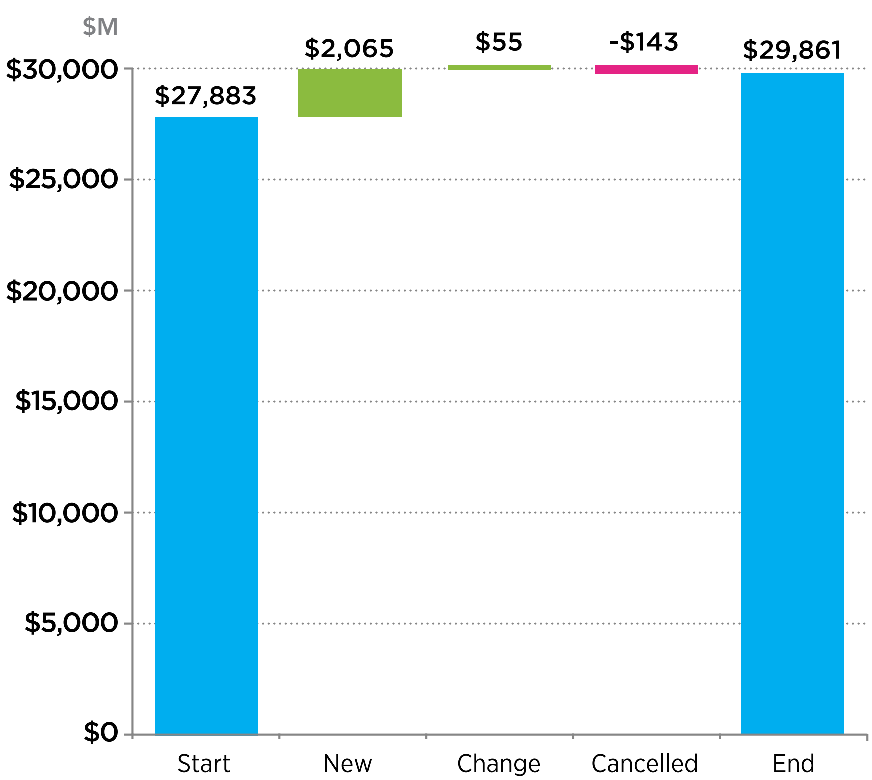
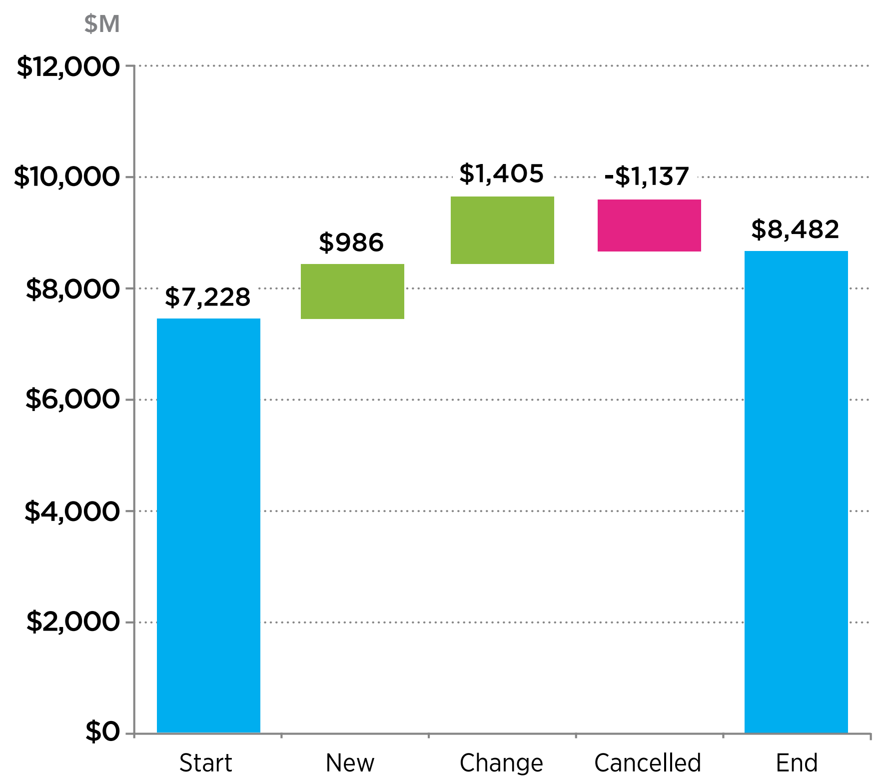


Figure 1.5: Network Project Differentials – 2018



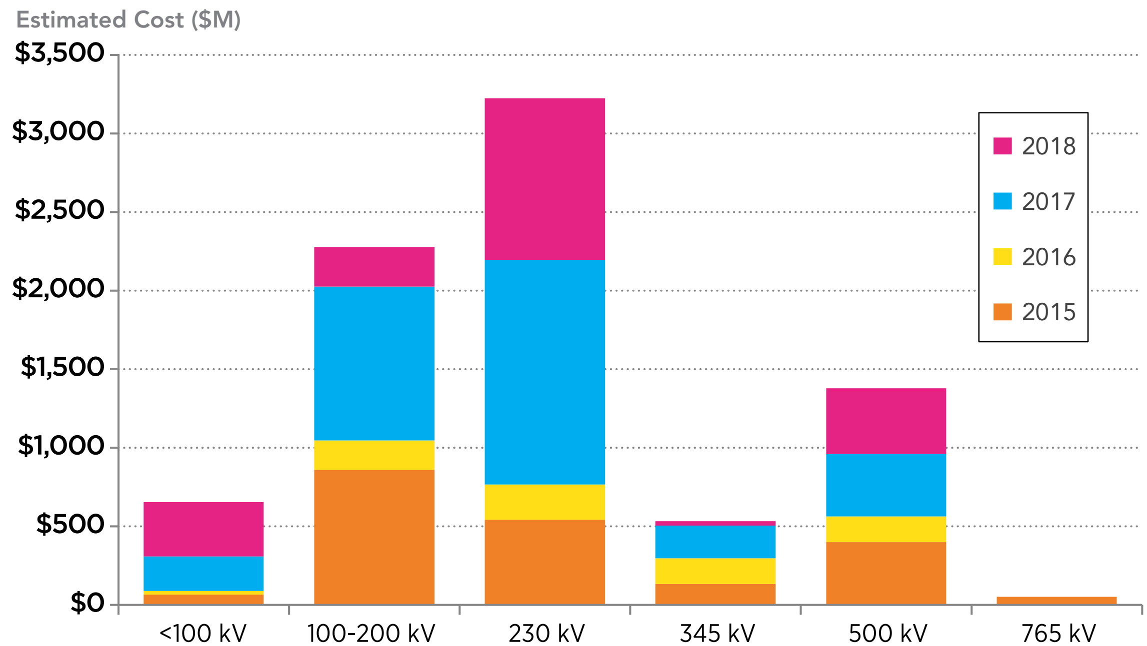
Shifting RTEP Dynamics

The $2.1 billion of baseline transmission investment approved during 2018 continues to reflect a shift in the dynamics driving transmission expansion needed through study year 2025. Flat load growth, energy efficiency, generation shifts and aging infrastructure drivers – among others – continue to shift transmission need away from large-scale, cross-system backbone projects towards projects focusing on transmission owner criteria. PJM Board-approved projects in 2018 will address market efficiency congestion and solve localized reliability criteria violations. **Figure 1.6** reflects lower investment at 345 kV and above over the past four years and higher levels of transmission investment at 230 kV.

Flat Load Growth

PJM's 2018 RTEP baseline power flow model for study year 2023 was based on the 2018 PJM Load Forecast Report, summarized in **Appendix 1**, showing a 10-year RTO summer normalized peak growth rate of 0.4 percent. Average 10-year annualized summer growth rates for individual PJM zones ranged from -0.2 percent to 0.8 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.

Figure 1.6: Approved Baseline Projects by Voltage 2015-2018



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 now exceeds that of coal. Natural gas plants totaling over 50,600 MW constitute 67 percent of the generation currently seeking capacity interconnection rights in PJM's new services queue.

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 2018, totaling 12,279 MW. The impacts of deactivation notices received during 2018 are discussed in **Section 2.1**.

Distributed Energy Resources

Distributed energy resources are introducing 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 and distribution 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. Additionally, these units impact PJM's load forecast, both on a day ahead and real time basis, as well as 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.

1.1: Generation in Transition

1.1.1 — Shift to Natural Gas Continues

PJM's 184,724 MW of RPM-eligible existing installed capacity reflects a fuel mix comprising 40 percent natural gas, 31 percent coal and 18 percent nuclear, as shown in **Figure 1.7**. 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 stack price volatility.

Natural gas powers 67 percent of the generation in PJM's interconnection queue, shown in **Figure 1.8**. 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. **Figure 1.8** shows PJM's fuel mix based on requested interconnection capacity rights for generation that is active, under construction or suspended as of December 31, 2018.

Figure 1.7: PJM Existing Installed Capacity Mix RPM Eligible Capacity (December 31, 2018)

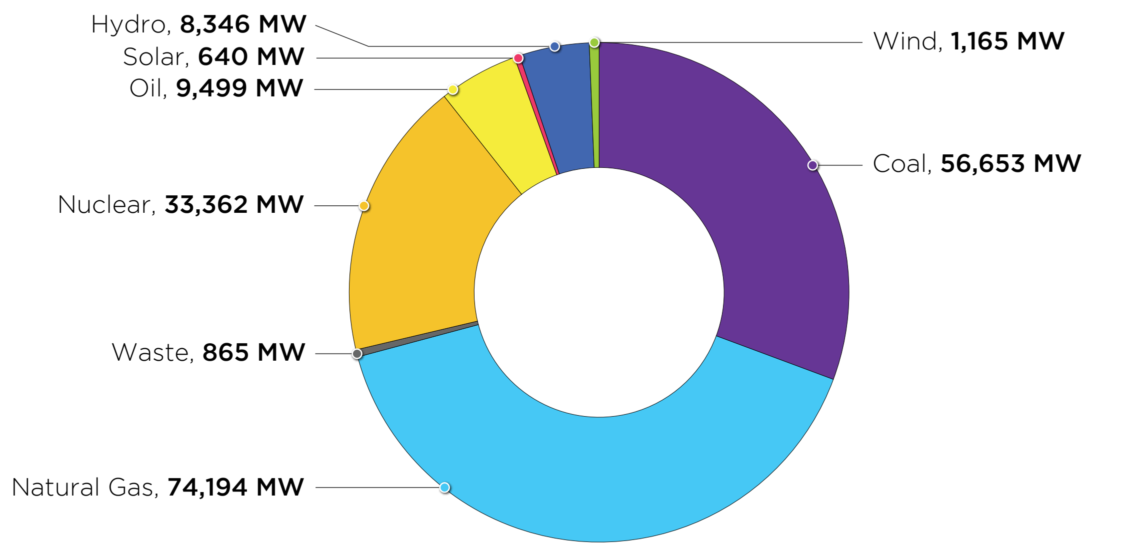
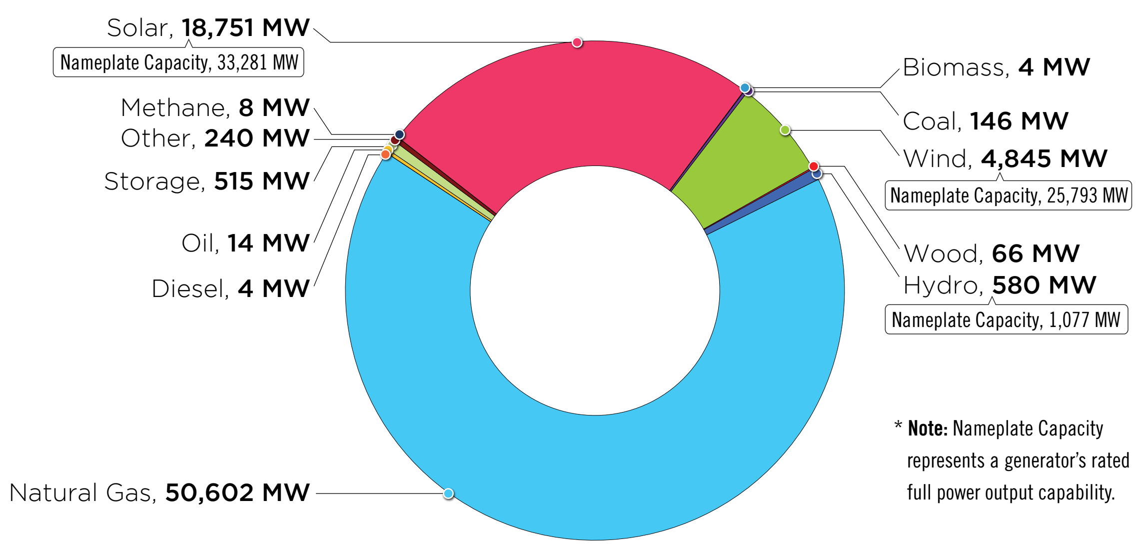


Figure 1.8: PJM Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (December 31, 2018)



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

Interconnection requests by fuel type and status for renewable and non-renewable fuels are summarized in **Table 1.2** and **Table 1.3**, respectively.

1.1.2 — Renewables

PJM's interconnection queue process continues to see renewable-powered generation growth. As **Figure 1.8** and **Table 1.2** show, queued requests as of December 31, 2018, for capacity interconnection rights (CIRs) totaled 4,845 MW for wind-powered generators, as of December 31, 2018, that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 25,793 MW. Queued solar-powered generator requests for CIRs totaled 18,751 MW that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 33,281 MW.

Nameplate Capacity vs. Capacity Interconnection Rights

Nameplate capacity represents a generator's rated full power output capability. As **Figure 1.8** shows, nameplate capacity is typically much greater than CIRs for wind and solar powered generators. This arises from the fact that while some renewable resources can operate continually like conventional fossil-fueled power plants, others operate intermittently, such as wind and solar.

Table 1.2: Requested Capacity Interconnection Rights, Renewable Fuels (December 31, 2018)

	In Queue						Complete				Grand Total	
	Active		Suspended		Under Construction		In Service		Withdrawn			
	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW
Biomass	1	4.0	0	0.0	0	0.0	12	268.8	35	682.9	48	955.7
Hydro	4	517.4	0	0.0	4	62.2	29	1,208.5	44	1,876.4	81	3,664.5
Methane	1	0.8	0	0.0	3	7.4	92	436.0	95	488.1	191	932.3
Solar	422	17,341.0	32	171.3	77	1,239.0	146	704.5	984	14,240.5	1,661	33,696.2
Wind	77	3,948.8	10	174.3	32	722.3	84	1,555.4	427	12,046.2	630	18,446.9
Wood	0	0.0	1	16.0	1	50.0	1	4.0	3	137.0	6	207.0
Total	**505**	**21,812.0**	**43**	**361.5**	**117**	**2,080.8**	**364**	**4,177.3**	**1,588**	**29,471.1**	**2,617**	**57,902.6**

Table 1.3: Requested Capacity Interconnection Rights, Non-Renewable Fuels (December 31, 2018)

	In Queue						Complete				Grand Total	
	Active		Suspended		Under Construction		In Service		Withdrawn			
	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW
Coal	2	29.0	0	0.0	5	117.2	59	2,182.2	69	33,537.6	135	35,866.0
Diesel	0	0.0	0	0.0	1	4.1	10	72.4	15	76.7	26	153.2
Natural Gas	108	31,034.2	18	4,019.4	50	15,548.6	292	40,713.1	599	220,820.2	1,067	312,135.5
Nuclear	8	125.4	0	0.0	1	44.0	43	3,881.6	18	8,988.0	70	13,039.0
Oil	1	14.0	0	0.0	0	0.0	18	539.8	22	2,300.0	41	2,853.8
Other	2	240.0	0	0.0	0	0.0	7	376.5	82	1,068.8	91	1,685.3
Storage	37	507.3	11	5.8	27	1.9	23	0.1	115	476.9	213	992.0
Total	**158**	**31,949.9**	**29**	**4,025.2**	**84**	**15,715.8**	**452**	**47,765.7**	**920**	**267,268.2**	**1,643**	**366,724.8**

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 history data for individual units may merit. Until such time, these class averages 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 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: http://www.pjm.com/-/media/documents/manuals/m14a.ashx.

1.1.3 — Energy Storage Devices

PJM's resource mix includes energy storage projects as a means to enhance operational flexibility. The importance of these projects continues to grow. There are 27 storage devices located in PJM that are in service or partially in service, totaling 277 MW as of December 31, 2018. These devices consist mainly of battery and flywheel technology. A number of these are part of hybrid plants that are paired with wind-powered generation. Mainly energy-only devices, these storage facilities participate in PJM Ancillary Services Markets. Many of them supply frequency regulation. Other prototype projects within PJM are exploring the benefits of electric vehicle-to-grid technology and thermal storage, which uses large electric water heaters that respond to grid needs.

One of the challenges facing grid operators like PJM is the inability to store electricity during times of oversupply or low price for later use during times of high demand, high prices or other power source unavailability. Unlike other forms of energy, electricity cannot be stored in a conventional sense. Electricity is consumed at the time it is produced. Until recently, the only large-scale energy storage option for electricity available was pumped-storage hydroelectricity. Pumped storage resources, though, are difficult to build.

Future storage innovations, could provide PJM a number of options: improved battery technology, flywheels, compressed air energy storage, thermal storage and hybrid-electric vehicles. These technologies will become even more important as intermittent renewable energy sources play a greater role in PJM's resource mix.

Storage as a Transmission Asset

The Federal Energy Regulatory Commission (FERC), decided in 2010 to address the classification of energy storage devices on a case-by-case basis. In the same order, FERC ruled that, given certain specific criteria being met, storage devices could be treated as transmission facilities and therefore be compensated in the same way as other transmission facilities.

More recently, as part of the 2018 RTEP Proposal Window No. 1, discussed in **Section 2**, PJM received one proposal that includes battery energy storage systems. This proposal sought to address an overload of a 69 kV circuit for a single contingency loss of another 69 kV circuit by installing a battery storage devices in the area. Evaluation of this proposal continues into 2019.

1.1.4 — 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 370,913 MW, as shown in **Figure 1.9**. and over 53,762 MW of interconnection requests we're actively under study. Over 22,184 MW were under construction or suspended as of December 31, 2018, 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.

Queue Progression History

PJM reviews generation queue progression annually to understand trends more fully. As shown in **Figure 1.9**, PJM received 370,913 MW of queued generation interconnection requests for capacity interconnection rights from Queue A in 1999 through December 31, 2018. Only 55,876 MW – 15 percent – of these projects have reached commercial operation. Note that **Figure 1.9** 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, 17,822 MW of capacity with ISAs and 767 MW of capacity with WMPAs withdrew from PJM's interconnection process. Overall, 24 percent of projects requesting capacity uprates reach commercial operation whereas, only 11.7 percent of new generator requests reach commercial operation.

Table 1.4: Study Requests Queued Since 1999

Status	Number of Projects	Requested Capacity Interconnection Rights (MW)	Nameplate Capacity (MW)
Active	663	53,762	85,430.5
In Service	816	51,943	61,128.0
Under Construction	201	17,797	23,433.9
Suspended	72	4,387	6,089.3
Withdrawn	2,508	296,739	368,341.9
Total	**4,260**	**424,627**	**544,423.5**

Figure 1.9: Queued Generation Progression – Requested Capacity Rights (December 31, 2018)

Note: Figure 1.9 does not include projects that are listed as active in the queue process prior to required agreement execution.

NOTE:

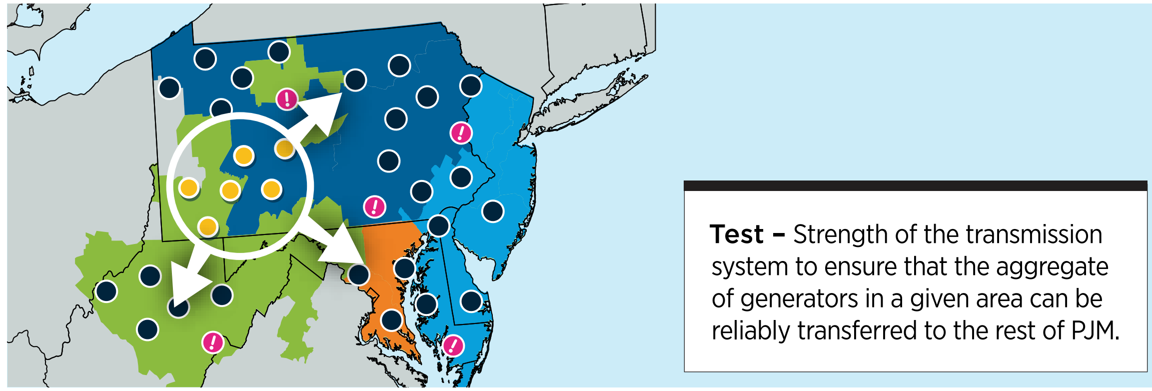
A Wholesale Market Participant Agreement (WMPA) is executed among PJM, the generator owner and the TO if the transmission facility to which a generator seeks interconnection is not FERC jurisdictional. This is frequently the case with generators connecting at the distribution level voltages on facilities over which FERC does not have jurisdiction.

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 $7.2 billion to interconnect over 85,00 MW of new generating resources and satisfy other new service requests – merchant transmission interconnection, for example. The PJM Board approved 60 new network system enhancements totaling $1.1 billion in 2018 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 identify system conditions that sufficiently stress the transmission system be evaluated 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 1.10**. In addition to generator interconnection requests, PJM conducts this power flow test under summer and winter peak load conditions, when capacity is most needed to serve load, as well as under light load conditions to ensure that a range of resource combinations and conditions is examined.

Figure 1.10: Generator Deliverability Concept



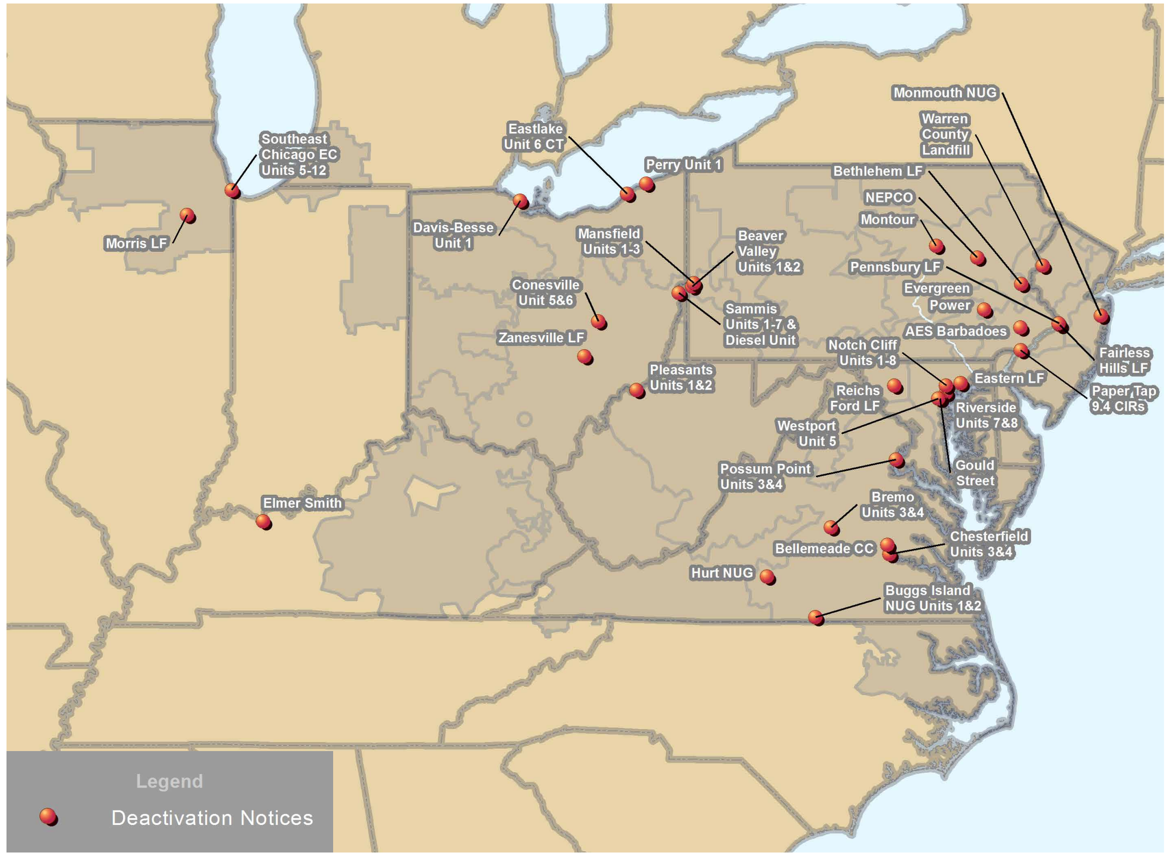
1.1.5 — Deactivations

PJM received 63 deactivation notifications in 2018 totaling 12,279 MW. This was up from the previous five years, but below the 14,444 MW of announced deactivations in 2012. By contrast, PJM received and studied deactivation requests for only 11,000 MW in total during the eight years ending November 1, 2011. **Map 1.2** shows the deactivation request locations received between January 1, 2018, and December 31, 2018.

Generator owners have requested deactivation of these units between April 2018 and June 2022. PJM maintains a list of formally submitted deactivation requests, accessible via the following link: https://www.pjm.com/planning/services-requests/gen-deactivations.aspx.

PJM has 30 days in which to respond to a generator owner with deactivation study results. Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. System expansion solutions may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. 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. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board or by supplemental projects proposed by the incumbent transmission owner.

Map 1.2: PJM Generator Deactivation Notifications Received January 1, 2018 through December 31, 2018



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1.2: Project Drivers in Transition

1.2.1 — 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, frequently 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 **Table 1.5** and 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.

Table 1.5: 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

PJM N-0 analysis – shown in Table 1.5 as a NERC planning event is mapped to planning event P0 – examines the bulk electric system as-is, with all facilities in service. PJM identifies facilities that have pre-contingency loadings that exceed applicable normal thermal ratings. Bus voltages are also identified that violate established limits 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 and within applicable emergency thermal ratings and voltage limits after the second 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.

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

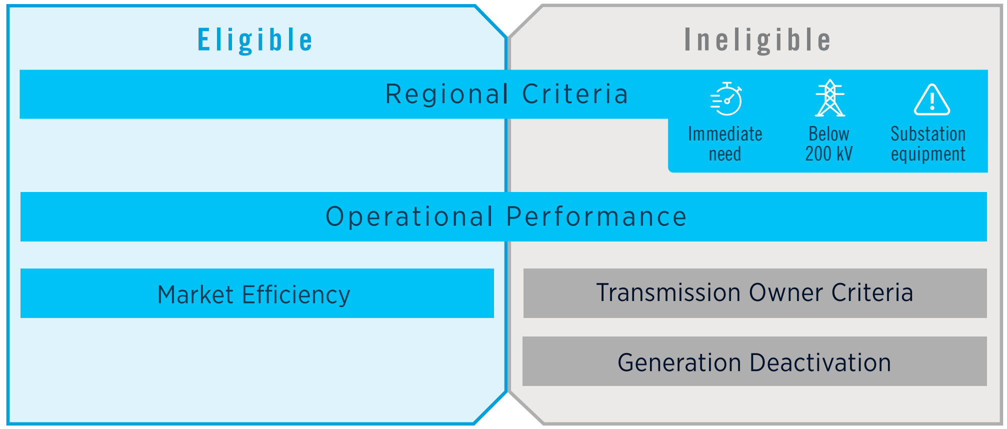
PJM conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operation throughout PJM's planning horizon. NERC criteria disturbances are those required by the NERC planning criteria applicable to system-normal, single-element outage and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

1.2.2 — Transmission Owner Criteria

The PJM Operating Agreement specifies that individual transmission owner (TO) planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions, such as in urban areas. TOs are required to include their individual criteria as part of their respective FERC Form No. 715 filings. TO criteria can be found on the PJM website: http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx.

Figure 1.11: Window Eligibility



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 1.11**. Under the terms of the OATT, the costs of such projects are allocated 100 percent to the TO zone.

2018 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 deteriorating facilities. 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.

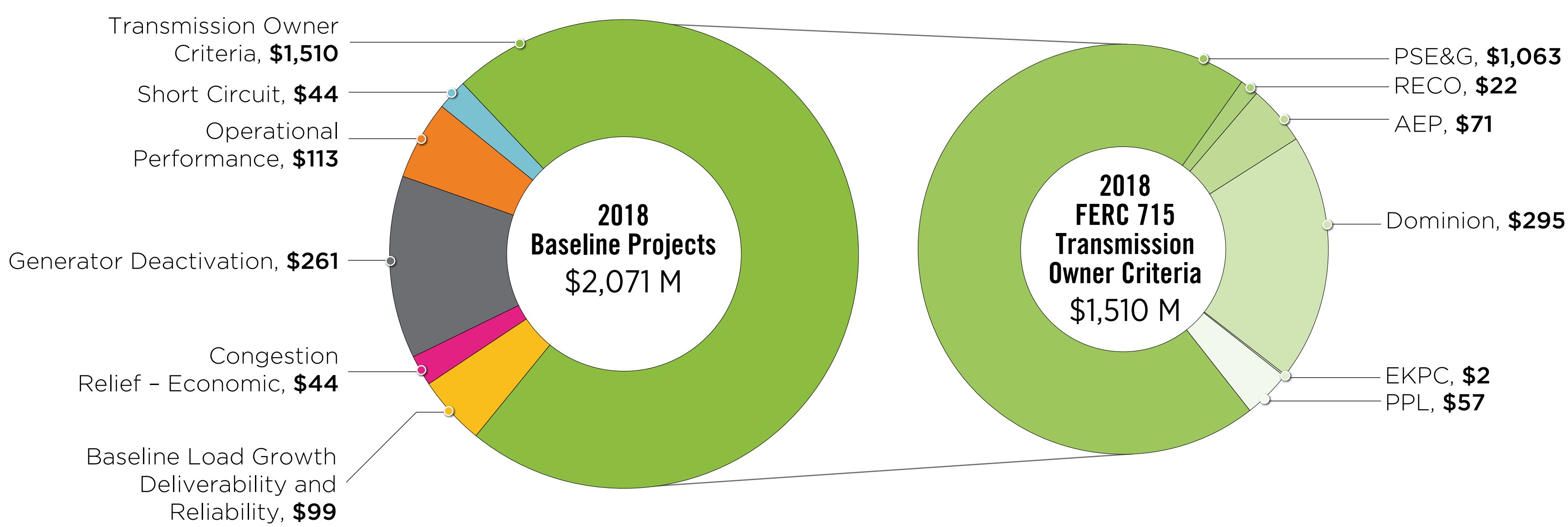
In other instances, TO criteria encompass local loss-of-load thresholds, particularly on radial facilities. The threshold for some is on a megawatt-mile basis, others on a megawatt-magnitude basis to reduce the extent of load impacted.

Section 2.2.1 summarizes TO criteria-driven transmission projects with cost estimates greater than $10 million, as approved by the PJM Board in 2018.

2018 RTEP Summary

As RTEP dynamics shift, PJM has observed a correlated shift in the categories of projects that PJM analyzes and ultimately recommends for inclusion in the RTEP. **Figure 1.12** summarizes the total dollars approved by the PJM board for inclusion in the 2018 RTEP, categorized by driver.

Figure 1.12: 2018 RTEP Baseline Projects by Driver



1.2.3 — Market Efficiency

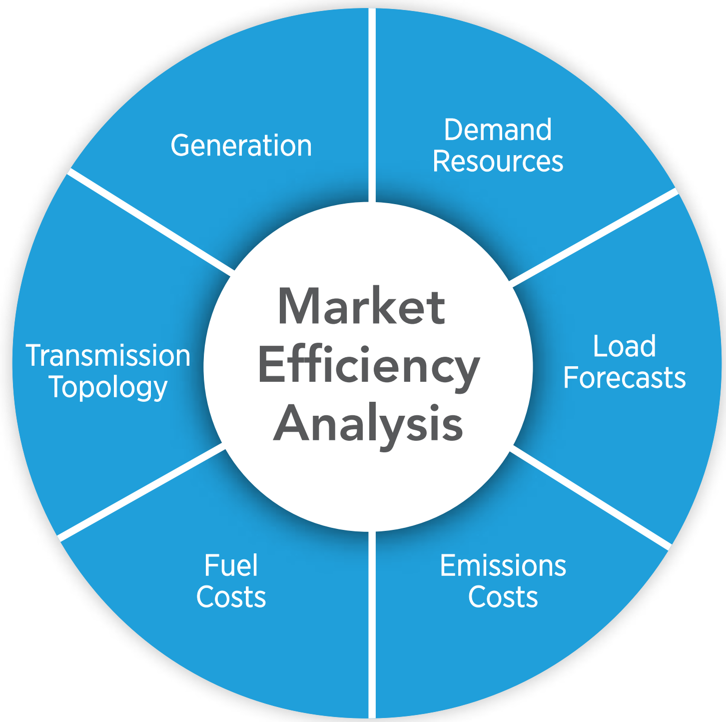
PJM's RTEP process includes a market efficiency analysis to accomplish the following goals:

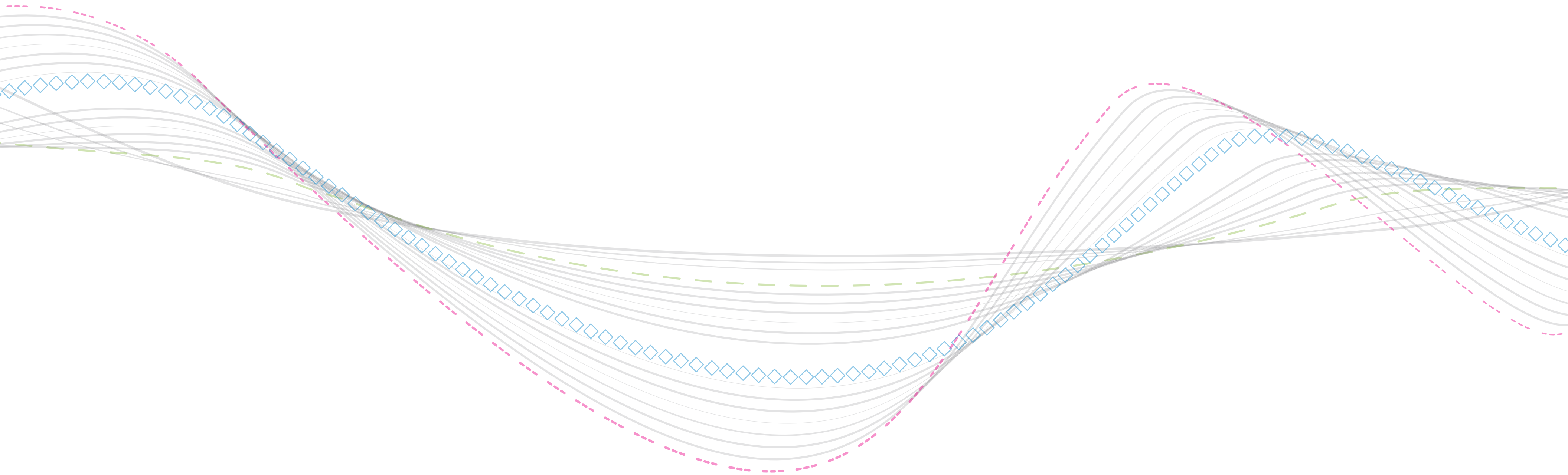
- Determine which reliability-based enhancements have economic benefit if accelerated
- Identify new transmission enhancements that may realize economic benefit
- Identify the economic benefits associated with reliability-based enhancements already included in the RTEP that, if modified, would relieve 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 the 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**. During 2018, the PJM Board approved 2 projects driven by market efficiency totaling $25.7 million.

Figure 1.13: Market Efficiency Analysis Parameters





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

1.3: RTEP Process Improvement Milestones

PJM's RTEP process is not static. It continues to evolve with the scope of system enhancement drivers it addresses, as described earlier in **Section 1.0**. Process improvements continued in 2018, milestones for which are discussed below.

1.3.1 — 2018 Activities

Supplemental Planning Process/Transparency

PJM's Markets and Reliability Committee authorized the creation of the Transmission Replacement Processes Senior Task Force (TRPSTF) in 2016. The TRPSTF is charged with increasing transparency and consistency in the establishment, communication and the review of aging infrastructure supplemental projects. It also considers potential criteria and guidelines for transmission owner aging infrastructure projects. The TRPSTF arose in part due to concern over the increase in supplemental projects and aging infrastructure replacements.

With reduced load growth and growing distributed technologies, the drivers for new transmission investment are shifting to those associated with the replacement of aging transmission infrastructure and attachment of new concentrated loads (e.g., new data centers).

FERC issued a Show Cause Order in August 2016 establishing a proceeding to determine whether the PJM transmission owners are complying their Order 890 obligations specific to supplemental projects. In October 2016, the PJM transmission owners filed a proposed a new PJM Tariff, Attachment M-3 process, which provides additional detail and transparency regarding the process for planning supplemental projects, and PJM proposed revisions to the Operating Agreement, Schedule 6 to ensure compliance with Order No. 890. In compliance with FERC Order dated February 2018 the PJM transmission owners revised Attachment M-3 to further enhance the supplemental project planning process by including timelines specific to providing opportunity for review and comment of local TO assumptions, needs and solutions. In September 2018, FERC issued an Order accepting the Attachment M-3 and Operating Agreement revisions. Following discussions with PJM stakeholders, PJM also revised Manual 14B to, among other things, include references to the TOs Attachment M-3 supplemental project planning process.

Market Efficiency Process Enhancements

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. The task force has been investigating a number of tasks, including:

- Provide educational material
- Evaluate benefit-to-cost calculation
- Evaluate facility service agreement (FSA) 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 two phases. Strawman polls among the task force are providing direction for additional review to be conducted in 2019. More information can be accessed on the PJM website: https://pjm.com/committees-and-groups/task-forces/mepetf.aspx. Additional discussion on the MEPETF activities including those that continued into 2019 are included in **Section 3**.

FERC Generator Interconnection Order

FERC Order No. 845 became effective July 23, 2018. This order adopted reforms for generation interconnection to the grid focusing on the following topics:

- Customer's option to build
- Dispute resolution
- Identification and definition of contingent facilities
- Transparency regarding study models and assumptions
- Interconnection study deadlines
- Requesting interconnection service below generation facility capacity
- Provisional interconnection service
- Utilization of surplus interconnection service
- Material modification and incorporation of advanced technologies

PJM has drafted a number of changes to comply with the order. Final compliance filings will be due in 2019 pending FERC order on request for rehearing.

Summer Only Demand Response

PJM worked with the Summer Only Demand Response Senior Task Force during 2018 to develop a proposal to improve long-term zonal and RTO load forecasts. The proposal attempts to respond to participant Demand Response (DR)program design while still satisfying PJM's planning needs to be both predictable and measurable. The purpose is to improve demand response resource evaluation that are only available during the summer. Adjusting the load forecasting process would provide an alternative to supply-side participation in the capacity market and more accurately capture the peak-shaving actions of these resources in the load forecasts.

Participation would be restricted to load reduction programs (both direct control and behavioral) governed by a tariff or an order approved by each state's applicable regulatory authorities. Participants would be responsible for satisfying the peak-shaving adjustment requirements. They would not also participate as demand response or as price responsive demand for the same delivery year to avoid double-counting.

The program details the information that must be provided to PJM, the time frames by which programs must be filed in order to be included in the next PJM load forecast, the metrics to measure participant performance and the value received by those participants, in the form of avoided capacity costs, adjusted for their performance.

OATT and Reliability Assurance Agreement (RAA) filings were made with FERC on December 7, 2018. Based on FERC's decision on the filing, participant peak-shaving plans could be used in the 2022/2023 Base Residual Auction conducted in August 2019.

Loss of Load Expectation (LOLE) – Peak Winter Generation

The severe winter weather in 2014 and 2015 resulted in a large amount of forced and planned generation outages. PJM and the Resource Adequacy Analysis Subcommittee completed an analysis to investigate whether the capacity model used in the Reserve Requirement Study accurately reflected historical forced and planned generation outage observations during the winter peak week.

The study concluded that forced and planned generation outages in the model understated the amount of generation unavailable during the peak week of the winter compared with historical outage levels. The model had previously assumed that forced outages were mutually independent and occurred in a random fashion, regardless of the time of the year, the amount of load, or weather conditions. When the model was corrected to be consistent with historical outages, the winter peak week LOLE was greater than the model had previously calculated.

Following stakeholder discussion and review, Manual 20 was revised in June 2018 to properly recognize the risk caused by the volume of concurrent outages historically observed during the winter peak week. The capacity outage probability distribution for the winter peak week in the Reserve Requirement Study is now created using historical forced outage data aggregated across the RTO. Also, for the winter peak week, the amount of planned generator outages is now based on the average historical planned outages aggregated across the RTO. As part of the Reserve Requirement Study process, the Planning Committee will annually review the data to determine the specific historical period to be used in the Reserve Requirement Study's winter peak capacity model.

1.3.2 — Looking Ahead

Electric Storage Participation

FERC issued an energy storage and distributed energy resources final ruling, FERC Order No. 841, February 2018. During 2018, PJM and its stakeholders worked to enhance PJM markets to further recognize and take advantage of the unique characteristics of energy storage resources. The key components FERC Order No. 841 include:

- Electric storage resources (ESRs) are eligible to provide energy, capacity and ancillary services which the resource is technically capable of providing
- ESRs can be dispatched and set price as a seller and a buyer
- Bid parameters account for ESR characteristics
- Minimum market threshold is 100 kW

An ESR is defined as a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid. PJM was already compliant on two of these components and proposed several enhancements for the other two. PJM submitted two filings on December 3, 2018 with a proposed implementation date of December 3, 2019.

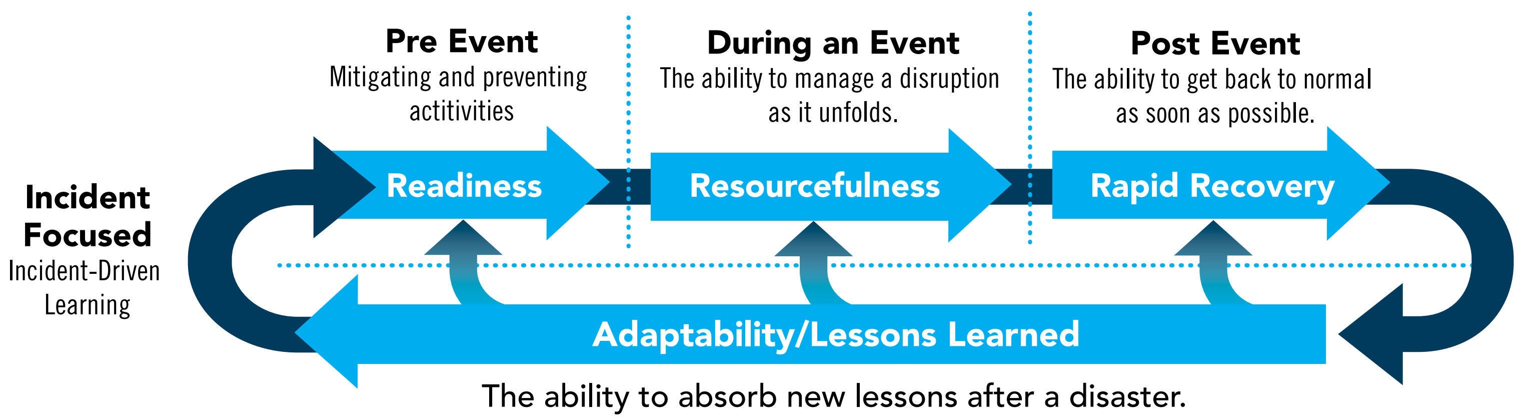
Resilience

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 1.14**:

- **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

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. From a transmission perspective, PJM has initiated efforts to implement RTEP process criteria and metrics to enhance grid resilience beyond that in place today by virtue of compliance with NERC Standards TPL-001-4, TPL-007-1 and CIP-014. PJM is working with its members to incorporate resilience into the transmission planning process. Current efforts have narrowed into the development of a new planning tool, using a "cascading trees" event analysis, which complements existing studies by simulating and testing system resilience.

Figure 1.14: Defining Resilience



PJM has a methodology to measure the resilience of the grid using the cascading tree methodology. The 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, quantify the loss of load and generation and to determine if the event is bounded, unbounded or unstable. Monte Carlo analysis is then performed to identify the repeat offenders or lines/substations that are impacted more frequently and reinforce those facilities. Beyond extreme events, PJM can use this methodology to compare competing projects to measure which one increases or decreases the probability of cascading or resilience.

PJM has adopted three approaches to integrating resilience into the Regional Transmission Expansion Plan (RTEP) and the RTEP decision-making process. The do no harm, opportunistic and a stand-alone resilience criteria are the three approaches.

Further development of the resilience process and how it fits into the RTEP process will continue into 2019 by way of PJM Planning Committee meetings.

Section 2: 2018 RTEP Highlights

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

2.0: 2018 RTEP Proposal Window No. 1

RTEP Process Context

PJM seeks transmission proposals during each RTEP window to address one or more identified needs – reliability, market efficiency, operational performance and public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to PJM for consideration. Once a window closes, PJM proceeds with specific company, analytical and constructability 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.

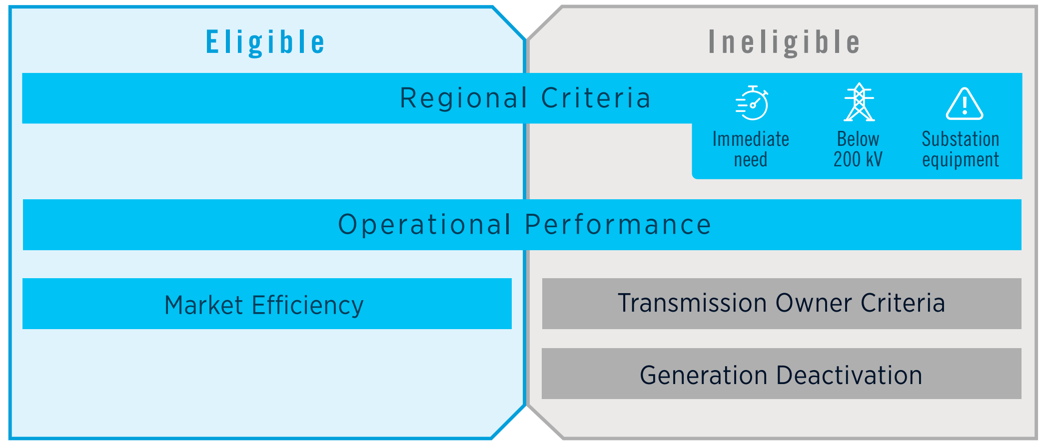
PJM's Manual 14 series addresses the rules governing the RTEP process. In particular, Manual 14F, describes PJM's competitive transmission process, including all aspects of analysis and evaluation pertaining to proposal windows. The manual provides one consistent source of business rules for stakeholders and PJM and is available on the PJM website: http://www.pjm.com/-/media/documents/manuals/m14f.ashx.

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 and designating projects to the incumbent Transmission Owner (TO), as described in the PJM Operating Agreement, Schedule 6 Section 1.5.8. These exclusions were developed with input from PJM stakeholders and have been approved by FERC:

- *Immediate Need Exclusion:* The required in-service date drives these projects, excluded from the competitive process to ensure they can be completed in advance of the required in-service date.
- *Below 200 kV:* Due to the high likelihood that the selected solution will be reserved for the local TO, solutions below 200 kV are excluded from the competitive process.
- *FERC Form No. 715 (TO criteria):* As the need for this project results solely from the individual TOs FERC form No. 715 reliability criteria, the designation is reserved for the incumbent.
- *Substation Equipment:* Due to identification of the limiting element(s) as substation equipment, these projects are reserved from the local Transmission Owner, and therefore excluded from competition.

Figure 2.1: Window Eligibility



Proposal Window No. 1 Analysis Results

PJM's analysis of summer 2023 identified 159 thermal and voltage criteria violations. All but three of these violations were excluded from the competitive planning process on the basis of the above criteria. These violations are shown in **Table 2.1** and on **Map 2.1**.

The three flowgates that were included in Proposal Window No. 1 are shown in **Map 2.2**. One is located in the West region and two are in the South region.

These violations include:

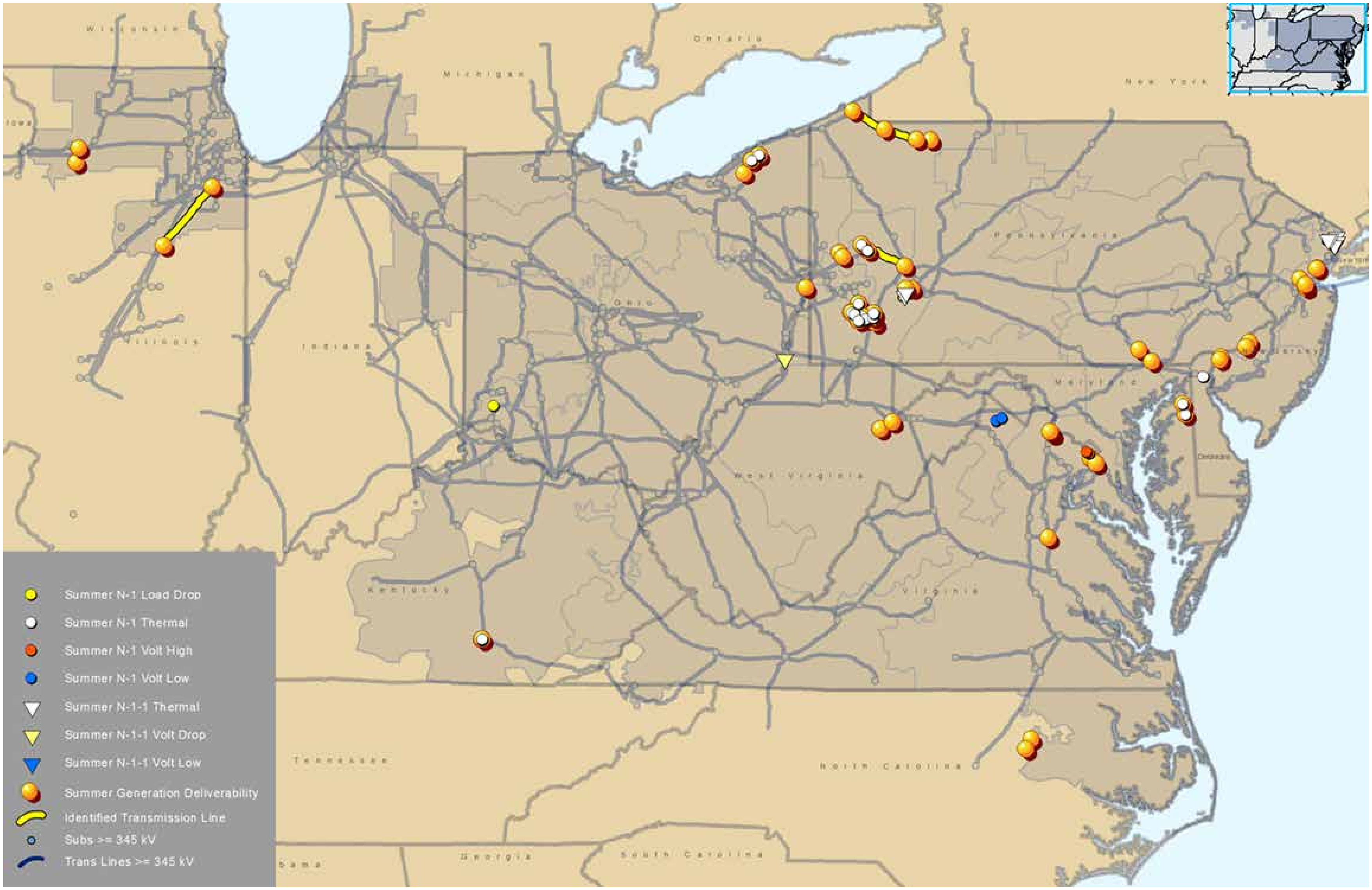
- N-1 high voltage at:
  - Randor Heights 230 kV
  - Davis 230 kV

- N-1 load drop at Port Union 138 kV

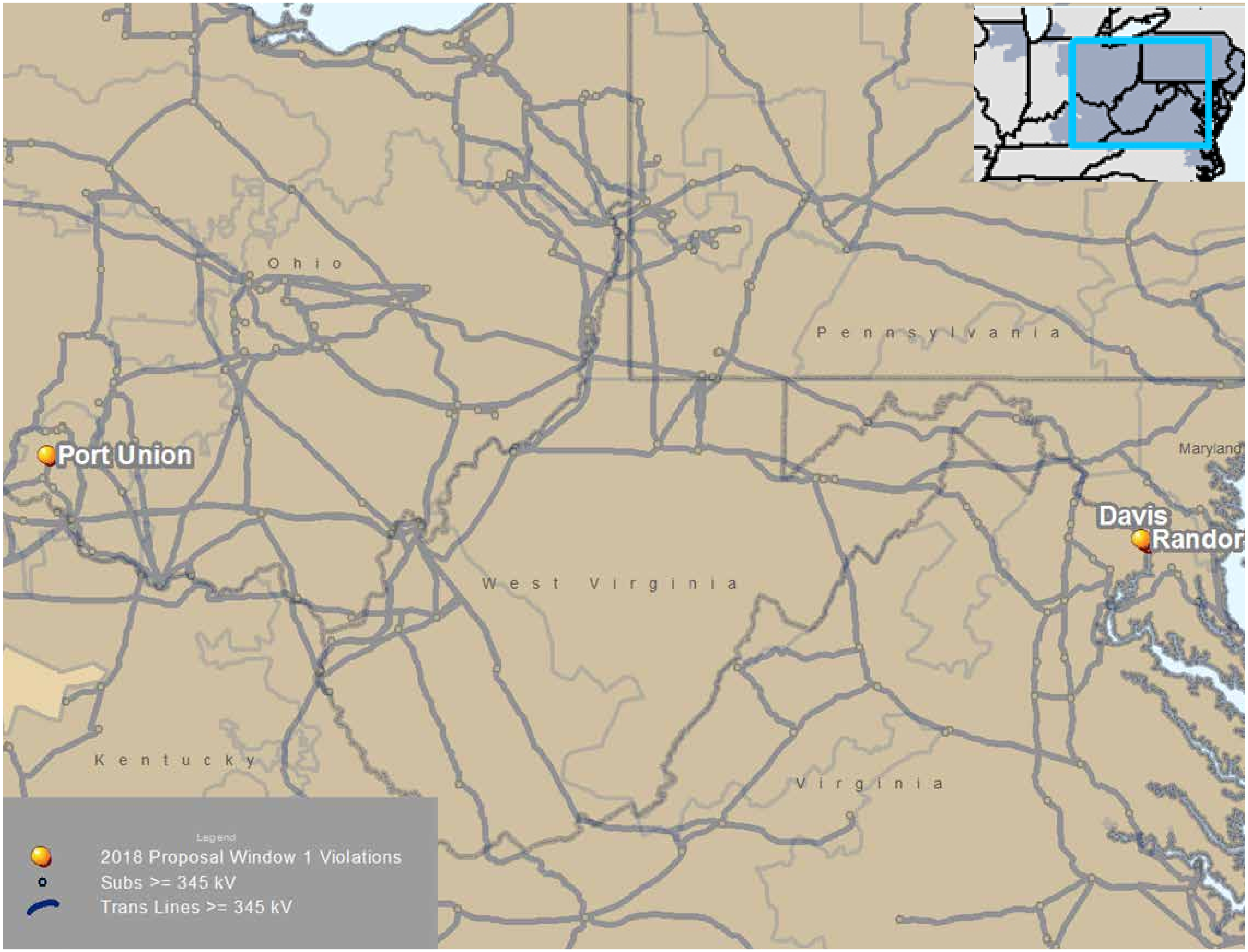
Table 2.1: 2018 RTEP Proposal Window No. 1 Thermal and Voltage Criteria Violations

	Exclusion Criteria							
TO Zones	**Accepting Proposals**	**Below 200 kV**	**Station Equipment**	**TO Criteria**	**Immediate Need**	**Non-Violation**	**Generator Deactivation**	**No. of Flowgates**
AE	0	0	1	0	0	0	0	1
AEP	0	18	1	0	0	5	0	24
AP	0	0	0	0	74	0	72	74
AP/AEP	0	0	0	0	1	0	0	1
AP/ATSI	0	0	0	0	0	3	0	3
AP/DLCO	0	0	0	0	17	0	15	17
ATSI	0	2	2	0	4	8	2	16
CE	0	0	0	0	2	1	0	3
DEO&K	1	0	0	0	0	0	0	1
DPL	0	4	0	0	0	2	0	6
JCP&L	0	0	0	0	0	1	0	1
PENELEC	0	2	0	0	10	1	10	13
PEPCO	0	0	0	0	0	2	0	2
PJM	0	0	0	0	2	0	1	2
PJM/AP	0	0	0	0	2	0	2	2
PSE&G	0	0	0	0	11	9	0	20
OVEC	0	0	0	0	0	1	0	1
DOM	2	0	0	0	2	0	0	4
PENELEC/AP	0	0	0	0	1	0	1	1
JCP&L/PSE&G	0	0	0	0	0	4	0	4
CPLE/DOM	0	0	0	0	0	1	0	1
DOM/CPLE	0	0	0	0	0	1	0	1
LGEE/EKPC	0	0	0	0	0	4	0	4
Grand Total	**3**	**26**	**4**	**0**	**126**	**43**	**103**	**202**

Map 2.1: 2018 RTEP Proposal Window No. 1 Thermal and Voltage Criteria Violations



Map 2.2: Summer 2023 Proposal Window No.1 Violations



Proposal Window No. 1 Proposals

Proposal Window No. 1 opened on July 2, 2018 and closed on August 31, 2018. PJM received seven proposals from two entities addressing the two target zones. All proposals were TO upgrades. These proposals are shown in **Table 2.2**.

Table 2.2: 2018 RTEP Proposal Window No. 1 Proposals Received

Project ID	Upgrade/ Greenfield	Proposing Entity	Project Cost ($M)	Target Zone(s)	kV Level(s)	Analysis Type	Major Components/Project Description
1A	Upgrade	DEO&K	$0.377	DEO&K	138 kV	Summer N-1 Load Drop	Add redundant relaying to Port Union 138 kV bus 2 to eliminate the contingency driving the reliablility criteria violation.
2A	Upgrade	Dominion	$0.0	Dominion	69 kV	Summer N-1 High Voltage	This is an operational solution that will remotely open Pentagon Transformer No.1 breaker L122, immediately following the breaker-failure event (2036T2142) at Randor Substation, thus resolving the post contingency high voltage.
2B	Upgrade	Dominion	$0.481	Dominion	230/69 kV	Summer N-1 High Voltage	Move the existing 230/69 kV Transformer No. 4 to the vacant 230/69 kV Transformer No. 2 spot at Pentagon Substation.
2C	Upgrade	Dominion	$0.537	Dominion	230/69 kV	Summer N-1 High Voltage	Move spare 230/69 kV transformer from Jefferson Street Substation to the vacant Transformer No. 2 bay at Pentagon Substation.
2D	Upgrade	Dominion	$13.493	Dominion	230 kV	Summer N-1 High Voltage	Construct a 230 kV four breaker GIS ring bus in Pentagon Substation and terminate existing Lines No. 2037 and No. 2121.
2E	Upgrade	Dominion	$3.161	Dominion	69 kV	Summer N-1 High Voltage	Install a 50 MVAR fixed shunt reactor at Pentagon Substation on the 69 kV bus.
2F	Upgrade	Dominion	$12.732	Dominion	230 kV	Summer N-1 High Voltage	Construct a new substation called Cloverleaf with a 230 kV variable shunt reactor with a new 230 kV underground line roughly 300 feet extending from Cloverleaf Substation to Pentagon substation terminating at the 230 kV bus.

NOTE:

On February 11, 2019, the PJM Board approved project b3055 (2018_1-2C).

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

2.1: Generator Deactivations

PJM received 63 deactivation notices totaling 12,279 MW during 2018. **Map 2.3** and **Table 2.3** show the 20 generators being deactivated with a capacity greater than or equal to 100 MW. The remaining 43 generators had a combined capacity of 1,235 MW. Deactivation notifications in 2018 included four nuclear unit deactivations in ATSI and DLCO for a total of 3,954 MW. Additional 11 coal unit deactivations accounted for 4,684 MW.

PJM completed the required analysis to identify reliability criteria violations caused by these deactivations. New baseline upgrades were required for several deactivations. Other violations were resolved with existing baseline transmission enhancements or had no reliability impacts identified. All units studied in 2018 can retire as requested. Operational flexibility will allow PJM to bridge any delays with the completion of required transmission enhancements.

Map 2.3: Deactivations Greater than or equal to 100 MW

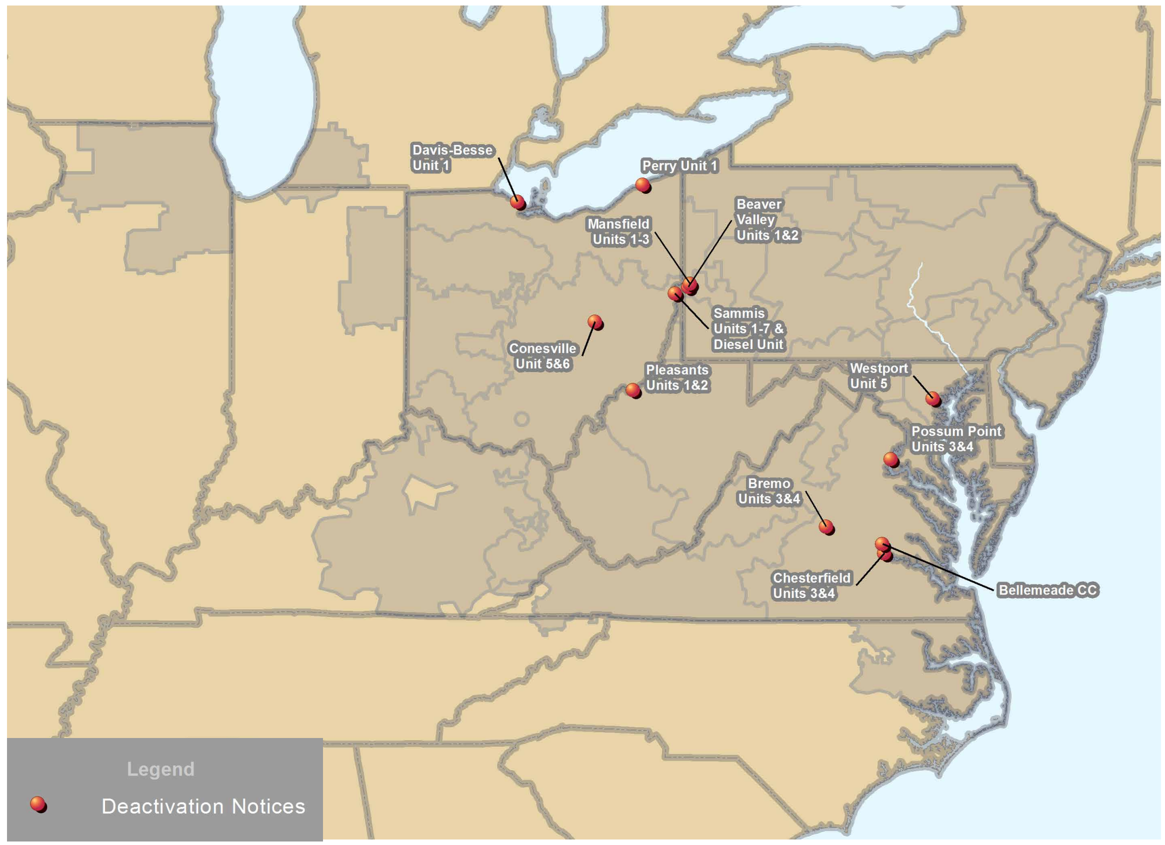


Table 2.3: PJM Generator Deactivations Greater than or equal to 100 MW Received January 1, 2018 through December 31, 2018

Unit	Capacity (MW)	Transmission Zone	Age (Years)	Request Submittal Date	Requested Deactivation Date	Projected/Actual Deactivation Date
Westport 5	116.0	BGE	49	11/30/2018	6/1/2020	6/1/2020
Conesville 6	405.0	AEP	40	11/14/2018	6/1/2019	6/1/2019
Conesville 5	405.0	AEP	42	11/14/2018	6/1/2019	6/1/2019
Mansfield 3	830.0	ATSI	38	8/29/2018	6/1/2021	6/1/2021
Mansfield 2	830.0	ATSI	41	8/29/2018	6/1/2021	2/5/2019
Mansfield 1	830.0	ATSI	42	8/29/2018	6/1/2021	2/5/2019
Sammis 7	600.0	ATSI	47	8/29/2018	6/1/2022	6/1/2022
Sammis 6	600.0	ATSI	49	8/29/2018	6/1/2022	6/1/2022
Sammis 5	291.3	ATSI	51	8/29/2018	6/1/2022	6/1/2022
Beaver Valley U2 Nuclear Generating Unit	902.0	DLCO	31	3/28/2018	10/31/2021	10/31/2021
Beaver Valley U1 Nuclear Generating Unit	909.0	DLCO	42	3/28/2018	5/31/2021	5/31/2021
Perry U1 Nuclear Generating Unit	1,247.0	ATSI	31	3/28/2018	5/31/2021	5/31/2021
Davis Besse U1 Nuclear Generating Unit	896.0	ATSI	41	3/28/2018	5/31/2020	5/31/2020
Pleasants Power Station U2	639.0	APS	38	2/16/2018	1/1/2019	6/1/2022
Pleasants Power Station U1	639.0	APS	38	2/16/2018	1/1/2019	6/1/2022
Possum Point 4	221.0	Dominion	56	1/16/2018	12/1/2018	12/13/2018
Chesterfield 4	162.1	Dominion	58	1/16/2018	12/1/2018	12/13/2018
Chesterfield 3	100.0	Dominion	66	1/16/2018	12/1/2018	12/13/2018
Bremo 4	156.0	Dominion	60	1/16/2018	4/16/2018	4/16/2018
Bellemeade	265.7	Dominion	21	1/16/2018	4/16/2018	4/16/2018

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2.2: Transmission Owner Criteria

The PJM Operating Agreement specifies that individual transmission owner (TO) planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions, such as in urban areas. TOs are required to include their individual criteria as part of their respective FERC Form No. 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 of each that are included in the PJM Open Access Transmission Tariff 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 2.1**. Under the terms of the OATT, the costs of such projects are allocated 100 percent to the TO zone.

2.2.1 — Aging Infrastructure

In recent years, reviews of existing infrastructure have identified the need for replacement of 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 No. 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.

Each TOs planning criteria is provided on the PJM website. Dominion and PSE&G have specific criteria to address end-of-life and storm hardening, respectively, as described in **Section 2.2.2** and **Section 2.2.4**.

Table 2.4: Transmission Owner Criteria Projects with a Cost Greater than $10 Million

Upgrade ID	Description	TO Zone	Estimated Cost ($M)	Required In-service Date	Projected In-service Date
b2982	Construct new Hillsdale 230/69 kV Substation	PSE&G	$115	June 2018	June 21
b2983	Convert Kuller Road Substation to a 69/13 kV Station	PSE&G	$98	June 2018	December 21
b2838	Build a new 230/69 kV substation by tapping the Montour-Susquehanna 230 kV double circuits and Berwick-Hunlock & Berwick-Colombia 69 kV circuits	PPL	$57	June 2017	December 21
b2986	Replace Roseland-Branchburg-Pleasant Valley 230 kV corridor	PSE&G	$546	June 2021	June 21
b3003	Construct a new 230/69 kV station at Maywood	PSE&G	$87	June 2018	March 22
b3004	Construct a 230/69/13 kV station by tapping the Mercer-Kuser Rd. 230 kV line	PSE&G	$62	June 2018	June 23
b3025	Construct two new 69/13kV stations in the Doremus area and relocate the Doremus load to the new stations	PSE&G	$155	June 2018	December 22
b3029	Install 69 kV underground transmission line from Harings Corner Station terminating at Closter Station (about three miles).	RECO	$22	May 2020	May 20
b3040	Rebuild Ripley-Ravenswood-Racine Tap 69 kV line	AEP	$68	June 2022	June 21

2.2.2 — Transmission Owner FERC No. 715 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 No. 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. 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 2.4**, **Map 2.4**, **Map 2.5**, **Map 2.6** and **Map 2.7.** These provide the description and location of projects with a cost greater than $10 million. More detailed descriptions of these projects can be found in the TEAC PJM Board White Paper on the PJM website.

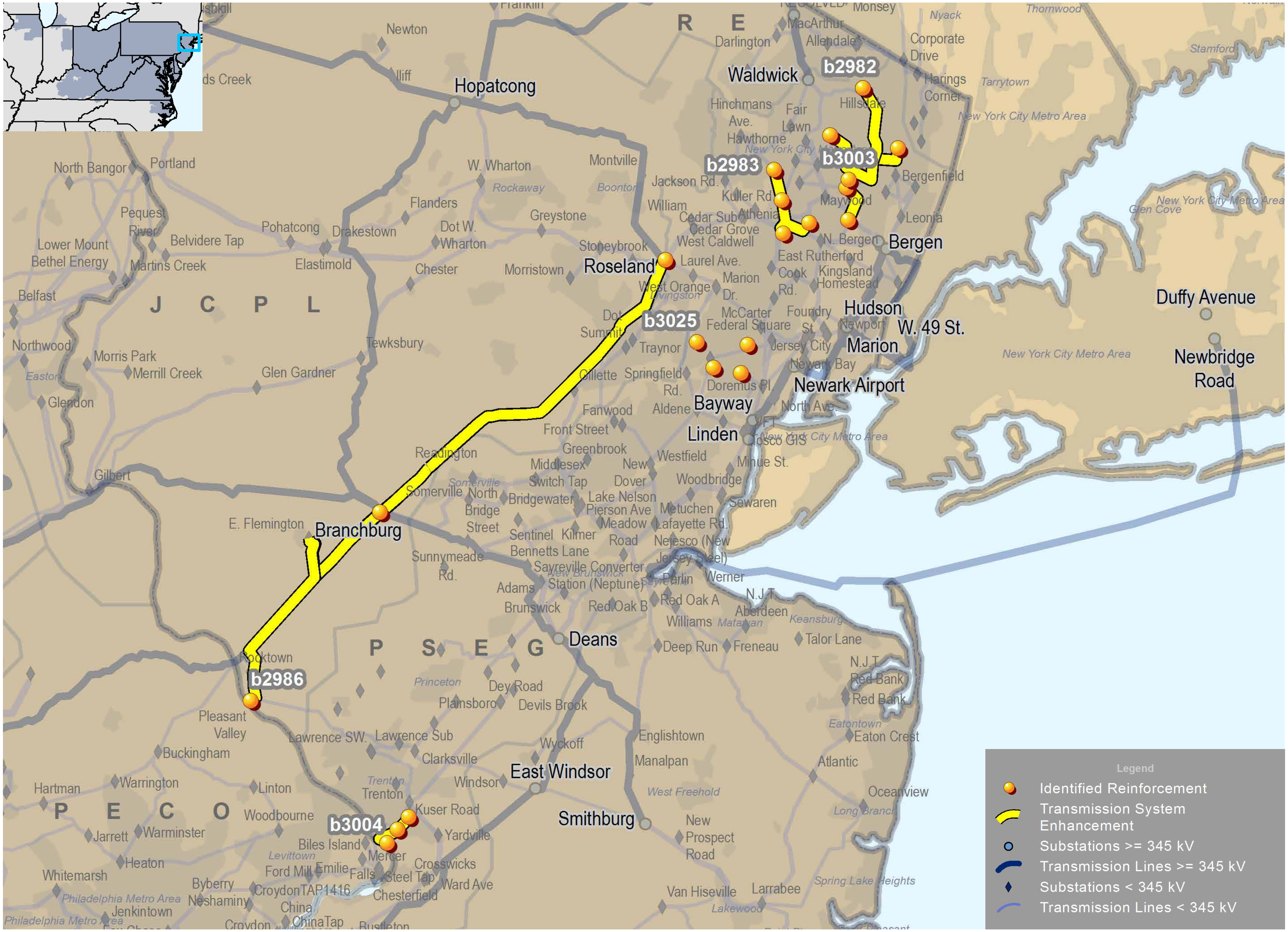
In situations where the TO is not able to complete construction by the required in-service date, PJM works to establish operating procedures to ensure that the system remains reliable until the reinforcement is in service.

2.2.3 — Storm Hardening in PSE&G

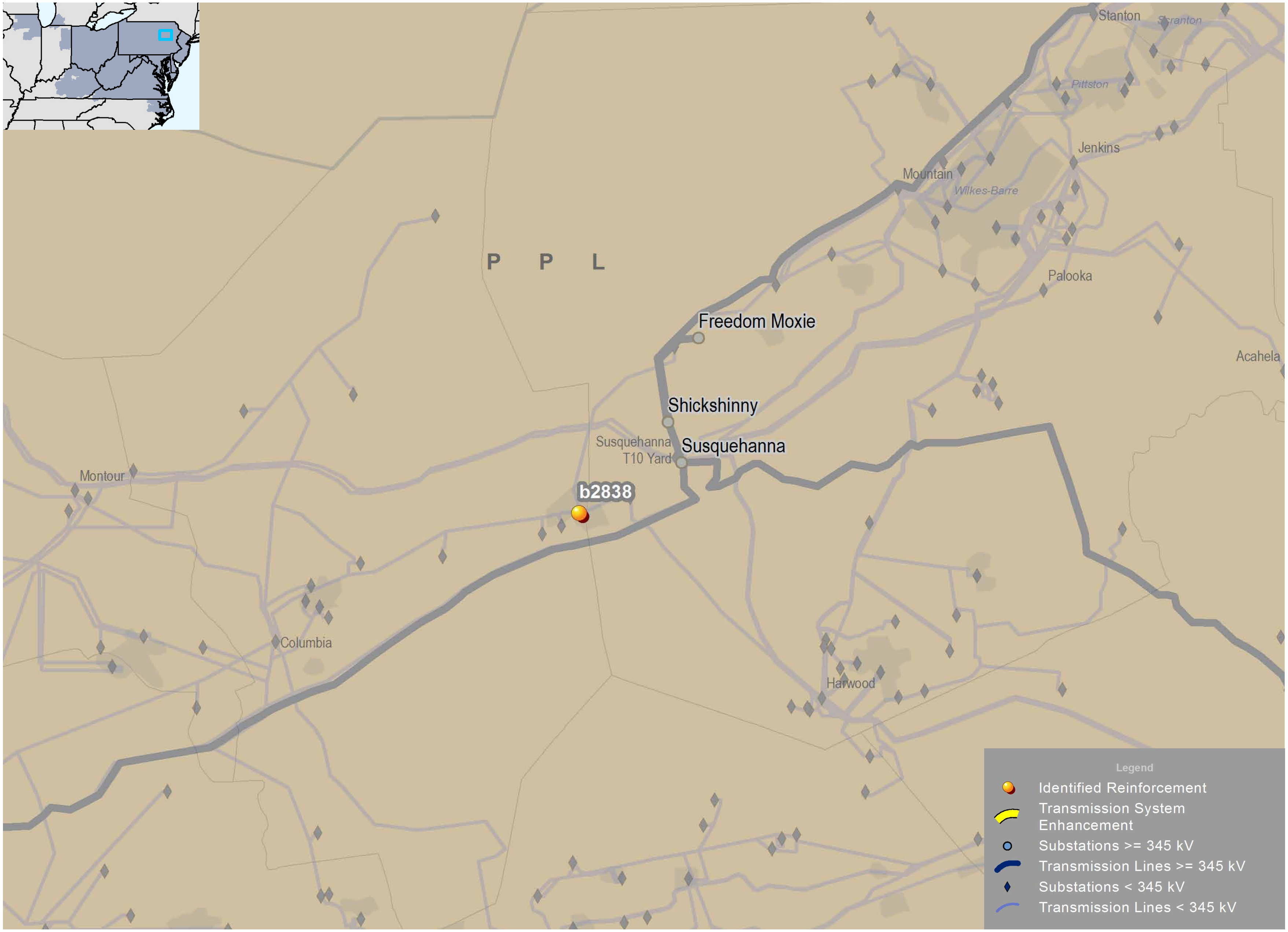
PSE&G's TO criteria includes requirements to perform equipment assessment and storm hardening. In order to maintain system integrity and reliability, condition assessment of switching and substation assets is periodically reviewed. The condition assessment includes physical condition, age, electrical parameters, the past history of the asset as well as performance of similar equipment in a peer group.

Based on equipment performance, condition assessment and system needs, recommendations will be made to maintain or replace facilities either in kind or with alternative designs. Additional analysis will evaluate operational performance meeting future needs right-of-way market efficiency impacts, radial load cascading, and excessive use of system reliability margins. Storm hardening projects in PSE&G are included in **Table 2.4** and shown on **Map 2.4**.

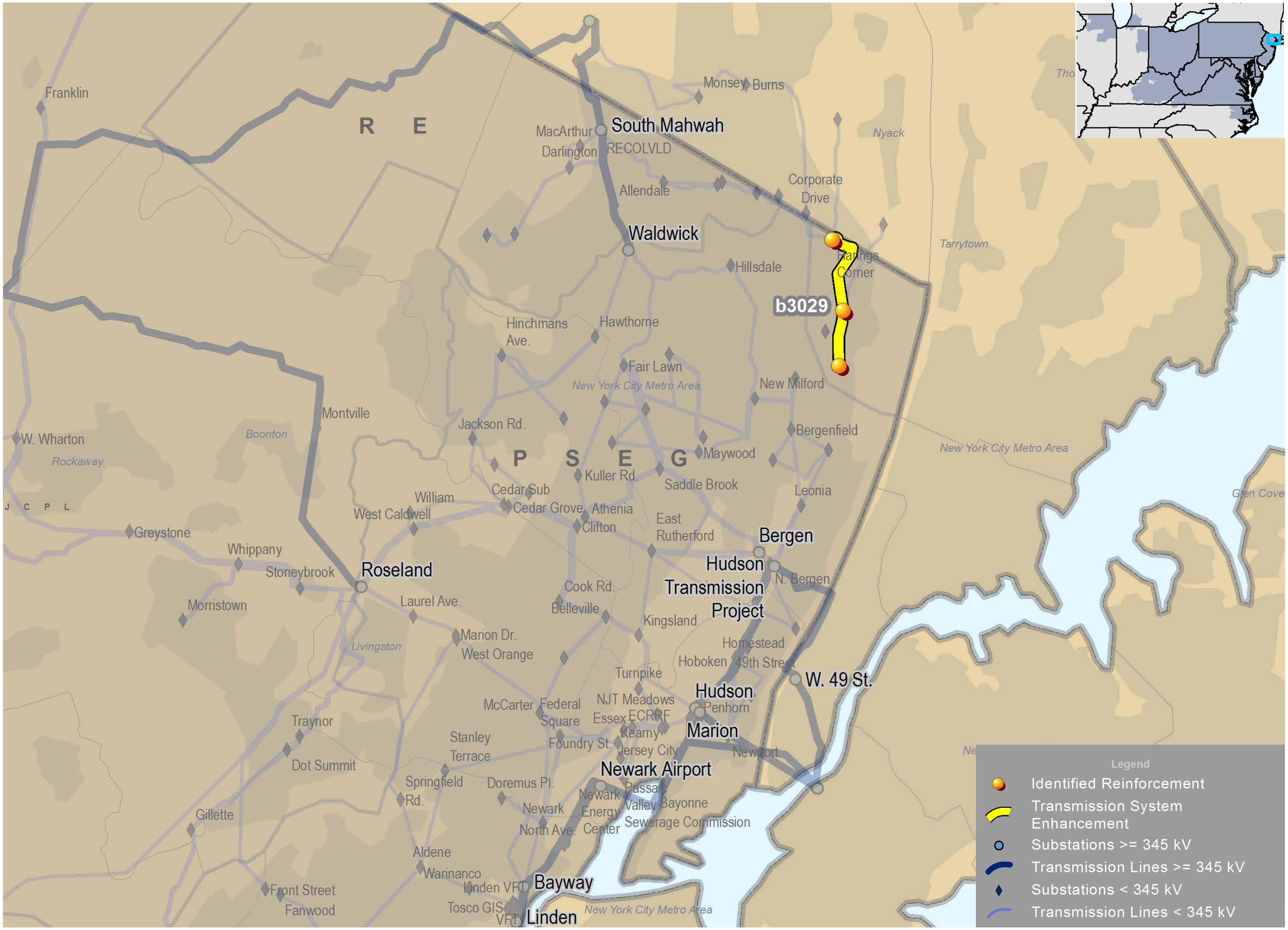
Map 2.4: Transmission Owner Criteria Projects in PSE&G with a Cost Greater than $10 Million



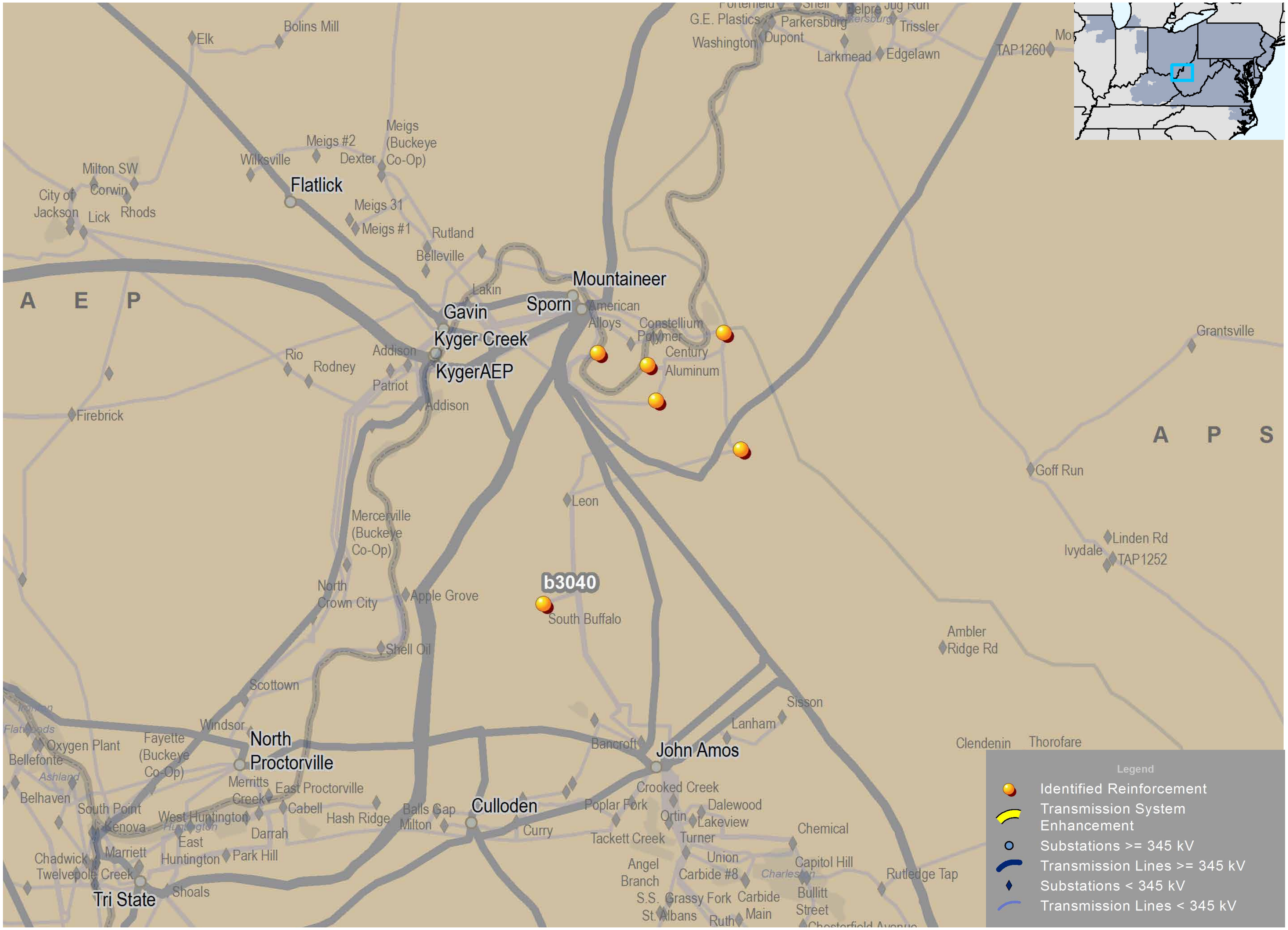
Map 2.5: Transmission Owner Criteria Project in PPL with a Cost Greater than $10 Million



Map 2.6: Transmission Owner Criteria Project in RECO with a Cost Greater than $10 Million



Map 2.7: Transmission Owner Criteria Project in AEP with a Cost Greater than $10 Million



2.2.4 — Dominion End-of-Life Criteria

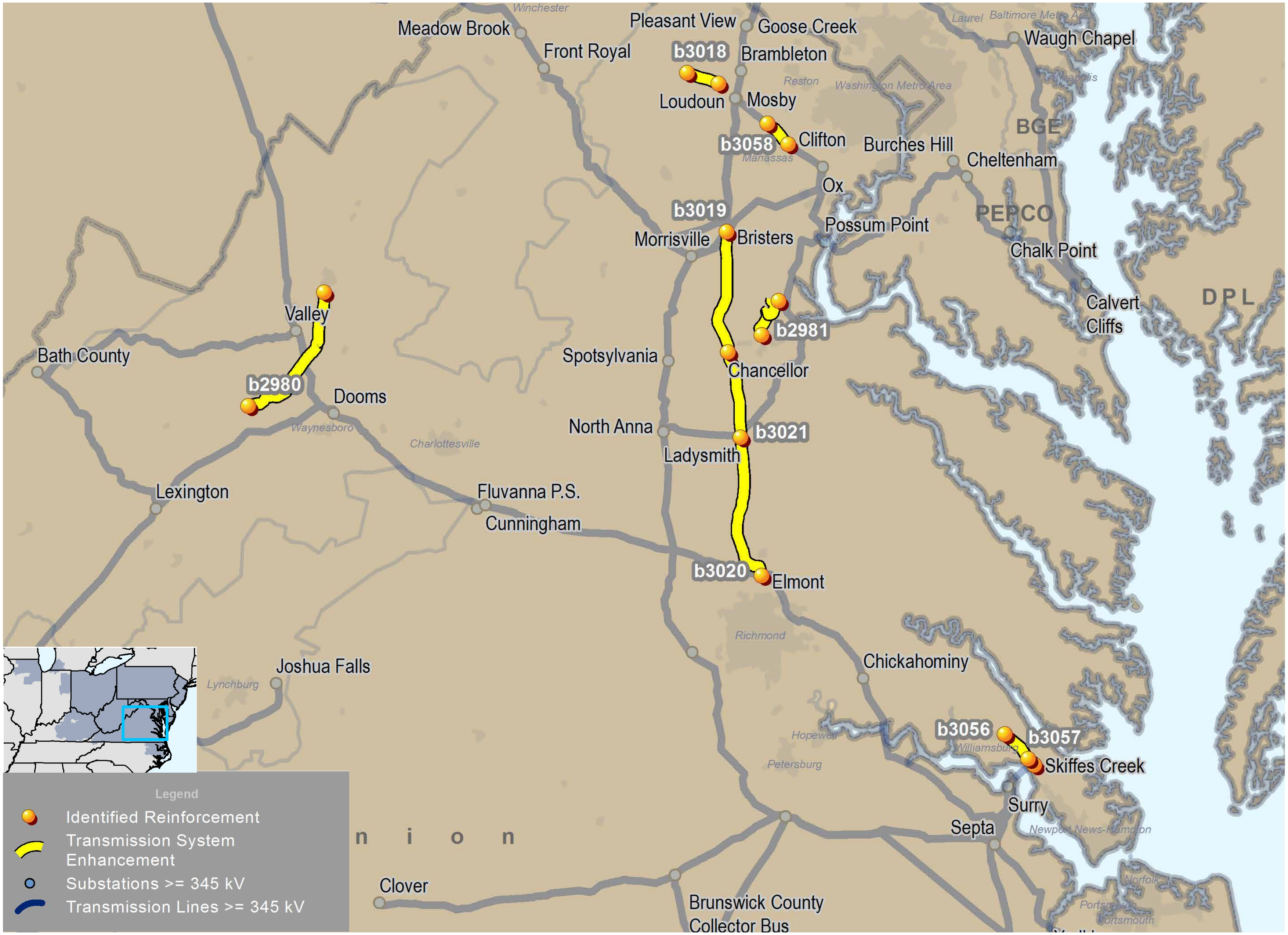
Several facilities in the Dominion transmission zone have been identified as violating their FERC Form No. 715 filed end-of-life criteria. In accordance with Section C.2.9 of Dominion's transmission planning criteria, age, condition and tower weakening were all identified as issues with a number of facilities. **Table 2.5** and **Map 2.8** describe and show the location of those facilities with a cost greater than or equal to $10 million.

More detailed descriptions of these projects can be found in the TEAC section of the PJM website: https://pjm.com/committees-and-groups/committees/teac.aspx.

