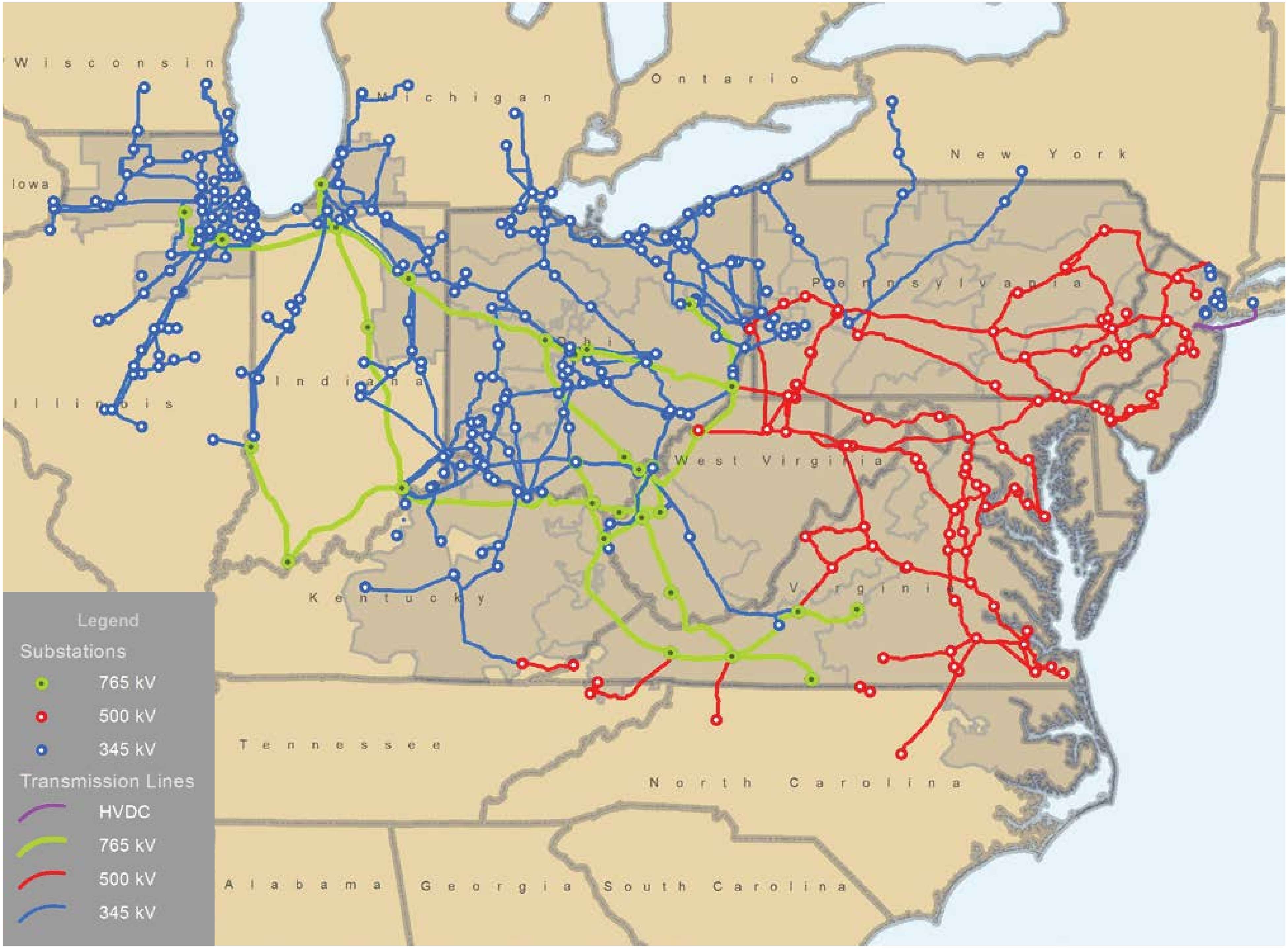
2017 PJM Regional Transmission Expansion Plan

February 28, 2018

Book 1
PJM 2017
RTEP in Review

Book 2
Inputs and Process

Book 3
Studies and Results



Wisconsin
Michigan
Ontario
New York
Iowa
Pennsylvania
Ohio
Indiana
Illinois
West Virginia
Kentucky
Virginia
Tennessee
North Carolina
Alabama
Georgia
South Carolina
Legend
Substations
765 kV
500 kV
345 kV
Transmission Lines
HVDC
765 kV
500 kV
345 kV

Preface

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

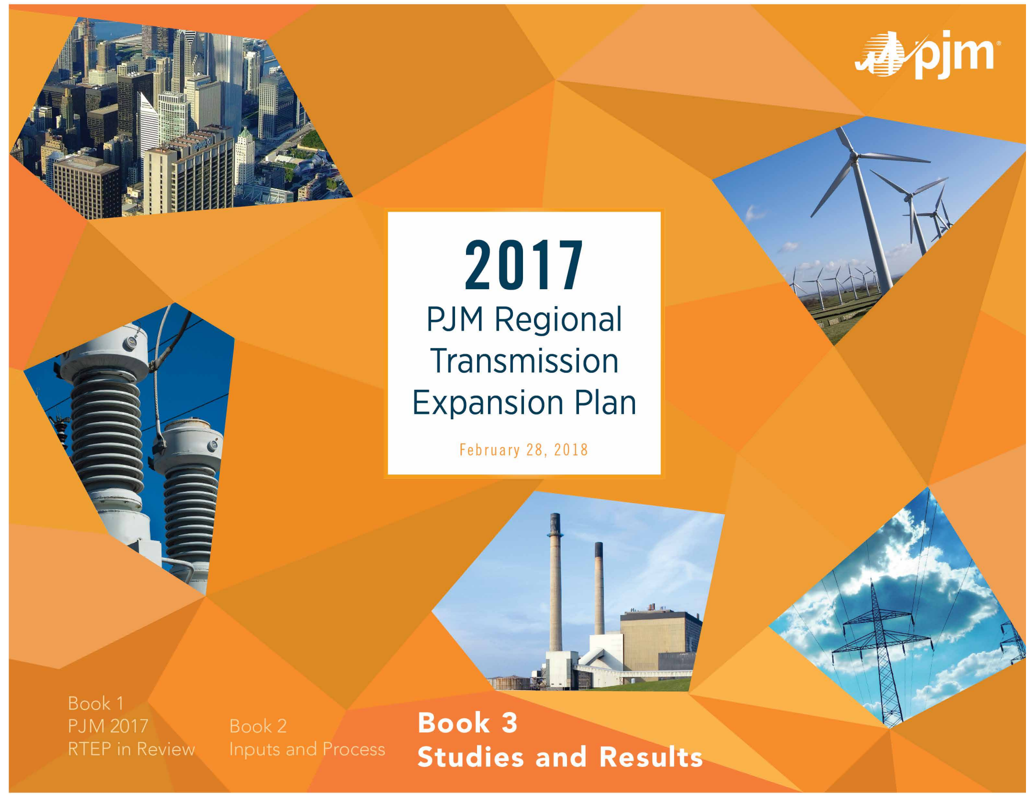
1.0: Preface

Book 3, Studies and Results, is the third in a series of three books that comprise PJM's 2017 Regional Transmission Expansion Plan Report:

- Book 1: PJM 2017 RTEP in Review
- Book 2: 2017 Inputs and Process
- **Book 3: Studies and Results**

Book 3 presents results from studies conducted throughout 2017, including:

- Recommendations and approvals associated with RTEP process window evaluation of baseline reliability and market efficiency proposals
- Immediate need system enhancements to address operational performance issues, generator deactivations, PJM criteria and transmission owner criteria violations
- Market efficiency analysis
- Interregional planning activities
- Ohio Valley Electric Cooperative (OVEC) integration
- Capacity market planning parameters



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

Planning Community

Book 3 also provides subregional summaries of RTEP projects approved by the PJM Board in 2017.

A separate PowerPoint file entitled "Key 2017 RTEP Report Graphics and Information" for the reader's individual communication needs can be found on PJM's website: http://www.pjm.com/library/reports-notices/rtep-documents.aspx.

RTEP Process Description

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

- The Manual 14 series contains the specific business rules that govern the RTEP Process. Specifically, Manual 14B describes the methodologies for conducting studies and developing solutions to solve planning criteria violations and market efficiency issues. PJM Manual 14B, Regional Planning Process can be found on PJM's website: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

- Schedule 6 of the PJM Operating Agreement codifies the overall provisions under which PJM implements its Regional Transmission Expansion Planning Protocol, more familiarly known (and used throughout this document) as the PJM RTEP process. The PJM Operating Agreement can be found on PJM's website: http://www.pjm.com/media/documents/merged-tariffs/oa.pdf.

- The PJM Open Access Transmission Tariff (OATT) codifies provisions for generating resource interconnection, merchant/customer funded transmission interconnection, Long-Term Firm Transmission Service and other specific new service requests. The PJM OATT can be found on PJM's website: http://www.pjm.com/media/documents/merged-tariffs/oatt.pdf.

- The status of individual PJM Board-approved Baseline and Network RTEP projects, as well as that of transmission owner Supplemental projects, can be found on PJM's website: http://www.pjm.com/planning/rtep-upgrades-status.aspx.

Stakeholder Forums

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

Additionally, the Planning Committee makes recommendations regarding generating capacity reserve requirement and demand-side valuation factors. Committee meeting materials and other resources are accessible from PJM's website: http://www.pjm.com/committees-and-groups/committees/pc.aspx.

The Transmission Expansion Advisory Committee (TEAC) and subregional RTEP committees continue to provide forums for PJM staff and stakeholders to exchange ideas, discuss study input assumptions and review results. Stakeholders are encouraged to participate in these ongoing committee activities. TEAC resources are 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 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 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 Independent State Agencies Committee, states have an opportunity to provide input on the assumptions and scenarios that PJM incorporates in the scope of its RTEP studies. Additional information is available on PJM's website: http://pjm.com/committees-and-groups/isac.aspx.

Book 3: Table of Contents

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Section 1: RTEP Process Context

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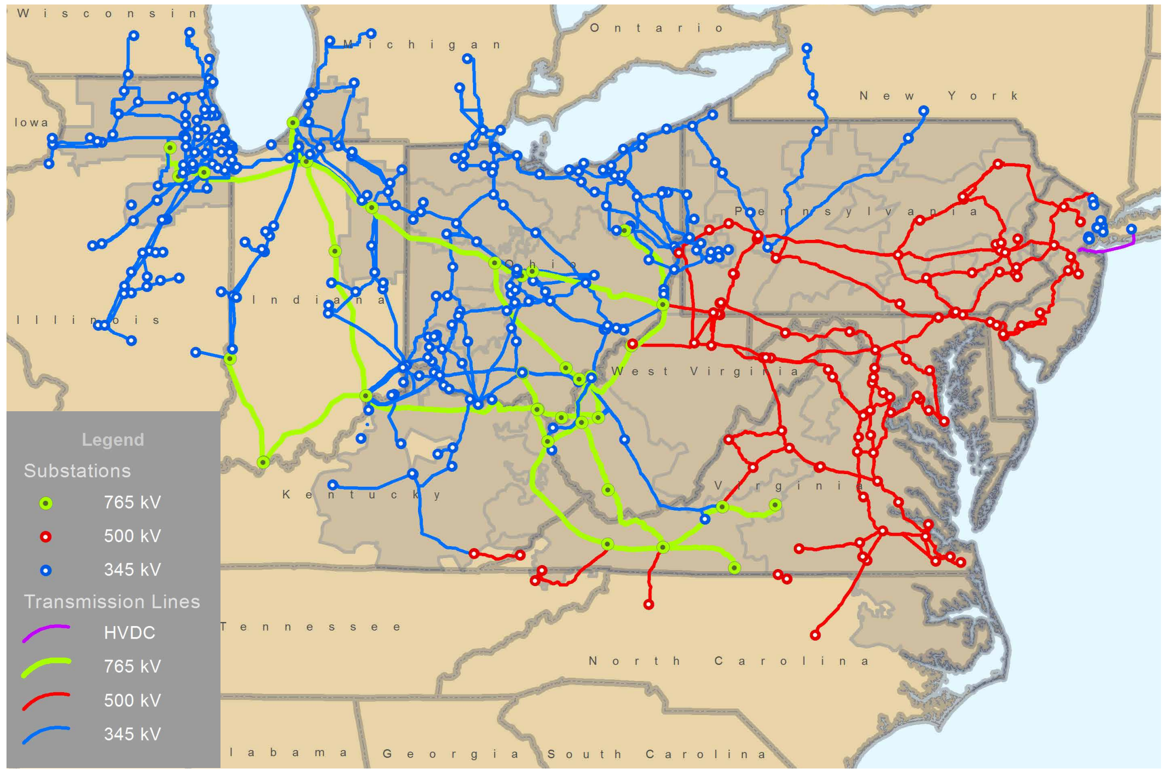
1.0: RTO Perspective

1.0.1 — Regional Scope

PJM, a FERC-approved RTO, coordinates the movement of wholesale electricity across a high voltage transmission system in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia as shown on **Map 1.1**. PJM's footprint encompasses major U.S. load centers from the Atlantic coast to Illinois'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 1,040 members, PJM dispatches more than 178,560 MW of generation capacity over 84,040 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 enhancements 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.

1.0.2 — RTEP Process Windows

As described in **Section 2, Section 7**. 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 as shown in **Figure 1.2**. Submittals include both greenfield and upgrade proposals. A greenfield proposal uses new right-of-way or creates a new substation, for example. An upgrade proposal enhances or expands existing transmission system

Figure 1.1: RTEP Process – RTO Perspective

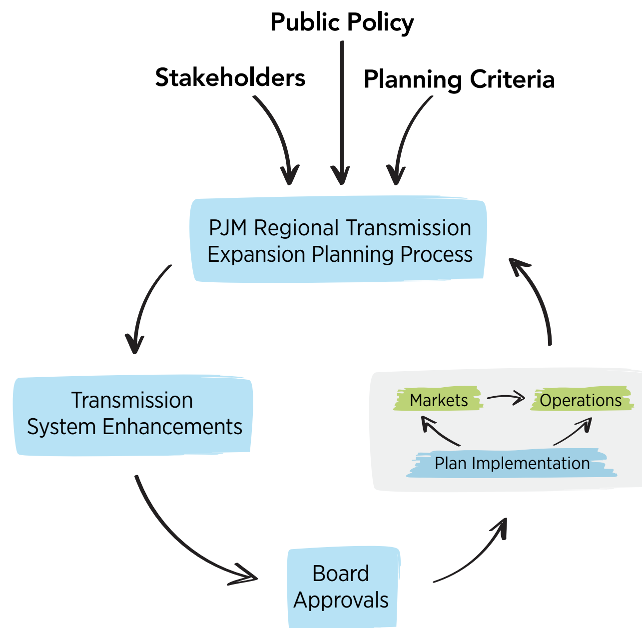
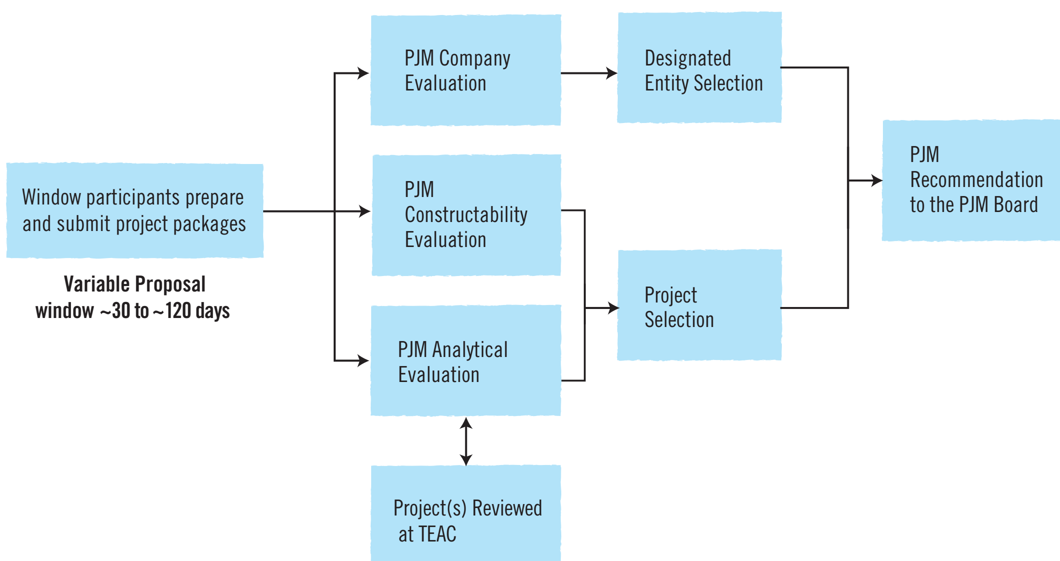


Figure 1.2: PJM RTEP Window Process



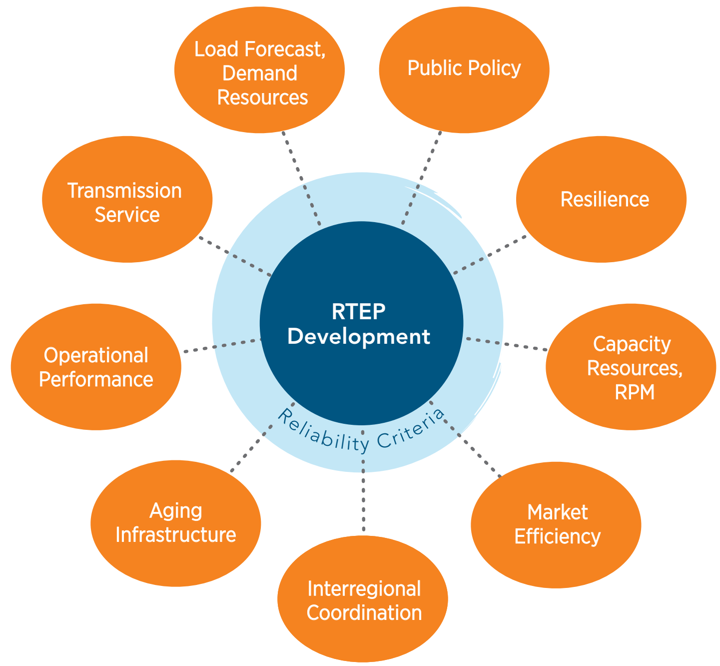
facilities. Upgrades can include new or replaced devices installed at existing substations and reconductoring of existing transmission lines.

PJM staff recommends 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, they formally become part of PJM's overall RTEP. The PJM Board approval obligates designated entities to construct those projects. If selected, designated developers become responsible for project construction, ownership, operation, maintenance and financing.

1.0.3 — System Enhancement Drivers

A 15-year long-term planning horizon allows PJM to consider the aggregate effects of many factors, shown in **Figure 1.3**. 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.

Figure 1.3: System Enhancement Drivers



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 1.1.3**. 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.

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 in 2017 studies is described in **Book 2, Section 6.0.7**.

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 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, as discussed in **Section 4.1**.

Scenario Studies

For the first 10 years following the inception of the RTEP process in 1997, PJM generally found that level of uncertainty regarding future system conditions driving transmission need was mainly 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 is 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. These studies provide valuable long-term expansion planning insights. Such was the case in 2017 when PJM conducted scenario analysis to examine the reliability impact of certain natural gas pipeline contingencies, as discussed in **Section 9.0**.

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 to increase interregional coordination. As described in **Section 7.0**, 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 are a key part of broader public policy discussions. Previous planning cycle focused on 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. The multi-driver concept falls within the context of PJM's FERC-approved state agreement approach.

RTEP projects will likely continue to be driven 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.

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1.1: NERC Reliability Criteria

1.1.1 — RTEP Perspective

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

PJM addresses transmission expansion planning from a regional perspective, spanning transmission owner zonal boundaries and state boundaries to address the comprehensive impact of many system enhancement drivers, including NERC reliability criteria violations. The relationship between violation and solution generally takes one of two forms. Reliability criteria violations may occur locally, 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 and potentially cause an overload. Violations may also be 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 resolve such violations more economically and efficiently than if they were approached individually.

1.1.2 — Bulk Electric System Facilities

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

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

2. Lines operated at voltages of 100 kV or higher

3. Associated auxiliary and protection and control system equipment that could automatically trip a bulk electric system facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment)

The ReliabilityFirst definition of BES excludes the following:

1. Radial facilities connected to load serving facilities or individual generation resources smaller than 20 MVA or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher

2. The balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and its associated step-up transformer), which facilities would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions

3. All other facilities operated at voltages below 100 kV

Given this BES definition, PJM conducts reliability analyses to ensure system compliance with NERC Standard TPL-001-4. If PJM identifies violations, it develops transmission expansion solutions to resolve them, frequently as part of its RTEP window process.

1.1.3 — 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 steady-state analyses as described in **Table 1.1** 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)

Table 1.1: 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

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

PJM N-0 analysis – mapped to planning event P0 – examines the bulk electric system “as is” with all facilities in service. PJM identifies facilities that have pre-contingency loadings which exceed applicable normal thermal ratings. Bus voltages are also identified that violate established limits specified in PJM Manual 3, Transmission Operations: http://pjm.com/directory/manuals/m03/index.html#about.html. Generator and load deliverability tests are also applied to event P0 per the methodologies described in **Book 2, Section 4.2**.

Similarly, N-1 analysis – mapped to planning event P1 – requires that bulk electric system 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.

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

Stability Requirements

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

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

NOTE:

NERC's website contains a complete description of Standard TPL-001-4 requirements: http://www.nerc.com/pa/Stand/Reliabilitypercent20Standards/TPL-001-4.pdf.

Section 2: 2017 Proposal Windows

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

2.0: 2017 RTEP Proposal Window No. 1

2.0.1 — RTEP Process Context

PJM opened the 2017 RTEP Proposal Window No. 1 from July 11, 2017, to August 25, 2017. The window sought solutions to a number of PJM reliability criteria violations identified as part of the following analyses:

- 2022 Summer Reliability Analysis
  - N-1
  - Generator Deliverability
  - Load Deliverability
  - N-1-1
- 2022 Winter Reliability Analysis
  - N-1
  - Generator Deliverability
  - Load Deliverability
  - N-1-1
- 2022 Light Load Reliability Analysis
  - N-1
  - Generator Deliverability

Based on these analyses, PJM identified thermal and voltage criteria violations for a number of flowgates – monitored element and contingency pairs – as discussed in **Section 2.0.2**.

Light Load Criteria

Light load system conditions, with system demand as low as 30 percent of summer peak in some transmission owner areas, have begun to present system dispatchers with operational performance issues. Generation dispatch under such conditions, for most fuel types, differs markedly from that under peak load conditions. PJM system operators have experienced thermal overloads and high-voltage events driven by low demand dispatch patterns and the capacitive effects of lightly loaded transmission lines. Light load reliability analysis ensures the transmission system is capable of delivering generating capacity under such conditions and that PJM operators have adequate reactive control. Light Load Criteria analysis and related study procedures are described in **Book 2, Section 4.4**.

Winter Criteria

Winter peak reliability analysis ensures that the Transmission System is capable of delivering the system generating capacity at winter peak load conditions. The PJM 50/50 winter peak demand level from the PJM Load Forecast was chosen as representative of typical winter peak conditions. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates at the winter peak demand level. Winter Criteria analysis and related study procedures are described in **Book 2, Section 4.5**.

Short Circuit Analysis

PJM performs short circuit analysis, also known as breaker interrupting studies, as part of the annual RTEP baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment to determine if the short circuit current interrupting duty of circuit breakers is sufficient for two-year and five-year planning cases. PJM conducts short circuit analysis to ensure circuit breakers on the transmission system are sufficiently rated to safely interrupt fault currents. Breaker replacement lead times are relativly short compared to transmission line lead times, these analyses are only conducted as part of the five-year planning horizon. Short Circuit Analysis and related study procedures are described in **Book 2, Section 4.6**.

2.0.2 — Identified Flowgates

PJM identified transmission line, transformer and voltage violations for 190 flowgates, 40 of which were eligible for the competitive planning process. These are summarized in **Table 2.1** and **Map 2.1**. PJM notes that consistent with established practices, certain flowgates are not eligible for competition: those requiring an immediate need solution, those falling below the 200 kV exclusion criteria, those representing constraints with limiting elements outside of PJM's footprint, and those reflecting contributions from retiring generators.

Map 2.1: 2017 RTEP Proposal Window No. 1 Violations

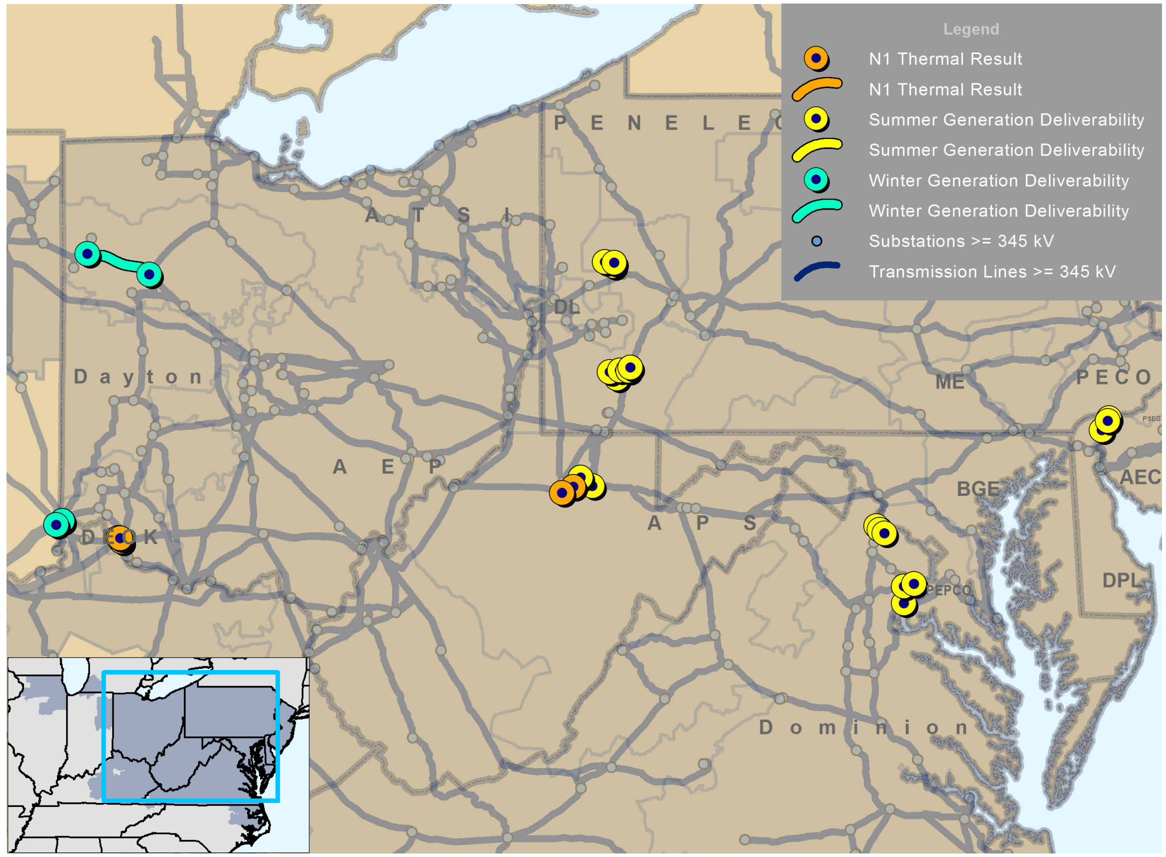

Table 2.1: 2017 RTEP Proposal Window No. 1 Violations

Analysis Type	Overloaded Facility	TO
Summer N-1 Thermal	Overload of the Pierce to BKJ 138 kV line No. 1	Duke Energy Ohio/Kentucky
Summer N-1 Thermal	Overload of the Pierce to BKJ 138 kV line No. 1	Duke Energy Ohio/Kentucky
Summer N-1 Thermal	Overload of the Pierce 345/138 kV transformer No. 18	OVEC/Duke Energy Ohio/Kentucky
Summer N-1 Thermal	Overload of the Pierce 345/138 kV transformer No. 17	OVEC/Duke Energy Ohio/Kentucky
Summer N-1 Thermal	Overload of the Pierce 345/138 kV transformer No. 17	OVEC/Duke Energy Ohio/Kentucky
Summer N-1 Thermal	Overload of the Mcalpn to Glenfl 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Pierce 345/138 kV transformer No. 18	OVEC/Duke Energy Ohio/Kentucky
Summer Generator Deliverability and Common Mode Outage	Overload of the Pierce to BKJ 138 kV line No. 1	Duke Energy Ohio/Kentucky
Summer Generator Deliverability and Common Mode Outage	Overload of the Pierce 345/138 kV transformer No. 17	OVEC/Duke Energy Ohio/Kentucky
Summer Generator Deliverability and Common Mode Outage	Overload of the Pierce to BKJ 138 kV line No. 1	Duke Energy Ohio/Kentucky
Summer Generator Deliverability and Common Mode Outage	Overload of the Pierce 345/138 kV transformer No. 17	OVEC/Duke Energy Ohio/Kentucky
Summer Generator Deliverability and Common Mode Outage	Overload of the Bulter to Shanor 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Shanor to Krendl 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Yukon to Smith 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Mcalpn to Glenfl 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Prnty to Whiteh 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Whiteh to Mcalpn 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Yukon to Smith 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Allenp to Charlr 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Smith to Sheplr 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Yukon to Smith 138 kV line No. 1	Allegheny Power
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Summer Generator Deliverability and Common Mode Outage	Overload of the Bulter to Shanor 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Shanor to Krendl 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Bulter to Shanor 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Shanor to Krendl 138 kV line No. 1	Allegheny Power
Summer Generator Deliverability and Common Mode Outage	Overload of the Woodbr to Occoqun 230 kV line No. 1	Dominion
Summer Generator Deliverability and Common Mode Outage	Overload of the Possum to Woodbr 230 kV line No. 1	Dominion
Summer Generator Deliverability and Common Mode Outage	Overload of the PL View to Ashburn 230 kV line No. 1	Dominion
Summer Generator Deliverability and Common Mode Outage	Overload of the PL View to Ashburn 230 kV line No. 1	Dominion
Summer Generator Deliverability and Common Mode Outage	Overload of the Clay 230 to Linwood 230 kV line No. 1	Delmarva Power and Light/PECO
Summer Generator Deliverability and Common Mode Outage	Overload of the Edgemr 5 to Clay 230 kV line No. 1	Delmarva Power and Light

Table 2.1: 2017 RTEP Proposal Window No. 1 Violations (Continued)

Analysis Type	Overloaded Facility	TO
Summer Generator Deliverability and Common Mode Outage	Overload of the Ashburn-Beamead 230 kV line No. 1	Dominion
Winter Generator Deliverability and Common Mode Outage	Overload of the Tanners Creek-Miami Fort 345 kV line No. 1	American Electric Power/Duke Energy Ohio/Kentucky
Winter Generator Deliverability and Common Mode Outage	Overload of the Tanners Creek-Miami Fort 345 kV line No. 1	American Electric Power/Duke Energy Ohio/Kentucky
Winter Generator Deliverability and Common Mode Outage	Overload of the Tanners Creek-Miami Fort 345 kV line No. 1	American Electric Power/Duke Energy Ohio/Kentucky
Winter Generator Deliverability and Common Mode Outage	Overload of the Tanners Creek-Miami Fort 345 kV line No. 1	American Electric Power/Duke Energy Ohio/Kentucky
Winter Generator Deliverability and Common Mode Outage	Overload of the Tanners Creek-Miami Fort 345 kV line No. 1	American Electric Power/Duke Energy Ohio/Kentucky
Winter Generator Deliverability and Common Mode Outage	Overload of the Maddox-East Lima 345 kV line No. 1	American Electric Power/Duke Energy Ohio/Kentucky

2.0.3 — Solution Proposals

PJM received 51 proposals, shown in **Table 2.2** and **Map 2.2,** from 10 entities in nine transmission owner zones to solve the identified reliability criteria violations. Transmission owner upgrades to existing facilities included 22 proposals with cost estimates ranging from $0.12 million to $28.4 million. In addition, PJM received 29 greenfield projects with cost estimates ranging from $4.5 million to $120.3 million.

NOTE:

In addition to the eight recommendations approved at the December 2017 PJM Board meeting, the PJM Board approved two additional projects from the 2017 Proposal Window No. 1 at their February 2018 meeting. Those projects are: 2017_1-6A and 2017_1-9L as listed in **Table 2.2**. PJM determined that only a portion of the 6A project was required to address the reliability criteria violations.

Map 2.2: 2017 RTEP Proposal Window No. 1 Proposals

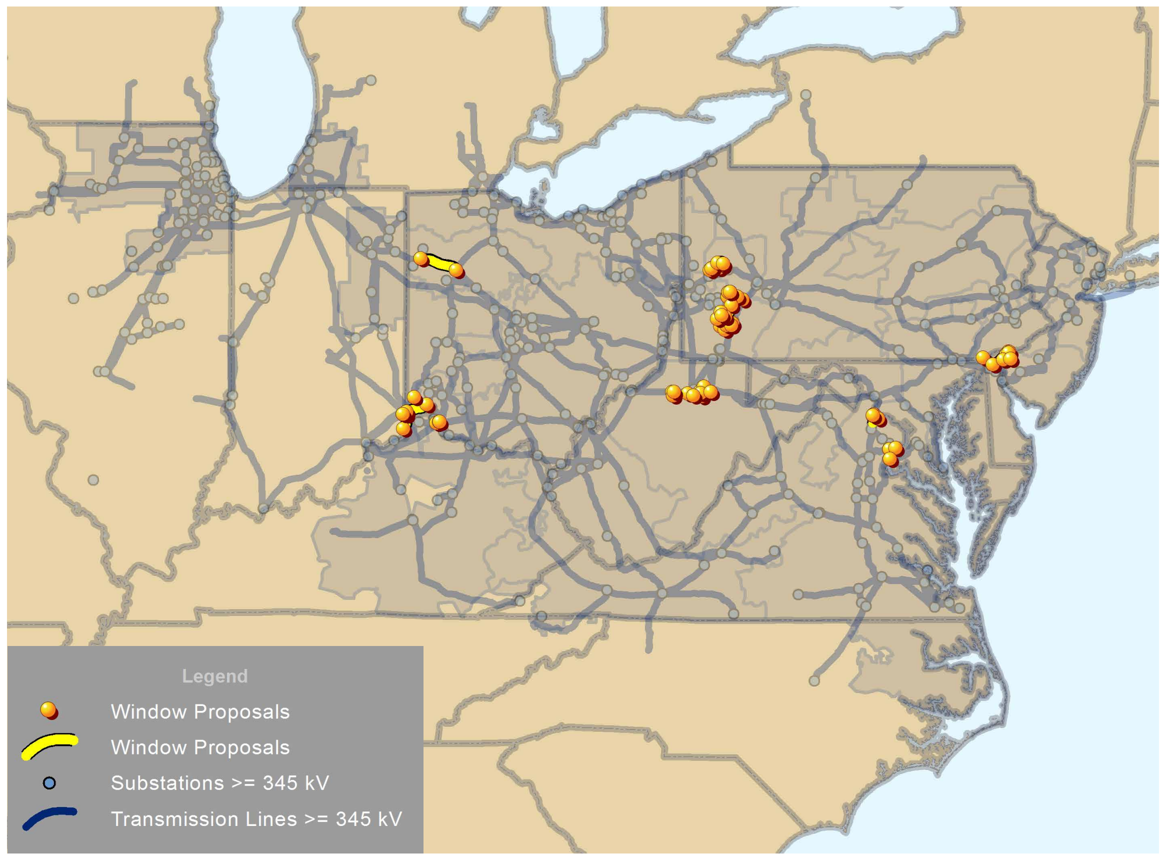


Table 2.2: 2017 RTEP Proposal Window No. 1 Proposals

Project ID	Upgrade/ Greenfield	Proposing Entity	Project Cost ($M)	Major Components/Project Description	Recommendation for Board Approval
2017_1-1A	Upgrade	Dominion	4.5	Reconductor the existing Pleasant View-Ashburn-Beaumeade 230 kV line (Line 274) with 1,068 MVA conductor and replace line terminal equipment at Pleasant View, Ashburn, and Beaumeade.	
2017_1-1B	Upgrade	Dominion	7.1	Reconductor the existing Pleasant View-Ashburn-Beaumeade 230 kV line (Line 274) with 1,295 MVA conductor and replace line terminal equipment at Pleasant View, Ashburn, and Beaumeade.	
2017_1-1C	Upgrade	Dominion	3.1	Split Line No. 227 (Brambleton-Beaumeade) and terminate into existing Belmont substation.	X
2017_1-1D	Upgrade	Dominion	4.5	Reconductor the Woodbridge to Occoquan 230 kV line segment of Line 2001 with 1,047 MVA conductor and replace line terminal equipment at Possum Point, Woodbridge, and Occoquan.	X
2017_1-1E	Upgrade	Dominion	5.0	Reconductor the Woodbridge to Occoquan 230 kV line segment of Line 2001 with 1,225 MVA conductor and replace line terminal equipment at Possum Point, Woodbridge, and Occoquan.	
2017_1-1F	Upgrade	Dominion	12.7	Rebuild the Woodbridge to Occoquan 230 kV line segment of Line 2001. This segment of line is made up of double circuit 230 kV structures, with Line 2001 and Line 215 sharing common structures. Line 215 from Woodbridge-Occoquan will be reconductored at the same time. Replace line terminal equipment at Possum Point, Woodbridge, and Occoquan.	
2017_1-2A	Greenfield	Northeast Transmission Development	39.1	Build a single circuit 138 kV transmission line from the existing Waldo Run 138 kV substation to a new substation (“Glade Run”) interconnecting the existing Harrison-Belmont 500 kV transmission line.	
2017_1-2B	Greenfield	Northeast Transmission Development	17.0	Build a single circuit 138 kV transmission line from the existing Logans Ferry 138 kV substation to a new substation (“Pucketa”) interconnecting the existing Springdale-AA2-161 138 kV transmission line and the Springdale-Huntingdon 138 kV transmission line.	
2017_1-2C	Greenfield	Northeast Transmission Development	22.2	Build a single circuit 138 kV line from the existing Logans Ferry 138 kV substation to a new substation (“Pucketa”) interconnecting the existing Springdale-AA2-161 138 kV transmission line and the Springdale-Federal Street 138 kV transmission line. Interconnect the remaining Pucketa-Federal Street 138 kV transmission line into the existing Schaffers Corner 138 kV substation.	
2017_1-2D	Greenfield	Northeast Transmission Development	64.8	Build a single circuit 345 kV transmission line from the existing Logans Ferry 345 kV substation to a new substation (“Thorn Run”) interconnecting the existing South Bend-Yukon 500 kV transmission line.	
2017_1-2E	Greenfield	Northeast Transmission Development	12.7	Build a 345 kV switching station (“Twelvemile”) interconnecting the existing Silver Grove-Zimmer 345 kV transmission line and the Pierce-Buffington 345 kV transmission line.	
2017_1-3A	Greenfield	PSE&G	120.3	Tap the South Bend to Yukon 500 kV line and build 500 kV line to Logan’s Ferry.	
2017_1-4A	Greenfield	Duquesne	4.5	This proposal recommends the reconfiguration of the DLC-owned Cheswick-Plum and APS-owned Springdale-Wycoff-Yukon 138 kV circuits to create two new tie lines between DLC and APS. These lines would be reconfigured to become the Cheswick-Wycoff-Yukon and Springdale-Plum 138 kV DLC-APS tie-lines. Once the lines are reconfigured, a portion of the newly established Springdale-Plum line would be reconductored.	
2017_1-5A	Greenfield	Nextera	30.1	Build a new 500/138 kV substation connecting the following existing lines: Harrison-Belmont 500 kV and Harrison Reserve Tap-Glenn Falls 138 kV line.	
2017_1-5B	Greenfield	Nextera	11.7	Build a new 138 kV switching station (including a 5 ohm series reactor) connecting the following existing lines: Yukon-Charleroi 138 kV and Mitchell-Sheppler Hill JCT 138 kV line. Build new ~1 mile of 138 kV connecting new Miracle switching station to Wycoff Tap.	
2017_1-5C	Greenfield	Nextera	11.8	Build a new 138 kV switching station connecting the following existing lines: Yukon-Charleroi 138 kV and Mitchell-Sheppler Hill JCT 138 kV line. Build new ~1 mile of 138 kV connecting new Miracle switching station to Wycoff Tap. Reconductor Miracle-Mitchell 138 kV line	

Table 2.2: 2017 RTEP Proposal Window No. 1 Proposals (Continued)

Project ID	Upgrade/ Greenfield	Proposing Entity	Project Cost ($M)	Major Components/Project Description	Recommendation for Board Approval
2017_1-6A	Upgrade	DEO&K	20.2	The two existing 345/138 kV transformers that connect Pierce 345 kV substation to Beckjord 138 kV substation are fed radially. This project will Reconfigure Pierce 345 kV substation by adding new breakers, moving a feeder, adding a third 345/138 kV transformer, and feed the Pierce-Beckjord transformers in a breaker and a half or double bus configurations. The three transformer feeds will be distributed across the three sets of buses at Beckjord.	X*
2017_1-7A	Greenfield	Transource	29.5	Establish Barking Road 138 kV switch station by cutting into the existing Logan's Ferry-Highland 138 kV line No. 2 and the Logan's Ferry-Universal 138 kV line. Establish Wright Road 138 kV switch station by cutting into the existing Springdale-Huntingdon 138 kV line and the Springdale-Yukon 138 kV (via AA2-161 and Wycoff). Build the Barking Road-Wright Road 138 kV double circuit line.	
2017_1-7B	Greenfield	Transource	19.3	Construct new greenfield 345 kV Switch Station to be called Anson Station. The existing Tanners Creek-East Bend 345 kV, East Bend-Terminal 345 kV and Miami Fort-Terminal 345 kV circuits will all be looped in and out of this station. The station will be comprised of six new 345 kV breakers and will be configured in a ring bus. Reconductor Tanners Creek-Anson 345 kV.	
2017_1-7C	Greenfield	Transource	9.7	Establish Sycolin Creek 230 kV switch station by cutting into the existing Belmont-Pleasant View 230 kV line and the Brambleton-Cochrane Mill-Ashburn 230 kV line.	
2017_1-7D	Greenfield	Transource	55.1	Tap the Tanners Creek-Losantville 345 kV line and build a single circuit line approximately 16.8 miles to a new 345/138 station (Coyote) next to Willey.	
2017_1-7E	Greenfield	Transource	34.7	Establish Narrow Run 500 kV switch station by cutting into the existing Belmont-Harrison 500 kV line. Expand Waldo Run station and install a 500/138 kV transformer. Build Narrow Run-Waldo Run 500 kV line.	
2017_1-7F	Greenfield	Transource	11.5	Construct a parallel 345 kV line from Tanners Creek to Miami Fort.	
2017_1-7G	Greenfield	Transource	9.9	Establish a new 138 kV switch station near Seneca by cutting into the Markwest-Seneca 138 kV line section. Construct a new 138 kV line from the new station to McCalmont station.	
2017_1-8A	Upgrade	AEP	1.5	Replace terminal equipment on Maddox Creek-East Lima 345 kV circuit.	X
2017_1-8B	Greenfield	AEP	111.6	Construct a new 345 kV single circuit line between Maddox Creek and Southwest Lima stations with 2-bundled 954 ACSR Cardinal conductor.	
2017_1-8C	Upgrade	AEP	1.2	Upgrade existing 345 kV terminal equipment at Tanners Creek station.	X
2017_1-9A	Upgrade	Exelon	1.8	Add Series Reactor at Claymont substation (DPL) on Claymont to Linwood (PECO) 230 kV line.	
2017_1-9B	Upgrade	Exelon	28.4	Rebuild Edge Moor (DPL) to Claymont (DPL) and Claymont (DPL) to Linwood (PECO) 230 kV circuits	
2017_1-9C	Upgrade	Exelon	5.7	Install Smart Wire solution at Claymont substation (DPL) on the Claymont to Linwood (PECO) 230 kV Line.	
2017_1-9D	Greenfield	Exelon	38.0	Construct new 230 kV line between Edge Moor (DPL) and Chichester (PECO) substations	
2017_1-9E	Greenfield	Exelon	26.8	Construct new 230 kV line between Edge Moor (DPL) and Linwood (PECO) substations	
2017_1-9F	Greenfield	Exelon	28.7	Construct new 230 kV line between Edge Moor (DPL) and Post (PECO) substations	
2017_1-9G	Greenfield	Exelon	36.6	Construct new substation near Linwood 230 kV substation (PECO). Cut and connect existing 230 kV circuit (220-43) to new substation. Build new 230 kV circuit between Edge Moor (DPL) and new substation.	
2017_1-9H	Greenfield	Exelon	55.7	Construct new 230 kV line between Harmony (DPL) and Linwood (PECO) substations	
2017_1-9I	Greenfield	Exelon	64.0	Construct new 230 kV line between Harmony (DPL) and Chichester (PECO) substations	
2017_1-9J	Greenfield	Exelon	37.7	Construct new 230 kV line between Harmony (DPL) and Clay (PECO) substations	

***Approved at the February 14, 2018 PJM Board Meeting**

Table 2.2: 2017 RTEP Proposal Window No. 1 Proposals (Continued)

Project ID	Upgrade/ Greenfield	Proposing Entity	Project Cost ($M)	Major Components/Project Description	Recommendation for Board Approval
2017_1-9K	Upgrade	Exelon	9.6	Reconductor Edge Moor (DPL)-Claymont (DPL) and Claymont (DPL)-Linwood (PECO) 230 kV circuits with high temperature conductor.	
2017_1-9L	Upgrade	Exelon	1.4	Replace the 230 kV circuit breaker No. 225 at Linwood substation (PECO) with a double circuit breaker (back to back circuit breakers in one device).	X*
2017_1-9M	Upgrade	Exelon	8.4	Install at Phase Angle Regulator (PAR) at Claymont substation (DPL) on Claymont (DPL) to Linwood (PECO) 230 kV Circuit	
2017_1-9N	Greenfield	Exelon	79.0	Construct new 230 kV line between Edge Moor (DPL) and Pedricktown (ACE) substations	
2017_1-10A	Upgrade	FirstEnergy	7.1	Reconductor Line with 954 ACSR Conductor, Replace Breaker Risers at Charleroi and Allenport	X
2017_1-10B	Upgrade	FirstEnergy	3.2	Reconductor the Yukon-Smithton-Shepler Hill Jct 138 kV Line with 795 ACSS conductor, replace line disconnects Switch at Yukon	X
2017_1-10C	Upgrade	FirstEnergy	7.0	Convert the existing 6-wire Butler-Shanor Manor-Krendale 138 kV Line into two separate 138 kV lines. New lines will be Butler-Keisters and Butler-Shanor Manor-Krendale 138 kV.	X
2017_1-10D	Upgrade	FirstEnergy	0.1	Replace the bus and line disconnect switches, bus taps, and bus conductor at the Cheswick Terminal at Springdale substation.	
2017_1-10E	Upgrade	FirstEnergy	2.7	Reconductor the Springdale-Cheswick 138 kV Line and Upgrade the Terminal Equipment at Springdale	
2017_1-10F	Greenfield	FirstEnergy	23.4	Construct Bunola substation, Loop in the Mitchell-Wilson 138 kV Line, Construct Double Circuit 138 kV lines (~2.43 miles) to Wycoff Jct.-Wycoff section of Springdale-Wycoff Jct.-Yukon 138 kV line. Reconductor/Install new conductor on ~1.7 miles of Wycoff Jct.-Wycoff line section.	
2017_1-10G	Upgrade	FirstEnergy	4.0	- Increase line ratings for 138 kV line segments from Pruntytown to White Hall Junction to Glen Falls. - Pruntytown 138 kV substation: Terminal work on the White Hall Junction terminal to replace line relays and retain the existing carrier communication in order to increase line segment rating. - Glen Falls 138 kV substation: Terminal work on the McAlpin terminal to upgrade bus risers and limiting conductor in order to increase line segment rating. - McAlpin-White Hall Junction 138 kV Line: Reconductor from structure No. 36-67 outside McAlpin substation to the 3-way junction (approximately 8.3 miles) to replace the existing 556 ACSR with 556 ACSS in order to increase line segment rating.	X
2017_1-10H	Upgrade	FirstEnergy	11.1	Separate the Shared Common Tower of the Pruntytown-Shinns Run 138 kV and the Pruntytown-Maple Lane 138 kV lines into two separate circuits utilizing the existing FirstEnergy right-of-way.	
2017_1-10I	Greenfield	FirstEnergy	40.1	Loop the Belmont-Harrison 500 kV line into the proposed Flint Run substation. Proposed location of substation is adjacent to existing line	
2017_1-10J	Greenfield	FirstEnergy	34.8	- Construct a new 138 kV line from Pruntytown to Glen Falls substations with 795 ACSR along new right-of-way approximately 15 miles. - Pruntytown 138 kV substation: Install a new terminal and all necessary terminal equipment with the addition of a new 138 kV breaker designated at P21 for the new Glen Falls-Pruntytown 138 kV line. - Glen Falls 138 kV substation: Install a new terminal on the east 138 kV bus with all necessary terminal equipment - Replace the No. 2 138-23 kV transformer to obtain space for the new terminal with a new 3-phase transformer, given that the No. 2 bank is a normally open, 3-1 phase transformer bank. - Glen Falls-Pruntytown 138 kV Line: Construct a new 138 kV line along new right-of-way approximately 15 miles with 795 ACSR.	

***Approved at the February 14, 2018 PJM Board Meeting**

Evaluation and Selection

Once the proposal window closed, PJM staff performed analytical, constructability and company evaluations – as described in **Book 2**, **Section 7.0** – to identify which proposals most effectively solved all reliability criteria violations and did not introduce new ones. Following stakeholder review with the Transmission Expansion Advisory Committee (TEAC), PJM recommended to the PJM Board, in December 2017, a set of eight recommendations – as noted in **Table 2.2** – to address 28 flowgate violations (the remaining 12 flowgates were approved at the February 2018 Board meeting). The recommended projects address violations in AEP, APS and Dominion and include replacing terminal equipment, reconductoring and splitting lines.

2.0.4 — Long-Term Proposal Windows

During 2017, PJM also completed the 2016/2017 RTEP Long-Term Proposal Window in February 2017. That window did not include any eligible reliability flowgates warranting window process solution solicitation. Rather, the window addressed market efficiency congestion issues, as discussed in **Section 5.2**, 2016/2017 RTEP Long-Term Proposal Window.

NOTE:

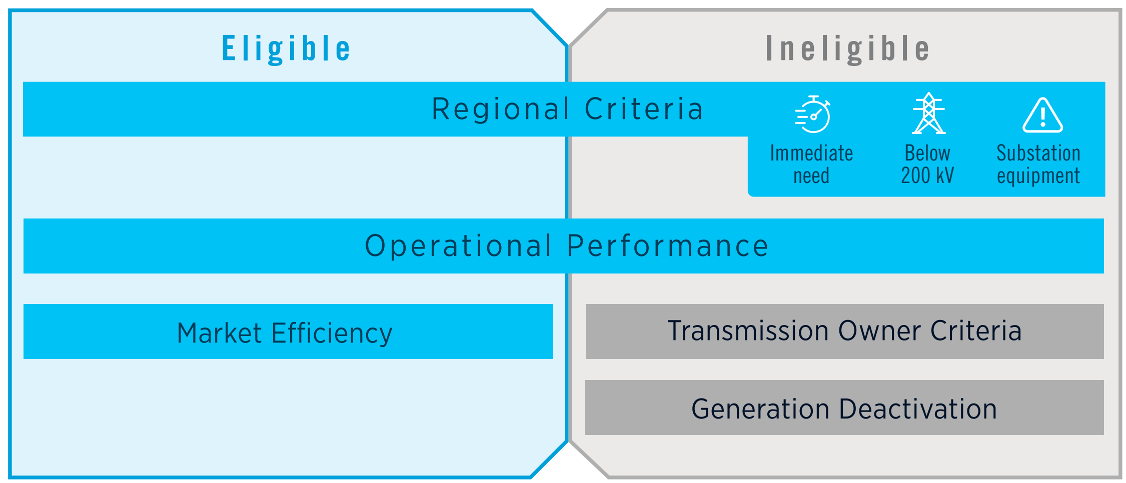
At the February 14, 2018, PJM Board meeting, Proposals 2017_1-6A and 2017_1-9L, addressing 12 reliability criteria violations, were approved for inclusion in the RTEP.

Section 3: Transmission Owner Criteria Violations

3.0: RTEP Context

The PJM Operating Agreement specifies that individual transmission owner (TO) planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions, such as in urban areas. TOs are required to include their individual criteria as part of their respective FERC Form No. 715 filings. TO criteria can be found on PJM's website: http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx. As part of its RTEP process, PJM applies TO criteria to the respective facilities of each that are included in the PJM Open Access Transmission Tariff facility list. While transmission enhancements driven by TO criteria are considered RTEP Baseline projects, they are assigned to the incumbent TO and are not eligible for proposal window consideration, as shown in **Figure 3.1.** Under the terms of the OATT, the costs of such projects are allocated 100 percent to the TO zone.

Figure 3.1: Window Eligibility



3.0.1 — 2017 TO Criteria Driven Projects

PJM has observed that transmission owner (TO) aging infrastructure criteria are increasingly driving the need for Baseline projects. Facilities built in the 1960s and earlier have revealed deteriorating facilities. Planning for aging infrastructure is not new to PJM. Spare 500/230 kV transformers, aging 500 kV line rebuilds and other equipment enhancements approved in prior years are already part of the RTEP.

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

This sections summarizes TO criteria driven transmission projects with cost estimates greater than $5 million as approved by the PJM Board in 2017.

NOTE:

Generation, merchant transmission and other new service interconnections to transmission owner facilities are subject to owner standards found at: http://www.pjm.com/planning/design-engineering.aspx.

These are technical interconnection requirements and do not factor into RTEP baseline planning analyses.

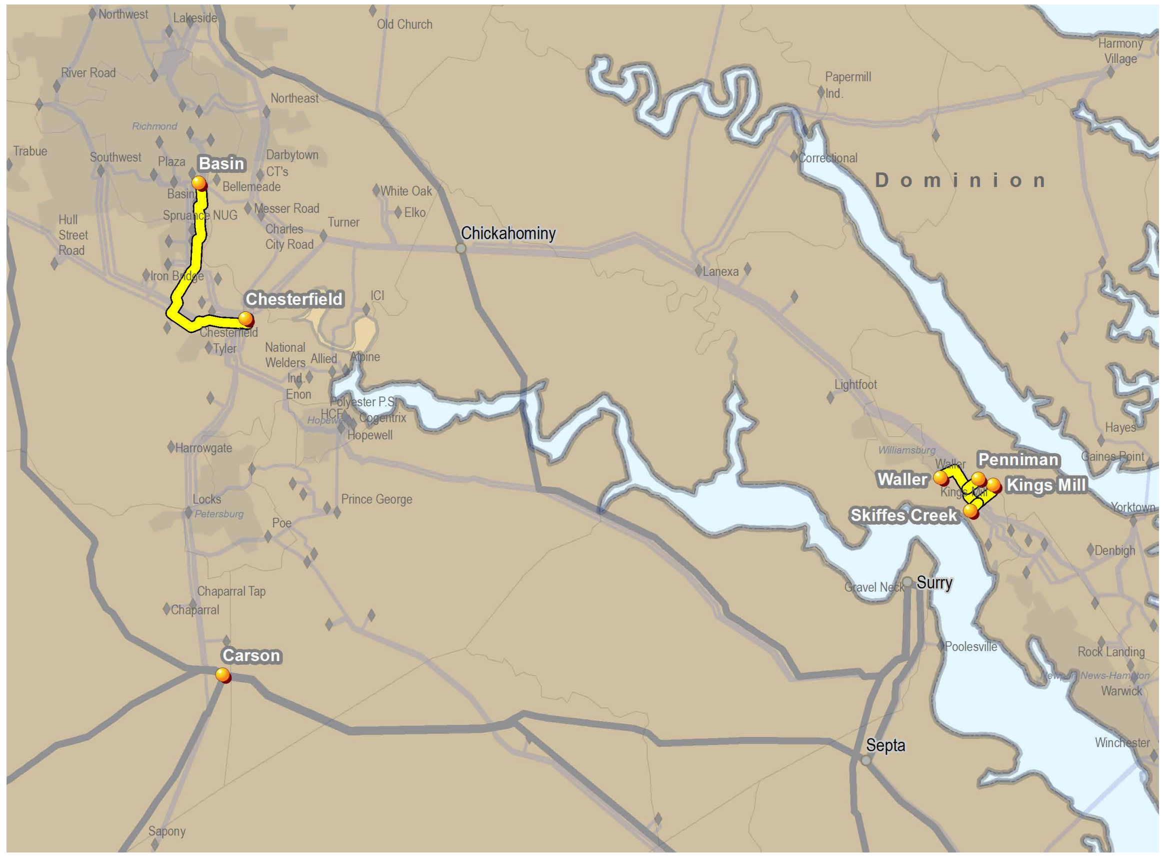
3.1: Dominion End-of-Life Criteria

Dominion's FERC Form No. 715 includes an end-of-life criterion that requires an equipment condition assessment for facilities that have reached or will reach end-of-life in the near future. The criterion also specifies a reliability evaluation to determine the system impacts due to facility removal. The PJM Board approved the following Dominion projects in 2017.

