3 PERSPECTIVES

Reliability

Economy

Environment

>82,546 MILES of transmission lines

Collaboration with over 1,000 members

15-YEAR LONG-TERM HORIZON

IMPACTS 65+ million people

PJM dispatches more than 176,560 MW of generation capacity

+ DC

13 STATES

2017 RTEP PROCESS SCOPE AND INPUT ASSUMPTIONS

WHITE PAPER

pjm®

WORKING TO PERFECT THE FLOW OF ENERGY

AUGUST 3, 2017 (REV 1)

Table of Contents

Preface

This white paper describes RTEP process assumptions, scope and input data to be applied to the baseline, market efficiency, new service request and scenario studies that PJM will conduct during 2017. PJM will continue to overlay baseline and market efficiency studies with RTEP process windows during which transmission developers may submit proposals to solve identified issues.

RTEP Process Description

In addition to this white paper, the online resources noted below provide additional description of RTEP process business rules and methodologies:

- PJM Manuals 14A through 14E contain the specific business rules that govern RTEP Process: http://www.pjm.com/library/manuals.aspx.

- Schedule 6 of the PJM Operating Agreement codifies the overall provisions under which PJM implements its Regional Transmission Expansion Planning protocol, more familiarly known as the PJM RTEP process. The PJM Operating Agreement can be found via the following link: http://www.pjm.com/directory/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 can be found via the following link: http://www.pjm.com/directory/merged-tariffs/oatt.pdf.

- The status of individual PJM Board-approved baseline and network RTEP projects, as well as that of TO supplemental projects, can be found on PJM's website: http://www.pjm.com/planning/rtep-upgrades-status/construct-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. It also reviews 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 accessible from PJM's website: http://www.pjm.com/committees-and-groups/committees/pc.aspx.

Transmission Expansion Advisory Committee 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 accessible from PJM's website: http://www.pjm.com/committees-and-groups/committees/teac.aspx.

Each subregional RTEP committee provides a forum for stakeholders to discuss more local planning concerns. Interested stakeholders can access subregional RTEP committee planning process information from PJM's 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 RTEP study assumptions and scenarios. Additional information is available on PJM's website: http://www.pjm.com/committees-and-groups/isac.aspx.

White Paper Structure

Section 2 outlines PJM's 24-month cycle which includes two conventional twelve month bodies of work that focus on system needs five years forward. The study cycle also includes a parallel 24-month analysis that considers the need for longer lead-time backbone transmission facilities.

Section 3 discusses PJM's January 2017 load forecast as the basis for modeling power flow case bus loads.

Section 4 goes on to summarize the electrical topology, generation scenario, and interchange modeled in power flow cases.

Section 5 describes the scope of the baseline analyses to be conducted by PJM in 2017.

Section 6 describes market efficiency input parameters and study methodologies.

Section 7 provides an overview of PJM's new services processes for generation interconnection, merchant transmission interconnection, merchant network upgrade, long-term firm transmission service, and incremental auction revenue rights requests.

Section 8 addresses interregional activities with adjoining systems and scenario studies during 2017.

A **Glossary** at the end of the white paper provides definitions for terminology used within the document.

Errata

- p. 33, **Section 4.2** text corrected to indicate proper sign convention.

- p. 47, **Table 5.3** corrected for Monitored Facility assumptions.

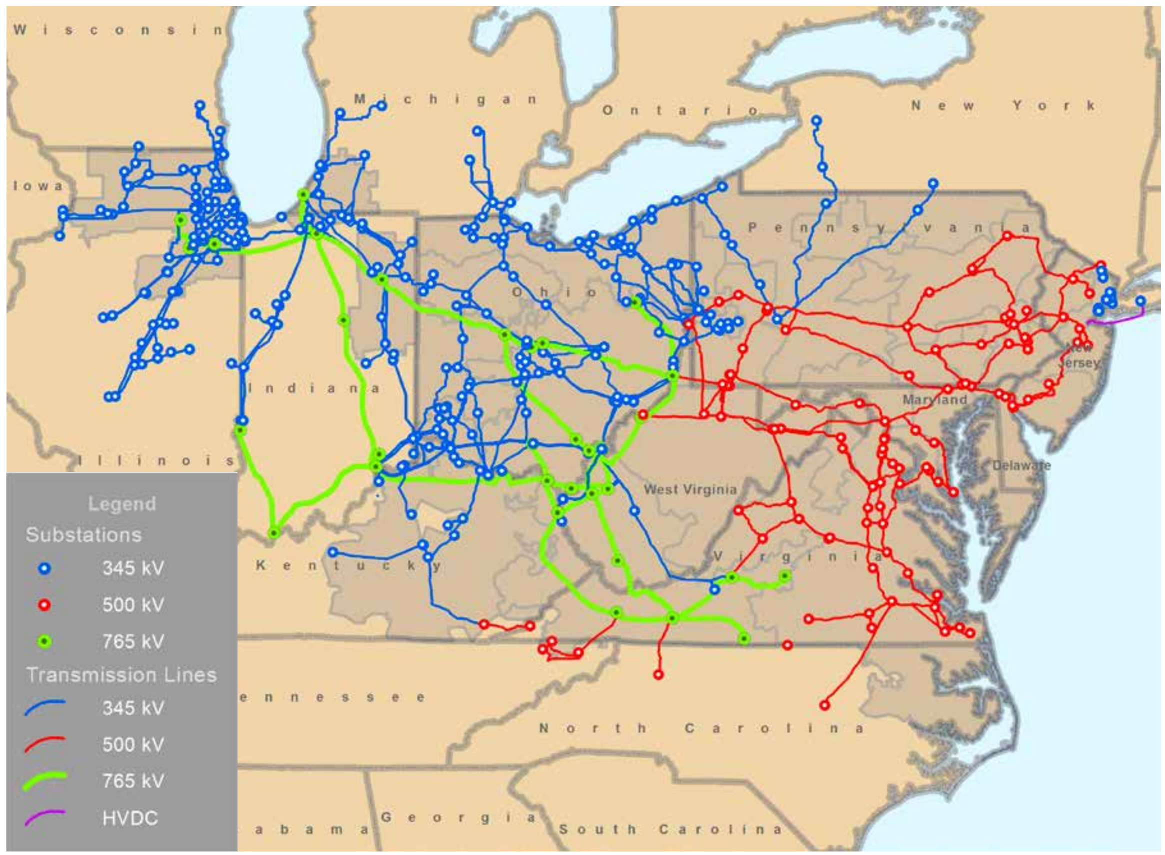
Section 1– RTEP Process Overview

1.0: RTO Perspective

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's 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 access to PJM's regional power markets as well as those of adjoining systems. Collaborating with more than 1,000 members, PJM dispatches more than 176,560 MW of generation capacity over 82,540 miles of transmission lines.

Map 1.1: PJM Backbone Transmission System

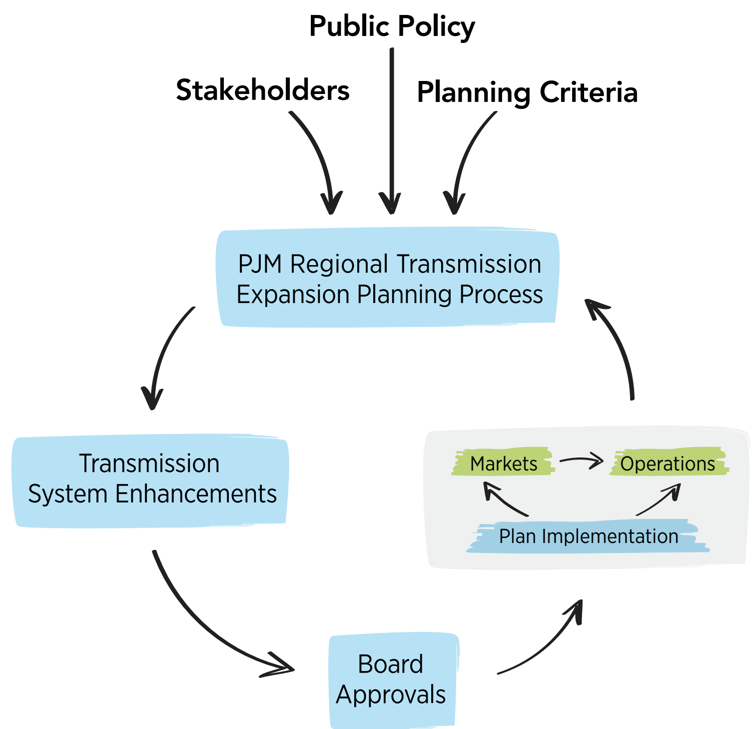


PJM's RTEP process spans state boundaries shown in **Map 1.1** in the broader context of the RTO functions shown in **Figure 1.1**. Doing so gives PJM the ability to identify one optimal, comprehensive set of solutions to resolve reliability criteria violations, operational performance issues and congestion 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 previously approved projects if expected system conditions have changed such that justification no longer exists.

RTEP Process Windows

As described in **Section 2.1**. 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 opportunity for non-incumbent transmission developers to submit project proposals to PJM for consideration. The scope and timing of the issue to be addressed and likely type of solutions to be submitted dictate window duration. 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.

Figure 1.1: RTEP Process – RTO Perspective



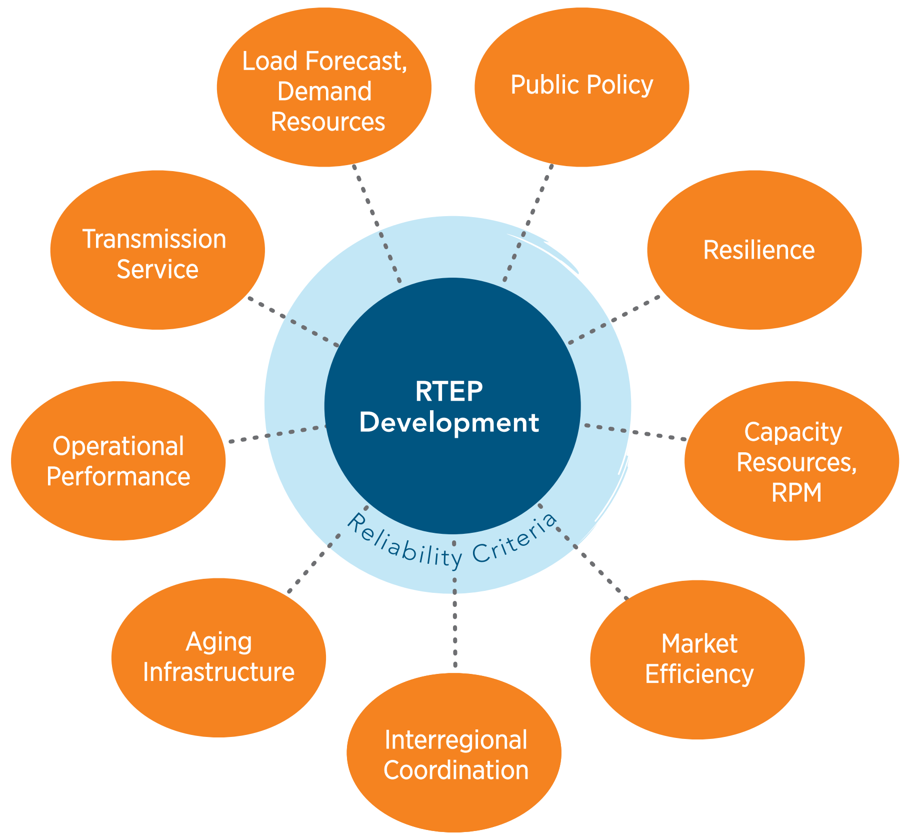
1.1: System Enhancement Drivers

A 15-year long-term planning horizon allows PJM to consider the aggregate effects of many factors, shown in **Figure 1.2**. Initially, beginning with its inception in 1997, PJM's RTEP consisted mainly of system enhancements driven by load growth and generating resource interconnection requests. Today, PJM's RTEP process considers the interaction of many system enhancement drivers including those arising out of federal and state public policy.

Reliability Criteria Violations

PJM's RTEP process encompasses a comprehensive assessment of system compliance with the thermal, reactive, stability and short-circuit NERC Standard TPL-001-4 events P0 through P7 as described in **Section 5.0.** The relationship between a reliability criteria violation and transmission project location generally takes one of two forms. Reliability criteria violations in a given Transmission Owner zone may be driven by a local issue in that same zone. For example, local load growth may drive local transformer loadings and, thus, be the potential cause of future overloads. Also, reliability criteria violations in one or more Transmission Owner zones may be driven by some combination of regional factors including those potentially arising some distance away. Transmission projects that improve reliability can also improve economics and vice versa.

Figure 1.2: System Enhancement Drivers



Market Efficiency

The RTEP process also examines market efficiency to identify transmission enhancements that relieve congested facilities, allowing lower cost power to flow to consumers. From a process perspective the goal is to accomplish one or more of the following objectives:

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

Such projects, originally identified to resolve reliability criteria violations, may be designed in a more robust manner to provide economic benefit as well. PJM identifies the economic benefit of proposed transmission projects by conducting production cost analyses. Simulations show the extent to which congestion is mitigated by the project for given transmission topologies and generation dispatch. Benefit metrics compare future year simulation congestion results with and without proposed transmission enhancements. The set of metrics and methods used to determine economic benefit are described in **Section 6**.

Operational Performance

Under Schedule 6, Section 1.5 of the PJM Operating Agreement, PJM may also identify transmission enhancements to address system limitations encountered during real-time operations, often under recurring, similar system conditions. To that end, PJM planners meet with operations staff several times each year to assess the need for transmission enhancement plans that would address identified thermal, reactive, stability and other issues. This was the case, for example, for the past several years under light load conditions during which operators experienced high voltage alarms. Additional studies replicating operating conditions revealed that reactors were needed in certain areas of PJM to resolve the issue.

Scenario Studies

For the first ten years following the inception of the RTEP process in 1997, PJM generally found that the magnitude of uncertainty regarding future system conditions driving transmission need was mainly limited to that associated with load growth and generation interconnection requests. RTEP process tests could reasonably define the expected date of future reliability violations with minimal risk of fluctuation. That has changed in many respects in more recent years. A single set of summer peak load baseline and market assumptions are simply not sufficiently flexible to assess the full extent and degree to which system drivers impact transmission need. Scenario studies also permit PJM to evaluate potential system conditions driven by factors outside its immediate sphere. Such studies provide valuable long-term expansion planning insights beyond those obtained from conventional baseline and market efficiency analyses.

Interregional Studies

PJM has engaged in successful, collaborative interregional studies for decades, many under the auspices of NERC. In recent years, PJM's interregional planning responsibilities have grown in parallel with the evolution of broader organized regional markets and interest at the state and federal level in favor of increased interregional coordination. As described in **Section 8.0**, under each interregional agreement, coordinated planning includes assessment of current operations to ensure that critical cross-border interface issues are identified and addressed before they impact system reliability or dilute effective market administration.

Interregional reliability and economic efficiency issues span large parts of the U.S. and comprise a key part of broader public policy discussions. Previous planning cycle focus on large-scale integration of wind and other renewable resources. That has broadened to include transmission planning effects of gas and electric infrastructure and the impacts of environmental regulations. Interregional efforts have also begun to focus on smaller, incremental system enhancements along common seams. Doing so increases system efficiency by addressing congestion issues of common concern with transmission projects that can be implemented in the near term.

Considering Multiple Drivers

PJM's RTEP process provides the flexibility to develop more efficient, cost-effective projects justified on the basis of multiple drivers – resolving reliability violation solutions, promoting market efficiency by resolving economic constraints and advancing public policy requirements. Much of the multi-driver concept falls within the context of PJM's FERC-approved state agreement approach and how to incorporate the voluntary nature of a public policy driver component within this context.

RTEP projects will likely continue to be driven primarily by reliability criteria violations. Others will continue to be approved based on market efficiency criteria. Some additional number of RTEP projects that provide a combination of benefits may suggest a greater scope than required to satisfy any one driver individually, and provide opportunities for economic efficiency. Future expansion of the multi-driver approach may also consider system needs driven by interconnection queue requests, aging infrastructure and grid resilience.

Regardless, multi-driver projects present challenges in terms of timing, certainty, state buy-in and cost allocation. Initial in-service dates must consider the onset of reliability criteria violations, the value of market efficiency benefits, the value of renewable energy delivery benefits, the uncertainty around planning process load and resource assumptions, and project construction lead time.

Section 2 – 2017 Planning Cycle

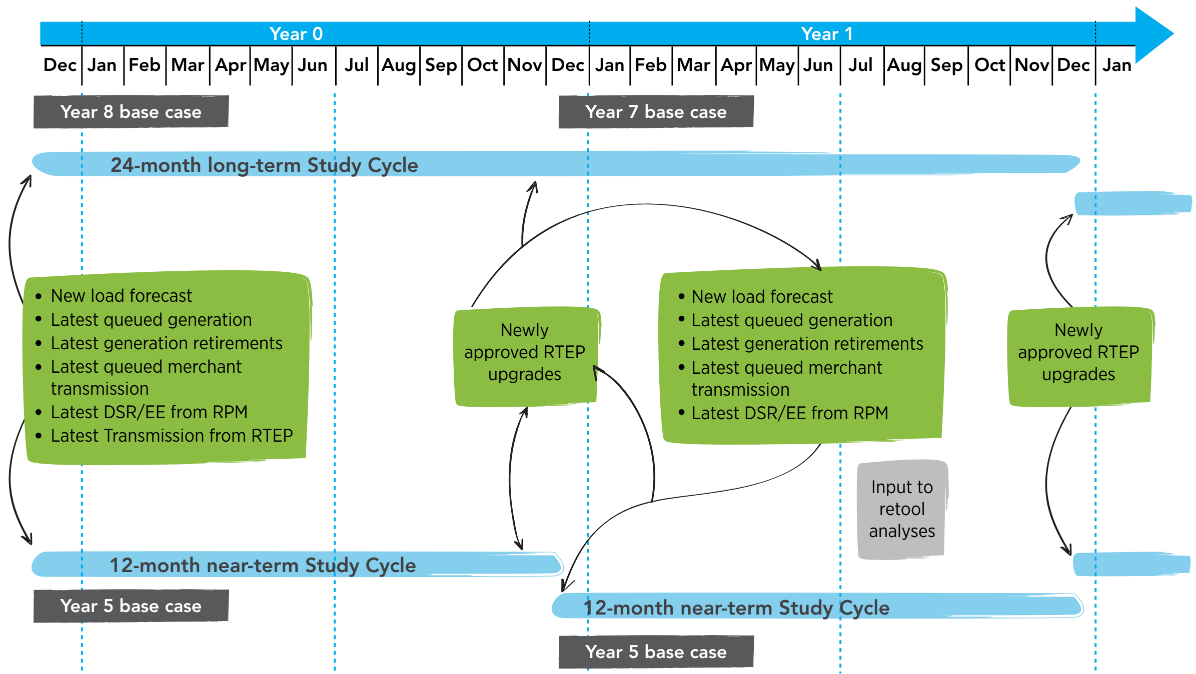
2.0: 24-Month Process

PJM's RTEP process encompasses a two-year cycle in coordination with the PJM Transmission Expansion Advisory Committee (TEAC), subregional RTEP committees and PJM Planning Committee. PJM has continued to expand and enhance the process in response to stakeholder and regulatory input, as defined in PJM's Operating Agreement Schedule 6, Open Access Transmission Tariff and Manual 14 series. In compliance with NERC Transmission Planning Reliability Standards, PJM's 24-month planning process – shown in **Figure 2.1** – includes the following:

- Two 12-month cycles, each of which examines the near-term need (years one through five) for transmission expansion plans.
- One 24-month cycle, which examines the long-term need (15 years forward) for transmission expansion plans.

Those study cycles drive power flow model development. Credible, consistent power flow study results ensure that PJM can develop robust transmission solutions to identified reliability criteria violations. To accomplish this, each study cycle begins with baseline analysis performed on a power flow case model that includes the latest information and assumptions with respect to zonal load forecasts, generating resources, transmission topology, demand resources and power transfer levels with adjoining systems (known also as interchange). PJM vets those assumptions with stakeholders at TEAC and subregional RTEP committee meetings. PJM Manual 14B, Attachment H provides more specific detail: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

Figure 2.1: RTEP Process Base Case Development



Note

PJM and its stakeholders are currently considering implementation of overlapping 18-month planning cycles beginning each September 1 as part of ongoing RTEP process improvement efforts.

This 24-month planning process identifies system enhancements based on a number of studies: baseline, new service including generation interconnection, generation retirement, market efficiency and operational performance. These studies are conducted consistent with established NERC, regional and transmission owner criteria. Proposed system enhancements are reviewed with stakeholders through the activities of the TEAC and recommended to the PJM Board for approval.

Conducting 2017 Studies

Consistent with established practice, the first step in PJM's 2017 RTEP process baseline analysis was to develop a set of study assumptions and related power flow cases. Assumptions were vetted with stakeholders at TEAC and subregional RTEP committee meetings. **Section 3** discusses PJM's January 2017 load forecast – including the impact of demand resources, solar and other parameters – as the basis for modeling power flow case bus loads. **Section 4** goes on to describe specific power flow case development: electrical topology, new generation, retiring generation and power transfer levels with adjoining systems – known as interchange. PJM Manual 14B, Attachment H provides more specific detail regarding the power system modeling data used to create RTEP base cases: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

Five-year out, 2022 study year baseline analysis completed as part of the 12-month planning cycle will test all bulk electric system (BES) facilities against applicable reliability planning criteria. A five-year forward approach provides sufficient lead time to complete transmission enhancement construction to solve identified reliability criteria violations.

The baseline system that emerges from this process – with transmission solutions that solve reliability criteria violations – becomes the basis for studies conducted to evaluate subsequent generation interconnection and other queued requests for new service. PJM will also conduct analysis on retooled base cases for years 2018 through 2021 as anticipated system conditions may warrant.

In parallel, 2017 marks Year 1 of the two-year (24-month) cycle shown in **Figure 2.1** based on system conditions expected in Year 7 (2024). In 2018, PJM will look at the Year 0 piece of the next 24-month cycle. This process permits PJM to complete studies in 2017 and to validate 2016 Year 0 findings as part of full alternating current power flow and linear analysis to determine BES facility loadings on facilities for years six through 15. Such long-term analysis permits PJM to evaluate the need for larger scope transmission line solutions – at 345 kV and above, for example – that often requires longer lead times to complete. Such projects provide broader RTO reliability and market efficiency benefits.

2.1: Competitive Planning Process

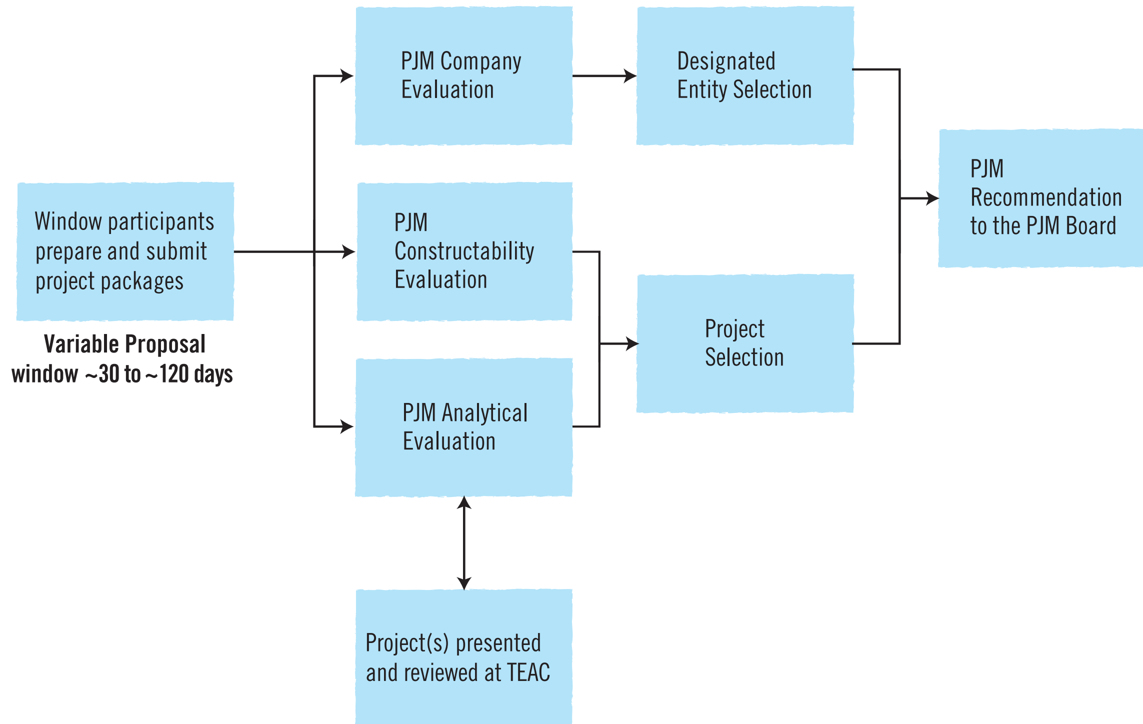
During 2017, PJM expects to conduct one or more RTEP process windows. As part of each window, PJM seeks transmission proposals to address one or more identified needs – reliability, market efficiency, operational performance and public policy. The scope and timing of the issue to be addressed and likely type of solutions to be submitted dictate window duration. Once a window closes, PJM proceeds with specific company, analytical and constructability evaluations to assess proposals for possible recommendation to the PJM Board as shown in **Figure 2.2**. If selected, designated developers become responsible for project construction, ownership, operation, maintenance and financial responsibility.

Submittals include both greenfield and upgrade proposals. A greenfield proposal is one that utilizes new right-of-way or creates a new substation, for example. An upgrade proposal is an enhancement or expansion to existing transmission system facilities. Upgrades can include new or replaced devices installed at existing substations and reconductoring of existing transmission lines.

Company Evaluation

PJM evaluates a company's specific ability to construct, own, operate, maintain and finance the specific project it has proposed. Prior to window activity, entities that desire to participate in the proposal window process, and perhaps ultimately be assigned as a project's Designated Entity, must submit a pre-qualification package to PJM during a separately specified period of time. Companies are evaluated based on their overall ability to engineer, develop, construct, operate and maintain a

Figure 2.2: PJM RTEP Window Process



Note

Stakeholders are encouraged to stay apprised of unfolding RTEP Window Process improvements through participation in the PJM Planning Committee: http://www.pjm.com/committees-and-groups/committees/pc.aspx.

transmission facility within PJM. If a company does not have experience in a specific area, PJM requires that it provide a detailed plan for leveraging the experience of affiliates and contractors.