Table 2.5: Dominion End-of-Life Criteria Projects Greater than $10 Million

Upgrade ID	Description	TO Zone	Estimated Cost ($M)	Required In-Service Date
b2980	Rebuild Staunton-Harrisonburg 115 kV	DOM	$37.5	October 2022
b3019	Rebuild Bristers-Chancellor 500 kV line	DOM	$64.6	Immediate
b3020	Rebuild Ladysmith-Elmont 500 kV line	DOM	$87.0	Immediate
b3021	Rebuild Ladysmith-Chancellor 500 kV line	DOM	$45.6	Immediate
b3057	Rebuild Waller-Skiffes Creek 230 kV lines	DOM	$10.0	December 2024
b2981	Rebuild Fredericksburg-Aquia Harbor 115 kV line	DOM	$12.5	December 2022
b3058	Partially rebuild three 230 kV lines between Cilfton and Johnson	DOM	$11.5	Immediate
b3018	Rebuild Middleburg-New Rd. 115 kV line	DOM	$13.8	December 2021

Map 2.8: Dominion End-of-Life Criteria Projects Greater than $10 Million



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2.3: Supplemental Projects

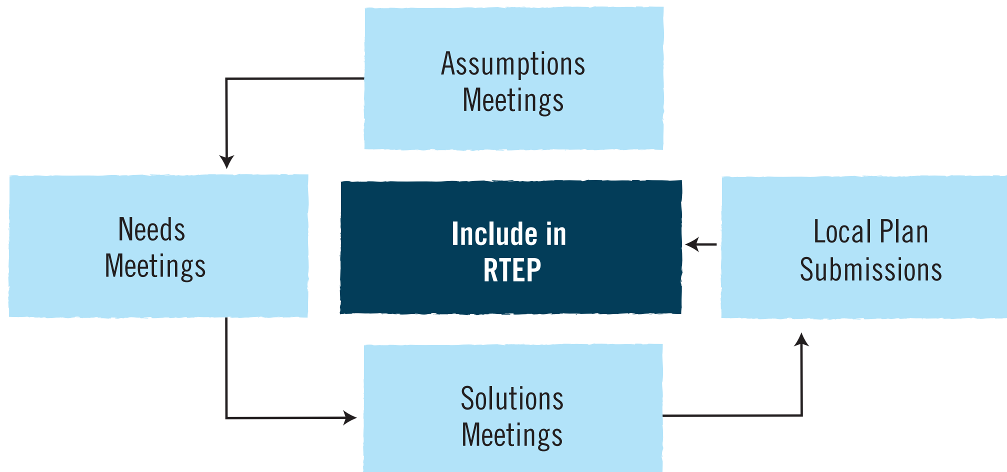
Supplemental projects, known at one time as Transmission Owner initiated projects, are not required for compliance with system reliability, operational performance or market efficiency economic criteria, as determined by PJM. PJM reviews these projects to ensure they do not introduce other reliability criteria violations. While not subject to PJM Board approval, they are included in PJM's RTEP models.

Such projects could include those that address:

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

Supplemental projects are introduced to the PJM regional planning process through PJM's TEAC and subregional RTEP committees. FERC issued a show cause order in 2017 and an order in February 2018 accepting, in part, and requiring tariff revisions associated with their requirement that the process for planning Supplemental Projects must be just, reasonable and not unduly discriminatory or preferential.

Figure 2.2: Attachment M3 Process for Supplemental Projects



Attachment M3 to the PJM Tariff was approved by FERC in September 2018, and provides additional details of the process that PJM and the PJM TOs will follow in connection with planning supplemental projects. The Attachment M3 process was integrated into planning, and analysis began in September of 2018.

The subregional RTEP committees have a meaningful opportunity to participate and provide feedback, including written comments, throughout the transmission planning process for supplemental projects. As shown **Figure 2.2**, his includes meetings to:

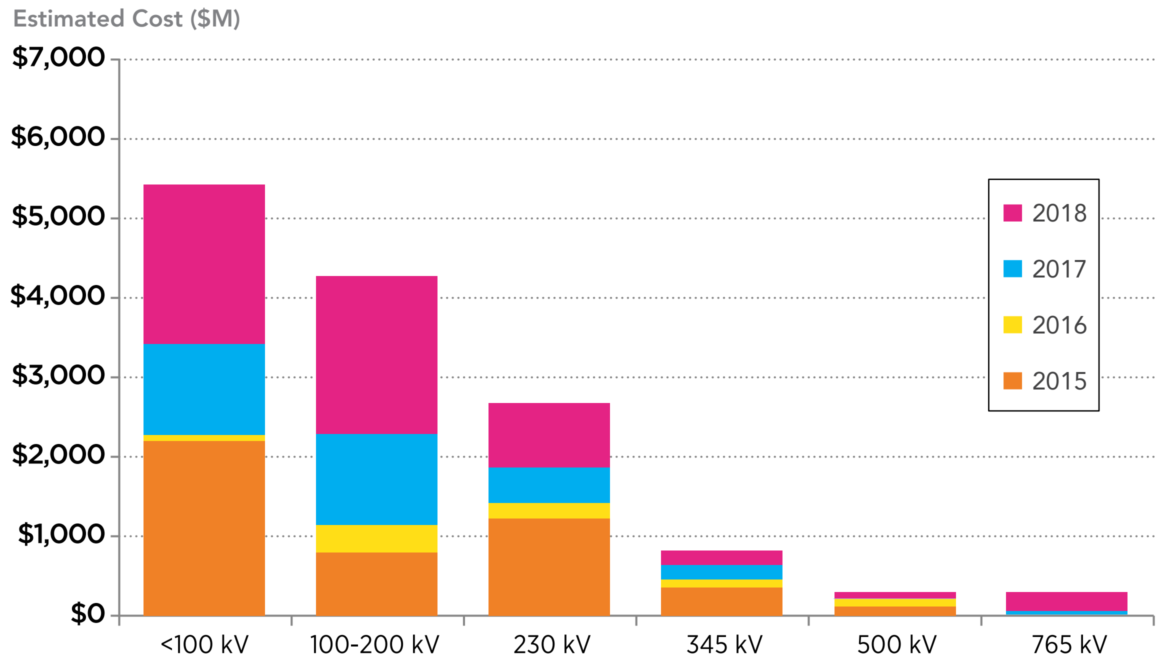
- Review the criteria, assumptions and models that TOs propose to use to plan and identify supplemental projects
- Review the identified criteria violations or system needs that may drive the need for a supplemental project
- Review potential solutions for the identified criteria violations

Provide comments on the supplemental projects in accordance with Section 1.3 of Schedule 6 of the PJM Operating Agreement before the local plan is integrated into the RTEP.

2018 Supplemental Projects

PJM Evaluated approximately $6 Billion of Transmission Owner supplemental projects in 2018. **Figure 2.3** and **Figure 2.4** show a breakdown of these projects organized by driver and voltage level respectively.

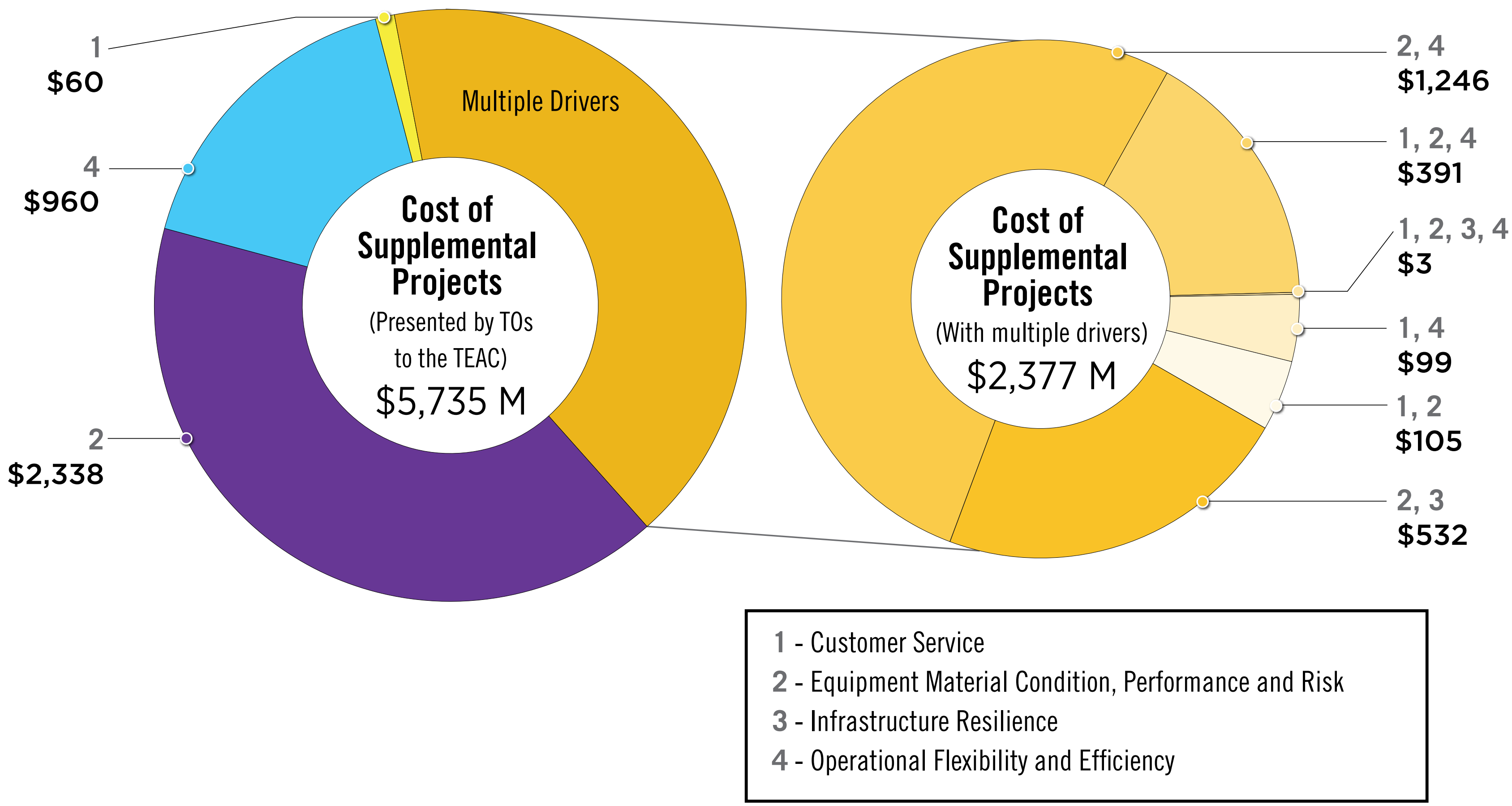
Figure 2.3: Supplemental Projects by Voltage 2015-2018



NOTE:

PJM expects to publish a "Value of Transmission" Whitepaper, expanding on this supplemental discussion in the first half of 2019.

Figure 2.4: 2018 Supplemental Projects by Driver



2.4: Re-Evaluations

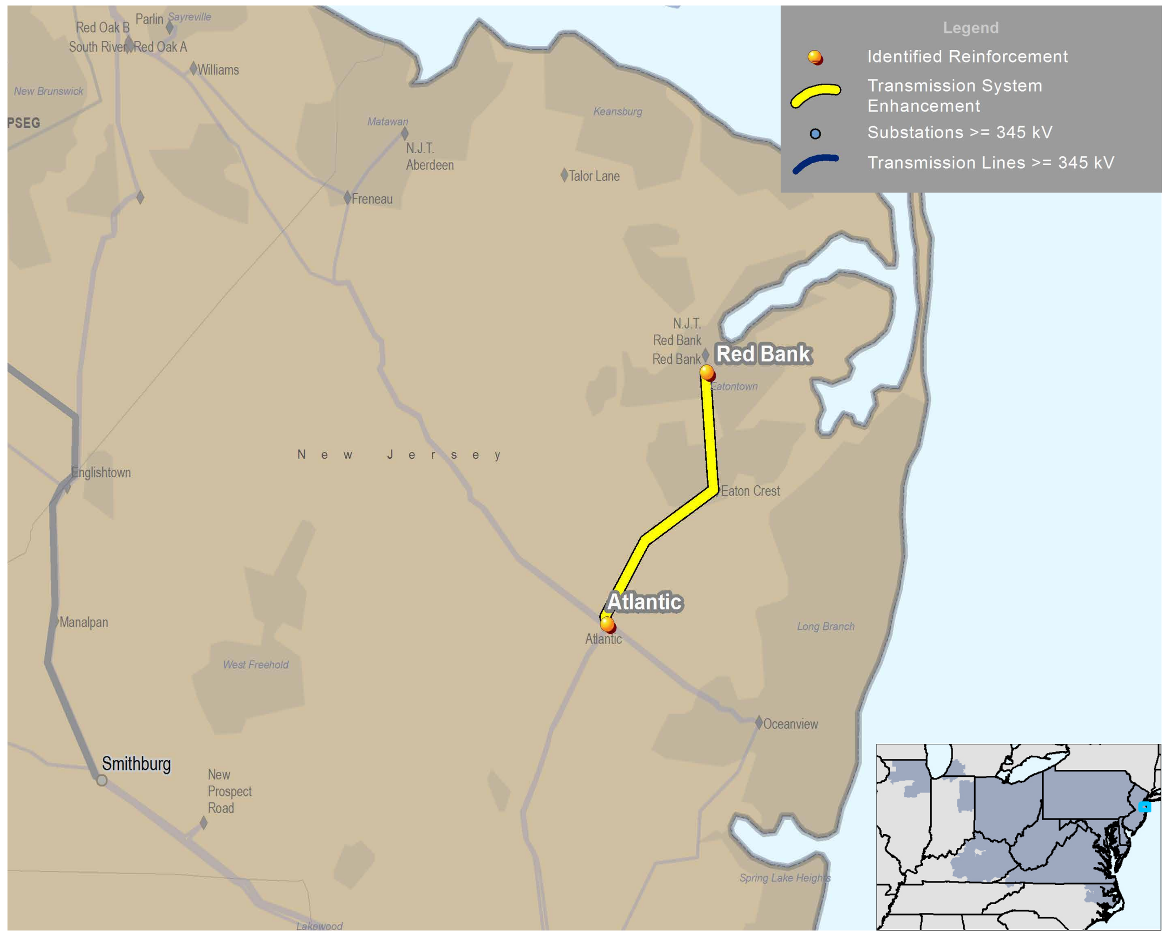
2.4.1 — JCP&L Transmission Zone

The 2011 RTEP identified FirstEnergy planning criteria violations in the Red Bank area of JCP&L's service territory, shown in **Map 2.9**. There was a potential voltage collapse on the 34.5 kV system for the loss of two Atlantic-Red Bank 230 kV circuits. At that time, the proposed solution was to build a third 230 kV circuit into the Red Bank 230 kV substation project b1690.

During 2018, PJM and FirstEnergy performed a retool analysis without the b1690 project, in light of recent regulatory proceedings, denying the siting of the project. This analysis again identified the following violations for which an immediate need solution is now required.

- Severe voltage drop violation on the Red Bank bus for the towerline outage loss of Atlantic-Red Bank 230 kV circuits
- Severe voltage drop violation on the Red Bank bus for N-1-1 contingency loss of Atlantic-Red Bank 230 kV circuits
- Several JCP&L 34.5 kV lines severely overloaded for the towerline outage loss of of Atlantic-Red Bank 230 kV circuits requiring dynamic cascade analysis

Map 2.9: Criteria Violations in Red Bank Area of JCP&L Transmission Zone



- Dynamic analysis resulted in tripping a significant number of 34.5 kV lines and loss of more than 520 MW of load due to voltage collapse

2.4.2 — AP-South Interface

The Transource Independence Energy Connection project is a market efficiency project that would establish two new 230 kV transmission lines across the Pennsylvania-Maryland border.

PJM performed a re-evaluation of the Transource project in September 2018 and a ratio update in October 2018. These analyses continued to find that the project would provide benefits that extend across a wide area, including areas of Pennsylvania and Maryland, as discussed in more detail in the Transource Independence Energy Connection Market Efficiency Project White Paper available on the PJM website.

NOTE:

At the February 7, 2019 TEAC meeting, PJM announced the cancelation of the b1690 project based on recent proceedings in the state of New Jersey. PJM and FirstEnergy are continuing to work with stakeholders as evaluations of alternate solutions are expected to continue throughout 2019.

Section 3: Market Efficiency Analysis

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3.0: 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
- Review the 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 enhancements by conducting production cost simulations. These simulations show the extent to which congestion is mitigated by a transmission enhancement 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:

- PJM Manual 14B, Section 2.6: http://www.pjm.com/~/media/documents/manuals/m14b.ashx
- PJM Operating Agreement, Schedule 6, Section 1.5.7: https://www.pjm.com/library/governing-documents.aspx

To conduct a market efficiency analysis, PJM uses a market simulation tool to model hourly security-constrained generation commitment and economic dispatch. Several base cases are developed. The primary difference among cases is the simulation data corresponding 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 a required in-service date of June 1 of the five-year-out study year.
- Project analysis includes the topology for the specific transmission enhancement under study.

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

- Collectively value the approved RTEP portfolio of enhancements
- Evaluate RTEP enhancement acceleration or modification for potential economic benefit
- Evaluate if specific proposed transmission enhancements are economically beneficial

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

24-Month Cycle

The 24-month market efficiency timeline is shown in **Figure 3.1**. The 2018 market efficiency body of analysis is represented in the first year of the 24-month cycle. The 2018 analysis focused on:

- Creation and validation of base case models and results
- Reviewing previously approved economic transmission enhancements
- Performing analyses to consider benefits of accelerating reliability-based enhancements that are included in the RTEP but not yet built
- Identifying the congestion drivers associated with the 2018/2019 long-term window

Near-Term Simulations: 2019 and 2023 Study Years

PJM uses near-term simulations to assess the individual and collective economic impact of RTEP enhancements not yet in service. PJM quantifies the transmission congestion reduction due to recently planned RTEP enhancements by comparing the simulation differences between the “as-is” base case and the “as-planned” base case for the 2019 and 2023 study years. Simulation comparisons help PJM to:

- Quantify the transmission congestion reduction due to the collection of recently planned RTEP enhancements
- Reveal if specific already-planned transmission enhancements may eliminate or relieve congestion so that the constraint is no longer an economic concern

Figure 3.1: Market Efficiency 24-Month Cycle

- Identify if a reliability-based enhancement may provide economic benefits that would make it a candidate for acceleration or modification

For example, if a constraint causes significant congestion in the 2019 “as-is” simulation but not in the 2023 “as-planned” simulation, then a reliability-based enhancement that eliminates this congestion in 2023 may be a candidate for acceleration. The acceleration cost is considered against the benefit of accelerating a reliability-based enhancement before any recommendation is made to the PJM Board.

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

In order to quantify future longer-range transmission system market efficiency needs, PJM developed a simulation database for study years 2019, 2023, 2026 and 2029. System modeling characteristics included in this database are broadly described in **Section 3.2**.

The proposed market efficiency transmission enhancements for the 2018/2019 long-term proposal window are described in **Section 3.5.** Initially they will be evaluated using the simulation data developed during the first nine months of 2018. However, during the 2019 evaluation phase of the proposed transmission enhancements, PJM will develop a 2019 mid-cycle update of the simulation database that will incorporate significant RTEP changes approved through the 2018 RTEP cycle. This mid-cycle update simulation will include potentially significant forecast changes in topology, generation, load and fuel costs. The purpose of the 2019 mid-cycle update is to ensure that proposed transmission enhancements are evaluated using the best available forecast of future conditions.

Benefit/Cost Threshold Test

PJM calculates a benefit/cost ratio to determine if there is a market efficiency justification for a particular transmission enhancement. The benefit/cost ratio is calculated by comparing the net present value of annual benefits for the first 15 years of the project's life to the net present value of the project's revenue requirement for the same 15-year period. Market efficiency proposed transmission enhancements that meet or exceed a 1.25 benefit/cost ratio are further assessed to examine their economic, system reliability and constructability impacts. PJM's Operating Agreement requires that proposed transmission enhancements with a total cost exceeding $50 million undergo an independent third-party cost review. This is intended to ensure consistent estimating practices and project-scope development.

For the majority of proposed transmission enhancements, PJM determines market efficiency benefits based on Energy Market simulations. Proposed transmission enhancements that may impact PJM reliability pricing model (capacity market) auction activities may derive additional economic benefits as determined through capacity market simulations.

PJM's market efficiency study process and benefit/cost ratio methodology are detailed in Manual 14B, Section 2, PJM Region Transmission Planning Process, which is available on the PJM website: http://pjm.com/~/media/documents/manuals/m14b.ashx.

Energy Benefit – Regional Facilities

The 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 transmission enhancement

The change in system production cost is the change in system generation variable costs (i.e., 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 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 the net load payments. Zones for which the net load payments increase because of the proposed transmission enhancement are excluded from the net load energy payment benefit.

Energy Benefit – Lower Voltage Facilities

The 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 transmission enhancement. The change in net load energy payment is the change in gross load payment offset by the change in transmission rights credits. The net load payment benefit is only calculated for zones in which the proposed transmission enhancement decreases the net load payments. Zones for which the net load payments increase because of the proposed transmission enhancement are excluded from the net load energy payment benefit.

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 transmission enhancement

The change in net load capacity payment is the change in gross capacity payment 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 transmission enhancement. The change in net load capacity payment is the change in gross capacity payment offset by the change in capacity transfer rights.

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3.1: Completion of the 2016/2017 RTEP Long-Term Proposal Window

During the first quarter of 2018, PJM evaluated two groups of projects solicited through the 2016/2017 RTEP long-term proposal window. The PPL group included projects submitted to address congestion on the Susquehanna-Harwood 230 kV line. The BGE group included projects submitted to address congestion seen on the Conastone-Graceton-Bagley 230 kV circuit.

Based on those evaluations, PJM recommended one market efficiency project in addition to the five that were approved in 2017. Market efficiency proposed transmission enhancement 5E, which is a baseline transmission enhancement to reconductor two Conastone-Graceton 230 kV lines along with other area enhancements, described later in this section, were approved at a cost of $25.4 million with a 2021 in-service date. As part of the market efficiency evaluation, PJM determined that the approved transmission enhancement provided a benefit/cost ratio of 8.1.

2016/2017 Proposal Window Process

PJM opened the 2016/2017 RTEP long-term proposal window on November 1, 2016, through February 28, 2017. Its purpose was to solicit technical solution alternatives to alleviate market efficiency congestion drivers most recently described in the 2017 RTEP Report, Book 3, Section 5.2.4, Table 5.4.

PJM also completed additional analysis in 2017 and early 2018 using updated assumptions for natural gas prices, future load and significant generation or transmission network changes. That analysis evaluated whether or not the submitted proposals still satisfied the benefit/cost ratio, prior to the PJM Board recommendation.

PPL Group Projects

PJM received six proposals to address congestion on the Susquehanna-Harwood 230 kV line with estimated costs ranging from $13 million to $34 million, (see the 2017 RTEP Report, Book 3, Section 5, Table 5.7 and Map 5.5). Based on the 2017 and 2018 model updates, PJM simulations indicated reduced congestion driven by the Susquehanna-Harwood 230 kV line constraint.

PJM production cost simulations reveal that several interconnection queue generators are contributing to the congestion. Importantly, though, those generators have only reached the facility study agreement (FSA) stage of PJM's interconnection study process. If some of these units are not completed, PJM expects lower congestion on the Susquehanna-Harwood 230 kV line (see the 2017 RTEP Report, Book 3, Section 5, Table 5.8).

Based on the results from the analysis performed with reduced congestion following removal of the FSA generation, no project was recommended from the PPL group.

BGE Group Projects

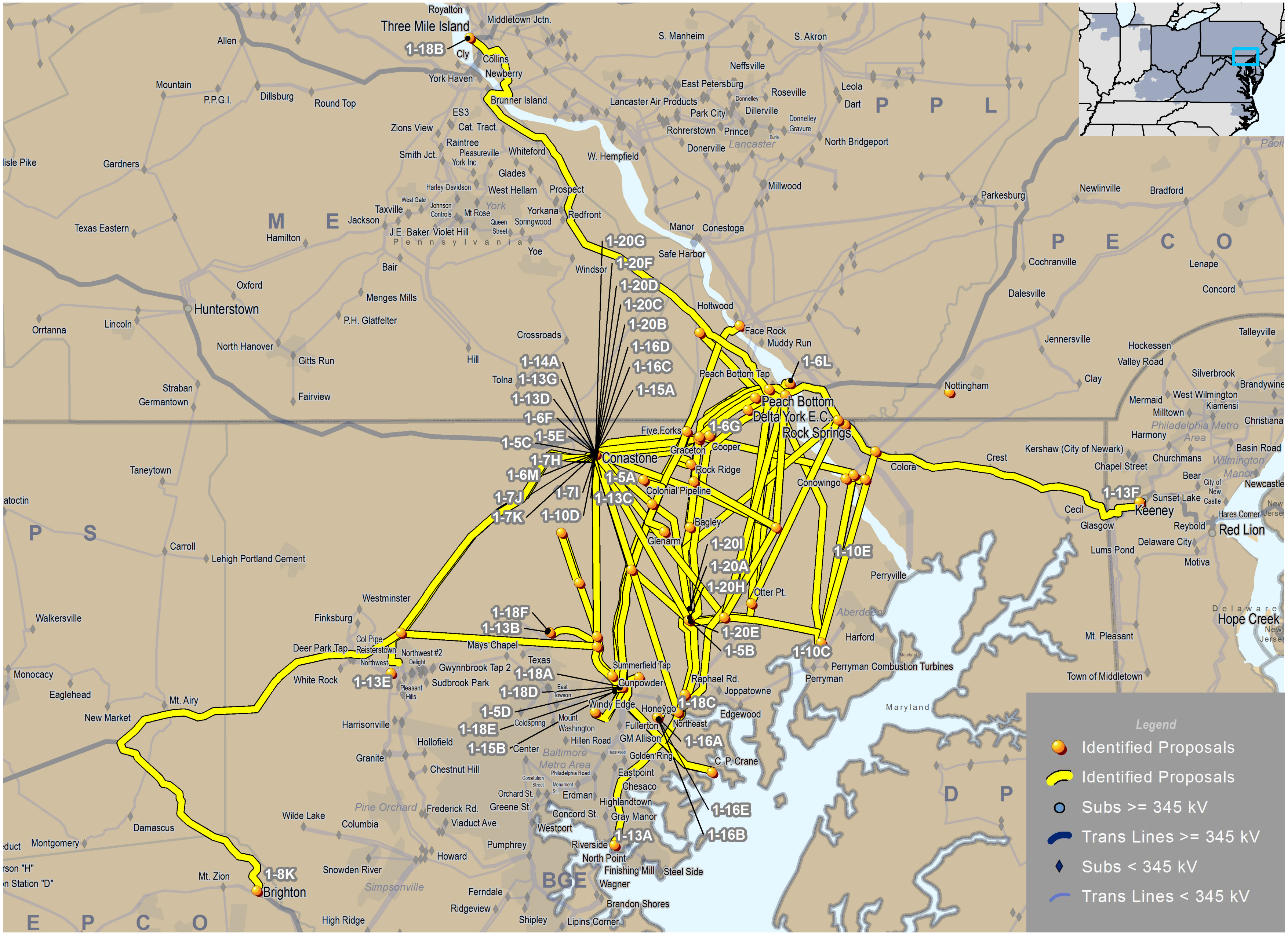
PJM received 46 proposals in the BGE area to address congestion seen on the Conastone-Graceton-Bagley 230 kV line, shown on **Map 3.1**. The estimated construction cost of these proposals ranged from $6 million to $483 million. Based on model updates done in 2017 and early 2018, PJM production cost simulations indicated persistent, though reduced, congestion on the Conastone-Graceton-Bagley 230 kV line.

PJM conducted an extensive analysis of the proposals to determine which projects satisfy the market efficiency criteria of having a benefit/cost ratio greater than 1.25, address the congestion driver, and are economically justified. PJM

Note:

The 2016/2017 window process is described in Book 3, Section 5.2 of the 2017 PJM RTEP report, available on the PJM website.

Map 3.1: BGE Group Projects – 2016/2017 Long-Term Proposal Window

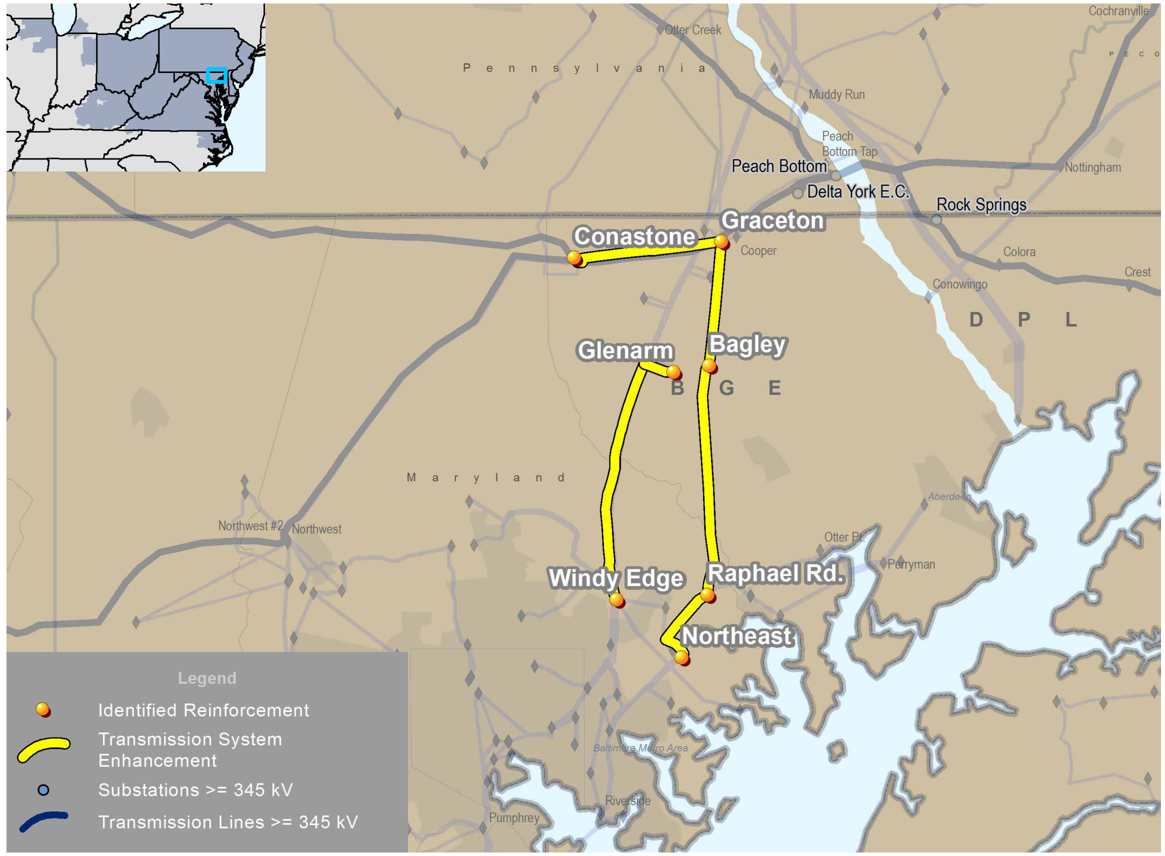


recommended to the board the 5E (b2992) proposal with an estimated cost of $25.4 million and a 2021 in-service date. As part of the market efficiency evaluation, PJM determined that the project provided a benefit/cost ratio of 8.1. Baseline project b2992 as currently approved, consists of the following elements and is shown on **Map 3.2**:

- Reconductor the Conastone-Graceton 230 kV lines
- Upgrade substation equipment at Conastone
- Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines
- Reconductor the Raphael Road-Northeast 230 kV double circuit lines
- Replace short segment of the Windy Edge-Glenarm 115 kV line and upgrade substation equipment at Windy Edge substation

In addition to the market efficiency base case analysis, PJM performed a sensitivity analysis on several key input assumptions. These market efficiency sensitivities included a range of natural gas prices and PJM load forecasts. An RTEP reliability analysis and constructability review was also completed for the selected project, b2992. The PJM Board approved the project in April 2018.

Map 3.2: BGE Group Recommended Project (b2992)



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3.2: 2018 Input Parameters

Overview

PJM licenses a commercially available production cost database containing the necessary data elements to perform detailed PJM market simulations. This database is periodically updated providing an up-to-date 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 3.2**. These parameters include fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology and several financial valuation assumptions.

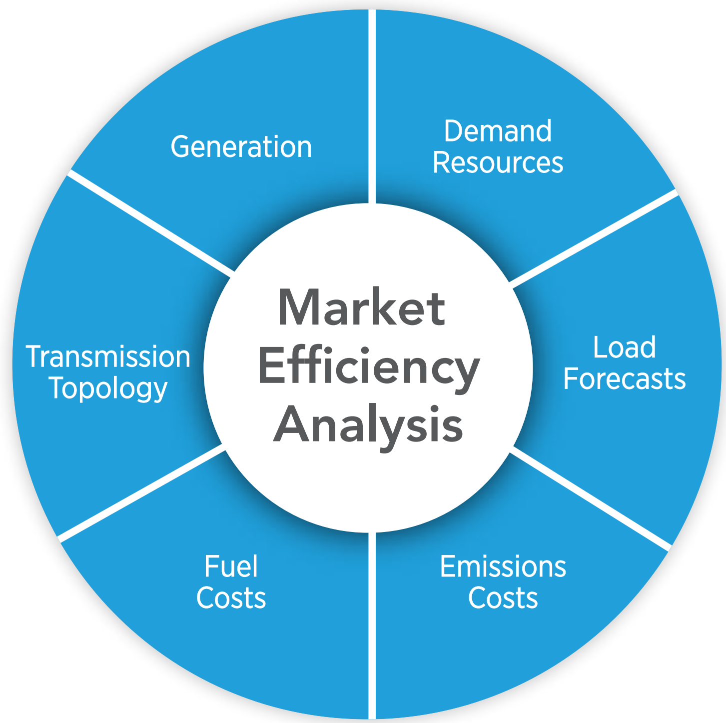
Transmission Topology

Market efficiency load flow models were developed to represent:

- The 2019 "as-is" transmission system topology
- The expected 2023 system topology for the five-year-out RTEP year

PJM derived the "as-is" system topology from its review of the Eastern Interconnection Reliability Assessment Group's Series 2018 Multi-Regional Modeling Working Group 2019 summer peak case. It included transmission enhancements expected to be in service by the summer of 2019. PJM derived system topologies for 2023 from the 2023 RTEP case and included significant RTEP projects approved during the 2017 RTEP cycle.

Figure 3.2: Market Efficiency Analysis Parameters



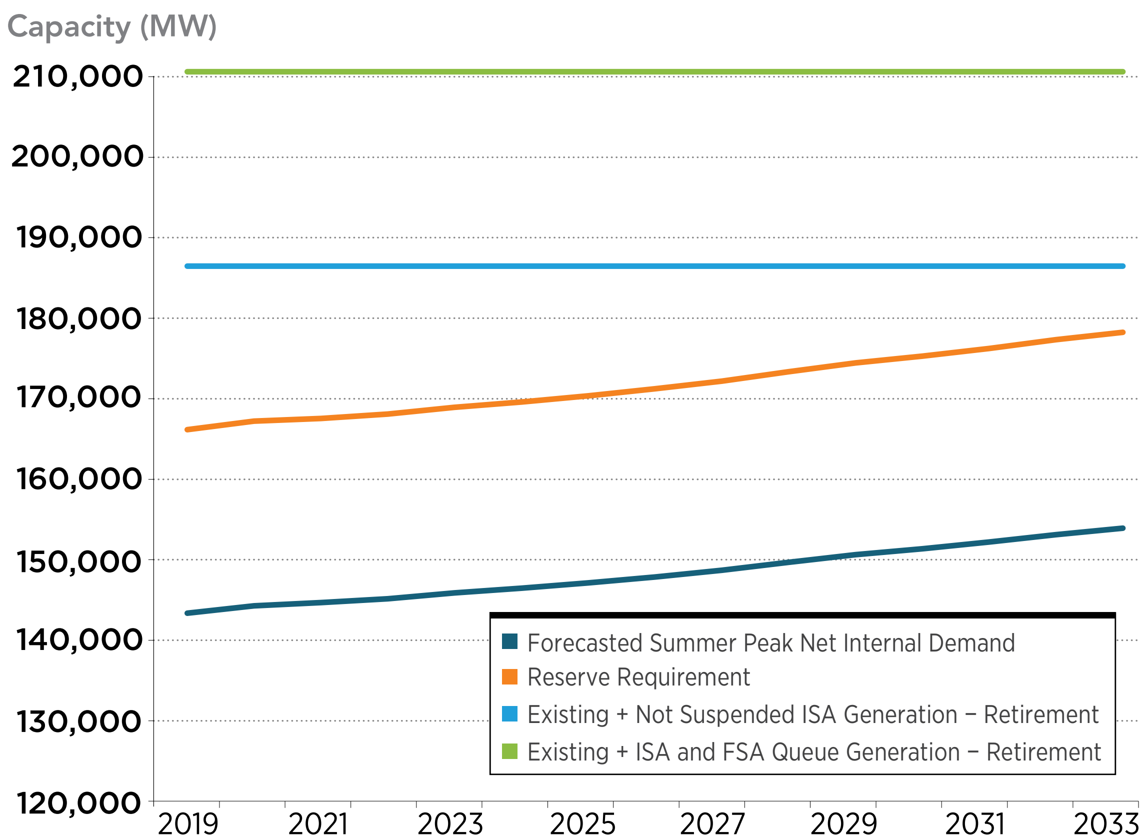
Monitored Constraints

Specific thermal and reactive interface transmission constraints are modeled for each base topology. Monitored thermal constraints are based on actual PJM market activity, historical PJM congestion events, PJM planning studies or studies compiled by NERC. PJM reactive interface limits are modeled as thermal values that correlate to power flows beyond which voltage violations may occur. The modeled reactive interface limits are based on voltage stability analysis and a review of historical values. Modeled values of future-year reactive interface limits incorporate the impact of approved RTEP enhancements on the reactive interfaces.

Generation Modeled

Market efficiency simulations model existing in-service generation plus actively queued generation with at least an executed interconnection service agreement, less planned generator deactivations that have given formal notification. The modeled generation provides enough capacity to meet PJM's installed reserve requirement through all study years, as shown in **Figure 3.3**.

Figure 3.3: PJM Market Efficiency Reserve Margin



Fuel Price Assumptions

PJM uses a commercially available production cost database 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 prices are obtained from commercially available databases, as are all coal price forecasts. Vendor-provided basis adders are applied to account for the commodity transportation cost to each PJM zone. The fuel price forecasts used in PJM's 2018 market efficiency analysis are represented in **Figure 3.4**.

Load and Energy Forecasts

PJM's 2018 Load Forecast Report provides the transmission zone peak load and energy data modeled in market efficiency simulations. **Table 3.1** summarizes the PJM peak load and energy values to be used in the 2018 market efficiency cases. The [2018 PJM Load Forecast] can be accessed on the PJM website.

Demand Resources

The amount of demand resources modeled in each transmission zone is based on the 2018 PJM Load Forecast Report. **Table 3.2** summarizes PJM demand resource totals by year.

Figure 3.4: Fuel Price Assumptions

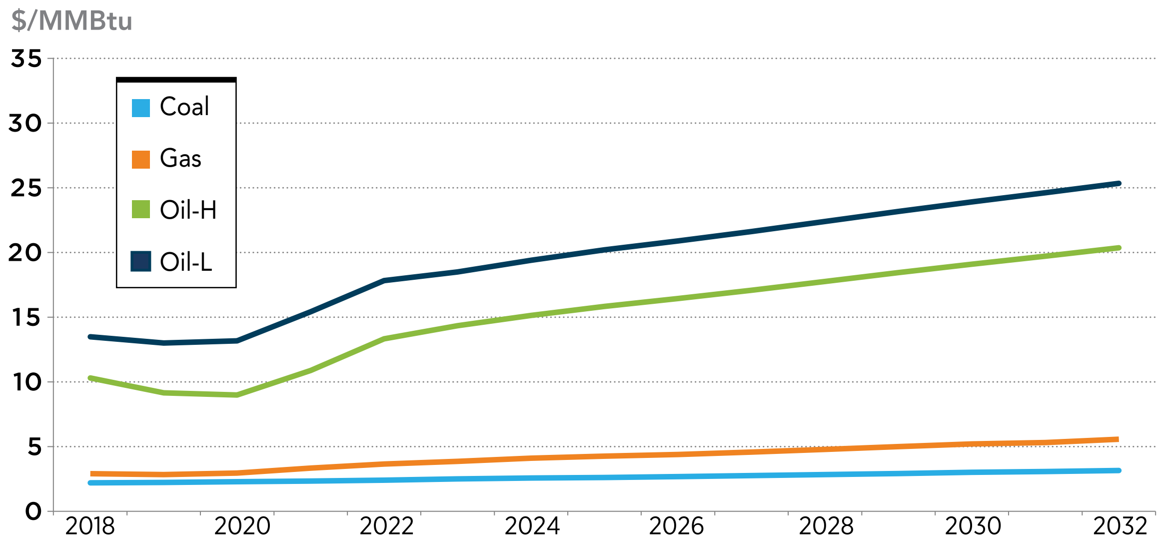


Table 3.1: 2018 PJM Peak Load and Energy Forecast

	2019	2023	2026	2029	2033
Peak (MW)	152,479	153,632	155,724	158,624	162,095
Energy (GWh)	809,000	816,817	828,788	845,058	864,236

Notes: 1.) Peak and energy values are from the 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.

Table 3.2: Demand Resource Forecast

	2019	2023	2026	2029	2033
Demand Resource (MW)	9,113	7,747	7,862	7,989	8,179

Note: Values from PJM's 2018 Load Forecast Report, Table B-7.

Emission Allowance Price Assumptions

PJM currently models three major power plant stack 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 3.5** and **Figure 3.6**, respectively. 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 assumption for both the national CO_2 and RGGI CO_2 program are shown in **Figure 3.7**.

Figure 3.5: SO_2 Emission Price Assumption

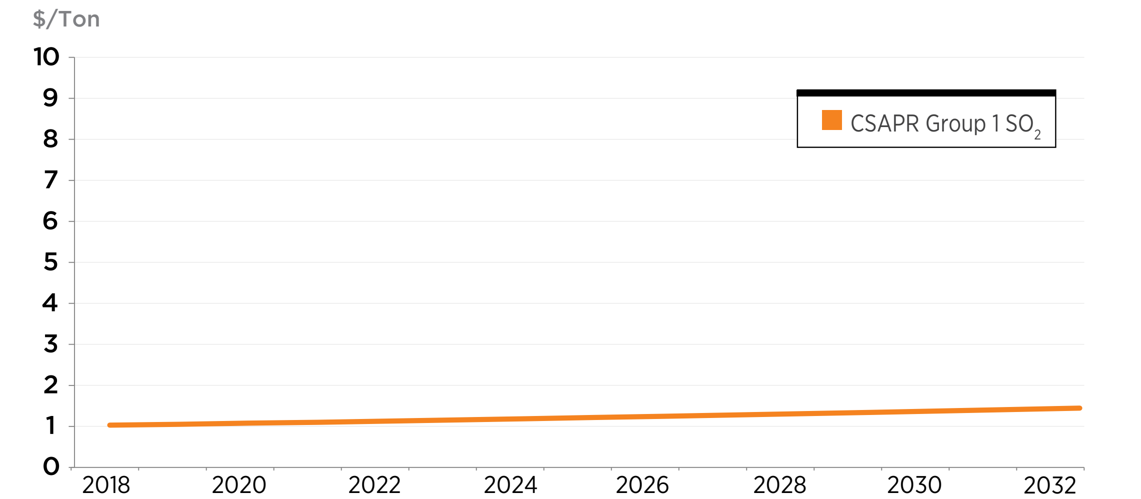
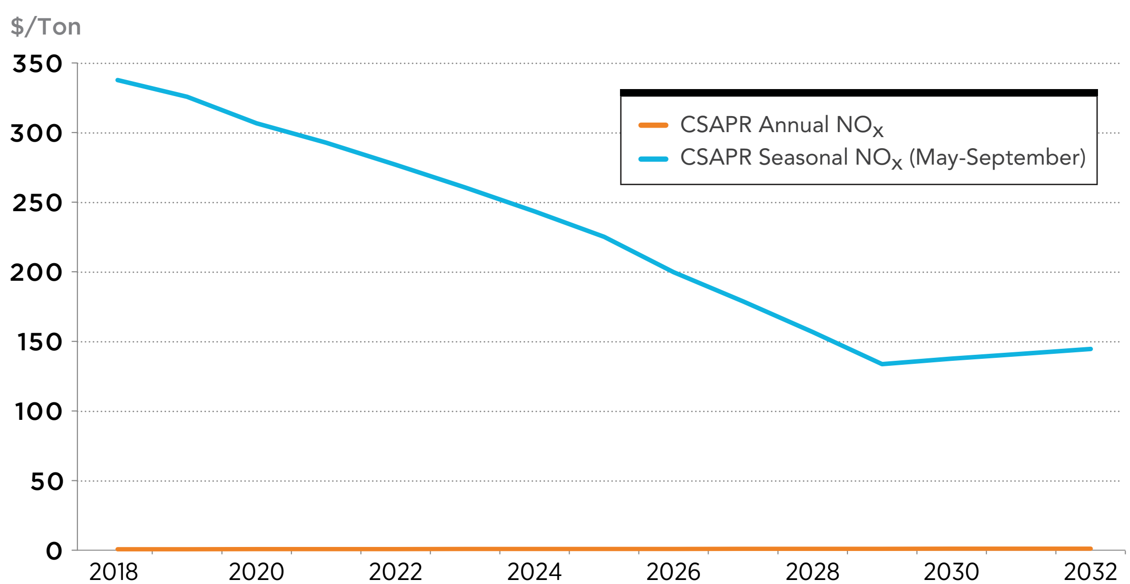


Figure 3.6: NO_x Emission Price Assumption

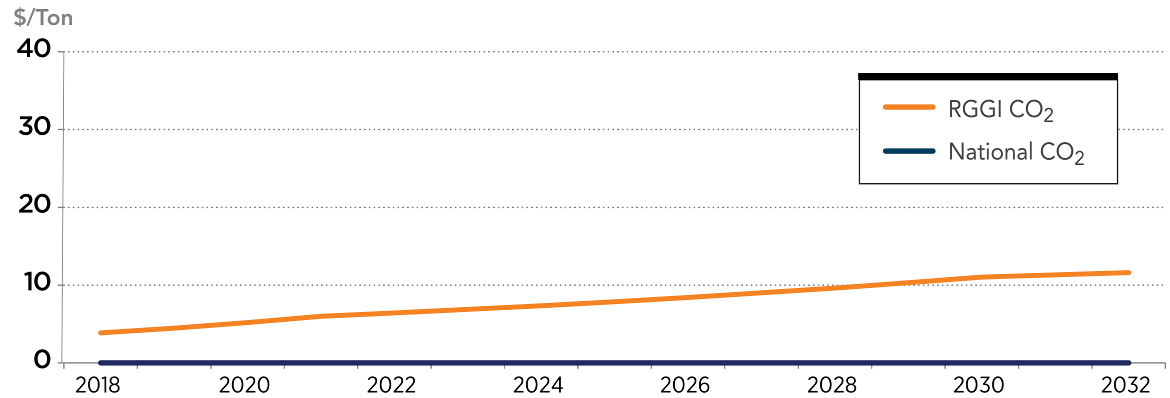


Carrying Charge Rate and Discount Rate

In order to determine and evaluate the potential economic benefit of RTEP projects, PJM performs market simulations and calculates a benefit/cost ratio for each candidate upgrade. To do so, the net present value of annual benefits is calculated for the first 15 years of project life and 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: http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx

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 2018 market efficiency studies use a levelized annual carrying charge rate of 12.84 percent and a discount rate of 7.37 percent.

Figure 3.7: CO_2 Emission Price Assumption



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

3.3: Study Results from 2018 Analysis

3.3.1 — Near-Term Simulation Results – Study Years 2019 and 2023

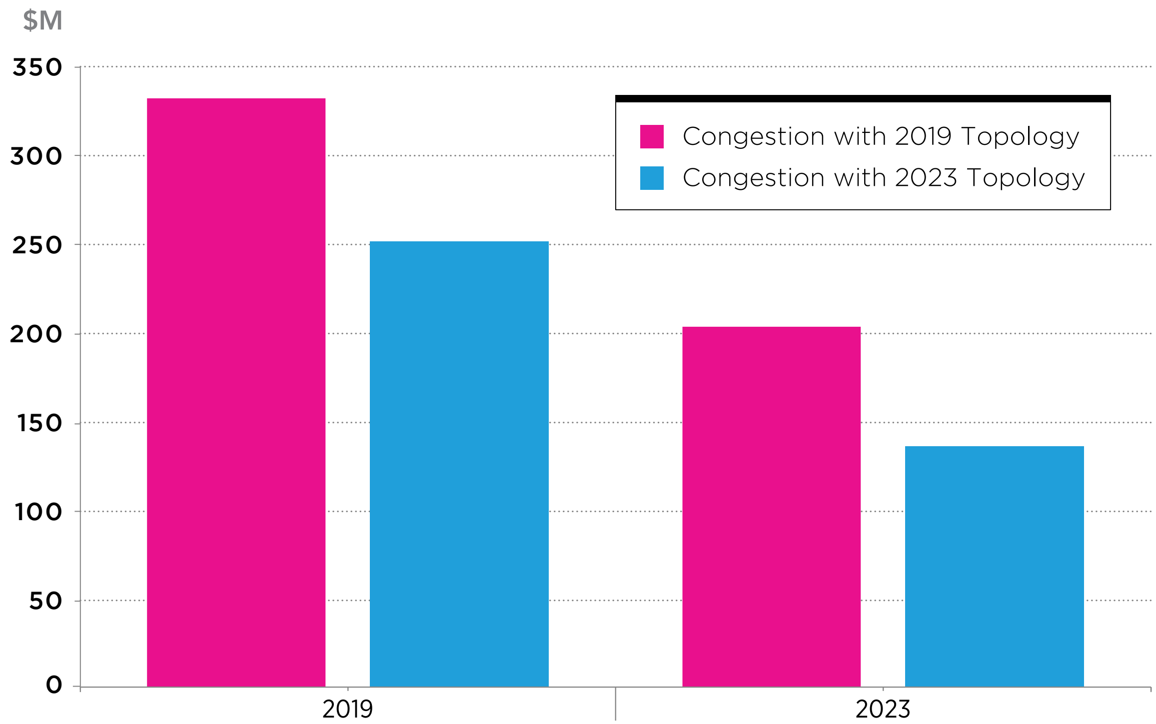
PJM's 2018 cycle of analysis included near-term simulations for study years 2019 and 2023. They identified collective and constraint-specific transmission system congestion due to the impacts of previously approved RTEP projects that are not yet in service. PJM conducted the simulations under two different transmission topologies:

1. 2019 “as-is” PJM transmission system topology
2. 2023 “as-planned” PJM RTEP transmission system topology

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

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

Figure 3.8: Simulated PJM Congestion Costs – 2019, 2023



PJM congestion costs from market simulations for study years 2019 and 2023 show annual congestion cost reductions of more than \$80 million (24 percent) for 2019 and more than \$67 million (33 percent) for 2023 using the 2023 RTEP topology as seen in **Figure 3.8**. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

Note:

On February 12, 2019, FERC accepted PJM's proposed changes to exclude generation with an executed ISA or FSA from market efficiency analysis.

Table 3.3: RTEP Projects Reducing Specific Congestion Drivers: 2023 Analysis

Congestion Decreases Associated With Approved Reliability Projects – 2023 Study Year			2023 Study Year				
			2019 Topology	2023 Topology			
Constraint Name	Area	Type	Congestion ($M)	Congestion ($M)	Congestion Savings ($M)	Upgrade Associated with Congestion Reduction	In-Service Date
Conastone-Peach Bottom 500 kV	BGE/ PECO	LINE	$1.9	$0.0	$1.9	b2766: Upgrade substation equipment at Conastone and Peachbottom 500 kV line	June 2020
Butler-Shanor Manor 138 kV	APS	LINE	$2.1	$0.0	$2.1	b2967: Convert the existing six-wire Butle-Shanor Manor-Krendale 138 kV line into two separate 138 kV lines	June 2020
Capitol Hill-Chemical 138 kV	AEP	LINE	$0.0	$0.0	$0.0	b2834: Reconductor and string open position and six-wire 6.2 miles of the Chemical-Capitol Hill 138 kV circuit	December 2021
Tanners Creek-Miami Fort 345 kV	AEP/ DEO&K	LINE	$0.2	$0.0	$0.2	b2831: Upgrade/rebuild Tanner Creek-Miami Fort 345 kV line	June 2021

Note: The congestion savings for the 2023 study year are calculated as the difference in simulated congestion between with as-is topology and the RTEP topology.

3.3.2 — Acceleration Analysis

PJM identified and evaluated specific RTEP enhancements that were most responsible for the congestion reductions identified in the near-term simulations. **Table 3.3** identifies approved RTEP reliability projects and related congestion reductions considered as part of the 2023 study year acceleration analysis.

Reliability-based baseline transmission enhancement b2766, a rating increase of substation equipment at Conastone and Peach Bottom 500 kV, previously had its in-service date moved from 2021 to 2020. The other identified reliability-based RTEP enhancements as shown in **Table 3.3**, 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.

3.3.3 — Long-Term Simulation Results: 2019, 2023, 2026 and 2029 Study Years

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 2023 RTEP "as-planned" transmission system topology and included RTEP projects approved through the 2017 RTEP cycle.

The highest cost congestion constraints from the 2018 long-term analysis, which represent over 95 percent of the PJM-related congestion in the 2023 and 2026 base simulations, are summarized in **Table 3.4**. This table includes congestion results for a sensitivity case that removes FSA units from PJM's generation fleet. Base generation modeled in the future may not include FSA units, pending approval of recommended process enhancements described in **Section 1.4**.

Overall, congestion levels in PJM's 2018 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

Note:

"FSA units" are generators, participating in PJM's interconnection process and have signed a "Facilities Study Agreement".

Table 3.4: Highest Cost PJM Congestion (Initial Posting for 2018/2019 Long-Term Proposal Window)

Constraint	From Area	To Area	Base with FSAs ($M)		Sensitivity No FSAs ($M)		Base with FSAs (Hours Binding)		Comments
			Simulated year						
			2023	2026	2023	2026	2023	2026	
AP-South Interface	-	-	$75.04	$96.73	$12.67	$9.28	1,226	1,363	Large congestion reduction without FSA generation. Significant portion of congestion addressed in previous windows
North Waverly-E. Sayre 115 kV Line	NYSEG	PN	$8.93	$17.30	$5.23	$6.90	3,367	4,421	Special protection scheme exists. NY reviewing
Hunterstown-Lincoln 115 kV Line	ME	ME	$7.45	$10.56	$24.99	$34.82	865	1,010	Seeking proposals
Cumberland-Juniata Bus 1 230 kV Line	PPL	PPL	$8.99	$13.10	$0.73	$4.10	357	316	Seeking proposals
Bosserman-Trail Creek 138 kV Line	AEP	MISOE	$7.04	$9.79	$0.69	$0.78	265	340	Seeking proposals
Face Rock-Five Forks 69 kV Line	PPL	PPL	$4.55	$3.48	$1.01	$0.66	166	120	Declining congestion since 16/17
Monroe 1 & 2-Wayne 345 kV Line	MISOE	MISOE	$4.38	$9.51	$0.09	$2.26	148	271	Seeking proposals – MISO M2M
Hubbell-Sunman Weisburg 138 kV Line	MISOC	MISOC	$3.19	$3.20	$0.42	$0.80	122	110	Seeking proposals – MISO M2M
Dauphin-Copperstone/N. Lebanon 230 kV Line	PPL	PPL	$2.87	$1.12	$0.00	$0.00	349	85	Congestion depends on one FSA unit
Furnace Run-Conastone 230 kV Line	PECO	BGE	$2.24	$2.19	$0.28	$0.29	80	78	Large congestion reduction without FSA generation. Significant portion of congestion addressed in previous windows
Towanda East-North Meshoppen 115 kV Line	PN	PN	$1.89	$6.51	$0.04	$0.25	1,180	2,080	Large congestion reduction without FSA generation
Milton-Montour 230 kV Line	PPL	PPL	$0.97	$0.34	$0.01	$0.00	234	82	Congestion under $1 million
Marblehead North 138/161 kV Transformer	MISOC	MISOC	$0.95	$0.60	$2.97	$1.34	160	118	Seeking proposals – MISO M2M
5004/5005 Interface	-	-	$0.80	$19.97	$0.02	$3.57	92	756	Under $1 million
Sullivan-Casey West 345 kV Line	AEP	MISOC	$0.65	$0.42	$0.06	$0.00	32	34	Under $1 million
PEPCO Interface	-	-	$0.63	$0.59	$0.00	$0.00	25	22	Under $1 million
Clifty Creek-Northside 138 kV Line	OVEC	LKE	$0.58	$2.59	$0.00	$0.05	23	90	Under $1 million
E. Frankfort (R)-Goodings (R) 345 kV Line	ComEd	ComEd	$0.56	$1.46	$0.33	$0.69	58	145	Seeking proposals – MISO M2M

Note: Light blue highlighted constraints indicate solution alternatives sought in the 2018/2019 RTEP long-term proposal window.

3.3.4 — 2018/2019 RTEP Long-Term Proposal Window – Market Efficiency Proposals

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 November 2, 2018, and is expected to close on March 1, 2019. It seeks technical solution alternatives to resolve or alleviate market efficiency congestion identified in the long-term simulation congestion results shown in **Table 3.4** – those that are highlighted in light blue.

In preparation for the proposal window, PJM developed and posted a Problem Statement and Requirements Document, available on the PJM website.

Note:

On February 22, 2019, PJM announced that the close of the 2018/2019 long-term proposal window was extended from March 1, 2019 to March 15, 2019 as a result of the February 12, 2019 FERC order accepting PJM's Operating Agreement changes regarding modeling of FSA generation in market efficiency analysis.

3.3.5 — Re-Evaluation of 2014/2015 and 2016/2017 RTEP Window Projects

PJM's 2018 long-term analysis included a re-evaluation of 14 previously approved market efficiency transmission enhancements from the 2014/2015 long-term window and four previously approved market efficiency transmission enhancements from 2016/2017 long-term windows. Re-evaluation ensures that previously approved RTEP transmission enhancements continue to meet the market efficiency criteria.

Each transmission enhancement was included in the 2018 market efficiency base case discussed earlier in **Section 3.2**. PJM recalculated economic value by production cost simulations in which each project was removed from the model to determine the benefit that retaining it otherwise still provided. The benefit/cost ratio was derived by comparing the base case simulation to the individual simulations that did not include the transmission enhancement, while adhering to the methods described in **Section 3.0**.

Table 3.6 and **Table 3.5** show the re-evaluation results. Each of the previously approved transmission enhancements either maintained a benefit/cost ratio greater than 1.25 or was already in-service. **Map 3.3** and **Map 3.4** depict the project locations.

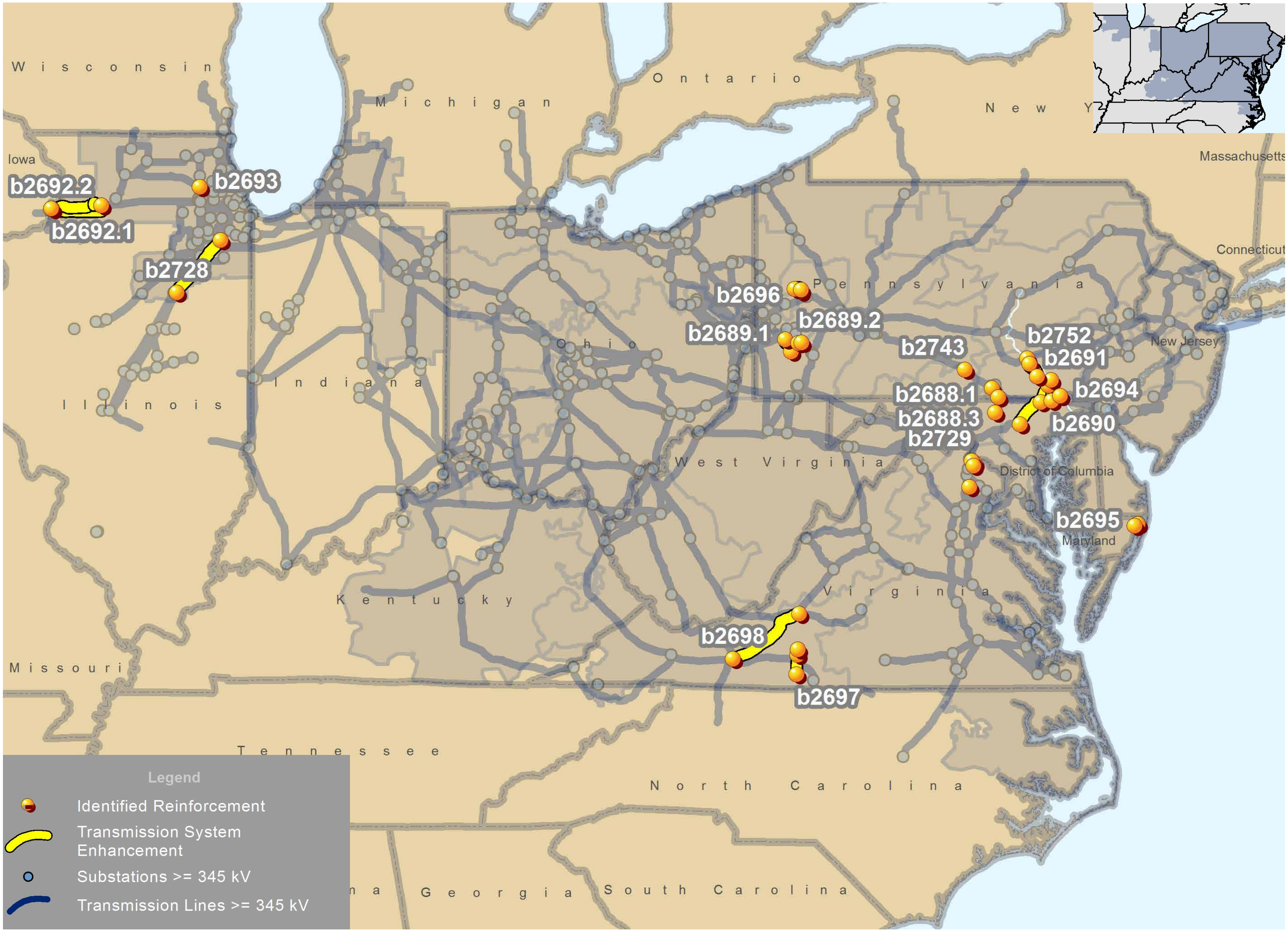
Table 3.5: 2018 Re-Evaluation Results – 2016/2017 Long-Term Proposal Window

Baseline Project ID	Project Description	Type	Area	Constraint	Cost ($M)	In-Service Year	Benefit/Cost Ratio			Status
							2016/17 Window	Re-Evaluation 2017	Re-Evaluation 2018	
b2930 (RPM) AC1-223	Upgrade capacity on E. Frankford-University Park 345 kV	Upgrade	ComEd	E. Frankfort-University Park 345 kV	0.84	2019	147.69	N/A	N/A	Work Completed
b2931 (RPM)	Upgrade substation equipment at Pontiac Midpoint station	Upgrade	ComEd	Pontiac-Brokaw 345 kV	5.62	2021	13.45	N/A	22.89	Engineering Procurement
b2976 (RPM)	Upgrade terminal equipment at Tanners Creek 345 kV station; Upgrade 345 kV Bus and Risers at Tanners Creek for the Dearborn circuit	Upgrade	DEO&K	Tanners Creek-Dearborn 345 kV	0.60	2021	151.61	N/A	470.28	Engineering Procurement
b2992.1-4	- Reconductor the Conastone-Graceton 230 kV 2323 & 2324 circuits - Add Bundle conductor on the Graceton-Bagley-Raphael Road 2305 & 2313 230 kV circuits Reconductor - Raphael Road-Northeast 2315 and 2337 circuits	Upgrade	BGE	Conastone-Graceton-Bagley 230 kV	39.65	2021	5.23	N/A	9.18	Engineering Procurement
b2743.1-8, b2752.1-7	- Tap Conemaugh-Hunterstown 500 kV line; Construct new Rice 500 kV and 230 kV substations; Install two 500/230 kV transformers at Rice - Tie in New Furnace Run substation to Peach Bottom-TMI 500 kV line	Greenfield	APS/ BGE	AP-South Interface	340.60	2020	2.50	1.3	1.40	Engineering Procurement

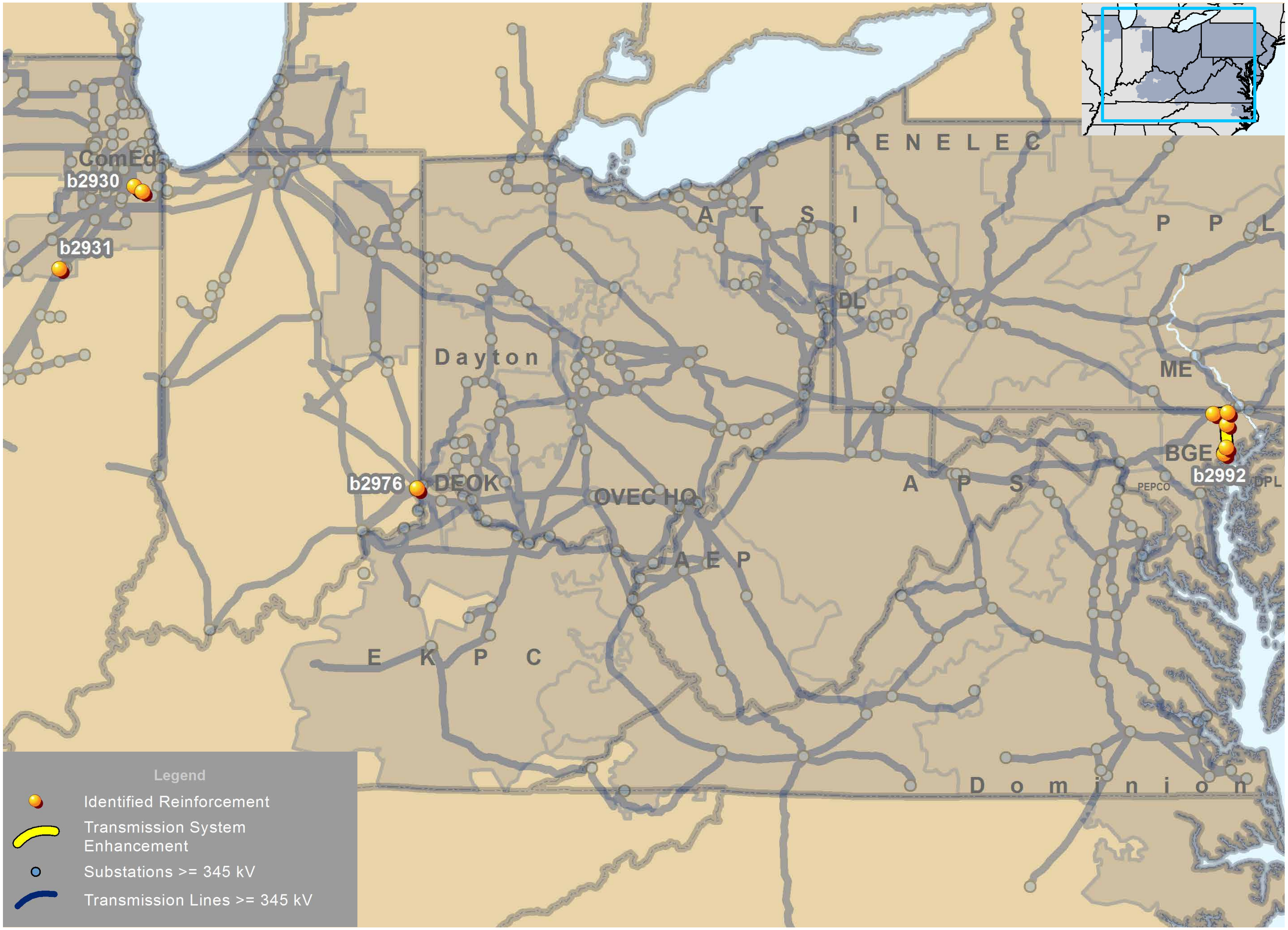
Table 3.6: 2018 Re-Evaluation Results – 2014/2015 Long-Term Proposal Window

Baseline Project ID	Project Description	Type	Area	Constraint	Cost ($M)	In-Service Year	Benefit/Cost Ratio 2016/17 Window	Benefit/Cost Ratio Re-Evaluation 2017	Benefit/Cost Ratio Re-Evaluation 2018	Status
b2688.1-3	- Upgrade Lincoln substation; Replace Germantown 138/115 kV transformer and related equipment - Replace terminal equipment at Carroll substation	Upgrade	APS	Taneytown-Carroll 138 kV line	5.2	2019	90.1	8.5	N/A	1: Under Construction 2 & 3: In Service
b2689.1-2	- Reconductor Woodville-Peters 138 kV line - Reconfigure West Mifflin-USS Clairton 138 kV line to create Dravosburg-USS Clairton and West	Upgrade	DUQ	Dravosburg-West Mifflin 138 kV line	11.2	2018	2.0	2.6	N/A	In Service
b2690	Reconductor Graceton-Safe Harbor 230 kV line	Upgrade	PPL/BGE	Safe Harbor-Graceton 230 kV line	1.1	2019	14.4	1.7	N/A	Under Construction
b2691	Reconductor three spans limiting Brunner Island-Yorkana 230 kV line	Upgrade	METED/ PPL	Brunner Island-Yorkana 230 kV line	3.1	2017	22.2	2.8	N/A	In Service
b2692.1-2	- Replace station equipment at Nelson and Quad Cities 345 kV substations - Upgrade conductors on Cordova-Nelson and Quad Cities-Nelson 345 kV lines	Upgrade	ComEd	Cordova-Nelson 345 kV line	24.6	2019	1.9	1.6	N/A	Under Construction
b2693	Replace L7915 B phase line trap at Wayne substation	Upgrade	ComEd	Wayne-South Elgin 138 kV	0.1	2018	6.4	25.0	N/A	In Service
b2694	Improvements to Peach Bottom 500/230 kV transformer to increase ratings	Upgrade	PECO	Peach Bottom 500 kV area congestion	9.7	2019	3.0	5.7	N/A	Engineering Procurement
b2695	Rebuild Worcester-Ocean Pines 69 kV line	Upgrade	DPL	Worcester-Ocean Pines 69 kV line	2.4	2018	65.3	10.1	N/A	In Service
b2696	Upgrade equipment at Butler, Shanor Manor and Krendale 138 kV substations	Upgrade	APS/ATSI	Krendale-Shanor Manor 138 kV line	0.6	2019	123.4	78.9	N/A	Under Construction
b2697.1-2	Upgrade Fieldale-Thornton-Franklin 138kV line	Upgrade	AEP	Fieldale-Thornton 138 kV line	0.8	2019	101.2	9.5	3.30	Engineering Procurement
b2698	Replace relays at Cloverdale and Jacksons Ferry substations	Upgrade	AEP	Jacksons Ferry-Cloverdale 765 kV line	0.5	2018	62.0	46.2	N/A	In Service
b2728	Mitigate sag limitations on Loretto-Wilton Center 345 kV line and replace station conductor at Wilton Center	Upgrade	ComEd	Loretto-Wilton 345 kV (RPM)	11.5	2018	64.5	N/A	N/A	In Service
b2729	Optimal capacitor configurations at Brambleton, Ashburn, Shelhorn, and Liberty 230 kV substations	Upgrade	Dominion	AP-South Interface	9.0	2019	15.4	2.2	2.51	Engineering Procurement
b2743.1-8, b2752.1-7	- Tap Conemaugh-Hunterstown 500 kV line; Construct new Rice 500 kV and 230 kV substations; Install two 500/230 kV transformers at Rice - Tie in New Furnace Run substation to Peach Bottom-TMI 500 kV line	Greenfield	APS/BGE	AP-South Interface	340.6	2020	2.5	1.3	1.40	Engineering Procurement

Map 3.3: 2018 Re-Evaluation Results – 2014/2015 Long-Term Proposal Window



Map 3.4: 2018 Re-Evaluation Results – 2016/2017 Long-Term Proposal Window



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

3.4: 2017 Historical Congestion Analysis

As part of the RTEP market efficiency planning process, PJM is charged with identifying historical transmission constraints that have a significant economic impact. Constraints that have an economic impact include, but are not limited to, those that cause:

- Significant historical gross congestion
- Pro-ration of Stage 1B ARR
- Significant future congestion projected in the long-term market efficiency simulations

This congestion and its economic impact are considered in the solution alternatives being sought as part of the long-term window process.

Table 3.7 lists the highest 25 congestion causing constraints from 2017. Total market congestion for 2017 was about $697.6 million of which $389.2 million (55.8 percent) is accounted for by the top 25 constraints. The comment column of **Table 3.7** identifies the RTEP Transmission enhancement expected to reduce congestion in the future.

Table 3.7: Top 25 Historical Congestion-Causing Constraints in 2017

Rank	Constraint	Type	Location	Approximate Total Market Congestion ($M)*	Percent of Total Congestion*	Comment
1	Braidwood-East Frankfort	M2M	ComEd	$43.40	6.20%	RTEP upgrades expected to reduce congestion (s0756 breaker replacement)
2	Conastone-Peach Bottom	PJM Line	BGE/PECO	$39.50	5.70%	RTEP upgrades expected to reduce congestion (b2766 substation equipment upgrade)
3	Emilie-Falls	PJM Line	PECO	$25.10	3.60%	RTEP upgrades expected to reduce congestion (b2774 Emilie-Falls 138 kV line reconductoring); partial congestion is outage related
4	Graceton-Safe Harbor	PJM Line	BGE	$23.90	3.40%	RTEP upgrades expected to reduce congestion (b2690 Graceton-Safe Harbor 230 kV line reconductoring); partial congestion is outage related
5	5004/5005 Interface	Interface	500	$22.50	3.20%	West-east transfers across the interface
6	AP-South Interface	Interface	APS	$21.60	3.10%	RTEP upgrades expected to reduce congestion (b2752, b2743)
7	Westwood	M2M	MISO	$19.60	2.80%	
8	Cherry Valley Transformer	M2M	ComEd	$18.70	2.70%	RTEP upgrades expected to reduce congestion (s0900 parallel transformer)
9	Carson-Rawlings	PJM Line	Dominion	$18.20	2.60%	
10	Conastone-Otter Creek	PJM Line	PPL	$15.10	2.20%	RTEP upgrades expected to reduce congestion (s0233 Otter Creek-Conastone 230 kV line rebuild); partial congestion is outage related

*Data from 2017 State of Market Report

Table 3.7: Top 25 Congestion-Causing Constraints in 2017 (Cont.)

Rank	Constraint	Type	Location	Approximate Total Market Congestion ($M)*	Percent of Total Congestion*	Comment
11	Conastone-Northwest	PJM Line	BGE	$14.10	2.00%	RTEP upgrades expected to reduce congestion (b2752.7 Conastone-Northwest 230 kV lines reconductor/rebuild); partial congestion is outage related
12	Three Mile Island	Transformer	500	$13.30	1.90%	Impacted by Three Mile Island retirement
13	Butler-Shanor Manor	PJM Line	APS	$11.40	1.60%	RTEP upgrades expected to reduce congestion (b2696 substation equipment upgrade at Butler, Shanor Manor and Krendale substations)
14	Lakeview-Greenfield	PJM Line	ATSI	$10.80	1.50%	Partial congestion is outage related
15	Alpine-Belvedere	M2M	MISO	$10.80	1.50%	RTEP upgrades expected to reduce congestion (b2141 construct Byron-Wayne 345 kV line)
16	Bedington-Black Oak	Interface	500	$9.50	1.40%	West-east transfers; future reactive upgrades expected to reduce congestion
17	Person-Sedge Hill	PJM Line	Dominion	$9.30	1.30%	Partial congestion is outage related
18	Lake George-Aetna	M2M	MISO	$9.20	1.30%	
19	Batesville-Hubble	M2M	MISO	$8.90	1.30%	RTEP upgrades expected to reduce congestion (b2634 convert Miami Fort 345 kV substation to a ring bus)
20	Byron-Cherry Valley	M2M	MISO	$8.00	1.10%	RTEP upgrades expected to reduce congestion (b2141 construct Byron-Wayne 345 kV line)
21	AEP-DOM	Interface	500	$7.80	1.10%	West-east transfers; future reactive upgrades expected to reduce congestion
22	Brunner Island-Yorkanna	PJM Line	METED	$7.50	1.10%	RTEP upgrades expected to reduce congestion (b2691 reconductor Brunner Island-Yorkana 230 kV line)
23	Brokaw-Leroy	M2M	MISO	$7.30	1.00%	
24	Loretto-Vienna	PJM Line	DPL	$6.90	1.00%	Partial congestion is outage related
25	Pleasant View-Ashburn	PJM Line	Dominion	$6.80	1.00%	
		Top 25		**$389.20**		
		Total Congestion		**$697.60**		

*Data from 2017 State of Market Report

Section 4: Interregional Planning

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

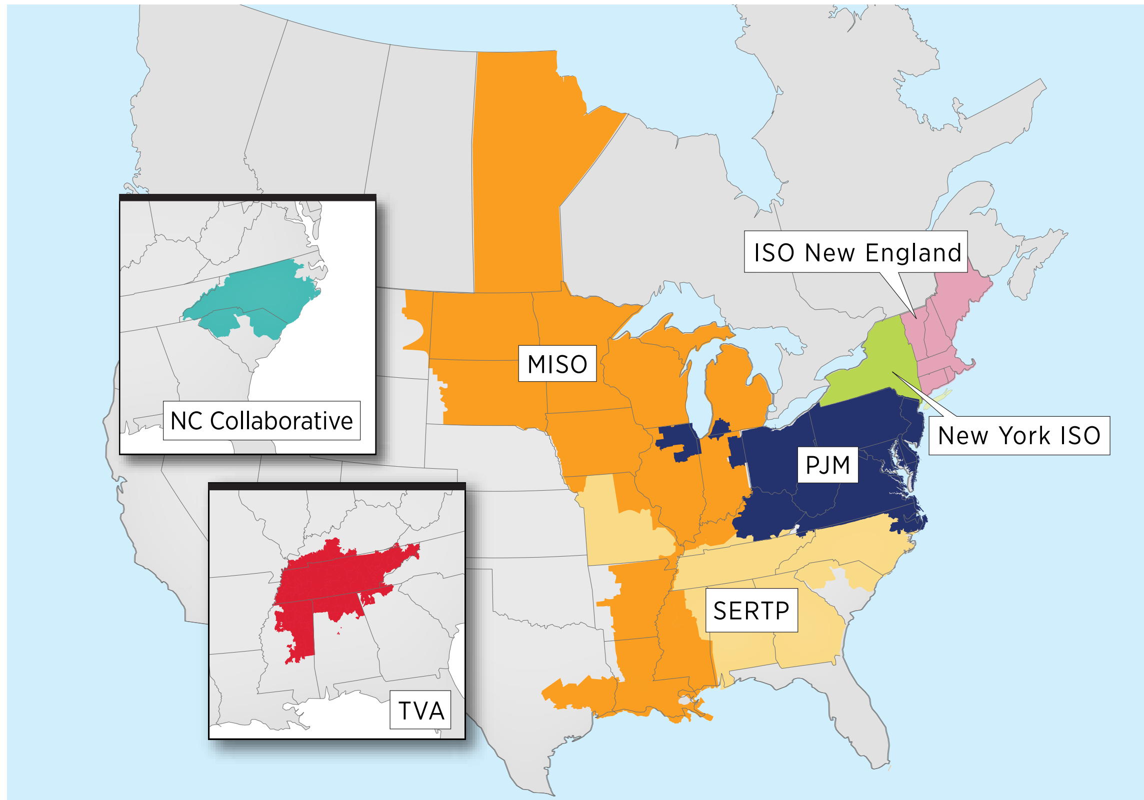
4.0: Interregional Planning

4.0.1 — Adjoining Systems

PJM's interregional planning responsibilities have grown in parallel with the evolution of broader organized markets and interest at state and federal levels in favor of increased interregional coordination. The nature of these activities include structured, tariff-driven analyses as well as targeted issue evaluations 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 4.1**.

In accordance with FERC Order No. 1000, interregional planning processes with the NC collaborative and TVA are conducted under the SERTP process, which is included in the Tariff provisions of PJM and the SERTP sponsors subject to FERC jurisdiction. SERTP sponsors include Duke Energy Progress (jurisdictional), TVA, Southern Company (jurisdictional), Georgia Transmission Corporation, Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric, Kentucky Utilities (jurisdictional), Associated Electric Cooperative, Ohio Valley Electric Corporation (OVEC)

Map 4.1: PJM Interregional Planning



NOTE:

The Ohio Valley Electric Corporation (OVEC) Integration was successfully completed on December 1, 2018.

(jurisdictional), and Dalton Utilities. In addition, PJM actively participates in the Eastern Interconnection Planning Collaborative.

Interregional Agreements

Under each interregional agreement, provisions governing coordinated planning ensure that critical cross-border operational and planning issues are identified and addressed before they impact system reliability or dilute effective 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.

4.0.2 — MISO

The 2018 planning efforts under Article IX of the MISO/PJM joint operating agreement continued the coordination of regional reliability, market efficiency, interconnection requests and deactivation notifications. Interconnection-driven network transmission enhancements are summarized in **Section 1.1.4**. Deactivation-driven baseline transmission enhancements are summarized in **Section 1.1.5**. Throughout the year, stakeholder input and feedback to the interregional planning process was coordinated through the MISO/PJM interregional planning stakeholder advisory committee (IPSAC).

Following the Annual Issues Review in the first quarter of 2018, PJM and MISO initiated two interregional studies under the Coordinated System Plan. The first was a Targeted Market Efficiency Project (TMEP) study completed in October 2018. This was the second iteration of this innovative project type aimed at quickly addressing historical congestion on the seam. The second study is a long-term Interregional Market Efficiency Project (IMEP) study, which began in mid-2018 and will run through the end of 2019. These studies are discussed in **Section 4.1**.

As part of the Annual Issues Review and ongoing stakeholder meetings, the interregional planning process also sought to identify interregional reliability projects that were more efficient or cost effective than the alternative regional plans. None were identified in 2018.

4.0.3 — 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 2018 were conducted in accordance with the protocol and ensured compliance with the provisions of FERC Order No. 1000. Stakeholder input continues to be coordinated through the activities of the IPSAC.

During 2018, PJM continued interconnection and transmission service coordination, data exchange and economic data updates. In April 2018, the 2017 Northeast Coordinated System Plan (NCSP) was published. 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 2018 did not identify any opportunities to pursue interregional transmission projects. Coordination activities will continue in 2019 as well as work on the 2019 NCSP, which will be published in early 2020.

4.0.4 — 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 4.1**, continued interregional data exchange and interregional coordination during 2018. 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), LGE/KU, and OVEC (Note: OVEC integrated into PJM on Dec. 1, 2018). Duke Energy, LGE/KU and OVEC are directly connected to PJM. Of the non-jurisdictional entities, only TVA is directly connected to PJM. The remaining five SERTP participants are planning areas south and west of Duke Energy and TVA.

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

In May 2018, PJM and its SERTP counterparts met in person for the biennial review. The meeting reviewed needs and planned upgrades identified in each individual regional planning process. No opportunities for an interregional project among PJM and SERTP members were identified.

This detailed plan review occurs every two years and is scheduled next for 2020. PJM also reviews and coordinates interconnection and deactivation requests on an ongoing basis that may have SERTP cross-border impacts.

NOTE:

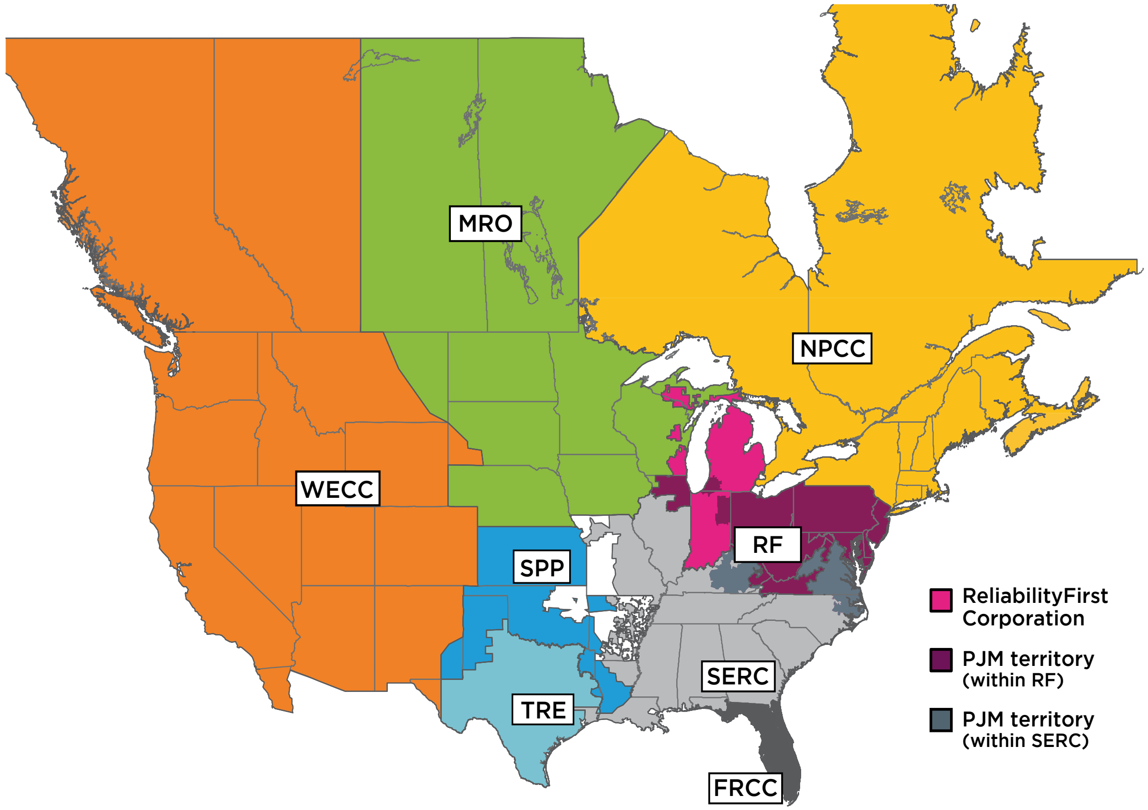
PJM notes that SERTP is an interregional effort, not to be confused with SRRTEP, PJM's subregional RTEP stakeholder committees.

SERC Activities

PJM continues to support its members that are located within SERC – shown on **Map 4.2**. 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 discussions to coordinate 2018 model development and study activities. In addition to the regular work on these committees during 2018, PJM continued to support SERC's analysis of the transmission impact of the changing resource mix and increasing penetration of renewable resources.

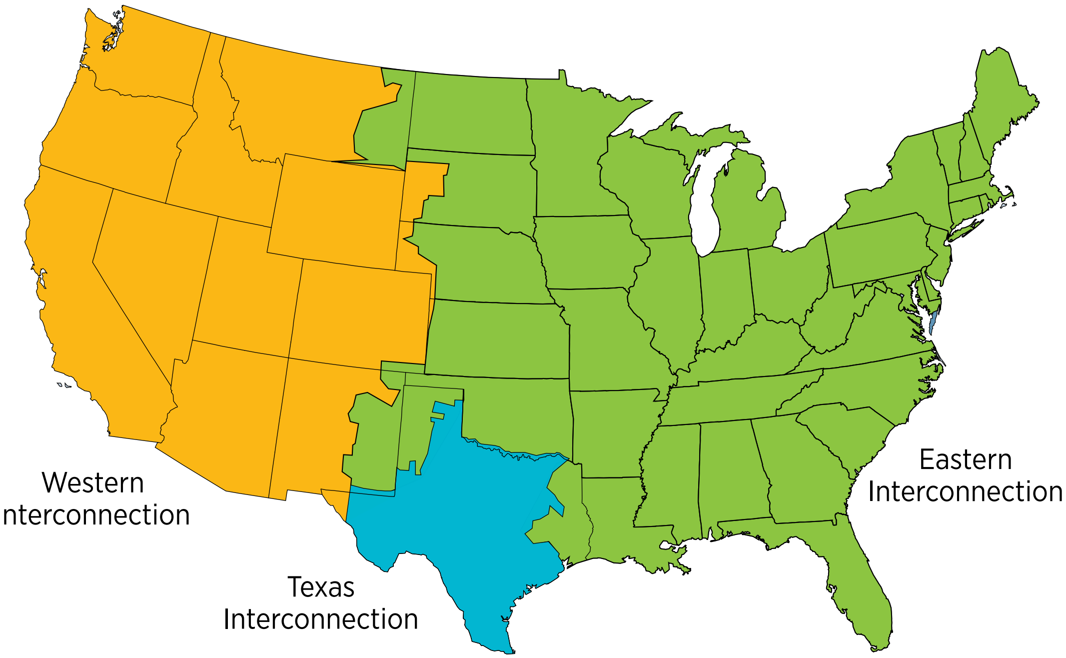
Map 4.2: NERC Areas



4.0.5 — Eastern Interconnection Planning Collaborative

The Eastern Interconnection Planning Collaborative (EIPC) is an interconnection-wide transmission planning coordination effort among NERC Planning Authorities in the Eastern Interconnection, shown on **Map 4.3**. 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 4.3: U.S. Interconnections



EIPC Activities

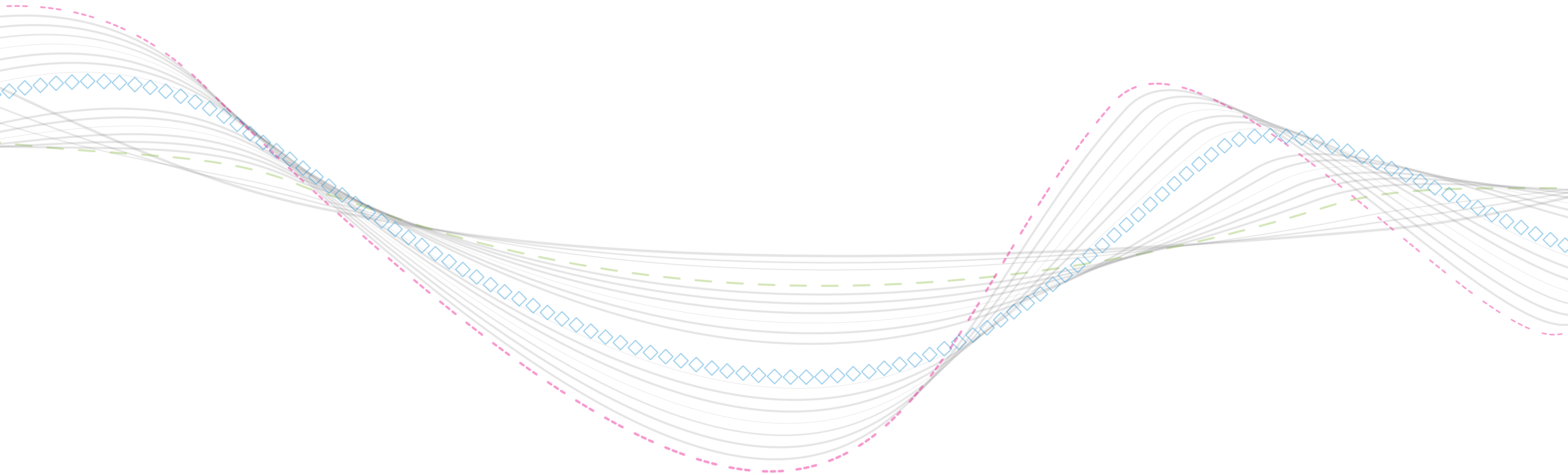
During 2018, EIPC continued to expand power system planning analysis activities beyond the requirements of FERC Order No. 1000 including the following:

- The Production Cost Task Force completed development of a first-of-its-kind Eastern Interconnection-wide production cost database. This database gives planning coordinators up-to-date data and tools to respond to broad impact public policy and power system economic questions.