3.1.1 — Chickahominy-Surry 500 kV River Crossing

Aging infrastructure is driving the need to replace four Chickahominy-Surry 500 kV line (operational designation No. 567) river crossing structures. The river crossing structures – two in the James River and two at the river's edge – have deteriorated to the point that they need to be replaced. In addition, a specialized conductor was used in river crossing construction, which limits the line to 1,954 MVA. (This is the only location on Dominion's system where this type of conductor has been used.) For perspective, without the line modeled in-service, RTEP studies have identified multiple generation deliverability violations, shown on **Map 3.1**:

Map 3.1: Dominion Generator Deliverability Violations



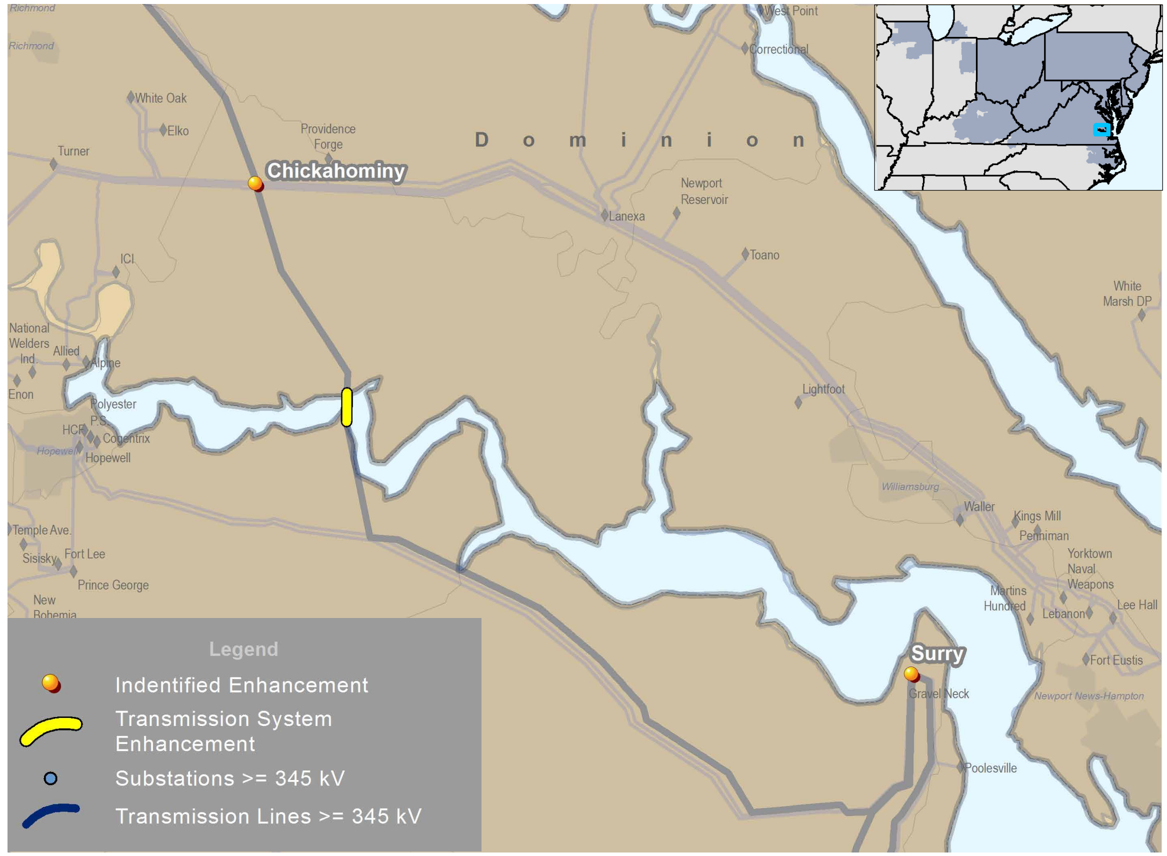
- Chesterfield-Basin 230 kV line overload for the loss of Carson-Midlothian 500 kV line or the loss of 230 kV line No. 217 Chesterfield-Lakeside 230 kV line
- Skiffes Creek-Kings Mill 230 kV overload for the loss of Carson-Midlothian 500 kV line
- Skiffes Creek-Kings Mill-Penniman-Waller 230 kV line overload for stuck breaker No. 56372 at Carson 500 kV substation
- Carson 500/230 kV transformer overload for stuck breaker No. 562T563 at Carson 500 kV substation
- Chesterfield-Basin 230 kV line overload for stuck breaker No. 205T217 at Chesterfield 230 kV substation

The proposed solution (b2928), shown on **Map 3.2**, approved by the PJM Board, addresses the aging infrastructure criteria violation by rebuilding the four river crossing structures using galvanized steel and replacing the river crossing conductor to increase the line's rating. The estimated project cost is $41 million with an anticipated December 30, 2017, in-service date.

3.1.2 — 115 kV and 230 kV Aging Infrastructure

Several Dominion 115 kV and 230 kV transmission lines are facing end-of-life criteria violations. Many tower structures, some dating back to the 1940s, must be replaced.

Map 3.2: Chickahominy-Surry 500 kV River Crossing

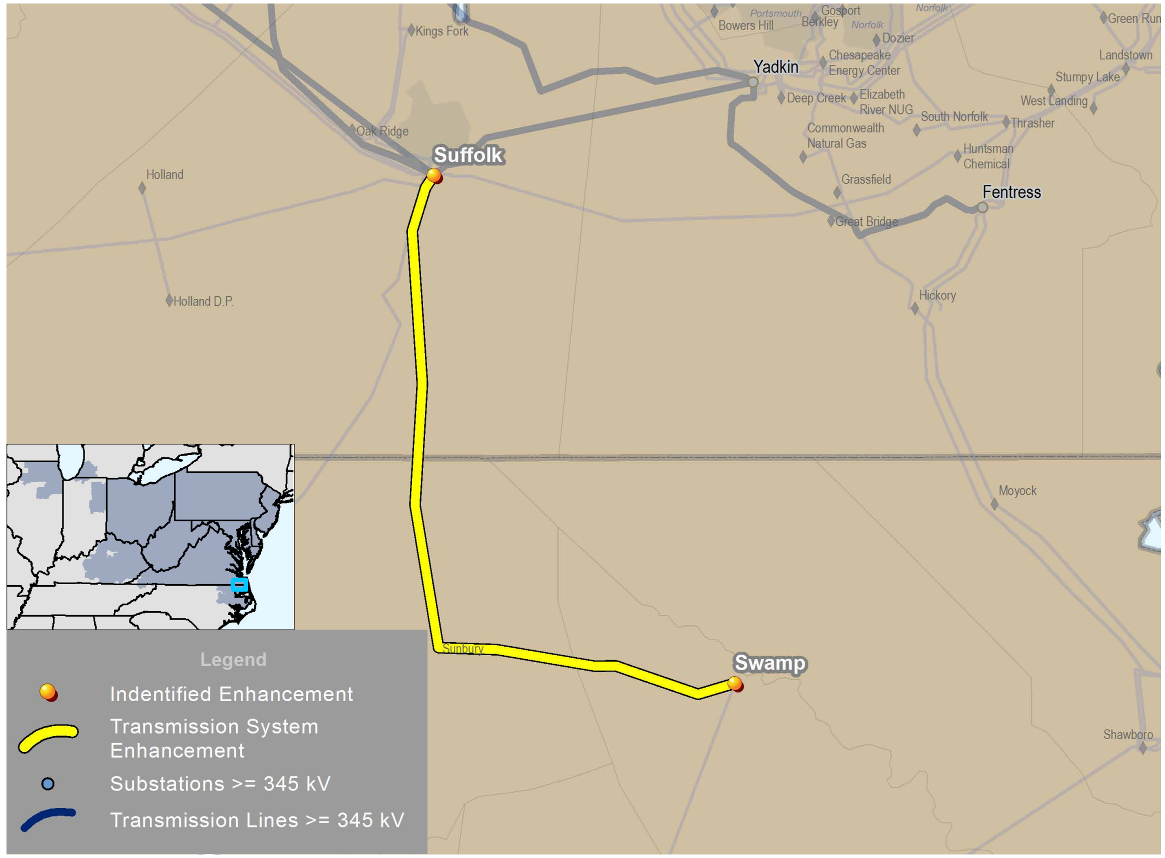


Swamp-Suffolk 230 kV Line

The Swamp-Suffolk 230 kV line was constructed mostly on wood H-frames in 1968, and now constitutes a Dominion end-of-life criteria violation.

The recommended solution (b2871), approved by the PJM Board in July 2017, is to rebuild the circuit to current 230 kV standards. Loss of the circuit, shown on **Map 3.3**, would cause a 21 MW loss of customer load. The estimated project cost is $31 million with a projected December 30, 2022, in-service date.

Map 3.3: Swamp-Suffolk 230 kV Line

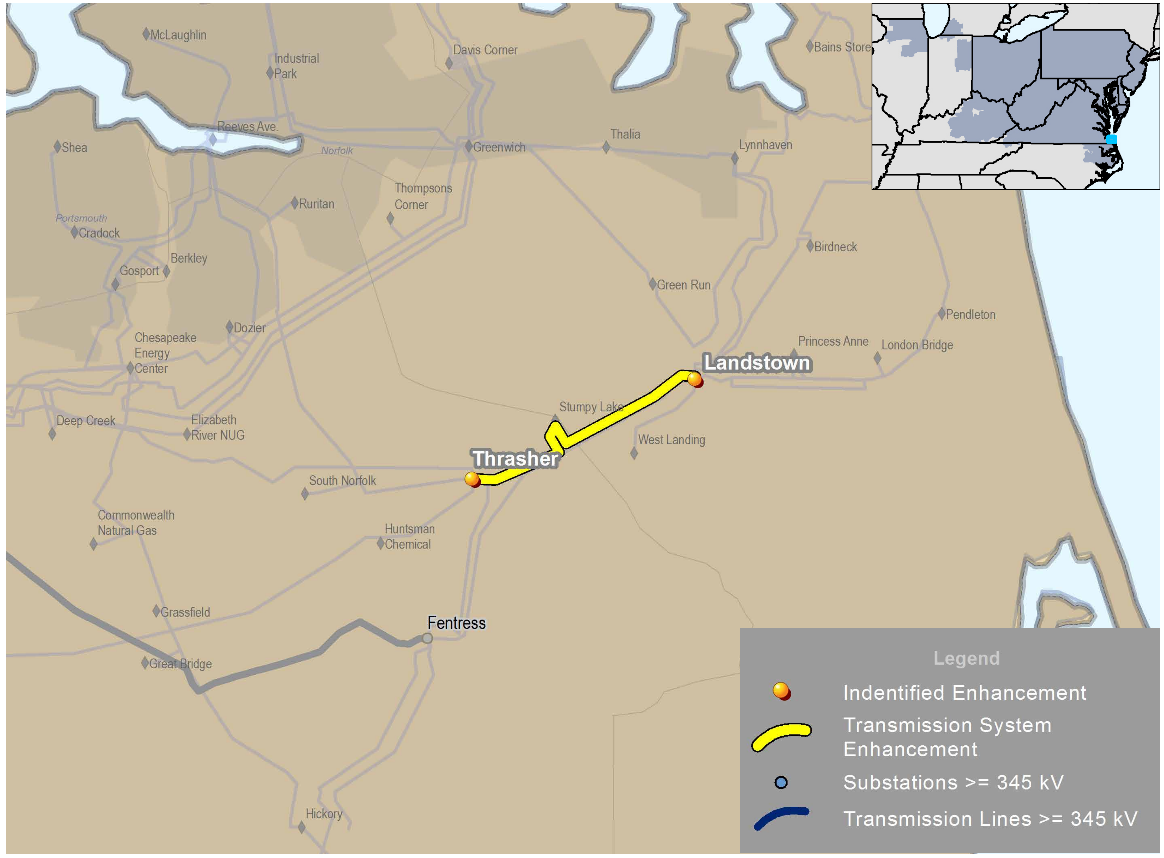


Landstown-Thrasher 230 kV Line

The Landstown-Thrasher 230 kV line, shown on **Map 3.4,** was built in 1965 mostly on double-circuit weathering steel towers and now constitutes a Dominion end-of-life criteria violation.

The recommended solution (b2899), approved by the PJM Board in October 2017, is to rebuild the circuit to current 230 kV standards with double-circuit steel pole and double circuit galvanized steel towers. Doing so will raise the emergency summer rating of the line. The estimated cost for the project is $22 million with a projected December 2020, in-service date.

Map 3.4: Landstown-Thrasher 230 kV Line

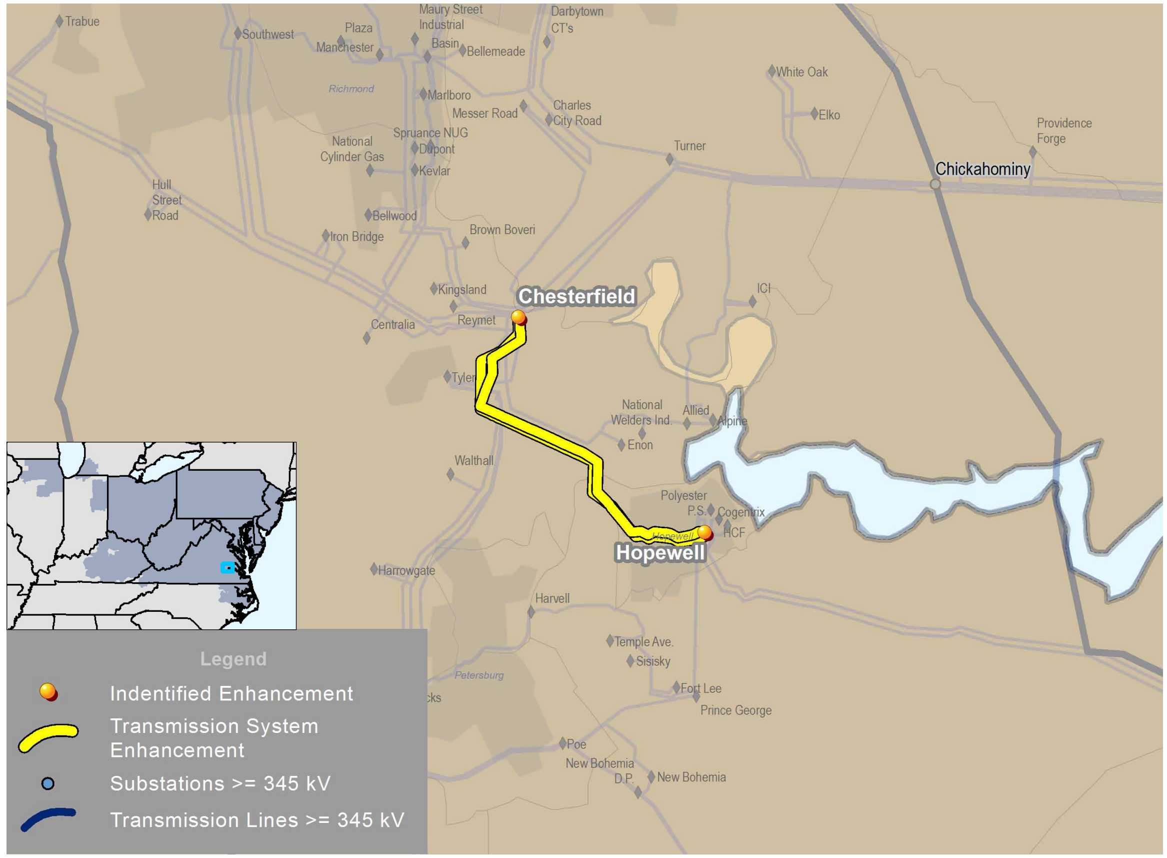


Chesterfield-Hopewell 230 kV Lines

The two Chesterfield-Hopewell 230 kV lines, shown on **Map 3.5**, include sections that were built in 1969 on double-circuit weathering steel towers. Field reports and condition assessment indicate the tower structures constitute a Dominion end-of-life criteria violation. The lines provide a critical outlet for the Chesterfield, Hopewell Cogeneration Facility, and Polyester generating stations.

The recommended solution (b2922), approved by the PJM Board in October 2017, is to rebuild the identified sections of the two lines to current 230 kV standards. The estimated project cost is $28.1 million with a projected December 2020, in-service date.

Map 3.5: Chesterfield-Hopewell 230 kV Lines

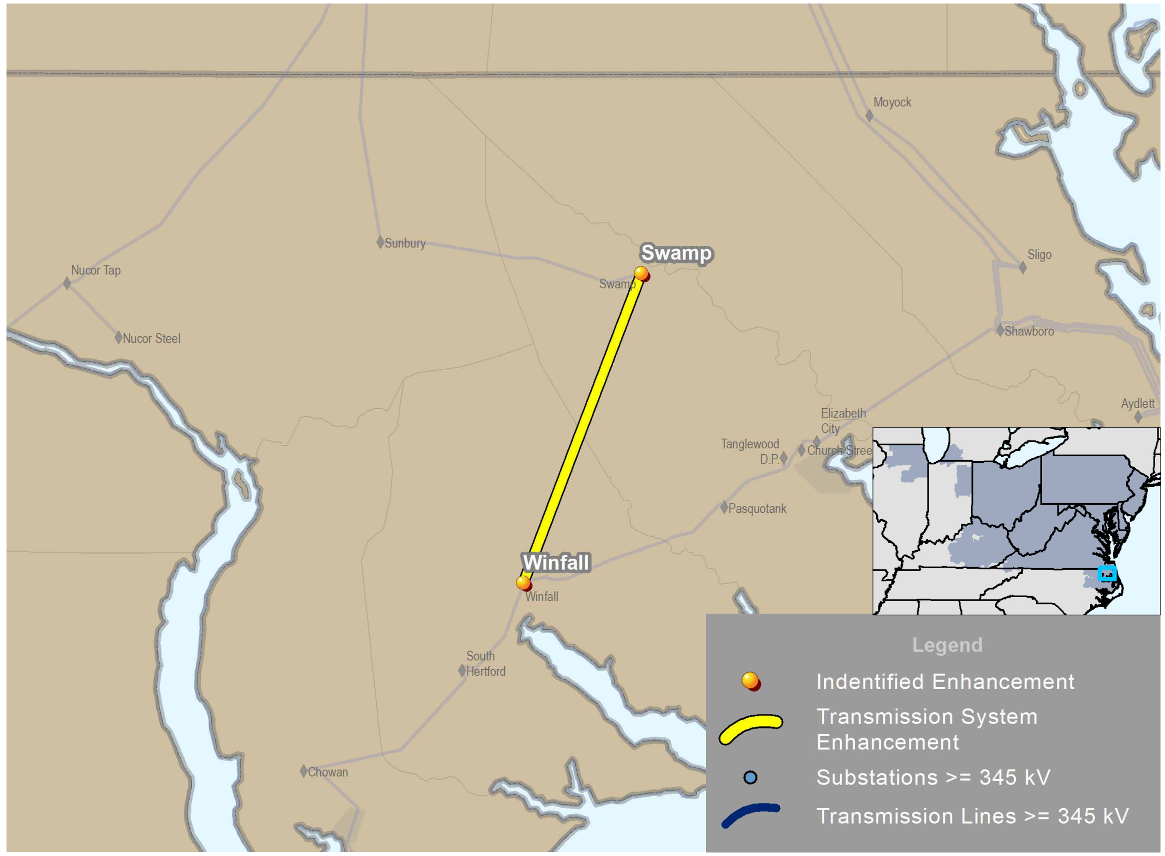


Winfall-Swamp 230 kV Line

The Winfall-Swamp 230 kV line, shown on **Map 3.6,** was constructed in 1968 on mostly wood H-frame tower structures and now constitutes a Dominion end-of-life criteria violation. Permanent retirement of this line would change the Suffolk-Swamp 230 kV line to a 31-mile-long radial circuit serving 3,900 customers. Dominion's 700 MW-mile radial line criterion would also be violated if future load growth exceeded just 0.5 MW.

The solution (b2929), approved by the PJM Board in October 2017, is to rebuild this 4.3-mile circuit to current 230 kV standards. The estimated project cost is $6 million with a December 30, 2022, projected in-service date.

Map 3.6: Winfall-Swamp 230 kV Line

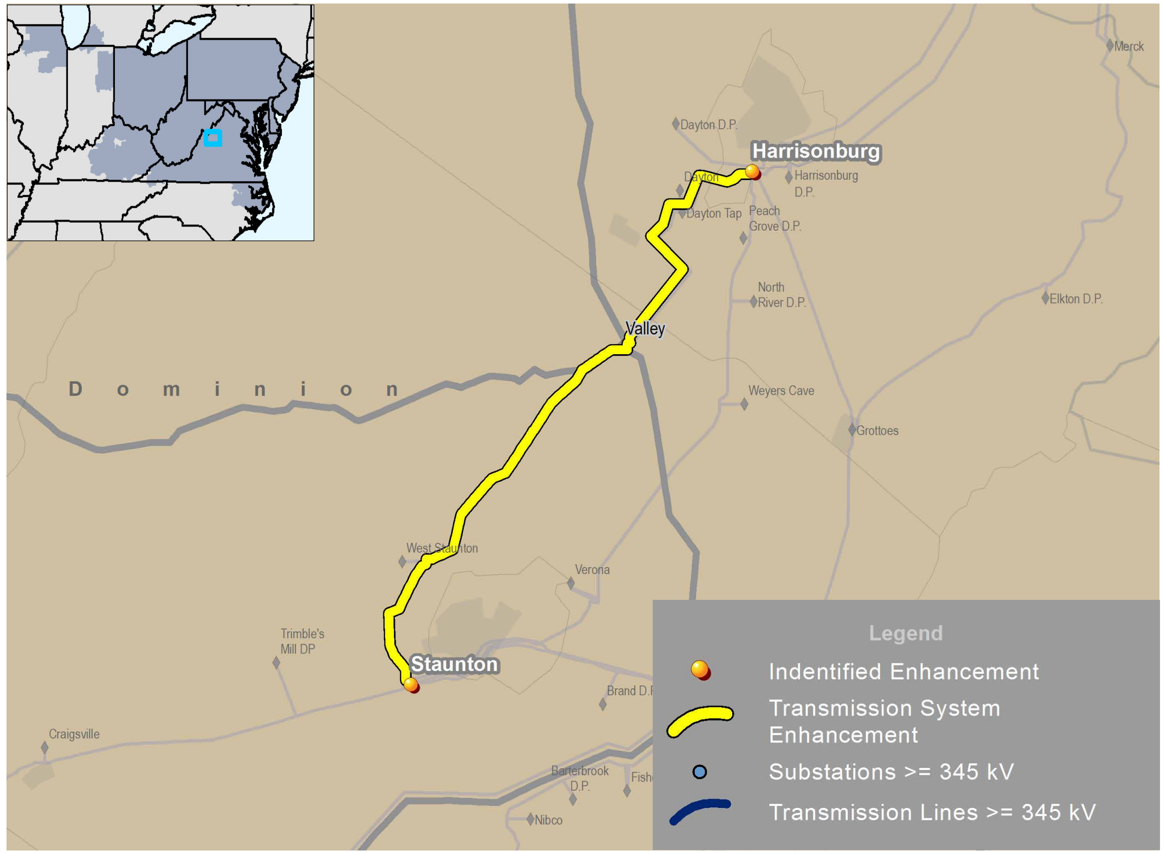


Staunton-Harrisonburg 115 kV Line

The Staunton-Harrisonburg 115 kV line, shown on **Map 3.7,** was constructed on wood H-frame structures in 1958 and constitutes a Dominion end-of-life criteria violation. The line feeds several substations that serve about 7,700 customers with load totaling 58 MW.

The solution (b2980), approved by the PJM Board in February 2018, is to rebuild the line to current standards. The estimated cost is $37.6 million with a projected October 31, 2022, in-service date.

Map 3.7: Staunton-Harrisonburg 115 kV Line



NOTE:

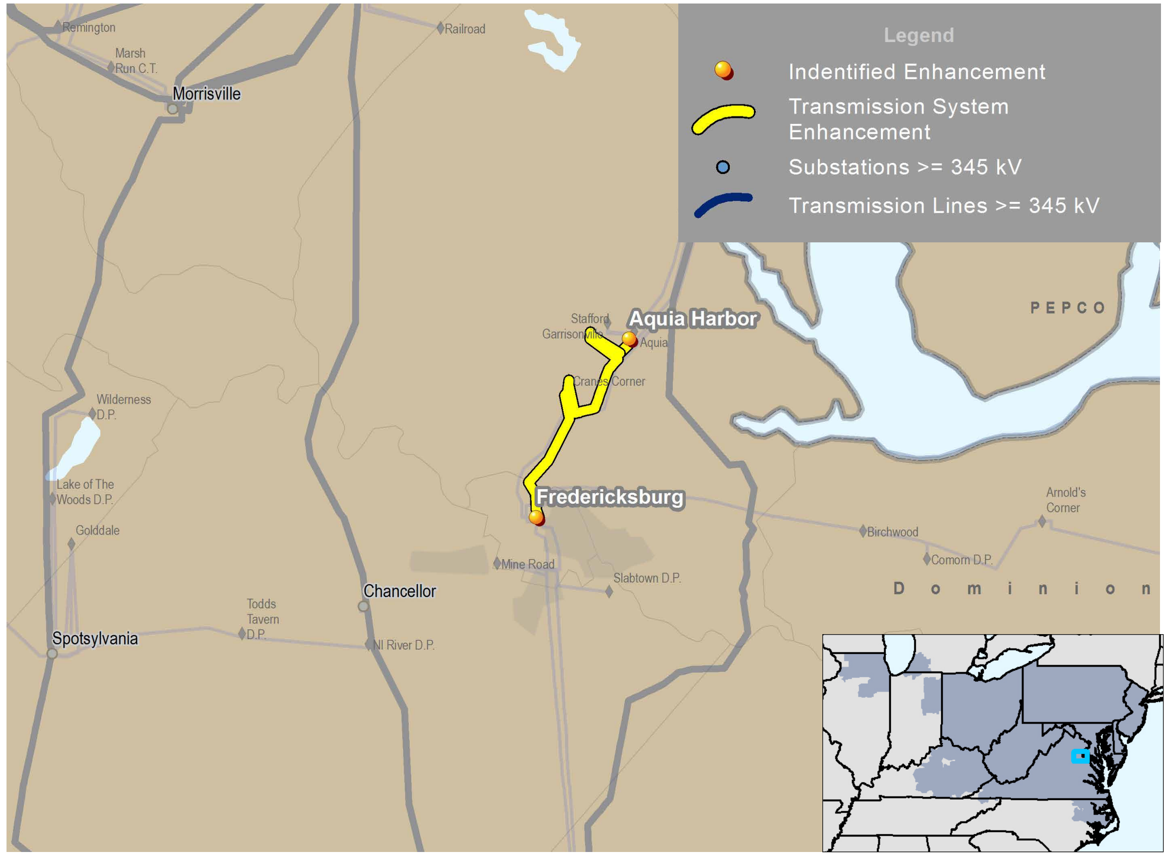
Project b2980 was approved by the PJM Board on February 14, 2018 for inclusion in the RTEP.

Fredericksburg-Aquia Harbor 115 kV Line

A 12-mile section of the 24.4-mile-long Fredericksburg-Possum Point 115 kV line, shown on **Map 3.8**, between Fredericksburg and Aquia Harbor, was constructed on wood H-frame structures in 1957 and now constitutes a Dominion end-of-life criteria violation. The line provides service to Quantico substation with 440 customers, including the Quantico USMC base.

The solution (b2981), approved by the PJM Board in February 2018, is to rebuild the line segment to current 230 kV standards while operating initially at 115 kV. The estimated project cost is $12.5 million with a December 31, 2022, projected in-service date.

Map 3.8: Fredericksburg-Aquia Harbor 115 kV Line



NOTE:

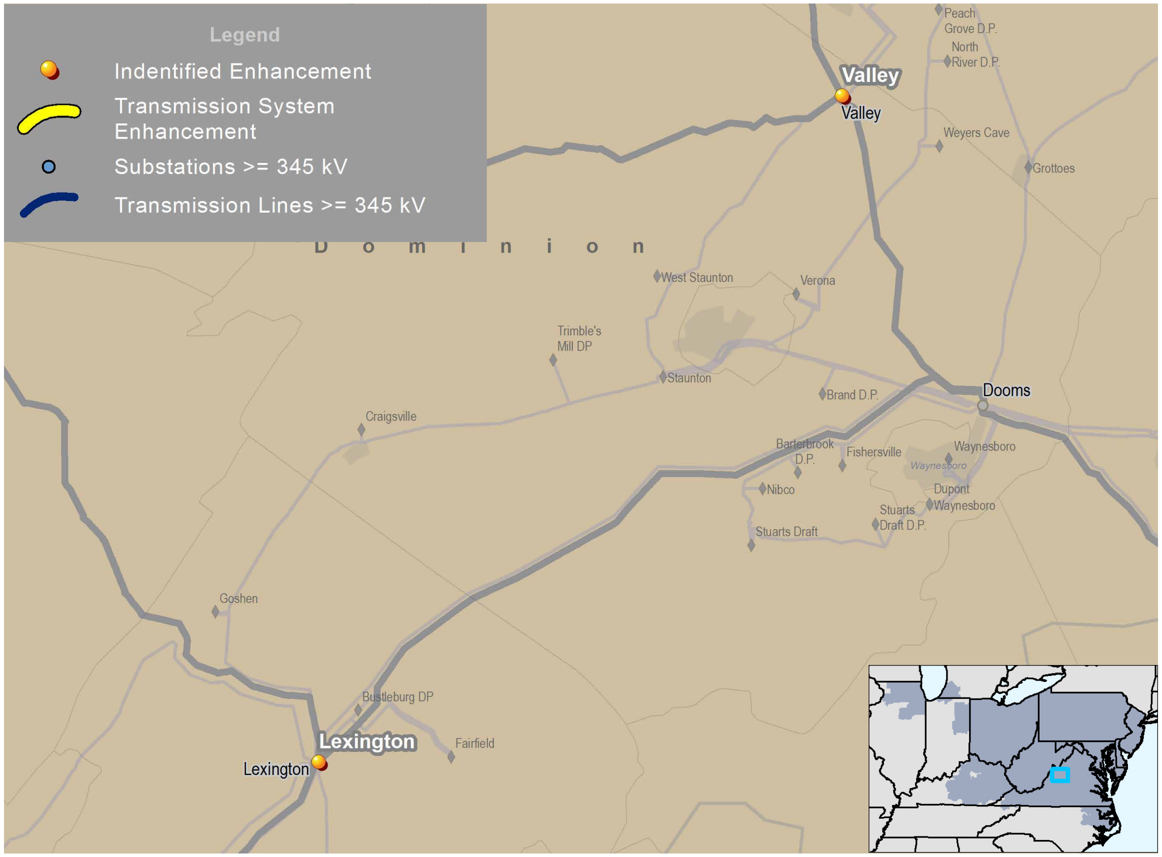
Project b2981 was approved by the PJM Board on February 14, 2018, for inclusion in the RTEP.

Lexington and Valley 500 kV Fixed Series Capacitors

The fixed series capacitors (FSC) at Lexington on the Lexington-Bath County 500 kV line and at Valley on the Valley-Bath County 500 kV line, shown on **Map 3.9**, were installed in 2000 and 2001 to solve Bath County Pumped Storage Plant angular stability issues. Dominion's end-of-life criteria require that these capacitors be rebuilt to current standards. Additionally, the manufacturer no longer provides spare parts for these devices. Absence of these devices limits the allowable power out of Bath County.

The solution (b2960), approved by the PJM Board in December 2017, is to replace the FSCs with newer models of the same size but with higher ratings. Doing so will permit greater power flow on the Lexington and Valley lines. The estimated project cost is $28.9 million with an April 1, 2020, projected in-service date.

Map 3.9: Lexington and Valley 500 kV Fixed Series Capacitors

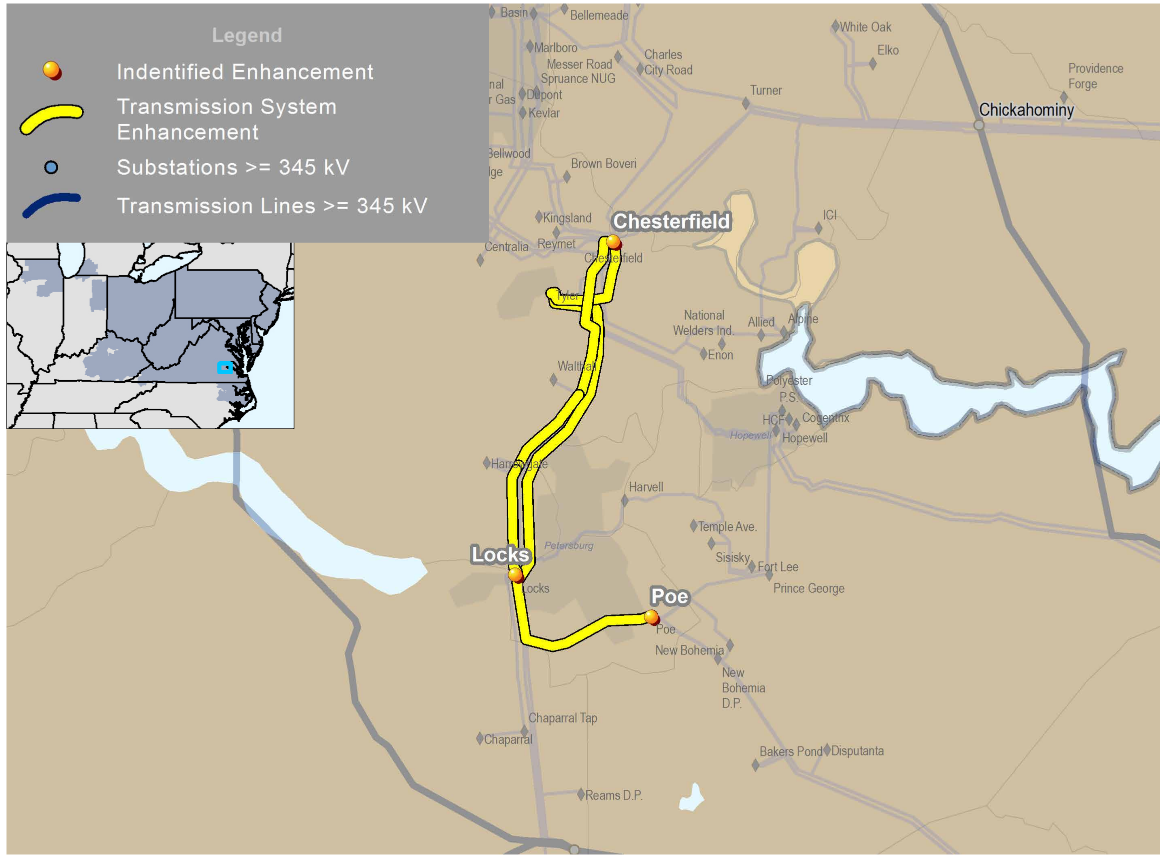


Chesterfield-Locks and Chesterfield-Poe 230 kV Lines

A three-mile section of the Chesterfield-Locks and Chesterfield-Poe 230 kV Lines between Chesterfield and Tyler, shown on **Map 3.10,** was built on double-circuit weathering steel towers in 1962. They now constitute a Dominion end-of-life criteria violation. Removing the lines would cause a permanent load loss totaling 140 MW.

The solution (b2961), approved by the PJM Board in December 2017, is to rebuild the three-mile section to current 230 kV standards. The estimated cost is $9.5 million with a December 31, 2022, projected in-service date.

Map 3.10: Chesterfield-Locks and Chesterfield-Poe 230 kV Lines

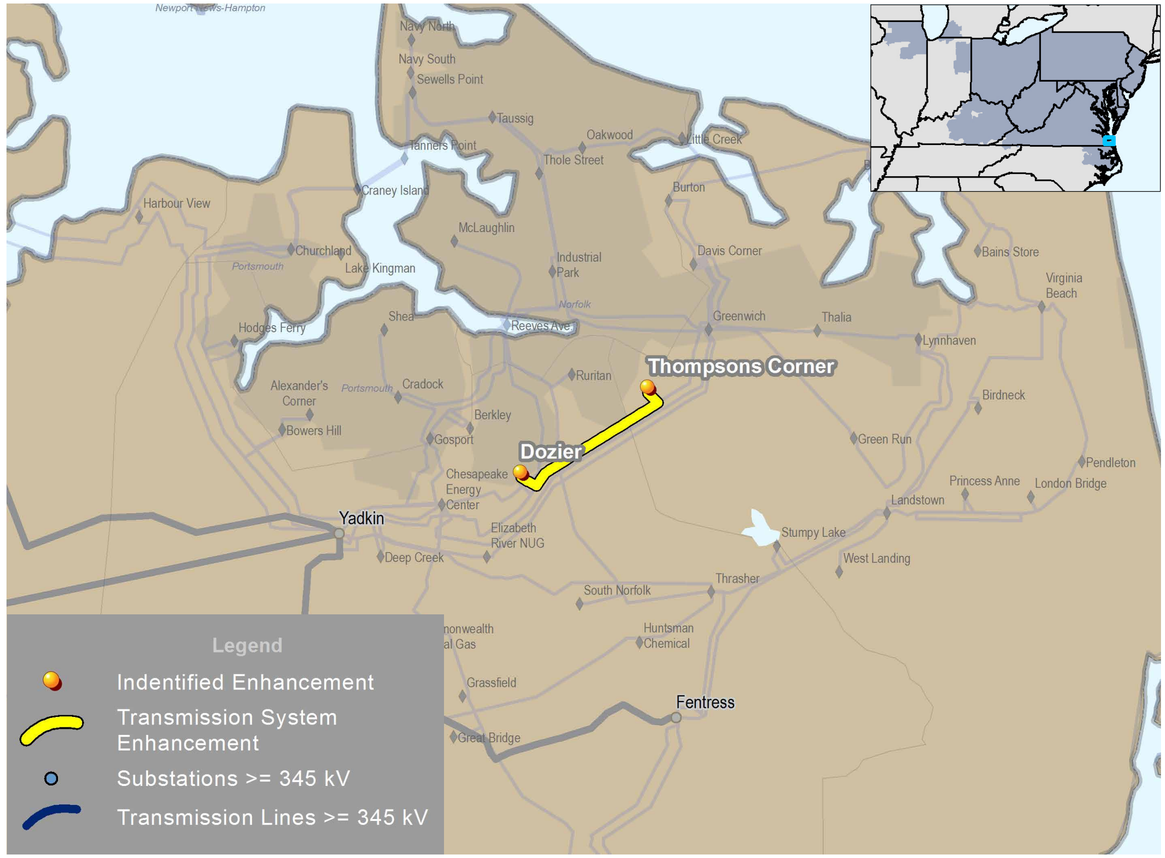


Dozier–Thompsons Corner 115 kV Line

A seven-mile segment of the Dozier-Thompsons Corner 115 kV line, shown on **Map 3.11**, was constructed on wood H-frame structures in 1955. Dominion must rebuild the line to current standards based on their end-of-life criteria. Removing the lines would cause a permanent load loss totaling 100 MW.

The solution (b2800), approved by the PJM Board in October 2017, is to rebuild the seven-mile segment to current standards. The estimated project cost is $6.5 million with a projected December 30, 2021, in-service date.

Map 3.11: Dozier-Thompsons Corner 115 kV Line

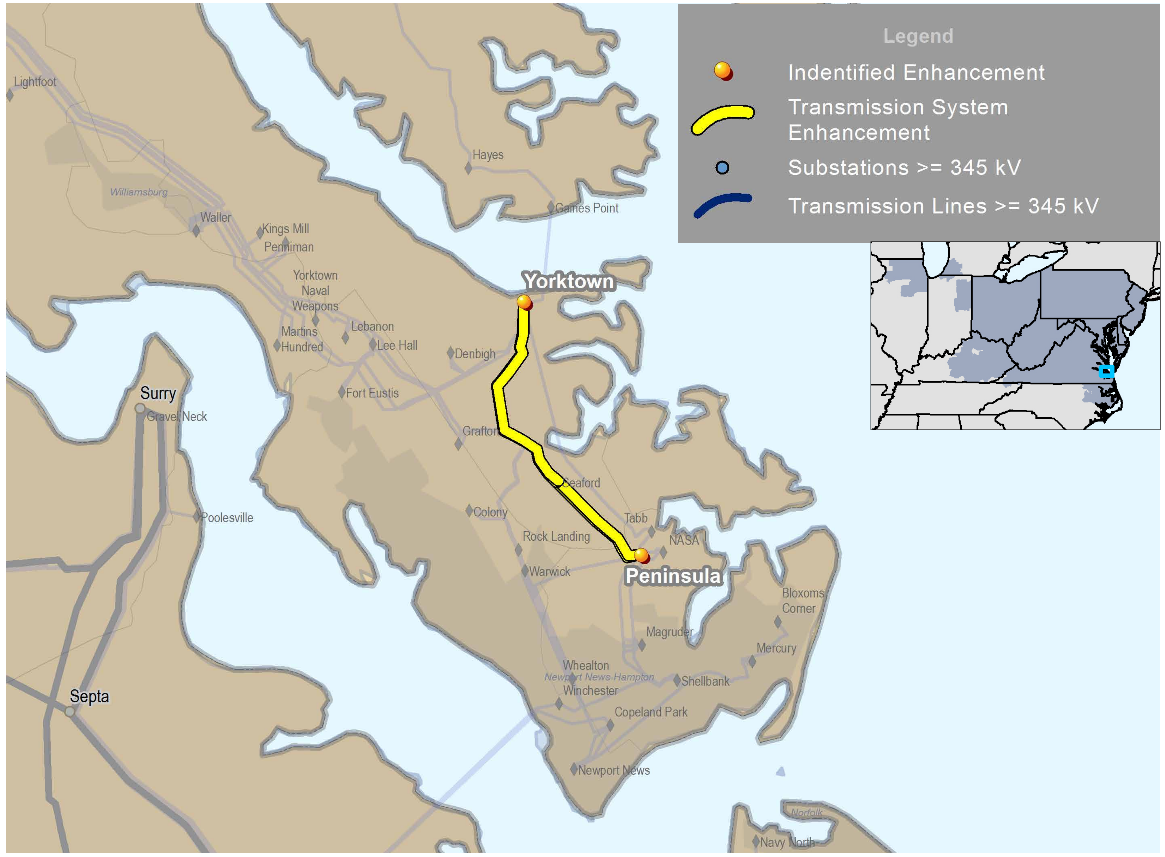


Yorktown-Peninsula 115 kV Lines

The two Yorktown-Peninsula 115 kV lines, shown on **Map 3.12**, were constructed on double-circuit three-pole wood H-frame structures in 1957. Removal of the lines would cause permanent load loss totaling 30 MW. The lines must be rebuilt to current standards based on Dominion's end-of-life criteria.

The solution (b2801), approved by the PJM Board in October 2017, is to rebuild the two lines to current standards. The estimated project cost is $22 million with a projected December 30, 2020, in-service date.

Map 3.12: Yorktown-Peninsula 115 kV Lines

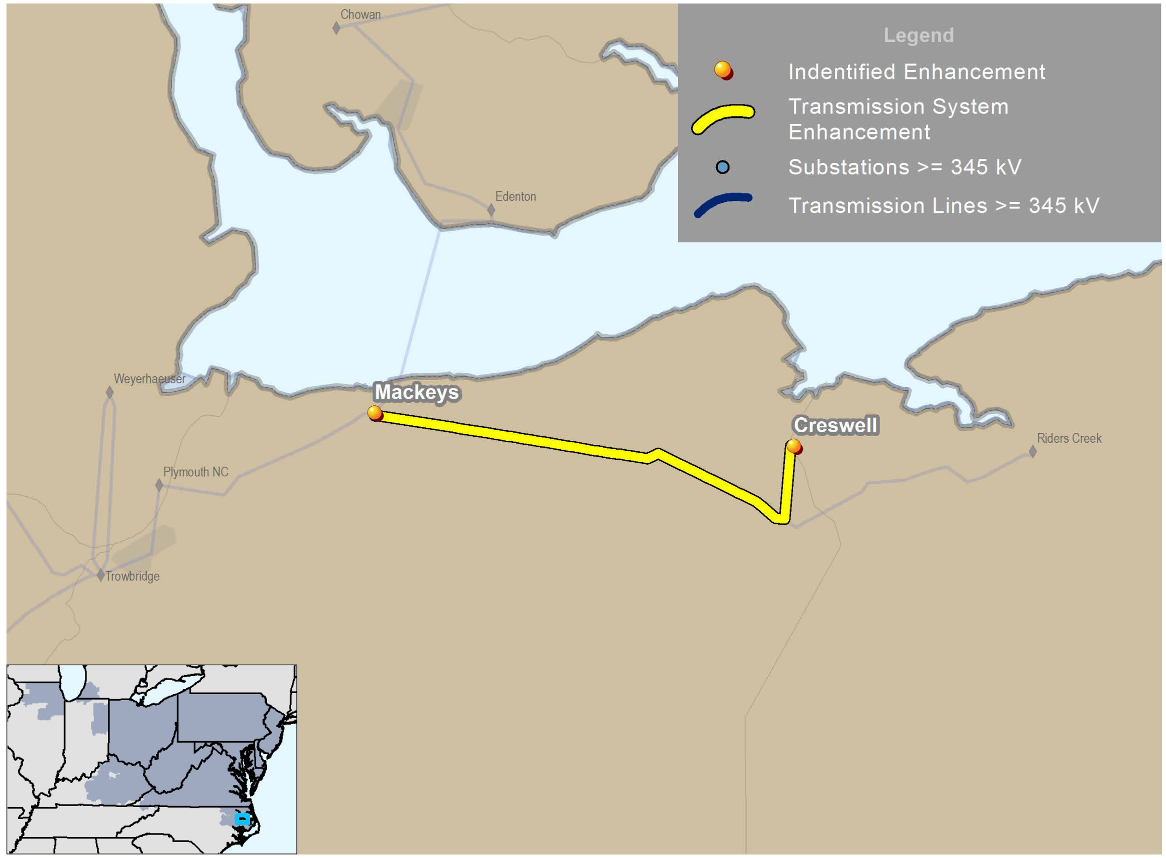


Mackeys-Creswell 115 kV Line

The 14-mile long Mackeys-Creswell 115 kV line, shown on **Map 3.13,** was constructed on wood H-frames that date back to 1970. The conductor has broken strands along its entire 14-mile length. The line must be rebuilt to current standards based on Dominion's end-of-life criteria. Line removal would cause permanent megawatt load loss totaling 21 MW. Additionally, Dominion's megawatt-mile limit for the lines would be exceeded if new future load totaling 8 MW were to be added.

The solution (b2876), approved by the PJM Board in October 2017, is to rebuild the line with double circuit steel structures and with one circuit initially installed with new conductor that meets current standards. The estimated project cost is $40 million with a December 30, 2022, projected in-service date.

Map 3.13: Mackeys-Creswell 115 kV Line

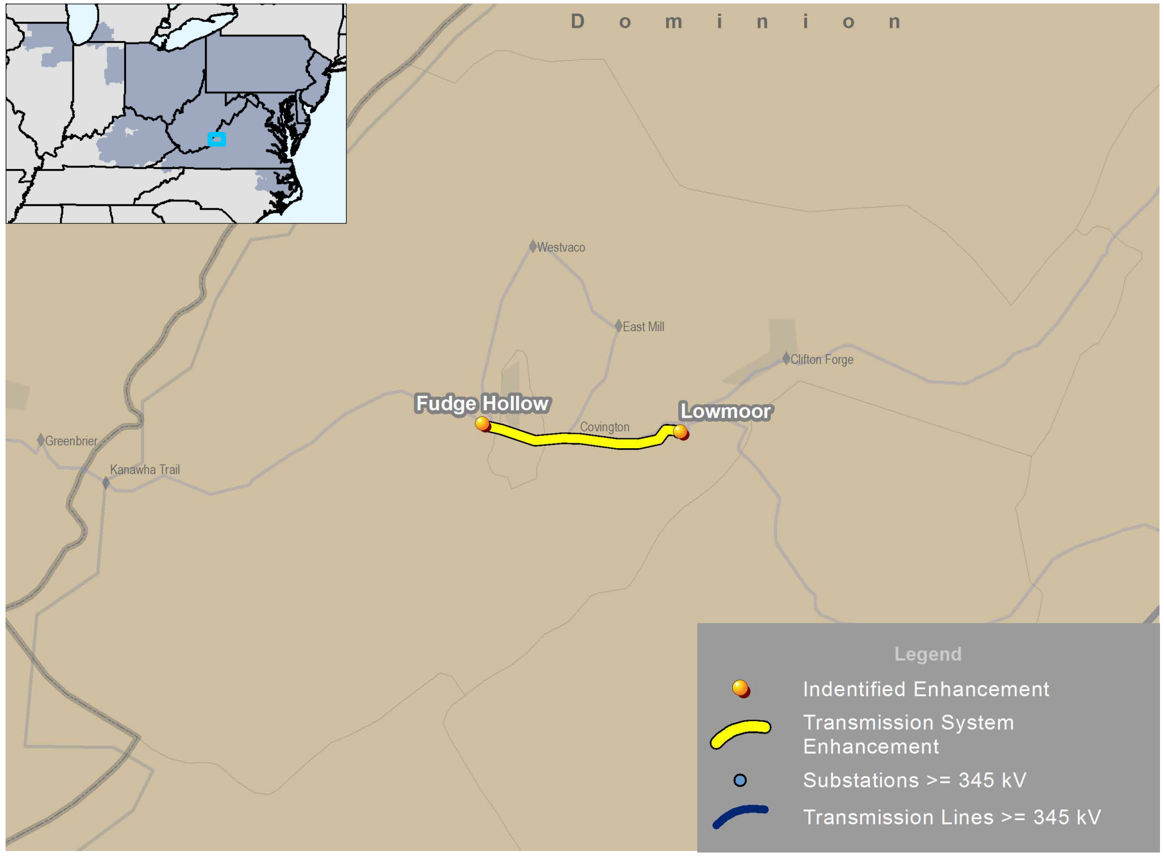


Fudge Hollow-Lowmoor 138 kV Line

The Fudge Hollow-Lowmoor 138 kV line, shown on **Map 3.14,** was constructed in 1929. Steel lattice towers supporting the line now exhibit severe corrosion, and foundations are no longer considered dependable, violating Dominion's end-of-life criteria. Loss of the line would cause loss of service to approximately 10,000 customers, including some 3,600 served by a local co-operative.

The solution (b2877), approved by the PJM Board in October 2017, is to rebuild the line to current standards. The estimated project cost is $8 million with a projected October 31, 2020, in-service date.

Map 3.14: Fudge Hollow-Lowmoor 138 kV Line

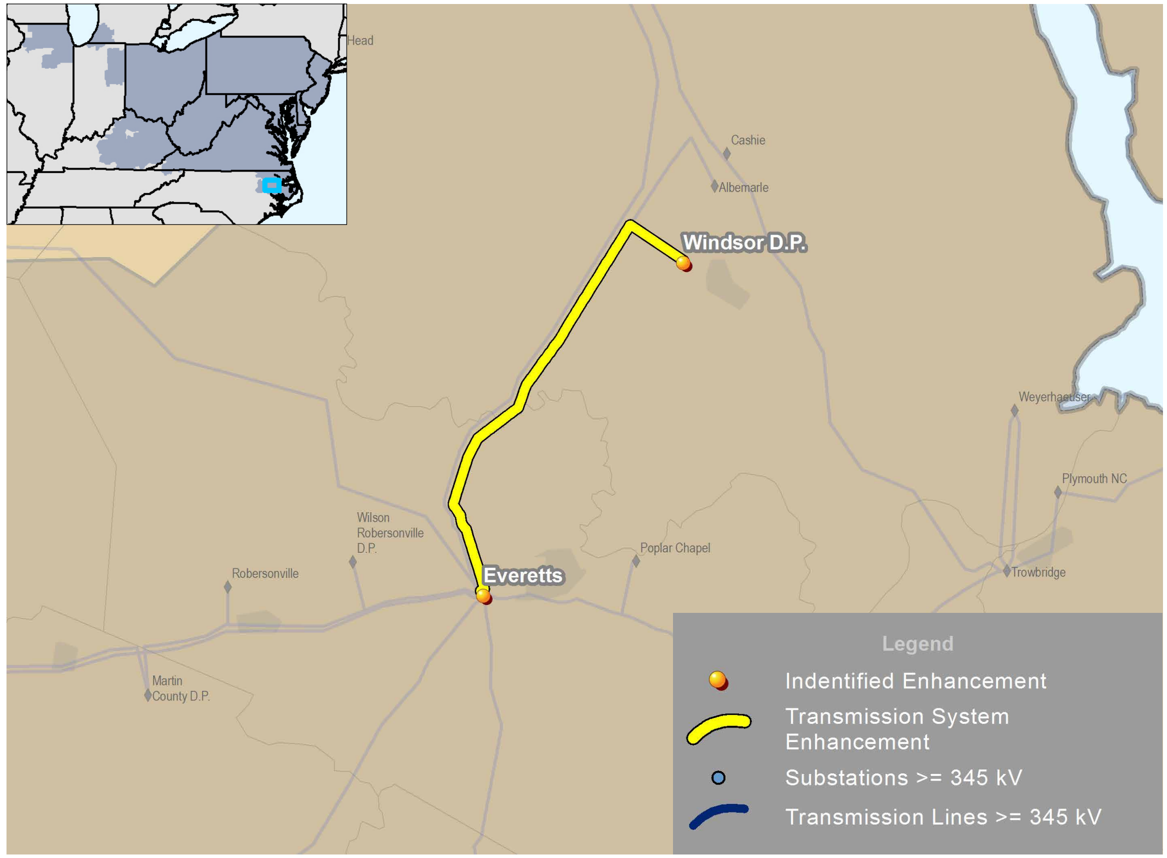


Everetts-Windsor 115 kV Line

The Everetts-Windsor 115 kV line, shown on **Map 3.15,** was constructed in 1951 on wood H-frame towers and radially serves 10 MW of load at Windsor. Dominion end-of-life criteria require that either the line must be rebuilt to current standards or a new source for Windsor must be provided.

The solution (b2900), approved by the PJM Board in October 2017, is to build a new 230/115 kV switching substation connecting to the Earleys-Everetts 230 kV line; install a 230/115 kV transformer and spare transformer) and retire the Everetts-Windsor 115 kV line. The estimated project cost is $11.5 million with a projected December 30, 2022, in-service date.

Map 3.15: Everetts-Windsor 115 kV Line



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

3.2: AEP Criteria Violations

PJM 2017 RTEP Baseline projects included a number of AEP transmission enhancements at 69 kV, 46 kV and 34.5 kV. They are considered AEP TO criteria-driven projects given that they are "tariff facilities". At those voltage levels, they are not examined as a matter of course in PJM's RTEP process as part of AEP's monitored facilities list. Tariff facilities are those each TO has included in its respective FERC Form No. 1. They are used to provide transmission service under the PJM Open Access Transmission Tariff. Monitored facilities are those modeled in PJM's real-time operations energy management system (EMS) and assessed in PJM's RTEP process.

PJM reliability analysis of AEP 69 kV, 46 kV and 34.5 kV tariff facilities identified thermal overloads and voltage violations for various N-1 and N-1-1 contingencies driving the need for Board-approved RTEP transmission enhancements summarized in **Table 3.1** and **Map 3.16.** Additional project detail can be found on the construction status page of PJM's website: http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx.