Constructability Evaluation

Constructability evaluation assesses proposals in terms of cost, schedule, siting, permitting, right-of-way, land acquisition, project complexity and coordination risks. Project completion schedules and cost estimates are influenced by a number of factors: for example, line routing, siting and permitting, environmental remediation, engineering, material procurement, line construction, expansion of existing substations, project management and contingencies. Greenfield projects typically need to acquire land and rights of way. PJM may engage in discussions with federal, state and local regulatory agencies to understand the scope of specific permitting issues.

Analytical Evaluation

Analytical evaluation assesses proposals in terms of performance with respect to the specific, identified needs:

- Reliability analyses evaluate transient stability, voltage, thermal and short circuit performance, per established NERC reliability planning criteria.
- Market efficiency analyses evaluate a proposed project's ability to relieve transmission congestion consistent with established benefit-to-cost metrics.
- Public policy analyses evaluate a proposal's performance with respect to its ability to satisfy public policy objectives and requirements, such as the delivery of renewable energy to customer load within a given state.
- Following completion of these evaluations and review with stakeholders via TEAC, PJM submits its recommendation to the PJM Board for consideration.

Recommendation to the PJM Board

PJM staff will recommend projects to the PJM Board that represent solutions that satisfy technical performance requirements and balance advantages and risks with regard to cost commitment, constructability and other factors. Once the PJM Board approves recommended projects – new facilities (greenfield) and upgrades to existing ones – they formally become part of PJM's overall RTEP. The PJM Board approval obligates Designated Entities to construct those projects.

2017 RTEP Context

RTEP window activity in 2017 continues along several fronts. First, several evaluation studies for windows conducted in 2016 have been completed in 2017 as shown in **Table 2.1**. Work completed during 2016 itself is described in **Sections 5 and 6** of PJM's *2016 RTEP Report, Book 3*: http://pjm.com/~/media/library/reports-notices/2016-rtep/2016-rtep-book-3.ashx. PJM anticipates at least one or more new submittal windows to open in 2017.

PJM opened the 2016/2017 RTEP Long-Term Proposal Window on November 1, 2016, to seek solutions associated with market efficiency congestion and 15-year reliability analysis. This window closed in February 2017 and analysis of these proposals is underway. As PJM completes 2017 RTEP analyses, results will be posted for stakeholder review. The scope of those results and anticipated timing of need for system enhancements will guide PJM's decision to open a window to solicit proposed solutions. Stakeholders are encouraged to participate in the PJM TEAC meeting discussions to stay apprised of relevant RTEP window activities: http://www.pjm.com/committees-and-groups/committees/teac.aspx.

Table 2.1: RTEP Windows Summary – 2017 Activity

	2016 RTEP Proposal Window 1	2016 RTEP Proposal Window 2	2016 RTEP Proposal Window 3	2016 RTEP Proposal Window 3 Addendum 1	2016/17 RTEP Long-Term Proposal Window
Window Open	2/16/2016	6/29/2016	9/30/2016	11/28/2016	11/1/2016
Window Close	3/17/2016	7/29/2016	10/31/2016	12/13/2016	2/28/2017
Objective	Generator Deliverability and Common Mode Outage Violations related to Carson-Rogers Rd 500 kV and Chesterfield-Messer Rd-Charles City Rd 230 kV and aging infrastructure criteria.	N-1 Thermal and Voltage; Gen Deliv and Common Mode Outage, Load Deliv Thermal and Voltage; N-1-1 Thermal and Voltage	Winter Reliability, Light Load Reliability, Short Circuit	Winter Reliability	Market Efficiency Congestion, 15-Year Reliability Analysis
Proposals	25	87	29	6	96
Entities	7	13	7	3	19
Status	Recommendations Completed	Recommendations Completed	Anticipated Recommendations in 2017	Anticipated Recommendations in 2017	Proposal analysis underway

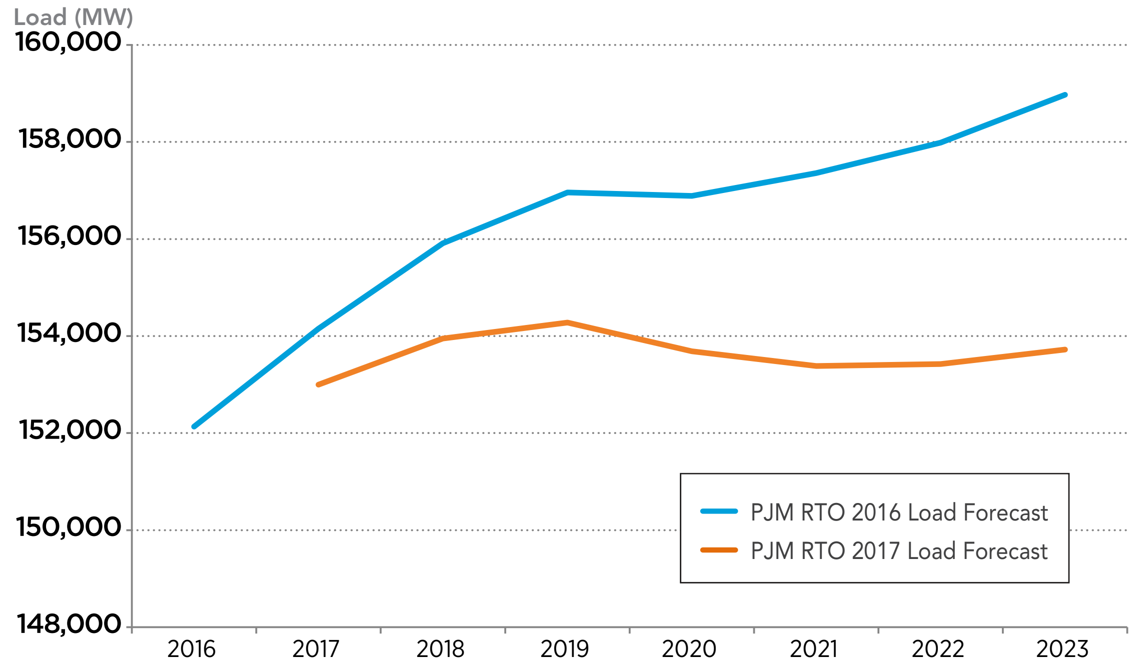
Section 3 – Load Forecast

3.0: 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. Up to date, comprehensively determined zonal load forecasts – the basis for modeling power flow case bus loads – are 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, generally lowering 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 3.1: Summer Peak Load Forecast – 2017 vs. 2016



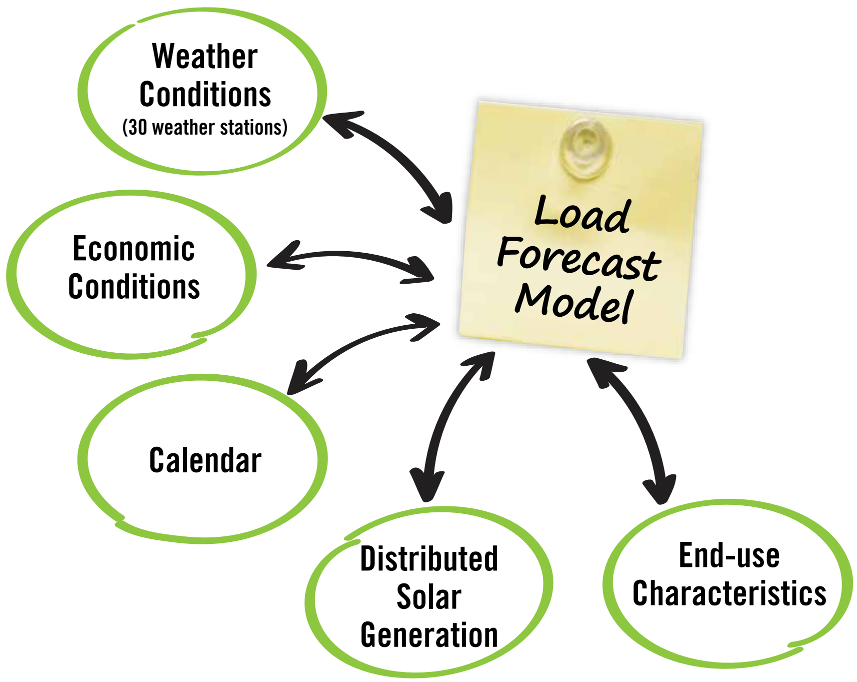
2017 RTEP Process Context

PJM's 2017 RTEP baseline power flow model for study year 2022 is based on the 2017 PJM Load Forecast Report. Summarized in the white paper sections that follow, PJM's January 2017 load forecast covered the 2017 through 2032 planning horizon. From a power flow modeling perspective, the 2022 summer peak from that January 2017 forecast – at an overall RTO demand of 153,425 MW was the basis for developing PJM's 2022 base case power flow model bus loads. Doing so will reflect that PJM now projects its RTO summer normalized peak to grow 0.2 percent annually over the next 10 years, shown in **Figure 3.1** in terms of megawatt load level, down 0.4 percentage points from the 2016 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 3.2**. The model is described in more detail in PJM Manual 19, "Load Forecasting and Analysis", available on PJM's website via the following URL: http://www.pjm.com/~/media/documents/manuals/m19.ashx. Additional specifics are available via the following URL: http://www.pjm.com/~/media/library/reports-notices/load-forecast/2016-load-forecast-whitepaper.ashx.

Figure 3.2: Load Forecasting 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 have, and continue to, become more 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 updated its load forecast model to recognize the breakdown in the relationship between energy and economics. In large part, this reflects the continued evolution to 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.

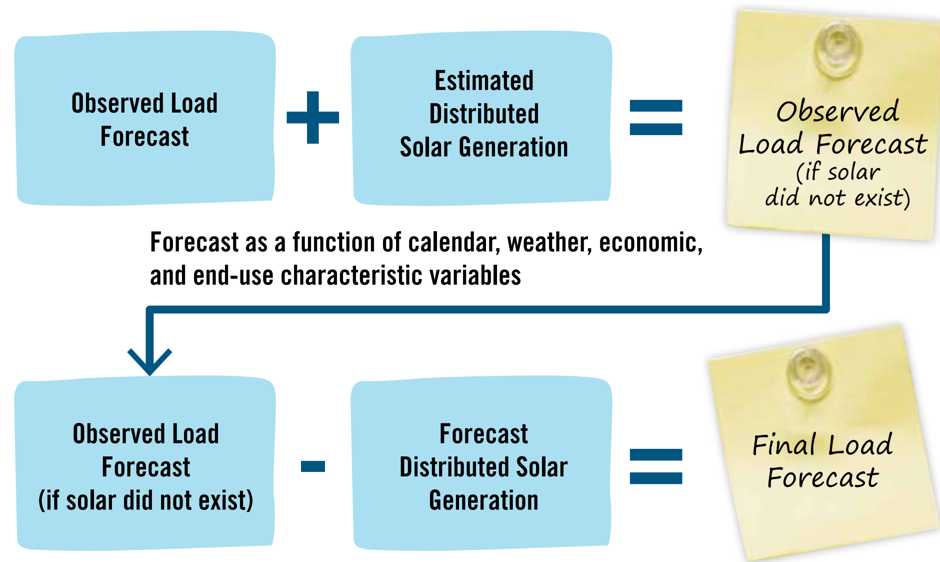
Distributed Solar

Recent years have witnessed a significant ramp-up in behind-the-meter distributed solar resources: over 2,000 MW since 1998, with more than 90 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 3.3** 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 insolation, 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 3.3: Accounting for Distributed Solar Generation



3.1: January 2017 Load Forecast

PJM's January 2017 load forecast covered the 2017 through 2032 planning horizon, highlights of which are summarized here. The complete January 2017 PJM Load Forecast report is accessible from PJM's website via the following link: http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx. As that report states, PJM's 2022 RTO summer peak is forecasted to be 153,425 MW.

Forecasting Trends

Table 3.1 summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2017 through 2027. All load forecasts in the table reflect adjustment for distributed solar generation, as described in **Table 3.1** Adjustments to the summer 10-year forecast are summarized in **Table 3.2**. Adjustments to the winter forecast are approximately zero.

Table 3.3 compares 10-year load growth rates for each PJM Transmission Owner zone and for the overall RTO, per the respective load forecasts produced each year, 2013 through 2017. 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 as described in **Section 3.0**.

Table 3.1: 2017 Load Forecast Report

	Summer Peak (MW)			Winter Peak (MW)		
T.O.	2017	2027	Growth Rate	2016/17	2026/27	Growth Rate
Atlantic City Electric Company	2,495	2,445	-0.2%	1,630	1,565	-0.4%
Baltimore Gas and Electric Company	6,889	6,911	0.0%	5,883	5,920	0.1%
Delmarva Power and Light	4,028	3,983	-0.1%	3,443	3,515	0.2%
Jersey Central Power and Light	6,056	6,108	0.1%	3,864	3,797	-0.2%
Metropolitan Edison Company	2,940	3,028	0.3%	2,615	2,670	0.2%
PECO Energy Company	8,547	8,693	0.2%	6,694	6,741	0.1%
Pennsylvania Electric Company	2,891	2,847	-0.2%	2,821	2,807	0.0%
PPL Electric Utilities Corporation	7,132	7,186	0.1%	7,177	7,218	0.1%
Potomac Electric Power Company	6,614	6,543	-0.1%	5,352	5,444	0.2%
Public Service Electric and Gas Company	10,057	10,012	0.0%	6,821	6,754	-0.1%
Rockland Electric Company	404	404	0.0%	234	233	0.0%
UGI	191	185	-0.3%	195	188	-0.4%
Diversity - Mid-Atlantic	-1,080	-1,161		-481	-557	
Mid-Atlantic	**57,164**	**57,184**	**0.0%**	**46,248**	**46,295**	**0.0%**
American Electric Power Company	22,945	23,888	0.4%	22,317	23,522	0.5%
Allegheny Power	8,802	9,087	0.3%	8,606	9,035	0.5%
American Transmission Systems, Inc.	12,994	13,177	0.1%	10,644	10,856	0.2%
Commonwealth Edison Company	22,296	22,872	0.3%	15,807	16,308	0.3%
Dayton Power and Light	3,479	3,503	0.1%	2,934	2,954	0.1%
Duke Energy Ohio and Kentucky	5,497	5,741	0.4%	4,469	4,663	0.4%
Duquesne Light Company	2,884	2,882	0.0%	2,171	2,179	0.0%
East Kentucky Power Cooperative	1,948	2,010	0.3%	2,611	2,696	0.3%
Diversity - Western	-1,529	-1,468		-1,268	-1,525	
Western	**79,316**	**81,692**	**0.3%**	**68,291**	**70,688**	**0.3%**
Dominion Virginia Power	19,729	20,501	0.4%	17,925	18,938	0.6%
Southern	**19,729**	**20,501**	**0.4%**	**17,925**	**18,938**	**0.6%**
Diversity - RTO	-3,210	-3,604		-1,073	-1,006	
PJM RTO	**152,999**	**155,773**	**0.2%**	**131,391**	**134,915**	**0.3%**

Table 3.2: Distributed Solar Generation Adjusted to Summer Peak

Distributed Solar Generation Adjustment to Summer Peak (MW)		
T. O.	2017	2027
Atlantic City Electric Company	74	78
Baltimore Gas and Electric Company	77	209
Delmarva Power and Light	51	163
Jersey Central Power and Light	126	138
Metropolitan Edison Company	13	75
PECO Energy Company	18	178
Pennsylvania Electric Company	3	76
PPL Electric Utilities Corporation	29	183
Potomac Electric Power Company	56	191
Public Service Electric and Gas Company	202	229
Rockland Electric Company	5	6
UGI	0	4
Mid-Atlantic	**654**	**1,530**
American Electric Power Company	20	244
Allegheny Power	32	170
American Transmission Systems, Inc.	19	169
Commonwealth Edison Company	12	193
Dayton Power and Light	5	46
Duke Energy Ohio and Kentucky	5	57
Duquesne Light Company	2	50
East Kentucky Power Cooperative	0	10
Western	**95**	**939**
Dominion Virginia Power	130	466
Southern	**130**	**466**
PJM RTO	**879**	**2,935**

Table 3.3: Comparison of 10-year Summer Peak Load Growth Rates

	2013 Load Forecast Report			2014 Load Forecast Report			2015 Load Forecast Report			2016 Load Forecast Report			2017 Load Forecast Report		
	Summer Peak (MW)			Summer Peak (MW)			Summer Peak (MW)			Summer Peak (MW)			Summer Peak (MW)		
T. O.	2013	2023	Growth Rate	2014	2024	Growth Rate	2015	2025	Growth Rate	2016	2026	Growth Rate	2017	2027	Growth Rate
Atlantic City Electric Company	2,733	3,053	1.1%	2,750	2,969	0.8%	2,664	2,827	0.6%	2,524	2,502	-0.1%	2,495	2,445	-0.2%
Baltimore Gas and Electric Company	7,218	8,034	1.1%	7,283	7,971	0.9%	7,127	7,753	0.8%	6,945	7,220	0.4%	6,889	6,911	0.0%
Delmarva Power and Light	4,141	4,717	1.3%	4,181	4,600	1.0%	4,177	4,557	0.9%	3,991	4,135	0.4%	4,028	3,983	-0.1%
Jersey Central Power and Light	6,253	7,068	1.2%	6,361	6,944	0.9%	6,269	6,851	0.9%	5,968	6,156	0.3%	6,056	6,108	0.1%
Metropolitan Edison Company	2,978	3,509	1.7%	3,019	3,444	1.3%	2,954	3,310	1.1%	2,940	3,176	0.8%	2,940	3,028	0.3%
PECO Energy Company	8,722	10,026	1.4%	8,843	9,827	1.1%	8,645	9,434	0.9%	8,547	9,122	0.7%	8,547	8,693	0.2%
Pennsylvania Electric Company	2,918	3,535	1.9%	2,966	3,441	1.5%	2,914	3,276	1.2%	2,890	2,919	0.1%	2,891	2,847	-0.2%
PPL Electric Utilities Corporation	7,271	8,264	1.3%	7,334	8,079	1.0%	7,162	7,759	0.8%	7,193	7,560	0.5%	7,132	7,186	0.1%
Potomac Electric Power Company	6,855	7,392	0.8%	6,870	7,249	0.5%	6,640	7,022	0.6%	6,563	6,813	0.4%	6,614	6,543	-0.1%
Public Service Electric and Gas Company	10,562	11,475	0.8%	10,614	11,185	0.5%	10,306	10,907	0.6%	10,090	10,222	0.1%	10,057	10,012	0.0%
Rockland Electric Company	420	447	0.6%	423	439	0.4%	424	441	0.4%	407	410	0.1%	404	404	0.0%
UGI	195	218	1.1%	198	218	1.0%	197	212	0.7%	188	190	0.1%	191	185	-0.3%
Diversity - Mid-Atlantic	-530	-512		-511	-507		-578	-530		-1,072	-872		-1,080	-1,161	
Mid-Atlantic	**59,736**	**67,226**	**1.2%**	**60,331**	**65,859**	**0.9%**	**58,901**	**63,819**	**0.8%**	**57,174**	**59,553**	**0.4%**	**57,164**	**57,184**	**0.0%**
American Electric Power Company	23,793	26,605	1.1%	23,556	25,414	0.8%	23,511	25,343	0.8%	23,006	24,891	0.8%	22,945	23,888	0.4%
Allegheny Power	8,661	9,829	1.3%	8,837	9,722	1.0%	8,734	9,701	1.1%	8,817	9,554	0.8%	8,802	9,087	0.3%
American Transmission Systems, Inc.	13,270	14,535	0.9%	13,341	14,038	0.5%	13,256	13,835	0.4%	12,921	13,413	0.4%	12,994	13,177	0.1%
Commonwealth Edison Company	22,761	26,742	1.6%	23,275	26,182	1.2%	22,914	25,953	1.3%	22,001	23,633	0.7%	22,296	22,872	0.3%
Dayton Power and Light	3,442	4,069	1.7%	3,476	3,926	1.2%	3,497	3,966	1.3%	3,403	3,647	0.7%	3,479	3,503	0.1%
Duke Energy Ohio and Kentucky	5,530	6,244	1.2%	5,597	6,079	0.8%	5,511	6,015	0.9%	5,436	5,853	0.7%	5,497	5,741	0.4%
Duquesne Light Company	2,966	3,331	1.2%	2,997	3,266	0.9%	2,969	3,161	0.6%	2,893	2,985	0.3%	2,884	2,882	0.0%
East Kentucky Power Cooperative	1,910	2,124	1.1%	1,899	2,033	0.7%	1,983	2,170	0.9%	1,924	2,041	0.6%	1,948	2,010	0.3%
Diversity - Western	-1,721	-2,047		-1,876	-2,095		-1,682	-1,997		-1,572	-1,574		-1,529	-1,468	
Western	**80,612**	**91,432**	**1.3%**	**81,102**	**88,565**	**0.9%**	**80,693**	**88,147**	**0.9%**	**78,829**	**84,443**	**0.7%**	**79,316**	**81,692**	**0.3%**
Dominion Virginia Power	19,619	23,558	1.8%	20,197	24,224	1.8%	19,999	23,676	1.7%	19,531	22,041	1.2%	19,729	20,501	0.4%
Southern	**19,619**	**23,558**	**1.8%**	**20,197**	**24,224**	**1.8%**	**19,999**	**23,676**	**1.7%**	**19,531**	**22,041**	**1.2%**	**19,729**	**20,501**	**0.4%**
Diversity - RTO	-4,414	-4,777		-4,351	-4,919		-4,049	-4,062		-3,403	-4,146		-3,210	-3,604	
PJM RTO	**155,553**	**177,439**	**1.3%**	**157,279**	**173,729**	**1.0%**	**155,544**	**171,580**	**1.0%**	**152,131**	**161,891**	**0.6%**	**152,999**	**155,773**	**0.2%**

2017 Forecast Summer Zonal Load Growth Rates

Average 10-year annualized summer growth rates for individual PJM zones vary from a low of -0.3 percent in the UGI to a high of 0.4 percent in the American Electric Power Company, Duke Energy Ohio and Kentucky and Dominion zones as shown in **Figure 3.4** and **Figure 3.5**. The forecasted summer peak for 2017 is 152,999 MW and is projected to grow to 155,773 MW in 2027, a 10-year increase of 2,774 MW.

Figure 3.4: PJM Mid-Atlantic Summer Peak Load Growth: 2017– 2027

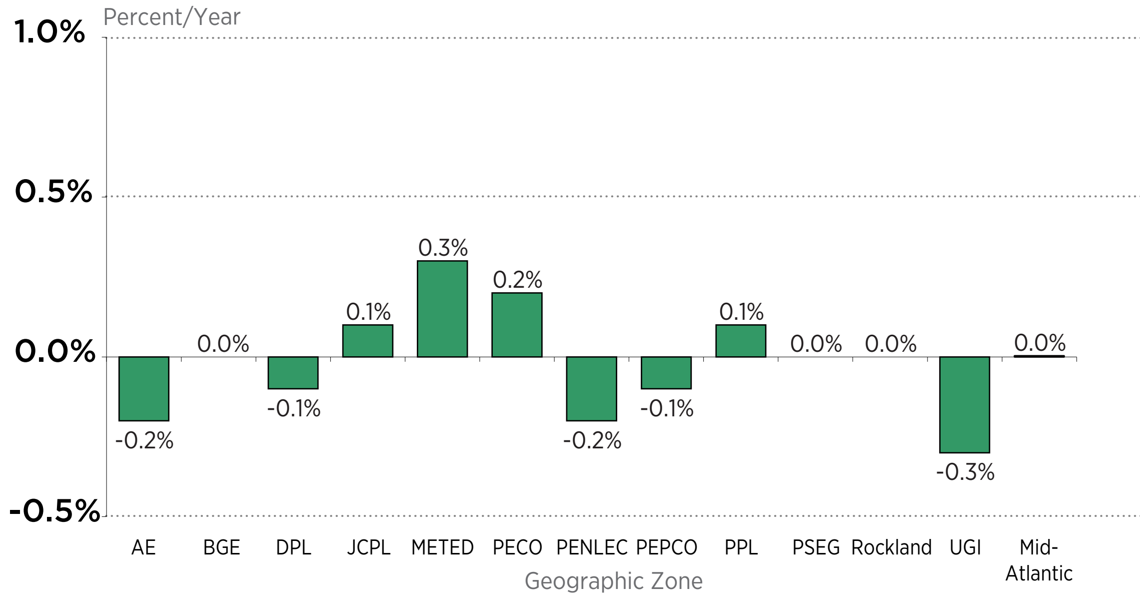
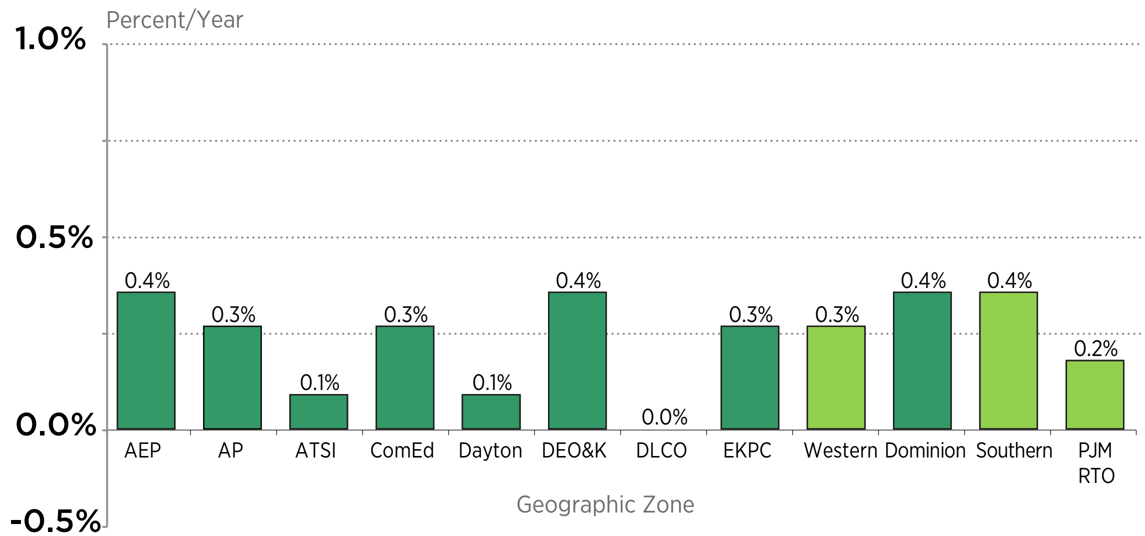


Figure 3.5: PJM Western and Southern Summer Peak Load Growth: 2017 - 2027



2017 Forecast Winter Zonal Load Growth Rates

The PJM RTO weather normalized winter peak is forecasted to grow at an average rate of 0.3 percent per year for the next 10-year period. The PJM RTO winter peak is forecasted to be 134,915 MW in 2026/27, an increase of 3,524 MW over the 2016/17 peak of 131,391 MW. Individual geographic zone growth rates vary from -0.4 percent to 0.6 percent, as shown in **Figure 3.6** and **Figure 3.7**.