- The Frequency Response Task Force completed its analysis of the ability of the Eastern Interconnection to maintain frequency following a disturbance during low inertia periods. The study concluded that over the five-year planning horizon, system inertia and primary frequency response will be sufficient even with expected increases in non-synchronous generation.

- The State of the Eastern Interconnection report was published in October 2018. This report provides a summary of the analysis EIPC has performed and the state of interconnected planning across the Eastern Interconnection. The report is available on the PJM website.

PJM expects many of these activities to continue in 2019. The transmission analysis working group will complete an updated reliability screening aimed at identifying emerging issues between planning regions. The Production Cost Task Force is currently evaluating potential studies to be completed in 2019.



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

4.1: MISO/PJM Market Efficiency Studies

4.1.1 — Overview

Following the Annual Issues Review in the first quarter of 2018, PJM and MISO initiated two market efficiency studies under the Coordinated System Plan (CSP). The first was a TMEP study to address persistent historical congestion issues on market-to-market flowgates. The second is a long-term IMEP study to identify and resolve current and projected future market efficiency concerns. These studies are conducted in accordance with the currently effective joint operating agreement.

In 2018, stakeholders at the IPSAC discussed further changes to Article 9 of the JOA. These changes centered on cleanup of language which referred to a "joint model" no longer being developed following a 2016 FERC compliance directive. Additional changes removing the distribution factor threshold for interregional projects were endorsed. Interregional projects must still meet the regional criteria of both PJM and MISO, but there would be no separate criteria in the JOA under this proposal. PJM anticipates these changes will be accepted by the FERC in early 2019.

4.1.2 — TMEP 2018 Activities

TMEP interregional projects address historical congestion on market-to-market flowgates – a set of specific flowgates subject to joint and common market (JCM) congestion management. The JCM congestion management process is described in the MISO/PJM Joint Operating Agreement. Congestion arising from joint market operations creates significant financial consequences for market participants. PJM and MISO agree that in addition to evaluating the need for IMEPs based on future system projections, there is also a need to remedy historical congestion on the seam.

2018 Targeted Market Efficiency Project Study

As a result of the 2018 annual issues review, the Joint RTO Planning Committee (JRPC), in consultation with IPSAC, decided to conduct a TMEP study in 2018. The study was initiated in April and concluded in October, culminating in December approval of two recommended projects by the PJM and MISO Boards.

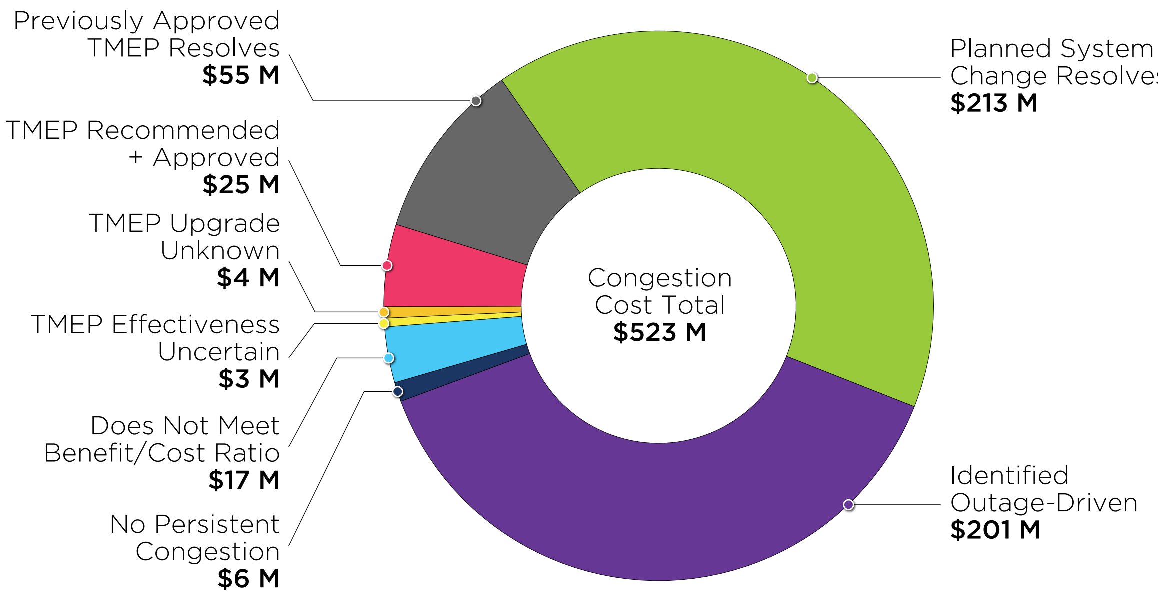
The 2018 study evaluated the 61 most congested market-to-market flowgates in 2016 and 2017. Cumulative PJM and MISO congestion on these facilities was approximately $523 million. Following detailed review of these flowgates, previously planned projects (RTEP, Midwest ISO Transmission Expansion Plan [MTEP], or interregional TMEPs) were identified that are expected to address $268 million (just over 50 percent) of this congestion. An additional $201 million in congestion (approximately 40 percent) was identified as driven by transmission outages. Since these specific outages are not expected to persist, no projects were developed to address that congestion.

For the remaining $54 million of congestion, which a TMEP would be eligible to address, potential projects were identified and evaluated. Ultimately, two upgrades shown in **Table 4.1** that met all the TMEP criteria were identified. These two projects are expected to relieve $25 million of congestion; nearly half the remaining eligible congestion. Projects to relieve congestion on the remaining flowgates did not meet the benefit/cost requirement or other TMEP criteria.

Figure 4.1 shows how the $523 million is being addressed by the TMEP process.

Congestion management on market-to-market (M2M) flowgates is a complicated and multifaceted issue. Elimination of all congestion is neither a feasible nor cost-effective goal. Outage conditions – often driven by construction of upgrades – will continue to cause congestion. New constraints will emerge as transfer patterns change, driven by evolving economic and system conditions. Overall, the 2018 TMEP study results show that the regional and interregional planning processes are effective at developing cost-effective solutions to persistent congestion issues.

Figure 4.1: Targeted Market Efficiency Project Study Results – Congestion Cost

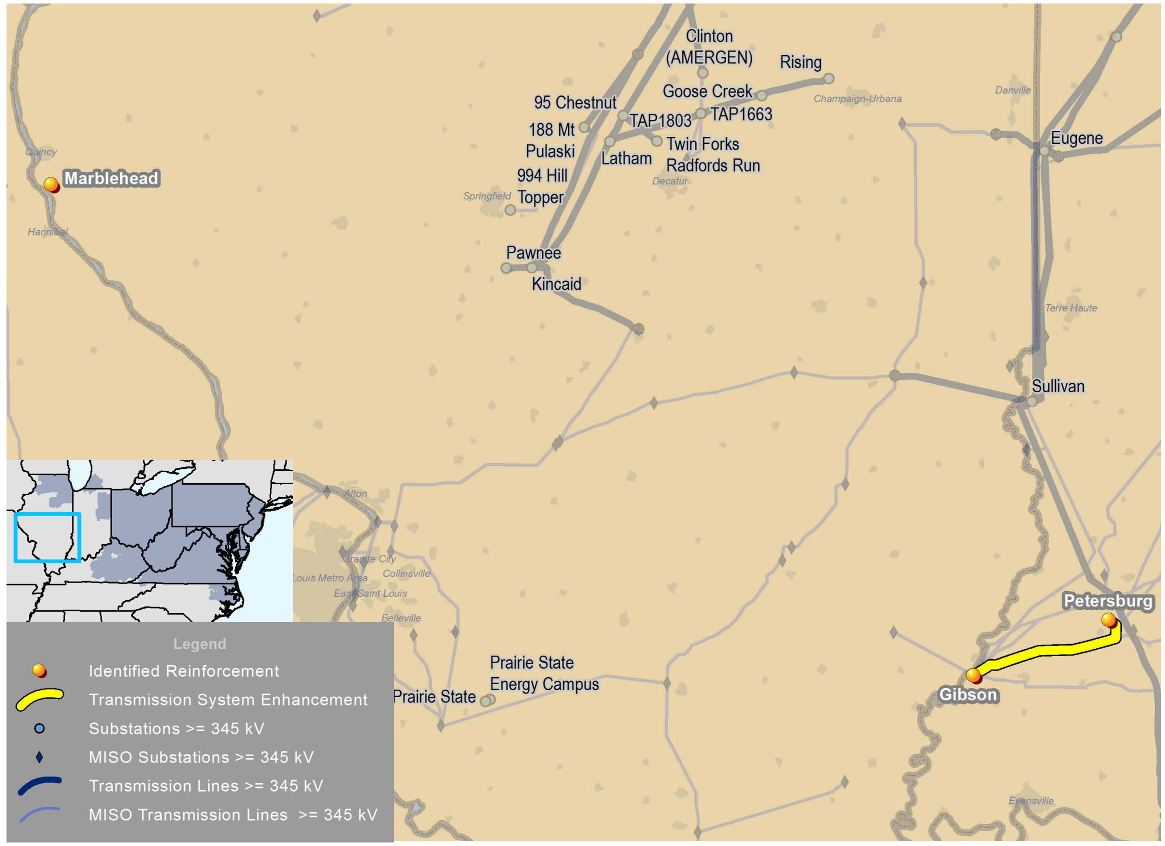


Approved Targeted Market Efficiency Projects

PJM and MISO completed the second TMEP analysis in October 2018, leading to the development of two transmission projects that were recommended to and approved by the PJM and MISO Boards in December 2018. The two projects, shown in **Table 4.1** and on **Map 4.4**, are estimated to cost a combined $4.5 million and will produce joint market congestion savings totaling approximately $32 million in the first four years of operation. PJM and MISO expect both projects to be in service no later than June 1, 2021.

In 2019, as part of the Annual Issues Review, PJM and MISO will review historical M2M congestion along their seam. Results of this review will determine the merits of a full TMEP study in 2019.

Map 4.4: Approved Targeted Market Efficiency Projects



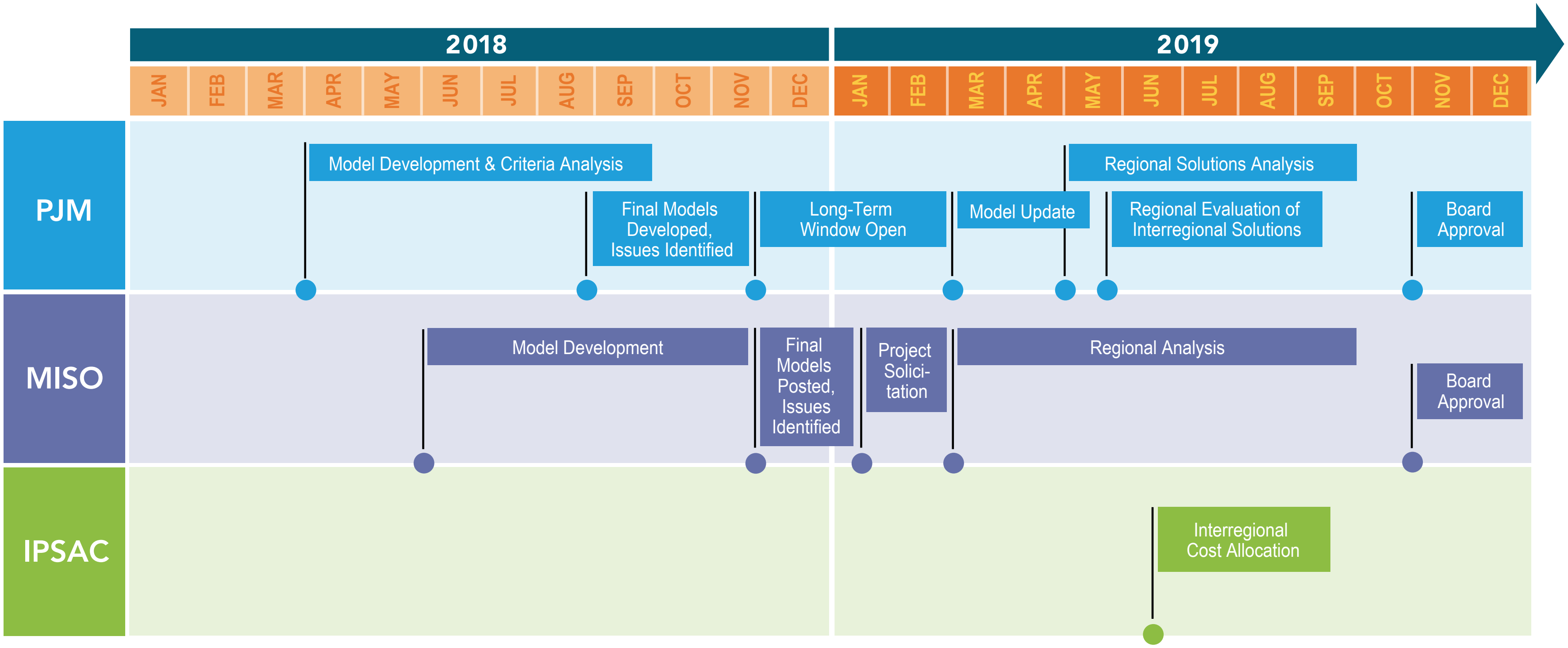
NOTE:

Marblehead transformer was not designated as a M2M facility for a majority of the historical period evaluated in this study, which resulted in no benefit allocation to PJM. Since there is no cost allocation or construction responsibility assigned to PJM, a baseline ID has not been designated for this project.

Table 4.1: Approved 2018 Targeted Market Efficiency Projects

M2M Facility	Upgrade	Transmission Owner	Benefit	Cost	Interregional Benefit Allocation	MTEP Project No.	RTEP Project No.
Marblehead 161/ 138 kV Transformer	Terminal equipment (disconnect switch and bus conductor)	Ameren (IL)	$12.4 M	$175 K	100% MISO	16227	N/A
Gibson-Petersburg 345 kV Line	Terminal equipment (switches, breakers, relays, bus work)	Duke/IPL	$19.5 M	$4.3 M	93% MISO/ 7% PJM	16228	b3053

Figure 4.2: Interregional Market Efficiency Project Study Timeline



4.1.3 — PJM/MISO Interregional Market Efficiency Study

Periodically, the 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. Consistent with currently effective interregional agreements, benefit determination is calculated independently by each region, following their unique regional process. For more information on PJM's regional market efficiency process, see **Section 3**.

During 2018, PJM and MISO each developed regional market analysis models to project future system conditions and identified eligible congestion drivers. PJM and MISO have solicited transmission developer proposals to address identified congestion issues along the mutual seam as identified in their respective regional planning processes. PJM's eligible drivers included five constraints near the MISO seam, as described in **Section 3.3,** which PJM asserts would most effectively be addressed by an interregional project.

Market efficiency proposals must be submitted during the RTEP market efficiency proposal window, which is open from November 2, 2018 to March 1, 2019. Proposals designated as interregional projects must also be submitted to the MISO process, triggering the consideration of a shared cost IMEP in accordance with the JOA. The evaluation of IMEP proposals will occur in 2019, culminating in potential project recommendations to the PJM and MISO Boards in December 2019. **Figure 4.2** shows the approximate IMEP schedule.

Note:

On February 22, 2019, PJM announced that the close of the 2018/2019 long-term proposal Window was extended from March 1, 2019 to March 15, 2019 as a result of the February 12, 2019 FERC order accepting PJM's Operating Agreement changes regarding modeling of FSA generation in Market Efficiency analysis.

Section 5: 2018/2019 Stage 1A ARR 10-Year Analysis

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

5.0: RTEP Context

Auction Revenue Rights (ARRs) are the mechanism by which the proceeds from the annual Financial Transmission Rights (FTR) auction are allocated. ARRs entitle the holder to receive an allocation of the revenues from the annual FTR auction. PJM conducts annual studies to determine if transmission system expansions are required to accommodate the Stage 1A ARRs so that all are simultaneously feasible for a 10-year period.

5.0.1 — Scope

Each year, PJM conducts an analysis to test the transmission system's ability 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 to a transmission zone based on each zone's total Stage 1A ARR flow percentage to the overloaded facility.

The analysis evaluates both PJM internal transmission facilities and interregional market-to-market (M2M) facilities. M2M facilities are those flowgates which are eligible for market-to-market coordination.

NOTE:

Stage 1A is the first round of the annual ARR allocation, which is designed to enable native load utilization of the transmission system while preserving long-term capability.

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

5.1: 2018/2019 Stage 1A ARR 10-Year Analysis Results

During 2018, PJM market simulation staff completed a 10-year simultaneous feasibility analysis for 2018/2019 Stage 1A ARR selections. The power flow case used in the 10-year feasibility analysis is the same one used in the 2018/2019 annual ARR allocation, but without any modeled maintenance transmission outages. The results of the 10-year analysis identified violations on both PJM internal and interregional M2M facilities. PJM determined that the transmission solutions that would address identified violations were previously noted during one of the following processes:

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

The list of infeasible facilities along with expected projects that will address the infeasibilities are provided in **Table 5.1**.

Internal PJM Facilities

The analysis shows only one internal facility with a Stage 1A 10-year violation. This facility, the Emilie-Falls 138 kV line, is located in the PECO zone. PJM RTEP project b2774, Emilie-Falls 138 kV line reconductoring with a projected in-service date of 2020, alleviates the violation and restores Stage 1A ARR capability. As the current PJM RTEP already contains a solution to this Stage 1A ARR constraint, no additional transmission enhancement is needed.

Market-to-Market Facilities

The analysis shows violations on multiple M2M transmission facilities, driven by impacts from internal PJM generation. Transmission enhancements have been identified for these violations. Since a plan has been established to address these violations, no further immediate action is necessary.

Table 5.1: 2018/2019 Stage 1A ARR 10-Year Infeasible Facilities

Facility Name	Facility Type	Proposed Solution	Expected In-Service Date
Emilie-Falls 138 kV line	Internal	PJM RTEP b2774: Reconductor Emilie-Falls 138 kV line	2020
Michigan City-Bosserman 138 kV line for the loss of Michigan City-Trail Creek 138 kV line	M2M Flowgate	PJM RTEP b2973: Reconductor Michigan City-Bosserman 138 kV line	2020
Monroe-Bayshore 345 kV line for the loss of Allen Jct-Morocco 345 kV line	M2M Flowgate	PJM RTEP b2972: Reconductor limiting span of Lallendorf-Monroe 345 kV line (crossing of Maumee River)	2020
Eugene-Cayuga 345 kV line for the loss of Rockport-Jefferson 765 kV line	M2M Flowgate	PJM RTEP b2777: Reconductor the entire Dequine-Eugene 345 kV circuit No.1	2021
Tanners Creek-Miami Fort 345 kV line for the loss of East Bend-Terminal 345 kV line	M2M Flowgate	PJM RTEP b2968/2831: Upgrade and/or rebuild the Tanners Creek-Miami Fort 345 kV line	2021/2022
Miami Fort 345/138 transformer for the loss of East Bend-Terminal 345 kV line	M2M Flowgate	PJM RTEP b2968/2831: Upgrade and/or rebuild the Tanners Creek-Miami Fort 345 kV line	2021/2022
Hennepin S.-Hennepin Tap 138 kV line for the loss of Princeton Tap 138 kV substation	M2M Flowgate	MISO MTEP 7820: Reconductor Hennepin-Kewanee 138 kV line (line 6101)	2018
Miami Fort-Hebron 138 kV line for the loss of Eastbend-Terminal 345 kV line	M2M Flowgate	PJM RTEP b2968/2831: Upgrade and/or rebuild the Tanners Creek-Miami Fort 345 kV line	2021/2022
Lakeview-Zion 138 kV line for the loss of Pleasant Prairie-Zion 345 kV line and Pleasant Prairie-Zion EC 345 kV line	M2M Flowgate	MISO MTEP 8065: Connect 345 kV line 2224 (Zion-Libertyville 345 kV)	2021

Section 6: State Summaries

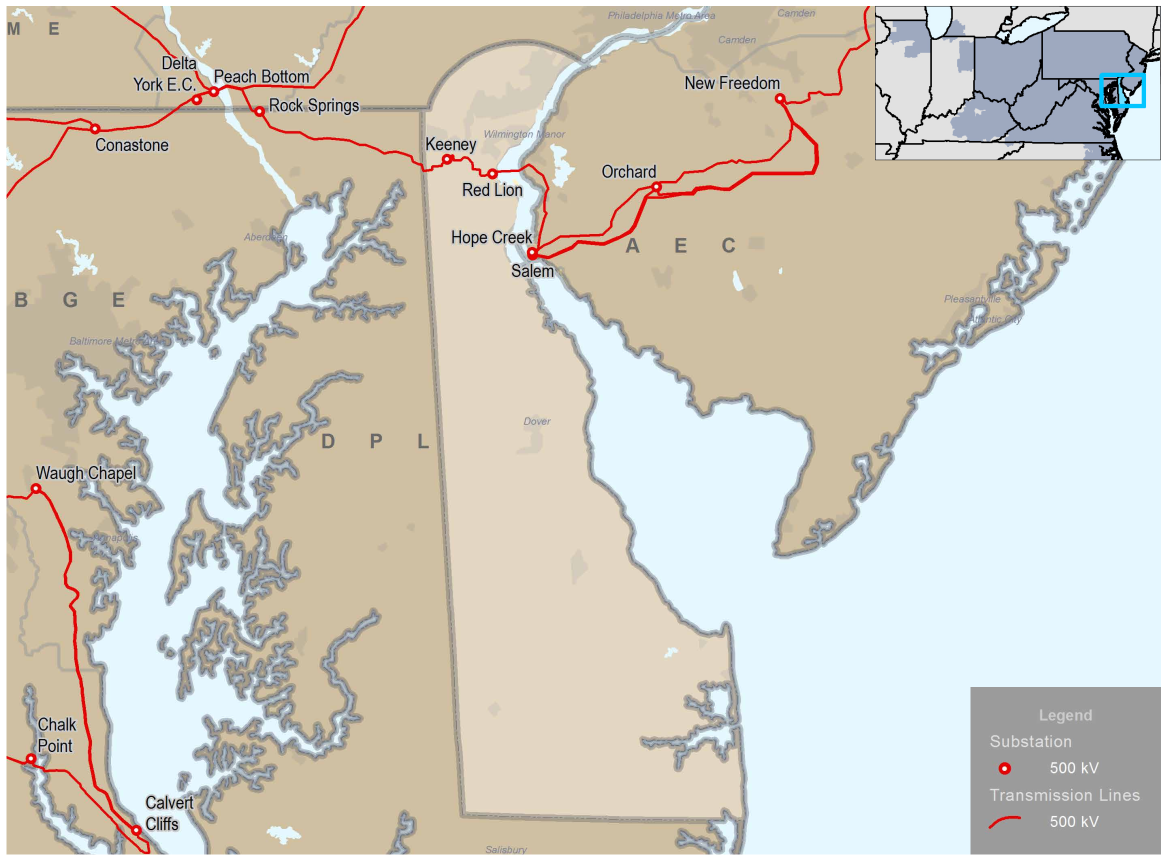
PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

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 (DPL) 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

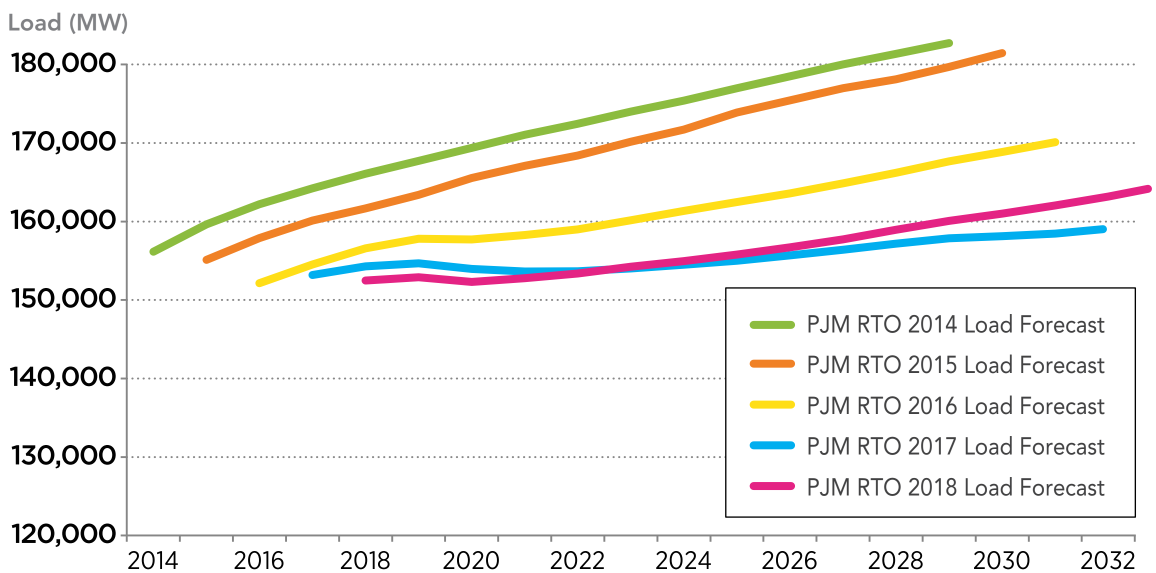
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.1** and **Figure 6.1** summarize the expected loads within the state of Delaware and across PJM.

Table 6.1: Delaware – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW) 2018	Summer Peak (MW) 2028	Summer Peak (MW) Growth Rate	Winter Peak (MW) 2017/ 2018	Winter Peak (MW) 2027/ 2028	Winter Peak (MW) Growth Rate
Delmarva Power and Light *	2,617	2,670	0.2%	2,117	2,200	0.4%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

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

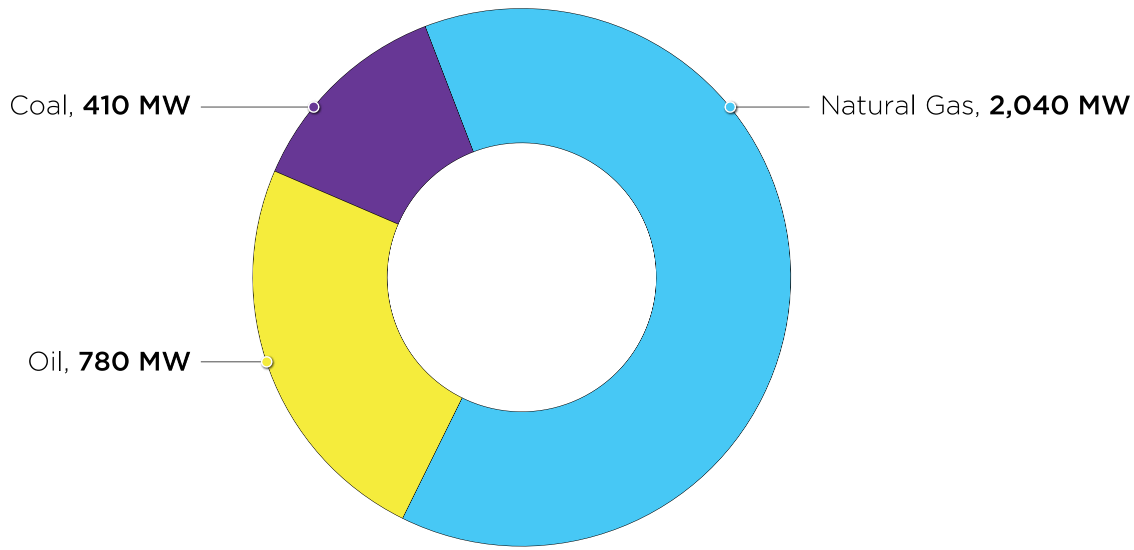
Figure 6.1: PJM RTO Summer Peak Demand Forecast



6.0.3 — Existing Generation

Existing generation in Delaware as of December 31, 2018, is shown by fuel type in **Figure 6.2.**

Figure 6.2: Delaware – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



6.0.4 — Interconnection Requests

As of December 31, 2018, 21 queued projects were actively under study, under construction or in suspension in the state of Delaware. A summary of those interconnection requests is shown in **Table 6.2, Table 6.3, Figure 6.3, Figure 6.4** and **Figure 6.5.**

Table 6.2: Delaware – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Natural Gas	451.0	451.0
Solar	197.6	418.3
Storage	0.2	1.0
Wind	160.4	599.8
Total	**809.2**	**1,470.1**

Figure 6.3: Delaware – Queued Capacity (MW) by Fuel Type (December 31, 2018)

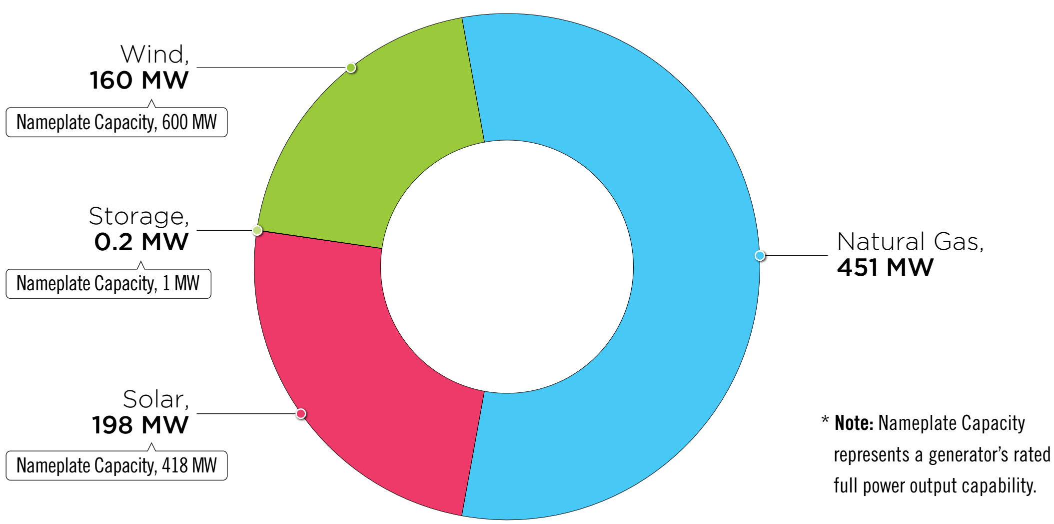


Table 6.3: Delaware – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue						Grand Total	
	In Service		Withdrawn		Active		Suspended		Under Construction			
	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	**28**	**1,318.3**	**25**	**6,232.4**	**1**	**0.2**	**1**	**451.0**	**0**	**0.0**	**55**	**8,001.9**
Coal	2	23.0	1	630.0	0	0.0	0	0.0	0	0.0	3	653.0
Natural Gas	19	1,097.1	19	5,556.4	0	0.0	1	451.0	0	0.0	39	7,104.5
Oil	5	168.2	1	1.0	0	0.0	0	0.0	0	0.0	6	169.2
Other	2	30.0	0	0.0	0	0.0	0	0.0	0	0.0	2	30.0
Storage	0	0.0	4	45.0	1	0.2	0	0.0	0	0.0	5	45.2
Renewable	**5**	**9.0**	**27**	**586.9**	**18**	**293.6**	**0**	**0.0**	**1**	**64.4**	**51**	**953.9**
Biomass	1	0.0	4	24.0	0	0.0	0	0.0	0	0.0	5	24.0
Methane	4	9.0	3	28.8	0	0.0	0	0.0	0	0.0	7	37.8
Solar	0	0.0	16	178.7	16	197.6	0	0.0	0	0.0	32	376.3
Wind	0	0.0	4	355.4	2	96.0	0	0.0	1	64.4	7	515.8
Grand Total	**33**	**1,327.3**	**52**	**6,819.3**	**19**	**293.8**	**1**	**451.0**	**1**	**64.4**	**106**	**8,955.8**

Figure 6.4: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

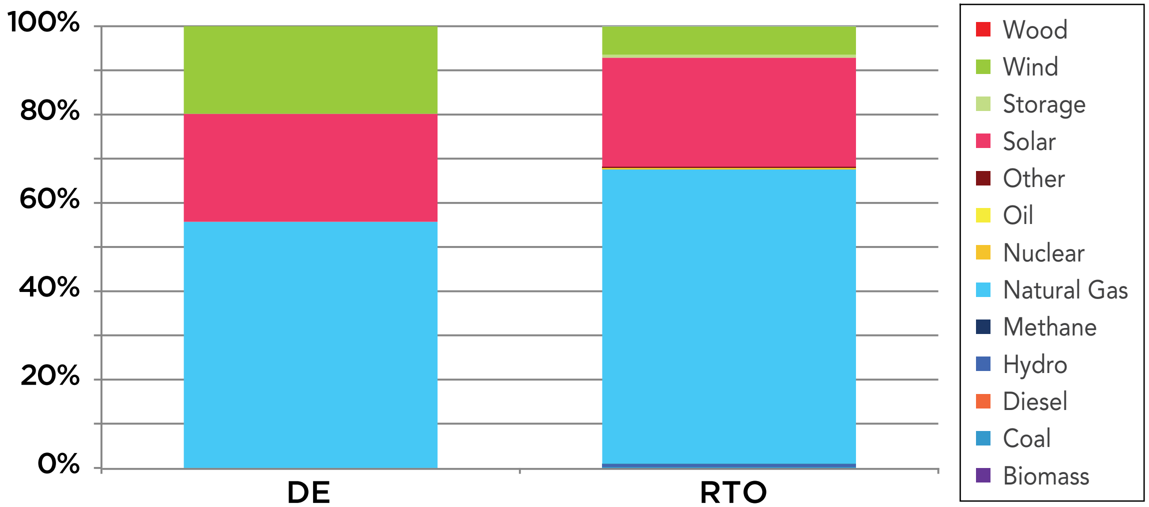
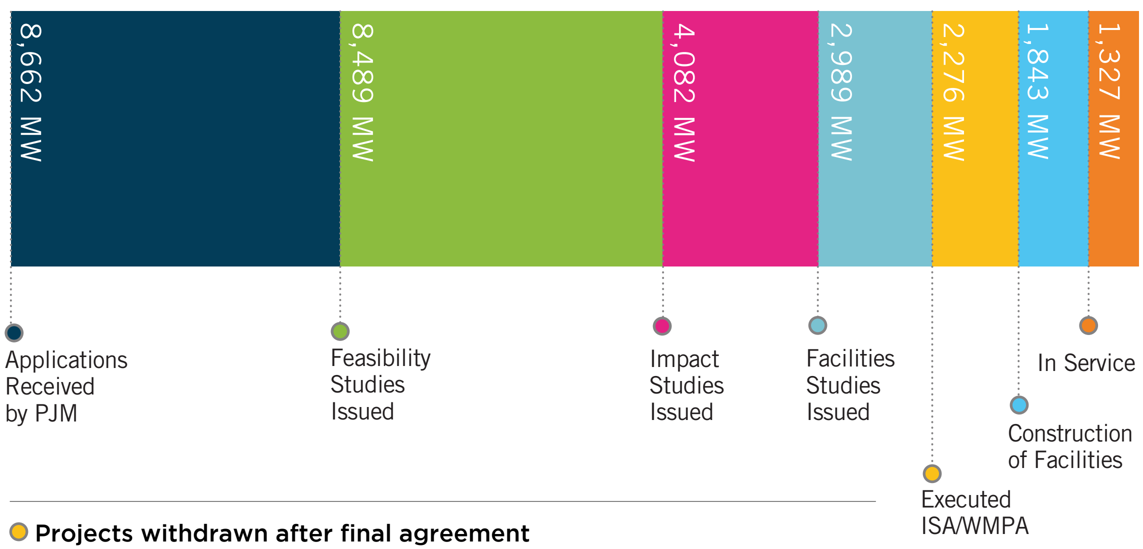


Figure 6.5: Delaware Progression History of Queue – Interconnection Requests (December 31, 2018)



Projects withdrawn after final agreement

- **3** Interconnection Service Agreements – 420 MW (Nameplate Capacity, 780 MW)
- **4** Wholesale Market Participation Agreements –13.3 MW (Nameplate Capacity, 46.9 MW)

Percentage of planned capacity and projects reached commercial operation

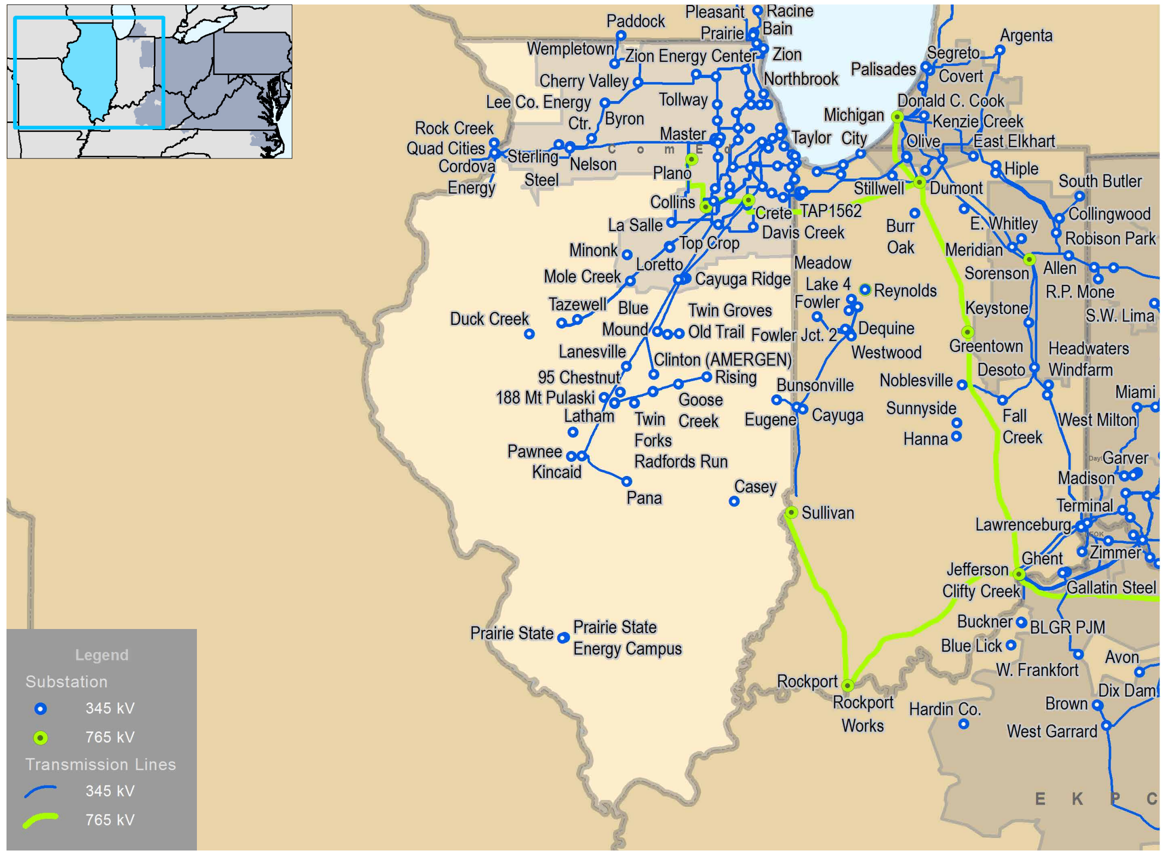
- **15.3 %** requested capacity megawatt
- **37.9 %** requested projects

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 6.2**. 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 6.2: PJM Service Area in Northern Illinois



6.1.2 — Load Growth

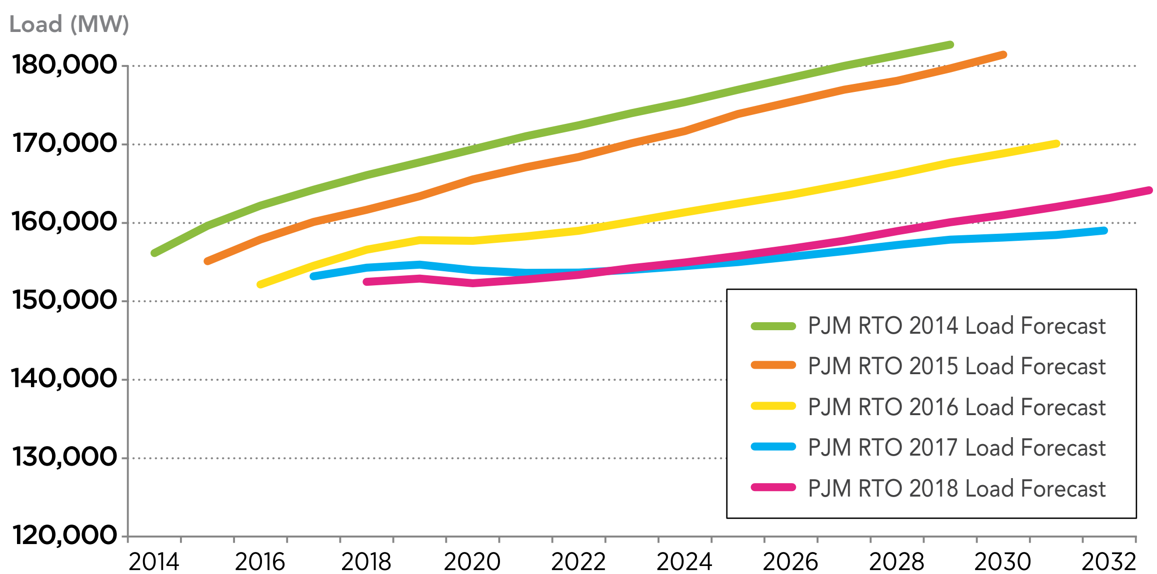
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.4** and **Figure 6.6** summarize the expected loads within the state of Northern Illinois and across all of PJM.

Table 6.4: Northern Illinois – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2018	2028	Growth Rate	2017/ 2018	2027/ 2028	Growth Rate
Commonwealth Edison Company	22,121	23,207	0.5%	15,714	16,329	0.4%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

* **Note:** PJM does not serve the entire state of Illinois.

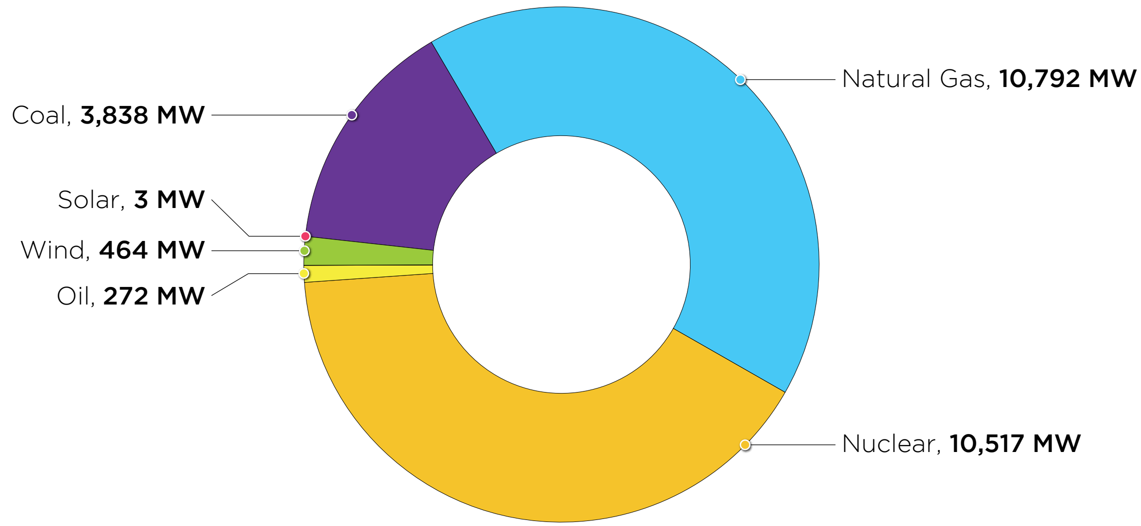
Figure 6.6: PJM RTO Summer Peak Demand Forecast



6.1.3 — Existing Generation

Existing generation in Northern Illinois as of December 31, 2018, is shown by fuel type in **Figure 6.7**.

Figure 6.7: Northern Illinois – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



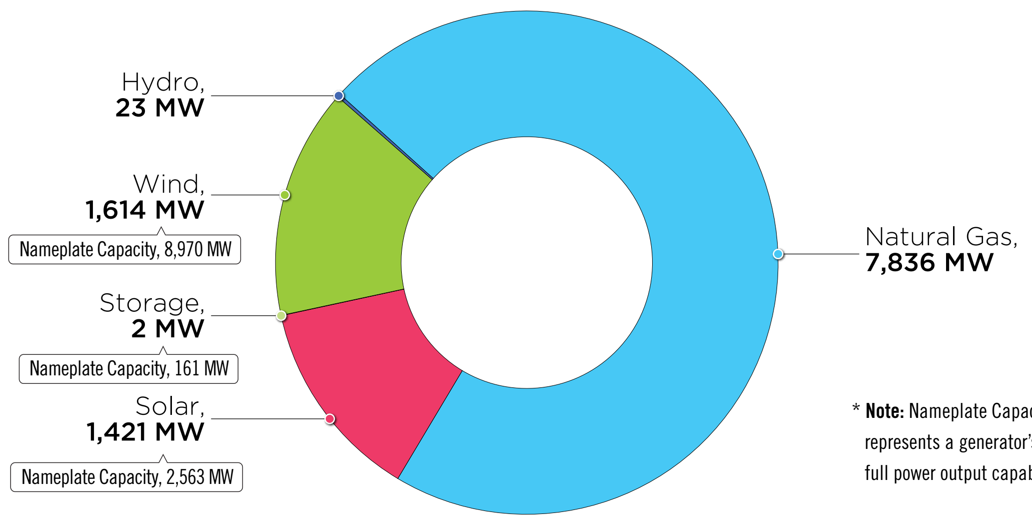
6.1.4 — Interconnection Requests

As of December 31, 2018, 104 queued projects were actively under study, under construction or in suspension in the state of Illinois. A summary of those interconnection requests is shown in **Table 6.5, Table 6.6, Figure 6.8, Figure 6.9** and **Figure 6.10.**

Table 6.5: Northern Illinois – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity (MW)	Nameplate Capacity (MW)
Natural Gas	7,835.6	8,011.2
Wind	1,613.6	8,970.2
Solar	1,420.5	2,562.5
Hydro	22.7	22.7
Storage	2.2	161.4
Total	**10,894.6**	**19,728.0**

Figure 6.8: Northern Illinois – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.6: Northern Illinois – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue				Grand Total	
	In Service		Withdrawn		Active		Under Construction			
	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	**32**	**7,777.2**	**3**	**60.6**	**33**	**1,850.8**	**43**	**10,489.3**	**111**	**20,177.9**
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	28	7,775.0	2	60.6	15	1,423.0	15	6,051.3	60	15,309.9
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	0.0	4	20.0
Storage	4	2.2	1	0.0	5	0.0	15	4.0	25	6.2
Renewable	**59**	**2,752.4**	**10**	**304.4**	**28**	**671.6**	**144**	**3,287.7**	**241**	**7,016.1**
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	6	49.0	14	63.9	20	112.9
Solar	25	1,420.5	0	0.0	1	3.4	32	845.0	58	2,268.9
Wind	34	1,331.9	8	281.7	21	619.2	93	2,284.5	156	4,517.3
Grand Total	**91**	**10,529.6**	**13**	**365.0**	**61**	**2,522.4**	**187**	**13,777.0**	**352**	**27,194.0**

Figure 6.9: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

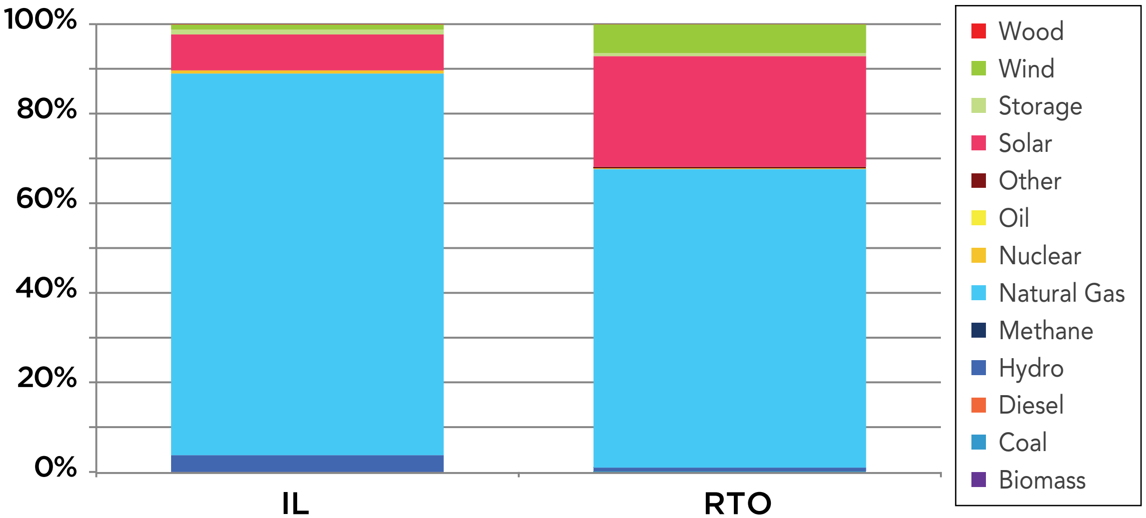
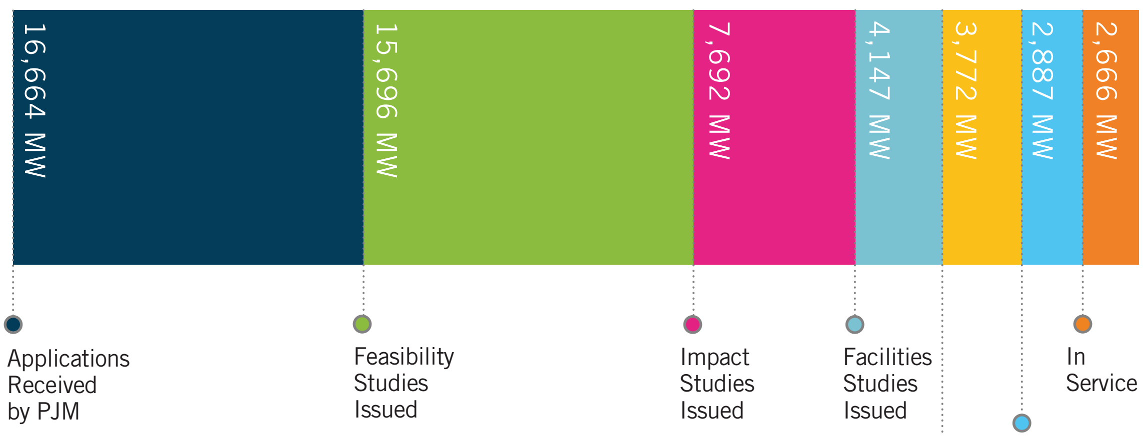


Figure 6.10: Northern Illinois Progression History of Queue – Interconnection Requests (December 31, 2018)



Projects withdrawn after final agreement

- **7** Interconnection Service Agreements – 275.6 MW (Nameplate Capacity, 1,178 MW)
- **4** Wholesale Market Participation Agreements – 3.8 MW (Nameplate Capacity, 14.7 MW)

Percentage of planned capacity and projects reached commercial operation

- **16 %** requested capacity megawatt
- **25.7 %** requested projects

6.1.5 — Generation Deactivation

Known generating unit deactivation requests in Northern Illinois between January 1, 2018, and December 31, 2018, are summarized in **Table 6.7** and **Map 6.3**.

Map 6.3: Northern Illinois Generation Deactivations (December 31, 2018)

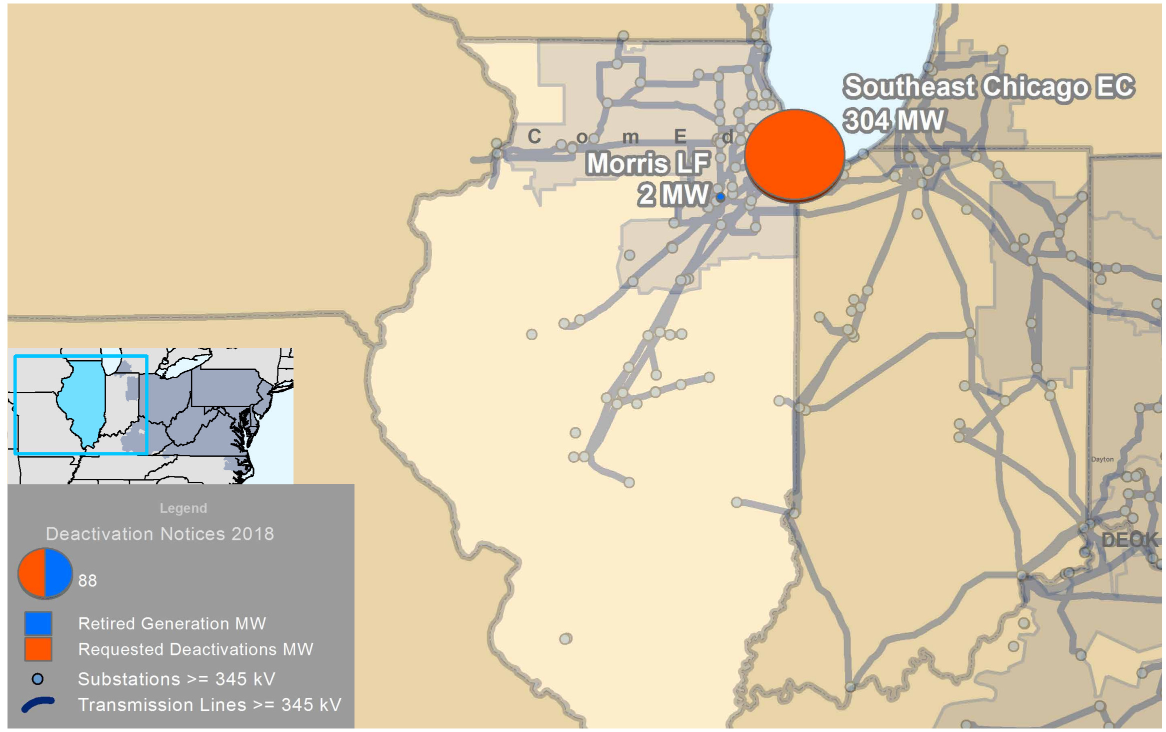


Table 6.7: Northern Illinois Generation Deactivations (December 31, 2018)

Unit	Capacity (MW)	TO Zone	Age (Years)	Projected/Actual Deactivation Date
Southeast Chicago 5	38	ComEd	16	6/1/2020
Southeast Chicago 6	38	ComEd	16	6/1/2020
Southeast Chicago 7	38	ComEd	16	6/1/2020
Southeast Chicago 8	38	ComEd	16	6/1/2020
Southeast Chicago 9	38	ComEd	16	6/1/2020
Southeast Chicago 10	38	ComEd	16	6/1/2020
Southeast Chicago 11	38	ComEd	16	6/1/2020
Southeast Chicago 12	38	ComEd	16	6/1/2020
Morris Landfill	2	ComEd	17	5/31/2018

6.1.6 — Baseline Projects

RTEP baseline upgrades greater than or equal to $10 million in Northern Illinois are summarized in **Table 6.8** and **Map 6.4**. In 2018, PJM added $15 million in total baseline projects in Northern Illinois.

Map 6.4: Northern Illinois Baseline Map

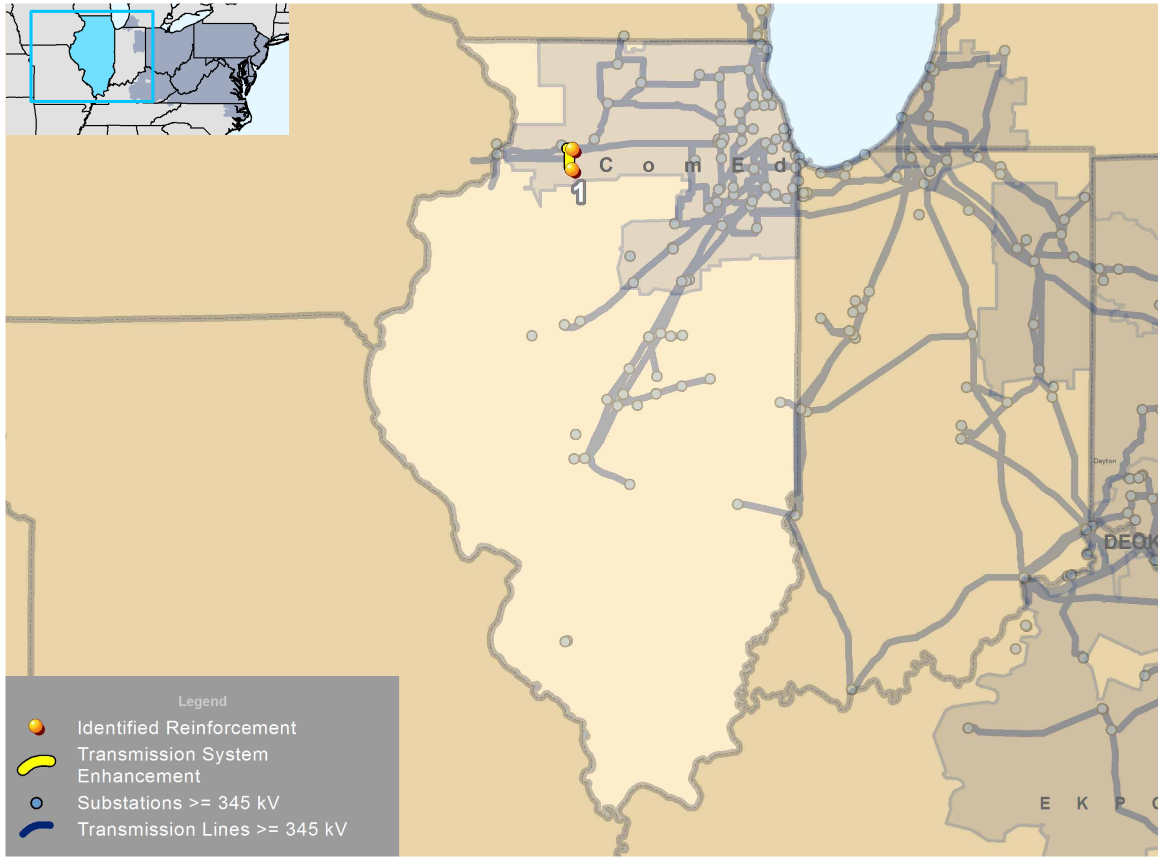


Table 6.8: Northern Illinois Baseline Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	Baseline Load Growth Deliverability and Reliability
1	b2999		Rebuild 12.36 miles of Schauff Road-Nelson Tap 138 kV line.	11/1/2019	$17.00	ComEd	5/21/2018	X

6.1.7 — Network Projects

RTEP network upgrades greater than or equal to $10 million in Northern Illinois are summarized in **Table 6.9** and **Map 6.5**.

Map 6.5: Northern Illinois Network Projects (Greater than $10 M) (December 31, 2018)

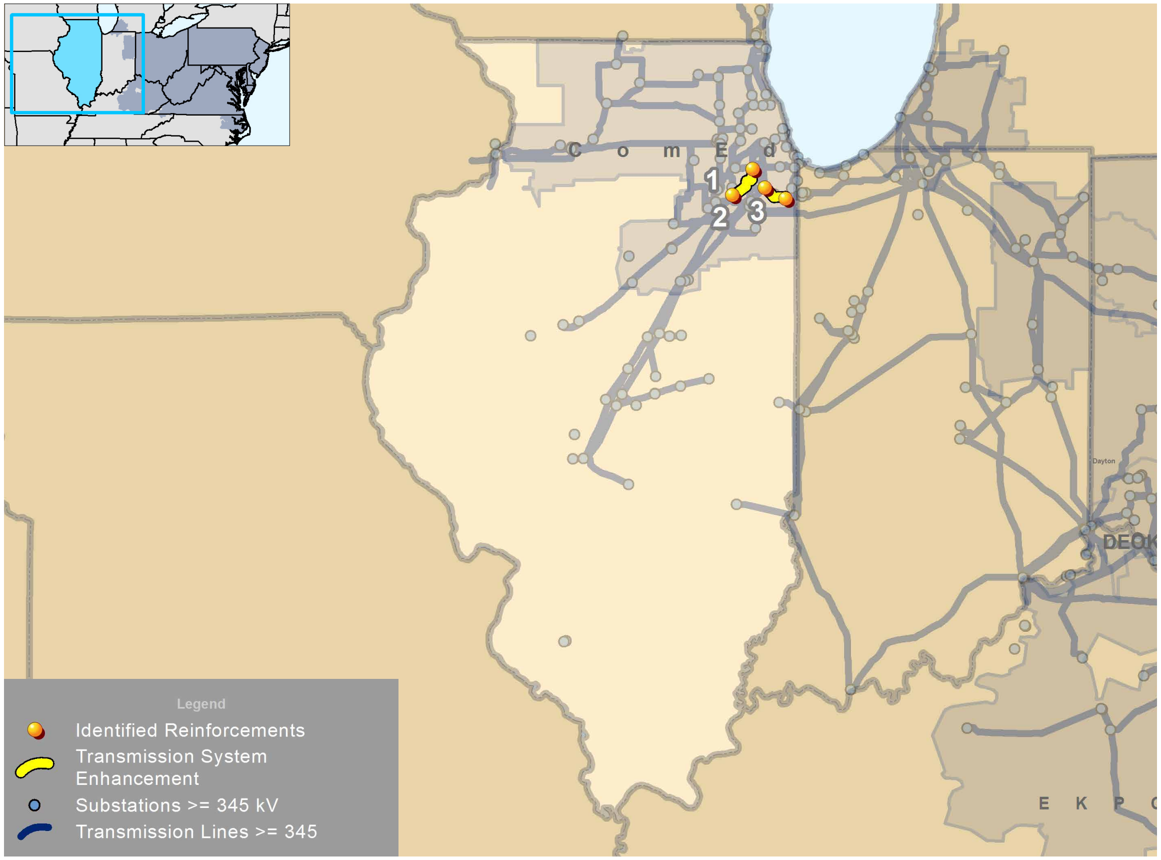


Table 6.9: Northern Illinois Network Upgrades (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Project Driver	Queue	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	n5915	Reconductor the Elwood-Goodings Grove 345 kV line, upgrade the station conductor at both line terminals, and upgrade the line circuit breaker at Goodings Grove.	Generation	AC1-204 (Natural Gas)	6/1/2022	$23.00	ComEd	9/13/2018
2	n5916	Reconductor the Elwood -Goodings Grove 345 kV line, upgrade the station conductor at both line terminals, and upgrade the line circuit breaker at Goodings Grove.	Generation	AC1-204 (Natural Gas)	6/1/2022	$23.00	ComEd	9/13/2018
3	n5917	Reconductor the E. Frankfort-Crete 345 kV line.	Generation	AC1-204 (Natural Gas)	6/1/2022	$10.00	ComEd	9/13/2018

6.1.8 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in Northern Illinois are summarized in **Table 6.10** and **Map 6.6**.

Map 6.6: Northern Illinois Supplemental Projects (December 31, 2018)

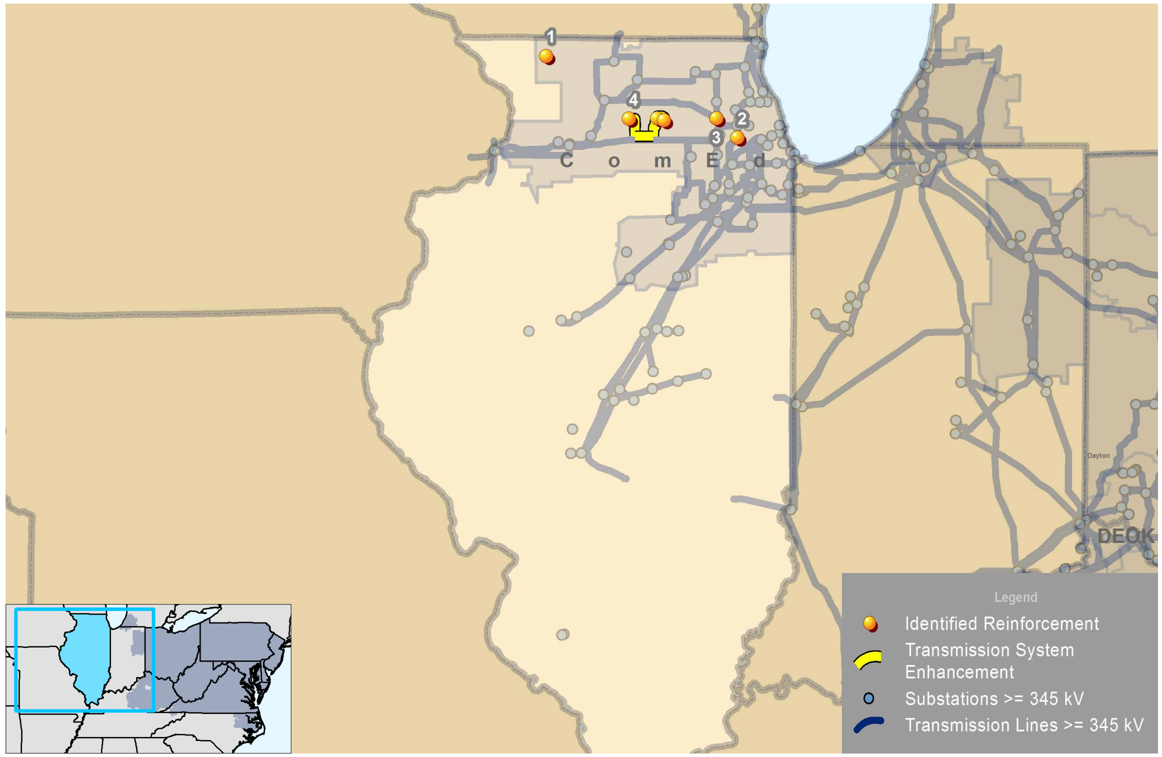


Table 6.10: Northern Illinois Supplemental Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	s1480	Install a new 138/34 kV transformer with high side and low side breakers at Lena. Expand the 34 kV switchgear. Replace line circuit switchers with 138 kV breakers, install new bus tie breaker.	6/1/2019	$14.20	ComEd	1/8/2018
		Normally close 138 kV line into Lena. Normally open the new 138 kV bus tie breaker.	6/1/2019		ComEd	1/8/2018
2	s1529	Install a 345 kV bus tie and breaker at Lisle 345 kV substation. Close the new and existing bus ties creating a large hybrid ring bus so each bus contains a transmission line and a transformers. Install four 345 kV line breakers and two 345 kV high-side transformer breakers.	12/31/2019	$30.00	ComEd	2/8/2018
3	s1530	Replace Wayne 345/138 kV transformer. Finish ring bus on 345 kV bus. Install two 34 5kV breakers. Retire existing cap bank and install 138 kV cap bank.	12/31/2019	$15.00	ComEd	2/8/2018
4	s1533	Construct new line from the Twombley Road substation to a tap of the West DeKalb-Glidden 138 kV line just outside the West DeKalb 138 kV substation.	10/1/2021	$18.00	City of Rochelle	3/9/2018
		ComEd work at West DeKalb to accommodate the connection.	10/1/2021		ComEd	3/9/2018

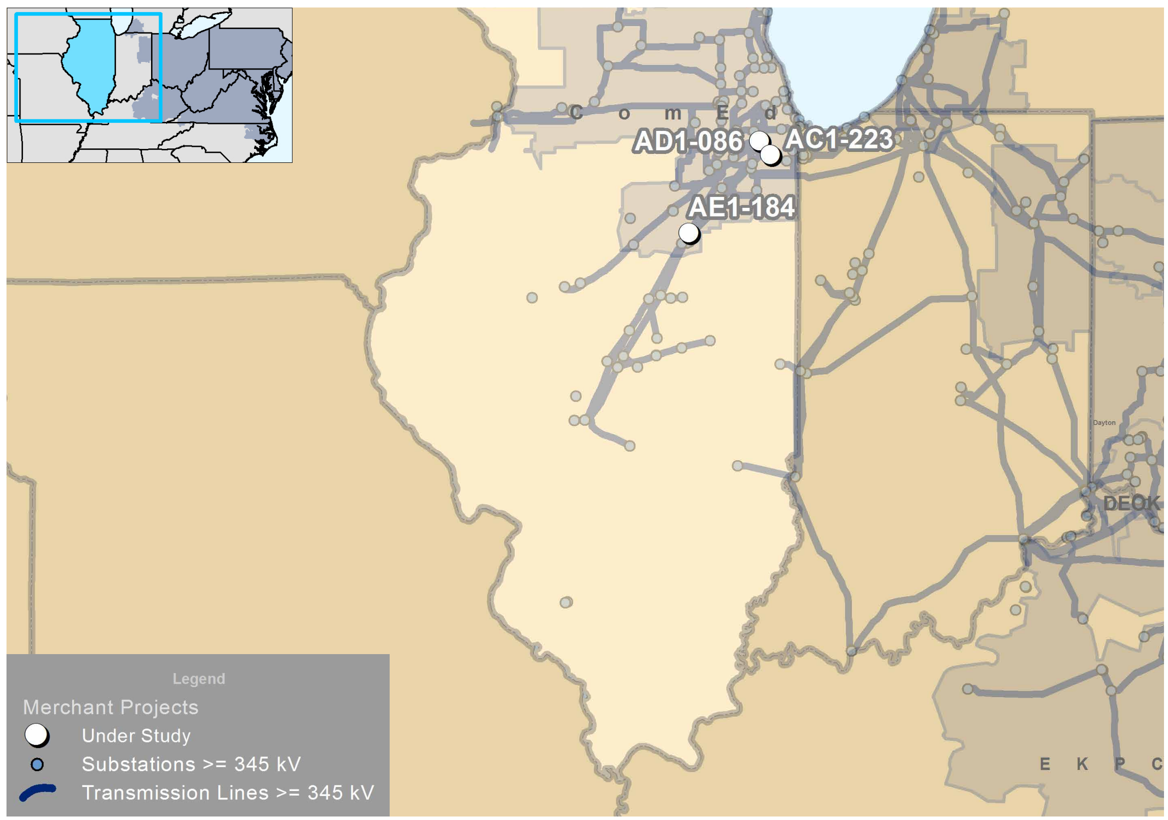
6.1.9 — Merchant Transmission Project Requests

As of December 31, 2018, PJM's queue contained three merchant transmission interconnection request projects, which included a terminal in Northern Illinois, as shown in **Table 6.11** and **Map 6.7**.

Table 6.11: Northern Illinois Merchant Transmission Project Requests (December 31, 2018)

Queue	Project Name	Maximum Fuel Output (MW)	Status	Projected In-Service Date	TO Zone
AC1-223	E. Frankfort-University Park North	43.2	Under Construction	6/1/2020	ComEd
AD1-086	E. Frankfort-Goodings Grove	23.9	Active	6/20/2021	ComEd
AE1-184	Pontiac Midpoint-Dresden	82.7	Active	6/1/2022	ComEd

Map 6.7: Northern Illinois Merchant Transmission Project Requests (December 31, 2018)

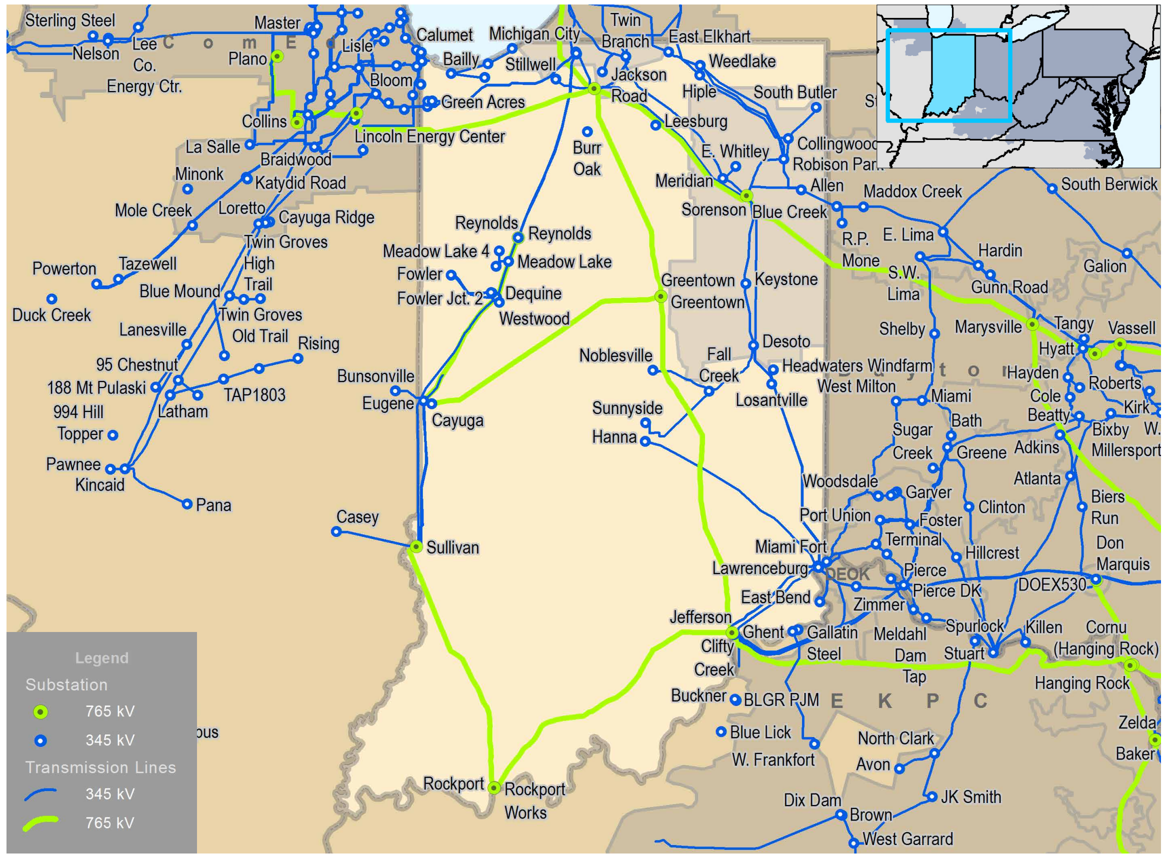


6.2: Indiana RTEP Summary

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 6.8**. 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 6.8: PJM Service Area in Indiana



6.2.2 — Load Growth

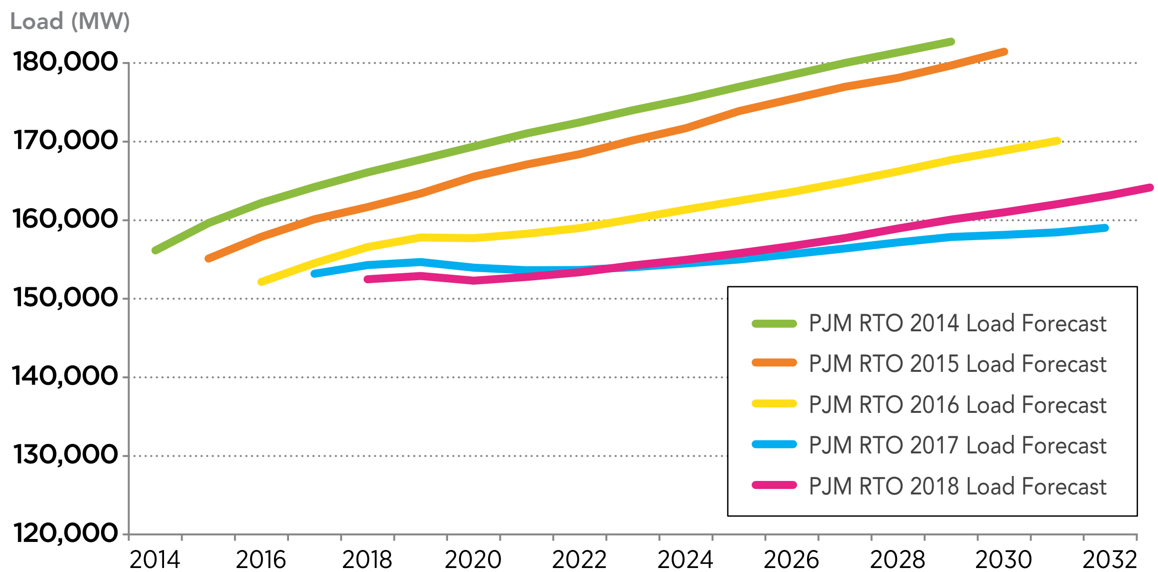
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.12** and **Figure 6.11** summarize the expected loads within the state of Indiana and across all of PJM.

Table 6.12: Indiana – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2018	2028	Growth Rate	2017/ 2018	2027/ 2028	Growth Rate
American Electric Power*	3,770	3,958	0.5%	3,212	3,377	0.5%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

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

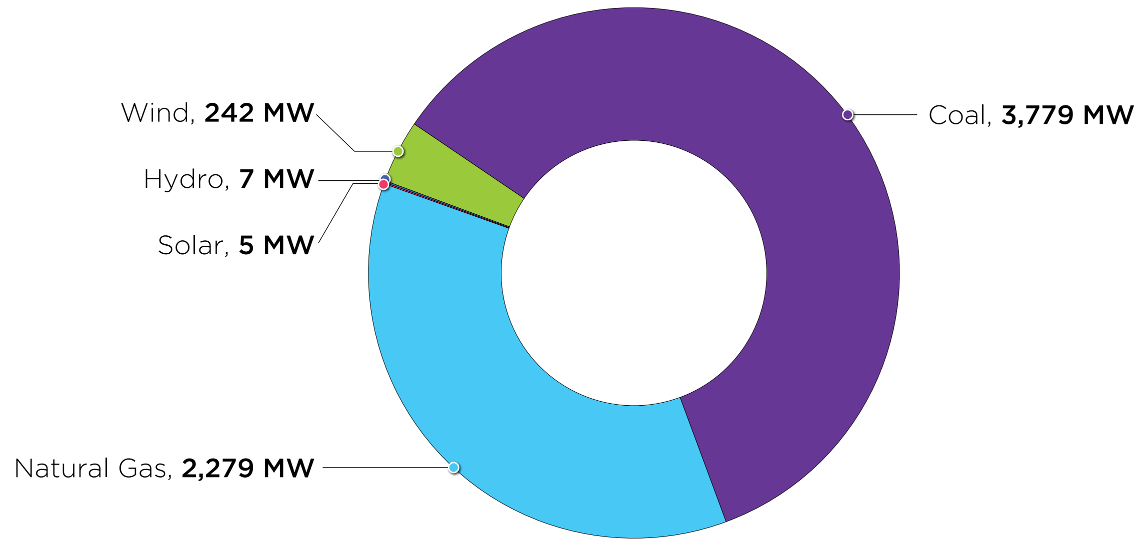
Figure 6.11: PJM RTO Summer Peak Demand Forecast



6.2.3 — Existing Generation

Existing generation in Indiana as of December 31, 2018, is shown by fuel type in **Figure 6.12**.

Figure 6.12: Indiana – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



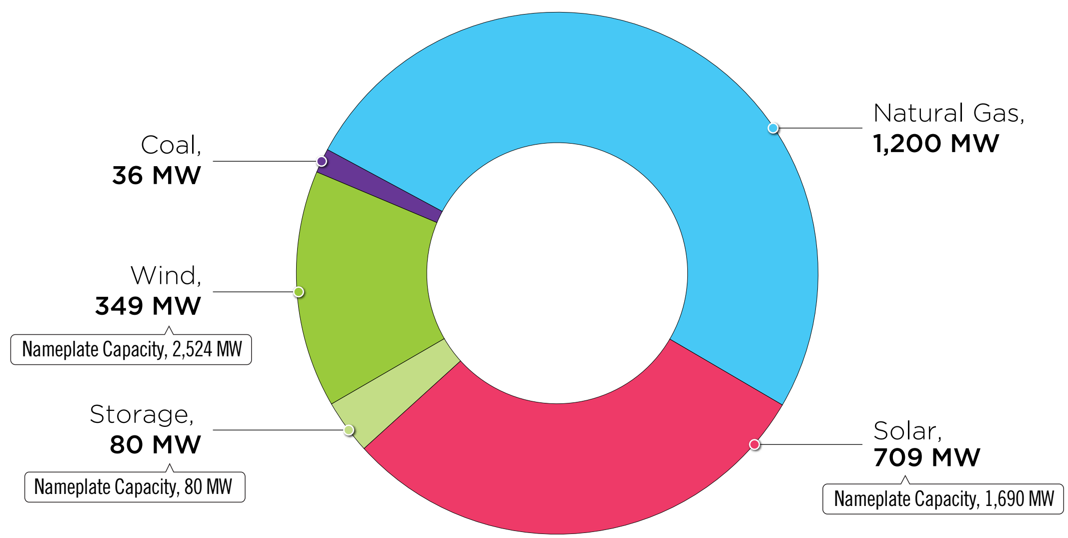
6.2.4 — Interconnection Requests

As of December 31, 2018, 31 queued projects were actively under study, under construction or in suspension in the state of Indiana. A summary of those interconnection requests is shown in **Table 6.13**, **Table 6.14, Figure 6.13, Figure 6.14** and **Figure 6.15**.

Table 6.13: Indiana – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Natural Gas	1,200.0	1,250.0
Solar	708.5	1,690.0
Wind	348.7	2,524.2
Storage	80.0	80.0
Coal	36.0	36.0
Total	**2,373.1**	**5,580.2**

Figure 6.13: Indiana – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.14: Indiana – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue				Grand Total	
	In Service		Withdrawn		Active		Under Construction			
	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	**7**	**791.0**	**8**	**2,671.3**	**3**	**1,180.0**	**3**	**136.0**	**21**	**4,778.3**
Coal	3	30.0	2	901.0	0	0.0	1	36.0	6	967.0
Natural Gas	4	761.0	2	1,747.0	2	1,100.0	2	100.0	10	3,708.0
Storage	0	0.0	4	23.3	1	80.0	0	0.0	5	103.3
Renewable	**13**	**359.1**	**55**	**3,555.2**	**23**	**1,005.1**	**2**	**52.0**	**93**	**4,971.4**
Methane	2	8.0	1	3.6	0	0.0	0	0.0	3	11.6
Solar	3	5.1	13	2,005.0	12	708.5	0	0.0	28	2,718.5
Wind	8	346.0	41	1,546.7	11	296.7	2	52.0	62	2,241.3
Grand Total	**20**	**1150.0**	**63**	**6,227.0**	**26**	**2,185.0**	**5**	**188.0**	**114**	**9,750.0**

Figure 6.14: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

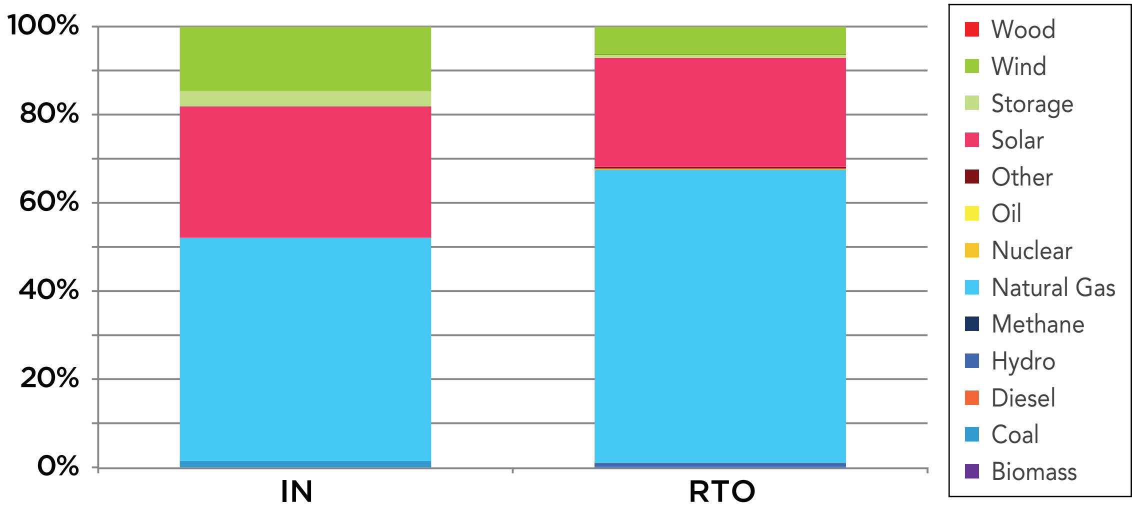
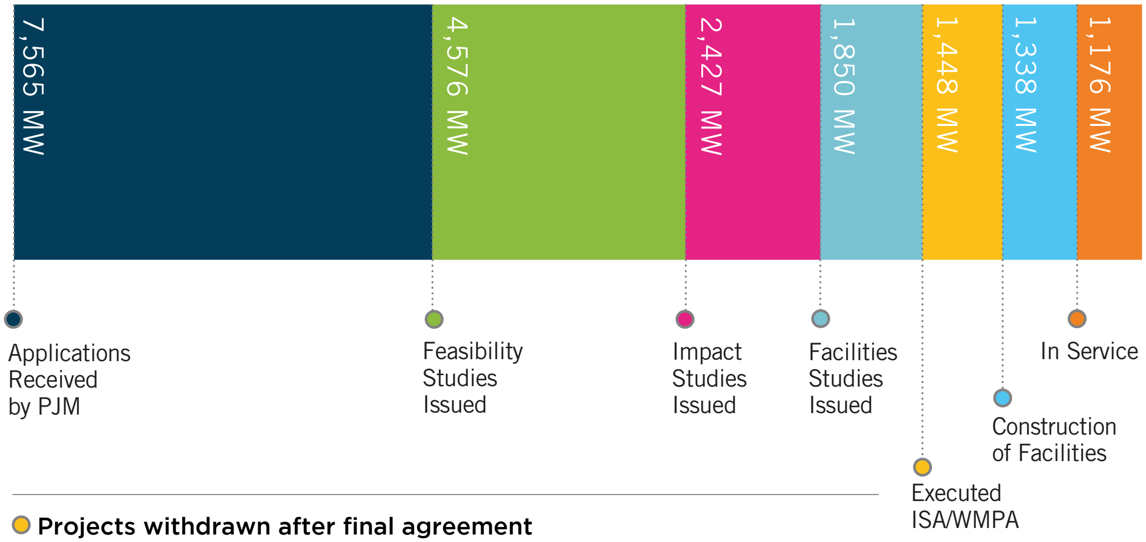


Figure 6.15: Indiana Progression History of Queue – Interconnection Requests (December 31, 2018)



Projects withdrawn after final agreement

- **3** Interconnection Service Agreements – 71.4 MW (Nameplate Capacity, 420 MW)

Percentage of planned capacity and projects reached commercial operation

- **15.5 %** requested capacity megawatt
- **23.9 %** requested projects

6.2.5 — Network Projects

RTEP network upgrades greater than or equal to$10 million in Indiana are summarized in **Table 6.15** and **Map 6.9**.