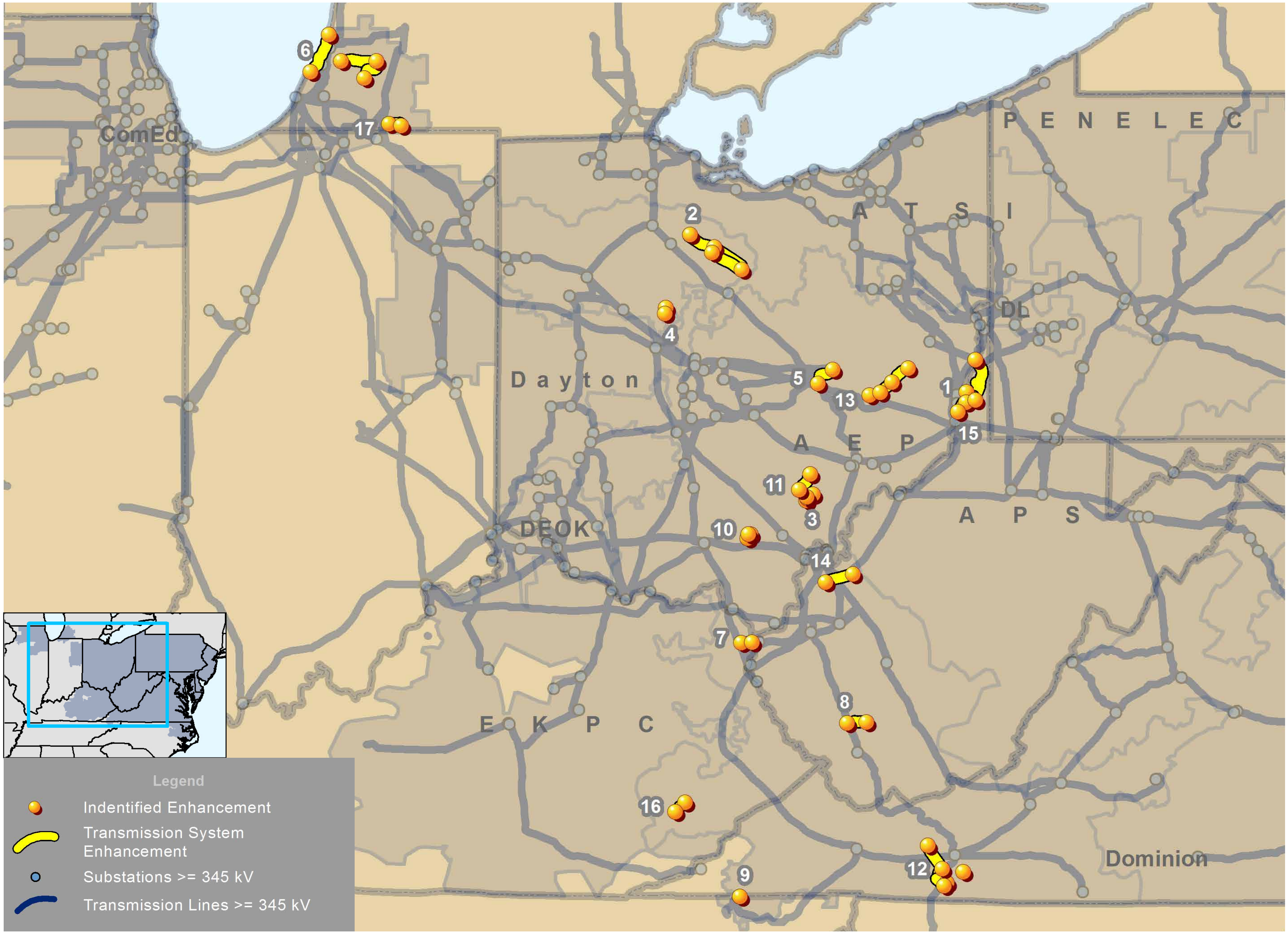
Table 3.1: AEP Criteria-Driven Baseline Projects (greater than $5 million)

Map ID	RTEP Project ID	Project Description	Criteria Violations	Project Cost Estimate ($M)	Required In-service Date
1	b2789	Rebuild Brues-Glendale Heights 69 kV line.	Line overloaded for multiple N-1-1 contingency pairs, common towerline, and breaker-failure contingencies.	16.7	6/1/2021
2	b2791	Rebuild portions of East Tiffin-Howard and Tiffin-Howard 69 kV lines. Install new 138/69 kV transformer at Chatfield substation.	Multiple area thermal and voltage violations caused by multiple N-1-1 contingency pairs.	20.4	6/1/2021
3	b2792	Replace Elliott 138/69 kV transformer. Reconductor Elliott-Ohio University 69 kV line. Rebuild Clark Street-Strouds Run 69 kV line.	Elliott transformer and Elliott-Ohio University 69 kV line overload edfor the loss of the Poston-Strouds Run-Crooksville 138 kV Line. Clark Street-Strouds Run 69 kV line overloaded for the loss of the Dexter-Elliot-Poston 138 kV line.	5.8	6/1/2021
4	b2794	Construct a new 138/69/34 kV substation and 1-34 kV circuit (designed for 69 kV) from new substation to Decliff substation.	Low voltage (0.883 per unit) and voltage drop (17 percent) violations at South Upper Sandusky, Harpster, Ridgedale, South Morral, Meeker and Decliff 69 kV buses	12.6	6/1/2021
5	b2797	Rebuild Ohio Central-Conesville 69 kV line. Replace Ohio Central 138-69 kV transformer.	Ohio Central-Conesville 69 kV line and Ohio Central 138/69 kV transformer overloaded for multiple N-1 and N-1-1 contingencies.	20.6	6/1/2021
7	b2799	Rebuild Valley-Almena 69 kV line as double circuit. Rebuild Almena-Hartford 69 kV line. Rebuild Riverside-South Haven 69 kV line. Install new 138/69 kV transformer and breaker at Almena substation. Install second 138/69 kV transformer with a circuit breaker and circuit switcher at Hartford substation.	Numerous low voltage violations and transformer thermal overloads or multiple N-1-1 type contingencies involving area 138 kV and 69 kV sources and lines.	53.0	6/1/2021
8	b2880	Rebuild 4.7 miles of the Cannonsburg-South Neal 69 kV line.	Cannonsburg-South Neal 69 kV line overloaded for loss of Bellefonte 69 kV bus No. 2 or Bellefonte-Hoods Creek 69 kV line.	12.5	6/1/2021

Table 3.1: AEP Criteria-Driven Baseline Projects (greater than $5 million) (Continued)

Map ID	RTEP Project ID	Project Description	Criteria Violations	Project Cost Estimate ($M)	Required In-service Date
9	b2883	Rebuild the Craneco-Pardee-Three Forks-Skin Fork 46 kV line.	Line overloaded for N-1-1 outage of Huff Creek 138/69/46 kV and Chauncey 138/46 kV transformers.	12.2	6/1/2021
10	b2884	Install second Nagel 500/138 kV transformer.	Numerous thermal and voltage drop violations on Kingsport 34.5 kV sub-transmission system for various N-1 and N-1-1 outages	13.0	6/1/2021
11	b2885	Construct new Rhodes 138/69 kV substation on Lick-Ross 69 kV line. Install new switch at Ironman 69 kV substation. Replace Coalton 69 kV Switch with new three breaker Heppner 69 kV ring bus.	City of Jackson, Ohio, request for new 69 kV delivery point capable of carrying entire 37 MW city load.	13.0	3/1/2018
12	b2888	Retire Poston 138 kV substation. Install new Lemaster 138 kV substation. Relocate Trimble 69 kV radial delivery point to 138 kV on Poston-Strouds Run-Crooksville 138 kV line via new three-way switch. Retire the Poston-Trimble 69 kV line.	Elliott-Rosewood 138 kV line and Elliott-Ohio University 69 kV line overloads; low voltage and voltage drop violations at Poston 138 kV substation for multiple common mode contingencies.	26.9	1’2/31/2018
13	b2889	Install two 138/69 kV transformers, six 138 kV and four 69 kV circuit breakers at Cliffview substation. Tap Pipers Gap-Jubal Early 138 kV line into new Cliffview substation. Retire Byllesby-Wythe 69 kV line. Retire 13.5 miles of Galax-Wythe 69 kV circuit, terminate at Byllesby 69 kV substation to create new Galax-Byllesby 69 kV line.	Line overload for the loss of Jubal Early 138/69 kV transformer.	30.0	6/1/2021
14	b2890	Rebuild 23.6 miles of East Cambridge-Smyrna 34.5 kV; convert to 69 kV. Install 69 kV breaker for the line and install a 69 kV two way phase over switch at Old Washington.	Fairdale-Cambridge 69 kV, Summerfield-Derwent 69 kV, and Cambridge-West Cambridge 34.5 kV overloaded for several N-1-1 contingencies.	36.3	6/1/2021
15	b2892	Install new 138/12 kV transformer at Leon and new 138 kV line exit to Ripley. Construct a 138 kV bus at Ripley with a new 138/69 transformer and move distribution load to 138 kV service. Rebuild the Leon-Riplely 69 kV line and operate at 138 kV; rebuild Ripley 69 kV bus.	Leon-Ripley 69 kV line and Leon 138/69 transformer No. 3 overloads for N-1-1 contingency; voltage violations at Ripley 69 kV bus for N-1 loss of Leon-Ripley line.	27.1	6/1/2021
16	b2958	Cut George Washington-Tidd 138 kV line into Sand Hill and reconfigure Brues and Warton Hill line entrances; add two 138 kV breakers, disconnects and update relaying at Sand Hill.	Kammer-Aston 138 kV overload for loss of Brues-Sand Hill and Tidd-Sand Hill 138 kV lines or Sand Hill breaker “A” failure. Calis SW 138 kV area low voltages and voltage collapse for same contingencies. Tidd-Sand Hill 138 kV overloaded for loss of Brues-Sand Hill and Big Grave Creek-Kammer 138 kV lines.	7.3	7/1/2017
17	b2761.2	Rebuild the Hazard-Wooton 161 kV line.	Generator deliverability analysis identified Hazard-Wooton 161 kV line overload under summer and winter peak conditions.	16.5	6/1/2021
18	b2936	Rebuild Mottville-Pigeon River 69 kV line at 230 kV.	Local load growth. Operational performance: multiple Post Contingency Local Loading Relief Warnings	12.0	6/1/2020

Map 3.16: AEP Criteria-Driven Baseline Projects (greater than $5 million)



3.3: PSE&G Transmission Owner Criteria Violations

3.3.1 — Loss of Supply Criteria

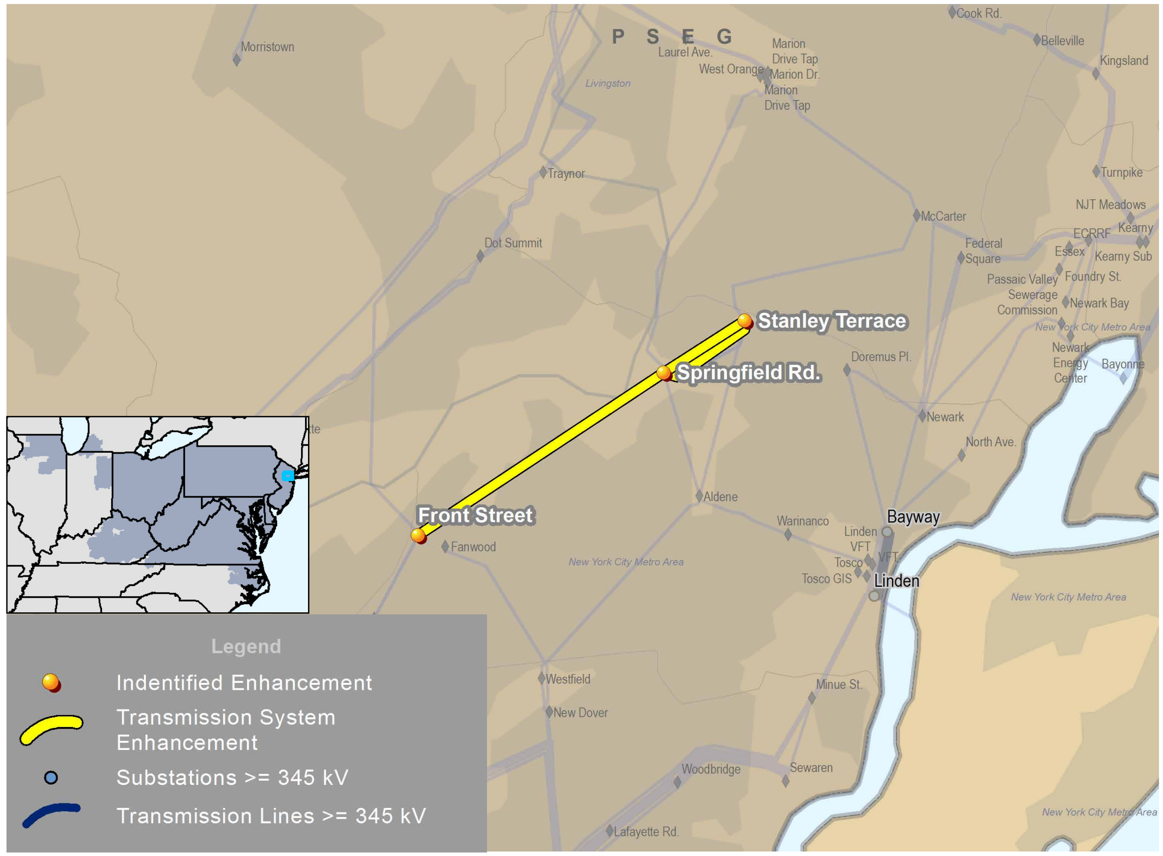
PSE&G FERC Form No. 715 contains transmission owner criteria that specify acceptable load drop levels and duration. The criteria applies to substations served by only two lines (frequently with underground cable sections) when one of the lines is out of service. PJM and PSE&G studies identified N-1-1 violations in 2017 driving the need for the following projects, each of scope greater than $5 million.

Springfield and Stanley Terrace 230 kV Substations

Two 230 kV underground lines feeding Springfield and Stanley Terrace substations supply load to more than 10,000 and 5,000 customers, respectively. At each substation, an N-1-1 contingency event would cause loss of all electric supply to that station for more than 24 hours.

The recommended solution (b2933) approved by the PJM Board includes constructing 230/69 kV substations at both Springfield and Stanley Terrace and constructing a 69 kV network between Front Street, Springfield and Stanley Terrace, as shown on **Map 3.17**. The estimated cost for the project is $197 million with a June 1, 2018 projected, in-service date.

Map 3.17: Front Street-Springfield-Stanley Terrace



NOTE:

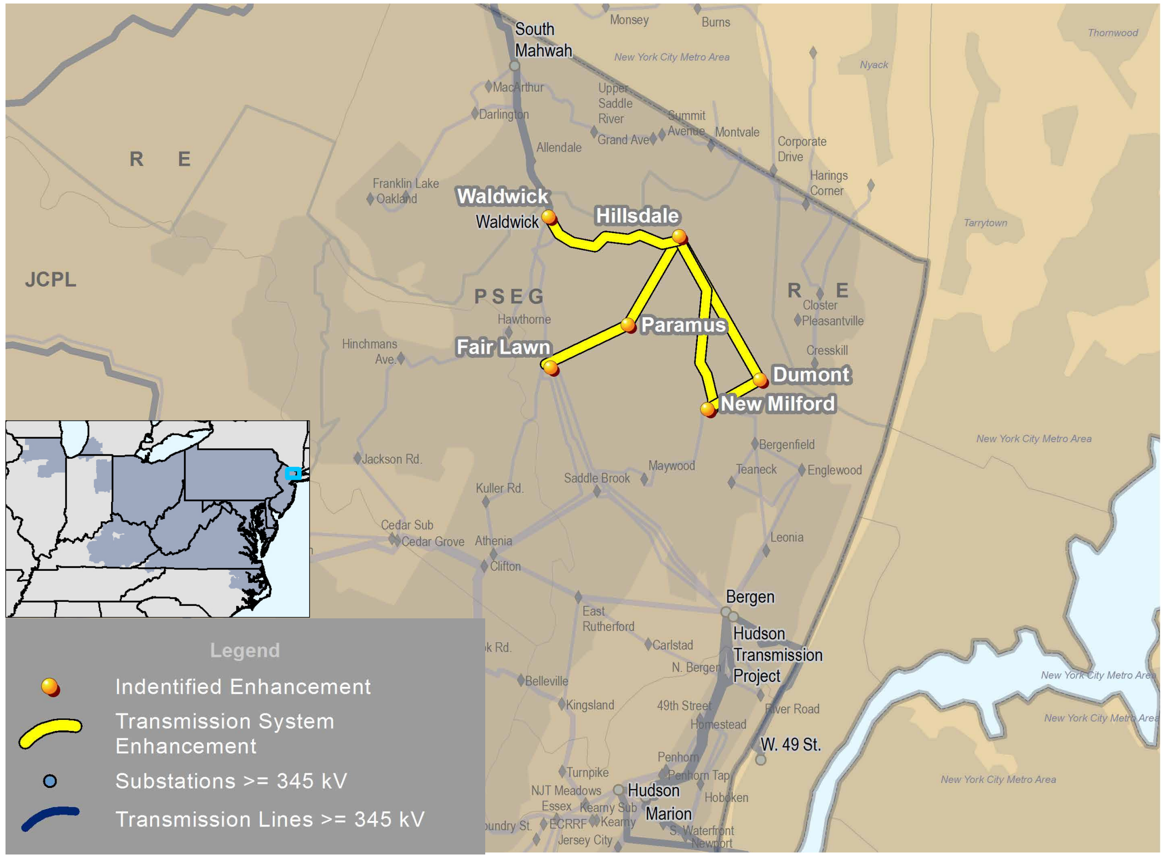
Individual TO criteria can be found on PJM's website: http://pjm.com/planning/planning-criteria/to-planning-criteria.aspx.

Hillsdale 230 kV Substation

Two underground 230 kV lines feed the Hillsdale 230 kV substation, supplying more than 17,000 customers with load in excess of 80 MVA. An N-1-1 contingency event would cause complete loss of electric supply for more than 24 hours.

The solution (b2982), approved by the PJM Board in February 2018, is to construct a 230/69 kV station at Hillsdale including a 69 kV ring bus and a 230/69 kV transformer and ties into existing lines to Paramus and Dumont, as shown on **Map 3.18**. The estimated project cost is $115 million. The required in-service date is June 1, 2018. Expected project completion and in-service date is June 30, 2021.

Map 3.18: Hillsdale Substation Area



NOTE:

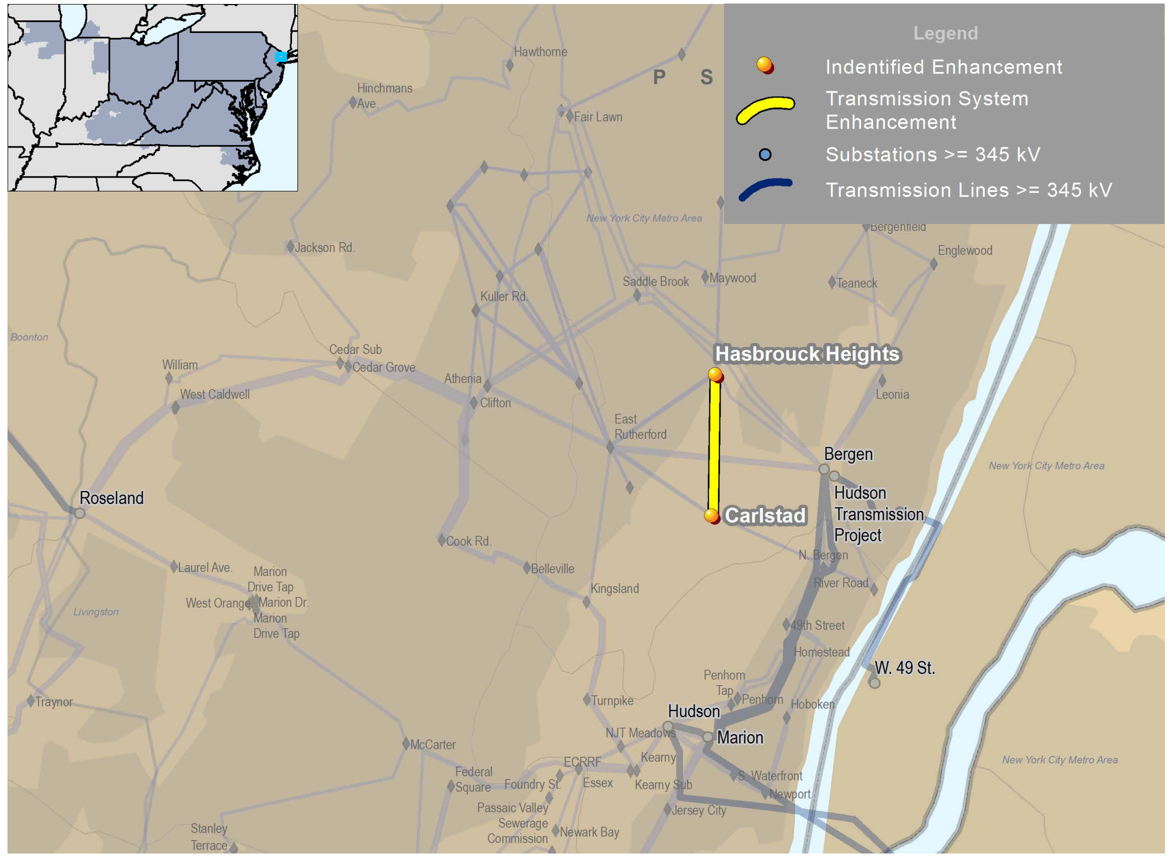
Project b2982 was approved by the PJM Board on February 14, 2018, for inclusion in the RTEP.

Carlstadt 69 kV Substation

Two partially underground 69 kV transmission lines feed Carlstadt 69 kV substation, which supplies more than 1,400 customers. An N-1-1 contingency would cause complete loss of electric supply for more than 24 hours.

The solution (b2934), approved by the PJM Board in October 2017, is to construct a new 69 kV line between Hasbrouck Heights and Carlstadt 69 kV substations, as shown on **Map 3.19**. The estimated project cost is $21 million with a June 1, 2018, projected in-service date.

Map 3.19: Hasbrouck Heights and Carlstadt 69 kV Line

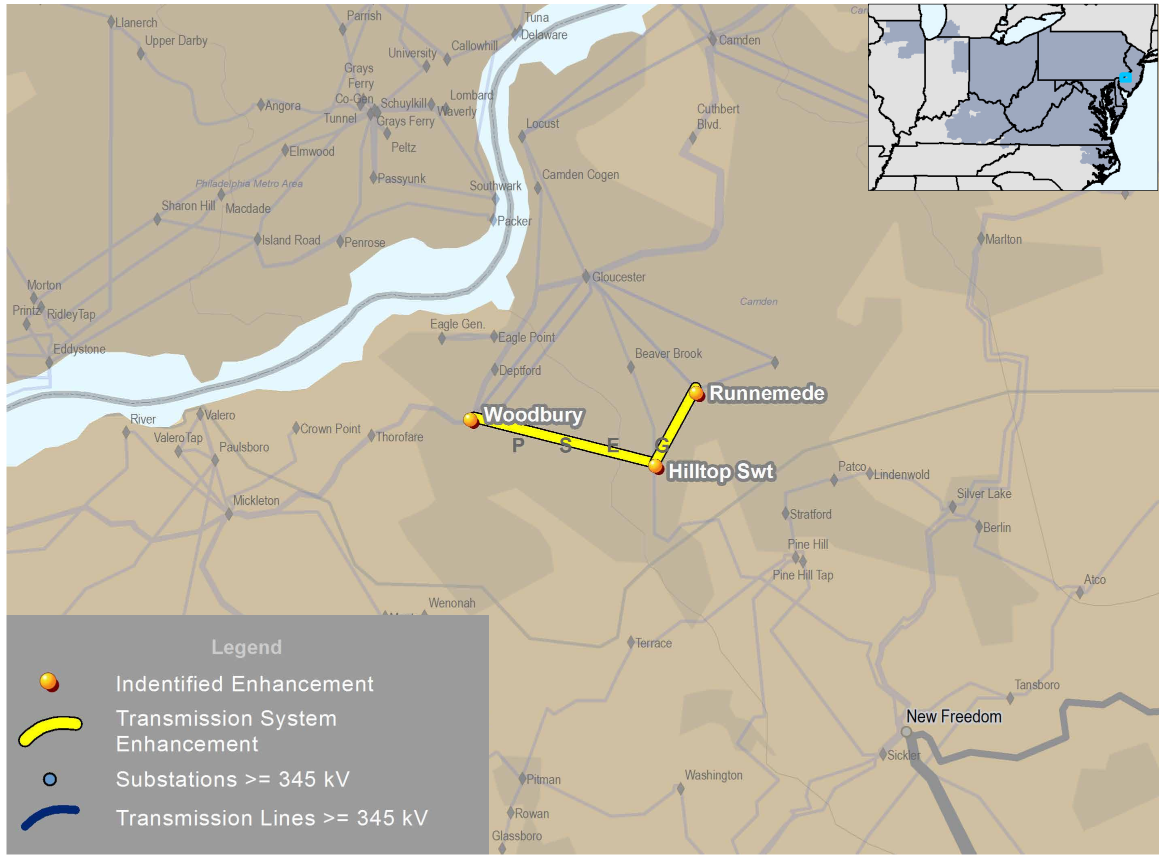


Runnemede 69 kV Substation

Two 69 kV lines feed Runnemede substation. Portions of one line compose an underground cable that would take longer than 24 hours to restore during an outage. In addition, a breaker failure on the Runnemede 69 kV bus would result in the loss of both 69 kV supply lines and would interrupt more than 11,000 customers.

The solution (b2935), approved by the PJM Board in October 2017, includes construction of a new 230/69 kV switching substation at Hilltop, a new line between Hilltop and Woodbury 69 kV, conversion of Runnemede's straight bus to a ring bus and a 69 kV line from Hilltop to Runnemede, as shown on **Map 3.20**. The estimated project cost is $98 million with a June 1, 2018, projected in-service date.

Map 3.20: Runnemede-Hilltop-Woodbury 69 kV Line

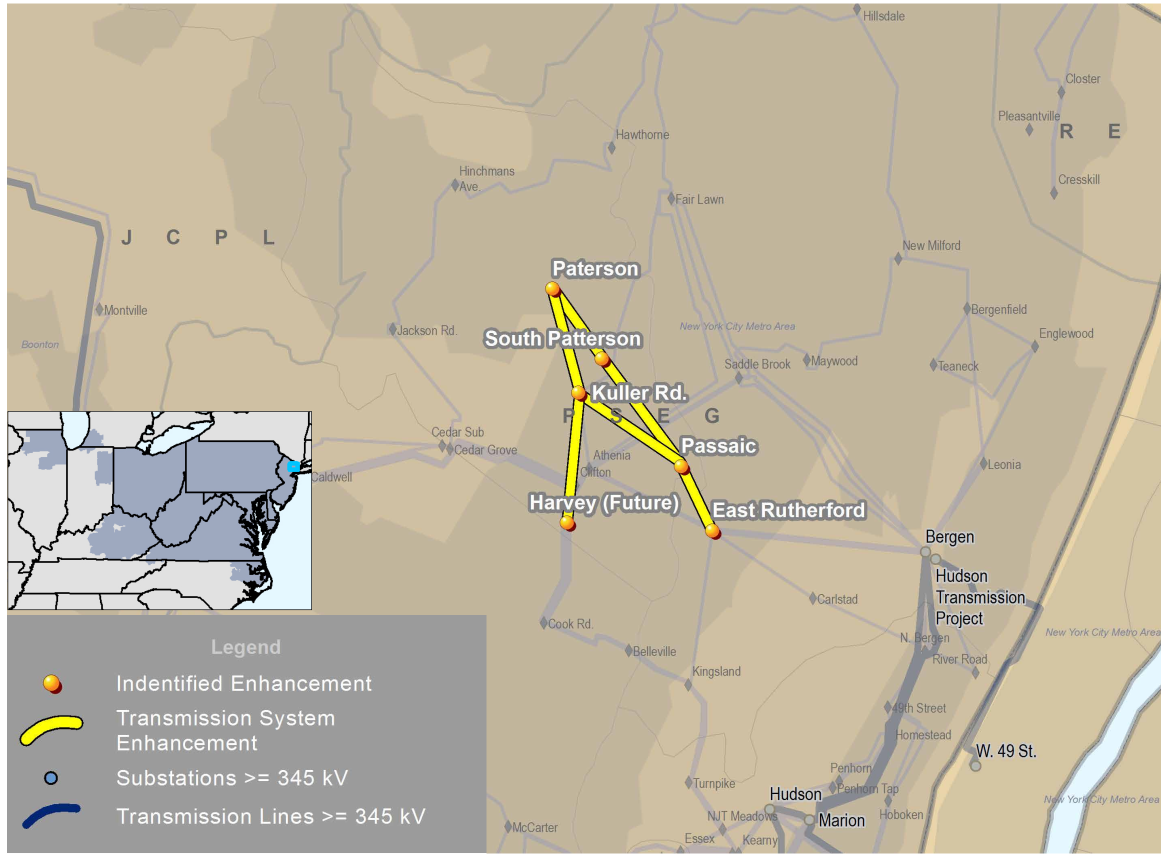


Kuller Road Substation

Two underground 138 kV lines supply Kuller Road, serving more than 18,000 customers in excess of 60 MVA. An N-1-1 event would cause the complete loss of electric supply for more than 24 hours.

The solution (b2983), approved by the PJM Board in February 2018, is to convert Kuller Road to a 69/13 kV station. This involves installing a 69 kV ring bus and two 69/13 kV transformers at Kuller Road; and constructing a 69 kV network between Kuller Road, Passaic, Paterson and Harvey (a new Clifton area switching station), as shown on **Map 3.21**. The estimated project cost is $98.3 million. The required in-service date is June 1, 2018. Expected project completion and projected in-service date is June 30, 2021.

Map 3.21: Kuller Road Substation



NOTE:

Project b2983 was approved by the PJM Board on February 14, 2018, for inclusion in the RTEP.

3.3.2 — Equipment Condition Assessment

PSE&G's FERC Form No. 715 also contains transmission owner criteria to address equipment condition. During 2017, PSE&G and PJM identified the need to develop a solution to address the condition of the Roseland-Branchburg-Pleasant Valley 230 kV line.

Roseland-Branchburg-Pleasant Valley 230 kV Corridor

Shown on **Map 3.22**, each of the two line segments – Roseland-Branchburg (30 miles long) and Branchburg-Pleasant Valley (22 miles long) – is about 90 years old. A portion of the line parallels the Roseland-Branchburg 500 kV corridor. Right-of-way terrain is variable and includes rural areas, a National Wildlife Refuge and local municipalities. The line also serves 240 MW of subtransmission load in adjacent JCPL territory. Line towers were built between 1927 and 1930. Small portions were rebuilt between 1961 and 2015.

PSE&G engaged a consultant who identified tower foundations requiring reconstruction, towers exceeding loading capability and industry standard grounding conflicts. Roughly 25 percent of the structures require either extensive foundation rehabilitation or total foundation replacement. Due to their present condition, 54 percent of the towers exceed 100 percent of the tower's load bearing capability and 84 percent of the towers exceed 95 percent of the tower's capability. Nine percent of the spans violate industry standard load bearing capability. Based on the condition assessment for the entire corridor, the equipment has reached the end of its life.

Map 3.22: Roseland-Branchburg-Pleasant Valley

PSE&G has considered several alternative solutions:

- Remove and retire the 230 kV corridor without replacing it.
- Install a new parallel circuit on a new right-of-way and remove the existing 230 kV corridor.
- Replace the existing 230 kV single-circuit corridor with new dual-circuit structures and initially stringing only one 230 kV circuit.

Alternative No. 1 would leave 240 MVA of JCPL load supplied by 34.5 kV subtransmission with significant voltage and thermal violations. These violations would require extensive construction and cost to remediate. Significant loss of transmission system capacity and thermal voltage violations would exist on JCP&L's system. Given these factors, this alternative is not a viable option.

Alternative No. 2 would require that four substations be provided feeds and associated additional lines to loop in and out of each substation. More than 50 miles of new overhead construction, new right-of-way and new permitting would be required. Installing this new equipment in new areas is also the highest cost option.

Alternative No. 3 would maintain system reliability; eliminate the safety risk from damaged structures; require minimal new siting, permitting and construction; and maintain transmission capacity between Branchburg and JCPL's Lawrence substations. This alternative would not require any new right-of-way, protection coordination, substations or reactive devices would be required.

PJM and PSE&G continue to evaluate these alternatives in anticipation of a recommendation to the PJM Board in 2018.

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

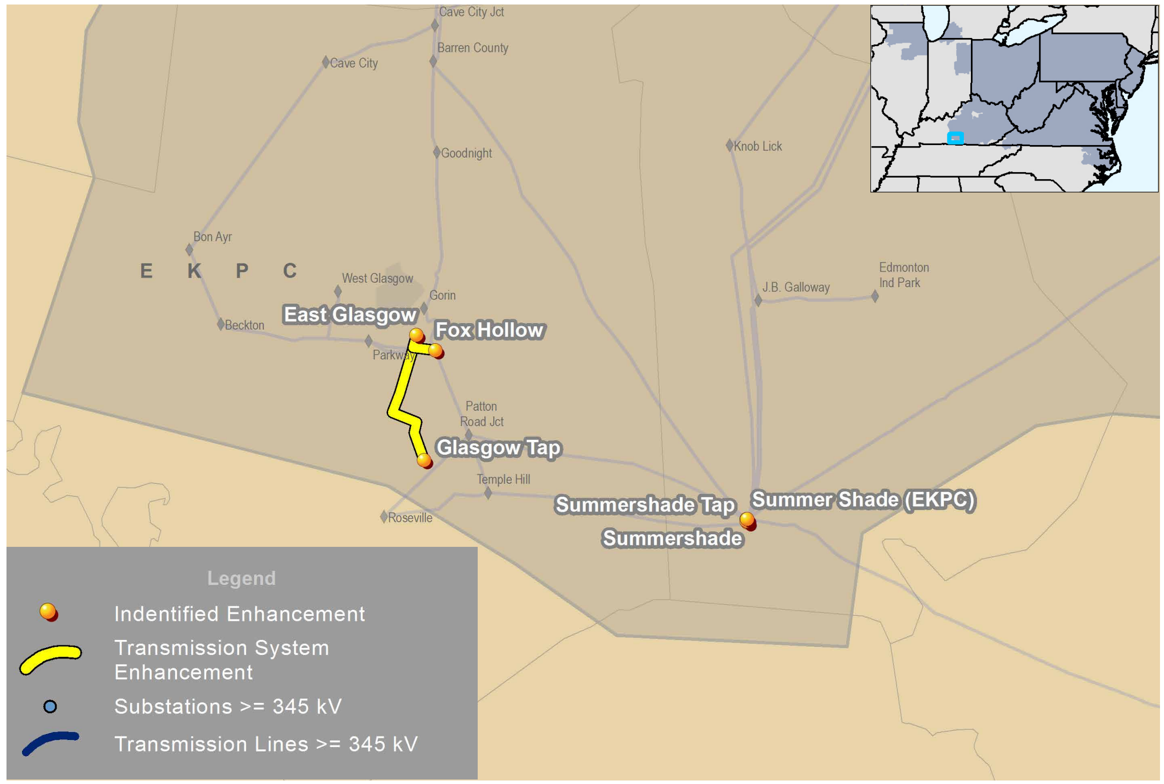
3.4: EKPC Transmission Owner Criteria

PJM 2017 RTEP Baseline projects driven by EKPC TO criteria included projects at 161 kV and 69 kV, including transmission enhancements in the Summer Shade-Fox Hollow-Glasgow area. Facilities at these voltage levels are included in RTEP analysis to the extent EKPC designates them as "tariff facilities" and they are not already examined as part of a TO's monitored facilities list. That list comprises facilities modeled in PJM's energy management system (EMS). Tariff facilities are defined as those each TO has included in its respective FERC Form No. 1 and as such are used to provide transmission service under PJM's Open Access Transmission Tariff. All EKPC Baseline projects are summarized on PJM's website: http://pjm.com/planning/rtep-upgrades-status/construct-status.aspx.

Summer Shade-Fox Hollow-Glasgow Area

EKPC first identified overloads in the Summer Shade area in 2013 for reliability criteria violations expected in summer 2018. Since that time, further evaluation has identified a number of other violations in 2020, 2022, 2023 and 2024 winter RTEP cases in this area. The recommended solution approved by the PJM Board is to add a new 161 kV interconnection on TVA's East Glasgow Tap-East Glasgow 161 kV line, install a 161/69 kV transformer at Fox Hollow, and construct new Fox Hollow-Fox Hollow Junction 161 kV line, as shown on **Map 3.23**.

Map 3.23: Summer Shade-Fox Hollow-Glasgow Area



NOTE:

Individual TO criteria can be found on PJM's website: http://pjm.com/planning/planning-criteria/to-planning-criteria.aspx.

The estimated cost of the project (b2921) is $18.1 million with a June 1, 2018 required in-service date. This new project allows that two other existing Baseline projects can be canceled:

1. Project b2414, construction of a second Summer Shade (EKPC)-Summer Shade (TVA) 161 kV circuit;

2. Project b2710, enhancement of the Summer Shade bus and combustion turbine associated with the 161/69 kV transformer No. 1

Section 4: Immediate Need Projects

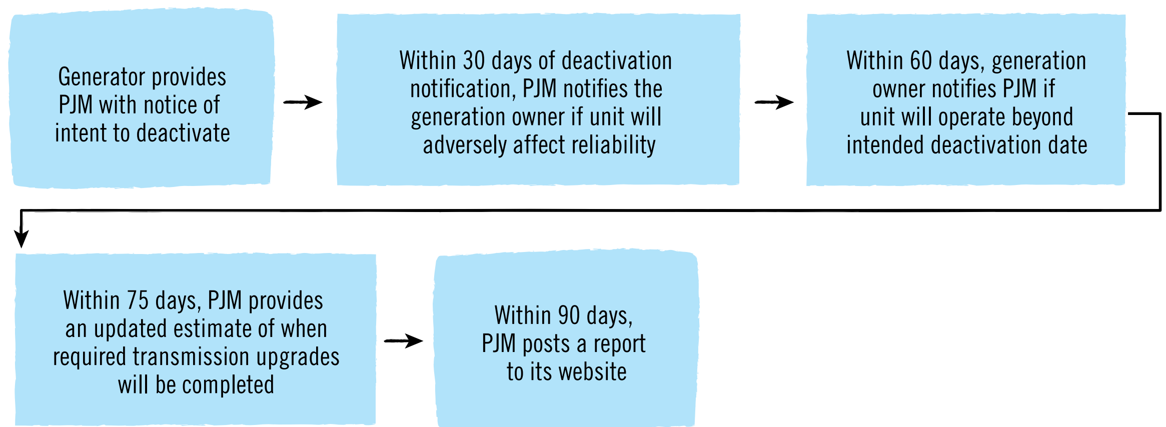
4.0: Generator Deactivations

4.0.1 — RTEP Process Context

Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can undermine voltage support. Generation owners are required to notify PJM of their intent to deactivate generation per Article V of the PJM Open Access Transmission Tariff. PJM cannot compel unit owners to remain in service, per FERC order. Unlike timelines associated with requests for interconnection, deactivation may take effect upon 90 days' notice. Given the general short-term notice to deactivate and the nature of the system reinforcements required, RTEP Baseline reinforcements are typically tagged as immediate need. Insufficient time exists to conduct RTEP proposal windows. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board or by Supplemental projects proposed by the native transmission owner.

After a deactivation request is received, PJM conducts reliability studies to identify RTEP Baseline system reinforcements needed to resolve all identified reliability criteria violations, as shown in **Figure 4.1**. The 90 days gives PJM time to identify reliability criteria violations and develop solutions to resolve them.

Figure 4.1: Generator Deactivation Process



Potential reliability issues have been forestalled through a combination of short lead-time Baseline RTEP transmission enhancements, previously approved Baseline projects, operating procedures to address conditions that cannot be resolved by new transmission before the requested deactivation date and, in some limited instances, reliability-must-run (RMR) agreements.

Reliability-Must-Run Units

If transmission enhancements are completed prior to a unit's intended deactivation date, reliability issues can be avoided. However, if transmission enhancements are not in place prior to deactivation, and if reasonable operating procedures cannot be implemented, then PJM can pursue an 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 TO 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.

Age and Public Policy Drivers

Generation owners weigh investments and operational costs against anticipated revenues from PJM markets and existing power purchase agreements to determine the economic viability of a facility. Those generators considered at-risk 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 regulatory requirements – such as those that address environmental policy. Units must compete with other resources offered into each PJM Reliability Pricing Model capacity auction: more efficient plants, renewable energy resources, demand response programs and energy efficiency programs, for example. PJM continues to monitor federal public policy for its potential impact on deactivation activity.

4.0.2 — 2017 Deactivation Requests

PJM continued to receive deactivation notifications throughout 2017, totaling 4,588 MW, up from 2,273 MW in 2016, 1,626 MW in 2015, and 4,291 MW in 2014, but below 7,745 MW in 2013 and 14,444 MW in 2012. By contrast, PJM received and studied deactivation requests for only 11,000 MW in total during the eight years ending November 1, 2011. **Table 4.1** and **Map 4.1** show the deactivation requests received between January 1, 2017, and December 31, 2017. Generator owners have requested deactivation of these units between August 2017 and October 2020. PJM maintains a list of formally submitted deactivation requests, accessible from PJM's website: http://www.pjm.com/planning/generation-deactivation.aspx.

Table 4.1: PJM Generator Deactivations Received January 1, 2017, through December 31, 2017

Unit	Capacity	Transmission Zone	Age (Years)	Request Submittal Date	Requested Deactivation Date	Actual/Projected Deactivation Date
Edgecomb NUG	116.0	Dominion	26	1/31/2017	10/31/2020	10/31/2020 Projected
Spruance NUG1	116.0	Dominion	24	1/31/2017	1/12/2019	01/12/2019 Projected
Spruance NUG2	86.0	Dominion	24	1/31/2017	1/12/2019	1/12/2019 Projected
Killen 2	600.0	DAYTON	34	3/17/2017	6/1/2018	6/1/2018 Projected
Killen CT	18.0	DAYTON	34	3/17/2017	6/1/2018	6/1/2018 Projected
Stuart 1	580.6	DAYTON	45	3/17/2017	9/30/2017	9/30/2017 Actual
Stuart 2	580.0	DAYTON	46	3/17/2017	6/1/2018	6/1/2018 Projected
Stuart 3	580.4	DAYTON	44	3/17/2017	6/1/2018	6/1/2018 Projected
Stuart 4	577.0	DAYTON	42	3/17/2017	6/1/2018	6/1/2018 Projected
Stuart Diesels 1-4	9.2	DAYTON	47	3/17/2017	6/1/2018	6/1/2018 Projected
GUDE Landfill	0.8	PEPCO	11	5/26/2017	8/24/2017	8/24/2017 Actual
Three Mile Island Unit 1 Nuclear Generating Station	802.8	Met-Ed	42	5/30/2017	9/30/2019	9/30/2019 Projected
Tait Battery*	0.0	DAYTON	4	9/1/2017	12/31/2017	12/13/2017 Actual
Crane 1	190.0	BGE	56	10/26/2017	6/1/2018	6/1/2018 Projected
Crane 2	195.0	BGE	54	10/26/2017	6/1/2018	6/1/2018 Projected
Crane GT1	14.0	BGE	50	10/26/2017	10/31/2019	10/31/2019 Projected
Colver Power Project	110.0	PENELEC	22	11/22/2017	9/1/2020	9/1/2020 Projected
Brunner Island Diesels	8.1	PPL	60	11/27/2017	2/25/2018	2/25/2018 Projected
Dixon Lee Landfill generator	3.7	ComEd	18	12/6/2017	3/6/2018	1/10/2018 Actual
Laurel Mountain Battery*	0.0	APS	6	12/15/2017	3/16/2018	3/16/2018 Projected

*Note: Energy only

Map 4.1: PJM Generator Deactivations Received January 1, 2017, through December 31, 2017

Table 4.2: Mid-Atlantic PJM 2017 RTEP Baseline Projects Driven by Generator Deactivations

Baseline ID	Recommended Project	TO Zone	Identified Reliability Criteria Violations	Deactivated Unit(s)
b2816	Reconnect Crane-Windy Edge 115 kV lines into Northeast substation with addition of a new 115 kV three-breaker bay	BGE	Overload of Constitution-Concord 115 kV line	Crane 1, 2 and GT1
b2984	Reconfigure Glory 115 kV bus and install a 50.4 MVAR 115 kV capacitor	PENELEC	Voltage magnitude and voltage drop violations	Colver NUG

Deactivation reliability studies comprise thermal and voltage analysis including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. System expansion solutions may include upgrades to existing facilities, scope expansion for current Baseline projects already in the RTEP or construction of new transmission facilities.

4.0.3 — Mid-Atlantic Subregion

PJM conducted generator deactivation studies during 2017 that identified reliability criteria violations requiring system reinforcements in the Mid-Atlantic Subregion. While PJM evaluated all the deactivation notifications received in 2017 listed earlier in **Table 4.1**, new system reinforcements were identified specifically for the Colver NUG generator deactivation located in central Pennsylvania and for the Crane 1, 2 and GT generator deactivations in the Baltimore area. These reinforcements are shown in **Table 4.2** and on **Map 4.2** and **Map 4.3**.

Map 4.2: Mid-Atlantic PJM 2017 RTEP Baseline Projects Driven by Generator Deactivations

Map 4.3: Mid-Atlantic PJM 2017 RTEP Baseline Projects Driven by Generator Deactivations

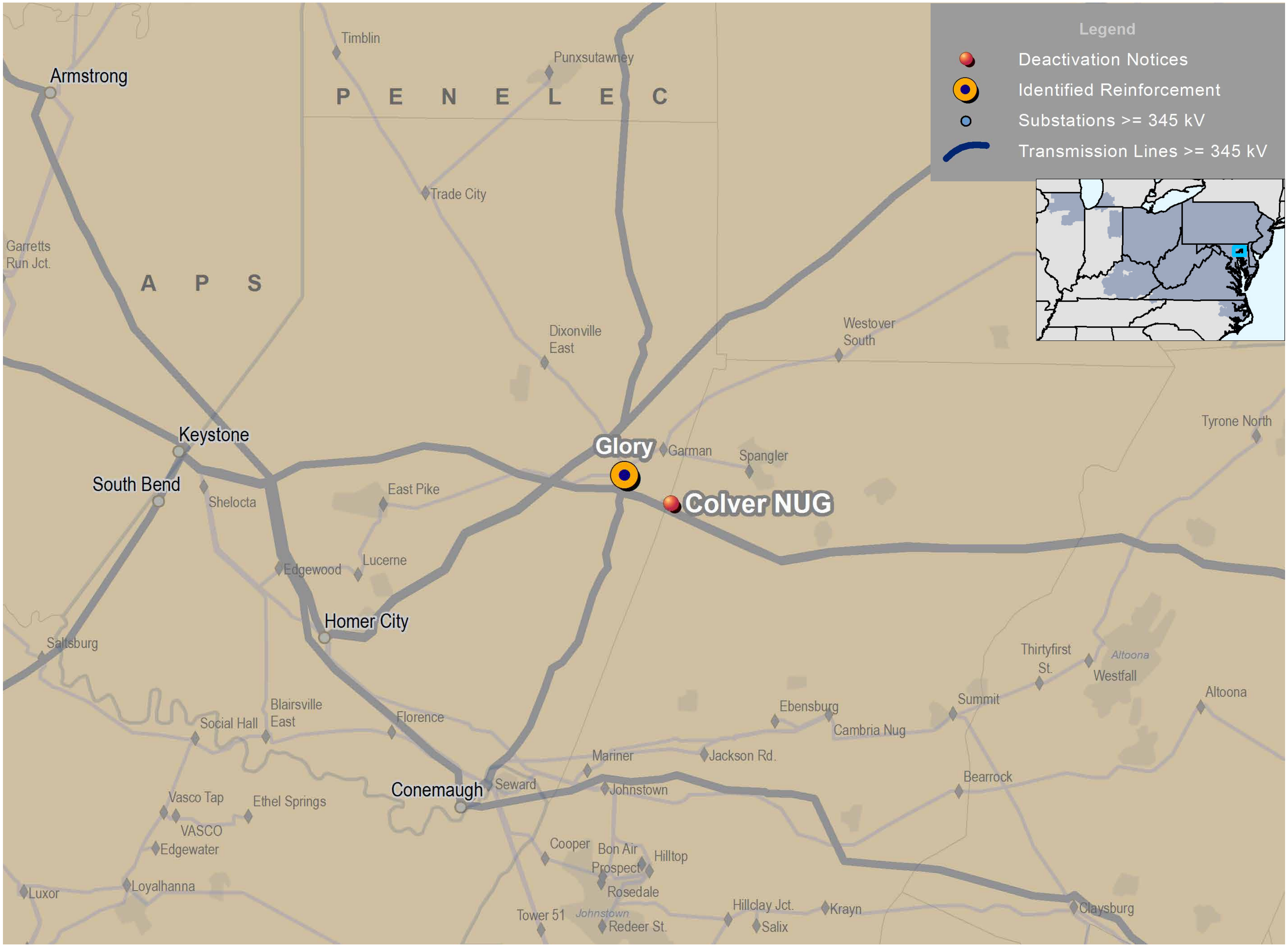


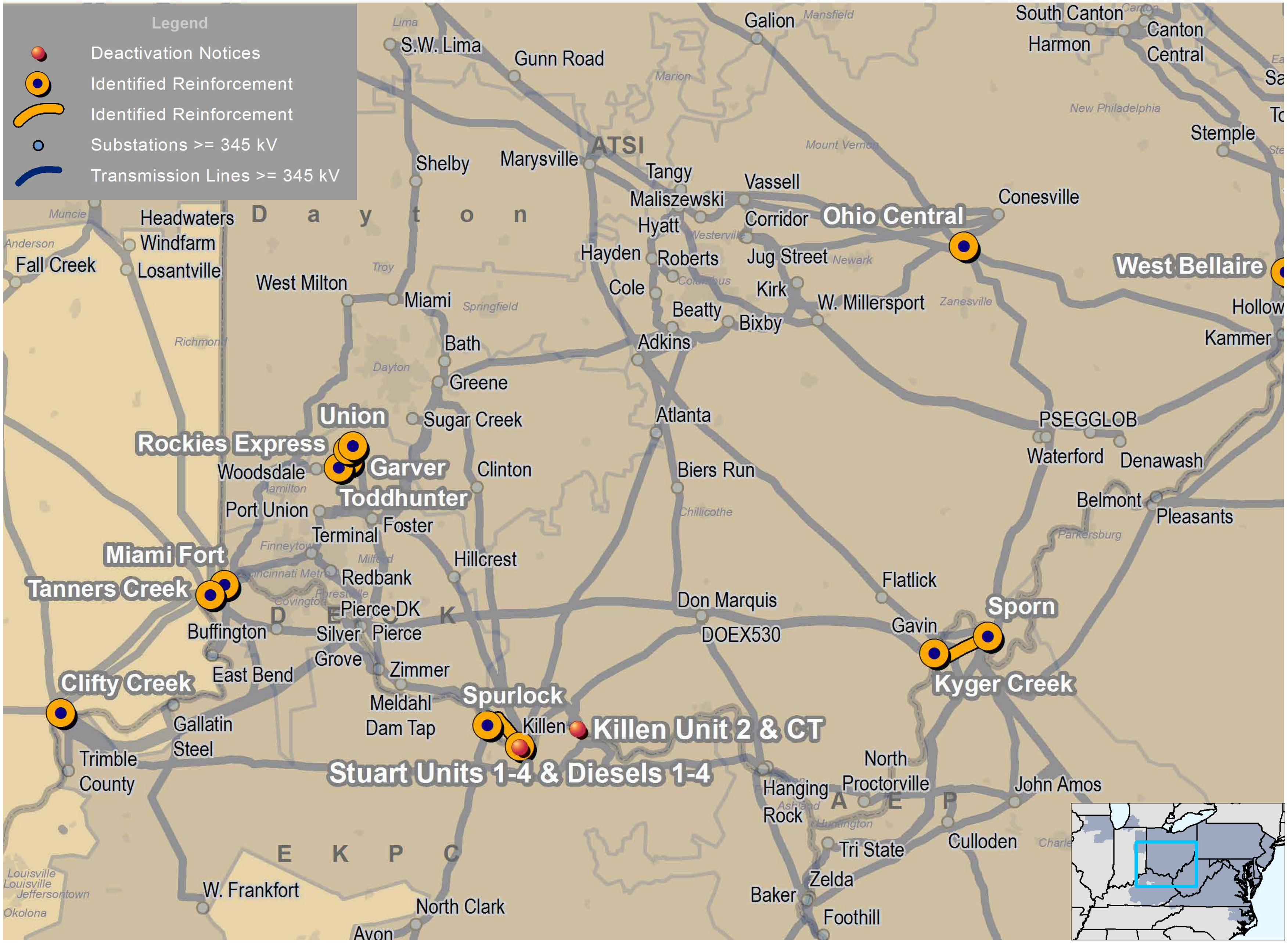
Table 4.3: Western PJM 2017 RTEP Baseline Projects Driven by Generator Deactivations

Baseline ID	Recommended Project	TO Zone	Identified Reliability Criteria Violations	Deactivated Unit(s)
b2879.2	Reconductor EKPC portion of the Stuart-Spurlock 345 kV line	EKPC	Overload of Stuart-Spurlock 345 kV line	Stuart 1-4, Stuart Diesels 1-4, Killen 2, Killen CT
b2879.1	Replace wavetrap at the Stuart 345 kV substation	Dayton	Overload of Stuart-Spurlock 345 kV line	Stuart 1-4, Stuart Diesels 1-4, Killen 2, Killen CT
b2878	Upgrade Clifty Creek 345 kV risers	AEP	Overload of Jefferson-Clifty Creek 345 kV line	Stuart 1-4, Stuart Diesels 1-4, Killen 2, Killen CT
b2832	Upgrade the Kyger Creek-Sporn 345 kV lines No.1 and No. 2 to six-wire configuration and convert to one circuit.	AEP	Overload of Kyger Creek-Sporn 345 kV line No. 2	Stuart 1-4, Stuart Diesels 1-4, Killen 2, Killen CT
b2831.2	Upgrade the Tanners Creek-Miami Fort 345 kV circuit (DEO&K portion)	DEO&K	Overload of Tanners Creek-Miami Fort 345 kV line	Stuart 1-4, Stuart Diesels 1-4, Killen 2, Killen CT
b2831.1	Upgrade the Tanners Creek-Miami Fort 345 kV circuit (AEP portion)	AEP	Overload of Tanners Creek-Miami Fort 345 kV line	Stuart 1-4, Stuart Diesels 1-4, Killen 2, Killen CT
b2830	- Expand Garver 345 kV substation to include 138 kV. - Install one 345 kV breaker, one 345/138 kV 400 MVA transformer, six 138 kV circuit breakers and bus structure. - Connect local 138 kV lines from Todhunter, Rockies Express and Union.	DEO&K	Overload of Nickel-Warren 138 kV line; Overload of third of three Todhunter 345/138 kV transformers	Stuart 1-4, Stuart Diesels 1-4, Killen 2, Killen CT
b2828	Install 10 percent reactors at Miami Fort 138 kV to limit current	DEO&K	Overload of Clifty Creek-Miami Fort 138 kV line	Stuart 1-4, Stuart Diesels 1-4, Killen 2, Killen CT
b2826.2	Install 300 MVAR reactor at West Bellaire 345 kV substation	AEP	Ongoing high voltages on AEP area EHV system under light load conditions	Stuart 1-4, Stuart Diesels1-4, Killen 2, Killen CT
b2826.1	Install 300 MVAR reactor at Ohio Central 345 kV substation	AEP	Ongoing high voltages on AEP area EHV system under light load conditions	Stuart 1-4, Stuart Diesels 1-4, Killen 2, Killen CT

4.0.4 — Western PJM Subregion

PJM conducted generator deactivation studies during 2017 that identified reliability criteria violations requiring system reinforcements in PJM's Western Subregion. While PJM evaluated all the deactivation notifications received in 2017 listed earlier in **Table 4.1**, the need for new system reinforcements in the AEP, DEO&K, EKPC and Dayton TO zones were identified for the deactivation of the Killen Unit No. 2, Killen CT, and Stuart Units No. 1, 2, 3, 4 and diesel generators. The PJM Board approved the 10 Baseline reliability projects shown in **Table 4.3** and **Map 4.4**.

Map 4.4: Western PJM 2017 RTEP Baseline Projects Driven by Generator Deactivations



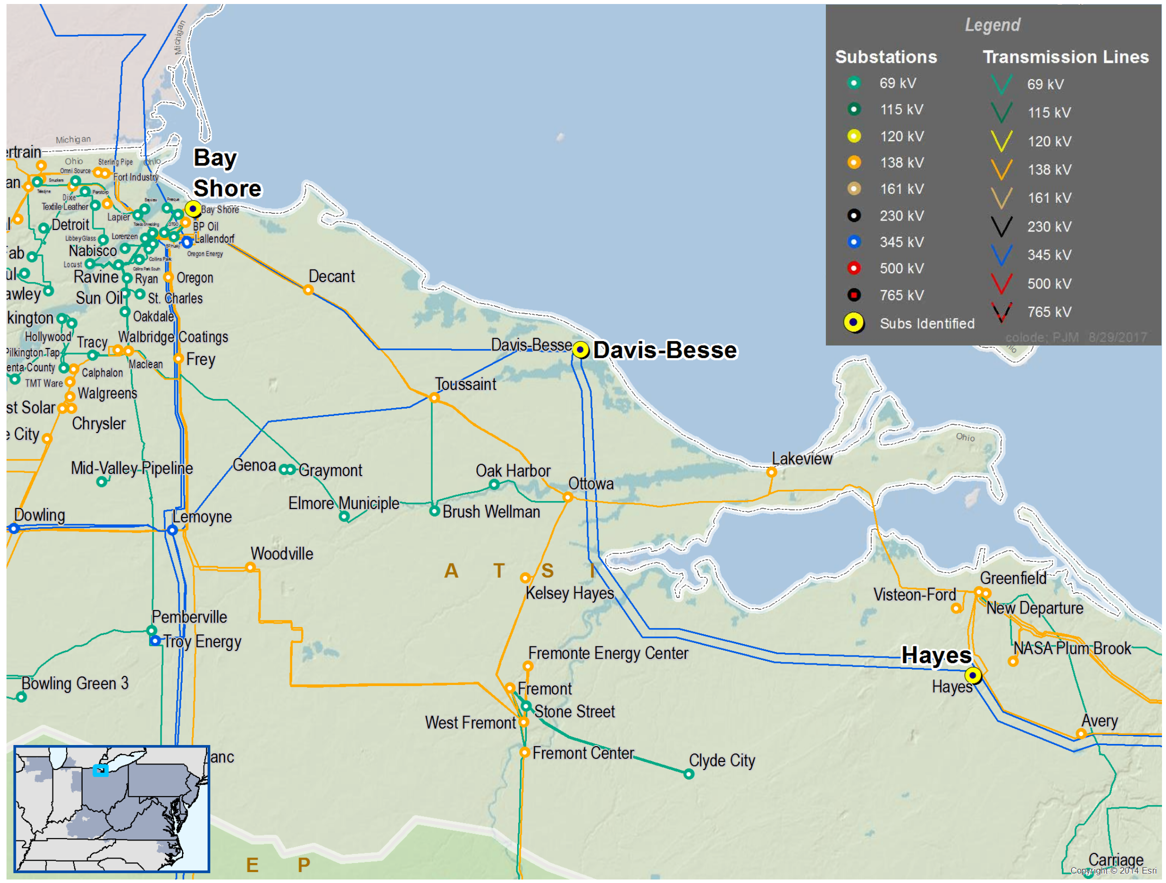
4.1: Operational Performance

4.1.1 — Real-Time High Voltages

PJM system operators continue to encounter location-specific, real-time high-voltage alarms across the RTO during low load conditions. These alarms identify substation voltages that have reached levels exceeding limits set by PJM and transmission owners to protect electrical equipment and preserve reliable system operation. PJM's generation dispatch stack during low load periods differs markedly under peak load conditions. Large unit deactivations include the loss of their aggregate capability to absorb excess system reactive power. These factors, coupled with the capacitive effect of more lightly loaded transmission lines, increase bus voltages even further.