Figure 3.6: PJM Mid-Atlantic Winter Peak Load Growth: 2016/2017 – 2026/2027

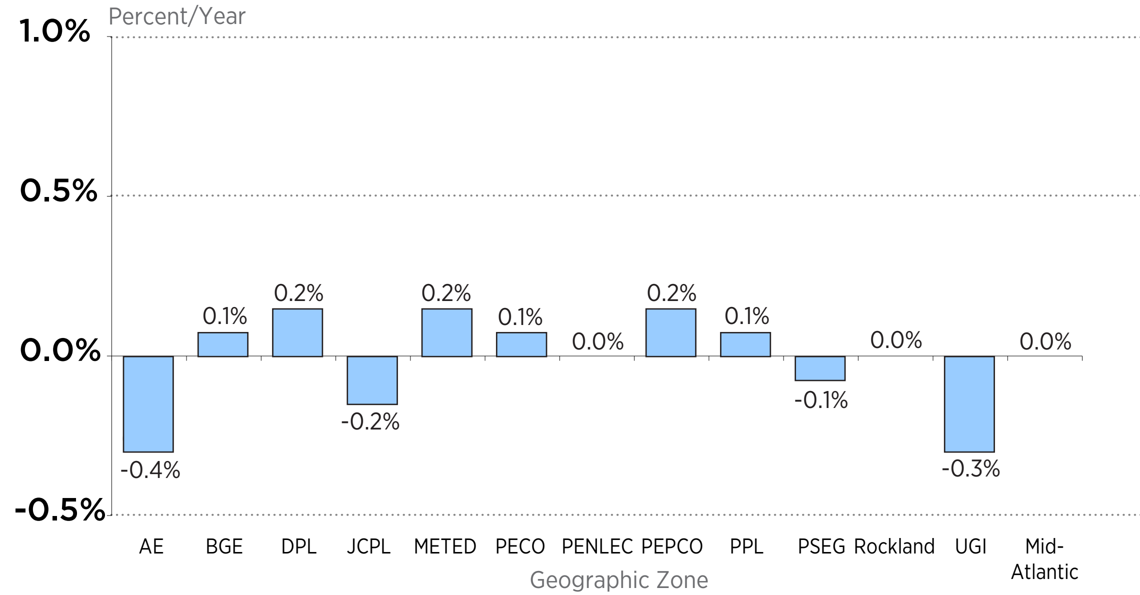
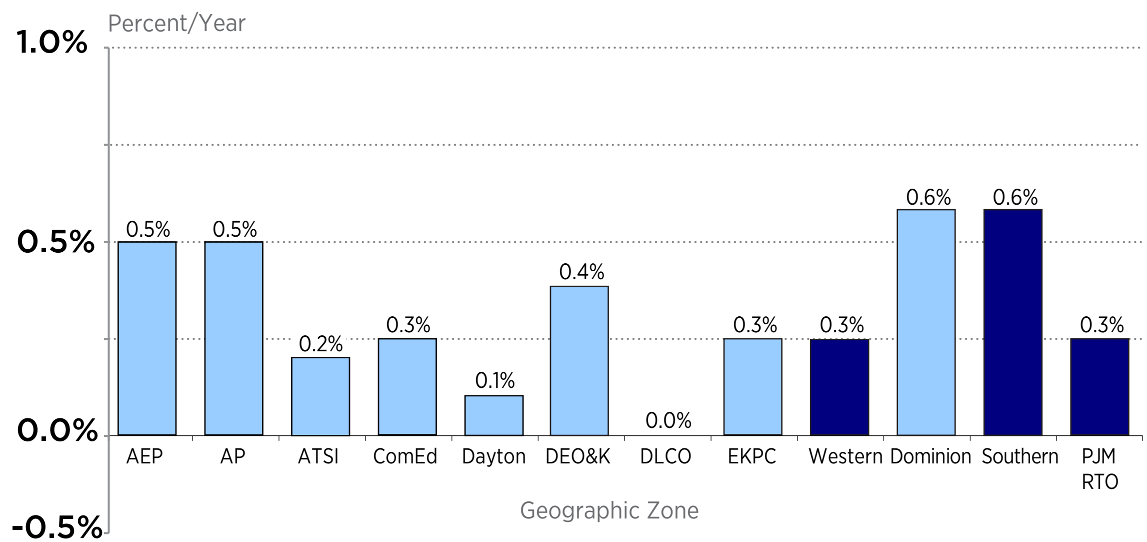


Figure 3.7: PJM Western and Southern Winter Peak Load Growth: 2016/2017 – 2026/2027

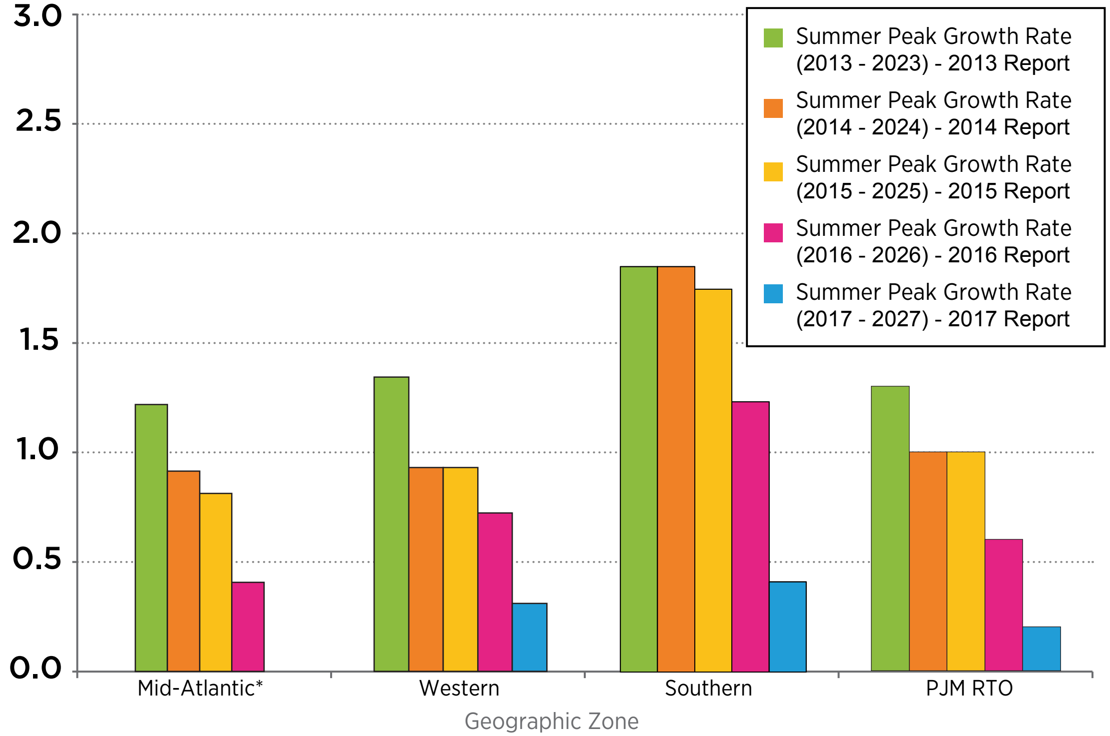


Subregional Forecast Trends

Figure 3.8 provides a summary based on load growth rates trends from the respective January load forecast over each of the last five years, from 2013 through 2017 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 2017 over 2016 forecast load growth rates for Mid-Atlantic PJM, Western PJM and the RTO decreased by 0.4 percentage points.

Figure 3.8: PJM 10-Year Summer Peak Load Growth Rate Comparison: 2017 – 2027



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

3.2: 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 2017 Load Forecast Report, are shown in **Table 3.4** for each Transmission Owner zone. The adjusted forecast is then used in RTEP power flow model development as described in **Section 3.0**. 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.

Table 3.4: 2017 Load Forecast Report Demand Resources*

T. O.	2017	2027
Atlantic City Electric Company	108	71
Baltimore Gas and Electric Company	695	460
Delmarva Power and Light	269	175
Jersey Central Power and Light	140	94
Metropolitan Edison Company	231	158
PECO Energy Company	380	257
Pennsylvania Electric Company	269	174
PPL Electric Utilities Corporation	621	413
Potomac Electric Power Company	502	327
Public Service Electric and Gas Company	376	253
Rockland Electric Company	4	3
UGI	0	0
Mid-Atlantic	**3,595**	**2,385**
American Electric Power Company	1,423	996
Allegheny Power	675	473
American Transmission Systems, Inc.	742	507
Commonwealth Edison Company	1,253	867
Dayton Power and Light	165	112
Duke Energy Ohio and Kentucky	244	169
Duquesne Light Company	134	91
East Kentucky Power Cooperative	133	104
Western	**4,769**	**3,319**
Dominion Virginia Power	756	533
Southern	**756**	**533**
PJM RTO	**9,120**	**6,237**

*Note: Demand Resources are also known as Load Management

Capacity Performance Impacts

PJM's Reliability Pricing Model transition to Capacity Performance has required a transition in the treatment of demand resources as well. **Table 3.4** reflects 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.

- A portion of base capacity demand resources are assumed to become Capacity Performance demand resources based on the ratio of coupled base demand resource offers to total cleared base demand resource offers from the 2018 Base Residual Auction results.

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" accessible from PJM's website via the following link: http://pjm.com/~/media/documents/manuals/m19.ashx.

Section 4 – Topology, Generation and Interchange

4.0: 2022 Model Year Topology

Each year, PJM creates and maintains a series of power flow cases that provide the basis for baseline, market efficiency, new service request, scenario studies and other analysis. In order to develop a 2022 study year power flow case, PJM removed its portion of the most recent multi-region modeling working group 2022 case, and replaced it with its own internally developed model. PJM's 2016 as-is base case, reflecting existing topology conditions as of June 1, 2016, provided the starting point for the 2022 model. The 2016 case was updated for internal topology changes, generation additions, generator deactivations, bus load, interchange schedule and other modeling parameters. PJM's study year 2022 case includes all enhancements approved by the PJM Board through the end of 2016, and expected to be in service by June 1, 2022. The status of approved transmission lines at 345 kV and above not yet in-service or recently placed in-service is summarized in **Table 4.1.** The location of these facilities is shown on **Map 4.1** through **Map 4.4.**

Table 4.1: Status of Approved Transmission Lines – 345 kV and Above

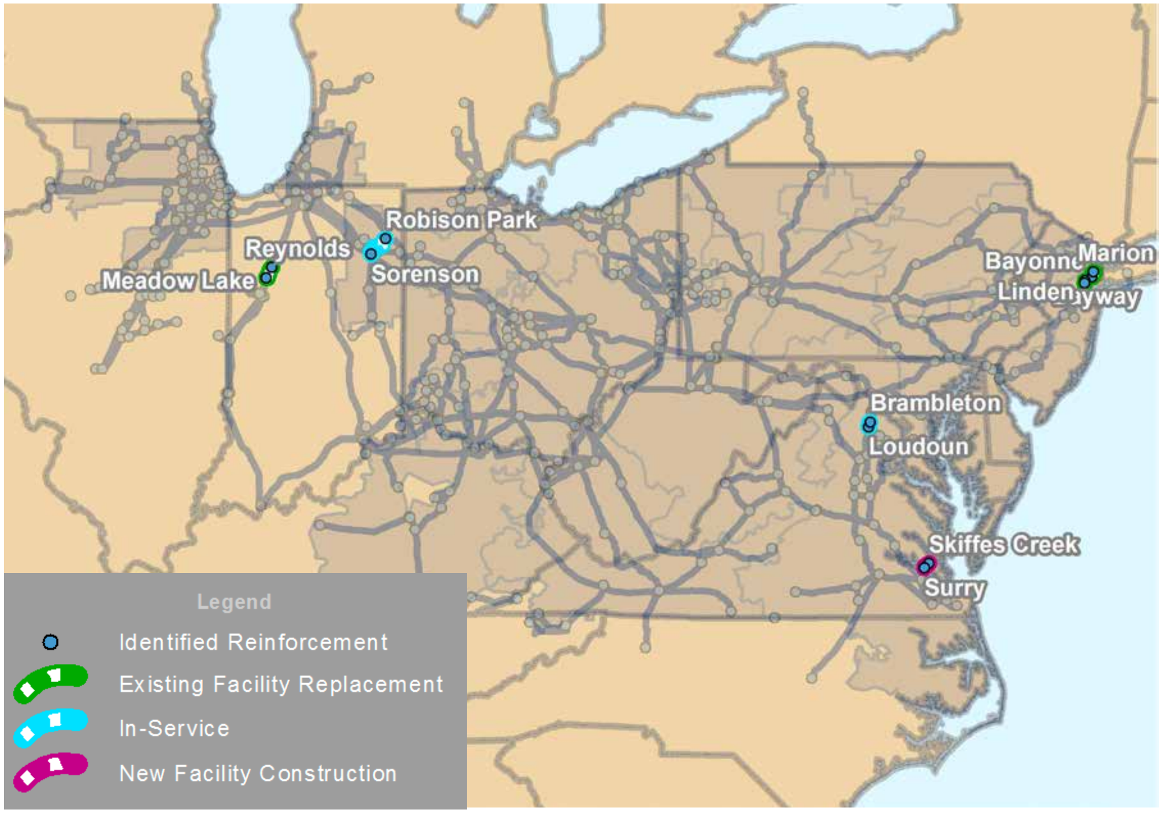
Facility	Status
Surry to Skiffes Creek 500 kV Line	December 2018 expected in-service date
Loudoun-Brambleton 500 kV Line	Second circuit completed September 2016
Marion-Bayonne 345 kV Line	Convert 138 kV line to 345 kV, Expected in June 2018
Bayway-Linden 345 kV	Convert three 138 kV lines to 345 kV, Expected completion in December 2017
Robinson Park-Sorenson 345 kV Line	Convert line into double circuit 345 kV, Completed in November 2016
Meadow Lake-Reynolds 345 kV	Line rebuild completion expected June 2017

Simulation Tools and Supporting Files

PJM employs a number of models and methodologies to create and maintain RTEP study simulation models. Base case creation, though, necessarily remains a collaborative process among PJM, transmission owners, and generation owners who update starting point case files provided by PJM. PJM uses commercially available software for modeling, standard power flow analysis, and for more complex analysis such as generator deliverability. Supporting contingency files, monitor files, subsystem files and unit availability data are updated each year.

Contingency files contain the sets of transmission facility outage combinations to be studied. Monitor files identify facilities to be analyzed for potential reliability criteria violations. All PJM bulk electric system facilities, tie lines to neighboring systems, and lower voltage facilities operated by PJM are monitored. Thermal and voltage limits are consistent with those used in operations as described in PJM Manual 3, "Transmission Operations", accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m03.ashx. Subsystem files identify source-sink pairs modeled in deliverability analysis area power transfers. Unit availability files contain probability data to establish peak-load test condition dispatch scenarios in deliverability studies. These files play a crucial role, ensuring that reliability criteria violations are accurately identified.

Map 4.1: Approved PJM Backbone Transmission Lines 345 kV and Above – Dominion

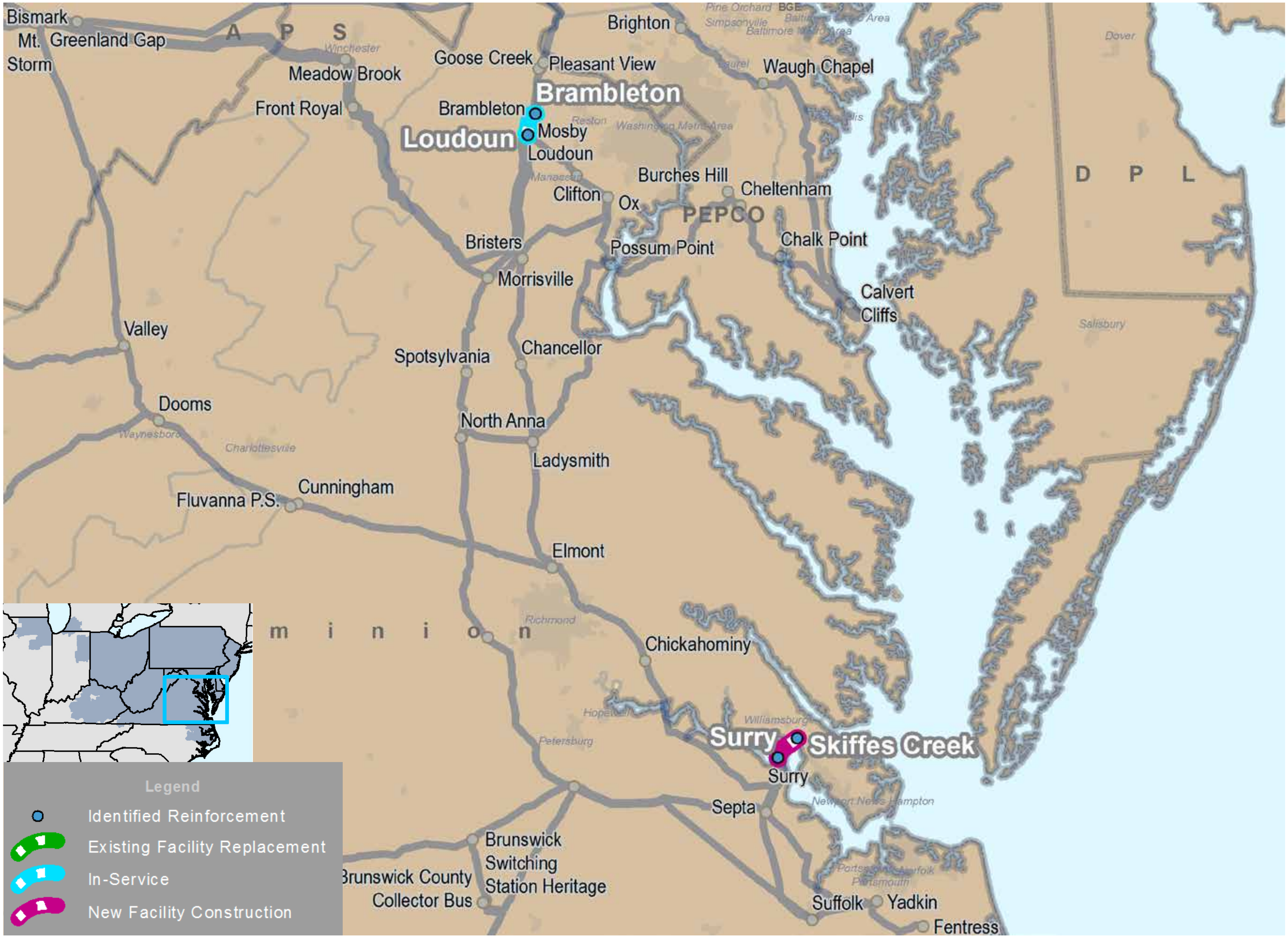


Note

Beginning with the 2017 RTEP process cycle, Transmission Owners will be using PJM's recently implemented Model-on-Demand tool to upload discrete model changes to transmission system topology and load profiles. Doing so will allow PJM to develop requisite annual and seasonal RTEP power flow cases with greater consistency and efficiency.

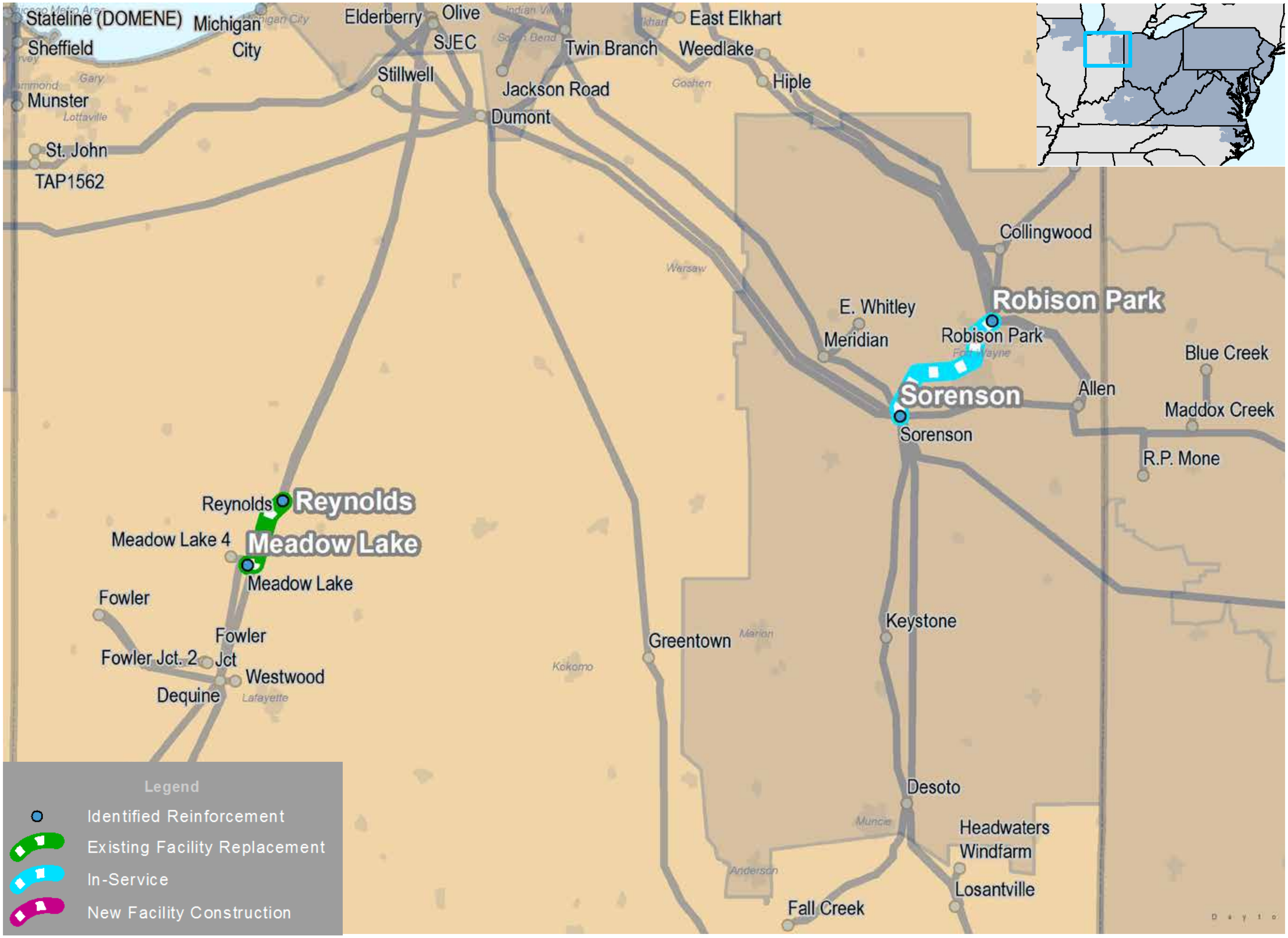
PJM has also implemented its Planning Center website application. This tool permits generating plant data to be submitted more effectively and efficiently to PJM. This data is used to conduct dynamic stability studies, short circuit studies and power flow model verification.

Map 4.2: Approved PJM Backbone Transmission Lines 345 kV and Above – Dominion



Map 4.3: Approved PJM Backbone Transmission Lines 345 kV and Above – Northern New Jersey

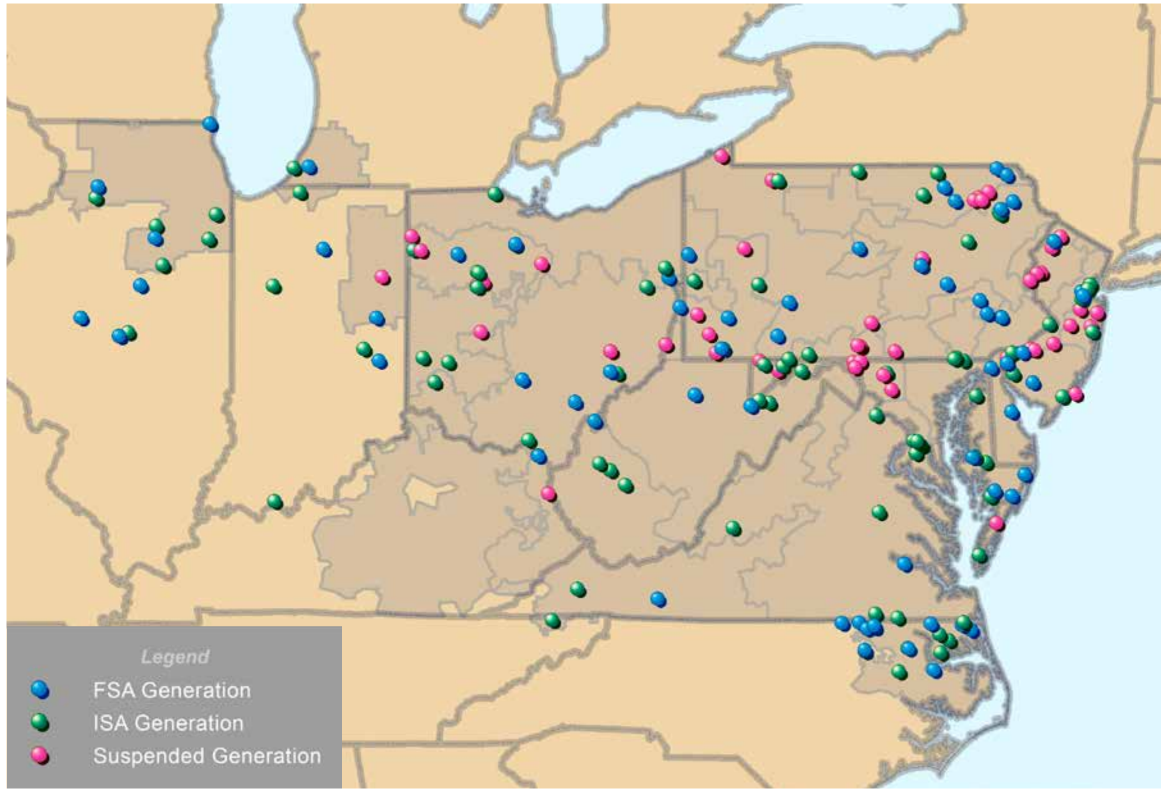
Map 4.4: Approved PJM Backbone Transmission Lines 345 kV and Above – Indiana



4.1: Generation Modeling

PJM has modeled all generators expected to be in-service by June of the 2022 study year at output levels expected under applicable 2022 study load conditions. For existing generation resources, the maximum generator capability, known as Pmax, typically represents the capacity interconnection rights already assigned to each unit. For units that have or are seeking "energy only status," Pmax is set at that energy level and modeled offline. Generation outage rates are based on the most recent reserve requirement study conducted by PJM planning staff. Generation outage rates for future, queued units are estimates based on class average rates. Generation modeled in annual power flow cases is based on unit status as of a specified lock down date. This guides how PJM models queued generation and expected deactivations. A full description of PJM's base case generation modeling procedures can be found in Manual 14B, "PJM Region Transmission Planning Process," accessible from PJM's website via the following URL: http://pjm.com/-/media/documents/manuals/m14b.ashx.