Map 6.9: Indiana Network Projects (Greater than $10 M) (December 31, 2018)

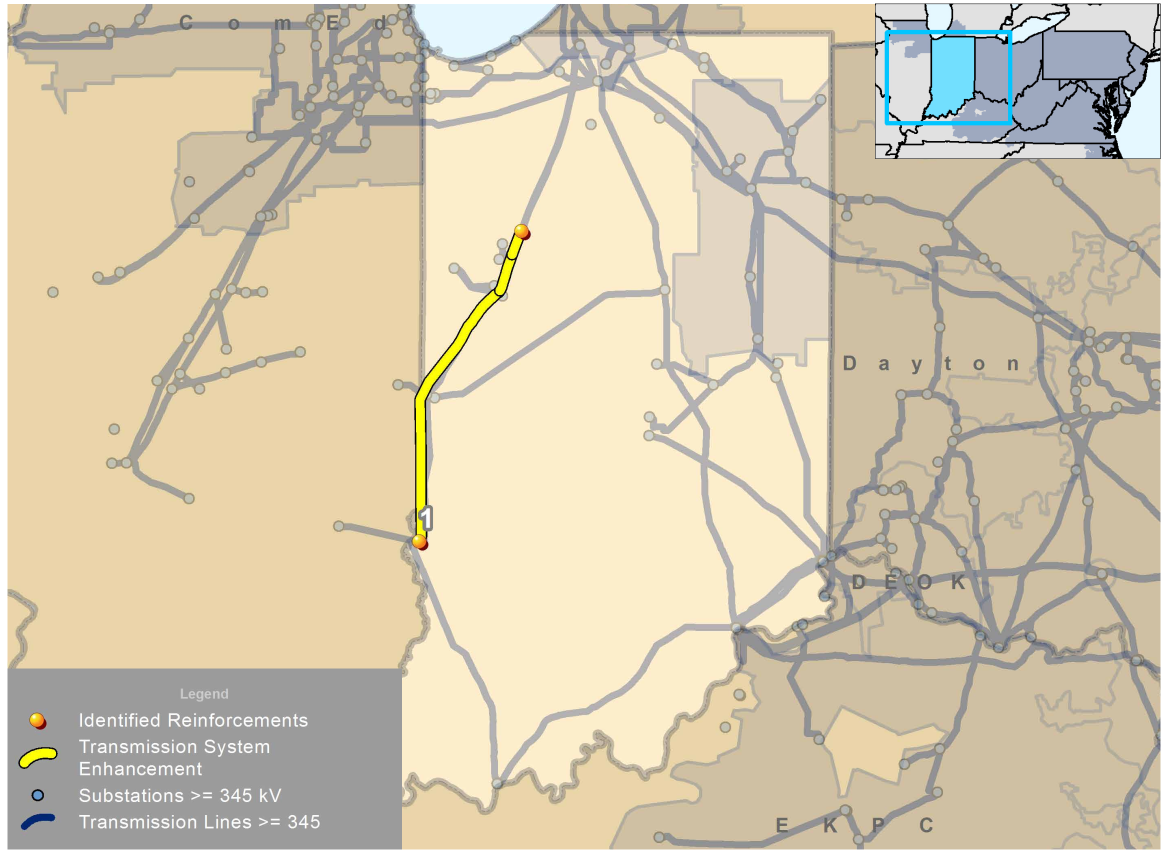


Table 6.15: Indiana Network Upgrades (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Project Driver	Queue	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	n5034	Build a new Sullivan-Reynolds 765 kV line.	Merchant Transmission	X3-028	6/1/2021	$464.00	AEP	9/13/2018

6.2.6 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in Indiana are summarized in **Table 6.16** and **Map 6.10**.

Map 6.10: Indiana Supplemental Projects (Greater than $10 M) (December 31, 2018)

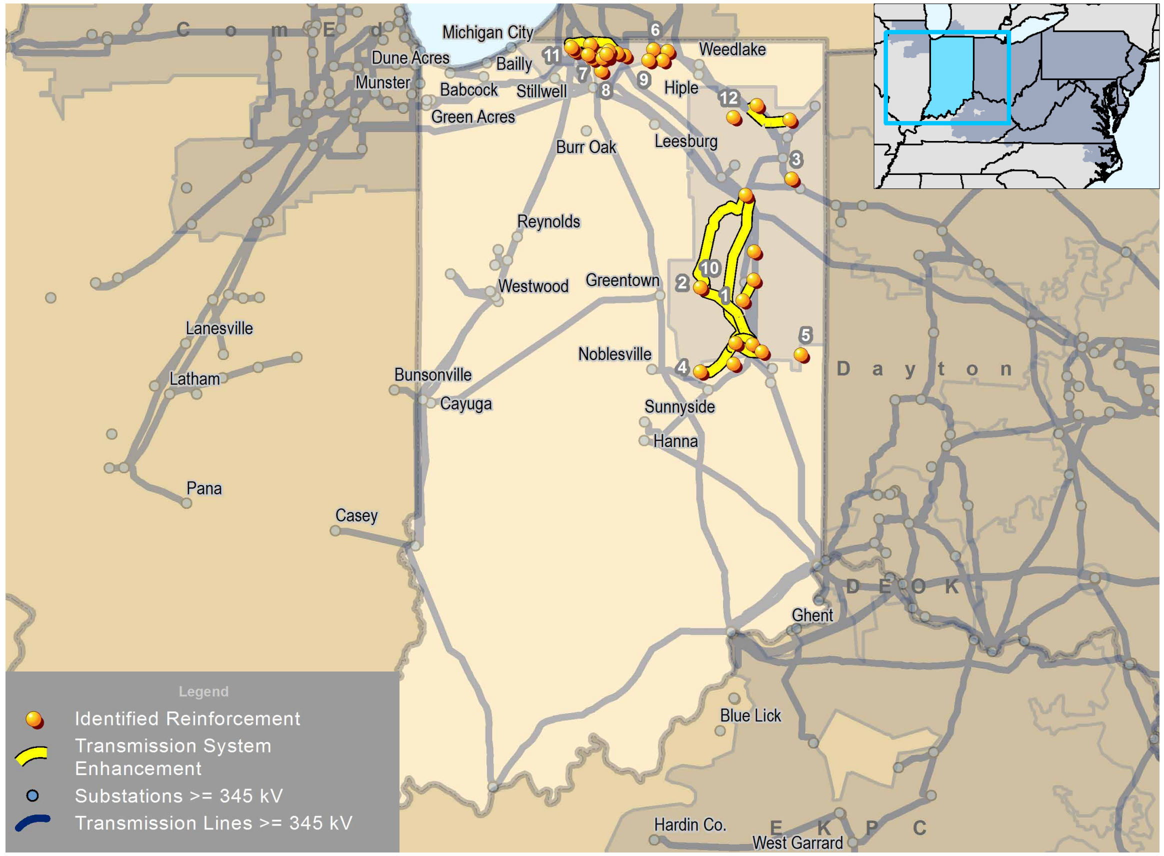


Table 6.16: Indiana Supplemental Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	s1430	Replace two circuit breakers at Liberty Center and install a new high-side 69 kV circuit switcher.	12/20/2019	$14.98	AEP	1/8/2018
		Replace three circuit breakers at Hartford City 69 kV with 40 kA models.	6/1/2020		AEP	1/8/2018
		Rebuild approximately 8.5 miles of the Hartford City-Montpelier 69 kV line utilizing aluminum conductor steel cable (68 MVA rating, non-conductor limited).	7/23/2019		AEP	1/8/2018
2	s1495	Rebuild approximately 32 miles of the Delaware-Sorenson & Sorenson-Deer Creek 138 kV double circuit line using aluminum conductor steel cable (257 MVA rating).	12/2/2019	$84.30	AEP	1/30/2018
		Rebuild approximately 3 miles of the Deer Creek 138 kV double circuit extension using aluminum conductor steel cable, 257 MVA rating.	12/2/2019		AEP	1/30/2018

Table 6.15: Indiana Supplemental Projects (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
3	s1496	Rebuild approximately 2 miles of single circuit line with aluminum conductor steel cable from Anthony Station to Structure 66 (just south of Lakeside station) and continue to Storm Water Station. The rebuilt 34.5 kV circuit from Anthony-Storm Water 34.5 kV will be limited by switches at Storm Water creating an overall rating of 41/45 MVA and 53/57 MVA.	9/23/2020	$16.60	AEP	1/30/2018
		At Water Pollution Station, replace two 34.5 kV circuit breakers with 1200 A 25 kA breakers.	9/23/2020		AEP	1/30/2018
		At Anthony Station, replace a 34.5 kV circuit breaker with a 25 kA breaker.	3/25/2020		AEP	1/30/2018
4	s1498	Rebuild the approximately 19 miles of the Delaware-Madison double circuit 138 kV line utilizing double circuit aluminum conductor steel cable.	12/20/2019	$54.80	AEP	1/30/2018
		Replace risers at Delaware station with 1200 A jumpers.	12/18/2021		AEP	1/30/2018
		Replace the switches at Daleville station with 100 kA switches.	12/31/2021		AEP	1/30/2018
5	s1508	Rebuild from structure near Anchor Hocking Station to structure near Price station using approximately 6.5 miles aluminum conductor steel cable.	5/14/2020	$10.60	AEP	2/14/2018
6	s1549	At Osolo station, replace two 34.5 kV breakers with 69 kV 40 kA breakers. Replace Transformer 1 with a 138/69/34.5 kV 75 MVA unit and install a high-side circuit switcher. Install two line breakers and a bus tie breaker in between the two loads utilizing 138 kV 40 kA breakers.	4/10/2020	$12.10	AEP	3/9/2018
		At East Elkhart station, replace Transformer 2 with a 138/69/34.5 kV 75 MVA transformer. Replace a circuit breaker with a 40 kA 69 kV breaker.	4/10/2020		AEP	3/9/2018
7	s1550	Rebuild from Tulip Road to Grandview station utilizing 7.4 miles of single circuit aluminum conductor steel cable (64 MVA rating) built to 69 kV but energized at 34.5 kV. From Grandview-West Side, build 1.2 miles of double circuit aluminum conductor steel cable built to 69 kV but operated at 34.5 kV. Remove the emergency switch toward Bendix station. Remove the Grandview hard tap and feed the station radially from West Side.	11/30/2018	$17.20	AEP	3/9/2018
8	s1582	At Jackson Road station, replace 138 kV air blast circuit breakers with new 63 kA circuit breakers. Install five new 63 kA 138 kV breakers. Install three new 345 kV circuit breakers with 63 kA model. Replace 345/138/34.5 kV Transformer 3 with a 675 MVA unit.	12/31/2018	$13.79	AEP	3/8/2018
9	s1592	Rebuild Harrison Street station as a 69 kV ring bus station using 340 kA breakers.	4/1/2019	$38.90	AEP	3/27/2018
		Rebuild Lusher Avenue as a 69 kV station using a bus tie breaker with two air breakers on the line exits.	4/1/2019		AEP	3/27/2018
		Install a 69 kV 3000 A 40 kA breaker at Concord station toward Harrison Street. Install a 69 kV (34.5 kV operated) 3000 A 40 kA breaker at Concord station toward AE Comp.	4/1/2019		AEP	3/27/2018
		At Dunlap Station replace Transformer 2 with a 138/69-34.5 kV 90 MVA transformer. The transformer will have a high-side 40 kA circuit switcher. Install two 138 kV line breakers using 40 kA breakers. Replace two circuit breakers with 69 kV 40 kA models.	4/1/2019		AEP	3/27/2018
		Rebuild Elkhart Hydro to 69 kV standards but operate it at 34.5 kV. Replace two circuit breakers with 40 kA breakers. Install a 3000 A 40 kA 69 kV line breaker.	4/1/2019		AEP	3/27/2018
		Remove Harrison Street Tap Switch.	4/1/2019		AEP	3/27/2018
		Build approximately 1.5 miles of line from the existing Concord-Wolf de-energized 138 kV line to Harrison Street at 69 kV utilizing aluminum conductor steel cable (64 MVA rating). Retire the line portion from AE Comp-Harrison Street.	4/1/2019		AEP	3/27/2018
		Build approximately 1.5 miles from the Dunlap-Concord line to Harrison Street station. Rebuild 0.5 miles of the existing Dunlap-Lusher line to 69 kV standards and retire the portion between Harrison Street Tap and the new line. All new line will utilize aluminum conductor steel cable (64 MVA rating).	4/1/2019		AEP	3/27/2018

Table 6.15: Indiana Supplemental Projects (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
10	s1610	At Desoto station, install four 345 kV 63 kA breakers in the 345 kV yard with two breakers protecting the Tanners Creek No. 1 line, a breaker protecting Transformer 1's high side, and an additional breaker protecting Transformer 2's high side. Install five 138 kV kA breakers.	4/29/2019	$21.10	AEP	4/5/2018
		At Delaware station, retire exits toward College Corner and Selma Parker. Upgrade risers and busses on Deer Creek and Desoto exits.	4/29/2019		AEP	4/5/2018
		Retire 7 miles of the Delaware-College Corner/Selma Parker double circuit 138 kV line and re-terminate it into Desoto station.	4/29/2019		AEP	4/5/2018
		Rebuild roughly 2 miles of the Delaware-Deer Creek/Desoto line using aluminum conductor steel cable (257 MVA rating).	4/29/2019		AEP	4/5/2018
11	s1611	At German Station, install 40 kA 138 kV line breakers towards South Bend Station and Olive Stations.	6/30/2020	$68.80	AEP	4/5/2018
		At South Bend Station, upgrade risers towards Olive and Twin Branch.	6/30/2020		AEP	4/5/2018
		At Twin Branch Station, upgrade risers towards South Bend.	6/30/2020		AEP	4/5/2018
		At Olive Station, install one 345 kV circuit breaker, one 138 kV circuit breaker, replace a 69 kV circuit breaker and replace 138/69/34 kV Transformer No. 3 with 60 MVA 138/69 kV transformer.	6/30/2020		AEP	4/5/2018
		Rebuild existing double circuit South Bend-New Carlisle 138 kV with aluminum conductor steel cable (257 MVA rating), approximately 18.74 miles.	6/30/2020		AEP	4/5/2018
		Rebuild existing six-wired Twin Branch-South Bend 138 kV line asset with single circuit line with aluminum conductor steel cable (257 MVA rating), approximately 4.8 miles.	6/30/2020		AEP	4/5/2018
		Rebuild existing double circuit Olive Entrance B 138 kV Line with aluminum conductor steel cable (257 MVA rating), approximately 1 mile.	6/30/2020		AEP	4/5/2018
		Split the East Side-South Bend line from of the South Bend-Twin Branch shared pole.	6/30/2020		AEP	4/5/2018
12	s1613	Rebuild the existing Auburn-Kendallville 69 kV line using aluminum conductor steel cable overhead conductor (~15 miles, 102 MVA rating).	6/30/2019	$16.90	AEP	4/17/2018
		At Kendallville Station, replace three 69 kV circuit breakers and associated equipment with 69 kV 40 kA circuit breakers.	6/30/2019		AEP	4/17/2018
		At Albion Station, replace one 69 kV circuit breaker and associated equipment with 69 kV circuit breaker.	6/30/2019		AEP	4/17/2018
13	s1666	Construct approximately 2.5 mile 69 kV underground line between Colfax and Muessel.	9/2/2019	$40.40	AEP	4/17/2018
		Install Drewry's Extension 34.5 kV.	3/31/2020		AEP	4/17/2018
		Retire Kankakee-Colfax (UG) 34 kV Line.	5/10/2020		AEP	4/17/2018
		Rebuild 0.33 miles of the South Bend-Colfax underground line.	3/31/2020		AEP	4/17/2018
		Rebuild 1.9 miles of the South Bend-West Side Line using aluminum conductor steel cable (64 MVA rating).	5/10/2020		AEP	4/17/2018
		Bendix-Kankakee 34.5 kV line work.	3/31/2020		AEP	4/17/2018
		South Bend station work to set up 69 kV energization.	6/30/2019		AEP	4/17/2018
		Set up 69 kV energization at West Side station.	3/31/2020		AEP	4/17/2018
		Rebuild Colfax station. Install a 69 kV circuit breaker towards Muessel Station. Replace 34 kV circuit breaker with a 69 kV circuit breaker towards South Bend Station. Install a 69 kV standing wave ratio meter, 69/12 kV Transformer 1 and four 12 kV circuit breakers.	5/7/2020		AEP	4/17/2018
		Rebuild Drewrys station as Muessel station in the clear. Install three 69 kV line circuit breakers, a bus tie circuit breaker, two 69 kV standing wave ratio meters, two 69/12 kV transformers and seven 12 kV circuit breakers.	5/10/2020		AEP	4/17/2018
		At St. Mary's College, install 69 kV circuit switcher. Replace 69/12 kV transformer and two 69 kV switches.	4/1/2019		AEP	4/17/2018
		Relocate Goodland Sw to West Side-Bendix 34 kV line.	3/5/2020		AEP	4/17/2018
		Remove 34.5 kV breaker at Kankakee.	5/10/2020		AEP	4/17/2018

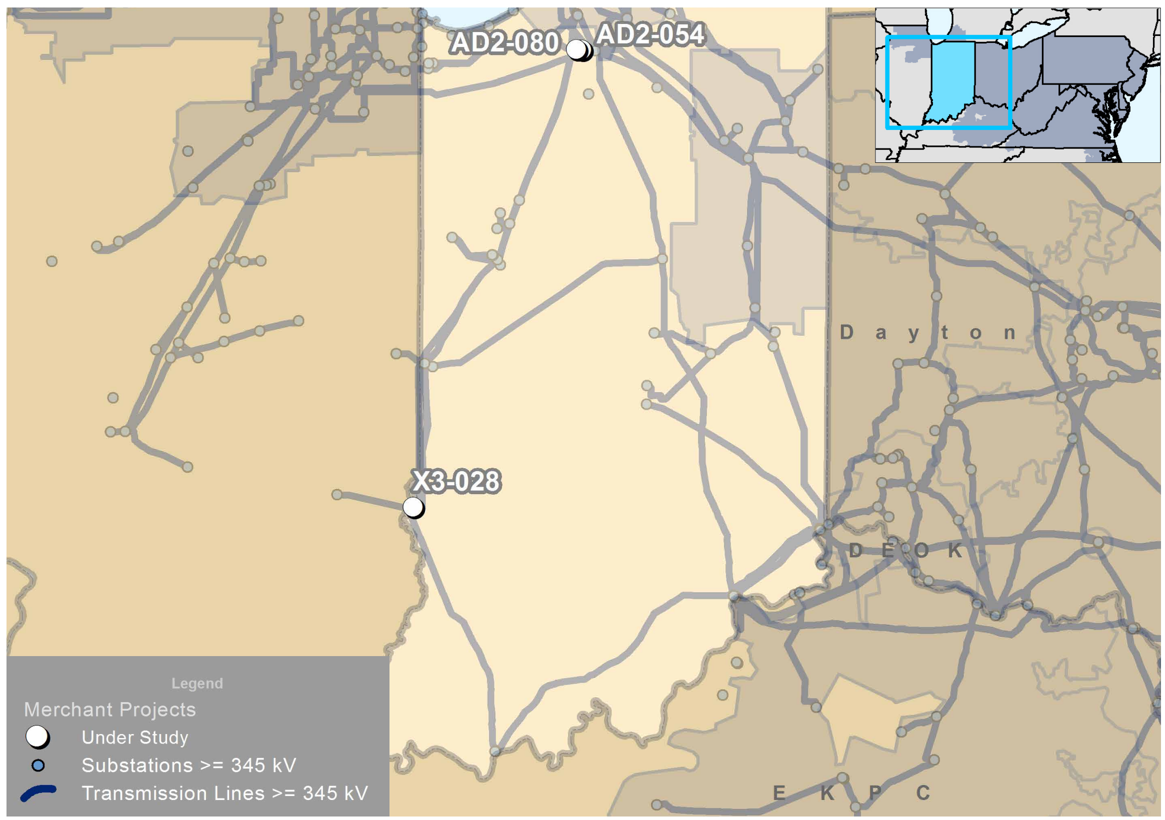
6.2.7 — Merchant Transmission Project Requests

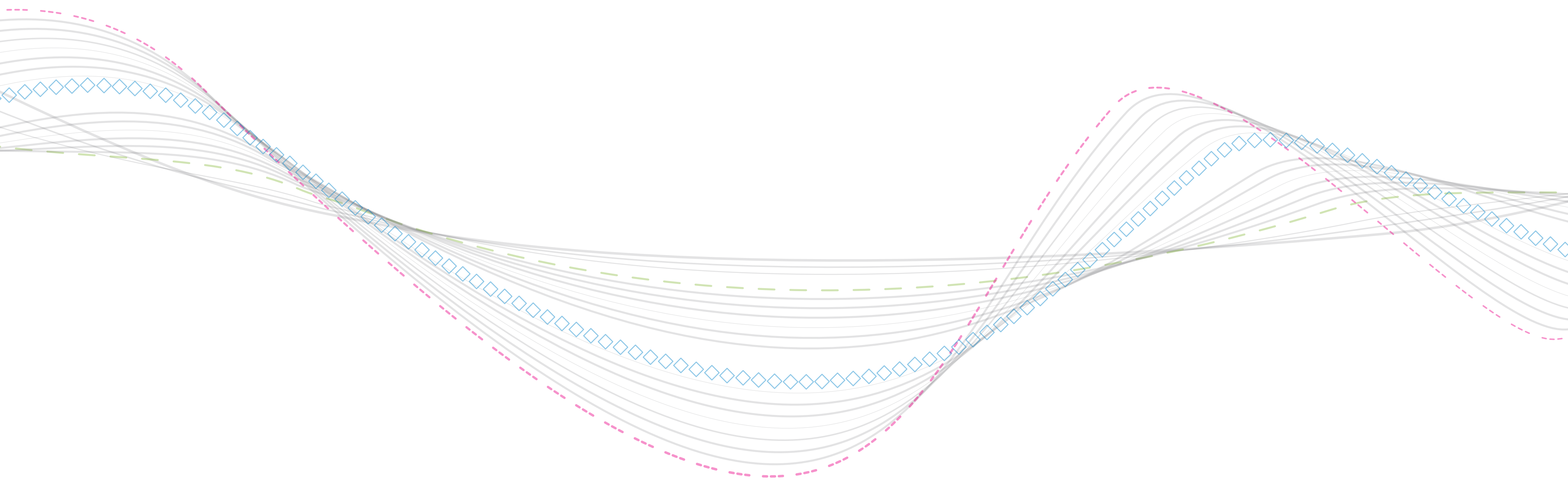
As of December 31, 2018, PJM's queue contained three merchant transmission interconnection request projects which included a terminal in Indiana as shown in **Table 6.17** and **Map 6.11**.

Table 6.17: Indiana Merchant Transmission Project Requests (December 31, 2018)

Queue	Project Name	Maximum Output (MW)	Status	Projected In-Service Date	TO Zone
X3-028	Breed 345 kV	3,500	Active	12/31/2016	AEP
AD2-054	Dumont-Stillwell 345 kV	50	Active	6/1/2020	AEP
AD2-080	Dumont-Stillwell 345 kV	309	Active	6/1/2020	AEP

Map 6.11: Indiana Merchant Transmission Project Requests (December 31, 2018)





6.3: Kentucky RTEP Summary

6.3.1 — 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 Eastern Kentucky Power Cooperative (EKPC) as shown on **Map 6.12**. 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 6.12: PJM Service Area in Kentucky

6.3.2 — Load Growth

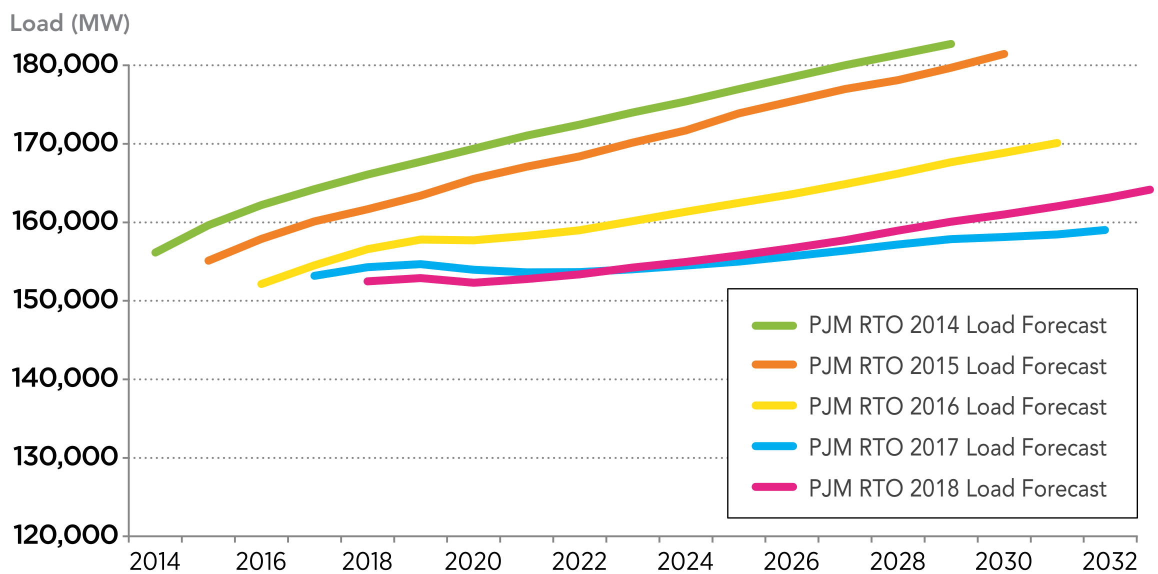
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.18** and **Figure 6.16** summarize the expected loads within the state of Kentucky and across all of PJM.

Table 6.18: Kentucky – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2018	2028	Growth Rate	2017/2018	2027/2028	Growth Rate
American Electric Power Company *	1,001	1,051	0.5%	1,199	1,260	0.5%
Duke Energy Ohio and Kentucky *	923	979	0.6%	746	784	0.5%
East Kentucky Power Cooperative	1,960	2,033	0.4%	2,587	2,693	0.4%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

* **Notes:** PJM notes that AEP and DEO&K serve load other than in Kentucky. The summer peak and winter peak megawatt values in this table each reflect an estimated amount of forecasted load to be served by each of those transmission owners solely in Kentucky. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Kentucky over the past five years.

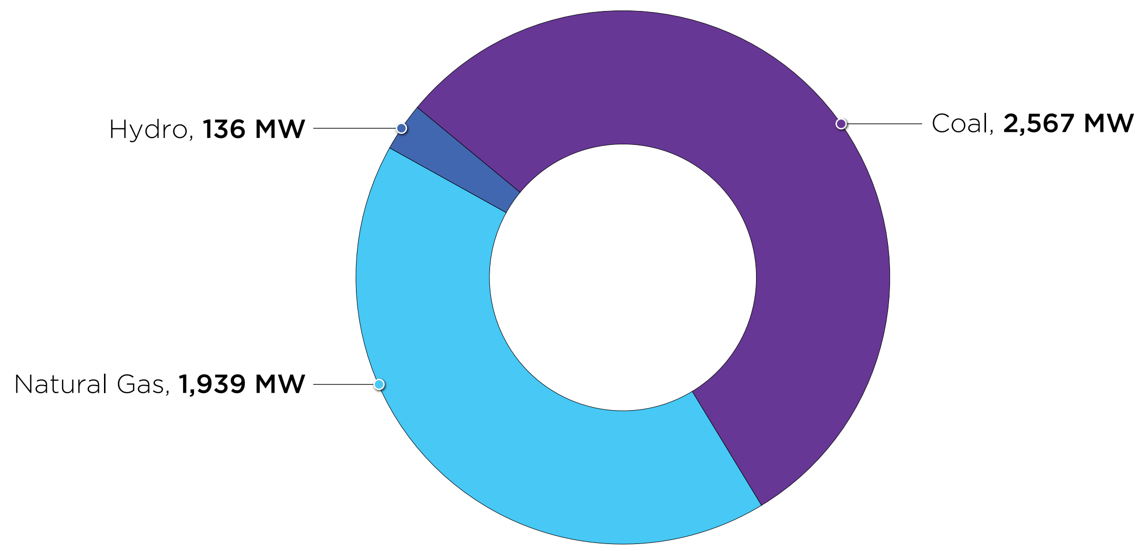
Figure 6.16: PJM RTO Summer Peak Demand Forecast



6.3.3 — Existing Generation

Existing generation in Kentucky as of December 31, 2018, is shown by fuel type in **Figure 6.17**.

Figure 6.17: Kentucky – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



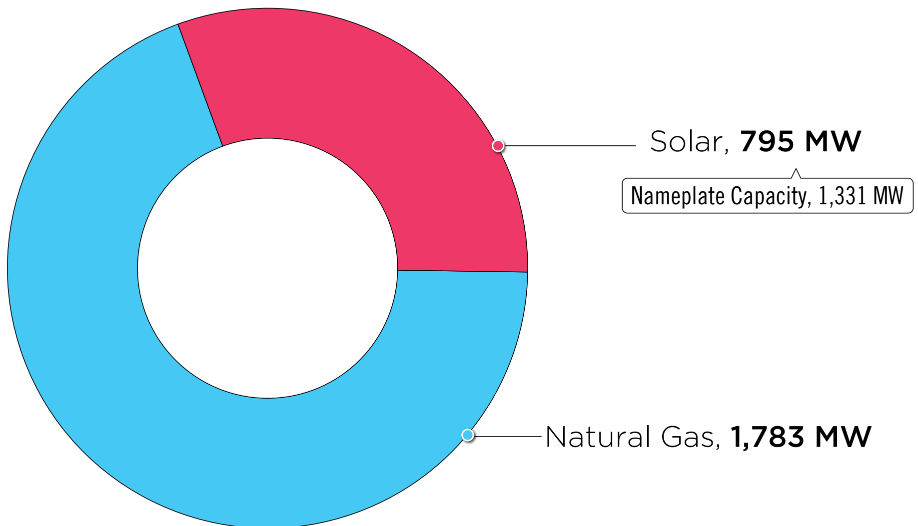
6.3.4 — Interconnection Requests

As of December 31, 2018, 20 queued projects were actively under study, under construction or in suspension in the state of Kentucky. A summary of those interconnection requests is shown in **Table 6.19, Table 6.20, Figure 6.18, Figure 6.19** and **Figure 6.20.**

Table 6.19: Kentucky – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Natural Gas	1,782.9	1,838.0
Solar	794.8	1,331.0
Total	**2,577.7**	**3,169.0**

Figure 6.18: Kentucky – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.20: Kentucky – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue						Grand Total	
	In Service		Withdrawn		Active		Suspended		Under Construction			
	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	**3**	**46.0**	**10**	**4,600.8**	**2**	**85.9**	**1**	**585.0**	**2**	**1,112.0**	**18**	**6,429.7**
Coal	0	0.0	6	2,969.0	0	0.0	0	0.0	0	0.0	6	2,969.0
Natural Gas	3	46.0	4	1,631.8	2	85.9	1	585.0	2	1,112.0	12	3,460.7
Renewable	**0**	**0.0**	**14**	**411.0**	**15**	**794.8**	**0**	**0.0**	**0**	**0.0**	**29**	**1,205.7**
Biomass	0	0.0	5	198.5	0	0.0	0	0.0	0	0.0	5	198.5
Hydro	0	0.0	1	70	0	0.0	0	0.0	0	0.0	1	70.0
Solar	0	0.0	6	115.1	15	794.8	0	0.0	0	0.0	21	909.9
Wind	0	0.0	2	27.33	0	0.0	0	0.0	0	0.0	2	27.3
Grand Total	**3**	**46.0**	**24**	**5,011.7**	**17**	**880.7**	**1**	**585.0**	**2**	**1,112.0**	**47**	**7,635.4**

Figure 6.19: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

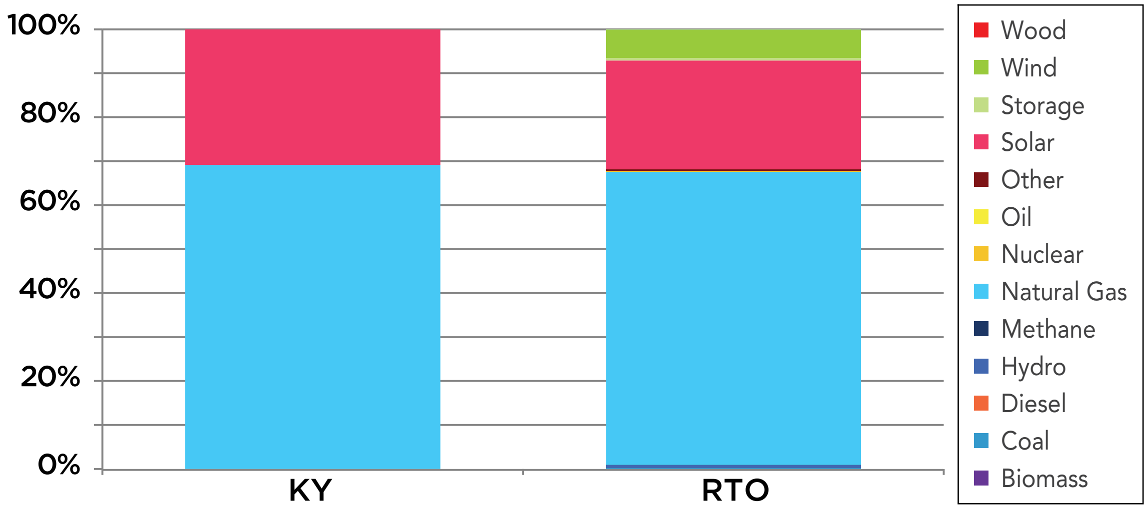
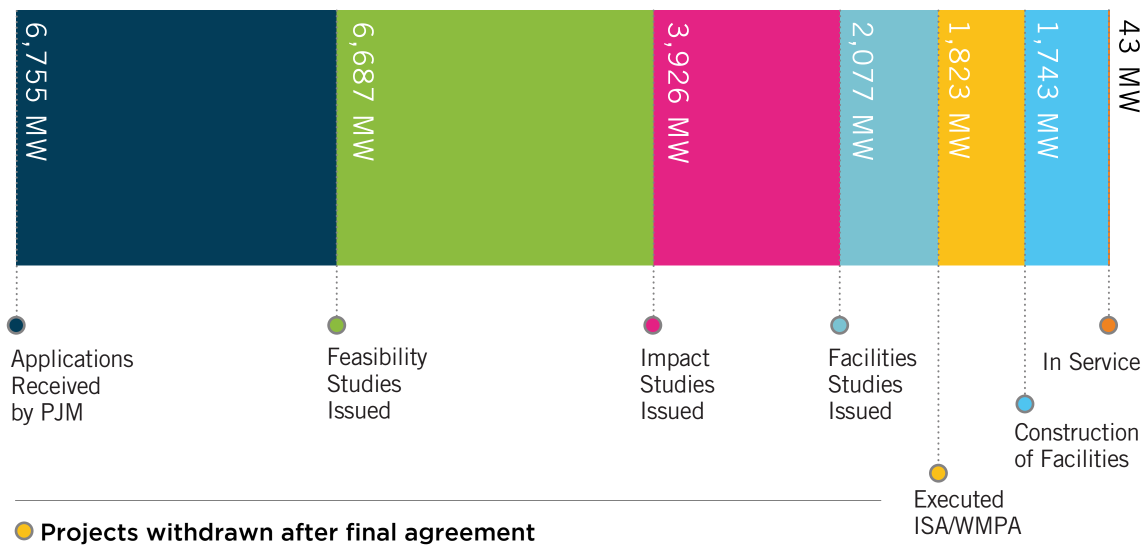


Figure 6.20: Kentucky Progression History of Queue – Interconnection Requests (December 31, 2018)



Projects withdrawn after final agreement

- **1** Interconnection Service Agreement – 80 MW (Nameplate Capacity, 80 MW)

Percentage of planned capacity and projects reached commercial operation

- **0.7 %** requested capacity megawatt
- **10 %** requested projects

6.3.5 — Network Projects

RTEP network upgrades greater than or equal to $10 million in Kentucky are summarized in **Table 6.21** and **Map 6.13**.

Map 6.13: Kentucky Network Projects (Greater than $10 M) (December 31, 2018)

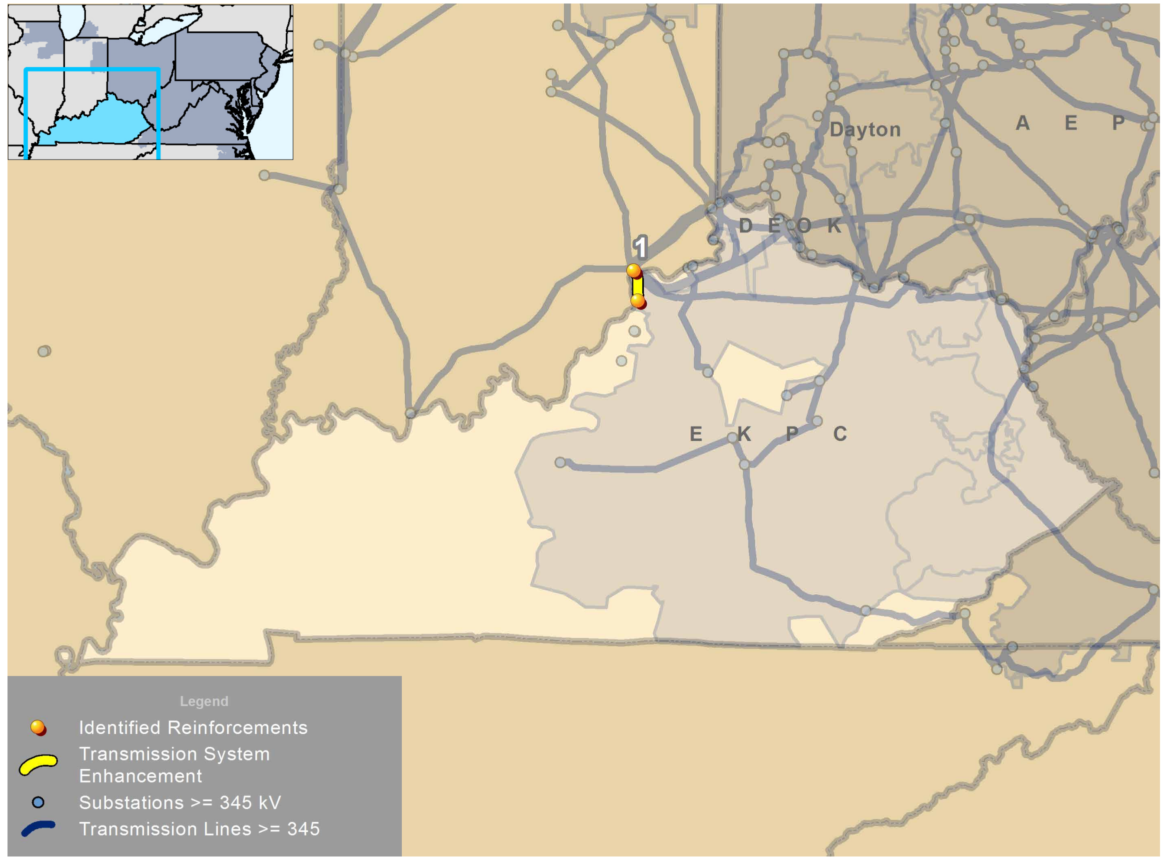


Table 6.21: Kentucky Network Upgrades (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Project Driver	Queue	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	n5469	Reconductor Trimble-Clifty 345 kV line and upgrade any necessary terminals.	Merchant Transmission	X3-028	6/1/2021	$17.40	LG&E	9/13/2018

6.3.6 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in Kentucky are summarized in **Table 6.22** and **Map 6.14**.

Map 6.14: Kentucky Supplemental Projects (December 31, 2018)

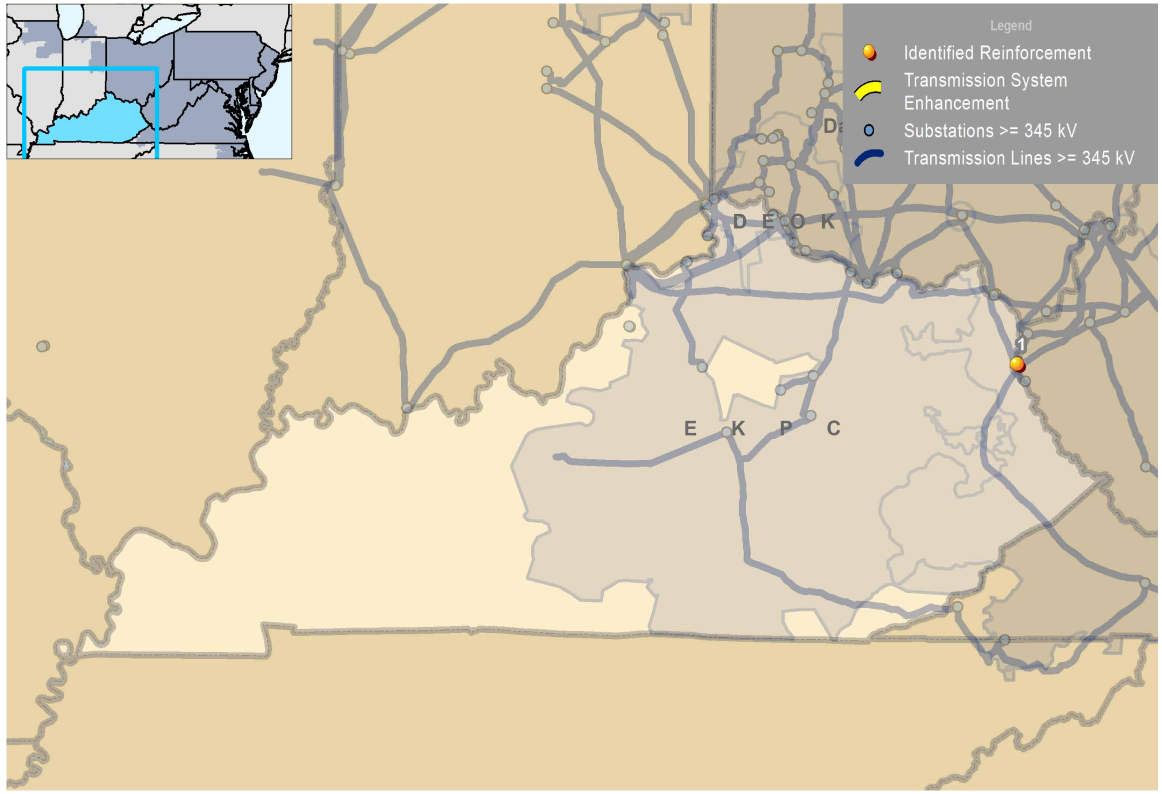


Table 6.22: Kentucky Supplemental Projects (Greater than $10 M) (December 31, 2018)

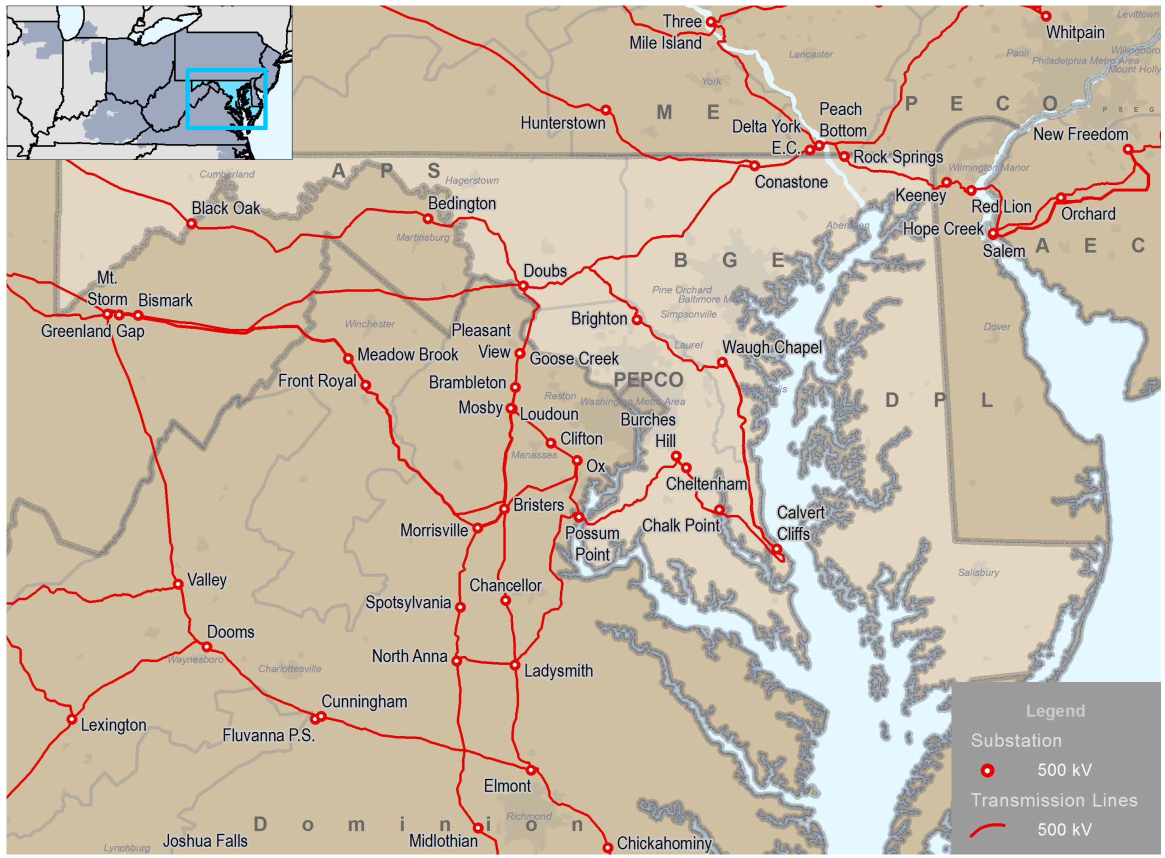
Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	s1583	At Baker Station, replace three existing 765 kV 50 kA circuit breakers with new 765 kV 63 kA breakers. Install an additional new 345 kV 63 kA breaker. Replace the 600 MVA transformer with a new 345/138 kV 675 MVA unit that will be relocated to a new position between the existing and newly installed breakers.	11/20/2018	$26.90	AEP	3/8/2018

6.4: Maryland and the 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 6.15**. 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 6.15: PJM Service Area in Maryland and the District of Columbia



6.4.2 — Load Growth

PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.23** and **Figure 6.21** summarize the expected loads within the state of Maryland and the District of Columbia and across all of PJM.

Figure 6.21: PJM RTO Summer Peak Demand Forecast

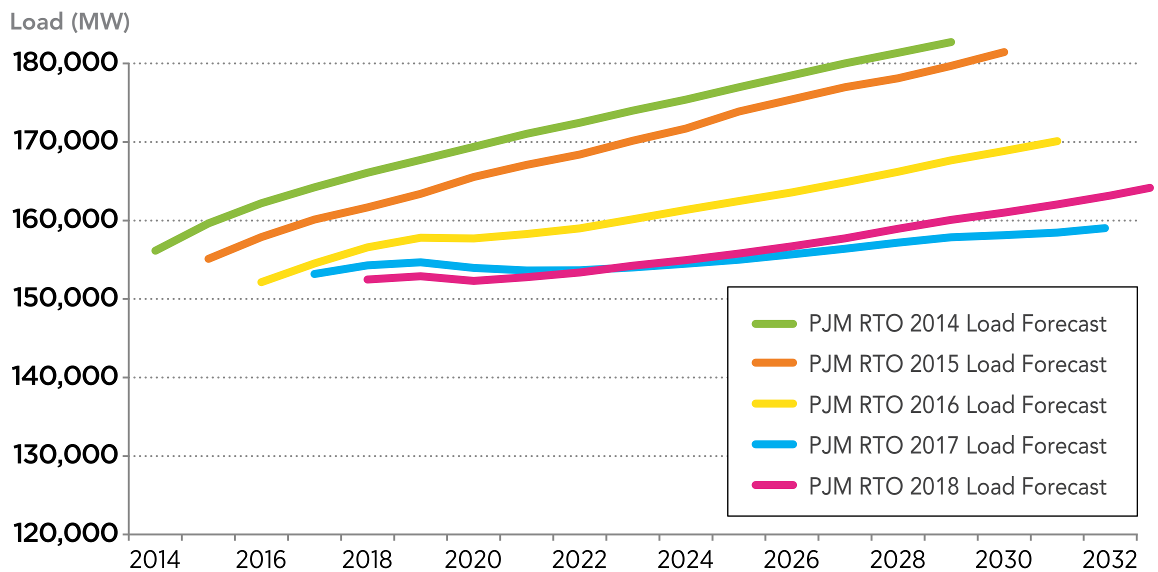


Table 6.23: Maryland and the District of Columbia – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW) 2018	Summer Peak (MW) 2028	Summer Peak (MW) Growth Rate	Winter Peak (MW) 2017/2018	Winter Peak (MW) 2027/2028	Winter Peak (MW) Growth Rate
Potomac Electric Power Company*	2,039	2,031	0.0%	1,641	1,687	0.3%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

* **Note:** PJM notes that PEPCO serves load other than in the District of Columbia. The summer peak and winter peak megawatt values in this table each reflect the estimated amount of forecasted load to be served by PEPCO solely in the District of Columbia. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in the District of Columbia over the past five years.

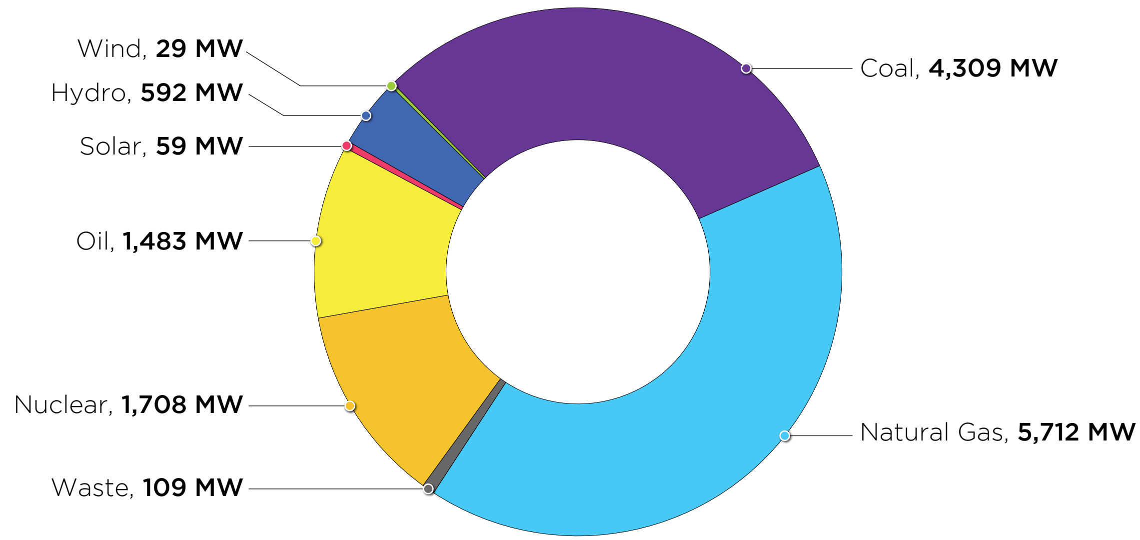
Transmission Owner	Summer Peak (MW) 2018	Summer Peak (MW) 2028	Summer Peak (MW) Growth Rate	Winter Peak (MW) 2017/2018	Winter Peak (MW) 2027/2028	Winter Peak (MW) Growth Rate
Allegheny Power *	1,335	1,430	0.7%	1,376	1,493	0.8%
Baltimore Gas & Electric Company	6,848	6,744	-0.2%	5,883	5,956	0.1%
Delmarva Power & Light*	1,177	1,202	0.2%	1,181	1,228	0.4%
Potomac Electric Power Company*	4,454	4,435	0.0%	3,742	3,847	0.3%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

* **Note:** PJM notes that APS, DP&L and PEPCO serve load other than in Maryland. The summer peak and winter peak MW values in this table each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in Maryland. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Maryland over the past five years.

6.4.3 — Existing Generation

Existing generation in Maryland and the District of Columbia as of December 31, 2018, 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 (December 31, 2018)



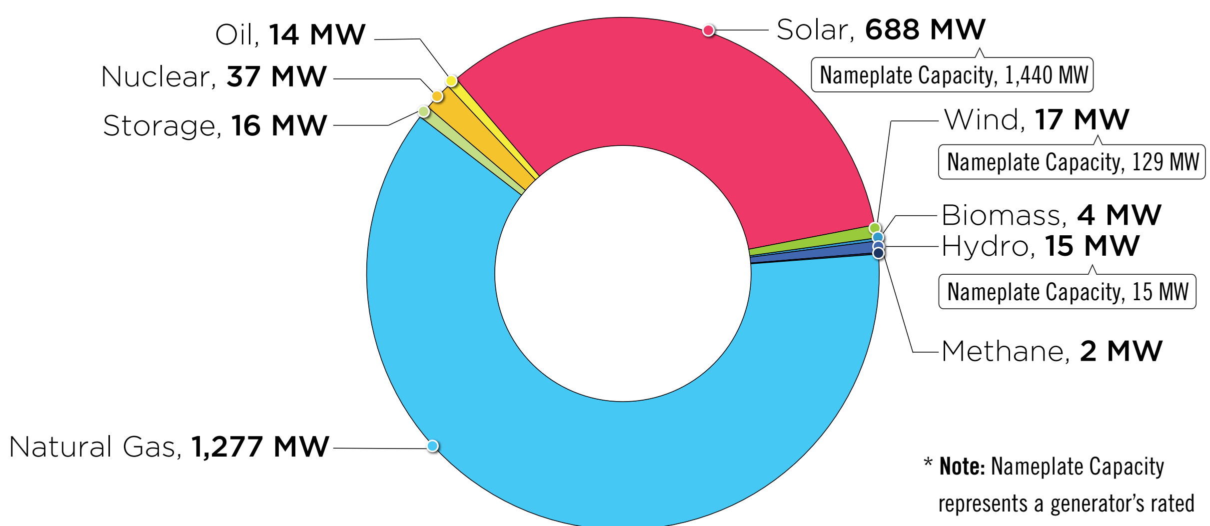
6.4.4 — Interconnection Requests

As of December 31, 2018, 101 queued projects were actively under study, under construction or in suspension in the state of Maryland and the District of Columbia. A summary of those interconnection requests is shown in **Table 6.24, Table 6.25, Figure 6.23, Figure 6.24** and **Figure 6.25**.

Table 6.24: Maryland and the District of Columbia – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Biomass	4.0	4.0
Hydro	15.0	15.0
Methane	2.0	2.0
Natural Gas	1,277.1	1,442.0
Nuclear	37.4	45.5
Oil	14.0	14.0
Solar	687.9	1,440.1
Storage	16.0	20.1
Wind	16.9	129.1
Total	**2,070.3**	**3,111.8**

Figure 6.23: Maryland and the District of Columbia – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.25: Maryland and the District of Columbia – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue						Grand Total	
	In Service		Withdrawn		Active		Suspended		Under Construction			
	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	**35**	**3,764.7**	**80**	**36,478.5**	**9**	**348.0**	**3**	**952.0**	**23**	**44.5**	**150**	**41,587.7**
Coal	1	10.0	0	0,0	0	0.0	0	0.0	0	0.0	1	10.0
Diesel	1	0.0	1	5.0	0	0.0	0	0.0	0	0.0	2	5.0
Natural Gas	30	3,749.7	59	31,299.5	4	280.6	3	952.0	3	44.5	99	36,326.3
Nuclear	1	0.0	4	4,955.0	3	37.4	0	0.0	0	0.0	8	4,992.4
Oil	2	5.0	1	2.0	1	14.0	0	0.0	0	0.0	4	21.0
Other	0	0.0	5	157.0	0	0.0	0	0.0	0	0.0	5	157.0
Storage	0	0.0	10	60.0	1	16.0	0	0.0	20	0.0	31	76.0
Renewable	**25**	**144.5**	**167**	**1,278.3**	**37**	**520.9**	**18**	**131.9**	**11**	**73.0**	**258**	**2,148.6**
Biomass	0	0.0	10	198.6	1	4.0	0	0.0	0	0.0	11	202.6
Hydro	3	60	3	73.4	1	15.0	0	0.0	0	0.0	7	148.4
Methane	9	21.5	5	16.3	0	0.0	0	0.0	1	2.0	15	39.8
Solar	9	30.5	140	733.5	35	501.9	17	122.8	9	63.2	210	1,451.9
Wind	4	32.5	9	256.5	0	0.0	1	9.1	1	7.8	15	305.9
Grand Total	**60**	**3,909.2**	**247**	**37,756.8**	**46**	**868.9**	**21**	**1,083.9**	**34**	**117.5**	**408**	**43,736.3**

Figure 6.24: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

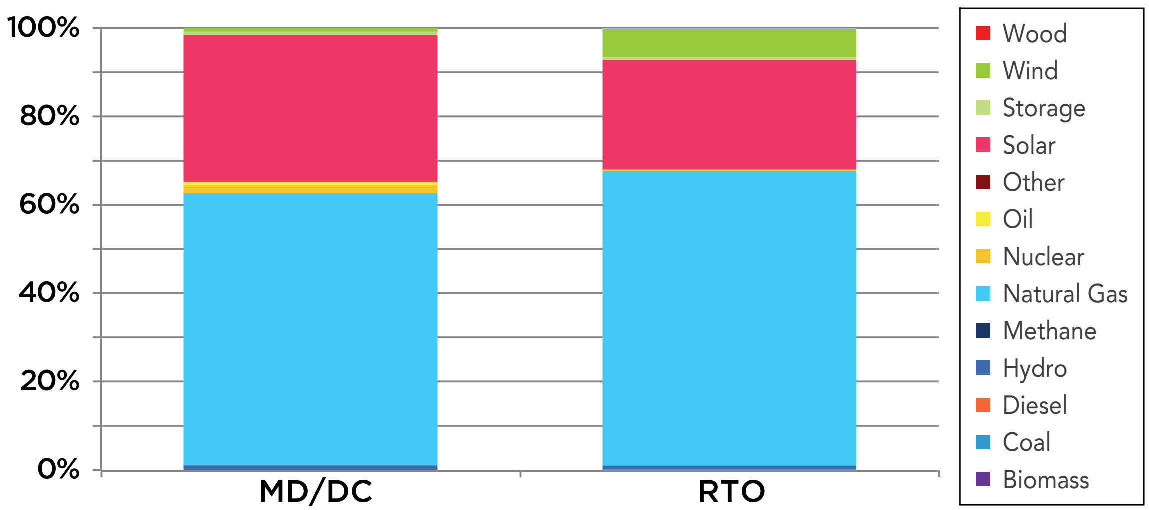
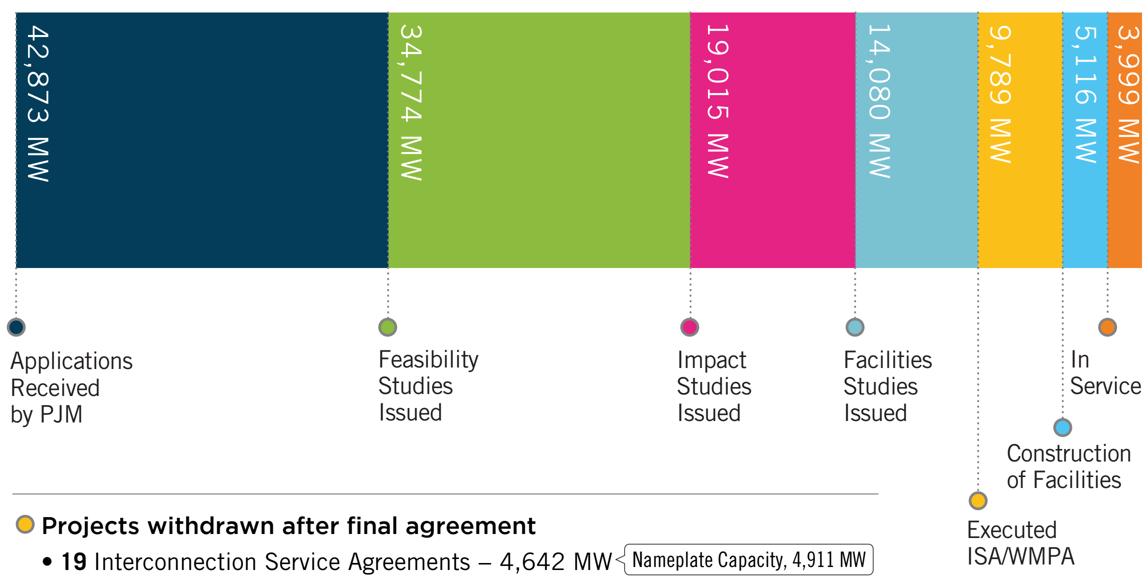


Figure 6.25: Maryland and the District of Columbia Progression History of Queue – Interconnection Requests (December 31, 2018)



Projects withdrawn after final agreement

- **19** Interconnection Service Agreements – 4,642 MW (Nameplate Capacity, 4,911 MW)
- **14** Wholesale Market Participation Agreements – 55 MW (Nameplate Capacity, 94 MW)

Percentage of planned capacity and projects reached commercial operation

- **9.3 %** requested capacity megawatt
- **17.4 %** requested projects

6.4.5 — Generation Deactivation

Known generating unit deactivation requests in Maryland and the District of Columbia between January 1, 2018 and December 31, 2018, are summarized in **Table 6.26** and **Map 6.16**.

Map 6.16: Maryland and the District of Columbia Generation Deactivations (December 31, 2018)

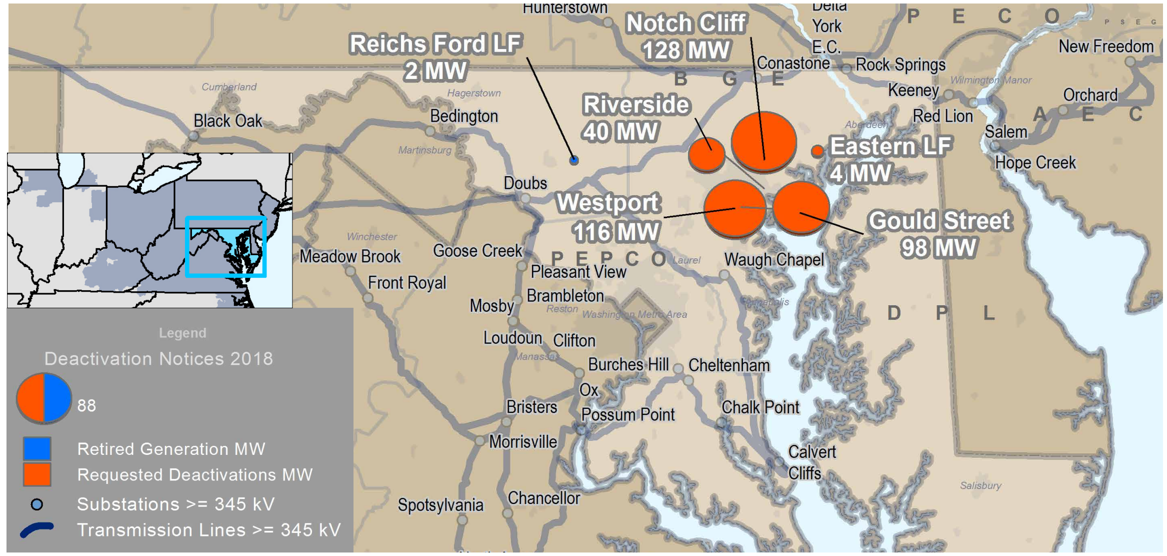


Table 6.26: Maryland and the District of Columbia Generation Deactivations (December 31, 2018)

Unit	Capacity (MW)	TO Zone	Age (Years)	Projected/Actual Deactivation Date
Westport 5	116	BGE	49	6/1/2020
Gould Street	98	BGE	66	6/1/2020
Riverside 7	20	BGE	48	3/14/2019
Riverside 8	20	BGE	48	6/1/2020
Notch Cliff 1	16	BGE	49	6/1/2020
Notch Cliff 2	16	BGE	49	6/1/2020
Notch Cliff 3	16	BGE	49	6/1/2020
Notch Cliff 4	16	BGE	49	6/1/2020
Notch Cliff 5	16	BGE	49	6/1/2020
Notch Cliff 6	16	BGE	49	6/1/2020
Notch Cliff 7	16	BGE	49	6/1/2020
Notch Cliff 8	16	BGE	49	6/1/2020
Eastern Landfill	4	BGE	12	6/1/2020
Reichs Ford Road Landfill	2	APS	9	5/31/2018

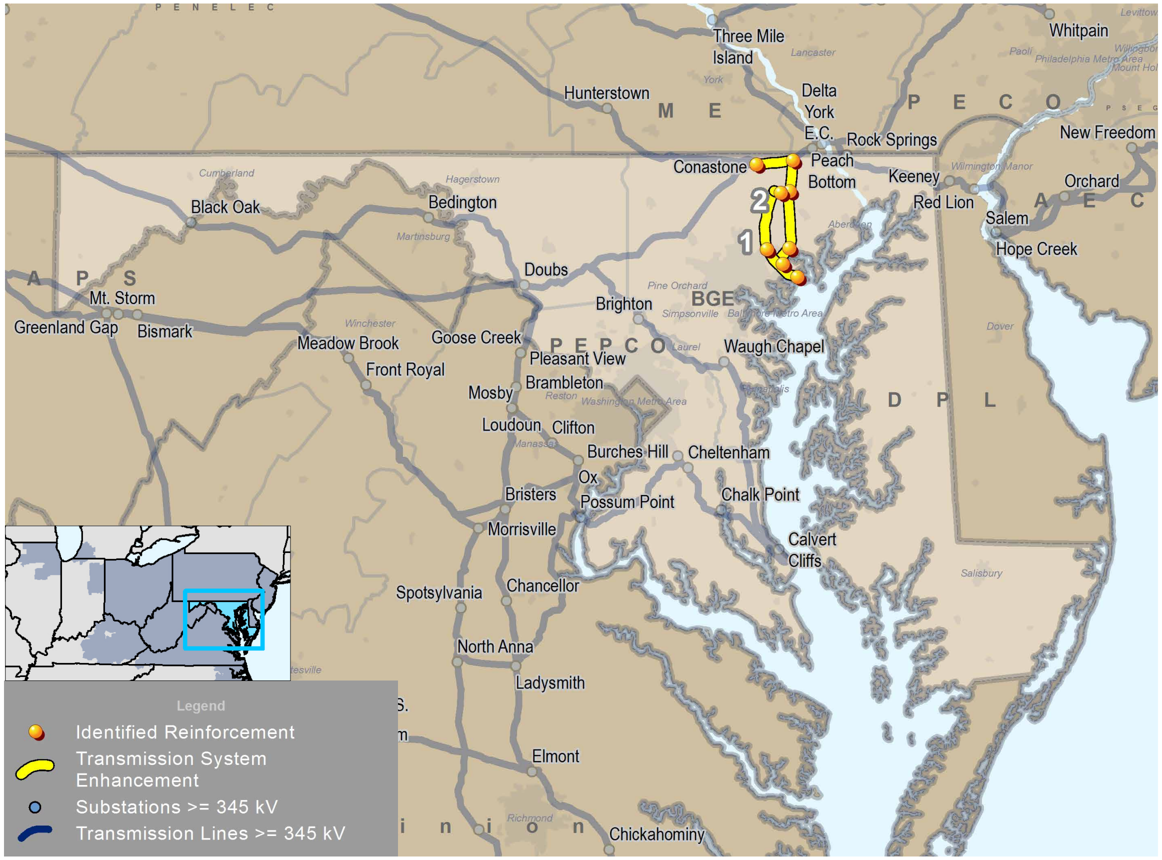
6.4.6 — Baseline Projects

RTEP baseline upgrades greater than or equal to $10 million in Maryland and the District of Columbia are summarized in **Table 6.27** and **Map 6.17**. In 2018, PJM added $52.6 million in baseline projects in Maryland and the District of Columbia.

Table 6.27: Maryland and the District of Columbia Baseline Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	Congestion Relief-Economic	Generator Deactivation
1	b2816		Reconnect the Crane-Windy Edge 110591 and 110592 115 kV circuits into the Northeast Substation with the addition of a new 115 kV three-breaker bay.	6/1/2018	$12.00	BGE	12/14/2017		X
		.1	Modify the Crane-Windy Edge 110591 and 110592 115 kV circuits by terminating Windy Edge Circuits 110591 and 110592 into Northeast Substation with the addition of new 115 kV breaker positions at Northeast substation.	6/1/2018		BGE	12/14/2017		X
		.2	Modify the Crane-Windy Edge 110591 and 110592 115 kV circuits by terminating Crane Circuits 110591 and 110592 into Northeast Substation with the addition of new 115 kV breaker positions at Northeast substation.	6/1/2018		BGE	12/14/2017		X
2	b2992	.1	Reconductor the Conastone-Graceton 230 kV 2323 and 2324 circuits. Replace seven disconnect switches at Conastone Substation.	3/1/2021	$39.60	BGE	2/14/2018	X	
		.2	Add bundle conductor on the Graceton-Bagley-Raphael Road 2305 and 2313 230 kV circuits.	3/1/2021		BGE	2/14/2018	X	
		.3	Replace short segment of substation conductor on the Windy Edge-Glenarm 115 kV circuit.	3/1/2021		BGE	2/14/2018	X	
		.4	Reconductor the Raphael Road-Northeast 2315 and 2337 230 kV circuits.	3/1/2021		BGE	2/14/2018	X	

Map 6.17: Maryland and the District of Columbia Baseline Map (December 31, 2018)



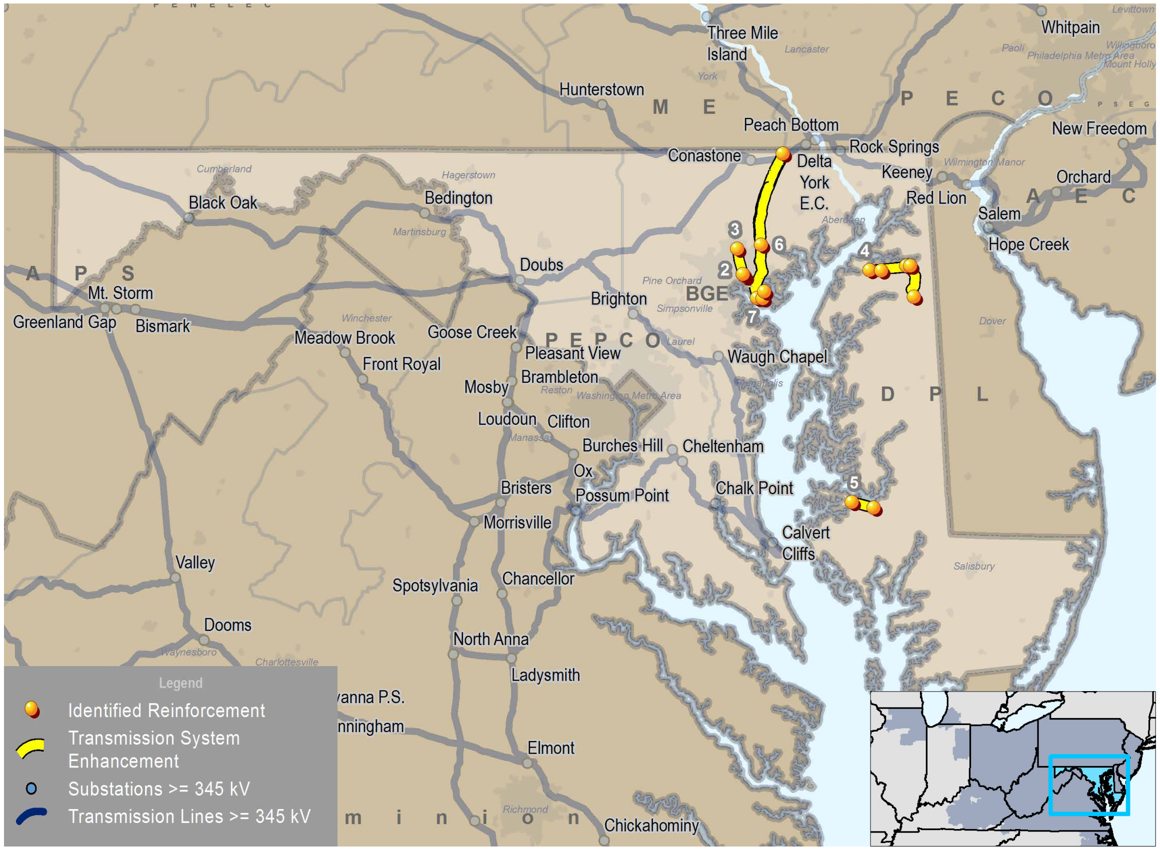
6.4.7 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in Maryland and the District of Columbia are summarized in **Table 6.28** and **Map 6.18**.

Table 6.28: Maryland and the District of Columbia Supplemental Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	s1532	Reconfigure the Calvert Cliff 500 kV switchyard, including the addition of four breakers in a new 500 kV bay. Two additional breakers will be installed for the current plant service transformers.	9/30/2020	$59.80	BGE	2/8/2018
2	s1631	Create a new Loch Raven 115/13 kV substation.	6/1/2024	$130.00	BGE	3/23/2018
		Build a new Loch Raven 115/13 kV substation. Supply substation with underground 115 kV cables from Erdman Substation.	6/1/2024		BGE	3/23/2018
		New Loch Raven substation, install 115 kV breakers and perform high side bus work to supply the distribution station.	6/1/2024		BGE	3/23/2018
		At Erdman 115 kV substation, expand to a gas insulated substation, breaker-and-a-half configuration to connect new circuits that supply Loch Raven.	6/1/2024		BGE	3/23/2018
3	s1632	Network East Towson substation to Loch Raven Substation with underground 115 kV cross-linked polyethylene cables.	6/1/2024	$93.00	BGE	3/23/2018
		Build a 115 kV circuit between East Towson and Loch Raven stations with underground 115 kV cross-linked polyethylene cables.	6/1/2024		BGE	3/23/2018
		Install 115 kV circuit breakers and equipment at East Towson and Summerfield substation to accommodate transmission network.	6/1/2024		BGE	3/23/2018
4	s1636	Rebuild line between Church and Chestertown substations. All structures, conductor and static wire will be replaced with new steel poles and conductor.	12/31/2022	$35.00	DPL	3/23/2018
		Rebuild the Church-Massey REA 69 kV circuit.	12/31/2022		DPL	3/23/2018
		Rebuild Massey REA-Lynch 69 kV circuit.	12/31/2022		DPL	3/23/2018
		Rebuild Lynch-Chestertown 69 kV circuit.	12/31/2022		DPL	3/23/2018
5	s1639	Rebuild line 6719 between East New Market and Cambridge substations. All structures, conductor, and static wire will be replaced with new poles, conductor, and optical ground wire.	5/31/2021	$17.90	DPL	3/23/2018
6	s1670	Rebuild both Five Forks-Windy Edge 115 kV circuits using steel monopole, double circuit construction.	12/31/2022	$60.00	BGE	5/25/2018
7	s1671	Build new 115 kV station to supply 34 kV and 13 kV distribution station. Provide diverse overhead transmission supplies from Riverside and Windy Edge substations to new 115 kV station.	12/1/2026	$45.00	BGE	5/25/2018
		Build new 115 kV ring bus station, Fitzell, and install two 115/34 kV and two 115/13 kV transformers.	12/1/2026		BGE	5/25/2018
		Extend the existing Windy Edge-Riverside 115 kV double circuit to the new station.	12/1/2026		BGE	5/25/2018
		Rebuild and extend the existing Riverside-North Point-Finishing Mill 115 kV double circuit to the new station.	12/1/2026		BGE	5/25/2018

Map 6.18: Maryland and the District of Columbia Supplemental Projects (December 31, 2018)



6.4.8 — Merchant Transmission Project Requests

As of December 31, 2018, PJM's queue contained two merchant transmission interconnection request projects, which include a terminal in Maryland and/or the District of Columbia as shown in **Table 6.29** and **Map 6.19**.

Map 6.19: Maryland and the District of Columbia Merchant Projects

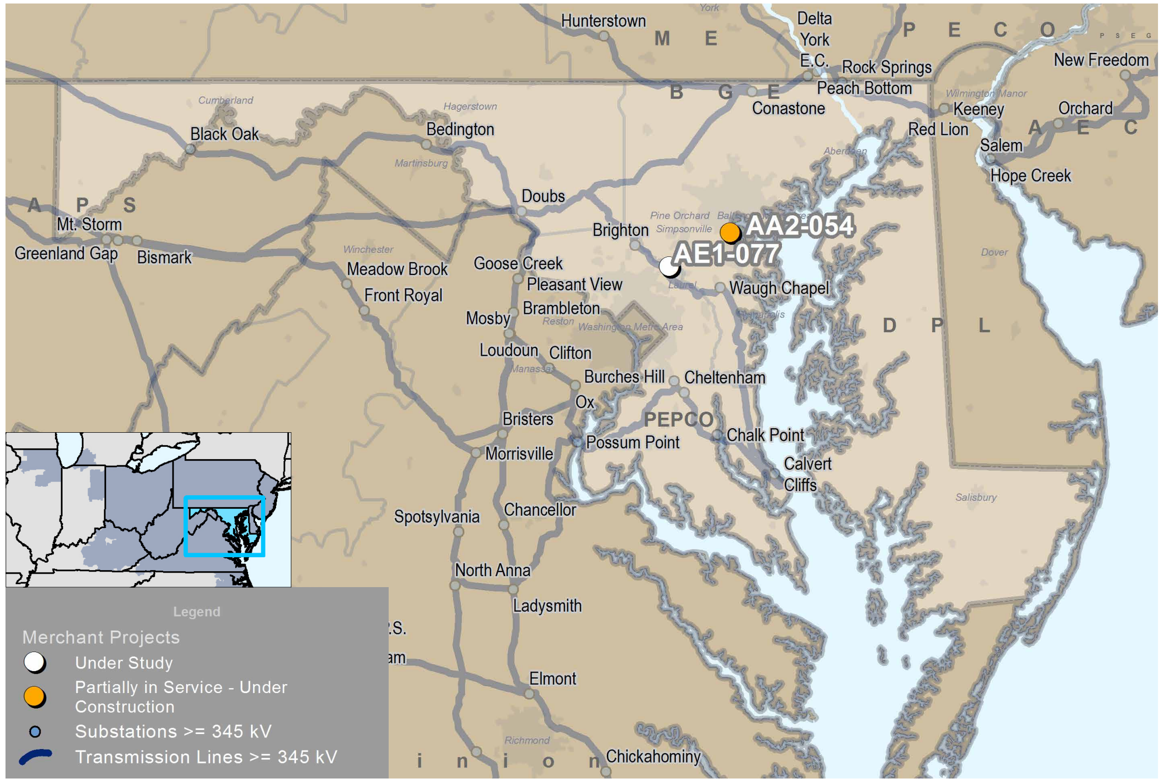


Table 6.29: Maryland and the District of Columbia Merchant Projects

Queue	Project Name	Maximum Output (MW)	Status	Projected In-Service Date	TO Zone
AA2-054	Pumphrey 230 kV	155	Partially in Service - Under Construction	6/7/2017	BGE
AE1-077	Sandy Springs-High Ridge 230 kV	100	Active	6/1/2020	BGE

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

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

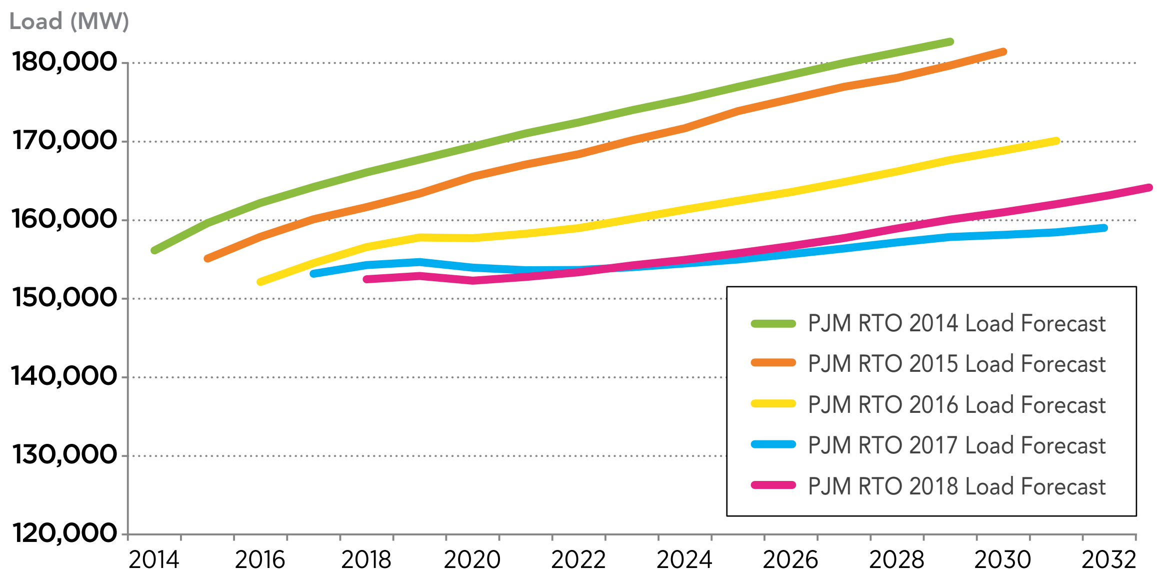
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.30** and **Figure 6.26** summarize the expected loads within the state of Michigan and across all of PJM.

Table 6.30: Southwestern Michigan – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW) 2018	Summer Peak (MW) 2028	Summer Peak (MW) Growth Rate	Winter Peak (MW) 2017/2018	Winter Peak (MW) 2027/2028	Winter Peak (MW) Growth Rate
American Electric Power Company *	904	949	0.5%	696	732	0.5%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

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

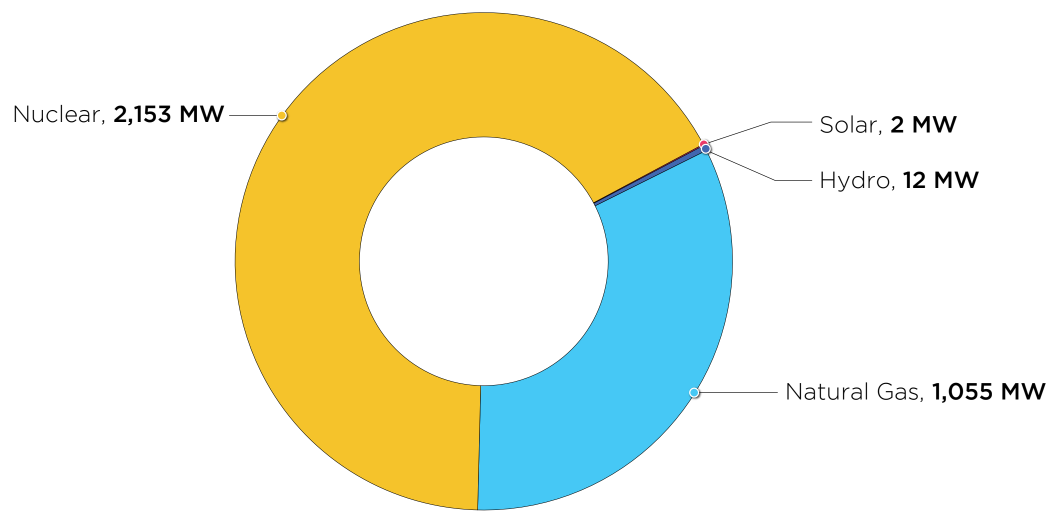
Figure 6.26: PJM RTO Summer Peak Demand Forecast



6.5.3 — Existing Generation

Existing generation in Southwestern Michigan as of December 31, 2018, is shown by fuel type in **Figure 6.27**.

Figure 6.27: Southwestern Michigan – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



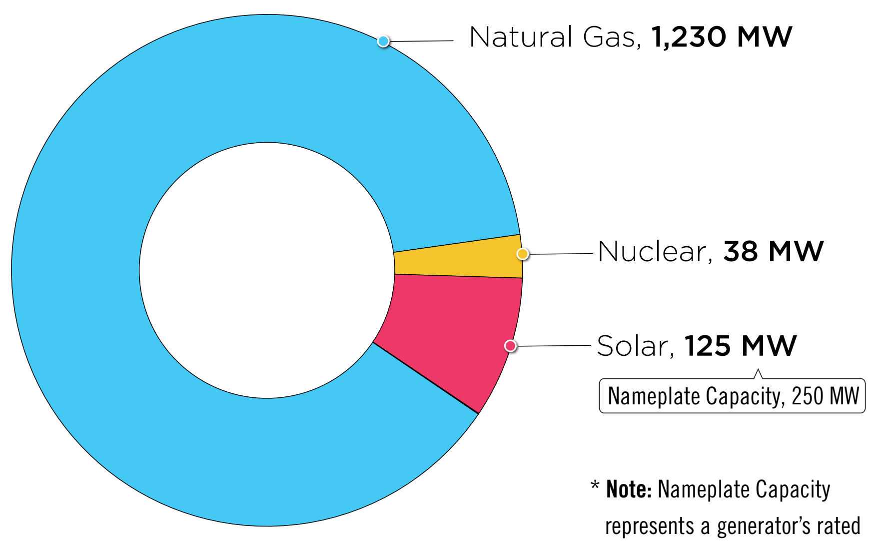
6.5.4 — Interconnection Requests

As of December 31, 2018, 7 queued projects were actively under study, under construction or in suspension in the state of Michigan. A summary of those interconnection requests is shown in **Table 6.31, Table 6.32, Figure 6.28, Figure 6.29** and **Figure 6.30.**

Table 6.31: Southwestern Michigan – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Natural Gas	1230.0,	1,370.0
Solar	124.9	250.0
Nuclear	38.0	28.0
Methane	0.8	0.8
Total	**1,393.7**	**1,648.8**

Figure 6.28: Southwestern Michigan – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.32: Southwestern Michigan – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue				Grand Total	
	In Service		Withdrawn		Active		Under Construction			
	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	**4**	**1,222.0**	**2**	**1,120.0**	**3**	**274.0**	**1**	**994.0**	**10**	**3,610.0**
Natural Gas	2	1,055.0	1	1,120.0	2	236.0	1	994.0	6	3,405.0
Nuclear	2	167.0	0	0.0	1	38.0	0	0.0	3	205.0
Other	0	0.0	1	0.0	0	0.0	0	0.0	1	0.0
Renewable	**3**	**11.9**	**2**	**91.8**	**3**	**125.7**	**0**	**0.0**	**8**	**229.4**
Methane	2	9.6	0	0.0	1	0.8	0	0.0	3	10.4
Solar	1	2.3	1	65.8	2	124.9	0	0.0	4	193.0
Wind	0	0.0	1	26	0	0.0	0	0.0	1	26.0
Grand Total	**7**	**1,233.9**	**4**	**1,211.8**	**6**	**399.7**	**1**	**994.0**	**18**	**3,839.4**

Figure 6.29: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

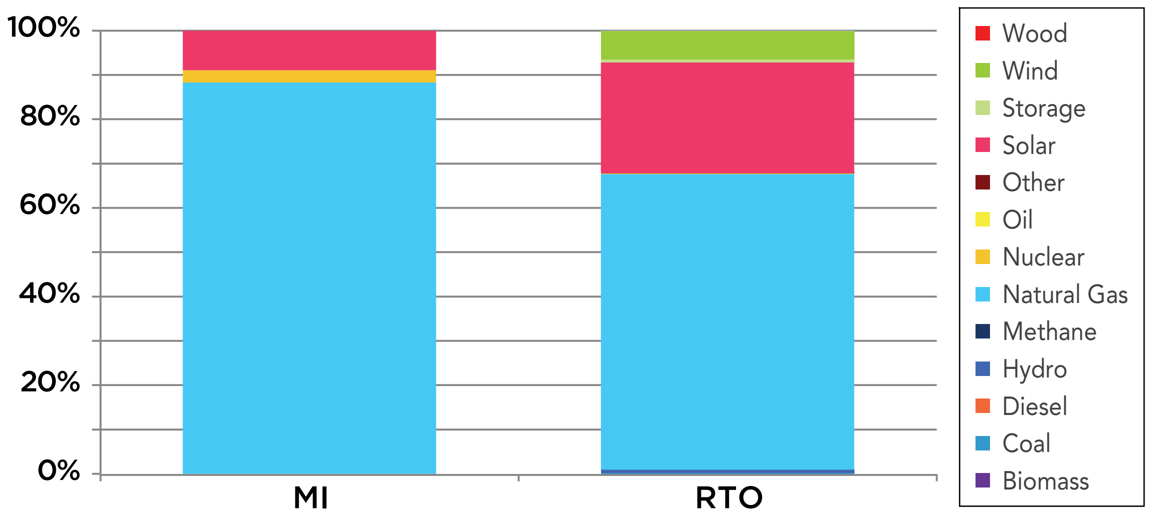
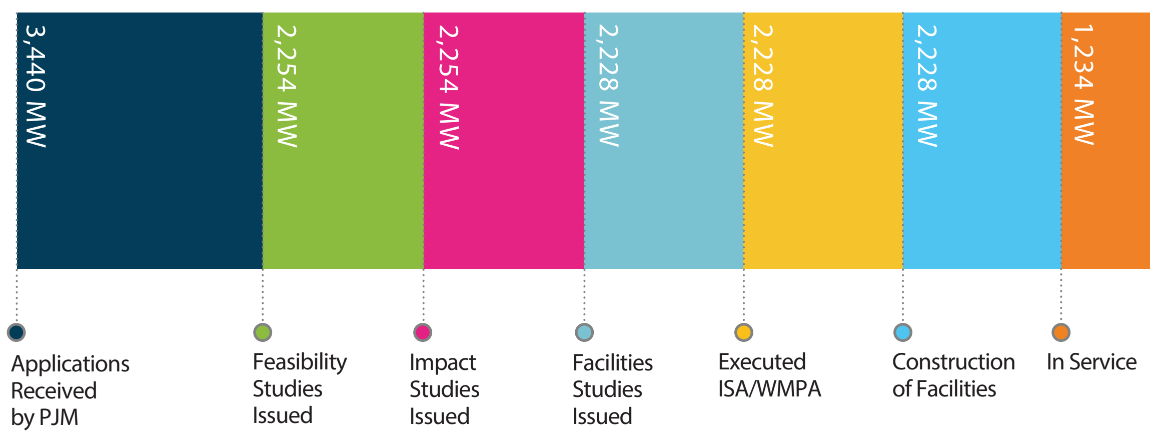


Figure 6.30: Southwestern Michigan Progression History of Queue – Interconnection Requests (December 31, 2018)



Percentage of planned capacity and projects reached commercial operation

- 35.9 % requested capacity megawatt
- 58.3 % requested projects

6.5.5 — Network Projects

RTEP network upgrades greater than $10 million in Southwestern Michigan are summarized in **Table 6.33** and **Map 6.21**.