During light load conditions, when high voltages can be expected, PJM operations staff studies possible actions to control them. Such actions can include switching out capacitors, switching on shunt reactors, changing transformer tap positions and other actions up to and including opening transmission lines. These measures indicate a more fundamental issue that needs to be addressed as part of RTEP process analysis.

Map 4.5: ATSI Zone High Voltage Solution



4.1.2 — ATSI Zone High Voltage

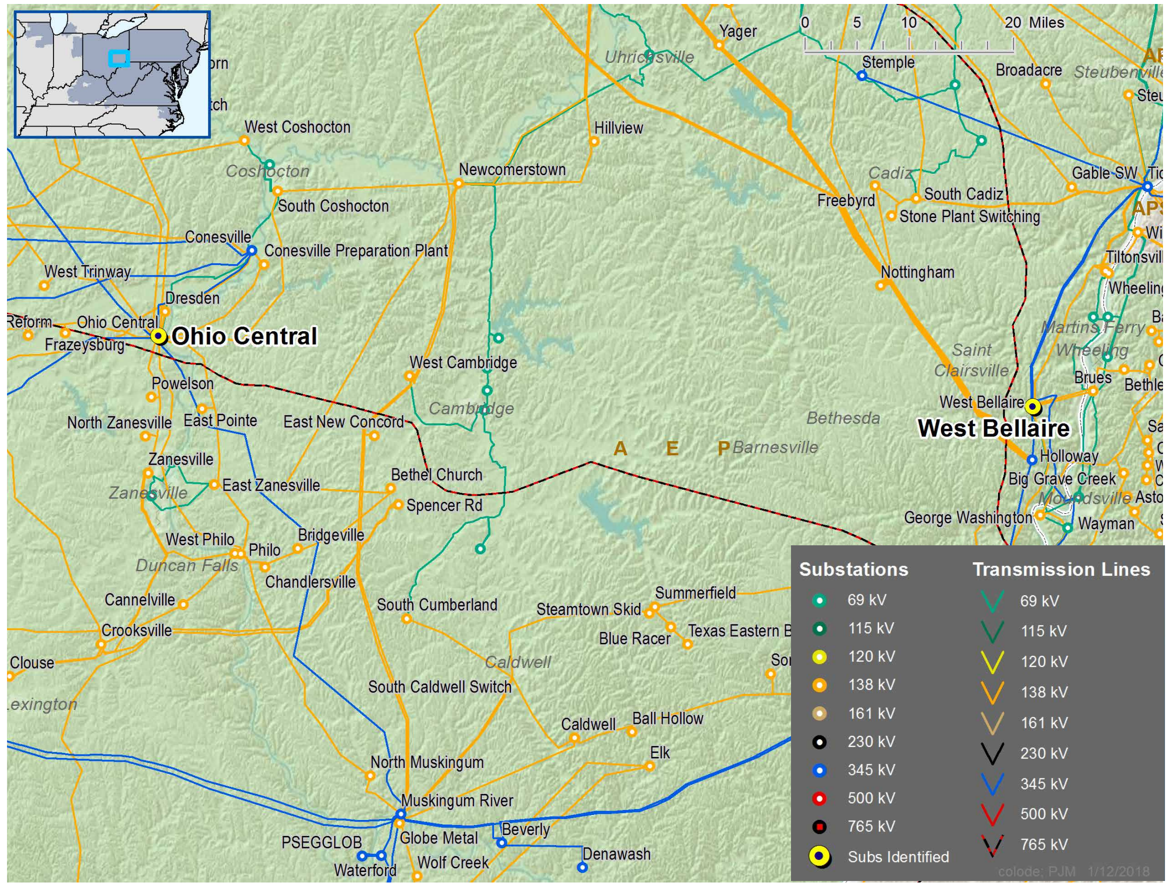
PJM system operators routinely observed high voltages within the ATSI Transmission Zone. In some instances, transmission system voltages have exceeded limits near the Davis Besse nuclear plant under system light load conditions. In the past, PJM implemented an existing operational switching solution, mitigating the high system voltages. These chronic high voltages require an RTEP solution to address the operational performance issue.

The recommended solution will install a 100 MVAR 345 kV shunt reactor at Hayes substation (b2942.1) and a 200 MVAR 345 kV shunt reactor at Bayshore substation (b2942.2), as shown on **Map 4.5**. Given the immediate need, the timing required for an RTEP proposal window is infeasible. The local transmission owner will be the designated entity. This solution increases operational flexibility to adjust system voltage at the Davis Besse 345 kV bus under light load conditions with both reactors online. The solution is required as soon as possible.

4.1.3 — AEP Zone High Voltage

Under light load conditions, the PJM AEP Transmission zone and surrounding areas experience ongoing high voltages at high voltage substation busses. PJM planners worked closely with AEP planners to determine available operational and planning solutions. PJM reviewed energy management system snapshots of the high voltage conditions and recommended the installation of a 300 MVAR reactor at Ohio Central 345 kV substation (b2826.1) and a 300 MVAR reactor at West Bellaire 345 kV substation (b2826.2), as shown on **Map 4.6**. The cost of the reactors is estimated at $5 million each. The expected in-service date is September 1, 2018.

Map 4.6: AEP High Voltage Solution



4.1.4 — Dominion Zone High Voltage

PJM system operators have experienced high voltages at Dominion 500 kV substations, particularly the Carson area, during winter and spring light load period system conditions. PJM Operations implemented procedures to switch out multiple 500 kV transmission lines and schedule necessary generation for voltage control. From an RTEP perspective, PJM and Dominion considered a number of static synchronous compensators and shunt reactor alternative solutions as summarized in **Table 4.4** and shown on **Map 4.7**.

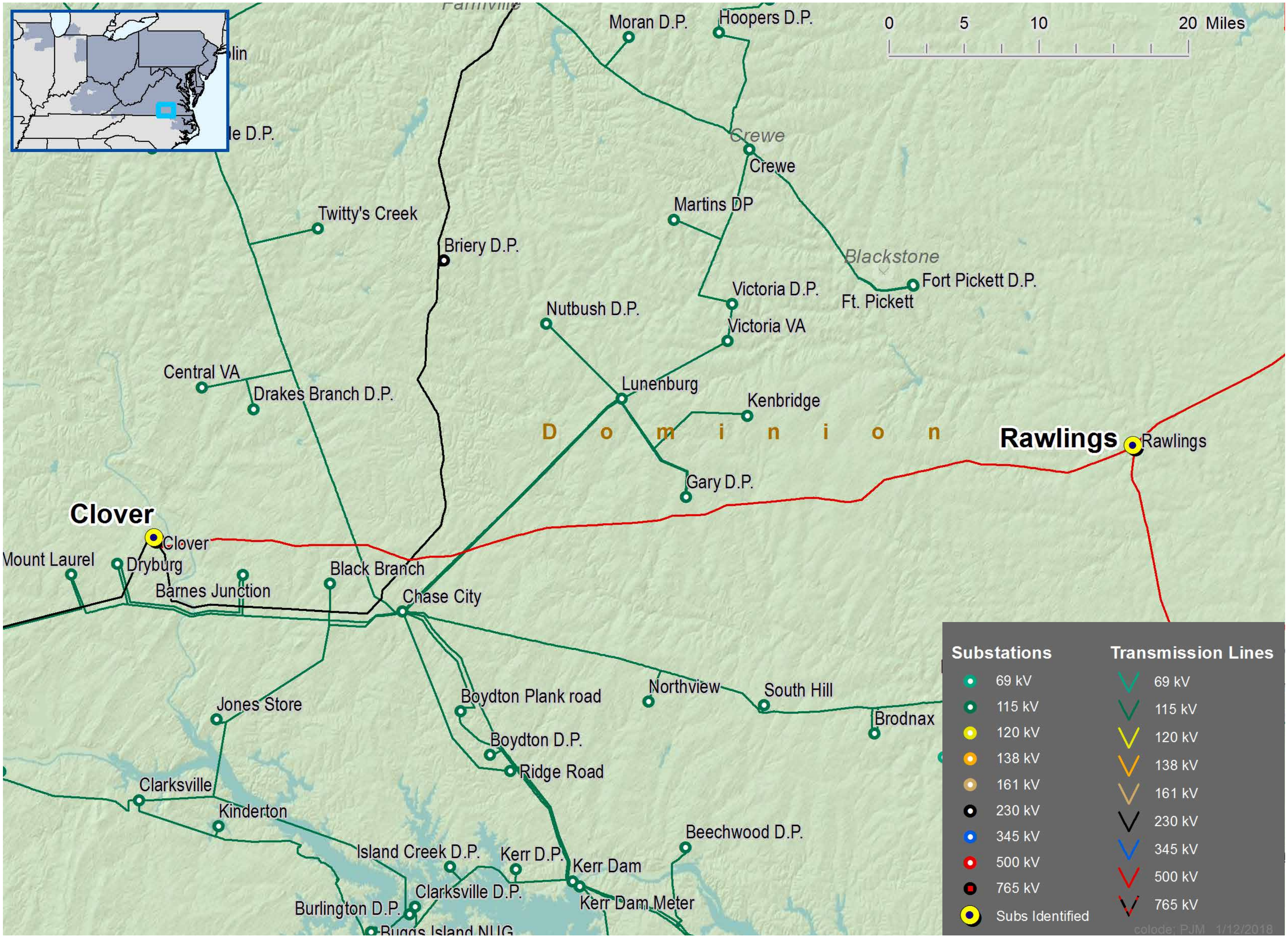
Voltage Analysis

PJM and Dominion conducted the voltage analysis shown in **Figure 4.2**. A base case was developed modeling a real-time high voltage event. Then, each proposed alternative was analyzed for its effect at Clover, Rawlings, Heritage, Carson and Midlothian 500 kV substations. Each of these experienced base case real-time snapshot voltages that exceeded the established 535.5 kV high voltage limit. In several cases, those voltages exceeded the 540 kV emergency high voltage limit.

Table 4.4: Dominion High Voltage Alternative Solutions

Alternative	Cost ($M)
Install two 125 MVAR STATCOMs at Clover 500 kV substation	$65
Install two 125 MVAR STATCOMs at Midlothian 500 kV substation	$60
Install two 125 MVAR STATCOMs at Rawlings and Midlothian 500 kV substations	$115
Install two 500 kV 125 MVAR STATCOMs at Clover and at Midlothian substation.	$125
Install two 500 kV 125 MVAR STATCOMs at Carson and one 500 kV 125 MVAR STATCOM at Clover substation.	$110 (plus real estate and related transmission line costs)
Install two 500 kV 125 MVAR STATCOMs at Rawlings and one 500 kV 125 MVAR STATCOM each at Midlothian and Clover substations	$140
Install one 500 kV 150 MVAR Fixed Shunt Reactor bank each at Rawlings Substation, Clover Substation and Midlothian Substation	$30.50

Map 4.7: Dominion High Voltage Solution Alternatives



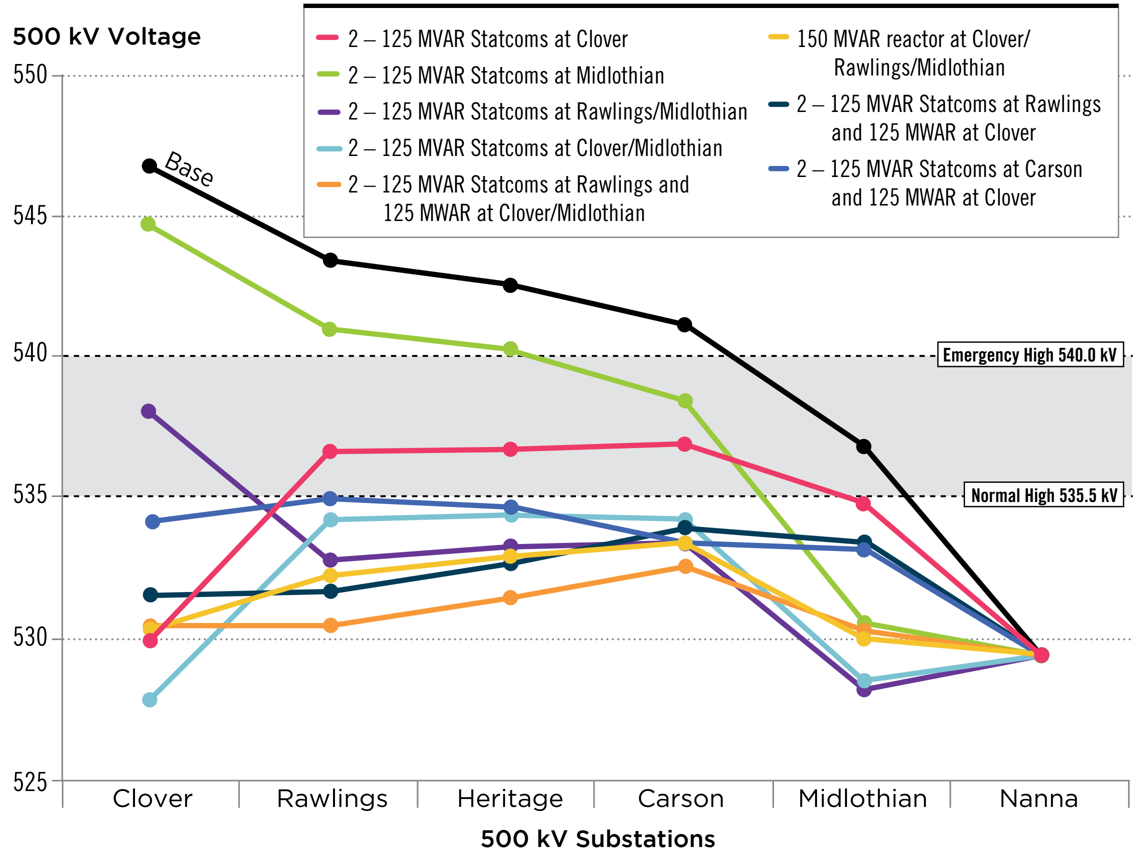
As **Figure 4.2** shows, the solution to install three 500 kV, 125 MVAR static synchronous compensators – two at Rawlings and one at Clover substations (b2978, combined) – adequately reduced voltages to acceptable levels below the 535.5 kV high voltage limit.

This solution performed as well as or better than other alternatives and/or had lower estimated cost. The recommended solution (b2978), approved by the PJM Board in February 2018, has an estimated cost of $100 million and the projected in-service date is May 2021. Given the immediate need of the issue, the timing required for an RTEP proposal window is infeasible. Dominion, the transmission owner, will be assigned as the designated entity.

A static synchronous compensator is a reactive shunt device that uses power electronics to control power flow and improve power grid transient stability.

A shunt reactor is an inductive device at a substation bus that can be switched into service to absorb reactive power, lowering voltage at that location.

Figure 4.2: Voltage Analysis of Alternative Solutions



Note: Original figure content provided by Dominion Virginia Power.

NOTE:

- A **static synchronous compensator** is a reactive shunt device that uses power electronics to control power flow and improve power grid transient stability.
- A **shunt reactor** is an inductive device at a substation bus that can be switched into service to absorb reactive power, lowering voltage at that location.

NOTE:

Project b2978 was approved by the PJM Board on February 14, 2018, for inclusion in the RTEP.

4.1.5 — ComEd Zone Uplift Charges

PJM system operators experience real-time high voltage at 345 kV substations in the Powerton area, shown on **Map 4.8**. PJM operators have directed Powerton generation to run out of economic merit order to provide 345 kV voltage relief. As a result, the units have incurred uplift charges totaling nearly $10 million to date as summarized in **Table 4.6**.

PJM and ComEd continue to study the alternatives summarized in **Table 4.5**. Each alternative provides customer cost savings by solving high voltage issues, mitigating the need to run Powerton Unit 6, and minimizing uplift charges. The solutions described have the added benefit of providing operational flexibility. A solution which addresses high voltage issues also reduces the likelihood that units including wind farms will be directed offline.

Table 4.6: Powerton Unit No. 6 Uplift Charges

Year	Uplift Charges
2017	$6,989,159
2016	$1,799,686
2015	$835,492

NOTE:

Uplift payments provide a generator operating at the direction of PJM – as when running out of economic merit order for operational control – the means to recover incremental operating costs.

Map 4.8: ComEd Zone – Powerton Area

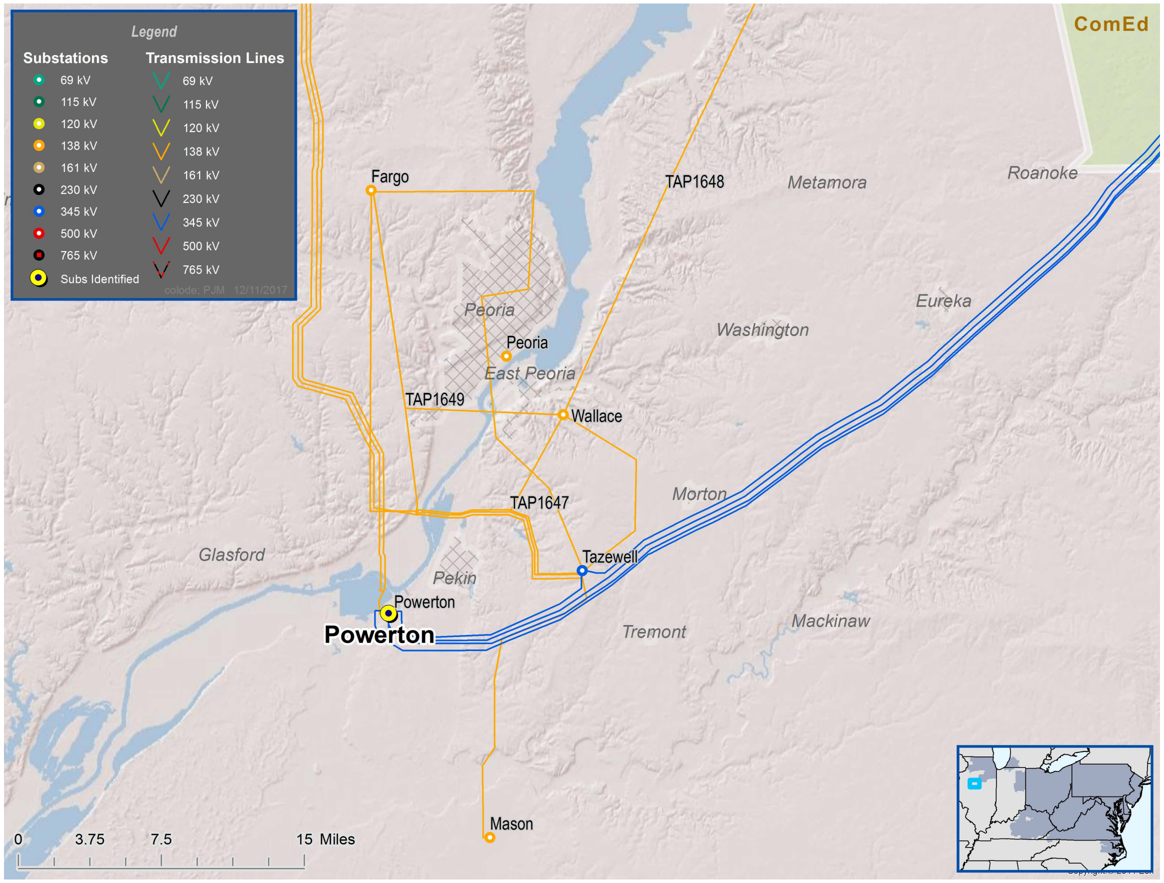


Table 4.5: ComEd Uplift Charge Transmission Solution Alternatives

Alternative	Estimated Cost	Considerations
Install a shunt inductor at Katydid	$6 million	- 345 kV Mole Creek remains high but below 1.05 per unit. - Otter Creek line will cut into 345 kV; shunt inductor to avoid over-voltage.
Install a shunt inductor at Katydid and Mole Creek	$12 million plus land purchase that may be required	- Otter Creek line will cut into 345 kV; shunt inductor to avoid over-voltage. - Adding an inductor at Mole Creek would assure operations would not have issues with line outage in future.
Cut-in three additional 345 kV Powerton lines at Mole Creek	$33 million plus land purchase that may be required	- Studies continue - Requires purchasing additional property - Requires breaker and a half layout - Generators should not be required to install inductors when cutting Powerton lines.

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

4.2: Immediate Need Regional Criteria

4.2.1 — RTEP Process Context

Immediate-need reliability projects comprise reliability-based transmission enhancements with a required in-service date of three years or less, as shown in **Figure 4.3**. If PJM determines insufficient time remains to develop and implement short-term solutions by way of a proposal window, then PJM works directly with the impacted transmission owner to develop and implement solutions. If PJM determines that sufficient time remains before a solution is required in-service, PJM conducts a RTEP proposal window. PJM has the authority to specify proposal window length based on the issue complexity. Reliability criteria violations and long-term market criteria congestion issues that warranted RTEP window solution solicitation in 2017 are summarized in **Section 2.0** and **Section 5.2**, respectively.

4.2.2 — 2017 Immediate Need Projects

PJM RTEP process analysis in 2017 identified 52 criteria violations requiring solutions within three years. Given the timeframe and the nature of the expected solutions, PJM decided that an RTEP window to seek solutions was infeasible. Working with the impacted transmission owner, PJM developed requisite solution projects. Those greater than $5 million in scope are summarized in **Table 4.7** and on **Map 4.9**.

Figure 4.3: Window Eligibility

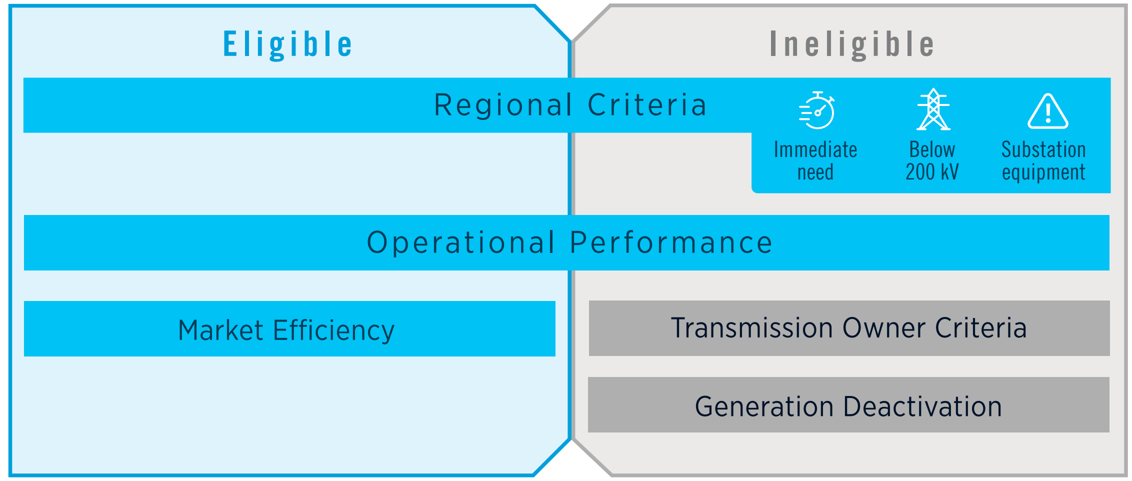
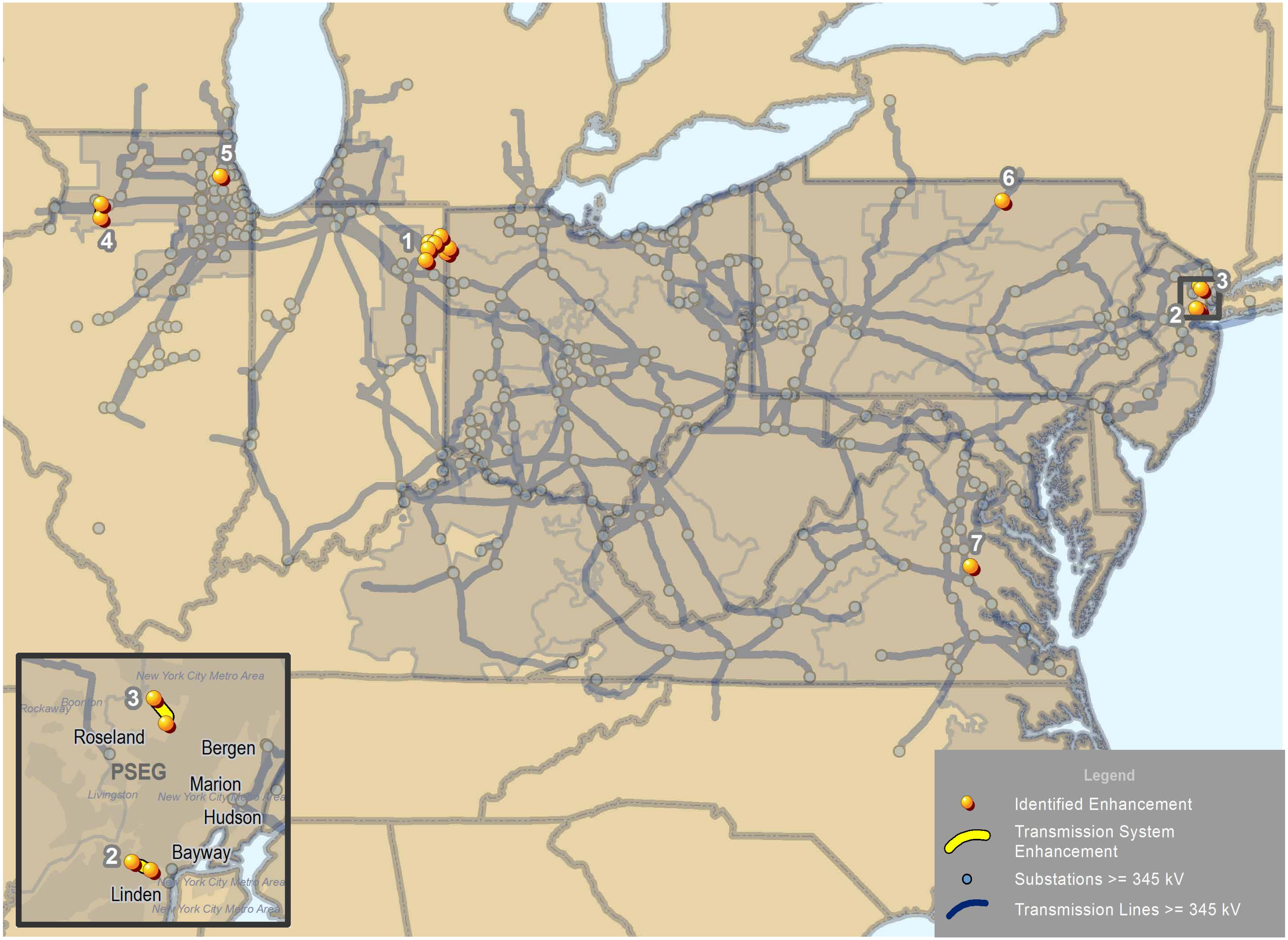


Table 4.7: Immediate Need Transmission Projects (greater than $5 million)

Map ID	RTEP Project ID	Project (Solution) Description	Driver(s)	Transmission Owner	Project Cost Estimate ($M)	Required In-service Date
1	b2779	Construct a new 138 kV station, Campbell Road, tapping into the Grabill-South Hicksville 138 kV line. Reconstruct sections of the Butler-N. Hicksville and Auburn-Butler 69 kV circuits as 138 kV double circuit and extend 138 kV from Campbell Road substation. Loop 138 kV circuits in and out of new SDI Willington substation. Reconductor 138 kV line section between Dunton Lake-SDI Willington. Expand 138 kV bus at Auburn substation.	Consequential load loss greater than 300 MW: - South Butler-Collingwood 345 kV line.	AEP	107.7	6/1/2019
2	b2955	Rebuild VFT-Warinanco-Aldene 230 kV line with paired conductor	Generation Deliverability (Summer and Winter): - VFT-Warinanco 230 kV line overload for several contingencies - Warinanco-Aldene 230 kV overload for tower contingency loss of the Linden-Deans and Linden-Sewaren 230 kV lines.	PSE&G	90.4	6/1/2018
3	b2956	Replace Cedar Grove-Jackson Rd 230 kV existing cable with 5,000 kcmil XLPE cable	Generation Deliverability (Summer): - Cedar Grove-Jackson Rd 230 kV overload for tower contingency loss of Cedar Grove-Athenia 230 kV lines	PSE&G	80	6/1/2018
6	b2959	Install new Schauff Road-Rock Falls 138 kV line. Install fourth breaker-and-a-half scheme at Schauff Road substation	Generator Deliverability (Light Load): - Rock Falls-Nelson-138 kV red line, Schauff Road-Nelson Tap 138 kV red line and Schauff Road-Rock Falls 138 kV red line base case overloads and multiple single contingency overloads	ComEd	20	11/1/2019
7	b2941	Build new indoor Elk Grove 138 kV GIS substation between Landmeier and Busse.	Consequential load loss greater than 300 MW: - Loss of Des Plaines-Busse-Schaumburg-Landmeier - Tonne red line and Des Plaines-Busse-Schaumburg - Landmeier-Tonne blue line 138 kV tower lines.	ComEd	90	6/1/2021
8	b2944	Install two 345 kV 80 MVAR shunt reactors at Mainesburg substation	Baseline Voltage Analysis Voltage (Summer, Winter, Light Load) and Operational High Voltage: -High voltage issues for several contingencies in each case -Operational high voltages experienced over recent years	PENELEC	11.49	6/1/2017
9	b2815	Build new Pinewood 115 kV, four-breaker ring bus switching station at tap serving North Doswell.	Violation of TO Criteria limiting number of breaker-protected taps on a transmission line.	Dominion	12.8	5/1/2021

Map 4.9: Immediate Need Transmission Projects (greater than $5 million)



Section 5: 2017 Market Efficiency Analysis

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

5.0: Scope

5.0.1 — RTEP Process Context

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

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

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

- 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/directory/merged-tariffs/oa.pdf

To conduct a market efficiency analysis, PJM uses a market simulation tool to model hourly security-constrained generation commitment and economic dispatch. Several base cases are developed. The primary difference between these cases is the transmission topology to which the simulation data corresponds:

- **An "as-is" base case** power flow models a one-year-out study year transmission topology.
- **An "as-planned" base case** power flow models PJM Board-approved RTEP projects with required in-service date of June 1 of the five-year-out study year.
- Project analysis includes topology for specific project under study.

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

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

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

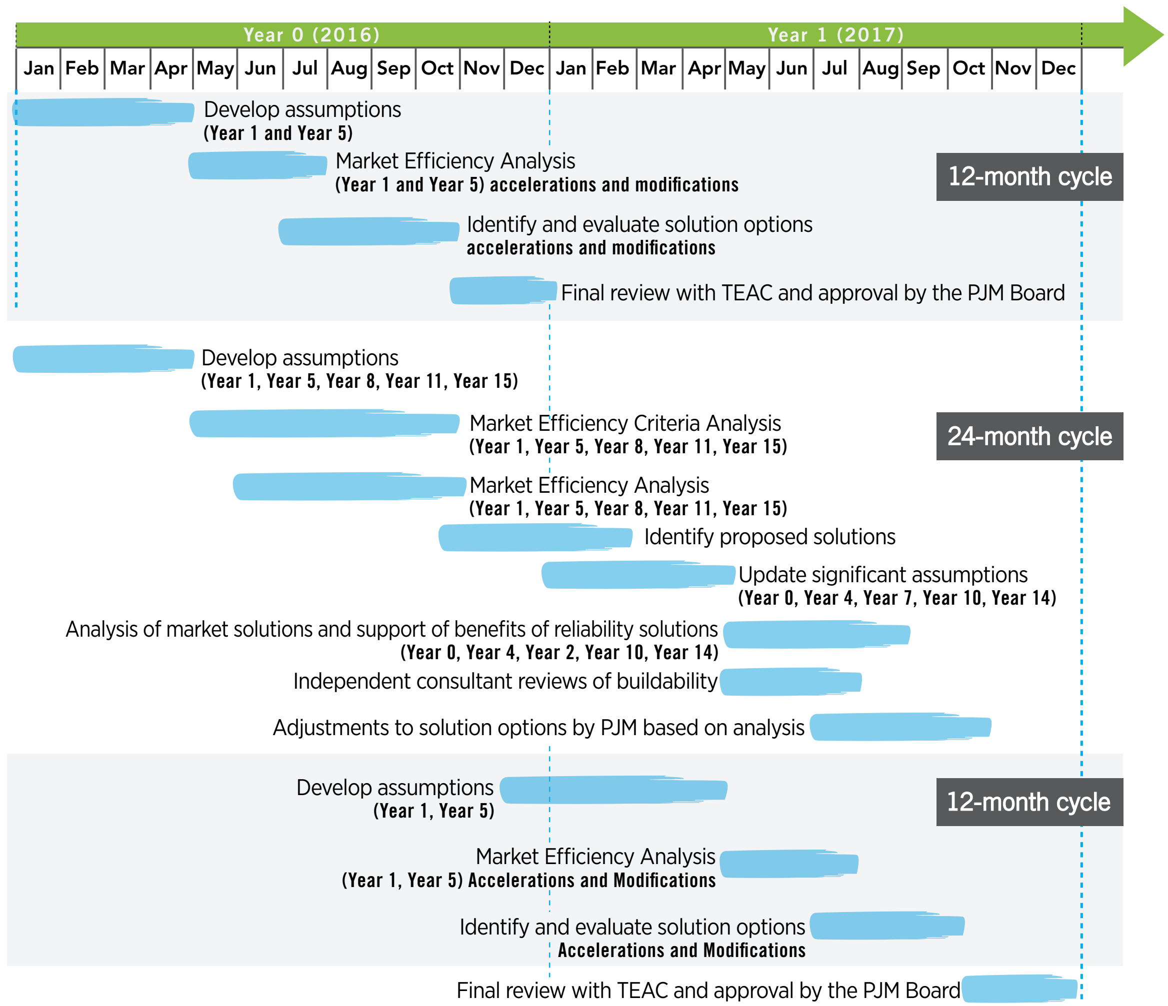
5.0.2 — 24-Month Cycle

The 24-month market efficiency timeline is shown in **Figure 5.1.** The work which comprised PJM's 2017 market efficiency body of analysis comprised "Year 1" of that 24-month cycle. The 2017 analysis focused on:

- Evaluating projects submitted in the 2016/2017 RTEP long-term proposal window
- Reviewing previously approved economic transmission projects
- Performing analysis to consider benefits of accelerating Baseline projects not yet built

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

Figure 5.1: Market Efficiency 24-Month Cycle



5.0.3 — Near-Term Simulations: 2018 and 2022 Study Years

PJM uses near-term simulations to assess the collective economic impact of RTEP enhancements not yet in-service. The goal is to identify potential benefit from acceleration or modification to individual RTEP projects. PJM can quantify the total transmission congestion reduction due to recently planned RTEP enhancements by comparing the total simulation differences from the "as-is" base case to the "as-planned" base case for the 2018 and 2022 study years. Simulation comparisons help PJM to:

- Identify constraints that may cause significant congestion
- Reveal if already-planned transmission enhancements may eliminate or relieve congestion so that the constraint is no longer an economic concern
- Reveal if a project may provide benefits that would make it a candidate for acceleration or modification

For example, if a constraint causes significant congestion in the 2018 "as-is" simulation but not in the 2022 "as-planned" simulation, then a project that eliminates this congestion in 2022 may be a candidate for acceleration. The acceleration cost is considered against the benefit of accelerating a project before any recommendation is made to the PJM Board.

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

In order to quantify future longer-range transmission system market efficiency needs, PJM developed a simulation database comprising base congestion for study years 2017, 2021, 2024 and 2027.

During evaluation of projects proposed through the 2016/2017 Long-Term Proposal Window. PJM conducted a 2017 mid-cycle update to examine the impact of recent RTEP changes. The cases included changes in topology, generation, load and fuel costs. The mid-cycle update ensured that selected projects yielded economic justification and did not introduce additional reliability criteria violations. For reference, the original base case used for the 2016/2017 Long-Term Proposal Window included a 2021 RTEP "as-planned" transmission system topology, which included RTEP projects submitted for approval through the 2015 RTEP cycle.

5.0.5 — Benefit-to-Cost Threshold Test

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

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

Energy Benefit – Regional Facilities

Energy benefit calculation for Regional Facilities is weighted as follows:

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

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

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

NOTE:

Regional facilities generally speaking are those operating at 500 kV or at 345 kV if double circuit tower construction.

Energy Benefit – Lower Voltage Facilities

Energy benefit calculation for lower voltage facilities is weighted 100 percent to zones with a decrease in net load payments as a result of the proposed project. The change in net load energy payment is the change in gross load payment 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.

Capacity Benefit – Regional Facilities

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

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

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

Capacity Benefit – Lower Voltage Facilities

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

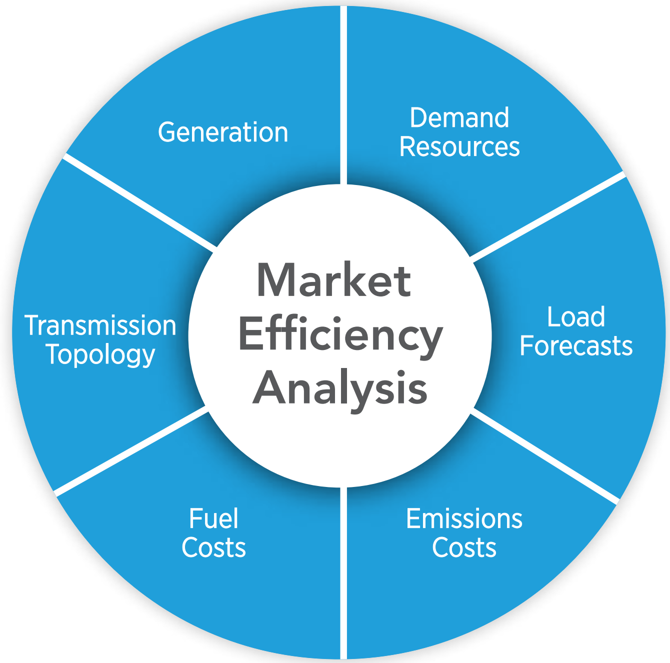
PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

5.1: 2017 Input Parameters

5.1.1 — Overview

PJM licenses a commercially available database containing the necessary data elements to perform detailed market simulations. This database is periodically updated, which permits up-to-date representation of the Eastern Interconnection and, in particular, PJM markets. The PJM Transmission Expansion Advisory Committee (TEAC) reviews the key analysis input parameters, shown in **Figure 5.2**.This data is used to develop forecasted system conditions, consistent with established RTEP process practice. Parameters include fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology and several financial valuation assumptions.

Figure 5.2: Market Efficiency Analysis Parameters



5.1.2 — Transmission Assumptions

Market efficiency power flow models were developed to represent:

1. The 2018 "as-is" transmission system topology

2. The expected 2021 system topology for the four-year-out RTEP year

PJM derived the "as-is" system topology from its review of the Eastern Interconnection Reliability Assessment Group's Series 2017 Multi-Regional Modeling Working Group 2018 summer peak case. It included transmission enhancements expected to be in service by the summer of 2018. PJM derived system topologies for 2021 and from the 2021 final RTEP case and included significant RTEP projects approved during 2017.

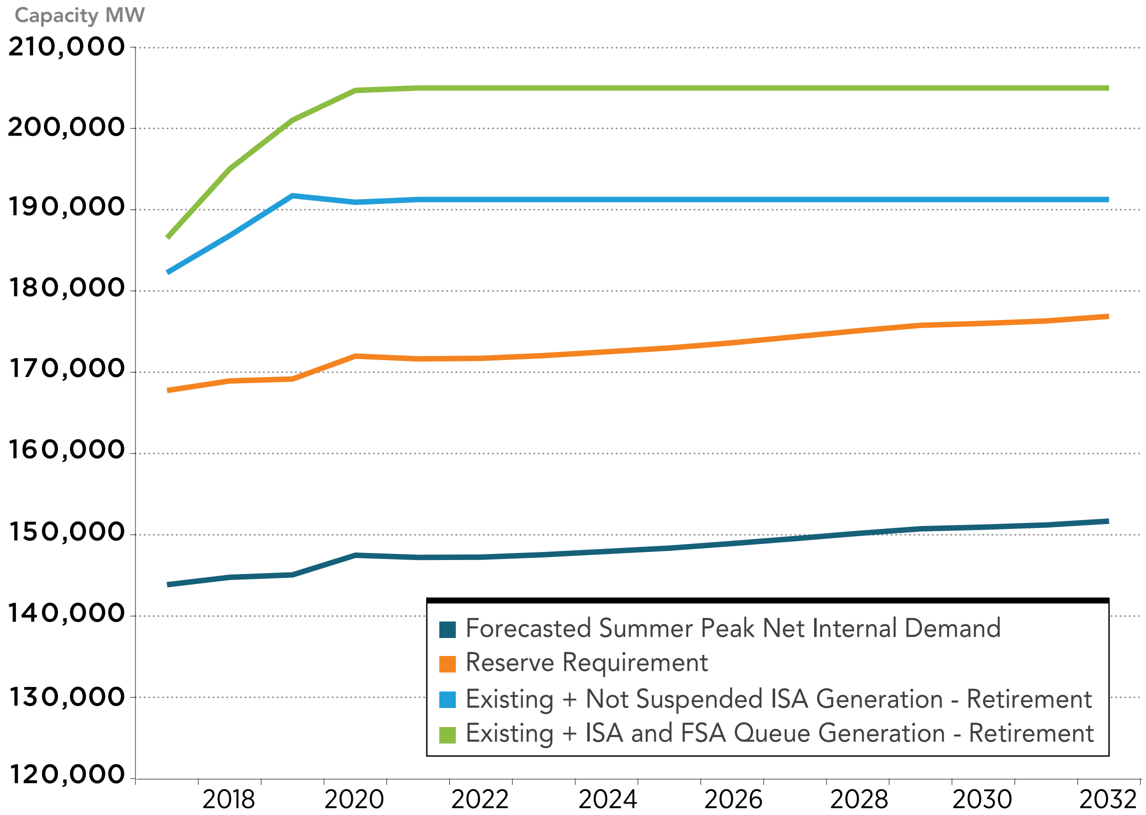
5.1.3 — Monitored Constraints

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

5.1.4 — Generation Parameters

Market efficiency simulations model existing in-service generation plus actively queued generation with at least an executed facilities study agreement, less planned generator deactivations that have given formal notification. The modeled generation provides enough capacity to meet PJM's installed reserve requirement through all study years, as shown in **Figure 5.3**.

Figure 5.3: PJM Market Efficiency Reserve Margin



NOTE:

Figure 5.3: Generation includes existing and projected PJM internal capacity resources. The generation model was based on the 2022 RTEP study year machine list.

5.1.5 — Fuel Price Assumptions

PJM uses a commercially available database tool that includes generator fuel price forecasts. Forecasts for short-term gas and oil prices are derived from New York Mercantile Exchange future prices. Long-term forecasts for gas and oil are obtained from commercially available databases, as are all coal price forecasts. Vendor-provided basis adders are applied as well to account for commodity transportation cost to each PJM zone. The fuel price forecasts used in PJM's 2017 Market Efficiency Analysis are represented in **Figure 5.4**.

5.1.6 — Load and Energy Forecasts

PJM's 2017 Load Forecast Report provides the transmission zone peak load and energy data modeled in market efficiency simulations. For perspective, **Table 5.1** summarizes PJM peak load and energy. The 2017 PJM Load Forecast can be found on PJM's website: http://pjm.com/-/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx?la=en

5.1.7 — Demand Resources

The amount of demand resources modeled in each transmission zone is based on the 2017 PJM Load Forecast Report per the link in **Section 5.1.6**. For perspective, **Table 5.2** summarizes PJM demand resource totals by year.

Figure 5.4: Fuel Price Assumptions

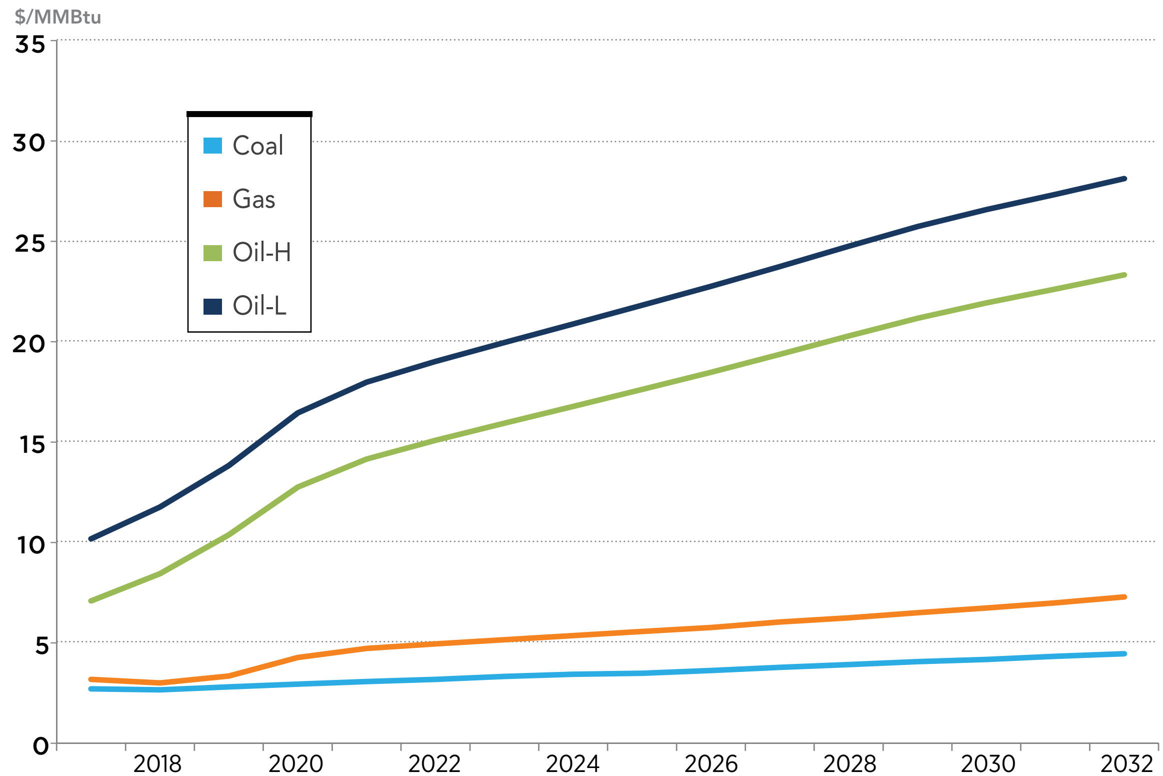


Table 5.1: 2017 PJM Peak Load and Energy Forecast

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 the PJM Load Forecast Report, Table B-1 and Table E-1, respectively.
2. Model inputs are at the zonal level, to the extent zonal load shapes create different diversity – modeled PJM peak load may vary.

Table 5.2: 2017 PJM Demand Resource Forecast

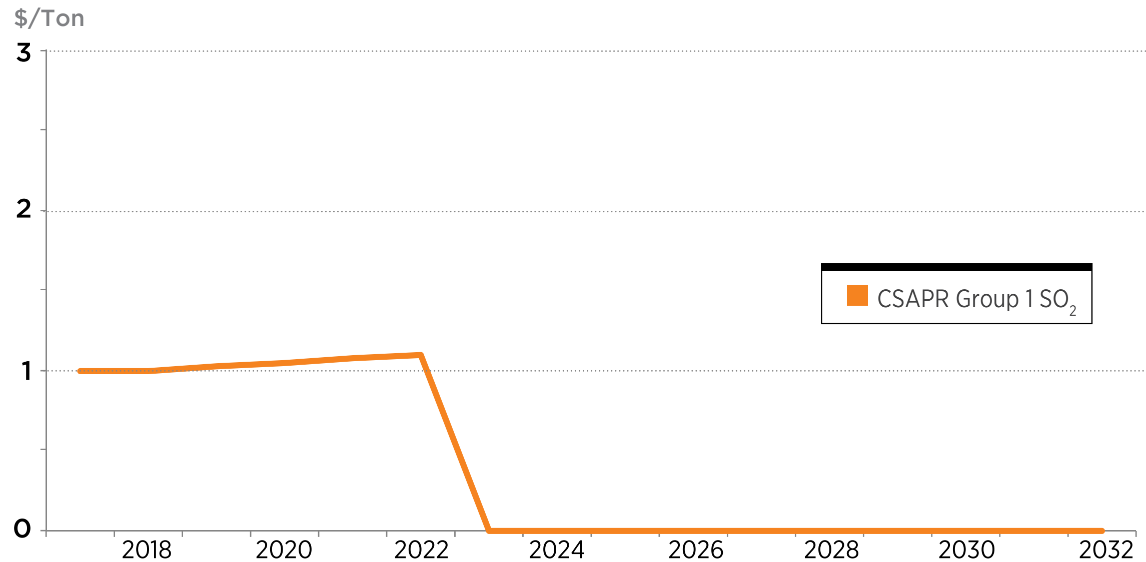
	2017	2021	2024	2027	2031
Demand Resource (MW)	9,120	6,169	6,187	6,237	6,290

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

5.1.8 — Emission Allowance Price Assumptions

PJM currently models three major effluents – SO_2, NO_x and CO_2 – within its Market Efficiency simulations. SO_2 and NO_x emission price forecasts reflect implementation of the Cross-State Air Pollution Rule (CSAPR) and are shown in **Figure 5.5** and **Figure 5.6**, respectively. PJM unit CO_2 emissions are modeled as either part of the national CO_2 program or, for Maryland and Delaware units, as part of the Regional Greenhouse Gas Initiative (RGGI) program. The base emission price assumption for both the national CO_2 and RGGI CO_2 program are shown in **Figure 5.7**.

Figure 5.5: SO_2 Emission Price Assumption



NOTE

SO_2	Sulfur dioxide
NO_x	Nitrogen oxides
CO_2	Carbon dioxide

5.1.9 — 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 potential project, as described in **Section 5.0**. To do so, the net present value of annual benefits is calculated for the first 15 years of project life and compared to the net present value of the project revenue requirement for the same 15-year period. A discount rate and levelized carrying charge rate is developed using information contained in Attachment H of the transmission owner (TO) formula rate sheets, as posted on 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 TO total capitalization). The levelized annual carrying charge rate is based on the weighted-average net plant carrying charge (average weighted by TO total capitalization) levelized over an assumed 45-year life of the project. PJM's 2017 market efficiency studies used a levelized annual carrying charge rate of 15.3 percent and a discount rate of 7.4 percent.

Figure 5.6: NO_x Emission Price Assumptions

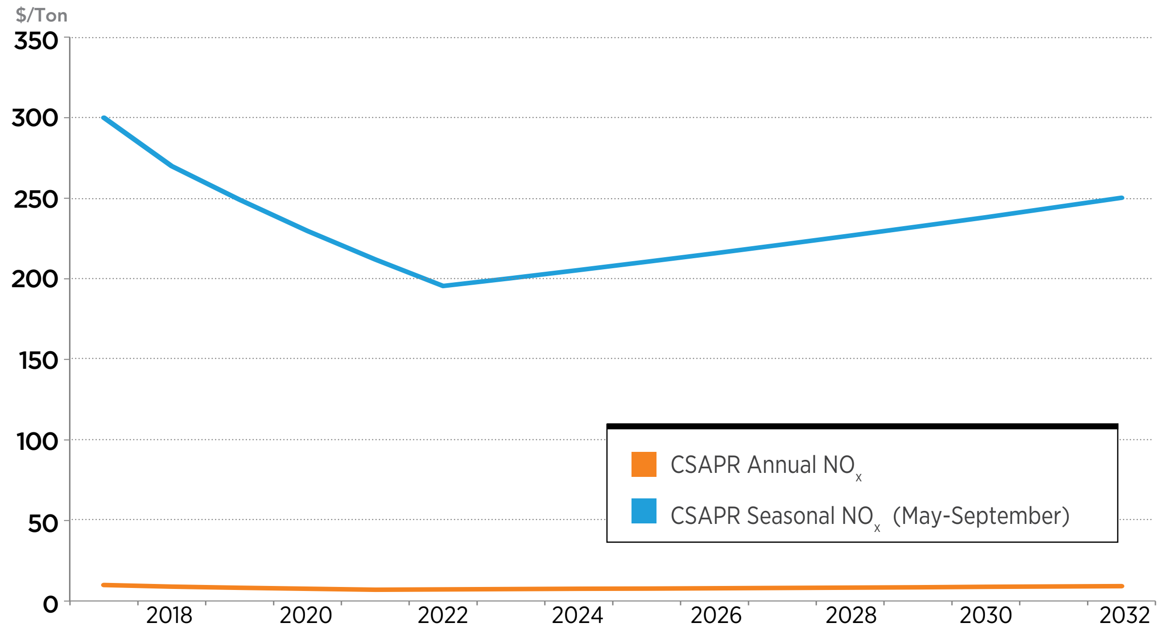
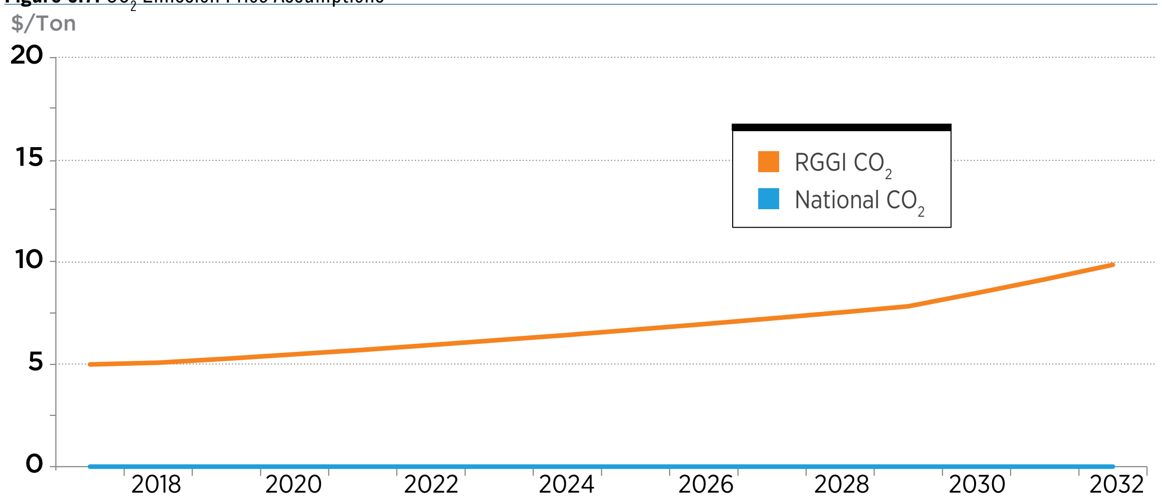


Figure 5.7: CO_2 Emission Price Assumptions



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

5.2: 2017 Market Efficiency Analysis

5.2.1 — Near-Term Simulation Results – Study Years 2018 and 2022

PJM's 2017 cycle of analysis included near-term simulations for study years 2018 and 2022. They identified collective and constraint-specific transmission system congestion due to the impacts of previously approved RTEP projects not yet in service. PJM conducted the simulations under two different transmission topologies:

1. 2018 "as-is" PJM transmission system topology

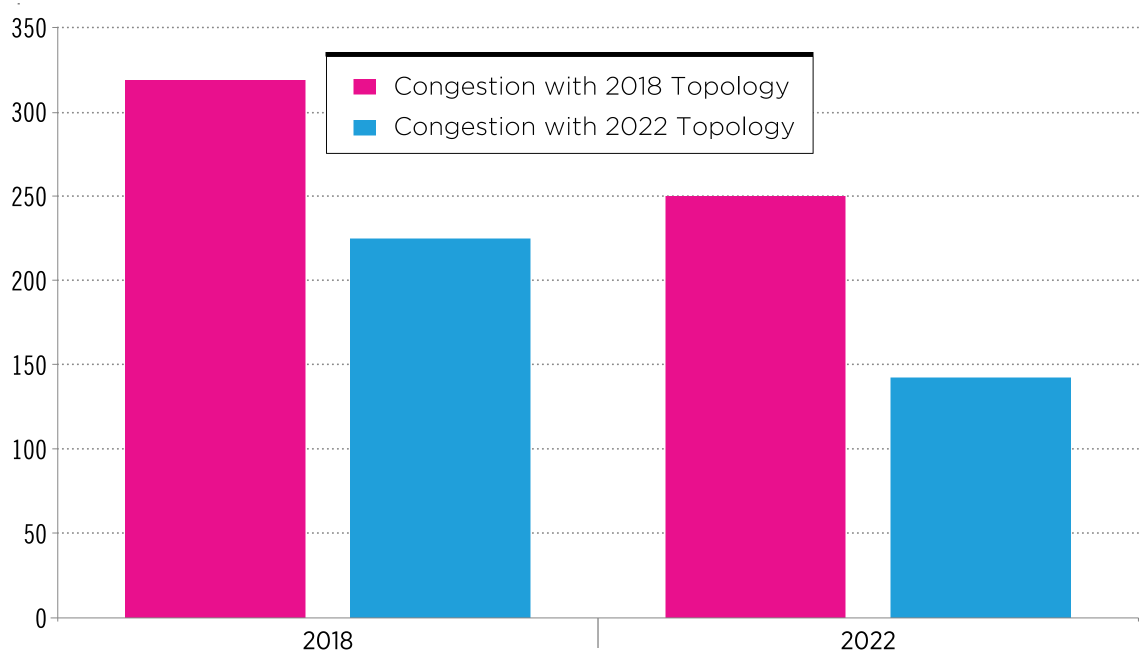
2. 2022 base case PJM transmission system topology

To determine the economic value of a transmission enhancement, PJM compares the results of multiple simulations that have the same fundamental supply and demand operating constraints but differing transmission topologies. This technique allows PJM to:

1. Value collectively the congestion benefits of approved RTEP projects

2. Evaluate the congestion benefits of accelerating or modifying specific RTEP projects

Figure 5.8: Simulated PJM Congestion Costs: 2018 and 2022



PJM's congestion costs from market simulations for study years 2018 and 2022 are shown in **Figure 5.8**. The annual congestion cost reductions are more than $94 million (29 percent) for 2018 and more than $107 million (43 percent) for 2022. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

5.2.2 — Acceleration Analysis

PJM identified and evaluated the RTEP enhancements most responsible for the congestion reductions identified in 2018 and 2022 study year simulations as shown in **Table 5.3** and **Map 5.1**. Congestion savings for the 2022 study year are calculated as the difference in simulated congestion between as-is topology and RTEP topology.