Map 4.5: RTEP 2022 Study Year ISA and FSA Generation



Modeling Queued Generation

Queued generation projects are included in RTEP power flow case models if they have received a completed System Impact Study and have executed a Facilities Study Agreement (FSA) or Interconnection Service Agreement (ISA). PJM's queue experience has shown that interconnection request withdrawal rates fall off significantly after FSA execution. Modeling queued generators in this manner minimizes the need for retooling studies that would otherwise be required by interconnection requests that withdraw, while acknowledging the impact of generation likely to reach commercial operation. For perspective, **Map 4.5** shows the RTO-wide geographic scope of FSA and ISA generation in PJM's 2022 study year power flow cases. A complete list of existing and queued generation modeled in PJM's power flow cases is included in the January 2017 TEAC materials, accessible via the following URL: http://pjm.com/~/media/committees-groups/committees/teac/20170112/20170112-2022-list-of-machines.ashx.

Once included in a power flow case, a queued generator's status may be either online or offline according to its status within PJM's RTEP interconnection process:

- Queued generators with an executed FSA are initially modeled offline in power flow cases; all associated transmission reinforcements are also modeled. If the output of existing and ISA generators is not sufficient to meet load, real system megawatt loss and firm interchange requirements, then FSA units will be turned on in the case and dispatched accordingly.

- Queued generators with an executed ISA – together with required network reinforcements – are modeled at output equal to expected capacity interconnection rights. Only those queued generation projects with executed ISAs and units that have cleared in the Reliability Pricing Model auction are permitted to back off power flows to alleviate an identified transmission constraint.

- From a Reliability Pricing Model perspective, queued generators larger than 20 MW must have an executed FSA; Queued Generators less than or equal to 20 MW must have at least executed a System Impact Study Agreement in order to be eligible to bid into base residual auctions. (An ISA or Wholesale Market Participant Agreement must be executed for a unit to participate in an Incremental Auction).

- Suspended queued projects are modeled offline in the base case, similar to queued generators with an executed FSA. The energy portions of intermittent resources such as solar and wind are also modeled offline. If a generator formally withdraws from PJM's interconnection queue, then that generator and any associated transmission system enhancements are also removed from the baseline power flow case model. Withdrawn interconnection request projects simply reflect ongoing business decisions by developers in response to changing public policy, regulatory, industry, economic and other competitive factors.

Modeling Generator Deactivations

Generation owners are weighing the costs of increased investment to address environmental compliance issues against anticipated revenue streams: PJM energy, capacity, and ancillary services markets and existing power purchase agreements. Generation owners are only required to provide 90 days notification of their intent to deactivate, per Article V of the PJM Open Access Transmission Tariff, and may do so throughout the year. Generation that has officially notified PJM of deactivation are modeled offline in RTEP base cases for all study years after the intended deactivation date, though such units are only removed from power flow case models one year after their actual deactivation date. Under generator deliverability testing, deactivated units that are modeled offline are allowed to contribute to transmission facility loading, but not allowed to reduce it. For all other RTEP power flow analyses, these units are modeled as offline and do not contribute to or reduce facility loading.

4.2: Interchange

Interchange values reflect expected net power transfers across one of PJM's interfaces with adjoining systems. Power flow case interchange levels, listed in **Table 4.2**, reflect PJM Open Access Same-Time Information System (OASIS) reservations for long-term firm transmission service with rollover rights. Doing so ensures that RTEP analyses are modeling cross-border transfers at levels consistent with those expected in actual operations. Indeed, such transfers may include transactions sourced from areas beyond systems immediately adjoining PJM. A negative interchange value in **Table 4.2** indicates a net PJM import. RTEP 2022 cases were developed comparing Eastern Interconnection Reliability Assessment Group case contractual interchange with PJM OASIS values. Any differences are reconciled by scaling generation and load accordingly.

Table 4.2: 2022 RTEP Interchange

Source	Sink	System Name	Total (MW)
PJM	NYISO	New York ISO	1,792.0
PJM	OVEC	Ohio Valley Electric Corporation	-2,111.0
PJM	TVA	Tennessee Valley Authority	-230.0
PJM	SMT	Brookfield / Smokey Mountain Hydropower, LLC	-384.0
PJM	LGEE	Louisville Gas and Electric / Kentucky Utilities	-660.3
PJM	OMUA	Owensboro Municipal Utilities	-150.0
PJM	CPLE	Carolina Power & Light Company – East	-89.0
PJM	DUK	Duke Energy Carolinas	-590.0
PJM	MISO	Midcontinent ISO	-2,321.0
Total			**-4,743.3**

Note

PJM's OASIS provides information by electronic means about available transmission capability for point-to-point service and a process for requesting transmission service on a nondiscriminatory basis. Once a transmission service request is received on OASIS, PJM evaluates it to determine if sufficient capability to accept the request and ensure reliable service to all transmission customers.

Section 5: Baseline Analyses – 2017 Scope

5.0: NERC Reliability Criteria

PJM's RTEP process rigorously applies NERC's Planning Standard TPL-001-4 through the application of a wide range of reliability analyses – including load and generation deliverability tests – over a 15-year planning horizon. PJM documents all instances that did not meet applicable Reliability Standards and develops system reinforcements to ensure compliance. Compliance with NERC standards is mandatory. Penalties for violation of a standard can be as high as $1 million per violation per day.

RTEP Perspective

PJM addresses transmission expansion planning from a regional perspective, spanning Transmission Owner zonal boundaries and state boundaries to address the comprehensive impact of a myriad of system enhancement drivers, including NERC reliability criteria violations. The relationship between violation and solution generally takes one of two forms. Reliability criteria violations may occur in a given Transmission Owner zone driven by an issue in that same zone. For example, local load growth or generator deactivations may drive higher power flow on a specific transformer causing an overload. Or, violations may appear in one or more Transmission Owner zones driven by some combination of regional factors including those potentially arising some distance away. In such instances, PJM is able to pursue optimal regional solutions to solve such violations more economically and efficiently than if approached individually.

Bulk Electric System Facilities

NERC's planning standards apply to all bulk electric system (BES) facilities, defined by Reliability First 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 Reliability First 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); these facilities would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions

3. All other facilities operated at voltages below 100 kV

Given this 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 solve them, frequently as part of an RTEP window solicitation.

NERC Reliability Standard TPL-001-4

Under NERC Reliability Standard TPL-001-4, planning events – in NERC parlance – are categorized as P0 through P7 and defined in the context of system contingency. PJM studies each event as part of one or more RTEP process steady-state analyses as mapped in **Table 5.1** and described in PJM Manual 14B, "PJM Region Transmission Planning Process:" http://www.pjm.com/~/media/documents/manuals/m14b.ashx

- 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 5.1: 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 – mapped to planning event P0 – examines the BES as is with all facilities in service. PJM identifies facilities that have pre-contingency loadings which exceed applicable normal thermal ratings. Bus voltages are also identified that violate established limits specified in PJM Manual 3, "Transmission Operations:" http://www.pjm.com/~/media/documents/manuals/m03.ashx. Generator and load deliverability tests are also applied to event P0 per the methodologies described in **Section 5.2**.

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 applied to event P1 here as well.

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.

Note

NERC's website contains a complete description of Standard TPL-001-4 requirements: http://www.nerc.com/files/tpl-001-4.pdf.

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 generator deliverability system test facility loading methodology, discussed in PJM Manual 14B, "PJM Region Transmission Planning Process": http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

NERC Standard TPL-001-4 also includes extreme events known as maximum credible disturbances. PJM studies system conditions following a number of extreme events, judged to be critical from an operational perspective for risk and consequences to the system.

Stability Requirements

Stability studies ensure that the PJM system as-planned can withstand system disturbances defined by NERC and remain within stable system operational limits. NERC's planning criteria apply to normal system, 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.

5.1: Comprehensive Analysis

PJM's 24-month cycle – shown earlier in **Figure 2.1** – includes two conventional 12-month bodies of work that focus on system needs five years forward driven by near-term reliability criteria violations, market efficiency, operational performance and Transmission Owner criteria. A parallel 24-month analysis itself covers a full fifteen year horizon to identify the need for larger-scale, longer lead-time solutions – such as 500 kV and 765 kV lines for example. Doing so allows PJM to optimize solution alternatives by addressing groups of recurring violations regionally.

Baseline Reliability Analysis

Consistent with established RTEP process practice, the scope of 2017 baseline analyses will assess base case thermal and voltage conditions. These are described in the remainder of this section in the context of RTEP process load deliverability and generation deliverability test conditions, N-1-1 contingencies, common mode contingencies, light load criteria, winter criteria, as well as short circuit duty and system stability studies. Contingency analysis examines all PJM bulk electric facilities (BES), lower voltage facilities monitored by PJM and critical facilities in systems adjoining PJM, including tie lines.

All reliability analyses are conducted to ensure compliance with NERC Reliability Standard TPL-001-4 as described in **Section 5.0** and with PJM Reliability Planning Criteria as described in Manual 14B, Attachment G: http://www.pjm.com/documents/manuals.aspx and Transmission Owner reliability planning criteria as contained in their respective FERC No. 715 filings and accessible from PJM's website via the following link: http://www.pjm.com/planning/planning-criteria.aspx.

2017 Body of Analysis

Near-term analysis in 2017 will examine a five-year-out, 2022 – baseline reliability analysis as well as retool studies for years one through four. PJM's 2017 RTEP cycle also included an eight-year-out – 2024 – analysis (Year 0 of the 24-month cycle), also shown in **Figure 2.1**, to reflect PJM's latest assumptions regarding load, generation, demand resources, energy efficiency and transmission topology. PJM's 2018 long-term base case development for Year 0 of the 24-month cycle will be based on system conditions expected in Year 7 – 2024 – of the fifteen-year planning horizon. This process permits PJM to validate 2017 year zero findings as part of full alternating current power flow and linear analysis to determine BES facility loadings on facilities for years six through fifteen. Consistent with established practice, 15-year analyses will include normal system, single and common mode contingency analysis. Both generator deliverability and load deliverability procedures will be used to establish the critical system conditions for evaluation. Load forecasts from the 2017 PJM Load Forecast Report will be used in combination with linear direct current scaling factors to develop projected facility loadings for each of the highest loaded flowgates in each study year.

Market Efficiency

PJM's RTEP process includes a market efficiency analysis as discussed in **Section 6**. Comparing results of multiple "as-is" versus "as-planned" simulations allow PJM to value the approved RTEP portfolio of enhancements, determine if acceleration or modification of RTEP projects are economically beneficial or if specific proposed transmission enhancements would be economically beneficial. Importantly, the simulated transmission congestion results also provide important system information and trends to PJM stakeholders and potential transmission developers.

RTEP Windows

PJM will continue to overlay baseline and market efficiency studies with RTEP process windows during which transmission developers may submit proposals to solve identified reliability and market efficiency issues. As discussed in **Section 2.1**, PJM seeks transmission proposals during each window to address one or more identified needs – reliability, market efficiency, operational performance and public policy, for example.

Reassessing Need

Planning is a dynamic process. Input assumptions - load forecasts, interconnection request withdrawals, generator deactivations, for example – can change over time. Such volatility can shift violations earlier or later than initially identified. In some cases, the collective effect of several shifting parameters can mean that a violation disappears altogether. This uncertainty drives the need to adjust assumptions used in planning studies and re-evaluate decisions made in previous planning cycles. As part of each RTEP cycle, PJM reviews transmission plans developed.

in earlier years. By doing so PJM can determine whether as a result of changing assumptions previously approved transmission projects are still required and, if so, whether they are still required in the year originally identified.

As part of the 2017 RTEP cycle, PJM will review – as it does every year – transmission plans developed in earlier years, examining 2018, 2019, 2020 and 2021 baseline analyses which were conducted during 2013, 2014, 2015 and 2016 RTEP process cycles, respectively. Those analyses were based on the original 2013, 2014, 2015 and 2016 load forecasts for 2018 through 2021.

Interregional and Scenario Studies

PJM's RTEP process does not end with baseline reliability and market efficiency studies. Transmission expansion plans during the first several years of PJM's RTEP process – beginning in 1997 – were mainly driven by load growth and generator interconnection requests. Today, public policy, regulatory action and fuel economics are examined as part of interregional and scenario studies, as discussed in **Section 8.0** and **Section 8.1**, respectively. These studies provide valuable long-term expansion planning insights beyond those obtained from conventional baseline and market efficiency analyses.

5.2: Deliverability

PJM tests for compliance with all reliability criteria imposed by the NERC reliability standards described in **Section 5.0**. NERC reliability standards require that PJM identify the system conditions that sufficiently stress the transmission system be evaluated to ensure that it meets the performance criteria specified in the standards.

PJM establishes the critical system conditions through the application of its load deliverability and generator deliverability test procedures.

Generator Deliverability

The generator deliverability test ensures that sufficient transmission capability exists to deliver generating capacity reliably from a defined area to the rest of PJM load, as shown in **Figure 5.1**, test areas are defined based on the potential ramping impact of generators that are electrically close to a particular flowgate. 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 are examined. Generator deliverability testing assesses single contingencies as part of baseline analysis and interconnection request studies. Testing methods are described in more detail in PJM Manual 14B, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

In addition, common mode analysis evaluates planning events P2, P4, P5 and P7 to look at the loss of multiple facilities in the context of generator deliverability test conditions, as also described in Manual 14B.

Figure 5.1: Generator Deliverability Concept

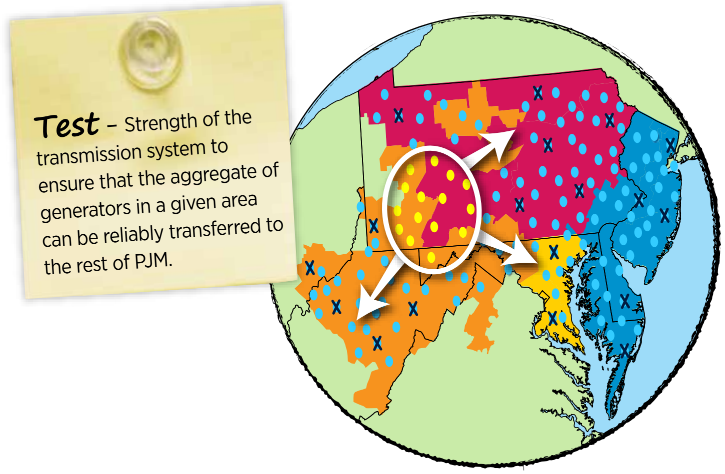
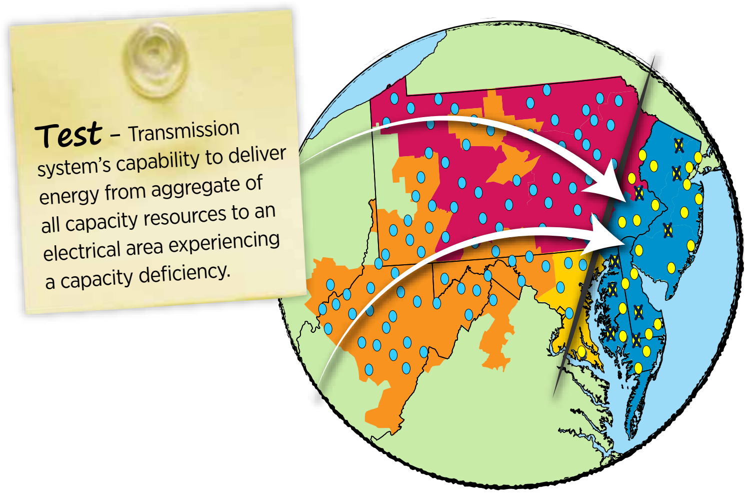


Figure 5.2: Load Deliverability Concept



Load Deliverability

PJM's load deliverability test ensures that load inside a load deliverability area experiencing a capacity deficiency can be served by generating resources external to it, shown conceptually in **Figure 5.2**.

More specifically, load deliverability studies test the transmission system's capability to import sufficient power to meet a defined Capacity Emergency Transfer Objective. An locational deliverability area fails the test if sufficient generating capacity cannot be delivered to load because of one or more limiting transmission constraints.

The methodology requires that PJM stress the locational deliverability area being tested by increasing its load from a 50/50 forecast level to a 90/10 level; and, (2) increasing the level of unavailable generation higher than typically encountered. Testing methods are described in more detail in PJM Manual 14B, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

Capacity Emergency Transfer Objective and the Capacity Emergency Transfer Limit

As part of load deliverability analysis, PJM first establishes a capacity emergency transfer objective (CETO) for each of 27 locational deliverability areas, as shown in **Table 5.2** and **Map 5.1**. The CETO calculated for the load deliverability test is the import capability required for the area to meet a loss-of-load expectation (LOLE) risk level of one event in 25 years. The risk refers to the probability that an locational deliverability area would need to shed load due solely to its inability to import needed capacity assistance during a capacity emergency (i.e. the transmission system is not robust enough to import sufficient power during a capacity emergency).

Table 5.2: PJM Locational Deliverability Areas

LDA	Description
AE	Atlantic City Electric
AEP	American Electric Power
APS	Allegheny Power
ATSI	American Transmission Systems, Incorporated
BGE	Baltimore Gas and Electric
Cleveland	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
DPLSOUTH	Southern Portion of DPL
Eastern Mid-Atlantic	Global area – PJM 500, JCPL, PECO, PSE&G, AE, DPL, RECO
EKPC	East Kentucky Power Cooperative
JCPL	Jersey Central Power and Light
Met-Ed	Metropolitan Edison
Mid-Atlantic	Global area – PJM 500, Penelec, Meted, JCPL, PPL, PECO, PSE&G, BGE, PEPCO, AE, DPL, UGI, RECO
PECO	PECO
PENELEC	Pennsylvania Electric
PEPCO	Potomac Electric Power Company
PPL	PPL Electric Utilities Corporation, UGI
PSE&G	Public Service Electric and Gas
PSNORTH	Northern Portion of PSE&G
Southern Mid-Atlantic	Global area – BGE and PEPCO
Western Mid-Atlantic	Global Area – PJM 500, Penelec, Meted, PPL, UGI
Western PJM	Global Area – APS, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC

PJM calculates a CETO value for each locational deliverability area using a probabilistic model of the load and capacity located within each locational deliverability area. The model recognizes, among other factors, historical load variability, load forecast error, generating unit maintenance requirements and generating unit forced outage rates. A number of factors drive CETO value increases, including the following:

- Locational deliverability area peak load increase
- Locational deliverability area capacity resources decrease including generation, demand resource programs and energy efficiency
- Locational deliverability area capacity resource availability factor decrease

The reverse is also true for a decrease in locational deliverability area CETO values.

Analysis

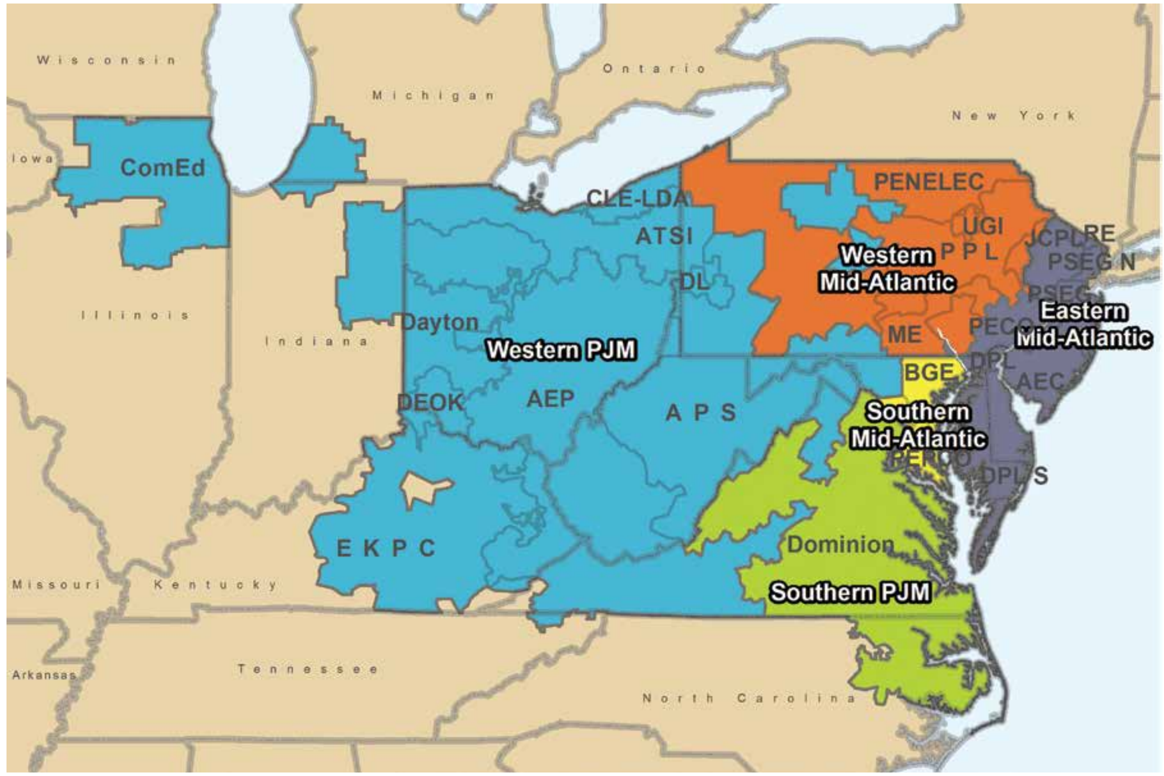
Load deliverability power flow analysis results identify the capacity emergency transfer limit (CETL) for each locational deliverability area. This value represents the maximum megawatts that an locational deliverability area can import under specified peak load test conditions. Transmission system topology changes, load forecasts, generation additions and generation deactivations can all impact CETL values. Each locational deliverability area is tested for its expected import capability up to established transmission facility limits, indicating how much an area can actually be expected to import, CETL. If the CETL value is less than CETO, the test fails, indicating the need for additional transmission capability. Transmission limits are defined in terms of facility thermal ratings and voltage limits. From a planning perspective, a thermal overload occurs on a bulk electric system facility, if flow on that facility exceeds 100 percent of one of the following:

- The facility's normal rating with all facilities in service
- The facility's emergency rating following the loss of a single facility

Likewise, voltages are also monitored for compliance with existing voltage limits specified in terms of permissible bus voltage level and contingency voltage drop, as specified by PJM operations in Manual 3, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m03.ashx.

Once PJM completes its load deliverability analysis, results are reviewed to determine the need for immediate project solutions or whether an RTEP proposal window is warranted, as discussed in **Section 2.1**.

Map 5.1: Locational Deliverability Areas

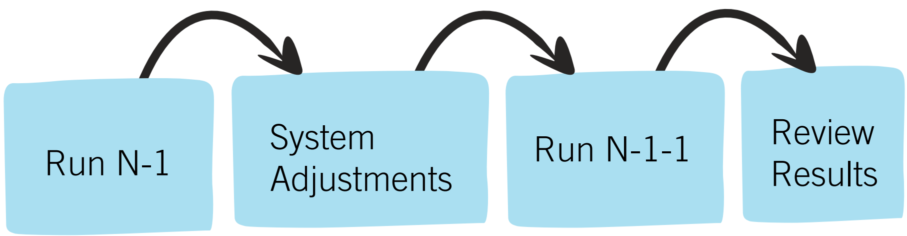


N-1-1 Analyses

N-1-1 contingency studies examine the impact of two successive N-1 events with system adjustments prior to the second event, as shown in **Figure 5.3**. PJM identifies facilities which have post-contingency flows that exceed applicable emergency ratings and that exceed normal ratings after system adjustment. Voltages are also monitored for compliance with existing voltage limits specified by PJM operations in Manual 3, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m03.ashx.

RTEP enhancements are developed to resolve criteria violations where the applicable rating after the first contingency or the applicable rating after the second contingency are exceeded.

Figure 5.3: N-1-1 Analysis



Prior Year Load Deliverability Review

PJM revisits the RTEP Load Deliverability analyses conducted during the prior year to determine changes to locational deliverability area CETO and CETL values caused by system changes identified during the prior year's RTEP cycle:

- Most recent PJM load forecast report
- PJM Board approved projects and Transmission Owner supplemental projects
- Generation deactivation and interconnection projects
- Transmission service

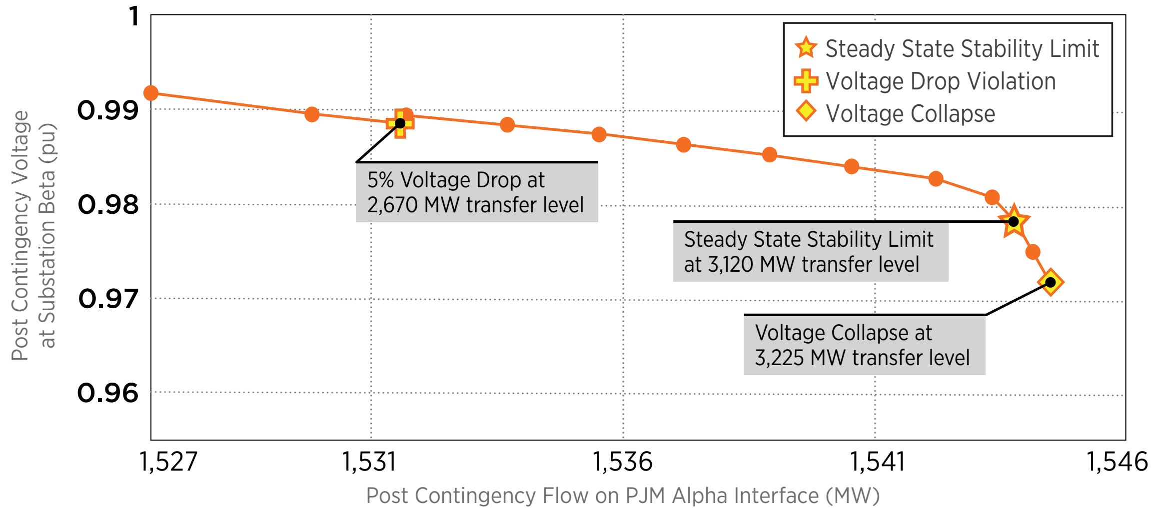
Doing so identifies limiting facilities for locational deliverability areas with a CETL to CETO margin less than 150 percent. This provides stakeholders a sense of system margin.