Map 6.21: Southwestern Michigan Network Projects (Greater than $10 M) (December 31, 2018)

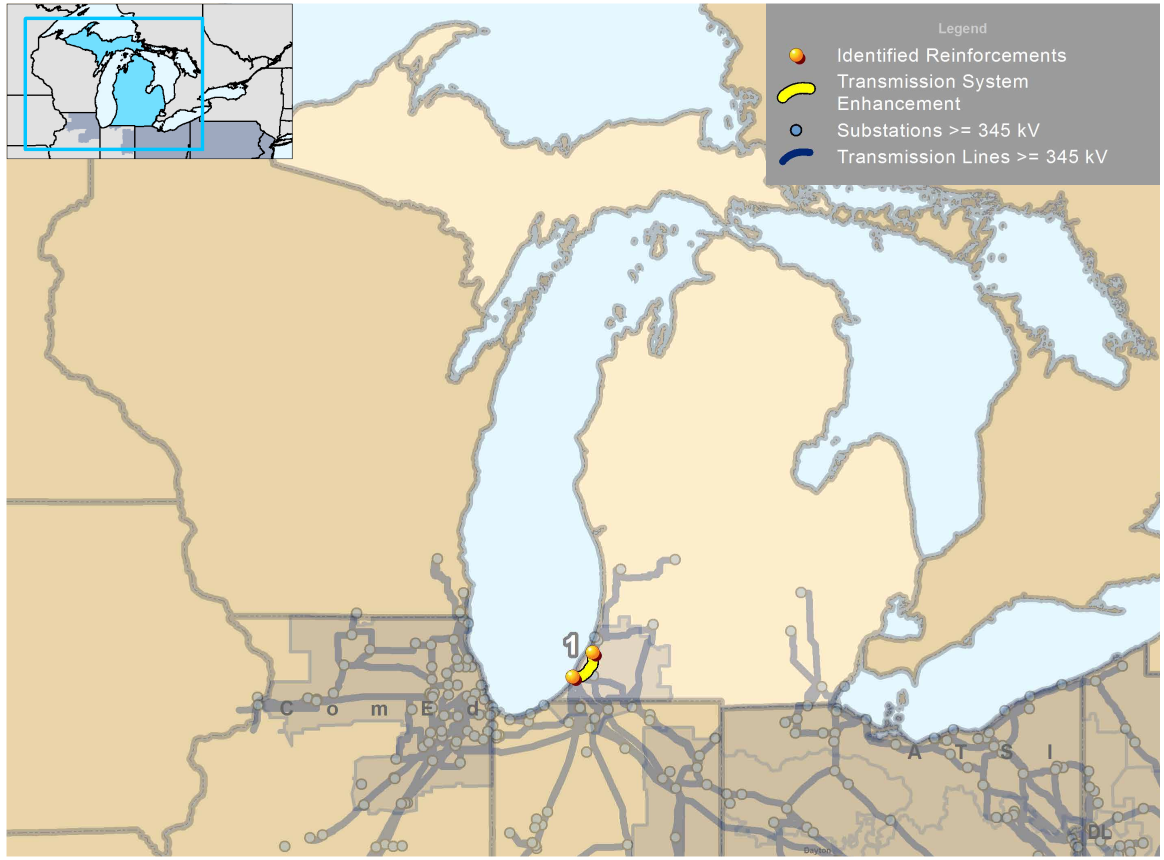


Table 6.33: Southwestern Michigan Network Upgrades (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Project Driver	Queue	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	n5487	Rebuild approximately 22 miles of Cook-Benton Harbor 345 kV line.	J873 (MISO)*	N/A	6/1/2020	$44.32	AEP	9/13/2018

* **Note:** J873 is a MISO DPP project.

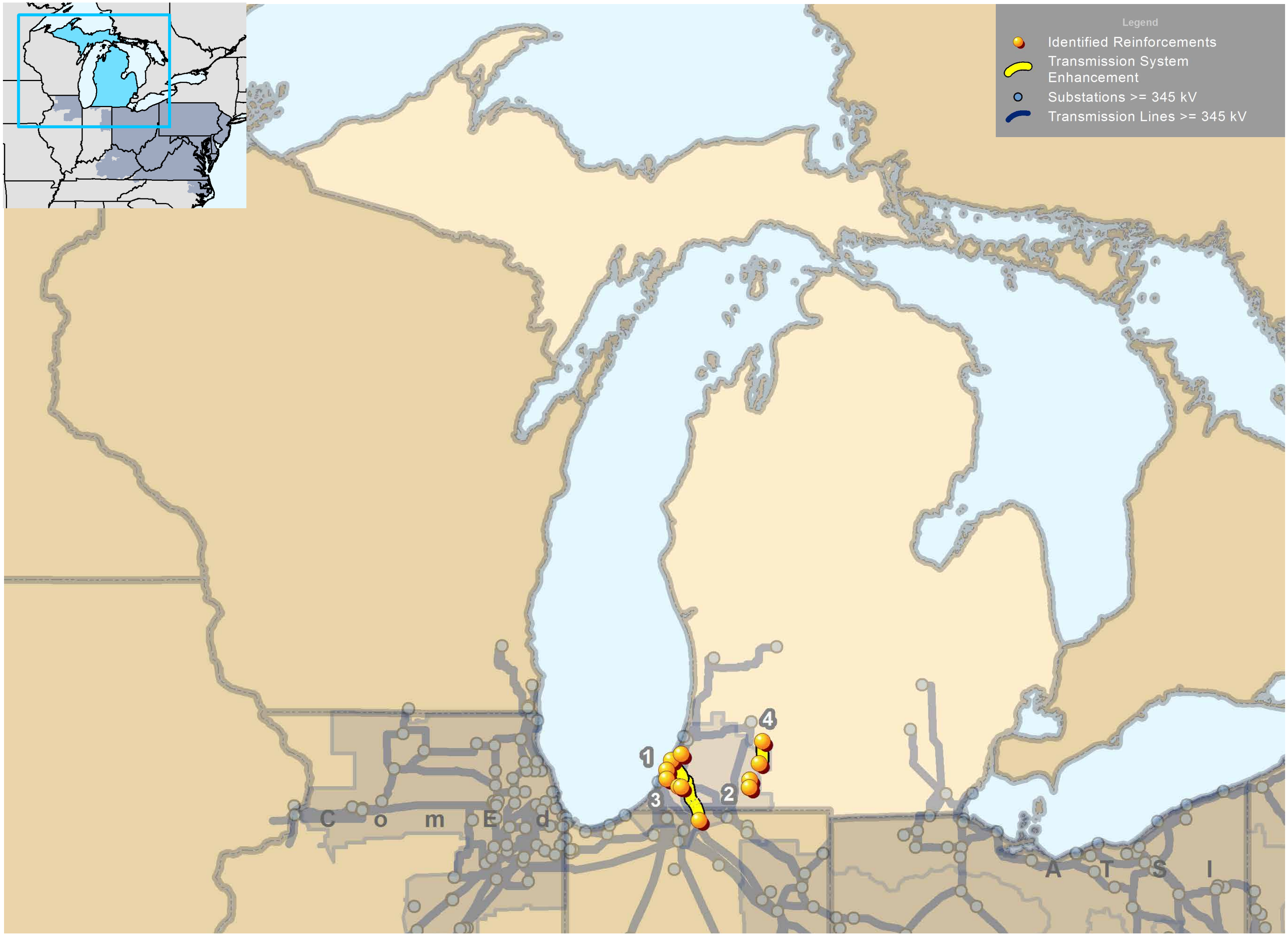
6.5.6 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in Southwestern Michigan are summarized in **Table 6.34** and **Map 6.22.**

Table 6.34: Southwestern Michigan Supplemental Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost	TO Zone	2018 TEAC Review
1	s1622	Rebuild roughly 43 miles from the Twin Branch to Riverside station with double-circuit 138 kV aluminum conductor steel cable (296 MVA rating).	12/1/2021	$127.70	AEP	4/17/2018
		Rebuild the 6-mile double-circuit Benton Harbor 138 kV extension with double-circuit 138 kV aluminum conductor steel cable.	9/1/2021		AEP	4/17/2018
		Rebuild the 5-mile double-circuit Hickory Creek 138 kV extension with double-circuit 138 kV aluminum conductor steel cable.	12/1/2021		AEP	4/17/2018
2	s1435	Rebuild 69 kV Three Rivers station in the clear. New station name will be Ripple station.	8/22/2019	$20.30	AEP	1/8/2018
		Replace two circuit breakers at Moore Park 69 kV station with new 40 kA breakers.	8/22/2019		AEP	1/8/2018
		Add motor-operated air breaker switch at Dock Foundry 69 kV station, towards Wheeler station.	8/22/2019		AEP	1/8/2018
		Rebuild approximately 5.7 miles of 69 kV line between Moore Park and Three Rivers using aluminum conductor steel cable. Upgrade line relaying and extension towards Corey and towards Three Rivers.	8/22/2019		AEP	1/8/2018
3	s1593	Relocate Derby - Bendix line exits and eliminate the need for underground 69/34 kV lines at Derby. Replace Bendix Tap Southwest pole.	6/1/2020	$18.40	AEP	3/27/2018
		Eliminate underground 69 kV section at Oronoko. Rebuild approximately 1 mile of 34.5 kV as 69 kV double circuit. Build line extension to the proposed site for Kephart station.	6/1/2020		AEP	3/27/2018
		Rebuild Derby station in the clear. Proposed station will have two 138 kV circuit breakers, four 69 kV circuit breakers, one 34.5 kV circuit breaker, one dual voltage 138-69/34.5 kV transformer with a circuit switcher on the primary.	6/1/2020		AEP	3/27/2018
		Construct a new Kephart station with two 69 kV circuit breakers, one 34.5 kV circuit breaker, one 69/12 kV transformer, one 69/34.5 kV transformer, and three 12 kV circuit breakers. Construct a 69 kV yard that can accommodate 34.5 kV and 69 kV operation.	6/1/2020		AEP	3/27/2018
		At Berrien Springs, retire existing 34.5 kV yard, concrete platform and associated transmission equipment. Install two 69 kV circuit breakers and replace 69 kV circuit breaker on the primary side of Transformer No. 1.	6/1/2020		AEP	3/27/2018
		At Blossom Trail, install a dual-voltage 138-69/34.5 kV transformer, four 138 kV circuit breakers, one 138 kV circuit switcher, one 69 kV circuit breaker , one 34.5 kV circuit breaker, and a 34.5 kV ground bank.	6/1/2020		AEP	3/27/2018
		Replace Bendix tap switch with 69 kV phase-over-phase switch.	6/1/2020		AEP	3/27/2018
4	s1523	Rebuild Schoolcraft 69 kV station as Kalamazoo 69 kV station in the clear. Kalamazoo station will have a breaker-and-a-half configuration with six 69 kV circuit breakers, two 69/12 kV transformers, 12 kV bus with associated feeders, and a 14.4 MVAR cap bank.	12/12/2018	$16.40	AEP	2/14/2018
		Install two 69 kV circuit breakers and install drop-in control module at Vicksburg to accommodate the new second line.	11/28/2018		AEP	2/14/2018
		Construct a new 5-mile 69 kV line between Kalamazoo and Vicksburg stations with aluminum conductor steel cable. Install fiber between Kalamazoo and Vicksburg Station. Extend Moore Park-Schoolcraft line into Kalamazoo.	12/11/2018		AEP	2/14/2018

Map 6.22: Southwestern Michigan Supplemental Projects (December 31, 2018)

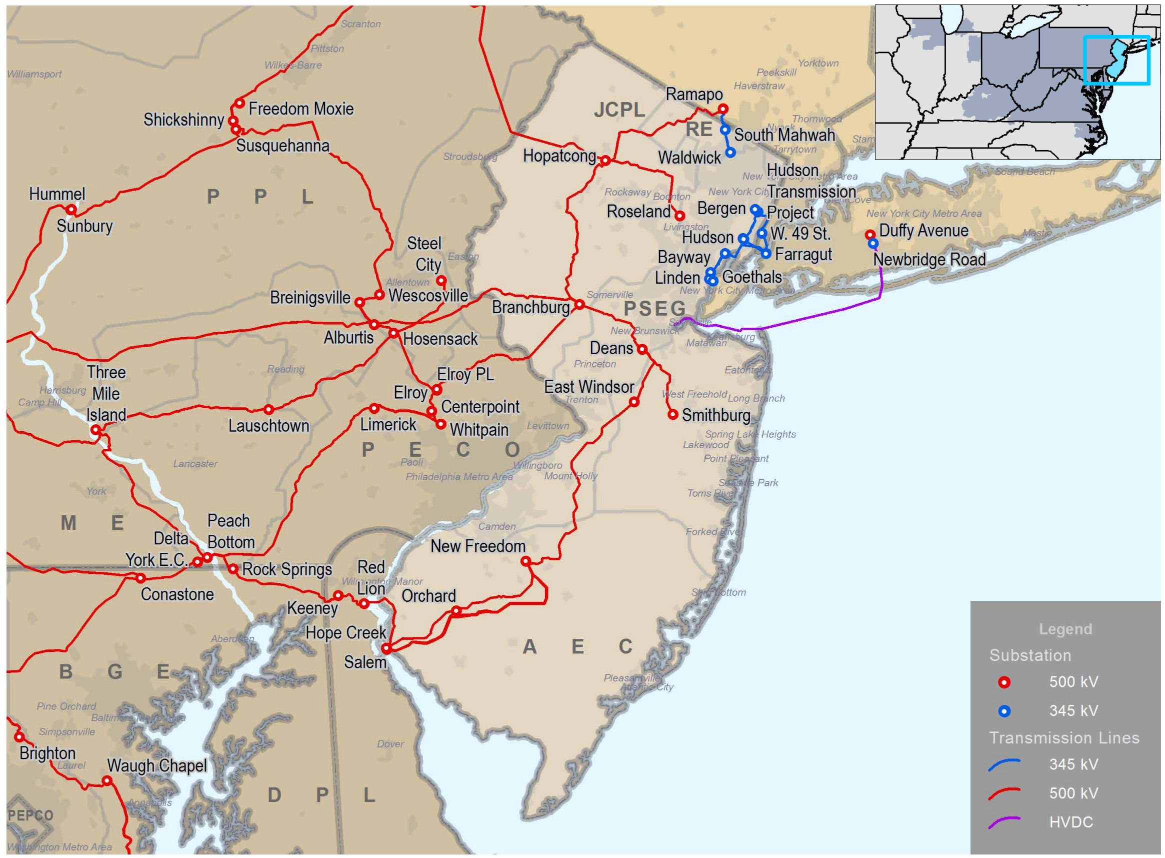


6.6: New Jersey RTEP Summary

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 (AEC), Jersey Central Power & Light (JCP&L), Linden VFT, Neptune Regional Transmission System, Public Service Electric and Gas Company (PSE&G) 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

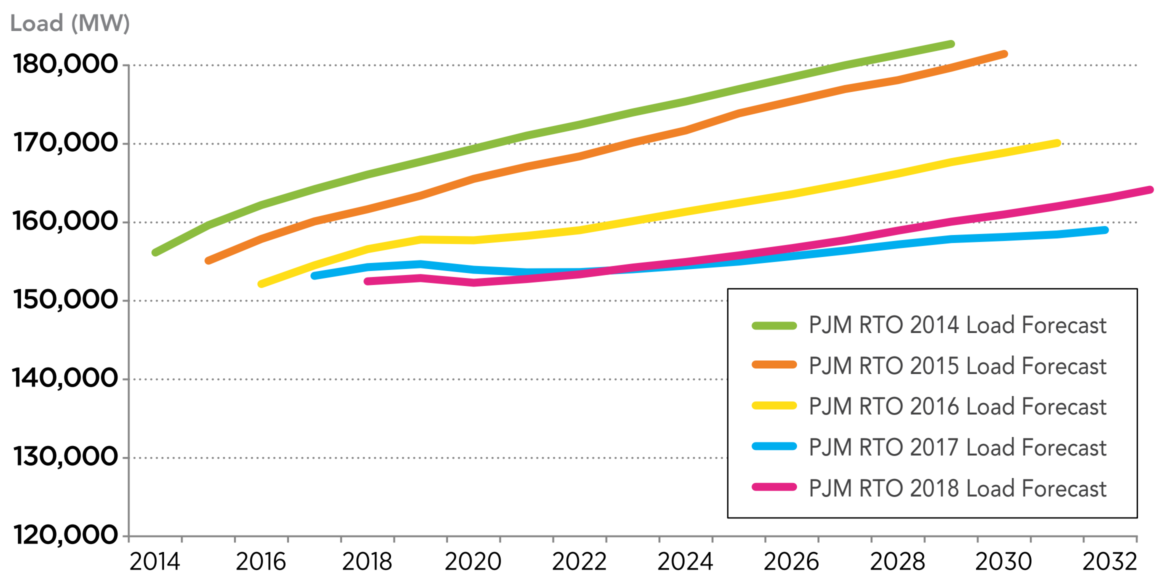
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.35** and **Figure 6.31** summarize the expected loads within the state of New Jersey and across all of PJM.

Table 6.35: New Jersey – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2018	2028	Growth Rate	2017/ 2018	2027/ 2028	Growth Rate
Atlantic City Electric Company	2,460	2,409	-0.2%	1,589	1,537	-0.3%
Jersey Central Power and Light	5,942	5,943	0.0%	3,720	3,681	-0.1%
Public Service Electric and Gas Company	9,903	9,876	0.0%	6,655	6,626	0.0%
Rockland Electric Company	402	402	0.0%	230	229	0.0%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

* **Notes:** The summer peak and winter peak megawatt values in this table each reflect the estimated amount of forecasted load to be served by Atlantic City Electric, Jersey Central Power and Light, Public Service Electric and Gas and Rockland Electric solely in New Jersey. Estimated amounts were calculated based on the average share of real-time summer and winter peak load located in New Jersey over the past five years.

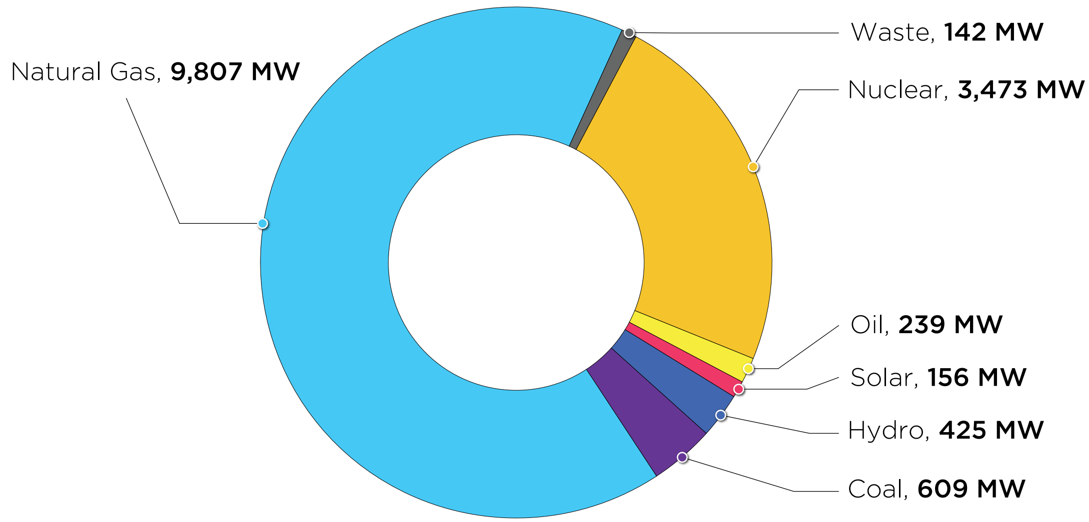
Figure 6.31: PJM RTO Summer Peak Demand Forecast



6.6.3 — Existing Generation

Existing generation in New Jersey as of December 31, 2018, is shown by fuel type in **Figure 6.32**.

Figure 6.32: New Jersey – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



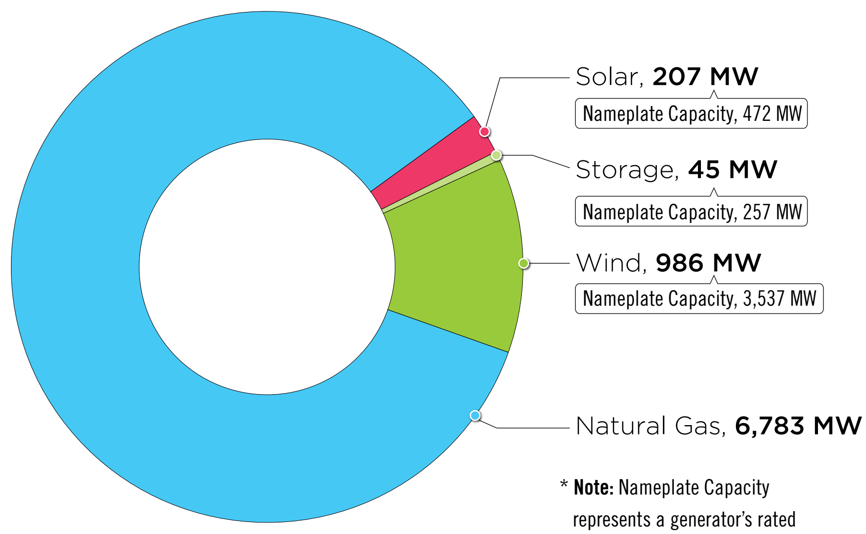
6.6.4 — Interconnection Requests

As of December 31, 2018, 98 queued projects were actively under study, under construction or in suspension in the state of New Jersey. A summary of those interconnection requests is shown in **Table 6.36, Table 6.37, Figure 6.33, Figure 6.34** and **Figure 6.35.**

Table 6.36: New Jersey – Percent MW Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Natural Gas	6,782.5	6,922.1
Solar	207.1	472.0
Storage	45.0	256.9
Wind	985.8	3,537.0
Total	**8,020.4**	**11,188.0**

Figure 6.33: New Jersey – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.37: New Jersey – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue						Grand Total	
	In Service		Withdrawn		Active		Suspended		Under Construction			
	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	**85**	**7,649.0**	**217**	**47,771.4**	**23**	**4,618.5**	**10**	**660.0**	**10**	**1,549.0**	**345**	**62,247.9**
Coal	1	24.0	1	15.0	0	0.0	0	0.0	0	0.0	2	39.0
Diesel	1	8.0	0	0.0	0	0.0	0	0.0	0	0.0	1	8.0
Natural Gas	72	7,201.0	168	46,745.4	12	4,573.5	3	660.0	9	1,549.0	264	60,729.4
Nuclear	6	381.0	0	0.0	0	0.0	0	0.0	0	0.0	6	381.0
Oil	2	35.0	8	945.0	0	0.0	0	0.0	0	0.0	10	980.0
Other	0	0.0	7	45.5	0	0.0	0	0.0	0	0.0	7	45.5
Storage	3	0.0	33	20.0	11	45.0	7	0.0	1	0.0	55	65.0
Renewable	**113**	**265.8**	**433**	**2,461.8**	**31**	**1,136.0**	**6**	**6.0**	**18**	**50.0**	**601**	**4,419.4**
Biomass	0	0.0	2	17.3	0	0.0	0	0.0	0	0.0	2	17.3
Hydro	2	20.5	2	1,006.2	0	0.0	0	0.0	0	0.0	4	1,021.6
Methane	16	45.3	9	40.6	0	0.0	0	0.0	0	0.0	25	85.9
Solar	94	200.0	403	1,300.9	27	153.5	6	6.0	16	47.0	546	1,707.4
Wind	1	0.0	17	601.7	4	982.6	0	0.0	2	3.0	24	1,587.3
Grand Total	**198**	**7,914.8**	**650**	**50,733.0**	**54**	**5,754.5**	**16**	**666.0**	**28**	**1,599.0**	**946**	**66,667.4**

Figure 6.34: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

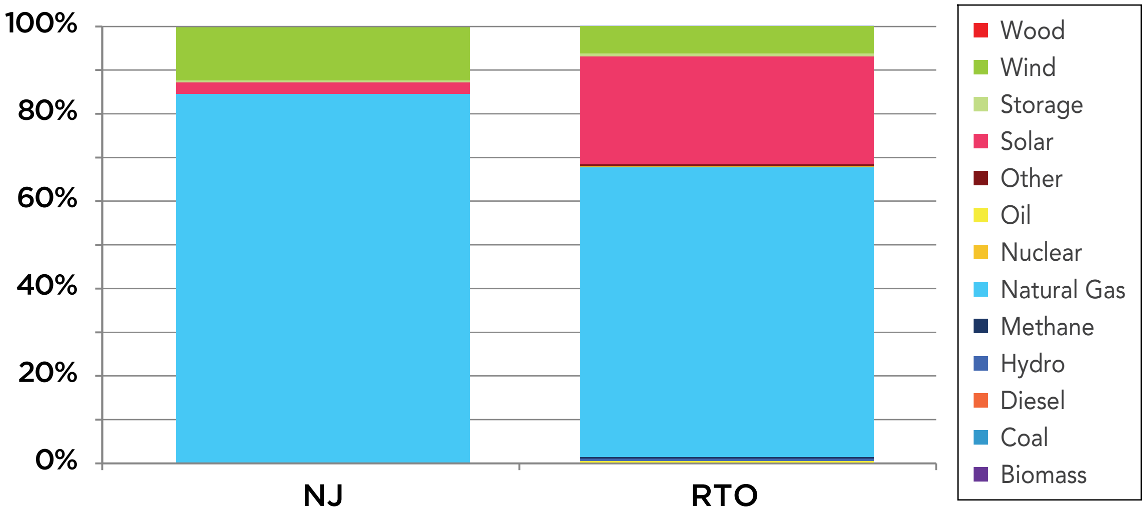
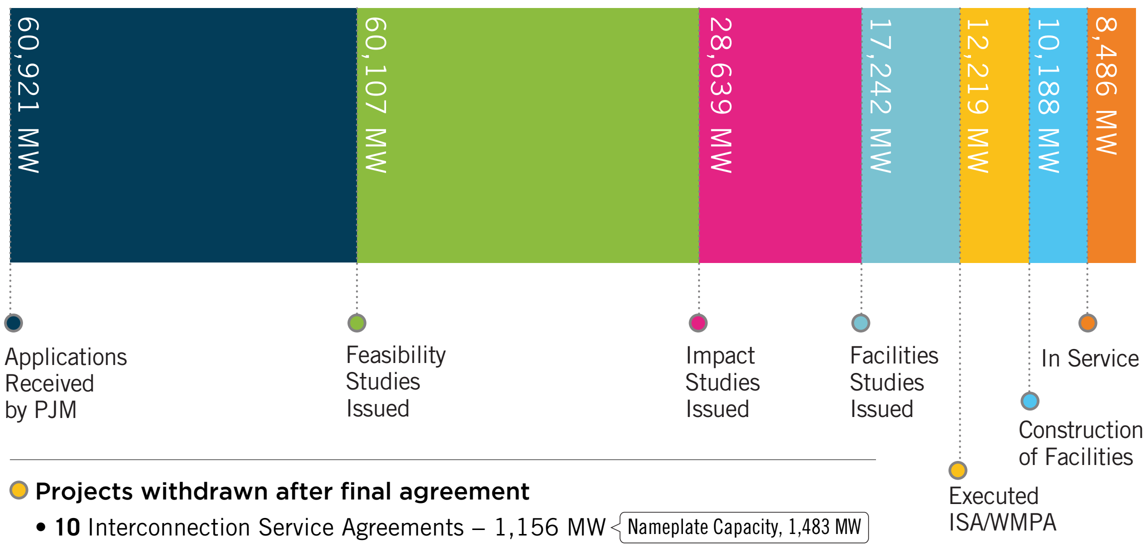


Figure 6.35: New Jersey Progression History of Queue – Interconnection Requests (December 31, 2018)



Projects withdrawn after final agreement

- **10** Interconnection Service Agreements – 1,156 MW (Nameplate Capacity, 1,483 MW)
- **141** Wholesale Market Participation Agreements – 363 MW (Nameplate Capacity, 1,035 MW)

Percentage of planned capacity and projects reached commercial operation

- **13.9 %** requested capacity megawatt
- **23.2 %** requested projects

6.6.5 — Generation Deactivation

Known generating unit deactivation requests in New Jersey between January 1, 2018, and December 31, 2018, are summarized in **Table 6.38** and **Map 6.24**.

Map 6.24: New Jersey Generation Deactivations

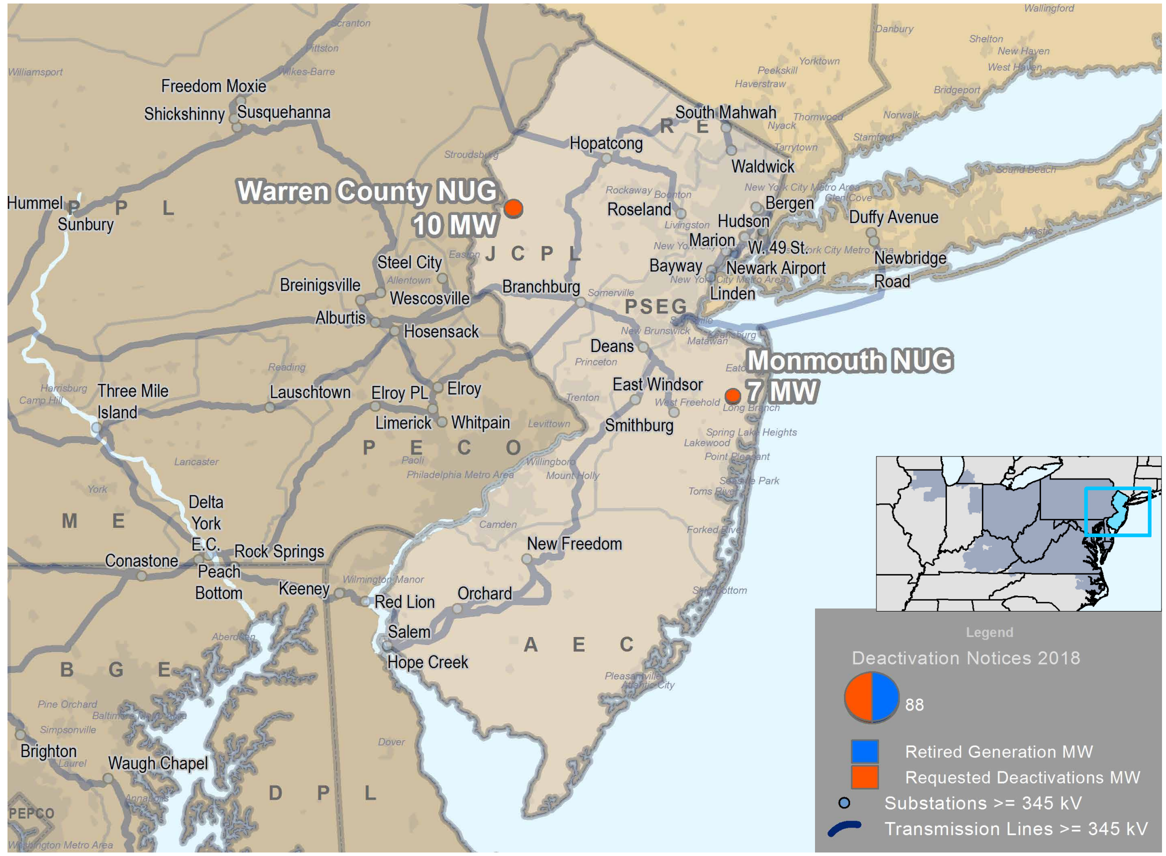


Table 6.38: New Jersey Generation Deactivations

Unit	Capacity (MW)	TO Zone	Age (Years)	Projected/Actual Deactivation Date
Monmouth NUG	7	JCP&L	20	5/31/2019
Warren County NUG	10	JCP&L	30	6/1/2019

6.6.6 — Baseline Projects

RTEP baseline upgrades greater than or equal to $10 million in New Jersey are summarized in **Table 6.39** and **Map 6.25**. In 2018, PJM added $1.6 billion of total baseline projects in New Jersey.

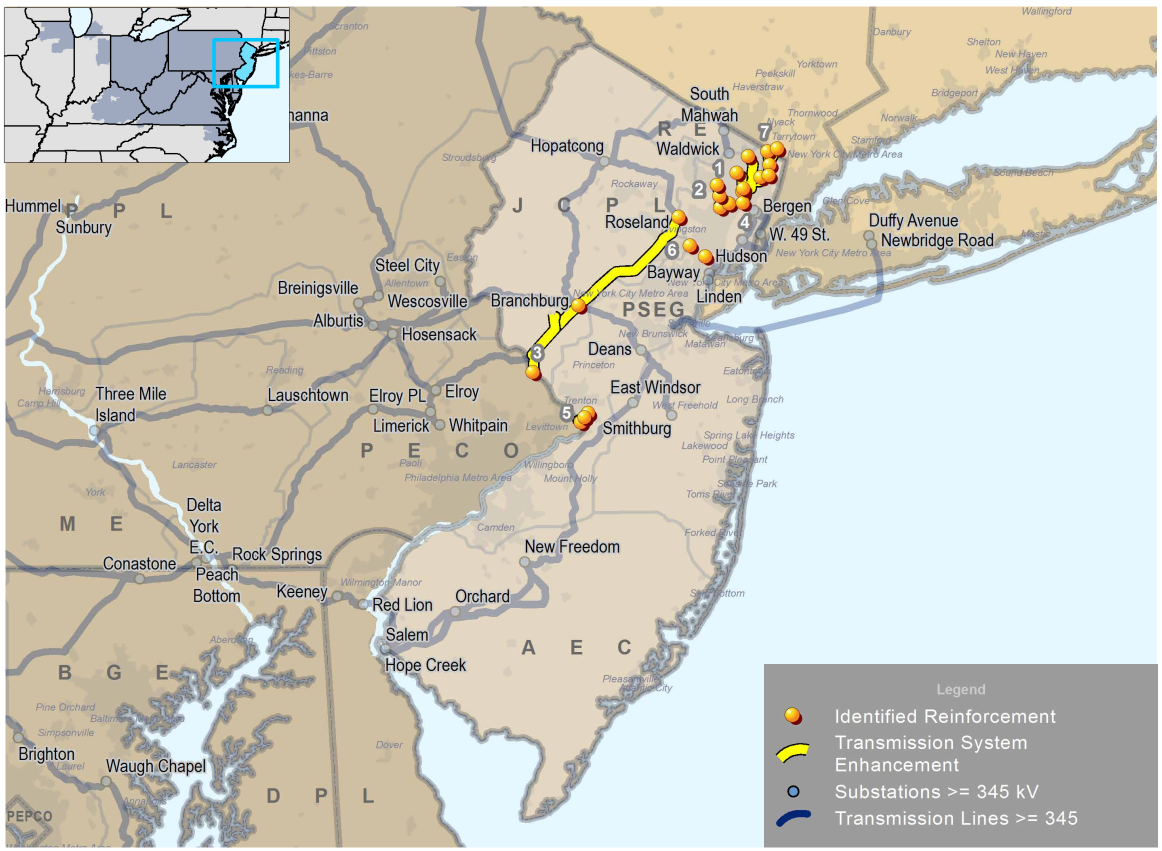
Table 6.39: New Jersey Baseline Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	TO Criteria Violation
1	b2982	.0	Construct a 230/69 kV station at Hillsdale Substation and tie to Paramus and Dumont at 69 kV	6/1/2018	$115.00	PSE&G	12/19/2017	X
		.1	Install a 69 kV ring bus and one 230/69 kV transformer at Hillsdale	6/1/2018		PSE&G	12/19/2017	X
		.2	Construct a 69 kV network between Paramus, Dumont and Hillsdale Substation using existing 69 kV circuits	6/1/2018		PSE&G	12/19/2017	X
2	b2983	.0	Convert Kuller Road to a 69/13 kV station	6/1/2018	$98.25	PSE&G	12/19/2017	X
		.1	Install 69 kV ring bus and two 69/13 kV transformers at Kuller Road	6/1/2018		PSE&G	12/19/2017	X
		.2	Construct a 69 kV network between Kuller Road, Passaic, Paterson, and Harvey (new Clifton-area switching station)	6/1/2018		PSE&G	12/19/2017	X
3	b2986	.0	Replace the existing Roseland-Branchburg-Pleasant Valley 230 kV corridor with new structures	6/1/2018	$1,092.00	PSE&G	1/11/2018	X
		.1	Roseland-Branchburg 230 kV corridor rebuild	6/1/2018		PSE&G	1/11/2018	X
		.2	Branchburg-Pleasant Valley 230 kV corridor rebuild	6/1/2018		PSE&G	1/11/2018	X
4	b3003	.0	Construct a 230/69 kV station at Maywood	6/1/2018	$87.00	PSE&G	3/23/2018	X
		.1	Purchase properties at Maywood to accommodate new construction	6/1/2018		PSE&G	3/23/2018	X
		.2	Extend Maywood 230 kV bus and install one 230 kV breaker	6/1/2018		PSE&G	3/23/2018	X
		.3	Install one 230/69 kV transformer at Maywood	6/1/2018		PSE&G	3/23/2018	X
		.4	Install Maywood 69 kV ring bus	6/1/2018		PSE&G	3/23/2018	X
		.5	Construct a 69 kV network between Spring Valley Road, Hasbrouck Heights, and Maywood	6/1/2018		PSE&G	3/23/2018	X
5	b3004	.0	Construct a 230/69/13 kV station by tapping the Mercer-Kuser Road 230 kV circuit	6/1/2018	$62.00	PSE&G	3/23/2018	X
		.1	Install a new Clinton 230 kV ring bus with one 230/69 kV transformer Mercer-Kuser Rd 230 kV circuit	6/1/2018		PSE&G	3/23/2018	X
		.2	Expand existing 69 kV ring bus at Clinton Ave with two additional 69 kV breakers	6/1/2018		PSE&G	3/23/2018	X
		.3	Install two 69/13 kV transformers at Clinton Avenue	6/1/2018		PSE&G	3/23/2018	X
		.4	Install 18 MVAR capacitor bank at Clinton Avenue 69 kV	6/1/2018		PSE&G	3/23/2018	X

Table 6.38: New Jersey Baseline Projects (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	TO Criteria Violation
6	b3025	.0	Construct two new 69/13 kV stations in the Doremus area and relocate the Doremus load to the new stations	6/1/2018	$155.00	PSE&G	5/25/2018	X
		.1	Install a new 69/13 kV Vauxhall station with a ring bus configuration	6/1/2018		PSE&G	5/25/2018	X
		.2	Install a new 69/13 kV station with a ring bus configuration	6/1/2018		PSE&G	5/25/2018	X
7	b3029	.0	Install 69 kV underground transmission line from Harings Corner-Station terminating at Closter-Station	5/31/2020	$22.00	RECO	7/20/2018	X
		.1	Reconfigure Closte-Station to accommodate the underground transmission line from Harings Corner-Station	5/31/2020		RECO	7/20/2018	X
		.2	Loop in the existing Sparkill-Cresskill 69 kV line into Hardings Closter 69 kV station	5/31/2020		RECO	7/20/2018	X

Map 6.25: New Jersey Baseline Projects (Greater than $10 M) (December 31, 2018)



6.6.7 — Network Projects

RTEP network upgrades greater than or equal to $10 million in New Jersey are summarized in **Table 6.40** and **Map 6.26**.

Map 6.26: New Jersey Network Upgrades (Greater than $10 M) (December 31, 2018)

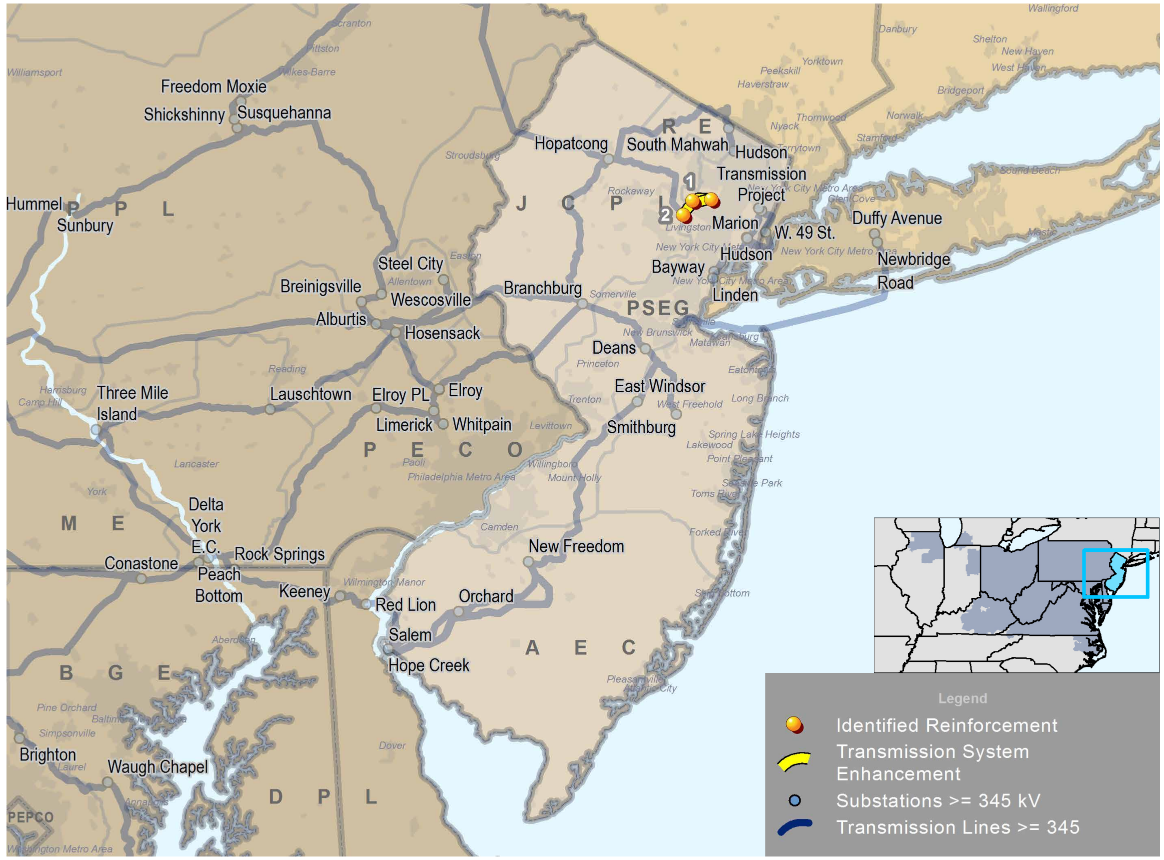


Table 6.40: New Jersey Network Upgrades (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Project Driver	Queue	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	n5564	Reconductor the Williams-Cedar Grove 230 kV line with aluminum conductor steel cable	Merchant Transmission	AD2-018	6/1/2019	$19.09	PSE&G	9/13/2018
2	n5565	Reconductor the Roseland-Cedar Grove 230 kV line with aluminum conductor steel cable	Merchant Transmission	AD2-019	6/1/2019	$18.70	PSE&G	9/13/2018

6.6.8 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in New Jersey are summarized in **Table 6.41** and **Map 6.27**.

Map 6.27: New Jersey Supplemental Projects (Greater than $10 M) (December 31, 2018)

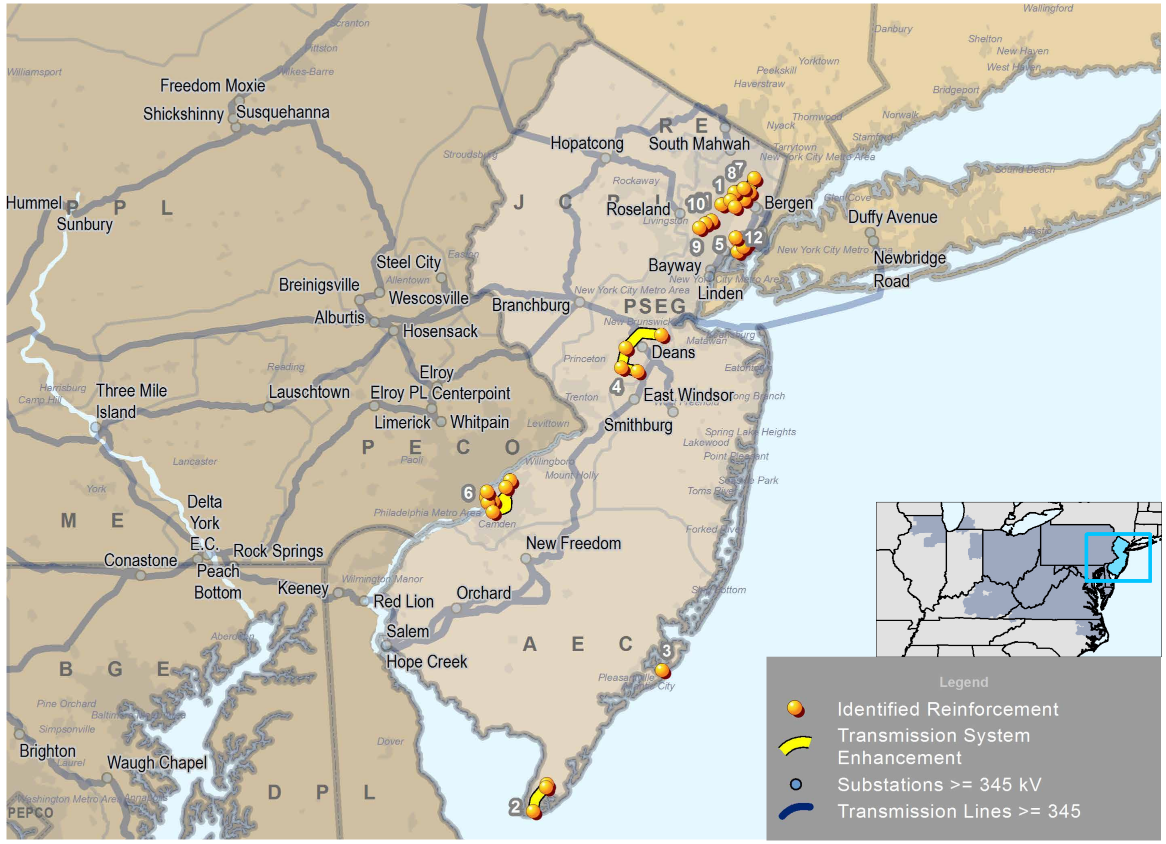


Table 6.41: New Jersey Transmission Owner Supplemental Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	s1575	Construct a new 230/69 kV and a new 69/13 kV station in the Clifton area on the existing right-of-way	12/30/2022	$195.00	PSE&G	1/26/2018
		Construct a new 230/69 kV station (Harvey) in the Clifton area	12/30/2022		PSE&G	1/26/2018
		Install 230 kV ring bus with two 230/69 kV transformers and 69 kV ring bus at Harvey switching station	12/30/2022		PSE&G	1/26/2018
		Loop overhead line (230 kV Athenia to Cook Rd.) into the Harvey switching station	12/30/2022		PSE&G	1/26/2018
		Install two 69/13 kV transformers fed from (Harvey) 69 kV ring bus	12/30/2022		PSE&G	1/26/2018
		Provide a source for a third supply to Kuller Road from Harvey 69 kV	12/30/2022		PSE&G	1/26/2018

Table 6.41: New Jersey Transmission Owner Supplemental Projects (Greater than $10 M) (December 31, 2018) (cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
2	s1628	Rebuild line 0735 No. 1 between Middle, Rio Grande and Cape May substations. All structures, conductor and static wire will be replaced with new weathering steel poles, conductor, and Optical Ground Wire (OPGW).	5/31/2023	$11.40	AE	3/23/2018
3	s1629	Build a new six breaker 69 kV Gas Insulated Substation (GIS) ring bus at Harbor Beach. Install two new 69 kV sources from Huron and from Ontario. Retire the two existing Brigantine Island 23 kV substations and 23 kV lines.	5/31/2022	$70.30	AE	3/23/2018
4	s1647	Construct a new 69/13 kV station in Cranbury, construct a 230/69 kV station at Plainsboro (Hunters Glen) and reconfigure 69 kV bus at Harts Lane and Sand Hills.	11/30/2021	$307.00	PSE&G	3/23/2018
		Reconfigure 230 kV bus, install a 69 kV ring bus, and install one 230/69 kV transformer at Plainsboro (Hunters Glen)	11/30/2021		PSE&G	3/23/2018
		Install a 69 kV ring bus, two 69/13 kV transformers, and an 18 MVAR capacitor bank at new Cranbury station.	11/30/2021		PSE&G	3/23/2018
		Convert 69 kV straight bus to 69 kV ring bus at Harts Lane to provide a new line position	11/30/2021		PSE&G	3/23/2018
		Convert 69 kV straight bus to 69 kV breaker-and-a-half bus at Sand Hills to resolve voltage issues and provide a line position	11/30/2021		PSE&G	3/23/2018
		Construct a 69 kV network between Cranbury, Harts Lane, Hunters Glen, Penns Neck, and Sand Hills	11/30/2021		PSE&G	3/23/2018
5	s1674	Eliminate Academy St and construct a new station at a nearby location	12/31/2022	$90.00	PSE&G	5/25/2018
		Purchase new property in Jersey City and install a 69 kV ring bus and two 69/13 kV transformers to feed Academy St. load	12/31/2022		PSE&G	5/25/2018
		Construct a 69 kV network between the following stations: Greenville, Kearny, Madison and the new station.	12/31/2022		PSE&G	5/25/2018
6	s1675	Eliminate State St and construct a new station at a nearby location. Raise and rebuild Woodlynne above FEMA flood elevation	6/1/2022	$153.00	PSE&G	5/25/2018
		Install a 69 kV ring bus and three 69/4 kV transformers at a new location to feed State St load	6/1/2022		PSE&G	5/25/2018
		Relocate Woodlynne station by purchasing adjacent property and installing a 69 kV ring bus with two 69/13 kV transformers	6/1/2022		PSE&G	5/25/2018
		Construct a 69 kV network between the following stations: Camden, Gloucester, Delair, Locust St, Woodlynne, and the new station	6/1/2022		PSE&G	5/25/2018
7	s1752	Upgrade the Hackensack 26 kV station to 69 kV	5/31/2023	$83.00	PSE&G	10/29/2018
		Install a 69 kV ring bus with three 69/4 kV transformers at Hackensack station	5/31/2023		PSE&G	10/29/2018
		Construct a 69 kV network between Hackensack, Hasbrouck Heights, Maywood, and New Milford	5/31/2023		PSE&G	10/29/2018
8	s1753	Upgrade the Plauderville 26 kV Station to 69 kV	5/31/2023	$94.00	PSE&G	10/29/2018
		Purchase nearby property to accommodate new construction (Plauderville 69 kV)	5/31/2023		PSE&G	10/29/2018
		Install Plauderville 69 kV ring bus with two 69/13 kV transformers	5/31/2023		PSE&G	10/29/2018
		Construct a 69 kV network between East Rutherford, Maywood, Passaic and Plauderville	5/31/2023		PSE&G	10/29/2018
9	s1722	Construct a 230/69/4kV station near the location of Orange Valley	10/31/2022	$328.00	PSE&G	8/24/2018
10	s1723	Relocate Lakeside (69kV station) outside of the FEMA flood zone.	10/31/2022	$106.00	PSE&G	8/24/2018
11	s1724	Raise and rebuild Toney's Brook above FEMA flood elevation	10/31/2022	$98.00	PSE&G	8/24/2018
12	S1749	Re-configure the existing NJT Meadow 230 kV substation with 4-bay GIS breaker-and-half configuration	12/31/2021	127	PSE&G	9/13/2018

6.6.9 — Merchant Transmission Project Requests

As of December 31, 2018, PJM's queue contained six merchant transmission interconnection request projects which include a terminal in New Jersey as shown in **Table 6.42** and **Map 6.28**

Map 6.28: New Jersey Merchant Projects

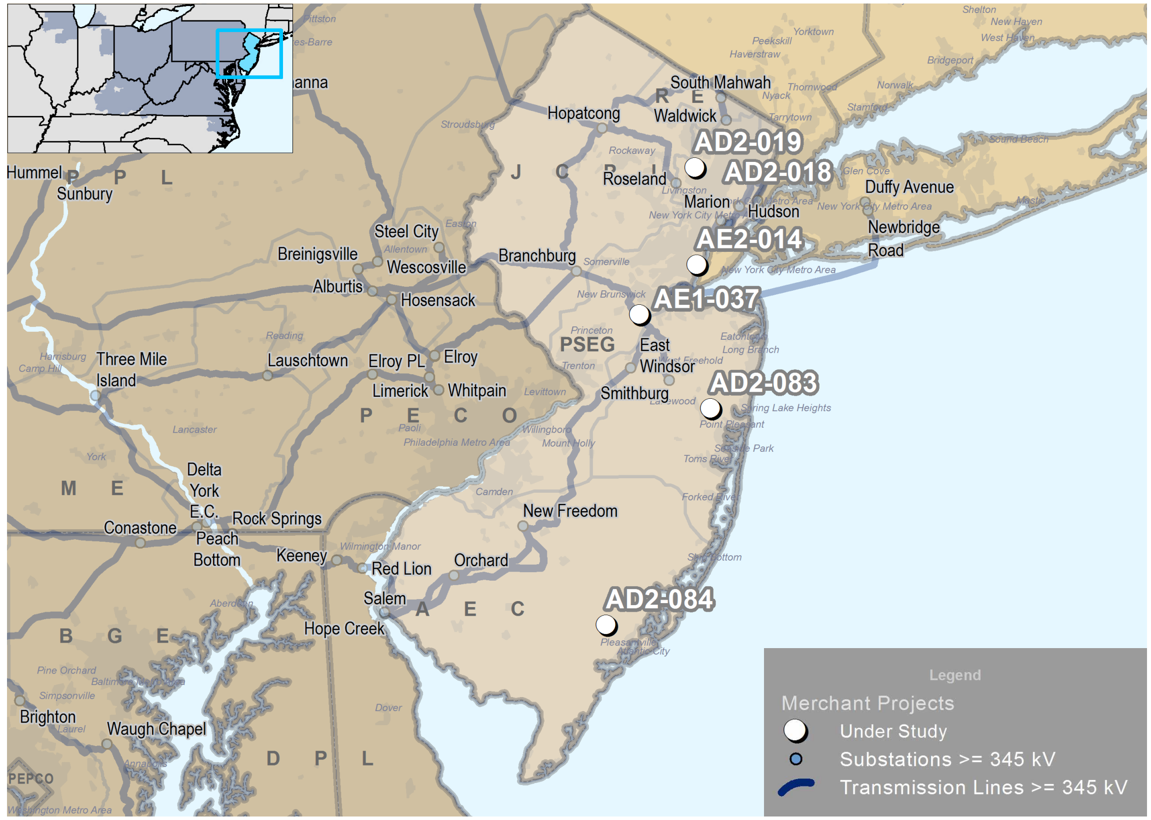


Table 6.42: New Jersey Merchant Projects

Queue	Project Name	Maximum Output (MW)	Status	Projected In-Service Date	TO Zone
AD2-083*	Larrabee 230 kV	1,100	Active	12/31/2025	JCP&L
AD2-084*	Cardiff 230 kV	1,100	Active	12/31/2025	AE
AD2-018	Roseland-Cedar Grove	63	Active	6/1/2019	PSE&G
AD2-019	Williams-Cedar Grove	63	Active	6/1/2019	PSE&G
AE1-037*	Deans 500 kV	1,200	Active	12/31/2025	PSE&G
AE2-014*	Sewaren 230 kV	1,263	Active	1/1/2024	PSE&G

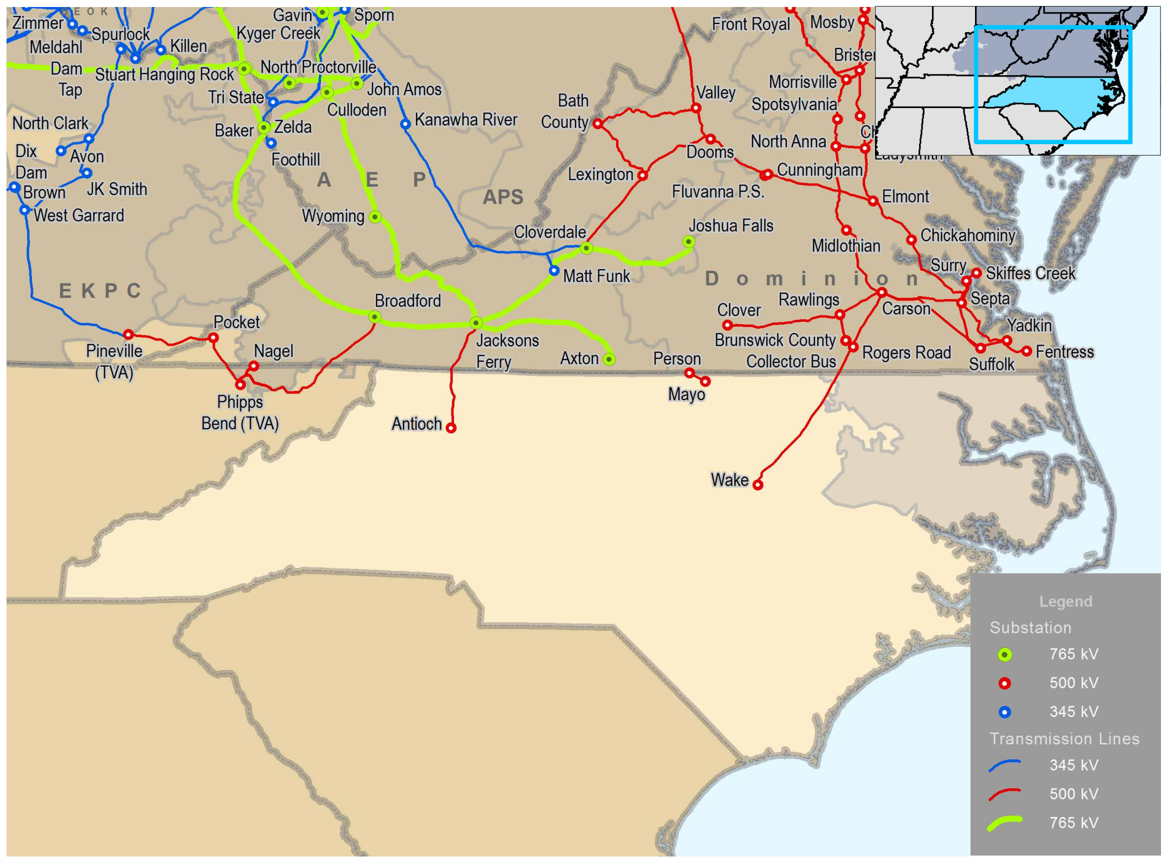
* **NOTE:** Merchant projects to supportive future off-shore wind generation.

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 6.29**. 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 6.29: PJM Service Area in North Carolina



6.7.2 — Load Growth

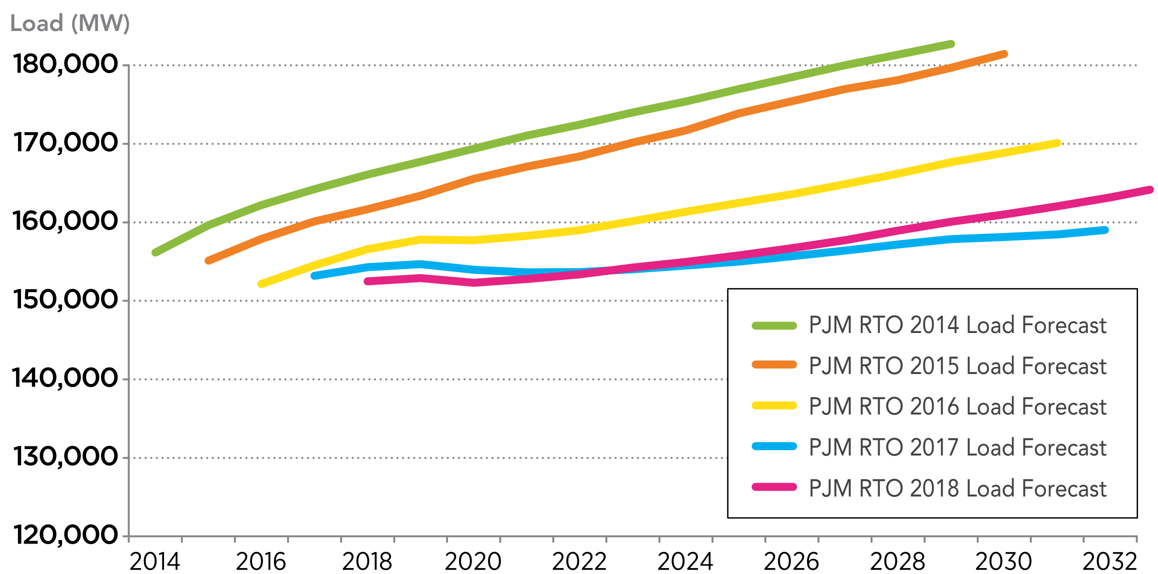
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.43** and **Figure 6.36** summarize the expected loads within the state of North Carolina and across all of PJM.

Table 6.43: North Carolina – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW) 2018	Summer Peak (MW) 2028	Summer Peak (MW) Growth Rate	Winter Peak (MW) 2017/2018	Winter Peak (MW) 2027/2028	Winter Peak (MW) Growth Rate
Dominion Virginia Power *	1,027	1,109	0.8%	1,005	1,097	0.9%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

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

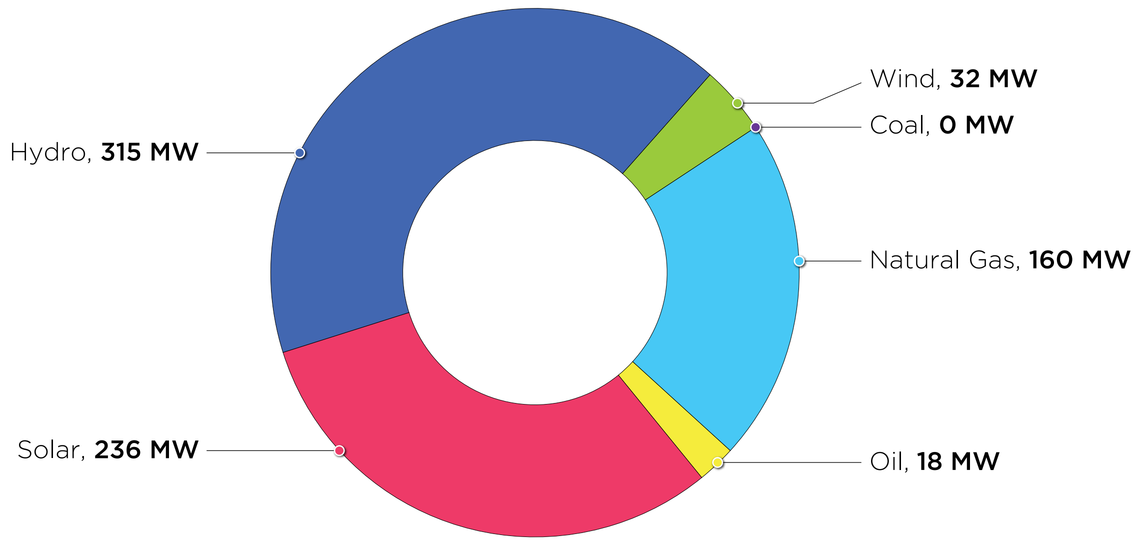
Figure 6.36: PJM RTO Summer Peak Demand Forecast



6.7.3 — Existing Generation

Existing generation in North Carolina as of December 31, 2018, is shown by fuel type in **Figure 6.37**.

Figure 6.37: North Carolina – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



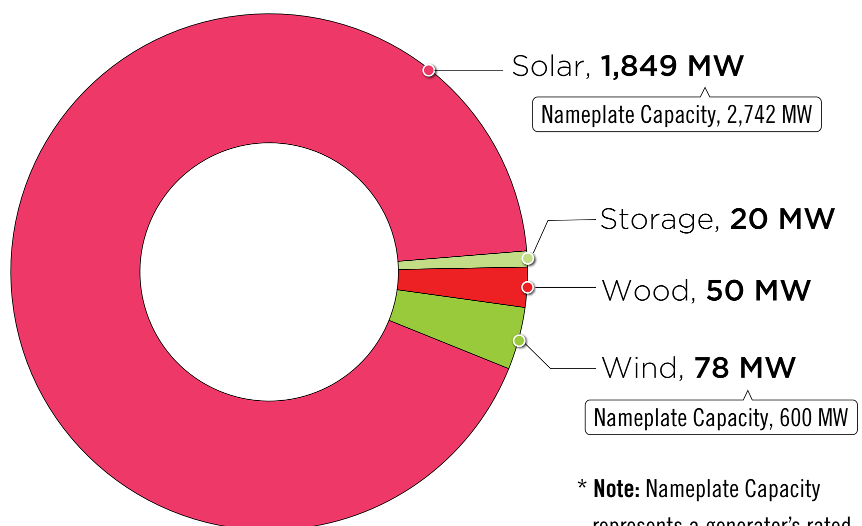
6.7.4 — Interconnection Requests

As of December 31, 2018, 44 queued projects were actively under study, under construction or in suspension in the state of North Carolina. A summary of those interconnection requests is shown in **Table 6.44, Table 6.45, Figure 6.38, Figure 6.39** and **Figure 6.40**.

Table 6.44: North Carolina – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Solar	1,849.0	2,741.7
Wind	78.0	600.3
Wood	50.0	62.5
Storage	20.0	20.0
Total	**1,997.0**	**3,424.5**

Figure 6.38: North Carolina – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.45: North Carolina – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue				Grand Total	
	In Service		Withdrawn		Active		Under Construction			
	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	**0**	**0.0**	**2**	**32.0**	**1**	**20**	**0**	**0.0**	**3**	**52.0**
Storage	0	0.0	2	32.0	1	20.0	0	0.0	3	52.0
Renewable	**11**	**250.7**	**73**	**2,710.5**	**29**	**1376.6**	**14**	**600.4**	**127**	**4,938.18**
Methane	0	0.0	1	12.0	0	0.0	0	0.0	1	12.0
Solar	11	250.7	62	2,423.2	29	1,376.6	11	472.4	113	4,522.9
Wind	0	0.0	9	195.3	0	0.0	2	78.0	11	273.3
Wood	0	0.0	1	80.0	0	0.0	1	50.0	2	130.0
Grand Total	**11**	**250.7**	**75**	**2,742.5**	**30**	**1,396.6**	**14**	**600.4**	**130**	**4,990.2**

Figure 6.39: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

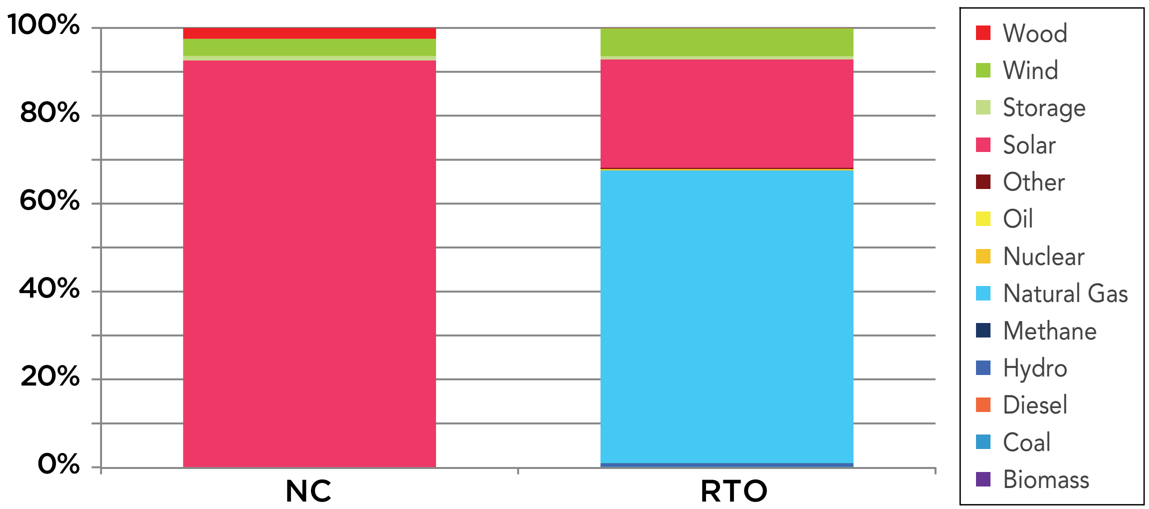
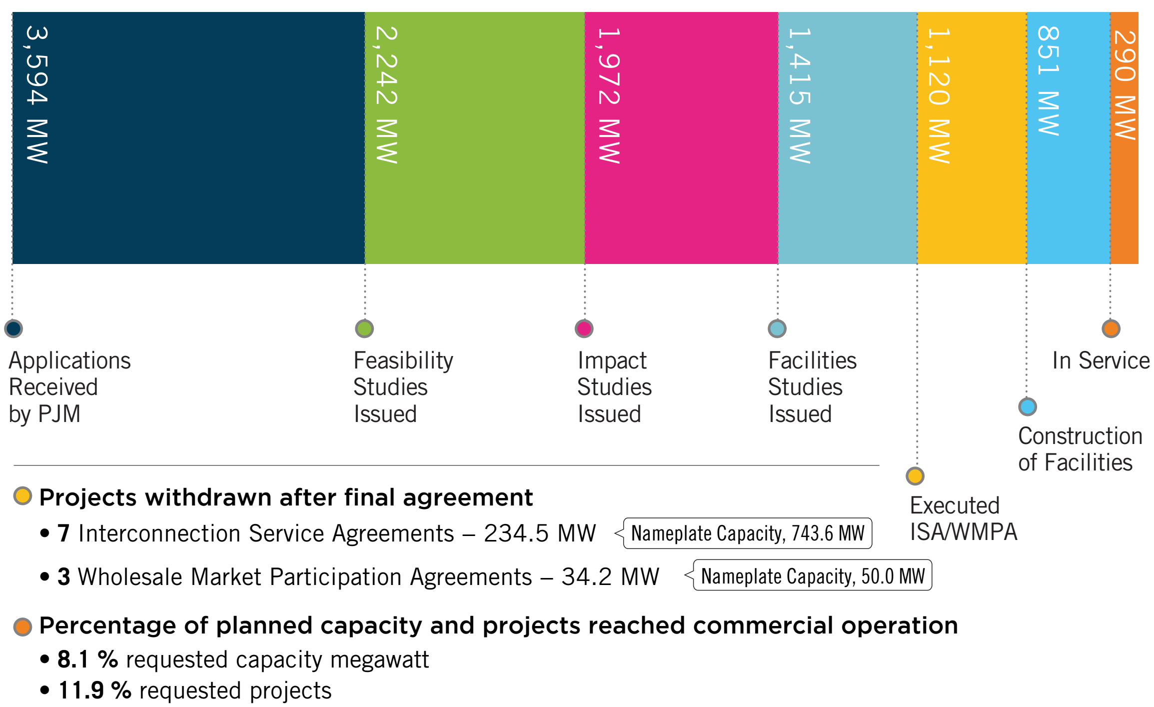


Figure 6.40: North Carolina Progression History of Queue – Interconnection Requests (December 31, 2018)

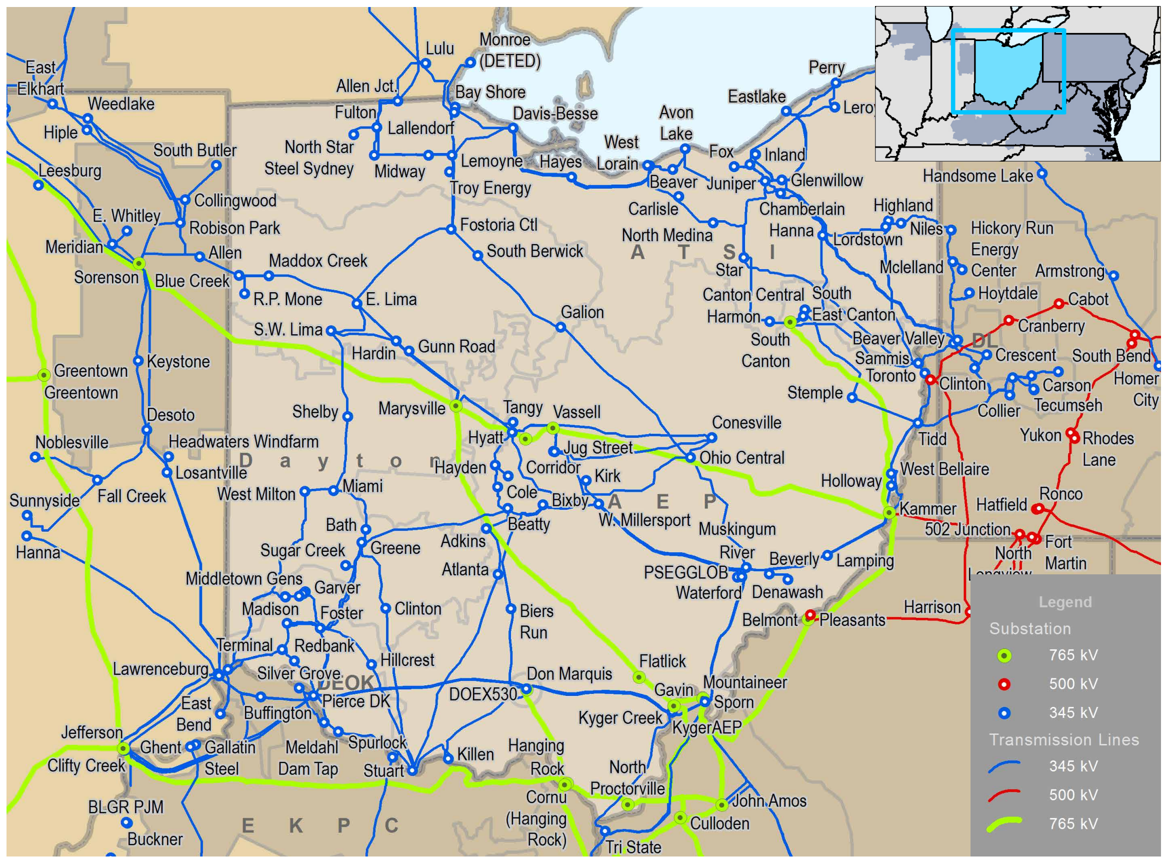


6.8: Ohio RTEP Summary

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 (Dayton), American Transmission Systems, Inc. (ATSI), Duke Energy Ohio & Kentucky (DEO&K), City of Cleveland and the City of Hamilton as shown on **Map 6.30**. 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 6.30: PJM Service Area in Ohio



6.8.2 — Load Growth

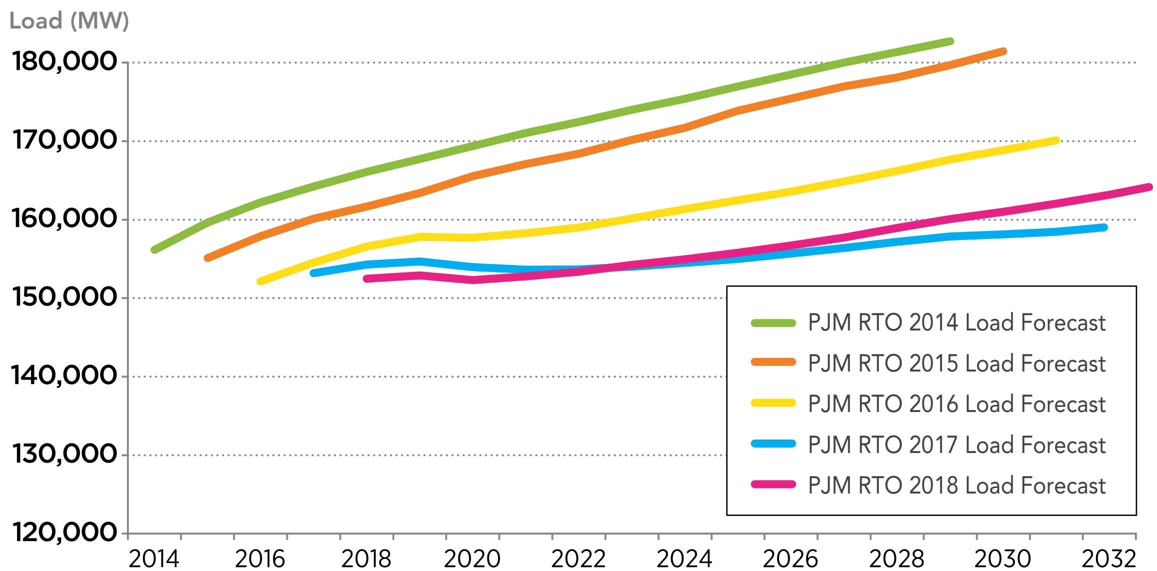
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.46** and **Figure 6.41** summarize the expected loads within the state of Ohio and across all of PJM.

Table 6.46: Ohio – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2018	2028	Growth Rate	2017/ 2018	2027/ 2028	Growth Rate
American Electric Power Company *	10,415	10,935	0.5%	9,199	9,671	0.5%
American Transmission Systems, Inc. *	12,020	12,351	0.3%	9,810	10,044	0.2%
Dayton Power and Light	3,459	3,508	0.1%	2,917	2,932	0.1%
Duke Energy Ohio and Kentucky *	4,600	4,881	0.6%	3,732	3,921	0.5%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

*PJM notes that AEP, ATSI and DEO&K serve load other than in Ohio. The summer peak and winter peak megawatt values in this table each reflect an estimated amount of forecasted load to be served by each of those transmission owners solely in Ohio. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Ohio over the past five years.

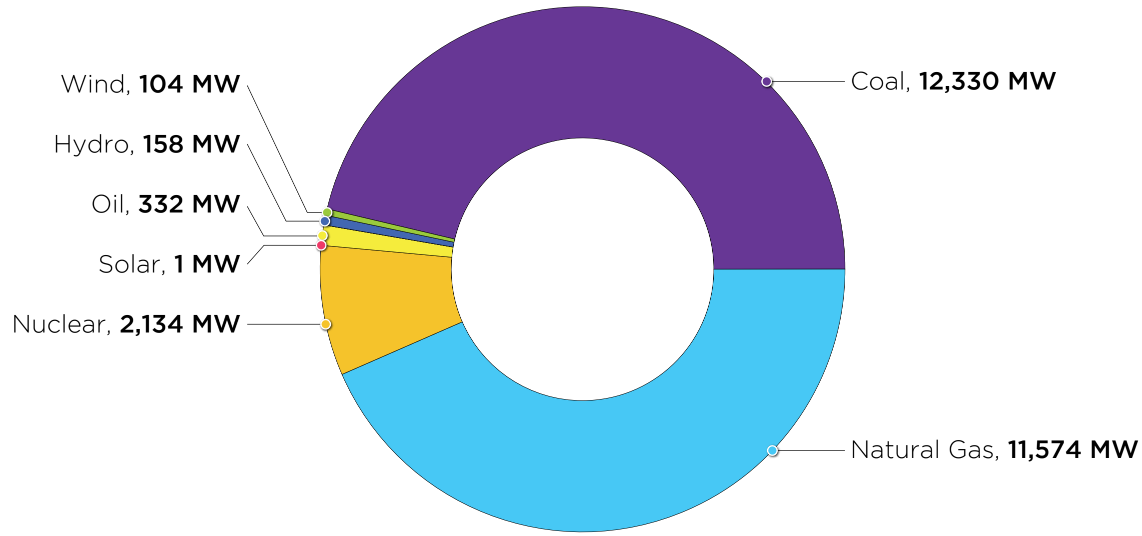
Figure 6.41: PJM RTO Summer Peak Demand Forecast



6.8.3 — Existing Generation

Existing generation in Ohio as of December 31, 2018, is shown by fuel type in **Figure 6.42**.

Figure 6.42: Ohio – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



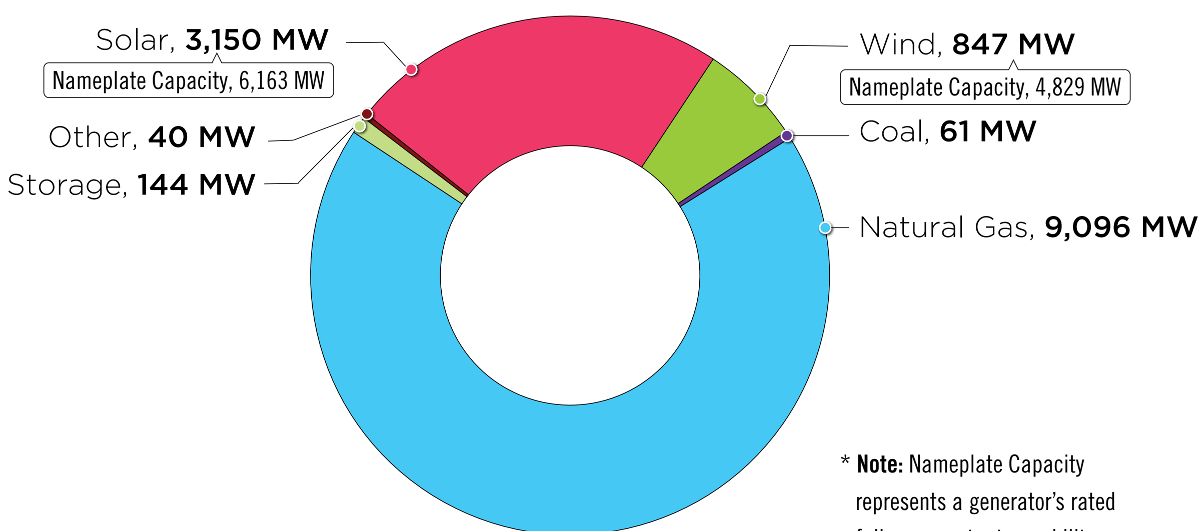
6.8.4 — Interconnection Requests

As of December 31, 2018, 120 queued projects were actively under study, under construction or in suspension in the state of Ohio. A summary of those interconnection requests is shown in **Table 6.47, Table 6.48, Figure 6.43, Figure 6.44** and **Figure 6.45**.

Table 6.47: Ohio – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Natural Gas	9,095.7	9,686.0
Solar	3,149.9	6,163.5
Wind	847.0	4,829.1
Storage	143.9	181.7
Coal	61.0	61.0
Other	40.0	40.0
Total	**13,337.5**	**20,961.3**

Figure 6.43: Ohio – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.48: Ohio – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue						Grand Total	
	In Service		Withdrawn		Active		Suspended		Under Construction			
	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	**51**	**4,166**	**64**	**19,909**	**21**	**8,202**	**1**	**0.0**	**4**	**1,139**	**141**	**33,416**
Coal	17	299.5	15	8,883.0	2	29.0	0	0.0	2	32.0	36	9,243.5
Diesel	1	7.0	0	0.0	0	0.0	0	0.0	0	0.0	1	7.0
Natural Gas	24	3,843.5	28	10,701.4	15	7,990.7	0	0.0	1	1,105.0	68	23,640.6
Nuclear	1	16.0	0	0.0	0	0.0	0	0.0	0	0.0	1	16.0
Oil	0	0.0	1	5.0	0	0.0	0	0.0	0	0.0	1	5.0
Other	0	0.0	4	320.0	1	40.0	0	0.0	0	0.0	5	360.0
Storage	8	0.0	16	0.0	3	142.0	1	0.0	1	1.9	29	143.9
Renewable	**17**	**289**	**169**	**3,750**	**80**	**3,676**	**6**	**104**	**8**	**217**	**280**	**8,036**
Biomass	1	0.0	1	0.0	0	0.0	0	0	0	0.0	2	0.0
Hydro	1	112.0	8	76.2	0	0.0	0	0	0	0.0	9	188.2
Methane	9	50.9	10	26.1	0	0.0	0	0	0	0.0	19	77.0
Solar	1	1.0	89	2,143.9	66	3,054.9	3	19.0	2	76.0	161	5,294.7
Wind	5	125.0	61	1,503.5	14	621.5	3	84.5	6	141.0	89	2,475.6
Grand Total	**68**	**4,454.8**	**233**	**23,659.1**	**101**	**11,878.1**	**7**	**103.5**	**12**	**1,355.9**	**421**	**41,451.5**

Figure 6.44: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

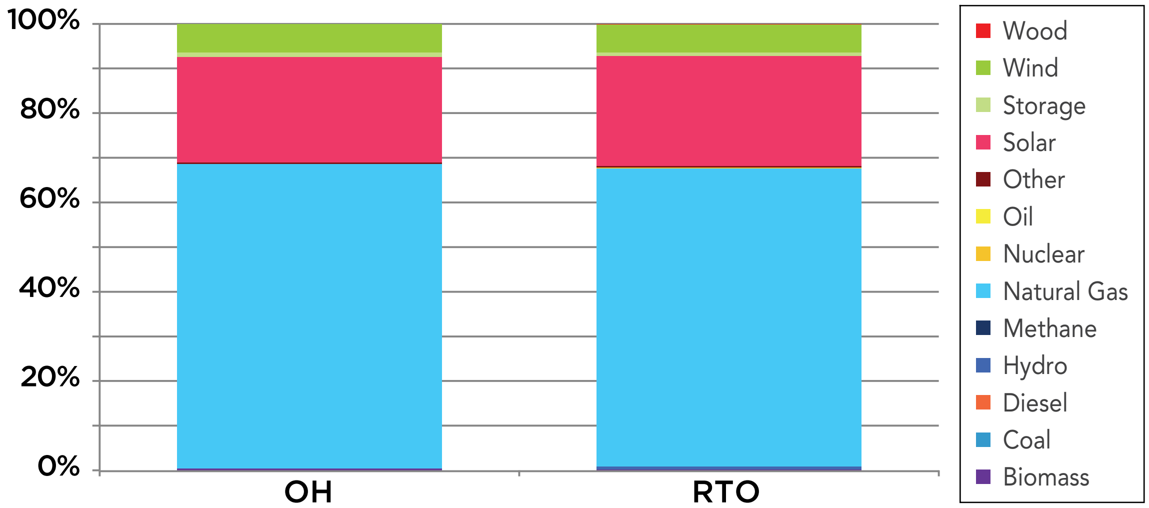
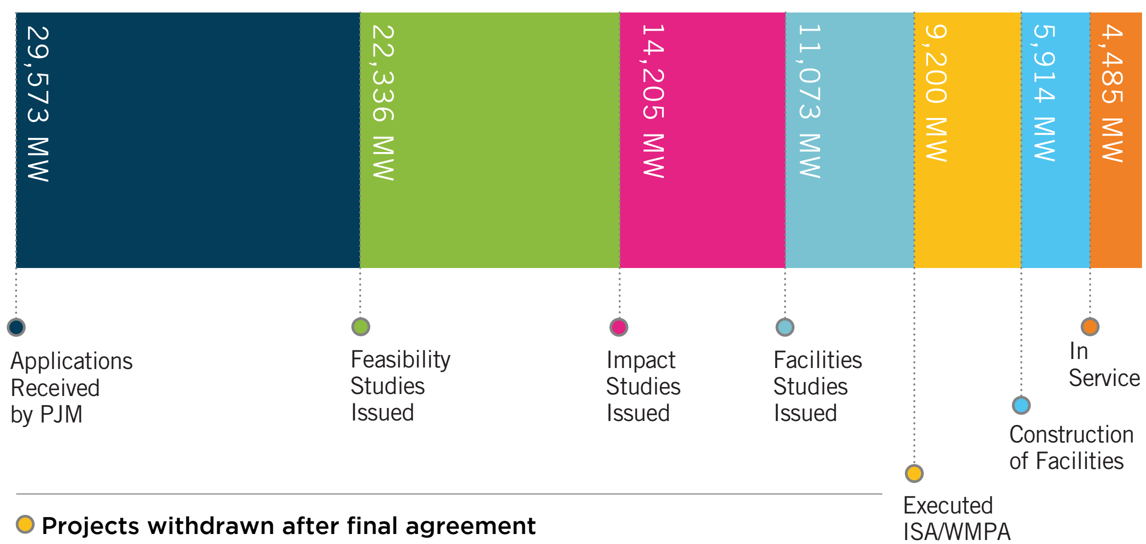


Figure 6.45: Ohio Progression History of Queue – Interconnection Requests (December 31, 2018)



Projects withdrawn after final agreement

- **16** Interconnection Service Agreements – 3,462 MW (Nameplate Capacity, 4,743 MW)
- **11** Wholesale Market Participation Agreements – 16 MW (Nameplate Capacity, 53 MW)

Percentage of planned capacity and projects reached commercial operation

- **15.2 %** requested capacity megawatt
- **21.6 %** requested projects

6.8.5 — Generation Deactivation

Known generating unit deactivation requests in Ohio between January 1, 2018 and December 31, 2018, are summarized in **Table 6.49** and **Map 6.31**.