As a result of the analysis, PJM has recommended that existing Baseline project b2766 to upgrade the substation equipment at Conastone and Peach Bottom 500 kV substations should be accelerated from a 2021 to a 2020 completion date to realize $4.4 million in congestion savings. No additional project cost is anticipated. The other RTEP Baseline reliability projects identified in **Table 5.3** will not be recommended for acceleration. These projects do not provide significant congestion benefits or are impractical to accelerate given their existing near-term in-service date or significant project scope.

5.2.3 — Long-Term Simulation Results: 2017, 2021, 2024 and 2027 Study Years

To identify and quantify long-term transmission system congestion, market simulations were conducted for study years 2017, 2021, 2024 and 2027, leading to the 2016/2017 Long-Term RTEP Proposal Window solicitation for market efficiency projects to solve identified congestion, discussed next in **Section 5.2.4.** The original base case used for the 2016/2017 Long-Term Proposal Window included a 2021 RTEP base case transmission system topology that included RTEP projects approved from the 2015 RTEP cycle.

Table 5.3: RTEP Projects Reducing Specific Congestion Drivers: 2022 Analysis

			2018 Topology	2022 Topology			
Map ID	Constraint	Area	Year 2022 Congestion ($M)	Year 2022 Congestion ($M)	Congestion Savings ($M)	RTEP Project Associated with Congestion Reduction	Projected In-Service Date
1	Tanners-Miami Fort 345 kV line	AEP/ DEO&K	$5.2	$0.0	$5.2	Upgrade the Tanners Creek-Miami Fort 345 kV circuit (b2831)	2018
2	Roxbury 138/115 kV line	PENELEC	$9.3	$0.0	$9.3	Build new 230 kV double circuit line between Rice and Ringgold 230 kV (b2743)	2020
3	Yorkana-Brunner Island 230 kV line	Met-Ed/ PPL	$7.3	$0.0	$7.3	Reconductor three spans limiting Brunner Island-Yorkana 230 kV line (b2691)	In-Service
4	Conastone-Peach Bottom 500 kV line	BGE/ PECO	$4.4	$0.0	$4.4	Upgrade substation equipment at Conastone and Peach Bottom 500 kV (b2766)	2021
5	Northwest-Consatone 230 kV line	BGE	$2.4	$0.0	$2.4	Reconductor/rebuild the two Conastone-Northwest 230 kV lines and upgrade terminal equipment on both ends (b2752.7)	2020
6	Safe Harbor-Graceton 230 kV line	PPL/BGE	$3.4	$0.0	$3.4	Reconductor two spans of the Graceton-Safe Harbor 230 kV transmission line. Includes termination point upgrades (b2690)	2018
7	Peach Bottom 500/230 kV transformer	PECO	$60.0	$0.0	$60.0	Increase ratings of Peach Bottom 500/230 kV transformer (b2694)	2019

Note: The congestion savings for the 2022 study year are calculated as the difference in simulated congestion between the as-is topology and the RTEP topology.

In parallel with evaluation of the projects submitted as part of the window, PJM also conducted a 2017 mid-cycle update which incorporated RTEP projects recently approved by the PJM Board. The update also reflected forecasted changes in topology, generation, load, and fuel costs. The mid-cycle update ensured that selected projects still yielded economic justification and did not introduce additional reliability criteria violations.

Map 5.1: RTEP Projects Reducing Specific Congestion Drivers: 2022 Analysis

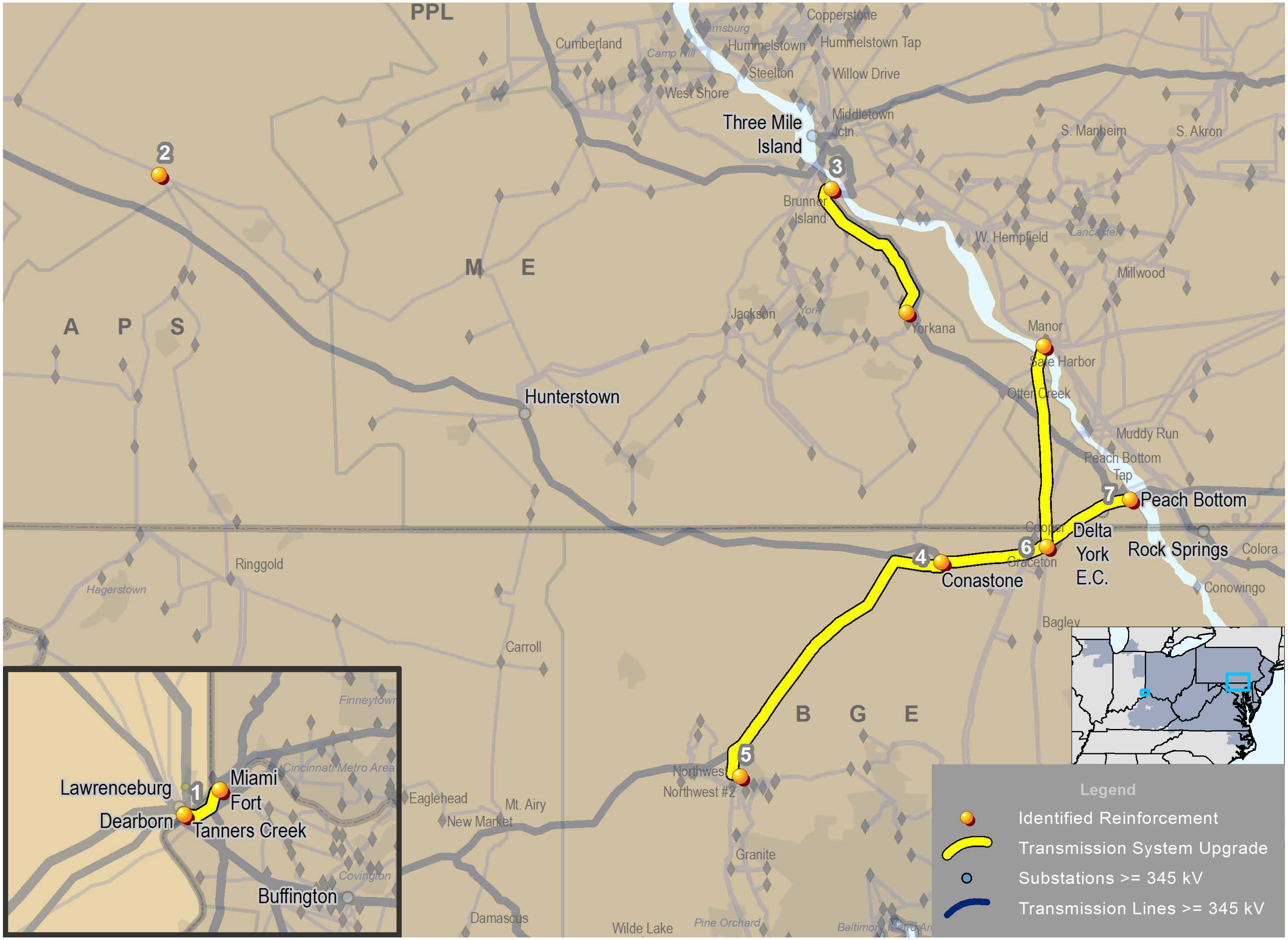


Table 5.4 presents constraints with the highest congestion costs from the 2016 long-term market efficiency analysis. These transmission constraints represent over 95 percent of the PJM-related congestion in the original base case 2021 and 2024 simulations. Facilities highlighted in yellow are constraints for which solution alternatives were sought as part of the 2016/2017 RTEP Long-Term Proposal Window. They continue to show persistent congestion, albeit at lower levels in the 2017, mid-cycle update.

Overall, congestion levels in PJM's 2017 market efficiency analyses are lower compared to previous RTEP cycles. This is due, in part, to:

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

Table 5.4: Largest Congestion Cost Constraints – 2016 Long-Term Market Efficiency Analysis

Constraint	Area	2017 Market Congestion ($M)	2021 Market Congestion ($M)	2024 Market Congestion ($M)	2027 Market Congestion ($M)
Graceton-Conastone 230 kV Flowgate	BGE	$51.80	$58.26	$72.10	$68.88
Bagley-Graceton 230 kV Flowgate	BGE	$23.59	$33.01	$49.55	$59.57
AP South Interface for the loss of Bedington-Black Oak 500 kV line		$37.64	$36.68	$32.83	$40.57
Keystone-Juniata and Conemaugh-Juniata 500 kV Interface for the loss of the Lackawanna-Hopatcong 500 kV line		$24.35	$24.46	$22.33	$18.12
PJM Central Interface		$4.18	$9.56	$6.93	$4.60
Susquehanna-Harwood 230 kV Flowgate	PLGRP		$3.98	$5.60	$8.32
AEP-Dominion 500 kV Interface for the loss of Bedington-Black Oak 500 kV line		$1.46	$2.34	$6.33	$10.45
Red Oak-Raritan River 230 kV Flowgate	JCPL	$0.19	$3.63	$4.03	$5.21
Peach Bottom-Conastone 500 kV line	BGE	$32.78	$1.78	$3.84	$1.90
South River-Red Oak A 230 kV line	JCPL		$2.03	$3.51	$4.52
Maple-Hoytdale 138 kV Flowgate	FE-ATSI	$1.29	$1.55	$2.96	$2.77
North Waverly-East Sayre 115 KV Flowgate	PENELEC	$0	$1.13	$1.82	$1.20
Bosserman to Olive 138 kV market-to-market limit	AEP		$0.36	$1.98	$1.04

Note: Highlighted constraints indicate solution alternatives sought in the 2016/2017 RTEP Long-Term Proposal Window.

5.2.4 — 2016/2017 RTEP Long-Term Window Market Efficiency Proposals

PJM solicited stakeholder proposals for market efficiency projects as part of an RTEP proposal window focusing on long-term analysis. The 2016/2017 RTEP Long-Term Proposal Window opened on November 1, 2016, and closed on February 28, 2017. It sought solutions to resolve or alleviate market efficiency congestion identified in the long-term simulation results highlighted in yellow in **Table 5.4**. Proposals to address other system constraints – including Reliability Pricing Model (RPM) transmission system limitations and interregional constraints – were evaluated within the long-term analysis where impacts were identified as such.

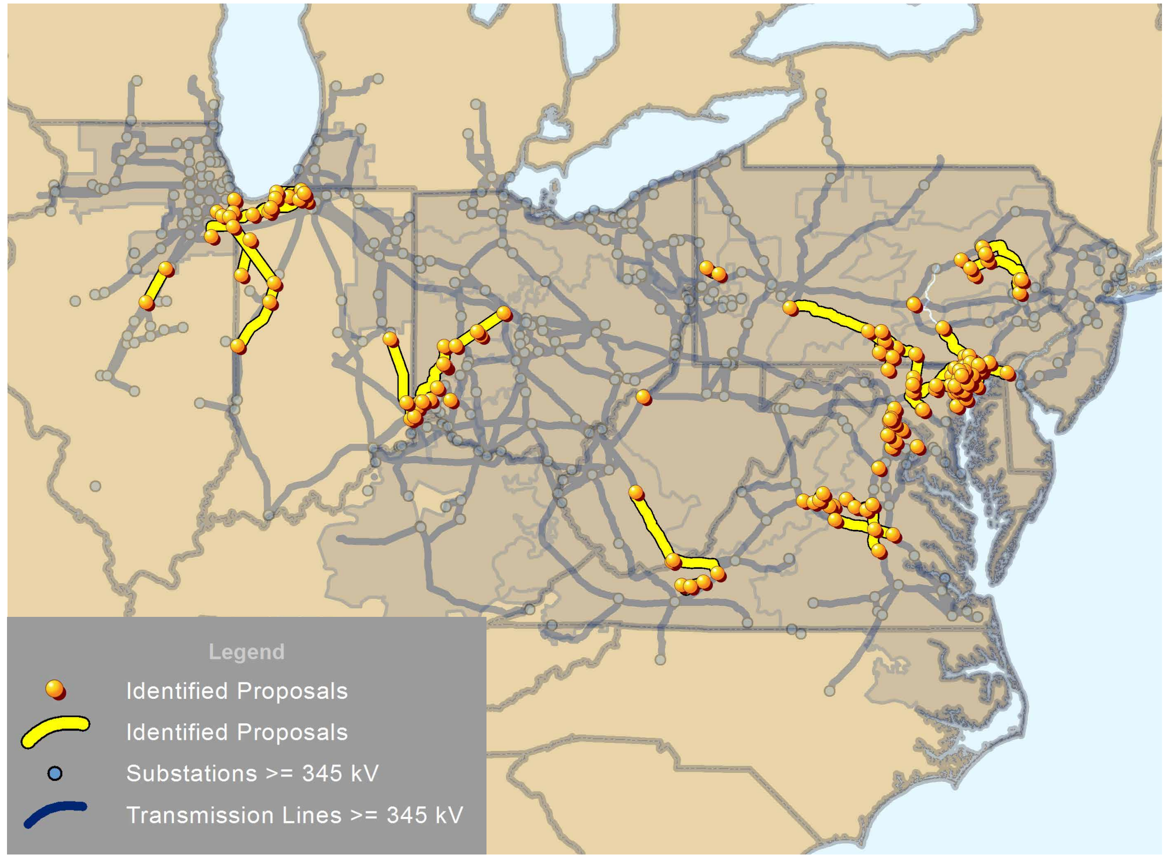
Background

In preparation for the proposal window, PJM developed and posted a problem statement and requirements document that can be accessed on the PJM website: http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx. PJM received 96 market efficiency project submissions that address future simulated congestion and capacity market constraints. Proposals spanned many areas of PJM as depicted on **Map 5.2** and comprised the following:

- 44 transmission owner upgrades ranging in cost from $0, to accelerate existing Baseline projects, to $192 million for new projects
- 52 greenfield projects ranging in cost from $16 million to $432 million

PJM grouped the proposed projects based on type of market efficiency project driver and affected geographic zone. Doing so permitted PJM to compare projects with similar purpose and minimize market efficiency and power flow interactions with the proposed transmission facilities in other project groups. During 2017, PJM evaluated several proposal groups: ComEd RPM projects, interregional projects, PPL projects and BGE projects.

Map 5.2: 2016/2017 Long-Term Window Proposals



ComEd Projects

Four proposals were submitted to address ComEd locational deliverability area (LDA) capacity market constraints. The proposals were received from three entities, with costs ranging from $0 to $5.62 million. Two proposals were zero-cost accelerations of previously approved Baseline reliability enhancements to address LDA import constraints identified in the 2020/2021 RPM Base Residual Auction conducted in May 2017, shown in **Table 5.5**.

PJM evaluated the proposals to determine the impact of each on the ComEd LDA Capacity Emergency Transfer Limit (CETL). Subsequently, PJM evaluated proposals to determine which produced a benefit-cost ratio greater than 1.25.

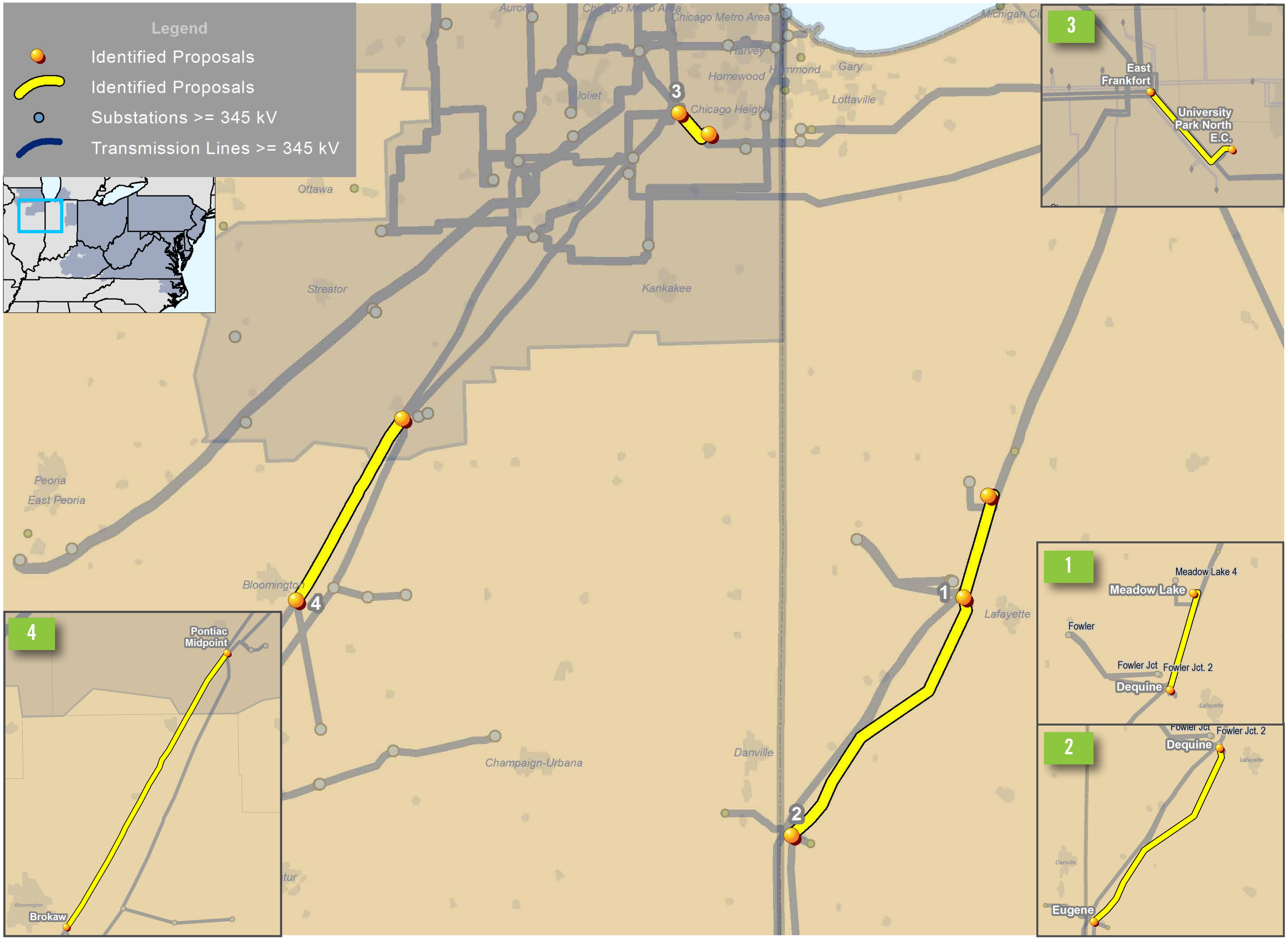
The total market efficiency benefit of a project is the sum of energy market benefits and the capacity market benefits. The energy market benefits were derived from production cost simulations and the capacity benefits were derived from capacity market simulations. From a capacity market perspective, increasing an LDA's import capability by mitigating limiting transmission constraints, can enable a zone like ComEd to satisfy capacity requirements at a lower overall cost. PJM simulated the RPM process for multiple study years with the updated CETL values and measured each project's capacity benefits over a 15-year period. **Table 5.5** shows the projects that provide the highest total benefits, satisfy the benefit-cost ratio of 1.25 and are recommended to the PJM Board.

Table 5.5: Recommended Market Efficiency ComEd Reliability Pricing Model Projects

Map ID	PJM Baseline ID	Project Description	Transmission Zone	Constraint Benefits	Project Cost ($M)	In-Service Year	B/C Ratio
1	b2776	Accelerate previously approved upgrade to reconductor Dequine-Meadow Lake 345 kV line	AEP	Dequine-Meadow 345 kV line; RPM	$0.00	2019	
2	b2777	Accelerate previously approved upgrade to reconductor Dequine-Eugene 345 kV line	AEP	Eugene-Dequine 345 kV line; RPM	$0.00	2019	
3	b2930	Upgrade capacity on E. Frankfort-University Park 345 kV line	ComEd	East Frankfort-University Park 345 kV line; RPM	$0.84	2021	147.69
4	b2931	Upgrade substation equipment at Pontiac Midpoint station to increase capacity on Pontiac-Brokaw 345 kV line	ComEd	Pontiac-Brokaw 345 kV line; RPM	$5.62	2021	13.45

The projects will save customers an estimated $18 million in average annual energy and capacity payments by 2021. Given that these projects are all upgrades to existing equipment, the incumbent transmission owner will be assigned as the designated entity to implement the projects. **Map 5.3** shows the locations of the recommended projects.

Map 5.3: Recommended Market Efficiency ComEd Reliability Pricing Model Projects



Interregional Group Projects

In coordination with the parallel MISO efforts discussed in **Section 7.1**, PJM received eight interregional proposals along the PJM/MISO seam, ranging in estimated cost from $2.5 million to $198 million, as part of the 2016/2017 RTEP Long-Term Proposal Window. Interregional proposals are designed to address congestion and its associated costs along the MISO-PJM border within the context of PJM-MISO JOA Interregional Market Efficiency Projects (IMEPs):

- If approved, the costs are allocated interregionally, based on the pro rata share of benefits.
- Regional benefits are determined by each RTO, using its respective regional process and metrics.
- Projects must be identified by both RTOs as the best solution and must meet each RTO's benefit-to-cost criteria based on allocated costs.

The interregional projects submitted to the 2016/2017 long-term proposal window are shown in **Table 5.6.**

Table 5.6: Interregional Group Projects – 2016/2017 Long-Term Proposal Window

Map ID	Submitting Party	Description	In-Service Year	Cost ($M)	Constraint
1	NextEra	Build a new 345/138 kV substation (Rolling Prairie) connecting University Park-Olive 345 kV, Maple-New Carlisle 138 kV and Maple-LNG 138 kV	2021	$19.2	Olive-Bosserman 138 kV
2	AEP/NIPSCO	Rebuild New Carlisle-Silver Lake 34.5 kV as 138 kV. Rebuild the Michigan City-Trail Creek-Bosserman 138 kV line.	2022	$17.0	Olive-Bosserman 138 kV
3	Transource	Tap the Tanners Creek-Losantville 345 kV line and build a single circuit line to a new 345/138 station (Coyote) next to Wiley.	2022	$71.9	Tanners Creek-Miami Fort 345 kV
4	AEP/Exelon	Meadow Lake-Pike Creek 345 kV Double Circuit Greenfield Line and new Pike Creek 345 kV Station	2022	$198.0	Olive-Bosserman 138 kV
5	Northeast Transmission Development	Build a 345/138 kV substation ("Coffee Creek") interconnecting Green Acres to Olive 345 kV line and Flint Lake to Luchtman Road 138 kV line.	2022	$17.4	Olive-Bosserman 138 kV
6	WPPI	Construct second New Carlisle-Olive 138 kV circuit. Upgrade substation equipment at New Carlisle and Olive substations.	2020	$2.5	Olive-Bosserman 138 kV
7	NIPSCO	Reconductor existing NIPSCO line sections between AEP Bosserman and Olive 138 kV substations and between AEP Bosserman and New Carlisle 138 kV substations.	2020	$8.0	Olive-Bosserman 138 kV
8	NIPSCO	New NIPSCO line section between Thayer and Morrison 138 kV substations.	2023	$42.5	Paxton-Gifford 138 kV

Subsequent analysis indicates that no projects met IMEP criteria: either the PJM congestion driver is no longer a concern or the project benefit-to-cost ratio is less than 1.25.

- *Olive-Bosserman 138 kV Line:* Six projects were proposed to remedy market-to-market congestion on the Olive-Bosserman 138 kV line. As part of its own local planning process, the transmission owner identified issues and addressed them with a Supplemental project. None of the six interregional proposals successfully remedied both the interregional congestion issues and the local planning issues. Once the Supplemental project to address the local planning issues is implemented, lower remaining levels of congestion would not justify any of the interregional proposals. Consequently, none will be pursued.
- *Paxton-Gifford 138 kV Line:* Additional evaluation of the Paxton-Gifford 138 kV line revealed that a scheduled interconnection project transmission enhancement in MISO would increase the line's rating. Doing so would mitigate much of the market-to-market area congestion constraining that line. The remaining identified congestion in that area did not pass criteria to establish the issue as significant to PJM markets. The proposal for this line, therefore, was referred to MISO for consideration as a regional congestion remedy.
- *Tanners Creek-Miami Fort 345 kV Line:* The interregional proposal to address the Tanners Creek to Miami Fort 345 kV market-to-market congestion did not successfully pass the regional benefits to cost threshold and was not pursued further.

These lines are shown on **Map 5.4**.

Map 5.4: Interregional Group Projects – 2016/2017 Long-Term Proposal Window

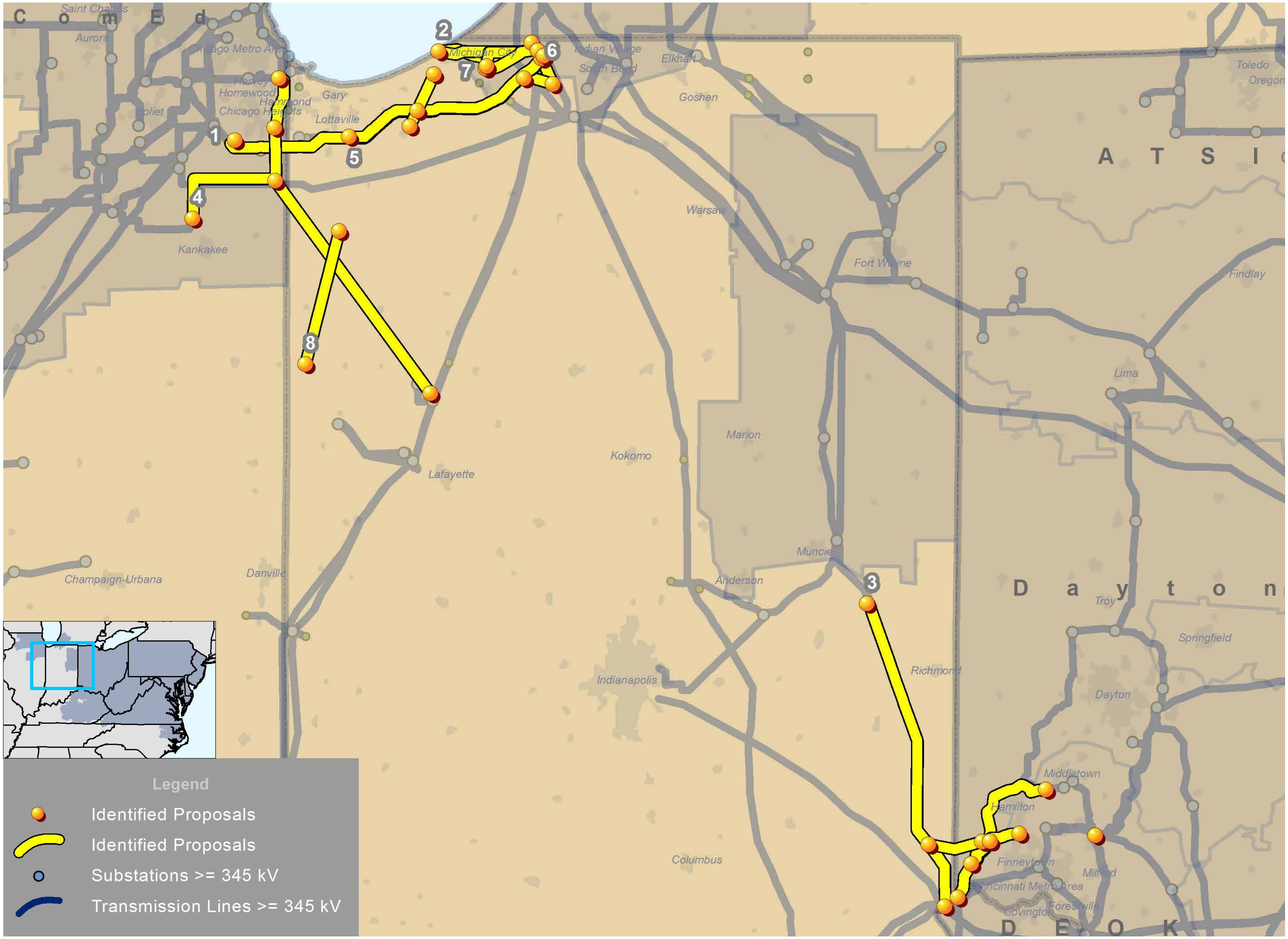


Table 5.7: PPL Group Projects

Map ID	Submitting Party	Project Description	Upgrade/ Greenfield	Cost ($M)	In-Service Year
1	PPL	Reconductor Susquehanna-Harwood and Susquehanna-Sugarloaf-Harwood 230 kV double-circuit tower lines and replace structures as necessary to accommodate the heavier conductor.	Upgrade	13.1	2021
2	PPL	Reconductor Susquehanna-Harwood and Susquehanna-Sugarloaf-Harwood 230 kV double-circuit tower lines and replace structures as necessary to accommodate the heavier conductor.	Upgrade	13.0	2021
3	PPL	Tap the Susquehanna-Wescosville 500 kV line at Siegfried. Expand Siegfried to include a 500/230 kV substation.	Upgrade	18.3	2021
4	NextEra	Tap the Susquehanna-Wescosville 500 kV line near Siegfried and build a new 500/230 kV substation (Spring Hill). Tie Spring Hill 230 kV into the existing Siegfried 230 kV substation.	Greenfield	33.8	2021
5	Northeast Transmission Development	Tap the Susquehanna-Wescosville 500 kV line near Siegfried and build a new 500/230 kV substation (Fells Creek). Tie the Fells Creek 230 kV into the existing Siegfried 230 kV substation.	Greenfield	32.9	2021
6	Northeast Transmission Development	Tap the Catawissa-Frackville 230 kV line and build a new 230 kV switchyard (Trexler Run). Build a new Harwood-Trexler Run 230 kV line.	Greenfield	33.7	2021

PPL Group Projects

PJM received six proposals to address congestion on the Susquehanna-Harwood 230 kV line with estimated costs ranging from $13 million to $34 million, as shown on **Table 5.7** and **Map 5.5**. Based on the 2017 mid-cycle update, discussed earlier in **Section 5.2.3**, PJM production cost simulations indicated reduced congestion driven by the Susquehanna-Harwood 230 kV line constraint.

PJM production cost simulations also revealed that several interconnection queue generators are contributing to the congestion. Importantly, though, those generators have only reached the facility study agreement (FSA) stage of PJM's interconnection study process. Historically, units at this stage, not yet constructed, have a higher probability of not reaching commercial operation compared to other units further along in the generator queue process. If some of these units are not completed, PJM expects lower congestion on the Susquehanna-Harwood 230 kV line.

Map 5.5: PPL Group Projects

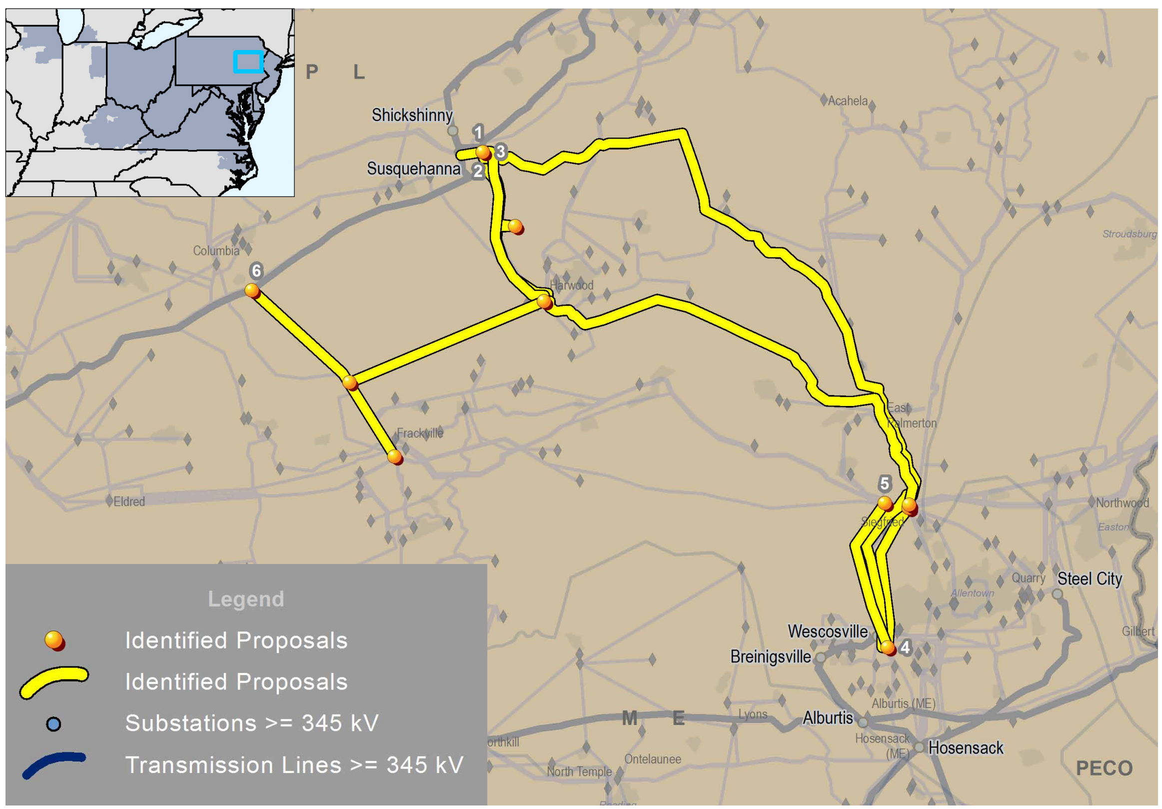


Table 5.8 shows levels of congestion expected for various scenarios including the effect of the generators at the FSA stage.

Given the results of these scenario studies coupled with the high likelihood that results could be impacted by the solution selected for the BGE group, no project recommendation was made in 2017. Further analysis of the PPL group projects will be performed after completing BGE group analysis and is expected to be completed in early 2018.

Table 5.8: Simulated Congestion Susquehanna-Harwood 230 kV

Susqeuhanna-Harwood 230 kV Scenario	2021 Market Congestion ($M)	2024 Market Congestion ($M)	Notes
Initial 2016 study	$3.98	$5.60	Facilities recommended for proposals criteria: $1 million for 2021 and 2024
2017 study	$2.94	$2.27	45% congestion decrease compared to 2016 study
2017 study with no generators at FSA stage modeled	$1.34	$0.48	80% congestion decrease compared to 2016 study

BGE Group Projects

PJM received 46 proposals in the BGE area to address congestion seen on the Conastone-Graceton-Bagley 230 kV line, shown on **Map 5.6**. The estimated construction cost of these proposals ranged from $6 million to $483 million, shown in **Table 5.9**. Based on the 2017 mid-cycle update, discussed earlier in **Section 5.2.3**, PJM production cost simulations indicated persistent, though reduced congestion on the Conastone-Graceton-Bagley 230 kV line.

Additional PJM analysis has indicated that the highest benefit-to-cost ratios are produced by projects encompassing upgraded station equipment and transmission line reconductoring. Before PJM makes specific recommendations, additional verification of cost and constructability factors, reliability and economic robustness of potential projects is required. This work will continue into 2018.

Remaining Project Proposals

The remaining proposed projects addressed simulated congestion for which PJM was not seeking solution alternatives. Many were reactive proposals in areas that have limited operational need for additional capacitors. Others were designed for congestion that continues to decline or was non-existent in the 2017 mid-cycle model. PJM does not intend to evaluate these proposals further.

Map 5.6: BGE Group Projects – 2016/2017 Long-Term Proposal Window

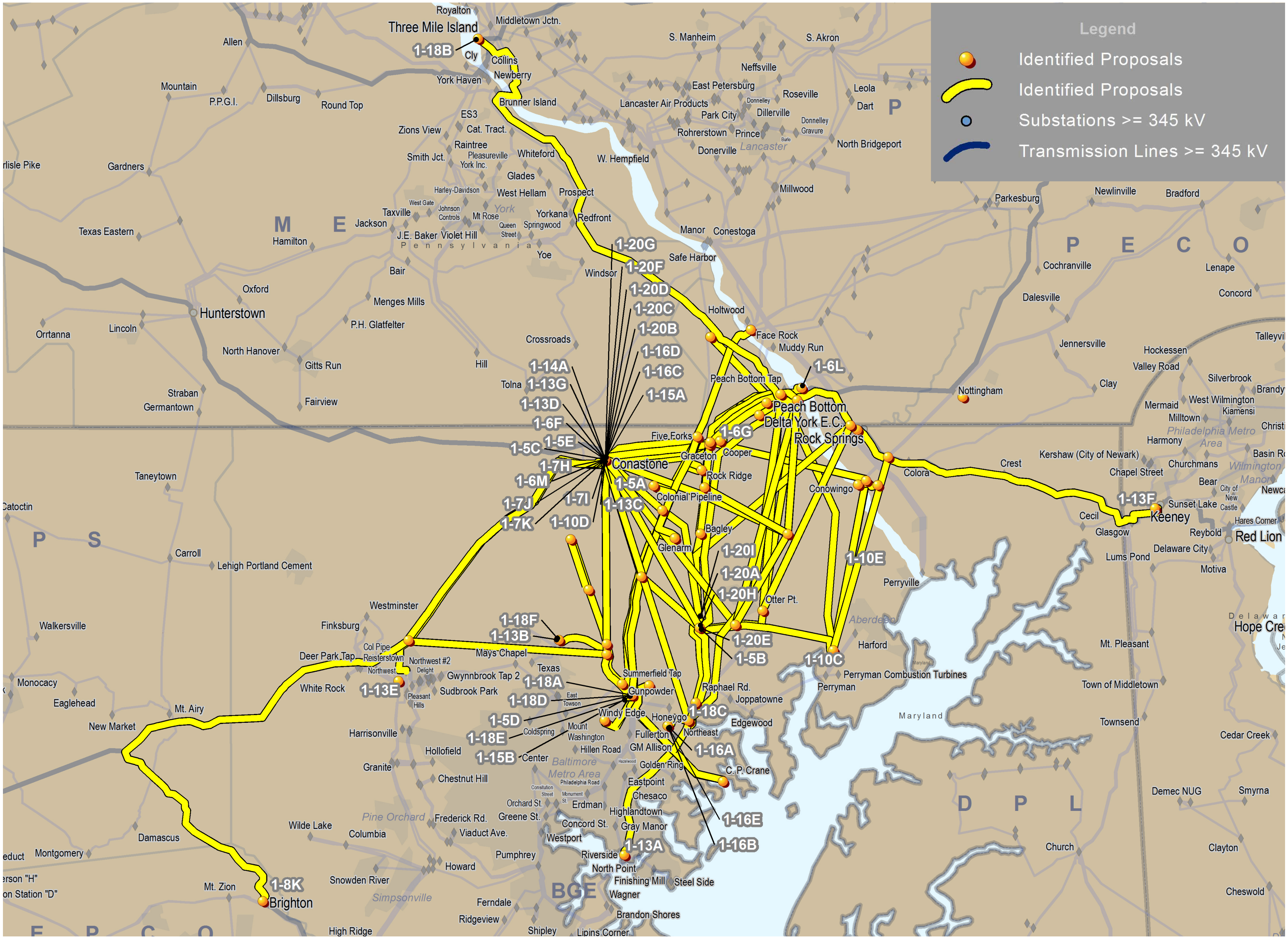


Table 5.9: BGE Group Projects – 2016/2017 Long-Term Proposal Window

Submitting Party	Project Description	Upgrade/ Greenfield	Cost ($M)	In-Service Year
BGE	Reconductor the Conastone to Graceton 230 kV lines. Upgrade substation equipment at Conastone.	Upgrade	6.0	2020
BGE	Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines.	Upgrade	14.2	2021
BGE	Reconductor the Conastone to Graceton 230 kV lines. Upgrade substation equipment at Conastone. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines.	Upgrade	20.3	2021
BGE	Reconductor the Conastone to Graceton 230 kV lines. Upgrade substation equipment at Conastone. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Upgrade substation equipment at Windy Edge substation.	Upgrade	20.4	2021
BGE	Reconductor the Conastone to Graceton 230 kV lines. Upgrade substation equipment at Conastone. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Reconductor the Raphael Road to Northeast 230 kV double circuit lines. Upgrade substation equipment at Windy Edge substation.	Upgrade	25.4	2021
BGE/PECO	Tap the Peach Bottom-Conastone 500 kV line at Graceton. Expand Graceton to include a 500/230 kV substation. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Reconductor the Raphael Road to Northeast 230 kV double circuit lines. Upgrade substation equipment at Windy Edge 115 kV substation.	Upgrade	49.2	2021
BGE/PECO	Tap the Peach Bottom-Conastone 500 kV line at Graceton. Expand Graceton to include a 500/230 kV substation. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Reconductor the Raphael Road to Northeast 230 kV double circuit lines. Reconductor Graceton-Cooper 230 kV line. Upgrade substation equipment at Cooper 230 kV and Windy Edge 115 kV substations.	Upgrade	56.0	2021
BGE/PECO	New Peach Bottom-Cooper 230 kV line with series reactor; resupply PB Tap. Reconductor the Conastone to Graceton 230 kV lines. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Reconductor the Raphael Road to Northeast 230 kV double circuit lines. Reconductor Graceton-Cooper 230 kV line. Upgrade substation equipment at Peach Bottom 230 kV, Cooper 230 kV, Conastone 230 kV and Windy Edge 115 kV substations.	Upgrade	41.7	2021
BGE/PECO	Tap the Peach Bottom-Conastone 500 kV line at Graceton. Expand Graceton to include a 500/230 kV substation. New Peach Bottom-Cooper 230 kV line with series reactor; resupply PB Tap. Reconductor the Conastone to Graceton 230 kV lines. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Reconductor the Raphael Road to Northeast 230 kV double circuit lines. Reconductor Graceton-Cooper 230 kV line. Upgrade substation equipment at Peach Bottom 230 kV, Cooper 230 kV, Conastone 230 kV and Windy Edge 115 kV substations.	Upgrade	65.5	2021
PECO	New Peach Bottom-Cooper 230 kV line with series reactor. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Reconductor the Raphael Road to Northeast 230 kV double circuit lines. Reconductor Graceton-Cooper 230 kV line. Upgrade substation equipment at Peach Bottom 230 kV, Cooper 230 kV and Windy Edge 115 kV substations.	Upgrade	35.6	2021
PECO	New Peach Bottom-Cooper 230 kV line with series reactor. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Reconductor the Raphael Road to Northeast 230 kV double circuit lines. Reconductor Graceton-Cooper 230 kV line. Upgrade substation equipment at Peach Bottom 230 kV, Cooper 230 kV and Windy Edge 115 kV substations.	Upgrade	59.8	2021
PECO	New Peach Bottom-Graceton 230 kV line with series reactor. Reconductor Graceton-Cooper 230 kV line; add reactor. Reconductor Peach Bottom-Cooper section of 220-08 line. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Reconductor the Raphael Road to Northeast 230 kV double circuit lines. Upgrade substation equipment at Peach Bottom 230 kV, Graceton 230 kV, Cooper 230 kV and Windy Edge 115 kV substations.	Upgrade	68.1	2022
PECO	Add two 500/230 kV transformers at Peach Bottom substation. New Peach Bottom-Graceton 230 kV double circuit line. Replace Graceton-Cooper 230 kV line and Peach Bottom-Cooper section of 220-08 line with underground cable. Add reactor to Graceton-Cooper 230 kV line. Add bundled conductors to the Graceton-Bagley-Raphael Road 230 kV double circuit lines. Reconductor the Raphael Road-Northeast 230 kV double circuit lines. Upgrade substation equipment at Peach Bottom 500/230 kV, Graceton 230 kV, Cooper 230 kV and Windy Edge 115 kV substations.	Upgrade	191.4	2022
NextEra	Build a new 230 kV line between existing Perryman and Conowingo substations.	Greenfield	44.4	2021
NextEra	Tap the Peach Bottom-Conastone 500 kV line at near Graceton and build a new 500/230 kV substation (Pylesville) tying into Graceton 230 kV. Build a new 230 kV switchyard (Rowland) near Conowingo and a new Perryman-Roland 230 kV line. Loop the Conowingo-Colora and Conowingo-Nottingham 230 kV lines into the new switchyard.	Greenfield	93.5	2021
NextEra	Tap the Peach Bottom-Conastone 500 kV line at near Graceton and build a new 500/230 kV substation (Pylesville) tying into Graceton 230 kV. Build a new 230 kV switchyard (Rowland) near Conowingo and a new Perryman-Roland 230 kV line. Loop the Conowingo-Colora and Conowingo-Nottingham 230 kV lines into the new switchyard. Build a new 230 kV line from Pylesville 500/230 kV to Rowland 230 kV.	Greenfield	105.7	2021

Table 5.9: BGE Group Projects – 2016/2017 Long-Term Proposal Window (Continued)

Submitting Party	Project Description	Upgrade/ Greenfield	Cost ($M)	In-Service Year
Transource	Tap the Peach Bottom-Rock Springs 500 kV line. Build a new 500/230 kV substation (Baldwin Road). Build a new Baldwin Road-Raphael Road 230 kV line. Rebuild Raphael Road-Northeast 230 kV lines, Northeast-Riverside 230 kV lines and Five Forks-Windy Edge 115 kV double circuit tower lines. Loop Crane-Windy Edge 115 kV lines into Northeast substation. Replace both 115/69 kV transformers at Face Rock.	Greenfield	457.8	2024
Transource	Build a new 230/115 kV substation (Dulaney Valley) along the Windy Edge-Texas line. Build a new Conastone-Dulaney Valley 230 kV line. Loop Windy Edge-Texas 115 kV and Summerfield-Shawan Road 115 kV lines into Dulaney Valley substation. Reconductor Dulaney Valley-Summerfield 115 kV lines and a section of Windy Edge-Hazelwood 115 kV. Replace transformers at Face Rock and upgrade transformer replacement at Furnace Run.	Greenfield	107.5	2022
Transource	Build a new 230/115 kV substation (Long Green) south of Glenarm. Build a new Conastone-Long Green 230 kV line. Loop Windy Edge-Glenarm and Windy Edge-Gunpowder 115 kV lines into Long Green substation. Rebuild/upgrade 115 kV lines and substation facilities from Windy Edge to Face Rock and Windy Edge to Gunpowder. Reconductor a section of Windy Edge-Hazelwood 115 kV. Replace transformers at Face Rock and upgrade transformer replacement at Furnace Run.	Greenfield	169.3	2022
Transource	Build a new 230/115 kV substation (Long Green) south of Glenarm. Build a new Conastone-Long Green 230 kV line and a new Long Green-Raphael Road 230 kV line. Loop Windy Edge-Glenarm and Windy Edge-Gunpowder 115 kV lines into Long Green substation. Rebuild/upgrade 115 kV lines and substation facilities from Windy Edge to Face Rock and Windy Edge to Gunpowder. Reconductor a section of Windy Edge-Hazelwood 115 kV. Replace transformers at Face Rock and upgrade transformer replacement at Furnace Run.	Greenfield	183.0	2022
Transource	Tap the Conastone-Brighton 500 kV line and build a new 500/230 kV substation (Hereford). Build a new 230/115 kV substation along the Windy Edge-Texas 115 kV lines (Dulaney Valley). Build a new 230 kV line from Hereford to Dulaney Valley. Loop Conastone-Northwest 230 kV line into Herford and rebuild from Conastone to Herford. Loop Windy Edge-Texas 115 kV and Summerfield-Shawan Road 115 kV lines into Dulaney Valley substation. Reconductor Dulaney Valley-Summerfield 115 kV lines and a section of Windy Edge-Hazelwood 115 kV. Replace transformers at Face Rock and upgrade transformer replacement at Furnace Run.	Greenfield	179.2	2022
Transource	Tap the Rock Springs-Keeney 500 kV line and build a new 500/230 kV substation (Love Run). Build a new 230 kV line from Love Run to Perryman. Rebuild Perryman-Raphael Road 230 kV lines, Raphael Road-Northeast 230 kV lines, Northeast-Riverside 230 kV lines and Five Forks-Windy Edge 115 kV lines. Loop the Crane-Windy Edge 115 kV lines into Northeast substation. Replace transformers at Face Rock. Substation work at Rock Springs 500 kV station.	Greenfield	483.2	2024
Transource	Reconductor Conastone-Graceton 230 kV lines. Reconductor Graceton-Bagley and Bagley-Raphael Road 230 kV lines. Rebuild Raphael Road-Northeast 230 kV lines and Five Forks-Windy Edge 115 kV lines. Replace transformers at Face Rock and upgrade transformer replacement at Furnace Run.	Upgrade	192.1	2022
ATC	Build a new Furnace Run-Perryman 230 kV line. Add series reactors to both Conastone-Graceton 230 kV lines. Rebuild the Glenarm to Windy Edge 115 kV lines.	Greenfield	114.8	2023
ATXI East/PPL	Build a new 230/115 kV Substation (Baldwin) north of Glenarm. Build a new Conastone-Baldwin 230 kV double circuit line and a new Baldwin-Raphael Road double circuit 230 kV line. Reconductor the Raphael Road to Northeast 230 kV lines. Loop the Glenarm-Colonial Pipe 115 kV lines into Baldwin. Rebuild the Baldwin to Windy Edge 115 kV lines.	Greenfield	138.5	2022
ATXI East/PPL	Build a new 230/115 kV Substation (Baldwin) north of Glenarm. Build a new Peach Bottom-Otter Point 230 kV double circuit line and a new Raphael Road-Baldwin 230 kV double circuit line. Loop the Glenarm-Colonial Pipe 115 kV lines into Baldwin. Rebuild the Baldwin to Windy Edge 115 kV lines. Reconductor the Otter Point to Raphael Road 230 kV lines and the Raphael Road to Northeast 230 kV lines.	Greenfield	178.3	2022
PSE&G	Build a new Peach Bottom-Otter Point 230 kV line. Reconductor/Rebuild Raphael Road-Northeast 230 kV lines. Reconductor/Rebuild Northeast to General Motors 115 kV lines.	Greenfield	70.5	2021
PSE&G	Build a new Peach Bottom-Raphael Road 230 kV line. Reconductor/Rebuild Raphael Road-Northeast 230 kV lines. Reconductor/Rebuild Northeast to General Motors 115 kV lines.	Greenfield	92.2	2021
PSE&G	Build a new Conastone-Raphael Road 230 kV line. Reconductor/Rebuild Raphael Road-Northeast 230 kV lines. Reconductor/Rebuild Northeast to General Motors 115 kV lines.	Greenfield	87.2	2021
PSE&G	Build a new Conastone-Northeast 230 kV line. Reconductor/Rebuild Northeast to General Motors 115 kV lines.	Greenfield	105.1	2021
PSE&G	Build a new Peach Bottom-Northeast 230 kV line. Reconductor/Rebuild Northeast to General Motors 115 kV lines.	Greenfield	109.3	2021
Northeast Transmission Development	Tap the Peach Bottom-Delta Power Plant (York) 500 kV line and build a new 500/230 kV substation (Robinson Run). Build a new Robinson Run-Graceton 230 kV double circuit line. Upgrade the Graceton-Bagley-Raphael Road double circuit 230 kV lines. Rebuild the Raphael Road-Northeast 230 kV double circuit lines. Upgrade the Rock Ridge to Windy Edge 115 kV lines. Tap the Raphael Road-Northeast 230 kV lines and build a new 230/115 kV substation (Pumpkin Run). Loop in the Crane-Windy Edge 115 kV lines.	Greenfield	126.2	2021

Table 5.9: BGE Group Projects – 2016/2017 Long-Term Proposal Window (Continued)

Submitting Party	Project Description	Upgrade/ Greenfield	Cost ($M)	In-Service Year
Northeast Transmission Development	Tap the Peach Bottom-Three Mile Island 500 kV line and build a new 500/230 kV substation (Bookers Run). Build a new Bookers Run-Graceton 230 kV double circuit line. Upgrade the Graceton-Bagley-Raphael Road double circuit 230 kV lines. Rebuild the Raphael Road-Northeast 230 kV double circuit lines. Rebuild Five Forks-Rock Ridge 115 kV lines. Upgrade the Rock Ridge to Windy Edge 115 kV lines.	Greenfield	132.8	2021
Northeast Transmission Development	Tap the Peach Bottom-Delta Power Plant (York) 500 kV line and build a new 500/230 kV substation (Robinson Run). Build a new Robinson Run-Otter Point 230 kV double circuit line. Rebuild the Raphael Road-Northeast 230 kV double circuit lines.	Greenfield	149.9	2021
Northeast Transmission Development	Tap the Peach Bottom-Rock Springs 500 kV line and build a new 500/230 kV substation (Slate). Build a new Slate-Otter Point 230 kV double circuit line. Rebuild the Raphael Road-Northeast 230 kV double circuit lines. Tap the Raphael Road-Northeast 230 kV lines and build a new 230/115 kV substation (Pumpkin Run). Loop in the Crane-Windy Edge 115 kV lines.	Greenfield	166.0	2021
Northeast Transmission Development	Tap the Peach Bottom-Rock Springs 500 kV line and build a new 500/230 kV substation (Slate). Build a new Slate-Otter Point 230 kV double circuit line. Rebuild the Raphael Road-Northeast 230 kV double circuit lines. Upgrade the Rock Ridge to Windy Edge 115 kV lines.	Greenfield	152.9	2021
Northeast Transmission Development	Build a new 230/115 kV substation (Fitzhugh Run). Build a new Conastone-Fitzhugh Run 230 kV double circuit line. Loop Shawan Road-Summerfield 115 kV lines and Windy Edge-Texas 115 kV lines into Fitzhugh Run substation. Upgrade the Graceton-Bagley-Raphael Road 230 kV double circuit line.	Greenfield	95.3	2021
ITC	Tap the Raphael Road-Otter Point 230 kV line and build a new 230 kV switchyard (Old Post). Build a new Peach Bottom-Old Post 230 kV line.	Greenfield	73.6	2021
ITC	Build a new Conastone-Raphael Road 230 kV line.	Greenfield	63.0	2021
ITC	Build a new Conastone-Northeast 230 kV line.	Greenfield	135.8	2021
ITC	Tap the Raphael Road-Otter Point 230 kV line and build a new 230 kV switchyard (Old Post). Build a new Conastone-Old Post 230 kV line.	Greenfield	75.9	2021
ITC	Tap the Graceton-Bagley 230 kV line and build a new 230 kV switchyard (Fallston Road). Tap the Raphael Road-Otter Point 230 kV line and build a new 230 kV switchyard (Old Post). Build a new 230 kV switchyard (Pyle Road). Build a new Peach Bottom-Pyle Road 230 kV line, a new Pyle Road-Fallston Road 230 kV line and a new Pyle Road-Old Post 230 kV line.	Greenfield	132.2	2021
ITC	Tap the Graceton-Bagley 230 kV line and build a new 230 kV switchyard (Fallston Road). Tap the Raphael Road-Otter Point 230 kV line and build a new 230 kV switchyard (Old Post). Build a new 230 kV switchyard (Pyle Road). Build a new Conastone-Pyle Road 230 kV line, a new Pyle Road-Fallston Road 230 kV line and a new Pyle Road-Old Post 230 kV line.	Greenfield	126.0	2021
ITC	Build a new Peach Bottom-Northeast 230 kV line.	Greenfield	151.5	2021
ITC	Tap the Raphael Road-Otter Point 230 kV line and build a new 230 kV switchyard (Old Post). Build a new Peach Bottom-Old Post 230 kV line. Install a transmission battery energy storage system at the Old Post 230 kV switchyard.	Greenfield	107.5	2021
ITC	Tap the Graceton-Bagley 230 kV line and build a new 230 kV switchyard (Fallston Road). Tap the Raphael Road-Otter Point 230 kV line and build a new 230 kV switchyard (Old Post). Build a new 230 kV switchyard (Pyle Road). Build a new Peach Bottom-Pyle Road 230 kV line, a new Pyle Road-Fallston Road 230 kV line and a new Pyle Road-Old Post 230 kV line. Install a transmission battery energy storage system at the Fallston Road 230 kV switchyard.	Greenfield	165.7	2021

5.2.5 — Addendum 2016/2017 Long-term Proposal Window No. 1A

The 2020/2021 RPM Base Residual Auction conducted in May 2017 identified that capacity imports into the DEO&K LDA were limited by a Tanners Creek-Dearborn 345 kV line constraint. As a result, PJM opened an additional proposal window, Addendum Window No. 1A from September 14, 2017, through September 28, 2017, to solicit proposals to mitigate the constraint. Three proposals were submitted with cost estimates ranging from $0.6 to $12.7 million. Two were transmission owner upgrades and one was a greenfield project from a non-incumbent party.