5.3: Reactive Analysis

NERC Reliability Standard TPL-001-4 requires that a transmission system remain stable, within applicable equipment thermal ratings and substation voltage limits. PJM assesses voltage response under P0 through P7 planning events for deliverability base case analysis and N-1-1 tests. As described earlier in this section, those tests ensure that the transmission system is able to deliver energy to a portion of the system that is experiencing a capacity deficiency. Typically, as more power is transferred across a line or set of lines, voltage levels deteriorate. The more abrupt the decline in voltage level for each incremental increase in power transfers, the more difficult voltage is to control in real-time.

If voltage level or voltage drop magnitude following the loss of a bulk electric system (BES) element violates specified limits, then system enhancements must be developed to resolve the violation. Permissible voltage magnitudes and voltage drop percentages are determined based on operational conditions at each substation. Voltage drop is limited at many 500 kV substations to five percent; emergency voltage magnitude is limited to no lower than 0.97 per unit, i.e. 97 percentage of nominal. Voltage magnitude and voltage drop limits are defined in PJM Manual 3, “Transmission Operations”: http://www.pjm.com/~/media/ documents/manuals/m03.ashx. RTEP process deliverability base case analysis and N-1-1 analyses examine voltage magnitude and voltage drop.

Figure 5.4: Example Power-Voltage Curve



Power Voltage Curves

Power-voltage curve analysis provides a much more rigorous examination of voltage collapse phenomena frequently suggested by NERC and regional voltage magnitude and voltage drop criteria violations identified in deliverability tests. Power-voltage analysis allows engineers to evaluate critical BES contingencies on system voltages as power transfers are increased. Substation voltage levels are represented on a curve and can show when reliability criteria violations occur and, beyond that, the point at which voltage collapse can eventually occur, an example of which is shown on **Figure 5.4**. Power-voltage curves of this type show how increasing power flows on a given line can reach a critical point where further increases would cause the transmission system to collapse. This critical point is the “steady state stability limit.” In the **Figure 5.4** example, this limit is very pronounced. A slight increase in power transfer would cause voltages to collapse following the contingency. Such situations leave little margin for system operators to manage the grid. If presented with the situation in real-time operations, system operators would have little time to react and need to take quick, decisive action by shedding load.

N-1-1 Voltage Analysis

PJM’s N-1-1 analysis also assesses applicable voltage magnitude and voltage drop limits. For voltage magnitude and voltage drop testing, PJM screens power flow results for potential voltage violations. Voltage violations include exceeding the emergency low limit after the second contingency, or exceeding the emergency voltage drop limit after the second contingency. Reinforcements are developed where voltage violations are identified.

5.4: Light Load Analysis

Light load system conditions within PJM have been observed as low as 30 percent of summer peak in some transmission owner zones. PJM system operators have encountered thermal overloads and high voltage events driven by low demand generation dispatch patterns and the capacitive effects of lightly loaded transmission lines. Generation dispatch differs markedly from that under peak load conditions, particularly for units powered by intermittent, renewable sources like wind. RTEP process light load analysis ensures that the transmission system is capable of delivering generating capacity during light load periods.

Modeling Light Load Conditions

PJM's modifies its peak load baseline power flow base case to reflect light load demand levels, interchange, and generation dispatch. System analysis is conducted at a load level reflecting 50 percent of the 50/50 summer peak demand forecast, representative of reasonably stressed light load conditions. PJM zonal interchange levels reflect statistical averages typical of those in prior years during light load periods. Likewise, interchange is based on historical statistical averages. As shown in **Table 5.3**, planning studies consider capacity factor by type of generator, including wind-powered facilities

PJM's generator deliverability test does not guarantee that a specific resource will be able to deliver energy under light load conditions. Rather, the purpose is to demonstrate that generators that typically run during light load periods in a given area can run simultaneously. The test also demonstrates that excess power above an area's demand can be exported to the rest of PJM without causing reliability criteria violations.

Table 5.3: Light Load Analysis Assumptions

Light Load Analysis Elements	Initial Study Assumptions
Network Model	5-year-out base case
Load Model	Light load level at 50 percent of a non-diversified forecasted 50/50 summer peak load, reduced by energy efficiency
PJM Base Generation Resource Capacity Factors	Nuclear at 100 percent
Modeled Online in Base Case Dispatch Percent of Summer Max Megawatt	Coal >= 500 MW at 60 percent
	Coal < 500 MW at 45 percent
	Oil at 0 percent
	Natural Gas at 0 percent
	Wind at 40 percent
	All other resources at 0 percent
	Pumped storage at full pump
MISO Base Generation Resource Capacity Factors (Modeled Online in Base Case Dispatch)	Wind at 100 percent
Interchange Values	Historical statistical averages during off-peak load periods.
Contingencies	NERC Categories P0 – P7 (except N-1-1)
Monitored Facilities	BES (Base Analysis) and all PJM market monitored facilities (Generator Deliverability)

Methodology

In order to implement study methodologies that simulate conditions experienced in actual operations, PJM has modified its generator deliverability tool in order to test sensitivity of light load case parameters due to wind generation ramping above peak case output levels. All bulk electric system facilities and non-bulk electric system facilities in the PJM's real-time congestion management control facility list are monitored. The same single contingency power flow solution techniques also apply. Wind generation is allowed to ramp from 40 percent to 80 percent if selected by the generator deliverability test process.

The contingency set used for light load reliability analysis include NERC TPL-001-4 planning events P0, P1, P2, P4, P5 and P7. All bulk electric system facilities as well as all non-bulk electric system facilities in the PJM real-time congestion management control facility list are monitored. Contingencies test for compliance with NERC TPL-001-4 single and multiple contingencies (with the exception of the N-1-1 criteria). Details of the light load reliability analysis procedure, including methods of creating the study dispatch, can be found in PJM Manual 14B, Section 2 and Attachment D: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

5.5: Winter Criteria

Winter peak reliability analysis tests the ability of an electrical area to export generation resources to the remainder of PJM during winter peak conditions. PJM models generation based on a historical mix of generation types and output levels typically observed during winter peak conditions. The analysis ensures that generation capability, including wind facilities that typically operate at winter peak – as well as pumped hydro can be delivered to the rest of PJM. **Table 5.4** summarizes winter peak base modeling parameters. The method to determine potential overloads is similar to the methods used for the generator deliverability test described in **Section 5.2**. Also, the Common Mode Outage analysis is conducted to evaluate the impacts of NERC P2, P4, P5, and P7 planning events: bus faults, faulted breakers, and double circuit tower line outages.

Winter criteria analysis also tests gas pipeline contingencies. PJM's gas pipeline contingency set includes those caused by failure of a gas pipeline or a compressor station. The contingency set will reviewed and validated periodically to ensure accurate analysis. The contingencies PJM tests align with NERC's new TPL-001-4 standard that became enforceable on January 1, 2016. The standard requires evaluation of extreme system events an example of which NERC cites as the "loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation". In addition, PJM will also evaluate gas temperature threshold, contingencies. This analysis assumes that at a pre-determined temperature threshold non-firm customers (i.e. non-heating demand and 100 percent of natural gas generation customers in a zone) will be interrupted. As required by NERC Standard TPL-001-4, if analysis identifies cascading conditions caused by the occurrence of extreme events, PJM will evaluate possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of those events. PJM's winter criteria is described in Manual 14B: http://www.pjm.com/-/media/documents/manuals/m14b.ashx.

Table 5.4: Winter Peak Base Case Modeling Parameters

Network Model	Current year + five base case	
Load Model	50/50 Winter Peak with the bus by bus load profile set by the local Transmission Owner	
Capacity Factor for Base Generation Dispatch for PJM Resources (Online in Base Case)	**Fuel Type**	**Percent**
	Solar	5
	Wind	33
	Water	38
	Nuclear	98
	Coal < 500 MW	51
	Coal >= 500 MW	73
	Landfill Gas	46
	Natural Gas	25
	Other Biomass Gas	111
	Oil (Distillate Fuel)	1
	Oil (Black Liquor)	74
	Oil (Kerosene)	0
	Oil (Residual Fuel)	2
	Municipal Solid Waste	79
	Wood Waste	66
	Waste Coal	75
	Petroleum Coke	75
	Other Solid	19
Interchange Values	Yearly long-term firm transmission service (except MAAC which will use historical averages)	
Contingencies	NERC Category P0, P1, P2, P3, P4, P5, P6 and P7	
Monitored Facilities	BES (N-1-1, Base Analysis) and all PJM market monitored facilities (Generator Deliverability)	

5.6: Short Circuit Studies

PJM conducts short circuit analysis to ensure compliance with NERC Reliability Standard TPL-001-4. The Standard requires that each bulk electric system circuit breaker have adequate fault interrupting capability. Simulated single-phase to ground and three-phase fault currents are compared to the breaker interrupting capabilities provided by transmission owners. All simulated fault currents greater than breaker ratings are identified and necessary enhancements developed, often requiring replacement of the breaker itself to implement a higher current interrupting rating. Short circuit analysis is performed consistent with the following industry standards:

- *ANSI/IEEE 551-2006* – Governs the recommended practice for calculating short-circuit currents in industrial and commercial power systems, how circuit breaker short circuit current information is provided and how related power system equipment is used to sense and interrupt fault currents.

- *ANSI/IEEE C37.04-1999* – Governs the rating structure for AC high-voltage circuit breakers and associated equipment.

- *ANSI/IEEE C37.010-1999* – Governs AC high-voltage circuit breakers rated on a symmetrical current basis, taking into consideration reclosing duration, reactance to resistance ratio differences, temperature conditions, etc.

- *ANSI/IEEE C37.5-1979* – Governs fault current calculation of AC high-voltage breakers that are rated on a total current basis.

Each of these standards is applied together with Transmission Owners' methodologies as a basis to calculate fault currents on all bulk electric system breakers. All breakers whose calculated fault currents exceed breaker interrupting capabilities are considered overdutied and reported to Transmission Owners for confirmation.

PJM develops two-year-out and five-year-out short circuit cases. The two-year planning case consists of the current system together with all RTEP system enhancements planned to be in service within the next two years. The five-year planning case uses the two-year-out planning case as modified to include all system enhancements, generating resources and merchant transmission projects planned to be in-service within five years, consistent with the five-year PJM RTEP power flow base case. Additional detail can be found in Section G.7 of Attachment G, PJM Manual 14B, "PJM Region Transmission Planning Process:" http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

5.7: Stability Analysis

PJM performs multiple tiers of analysis to ensure system stability in compliance with NERC Standard TPL-001-4 based on system contingencies of reasonable probability. Those contingencies comprise disturbances applicable to system normal, single element outage and common-mode multiple element outage conditions. Following a disturbance, any observed system oscillations must display sufficient positive damping.

- *PJM System-Wide Analysis* – System stability assessment at peak load is performed on one third of the network each year so that the entire system is analyzed every three years. In addition the analysis also includes an evaluation under light load conditions, typically the most challenging from a stability perspective.

- *Interconnection Request System Impact Studies* – Generating unit stability analysis is performed by PJM as a part of the System Impact Study for proposed generation interconnection to the PJM system. The analysis identifies any potential stability concerns between the new generator and existing bulk electric system facilities.

- *Operational Performance Issues* – Stability assessments are also conducted on an as-needed basis when system topology changes occur or are proposed in areas with known, limited stability margins. These assessments are frequently driven by system conditions and events arising out of actual operations.

PJM's stability study process is described in Attachment G of Manual 14B, "PJM Region Transmission Planning Process": http://www.pjm.com/~/media/documents/manuals/m14b.ashx

N-1-1 Stability Analysis

An N-1-1 contingency pair – associated with NERC Planning event P3 or P6 – is defined as a single-line to ground or three-phase fault with normal clearing, manual system adjustments, followed by another single-line to ground or three-phase fault with normal clearing. Manual adjustments after the first, N-1, contingency are allowed to relieve any thermal or voltage violations for applicable ratings and/or to prepare for the second, N-1-1, contingency. For a given N-1-1 contingency scenario, the first, N-1, contingency is applied to a pre-disturbance base case. If the system is stable, a new operating point is determined and manual adjustments are made if necessary, and then stability is monitored following the second, N-1-1, single contingency. Because a long time delay is assumed between two single contingencies, N-1-1 stability analysis is similar that conducted for maintenance outage studies.

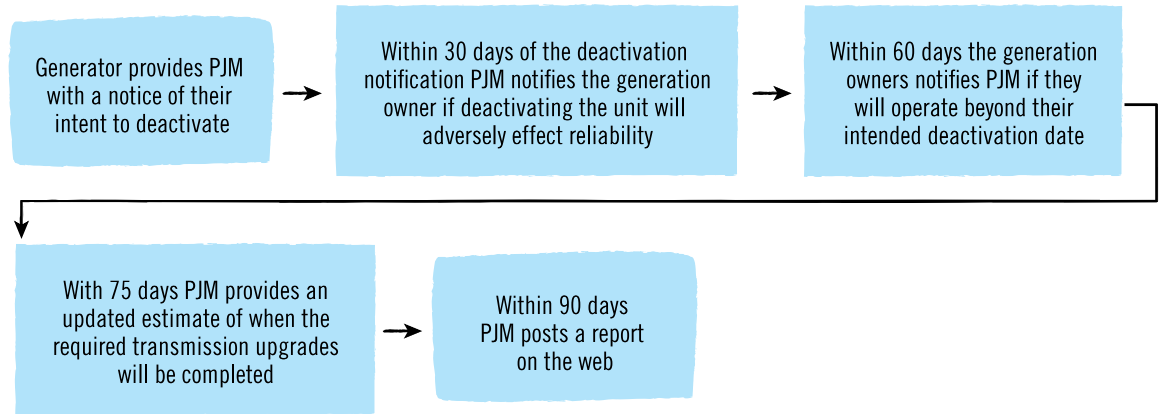
Dynamics Case Development

PJM's current RTEP summer peak case is used as a starting point to create peak load and light load dynamics cases. Additional information, however, is necessary for stability studies to simulate the combined dynamic responses of various power system components. This includes dynamics models for generators, excitation systems, power system stabilizers, governors, loads and various other equipment. The case is also modified to include generator step-up transformers, explicit modeling of generator station service power, and gross generator rating. Adjoining system models are obtained from the NERC System Dynamics Data Working Group. Required dynamic and other modeling information that must be supplied by generators is detailed in Manual 14A, "Generation and Transmission Interconnection Process : http://www.pjm.com/~/media/documents/manuals/m14a.ashx.

5.8: Generation Deactivation Analysis

PJM continues to evaluate the impacts of individual deactivation requests. Coal-fired generators in particular face the real possibility of deactivation given the economic impacts of increasing operating costs associated with unit age – many more than 40 years old – and environmental public policy, particularly with regard to emissions standards. For example, on August 3, 2015, the U.S. Environmental Protection Agency issued its final Clean Power Plan (CPP), a rule limiting carbon dioxide emissions from existing power generation resources. Generator deactivations alter power flows that often yield transmission line overloads and, given reductions in system reactive support from those generators, can undermine voltage support.

Figure 5.5: Generator Deactivation Process



Notification and Study

Generation owners are required to notify PJM of their intent to deactivate generation per Article V of the PJM tariff. Per FERC order, PJM cannot compel unit owners to remain in service. Unlike timelines associated with requests for interconnection, deactivation may take effect upon 90 days' notice, as shown in **Figure 5.5**. PJM maintains a list of generator deactivation notifications – as formally submitted by asset owners – online via the following link: http://pjm.com/planning/generation-deactivation.aspx.

After deactivation notification is received, PJM conducts a series of studies to determine if the generator removal will have an adverse impact on BES reliability in light of established criteria and standards. If reliability criteria violations are identified, baseline transmission enhancements are developed to resolve those violations. The scope of deactivation reliability studies comprises thermal and voltage analysis under generator deliverability, common mode outage, N-1-1 and load deliverability tests.

System expansion solutions may include enhancements to existing facilities, scope expansion for current baseline projects already in the RTEP or the construction of altogether new facilities. Transmission enhancements required to maintain a reliable system are identified and reviewed with the subregional RTEP committees and the Transmission Expansion Advisory Committee. The cost of transmission enhancements to mitigate criteria violations caused by generation deactivation is allocated to load.

Interim Measures

If transmission improvements are completed prior to a unit's intended deactivation date, reliability issues can be avoided. However, if improvements are not in place prior to deactivation, and if reasonable operating procedures cannot be implemented, then PJM can pursue a reliability-must-run (RMR) agreement with the generator owner. Doing so can keep a unit online beyond its announced retirement date until transmission improvements are completed. Under the PJM Open Access Transmission Tariff, costs incurred to compensate RMR generator owners are recovered through an additional transmission charge allocated to Transmission Owners zonal load that bears the financial responsibility for the required transmission improvements. Regardless, a generation owner is not under any obligation to pursue the RMR agreement and may retire the unit at any time. PJM cannot compel a generator to remain in service.

Recent Deactivations

PJM continued to receive deactivation notifications throughout 2016, including 28 units totaling 5,909 MW, up from 1,626 MW in 2015, and 4,291 MW in 2014. For perspective, PJM received and studied deactivation requests for nearly 11,000 MW during the eight years ending November 1, 2011. PJM will continue to study generator deactivations as notifications are received throughout the 2017 RTEP cycle.

As discussed in **Section 8.1**, PJM recently completed scenario studies that examined the impact of the Environmental Protection Agency's Clean Power Plan limiting carbon dioxide emissions from existing power generation resources. PJM will continue to monitor federal environmental policy. The scope of PJM regional and interregional studies will be revised accordingly.

5.9: Transmission Relay Loadability

The purpose of NERC Reliability Standard PRC-023-3 is to ensure that protective relay settings do not limit transmission loadability; do not interfere with system operators' ability to take remedial action to protect system reliability; and are set so that they reliably detect all fault conditions. The standard specifies how protective relays should be set to prevent potential cascade tripping that could occur when protective relay settings limit transmission loadability. The objective of the standard is to identify the facilities that must meet those requirements. Accordingly, a number of transmission system elements are subject to the requirements of PRC-023-3.

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except elements that connect the generator step-up transformer(s) to the transmission system that are used exclusively to export energy directly from a bulk electricity system generating unit or generating plant. Elements may also supply generating plant loads.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the bulk electricity system, except elements that connect the generator step-up transformer(s) to the transmission system that are used exclusively to export energy directly from a from a bulk electricity system generating unit or generating plant. Elements may also supply generating plant loads.

PJM conducts an assessment at least once each calendar year, with no more than 15 months between assessments. Doing can identify those facilities for which Transmission Owners, Generator Owners, and Distribution Providers must comply. Additional information can be found in PJM Manual 14B, Attachment G, Section 10, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

5.10: Transmission Owner Driven System Enhancements

The PJM Operating Agreement specifies that Transmission Owner planning criteria are to be evaluated as a part of the RTEP process. PJM has observed over the past several years that Transmission Owner criteria, particularly with respect to aging infrastructure, are increasingly driving the need for baseline projects. PJM expects this to continue in 2017.

Aging Infrastructure

PJM has observed over the past several years that Transmission Owner criteria, and aging infrastructure in particular, are increasingly driving the need for baseline projects. Many 500 kV lines were constructed in the 1960s; 230 kV and 115 kV lines date to the 1950s and earlier. Many Transmission Owners have added aging infrastructure to their planning criteria as part of respective FERC Form No. 715 filings. Each Transmission Owner's planning criteria is provided on PJM’s website: http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx. PJM includes transmission projects identified under these criteria as part of the RTEP consistent with section 1.2(e) of Schedule 6 of the Operating Agreement.

Transmission Owner Supplemental Projects

Supplemental projects were known as Transmission Owner Initiated Projects prior to FERC Order No. 890 in 2008. They are not required for compliance with system reliability, operational performance or economic criteria, as determined by PJM. PJM reviews these projects though to ensure that they do not introduce other reliability criteria violations. And while not subject to PJM Board approval, they are included in PJM’s RTEP. For example, individual Transmission Owner supplemental projects are addressing such drivers as the following:

- *Aging infrastructure* – to replace, retire or rebuild equipment
- *Underlying system reinforcements* – to add new distribution substations or delivery points to serve lower voltage systems
- *Customer load connections* – to extend transmission to serve new large customer facilities
- *Infrastructure resilience* – text (e.g., storm hardening)

Supplemental projects are introduced to the PJM regional planning process through PJM’s TEAC and subregional RTEP committees. They are subject to the same open, transparent and participatory stakeholder review as PJM initiated projects. Supplemental projects are not subject to regional cost allocation; the incumbent Transmission Owners zone customers pay 100 percent of their cost.

Note

PJM is currently awaiting clarification from FERC that Transmission Owner issues alone do not require that PJM conduct an RTEP window.

Section 6: 2017 RTEP Market Efficiency Analysis

6.0: Scope

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis to accomplish the following objectives:

- Determine which reliability upgrades, if any, have economic benefit if accelerated
- Identify new transmission upgrades that may realize economic benefit
- Identify economic benefits associated with modification to reliability-based enhancements already included in the RTEP that when modified would relieve one or more economic constraints. Such upgrades, originally identified to resolve reliability criteria violations, may be designed in a more robust manner to provide economic benefit as well.

PJM identifies the economic benefit of proposed transmission projects by conducting production cost simulations which show the extent to which congestion is mitigated by the project for given transmission topologies and generation dispatch. The benefit metrics are determined by comparing future year simulation with and without the proposed transmission enhancement. The set of metrics and methods used to determine economic benefit are described in PJM Manual 14B, Section 2.6 and PJM Operating Agreement, Schedule 6, Section 1.5.7 accessible on-line via the following links:

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

Market Simulation

The PJM market efficiency analysis employs a market simulation tool that models an hourly security-constrained unit commitment and economic dispatch. In order to accomplish the market efficiency objectives discussed above, several base cases are developed. The primary difference between these cases is the transmission topology to which the simulation data is mapped. The "As-Is" base case maps to a near-term transmission topology case and includes significant upgrades expected to be in service by June 1 of the near-term year. The "As-Planned" base case maps to a five-year out transmission system that includes PJM RTEP upgrades approved by the PJM Board through the RTEP cycle. Comparing results of multiple simulations with the same input assumptions and operating constraints but with differing transmission topologies allows PJM to determine a transmission enhancements economic value. Utilizing this basic technique coupled with additional benefit analysis allows PJM to perform the following:

- Collectively value the approved RTEP portfolio of enhancements
- Evaluate RTEP project acceleration or modification for economic benefit
- Evaluate proposed transmission enhancements for economic benefit

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

2017 Market Efficiency Analysis

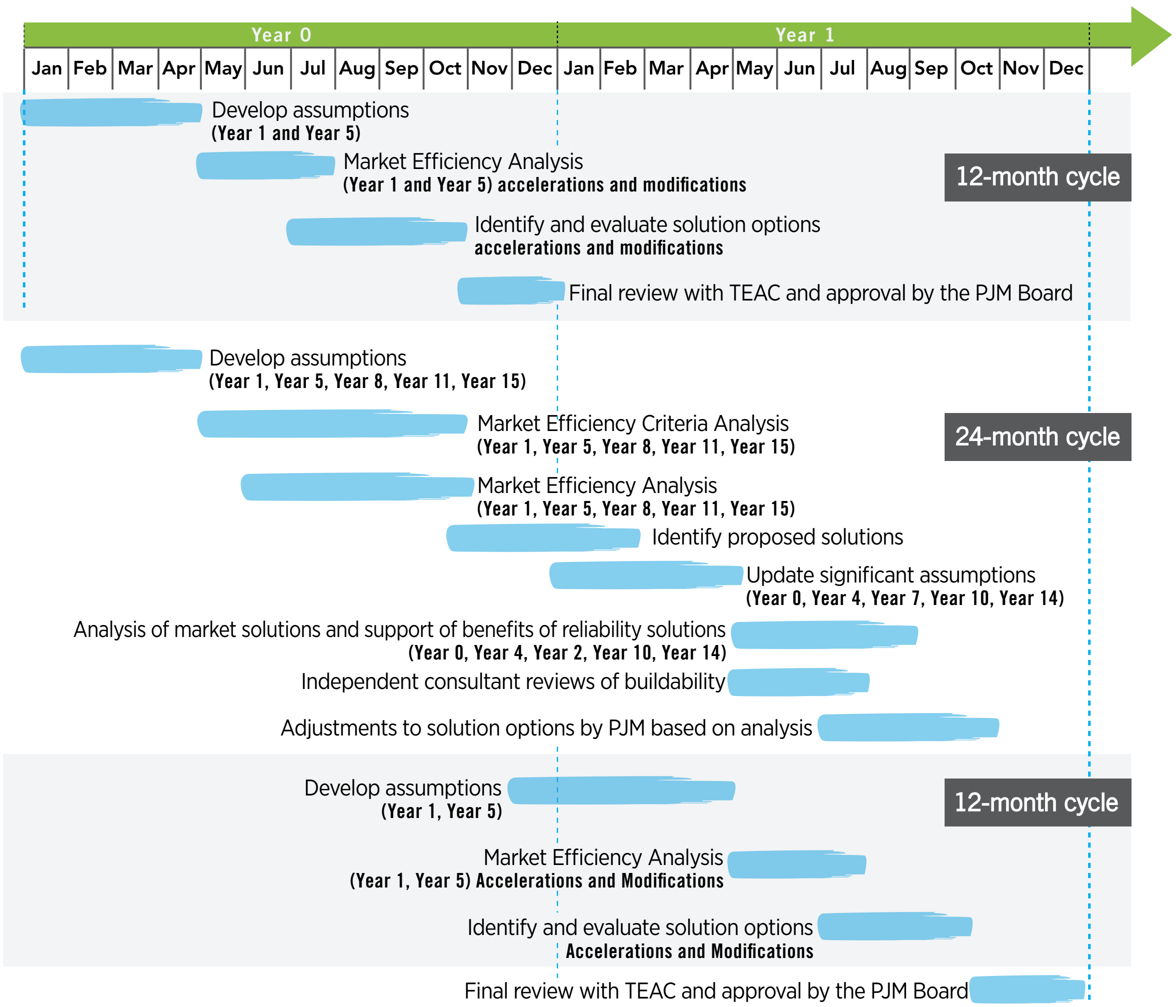
The time line of the 24-month market efficiency cycle is shown in **Figure 6.1.** The 2017 Market Efficiency Analysis represents the second year of the 24-month RTEP market efficiency cycle begun in 2016. As such, the 2017 market efficiency analysis focuses on the evaluation of the market efficiency projects submitted through the 2016/2017 RTEP Long-Term Proposal Window. Additionally, 2017 activity will include a review of the economic benefit of previously approved market efficiency solutions as well as analysis to assess opportunity for acceleration of approved reliability projects (with modification if deemed feasible).