Map 6.31: Ohio Generation Deactivations (December 31, 2018)

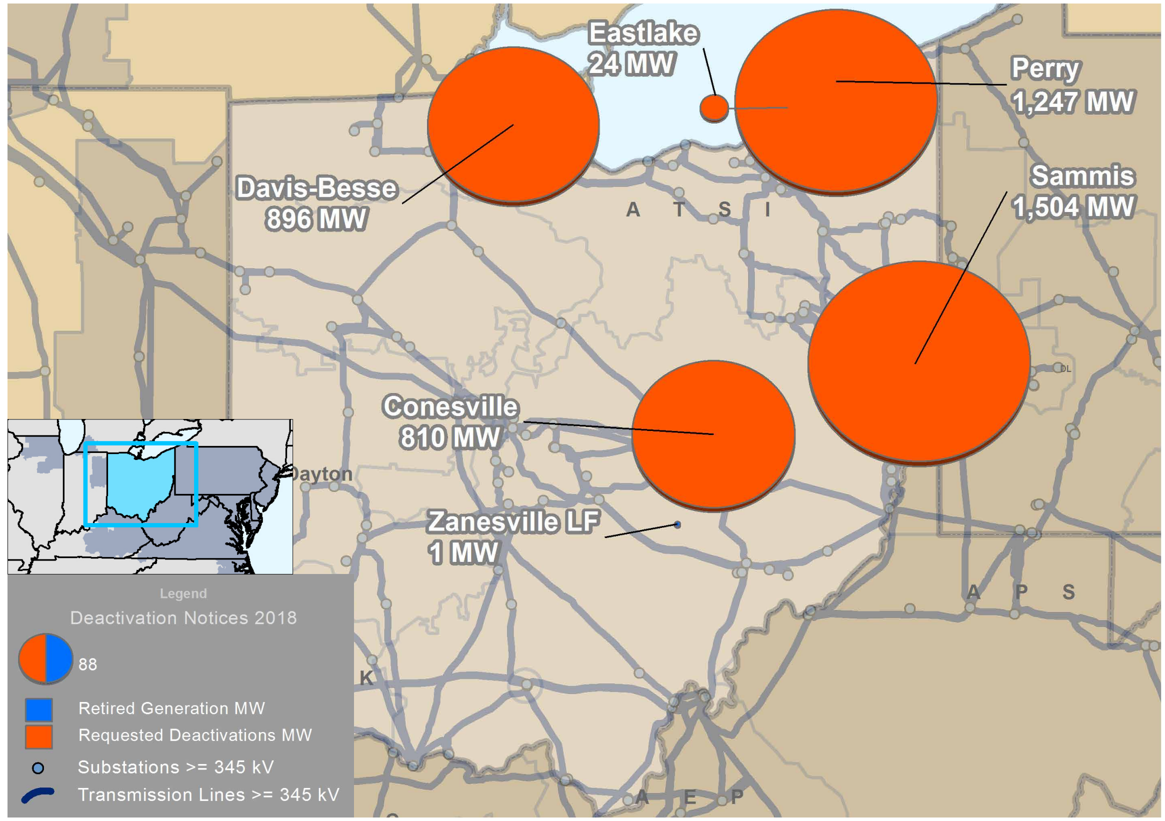


Table 6.49: Ohio Generation Deactivations (December 31, 2018)

Unit	Capacity (MW)	TO Zone	Age (Years)	Projected/Actual Deactivation Date
Perry	1,247	ATSI	31	5/31/2021
Davis Besse 1	896	ATSI	41	5/31/2020
Sammis 6	600	ATSI	49	6/1/2022
Sammis 7	600	ATSI	47	6/1/2022
Conesville 5	405	AEP	42	6/1/2019
Conesville 6	405	AEP	40	6/1/2019

Unit	Capacity (MW)	TO Zone	Age (Years)	Projected/Actual Deactivation Date
Sammis 5	291	ATSI	51	6/1/2022
Eastlake 6	24	ATSI	45	6/1/2021
Sammis Diesel	13	ATSI	46	6/1/2021
Zanesville Landfill	1	AEP	8	9/8/2018

6.8.6 — Baseline Projects

RTEP baseline upgrades greater than or equal to $10 million in Ohio are summarized in **Table 6.50** and **Map 6.32**. In 2018, PJM added $130 million of total baseline projects in Ohio.

Map 6.32: Ohio Baseline Projects (Greater than $10 M) (December 31, 2018)

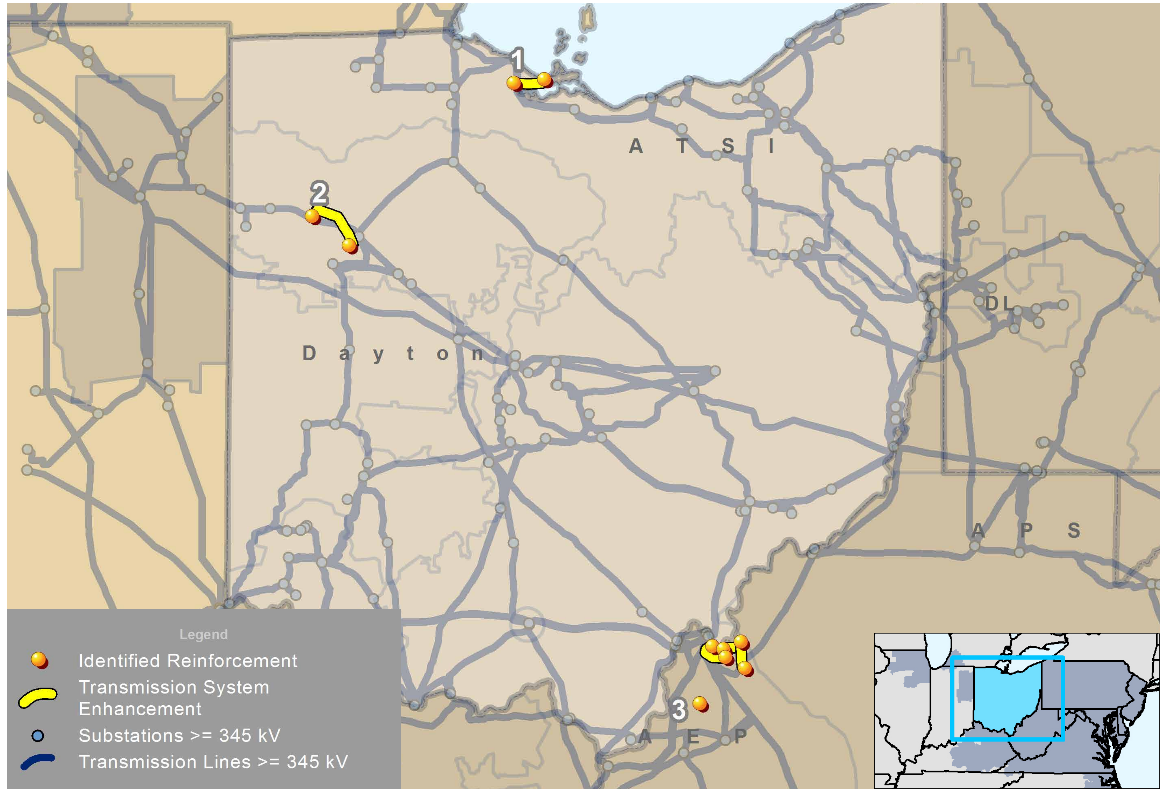


Table 6.50: Ohio Baseline Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	Baseline Load Growth Deliverability & Reliability	TO Criteria Violation
1	b3033	.0	Ottawa-Lakeview 138 kV reconductor and substation upgrades	12/1/2023	$20.00	ATSI	8/31/2018	X	
2	B3036	.0	Rebuild 15.4 miles of double circuit North Delphos-Rockhill 138 kV line	12/1/2023	$24.50	AEP	8/31/2018	X	
3	b3040	.1	Rebuild 15 miles of Ravenswood-Racine Tap 69 kV line to 69 kV standards, utilizing 795 26/7 ACSR conductor	6/1/2022	$68.10	AEP	8/31/2018		X
		.4	Install new 138/12 kV 20 MVA transformer at Polymer station to transfer load from Mill Run station to help address overload on the 69 kV network	6/1/2022		AEP	8/31/2018		X

6.8.7 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in Ohio are summarized in **Table 6.51** and **Map 6.33.**

Table 6.51: Ohio Transmission Owner Supplemental Projects – Interconnection Requests (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	s1621	Rebuild the 138 kV line from Waverly to Adams utilizing aluminum conductor steel cable (296 MVA). Remove old line after rebuild complete.	5/29/2020	$66.00	AEP	4/17/2018
		Rebuild two independent lines, less than 0.5 mile apart, between Seaman and Adams, one 138 kV and one 69 kV, as a double circuit for approximately 8.5 miles using aluminum conductor steel cable. Remove old lines after rebuild complete. There will also need to be a short single circuit tap for Lawshe 69 kV.	3/19/2021		AEP	4/17/2018
		A three-way switch structure will be constructed outside Lawshe 69 kV substation.	3/19/2021		AEP	4/17/2018
2	s1563	Rebuild 15.6 miles of double-circuit 138 kV line utilizing aluminum conductor steel cable conductor (296 MVA rating) at Haviland-North Delphos 138 kV.	12/18/2020	$48.80	AEP	2/14/2018
3	s1623	Rebuild the West Bellaire - Moundsville 69 kV circuit. Utilize aluminum conductor steel cable conductor (128 MVA rating). The extension into Monroe Street will be rebuilt as a double-circuit loop. The extension into Shadyside will be mostly rebuilt as a double-circuit loop.	3/1/2023	$42.30	AEP	4/17/2018
		Convert Monroe Street to in-and-out with two 69 kV breakers. Replace 12 kV breakers and regulators. Install 69 kV circuit switcher. Remove inoperable line switches at West Monroe Street and West Shadyside. Install new three-way motor-operated air breaker switch.	6/1/2022		AEP	4/17/2018
4	s1511	Construct double-circuit line extension to Clutch switch (0.5 miles).	6/14/2018	$35.60	AEP	2/14/2018
		Construct a single-circuit line to close the loop between Schafrath and Madisonburg (2 miles).	6/14/2018		AEP	2/14/2018
		Rebuild Clutch Switch to Tigers as single circuit (1.5 miles).	6/14/2018		AEP	2/14/2018
		Rebuild from Schafrath to Oakhills switch (3.0 miles single circuit) and from Oakhills to Highland (0.4 miles double circuit).	5/24/2018		AEP	2/14/2018
		Establish a new station to serve customer (Clutch).	6/14/2018		AEP	2/14/2018
		Establish a new station at Schafrath to eliminate hard tap and loop lines.	5/31/2018		AEP	2/14/2018
		Expand Madisonburg station to establish new line exit to Schafrath.	5/24/2018		AEP	2/14/2018
		Construct new station at Tigers to eliminate hard tap and replace Smithville station.	6/30/2020		AEP	2/14/2018
		Install new phase-over-phase switch at Geyer.	12/6/2019		AEP	2/14/2018
		Retire Oakhills switch and establish a new box bay at Highland Avenue for the double-circuit line.	6/30/2020		AEP	2/14/2018
		Retire Orrville Road switch.	1/15/2020		AEP	2/14/2018
		Upgrade relaying at West Wooster.	6/14/2018		AEP	2/14/2018
		Upgrade relaying at East Wooster.	6/14/2018		AEP	2/14/2018
		Retire Smithville station.	12/6/2019		AEP	2/14/2018
5	s1564	Rebuild approximately 27.7 miles from Harpster 69 kV Station-Waldo 69 kV station utilizing aluminum conductor steel cable conductor.	6/4/2021	$31.16	AEP	2/14/2018
		Replace existing two-way switch at Harpster Pump station with three-way switch.	6/4/2021		AEP	2/14/2018
		Install a one-way phase-over-phase switch just north of Ridgedale (Marion Rural Co-op).	6/4/2021		AEP	2/14/2018
		Remove station West Marion switch.	6/4/2021		AEP	2/14/2018

Table 6.50: Ohio Transmission Owner Supplemental Projects – Interconnection Requests (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
6	s1617	Rebuild North Spencerville station. Install two 69 kV circuit breakers.	12/20/2018	$30.10	AEP	4/17/2018
		At North Middlepoint station, construct new high-side switching facilities. Install one motor-operated air breaker, switch and circuit switcher.	7/11/2019		AEP	4/17/2018
		At South Kossuth station, install a new one-way switch toward North Spencerville, retire the existing one-way switch and build a section of line in the clear on the north side of the highway.	2/14/2019		AEP	4/17/2018
		Rebuild existing Delphos–Van Wert 69 kV line with aluminum conductor steel cable (128 MVA rating), including partial line reroute.	11/30/2020		AEP	4/17/2018
		Rebuild existing East Delphos–Kossuth 69 kV line with aluminum conductor steel cable, including partial reroute.	6/30/2020		AEP	4/17/2018
7	s1614	At Buckley Road Station, replace two 69 kV breakers with 40 kA breakers and associated equipment. Add a 138 kV circuit breaker for high-side protection of transformer No. 1. This will replace the existing ground switching protection currently at the station.	12/7/2018	$25.31	AEP	4/17/2018
		At Softail switch, replace the hard tap for the Rising Sun delivery point, on the Buckley Road–Fostoria Central 138 kV line, with a three-way phase-over-phase switch.	5/18/2018		AEP	4/17/2018
		Rebuild approximately 15.2 miles of the Allendale–Fremont Center 69 kV line with 138 kV line construction operated at 69 kV. The new line will be double circuit 138 kV construction for 0.6 miles at the Allendale end so that the customer served at Weaver switch can remain served at 69 kV even after a future 138 kV conversion of the rebuilt line. The remaining 14.6 miles of line rebuild will be single-circuit 138 kV construction.	12/31/2020		AEP	4/17/2018
8	s1537	Rebuild 9.5 miles of feeder between Evendale and Port Union 69 kV substations with new structures, hardware, switches and conductor.	4/1/2019	$25.00	DEO&K	3/9/2018
9	s1525	Rebuild 16.3 miles of the Van Buren – Liberty Center line utilizing aluminum conductor steel cable (129 MVA rating).	6/5/2019	$22.40	AEP	2/14/2018
		Install a new three-way phase-over-phase steel switching structure at the Buckeye Tap switch.	6/5/2019		AEP	2/14/2018
10	s1657	Rebuild 10.5 miles of 69 kV feeder between Symmes and Northgreen substations including the tap to Port Union with 298 new structures, hardware and conductor. Capacity of the line will increase from 97 MVA to 150 MVA.	12/31/2022	$21.30	DEO&K	5/21/2018
11	s1552	Expand Glidden substation from a straight bus to a ring bus. Install seven 138 kV breakers to create a ring bus. Install four transformer high side breakers.	12/31/2020	$21.00	ComEd	2/14/2018
12	s1559	Rebuild approximately 18.7 miles of the Ross–Highland 69 kV Line using aluminum conductor steel cable conductor (128 MVA rating) and 69 kV self-supporting steel with partial reroute around Hillsboro.	12/1/2019	$21.00	AEP	2/14/2018
		Replace Petersburg switch.	12/1/2019		AEP	2/14/2018
13	s1612	Rebuild the 69 kV Adams-Rarden line. The new line will be rebuilt adjacent to the existing one, leaving the old line in service until the work is completed. The new 69 kV line will be built with aluminum conductor steel cable (125 MVA).	6/1/2020	$20.30	AEP	4/17/2018
		The switch at the Peebles Tap will be replaced with a three-way motor-operated air breaker switch. A new three-way motor-operated air breaker switch will be installed at the Davon Tap.	6/1/2020		AEP	4/17/2018
14	s1616	Rebuild 6.91 miles on Columbus Grove-Ottawa 69kV line with 795 aluminum conductor steel cable (128 MVA rating) in existing ROW. Remove taps to Ottawa station. Build 69kV line extensions to serve Glandorf station using 795 aluminum conductor steel cable. Retire Pratt Extension 69kV Line. Reconfigure 69kV connections at Agner switch. Remove line sections and de-energized conductor that will no longer be needed.	4/8/2019	$19.10	AEP	4/17/2018
		Replace 69/12 kV Ottawa station with 69/12 kV Glandorf station at a new station site. Upgrade existing three-way switch at North Columbus Grove to three-way switch with a motor-operated air breaker. Replace three 69 kV circuit breakers and a 69 kV cap switcher at East Ottawa.	4/8/2019		AEP	4/17/2018
16	s1609	Build a 4.5-mile 138 kV double circuit line from Sardinia Station to tap point on the Kenton–Wildcat 138 kV circuit, capable of 200 MVA. Once complete, remove the 11.9-mile 69 kV Seaman-Sardinia transmission line and associated 69 kV equipment at the Seaman and Sardinia substations.	12/1/2021	$17.00	AEP	3/27/2018
		Install 138 kV bus and two 138 kV circuit breakers at Sardinia station.	12/1/2021		AEP	3/27/2018

Table 6.50: Ohio Transmission Owner Supplemental Projects – Interconnection Requests (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
17	s1514	Build a new 5.7-mile 69 kV line from Mount Sterling to Zanesville station with aluminum conductor steel cable (102 MVA rating) to close the radial loop.	12/7/2018	$16.50	AEP	2/14/2018
		Zanesville–Linden Avenue 69 kV structure removal.	6/29/2018		AEP	2/14/2018
		Mount Sterling–Zanesville 69 kV fiber cable.	12/7/2018		AEP	2/14/2018
		At Zanesville station, install a 69 kV 40 kA circuit breaker. Replace three 69 kV breakers. Install a 138 kV high-side circuit breaker and a 69 kV low-side circuit breaker for the 138/69 kV transformer.	11/9/2018		AEP	2/14/2018
		At Mount Sterling station, install two 69 kV 40 kA circuit breakers in a box-bay configuration.	11/16/2018		AEP	2/14/2018
18	s1539	Rebuild 6.4 miles of 69 kV feeder between Locust and Todd substations with 54 new structures, hardware and conductor.	12/1/2018	$16.00	DEO&K	3/9/2018
19	s1608	Retire existing Cavett two-way line switch. Replace with three-way line switch on new route with motor-operated air breaker facing West Van Wert.	12/31/2020	$16.00	AEP	3/27/2018
		Rebuild existing Haviland–West Van Wert 69 kV line asset (14.6 miles) with aluminum conductor steel cable conductor (68 MVA rating, non-conductor limited), including partial line reroute. Remove old aluminum conductor steel cable, copper and aluminum conductor steel cable conductor.	12/31/2020		AEP	3/27/2018
20	s1587	Rebuild 5.8 miles of feeder between Princeton and Port Union substations with one 161 new structures, hardware and conductor.	12/31/2019	$15.20	DEO&K	3/27/2018
21	s1567	Relocate the Newcomerstown-Ray line to the 69 kV bay at Newcomerstown station.	12/21/2018	$14.02	AEP	2/14/2018
		At Newcomerstown station, install a new 69 kV 40 kA circuit breaker for the Sundergroundarcreek terminal line exit. Remove the 34.5 kV circuit breaker. Replace the 50 MVA transformer with a 90 MVA transformer and install a high-side and low-side circuit breaker.	12/21/2018		AEP	2/14/2018
		At Ray station, install a 69 kV 40 kA bus tie circuit breaker and transformer circuit switchers. Install a 69/34.5 kV transformer to serve the existing customers.	12/16/2018		AEP	2/14/2018
		At Bakersville switch, remove existing and install new transformers due to the 34.5 kV to 69 kV conversion.	12/26/2018		AEP	2/14/2018
		At Sundergroundarcreek terminal station, install a 69 kV 40 kA circuit breaker for the Newcomerstown line exit. Remove 34.5 kV breaker.	12/21/2018		AEP	2/14/2018
		Relocate Ray-Sundergroundarcreek 69 kV line to 69 kV bay at Sundergroundarcreek terminal.	12/21/2018		AEP	2/14/2018
22	s1757	Replace two 345/138 kV transformers at Beaver and replace other equipment at station accordingly.	12/31/2021	$12.70	ATSI	10/26/2018
23	s1599	Rebuild two 138 kV transmission lines between Hillsboro and Hutchings Tap as double circuit construction. Construct the 19-mile AEP segment from Middleboro to Hutchings Tap as a single circuit line using aluminum conductor steel cable conductor.	12/1/2021	$114.60	AEP	3/27/2018
		The 1200 A switch at Middleboro will be upgraded to 2000 A. The new switch will have SCADA control, auto sectionalizing and loop opening/line dropping capability.	12/1/2021		AEP	3/27/2018

Table 6.50: Ohio Transmission Owner Supplemental Projects – Interconnection Requests (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
24	s1620	Rebuild the Northeast Canton 138/69/12 kV station on the existing property. Install a 138 kV four-breaker ring bus, 138-12 kV distribution transformer, 138-69 kV, 90 MVA transformer, 69 kV six-breaker ring bus, 69 kV capacitor bank (14 MVAR).	12/1/2020	$11.90	AEP	4/17/2018
		At West Canton 138 kV station, replace 138 kV breaker, disconnects and relays.	12/1/2020		AEP	4/17/2018
		At Wagenhals 138 kV station, change relay settings to coordinate with Northeast Canton.	11/1/2019		AEP	4/17/2018
		At Packard 138 kV station, convert two manual line switches to auto-sectionalizing motor-operated air breakers.	12/6/2019		AEP	4/17/2018
		At Stanley Court, upgrade relays to coordinate with Northeast Canton.	5/31/2019		AEP	4/17/2018
		At Oakwood Road 69 kV station, replace 69 kV breaker and relays.	12/20/2019		AEP	4/17/2018
		At Diamond Street 69 kV station, remove two 69 kV breakers and replace with sectionalizing motor-operated air breakers.	12/1/2020		AEP	4/17/2018
		At California 69 kV station, relocate two breakers from Diamond Street and install new relays.	11/1/2019		AEP	4/17/2018
25	s1517	Construct 138 kV-rated four-breaker ring bus, with a 14.4 MVAR capacitor bank.	10/28/2018	$10.17	AEP	2/14/2018
		Reroute the three 69 kV lines to enter Parlett station.	10/28/2018		AEP	2/14/2018
		Retire Parlett 69 kV switch	11/15/2018		AEP	2/14/2018
26	s1669	Rebuild 9.8 miles of feeder between South Bethel and Brown substations with new structures, hardware and conductor. Replace one 69 kV switch.	12/31/2019	$10.00	DEO&K	6/26/2018
27	s1487	Rebuild 54.4 miles of line between Harrison and Poston 138 kV stations with aluminum conductor steel cable (296 MVA rating) and steel poles.	6/27/2019	$61.90	AEP	1/8/2018
28	s1493	Build a new Beatty-Madison 69 kV line utilizing 795 aluminum conductor steel cable (129MVA rating) in new right-of-way. Acquire existing aluminum conductor steel cable and aluminum conductor steel cable (73 MVA rating) in existing right-of-way.	12/1/2019	$50.60	AEP	1/30/2018
		Rebuild single circuit 69 kV line from Harrison to Madison with aluminum conductor steel cable (129 MVA rating), mostly in existing right-of-way.	12/1/2019		AEP	1/30/2018
		Rebuild tap to Darbyville as double-circuit aluminum conductor steel cable (129 MVA rating).	10/18/2019		AEP	1/30/2018
		At Harrison station, replace the 138/69 kV transformer with a 90 MVA model. Install three 69 kV circuit breakers with 40 kA breakers. Install a 138 kV circuit breaker with a 63 kA breaker. Install a 69 kV capacitor.	2/1/2020		AEP	1/30/2018
		At Madison station, install two new 69kV 2,000A 40kA circuit breaker's and 1 600A 40kA circuit switcher	10/7/2019		AEP	1/30/2018
		At Big Darby switch, Dry Run switch, and Ballah switch, upgrade with 2000 A switches at new locations. Retire old switches.	9/30/2019		AEP	1/30/2018
29	s1432	Rebuild from Ross to Heppner (formerly Coalton). Single-circuit 138 kV rebuild with aluminum conductor steel cable Curlew conductor (148 MVA rating).	12/31/2021	$50.30	AEP	1/8/2018
		Replace switches at Ginger with a new 138 kV phase-over-phase switch with motor-operated air breakers. Replace switches at Vigo with a new box bay and 138 kV breakers. Replace Pine Ridge switch with a new 138 kV phase-over-phase switch with motor-operated air breakers.	12/31/2021		AEP	1/8/2018
30	s1488	Rebuild the 20-mile 69 kV transmission line between Newcomerstown and Dennison stations with aluminum conductor steel cable (148 MVA rating).	11/1/2019	$33.40	AEP	1/8/2018
		Rebuild the 1.6 mile radial tap to Lock 17 station as a double-circuit 69 kV loop with aluminum conductor steel cable (148 MVA rating).	12/1/2019		AEP	1/8/2018
		At Lock 17 69 kV station, add a 69 kV station bay structure and two 69 kV motor-operated air breaker switches. Relocate the 69 kV capacitor bank and expand to 10.8 MVAR. Replace the transformer protection with a circuit switcher.	11/1/2019		AEP	1/8/2018
		Replace East Newcomerstown 69 kV switch with a new two-way switch. Retire Belden 69 kV switch.	12/1/2019		AEP	1/8/2018

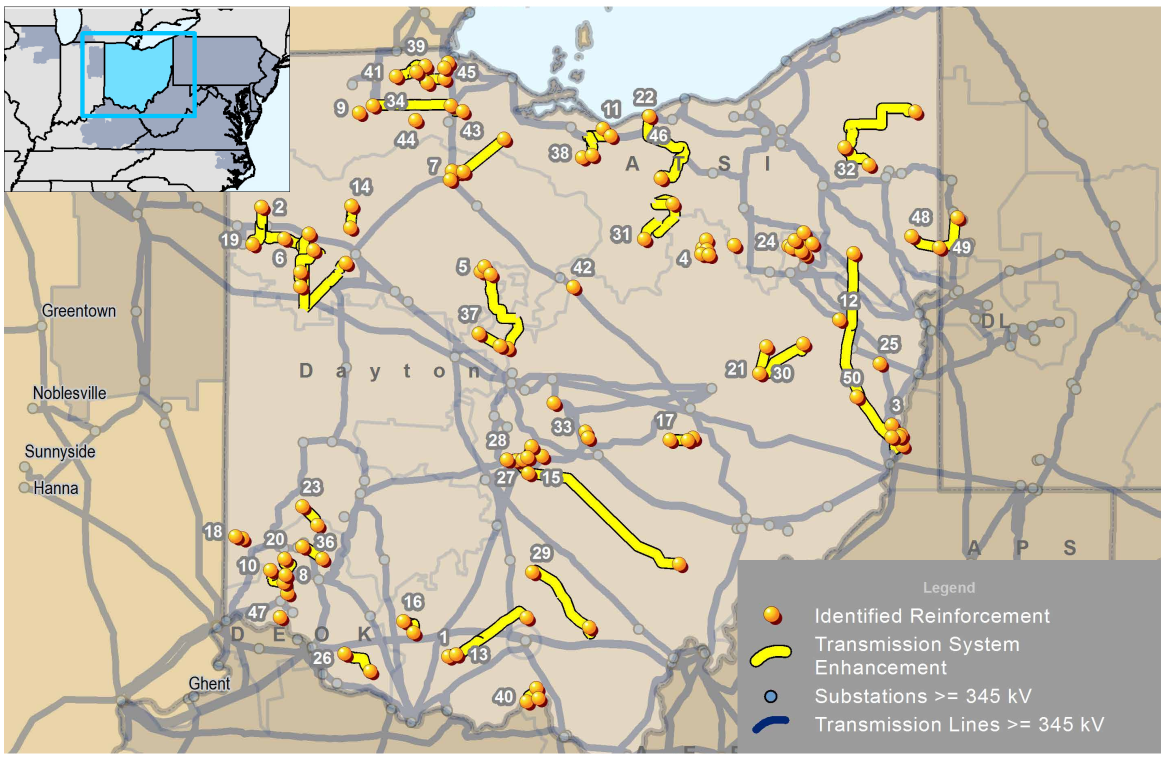
Table 6.50: Ohio Transmission Owner Supplemental Projects – Interconnection Requests (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
31	s1478	Rebuild the Brookside-Homer 69 kV (29.6 miles) mix of conductor sizes as single circuit 69 kV with aluminum conductor steel cable but designed for future capability of double circuit 138/69 kV.	6/1/2018	$27.40	ATSI	1/8/2018
32	s1475	Convert Dilworth substation to a five-breaker ring bus.	4/10/2019	$23.10	ATSI	1/8/2018
		Rebuild 3.2 miles of 69 kV single-circuit aluminum conductor steel cable between Garrettsville and Ledges as double circuit steel cable to establish the Garrettsville-Dilworth and Garrettsville-Newton Falls 69 kV lines.	4/10/2019		ATSI	1/8/2018
		Install 14.4 MVAR capacitor at Parkman substation.	4/10/2019		ATSI	1/8/2018
33	s1510	At Kirk, install four 345 kV circuit breakers and end bus to complete the 345 kV breaker-and-a-half configuration. Replace 345/138 kV transformer with 675 MVA unit. Connect in different 345 kV bay and on new 138 kV string before removing old unit. Upgrade two 138 kV circuit breakers and retire one circuit breaker. Install two 138 kV circuit breakers. Install three new 138 kV circuit breakers. Upgrade three 138 kV circuit breakers with 3,000 A model. Separate 138/69 kV and 138/34 kV transformer connections and install a 138kV circuit switcher on distribution bank. Replace 138/34 kV transformer and two 34 kV circuit breakers.	12/1/2019	$23.00	AEP	2/14/2018
		At Bixby, replace Kirk 345 kV line risers and line switch and upgrade relaying.	11/5/2019		AEP	2/14/2018
		Upgrade relaying at Junderground Street.	12/10/2020		AEP	2/14/2018
		Upgrade relaying at Junderground Street.	11/12/2019		AEP	2/14/2018
		Upgrade relaying at West Hebron.	6/4/2019		AEP	2/14/2018
34	s1479	Rebuild Lemoyne-Midway 138 kV line with aluminum conductor steel cable (24.5 miles).	12/1/2017	$19.00	ATSI	1/8/2018
35	s1429	Rebuild the Marion-Parson double circuit 40 kV line as single-circuit 69 kV energized to 40 kV.	3/7/2019	$17.31	AEP	1/8/2018
		At Harrison station, relocate and install existing spare 138/40 kV transformer, 138 kV circuit breaker, and 69 kV circuit breaker.	3/7/2019		AEP	1/8/2018
		Parsons station, Replace two 40kV circuit breaker's with two 2,000A 69KV circuit breaker's, install 9.4MVAr capacitor bank	3/7/2019		AEP	1/8/2018
		Marion station, Install 9.4 MVAr capacitor bank and retire unused equipment.	3/7/2019		AEP	1/8/2018
36	s1485	Rebuild 5.8 miles of feeder between Warren and Nickel 138 kV substations with new structures, hardware and conductor for line capacity increase from 198 MVA to 300 MVA.	12/31/2018	$15.00	DEO&K	1/8/2018
37	s1477	Rebuild 12.6 miles of single circuit aluminum conductor steel cable Kirby-Radnor 69 kV line with aluminum conductor steel cable and replace two-way switch with two separate one-way switches.	5/1/2019	$14.30	ATSI	1/8/2018
38	s1476	Convert Adam substation to a four-breaker, future five-ring bus.	2/28/2019	$12.40	ATSI	1/8/2018
		Reconfigure Adams substation to include terminals for: Carriage-Adams 69 kV, Adams-Shinrock 69 kV, Adams transformers No. 1 and No. 2 to make the substation layout to support line-load-line configuration.	5/8/2019		ATSI	1/8/2018
39	s1472	Convert Ford Road substation to a four breaker ring bus.	12/31/2018	$10.00	ATSI	1/8/2018
		Reconfigure line exits for Ford Road-Maclean 69 kV, Ford Road-Vulcan 69 kV, 69 kV capacitor bank and Ford Road transformer to make the substation layout support line-load-line configuration.	12/31/2018		ATSI	1/8/2018
40	s1692	At Friendship station, install a 69 kV line circuit breaker & line motor-operated air break. At Sugar Hill station, upgrade bus though-path and replace switches to accommodate the line reconfigurations. At North Portsmouth, replace 138-69 kV transformer with a 90 MVA unit with a 138 kV circuit switcher, replace 138 kV circuit breaker C and 69 kV circuit breaker A. Remove bus tie 138 kV circuit breaker D and install a new 138 kV circuit breaker to isolate Millbrook Park line. Install a new 69 kV circuit breaker on low side of the transformer. At Millbrook Park, replace relay & install a CCVT on North Portsmouth Line. At Central Portsmouth, replace 138 kV circuit breakers G & H. At Rosemount, install two line MOAB switches inside substation and replace the ground switch MOAB with a 69 kV circuit switcher.	3/24/2023	54.4	AEP	8/31/2018
		Build a new 8.5 mile 69 kV line from Friendship Station to Central Portsmouth Station, using 556 ACSR (102 MVA) and remove the old Central Portsmouth-Sugar Hill Line. Rebuild the remaining 13.9 miles of the Friendship Loop from North Portsmouth to Rosemount, from Rosemount to Sugar Hill and from Sugar Hill to Friendship using 556 ACSR (102 MVA) and ADSS.	11/6/2020		AEP	8/31/2018

Table 6.50: Ohio Transmission Owner Supplemental Projects – Interconnection Requests (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
41	s1700	Angola-Eber-Vulcan 138 kV three-terminal line elimination project	6/1/2021	13.4	ATSI	9/28/2018
42	s1701	Build new Snyder 69 kV switching station	6/1/2020	13.2	ATSI	9/28/2018
43	s1702	Lemoyne-Woodville-Fostoria 138 kV four-terminal line elimination project	6/1/2020	11.3	ATSI	9/28/2018
44	s1703	Expand Brim 138/69 kV substation	3/1/2020	19.9	ATSI	9/28/2018
45	s1705	Expand 69 kV bus at Ryan substation	3/1/2020	10.8	ATSI	9/28/2018
46	s1711	Rebuild Beaver-Wellington 138 kV line to double circuit	12/31/2020	20.0	ATSI	9/28/2018
47	s1714	Build new Ashland 138/69 kV Substation	8/28/2020	12.9	ATSI	9/28/2018
48	s1715	Rebuild Columbiana-State 69 kV line	12/31/2019	16.7	ATSI	9/28/2018
49	s1716	Rebuild New Castle-State 69 kV line	12/31/2021	29.2	ATSI	9/28/2018
50	s1718	Rebuild Holloway-Nottingham-Knox 138 kV line	6/1/2021	79.9	ATSI	9/28/2018

Map 6.33: Ohio Supplemental Projects (December 31, 2018)



6.8.8 — Merchant Transmission Project Requests

As of December 31, 2018, PJM's queue contained two merchant transmission interconnection request projects which include a terminal in Ohio as shown in **Table 6.52** and **Map 6.34.**

Map 6.34: Ohio Merchant Projects

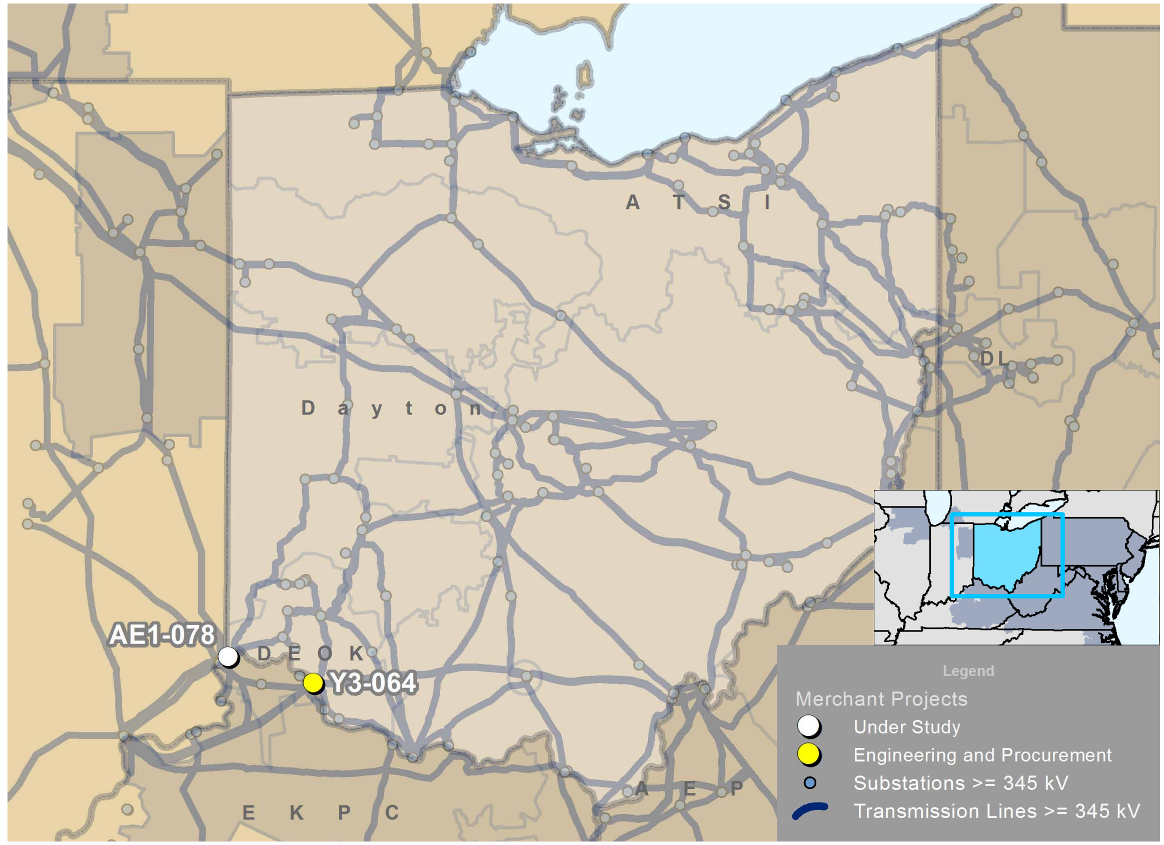


Table 6.52: Ohio Merchant Projects

Queue	Project Name	Maximum Output (MW)	Status	Projected In-Service Date	TO Zone
Y3-064	Pierce-Beckjord 138 kV	160	Engineering and Procurement	4/3/2019	DEO&K
AE1-078	Greendale-Miami Fort 138 kV	50	Active	6/1/2020	DEO&K

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 (METED), 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 6.35**.

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 6.35: PJM Service Area in Pennsylvania

6.9.2 — Load Growth

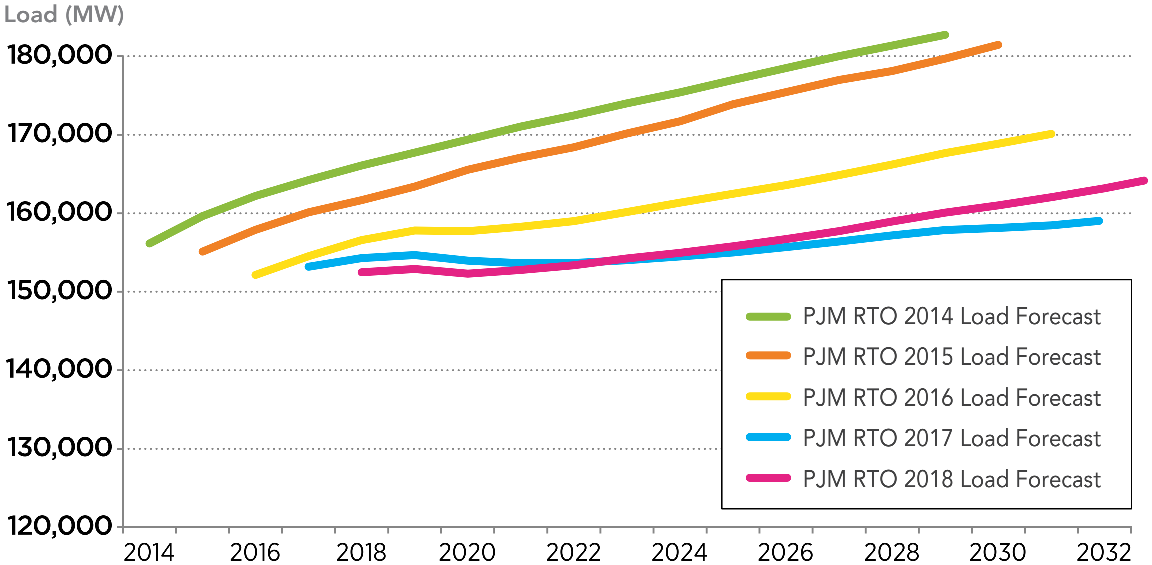
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.53** and **Figure 6.46** summarize the expected loads within the state of Pennsylvania and across all of PJM.

Table 6.53: Pennsylvania – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2018	2028	Growth Rate	2017/2018	2027/2028	Growth Rate
Allegheny Power*	3,949	4,228	0.7%	3,737	4,055	0.8%
American Transmission Systems, Inc.*	932	958	0.3%	877	898	0.2%
Duquesne Light Company	2,872	2,924	0.2%	2,153	2,175	0.1%
Metropolitan Edison Company	2,974	3,115	0.5%	2,607	2,697	0.3%
PECO Energy Company	8,642	8,979	0.4%	6,752	6,881	0.2%
Pennsylvania Electric Company	2,895	2,922	0.1%	2,866	2,875	0.0%
PPL Electric Utilities Corporation	7,140	7,350	0.3%	7,211	7,343	0.2%
UGI Utilities, Inc.	190	188	-0.1%	194	188	-0.3%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

* **Note:** PJM notes that APS and ATSI serve load other than in Pennsylvania. The summer peak and winter peak megawatt values in this table each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in Pennsylvania. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Pennsylvania over the past five years.

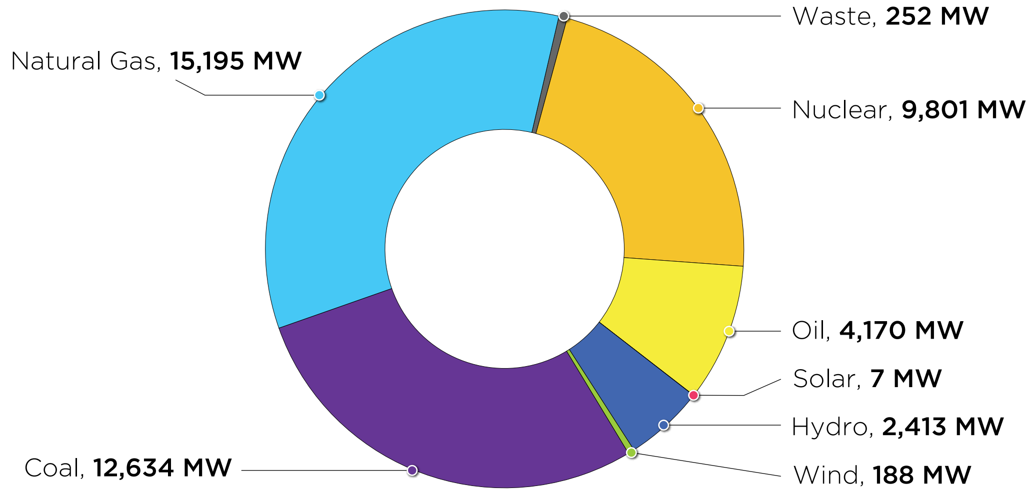
Figure 6.46: PJM RTO Summer Peak Demand Forecast



6.9.3 — Existing Generation

Existing generation in Pennsylvania as of December 31, 2018, is shown by fuel type in **Figure 6.47**.

Figure 6.47: Pennsylvania – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



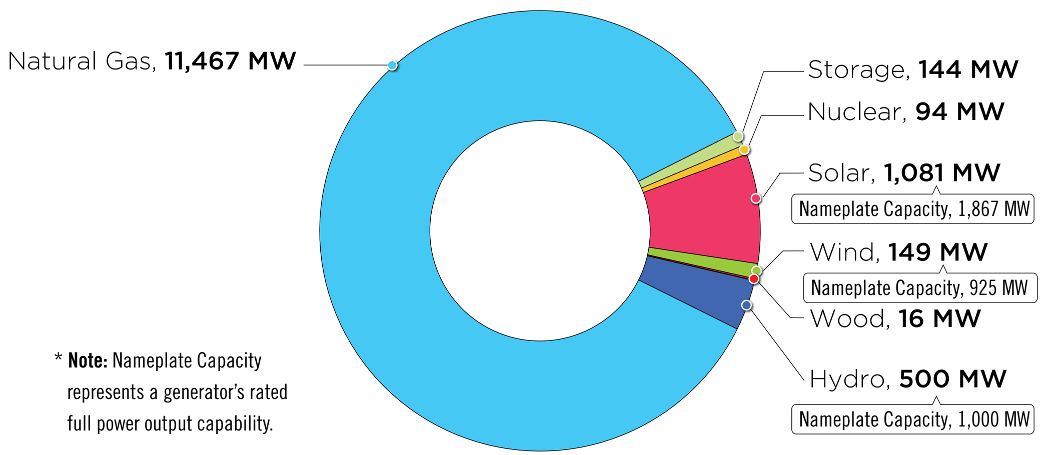
6.9.4 — Interconnection Requests

As of December 31, 2018, 139 queued projects were actively under study, under construction or in suspension in the state of Pennsylvania. A summary of those interconnection requests is shown in **Table 6.54, Table 6.55, Figure 6.48, Figure 6.49** and **Figure 6.50**.

Table 6.54: Pennsylvania – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity MW
Natural Gas	11,467.1	12,088.6
Solar	1,080.7	1,867.4
Hydro	500.0	1,000.0
Wind	149.2	925.0
Storage	143.8	359.1
Nuclear	94.0	94.0
Wood	16.0	16.0
Total	**13,450.8**	**16,350.1**

Figure 6.48: Pennsylvania – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.55: Pennsylvania – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue						Grand Total	
	In Service		Withdrawn		Active		Suspended		Under Construction			
	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	**124**	**18,792.0**	**313**	**104,078.0**	**40**	**3,876.0**	**10**	**1,371.0**	**25**	**6,462.0**	**512**	**134,579.0**
Coal	17	229.0	28	14,354.6	0	0.0	0	0.0	0	0.0	45	14,583.6
Diesel	3	33.3	12	51.5	0	0.0	0	0.0	1	4.1	16	88.9
Natural Gas	78	15,612.3	227	86,077.7	26	3,682.2	10	1,371.4	21	6,413.5	362	113,157.1
Nuclear	15	2,581.8	8	1,681.0	4	50.0	0	0.0	1	44.0	28	4,356.8
Oil	3	9.4	9	1,307.0	0	0.0	0	0.0	0	0.0	12	1,316.4
Other	3	326.5	6	344.0	0	0.0	0	0.0	0	0.0	9	670.5
Storage	5	0.1	23	262.1	10	143.8	0	0.0	2	0.0	40	406.0
Renewable	**82**	**897.0**	**281**	**3,065.0**	**42**	**1,548.0**	**6**	**58.0**	**16**	**140.0**	**427**	**5,708.0**
Biomass	3	31.4	4	36.5	0	0.0	0	0.0	0	0.0	7	67.9
Hydro	12	480.8	15	188.6	2	500.0	0	0.0	0	0.0	29	1,169.4
Methane	27	135.7	37	201.3		0.0	0	0.0	0	0.0	64	337.0
Solar	3	6.8	95	940.1	37	1,009.7	3	16.3	8	54.7	146	2,027.6
Wind	37	242.5	130	1,698.7	3	38.5	2	25.7	8	85.0	180	2,090.4
Wood	0	0.0	0	0 0.0	0	0.0	1	16.0	0	0.0	1	16.0
Grand Total	**206**	**19,689.6**	**594**	**107,143.1**	**82**	**5,424.3**	**16**	**1,429.4**	**41**	**6,601.3**	**939**	**140,287.6**

Figure 6.49: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

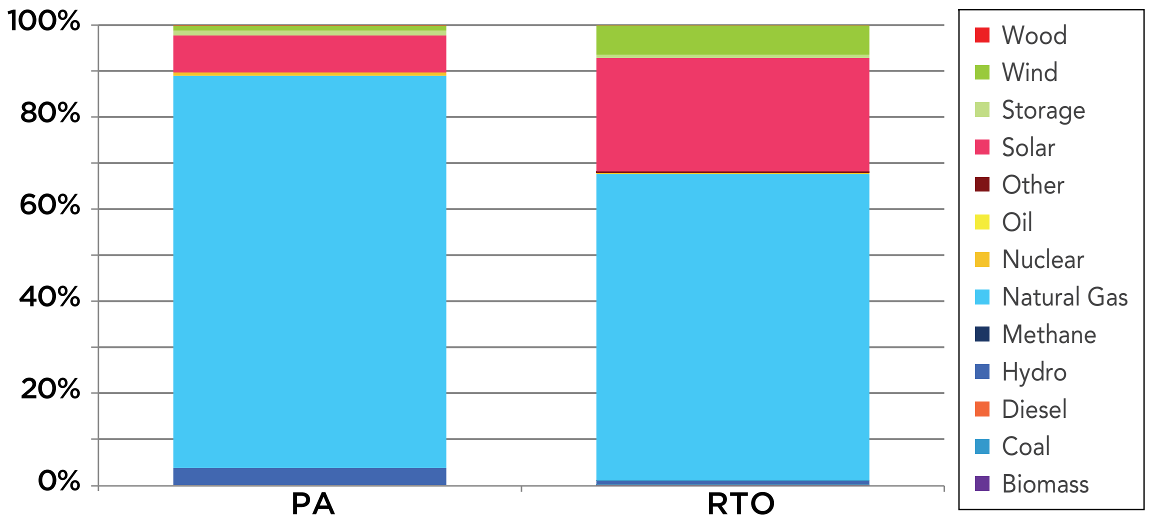
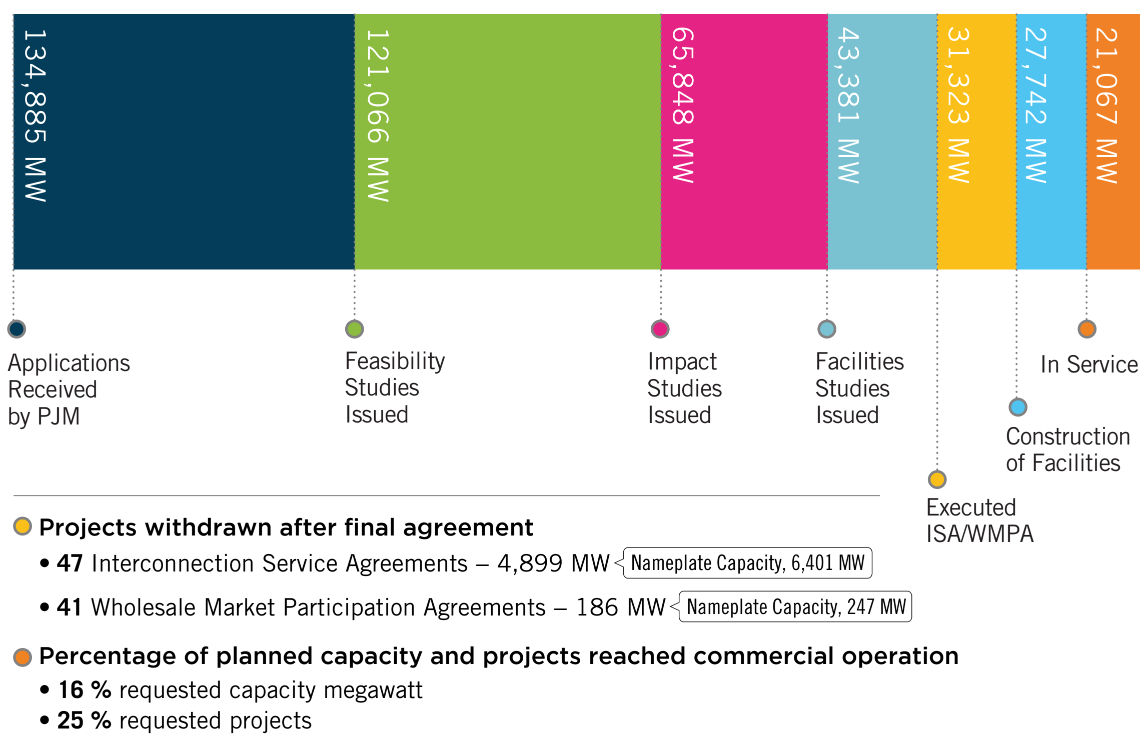


Figure 6.50: Pennsylvania Progression History of Queue – Interconnection Requests (December 31, 2018)



6.9.5 — Generation Deactivations

Known generating unit deactivation requests in Pennsylvania between January 1, 2018 and December 31, 2018, are summarized in **Table 6.56** and **Map 6.36**.

Map 6.36: Pennsylvania Generation Deactivations (December 31, 2018)

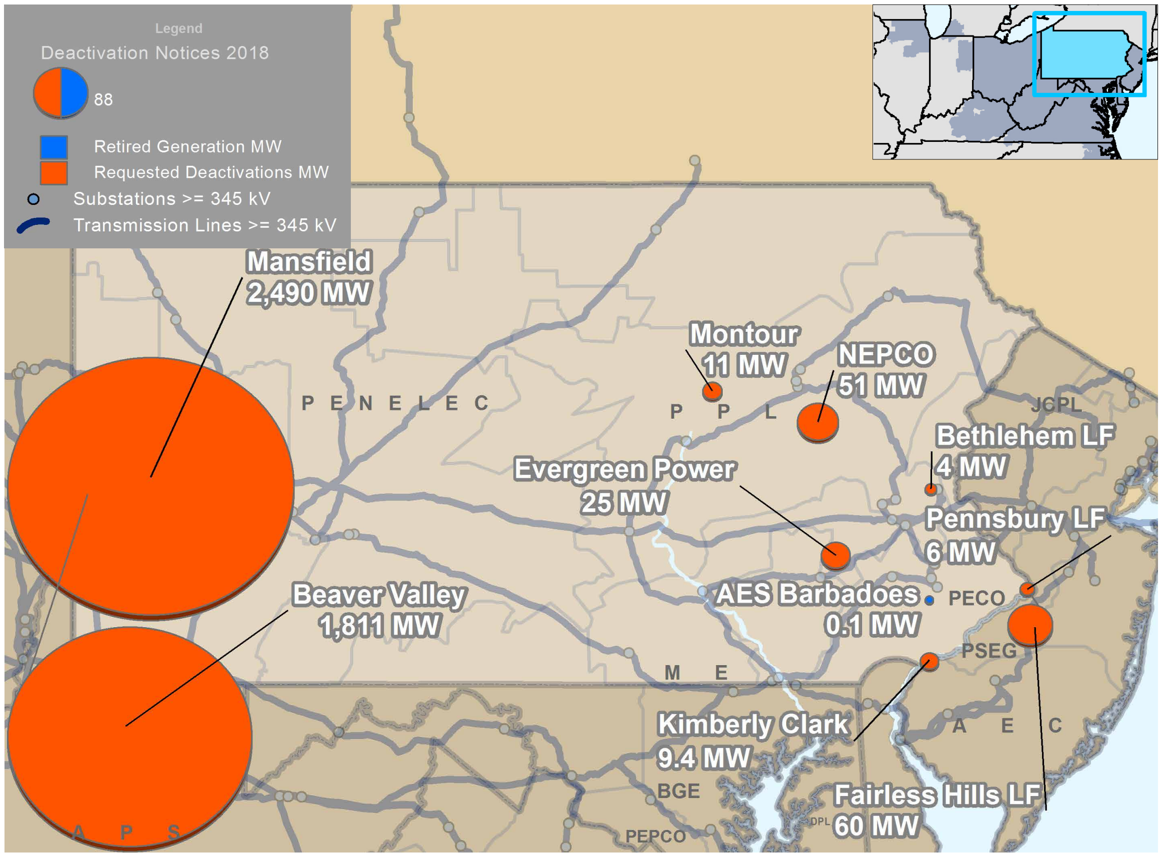


Table 6.56: Pennsylvania Generation Deactivations (December 31, 2018)

Unit	Capacity (MW)	TO Zone	Age (Years)	Projected/Actual Deactivation Date
Beaver Valley 1	909.0	DLCO	42	5/31/2021
Beaver Valley 2	902.0	DLCO	31	10/31/2021
Northeastern Power NEPCO	51.0	PPL	29	10/24/2018
Fairless Hills Unit A	30.0	PECO	22	6/1/2020
Fairless Hills Unit B	30.0	PECO	22	6/1/2020
Evergreen	25.0	METED	8	5/1/2018
Montour ATG	11.4	PPL	45	2/18/2019
Kimberly Clark	9.4	PECO	32	8/1/2019
Bethlehem	3.7	PPL	10	6/1/2020
Pennsbury 1	3.0	PECO	22	6/1/2020
Pennsbury 2	3.0	PECO	22	6/1/2020
Barbados Battery	0.1	PECO	10	7/29/2018
Mansfield 1	830	ATSI	42	2/5/2019
Mansfield 2	830	ATSI	41	2/5/2019
Mansfield 3	830	ATSI	38	6/1/2021

6.9.6 — Baseline Projects

RTEP baseline upgrades greater than or equal to $10 million in Pennsylvania are summarized in **Table 6.57** and **Map 6.37**. In 2018, PJM added $261M of total baseline projects in Pennsylvania.

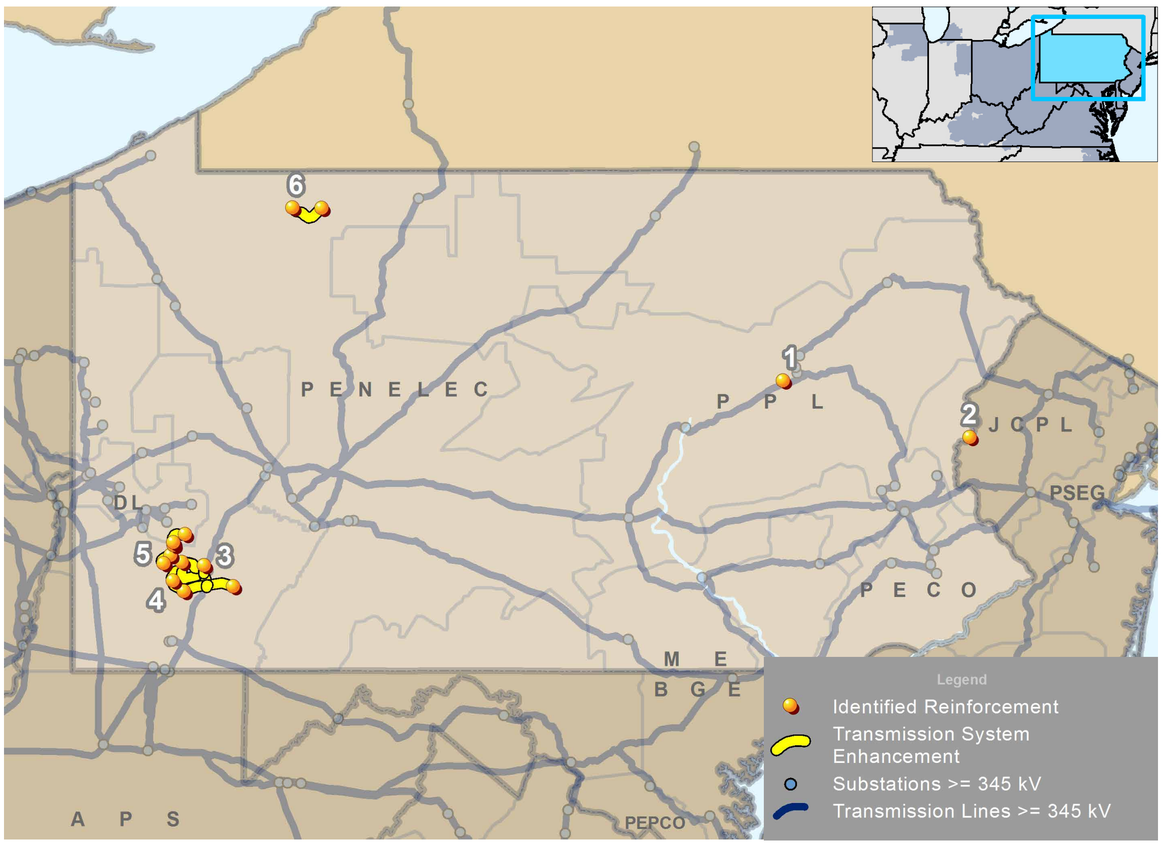
Table 6.57: Pennsylvania Baseline Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	Generator Deactivation	Short Circuit	TO Criteria Violation
1	b2838	.0	Build a new 230/69 kV substation by tapping the Montour-Susquehanna 230 kV double circuits and Berwick-Hunlock and Berwick-Colombia 69 kV circuits	6/1/2017	$57.00	PPL	1/24/2017			X
2	b2979	.0	Replace Martins Creek 230 kV circuit breakers with 80 kA rating	6/1/2018	$14.30	PPL	12/14/2017		X	
3	b3006	.0	Replace four Yukon 500/138 kV transformers with three transformers with higher rating and reconfigure 500 kV bus	6/1/2021	$55.56	APS	6/7/2018	X		
4	b3011	.1	Construct new Route 51 substation and connect 10 138 kV lines to new substation	6/1/2021	$27.62	APS	6/7/2018	X		
		.2	Upgrade terminal equipment at Yukon to increase rating on Yukon-Charleroi No. 2 138 kV line (Yukon to Route 51 No. 4 138 kV line)	6/1/2021		APS	6/7/2018	X		
		.3	Upgrade terminal equipment at Yukon to increase rating on Yukon-Route 51 No. 1 138 kV line	6/1/2021		APS	6/7/2018	X		
		.4	Upgrade terminal equipment at Yukon to increase rating on Yukon-Route 51 No. 2 138 kV line	6/1/2021		APS	6/7/2018	X		
		.5	Upgrade terminal equipment at Yukon to increase rating on Yukon-Route 51 No. 3 138 kV line	6/1/2021		APS	6/7/2018	X		
		.6	Upgrade remote end relays for Yukon-Allenport-Iron Bridge 138 kV line	6/1/2021		APS	6/7/2018	X		
5	b3015	.1	Construct new Elrama 138 kV substation and connect seven 138 kV lines to new substation	6/1/2021	$35.50	DLCO	6/7/2018	X		
		.2	Reconductor 4.8 miles of Elrama to Wilson 138 kV line.	6/1/2021		DLCO	6/7/2018	X		
		.3	Reconductor 3 miles of Dravosburg to West Mifflin 138 kV line	6/1/2021		DLCO	6/7/2018	X		
		.4	Run new conductor on existing tower to establish the new 10 miles Dravosburg-Elrama circuit	6/1/2021		DLCO	6/7/2018	X		
		.5	Reconductor DLCO portion of Elrama-Mitchell 138 kV line	6/1/2021		DLCO	6/7/2018	X		
		.6	Reconductor AP portion of Elrama-Mitchell 138 kV line	6/1/2021		APS	6/7/2018	X		
		.7	Reconductor 2 miles of Wilson-West Mifflin 138 kV line	6/1/2021		DLCO	6/7/2018	X		

Table 6.57: Pennsylvania Baseline Projects (Greater than $10 M) (December 31, 2018)(Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	Generator Deactivation	Short Circuit	TO Criteria Violation
6	b3017	.1	Rebuild 11.53 miles of Glade-Warren 230 kV line with new conductor and substation terminal upgrades.	6/1/2021	$33.40	PENELEC	6/7/2018	X		
		.2	Glade 230 kV substation terminal upgrades. Replace bus conductor, wave trap, and relaying	6/1/2021		PENELEC	6/7/2018	X		
		.3	Warren 230 kV substation terminal upgrades; replace bus conductor, wave traps, and relaying	6/1/2021		PENELEC	6/7/2018	X		

Map 6.37: Pennsylvania Baseline Projects (Greater than $10 M) (December 31, 2018)



6.9.7 — Network Projects

RTEP network upgrades greater than or equal to $10 million in Pennsylvania are summarized in **Table 6.58** and **Map 6.38**.

Map 6.38: Pennsylvania Network Projects (Greater than $10 M) (December 31, 2018)

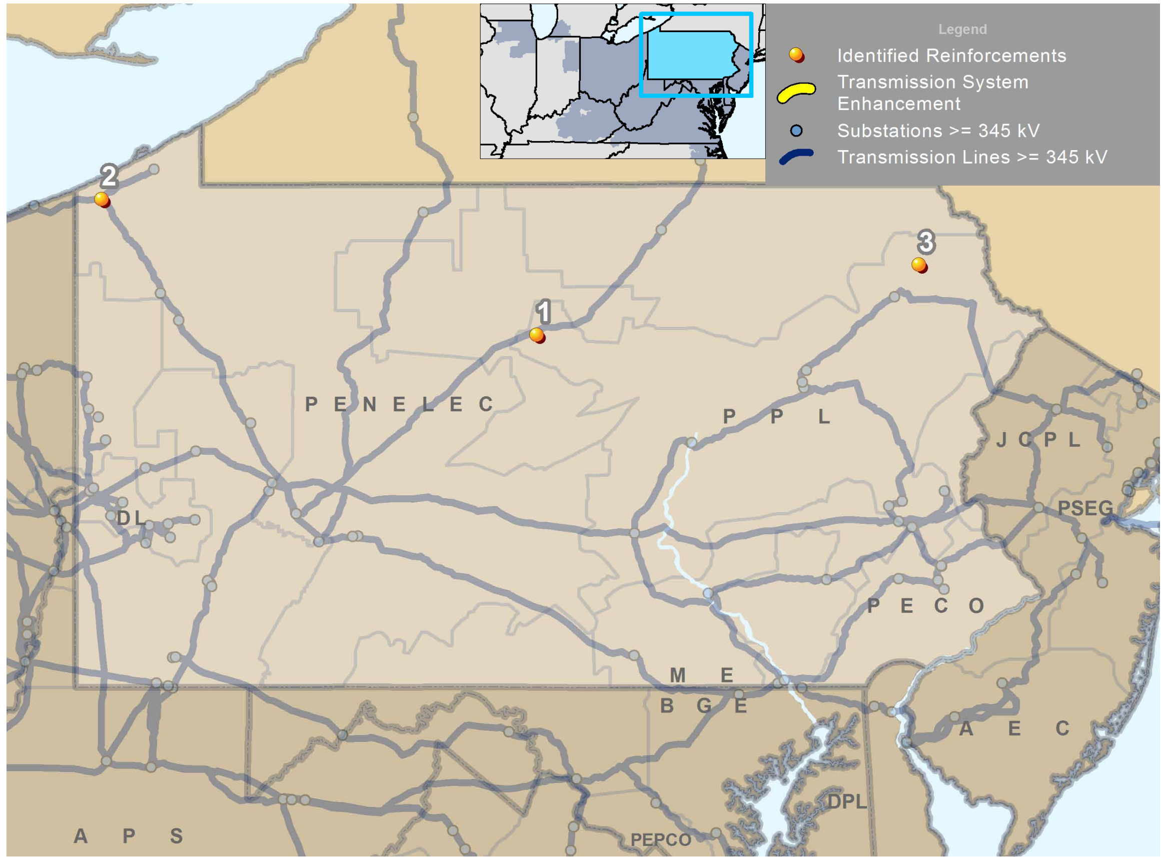


Table 6.58: Pennsylvania Network Upgrades (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Project Driver	Queue	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	n5740	Install one 345/230 kV transformer between the proposed AA1-111 switchyard and the NYSEG Q496 switchyard	Generation	AA1-111 (Natural Gas)	3/30/2021	$12.57	PENELEC	9/13/2018
2	n5741	Install one 230 kV phase angle regulator on the Dunkirk-S. Ripley 230 kV line.	Merchant Transmission	Y3-092	3/30/2021	$15.00	PENELEC	9/13/2018
3	n5900	Construct one new standard four-bay breaker-and-a-half 230 kV switchyard along the Lackawana-Paupack 230 kV line.	Generation	AC1-071 (Wind)	12/14/2018	$14.92	PPL	9/13/2018

6.9.8 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in Pennsylvania are summarized in **Table 6.59** and **Map 6.39.**

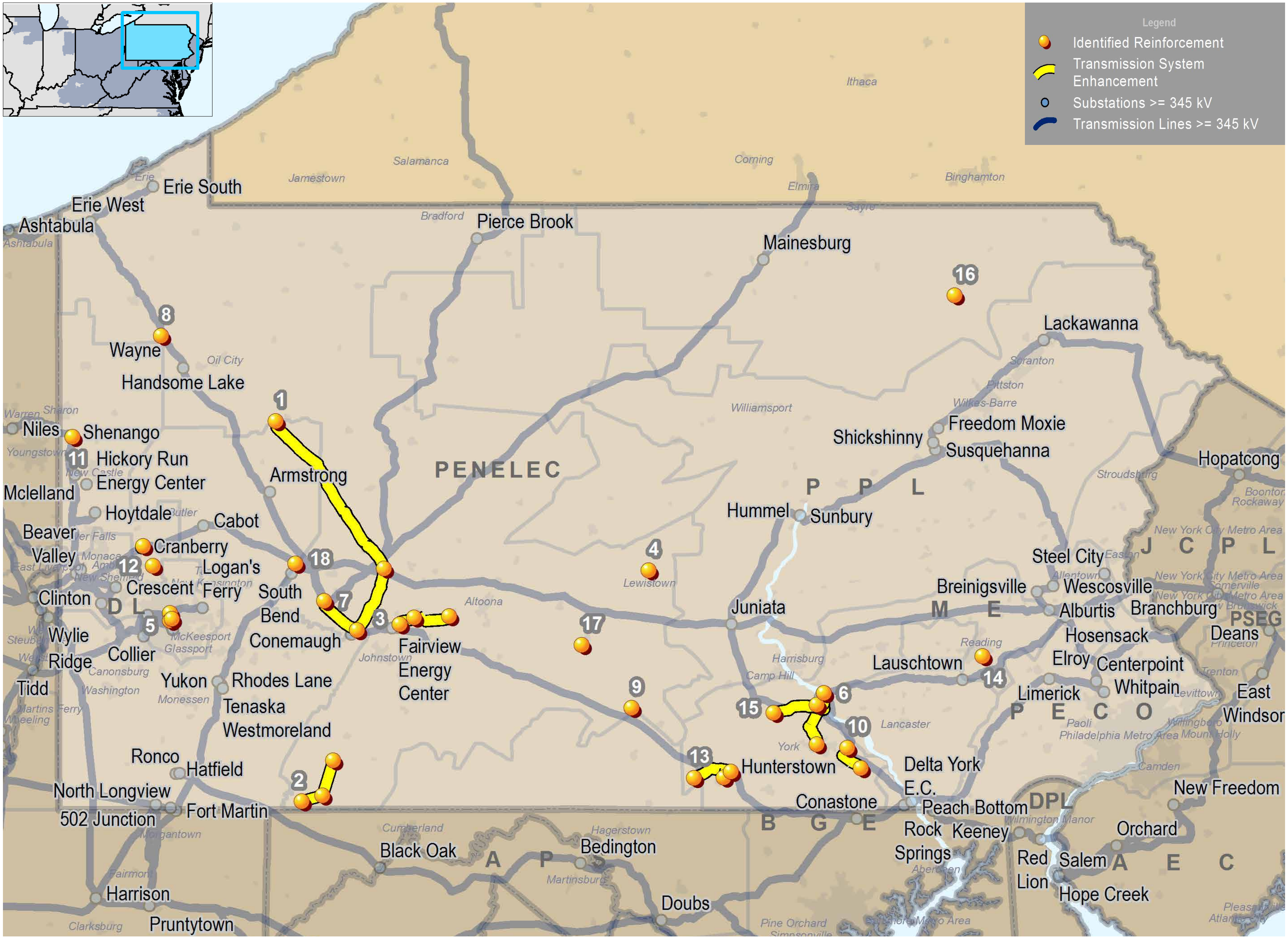
Table 6.59: Pennsylvania Supplemental Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	s1672	Rebuild approximately 66 miles of Seward-Glory-Piney 115 kV line using double-circuit 230 kV construction.	12/1/2023	$200.00	PENELEC	5/25/2018
2	s1770	Rebuild/reconductor approximately 14.8 miles of wood pole construction Penn Mar-High Point-Rockwood 115 kV line	6/1/2020	$29.30	PENELEC	10/29/2018
		Adjust current transformer ratios and replace substation conductor and breaker disconnect on the line.	6/1/2020		PENELEC	10/29/2018
		Adjust relaying and replace current transformers, substation conductor, line drops, circuit breaker and disconnect switches on Penn Mar-High Point-Rockwood 115 kV line	6/1/2020		PENELEC	10/29/2018
3	s1775	Construct a five-breaker 115 kV ring bus at Summit	12/31/2020	$26.30	PENELEC	10/29/2018
		Construct a 46 kV breaker-and-a-half station with eight breakers	12/31/2020		PENELEC	10/29/2018
		Replace the Summit No. 1 and No. 2 115/46 kV transformers with 45/60/75 MVA transformers of same voltage	12/31/2020		PENELEC	10/29/2018
		Adjust relay settings at remote ends of Summit	12/31/2020		PENELEC	10/29/2018
		Replace current transformers, substation conductor, circuit breaker and transformer switches at Eldorado 46 kV substation.	12/31/2020		PENELEC	10/29/2018
		Replace line relaying, substation transformer, arresters, line and bus transformer switches and circuit breaker at Jackson Road 46 kV substation	12/31/2020		PENELEC	10/29/2018
4	s1773	Construct a new five-breaker 230 kV ring bus at Yeagertown	12/31/2020	$20.40	PENELEC	10/29/2018
		Construct a new five-breaker 46 kV ring bus at Yeagertown	12/31/2020		PENELEC	10/29/2018
		Loop Lewistown-Logan line into the Yeagertown 46 kV ring bus	12/31/2020		PENELEC	10/29/2018
		Tap the existing Yeagertown-Logan line and connect to the new Yeagertown 46 kV ring bus	12/31/2020		PENELEC	10/29/2018
		Install a new Yeagertown 230/46 kV transformer	12/31/2020		PENELEC	10/29/2018
		Install a 46 kV bus tie breaker between the existing and the new ring bus to be operated as normally open	12/31/2020		PENELEC	10/29/2018
		Operate the Yeagertown 46-34.5 kV transformer high-side circuit breaker as normally open	12/31/2020		PENELEC	10/29/2018
5	s1588	Establish a new 138-23 kV substation, Panther Hollow, using the existing Arsenal-Oakland 138 kV circuit as a source	5/31/2020	$16.80	DLCO	3/27/2018
6	s1640	At Middletown Junction, install 11 230 kV circuit breakers to complete the double bus configuration including replacement of the No. 2 and No. 5 230/115 kV transformers and remove the No. 1 230/115 kV transformer	6/1/2023	$16.30	METED	3/23/2018
		Install 11 230 kV circuit breakers to complete the double bus configuration	6/1/2023		METED	3/23/2018
		Replace Middletown Junction No. 2 and No. 5 230/115 kV transformers with 180/240/300 MVA units	6/1/2023		METED	3/23/2018
7	s1774	Expand 230 kV ring bus to a six-breaker ring bus at Seward 230 kV substation	12/31/2020	$15.70	PENELEC	10/29/2018
		Relocate the Homer City-Seward 230 kV and Johnstown-Seward 230 kV line terminals	12/31/2020		PENELEC	10/29/2018
		Replace the Seward No. 9 230/115 kV with a 230/115 kV 180/240/300 MVA transformer	12/31/2020		PENELEC	10/29/2018
		Install a 115 kV reactor on the low side of the Seward No. 11 230/115 kV transformer	12/31/2020		PENELEC	10/29/2018

Table 6.58: Pennsylvania Supplemental Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
8	s1646	Install a second 345/115 kV 168/224 MVA transformer. Convert the 115 kV yard to a four-breaker ring bus	6/1/2019	$12.50	PENELEC	3/23/2018
		Install a second Wayne 345/115 kV 168/224 MVA transformer	6/1/2019		PENELEC	3/23/2018
		Convert the Wayne 115 kV yard to a four-breaker ring bus	6/1/2019		PENELEC	3/23/2018
9	s1643	Replace the existing Roxbury 138/115 kV transformer with a 224 MVA unit; Convert Roxbury 115 kV substation into a four-breaker ring bus	12/31/2019	$10.10	PENELEC	3/23/2018
10	s1763	Replace line relaying, line drops, capacitor voltage transformer, line trap, line tuner, arresters, breaker, and breaker disconnect switches on Windsor-Yorkana 115 kV line	6/1/2020	$10.00	METED	10/29/2018
		Replace line relaying, capacitor voltage transformer, line trap, line tuner, arresters, breaker, and breaker disconnect switch on Windsor-Yorkana 115 kV line	6/1/2020		METED	10/29/2018
11	s1712	Build new Shenango 69 kV switching station	12/31/2021	$16.30	ATSI	9/28/2018
12	s1713	Build new Pine-Cranberry #3 138 kV line	5/23/2021	$27.00	ATSI	9/28/2018
13	1725	Construct a five breaker 115 kV ring bus at Orrtanna substation	12/31/2021	$40.10	METED	8/24/2018
		Loop the Hunterstown – Lincoln (963) 115 kV line ~9 miles into Orrtanna substation	12/31/2021		METED	8/24/2018
14	s1726	Expand the existing South Reading 69 kV yard to a breaker-and-a-half configuration	12/31/2020	$19.40	METED	8/24/2018
15	s1727	Construct a five breaker 115 kV ring bus at Cly. Upgrade of the Cly substation and loop the existing Middletown Jct-Round Top and Middletown Jct-Smith Street 115 kV line into the ring bus.	12/31/2020	$12.20	METED	8/24/2018
16	s1729	Expand the existing North Meshoppen 115 kV yard to a breaker-and-a-half configuration	12/31/2020	$17.60	PENELEC	8/24/2018
17	s1733	Reconductor/Rebuild the Hill Valley-Mount Union 46 kV Line and upgrade terminal equipment	12/31/2020	$37.20	PENELEC	8/24/2018
18	s1736	Replace the existing Keystone 351 MVA 500/230 kV transformer and install a 500 kV high-side breaker	12/31/2019	$21.70	PENELEC	8/24/2018

Map 6.39: Pennsylvania Supplemental Projects (December 31, 2018)



6.9.9 — Merchant Transmission Project Requests

As of December 31, 2018, PJM's queue contained three merchant transmission interconnection request projects, which include a terminal in Pennsylvania, as shown in **Table 6.60** and **Map 6.40**.

Map 6.40: Pennsylvania Merchant Transmission Project Requests (December 31, 2018)

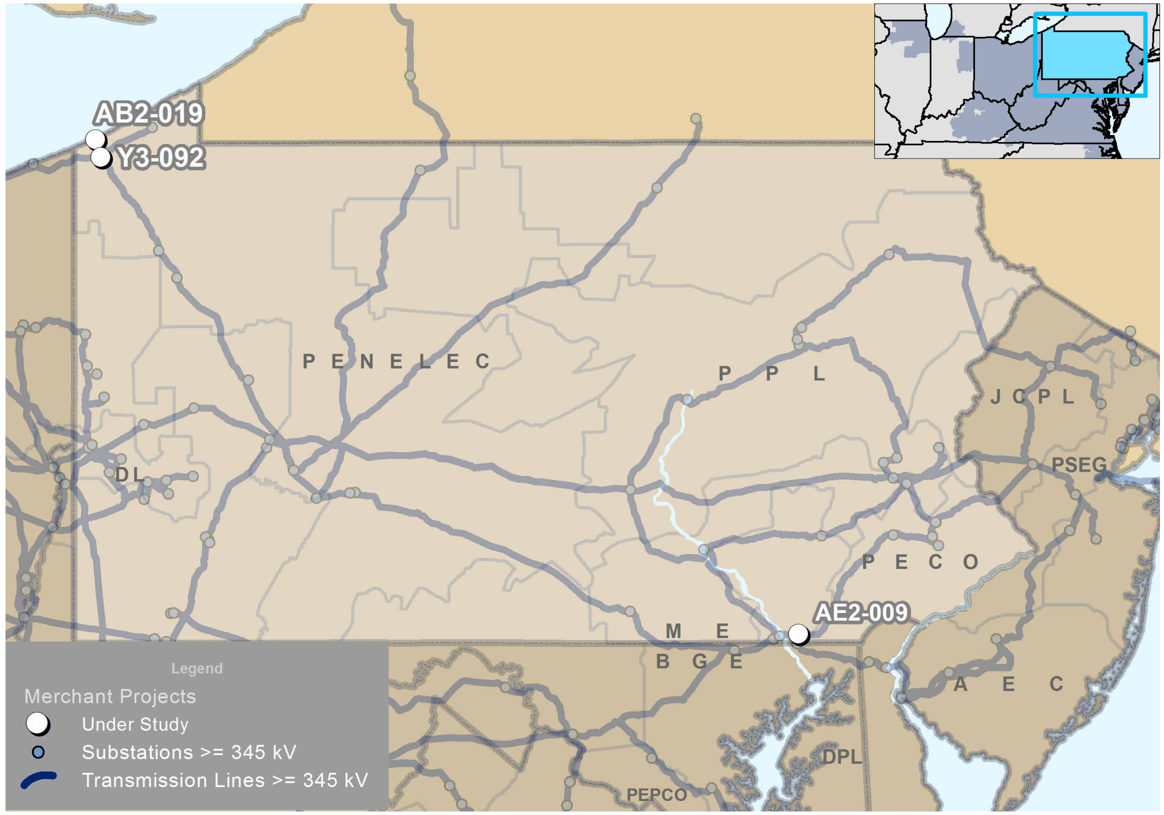


Table 6.60: Pennsylvania Merchant Transmission Project Requests (December 31, 2018)

Queue	Project Name	Maximum Output (MW)	Status	Projected In-Service Date	TO Zone
Y3-092	Erie West 345 kV	1,000	Active	3/31/2023	PENELEC
AB2-019	Erie West 345 kV	28	Active	12/31/2021	PENELEC
AE2-009	Nottingham-Peach Bottom Tap 230 kV	11	Active	6/1/2020	PECO

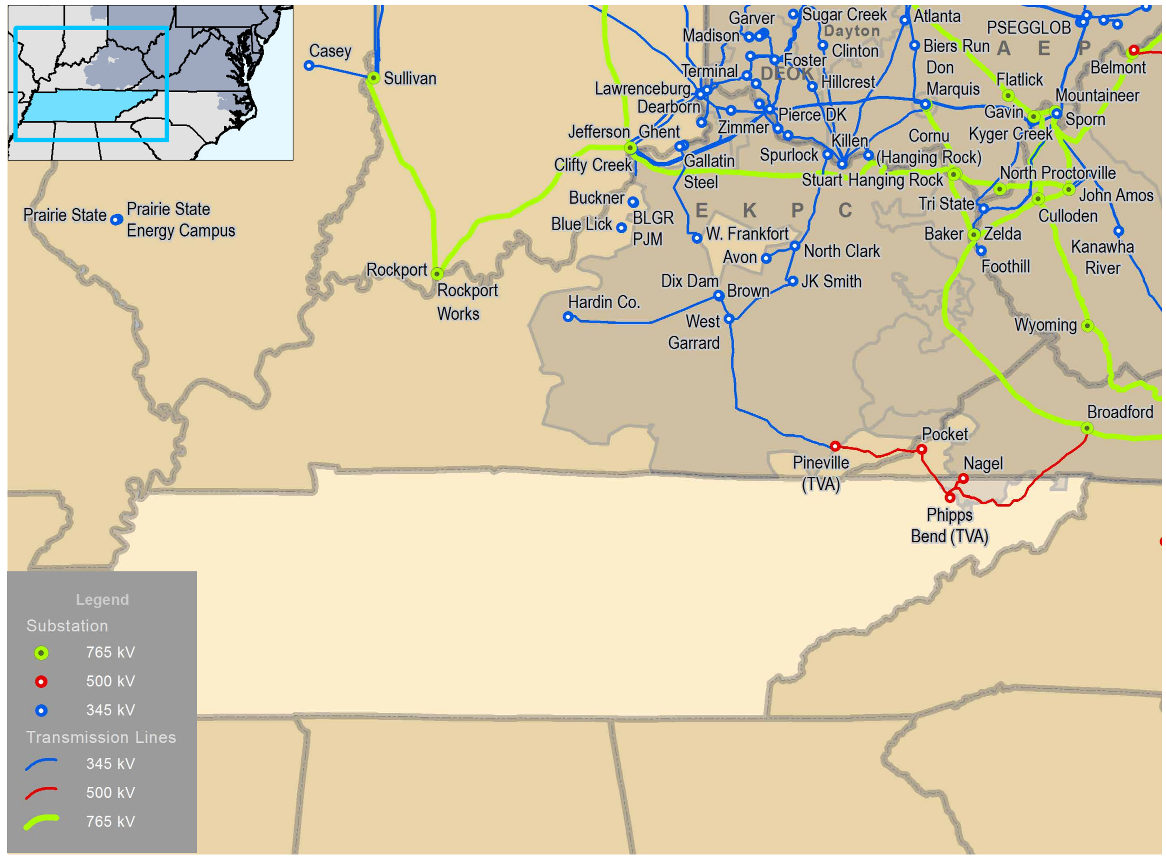
PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

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 6.41**. 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 6.41: PJM Service Area in Tennessee



6.10.2 — Load Growth

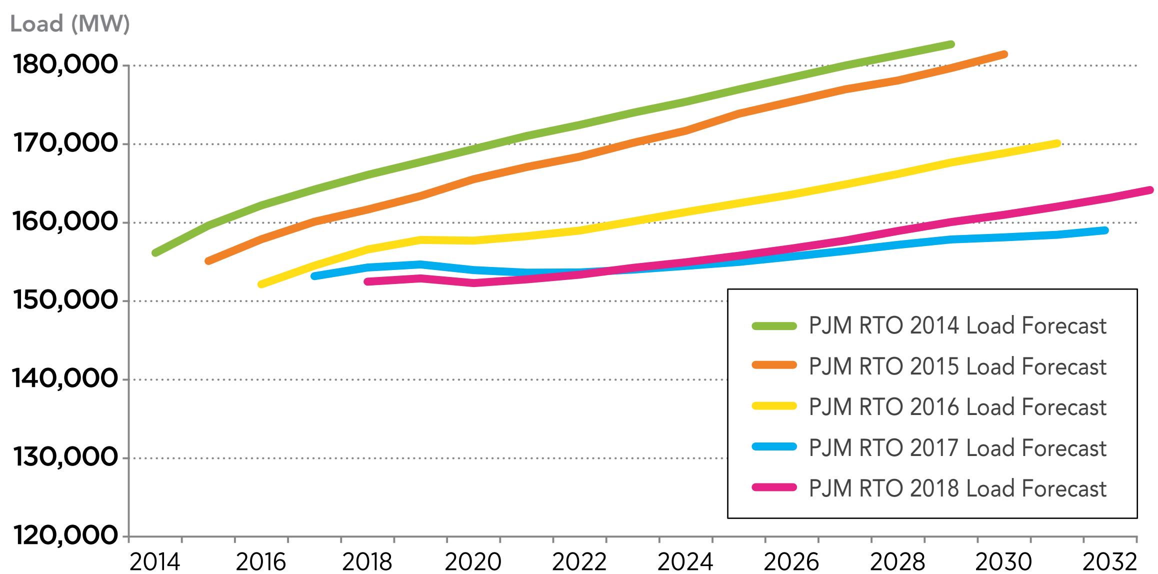
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.61** and **Figure 6.51** summarize the expected loads within the state of Tennessee and across all of PJM.

Table 6.61: Tennessee – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2018	2028	Growth Rate	2017/2018	2027/2028	Growth Rate
American Electric Power*	344	361	0.5%	440	462	0.5%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

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

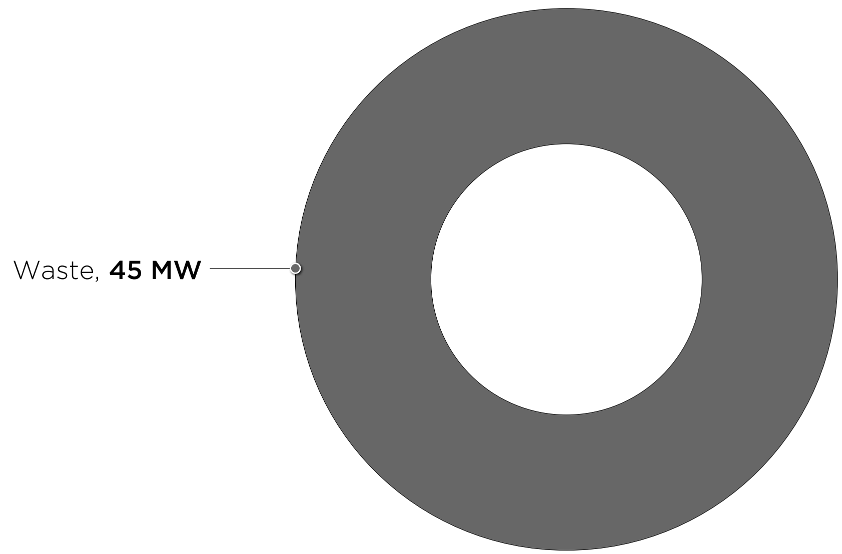
Figure 6.51: PJM RTO Summer Peak Demand Forecast



6.10.3 — Existing Generation

Existing generation in Tennessee as of December 31, 2018, is shown by fuel type in **Figure 6.52**.