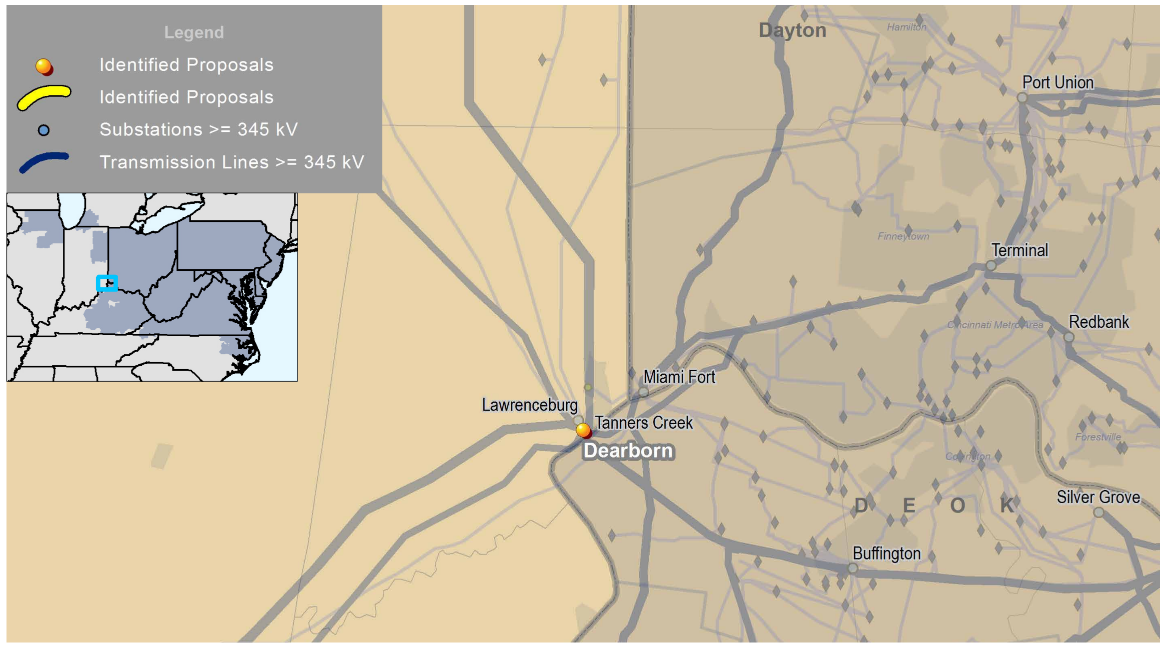
PJM evaluated the proposals to determine the impact of each on the DEO&K LDA Capacity Emergency Transfer Limit (CETL). Subsequently, PJM evaluated the three proposals to determine which produced a benefit-cost ration greater than 1.25.

PJM calculated capacity benefits associated with the proposed projects. PJM's annual capacity benefits calculation for lower-voltage facilities is weighted 100 percent to zones with a decrease in net load capacity payments as a result of the proposed project. The change in net load capacity payments is the change in gross capacity payments offset by the change in capacity transfer rights. PJM simulated the RPM process for multiple study years with the updated Capacity Emergency Transfer Limit (CETL) values and measured each project's capacity benefits over a 15-year period. PJM determined that by increasing the capability of the LDA's limiting element, the DEO&K zone and other LDAs may be able to satisfy capacity requirements at a lower overall cost.

Table 5.10: Recommended Tanners Creek Project

PJM Baseline ID	Project Description	TO Zone	Constraint Benefits	Project Cost ($M)	In-Service Year	B/C Ratio
b2976	Upgrade terminal equipment at Tanners Creek 345 kV station. Upgrade 345 kV Bus and Risers at Tanners Creek for the Dearborn circuit.	AEP	Tanners Creek-Dearborn 345 kV line – RPM	$0.60	2021	151.61

Map 5.7: Tanners Creek and Dearborn 345 kV Substations



The total market efficiency benefit of a project is the sum of the energy market benefits and the capacity market benefits. The energy market benefits were derived from production cost simulations and the capacity benefits were derived from capacity market simulations.

Table 5.10 shows the project that provides the highest total benefits and satisfies the benefit-cost ratio of 1.25. This project was recommended to the PJM Board and was designated to the incumbent transmission owner because it constitutes an upgrade to existing equipment. The project will save customers an estimated $8.2 million annually. The map in **Map 5.7** shows the location of the Tanners Creek and Dearborn Substations.

5.2.6 — 2014-2015 RTEP Window Reevaluation

PJM's 2017 long-term analysis included a reevaluation of 13 approved market efficiency projects from 2014/2015 long-term window. Reevaluation ensures that previously approved RTEP projects continue to meet the market efficiency criteria.

Each project was included in the 2017 mid-cycle update discussed earlier in **Section 5.2.3.** PJM recalculated economic value by production cost simulations in which each project was removed from the model to determine the benefit that retaining it otherwise still provided. The benefit-to-cost ratio was derived by comparing the base case simulation to the individual cases that did not include the project, while adhering to the methods described in **Section 5.0**. **Table 5.11** and **Map 5.8** show the re-evaluation results. Each of the projects either maintained a benefit-to-cost ratio greater than 1.25 or was already in-service.

Map 5.8: 2017 Reevaluation Results – 2014/2015 Long-Term Proposal Window

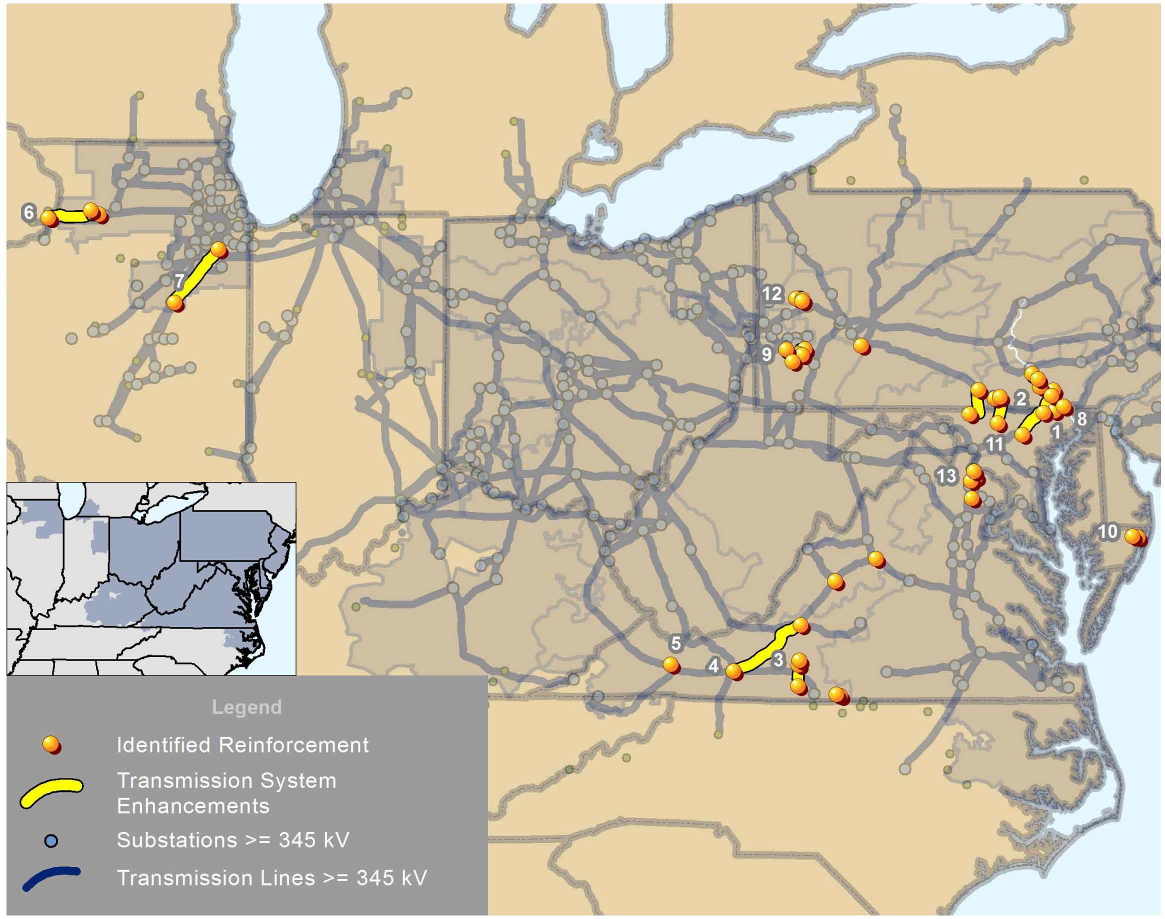


Table 5.11: 2017 Reevaluation Results – 2014/2015 Long-Term Proposal Window

Map ID	Baseline Project ID	Project Description	Type	Area	Constraint	*Cost ($M)	In-Service Date	B/C 2014/15 Window	BC Reevaluation 2017
1	b2690	Reconductor Graceton-Safe Harbor 230 kV line	Upgrade	PPL/BGE	Safe Harbor-Graceton 230 kV line	1.1	2019	14.4	1.7
2	b2691	Reconductor three spans limiting Bruner Island-Yorkana 230 kV line	Upgrade	Met-Ed/PPL	Brunner Island-Yorkana 230 kV line	3.1	2019	22.2	2.8
3	b2697.1-2	Upgrade Fieldale-Thornton-Franklin 138 kV line	Upgrade	AEP	Fieldale-Thornton 138 kV line	0.8	2019	101.2	9.5
4	b2698	Replace relays at Cloverdale and Jackson's Ferry substations.	Upgrade	AEP	Jacksons Ferry-Cloverdale 765 kV line	0.5	2019	62.0	46.2
5	b2743.1-8, b2752.1-7	- Tap Conemaugh-Hunterstown 500 kV line. Construct new Rice 500 kV & 230 kV substations. Install two 500/230 kV transformers at Rice. - Tie in new Furnace Run substation to Peach Bottom-TMI 500 kV line	Greenfield	APS/BGE	AP-South Interface	340.6	2020	2.5	1.3
6	b2692.1-2	- Replace station equipment at Nelson and Quad Cities 345 kV substations. - Upgrade conductors on Cordova-Nelson and Quad Cities-Nelson 345 kV lines	Upgrade	ComEd	Cordova-Nelson 345 kV line	24.6	2019	1.9	1.6
7	b2728	Mitigate sag limitations on Loretto-Wilton Center 345 kV line and replace station conductor at Wilton Center.	Upgrade	ComEd	Loretto-Wilton 345 kV (RPM)	11.5	2019	64.5	In-service
8	b2694	Improvements to Peach Bottom 500/230 kV transformer to increase ratings.	Upgrade	PECO	Peach Bottom 500 kV area congestion	9.7	2019	3.0	5.7
9	b2689.1-2	- Reconductor Woodville-Peters 138 kV line. - Reconfigure West Mifflin-USS Clairton 138 kV line to create Dravosburg-USS Clairton and West Mifflin-Wilson 138 kV lines.	Upgrade	DUQ	Dravosburg-West Mifflin 138 kV line	11.2	2018	2.0	2.6
10	b2695	Rebuild Worcester-Ocean Pine 69 kV line.	Upgrade	DPL	Worcester-Ocean Pines 69 kV line	2.4	2019	65.3	10.1
11	b2688.1-3	- Upgrade Lincoln substation. Replace Germantown138/115 kV transformer and related equipment. - Replace terminal equipment at Carroll substation.	Upgrade	APS	Taneytown-Carroll 138 kV line	5.2	2019	90.1	8.5
12	b2696	Upgrade equipment at Butler, Shanor Manor and Krendale 138 kV substations.	Upgrade	APS/ATSI	Krendal-Shanor Manor 138 kV line	0.6	2019	123.4	78.9
13	b2729	Optimal capacitor configurations at Brambleton, Ashburn, Shelhorn and Liberty 230 kV substations.	Upgrade	Dominion	AP-South Interface	9.0	2019	15.4	2.2

*Note: Project cost consistent with original project cost estimate

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

5.3: PJM-MISO Targeted Market Efficiency Projects

5.3.1 — Background

In mid-2015, PJM and MISO began discussions of a new type of project aimed at quickly addressing market-to-market (M2M) congestion on reciprocally coordinated flowgates. Based on past joint-study work experience, PJM and MISO developed the concept of a Targeted Market Efficiency Project (TMEP) to address this congestion. The TMEP process is intended to complement, not replace, the longer-term Interregional Market Efficiency Project (IMEP) process.

As discussed on **Section 7.1,** in 2016, working with the Interregional Planning Stakeholder Advisory Committee, PJM and MISO developed criteria for TMEPs, which focused on developing low cost, short-lead time, high-impact projects. FERC finalized and approved the TMEP project type in 2017. The FERC-accepted process provides an innovative approach to interregional coordination that is attracting notice from other entities interested in enhancing regional and interregional market efficiency planning processes. The interregional TMEP process itself encompasses a number of key features:

- **All significant congestion considered:** TMEPs are considered for all significant historical M2M congestion, except that driven by unusual outage patterns or that are expected to be resolved by planned transmission upgrades.
- **Single interregional review and analysis process:** The study includes a single, joint interregional review and analysis process, which culminates in recommendations to both PJM and MISO Boards.
- **Capital cost limits:** Project capital costs are limited to no more than $20 million. Larger projects are considered under the more expansive IMEP process described in the JOA as discussed in **Section 7.1.**
- **Project completion expectations:** Designated entities are expected to complete projects by the summer peak season three years from the study year (typically 2.5 years from Board approval).
- **TMEPs can only address M2M flowgates**
- **Congestion savings expectations:** The four-year market congestion savings must be equal to or greater than the estimated project capital cost.
- **Future congestion savings estimate:** Future annual market congestion savings are estimated based on an average of two years of historical day-ahead market congestion and balancing market congestion.

As interregional projects, PJM members and MISO members share TMEP costs. Allocation is based on historical congestion costs – day ahead plus balancing – adjusted for M2M settlements over the same historical period used to determine project benefits. The regional cost allocation within PJM is based on the historical flowgate-specific congestion impact on each affected transmission owner zone.

NOTE:

Reciprocal Coordinated Flowgates are those subject to operational coordination by PJM and MISO for the purposes of congestion management, as further defined in the PJM-MISO Joint Operating Agreement: http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf

A **Coordinated System Plan (CSP)** contains the results of coordinated PJM-MISO studies required to assure the reliable, efficient and effective operation of the transmission system. The CSP also includes the study results for interconnection requests and Long-Term Firm Transmission Service requests. Further description of CSP development can be found in the PJM-MISO Joint Operating Agreement, per the link above.

5.3.2 — Analysis, Recommendations and Approval

PJM and MISO examined 50 M2M flowgates with significant historical congestion. The goal was to determine which constrained flowgates could be candidates for TMEP consideration. If so, that meant as constraints they were not the result of facility outages or would be mitigated by existing PJM RTEP or MISO MTEP projects. PJM and MISO worked with facility owners to identify the limiting equipment on congested elements and determine the transmission enhancements required to increase ratings. PJM and MISO then conducted market efficiency and power flow analyses to determine the ability of identified enhancements to eliminate congestion.

Figure 5.9 summarizes results from evaluating the 50 flowgates. More than half of the flowgates had projects already planned in RTEP or MTEP that were expected to relieve observed congestion. The congestion on three flowgates was caused completely by specific transmission facility outages. Another three did not warrant TMEP consideration given the timeframe required to be eligible as such. Seven had upgrade proposals that failed to clear the benefit/cost criteria required for TMEP. As a result of this evaluation, PJM and MISO identified five projects that addressed 10 of the 50 historically binding M2M flowgates. The total capital cost for the five projects is approximately $20 million, with an estimated congestion savings benefit of $100 million over the first four years. Overall, the cost of the projects will be allocated 69 percent ($13.75 million) to PJM and 31 percent ($6.25 million) to MISO under established JOA provisions.

Figure 5.9: PJM/MISO Evaluation: TMEP Ability to Address Identified Flowgates

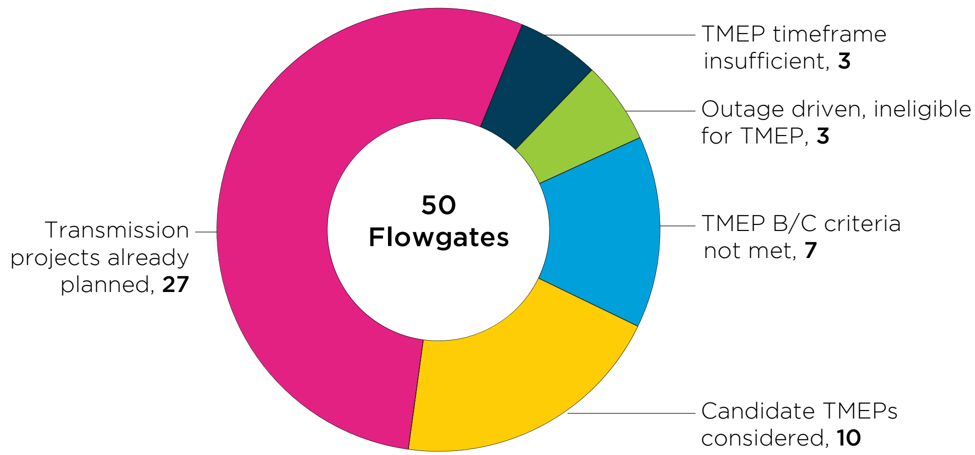


Table 5.12: PJM/MISO Approved Targeted Market Efficiency Projects

Project ID	Facility	TMEP Description	Transmission Owner(s)	Projected In-Service Date	Total Cost ($M)	TMEP Benefit ($M)	Benefit Allocation	
							PJM	MISO
b2971	Burnham-Munster 345 kV	Reconfigure Munster 345 kV NIPSCO substation as a ring bus; Replace terminal equipment	ComEd-NIPSCO	6/1/2020	6.7	32.0	88%	12%
b2972	Lallendorf-Monroe 345 kV	Reconductor Lallendorf-Monroe 345 kV Muamee River crossing (ATSI-ITC tie line)	ATSI-ITC	11/1/2019	1.0	17.0	89%	11%
b2973	Michigan City-Bosserman 138 kV	Reconductor the NIPSCO owned section of the Michigan City-Bosserman 138 kV line (NIPSCO-AEP tie line)	NIPSCO	12/1/2019	6.0	30.0	90%	10%
b2974	Reynolds-Magnetation 138 kV	Replace terminal equipment at the Reynolds 138 kV substation	NIPSCO	6/1/2019	0.2	15.0	41%	59%
b2975	Roxana-Praxair 138 kV	Reconductor the Roxana-Praxair 138 kV line	NIPSCO	6/1/2020	6.1	6.5	24%	76%
				Total	**20.0**	**100.0**	**69%**	**31%**

PJM and MISO each brought this portfolio of five TMEPs to their Boards for approval, and the PJM and MISO boards each independently approved all five projects in December 2017.

Table 5.12 summarizes the five projects, along with cost and projected benefit information. **Map 5.9** shows the location of the five projects.

5.3.3 — Next Steps

PJM and MISO expect all five approved projects to be in service no later than June 1, 2020. PJM and MISO will track construction progress of these projects in the same manner as each does for its own regional projects.

PJM and MISO are committed to review historical M2M congestion along the seam annually. Based on the results of this review, PJM and MISO will make a determination about the need for a full TMEP study.

NOTE:

AEP: American Electric Power (PJM TO)

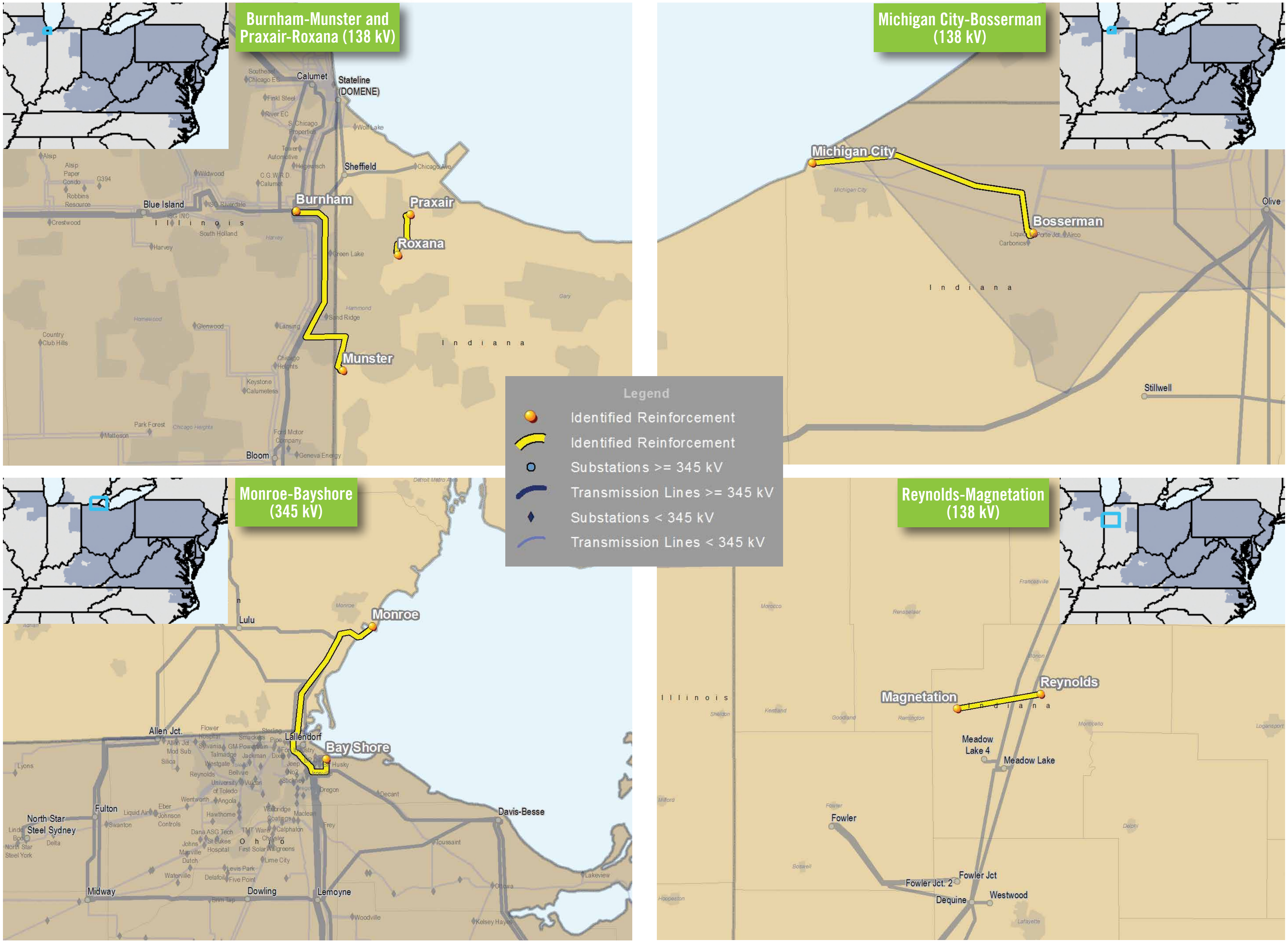
ATSI: American Transmission System, Inc (PJM TO)

ComEd: Commonwealth Edison (PJM TO)

ITC: ITC Transmission Company (MISO)

NIPSCO: Northern Indiana Public Service Company (MISO)

Map 5.9: PJM/MISO Approved Targeted Market Efficiency Projects



Section 6: Stage 1A ARR 10-Year Feasibility

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

6.0: 2017-2018 Analysis

6.0.1 — RTEP Context

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 10-year period.

Scope

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

6.0.2 — Results: 2017/2018 Stage 1A ARR 10-Year Analysis

During 2017, PJM market simulation staff completed a 10-year simultaneous feasibility analysis for 2017/2018 Stage 1A ARR selections. The power flow case used in the 10-year feasibility analysis is the same one used in the 2017/2018 annual ARR allocation, but without any modeled maintenance transmission outages. The results of the 10-year analysis identified violations on both PJM internal and interregional market-to-market (M2M) facilities. PJM determined that the development of transmission solutions would be addressed in one of the following:

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

The list of infeasible facilities along with expected projects that will address the infeasibilities are provided in **Table 6.1**.

Internal PJM Facilities

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

M2M Facilities

The analysis shows violations on multiple M2M transmission facilities, driven by one of the following: (1) impacts from internal PJM generation or (2) pseudo-tie arrangements. With regard to the second factor, PJM observed Stage 1A 10-year facility violations as a result of MISO pseudo-tie M2M flowgates introduced to facilitate MISO-PJM pseudo-tie transfers.

For M2M facilities that are non-pseudo-tie flowgates, transmission enhancements either have been identified or will be considered in the future for these violations. Since a plan is established to address these violations, no further immediate action is necessary. For M2M facilities identified as pseudo-tie flowgates, PJM is actively pursuing a solution to enhance the existing MISO-PJM M2M firm flow entitlement construct. PJM recently concluded a stakeholder effort to address pseudo-tie challenges related to operations, markets and planning. PJM anticipates the combination of these efforts will address these facility violations.

Table 6.1: 2017/2018 Stage 1A ARR 10-Year Infeasible Facilities

Facility Name	Facility Type	Pseudo Tie Flowgate	Proposed Solution	Expected In-Service Date
Emilie-Falls 138 kV line	Internal	No	PJM RTEP Baseline project b2774: Reconductor Emilie-Falls 138 kV	2020
Clifty Creek-Trimble County 345 kV line	Flowgate	No	Add series reactor on Clifty Creek-Trimble County 345 kV	Not finalized
Batesville-Hubble 138 kV line for the loss of Tanners Creek-Miami Fort 345 kV line	Flowgate	No	Future PJM-MISO interregional TMEP analysis or long-term proposal window consideration. *	-
Cayuga 345/230 transformer No. 9 for the loss of Cayuga 345/230 kV Transformer No. 10	Flowgate	No	Future PJM-MISO interregional TMEP analysis or long-term proposal window consideration. *	-
Roxana-Praxair 138 kV line for the loss of Gary Avenue-Sheffield 345 kV line	Flowgate	No	Existing TMEP *	2020
Monroe-Lallendorf 345 kV for the loss of Lulu 345 kV Substation	Flowgate	No	Existing TMEP *	2020
Hennepin S-Hennepin tap 138 kV line for the loss of Princeton tap 138 kV substation	Flowgate	No	MISO Transmission Expansion Plan, No. 7820	2017
Bunsonville transformer No. 1 for the loss of Sullivan-Casey 345 kV line	Flowgate	Yes	Pending outcome of MISO-PJM M2M firm flow entitlement construct stakeholder discussions.	-
Vermilion-N. Champaign 138n kV line for the loss of Casey-Sullivan 345 kV line	Flowgate	Yes	Pending outcome of MISO-PJM M2M firm flow entitlement construct stakeholder discussions.	-
Cayuga transformer No. 9 for the loss of Cayuga-Nucor 345 kV line	Flowgate	Yes	Pending outcome of MISO-PJM M2M firm flow entitlement construct stakeholder discussions.	-

*Note: TMEP = Targeted Market Efficiency Project

Section 7: Interregional Coordination

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

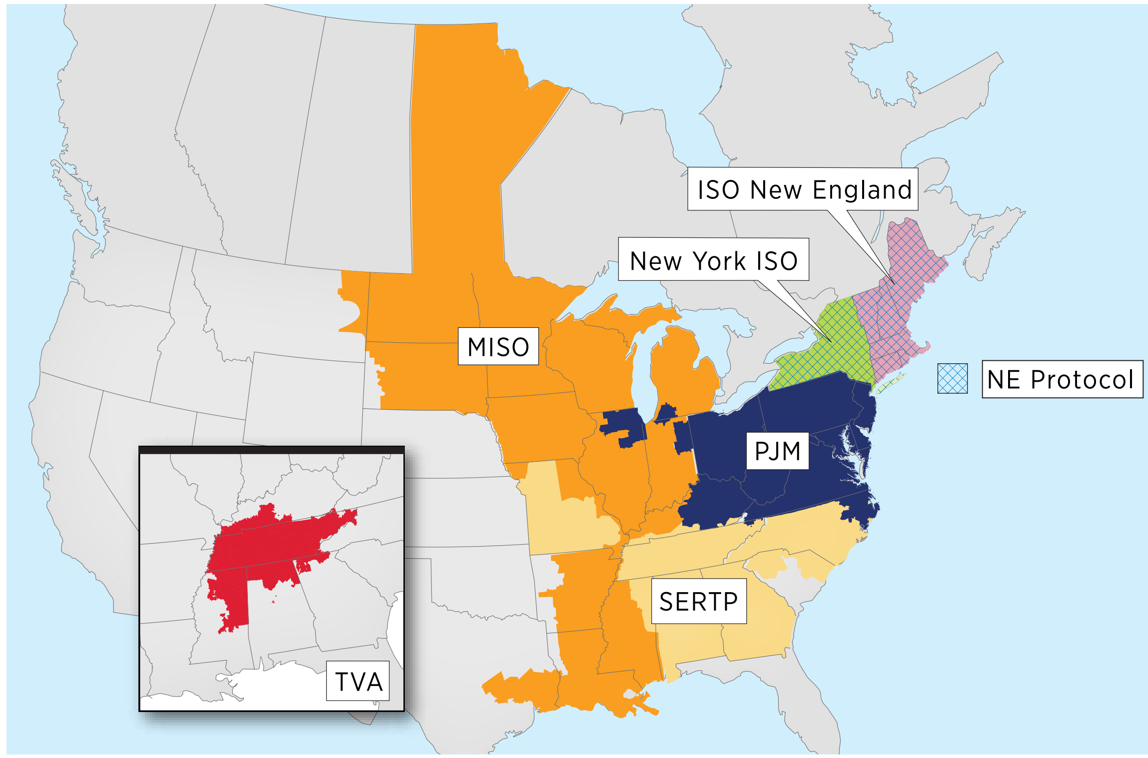
7.0: Interregional Scope

7.0.1 — Adjoining Systems

PJM continues to improve 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 state and federal levels in favor of increased interregional coordination. The nature of these activities includes structured, tariff-driven analyses as well as targeted issues that may arise each year. PJM currently has interregional planning arrangements with New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), Mid-Continent Independent System Operator (MISO), Tennessee Valley Authority (TVA), and Southeastern Regional Transmission Planning (SERTP), shown on **Map 7.1**.

FERC Order No. 1000 interregional planning processes 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. In addition, PJM actively participates in the Eastern Interconnection Planning Collaborative.

Map 7.1: PJM Interregional Planning



NOTE:

OVEC integration with PJM is expected by June 1, 2018. PJM regional planning activities associated with the integration can be found in **Section 8.**

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

- Interregional impacts of regional transmission plans
- Impacts of queued generator interconnection requests and deactivation requests for units impacting an interregional interface
- Opportunities for improved market efficiencies at interregional interfaces
- Solutions to reliability and congestion constraints on seams
- Interregional planning impacts of national and state public policy objectives
- Enhanced power flow modeling accuracy within individual RTO planning processes due to periodic exchange of power system modeling data and information

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

7.0.2 — MISO
Article IX of the JOA between PJM and MISO codifies coordinated regional transmission expansion planning processes between PJM and MISO, shown on **Map 7.1**. The 2017 planning efforts under this agreement continued to closely coordinate interconnection and deactivation requests as provided in the JOA. Interconnection-driven Network transmission enhancements are summarized in **Section 11**. Deactivation-driven Baseline transmission enhancements are summarized in **Section 4.0**.

2017 marked a historic milestone in the evolution of interregional planning. PJM and MISO Boards approved the first Targeted Market Efficiency Projects (TMEPs) developed under the PJM-MISO JOA as discussed in **Section 7.1**. Joint analysis also continued in 2017 on longer-term Interregional Market Efficiency Project (IMEP) proposals as also discussed in **Section 7.1**.

7.0.3 — NYISO and ISO-NE
PJM activities with the NYISO and ISO-NE, shown earlier on **Map 7.1**, focused in 2017 on compliance with provisions of FERC Order No. 1000 in accordance with the northeast ISO/RTO planning coordination protocol. Work in 2017 continued to ensure interregional coordination by enhancing reliability and economic system performance. Stakeholder input continues to be coordinated through the activities of the Interregional Planning Stakeholder Advisory Committee (IPSAC).

During 2017, PJM continued interconnection and transmission service coordination, data exchange and economic data updates. PJM/NYISO/NE-ISO IPSAC review of regional analyses and transmission plans completed in 2017 did not identify any opportunities to pursue interregional transmission projects. Work in 2018 will include review of the anticipated update to the biennial Northeast Coordinated System Plan (NCSP). The NCSP for the work completed in 2016 can be found online: http://www.pjm.com/committees-and-groups/stakeholder-meetings/ipsac-ny-ne.aspx.

7.0.4 — Adjoining Systems South of PJM
Interregional planning activities with entities south of PJM are conducted mainly under the auspices of the Southeastern Regional Transmission Planning (SERTP) activities and SERC activities.

Southeastern Regional Transmission Planning
PJM and the SERTP, shown earlier on **Map 7.1**, implemented the FERC Order No. 1000 interregional processes for data exchange and interregional coordination during 2017. SERTP membership includes several entities under FERC jurisdiction and voluntary participation among six non-jurisdictional entities. The jurisdictional entities include Southern Company, Duke Energy (including Duke Energy Carolinas and Duke Energy Progress), LGE/KU, and OVEC. Duke Energy, LGE/KU and OVEC are directly connected to PJM. Of the non-jurisdictional entities, only the TVA is directly connected to PJM. The remaining five SERTP participants are planning areas south and west of Duke Energy and TVA. SERTP interregional planning provisions are distinct in that the provisions for coordination are included in each jurisdictional entity's Open

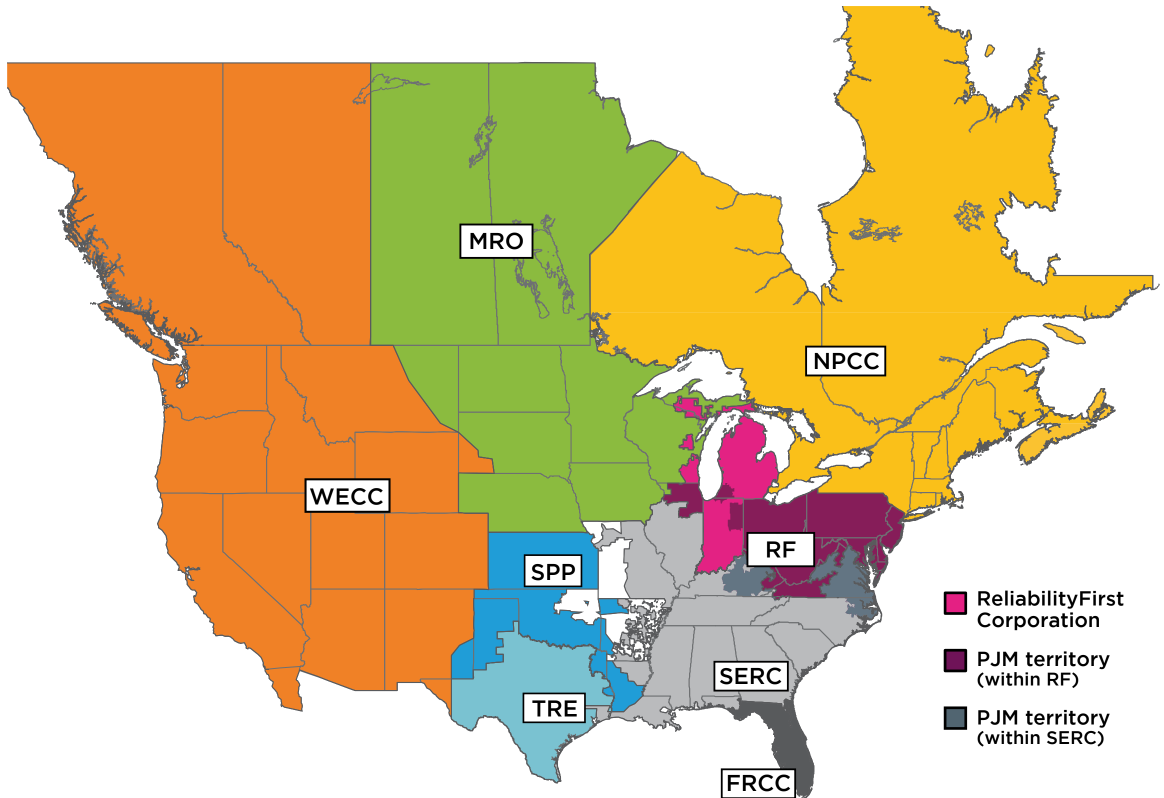
Access Transmission Tariff. The PJM provisions are codified in Schedule 6A of the PJM Operating Agreement. This contrasts with the joint agreements that govern coordinated interregional planning along PJM's northern and western interfaces.

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

In April 2016, PJM and its SERTP counterparts reviewed results from individual regional planning processes. This detailed plan review occurs every two years and is scheduled next for 2018. PJM also reviews and coordinates interconnection requests that may have SERTP cross-border impacts on an ongoing basis.

In 2017 PJM provided Duke Energy updated information from the most recent PJM Base Residual Auction. This information included notification of SERTP units that cleared PJM auctions. Doing so allows Duke to assess impacts to its own system in order to identify any planning issues.

Map 7.2: NERC Areas



SERC Activities

PJM continues to support its members that are located within SERC – shown on **Map 7.2**. That support includes active participation in the Regional Studies Steering Committee, Long-Term Studies Group, Dynamic Studies Group, Short Circuit Database Working Group, and Near-Term Studies Group. PJM actively contributed to SERC committee and working group discussions to coordinate 2017 model building and study activities. SERC activities continue to grow as its practices evolve to recognize and more accurately model the impacts of market areas adjoining it. During 2017, PJM continued to implement coordinated process improvements to

NOTE:

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

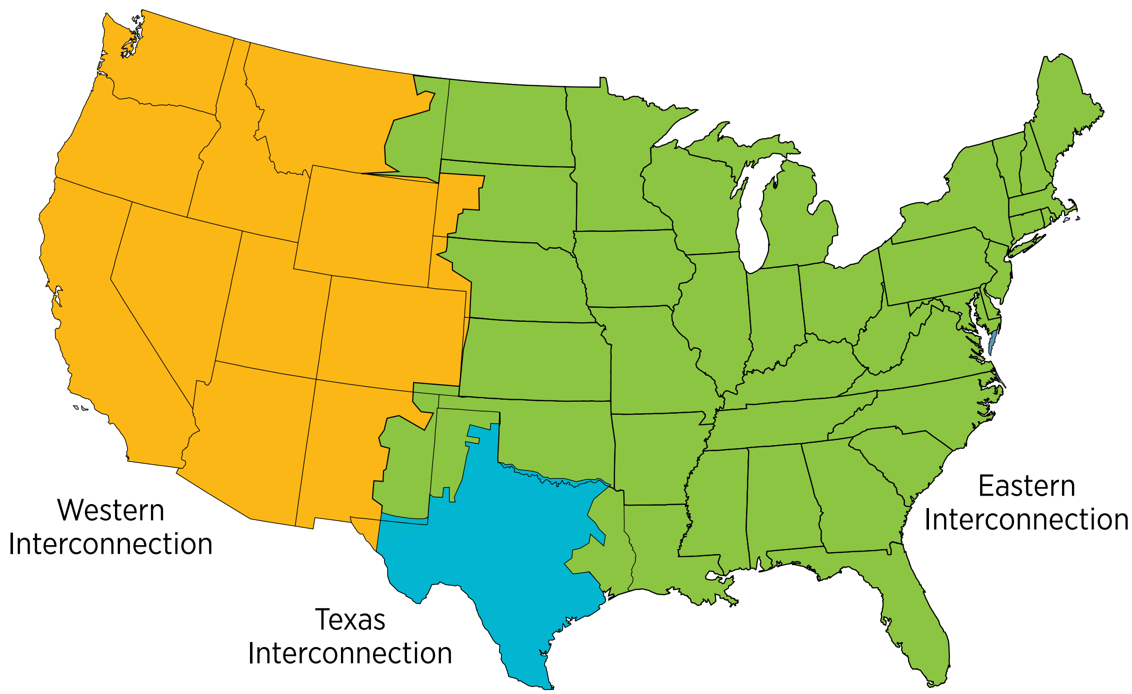
improve eastern interconnection firm power flow transaction modeling. Additionally in 2017, PJM supported the SERC Long Term Study Group's "RTO Sensitivity" which informed members on the impact of modeling RTOs as single dispatch pools rather than as historical Balancing Authority areas.

7.0.5 — Eastern Interconnection Planning Collaborative

The Eastern Interconnection Planning Collaborative (EIPC) is an interconnection-wide transmission planning coordination effort among NERC Planning Authorities in the Eastern Interconnection, shown on **Map 7.3**. The EIPC consists of 20 Planning Coordinators comprising approximately 95 percent of the eastern interconnection load. EIPC coordinates analysis of regional transmission plans to ensure their coordination and provides resources to conduct analysis of emerging issues impacting the transmission grid. EIPC work builds on, rather than replaces, existing regional and interregional transmission planning processes already in place by participating planning authorities. EIPC's efforts are intended to inform regional planning processes.

The EIPC also coordinates this work with federal and state organizations. Formed in 2008, the EIPC was initially funded by a $16 million American Recovery and Reinvestment Act grant administered by the U.S. Department of Energy (DOE), through 2013. Since then, the EIPC's work has been self-funded by the member organizations. EIPC coordinates closely with the states in the eastern interconnection that now participate in the National Council on Electricity Policy (NCEP). The group is funded by the DOE and managed by the National Association of Regulatory Utility Commissioners (NARUC). NCEP convenes regulators, state legislators, energy and air officials, consumer advocates and governors' office representatives to serve as an important forum for discussions on electricity policy.

Map 7.3: U.S. Interconnections



2017 EIPC Activities

During 2017, EIPC embarked on a new initiative to consolidate the roll-up of planning coordinator power flows – typically a Year 1 activity of EIPC's two-year planning cycle – with industry-wide NERC MOD-032-1 compliance efforts. The goal is to eliminate redundancy and timing issues created by what are essentially two parallel power flow development processes. (PJM's regional efforts with respect to NERC MOD-032-1 compliance are discussed in **Book 1, Section 3.2**.)

During 2017, EIPC also continued to expand power system planning analysis activities beyond the requirements of FERC Order No. 1000:

- A Planning Coordinator summit to exchange technical planning method techniques and best practices
- A first-of-its-kind Eastern Interconnection-wide production cost data base giving planning coordinators tools to respond to large-scale public policy and power system economic questions
- A commitment to NERC to assist in tracking and modeling Eastern Interconnection frequency response
- An EIPC proposal to offer NERC to become its designee to develop the annual Eastern Interconnection portfolio of power flow models
- An effort to develop a state of the grid report

PJM expects these activities to continue in 2018.

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

7.1: PJM-MISO Market Efficiency Transmission Projects

7.1.1 — Overview

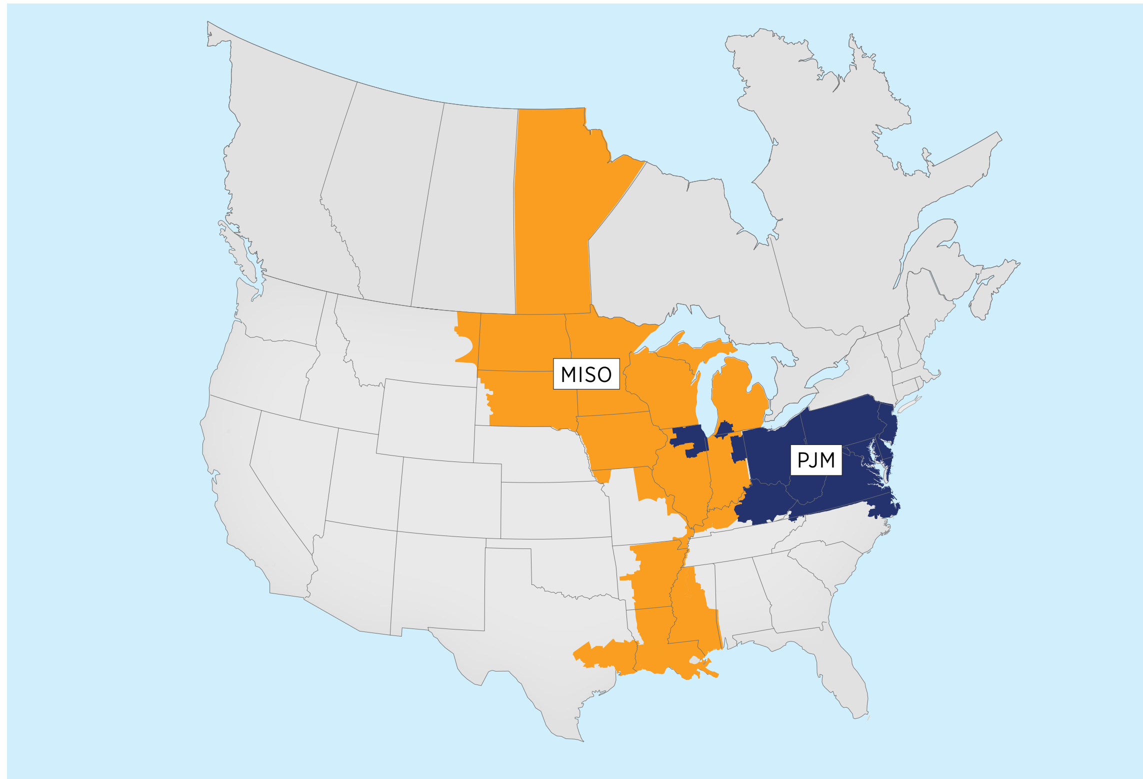
Article IX of the Joint Operating Agreement (JOA) between PJM and MISO codifies coordinated regional transmission expansion planning processes between PJM and MISO, shown on **Map 7.4**. The 2017 planning efforts under this agreement continued to closely coordinate interconnection and deactivation requests as provided in the JOA. Interconnection-driven Network transmission enhancements are summarized in **Section 11**. Deactivation-driven Baseline transmission enhancements are summarized in **Section 4.0**.

The evolution of interregional planning reached an historic milestone in 2017 when the PJM and MISO Boards approved a set of five Targeted Market Efficiency Projects (TMEPs). Joint analysis also continued on longer-term Interregional Market Efficiency Project (IMEP) proposals. TMEP and IMEP activities in 2017 are discussed next.

Evolving Metrics

A year-end 2015 filing approved by the FERC in February 2016 eliminated a JOA cost threshold that limited cross-border market efficiency transmission solutions to only those greater than $20 million. This metric, applicable to the longer, two-year market efficiency process, had previously prevented consideration of more efficient and cost effective interregional options. Eliminating this threshold should increase the number of transmission project options to relieve congestion along the PJM-MISO seam.

Map 7.4: PJM-MISO Interregional Coordination



A series of filings throughout 2016 and 2017 also added significant details to the schedule, binding deadlines, cost thresholds, and voltage thresholds related to coordinated system plan (CSP) development. The filings also clarified CSP process coordination with PJM and MISO respectively and the parallel regional market efficiency planning processes. In particular, on

December 30, 2016, PJM and MISO filed JOA changes formally establishing a new CSP study process for TMEPs to identify projects to remedy historical congestion, in contrast to the IMEP process that addresses forward-looking, projected interregional congestion. In April and August 2017 PJM and MISO, respectively, submitted FERC filings to implement regional cost allocation associated with TMEPs. These filings were accepted by FERC Orders issued in June and October 2017.

7.1.2 — TMEP 2017 Activities

TMEP interregional projects address historical congestion on reciprocal coordinated flowgates – a set of specific flowgates subject to joint and common market (JCM) congestion management. The JCM congestion management process is described in the PJM-MISO Joint Operating Agreement: http://pjm.com/directory/merged-tariffs/miso-joa.pdf. Congestion arising from joint market operations creates significant financial consequences for market participants. PJM and MISO agreed that in addition to evaluating the need for IMEPs based on future system projections, the need also existed to remedy historical congestion on reciprocal coordinated flowgates.

Background

In mid-2015, PJM and MISO began discussions about a new project type aimed at quickly addressing market-to-market (M2M) congestion on reciprocally coordinated flowgates. Based on past joint-study experience, PJM and MISO developed the TMEP concept to address this congestion. The TMEP process is intended to complement, not replace, the forward-looming, longer-term IMEP process. In 2016, working with the Interregional Planning Stakeholder Advisory Committee (IPSAC), PJM and MISO developed criteria for TMEPs focusing on low-cost, short lead-time, high-impact projects. The criteria include a study that is to be conducted as part of a coordinated system plan study. The need for a TMEP study is determined by PJM and MISO, with stakeholder input. FERC finalized and approved the TMEP project type in 2017. The FERC-accepted process provides an innovative approach to interregional coordination that is attracting notice from other entities interested in enhancing regional and interregional market efficiency planning. The TMEP process itself encompasses a number of key features:

- **All Significant Congestion Considered:** TMEPs will be considered for all significant historical M2M congestion, except when driven by unusual transmission outage patterns or when they are expected to be resolved by previously planned transmission projects.

- **Single Interregional Review and Analysis Process:** The study includes a single, joint interregional review and analysis process, which culminates in recommendations to both PJM and MISO Boards.

- **Capital Cost Limits:** Project capital costs are limited to no more than $20 million. Larger projects are considered under the more expansive IMEP process described in the JOA and discussed in **Section 7.1.3**.

- **Project Completion Expectations:** Designated entities are expected to complete projects by the summer peak season three years from the study year (typically 2.5 years from board approval).

- **Projects are limited to M2M flowgates.**

- **Congestion Savings Expectations:** The four-year market congestion savings must be equal to or greater than the capital cost of the project.

- **Future Congestion Savings Estimate:** Future annual market congestion savings are estimated based on an average of two years of historical day-ahead market congestion and balancing market congestion.

Because TMEPs are interregional projects, PJM and MISO members share the costs associated with TMEPs. The interregional cost allocation between PJM and MISO is calculated based on historical congestion costs (day ahead plus balancing), adjusted for M2M settlements over the same period used to determine project benefits. Regional cost allocation within PJM is based on the historical flowgate-specific congestion impact on each affected transmission owner zone.

Table 7.1: Approved 2017 TMEP Projects

Project ID	Facility	TMEP Description	Transmission Owner(s)	Projected In-Service Date	Total Cost ($M)	TMEP Benefit ($M)	Benefit Allocation	
							PJM	MISO
b2971	Burnham-Munster 345 kV	Reconfigure Munster 345 kV NIPSCO substation as a ring bus; Replace terminal equipment	ComEd-NIPSCO	6/1/2020	6.7	32.0	88%	12%
b2972	Lallendorf-Monroe 345 kV	Reconductor Lallendorf-Monroe 345 kV Muamee River crossing (ATSI-ITC tie line)	ATSI-ITC	11/1/2019	1.0	17.0	89%	11%
b2973	Michigan City-Bosserman 138 kV	Reconductor the NIPSCO owned section of the Michigan City–Bosserman 138 kV line (NIPSCO-AEP tie line)	NIPSCO	12/1/2019	6.0	30.0	90%	10%
b2974	Reynolds-Magnetation 138 kV	Replace terminal equipment at the Reynolds 138 kV substation	NIPSCO	6/1/2019	0.2	15.0	41%	59%
b2975	Roxana-Praxair 138 kV	Reconductor the Roxana-Praxair 138 kV line	NIPSCO	6/1/2020	6.1	6.5	24%	76%
				Total	**20.0**	**100.0**	**69%**	**31%**

Approved Targeted Market Efficiency Projects

PJM and MISO completed the first TMEP analysis in November 2016, ultimately leading to the development of five transmission projects that were recommended to and approved by the respective PJM and MISO boards in December 2017. The five projects, shown in **Table 7.1** and on **Map 7.5**, are estimated to cost approximately $20 million and produce joint market congestion savings totaling approximately $100 million in the first four years of operation. PJM and MISO expect all five approved projects to be in service no later than June 1, 2020. PJM and MISO will track construction progress of these projects in the same manner as each RTO does for its own regional projects.

PJM and MISO will review historical M2M congestion annually along their joint seam. Based on the results of each such review, PJM and MISO will determine if a full TMEP study is warranted.