Near-Term Simulations: 2018 and 2022 Study Years

PJM's 2017 market efficiency analysis includes near-term simulations to assess the collective economic impact of all previously approved future RTEP enhancements and to identify potential accelerations or modifications to individual RTEP projects. By comparing the total simulation differences from the "As-Is" base case to the "As-Planned" base case for both 2018 and 2022 study years, PJM can quantify the total transmission congestion reduction due to recently planned RTEP enhancements.

Similarly, comparison of the near-term "As-Is" and "As-Planned" simulations can identify constraints which may cause significant congestion and whether already planned enhancements may eliminate or relieve this congestion to the point that the constraint is no longer an economic concern. A comparison of these simulations can reveal if a particular RTEP upgrade may provide economic benefit that would make the enhancement a candidate for acceleration or modification. For example, if a constraint causes significant congestion in the 2018 "As-Is" simulation but not in the 2022 "As-Planned" simulation then the enhancement which eliminates this congestion in 2022, may be a candidate for acceleration. The benefit of accelerating an enhancement is then compared to the cost of the acceleration before any recommendation can be made to the PJM Board.

Figure 6.1: Market Efficiency 24-month Cycle



Long-Term Simulations: 2017, 2021, 2024, 2027 Study Years

In order to quantify future longer-range transmission system market efficiency needs, PJM identified base congestion for study years 2017, 2021, 2024 and 2027. PJM identified these needs during the first nine months of the 2016/2017 RTEP market efficiency cycle. The base cases for these evaluations represent a 2021 RTEP "As-Planned" transmission system topology and include RTEP projects submitted for approval through the 2015 RTEP cycle.

Mid-Cycle Update

Importantly, projects submitted during the 2016/2017 RTEP Long-Term Proposal Window, open from November 2016 through February 2017, arose out of market efficiency needs identified in base cases developed in 2016. To that end, PJM will also develop a 2017 mid-cycle update case that incorporates RTEP system enhancements approved by the Board during 2016. The updated case will also include changes in generation, load forecasts, fuel prices, and emission costs. The purpose of the 2017 mid-cycle analysis will be to ensure that identified projects are sufficiently robust under updated system conditions. Where deemed appropriate, PJM may also run additional sensitivity studies varying, but not limited to, such factors as load level, fuel forecasts, and generation availability.

Benefit-to-Cost Threshold Test

PJM performs a benefit-to-cost threshold test to determine if market efficiency justification exists for a particular transmission enhancement alternative. Market efficiency transmission proposals that meet or exceed the 1.25 benefit-to-cost ratio threshold test are further assessed to examine additional economic, system reliability, and constructability impacts before being submitted for the PJM Board approval. For projects with a total cost exceeding $50 million, PJM's Operating Agreement requires an independent review of project costs to ensure consistent estimating practices and project scope development.

The benefit-to-cost ratio is calculated by comparing the present value of annual benefits determined for the first 15 years of the upgrade life to the present value of the upgrade revenue requirement for the same 15-year period.

The market efficiency benefits for the majority of evaluations are derived solely through energy market simulations and resulting metrics. Other transmission evaluations, which may prospectively affect the capacity market, may derive additional benefits through capacity market simulations and metrics.

PJM's annual energy benefit calculation for regional facilities is weighted 50 percent to change in system production cost and 50 percent to change in net load energy payments for zones with a decrease in net load payments as a result of the proposed project. Change in system production cost comprises the change in system generation variable cost (fuel costs, variable operating and maintenance costs and emissions costs) associated with total PJM energy production. Change in net load energy payment comprises the change in gross load payment offset by the change in transmission rights credits. The net load 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 project are excluded from the net load energy payment benefit.

PJM's annual energy benefit calculation for lower voltage facilities is weighted 100 percent to zones with a decrease in net load payments as a result of the proposed project. Change in net load energy payment comprises 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 project decreases the net load payments. Zones for which the net load payments increase because of the proposed project are excluded from the net load energy payment benefit.

PJM's annual capacity benefit calculation for regional facilities is weighted 50 percent to change in total system capacity cost and 50 percent to change in net load capacity payments for zones with a decrease in net load capacity payments as a result of the proposed project. PJM's annual capacity benefit calculation for lower voltage facilities is weighted 100 percent to zones with a decrease in net load capacity payments as a result of the proposed project. Change in net load capacity payment comprises the change in gross capacity payment offset by the change in capacity transfer rights.

PJM's RTEP market efficiency study process and the benefit-to-cost ratio methodology are described in Section 2.6 of PJM Manual 14B, "PJM Region Transmission Planning Process", available on PJM's website via the following URL: http://pjm.com/~/media/documents/manuals/m14b.ashx.

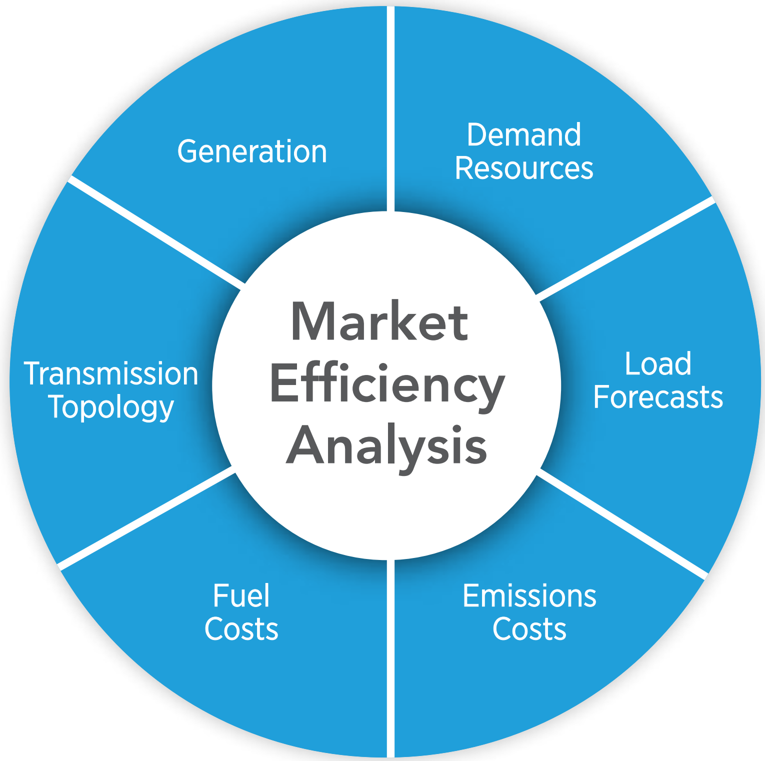
6.1: 2017 Input Parameters

PJM licenses a commercially available database containing the necessary data elements to perform detailed market simulations. This database is periodically updated permitting up-to-date representation of the Eastern Interconnection, and in particular, PJM markets. Because this data is used in developing forecasted system conditions, PJM reviews key assumptions before initiating any market efficiency studies. Consistent with established RTEP process practice, the PJM Transmission Expansion Advisory Committee (TEAC) reviews the key analysis input parameters, including those shown in **Figure 6.2**. These parameters include fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology, and several financial valuation assumptions.

Transmission Topology

Market Efficiency power flow models are developed to represent (1) an "As-Is" transmission system topology and (2) the expected "As-Planned" system topology for the five-year out RTEP year. PJM derives the "As-Is" system topology from review of the Eastern Interconnection Reliability Assessment Group Multi-Regional Modeling Working Group most recent year series of the next summer's peak case. System topologies for the "As-Planned" system are derived from the PJM RTEP base case used for baseline reliability studies.

Figure 6.2: Market Efficiency Analysis Parameters



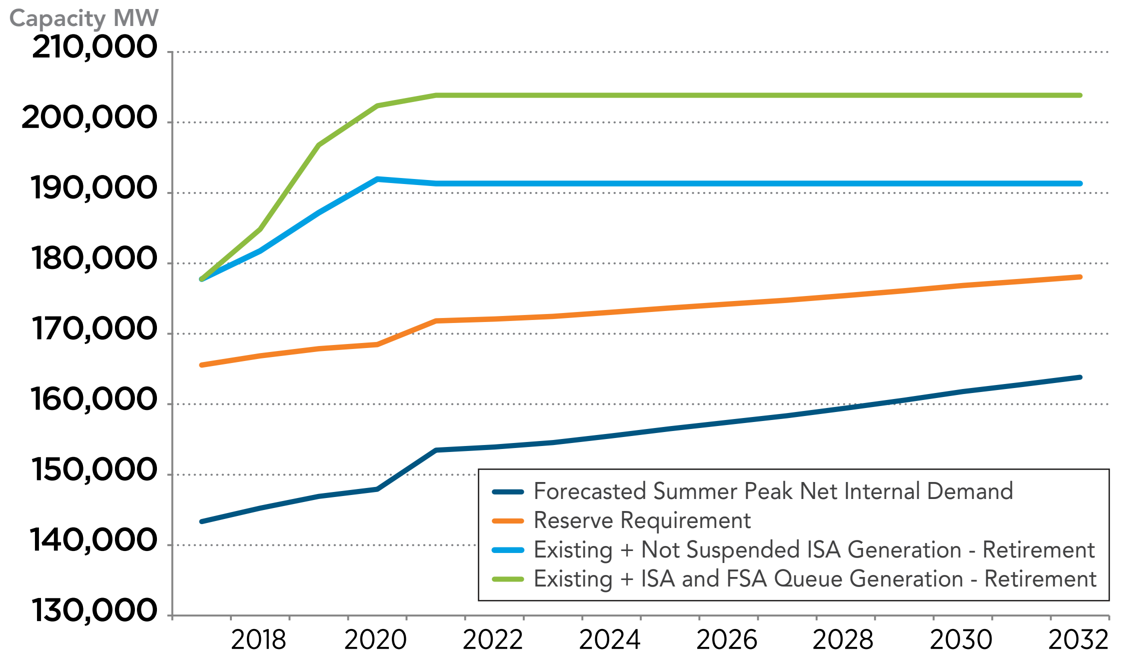
Monitored Constraints

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

Generation Modeled

Market efficiency simulations model existing in-service generation and active, queued generators that have executed a Facilities Service Agreement. PJM removes generation that has given formal deactivation notification to PJM. Taking all this into account reveals that currently modeled generation provides sufficient capacity to meet PJM's installed reserve requirement through all study years as shown in **Figure 6.3**.

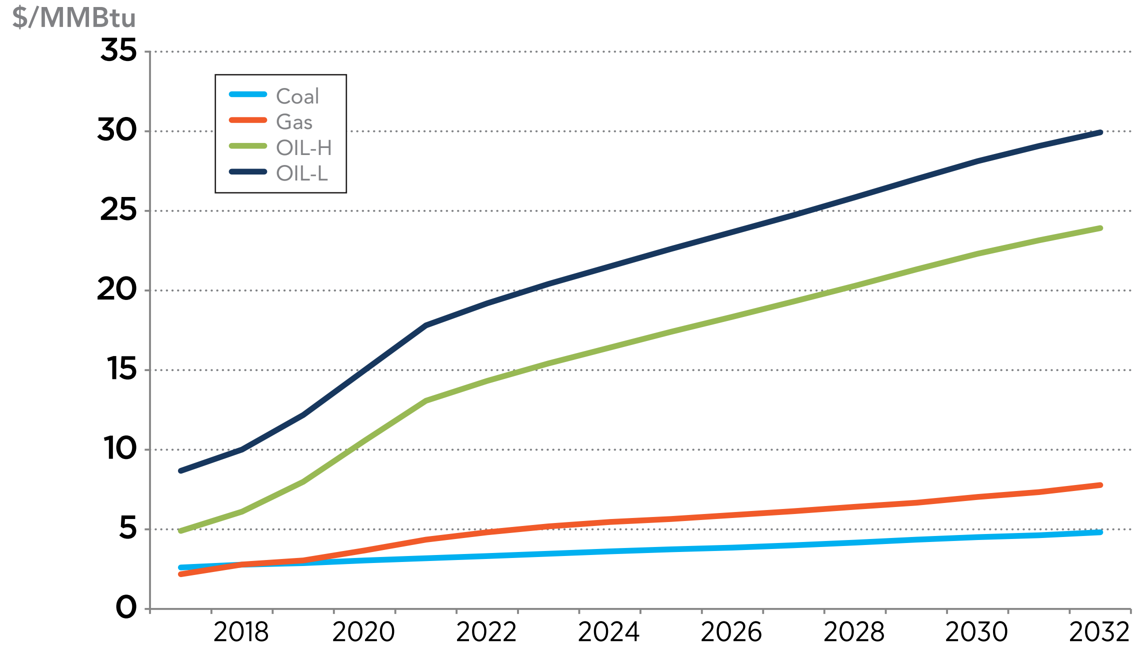
Figure 6.3: PJM Market Efficiency Reserve



Fuel Price Assumptions

PJM uses a commercially available 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 are obtained from commercially available databases, as are all coal price forecasts. In addition, vendor-provided basis adders are applied to account for commodity transportation cost to each PJM zone. The fuel price forecasts to be used in PJM's 2017 market efficiency analysis are shown in **Figure 6.4**.

Figure 6.4: Fuel Price Assumptions



Load and Energy Forecasts

PJM's 2017 load forecast report provides the transmission zone load and energy data modeled in 2017 market efficiency simulations. Energy efficiency is incorporated into the load forecast models. **Table 6.1** shows the PJM peak load and energy values to be used in this year's market efficiency analysis.

Demand Resources

The total PJM demand resource quantity modeled in each study year is shown in **Table 6.2,** consistent with the 2017 PJM Load Forecast Report.

Table 6.1: 2017 Peak Load and Energy Forecast

Load	2017	2021	2024	2027	2031
Peak (MW)	152,999	153,384	154,142	155,773	157,513
Energy (GWh)	814,838	820,415	827,522	835,137	845,602

Notes:
1.) Peak and energy values from PJM Load Forecast Report, Table B-1 and Table E-1, respectively.

2.) Model inputs are at the zonal level, to the extent zonal load shapes create different diversity – modeled PJM peak load m ay vary.

Table 6.2: Demand Resource Forecasts

Load	2017	2021	2024	2027	2031
Demand Resource (MW)	9,120	6,169	6,187	6,237	6,290

Notes:
1.) Values from PJM Load Forecast Report, Table B-7.

Emission Allowance Price Assumptions

PJM currently models three major effluents – SO_2, NO_x and CO_2 within the market efficiency simulations. SO_2 and NO_x emission price forecasts reflect implementation of the Cross State Air Pollution Rule and are shown in **Figure 6.5** and **Figure 6.6,** 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. Base emission price assumptions for both the national CO_2 and RGGI CO_2 program are shown in **Figure 6.7**.

Carrying Charge Rate and Discount Rate

In order to determine and evaluate the potential economic benefit of RTEP projects, PJM performs market simulations and calculates a benefit-to-cost ratio for each candidate upgrade. Doing so requires that the net present value of annual benefits be calculated for the first 15 years of upgrade life and compared to the net present value of the upgrade revenue requirement for the same 15-year period. A discount rate and levelized carrying charge rate is developed using information contained in Transmission Owner formula rate

Figure 6.5: SO_2 Emission Price Assumption

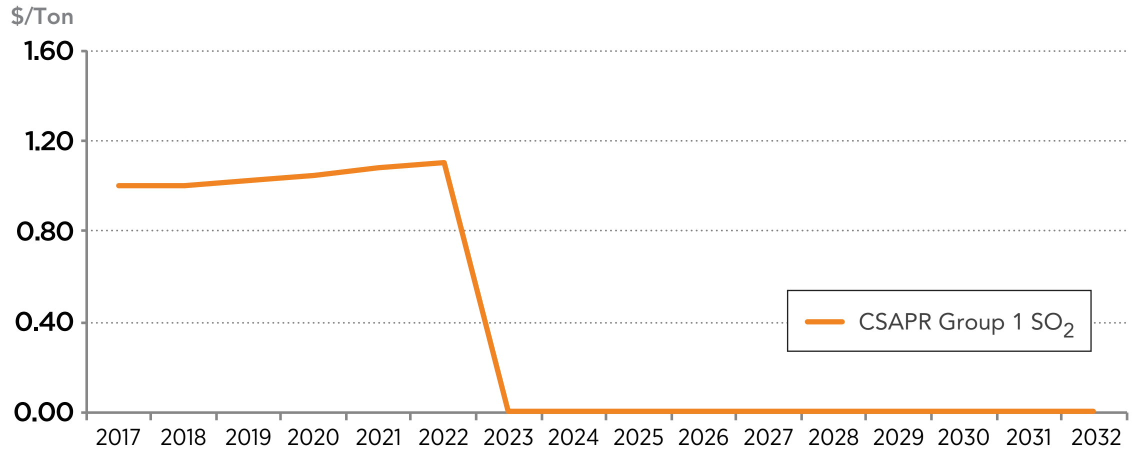
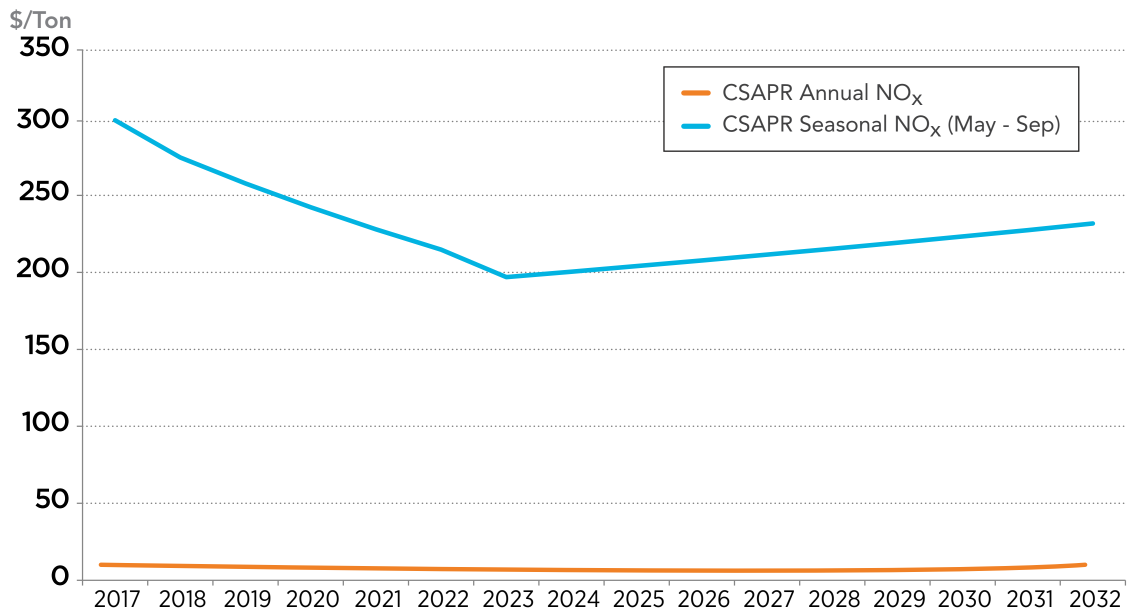


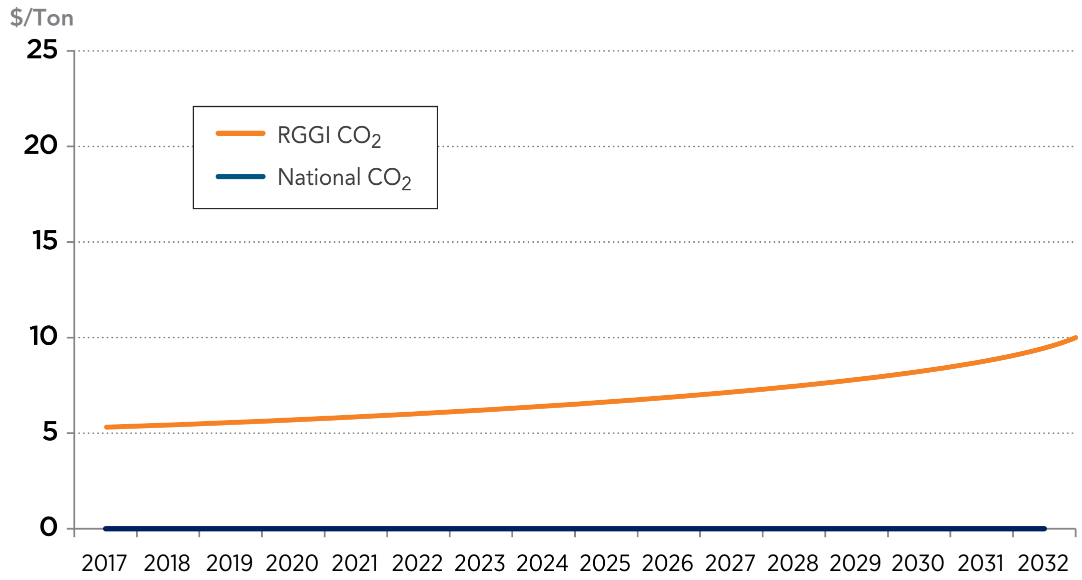
Figure 6.6: NO_x Emission Price Assumption



sheets (Attachment H) as posted on PJM's 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 Transmission Owner total capitalization). The levelized annual carrying charge rate is based on weighted average net plant carrying charge (average weighted by Transmission Owner total capitalization) levelized over an assumed 45-year life of the project. PJM's 2017 market efficiency studies will use a levelized annual carrying charge rate of 15.3 percent and a discount rate of 7.4 percent.

Figure 6.7: CO_2 Emission Price Assumptions



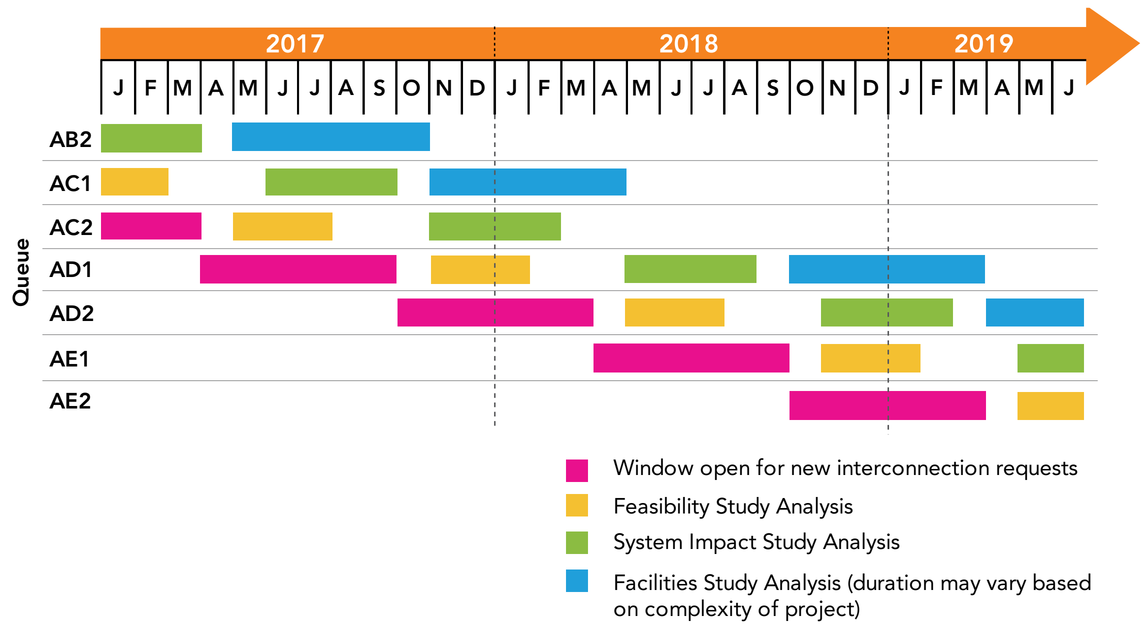
Section 7 – New Service Requests – 2017 Scope

7.0: Generation Interconnection

The five-year dimension of PJM's Regional Transmission Expansion Plan (RTEP) process permits PJM to assess and recommend transmission enhancements not only to meet forecasted near-term load growth but to ensure reliability in light of new customer requests for the following:

- Generation interconnection
- Merchant transmission interconnection
- Merchant network upgrade
- Long-term firm transmission service
- Incremental Auction Revenue Rights

Figure 7.1: PJM Queue Timeline – 2017 - 2019



PJM conducts two New Service Queue windows per year according to the PJM Open Access Transmission Tariff for PJM to accept New Service Requests. Each window is open for six months: the first queue window closes on March 31 of the calendar year. The second closes on September 30 of the same calendar year. A New Service Request will be assigned a queue position only when all Tariff-required information, data, agreements, and deposits are submitted.

PJM's queue based new service request process offers developers the flexibility to pursue capacity, energy, ancillary service, and other business opportunities in PJM. **Figure 7.1** shows the current queue window and study timeline for 2017 through 2019. While a developer can withdraw at any point, the process is structured such that each step imposes its own increasing financial obligations on the developer. As part of queue studies, PJM conducts the necessary deliverability and other tests to identify any NERC, regional and Transmission Owner reliability criteria violations to be resolved. These are described in **Section 5.2.** PJM's Open Access Transmission Tariff, Section VI governs the terms and conditions under which parties seek new service: http://www.pjm.com/directory/merged-tariffs/oatt.pdf. PJM Manual 14A and 14B describe related business rules and test methodologies: http://www.pjm.com/library/manuals.aspx.