Figure 6.52: Tennessee – Queued Capacity (MW) by Fuel Type (December 31, 2018)



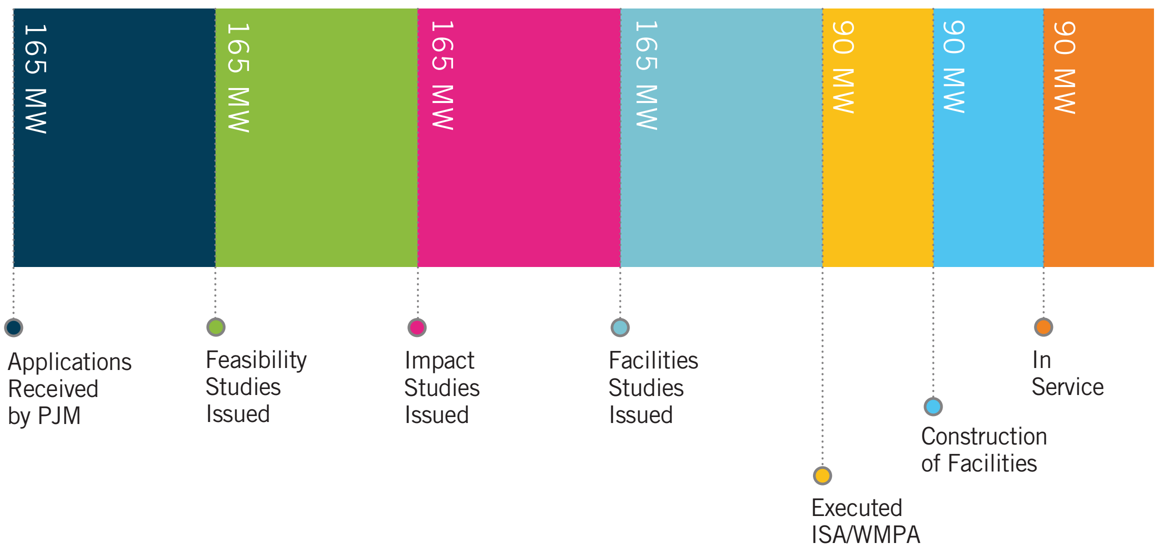
6.10.4 — Interconnection Requests

As of December 31, 2018, zero queued projects were actively under study, under construction or in suspension in the state of Tennessee. A summary of those interconnection requests is shown in **Table 6.62** and **Figure 6.53.**

Table 6.62: Tennessee – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				Grand Total	
	In Service		Withdrawn			
	No. of Projects	Capacity, MW	No. of Projects	Capacity, MW	No. of Projects	Capacity, MW
Non-Renewable	**0**	**0**	**1**	**75**	**1**	**75**
Coal	0	0	1	75	1	75
Renewable	**2**	**90**	**0**	**0**	**2**	**90**
Biomass	2	90	0	0	2	90
Grand Total	**2**	**90**	**1**	**75**	**3**	**165**

Figure 6.53: Tennessee Progression History of Queue – Interconnection Requests (December 31, 2018)



Percentage of planned capacity and projects reached commercial operation

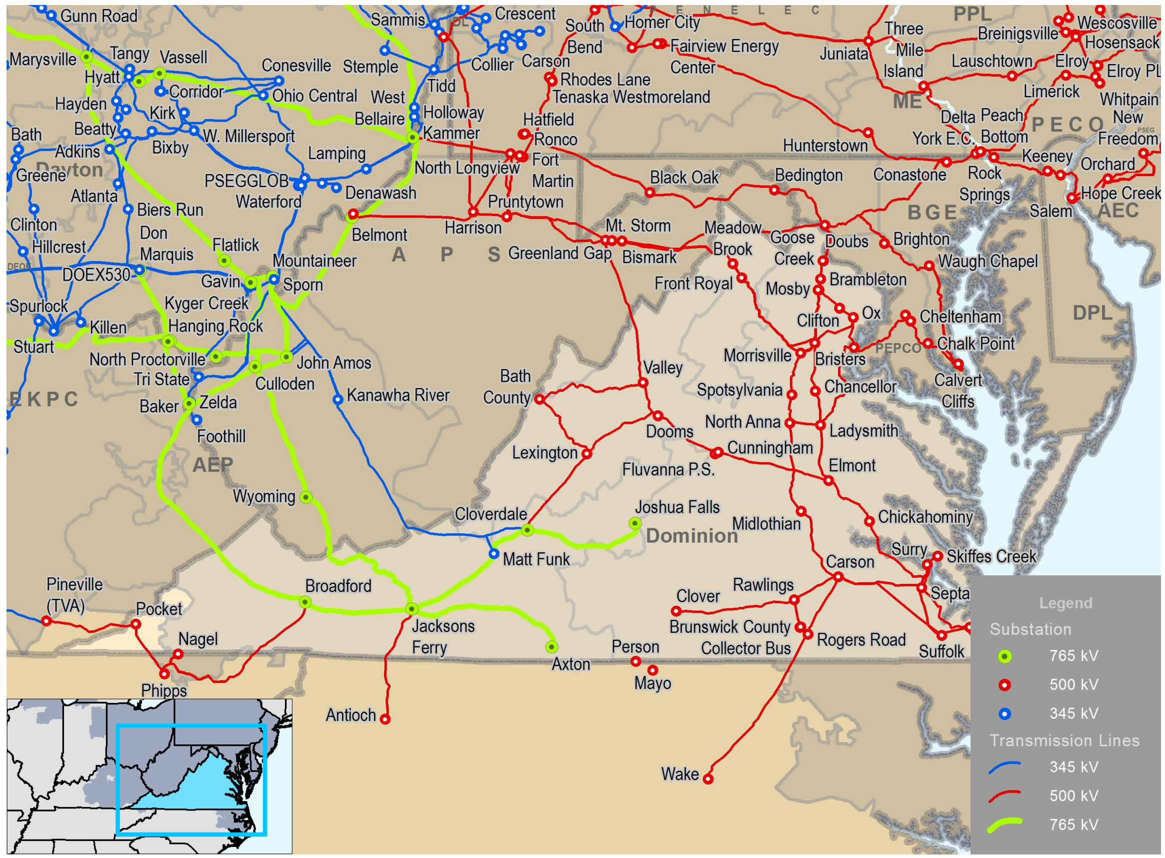
- **54.5 %** requested capacity megawatt
- **66.7 %** requested projects

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 (DOM) as shown on **Map 6.42**. 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 6.42: PJM Service Area in Virginia



6.11.2 — Load Growth

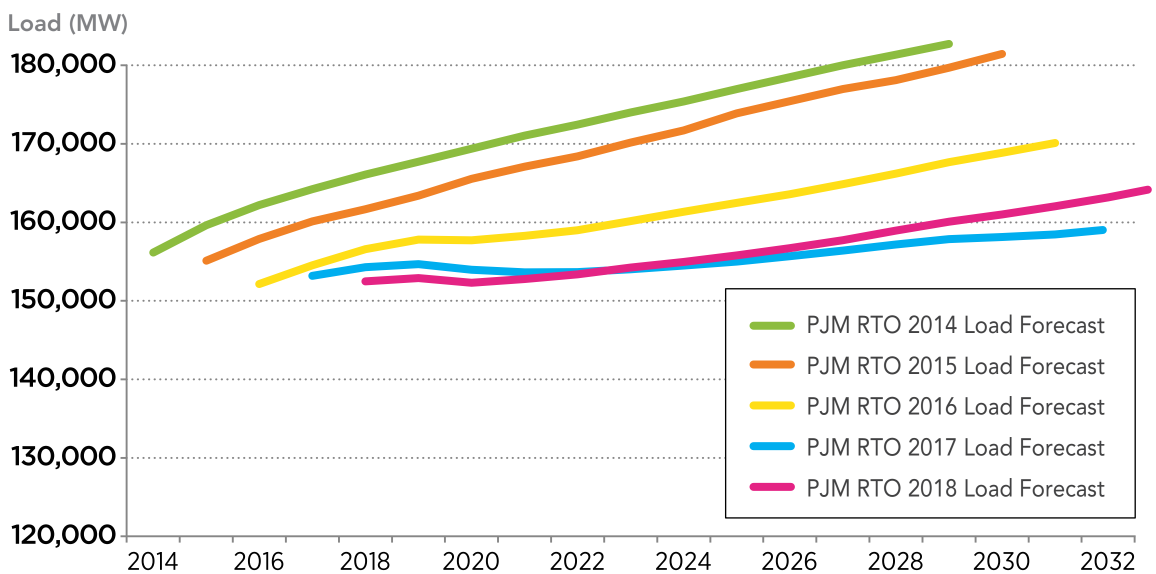
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.63** and **Figure 6.54** summarize the expected loads within the state of Tennessee and across all of PJM.

Table 6.63: Virginia - 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW) 2018	Summer Peak (MW) 2028	Summer Peak (MW) Growth Rate	Winter Peak (MW) 2017/2018	Winter Peak (MW) 2027/2028	Winter Peak (MW) Growth Rate
American Electric Power Company *	3,367	3,535	0.5%	4,070	4,279	0.5%
Allegheny Power *	665	712	0.7%	697	757	0.8%
Delmarva Power and Light *	143	146	0.2%	145	150	0.3%
Dominion Virginia Power *	18,569	20,052	0.8%	17,091	18,672	0.9%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

***Note**: PJM notes that AEP, DP&L, APS and DVP serve load other than in Virginia. The summer peak and winter peak megawatt values in this table each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in Virginia. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Virginia over the past five years.

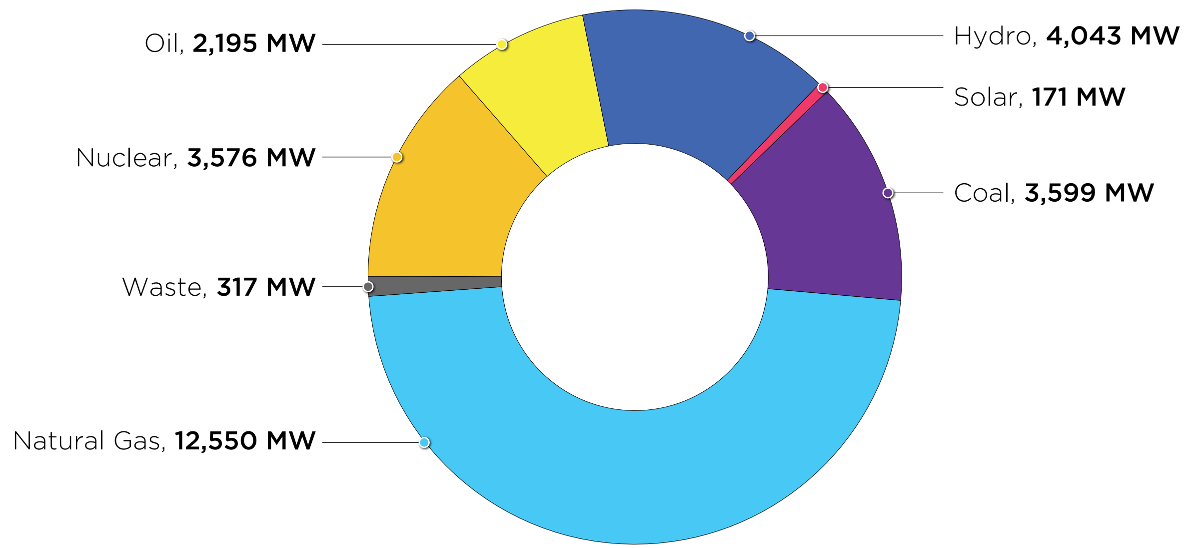
Figure 6.54: PJM RTO Summer Peak Demand Forecast



6.11.3 — Existing Generation

Existing generation in Virginia as of December 31, 2018, is shown by fuel type in **Figure 6.55**.

Figure 6.55: Virginia – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



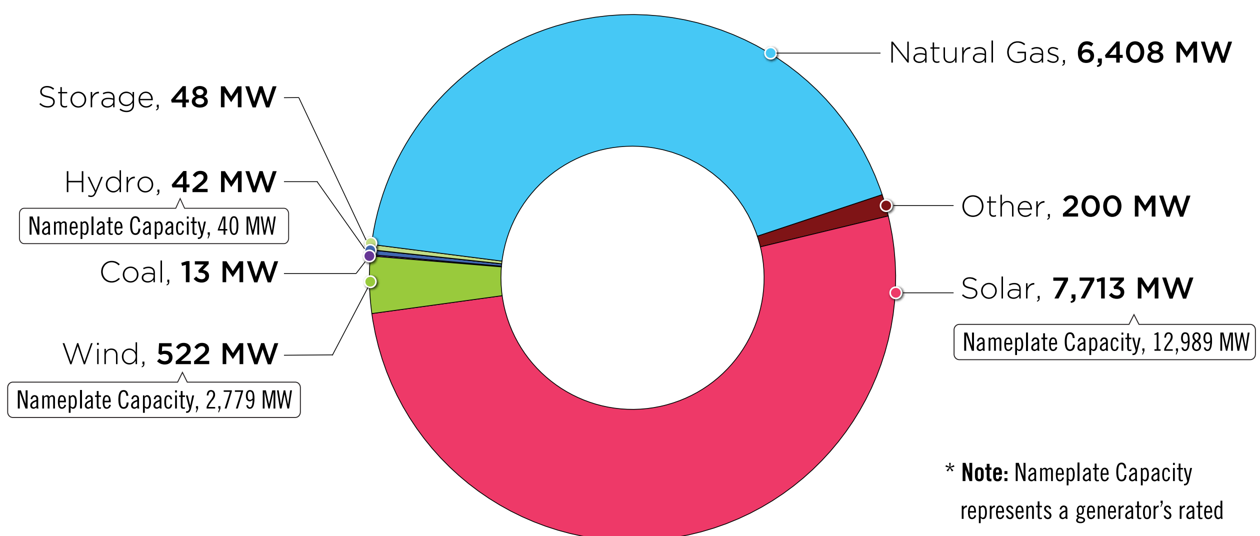
6.11.4 — Interconnection Requests

As of December 31, 2018, 212 queued projects were actively under study, under construction or in suspension in the state of Virginia. A summary of those interconnection requests is shown in **Table 6.64, Table 6.65, Figure 6.56, Figure 6.57** and **Figure 6.58**.

Table 6.64: Virginia – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Solar	7,713.5	12,988.7
Natural Gas	6,407.7	6,607.3
Wind	521.9	2,778.9
Other	200.0	200.0
Storage	48.0	64.0
Hydro	41.9	39.5
Coal	13.2	14.0
Methane	2.2	0.0
Total	**14,948.3**	**22,692.4**

Figure 6.56: Virginia – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.65: Virginia – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue						Grand Total	
	In Service		Withdrawn		Active		Suspended		Under Construction			
	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	**65**	**6,912.8**	**49**	**17,356.0**	**17**	**3,895.7**	**1**	**0.0**	**6**	**2,773.2**	**138**	**30,937.7**
Coal	8	705.7	2	35.0	0	0.0	0	0.0	1	13.2	11	753.9
Diesel	2	2.1	2	20.2	0	0.0	0	0.0	0	0.0	4	22.3
Natural Gas	40	5,532.8	35	15,542.0	13	3,647.7	0	0.0	4	2,760.0	92	27,482.5
Nuclear	8	350.0	1	1,570.0	0	0.0	0	0.0	0	0.0	9	1,920.0
Oil	6	322.2	2	40.0	0	0.0	0	0.0	0	0.0	8	362.2
Other	1	0.0	2	136.3	1	200.0	0	0.0	0	0.0	4	336.3
Storage	0	0.0	5	12.5	3	48.0	1	0.0	1	0.0	10	60.5
Renewable	**50**	**842**	**156**	**4,175.0**	**147**	**7,677.0**	**5**	**26.0**	**36**	**576.0**	**394**	**13,296.0**
Biomass	5	147.4	4	70.0	0	0.0	0	0.0	0	0.0	9	217.4
Hydro	6	381.5	2	254.0	1	2.4	0	0.0	2	39.5	11	677.4
Methane	15	104.6	11	81.8	0	0.0	0	0.0	1	2.2	27	188.6
Solar	23	204.8	110	3,303.9	142	7,181.3	3	6.9	31	525.3	309	11,222.3
Wind	0	0.0	27	407.9	4	493.5	2	19.3	2	9.1	35	929.7
Wood	1	4.0	2	57.0	0	0.0	0	0.0	0	0.0	3	61.0
Grand Total	**115**	**7,755.2**	**205**	**21,530.5**	**164**	**11,572.9**	**6**	**26.2**	**42**	**3,349.3**	**532**	**44,234.1**

Figure 6.57: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

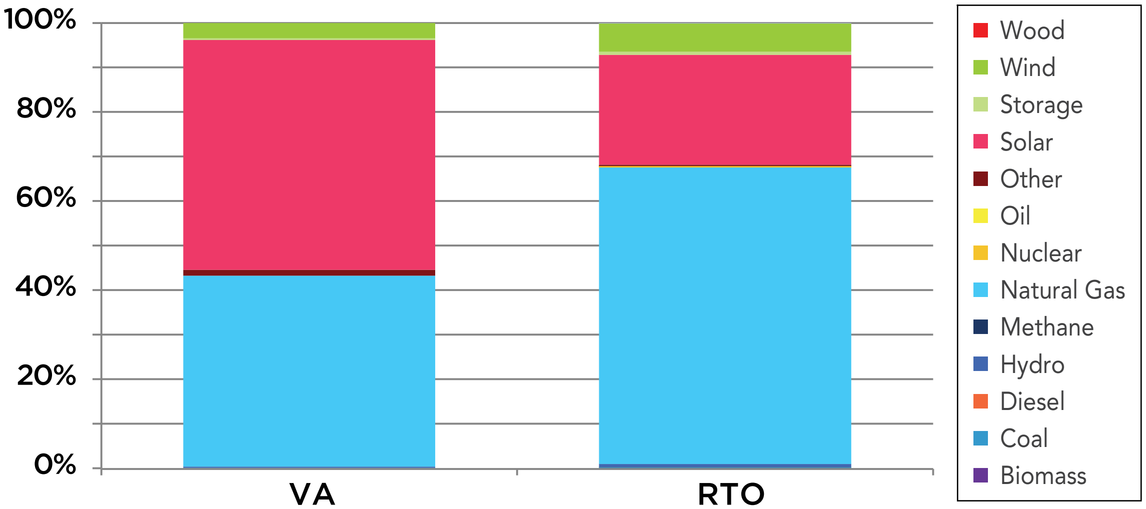


Figure 6.58: Virginia Progression History of Queue – Interconnection Requests (December 31, 2018)

Projects withdrawn after final agreement

- **15** Interconnection Service Agreements – 1,934 MW (Nameplate Capacity, 2,275 MW)
- **9** Wholesale Market Participation Agreements – 89 MW (Nameplate Capacity, 138 MW)

Percentage of planned capacity and projects reached commercial operation

- **28.8 %** requested capacity megawatt
- **32 %** requested projects

6.11.5 — Generation Deactivation

Known generating unit deactivation requests in Virginia between January 1, 2018, and December 31, 2018, are summarized in **Table 6.66** and **Map 6.43.**

Map 6.43: Virginia Generation Deactivations (December 31, 2018)

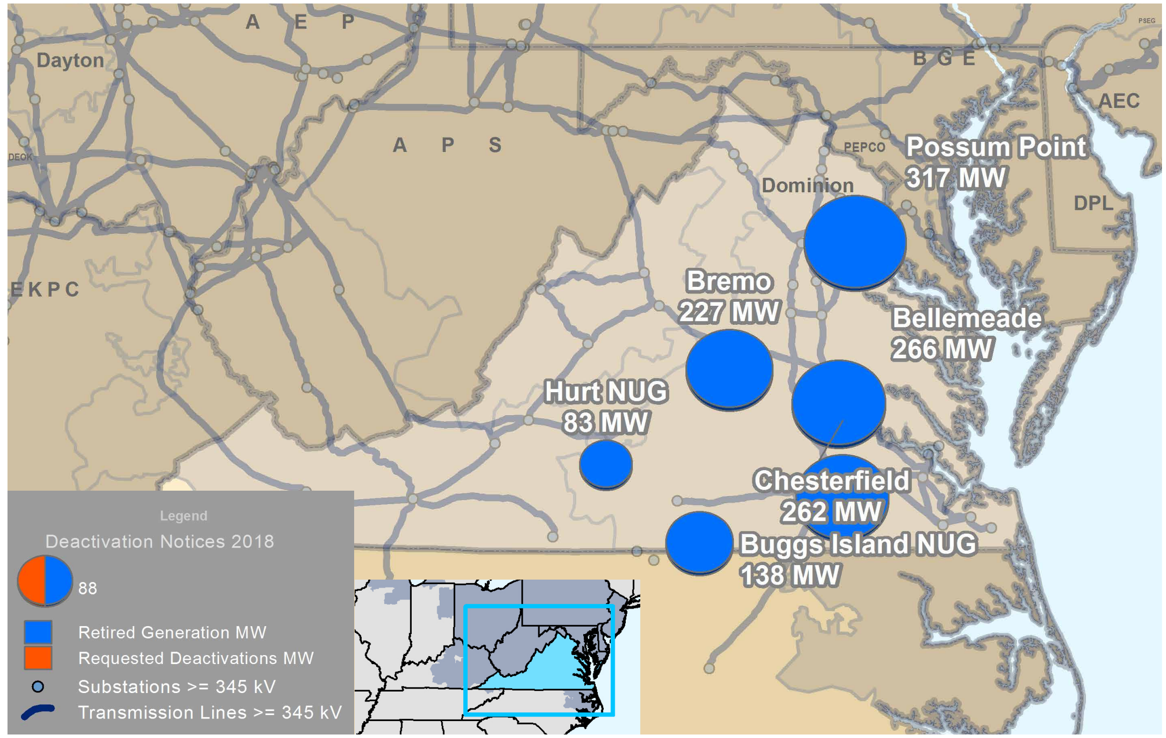


Table 6.66: Virginia Generation Deactivations (December 31, 2018)

Unit	Capacity (MW)	TO Zone	Age (Years)	Projected/Actual Deactivation Date
Bellemeade	266	Dominion	21	4/16/2018
Possum Point 4	221	Dominion	56	12/13/2018
Chesterfield 4	162	Dominion	58	12/13/2018
Bremo 4	156	Dominion	60	4/16/2018
Chesterfield 3	100	Dominion	66	12/13/2018
Possum Point 3	97	Dominion	63	12/13/2018
Hurt NUG	83	Dominion	24	7/24/2018
Bremo 3	71	Dominion	68	4/16/2018
Buggs Island 1	69	Dominion	26	4/9/2018
Buggs Island 2	69	Dominion	26	4/9/2018

6.11.6 — Baseline Projects

RTEP baseline upgrades greater than or equal to $10 million in Virginia are summarized in **Table 6.67** and **Map 6.44.** In 2018, PJM added $452 million of total baseline projects in Virginia.

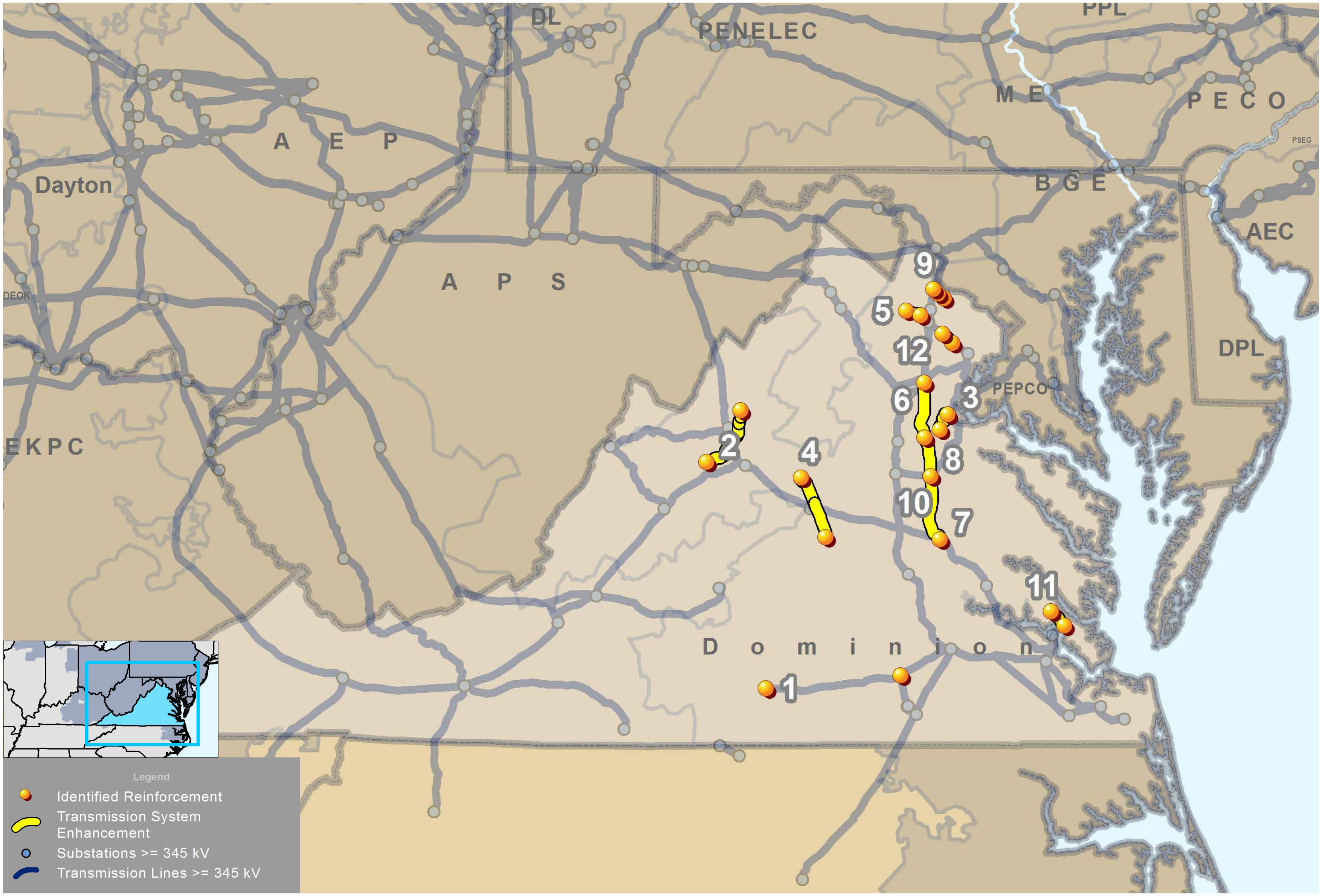
Table 6.67: Virginia Baseline Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	Baseline Load Growth Deliverability & Reliability	Generator Deactivation	Operational Performance	Short Circuit	TO Criteria Violation
1	b2978		Install two 125 MVAR STATCOMs at Rawlings substations and one 125 MVAR STATCOM at Clover 500 kV substations	5/31/2021	$100.00	Dominion	12/14/2017			X		
2	b2980		Rebuild 22.8 miles of 115 kV Line No. 43 between Staunton and Harrisonburg to current standards with a summer emergency rating of 261 MVA at 115 kV	10/31/2022	$37.50	Dominion	12/18/2017					X
3	b2981		Rebuild 115kV 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 230kV)	12/31/2022	$12.50	Dominion	12/18/2017					X
4	b2989		Install a second 230/115 kV transformer (224 MVA) approximately one mile north of Bremo substation and tie 230 kV Line No. 2028 (Bremo-Charlottesville) and 115 kV Line No. 91 (Bremo-Sherwood) together. A three breaker 230 kV ring bus will split Line No. 2028 into two lines and Line No. 91 will also be split into two lines with a new three breaker 115 kV ring bus. Install a temporary 230/115 kV transformer at Bremo substation for the interim until the new substation completes.	6/1/2018	$27.00	Dominion	4/5/2018		X			
5	b3018		Rebuild New Road and Middleburg substations with single circuit steel structures to current 115 kV standards with a minimum summer emergency rating of 261 MVA	12/31/2021	$13.80	Dominion	6/7/2018					X
6	b3019		Rebuild 21.6 miles of 500 kV Bristers-Chancellor.	6/1/2018	$64.65	Dominion	6/7/2018					X
7	b3020		Rebuild 26.2 miles of 500 kV Ladysmith-Elmont.	6/1/2018	$87.00	Dominion	6/7/2018					X
8	b3021		Rebuild 15.2 miles of 500 kV Ladysmith-Chancellor.	6/1/2018	$45.60	Dominion	6/7/2018					X
9	b3026		Re-conductor 230 kV (Pleasant View-Ashburn-Beaumeade) with a minimum rating of 1200 MVA. Also upgrade terminal equipment.	6/1/2021	$10.00	Dominion	8/9/2018	X				

Table 6.66: Virginia Baseline Projects (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	Baseline Load Growth Deliverability & Reliability	Generator Deactivation	Operational Performance	Short Circuit	TO Criteria Violation
10	b3027	.1	Add a second 500/230 kV 840 MVA transformer at Dominion Ladysmith substation	6/1/2021	$23.44	Dominion	8/9/2018	X				
		.2	Re-conductor Ladysmith and Ladysmith CT substations to increase the line rating from 1047 MVA to 1,225 MVA	6/1/2021		Dominion	8/9/2018	X				
		.3	Replace the Ladysmith 500kV breaker "H1T581" with 50 kA breaker	6/1/2021		Dominion	10/11/2018				X	
		.4	Update the nameplate for Ladysmith 500 kV breaker "H1T575" to be 50 kA breaker	6/1/2021		Dominion	10/11/2018				X	
		.5	Update the nameplate for Ladysmith 500 kV breaker "568T574" (will be renumbered as "H2T568") to be 50 kA breaker	6/1/2021		Dominion	10/11/2018				X	
11	b3057		Rebuild 6.1 miles of Waller-Skiffess Creek 230 kV Line (No. 2154) between Waller and Kings Mill to current standards with a minimum summer emergency rating of 1047 MVA utilizing single circuit steel structures. Remove the section of Line No. 58 between Waller and Kings Mill. Rebuild the 1.6 miles of Kings Mill and Skiffes Creek.	6/1/2018	$10.00	Dominion	10/11/2018					X
12	b3058		Partial rebuild of 230 kV lines between Clifton and Johnson DP with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1,200 MVA	6/1/2018	$11.50	Dominion	10/11/2018					X

Map 6.44: Virginia Baseline Projects (Greater than $10 M) (December 31, 2018)



6.11.7 — Network Projects

RTEP network upgrades greater than or equal to $10 million in Virginia are summarized in **Table 6.68** and **Map 6.45**.

Map 6.45: Virginia Network Projects (Greater than $10 M) (December 31, 2018)

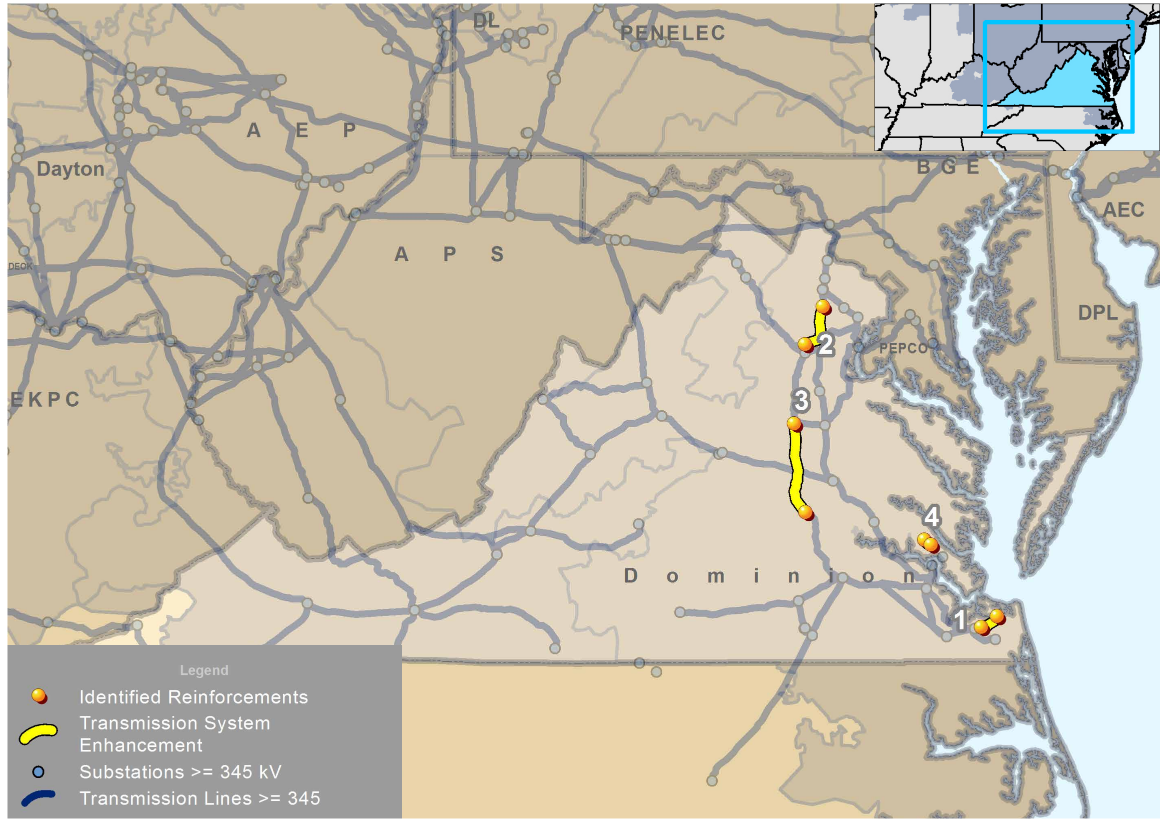


Table 6.68: Virginia Network Upgrades (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Project Driver	Queue	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	n5606	Wreck and rebuild 11 miles of Chesapeake-Greenwich 230 kV	Generation	AC2-012 (Solar)	12/31/2019	$26.50	Dominion	9/13/2018
2	n5938	Wreck and rebuild the Waller-Lightfoot 230 kV line	Generation	AC1-159 (Natural Gas)	1/1/2021	$15.20	Dominion	9/13/2018
3	n5607	Elk Run-Gainsville 230 kV: reconductor 21 miles to increase its line rating to 1203 MVA (normal), 1203 MVA (emergency), and 1383 MVA (load shed).	Generation	AC2-102 (Solar)	12/31/2019	$28.00	Dominion	9/13/2018
4	n5609	Midlothian-North Anna 500 kV: wreck and rebuild the line of 41 miles increase its line rating to 4453 MVA (normal), 4453 MVA (emergency), and 5121 MVA (load shed).	Generation	AC2-141 (Solar)	12/1/2021	$123.39	Dominion	9/13/2018

6.11.8 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in Virginia are summarized in **Table 6.69** and **Table 6.69**.

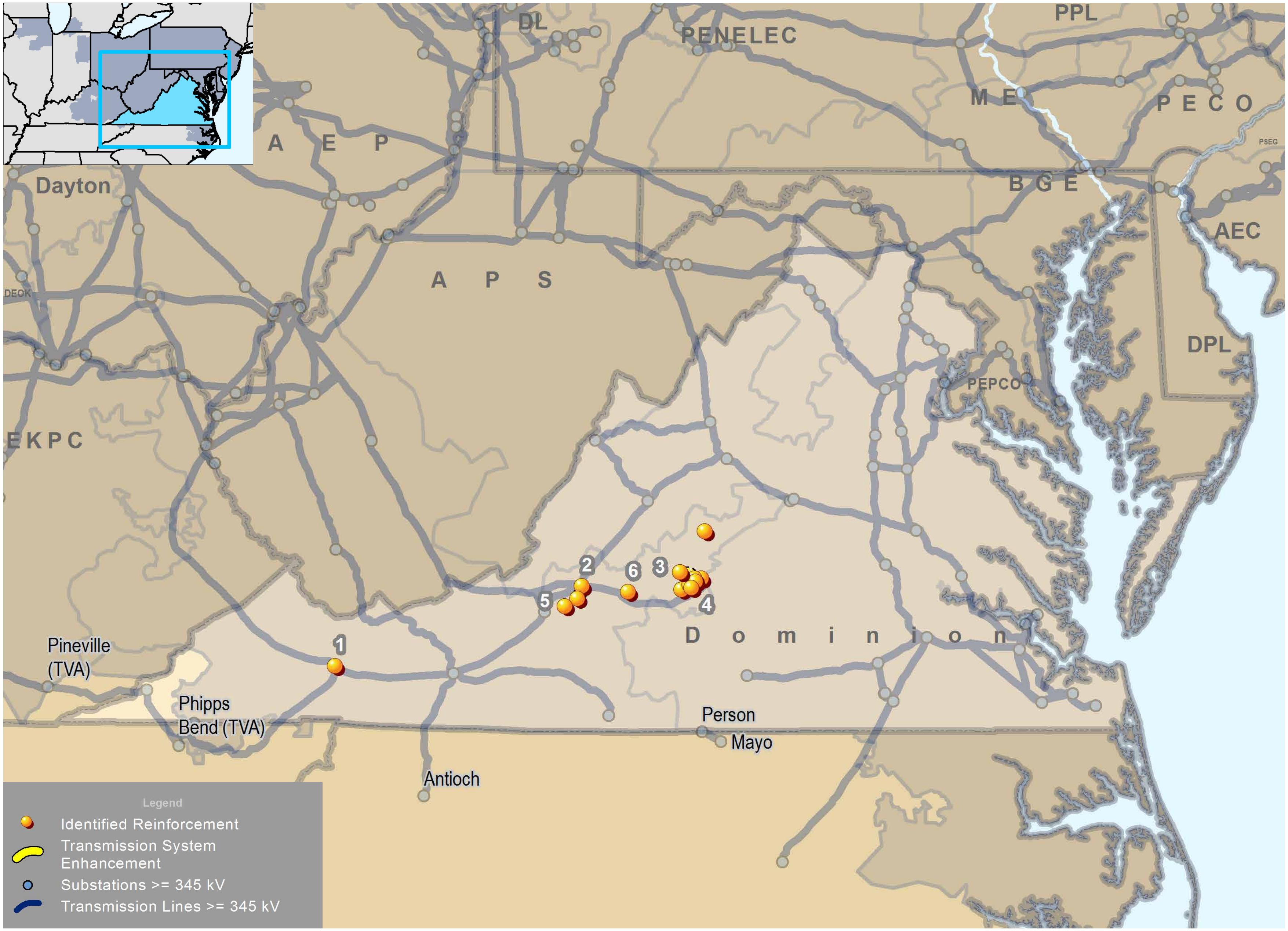
Table 6.69: Virginia Supplemental Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	s1462	Replace existing 765/138 kV 600 MVA transformer no. 1 with a new 765/138 kV 750 MVA transformer. Replace 765/500 kV 1500 MVA transformer No. 4 with a new 765/500 kV 1500 MVA transformer. Install one new 765 kV 50 kA circuit breaker. Install two new 765 kV 50 kA circuit breakers, all at Broadford 765 kV switchyard.	8/6/2021	$102.00	AEP	1/11/2018
		Replace six existing 138 kV circuit breakers with six new. Install three new 138 kV 63 kA circuit breakers in newly constructed string. Replace existing 138 kV 40 kA circuit breaker with a new 138 kV 40 kA breaker. Replace existing 138 kV reactor with a new model.	3/23/2022		AEP	1/11/2018
2	s1581	At Cloverdale station, replace all four single-phase 500 MVA 765/345 kV transformers with new AEP standard 750 MVA/phase units. Transformer no. 10 will be moved into a new string between two existing circuit breakers.	12/18/2020	$54.70	AEP	3/8/2018
		Replace 90 MVA 138/69/34 kV transformer no. 1 with a 130 MVA unit relocated into a new string between two existing circuit breakers.	12/18/2020		AEP	3/8/2018
		Retire a 138/69/34kV transformer. Retire a 34 kV circuit breaker, the Huntington Court 34.5 kV line, and associated 34 kV bus equipment.	12/18/2020		AEP	3/8/2018
		Add two 138 kV circuit breakers (3000 A, 63 kA) in order to bring the newly energized 138 kV Mt Union line into a new string position.	12/18/2020		AEP	3/8/2018
		Replace a 69 kV circuit breaker with new circuit breaker.	12/18/2020		AEP	3/8/2018
		Replace the Cloverdale – Huntington Court 138 kV line relays. Replace the Cloverdale – Roanoke 138 kV line relay. Replace Cloverdale – Mount Union 69 kV line relays.	12/18/2020		AEP	3/8/2018
		Replace 138 kV station service transformer.	12/18/2020		AEP	3/8/2018
		Replace a 41 kA 765 kV circuit breaker with new 63 kA breaker. Retire two 765 kV circuit breakers.	12/18/2020		AEP	3/8/2018
		Install new 138/69 kV 130 MVA transformer at Mount Union station and retire 138/69/34 kV 75 MVA transformer No. 4 at Cloverdale Station. Replace Cloverdale – Mount Union 69 kV line relays.	12/18/2020		AEP	3/8/2018
3	s1443	Install a new 138 kV bus at Opossum Creek and replace condenser units.	2/19/2019	$47.70	AEP	1/8/2018
		Replace seven 138 kV circuit breakers at Opossum Creek. Complete the circuit breaker string for the East Lynchburg exit and the new condenser unit. Complete the circuit breaker string for the Smith Mountain and Reusens lines. Replace two circuit switchers.	2/20/2019		AEP	1/8/2018
		Create a new 138 kV bus for the condenser unit no. 2 at Opossum Creek. Create a new 138 kV bus for the condenser unit no. 1. Install a spare transformer. Remove both 34.5 kV buses and transformers. Install station service off of the 138 kV bus.	2/19/2019		AEP	1/8/2018
		Change relay settings at South Lynchburg and Joshua Falls. At East Lynchburg, Smith Mountain and Peaksview, relay work will be needed.	12/31/2018		AEP	1/8/2018

Table 6.68: Virginia Supplemental Projects (Greater than $10 M) (December 31, 2018) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
4	s1668	At Joshua Falls, retire the existing 138 kV yard at Joshua Falls station and build a new one in the clear.	12/28/2021	$40.70	AEP	6/26/2018
		Construct 0.25 miles of aluminum conductor steel cable (operated at 138kV) connecting the Joshua Falls 765 kV station to the new 138 kV yard.	3/31/2021		AEP	6/26/2018
		Install 0.25 miles of aluminum conductor steel cable connecting the Gomingo – Joshua Falls line to the new 138 kV yard.	6/30/2021		AEP	6/26/2018
		Install 0.4 miles of double-circuited aluminum conductor steel cable connecting the Opossum Creek and Easy Lynchburg lines to the new 138 kV yard.	6/30/2021		AEP	6/26/2018
		At East Lynchburg, install a new 138 kV circuit breaker towards Opossum Creek. Replace the existing circuit breaker with a 138 kV circuit breaker. Install a new circuit breaker on the 69 kV station exit. Replace the existing 34.5 kV circuit breaker. Install a new station service transformer on the 138 kV bus and replace the existing 34.5 kV station service transformer. Retire capswitcher and 57.6 MVAR capacitor bank.	3/21/2021		AEP	6/26/2018
5	s1598	At Hancock station, build a new 138 kV breaker-and-a-half configuration. Install nine new 3000 A/40 kA circuit breakers. Replace a total of four existing circuit breakers with 3000 A/40 kA circuit breakers. Replace three existing circuit breakers with new 1200 A/25 kA models. Install new drop-in control module. Replace transformer no. 2 with new model. Add new transformer with high-side circuit switcher. Replace the existing circuit switcher with new 31.5 kA circuit switcher. Replace capacitor voltage transformers. Replace two 34.5 kV circuit breakers with new 34.5 kV, 40 kA circuit breakers. Replace 34.5 kV capacitor bank circuit switcher with new 40 kA circuit switcher. Install bus regulators on 34.5 kV bus. Replace remote end line relaying.	12/18/2021	$30.00	AEP	3/27/2018
6	s1607	At Reusens station, replace two existing circuit breakers with new 40 kA models. Replace two existing transformers with new 138/34.5 kV 130 MVA transformers. Add three new circuit switchers on the high side of their respective transformers. Replace existing cap switcher with new 650 A 31.5 kA cap switcher. Replace existing cap switcher with new 15 kA cap switcher. Install a new 40 kA 69 kV circuit breaker to the low side of transformer no. 4. Replace three existing 69 kV circuit breakers with new 40 kA circuit breakers. Replace the 138/69 kV 60 MVA transformer no. 4 with a new 138/70.5/13 kV 130 MVA transformer.	12/31/2022	$20.70	AEP	3/27/2018
		At Mosely station, replace existing 17.5 kA 138 kV circuit breaker with new 40 kA circuit breaker. Add a new 138 kV 40 kA line circuit breaker on the Roanoke exit. Replace existing 69 kV circuit breaker with new 40 kA circuit breaker. Replace the existing 61 kA grounding switch motor-operated air breaker with new 40 kA circuit switcher.	12/31/2022		AEP	3/27/2018
		At Clifford station, replace existing motor-operated air breaker with new 40 kA 138 kV circuit breaker on the Boxwood line exit. Replace grounding switch motor-operated air breaker with new 40 kA circuit switcher.	12/31/2022		AEP	3/27/2018

Map 6.46: Virginia Supplemental Projects (Greater than $10 M) (December 31, 2018)

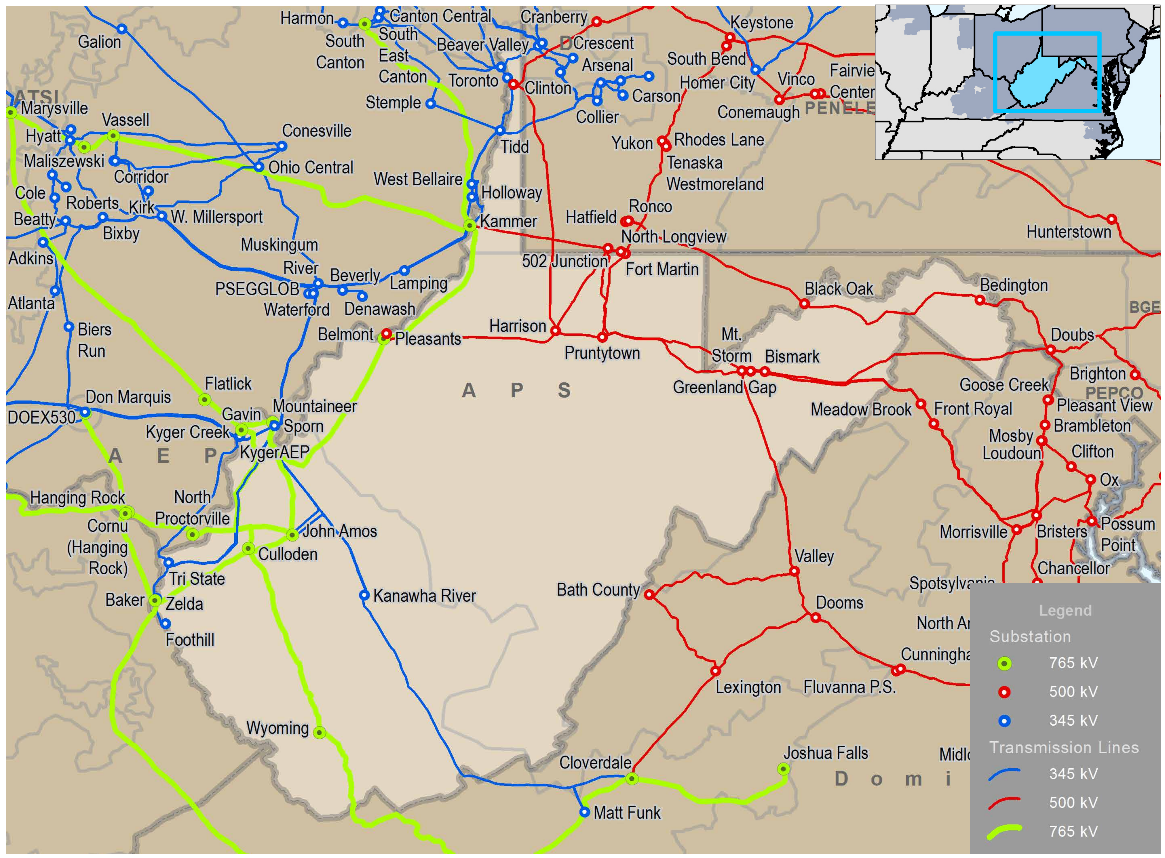


6.12: West Virginia RTEP Summary

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 6.47**. 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 6.47: PJM Service Area in West Virginia



6.12.2 — Load Growth

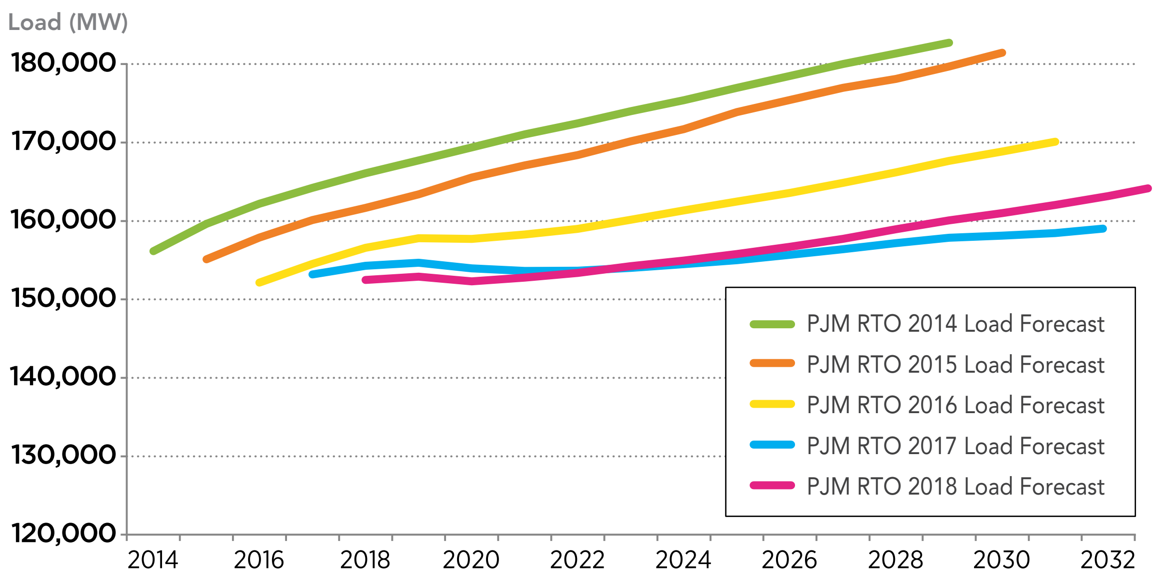
PJM's 2018 Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2018 analyses. **Table 6.70** and **Figure 6.59** summarize the expected loads within the state of West Virgina and across all of PJM.

Table 6.70: West Virginia – 2018 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2018	2028	Growth Rate	2017/ 2018	2027/ 2028	Growth Rate
American Electric Power Company *	3,076	3,229	0.5%	3,632	3,819	0.5%
Allegheny Power *	2,875	3,078	0.7%	2,979	3,232	0.8%
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

* PJM notes that AEP and APS serve load other than in West Virginia. The summer peak and winter peak megawatt values in this table each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in West Virginia. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in West Virginia over the past five years.

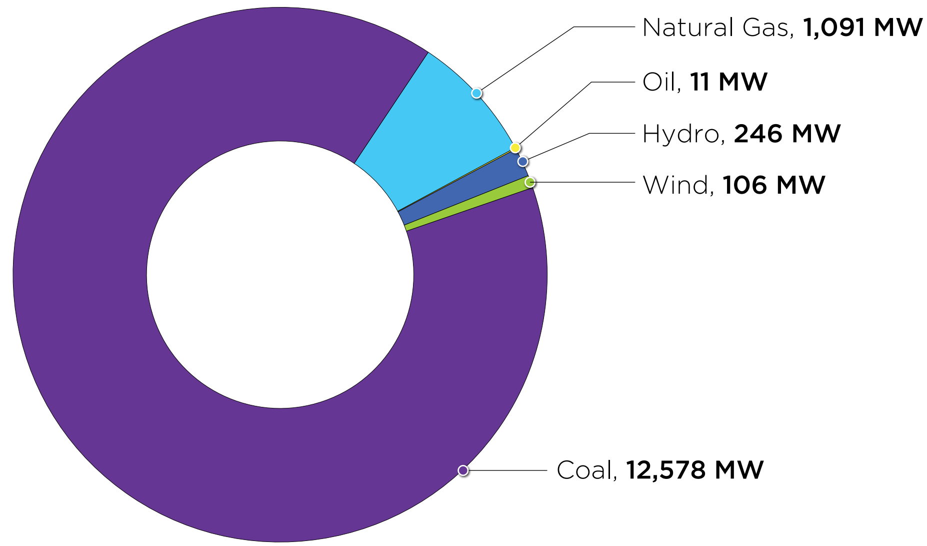
Figure 6.59: PJM RTO Summer Peak Demand Forecast



6.12.3 — Existing Generation

Existing generation in West Virginia as of December 31, 2018, is shown by fuel type in **Figure 6.60**.

Figure 6.60: West Virginia – Existing Installed Capacity (MW) by Fuel Type (December 31, 2018)



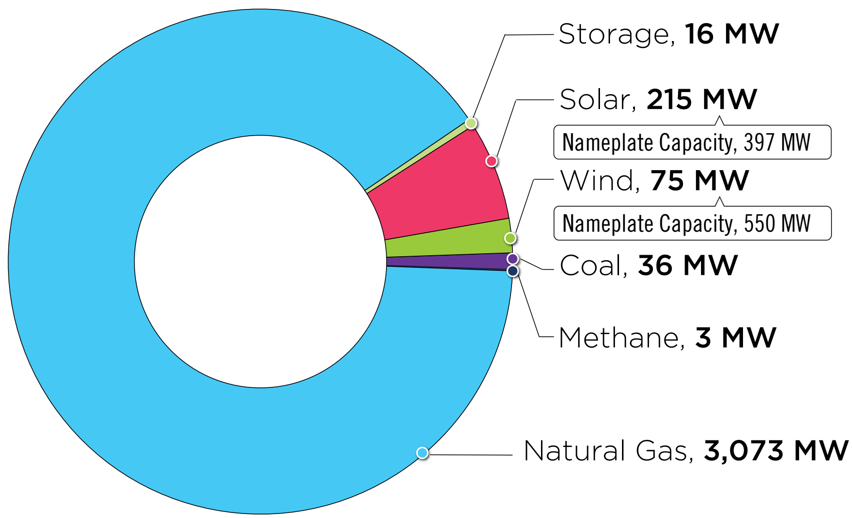
6.12.4 — Interconnection Requests

As of December 31, 2018, 27 queued projects were actively under study, under construction or in suspension in the state of West Virginia. A summary of those interconnection requests is shown in **Table 6.71, Table 6.72, Figure 6.61, Figure 6.62** and **Figure 6.63**.

Table 6.71: West Virginia – Capacity by Fuel Type – Interconnection Requests

Fuel Source	Capacity, MW	Nameplate Capacity, MW
Coal	36.0	36.0
Methane	3.2	3.2
Natural Gas	3,072.6	3,138.0
Solar	215.2	396.7
Storage	15.8	192.3
Wind	74.9	549.6
Total	**3,417.7**	**4,315.8**

Figure 6.61: West Virginia – Queued Capacity (MW) by Fuel Type (December 31, 2018)



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

Table 6.72: West Virginia – Interconnection Requests by Fuel Type (Nameplate Energy) (December 31, 2018)

	Complete				In Queue						Grand Total	
	In Service		Withdrawn		Active		Suspended		Under Construction			
	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	**17**	**1,252.7**	**46**	**15,054.2**	**6**	**1,672.6**	**2**	**5.8**	**7**	**1,446.0**	**78**	**1,9431.3**
Coal	10	861.0	7	2,023.0	0	0.0	0	0.0	1	36.0	18	2,920.0
Natural Gas	5	391.7	36	12,947.2	4	1,662.6	0	0.0	5	1,410.0	50	16,411.5
Other	0	0.0	2	66.0	0	0.0	0	0.0	0	0.0	2	66.0
Storage	2	0.0	1	18.0	2	10.0	2	5.8	1	0.0	8	33.8
Renewable	**3**	**361.0**	**391**	**753**	**1,123**	**263.0**	**256**	**38.0**	**37**	**4.0**	**1,085**	**1,419.0**
Biomass	0	0.0	2	48.0	0	0.0	0	0.0	0	0.0	2	48.0
Hydro	5	153.7	11	208.8	0	0.0	0	0.0	0	0.0	16	362.5
Methane	2	2.4	3	13.8	0	0.0	0	0.0	1	3.2	6	19.4
Solar	0	0.0	4	44.2	5	215.2	0	0.0	0	0.0	9	259.4
Wind	8	190.2	25	392.7	4	39.2	2	35.7	0	0.0	39	657.8
Grand Total	**32**	**1,599.0**	**91**	**15,761.7**	**15**	**1,927.0**	**4**	**41.5**	**8**	**1,449.2**	**150**	**20,778.4**

Figure 6.62: Percentage of Projects in Queue by Fuel Type (December 31, 2018)

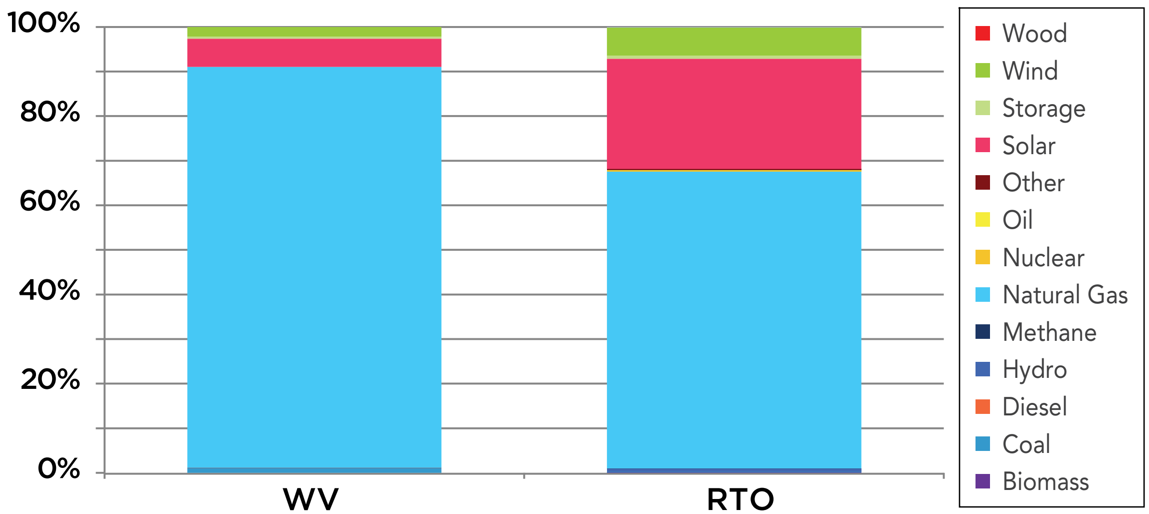
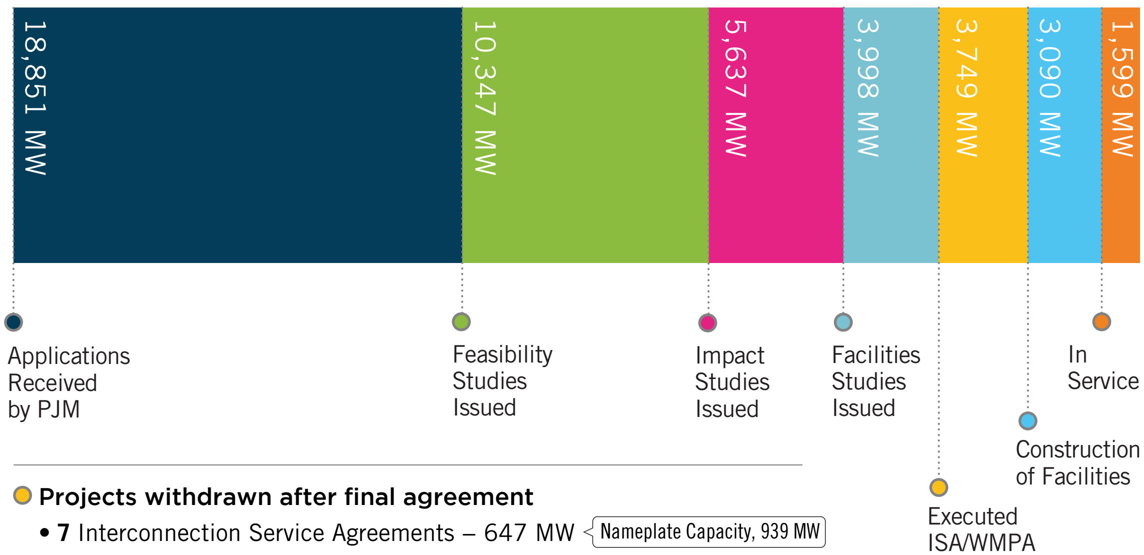


Figure 6.63: West Virginia Progression History of Queue – Interconnection Requests (December 31, 2018)



Projects withdrawn after final agreement

- **7** Interconnection Service Agreements – 647 MW (Nameplate Capacity, 939 MW)
- **2** Wholesale Market Participation Agreements – 6 MW (Nameplate Capacity, 11 MW)

Percentage of planned capacity and projects reached commercial operation

- **8.5 %** requested capacity megawatt
- **24.4 %** requested projects

6.12.5 — Generation Deactivation

Known generating unit deactivation requests in West Virginia between January 1, 2018, and December 31, 2018, are summarized in **Table 6.73** and **Map 6.48**.

Map 6.48: West Virginia Generation Deactivations (December 31, 2018)

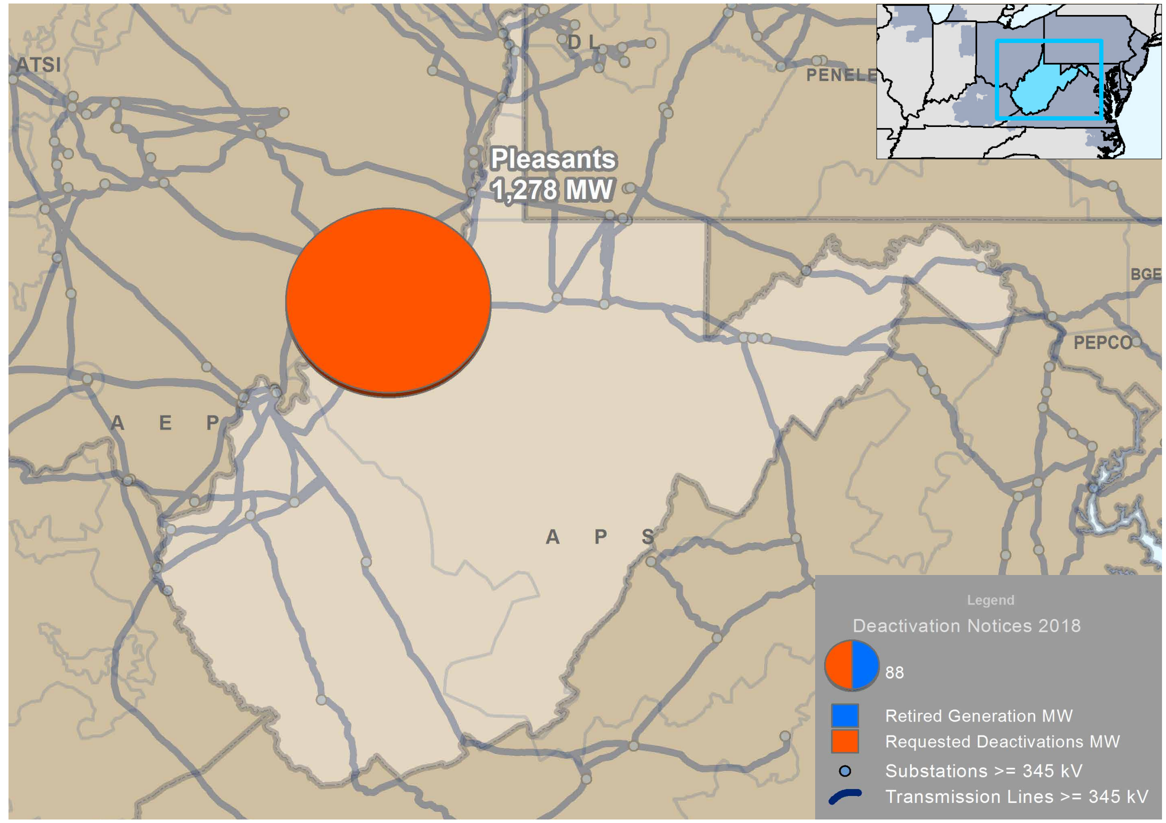


Table 6.73: West Virginia Generation Deactivations (December 31, 2018)

Unit	Capacity (MW)	TO Zone	Age (Years)	Projected/Actual Deactivation Date
Pleasants 1	639	APS	38	6/1/2022
Pleasants 2	639	APS	38	6/1/2022

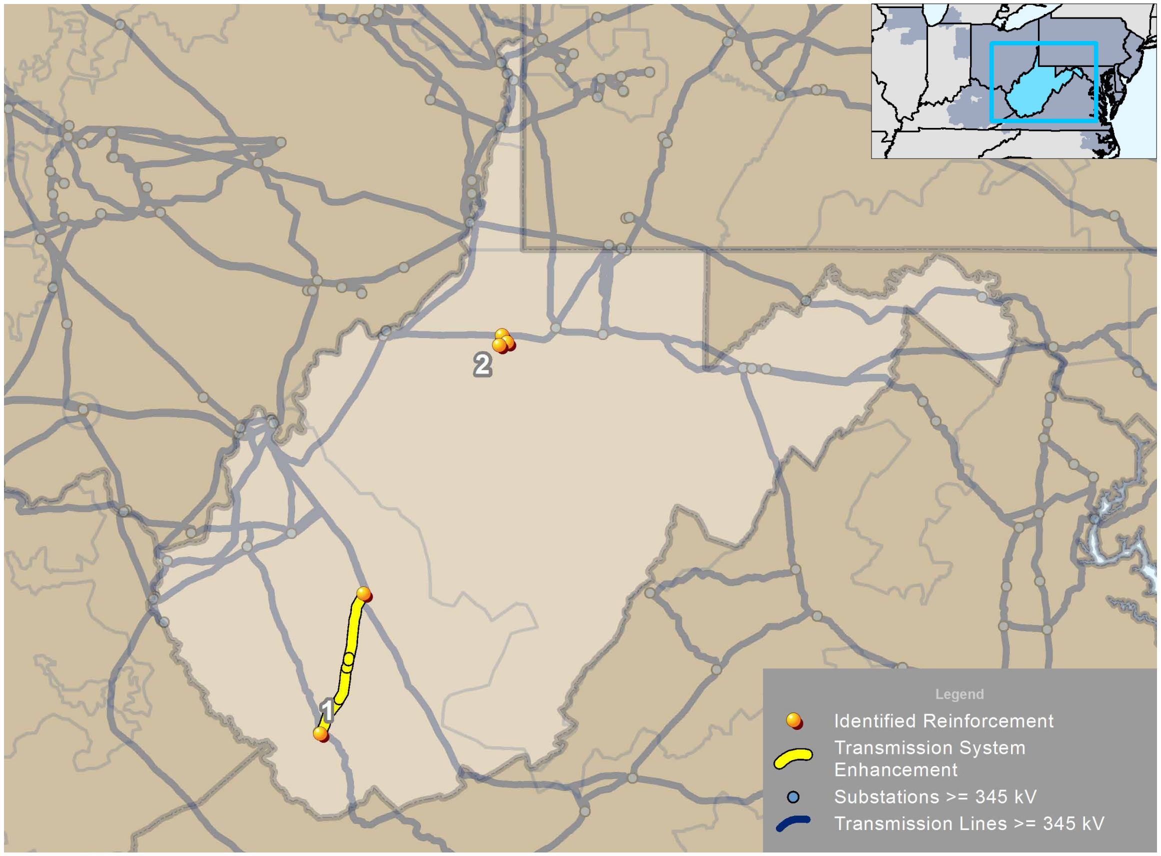
6.12.6 — Baseline Projects

RTEP baseline upgrades greater than or equal to $10 million in West Virginia are summarized in **Table 6.74** and **Map 6.49**. In 2018, PJM added $130 million of total baseline projects in West Virginia.

Table 6.74: West Virginia Baseline Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review	Generator Deactivation	TO Criteria Violation
1	b2611	.1	Build a new 138 kV double circuit off the Kanawha-Baileysville No. 2 138 kV circuit to Skin Fork station	6/1/2015	$17.10	AEP	10/29/2010		X
1	b2611	.2	Install a new 138/46 kV transformer at Skin Fork	6/1/2015	$17.10	AEP	10/28/2010		
2	b2996		Construct a new 500/138 kV substation as a four-breaker ring bus with expansion plans for double-breaker-double-bus on the 500 kV bus and breaker-and-a-half on the 138 kV bus to provide extra high voltage source to the Marcellus shale load growth area. Projected load growth of additional 160 MVA to current plan of 280 MVA, for a total load of 440 MVA served from Waldo Run substation. Replace primary relaying and carrier sets on Belmont and Harrison 500 kV remote end substations. Construct additional three-breaker string at Waldo Run 138 kV bus. Relocate the Sherwood No. 2 line terminal to the new string. Construct two single circuit Flint Run - Waldo Run 138 kV lines using 795 ACSR (approximately 3 miles). After terminal relocation on new three-breaker string at Waldo Run, terminate new Flint Run 138 kV lines onto the two open terminals.	6/1/2019	$40.10	APS	5/3/2018	X	
3	b3040	.1	Rebuild 15 miles Ravenswood-Racine Tap 69 kV line section to 69 kV standards, utilizing 795 26/7 ACSR conductor.	6/1/2022	$68.10	AEP	8/31/2018		X
3	b3040	.2	Rebuild nine miles existing Ripley - Ravenswood 69 kV circuit to 69 kV standards, utilizing 795 26/7 ACSR conductor.	6/1/2022	$68.10	AEP	8/31/2018		X
3	b3040	.3	Install new three-way phase over phase switch at Sarah Lane station to replace the retired switch at Cottageville.	6/1/2022	$68.10	AEP	8/31/2018		X
3	b3040	.5	Retire Mill Run station.	6/1/2022	$68.10	AEP	8/31/2018		X
3	b3040	.6	Install 28.8 MVAr cap bank at South Buffalo station.	6/1/2022	$68.10	AEP	8/31/2018		X
3	b3040	.6	Upgrade remote end relays for Yukon-Allenport-Iron Bridge 138 kV line	6/1/2021	$68.10	APS	6/7/2018		X

Map 6.49: West Virginia Baseline Projects (Greater than $10 M) (December 31, 2018)



6.12.7 — Supplemental Projects

RTEP supplemental upgrades greater than or equal to $10 million in West Virginia are summarized in **Table 6.75** and **Map 6.50.**

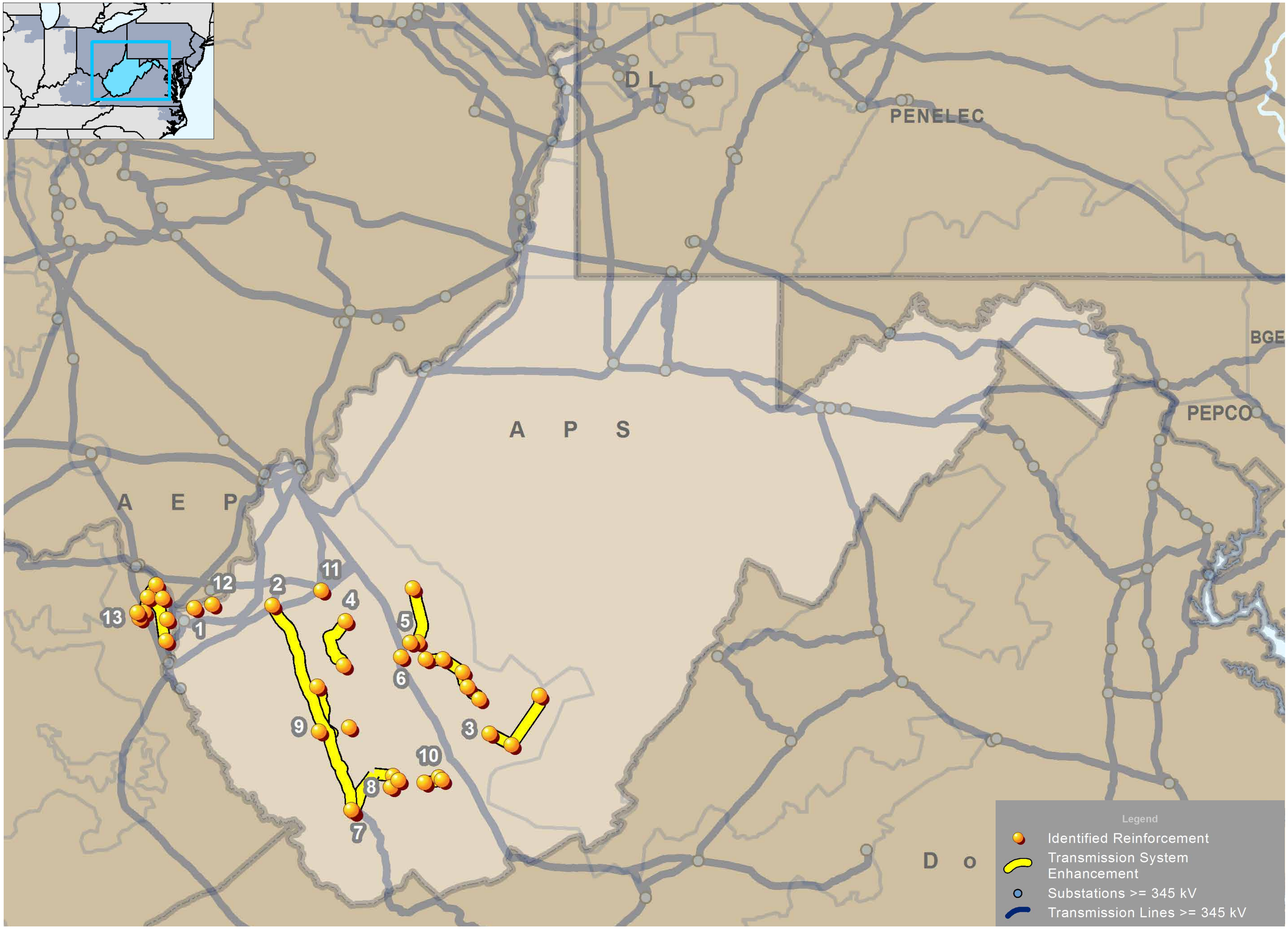
Table 6.75: West Virginia Supplemental Projects (Greater than $10 M) (December 31, 2018)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	2018 TEAC Review
1	s1377	Sheridan Area improvements including terminal equipment updates at Midkiff, Lavalette, Chapman and Darrah 138 kV substation and construction of new 138 kV circuits in the Midkiff, Stone Branch, Champman, Logan and Hopkins 138 kV substations.	5/1/2018	$88.70	AEP	2/14/2018
2	s1580	At Wyoming 765 kV yard, replace existing Transformer No. 1 with a new 765/138 kV 750 MVA transformer. Replace existing transformer No. 2 with a new 765/138 kV 750 MVA transformer. Install a new switchable spare 250 MVA transformer. Replace existing 300 MVAR reactor bank on the Wyoming-Culloden 765 kV line and 40 kA switcher with a new 300 MVAR reactor bank and 50 kA switcher. Make the spare reactor switchable.	12/31/2020	$53.00	AEP	3/8/2018
3	s1566	At Meadow Bridge station, replace the two-way phase-over-phase switch with a new two-way phase-over-phase switch (motorized)	12/4/2020	$35.00	AEP	2/14/2018
		Rebuild approximately 20 miles of the Layland-McClung 69 kV line with aluminum conductor steel cable	12/4/2020		AEP	2/14/2018
4	s1501	Rebuild approximately 17.5 miles of the Boone-Ward Hollow circuit utilizing aluminum conductor steel cable (86 MVA rating) at 69 kV standards (operated at 46 kV). Switching structures at Mikes Run, Emmons, and Alum Creek will be replaced with a standard three-way phase-over-phase switch. Retire Timberland switching station.	11/18/2020	$32.70	AEP	1/30/2018
5	s1560	Rebuild approximately 17.5 miles of the Clendenin-Kelly Creek 46 kV line to 69 kV standards (energized at 46 kV) utilizing aluminum conductor steel cable (68 MVA rating). Retire Kendalia switch.	12/4/2020	$30.70	AEP	2/14/2018
		At Kelly Creek retire the switching structure and replace it with a 1200 A three-way-phase-over-phase (POP) motorized switching structure.	12/4/2020		AEP	2/14/2018
		At Mammoth station, install a three-way phase-over-phase motorized switching structure.	12/4/2020		AEP	2/14/2018
6	s1461	Replace three existing 50 kA 345 kV circuit breakers with new 63 kA circuit breakers. Replace the three sections of the existing Kanawha River Series Capacitor with a single series capacitor. Replace existing 400 MVA 345/138/13.8 kV transformer with a new 450 MVA 345/138/13.8 kV transformer.	10/25/2019	$30.00	AEP	1/11/2018
7	s1497	Rebuild about 16.6 miles of the Baileysville-Bolt line with aluminum conductor steel cable to 138 kV standards (energized at 46 kV, 86 MVA rating). Existing right-of-way will be used when possible but supplemental may be needed in order to build to 138 kV standards.	5/2/2019	$29.11	AEP	1/30/2018
		At Baileysville station, replace 46 kV bus, risers and switches on circuit breaker	12/6/2019		AEP	1/30/2018
		At Marianna station, replace the existing switches with a phase-over-phase switch and replace the bus/risers	8/13/2019		AEP	1/30/2018
		At Rock View station, replace the existing switches with a phase-over-phase switch	9/26/2019		AEP	1/30/2018
		At Poplar Gap station, replace the existing switches with a phase-over-phase switch	6/26/2019		AEP	1/30/2018
		Retire Milam Tap station	12/1/2019		AEP	1/30/2018
		Retire Penn Hollow Tap station	12/20/2019		AEP	1/30/2018
		Install a circuit breaker at McGraws station towards Baileysville	12/20/2019		AEP	1/30/2018

Table 6.74: West Virginia Supplemental Projects (Greater than $10 M) (December 31, 2018)(Cont.)

<table>
<tr><th>Map ID</th><th>Project</th><th>Description</th><th>Projected In-Service Date</th><th>Project Cost ($M)</th><th>TO Zone</th><th>2018 TEAC Review</th></tr>
<tr><td rowspan="2">8</td><td rowspan="2">s1509</td><td>Rebuild ~4 miles of the Carbondale-Brownsville 69 kV line utilizing 795 ACSR conductor (125 MVA rating) at 69 kV standards with steel equivalent H frame structures. Rebuild ~5.6 miles of the Brownsville-Gauley Mountain 69 kV line utilizing 795 ACSR conductor at 69 kV standards with steel equivalent H frame structures. Rebuild 0.1 miles of the Elmo-Tower 117 69 kV line over route 19 with 795 ACSR conductor at 69 kV standards.</td><td>10/1/2019</td><td rowspan="2">$26.00</td><td>AEP</td><td>2/14/2018</td></tr>
<tr><td>Replace Gauley Mountain switches with a new three-way motorized phase-over-phase structure</td><td>12/14/2018</td><td>AEP</td><td>2/14/2018</td></tr>
<tr><td>9</td><td>s1431</td><td>Rebuild approximately 11 miles of the Hopkins-Sharples circuit including 2.6 miles of the Hopkins-Bim line that is double circuited with Hopkins-Sharples. Replace switches at Hewett station with three-way phase-over-phase switch. On all lines, install optical ground wire.</td><td>12/1/2019</td><td>$23.70</td><td>AEP</td><td>1/8/2018</td></tr>
<tr><td rowspan="2">10</td><td rowspan="2">s1667</td><td>At Tams Mtn. Station, replace all 46 kV circuit breakers with 3000 A 40 kA breakers designed to 138 kV standards in ring bus operated at 46 kV. Replace an existing motor-operated air breaker with a new circuit switcher. Retire 138 kV bus tie breaker and establish one 138 kV bus. Install two new 3000 A 40 kA 138 kV circuit breakers on Pierpont 138 kV line and Pemberton 138 kV lines. Replace existing 138/69/46 kV 40 MVA transformer with a new 138/69/46 130 MVA transformer. Reconfigure transmission lines entering the station to accommodate new ring configuration.</td><td>6/1/2021</td><td rowspan="2">$21.20</td><td>AEP</td><td>6/26/2018</td></tr>
<tr><td>Pemberton 138 kV Station remote-end relay work detail</td><td>6/1/2021</td><td>AEP</td><td>6/26/2018</td></tr>
<tr><td>11</td><td>s1463</td><td>Replace three existing 29 kA 765 kV circuit breakers at Amos 765 kV with new 50 kA 765 kV circuit breakers</td><td>12/13/2018</td><td>$11.78</td><td>AEP</td><td>1/11/2018</td></tr>
<tr><td>12</td><td>s1595</td><td>At Darrah station, replace the existing 1600 A 42 kA 138 kV circuit breaker “T” with a new 3000 A 40 kA 138 kV circuit breaker. Replace the existing 1200 A 17 kA 34.5 kV circuit breakers “C”, “D”, “F”, and “I” with new 3000 A 40 kA 34.5 kV. Replace the existing 1800 A 27 kA 34.5 kV circuit breakers “J”, “G”, and “N” with new 3000 A 40 kA 34.5 kV circuit breakers. 138 kV circuit switchers will be added to the high side of Darrah transformers No. 1, 2, 3, and 4. The existing 45 MVA 138/34.5 kV transformer No. 1 will be replaced by 138/69/34.5 kV transformer with a 50 MVA tertiary.</td><td>6/1/2020</td><td>$11.50</td><td>AEP</td><td>3/27/2018</td></tr>
<tr><td rowspan="9">13</td><td rowspan="9">S1687</td><td>Construct a new greenfield station, named Ramey, tapping the Bellefonte-Grangston 138 kV circuit. Four 138 kV circuit breakers (3000 A 40 kA) will be installed as well as a 138/19 kV transformer (25 MVA). AEP already owns the land at the proposed Ramey station site.</td><td>6/30/2021</td><td rowspan="9">53.9</td><td>AEP</td><td>8/31/2018</td></tr>
<tr><td>Construct 3.4 mile 138 kV line between Princess and Moore Hollow stations.</td><td>12/31/2021</td><td>AEP</td><td>8/31/2018</td></tr>
<tr><td>Convert Princess station to 138 kV by installing five 138 kV circuit breakers (3000 A 40 kA), a 138/69 kV transformer (to Coalton), and a 138/34.5 kV transformer.</td><td>12/31/2020</td><td>AEP</td><td>8/31/2018</td></tr>
<tr><td>Convert Hoods Creek station to 138 kV by rebuilding the station in the adjacent lot with a 138/12 kV transformer.</td><td>12/1/2021</td><td>AEP</td><td>8/31/2018</td></tr>
<tr><td>Convert the existing Bellefonte to Coalton 69 kV line between Bellefonte and Princess to 138 kV (line is built to 138 kV standards).</td><td>12/31/2021</td><td>AEP</td><td>8/31/2018</td></tr>
<tr><td>Construct a new 2.8 mile 138 kV extension from Ramey to the existing Bellefonte-Coalton line.</td><td>6/30/2021</td><td>AEP</td><td>8/31/2018</td></tr>
<tr><td>At Chadwick Station, remote end relaying work will be required.</td><td>2/1/2021</td><td>AEP</td><td>8/31/2018</td></tr>
<tr><td>Construct a 2.7 mile 138 kV line extension between Moore Hollow and Kentucky Electric Steel (KES). At this time the existing KES metering structure will be retired due to the announced closure of the KES plant.</td><td>2/1/2021</td><td>AEP</td><td>8/31/2018</td></tr>
<tr><td>Construct a new greenfield station named Moore Hollow. Six 138 kV circuit breakers (3000 A 40 kA) will be installed as well as a 138/34.5 kV transformer (30 MVA) and a 57.6 MVAR capacitor at the station.</td><td>2/1/2021</td><td>AEP</td><td>8/31/2018</td></tr>
</table>

Map 6.50: West Virginia Supplemental Projects (Greater than $10 M) (December 31, 2018)



Appendix 1: Load Forecast Modeling

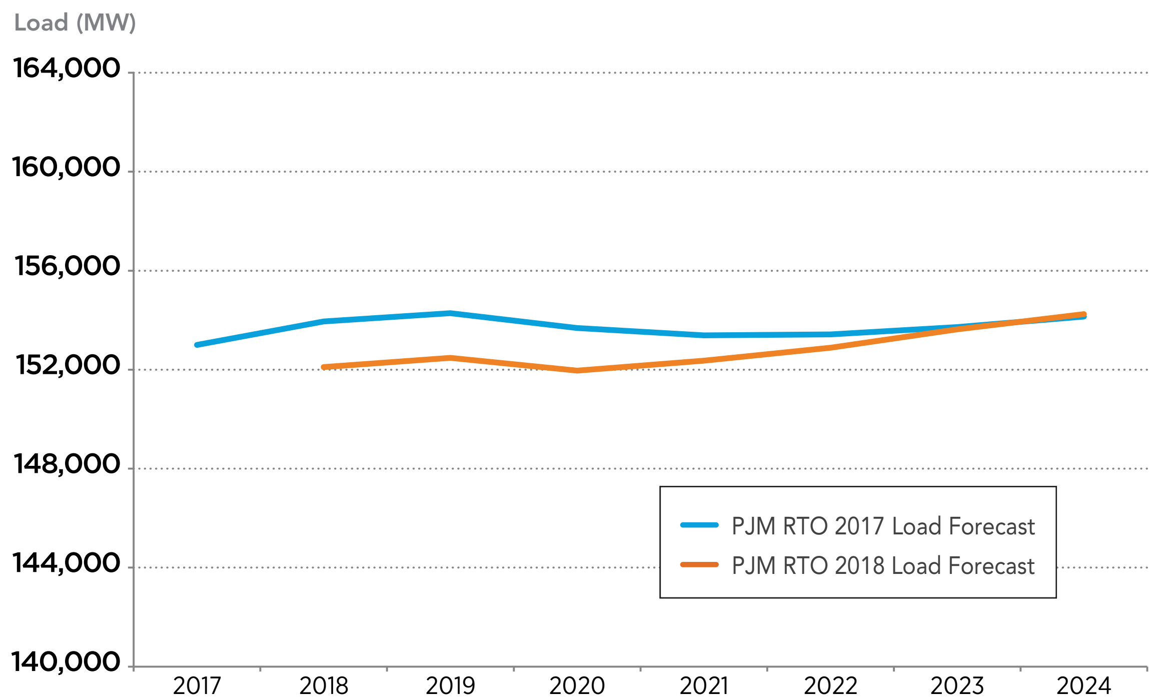
PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

1.0: Power Flow Model Load

Fundamentally, PJM's planning process identifies future system transmission needs based on power flow studies that reveal NERC 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. Specifically, for load deliverability studies, zonal load is modified to account for load diversity, which generally lowers the overall peak load in each area given that peak loads in different geographical areas happen at different times (i.e., are non-coincident).

Figure 1.1: Summer Peak Load Forecast 2018 vs. 2017



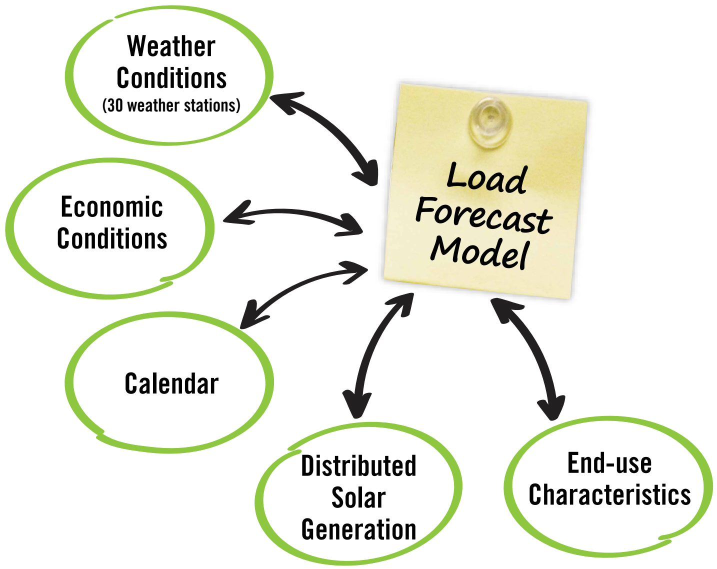
2018 RTEP Process Context

PJM's 2018 RTEP baseline power flow model for study year 2023 is based on the 2018 PJM Load Forecast Report. Summarized in the sections that follow, PJM's January 2018 load forecast covered the 2018 through 2033 planning horizon. From a power flow modeling perspective, the 2023 summer peak from that January 2018 forecast at an overall RTO demand of 153,632 MW was the basis for developing PJM's 2023 base case power flow model bus loads. Doing so will reflect that PJM now projects its RTO summer normalized peak to grow 0.4 percent annually over the next 10 years, shown in **Figure 1.1** in terms of megawatt load level, which is up 0.2 percentage points from the 2017 forecast.

Load Forecasting Process

PJM's load forecast model produces a 15-year forecast, assuming normal weather for each PJM zone and the RTO. The model estimates the historical impact of load (peak and energy) from a range of different drivers, including weather variables, economics, calendar effects, end-use characteristics (equipment/appliance saturation and efficiency), and distributed solar generation, shown in **Figure 1.2** The model is described in more detail in PJM Manual 19, Load Forecasting and Analysis, available on the PJM website. Additional specifics are available in the Load Forecasting White Paper Model.