NOTE:

AEP: American Electric Power (PJM TO)

ATSI: American Transmission System, Inc (PJM TO)

ComEd: Commonwealth Edison (PJM TO)

ITC: ITC Transmission Company (MISO)

NIPSCO: Northern Indiana Public Service Company (MISO)

Map 7.5: PJM/MISO Proposed Targeted Market Efficiency Projects

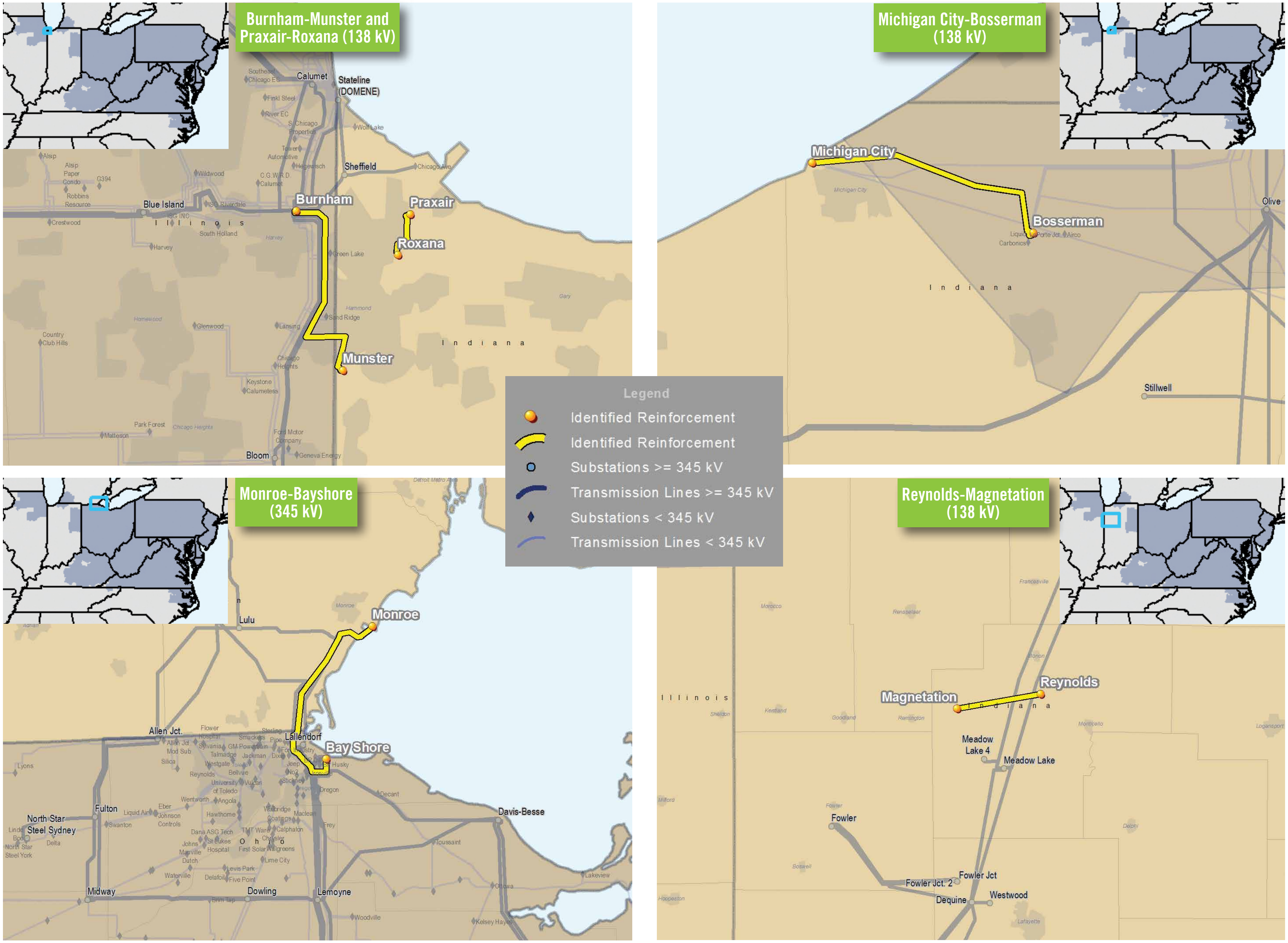


Table 7.2: 2016/2017 Long-Term Proposal Window IMEP Proposals

Map Id	Submitting Party	Description	In-Service Year	Cost ($M)	Constraint
1	NextEra	Build a new 345/138 kV substation (Rolling Prairie) connecting University Park-Olive 345 kV, Maple-New Carisle 138 kV and Maple-LNG 138 kV	2021	$19.2	Olive-Bosserman 138 kV
2	AEP/NIPSCO	Rebuild New Carlisle-Silver Lake 34.5 kV as 138 kV. Rebuild the Michigan City-Trail Creek-Bosserman 138 kV line.	2022	$17.0	Olive-Bosserman 138 kV
3	Transource	Tap the Tanners Creek-Losantville 345 kV line and build a single circuit line to a new 345/138 station (Coyote) next to Wiley.	2022	$71.9	Tanners Creek-Miami Fort 345 kV
4	AEP/Exelon	Meadow Lake-Pike Creek 345 kV Double Circuit Greenfield Line and Pike Creek 345 kV Station	2022	$198.0	Olive-Bosserman 138 kV
5	Northeast Transmission Development	Build a 345/138 kV substation ("Coffee Creek") interconnecting Green Acres to Olive 345 kV line and Flint Lake to Luchtman Road 138 kV line.	2022	$17.4	Olive-Bosserman 138 kV
6	WPPI	Construct second New Carlisle-Olive 138 kV circuit. Upgrade substation equipment at New Carlisle and Olive substations.	2020	$2.5	Olive-Bosserman 138 kV
7	NIPSCO	Reconductor existing NIPSCO line sections between AEP Bosserman and Olive 138 kV substations and between AEP Bosserman and New Carlisle 138 kV substations.	2020	$8.0	Olive-Bosserman 138 kV
8	NIPSCO	New NIPSCO line section between Thayer and Morrison 138 kV substations.	2023	$42.5	Paxton-Gifford 138 kV

7.1.3 — Interregional Market Efficiency Study

Periodically, the Joint RTO Planning Committee (JRPC), with input from the JOA's Interregional Planning Stakeholder Advisory Committee (IPSAC), may elect to perform a longer-term CSP Study. After review of each RTO's transmission issues and regional solutions, the JRPC initiated such a two-year study in 2016. This study followed the new CSP study process, including close coordination with the PJM and MISO regional market efficiency analyses. During 2016, PJM and MISO developed regional market analysis models to project future system congestion. Using these models and taking into account input from the IPSAC, the JRPC identified projected regional and interregional system congestion for study years 2021 and 2024.

PJM and MISO solicited transmission developer proposals addressing identified congestion issues along their mutual seam as identified in their respective regional planning processes. Proposals to PJM were submitted to the RTEP long-term proposal window from November 1, 2016, to February 28, 2017. Proposals designated as interregional proposals were also submitted in the MISO process, triggering the consideration of shared cost IMEP in accordance with to the JOA. PJM received eight interregional proposals, ranging in estimated cost from $2.5 million to $198 million, as shown in **Table 7.2** and **Map 7.6**.

Olive-Bosserman 138 kV Line Constraint

Six projects were proposed to remedy market-to-market congestion on the Olive-Bosserman 138 kV line. As part of its own local planning process, the transmission owner identified issues and addressed them with a Supplemental project. None of the six interregional proposals successfully remedied both the interregional congestion issues and the local planning issues. Once the Supplemental project to address the local planning issues is implemented, lower remaining levels of congestion would not justify any of the interregional proposals. Consequently, none will be pursued.

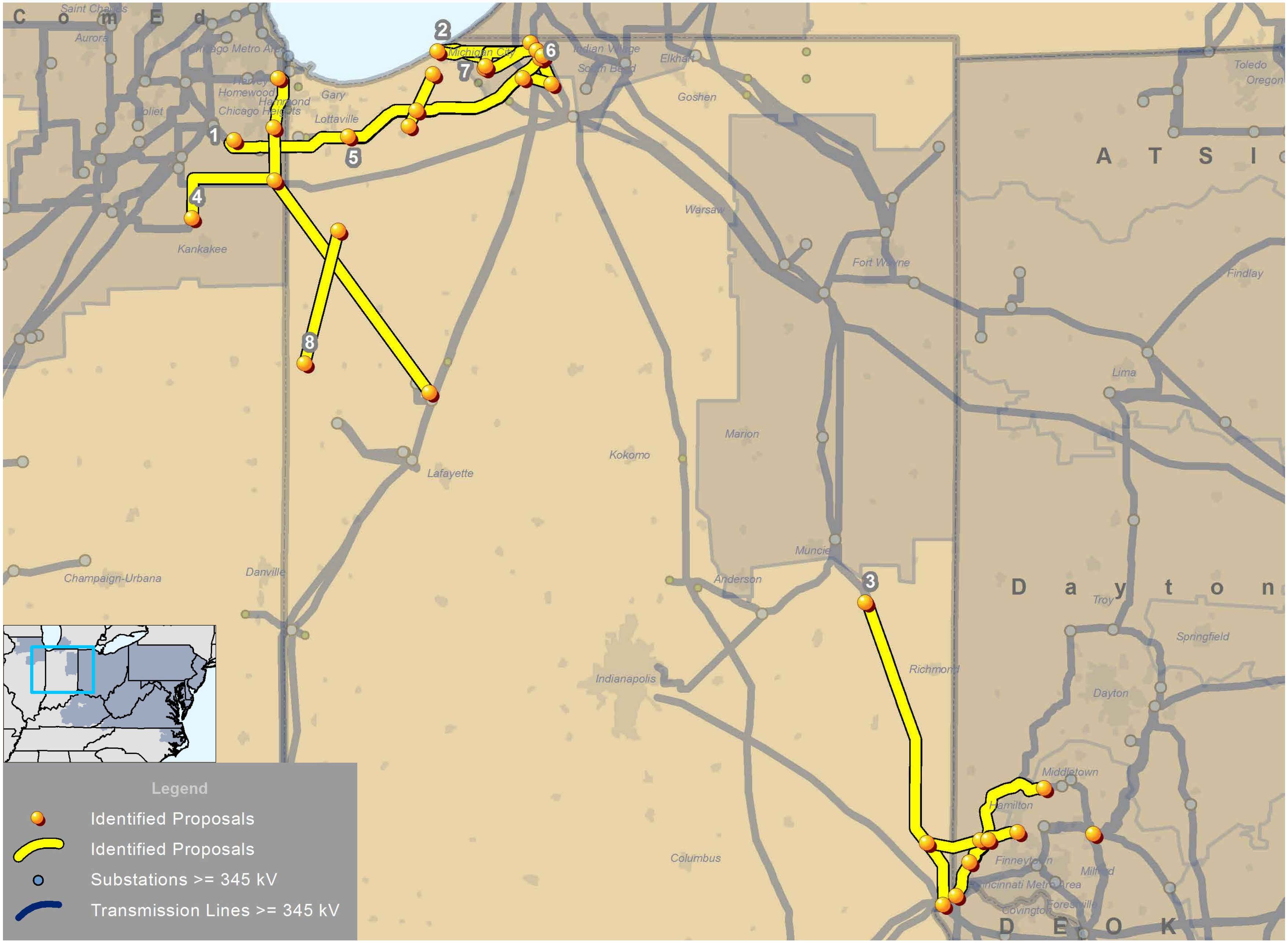
Paxton-Gifford 138 kV Line Constraint

Additional evaluation of the Paxton-Gifford 138 kV line revealed that a scheduled interconnection project transmission enhancement in MISO will increase the line's rating. Doing so would mitigate much of the market-to-market congestion constraining that line. The remaining identified congestion in that area did not pass criteria to establish the issue as significant to PJM markets. The proposal for this line, therefore, was referred to MISO for consideration as a regional project.

Tanners Creek-Miami Fort 345 kV Line

The interregional proposal to address the Tanners Creek-Miami Fort 345 kV market-to-market congestion did not successfully pass the regional benefits to cost threshold and was not pursued further.

Map 7.6: 2016/2017 Long-Term Proposal Window IMEP Proposals



Section 8: Ohio Valley Electric Corporation Integration

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

8.0: System Summary

8.0.1 — Background

Ohio Valley Electric Corporation (OVEC), and its wholly owned subsidiary, Indiana-Kentucky Electric, are expected to integrate with PJM on June 1, 2018. In addition to the OVEC transmission assets shown on **Map 8.1**, the filing includes the integration of Clifty Creek and Kyger Creek generation assets.

In 1952, OVEC was formed to serve the load of an Atomic Energy Commission uranium enrichment facility near Piketon, OH. Following this initial agreement, the Department of Energy (DOE) extended the agreement that eventually terminated in 2003. Currently, the DOE load is less than 45 MW, which is served from off-system resources through a request for proposal process. In addition, OVEC has two generating plants, Clifty Creek and Kyger Creek. Output of the units is sold to its eight utility and cooperative owners. Both Clifty Creek and Kyger Creek, 1,300 MW and 1,100 MW respectively, are coal-fired units on OVEC's 345 kV transmission system. No distribution system is included as part of the OVEC zone.

OVEC comprises six PJM member sponsors and two non-PJM member sponsors.

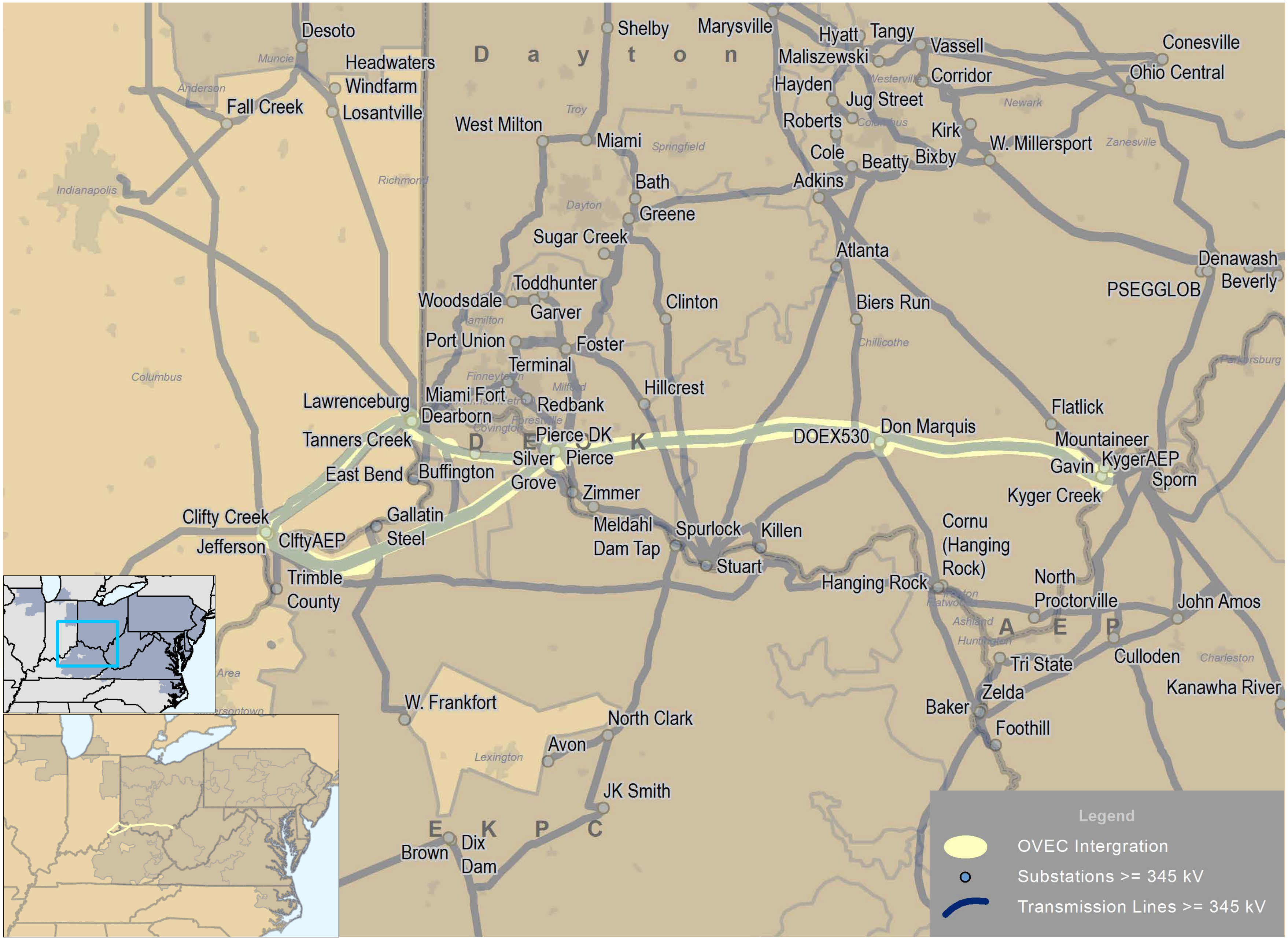
PJM member sponsors/owners:

- AEP
- Buckeye Power
- Duke Energy
- First Energy/AP
- Wolverine Power Cooperative
- Dayton

Non-PJM member sponsors/owners:

- LGE-KU
- Vectren

Map 8.1: OVEC Transmission System



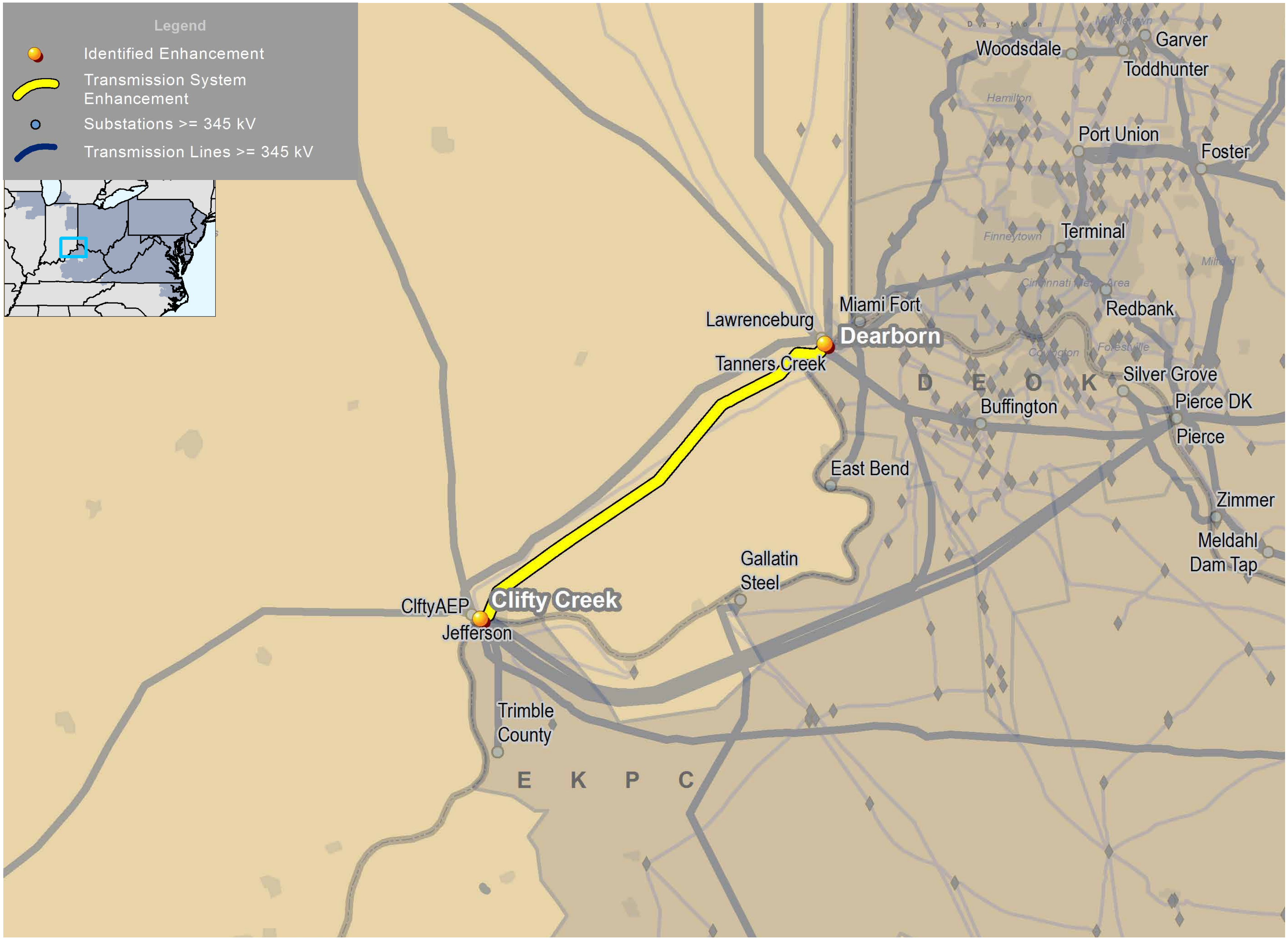
8.0.2 — Baseline Analysis

A key part of PJM market integration from a regional planning perspective is testing each new system for compliance with applicable reliability standards to accommodate forecasted demand, committed resources and firm transmission service obligations. Enhancement plans are then developed to resolve reliability criteria violations identified. PJM Planning studied OVEC facilities as part of thermal and voltage baseline analyses (including N-1-1), PJM generator deliverability analysis, winter deliverability analysis and light load deliverability analysis for the 2017 RTEP case. From the analyses, generator deliverability and common mode violations were identified for which an immediate need solution would be needed as summarized in **Table 8.1** and shown on **Map 8.2**.

Table 8.1: OVEC Baseline Need

Facilities	Violations	Solution	Project Cost Estimate ($M)	Required In-Service
Dearborn-Clifty Creek 345 kV line	Generator deliverability and common mode violations Dearborn-Clifty Creek 345 kV line over loaded for the loss of either JK Smith-Dale 138 kV line or the Jefferson-Greentown 765 kV line fault with a stuck breaker at the Jefferson 765 kV	- Perform a LIDAR study on the Dearborn-Clifty Creek 345 kV line to provide both terrain information and accurate sag and tension data along each span. - Results will help identify solution to increase the Summer Emergency rating.	$0.2	6/1/2018

Map 8.2: Dearborn-Clifty Creek 345 kV Line



Section 9: Scenario Analysis – Natural Gas Contingencies

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

9.0: Natural Gas Contingencies

9.0.1 — Background

PJM's winter planning criteria require testing 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 is 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."

The purpose of PJM's 2017 RTEP gas contingency analysis was to assess the impact of a loss of a gas pipeline on gas-fired generating plants and consequent reliability impacts. Using summer and winter 2022 peak cases, PJM performed N-1, N-1-1 thermal, N-1-1 voltage and load deliverability voltage studies. The study focus was on voltage collapse and potential cascading system conditions.

Assumptions

PJM adopted a conservative analysis for the scenario study. First, simultaneous and instantaneous loss of power plants for gas contingency events was assumed. In actuality, if a compressor station or pipeline failure occurred, the impact to power plants would be the loss of gas pressure, which may take minutes or even hours. Second, the loss of the gas power plant was assumed regardless of dual fuel capability. In actual operation, dual fuel units may take hours or days to switch to an alternate fuel. Third, the probability of a gas local distribution company (LDC) failure is low given that more than one gas supply source may actually exist. All gas contingencies were treated the same in this analysis.

9.0.2 — Scenario Study Results

The scenario study examined 38 contingencies conducted on 2022 summer and winter power flow cases, the results of which are shown in **Table 9.1.** Twenty six of the contingencies represented the loss of gas pipeline or compressor removing generation totaling 1,000 MW or more. The underlying study assumption was that all downstream gas generation would be lost, regardless of dual fuel status. Four contingencies examined winter case temperature threshold conditions in which non-firm gas customers would be interrupted. The scenario study also examined eight high-impact gas contingencies identified by PJM Operations energy management system analysis. Those eight included five representing gas compressor failure and three for gas LDC failure.

Winter 2022 results revealed no voltage collapse or cascading results. Summer 2022 study results revealed the potential for voltage collapse for three of the gas contingencies or combinations of specific single contingencies. These were identified primarily in the Eastern Mid-Atlantic (EMAAC) area. Additionally, study results also showed several potential locational deliverability area voltage collapse violations. Given the nature of these results and the severity of the contingencies examined, PJM intends to conduct additional scenario analysis that refines gas contingency definitions and to consider the benefit of dual fuels.

Table 9.1: Natural Gas Scenario Study Results

Analysis	Thermal Results	Voltage Magnitude Results	Voltage Drop Results
2022 Winter Results			
N-1 Analysis	No overloads	- All 38 contingencies converged - High voltage at 345 kV and 230 kV buses in Eastern Mid-Atlantic (EMAAC) observed for 6 gas contingencies - No low voltage issues	n/a
N-1-1 Analysis	No overloads	- All contingency pairs converged - High voltage at 138 kV and 230 kV busses in EMAAC for 11 gas contingencies paired with another single contingency	- All contingency pairs converged - All voltage drops are within emergency limits
Load Deliverability	n/a	- All contingencies converged - No voltage issues identified	- All gas contingencies converged - No voltage issues identified
2022 Summer			
N-1 Analysis	No overloads	- All contingencies converged - No voltage issues identified	- Three of the 34 gas contingencies studied showed voltage collapse. Two contingencies are pipeline outages in EMAAC with more than 11,000 MW and 10,000 MW of generation loss, respectively. The third contingency was an LDC failure in EMAAC. - Three other pipeline outages showed voltage drop violations at several 500 kV buses in EMACC.
N-1-1 Analysis	- Three gas contingencies, paired with another single contingency, caused thermal overloads in ComEd. - Eight gas contingencies, paired with another single contingency, caused overloads in EMAAC. - None had cascading consequences.	- All contingency pairs converged - Low voltage at 500 kV and 230 kV buses in EMAAC observed for 8 gas contingencies paired with another single contingency. Among these 8 contingencies, the majority result in mild voltage magnitude violations at a limited number of locations. Two of the nine gas contingencies result in low voltage over a large area. Both are pipeline outages in EMAAC with loss of more than 11,000 and 10,000 MW of generation, respectively.	- In addition to the three contingencies which did not converge in the N-1 voltage drop tests, five more gas contingencies were non-convergent after paired with several specific single contingencies in EMAAC. - Voltage drop violations at several 500 kV and 230 kV buses in EMACC for eight gas contingencies when paired with another single contingency. - One gas contingency paired with another specific single contingency caused mild voltage drop violations at several 500 kV buses in EMAAC. - Two of the eight gas contingencies caused low voltages over a large area.
Load Deliverability	n/a	- The following LDAs showed non-convergent cases for multiple gas contingencies: EMAAC, SWMAAC, MAAC, PSE&G, PSE&G North, BGE and ComEd.	- The following LDAs showed non-convergent cases for multiple gas contingencies: EMAAC, SWMAAC, MAAC, PSE&G, PSE&G North, BGE and ComEd.

Section 10: Planning Parameters

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

10.0: Reliability Pricing Model

10.0.1 — Recognizing Locational Constraints

PJM's Reliability Pricing Model (RPM) auctions provide a transparent forward capacity market mechanism for ensuring resource adequacy. The market selects resources to meet defined target capacity levels at least cost while recognizing locational transmission constraints. Market participants have the opportunity to bid-in resources that can include generation, demand side response, energy efficiency and transmission solutions. RPM aligns capacity pricing with system reliability requirements and provides advance, transparent information to all market participants.

As part of the Regional Transmission Expansion Plan (RTEP) process, PJM develops RPM resource input parameters for each locational deliverability area. Dividing the RTO into locational deliverability areas recognizes the reality that transmission system limitations may restrict capacity delivery to where it is needed to meet demand under peak conditions. PJM's RTEP process has identified 27 such locational deliverability areas as listed in **Table 10.1** and shown on **Map 10.1**. Inputs to RPM include locational deliverability area parameters such as:

- Capacity Emergency Transfer Objective (CETO)
- Capacity Emergency Transfer Limit (CETL) values

Table 10.1: PJM Locational Deliverability Areas

LDA	Description
AE	Atlantic 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
Delmarva South	Southern Portion of DPL
Eastern Mid-Atlantic	Global area – 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 – Penelec, Met-Ed, JCPL, PPL, PECO, PSE&G, BGE, PEPCO, AE, DPL, RECO
PECO	PECO
PENELEC	Pennsylvania Electric
PEPCO	Potomac Electric Power Company
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas
PSE&G North	Northern Portion of PSE&G
Southern Mid-Atlantic	Global area – BGE and PEPCO
Western Mid-Atlantic	Penelec, Met-Ed, PPL
Western PJM	APS, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K

Each CETO value serves to establish a transmission target for each locational deliverability area. CETL values represent the maximum amount of capacity that can be imported from resources located outside the locational deliverability area as limited by transmission constraints.

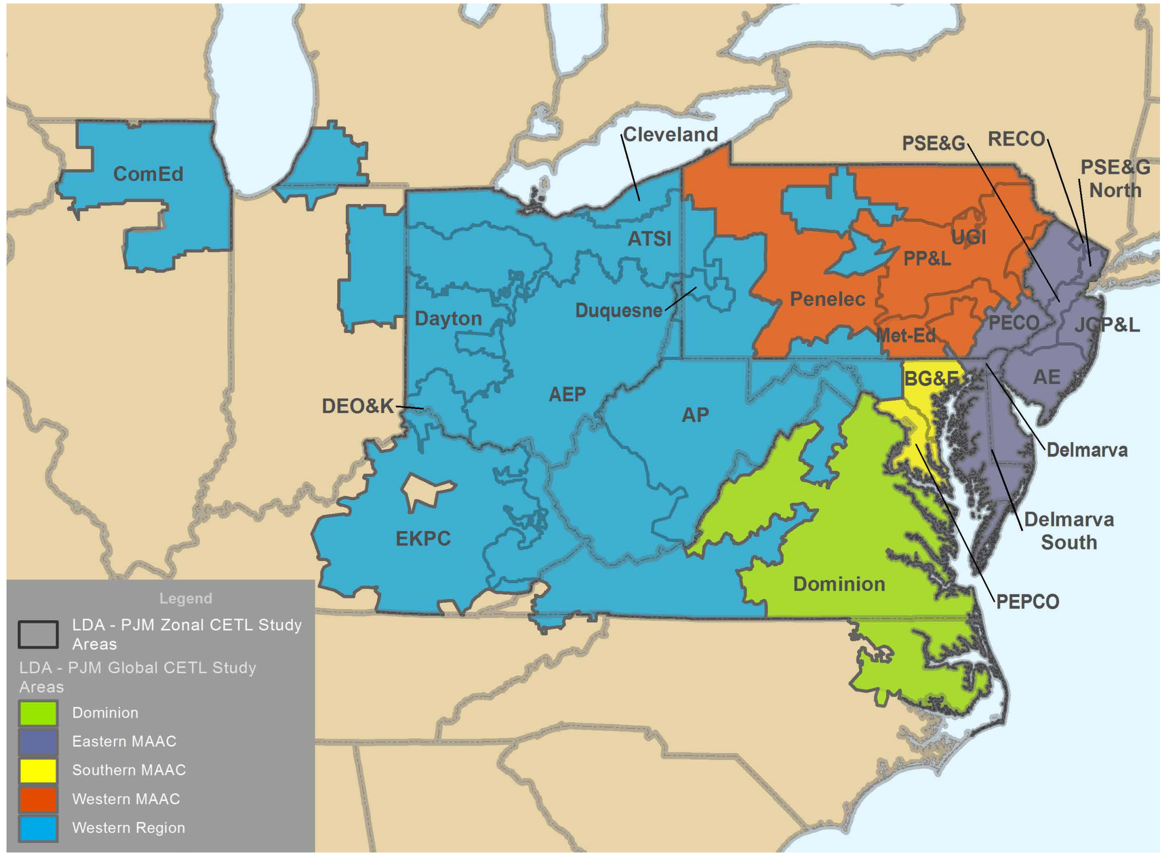
10.0.2 — CETO and CETL Development

Prior to each RPM Base Residual Auction, PJM calculates CETO and CETL for each locational deliverability area, as described in **Book 2, Section 4.2.2**. RPM explicitly models as import-constrained each locational deliverability area with a CETL less than 1.15 times its CETO. The PJM Open Access Transmission Tariff also requires that each auction specifically model Mid-Atlantic, eastern Mid-Atlantic and southwestern Mid-Atlantic locational deliverability areas regardless of prior CETL/CETO tests or auction results. Additionally, PJM has the discretion to model any locational deliverability area in the auction arising out of reliability concerns. PJM determines each locational deliverability area CETO value using a probabilistic model for the load and capacity 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. Many factors can drive an locational deliverability area CETO value increase, including the following:

- Peak load increase, capacity resource decrease (e.g., generation and demand resource programs)

- Capacity resource availability factor

Map 10.1: PJM Locational Deliverability Areas



The reverse of these factors would drive a locational deliverability area CETO value decrease.

Locational deliverability area CETL changes are driven by transmission system topology changes and load distribution profile. Generation additions or retirement also impact power flow and, consequently, CETL values, as well.

2019/2020 and 2020/2021 Base Residual Auctions

Table 10.2 compares the amount of transmission import capability into the locational deliverability area – i.e., CETL – and the CETO for each locational deliverability area as used in the 2019/2020 and 2020/2021 Base Residual Auctions. The comparison is not available for DAYTON and DEO&K because these locational deliverability areas were modeled separately in RPM for the first time in the 2020/2021 Base Residual Auction. The majority of 2020/2021 CETO values reported in **Table 10.2** are greater than those for the 2019/2020 Delivery Year. The larger CETO increases are mainly driven by lower forecasted resources in the corresponding locational deliverability area. The table also shows a majority of increases in 2020/2021 CETL values relative to those for the 2019/2020 Delivery Year.

The CETL increases and decreases reflect changes in local conditions rather than changes in RTO-wide trends. As stated above, CETL changes are primarily driven by the addition or removal of transmission facilities, the magnitude and location of generation deactivations and generation additions, and changes in load distribution profile within location deliverability areas.

Table 10.2: CETO and CETL Comparison: Base Residual Auction Values

	2019/2020 BRA			2020/2021 BRA			Change			
	CETO	CETL	CETL/ CETO	CETO	CETL	CETL/ CETO	CETO		CETL	
LDA	MW	MW	Ratio	MW	MW	Ratio	MW	Percent	MW	Percent
MAAC	-6,930	7,385	NA	-7,000	4,218	NA	-70	-1.0%	-3,167	-42.9%
EMAAC	1,580	8,856	5.61	3,650	8,800	2.41	2,070	131.0%	-56	-0.6%
SWMAAC	3,920	9,400	2.40	2,900	9,802	3.38	-1,020	-26.0%	402	4.3%
PSE&G	5,590	7,856	1.41	5,900	8,001	1.36	310	5.5%	145	1.8%
PS-NORTH	2,280	3,827	1.68	2,620	4,264	1.63	340	14.9%	437	11.4%
DPLSOUTH	1,230	1,898	1.54	1,230	1,872	1.52	0	0.0%	-26	-1.4%
PEPCO	2,870	6,985	2.43	1,540	7,625	4.95	-1,330	-46.3%	640	9.2%
ATSI	4,490	9,212	2.05	4,660	9,889	2.12	170	3.8%	677	7.3%
ATSI-Cleveland	3,390	5,501	1.62	3,540	5,605	1.58	150	4.4%	104	1.9%
COMED	610	5,160	8.46	640	4,064	6.35	30	4.9%	-1,096	-21.2%
BGE	4,060	6,169	1.52	4,410	6,244	1.42	350	8.6%	75	1.2%
PPL	-170	6,168	NA	-1,010	7,084	NA	-840	-494.1%	916	14.9%
DAYTON*	-	-	-	2,550	3,401	1.33	-	-	-	-
DEO&K*	-	-	-	3,650	5,072	1.39	-	-	-	-

Notes:
NA: Not applicable since CETO is negative
*LDA modeled separately in RPM for the first time in the 2020/2021 BRA

10.0.3 — Capacity Performance

The 2017 Reliability Pricing Model base residual auction for the 2020/2021 Delivery Year marked the third one conducted under Capacity Performance provisions and the first requiring exclusively offers from one product type, Capacity Performance. Previously, in addition to the Capacity Performance product, offers from a Base Capacity product were also allowed. Phasing-out the Base Capacity product has eliminated the need for calculating the Base Capacity Constraint, which in previous years was also an RTEP Reliability Pricing Model input.

10.0.4 — Reserve Requirements Parameters

The installed reserve margin (IRM) and forecast pool requirement (FPR) values are also required for the Reliability Pricing Model. These values represent the level of capacity reserves needed to satisfy the PJM reliability criterion that loss-of-load-expectation (LOLE) not exceed one occurrence in 10 years. The IRM and FPR represent the same level of required reserves but are expressed in different terms. The IRM expresses required installed capacity reserve as a percent of forecasted annual peak load. The FPR, when multiplied by forecasted annual peak load, provides total unforced capacity required. The FPR is equal to (1 + IRM) times (1 – PJM AverageEFORd). **Table 10.3** compares the IRM and FPR for the RTO for the 2019/2020 and 2020/2021 Base Residual Auction and shows no major parameter changes.

Table 10.3: Reserve Requirement Comparison: Base Residual Auctions

Reserve Requirement Parameters	2019/2020 BRA	2020/2021 BRA	Delta
Installed Reserve Margin (IRM)	16.50%	16.60%	0.10%
Pool Wide Five-Year Average EFORd	6.60%	6.59%	-0.01%
Forecast Pool Requirement	1.088	1.089	0.001

Section 11: Subregion Summaries

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

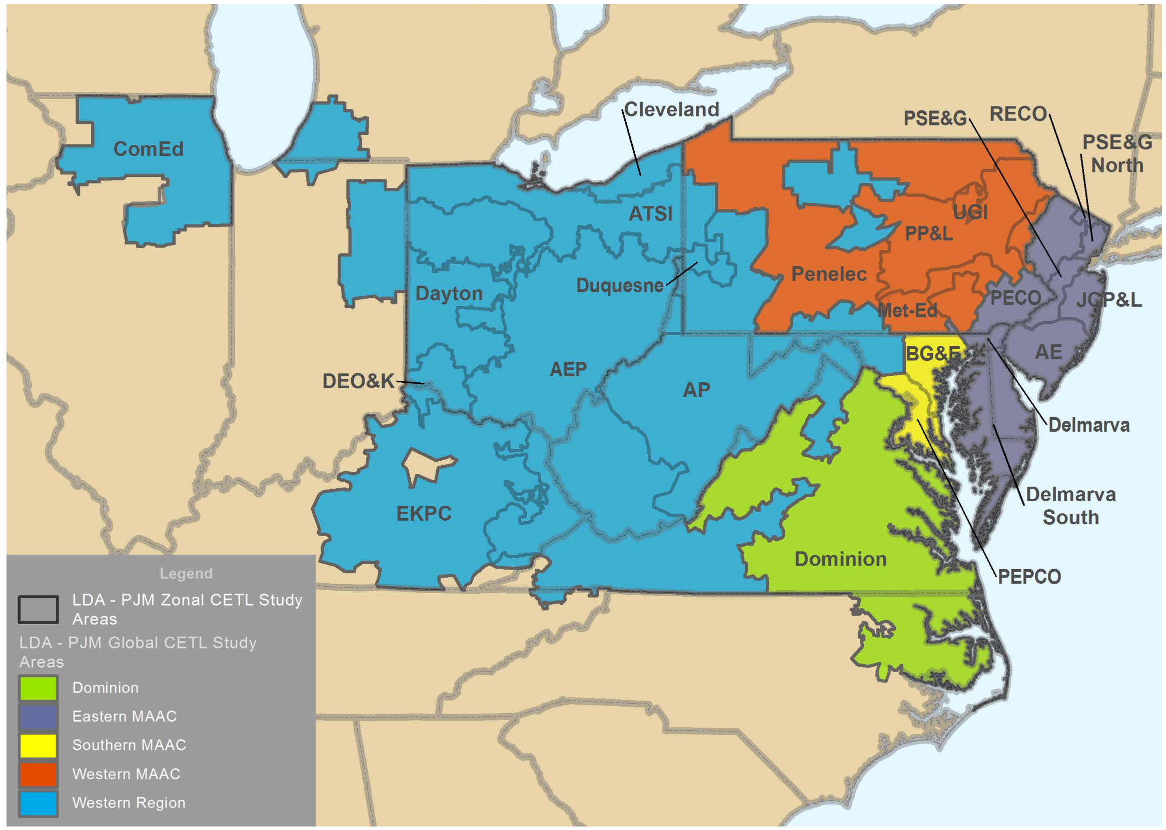
11.0: Mid-Atlantic PJM Summary

11.0.1 — RTEP Context

PJM operates the bulk electric system transmission facilities (and others monitored at lower voltage levels) throughout PJM's Mid-Atlantic subregion, shown in **Map 11.1**. Systems include those of 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), Old Dominion Electric Corporation (ODEC), PECO Energy (PECO), Pennsylvania Electric Company (PENELEC), Potomac Electric Power Company (PEPCO), PPL Electric Utilities Corporation (PPL), Public Service Electric and Gas (PSE&G), Rockland Electric (Rockland) and UGI Corporation (UGI). Mid-Atlantic PJM also includes several merchant and transmission facilities: Neptune Regional Transmission System, Linden Variable Frequency Transformer (VFT), and Hudson HVDC project.

A 15-year long-term planning horizon allows PJM to consider the aggregate effects of many drivers. At 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 identifies one optimal, comprehensive set of solutions to resolve baseline reliability criteria violations, operational performance issues and congestion constraints as well as Network

Map 11.1: Locational Deliverability Areas



reinforcements to accommodate generator interconnection and other new queued service requests. Specific system enhancements are justified to deliver needed power to distant load centers as well to meet local, subregional needs.

Stakeholder Participation

Subregional RTEP committees increase the opportunity for direct stakeholder participation in the planning process from initial assumption setting stages through review of planning analyses, violations and alternative transmission expansion plans. Each subregional RTEP committee provides a more local forum for surfacing and considering planning issues. Interested parties can access PJM Mid-Atlantic Subregional RTEP Committee information from PJM's website: http://www.pjm.com/committees-and-groups/committees/srrtep-ma.aspx.

11.0.2 — Baseline Projects

Baseline transmission projects are system enhancements identified through analysis of operational performance issues, market efficiency studies and conventional NERC criteria tests that include the following:

- Base case thermal and voltage analysis
- Load deliverability thermal and voltages analysis
- Generation deliverability thermal analysis
- N-1-1 thermal and voltage analysis
- Common mode contingency analysis
- Short circuit analysis
- Baseline stability analysis
- Transmission owner criteria tests

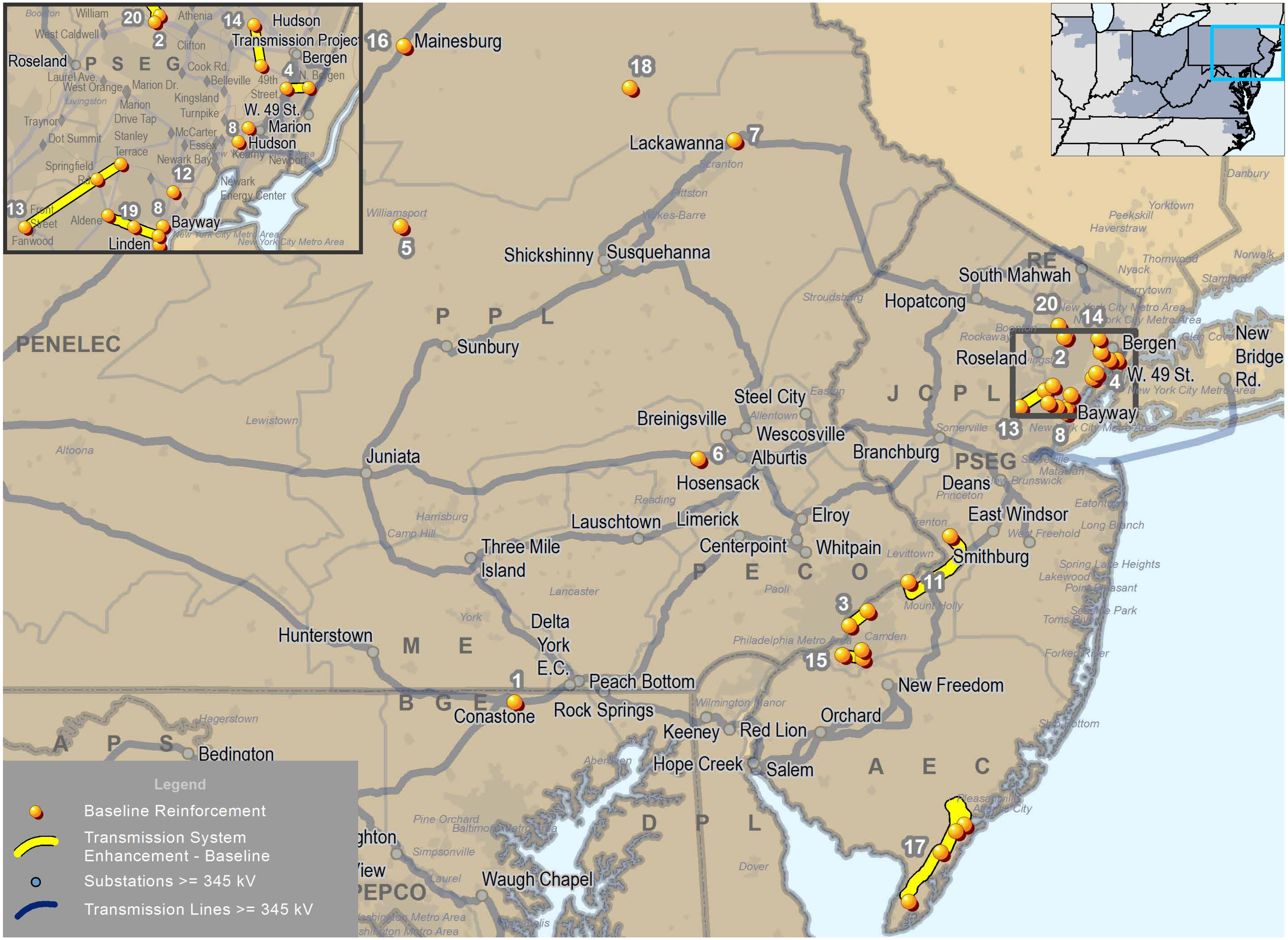
Contingency analysis includes all bulk electric system facilities, tie lines to neighboring systems, critical neighboring system facilities and lower voltage facilities operated by PJM.

Baseline projects with cost estimates greater than $5 million approved by the PJM Board in 2017 are listed in **Table 11.1** and shown on **Map 11.2**.

Table 11.1: Mid-Atlantic Subregion – Baseline Projects

Map ID	Project ID	Project	Mid-Atlantic Subregion Baseline Projects: Baseline Load Growth/ Deliverability & Reliability	Congestion Relief-Economic	Operational Performance	Short Circuit	TO Criteria Violation	Required Date	Cost ($M)	Designated Entity	2017 TEAC Review
1	b2752.9	Replace the Conastone 230 kV 2322 B6 breaker with a 63 kA breaker.				▲		6/1/2020		BGE	10/12/2017
2	b2810.1	Install second 230/69 kV transformer at Cedar Grove.					▲	6/1/2019	$44.00	PSE&G	12/1/2016
	b2810.2	Build a new 69 kV circuit from Cedar Grove to Great Notch.					▲	6/1/2019		PSE&G	12/1/2016
3	b2811	Build 69 kV circuit from Locust Street to Delair.					▲	6/1/2017	$13.50	PSE&G	12/1/2016
4	b2812	Construct River Road to Tonnelle Avenue 69 kV circuit.					▲	6/1/2017	$31.00	PSE&G	12/1/2016
8	b2825.1	Install two 50 MVAR shunt reactors at Kearny 230 kV substation.	▲					9/1/2018	$90.40	PSE&G	1/12/2017
	b2825.2	Increase the size of the Hudson 230 kV, two 50 MVAR shunt reactors to two 100 MVAR.	▲					9/1/2018		PSE&G	1/12/2017
	b2825.3	Install two 100 MVAR shunt reactors at Bayway 345 kV substation.	▲					9/1/2018		PSE&G	1/12/2017
	b2825.4	Install two 100 MVAR shunt reactors at Linden 345 kV substation.	▲					9/1/2018		PSE&G	1/12/2017
9	b2835	Convert the R-1318 and Q1317 (Edison-Metuchen) 138 kV circuits to one 230 kV circuit.					▲	6/1/2017	$125.00	PSE&G	1/12/2017
10	b2836	Convert the N-1340 and T-1372/D-1330 (Brunswick-Trenton) 138 kV circuits to 230 kV circuits					▲	6/1/2017	$302.00	PSE&G	1/12/2017
11	b2837	Convert the F-1358/Z1326 and K1363/Y-1325 (Trenton-Burlington) 138 kV circuits to 230 kV circuits					▲	6/1/2017	$312.00	PSE&G	1/12/2017
12	b2870	Build new 138/26 kV Newark GIS station in a building (layout Proposal Window No. 1A) located adjacent to the existing Newark Switch and demolish the existing Newark Switch.					▲	6/1/2017	$275.00	PSE&G	3/9/2017
13	b2933.1	Construct a 230/69 kV station at Springfield.					▲	6/1/2018	$197.00	PSE&G	8/31/2017
	b2933.2	Construct a 230/69 kV station at Stanley Terrace.					▲	6/1/2018		PSE&G	8/31/2017
	b2933.3	Construct a 69 kV network between Front Street, Springfield and Stanley Terrace.					▲	6/1/2018		PSE&G	8/31/2017
14	b2934	Build a new 69 kV line between Hasbrouck Heights and Carlstadt.					▲	6/1/2018	$21.00	PSE&G	8/31/2017
15	b2935.1	Build a new 230/69 kV switching substation at Hilltop utilizing the PSE&G property and the K-2237 230 kV line.					▲	6/1/2018	$98.00	PSE&G	8/31/2017
	b2935.2	Build a new line between Hilltop and Woodbury 69 kV providing the third supply.					▲	6/1/2018		PSE&G	8/31/2017
	b2935.3	Convert Runnemede's straight bus to a ring bus and construct a 69 kV line from Hilltop to Runnemede 69 kV.					▲	6/1/2018		PSE&G	8/31/2017
19	b2955	Wreck and re-build the VFT-Warinanco-Aldene 230 kV circuit with paired conductor.	▲					6/1/2018	$90.40	PSE&G	10/12/2017
20	b2956	Replace existing cable on Cedar Grove-Jackson Rd. with 5,000 kcmil XLPE cable.	▲					6/1/2018	$80.00	PSE&G	10/12/2017

Map 11.2: Mid-Atlantic Subregion – Baseline Projects



11.0.3 — Network Projects

PJM's RTEP also includes system reinforcements identified through interconnection process system impact studies. These Network projects are necessary to interconnect new generation, merchant transmission facilities and other new services. Direct connection Network projects are transmission enhancements that deliver power to a defined point of interconnection. Non-direct connection Network projects mitigate transmission system impacts beyond the point of interconnection. Network projects with cost estimates greater than $5 million approved by the PJM Board in 2017 are listed in **Table 11.2** and shown on **Map 11.3**.

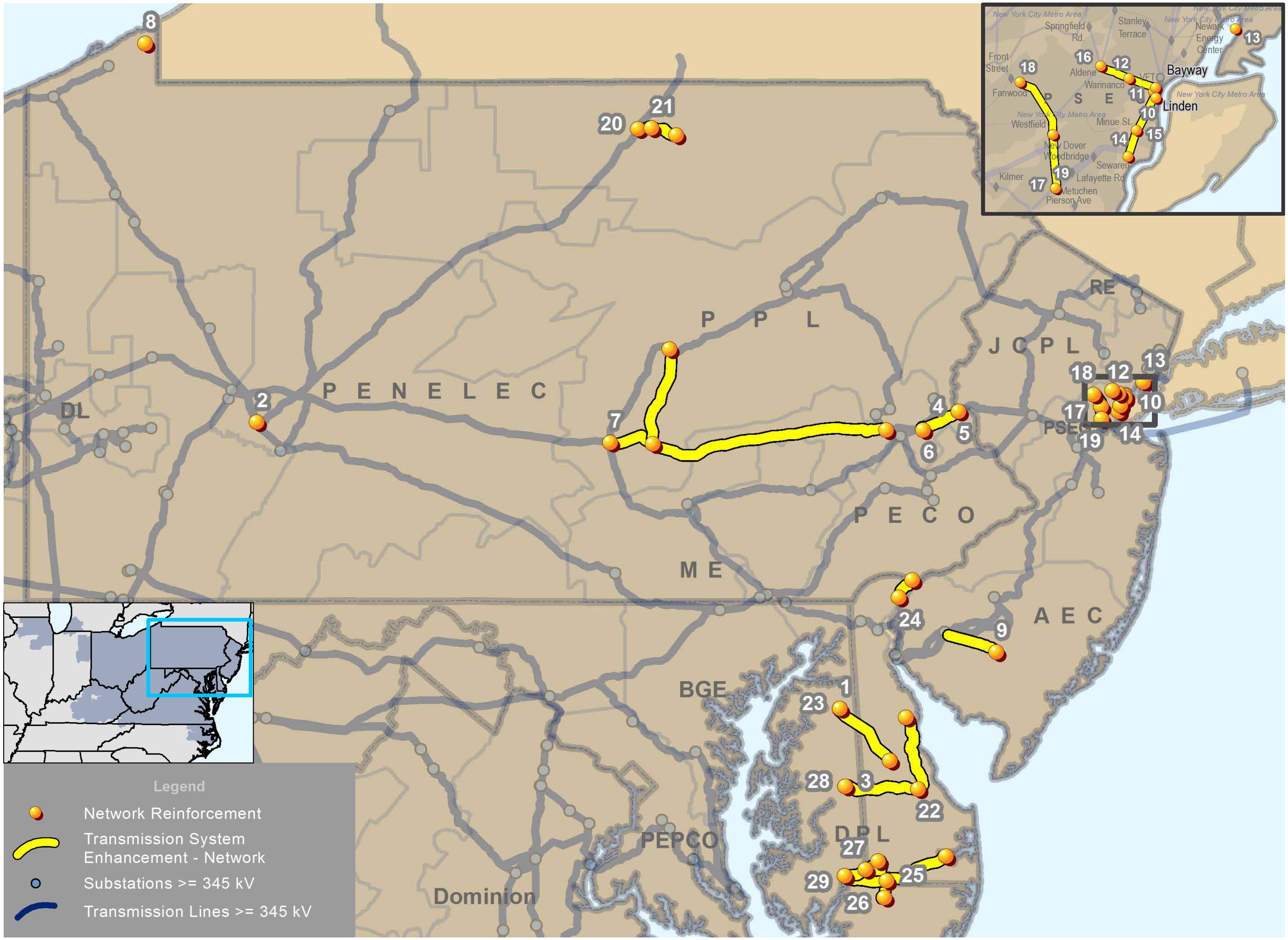
Table 11.2: Mid-Atlantic Subregion – Network Projects

			Mid-Atlantic Subregion – Network Projects						
Map ID	**Project ID**	**Project**	**Generation Interconnection**	**Merchant Transmission Interconnection**	**Auction Revenue Rights Request**	**Adjacent RTO Interconnection**	**Cost ($M)**	**TO Zone(s)**	**2017 TEAC Review**
1	n5015	Replace disconnect switch, rebuild line and replace conductor for Church-New Meredith 69 kV line			AA1-119		$11.30	DPL	10/12/2017
2	n5069	Replace South Homer City South Transformer				Q496 (NYISO)	$14.79	PENELEC	10/12/2017
3	n5117	Increase the emergency rating of the Milford to Steele 230 kV line by rebuilding the circuit, including the replacement of poles. The estimate to perform this work is $43,965,000 and will take four years to complete.	AB1-057				$43.90	DPL	10/12/2017
4	n5148	Install two line terminal breakers, risers, necessary disconnects and controls for the AB1-154 terminal at Gilbert 230 kV substation.	AB1-154				$5.17	JCPL	10/12/2017
5	n5150	Reconstruct Gilbert 230 kV yard as a breaker and a half layout.	AB1-154				$12.16	JCPL	10/12/2017
	n5150.1	Replace Gilbert 230 kV breaker A13 with a 63 kA breaker.	AB1-154					JCPL	10/12/2017
	n5150.2	Replace Gilbert 230 kV breaker PV with a 63 kA breaker.	AB1-154					JCPL	10/12/2017
	n5150.3	Replace Gilbert 230 kV breaker C11 with a 63 kA breaker.	AB1-154					JCPL	10/12/2017
	n5150.4	Replace Gilbert 230 kV breaker 13P with a 63 kA breaker.	AB1-154					JCPL	10/12/2017
	n5150.5	Replace Gilbert 230 kV breaker VC with a 63 kA breaker	AB1-154					JCPL	10/12/2017
	n5150.6	Replace Gilbert 230 kV breaker 1216 with a 63 kA breaker. Note: The cost of the replacement is lumped in the n5150 network upgrade.	AB1-154					JCPL	10/12/2017
6	n5165	Re-conductor 11.9 miles of Gilber-Springfield 230 kV circuit replacing 1590 ACSR with 1590 ACSS.	AB1-154				$15.33	JCPL	10/12/2017
7	n5170	Tap Juniata-Alburtis 500 kV line to create a new DAUP 500 kV station, and built 500 kV line from Sunberry 500 kV station to the new DAUP 500 kV station.	AA2-182				$200.00	PPL	10/12/2017
8	n5174	New 230 kV series reactor and required associated substation equipment at Erie East substation.	Y2-089				$10.00	PPL	10/12/2017

Table 11.2: Mid-Atlantic Subregion – Network Projects (Continued)

Map ID	Project ID	Project	Mid-Atlantic Subregion – Network Projects: Generation Interconnection	Merchant Transmission Interconnection	Auction Revenue Rights Request	Adjacent RTO Interconnection	Cost ($M)	TO Zone(s)	2017 TEAC Review
9	n5210.1	Tap the existing (see baseline upgrade b2479) new Orchard-Cardiff 230 kV line to install a 230 kV 4 position ring bus at Minotola substation, with four 230 kV breakers.	AB1-169A				$21.77	AE	10/12/2017
	n5210.2	Install one 138 kV breaker and 1-230/138 kV transformer at Minotola Substation.	AB1-169A					AE	10/12/2017
	n5210.3	Install one 138 kV breaker and 1-230/138 kV transformer at Minotola Substation.	AB1-169A					AE	10/12/2017
10	n5263	Linden-Tosco three 230 kV line: Rebuild with paired 795 ACSS.	AB2-055				$13.65	PSE&G	10/12/2017
11	n5264	Tosco-VFT 230 kV line: Rebuild with paired 1033 ACSS.	AB2-055				$7.50	PSE&G	10/12/2017
12	n5265	VFT-Warinico 230 kV line: Rebuild with paired 795 ACSS.	AB2-055				$38.93	PSE&G	10/12/2017
13	n5266	Bayonne 345 kV substation: Install a new GIS Breaker on the spare bay position and associated GIS / AIS bus work, UG cable, relaying, metering.	AB2-055				$18.90	PSE&G	10/12/2017
14	n5268	Sewaren-Minue Street 230 kV line: Rebuild with paired 795 ACSS	AB2-082				$30.84	PSE&G	10/12/2017
15	n5269	Minue Street-Linden 230 kV line: Wreck & Rebuild with paired 795 ACSS.	AB2-082				$34.78	PSE&G	10/12/2017
16	n5270	Warinico-Aleden 230 kV line: Reconductor with 1590 ACSS.	AB2-082				$8.59	PSE&G	10/12/2017
17	n5271	Metuchen-New Dover 230 kV line: Rebuild with paired 795 ACSS.	AB2-082				$51.86	PSE&G	10/12/2017
18	n5272	New Dover-Fanwood 230 kV line: Rebuild with paired 795 ACSS.	AB2-082				$47.87	PSE&G	10/12/2017
19	n5273	Metuchen 230 kV substation: Expand the existing substation yard and Install a new breaker position and associated fencing, ground grid, dead end structures, bus work, switches, relaying and metering.	AB2-082				$10.35	PSE&G	10/12/2017
20	n5402	Reconductor the Everts Drive-South Troy 115 kV Line with high temperature conductor.				Q496 (NYISO)	$5.91	PENELEC	10/12/2017
21	n5403	Reconductor ~8.8 miles of the Everts Drive-Mainesburg 115 kV Line with 795 ACSS conductor.				Q496 (NYISO)	$17.52	PENELEC	10/12/2017
22	n5442	Rebuild Line No. 23033 Cartanza to Mil 230 kV			AB1-186		$39.75	DPL	10/12/2017
23	n5444	Replace disconnect switch, rebuild line 6704-1 from Church-New Meredith and replace conductor on 6701-1 line			AB1-186		$11.30	DPL	10/12/2017
24	n5446	Rebuild Line No. 22085 from Edgemoor-Linwood to dual 1590 ACSR			AB1-186		$38.25	DPL	10/12/2017
25	n5448	Rebuild line No. 13703 Indian River to Nelson and replace substation bus			AB1-186		$31.53	DPL	10/12/2017
26	n5451	Rebuild line 6705_1 from Laurel to AA1-142 Tap with 954 ACSR			AB1-186		$10.91	DPL	10/12/2017
27	n5452	Rebuild line 6705_1 from Sharptown to AA1-142 Tap with 954 ACSR			AB1-186		$10.91	DPL	10/12/2017
28	n5453	Rebuild line No. 23076 from Milford to Steele with 1590 ACSR 125 C			AB1-186		$43.97	DPL	10/12/2017
29	n5454	Rebuild line 13707 from Nelson to Vienna with 1590 ACSR			AB1-186		$17.47	DPL	10/12/2017
30	n5455	Rebuild Line 6705_2 from Sharptown to Vienna 69 kV with 1590 ASCR, upgrade all substation equipment to 2000 A			AB1-186		$12.47	DPL	10/12/2017

Map 11.3: Mid-Atlantic Subregion – Network Projects



11.0.4 — Supplemental Projects

Prior to FERC Order No. 890 in 2008, Supplemental projects were referred to as Transmission Owner Initiated or TOI Projects. A Supplemental project is not required for compliance with system reliability, operational performance or economic criteria, as determined by PJM. Supplemental projects frequently address aging infrastructure, provide support to serve underlying systems and add connections to new, large load customers. PJM reviews Supplemental projects 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.