PJM's experience over the past 15 years has revealed that the ebb-and-flow of requests is driven by developer business decisions in the face of public policy, regulatory uncertainties, political climate, economic conditions and financing considerations. The RTEP process establishes milestone responsibilities for the developer, PJM and each affected Transmission Owner.

7.1: Generation Interconnection Requests

PJM's capacity, energy, and ancillary service markets have attracted over 471,000 MW of generator interconnection requests. These requests constitute a significant driver of regional transmission expansion needs.

Feasibility, system impact and facilities studies ensure that new resources interconnect without violating established NERC criteria. Interconnection requests for generation powered by renewable fuel sources require specific analytical studies unique to their particular characteristics. For example, wind-powered generator requests have clustered in remote areas most suitable to their operating characteristics and economics but with less robust transmission infrastructure. Such an injection of power increases system stress in areas already limited by existing operating restrictions. Consequently, PJM is increasingly encountering the need for complex power system stability studies and low-voltage ride-through analysis.

Electing Capacity or Energy Status

Each developer's interconnection request specifies whether its generation is to be evaluated as a PJM capacity resource, an energy-only resource, or a combination of both.

Capacity resource status allows a generator to participate in PJM's RPM-based capacity market or as a fixed revenue resource. Under the terms of PJM's Reliability Assurance Agreement, in order to qualify as a capacity resource sufficient transmission capability must exist to ensure that generator output is deliverable to PJM's aggregate network load under peak load conditions at the requested point of interconnection. From an RTEP process perspective, PJM conducts deliverability and common mode outage studies – as described in **Section 5.2** – as part of compliance with NERC and regional reliability criteria. Studies may identify system enhancement for a unit to interconnect to the PJM grid reliably and receive its requested capacity rights. The developer bears the cost responsibility for the reinforcements necessary to resolve identified reliability criteria violations. Subsequent annual RTEP cycles encompass studies to ensure the ongoing deliverability of all generators within PJM consistent with their capacity interconnection rights.

Energy Resource units are only permitted to participate in the energy market. Such units do not receive Capacity Interconnection Rights and may not participate in PJM Capacity markets. The planning studies for generating units seeking energy resource status do not include the deliverability analyses required of those units seeking Capacity Resource status.

Representation in Baseline Studies

PJM's RTEP process specifies that planning studies model all generation projects that have completed a system impact study and entered the Facilities Study phase. Only those generation projects with executed Interconnection Service Agreements (ISAs), however, are permitted to off-load an identified transmission constraint. More than 15 years of queue experience has demonstrated that this minimizes the need for retooling studies that would otherwise be required by interconnection requests that ultimately withdraw. While withdrawn projects make up a significant portion of total interconnection request activity, 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.

PJM Open Access Transmission Tariff provisions regarding ISA / Construction Service Agreement (CSA) execution permit an interconnection customer to suspend ISA/CSA attachment facility and network facility construction obligations for a cumulative period of up to three years. This means that the generating facility itself will not be online at the in-service date originally identified by the developer. PJM assesses each suspension notification for its impact on network upgrade requirements. If PJM's assessment identifies either reliability issues or customers who are materially harmed, the suspension period for the network facility is limited to one year.

Generation Powered by Renewables

PJM's interconnection process offers a structure that assures consistent opportunity for development across fuel types, while providing the flexibility to adapt to specific technical realities and market challenges. Presently, PJM's queues include interconnection requests for plants fueled by biomass, hydro, methane, solar, wind and wood.

While some renewable resources can operate in a manner similar to the traditional fossil fuel powered plants, other renewable energy sources, such as wind, are recognized as intermittent resources. Their ability to generate power is directly determined by the immediate availability and/or magnitude of their specific fuel. For example, wind turbines can generate electricity only when wind speed is within a range consistent with the physical specifications of the related turbines. This presents challenges with respect to real-time operational dispatch and specific capacity value. To address the latter issue, PJM has established a set of business rules unique to intermittent resources to determine reasonably available capacity during the PJM summer peak period. Capacity credit values – such as the initial 13 percent for new wind resources and 38 percent for solar – are used to ensure capacity resource adequacy in RPM auctions.

Generation Under 20 MW

Requests for the interconnection of new resources 20 MW or less may be processed through expedited procedures per the PJM Open Access Transmission Tariff. Expedited procedures are defined for three categories of these small resource additions: permanent capacity resource additions, permanent energy-only resource additions, and temporary energy-only resource additions. Procedures for these requests are described in PJM Manual 14A, "PJM Generation and Transmission Interconnection Process," available from PJM's website via the following link: http://www.pjm.com/library/manuals.aspx.

Analysis conducted during the feasibility and system impact studies will be expedited (to the degree possible) for new permanent Capacity Resources of 20 MW or less, or permanent Energy Resources of 20 MW or less, or increases of 20 MW or less to existing resources over any consecutive 24-month period. Power flow analysis will be performed based on a limited contingency set to identify the impact of the resource on the local system and any known violations in the area. Deliverability tests will be performed for small capacity resources in areas where margins are known to be limited. Similarly, stability analysis will only be performed for small resources where existing stability margins are limited. Generation Interconnection Facilities Studies for small resources can only be expedited consistent with the scope of the required transmission facility additions and upgrades.

Requests for the interconnection of new energy resources of two MW or less may also be expedited through the use of pre-certified generation equipment and systems that meet IEEE Standard 1547 technical and Tariff specified screening requirements.

Behind-the-Meter Generation

Behind-the-meter generation refers to one or more generating units with load at a single location. Behind-the-meter does not include generators designated as capacity resources nor does it include generators whose output is sold through PJM's energy market for consumption at another location. Generating resources operating behind-the-meter, in isolation from the PJM bulk power transmission system and which do not intend to participate in the PJM wholesale energy market must still coordinate all planning, construction and operation with the host Transmission Owner. Behind-the-meter generation must submit an interconnection request for the portion of it's output that will participate in PJM energy and capacity markets.

7.2: Transmission Specific Requests

As noted in **Section 7.0**, the five-year dimension of PJM's Regional Transmission Expansion Plan (RTEP) process ensure reliability in light of new customer requests for merchant transmission interconnection, merchant network upgrades, long-term firm transmission service, and incremental auction revenue rights. Here, also, PJM's Open Access Transmission Tariff, Section VI governs the terms and conditions under which parties seek new service: http://www.pjm.com/directory/merged-tariffs/oatt.pdf. PJM's Manual 14 series describes related business rules and test methodologies. Both manuals are accessible from PJM's website via the following link: http://www.pjm.com/library/manuals.aspx.

Merchant Transmission

Developers of Merchant Transmission Facilities that interconnect with the PJM Transmission System may be entitled, subject to certain restrictions, to elect certain transmission rights that are created by the addition of such facilities. Much like the generation interconnection requests, those for merchant transmission follow a queue-based driven series of feasibility, system impact and facilities studies to ensure that such facilities interconnect without violating established NERC criteria.

Merchant Network Upgrades

A developer can also request additions to, or modifications or replacements of existing Transmission Owner transmission facilities or existing RTEP system enhancements. This can include accelerating the construction of a transmission enhancements, other than Merchant Transmission Facilities, that are already included in PJM's RTEP. Once the request is received, PJM conducts a system impact study and coordinates the development of estimated costs.

Long-Term Firm Transmission Service Requests

PJM's fundamental responsibility is to plan and operate a safe and reliable transmission system that serves all long-term firm transmission uses on a comparable and not unduly discriminatory basis. This responsibility is addressed by PJM RTEP reliability planning studies that ensure reliability under the most stringent, applicable NERC, PJM or local transmission owner criteria. Indeed, an important, ongoing aspect of this responsibility is the consideration of specific Long-Term Firm Transmission Service requests (LTFTS) for point-to-point and integrated network transmission service for a period of a year or more.

Point-to-point transmission can be used for the transmission of capacity and/or energy into, out of, through, or within PJM. Firm transmission service is reserved and/or scheduled between specified Points of Receipt and Delivery. Network transmission service allows network customers to utilize their network resources to serve their network load located within PJM. Network service is used for the transmission of capacity and energy from network resources within or deliverable to PJM RTO and energy from PJM's energy market to network loads. Each network customer can integrate its current and planned network resources to serve its network load in a manner comparable to that by which load serving entities utilize PJM RTO transmission service facilities to serve their native load customers.

Once all required PJM OASIS steps have been completed, and transmission service agreements executed, the evaluation process can begin. Each request for transmission service is evaluated by PJM to determine if sufficient capability exists to ensure reliable service to all transmission customers. PJM evaluates each LTFTS request using the same deliverability tests employed for generation interconnection requests. These deliverability studies, described earlier in **Section 5.2**, can identify criteria violations driving the need for transmission enhancements to ensure system reliability. Once identified transmission system requirements are in place, the transmission service request can be awarded.

Incremental Auction Revenue Rights

Auction Revenue Rights (ARRs) are the mechanism by which the proceeds from the Annual FTR Auction are allocated. ARRs entitle the holder to receive an allocation of the revenues from the Annual FTR Auction. The PJM Operating Agreement, Section 7.8, Schedule 1 sets forth provisions permitting any party to request Incremental ARRs by agreeing to fund transmission improvements necessary to support the requested financial rights. Requests must specify a source, sink and megawatt amount. PJM conducts studies to determine if transmission system enhancements are required to accommodate the requested incremental ARRs so that all are simultaneously feasible for a ten-year period.

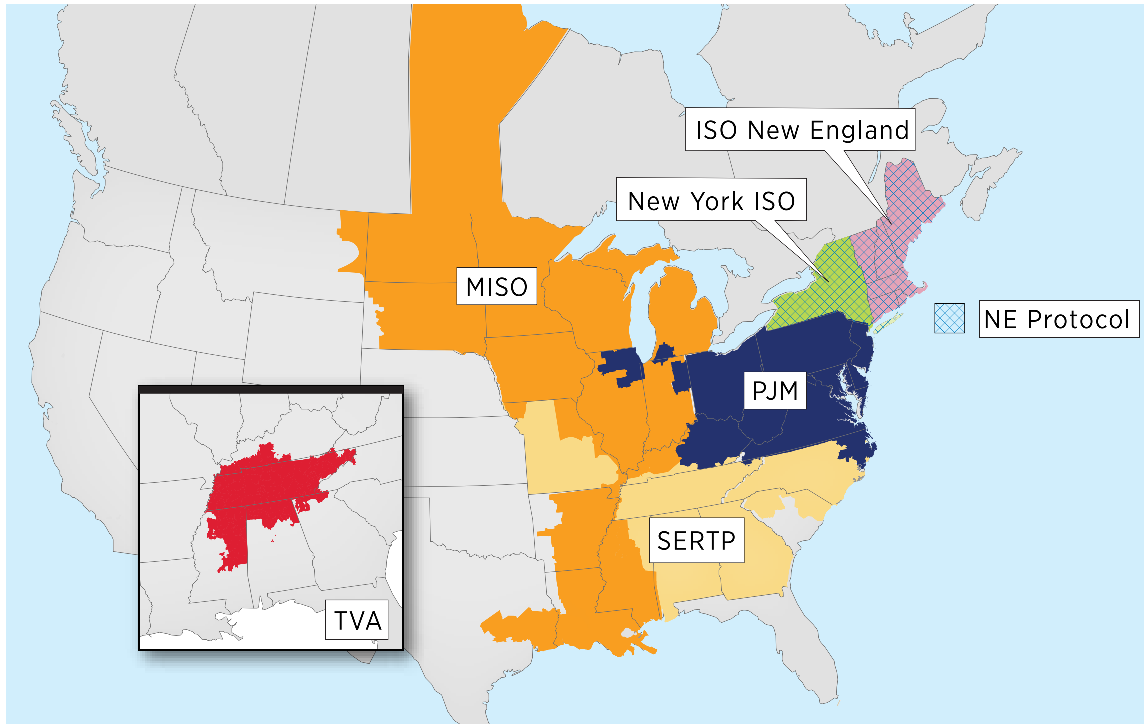
Section 8: Interregional and Scenario Studies – 2017 Scope

8.0: Interregional Planning

PJM continues to expand and improve its successful, collaborative transmission planning efforts with its neighbors. In recent years, PJM's interregional planning responsibilities have grown in parallel with the evolution of broader organized markets and interest at the state and federal level in favor of increased interregional coordination. The nature of these activities includes structured, tariff-driven analyses as well as targeted issues that arise each year. This is expected to continue as the terms of FERC Order No. 1000 compliance filings transition to implementation.

PJM currently has interregional planning arrangements with New York Independent System Operator, the Independent System Operator of New England, Midcontinent Independent System Operator (MISO), North Carolina Transmission Planning Collaborative, Duke Energy, Tennessee Valley Authority (TVA), and Southeastern Regional Transmission Planning (SERTP), shown on **Map 8.1**.

Map 8.1: PJM Interregional Planning



Interregional planning with the Carolinas and TVA are conducted under the SERTP process embodied 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 and Kentucky Utilities (jurisdictional), Associated Electric Cooperative, Ohio Valley Electric Corporation (jurisdictional) and Dalton Utilities. PJM also actively participates in ongoing activities of the Eastern Interconnection Planning Collaborative.

Interregional FERC Order No. 1000 compliance filings have been accepted and are being implemented. Doing so is improving processes and transparency among adjoining systems. In accordance with these processes, PJM annually exchanges planning information and reviews regional plans to ensure the most efficient or cost effective upgrades. PJM and its neighbors continue to pursue opportunities to improve interregional coordination.

Planning Activities

Under each interregional agreement, provisions governing coordinated planning include assessment of current operational issues to ensure that critical cross-border interface 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 interfaces include provisions to address system impacts of mutual concern:

- Individual regional transmission plans
- Queued generator interconnection requests
- Generator deactivation requests
- Operational performance
- National and state public policy objectives
- Power flow modeling accuracy within regional planning processes

Recent process improvements are also focusing attention on smaller, shorter lead-time upgrades to increase system efficiency by reducing congestion not easily addressed by an individual regional entity alone.

Studies are conducted in accordance with a specifically defined scope and may include cross-border analyses that examine reliability, market efficiency or public policy needs. Reliability studies may examine transfers, stability, short circuit, generation and merchant transmission interconnections and generator deactivations. PJM has continued to collaborate throughout 2017 on a number of interregional planning initiatives.

Eastern Interconnection Planning Collaborative

EIPC provides a centralized point of coordination to produce broad geographic transmission analyses useful to states, provinces and federal bodies addressing related public policy issues. These analyses enhance efficiencies among interregional planning reliability assessments. This work builds on, rather than replaces, existing regional and interregional transmission planning processes of the 20 participating EIPC Planning Authorities. Those bodies represent approximately 95 percent of Eastern Interconnection electricity demand. EIPC initiatives represent an expansion of power system planning analysis beyond the requirements contemplated by FERC Order No. 1000. EIPC long range planning studies over recent years have examined the performance of regional transmission plans on an Eastern Interconnection-wide basis. This information adds value to regional planning processes so that interregional impacts can be taken into account and investigated further if necessary. In addition, input from various federal and state public policy decision makers can be modeled and results provided for their consideration. Recent studies have looked at the long-range impact of public policy on generation expansion and its consequent impact on the need for transmission options to resolve identified reliability criteria violations.

EIPC's 2017 work plan builds on a recent agreement to conduct production cost hourly simulations of future transmission scenarios. The first step in this process is to assemble the first of its kind, fully vetted production cost and transmission model of the Eastern Interconnection. The model will be used to conduct test simulations of the Eastern Interconnection for further review. Other EIPC efforts are expected to include discussions with NERC to support future power system frequency response modeling and assessments, discussions with NERC for support of NERC power system modeling compliance, and consideration of the need for EIPC development of grid information reporting.

ISO New England and NYISO

PJM coordinates interregional planning with ISO New England (ISO-NE) and New York ISO (NYISO) – shown on **Map 8.2** –under the terms of the Northeastern ISO/RTO Planning Coordination Protocol. These activities continue the primary purpose of the protocol: to contribute to the reliable and economic performance of each system through coordinated planning. In doing so, all parties acknowledge, recognize and seek to address the impacts arising at the interfaces between their systems. Activities are coordinated under the auspices of the Interregional Planning Stakeholder Advisory Committee (IPSAC).

During 2017, PJM, NYISO and ISO-NE have continued to implement interregional processes consistent with FERC Order No. 1000 compliance filings. The parties will continue to develop and exchange databases and coordinate review of the following:

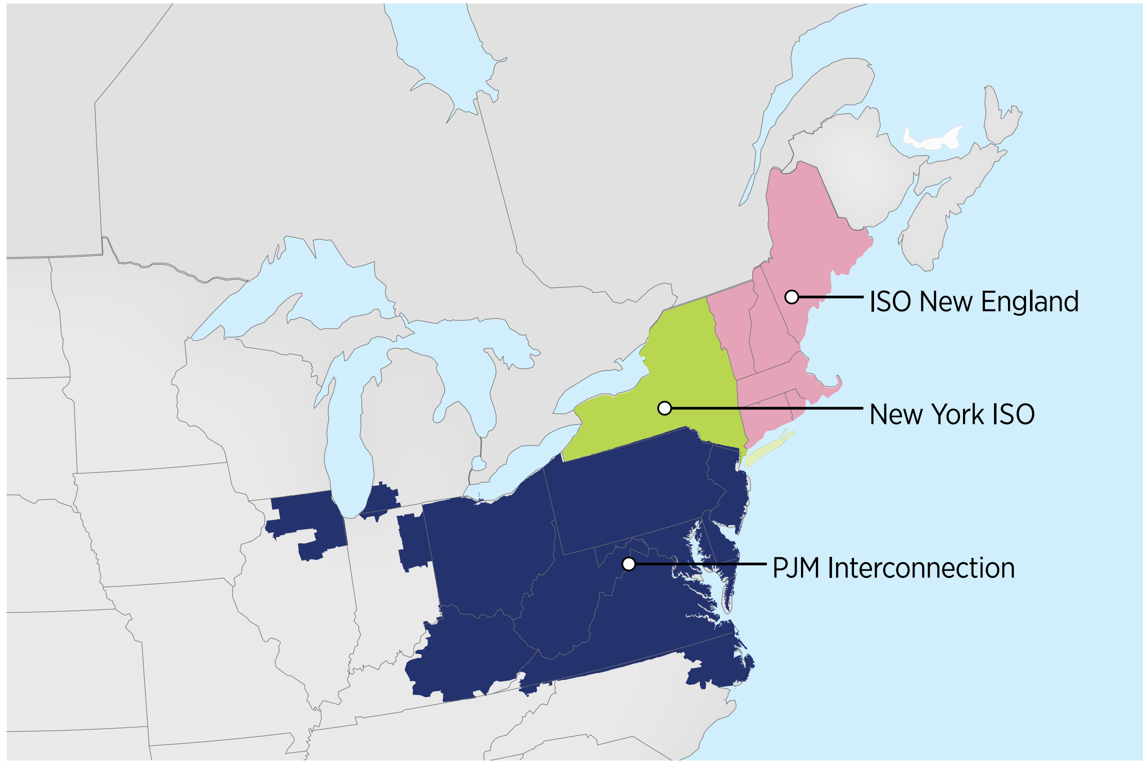
- Operational coordination issues
- Individual regional transmission projects

- Queued generation and merchant transmission interconnection queues, long-term firm
- Transmission service requests in each region
- Transmission needs and solutions identified by PJM, NYISO, and ISO-NE stakeholders

Additional steps will be taken to the extent that these factors have the potential to impact interregional system performance. The IPSAC also plans to refresh reviews completed in 2016. IPSAC information regarding northeast protocol activities can be found on-line: http://www.pjm.com/committees-and-groups/stakeholder-meetings/ipsac-ny-ne.aspx.

On a biennial cycle, under the Northeast Protocol, the parties prepare a northeast coordinated system plan. Plans to develop the scope and timeline for completing this plan are expected to begin in the latter part of 2017. PJM and NYISO also expect to complete development and implementation of new operating and planning protocol to address the termination of agreements related to "wheeling" transmission service on the PJM transmission system.

Map 8.2: PJM, NYISO and ISO-NE Coordination



MISO

Article IX of the Joint Operating Agreement (JOA) between PJM and MISO codifies coordinated transmission expansion planning processes between the two systems, shown on **Map 8.3.** This includes the development of a coordinated system plan to identify transmission system expansion and enhancement to maintain reliability, improve operational performance and enhance electricity market competitiveness. Joint studies take into consideration the unique, complex nature of the PJM-MISO seam and the power transfers across it. Results from reliability and production cost market simulation studies are documented and formally reviewed by the JOA's Interregional Planning Stakeholder Advisory Committee (IPSAC). PJM and MISO are currently operating under the recently approved FERC Order No. 1000 enhancements to the JOA as filed in compliance with FERC directives. Recent process enhancements include the following:

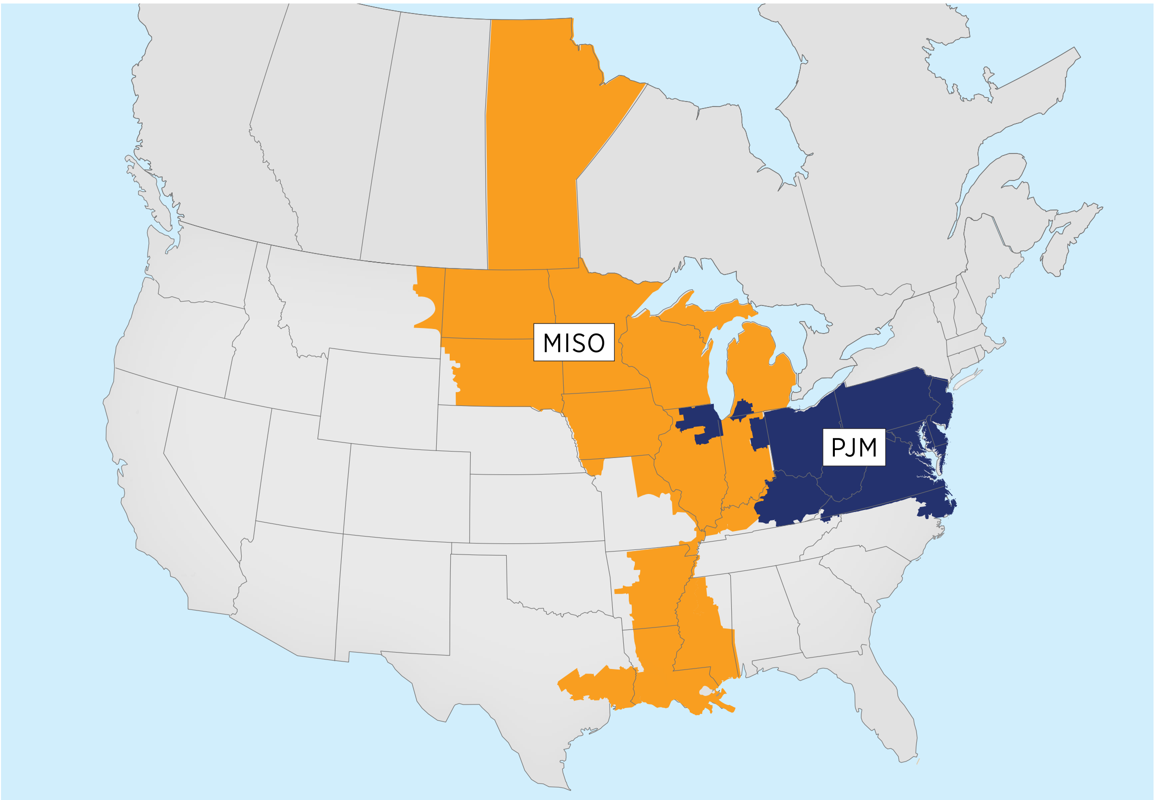
- Clarifications to interregional transmission planning timelines and processes
- Clarifications to interregional procedures to coordinate joint evaluations of requests for new transmission or interconnection service
- Clarifications to procedures to coordinate studies of the impacts of generation retirements
- Removal of MISOs lower voltage and cost threshold limitations to joint economic projects with PJM
- Removal of duplicative economic model development by each region

PJM-MISO interregional planning activities during 2017 analysis will address the scope-of-work established in the fourth quarter, 2016. Efforts will focus on completion of the JOA and tariff changes needed to implement the targeted market efficiency analysis process and the five recommended targeted market efficiency projects. The targeted market efficiency process focuses on replacement of limiting existing equipment that can achieve significant benefits relative to the low cost of doing so. Such efficient upgrades to targeted equipment releases "bottled" system capability. The study process is stream lined and more efficient than conventional studies that entail time consuming model development, multiple study years and complex alternative benefit calculations. Targeted studies have identified five projects that provide inter-RTO economic benefits of approximately $100 million with capital upgrades of existing equipment of approximately $17 million.

PJM and MISO will also continue to update their respective system regional models to evaluate proposals – submitted through respective regional planning process windows – that address regional economic issues with more efficient or cost effective interregional projects. Respective RTO windows for market efficiency proposals closed in the first quarter of 2017. Regional analyses are expected to proceed throughout the second and third quarters with results available by the end of the year.

PJM-MISO interregional planning activities are conducted under the auspices of the IPSAC: http://www.pjm.com/committees-and-groups/stakeholder-meetings/ipsac-midwest.aspx.

Map 8.3: PJM-MISO Interregional Coordination



Southeastern Regional Transmission Planning

During 2017, PJM and the Southeastern Regional Transmission Planning (SERTP) – shown earlier on **Map 8.1** – continue to implement FERC Order No. 1000 interregional processes for data exchange and interregional planning efficiencies. Efforts in 2017 will focus on review of long-term firm transmission service, interregional tie lines and dispatch as part of power flow case model development. The next biennial regional reviews are expected to occur early in 2018. Related SERTP activities can be found at the following URL: http://www.southeasternrtp.com/. As part of Southeastern Regional Transmission Planning activities, PJM also collaborates with adjoining systems Duke Energy, Louisville Gas & Electric and Kentucky Utilities, Ohio Valley Electric Cooperative and TVA.