Figure 1.2: Load Forecast Model



- Weather conditions across the RTO are accounted for by calculating a weighted average of temperature, humidity and wind speed as the weather drivers. PJM obtains weather data from over 30 identified weather stations across the PJM region.

- Calendar effects in the model are variables to 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, which 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 on an ongoing basis.

- 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.

- 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. 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 that central air conditioning units are increasingly commonplace and increasingly efficient.

- 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 in how they have historically affected system 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.

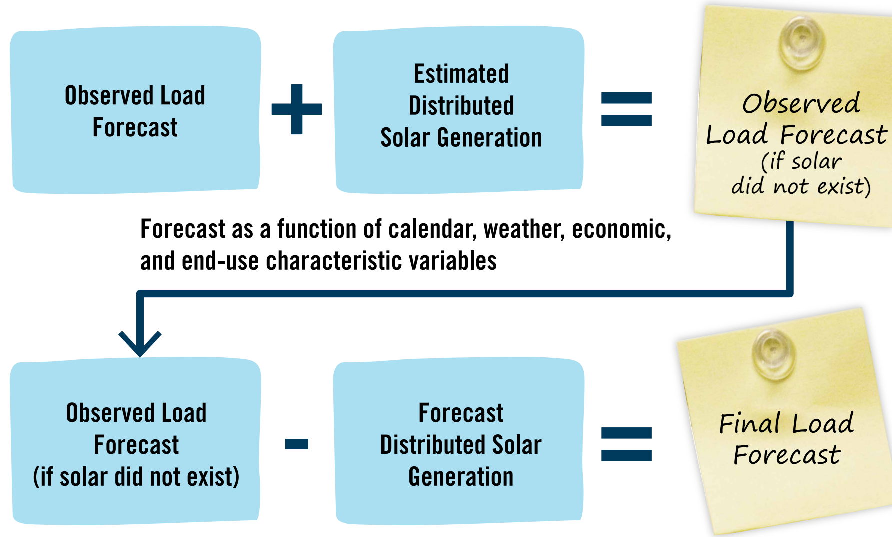
Distributed Solar Generation

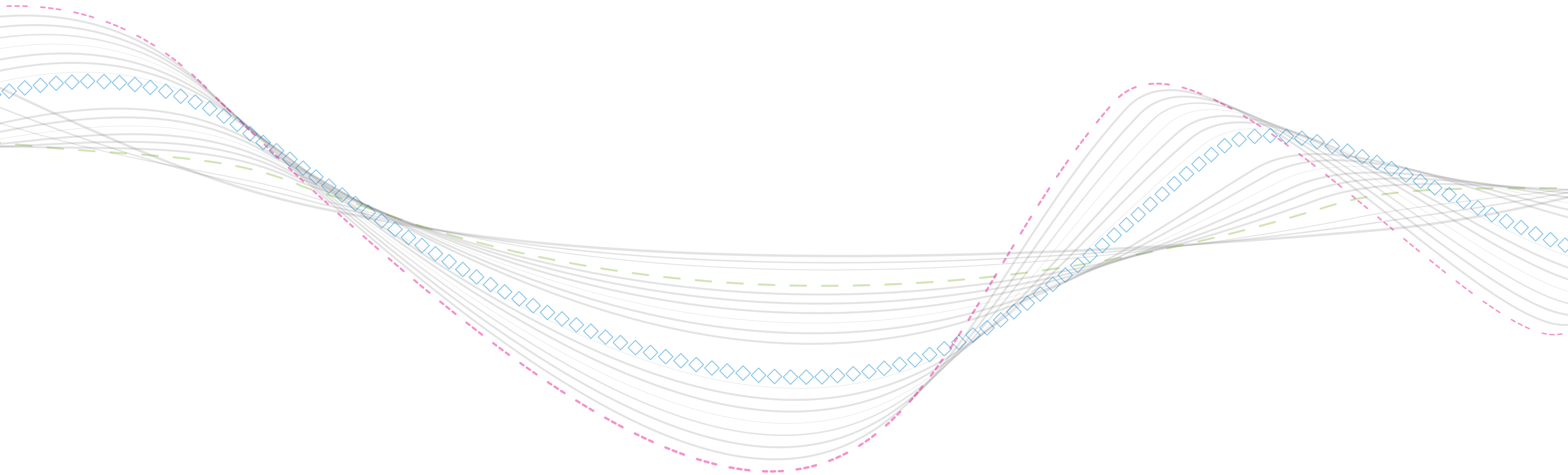
Recent years have witnessed a significant ramp-up in behind-the-meter distributed solar resources: more than 3,500 MW since 1998, with more than 95 percent of installations since 2010. Though not a large amount from an RTO perspective, the level of distributed solar is significant in certain areas of 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 1.3** in order to determine a final load forecast.

PJM first adds back estimated distributed solar generation to its observed load forecast to obtain a hypothetical observed load forecast value as if solar did not exist. PJM develops estimated distributed solar generation values based on historical installed capacity, DC to AC conversion factors, solar insulation, cloud cover, solar panel efficiency degradation due to temperature, and panel tilt angle.

Having obtained an observed load forecast as if solar did not exist, PJM then subtracts 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 1.3: Accounting for Distributed Solar Generation





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

1.1: January 2018 Forecast

PJM's January 2018 load forecast covered the 2018 through 2033 planning horizon, highlights of which are summarized in this section. The complete January 2018 PJM Load Forecast report is accessible on the PJM website. As that report states, PJM's 2023 RTO summer peak is forecasted to be 153,632 MW.

Forecasting Trends

Table 1.1 summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2018 through 2028. All load forecasts in the table reflect adjustment for distributed solar generation**.** Adjustments to the summer, 10-year forecast are summarized in **Table 1.2**. Adjustments to the winter forecast are approximately zero.

Table 1.3 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 1.1: 2018 Load Forecast Report

	Summer Peak (MW)			Winter Peak (MW)		
Transmission Owner	2018	2028	Growth Rate (%)	2017/2018	2027/2028	Growth Rate (%)
Atlantic City Electric Company	2,460	2,409	-0.2%	1,589	1,537	-0.3%
Baltimore Gas and Electric Company	6,848	6,744	-0.2%	5,883	5,956	0.1%
Delmarva Power and Light	3,937	4,018	0.2%	3,443	3,578	0.4%
Jersey Central Power and Light	5,942	5,943	0.0%	3,720	3,681	-0.1%
Metropolitan Edison Company	2,974	3,115	0.5%	2,607	2,697	0.3%
PECO Energy Company	8,642	8,979	0.4%	6,752	6,881	0.2%
Pennsylvania Electric Company	2,895	2,922	0.1%	2,866	2,875	0.0%
PPL Electric Utilities Corporation	7,140	7,350	0.3%	7,211	7,343	0.2%
Potomac Electric Power Company	6,493	6,466	0.0%	5,383	5,534	0.3%
Public Service Electric and Gas Company	9,903	9,876	0.0%	6,655	6,626	0.0%
Rockland Electric Company	402	402	0.0%	230	229	0.0%
UGI	190	188	-0.1%	194	188	-0.3%
Diversity – Mid-Atlantic	-1,225	-1,086		-582	-494	
Mid-Atlantic	56,601	57,326	0.1%	45,951	46,631	0.1%
American Electric Power Company	22,876	24,018	0.5%	22,447	23,600	0.5%
Allegheny Power	8,825	9,447	0.7%	8,789	9,536	0.8%
American Transmission Systems, Inc.	12,952	13,309	0.3%	10,687	10,942	0.2%
Commonwealth Edison Company	22,121	23,207	0.5%	15,714	16,329	0.4%
Dayton Power and Light	3,459	3,508	0.1%	2,917	2,932	0.1%
Duke Energy Ohio and Kentucky	5,523	5,860	0.6%	4,478	4,705	0.5%
Duquesne Light Company	2,872	2,924	0.2%	2,153	2,175	0.1%
East Kentucky Power Cooperative	1,960	2,033	0.4%	2,587	2,693	0.4%
Diversity – Western	-1,540	-1,522		-1,316	-1,351	
Western	79,048	82,784	0.5%	68,456	71,561	0.4%
Dominion Virginia Power	19,596	21,161	0.8%	18,096	19,769	0.9%
Southern	19,596	21,161	0.8%	18,096	19,769	0.9%
Diversity – RTO	-3,137	-3,636		-1,040	-1,259	
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

Table 1.2: Distributed Solar Generation Adjusted to Summer Peak

	Distributed Solar Generation Adjustment to Summer Peak (MW)	
Transmission Owner	2018	2028
Atlantic City Electric Company	105	147
Baltimore Gas and Electric Company	115	292
Delmarva Power and Light	63	108
Jersey Central Power and Light	160	254
Metropolitan Edison Company	18	33
PECO Energy Company	29	68
Pennsylvania Electric Company	5	24
PPL Electric Utilities Corporation	41	78
Potomac Electric Power Company	92	226
Public Service Electric and Gas Company	252	446
Rockland Electric Company	5	12
UGI	0	1
Mid-Atlantic	885	1,689
American Electric Power Company	26	239
Allegheny Power	48	140
American Transmission Systems, Inc.	30	124
Commonwealth Edison Company	18	115
Dayton Power and Light	7	35
Duke Energy Ohio and Kentucky	6	42
Duquesne Light Company	6	18
East Kentucky Power Cooperative	1	12
Western	142	725
Dominion Virginia Power	193	485
Southern	193	485
PJM RTO	**1,220**	**2,899**

Table 1.3: Comparison of 10-Year Summer Peak Load Growth Rates

	Load Forecast Report														
	2014			2015			2016			2017			2018		
	Summer Peak (MW)			Summer Peak (MW)			Summer Peak (MW)			Summer Peak (MW)			Summer Peak (MW)		
Transmission Owner	2014	2024	Growth Rate	2015	2025	Growth Rate	2016	2026	Growth Rate	2017	2027	Growth Rate	2018	2028	Growth Rate
Atlantic City Electric Company	2,750	2,969	0.8%	2,664	2,827	0.6%	2,524	2,502	-0.1%	2,495	2,445	-0.2%	2,460	2,409	-0.2%
Baltimore Gas and Electric Company	7,283	7,971	0.9%	7,127	7,753	0.8%	6,945	7,220	0.4%	6,889	6,911	0.0%	6,848	6,744	-0.2%
Delmarva Power and Light	4,181	4,600	1.0%	4,177	4,557	0.9%	3,991	4,135	0.4%	4,028	3,983	-0.1%	3,937	4,018	0.2%
Jersey Central Power and Light	6,361	6,944	0.9%	6,269	6,851	0.9%	5,968	6,156	0.3%	6,056	6,108	0.1%	5,942	5,943	0.0%
Metropolitan Edison Company	3,019	3,444	1.3%	2,954	3,310	1.1%	2,940	3,176	0.8%	2,940	3,028	0.3%	2,974	3,115	0.5%
PECO Energy Company	8,843	9,827	1.1%	8,645	9,434	0.9%	8,547	9,122	0.7%	8,547	8,693	0.2%	8,642	8,979	0.4%
Pennsylvania Electric Company	2,966	3,441	1.5%	2,914	3,276	1.2%	2,890	2,919	0.1%	2,891	2,847	-0.2%	2,895	2,922	0.1%
PPL Electric Utilities Corporation	7,334	8,079	1.0%	7,162	7,759	0.8%	7,193	7,560	0.5%	7,132	7,186	0.1%	7,140	7,350	0.3%
Potomac Electric Power Company	6,870	7,249	0.5%	6,640	7,022	0.6%	6,563	6,813	0.4%	6,614	6,543	-0.1%	6,493	6,466	0.0%
Public Service Electric and Gas Company	10,614	11,185	0.5%	10,306	10,907	0.6%	10,090	10,222	0.1%	10,057	10,012	0.0%	9,903	9,876	0.0%
Rockland Electric Company	423	439	0.4%	424	441	0.4%	407	410	0.1%	404	404	0.0%	402	402	0.0%
UGI	198	218	1.0%	197	212	0.7%	188	190	0.1%	191	185	-0.3%	190	188	-0.1%
Diversity – Mid-Atlantic	-511	-507		-578	-530		-1,072	-872		-1,080	-1,161		-1,225	-1,086	
Mid-Atlantic	60,331	65,859	0.9%	58,901	63,819	0.8%	57,174	59,553	0.4%	57,164	57,184	0.0%	56,601	57,326	0.1%
American Electric Power Company	23,556	25,414	0.8%	23,511	25,343	0.8%	23,006	24,891	0.8%	22,945	23,888	0.4%	22,876	24,018	0.5%
Allegheny Power	8,837	9,722	1.0%	8,734	9,701	1.1%	8,817	9,554	0.8%	8,802	9,087	0.3%	8,825	9,447	0.7%
American Transmission Systems, Inc.	13,341	14,038	0.5%	13,256	13,835	0.4%	12,921	13,413	0.4%	12,994	13,177	0.1%	12,952	13,309	0.3%
Commonwealth Edison Company	23,275	26,182	1.2%	22,914	25,953	1.3%	22,001	23,633	0.7%	22,296	22,872	0.3%	22,121	23,207	0.5%
Dayton Power and Light	3,476	3,926	1.2%	3,497	3,966	1.3%	3,403	3,647	0.7%	3,479	3,503	0.1%	3,459	3,508	0.1%
Duke Energy Ohio and Kentucky	5,597	6,079	0.8%	5,511	6,015	0.9%	5,436	5,853	0.7%	5,497	5,741	0.4%	5,523	5,860	0.6%
Duquesne Light Company	2,997	3,266	0.9%	2,969	3,161	0.6%	2,893	2,985	0.3%	2,884	2,882	0.0%	2,872	2,924	0.2%
East Kentucky Power Cooperative	1,899	2,033	0.7%	1,983	2,170	0.9%	1,924	2,041	0.6%	1,948	2,010	0.3%	1,960	2,033	0.4%
Diversity – Western	-1,876	-2,095		-1,682	-1,997		-1,572	-1,574		-1,529	-1,468		-1,540	-1,522	
Western	81,102	88,565	0.9%	80,693	88,147	0.9%	78,829	84,443	0.7%	79,316	81,692	0.3%	79,048	82,784	0.5%
Dominion Virginia Power	20,197	24,224	1.8%	19,999	23,676	1.7%	19,531	22,041	1.2%	19,729	20,501	0.4%	19,596	21,161	0.8%
Southern	20,197	24,224	1.8%	19,999	23,676	1.7%	19,531	22,041	1.2%	19,729	20,501	0.4%	19,596	21,161	0.8%
Diversity – RTO	-4,351	-4,919		-4,049	-4,062		-3,403	-4,146		-3,210	-3,604		-3,137	-3,636	
PJM RTO	**157,279**	**173,729**	**1.0%**	**155,544**	**171,580**	**1.0%**	**152,131**	**161,891**	**0.6%**	**152,999**	**155,773**	**0.2%**	**152,108**	**157,635**	**0.4%**

2018 Forecast Summer Zonal Load Growth Rates

The PJM RTO weather-normalized summer peak is forecasted to grow at an average rate of 0.4 percent per year for the next 10 years. The PJM RTO summer peak is forecasted to be 157,635 MW in 2028, an increase of 5,527 MW over the 2018 peak of 152,108 MW. Individual geographic zone growth rates vary from -0.2 percent to 0.8 percent,as shown in **Figure 1.4** and **Figure 1.5**.

Figure 1.4: PJM Mid-Atlantic Summer Peak Load Growth 2018-2028

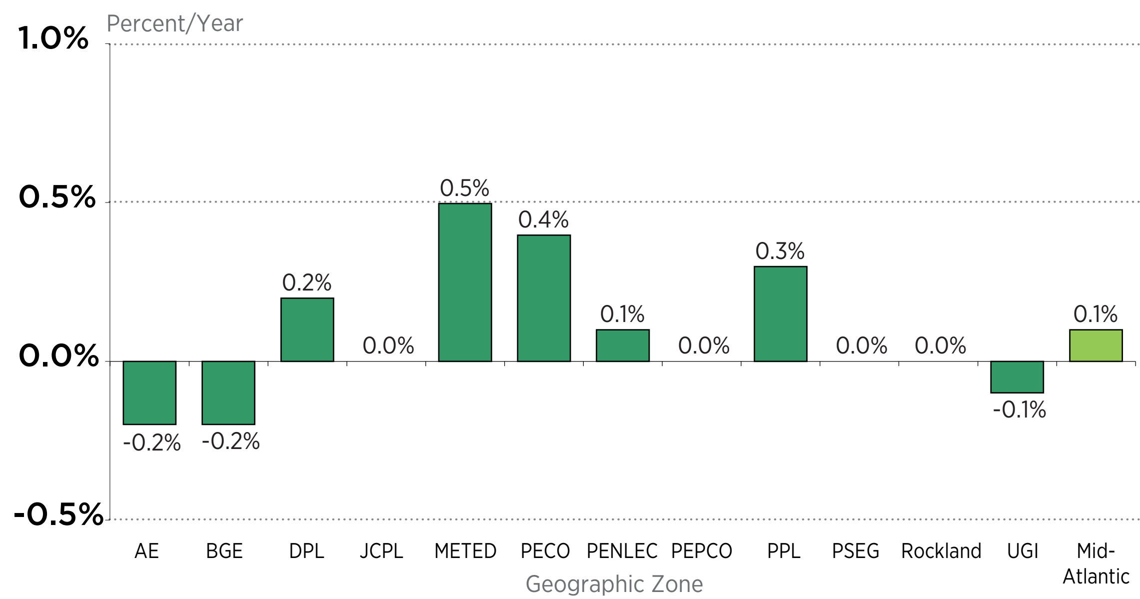
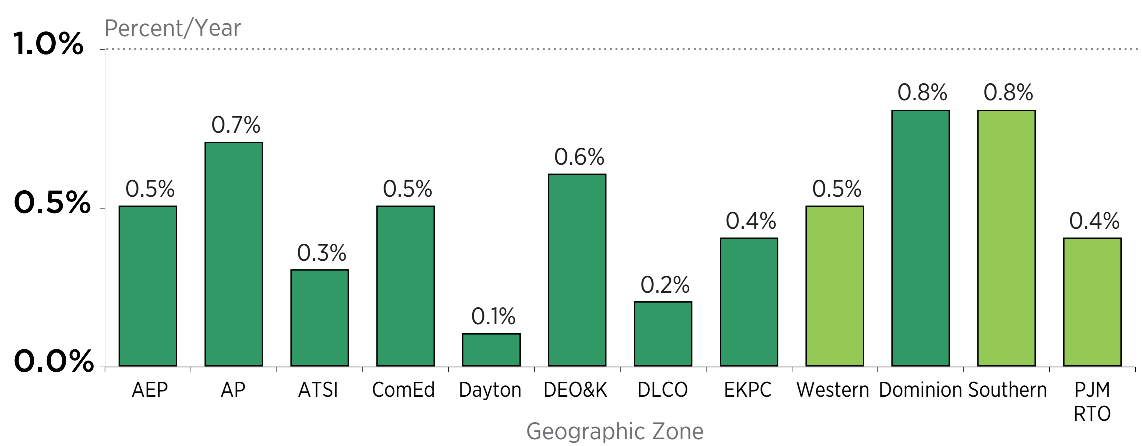


Figure 1.5: PJM Western and Southern Summer Peak Load Growth 2018-2028



2018 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 136,702 MW in 2027/2028, an increase of 5,239 MW over the 2017/2018 peak of 131,463 MW. Individual geographic zone growth rates vary from -0.3 percent to 0.9 percent, as shown in **Figure 1.6** and **Figure 1.7**.

Figure 1.6: PJM Mid-Atlantic Winter Peak Load Growth 2018-2028

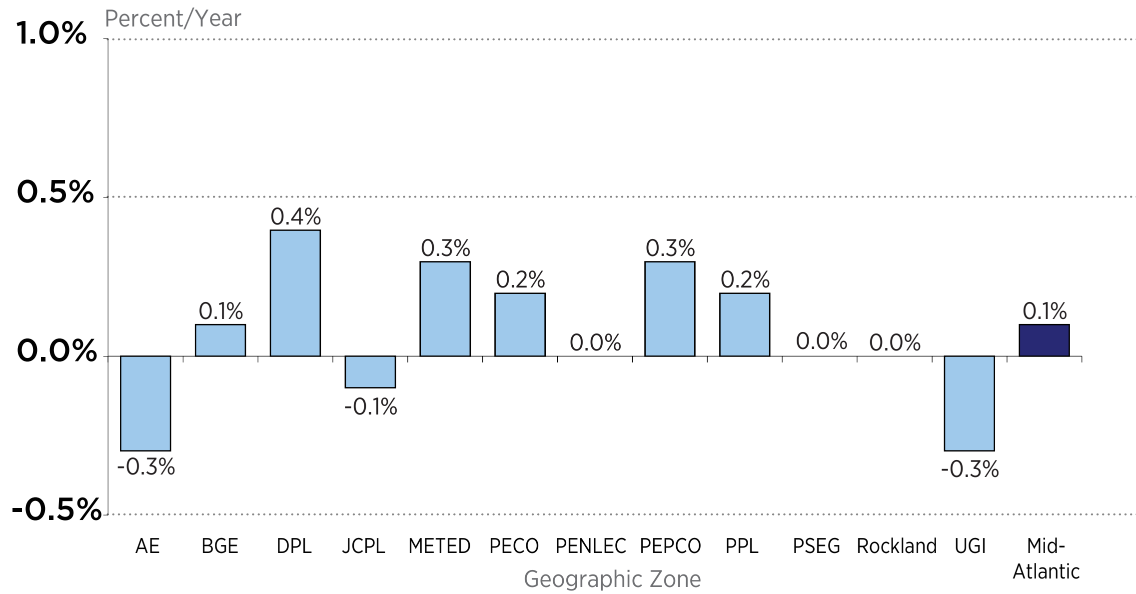
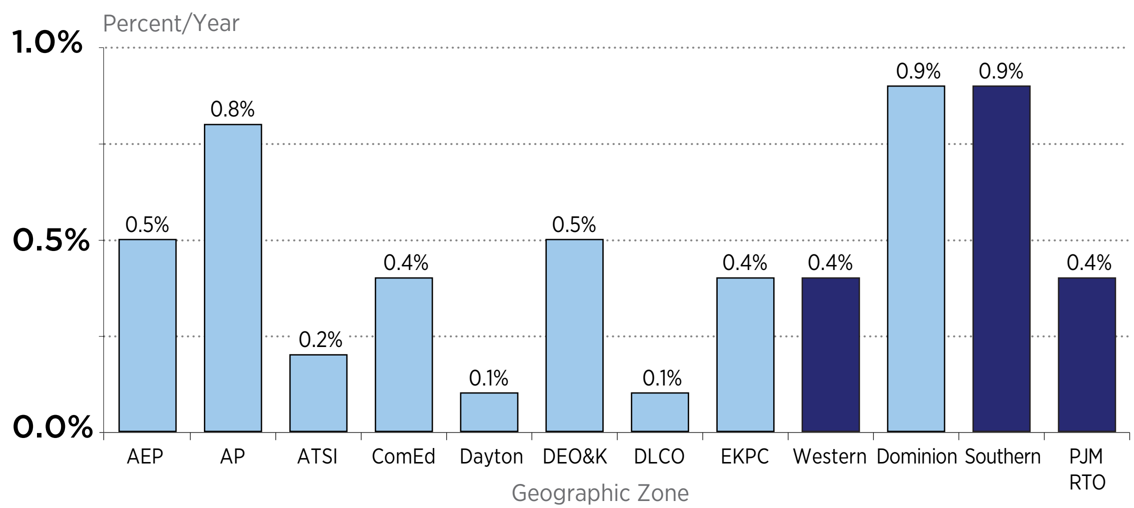


Figure 1.7: PJM Western and Southern Winter Peak Load Growth 2018-2028

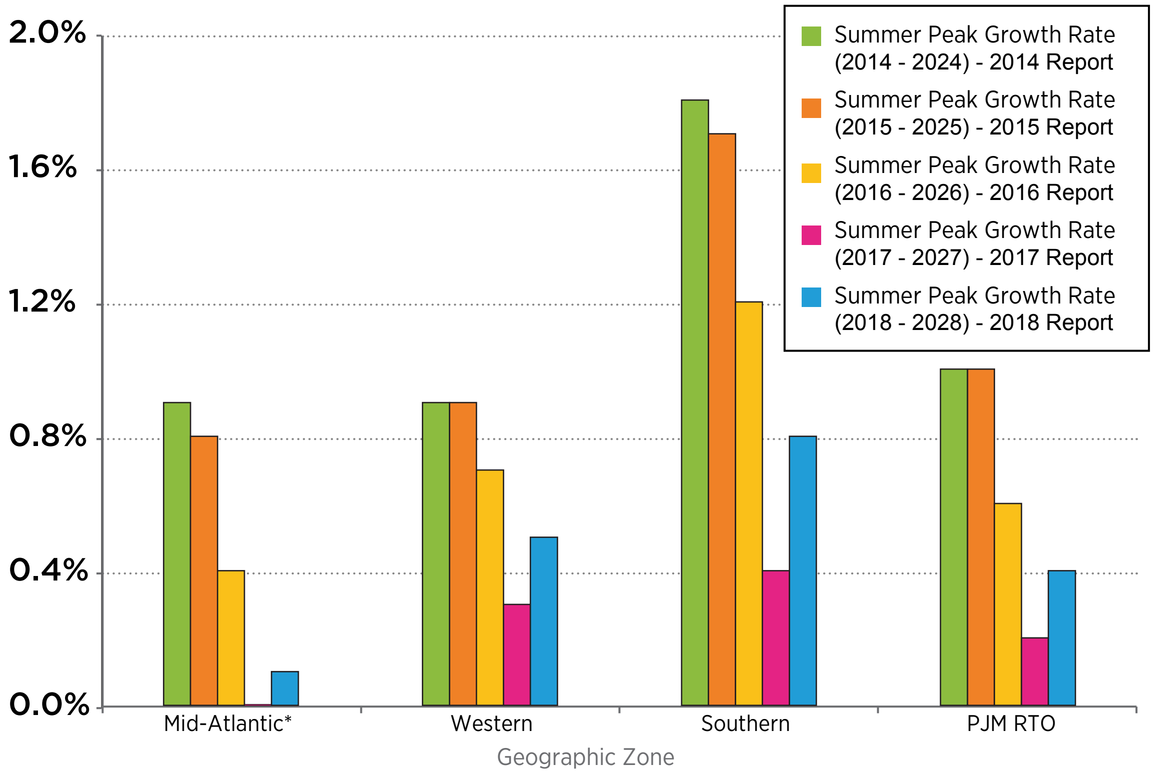


Subregional Forecast Trends

Figure 1.8 provides a summary based on load growth rate trends from the respective January load forecast over each of the last five years, from 2014 through 2018 for the ensuing ten 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 2018 report forecast load growth rate for the RTO increased by 0.2 percentage points when compared to the 2017 report.

Figure 1.8: PJM 10-Year Summer Peak Load Growth Rate Comparison: 2014-2018 Load Forecast Reports



*PJM's Mid-Atlantic Summer Peak Growth Rate for 2017-2027 is forecasted to be at 0.0%

1.2: Demand Resources

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 2018 Load Forecast Report, are shown in **Table 1.4** for each transmission owner zone. The adjusted forecast is then used in RTEP power flow model development as described in **Section 2.0**. Consequently, demand resources can have a measurable impact on future system conditions and potential need for transmission system enhancements to serve load. PJM recently changed the methodology to forecast demand resources. 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 2 to obtain the demand resource forecast for each zone.

Capacity Performance Impacts

PJM's RPM transition to Capacity Performance has required a transition in the treatment of demand resources as well. **Table 1.4** assumes the following:

- Delivery years 2018 and 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.

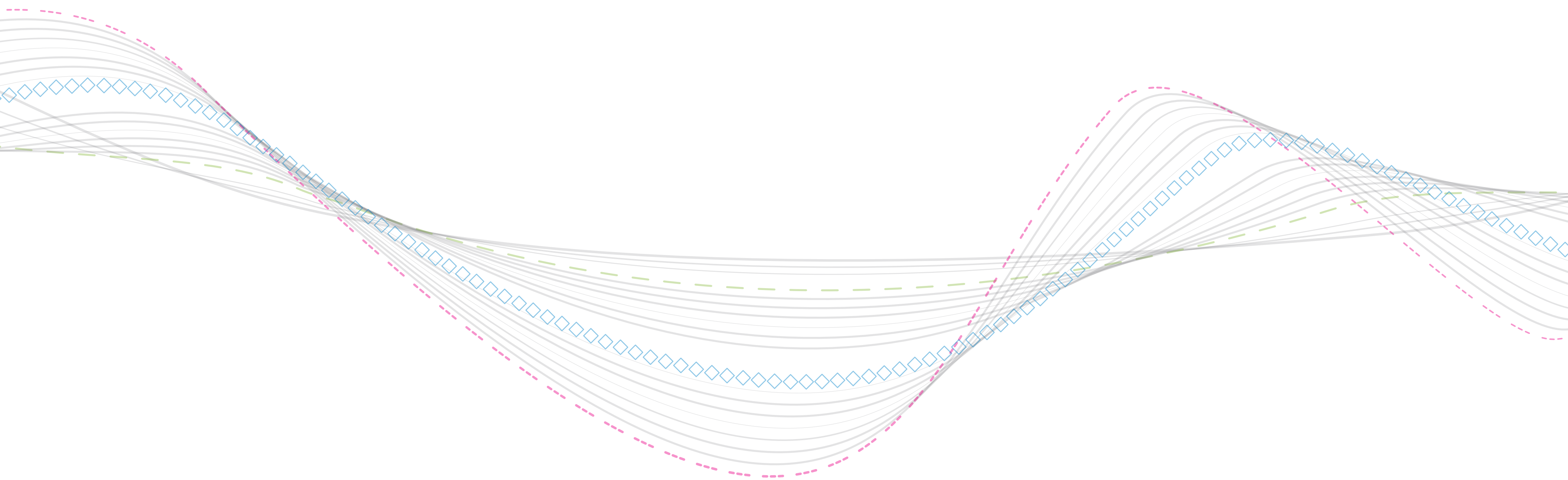
- Delivery years 2020 and beyond: Annual demand resources are assumed to become Capacity Performance demand resources and are based on actual cleared quantities of demand resource products in the 2020/2021 RPM Base Residual Auction.

- 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: http://pjm.com/~/media/documents/manuals/m19.ashx.

Table 1.4: 2018 Load Forecast Report Demand Resources

	Total Load Management	
Transmission Owner	2018	2028
Atlantic City Electric Company	110	57
Baltimore Gas and Electric Company	651	553
Delmarva Power and Light	304	257
Jersey Central Power and Light	125	130
Metropolitan Edison Company	227	232
PECO Energy Company	332	349
Pennsylvania Electric Company	247	282
PPL Electric Utilities Corporation	609	544
Potomac Electric Power Company	508	364
Public Service Electric and Gas Company	329	297
Rockland Electric Company	3	3
UGI	0	0
Mid-Atlantic	3,445	3,068
American Electric Power Company	1,503	961
Allegheny Power	686	688
American Transmission Systems, Inc.	775	645
Commonwealth Edison Company	1,332	1,442
Dayton Power and Light	173	152
Duke Energy Ohio and Kentucky	227	147
Duquesne Light Company	144	149
East Kentucky Power Cooperative	130	130
Western	4,970	4,314
Dominion Virginia Power	680	565
Southern	680	565
PJM RTO	**9,095**	**7,947**



Appendix 2: TO Zones and Locational Deliverability Areas

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

2.0: 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 2.1**. They are provided for the convenience of the reader based on definitions from other sources.

A transmission owner (TO) is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a TO. Schedule 15 of the Reliability Assurance Agreement defines the distinct zones that the PJM control area comprises and is available on the PJM website: http://www.pjm.com/directory/merged-tariffs/raa.pdf.

A Locational Deliverability Area (LDA) is an electrically cohesive area defined by transmission zones, parts of zones, or combination of zones. LDAs are used as part of PJM's RTEP process load deliverability test. They are restated in **Table 2.1**, below, for ease of reference.

Map 2.1: Locational Deliverability Areas

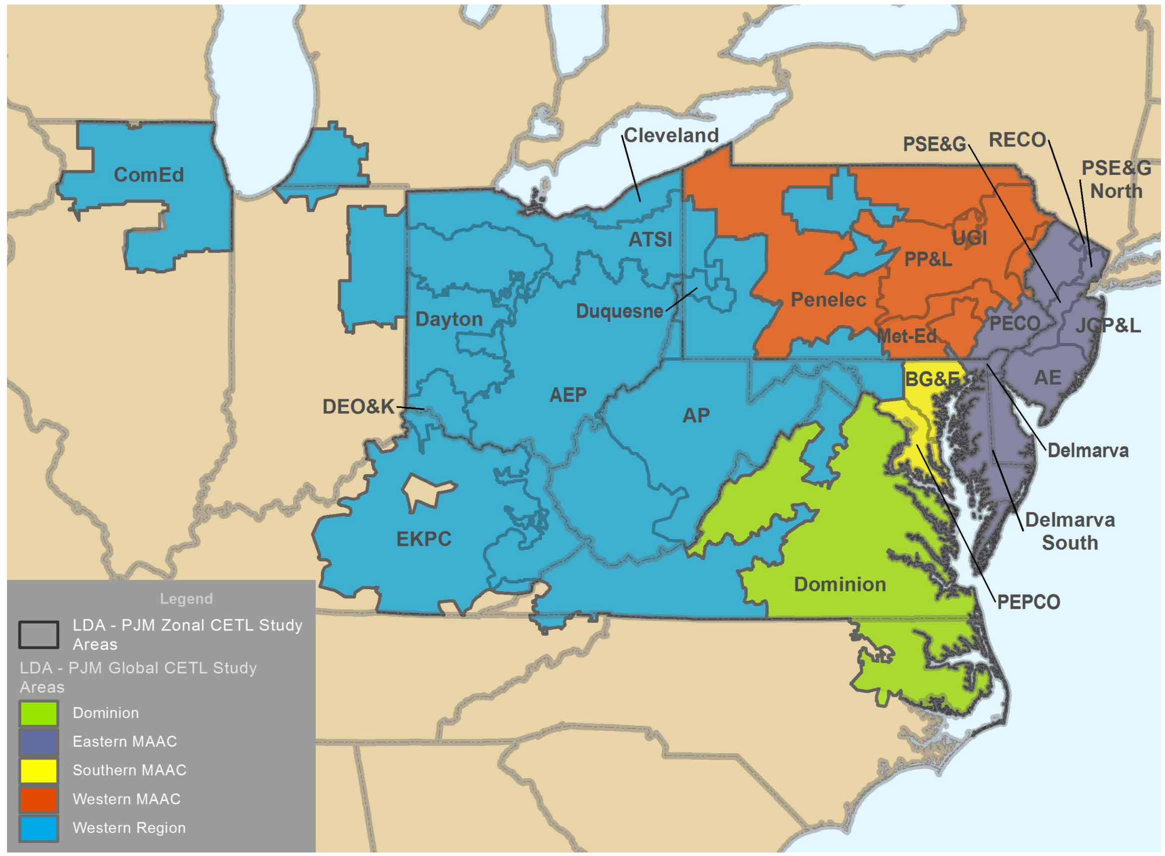


Table 2.1: Locational Deliverability Areas

Entity Name	TO Zone	LDA	Description
AE	▲	▲	Atlantic Electric
AEP	▲	▲	American Electric Power
APS	▲	▲	Allegheny Power
ATSI	▲	▲	American Transmission Systems, Incorporated
BGE	▲	▲	Baltimore Gas and Electric
Cleveland	n/a	▲	Cleveland Area
ComEd	▲	▲	Commonwealth Edison
DAYTON	▲	▲	Dayton Power and Light
DEO&K	▲	▲	Duke Energy Ohio and Kentucky
DLCO	▲	▲	Duquesne Light Company
Dominion	▲	▲	Dominion Virginia Power
DPL	▲	▲	Delmarva Power and Light
Delmarva South	n/a	▲	Southern Portion of DPL
Eastern Mid-Atlantic	n/a	▲	Global area – JCP&L, PECO, PSE&G, AE, DPL, RECO
EKPC	▲	▲	East Kentucky Power Cooperative
JCP&L	▲	▲	Jersey Central Power and Light
METED	▲	▲	Metropolitan Edison
Mid-Atlantic	n/a	▲	Global Area – Penelec, METED, JCP&L, PPL, PECO, PSE&G, BGE, PEPCO, AE, DPL, RECO
PECO	▲	▲	PECO
PENELEC	▲	▲	Pennsylvania Electric
PEPCO	▲	▲	Potomac Electric Power Company
PPL	▲	▲	PPL Electric Utilities Corporation, UGI
PSE&G	▲	▲	Public Service Electric and Gas
PSE&G North	n/a	▲	Northern Portion of PSE&G
Southern Mid-Atlantic	n/a	▲	Global area – BGE and PEPCO
Western Mid-Atlantic	n/a	▲	Global Area – Penelec, METED, PPL
Western PJM	n/a	▲	Global Area – APS, AEP, Dayton, DUQ, 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 – http://www.pjm.com/library/manuals.aspx
- NERC – North American Electric Reliability Council – http://www.nerc.com/
- OA – PJM Operating Agreement – http://www.pjm.com/media/documents/merged-tariffs/oa.pdf
- OATT – PJM Open Access Transmission Tariff – http://www.pjm.com/media/documents/merged-tariffs/oatt.pdf
- RAA – Reliability Assurance Agreement – http://www.pjm.com/media/documents/merged-tariffs/raa.pdf

Term	Reference	Acronym	Definition
Aluminum Conductor Steel Cable		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.

Term	Reference	Acronym	Definition
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.
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 in to 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 devices 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.

Term	Reference	Acronym	Definition
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 generally consists of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion Turbine		CT	A combustion turbine is a generating unit in which a combustion turbine engine is the prime mover.
Consolidated Transmission Owners Agreement	PJM.com	CTOA	The Consolidated Transmission Owners Agreement is an agreement between transmission owners, which PJM is a signatory to, establishing the rights and commitments of all parties involved.
Contingency			A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Coordinated System Plan		CSP	A Coordinated System Plan (CSP) contains the results of coordinated PJM/MISO studies required to assure the reliable, efficient and effective operation of the transmission system. The CSP also includes the study results for interconnection requests and long-term firm transmission service requests. Further description of CSP development can be found in the PJM/MISO Joint Operating Agreement.
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.

Term	Reference	Acronym	Definition
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.
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 type cease 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 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.

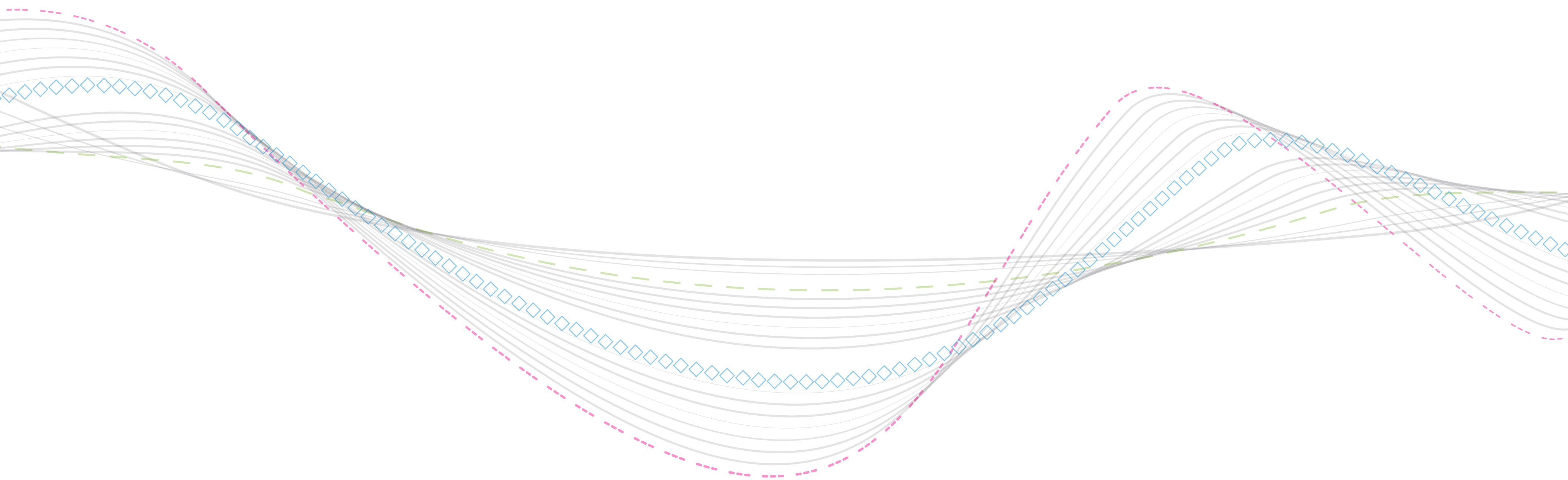
Term	Reference	Acronym	Definition
Horizontal Directional Drilling		HDD	Horizontal directional drilling technology for laying transmission cable employs a long, flexible drill bit to bore horizontally underground. This is a trenchless method in which no surface excavation is required except for drill entry and exit points, which minimizes surface restoration, ecological disturbances and environmental impacts. By contrast, jet-plowing techniques affect the riverbed over the length of the installation.
Independent State Agencies Committee	PJM.com	ISAC	The ISAC is a voluntary, stand-alone committee that consists of members from regulatory and other state agencies representing all of the states and the District of Columbia within the service territory of PJM. The ISAC is an independent committee that is not controlled or directed by PJM, the PJM Board or PJM members. The purpose of the ISAC is to provide PJM with input and scenarios for transmission planning studies.
Independent System Operator		ISO	An independent system operator is an entity that is authorized to operate an electric transmission system, and is independent of any influence from the owner(s) of that electric transmission system. See also “RTO.”
Installed Capacity		ICAP	Installed capacity is valued based on the summer net dependable rating of the unit as determined in accordance with PJM rules and procedures relating to the determination of generating capacity.
Interconnected Reliability Operating Limit	M14B	IROL	The interconnected reliability operating limit is a system operating limit that, if violated, could lead to instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk electric system.
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, 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 (DPL), Jersey Central Power and Light (JCPL), Metropolitan Edison Company (METED), Neptune, PECO Energy (PECO), Pennsylvania Electric Company (PENELEC), PEPCO, PPL Electric Utilities Corporation (PPL), Public Service Electric and Gas (PSE&G) 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 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.
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.

Term	Reference	Acronym	Definition
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 ensuring 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 Council (NERC) to become one of eight Regional Reliability Councils in North America and began operations on January 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.
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.

Term	Reference	Acronym	Definition
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.
Thyristor Controlled Series Compensator		TCSC	A thyristor controlled series compensator is a series capacitor bank that is shunted by a thyristor controlled reactor.

Term	Reference	Acronym	Definition
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 the 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.
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

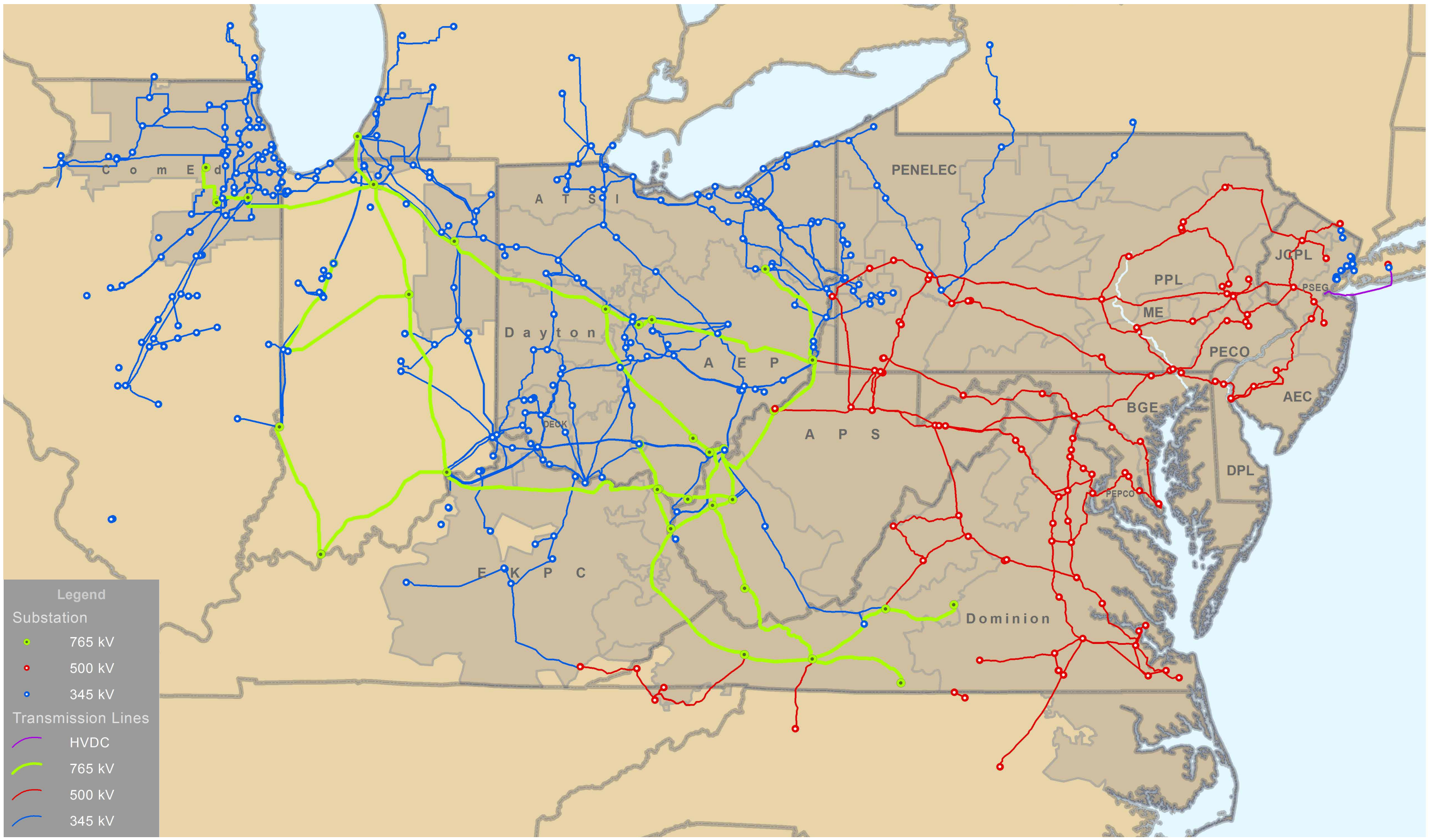


Figure 1.1: RTEP Process – RTO Perspective

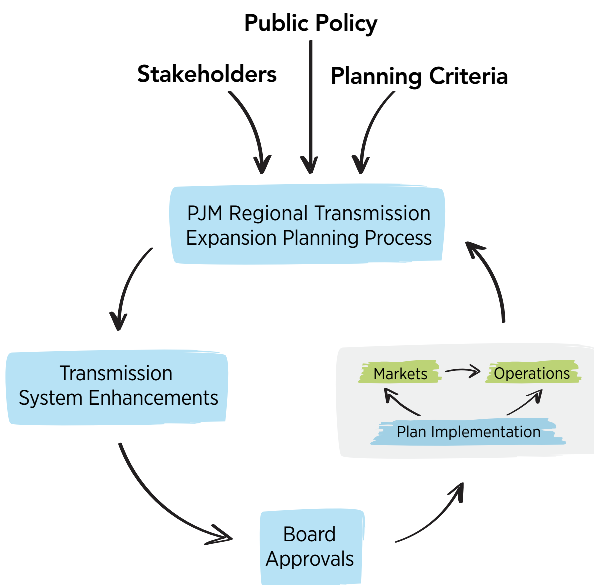


Figure 1.2: System Enhancement Drivers

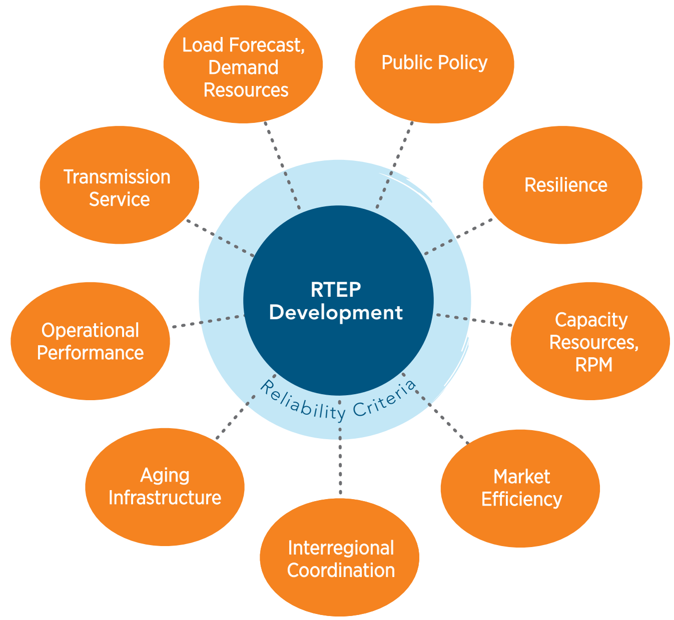
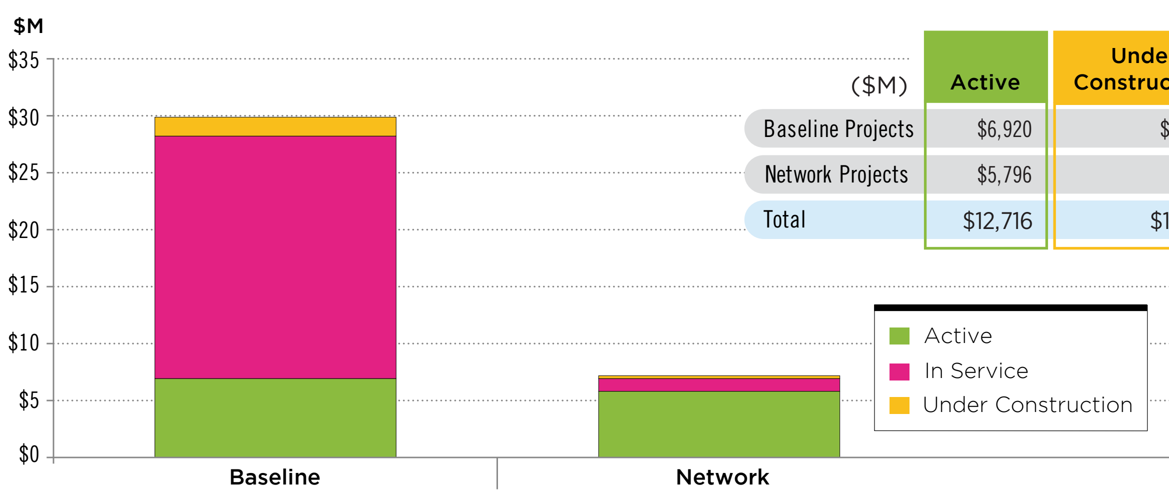


Figure 1.3: Approved RTEP Projects as of December 31, 2018



($M)	Active	Under Construction	In Service	Grand Total
Baseline Projects	$6,920	$1,659	$21,307	**$29,887**
Network Projects	$5,796	$244	$1,134	**$7,173**
Total	$12,716	$1,903	$22,441	$37,060

Figure 1.4: Approved Baseline Projects by Voltage 2015-2018

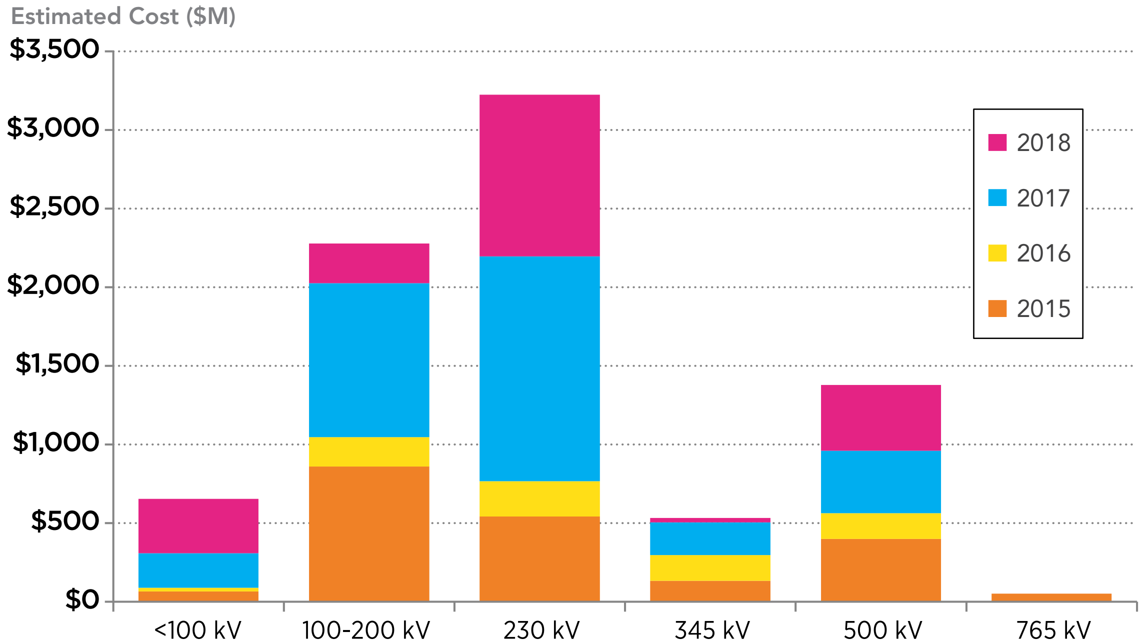


Figure 1.5: PJM Existing Installed Capacity Mix RPM Eligible Capacity (December 31, 2018)

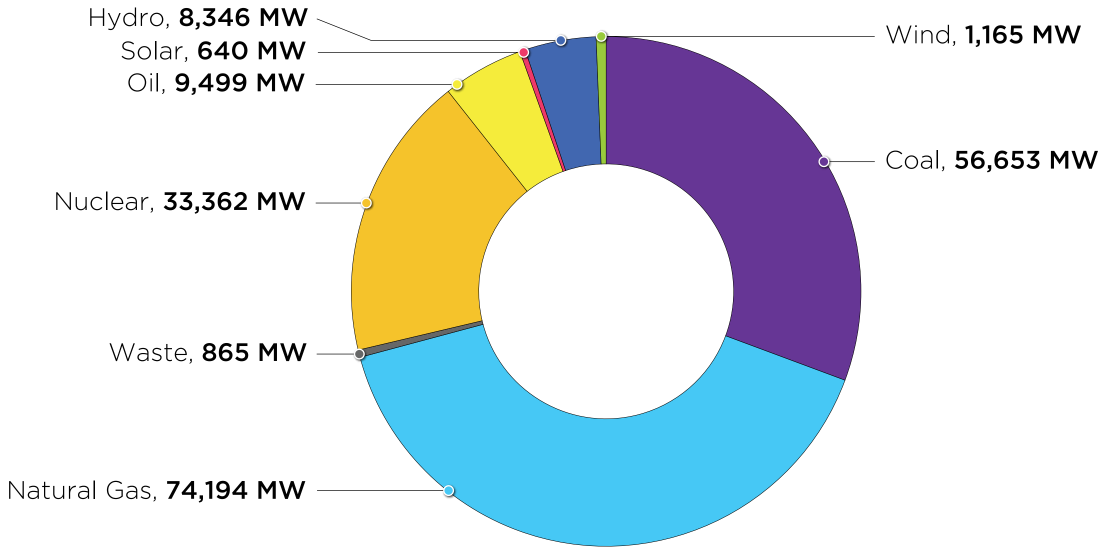


Figure 1.6: PJM Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (December 31, 2018)

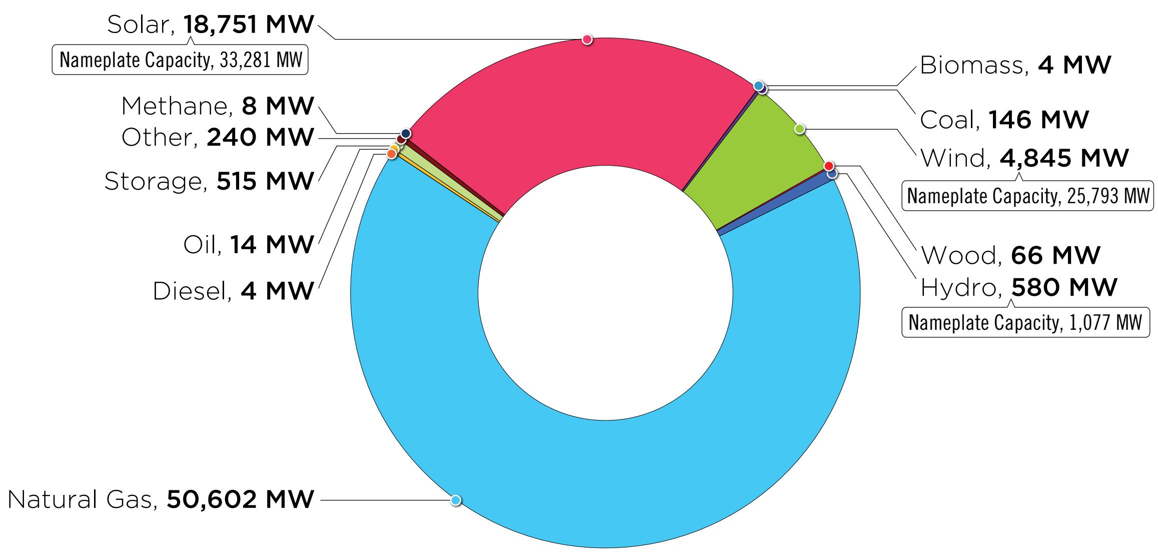


Table 1.1: Requested Capacity Interconnection Rights, Renewable Fuels (December 31, 2018)

	In Queue						Complete				Grand Total	
	Active		Suspended		Under Construction		In Service		Withdrawn			
	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW
Biomass	1	4.0	0	0.0	0	0.0	12	268.8	35	682.9	48	955.7
Hydro	4	517.4	0	0.0	4	62.2	29	1,208.5	44	1,876.4	81	3,664.5
Methane	1	0.8	0	0.0	3	7.4	92	436.0	95	488.1	191	932.3
Solar	422	17,341.0	32	171.3	77	1,239.0	146	704.5	990	14,466.8	1,667	33,922.6
Wind	77	3,948.8	10	174.3	32	722.3	84	1,555.4	427	12,046.2	630	18,446.9
Wood	0	0.0	1	16.0	1	50.0	1	4.0	3	137.0	6	207.0
Total	**505**	**21,812.0**	**43**	**361.5**	**117**	**2,080.8**	**364**	**4,177.3**	**1,594**	**29,697.4**	**2,623**	**58,129.0**

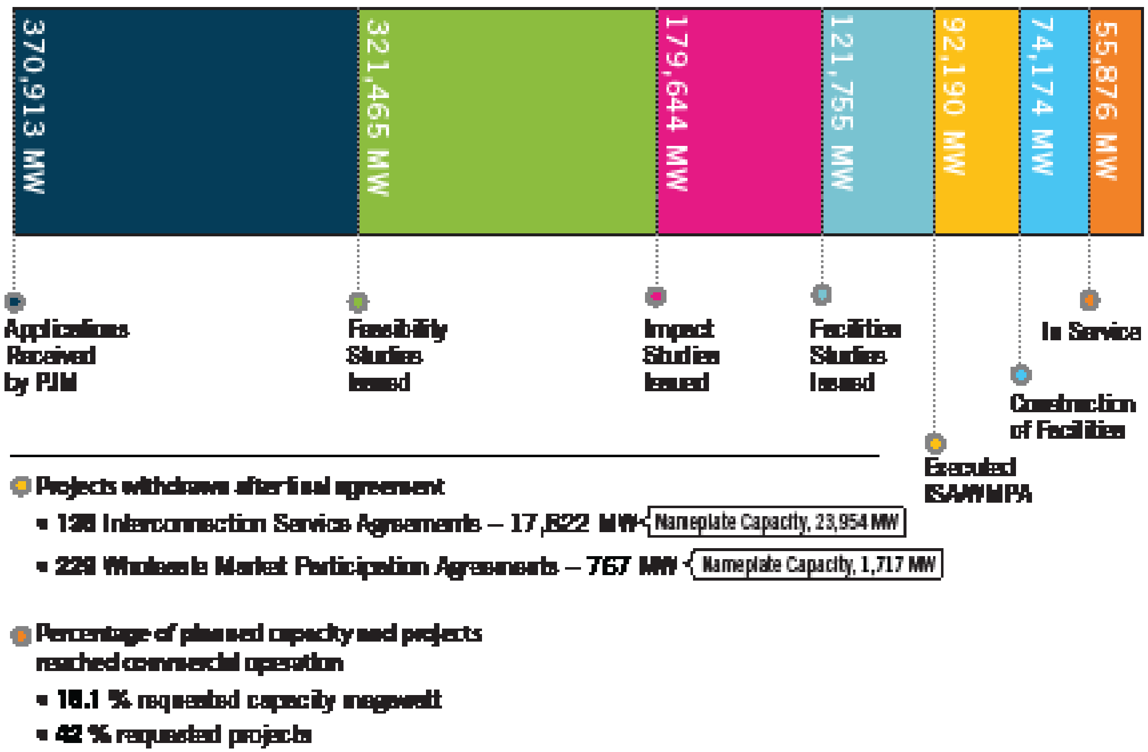
Table 1.2: Requested Capacity Interconnection Rights, Non-Renewable Fuels (December 31, 2018)

	In Queue						Complete				Grand Total	
	Active		Suspended		Under Construction		In Service		Withdrawn			
	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW	Number of Projects	Capacity, MW
Coal	2	29.0	0	0.0	5	117.2	59	2,182.2	69	33,537.6	135	35,866.0
Diesel	0	0.0	0	0.0	1	4.1	10	72.4	15	76.7	26	153.2
Natural Gas	108	31,034.2	18	4,019.4	50	15,548.6	292	40,713.1	599	220,820.2	1,067	312,135.5
Nuclear	8	125.4	0	0.0	1	44.0	43	3,881.6	18	8,988.0	70	13,039.0
Oil	1	14.0	0	0.0	0	0.0	18	539.8	22	2,300.0	41	2,853.8
Other	2	240.0	0	0.0	0	0.0	7	376.5	82	1,068.8	91	1,685.3
Storage	37	507.3	11	5.8	27	1.9	23	0.1	115	476.9	213	992.0
Total	**158**	**31,949.9**	**29**	**4,025.2**	**84**	**15,715.8**	**452**	**47,765.7**	**920**	**267,268.2**	**1,643**	**366,724.8**

Table 1.3: Queue Status Totals (December 31, 2018)

Status	Number of Projects	Requested Capacity Interconnection Rights (MW)	Nameplate Capability (MW)
Active	663	53,762	85,430.5
In Service	816	51,943	61,128.0
Under Construction	201	17,797	23,433.9
Suspended	72	4,387	6,089.3
Withdrawn	2,508	296,739	368,341.9
Total	**4,260**	**424,627**	**544,423.5**

Figure 1.7: Queued Generation Progression – Requested Capacity Rights (December 31, 2018)



NOTE:

A Wholesale Market Participant Agreement (WMPA) is executed among PJM, the generator owner and the TO if the transmission facility to which a generator seeks interconnection is not FERC jurisdictional. This is frequently the case with generators connecting at the distribution level voltages on facilities over which FERC does not have jurisdiction.

Map 1.2: PJM Generator Deactivations Received January 1, 2018 through December 31, 2018

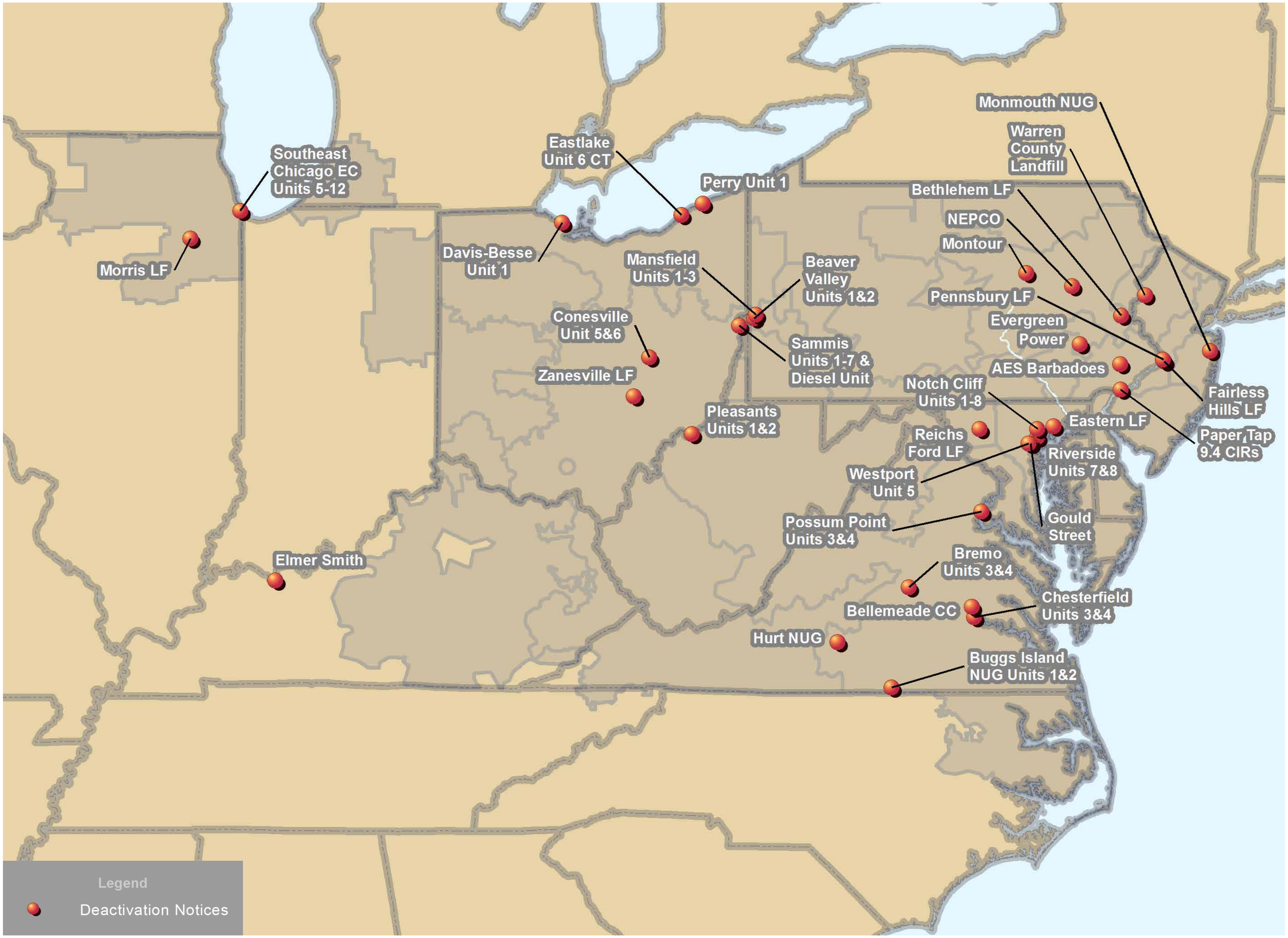


Figure 1.8: 2018 RTEP Baseline Projects by Driver

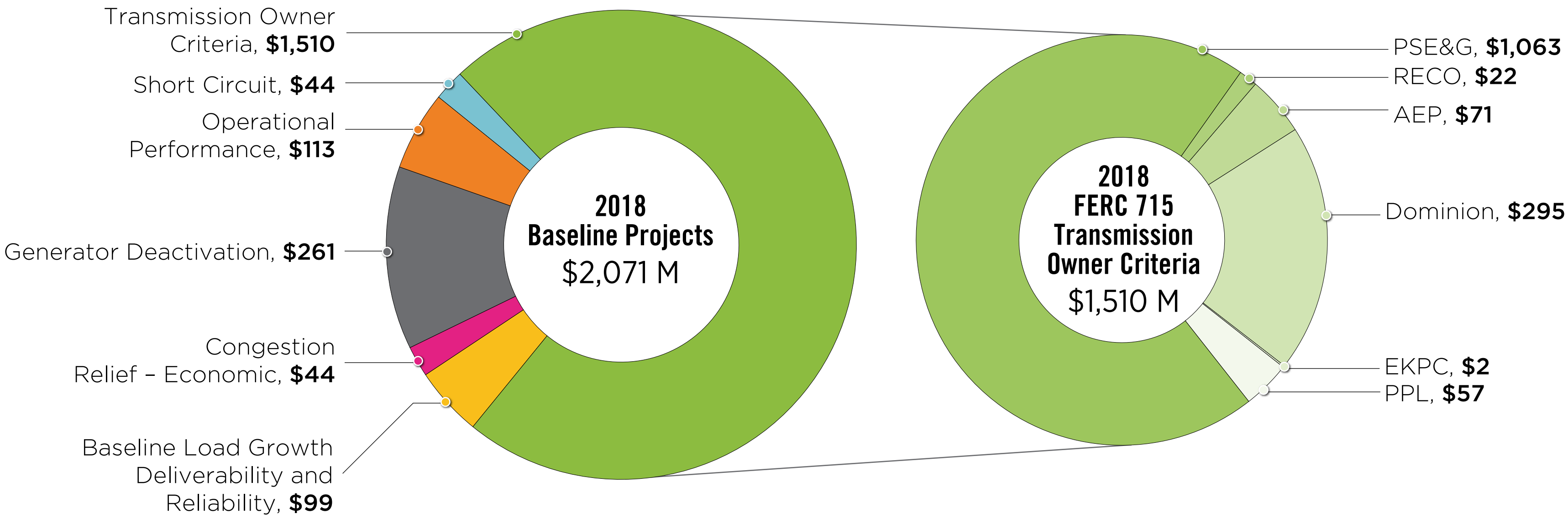


Figure 1.9: Attachment M3 Process for Supplemental Projects

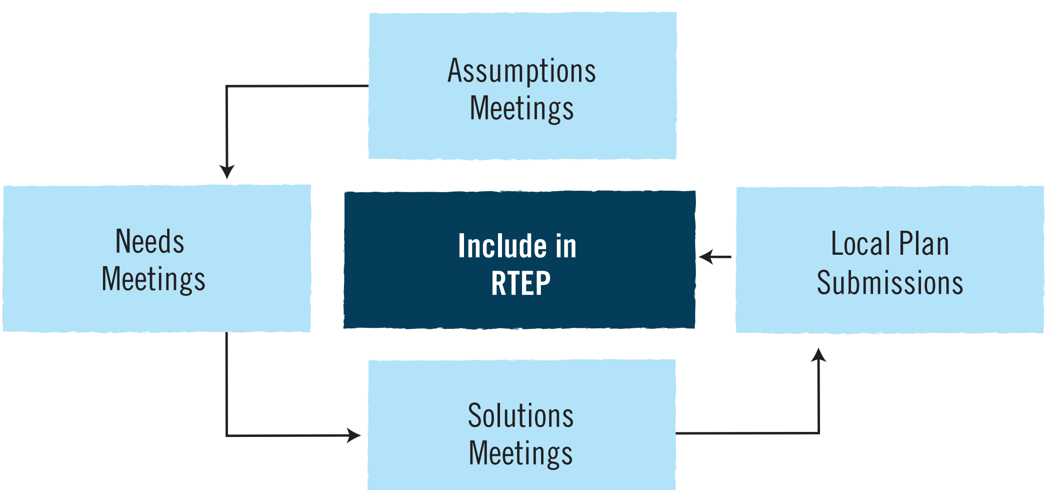
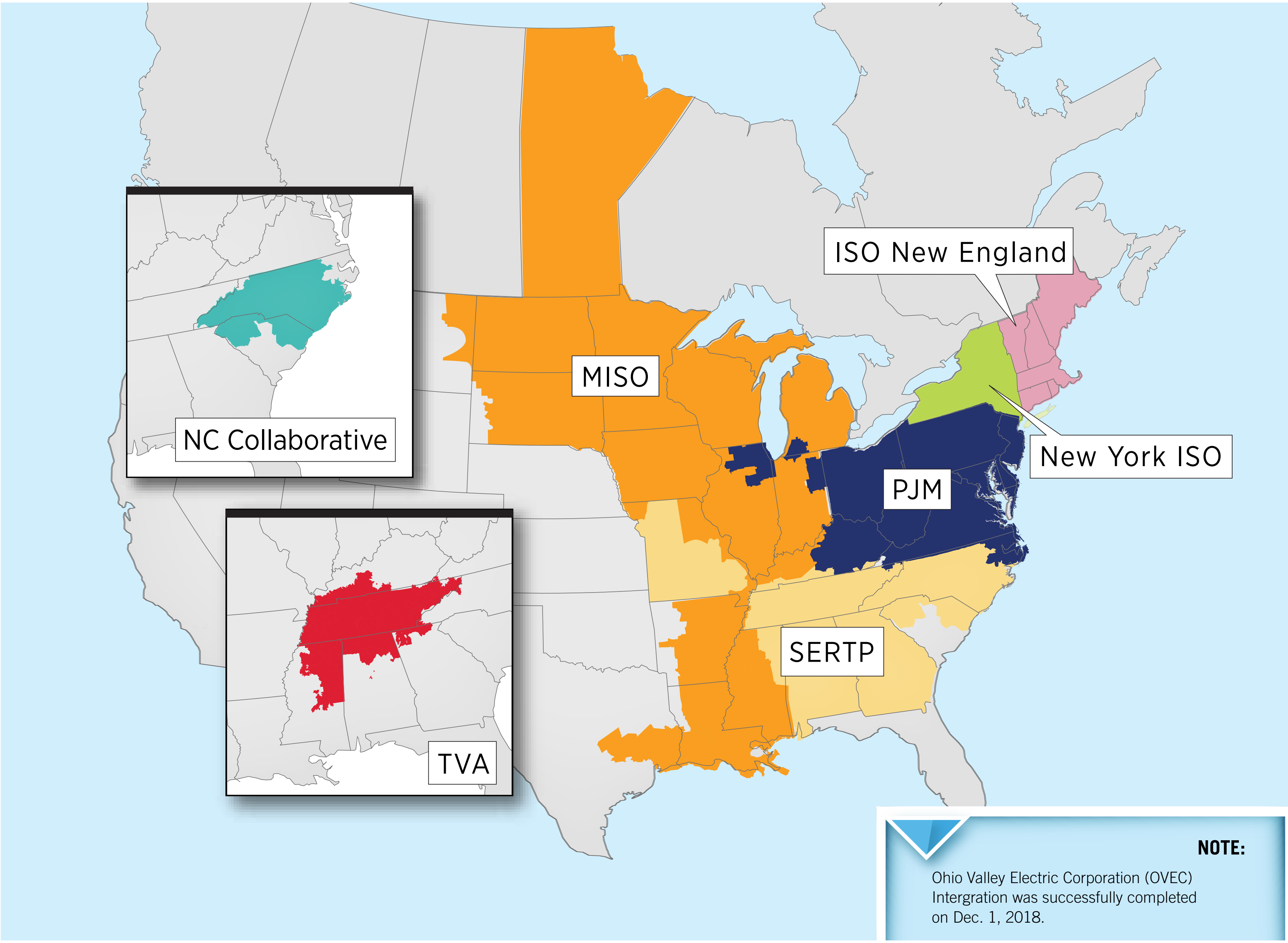


Figure 1.10: Market Efficiency 24-Month Cycle

Map 1.3: PJM Interregional Planning



NOTE:

Ohio Valley Electric Corporation (OVEC) Intergration was successfully completed on Dec. 1, 2018.

Figure 1.11: Targeted Market Efficiency Project Study Results—Congestion Cost

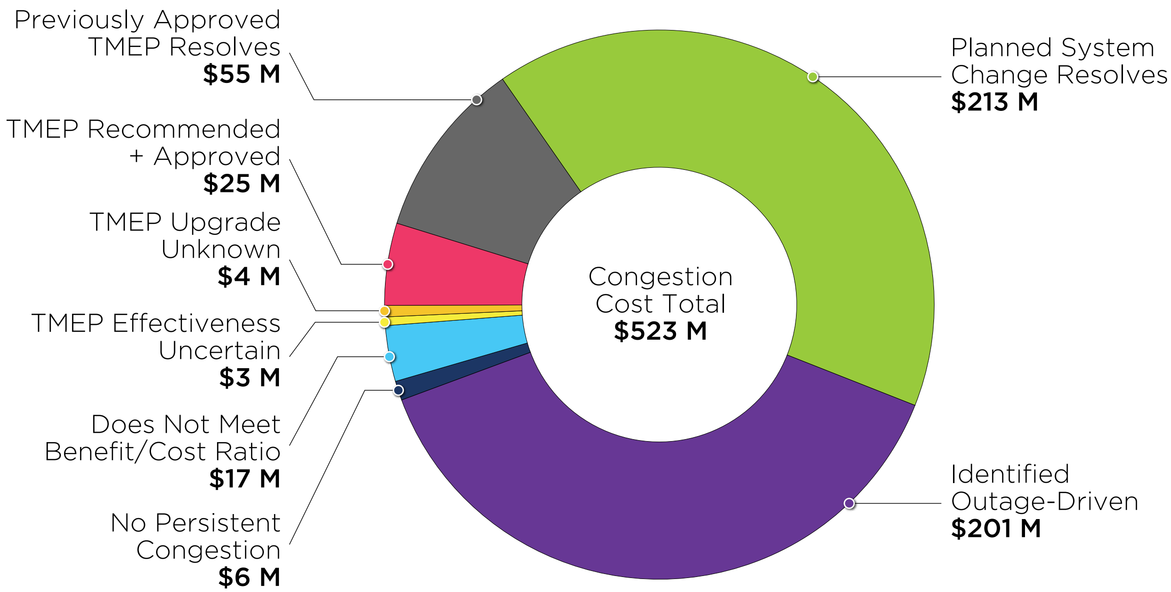


Figure 1.12: Interregional Market Efficiency Project Study Timeline

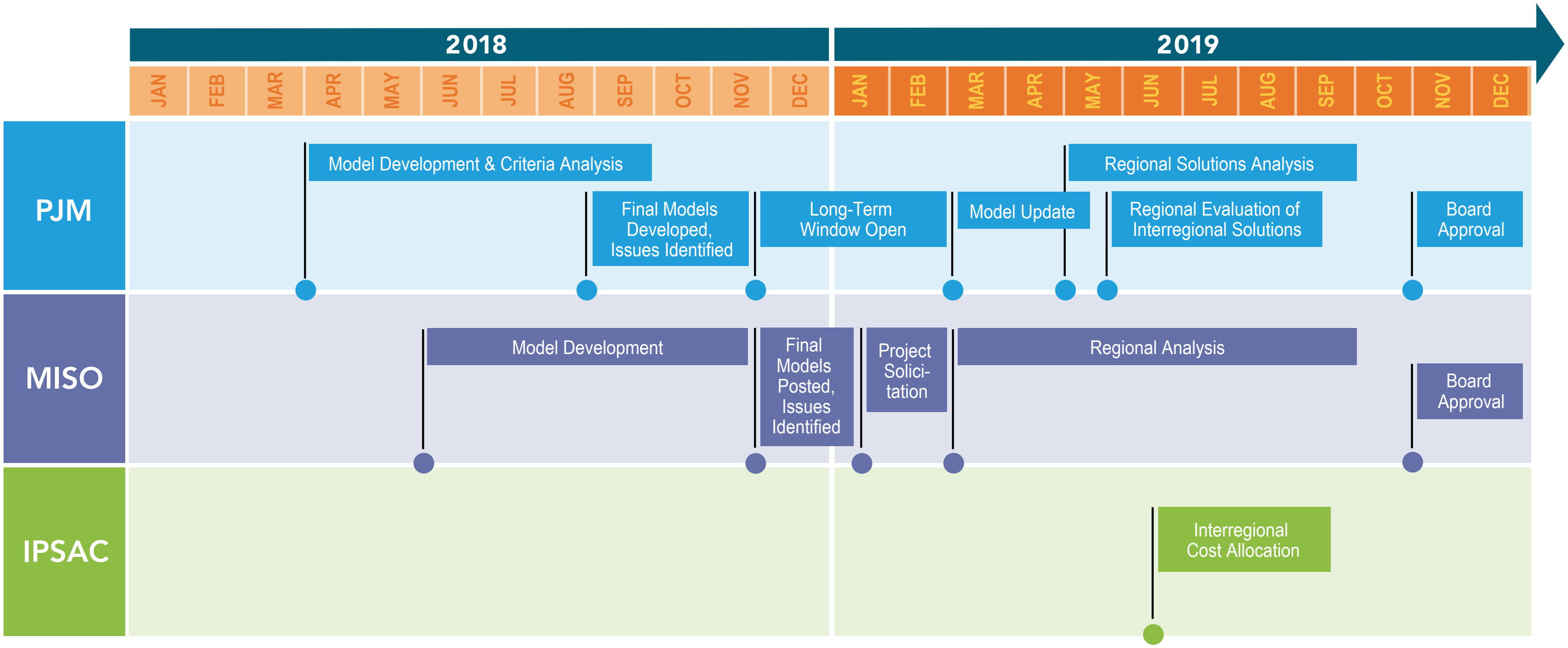


Figure 1.13: Summer Peak Load Forecast 2018 vs. 2017

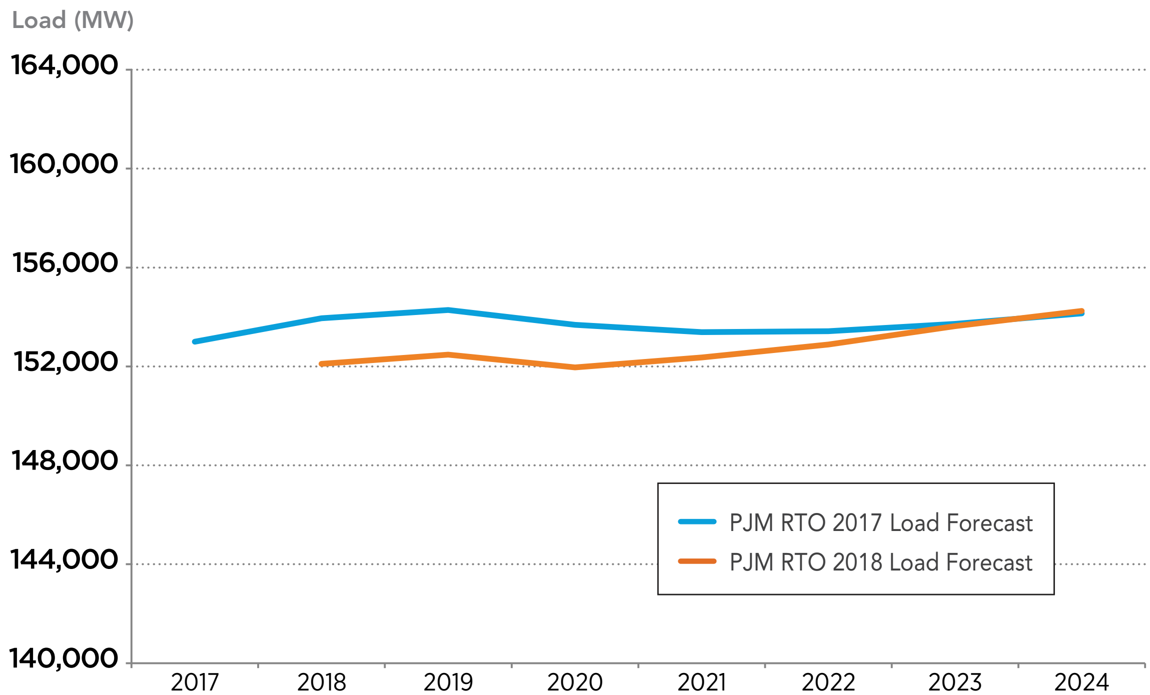
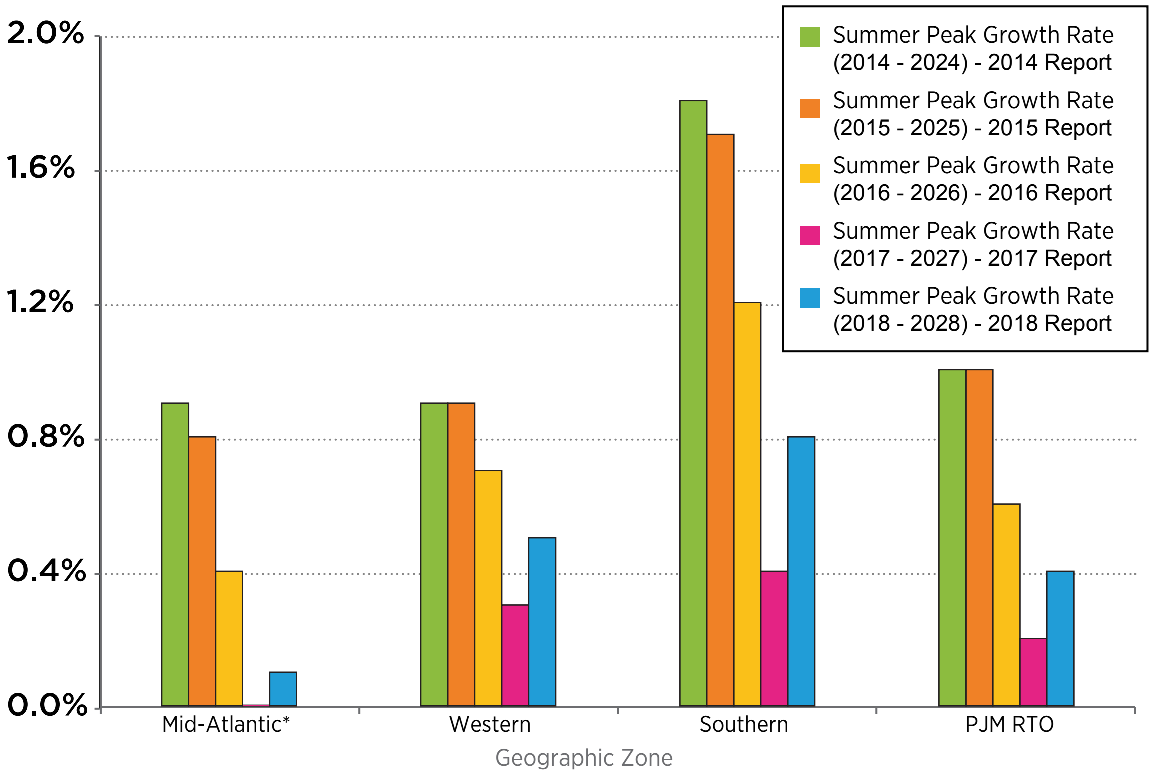


Table 1.4: 2018 Load Forecast Report

	Summer Peak (MW)			Winter Peak (MW)		
Transmission Owner	2018	2028	Growth Rate (%)	2017/2018	2027/2028	Growth Rate (%)
Atlantic City Electric Company	2,460	2,409	-0.2%	1,589	1,537	-0.3%
Baltimore Gas and Electric Company	6,848	6,744	-0.2%	5,883	5,956	0.1%
Delmarva Power and Light	3,937	4,018	0.2%	3,443	3,578	0.4%
Jersey Central Power and Light	5,942	5,943	0.0%	3,720	3,681	-0.1%
Metropolitan Edison Company	2,974	3,115	0.5%	2,607	2,697	0.3%
PECO Energy Company	8,642	8,979	0.4%	6,752	6,881	0.2%
Pennsylvania Electric Company	2,895	2,922	0.1%	2,866	2,875	0.0%
PPL Electric Utilities Corporation	7,140	7,350	0.3%	7,211	7,343	0.2%
Potomac Electric Power Company	6,493	6,466	0.0%	5,383	5,534	0.3%
Public Service Electric and Gas Company	9,903	9,876	0.0%	6,655	6,626	0.0%
Rockland Electric Company	402	402	0.0%	230	229	0.0%
UGI	190	188	-0.1%	194	188	-0.3%
Diversity - Mid-Atlantic	-1,225	-1,086		-582	-494	
Mid-Atlantic	56,601	57,326	0.1%	45,951	46,631	0.1%
American Electric Power Company	22,876	24,018	0.5%	22,447	23,600	0.5%
Allegheny Power	8,825	9,447	0.7%	8,789	9,536	0.8%
American Transmission Systems, Inc.	12,952	13,309	0.3%	10,687	10,942	0.2%
Commonwealth Edison Company	22,121	23,207	0.5%	15,714	16,329	0.4%
Dayton Power and Light	3,459	3,508	0.1%	2,917	2,932	0.1%
Duke Energy Ohio and Kentucky	5,523	5,860	0.6%	4,478	4,705	0.5%
Duquesne Light Company	2,872	2,924	0.2%	2,153	2,175	0.1%
East Kentucky Power Cooperative	1,960	2,033	0.4%	2,587	2,693	0.4%
Diversity – Western	-1,540	-1,522		-1,316	-1,351	
Western	79,048	82,784	0.5%	68,456	71,561	0.4%
Dominion Virginia Power	19,596	21,161	0.8%	18,096	19,769	0.9%
Southern	19,596	21,161	0.8%	18,096	19,769	0.9%
Diversity – RTO	-3,137	-3,636		-1,040	-1,259	
PJM RTO	**152,108**	**157,635**	**0.4%**	**131,463**	**136,702**	**0.4%**

Figure 1.14: PJM 10-Year Summer Peak Load Growth Rate Comparison: 2014-2018 Load Forecast Reports



*PJM's Mid-Atlantic Summer Peak Growth Rate for 2017-2027 is forecasted to be at 0.0%