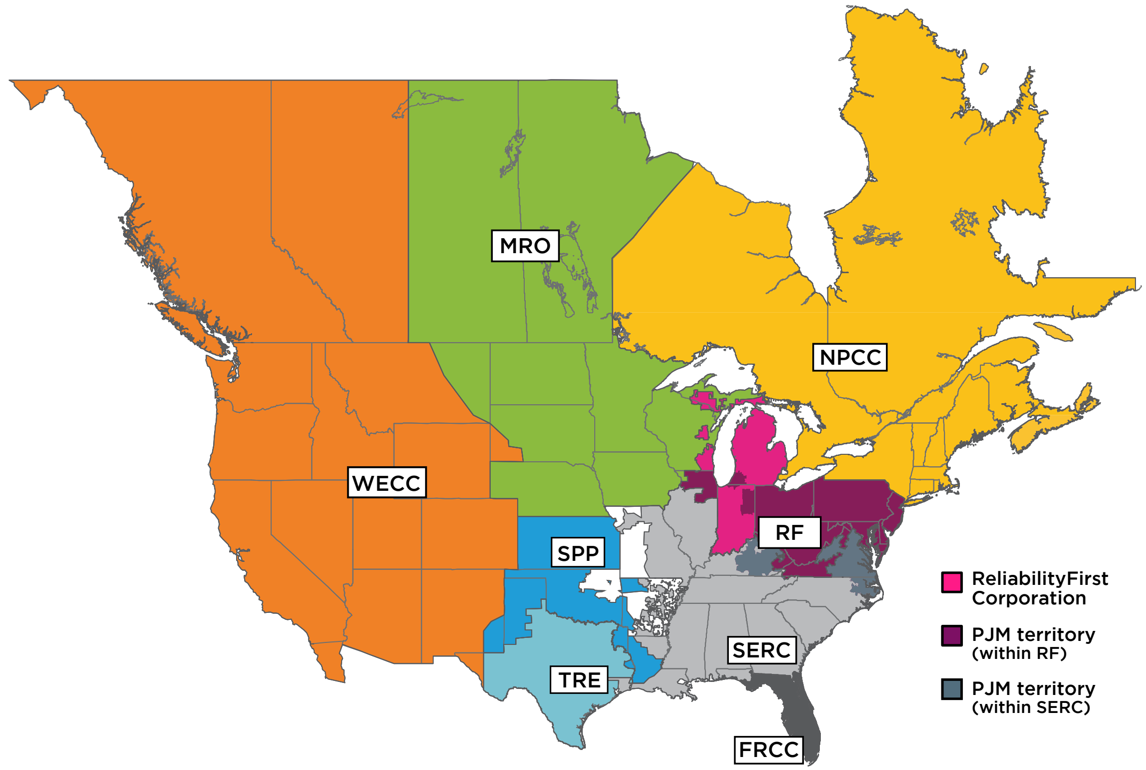
Duke Energy

PJM has continued its collaboration in 2017 with Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP), participating in periodic planning sessions and providing input as required. In addition, PJM expects to continue to enhance external transaction modeling coordination in planning power flow cases. PJM anticipates providing Duke Energy information related to 2020/21 Base Residual Auction results (enabled by existing confidentiality agreements). Doing so will assist Duke with evaluating potential changes in power flow across their system.

SERC and ReliabilityFirst Corporation Activities

The PJM region encompasses two subregional entities of the North American Electric Reliability Corporation (NERC): ReliabilityFirst Corporation (RF) and SERC Electric Reliability Corporation, shown on **Map 8.4**. PJM supports SERC and RF activities on behalf of the PJM members within their footprints. This includes near-term, long-term, dynamics and short circuit study group activities, including related model building. PJM anticipates that its support of SERC and RF activities will continue to grow as their respective planning, operations and power markets continue to evolve.

Map 8.4: NERC Areas



Note

PJM notes that the SERTP is an interregional effort, not to be confused with SRRTEP, PJM's own southern subregional RTEP committee.

8.1: Scenario Studies

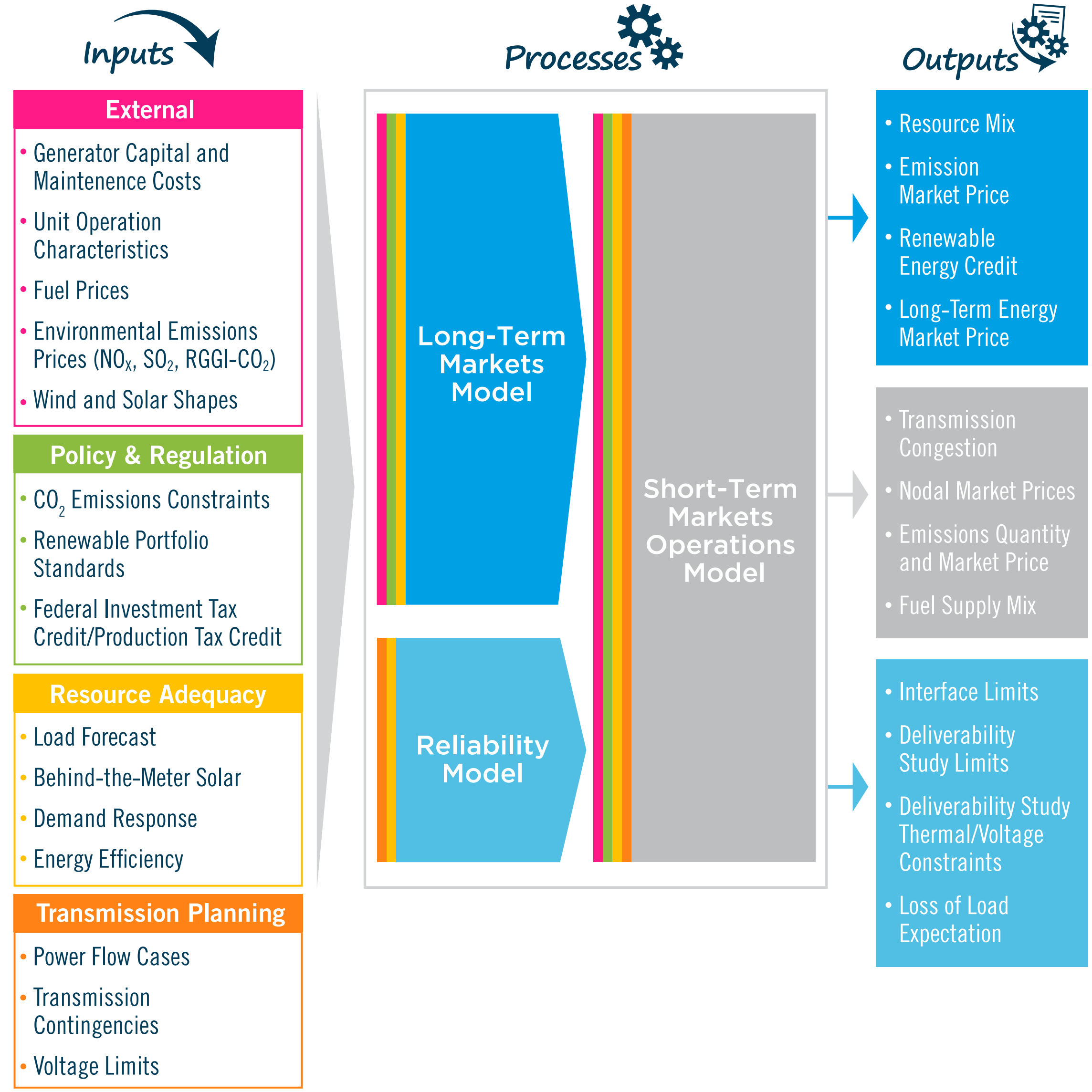
For the first ten years following the inception of the RTEP process in 1997, PJM generally found that the magnitude of uncertainty regarding future system conditions driving transmission need was mainly limited to that associated with load growth and generation interconnection requests. RTEP process tests could reasonably define the expected date of future reliability violations with minimal risk of fluctuation. That has changed in many respects in more recent years. A single set of summer peak load baseline and market assumptions are simply not sufficiently flexible to assess the full extent and degree to which system drivers impact transmission need. Scenario studies permit PJM to evaluate potential system conditions driven by factors outside its immediate sphere. Such studies provide valuable long-term expansion planning insights beyond those obtained from conventional baseline and market efficiency analyses.

Clean Power Plan Analysis

PJM initiated scenario studies in 2016 at the request of the Organization of PJM States, Inc., to evaluate economic and reliability impacts of the U.S. EPA's Clean Power Plan (CPP). Additional studies as part of that evaluation – shown in **Figure 8.1** – have continued into 2017.

PJM RTEP analyses begun in 2016 focused on identifying potential reliability criteria violations on monitored facilities at 230 kV and above for a 2025 study year case and will continue into 2017. Only extra-high-voltage transmission lines 230 kV and above that exceeded their conductor limits were identified given that they typically justify the need for higher capacity,

Figure 8.1: Clean Power Plan Evaluation Process



long lead-time transmission projects like those at 500 kV and higher voltages. **Book 3, Section 10** of the PJM *2016 Regional Transmission Expansion Plan Report* describes that work: http://www.pjm.com/~/media/library/reports-notices/2016-rtep/2016-rtep-book-3.ashx.

PJM has continued its reliability analysis in 2017 for OPSI focusing on load deliverability areas on CPP scenarios in which forecasted CETO exceed forecasted CETL values. Analysis will also include generator deliverability analysis as well as power-voltage (P-V) curve analysis on CPP scenarios to identify maximum transfer levels on the AP-South interface. PJM conducts power voltage analysis to examine potential voltage collapse phenomena that is more rigorous than what NERC and regional voltage magnitude and voltage drop criteria violations may indicate, as described earlier in **Section 5.3.**

Note

On March 28, 2017, President Trump issued an Executive Order which directed EPA to review and, if appropriate, initiate proceedings to suspend, revise or rescind the CPP.

Note

CPP reliability scenario study results were presented at the January and February 2017 PJM Transmission Expansion Advisory Committee (TEAC) meetings: http://www.pjm.com/committees-and-groups/committees/teac.aspx.

Glossary

The terms and concepts in this glossary are provided for the convenience of the reader and are in large part based on definitions from other sources, as indicated in the "Reference" column for each term. These references include the following:

- M-xx – 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/directory/merged-tariffs/oa.pdf
- OATT – PJM Open Access Transmission Tariff – http://www.pjm.com/directory/merged-tariffs/oatt.pdf
- RAA – Reliability Assurance Agreement – http://www.pjm.com/directory/merged-tariffs/raa.pdf

Term	Reference	Acronym	Definition
Adequacy	NERC		Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. "Resources" refers to a combination of electricity generating 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		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 otherwise on an approved maintenance outage. Product type ceases to exist following the commencement of Capacity Performance rules.
Artificial Island	AI		An island located along the eastern shore of the Delaware River. This island is home to the Salem and Hope Creek Nuclear Generating Stations
Attachment Facilities	OATT		The facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.
Auction Revenue Right	OA	ARR	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	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses
Base Capacity Resource	M-18		Capacity resources that are not capable of sustained, predictable operation throughout the entire Delivery Year. These resources will only be procured through the 2019/20 Delivery Year, at which point all resources will be Capacity Performance Resources starting with the 2020/21 Delivery Year. See "Capacity Performance".
Baseline Upgrades	M-14B		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	A generation unit that 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 into the PJM Interchange Energy Market.

Term	Reference	Acronym	Definition
Bilateral Transaction	OA		A contractual arrangement between two entities (one or both being PJM members) for the sale and delivery of a service
Bulk Electric System	NERC; M-14B	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 excludes: 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; The balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and step-up transformer); these facilities would include relays and systems that automatically trip a unit for boiler, turbine, environmental, and/or other plant restrictions; All other facilities operated at voltages below 100 kV.
Capacity Emergency	M-13		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, M-14B, M-18	CETL	Part of load deliverability analysis 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; M-14B, M-18, M-20	CETO	The CETO is the emergency import capability, expressed in megawatts, required of a PJM sub-area to satisfy established reliability criteria.
Capacity Interconnection Rights	OATT	CIRs	The rights to input generation as a Generation Capacity Resource into the transmission system at the point of interconnection where the generating facilities connect to the transmission system.
Capacity Performance			Capacity Performance is a set of rules governing resource participation in the Reliability Pricing Model (RPM). Following a series of transition auctions, Capacity Performance rules will be fully in place starting with the 2020/21 Delivery Year. See "Base Capacity Resource" and "Capacity Performance Resource".
Capacity Performance Resource	M-18		Capacity resources that are capable of sustained, predictable operation throughout the entire Delivery Year. All resources will be Capacity Performance Resources starting with the 2020/21 Delivery Year. See "Capacity Performance".
Capacity Resource	RAA. M-14A, M-14B		Megawatts of net capacity from existing or planned generation capacity resources or load reduction capability provided by demand resources or interruptible load for reliability (ILR) in the PJM region
Clean Air Interstate Rule		CAIR	An EPA rule regarding the interstate transport of soot and smog
Clean Power Plan		CPP	An EPA rule regarding carbon pollution from power plants
Coincident Peak	M-19		Zone's contribution to the RTO peak load or higher level LDA
Combined Cycle (Turbine)		CC/CCT	CC/CCT is a generating unit facility generally consisting 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 generating unit in which a combustion turbine engine is the prime mover
Consolidated Transmission Owners Agreement	PJM.com	CTOA	An agreement between Transmission Owners, which PJM is a signatory to, establishing the rights and commitments of all parties involved
Construction Service Agreement		CSA	Signatories to the CTOA agree to (i) facilitate the coordination of planning and operation of their respective Transmission Facilities within the PJM Region; (ii) transfer certain planning and operating responsibilities to PJM; (iii) provide for regional transmission service pursuant to the PJM Tariff and subject to administration by PJM; and (iv) establish certain rights and obligations that will apply to the signatories and PJM. Any entity that: (i) owns, or, in the case of leased facilities, has rights equivalent to ownership in, Transmission Facilities; (ii) has in place all equipment and facilities necessary for safe and reliable operation of such Transmission Facilities as part of the PJM Region; and (iii) has committed to transfer functional control of its Transmission Facilities to PJM must become a Party to the CTOA.
Contingency			The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Cost of New Entry	M-18	CONE	A RPM capacity market parameter defined as the levelized annual cost in ICAP $/MW-Day of a reference combustion turbine to be built in a specific LDA
Cross-State Air Pollution Rule		CSAPR	An EPA rule regarding reduction in air pollution related to power plant emissions
Deactivation			The retirement or mothballing of a generating unit governed by the PJM Open Access Transmission Tariff
Deliverability	RAA, M-14B, M-18		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.

Term	Reference	Acronym	Definition
Demand Resource	M-18	DR	See "Load Management"
Designated Entity			An entity, including an existing Transmission Owner or Non incumbent Developer, designated by the Office of the Interconnection 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, a Designated Entity Agreement is required to be executed. The Designated Entity Agreement 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 Designated Entity Agreement requirements the Agreement is no longer needed. The Designated Entity must execute the Consolidated Transmission Owners Agreement as a requirement for Designated Entity Agreement 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			Any solar generator which is not PJM grid interconnected and does not participate in the PJM markets. These resources do not go through the full interconnection queue process and do not offer as capacity or as energy resources. Furthermore, 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	The portion of an interchange transaction, typically expressed in per unit that flows across a transmission facility
Diversity	M-18		The amount of MWs 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 EIPC represents a first-of-its-kind effort to involve planning authorities in the Eastern Interconnection to model the impact on the grid of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders.
Eastern Interconnection Reliability Assessment Group		ERAG	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 focused transmission system conditions
Eastern MAAC	M-14B	EMAAC	A term used in PJM deliverability analysis to refer to the portion of PJM that includes AE, DPL, JCPL, PECO, PSE&G and Rockland
Eastern Wind Integration and Transmission Study		EWITS	The EWITS was a regional wind integration study initiated in 2008 to examine the operational impact of up to 20-30 percent energy penetration of wind on the power system in the Eastern Interconnection of the United States. The study was set up to answer questions that utilities, regional transmission operators, and planning organizations had about wind energy and transmission development in the east.
Effective Forced Outage Rate on Demand	M-22	EFORd	EFORd is a measure of the probability that generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate. See Generator Resource Performance Indices Manual (M-22) for equation.
Electrical Distribution Company		EDC	A company that owns and/or operates electrical distribution facilities for the delivery of electrical energy to end-use customers
End-use characteristics	M-19		End-use characteristics are the measures of the stock and efficiency of various electrical equipment and appliances used in residential and commercial settings. These are included in the forecast models, grouped by heating, cooling, and other.
Energy Efficiency Programs		EE	Incentives or requirements at the state or federal level that promote energy conservation and wise use of energy resources
Energy Resource	M-14A, M-14B	OATT	A generating facility that is not a capacity resource
Extended Summer Demand Resources			Demand Resources which 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 ceases to exist following the commencement of Capacity Performance rules.
Extra High Voltage		EHV	Transmission equipment operating at 230 kV and above
Facilities Study Agreement	M-14A	FSA	An agreement between the interconnection customer/developer and PJM to identify the scope of facility additions and upgrades to be included in the interconnection study
Fault			An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection
Federal Energy Regulatory Commission		FERC	An independent agency that regulates the interstate transmission of electricity, natural gas and oil
Fiber Optic Ground		FOG	A type of cable used in the construction of electric power transmission and distributions lines which combines the functions of grounding and communications
Financial Transmission Right	M-6	FTR	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

Term	Reference	Acronym	Definition
Firm Transmission Service	OATT		Transmission service that is intended to be available at all times to the maximum extent practicable. 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.
Flowgate			A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions
Generation Deliverability	M-14B		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 a suitable grid level voltage for transmission of electricity to load centers
Good Utility Practice	OATT		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 which, 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 acceptable practices, methods or acts generally accepted in the region.
Group/Gang Operated Air Break		GOAB	The portion of a circuit breaker which opens and closes to allow 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 which opens and closes the disconnect.
Horizontal Directional Drilling		HDD	Horizontal directional drilling technology for laying transmission cable employs a long, flexible drill bit to bore horizontally underground. Horizontal directional drilling is a trench-less 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 impact the riverbed over the length of the installation.
Independent State Agencies Committee	PJM.com	ISAC	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 inputs and scenarios for transmission planning studies.
Independent System Operator		ISO	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	Valued based on the summer net dependable rating of the unit as determined in accordance with PJM, rules and procedures of the determination of generating capacity
Interconnected Reliability Operating Limit	M-14B	IROL	System Operating Limits that, if violated, could lead to instability, uncontrolled separation or Cascading Outages that adversely impact the reliability of the Bulk Electric System
Interconnection Coordination Agreement	OATT	ICA	An agreement between Transmission Owners, and/or Transmission Developers outlining the schedules and responsibilities of each party involved
Interconnection Service Agreement	M-14A	ISA	An agreement among the transmission provider, an interconnection customer and an interconnected transmission owner regarding interconnection under Part IV and Part VI of the Tariff
Light Load Reliability Analysis	M-14B		Analysis to ensure 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			Demand Resources which 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			Demand for electricity at a given time, expressed in megawatts (MW)
Load Analysis Subcommittee	M-19	LAS	Subcommittee which 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 (PC).
Load Deliverability	M-14B		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	M-18	LM	Retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. LM derives a demand resource or Interruptible-Load-for-Reliability credit in RPM.
Load Serving Entity	RAA, OATT	LSE	Load-serving entities provide electricity to retail customers. LSEs include traditional distribution utilities.

Term	Reference	Acronym	Definition
Local Distribution Company		LDC	A LDC, or a local distribution company, 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	M-14B	LDA	Electrically cohesive load areas historically defined by Transmission Owner service territories and larger geographical zones comprised of a number of those service areas
Locational Marginal Price		LMP	The hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.
Loss-of-Load Expectation	M-14B	LOLE	Loss-of-load expectation (LOLE) defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, during only one day in ten years (1/10).
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 creditworthiness standards as established by PJM. Market buyers are otherwise able to make purchases and market sellers are otherwise able to make sales in PJM energy and capacity markets.
Megavolt-Ampere Reactive	OA	MVAR	Megavolt-ampere reactive. See “Reactive Power”.
Merchant Transmission Facility	OATT		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 of the transmission system; transmission facilities included in the rate base of a public utility on which a regulated return is earned; included in previous RTEPs; or, customer interconnection facilities.
Mercury and Air Toxins Standards		MATS	An EPA rule regarding limiting the emissions of toxic air pollutants like mercury, arsenic and metals from power plant emissions
Mid-Atlantic Subregion	M-14B	MAAC	The PJM Mid-Atlantic subregion encompasses 12 Transmission Owner zones: Atlantic City Electric Company (AE), Baltimore Gas and Electric (BGE), Delmarva Power and Light (DPL), Jersey Central Power and Light (JCPL), Metropolitan Edison Company (Met-Ed), Neptune, PECO Energy (PECO), Pennsylvania Electric Company (PENELEC), PEPCo, PPL Electric Utilities Corporation (PPL), Public Service Electric and Gas (PSE&G), Rockland Electric (Rockland) and UGI Corporation (UGI). 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	Midcontinent Independent System Operator (MISO) plan for enhancing the future of the power grid in their area
Motor Operated Air-Break		MOAB	The portion of a circuit breaker which opens and closes to allow 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. Motor operated refers to a motorized linkage which opens and closes the disconnect, and can be controlled remotely.
Multiregional Model Working Group		MMWG	A group who reports to the Eastern Interconnection Reliability Assessment Group (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
MVAR	OA		See “Reactive Power”.
National Renewable Energy Laboratory		NREL	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		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	M-19	NCP	A zone’s individual peak load
North American Electric Reliability Corporation	NERC	NERC	NERC is an international, independent, self-regulatory, not-for-profit organization, whose mission is to ensure the reliability of the bulk power system in North America.
Nuclear Plant Interface Requirement		NPIR	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.
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	A FERC filed tariff specifying the terms of conditions under which PJM provides transmission service and carries out its generation and merchant transmission interconnection process.

Term	Reference	Acronym	Definition
Optical Grounding Wire Communications		OPGW	A type of fiber optic cable used in the construction of electric power transmission and distribution lines which combines the functions of grounding and communications
Optimal Power Flow		OPF	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 maintains 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 Federal Energy Regulatory Commission, as well as their individual roles as statutory regulators within their respective state boundaries.
PJM Manuals			The instructions, rules, procedures and guidelines established by PJM for the operation, planning and accounting requirements of the PJM Region and the PJM Interchange Energy Market.
PJM Member	OA, M-33		Any entity that has completed an application and satisfies the requirements of PJM to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers
Planning Committee	OA	PC	A committee 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	M-14B		The annual RTEP process series of studies, analysis, assessments and related supporting functions
Planning Horizon	M-14B		The future time period over which system transmission expansion plans are developed based on forecasted conditions
Probabilistic Risk Assessment	M-14B	PRA	PJM assesses risk exposure using a PRA risk management tool. Initially, this tool is used to assess the risk of PJM's aging 500/230 kV transformer fleet. The goal of the PRA model is to minimize asset service cost. PJM's PRA method integrates the economics of transformation loss with the likelihood of incurring the precipitating event. Using the PRA, PJM can determine: the amount of risk each transformer poses to the system; the best way to mitigate each transformer's risk; the optimum number of spare transformers; where to locate them on the system; the value of moving a low-risk spare transformer to a higher-risk location; the value of a common transformer design; and, the point at which the risk associated with continued operation of an older transformer unit exceeds the value of a new unit.
Reactive Power (expressed in MVAR)	M-14A		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 in megavars (MVAR).
Regional Greenhouse Gas Initiative		RGGI	A regional initiative by states and provinces in the Northeastern United States and Eastern Canada to reduce greenhouse gas emissions
Regional RTEP Project	M-14B, OA		A transmission expansion or enhancement at a voltage level of 100 kV or higher
Regional Transmission Expansion Plan	M-14B	RTEP	The plan 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 PJM Region
Regional Transmission Organization	FERC	RTO	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 among load-serving entities in the PJM region. This Agreement 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 generation resource subject to the dispatch of PJM that, as a result of transmission constraints, PJM determines, in the exercise of good utility practice, must be run in order to maintain reliability.
Reliability Pricing Model		RPM	PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and load serving entity (LSE) obligations that is consistent with the PJM Regional Transmission Expansion Planning (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 (MAAC), the East Central Area Coordination Agreement (ECAR) and the Mid-American Interconnected Network organizations (MAIN).

Term	Reference	Acronym	Definition
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	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	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 corridor of land on which electric lines may be located. The transmission owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Security	NERC		The ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits, or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by man-made physical or cyber attacks. 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 OPF, or 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	M-14B		The PJM southern sub-region area comprises one transmission owner zone – Dominion Virginia Power (Dominion).
Special Protection System	M-03	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 as 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.
System Operating Limit	M-14B	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	A 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	M-14B, OA		A PJM committee that facilitates the development and review of the Subregional RTEP projects. The Subregional RTEP Committee will be responsible for the initial review of the subregional RTEP projects, and to provide recommendations to the Transmission Expansion Advisory Committee (TEAC) concerning the sub-regional RTEP projects.
Subregional RTEP Project	M-14B, OA		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, 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	M-14B, OA		Replaces the term "Transmission Owner Initiated or TOI Project." A regional RTEP project(s) or a sub-regional RTEP project(s), which 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's 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 MW, system voltage, machine voltage, duration of the disturbance and by system impedance. Transient stability examines this phenomenon over the first several seconds following a system disturbance.
Temperature-Humidity Index	M-19	THI	Temperature-humidity index 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 temperature-humidity index, 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 series capacitor bank that is shunted by a thyristor controlled reactor

Term	Reference	Acronym	Definition
Topology	M-14B		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.
Trans-Allegheny Interstate Line		TRAIL	A 500-kV backbone transmission line approved by the PJM Board in 2006 which will connect the 502 Junction substation in southwestern Pennsylvania with the Loudoun substation in northern Virginia.
Transmission Customer	M-14A, M-14B, M-2, OATT		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	M-14B	TEAC	A committee established by PJM to provide advice and recommendations to aid in the development of the Regional Transmission Expansion Plan
Transmission Loading Relief	M-03	TLR	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	M-14B, OATT	TO	A 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.
Transmission Owner Upgrade	OA		An upgrade to a Transmission Owner's own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility
Transmission Provider	M-14B, OATT		The Transmission Provider is PJM for all purposes in accordance with the PJM OATT.
Transmission Service Request	M-02	TSR	TSR 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 facilities operated by PJM used to provide transmission services. These facilities that transmit electricity: are within the PJM region; 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	An entitlement to a specified number of summer rated MW of capacity from a specific resource, on average, not experiencing a forced outage or derating, 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 an 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 an 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	M-14B		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	M-19		An estimate of the seasonal peak load at normal peak day weather conditions
Western Subregion	M-14B, 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.
XEffective Forced Outage Rate on Demand		XEFORd	XEFORd is a statistic that results from excluding outside management control events (outages deemed not to be preventable by the operator) from the EFORd calculation. See Effective Forced Outage Rate on Demand.
Zone/Control Zone	M-14B		An area within the PJM control area, as set forth in the PJM Open Access Tariff and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.