Transmission owners submitted a number of supplemental projects throughout 2017. Projects with cost estimates greater than $5 million are listed in **Table 11.3** and shown on **Map 11.4**.

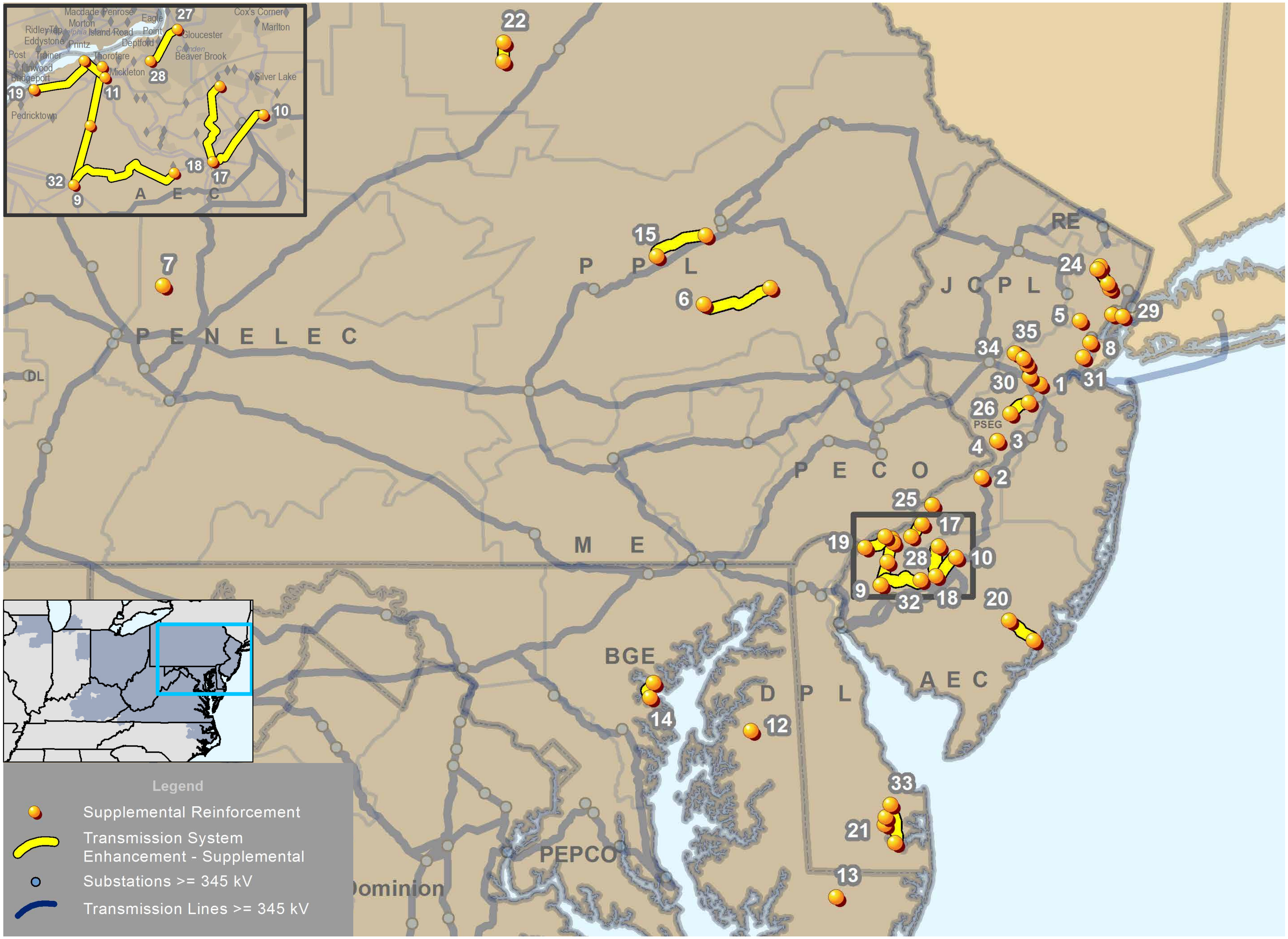
Table 11.3: Mid-Atlantic Subregion – Supplemental Projects

Map ID	Project ID	Project	Projected Date	Cost ($M)	TO Zone(s)	2017 TEAC Review
1	s1096	Replace Brunswick 230/69 kV transformer 220-4 with a new TMP equipped 230/69 kV auto-transformer with load tap changers.	6/15/2018	$8.00	PSE&G	1/5/2017
5	s1241	Build a 13 kV class-H substation at Stanley Terrace with two 230/13 kV transformers.	5/1/2018	$20.70	PSE&G	1/5/2017
6	s1242	Rebuild Hauto-Frackville No. 3 69 kV line to double circuit.	12/31/2018	$57.80	PPL	1/5/2017
7	s1243	Trade City 115 kV Substation: Construct a 115 kV ring bus.	12/31/2017	$7.00	PENELEC	1/5/2017
8	s1254	Linden 138 kV: Reroute, Reconductor and bundle with two conductors, to provide rated power flow of 600 MVA, and enter via one line U-1347 into the switchyard via one uprated 80 kA breaker 2BPB.	12/31/2018	$10.90	PSE&G	1/5/2017
9	s1255	Rebuild and upgrade 18.7 miles of existing Woodstown-Paulsboro 34.5 kV distribution line to create two 69 kV sources to the new High Street Substation.	5/31/2018	$38.20	AE	1/5/2017
10	s1257	Upgrade Tansboro 69 kV Bus to Ring Bus configuration.	9/28/2019	$5.74	AE	1/5/2017
11	s1260	Replace the existing Mickleton 69 kV line bus with a 69 kV ring bus configuration.	9/30/2020	$12.30	AE	1/5/2017
12	s1261	Construct a new 138/25 kV Carville substation with one new 138/25 kV 37.6 MVA transformer.	12/31/2018	$5.40	DPL	1/5/2017
13	s1263	Construct a new Beaglin 69/25 kV substation and tie into circuit 6726 (North Salisbury-Mt. Hermon).	4/29/2020	$11.50	DPL	1/5/2017
14	s1267	Replace underground submarine cables porti.on of the Brandon Shores-Riverside 230 kV circuits No. 2344 and No. 2345 with overhead conductors on towers.	12/31/2022	$203.00	BGE	1/5/2017
15	s1269	String second circuit on existing Columbia-Berick 69 kV towers for approximately 12 miles (Scott distribution substation to Berwick 69 kV substation).	7/1/2021	$12.00	PPL	1/5/2017
16	s1273	Replace the existing station light and power (SL&P) transformers with station service voltage transformers (SSVTs) fed from Kearny 230 kV Bus 1 and Bus 2.	11/30/2017	$6.30	PSE&G	6/9/2017
17	s1343	Rebuild line 0752 between Monroe and Pine Hill substations. All structures, conductor, and static wire will be replaced with new weathering steel poles, conductor and OPGW.	5/31/2020	$16.04	AE	6/9/2017
18	s1344	Rebuild line 0754 between Monroe and Tansboro substations. All structures, conductor, and static wire will be replaced with new weathering steel poles, conductor and OPGW.	12/31/2019	$13.62	AE	6/9/2017
19	s1345	Rebuild line 0763 between Monsanto and River substations. All structures, conductor and static wire will be replaced with new weathering steel poles, conductor, and OPGW. Tie the Monsanto-River (0763) line to the Mickleton-River (0747) to create a new Monsanto-Micketon 69 kV line.	5/31/2020	$14.36	AE	6/9/2017

Table 11.3: Mid-Atlantic Subregion – Supplemental Projects (Continued)

Map ID	Project ID	Project	Projected Date	Cost ($M)	TO Zone(s)	2017 TEAC Review
			Mid-Atlantic Subregion – Supplemental Projects			
20	s1347	Rebuild line 0721 between Lewis and Lenox substations. All structures, conductor, and static wire will be replaced with new weathering steel poles, conductor, and OPGW.	12/31/2020	$13.16	AE	6/9/2017
21	s1348	Rebuild Circuit 6734 from Harbeson substation to the Zoar tap. All structures, conductor, and static wire will be replaced with new weathering steel poles, conductor, and OPGW.	12/31/2018	$6.50	DPL	6/9/2017
22	s1350	Construct ~5 miles of 115 kV line using existing right-of-way (where possible). Install new 115 kV bus tie breaker at Niles Valley. Relocate Potter 115 kV line at Niles Valley. Install two SCADA controlled switches. Install switch structure for future network line extension.	6/1/2020	$12.80	PENELEC	6/9/2017
23	s1352	Providing a more robust and reliable power source to the 230 kV Kearny Switching Station, the existing station light & power (SL&P) transformers fed from street power will be replaced with Station Service Voltage Transformers (SSVTs) fed from Kearny 230 kV.	11/30/2017	$6.30	PSE&G	6/9/2017
24	s1366.1	Convert Paterson 26 kV to 69 kV station.	3/1/2021	$169.00	PSE&G	8/31/2017
	s1366.2	Convert Passaic 26 kV to 69 kV station.	3/1/2021		PSE&G	8/31/2017
	s1366.3	Build a 69 kV network between South Paterson, Paterson, North Paterson, Passaic and East Rutherford.	3/1/2021		PSE&G	8/31/2017
25	s1367	Replace the 69 kV AIS bus at Camden with a GIS breaker-and-a-half design	12/31/2020	$84.00	PSE&G	8/31/2017
26	s1368.1	Replace the 69 kV AIS straight bus at Penns Neck with an AIS breaker-and-a-half design	12/1/2020	$84.00	PSE&G	8/31/2017
	s1368.2	Install a 69 kV line between Penns Neck and Ridge Rd.	12/1/2020		PSE&G	8/31/2017
	s1368.3	Install 18 MVAR capacitor banks at Ridge Rd. 69 kV station.	12/1/2020		PSE&G	8/31/2017
27	s1369	Replace the 69 kV AIS straight bus at Gloucester with a GIS breaker-and-a-half design.	12/1/2020	$84.00	PSE&G	8/31/2017
28	s1370.1	Convert Woodbury 26 kV to a 69 kV substation.	12/31/2020	$114.00	PSE&G	8/31/2017
	s1370.2	Build two new lines between Gloucester and Woodbury 69 kV.	12/31/2020		PSE&G	8/31/2017
29	s1405.1	Install a new 230 kV bay at Newport 230 kV.	12/31/2020	$40.00	PSE&G	10/31/2017
	s1405.2	Build a second 230/13 kV substation at Newport.	12/31/2020		PSE&G	10/31/2017
30	s1406.1	Construct a new 69 kV line from Bennetts Lane to Franklin.	12/31/2020	$89.00	PSE&G	10/31/2017
	s1406.2	Replace Franklin 69 kV with a GIS ring.	12/31/2020	$89.00	PSE&G	10/31/2017
	s1406.3	Install one new 69 kV line position at Bennetts Lane.	12/31/2020	$89.00	PSE&G	10/31/2017
31	s1409	Sewaren, work associated with Sewaren generation retirement.	10/1/2018	$7.40	PSE&G	10/31/2017
32	s1411	Rebuild line 0714 69 kV between Clayton and Woodstown substations. All structures, conductor, and static wire will be replaced with new wood (in county ROW) and steel poles, conductor, and OPGW.	12/31/2022	$22.30	AE	10/31/2017
33	s1455	Rebuild line 23070 circuit between Cool Spring and Indian River 230 kV substations. All structures, conductor, and static wire will be replaced with new steel poles, conductor, and OPGW.	12/31/2020	$17.80	DPL	12/14/2017
35	s1459.1	Rebuild North Bridge Street 69 kV bus as a GIS ring bus.	10/31/2021	$60.00	PSE&G	12/19/2017
	s1459.2	Install new 69 kV overhead line from Bridgewater to North Bridge Street using existing line position at Bridgewater.	10/31/2021	$60.00	PSE&G	12/19/2017

Map 11.4: Mid-Atlantic Subregion – Supplemental Projects



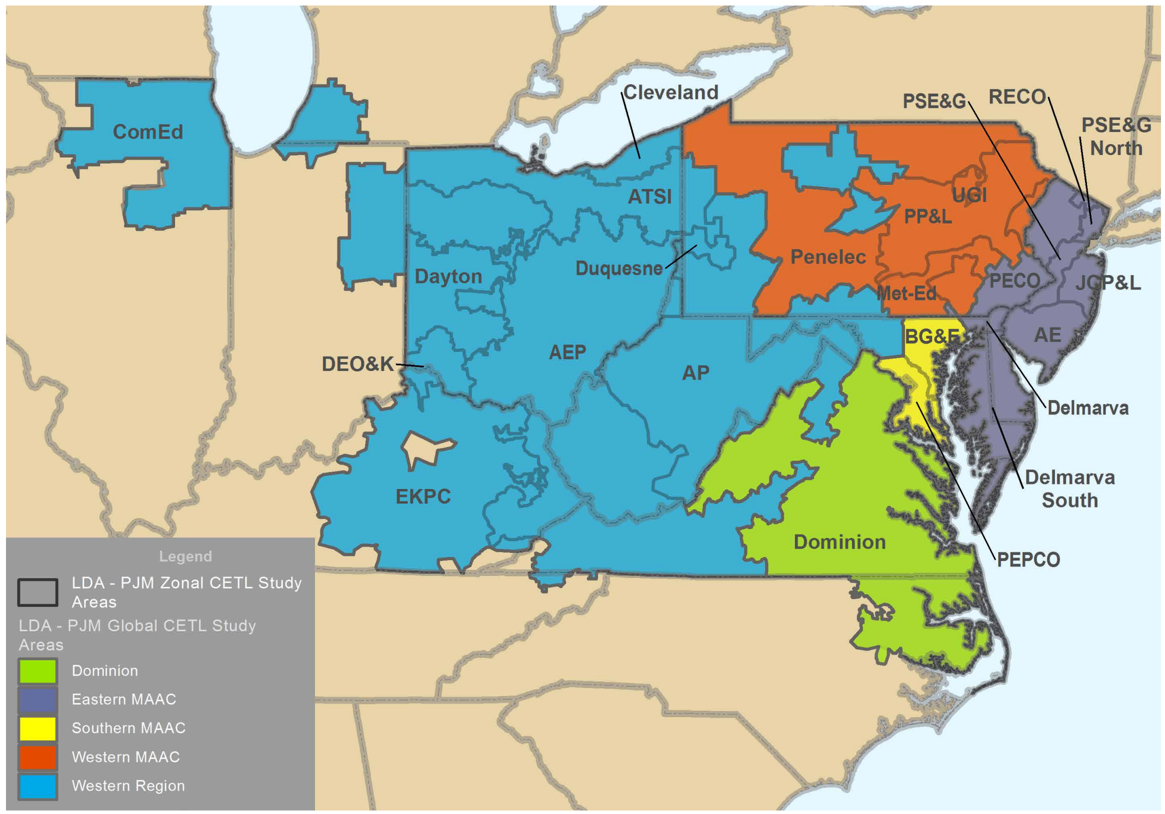
11.1: Western PJM Summary

11.1.1 — RTEP Context

PJM operates the bulk electric system transmission facilities (and others monitored at lower voltage levels) throughout PJM's Western subregion shown in **Map 11.5**. Systems include those of Allegheny Power (APS), American Electric Power (AEP), American Transmission Systems, Inc. (ATSI), Commonwealth Edison (ComEd), Dayton Power and Light (DAYTON), Duquesne Light Company (DLCO), Duke Energy Ohio and Kentucky (DEO&K), Eastern Kentucky Power Cooperative (EKPC) and ITC Holdings (ITC).

A 15-year long-term planning horizon allows PJM to consider the aggregate effects of many drivers. At 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 identifies one optimal, comprehensive set of solutions to resolve baseline reliability criteria violations, operational performance issues and congestion constraints as well as Network reinforcements to accommodate generator interconnection and other new queued service requests. Specific system enhancements are justified to deliver needed power to distant load centers as well to meet local subregional needs.

Map 11.5: Locational Deliverability Areas



Stakeholder Participation

Subregional RTEP committees increase the opportunity for direct stakeholder participation in the planning process from initial assumption setting stages through review of planning analyses, violations and alternative transmission expansion plans. Each subregional RTEP committee provides a more local forum for surfacing and considering planning issues. Interested parties can access PJM Western Subregional RTEP Committee information from PJM's website: http://www.pjm.com/committees-and-groups/committees/srrtep-w.aspx.

11.1.2 — Baseline Projects

Baseline transmission projects are system enhancements identified through analysis of operational performance issues, market efficiency studies and conventional NERC criteria tests that include the following:

- Base case thermal and voltage analysis
- Load deliverability thermal and voltages analysis
- Generation deliverability thermal analysis
- N-1-1 thermal and voltage analysis
- Common mode contingency analysis
- Short circuit analysis
- Baseline stability analysis
- Transmission owner criteria tests

Contingency analysis includes all bulk electric system facilities, tie lines to neighboring systems, critical neighboring system facilities and lower voltage facilities operated by PJM.

Baseline projects with cost estimates greater than $5 million approved by the PJM Board in 2017, are listed in **Table 11.4** and shown on **Map 11.6**.

Table 11.4: Western Subregion – Baseline Projects

			Western Subregion – Baseline Projects								
Map ID	Project ID	Project	Baseline Load Growth/ Deliverability & Reliability	Congestion Relief-Economic	Operational Performance	Short Circuit	TO Criteria Violation	Required Date	Cost ($M)	Designated Entity	2017 TEAC Review
1	b2689	Upgrade terminal equipment on Woodsville-Peters 138 kV circuit owned by FE (Structure 27A).		▲				6/1/2018	$11.25	APS	5/31/2017
2	b2753.9	Remove/Open Kammer 345/138 kV transformer No. 301.	▲					1/1/2019	$50.72	AEP	3/9/2017
	b2753.10	Complete sag study mitigation on the Muskingum-Natrium 138 kV line.	▲					1/1/2019		AEP	3/9/2017
3	b2761.3	Rebuild the Hazard-Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating).	▲					6/1/2021	$18.78	AEP	11/2/2017
4	b2779.1	Construction a new 138 kV station, Campbell Road, tapping into the Grabill-South Hicksville 138 kV line.	▲					6/1/2016	$107.70	AEP	11/3/2016
	b2779.2	Reconstruct sections of the Butler-N. Hicksville and Auburn-Butler 69 kV circuits as 138 kV double circuit and extend 138 kV from Campbell Road station.	▲					6/1/2016		AEP	11/3/2016
	b2779.3	Construct a new 345/138 kV SDI Wilmington Station which will be sourced from Collingwood 345 kV and serve the SDI load at 345 kV and 138 kV respectively.	▲					6/1/2016		AEP	11/3/2016
	b2779.4	Looped 138 kV circuits in-out of the new SDI Willington 138 kV station resulting in a direct circuit to Auburn 138 kV and in direct circuit to Auburn and Rob Park via Dunton Lake, and a circuit to Campbell Road; Reconductor 138 kV line section between Dunton Lake-SDI Willington.	▲					6/1/2016		AEP	11/3/2016
	b2779.5	Expand Auburn 138 kV bus	▲					6/1/2016		AEP	11/3/2016
5	b2789	Rebuild the Brues-Glendale Heights 69 kV line section (5 miles) with 795 ACSR (128 MVA rating, 43% loading).					▲	6/1/2021	$16.70	AEP	5/31/2017

Table 11.4: Western Subregion – Baseline Projects (Continued)

Map ID	Project ID	Project	Western Subregion – Baseline Projects: Baseline Load Growth/ Deliverability & Reliability	Congestion Relief-Economic	Operational Performance	Short Circuit	TO Criteria Violation	Required Date	Cost ($M)	Designated Entity	2017 TEAC Review
6	b2791.1	Rebuild portions of the East Tiffin-Howard 69 kV line from East Tiffin to West Rockaway Switch (0.8 miles) using 795 ACSR Drake conductor (129 MVA rating, 50% loading).					▲	6/1/2021	$20.39	AEP	5/31/2017
	b2791.2	Rebuild Tiffin-Howard 69 kV line from St. Stephen's Switch to Hinesville (14.7 miles) using 795 ACSR Drake conductor (90 MVA rating, non-conductor limited, 38% loading).					▲	6/1/2021		AEP	5/31/2017
	b2791.3	New 138/69 kV transformer with 138 kV and 69 kV protection at Chatfield station.					▲	6/1/2021		AEP	5/31/2017
	b2791.4	New 138 kV and 69 kV protection at existing Chatfield transformer.					▲	6/1/2021		AEP	5/31/2017
7	b2792	Replace the Elliott transformer with a 130 MVA unit, Reconductor 0.42 miles of the Elliott-Ohio University 69 kV line with 556 ACSR to match the rest of the line conductor (102 MVA rating, 73% loading) and rebuild 4 miles of the Clark Street-Strouds R					▲	6/1/2021	$5.76	AEP	5/31/2017
8	b2794	Construct new 138/69/34 kV station and 1-34 kV circuit (designed for 69 kV) from new station to Decliff station, approximately 4 miles, with 556 ACSR conductor (51 MVA rating).					▲	6/1/2021	$12.65	AEP	5/31/2017
9	b2797	Rebuild the Ohio Central-Conesville 69 kV line section (11.8 miles) with 795 ACSR conductor (128 MVA rating, 57% loading). Replace the 50 MVA Ohio Central 138-69 kV transformer with a 90 MVA unit.					▲	6/1/2021	$20.60	AEP	5/31/2017
10	b2799.1	Rebuild 12 miles of Valley-Almena 69 kV line as a double circuit 138 kV/69 kV line using 795 ACSR conductor (360 MVA rating) to introduce a new 138 kV source into the 69 kV load pocket around Almena station.					▲	6/1/2021	$53.00	AEP	5/31/2017
	b2799.2	Rebuild 3.2 miles of Almena to Hartford 69 kV line using 795 ACSR conductor (90 MVA rating).					▲	6/1/2021		AEP	5/31/2017
	b2799.3	Rebuild 3.8 miles of Riverside-South Haven 69V line using 795 ACSR conductor (90 MVA rating).					▲	6/1/2021		AEP	5/31/2017
	b2799.4	At Valley station, add new 138 kV line exit with a 3000A 40 kA breaker for the new 138 kV line to Almena and replace CB D with a 3000A 40 kA breaker.					▲	6/1/2021		AEP	5/31/2017
	b2799.5	At Almena station, install a 90 MVA 138 kV/69 kV transformer with low side 3000A 40 kA breaker and establish a new 138 kV line exit towards Valley.					▲	6/1/2021		AEP	5/31/2017
	b2799.6	At Hartford station, install a second 90MVA 138/69 kV transformer with a circuit switcher and 3000A 40 kA low side breaker.					▲	6/1/2021		AEP	5/31/2017
11	b2826.1	Install 300 MVAR reactor at Ohio Central 345 kV substation			▲			6/1/2018	$10.00	AEP	2/9/2017
	b2826.2	Install 300 MVAR reactor at West Bellaire 345 kV substation			▲			6/1/2018		AEP	2/9/2017
12	b2830	Expand Garver 345 kV sub to include 138 kV. Install 1-345 kV breaker, 1-345/138 kV 400 MVA transformer, 6-138 kV Breakers and bus work. Connect local 138 kV circuits from Todhunter, Rockies Express, and Union.	▲					6/1/2018	$18.70	DEO&K	1/12/2017

Table 11.4: Western Subregion – Baseline Projects (Continued)

Map ID	Project ID	Project	Western Subregion – Baseline Projects: Baseline Load Growth/ Deliverability & Reliability	Congestion Relief-Economic	Operational Performance	Short Circuit	TO Criteria Violation	Required Date	Cost ($M)	Designated Entity	2017 TEAC Review
13	b2831.1	Upgrade the Tanner Creek-Miami Fort 345 kV circuit (AEP portion)	▲					6/1/2018	$7.80	AEP	1/12/2017
	b2831.2	Upgrade the Tanner Creek-Miami Fort 345 kV circuit (DEO&K portion)	▲					6/1/2018		DEO&K	1/12/2017
14	b2833	Reconductor the Maddox Creek-East Lima 345 kV circuit with 2-954 ACSS Cardinal conductor	▲					12/1/2021	$18.20	AEP	1/12/2017
15	b2834	Reconductor and string open position and six wire 6.2 miles of the Chemical-Capitol Hill 138 kV circuit	▲					12/1/2021	$7.30	AEP	1/12/2017
16	b2880	Rebuild approximately 4.77 miles of the Cannonsburg-South Neal 69 kV line section utilizing 795 ACSR conductor (90 MVA rating, 83%)					▲	6/1/2021	$12.50	AEP	5/31/2017
17	b2883	Rebuild the Craneco-Pardee-Three Forks-Skin Fork 46 kV line section (approximately 7.2 miles) utilizing 795 26/7 ACSR conductor (108 MVA rating, 43%)					▲	6/1/2021	$12.20	AEP	5/31/2017
18	b2884	Install a second transformer at Nagel station, comprising three single phase 250 MVA 500/138 kV transformers. Presently, TVA operates their end of the Boone Dam-Holston 138 kV interconnection as normally open preemptively for the loss of the existing Nagel					▲	6/1/2021	$13.00	AEP	5/31/2017
19	b2885.1	Install a new Ironman Switch to serve a new delivery point requested by the City of Jackson for a load increase request.					▲	3/1/2018	$13.00	AEP	5/31/2017
	b2885.2	Install a new 138/69 kV station (Rhodes) to serve as a third source to the area to help relieve overloads caused by the customer load increase.					▲	3/1/2018		AEP	5/31/2017
	b2885.3	Replace Coalton Switch with a new three breaker ring bus (Heppner).					▲	3/1/2018		AEP	5/31/2017
20	b2888.1	Remove and retire the Poston 138 kV station.	▲					12/31/2018	$26.97	AEP	5/31/2017
	b2888.2	Install a new greenfield station, Lemaster 138 kV Station, in the clear.	▲					12/31/2018		AEP	5/31/2017
	b2888.3	Relocate the Trimble 69 kV AEP Ohio radial delivery point to 138 kV, to be served off of the Poston-Strouds Run-Crooksville 138 kV circuit via a new three-way switch. Retire the Poston-Trimble 69 kV line.	▲					12/31/2018		AEP	5/31/2017
21	b2889.1	Cliffview Station: Establish 138 kV bus. Install two 138/69 kV transformers (130 MVA), six 138 kV circuit breakers (40 kA 3000A) and four 69 kV circuit breakers (40 kA 3000A).					▲	6/1/2021	$30.00	AEP	5/31/2017
	b2889.2	Byllesby-Wythe 69 kV: Retire all 13.77 miles (1/0 CU) of this circuit (~4 miles currently in national forest)					▲	6/1/2021		AEP	5/31/2017
	b2889.3	Galax-Wythe 69 kV: Retire 13.53 miles (1/0 CU section) of line from Lee Highway down to Byllesby. This section is currently double circuited with Byllesby-Wythe 69 kV. Terminate the southern 3/0 ACSR section into the newly opened position at Byllesby					▲	6/1/2021		AEP	5/31/2017
	b2889.4	Cliffview Line: Tap the existing Pipers Gap-Jubal Early 138 kV line section. Construct double circuit in/out (~2 miles) to newly established 138 kV bus, utilizing 795 26/7 ACSR conductor.					▲	6/1/2021		AEP	5/31/2017

Table 11.4: Western Subregion – Baseline Projects (Continued)

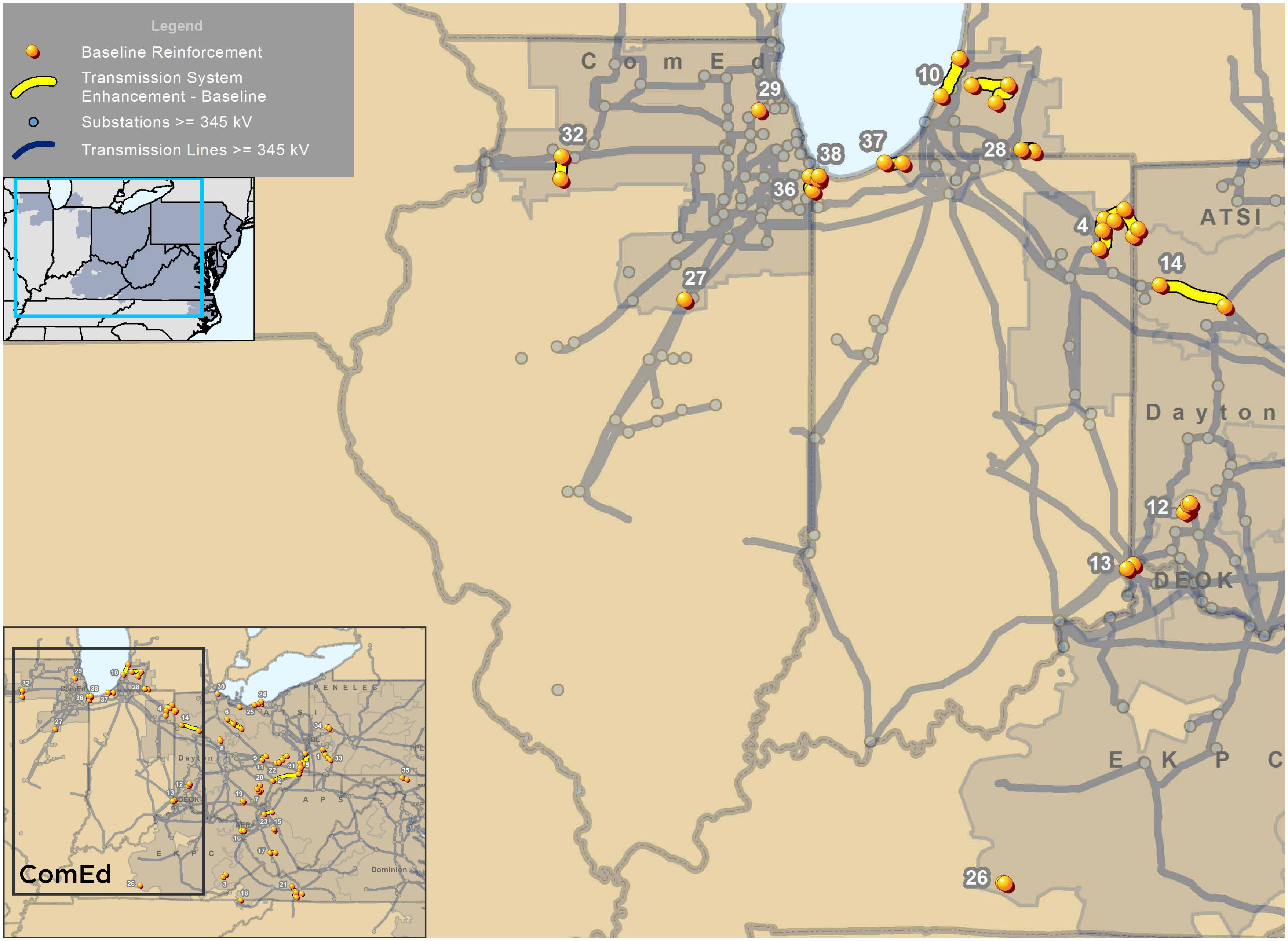
Map ID	Project ID	Project	Western Subregion – Baseline Projects: Baseline Load Growth/ Deliverability & Reliability	Congestion Relief-Economic	Operational Performance	Short Circuit	TO Criteria Violation	Required Date	Cost ($M)	Designated Entity	2017 TEAC Review
22	b2890.1	Rebuild 23.55 miles of the East Cambridge-Smyrna 34.5 kV circuit with 795 ACSR conductor (128 MVA rating) and convert to 69 kV.					▲	6/1/2021	$36.25	AEP	5/31/2017
	b2890.2	East Cambridge: Install a 2000 A 69 kV 40 kA circuit breaker for the East Cambridge-Smyrna 69 kV circuit.					▲	6/1/2021		AEP	5/31/2017
	b2890.3	Old Washington: Install 69 kV 2000 A two way phase-over-phase switch.					▲	6/1/2021		AEP	5/31/2017
	b2890.4	Antrim Switch: Install 69 kV 2000 A two way phase-over-phase switch.					▲	6/1/2021		AEP	5/31/2017
23	b2892	Install new 138/12 kV transformer with high side circuit switcher at Leon and a new 138 kV line exit towards Ripley. Establish 138 kV at the Ripley station with a new 138/69 kV 130 MVA transformer and move the distribution load to 138 kV service. Rebuild the existing 69 kV Leon-Ripley branch with 1033 ACSR and operate at 138 kV. Rebuild the Ripley 69 kV bus.					▲	6/1/2021	$27.10	AEP	5/31/2017
24	b2897	Reconductor the Avon-Lorain 138 kV section and upgrade line drop at Avon.	▲					6/1/2021	$13.46	ATSI	6/8/2017
25	b2898	Reconductor the Beaver-Black River 138 kV with 954 Kcmil ACSS conductor and upgrade terminal equipment on both stations	▲					6/1/2021	$19.97	ATSI	6/8/2017
26	b2921	New TVA 161 kV Interconnection to TVA's East Glasgow Tap-East Glasgow 161 KV line section (~1 mile due West of Fox Hollow). Add Fox Hollow 161/69 KV 150 MVA transformer. Construct new Fox Hollow-Fox Hollow Jct 161 KV line section using 795 MCM ACSR (~1 mile) and new 161 kV switching station at point of interconnection with TVA.					▲	6/1/2018	$18.10	EKPC	7/21/2017
27	b2931	Upgrade substation equipment at Pontiac Midpoint station to increase capacity on Pontiac-Brokaw 345 kV line.		▲				6/1/2021	$5.62	ComEd	8/10/2017
28	b2936.1	Rebuild approximately 6.7 miles of 69 kV line between Mottville and Pigeon River using 795 ACSR conductor (129 MVA rating). New construction will be designed to 138 kV standards but operated at 69 kV.					▲	6/1/2020	$12.00	AEP	9/11/2017
29	b2941	Build an indoor new Elk Grove 138 kV GIS substation at the point where Rolling Meadows and Schaumburg tap off from the main lines, between Landmeier and Busse. The four 345 kV circuits in the ROW will be diverted into a gas insulated bus (GIB) and go through the basement of the building to provide clearance for the above-ground portion of the building.	▲					6/1/2021	$90.00	ComEd	9/11/2017
30	b2942.1	Install a 100 MVAR 345 kV shunt reactor at Hayes substation.			▲			10/31/2017	$10.70	ATSI	9/14/2017
	b2942.2	Install a 200 MVAR 345 kV shunt reactor at Bayshore substation.			▲			10/31/2018		ATSI	9/14/2017
31	b2958.1	Cut George Washington-Tidd 138 kV circuit into Sand Hill and reconfigure Brues and Warton Hill line entrances.					▲	7/1/2017	$7.25	AEP	11/2/2017
	b2958.2	Add two 138 kV 3000A 40 kA breakers, disconnect switches, and update relaying at Sand Hill station.					▲	7/1/2017		AEP	11/2/2017

Table 11.4: Western Subregion – Baseline Projects (Continued)

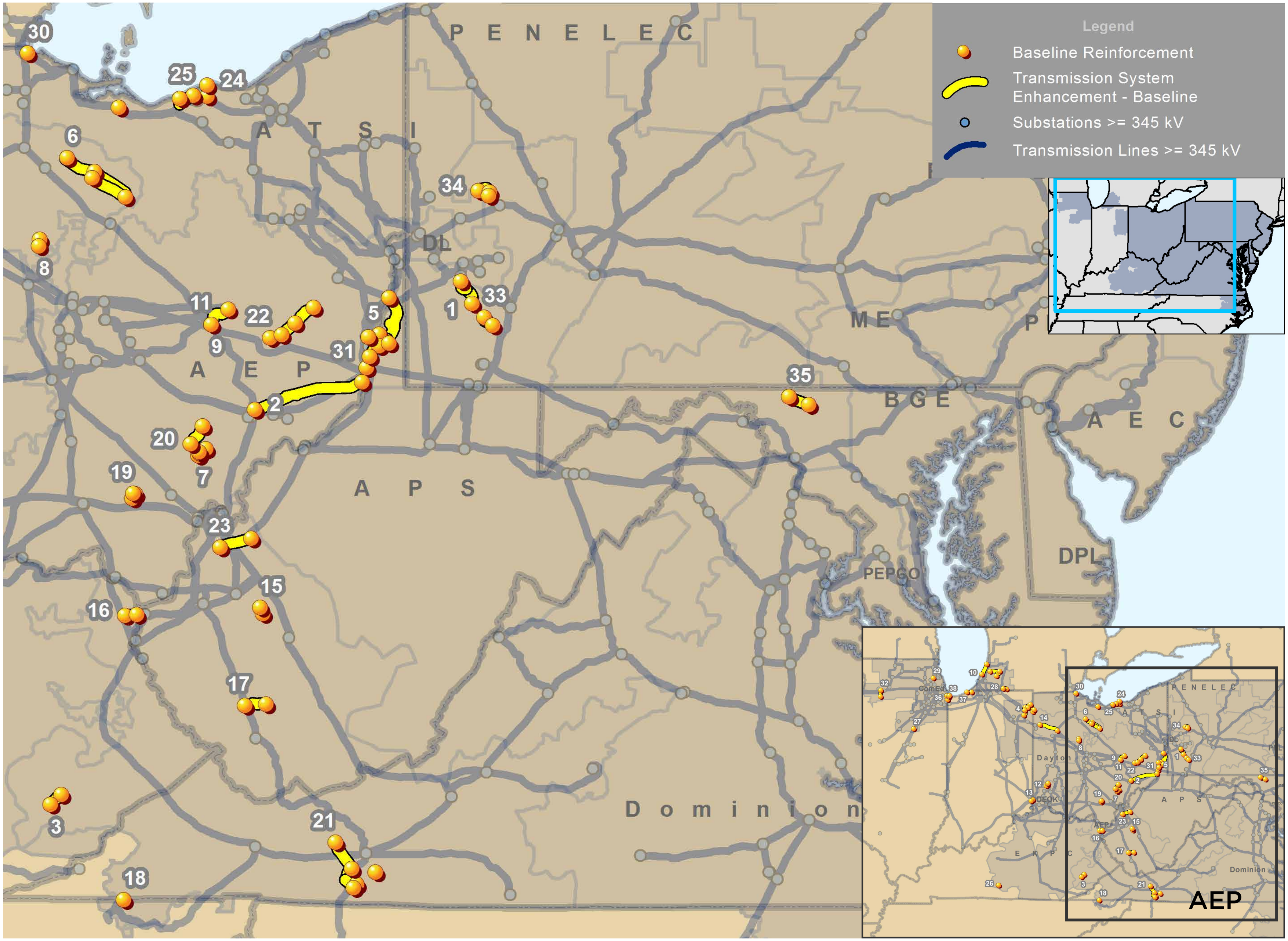
Map ID	Project ID	Project	Western Subregion – Baseline Projects: Baseline Load Growth/ Deliverability & Reliability	Congestion Relief-Economic	Operational Performance	Short Circuit	TO Criteria Violation	Required Date	Cost ($M)	Designated Entity	2017 TEAC Review
32	b2959	Install a new 138 kV circuit 18702 from Schauff Road to Rock Falls and install a fourth breaker and a half run at Schauff Road.	▲					11/1/2019	$20.00	ComEd	11/2/2017
33	b2965	Reconductor the Charleroi-Allenport 138 kV line with 954 ACSR Conductor. Replace Breaker Risers at Charleroi and Allenport.	▲					6/1/2022	$7.08	APS	11/2/2017
34	b2967	Convert the existing 6 wire Butler-Shanor Manor-Krendale 138 kV Line into two separate 138 kV lines. New lines will be Butler-Keisters and Butler-Shanor Manor-Krendale 138 kV.	▲					6/1/2022	$6.96	APS	11/2/2017
35	b2970.1	Install two new 230 kV positions at Ringgold for 230/138 kV transformers.	▲					6/1/2020	$13.33	APS	11/2/2017
	b2970.2	Install new 230 kV position for Ringgold-Catoctin 230 kV line.	▲					6/1/2020		APS	11/2/2017
	b2970.3	Install one new 230 kV breaker at Catoctin substation.	▲					6/1/2020		APS	11/2/2017
	b2970.4	Install new 230 / 138 kV transformer at Catoctin substation. Convert Ringgold-Catoctin 138 kV Line to 230 kV operation.	▲					6/1/2020		APS	11/2/2017
36	b2971. & .2	Reconfigure Munster 345 kV as ring bus.		▲				6/1/2020	$6.7	NIPSCO*	11/9/2017
37	b2973	Reconductor Michigan City-Bosserman 138 kV line.		▲				12/1/2019	$6.0	NIPSCO*	11/9/2017
38	b2975	Reconductor Roxana-Praxair 138 kV line.		▲				6/1/2020	$6.1	NIPSCO*	11/9/2017

* NOTE: PJM-MISO targeted market efficiency projects

Map 11.6: Western Subregion– Baseline Projects



Map 11.6: Western Subregion – Baseline Projects



11.1.3 — Network Projects

PJM's RTEP also includes system reinforcements identified through interconnection process system impact studies. These Network projects are necessary to interconnect new generation, merchant transmission facilities and other new services. Direct connection network projects are transmission enhancements that deliver power to a defined point of interconnection. Non-direct connection Network projects mitigate transmission system impacts beyond the point of interconnection. Network projects with cost estimates greater than $5 million approved by the PJM Board in 2017 are listed in **Table 11.5** and shown on **Map 11.7**.

Table 11.5: Western Subregion – Network Projects

			Western Subregion – Network Projects						
Map ID	Project ID	Project	Generation Interconnection	Merchant Transmission Interconnection	Auction Revenue Rights Request	Adjacent RTO Interconnection	Cost ($M)	TO Zone(s)	2017 TEAC Review
1	n2115	Construct a new switching station, including four 138 kV circuit breakers, relays, 138 kV revenue metering, SCADA and associated equipment	U4-028				$5.86	AEP	10/12/2017
2	n3666	Construct a new Iron Ridge 138 kV switching station.	Y1-006				$7.52	AEP	10/12/2017
	n3666.1	Install ADSS fiber at the new Iron Ridge 138 kV substation.	Y1-006					AEP	10/12/2017
	n3666.2	Construct Jubal Early-Austinville 138 kV T-line cut in.	Y1-006					AEP	10/12/2017
	n3666.3	Install 138 kV Revenue Metering at the new Iron Ridge 138 kV substation.	Y1-006					AEP	10/12/2017
3	n4317.1	Install one 345 kV breaker at the Leroy Center 345 kV.		Y3-092			$202.96	ATSI	10/12/2017
	n4317.3	Build a new Leroy Center-Erie West 345 kV line.		Y3-092				ATSI	10/12/2017
4	n4318	Reconduct Leroy Center-Spruce 138 kV line.		Y3-092			$8.90	ATSI	10/12/2017
5	n4320.1	Replace line side disconnect risers and connectors, and revise relay settings as necessary at the Butler terminal of the Butler-Karns City 138 kV line.		Y3-092			$25.88	APS	10/12/2017
	n4320.2	Reconductor the Karns City 138 kV line terminal at the Butler 138 kV including Wave Trap, line and bus side disconnects.		Y3-092				APS	10/12/2017
	n4320.3	Reconductor Butler-Karns City 138 kV line – 15.6 mile to achieve a 228 MVA summer emergency rating.		Y3-092				APS	10/12/2017
6	n4713.1	Sturgis-Howe 69 kV T-line removal.	X1-020				$6.05	AEP	10/12/2017
	n4713.2	Right of way.	X1-020					AEP	10/12/2017
7	n4742.1	Greentown-Dumont 765 kV T-line circuit cut-in.	X1-020				$34.66	AEP	10/12/2017
	n4742.2	765 kV metering.	X1-020					AEP	10/12/2017
	n4742.4	Telecommunications – fiber optic between stations.	X1-020					AEP	10/12/2017
8	n4790	Rebuild 9 miles of the AEP portion of the Stillwell-Dumont 345 kV line and upgrade necessary Dumont terminal equipment.	AB1-122				$20.00	AEP	10/12/2017

Table 11.5: Western Subregion – Network Projects (Continued)

Map ID	Project ID	Project	Western Subregion – Network Projects: Generation Interconnection	Merchant Transmission Interconnection	Auction Revenue Rights Request	Adjacent RTO Interconnection	Cost ($M)	TO Zone(s)	2017 TEAC Review
9	n5008	Reconfigure the Kewanee 138 kV bus by swapping the Bishop Hill and Edwards line terminals.	AA2-039				$7.50	ComEd	10/12/2017
10	n5048	Construct Saxony 138 kV Line ext.	V2-006				$7.24	AEP	10/12/2017
11	n5065	Reconductor or rebuild the Eugene-Dequine 345 kV line and replace the Dequine riser				J439 (MISO)	$88.30	AEP	10/12/2017
12	n5106	Reconductor or rebuild depending on the existing structures the portions of 345 kV lines between the Benton Harbor and Sagreto 345 kV substations.				J298 (MISO)	$19.00	AEP	10/12/2017
13	n5144	Upgrade L10805 Kendall; B-Lockport; B 345 kV line conductor.	AA2-035				$18.20	ComEd	10/12/2017
14	n5145	Reconfigure Wilton 765 kV bus, thereby allowing for 765 kV L11216 (currently on Bus 6) to be relocated to Bus 8. Along with this line relocation, installation of 2-765 kV bus tie circuit breakers (6-8 and 8-2).	AA2-035				$11.00	ComEd	10/12/2017
15	n5178.1	Replacement of 345 kV breaker at Sta 6 Byron BT5-6 with 2-cycle IPO breaker.	AB1-089				$12.00	ComEd	10/12/2017
	n5178.2	Replacement of 345 kV breaker at Sta 6 Byron BT4-5 with 2-cycle IPO breaker.	AB1-089					ComEd	10/12/2017
	n5178.3	Replacement of 345 kV breaker at Sta 6 Byron BT11-12 with 2-cycle IPO breaker.	AB1-089					ComEd	10/12/2017
	n5178.4	Replacement of 345 kV breaker at Sta 6 Byron BT12-13 with 2-cycle IPO breaker.	AB1-089					ComEd	10/12/2017
16	n5179	Installation of about 50 miles of 345 kV line from AB1-089/AB1-090 to Wayne.	AB1-089				$115.00	ComEd	10/12/2017
	n5179.1	Installation of fwo 345 kV breakers at Wayne and 3-345 kV breakers at AB1-089/AB1-090 terminal station.	AB1-089				$115.00	ComEd	10/12/2017
17	n5194.1	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker B5213(GEN B).	AB1-105				$13.01	ATSI	10/12/2017
	n5194.2	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker B5218(GEN B).	AB1-105					ATSI	10/12/2017
	n5194.3	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker BVR VLY(B456).	AB1-105					ATSI	10/12/2017
	n5194.4	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker BVR VLY(B459).	AB1-105					ATSI	10/12/2017
	n5194.5	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker GEN.3-E(B279).	AB1-105					ATSI	10/12/2017
	n5194.6	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker GEN.4-E.(B11).	AB1-105					ATSI	10/12/2017
	n5194.7	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker GEN.5-E(B284).	AB1-105					ATSI	10/12/2017
	n5194.8	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker GEN.6-E.B(B5).	AB1-105					ATSI	10/12/2017
	n5194.9	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker GEN.7-E(B453).	AB1-105					ATSI	10/12/2017
	n5194.10	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker HIL-W.B(B280).	AB1-105					ATSI	10/12/2017
	n5194.11	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker HL-GEN3(B278).	AB1-105					ATSI	10/12/2017
	n5194.12	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker S.CAN-W(B290).	AB1-105					ATSI	10/12/2017
	n5194.13	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker SN-GEN5(B287).	AB1-105					ATSI	10/12/2017
	n5194.14	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA breaker SR-W.BUS(B17).	AB1-105					ATSI	10/12/2017

Table 11.5: Western Subregion – Network Projects (Continued)

Map ID	Project ID	Project	Western Subregion – Network Projects: Generation Interconnection	Merchant Transmission Interconnection	Auction Revenue Rights Request	Adjacent RTO Interconnection	Cost ($M)	TO Zone(s)	2017 TEAC Review
	n5194.15	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA Breaker STRGEN.4(B14).	AB1-105					ATSI	10/12/2017
	n5194.16	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA Breaker TR-GEN6(B295).	AB1-105				$13.01	ATSI	10/12/2017
	n5194.17	At Sammis substation – Replace 345 kV circuit breaker with a 80 kA Breaker TRW.BUS(B298).	AB1-105					ATSI	10/12/2017
18	n5196	Install a new AB1-105 Interconnect SS. 345 kV 3-breaker ring bus, Hannah-Highland line.	AB1-105				$8.72	ATSI	10/12/2017
19	n5252	Mitigate the sag on the Wilton-Dumont 765 kV line L11215 to achieve an ALDR that exceeds 6,166 MVA.	AB1-122				$9.00	ComEd	10/12/2017
20	n5253	Reconductor the ComEd portion of Crete-St John 345 kV line.	AB1-122				$18.00	ComEd	10/12/2017
21	n5254	Reconductor the Lee County-Byron 345 kV line.				J534 (MISO)	$6.00	ComEd	10/12/2017
22	n5258	Install 138 kV three breaker ring bus connector station for new customer generation addition along the Galion-Roberts South 138 kV line.	AB2-131				$5.15	ATSI	10/12/2017
23	n5286	AB1-107 GT-1 SS-Construct a 138 kV three-breaker ring bus interconnect substation on the Bayshore-GM Powertrain line.	AB1-107				$5.22	ATSI	10/12/2017
24	n5303	Rebuild/Reconductor 40.61 miles of the AEP-owned section of the Olive-University Park 345 kV ACSR/PE 1414 62/19 line section 1 and replace Olive switches and riser.	AB1-122				$82.60	ComEd	10/12/2017
25	n5311	Rebuild or Reconductor approximately 30 miles of the Cook-T-094 (Segreto) 345 kV line.				J439 (MISO)	$60.00	AEP	10/12/2017
26	n5315	Reconductor the Cherry Valley-Garden Prairie 345 kV line and upgrade terminal equipment at both ends.	AB1-089				$50.00	ComEd	10/12/2017
27	n5316	Reconductor the Cordova-Nelson 345 kV line and replace station conductor at Cordova.				J302 (MISO)	$20.20	ComEd	10/12/2017
28	n5317	Reconductor the E Frankfort-Crete 345 kV line.				J415 (MISO)	$10.00	ComEd	10/12/2017
29	n5318	Reconductor the Garden Prairie-Silver Lake 345 kV line and station conductor at both terminals.	AB1-090				$50.00	ComEd	10/12/2017
30	n5319	Reconductor the Nelson-Lee County 345 kV line and upgrade station conductor, 2-345 kV bus tie circuit breakers, and disconnect switches at Nelson.				J456 (MISO)	$15.00	ComEd	10/12/2017
31	n5320	Reconductor the Pontiac-Dresden 345 kV line.				J474 (MISO)	$22.00	ComEd	10/12/2017
32	n5321	Reconductor the Quad Cities-ESS H471 345 kV line and upgrade station conductor at Sterling Steel and Quad Cities.				J302 (MISO)	$20.20	ComEd	10/12/2017
33	n5322	Reconductor the ESS H471-Nelson 345 kV line and upgrade station conductor.				J414 (MISO)	$20.20	ComEd	10/12/2017

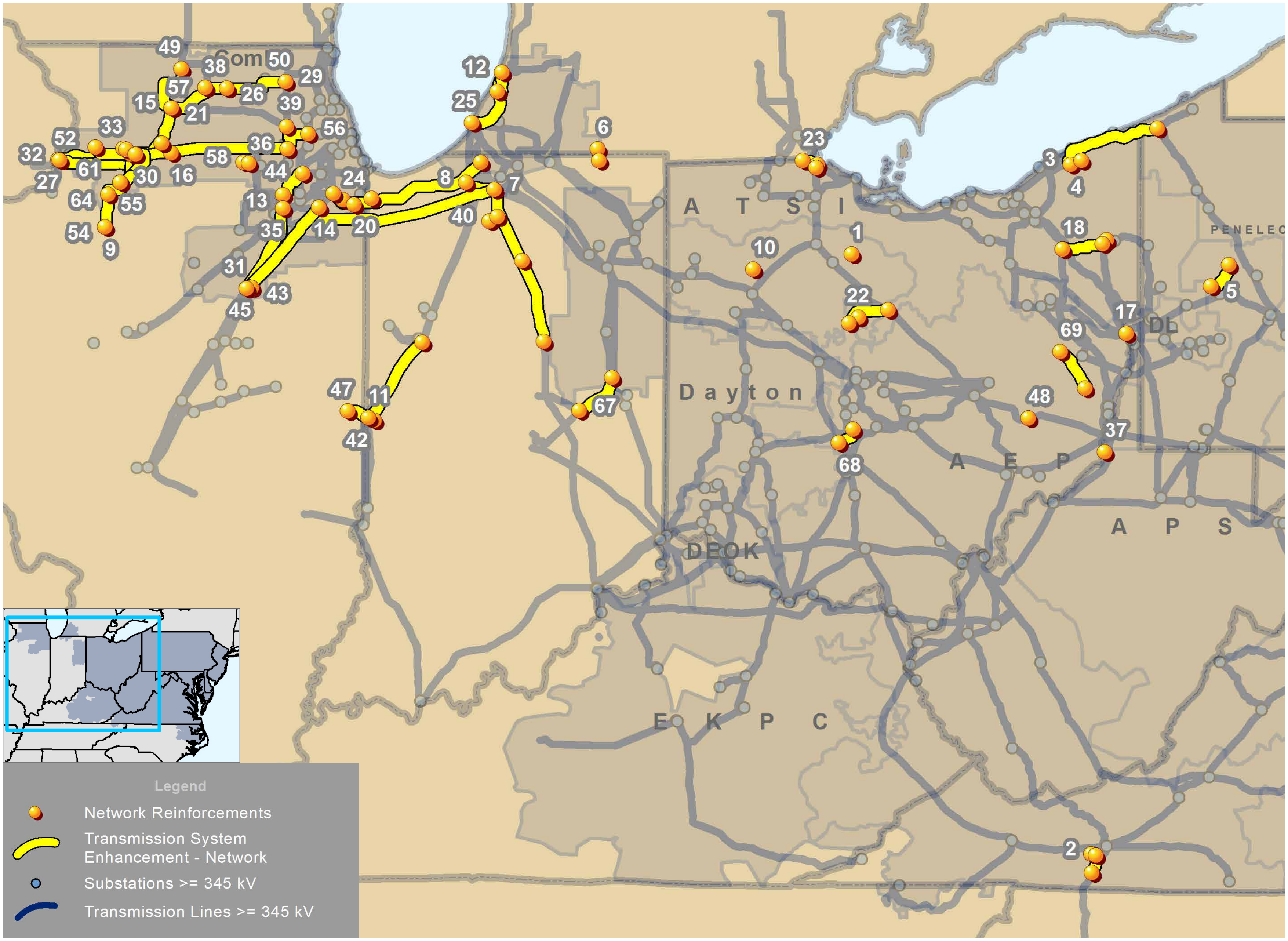
Table 11.5: Western Subregion – Network Projects (Continued)

			Western Subregion – Network Projects						
Map ID	Project ID	Project	Generation Interconnection	Merchant Transmission Interconnection	Auction Revenue Rights Request	Adjacent RTO Interconnection	Cost ($M)	TO Zone(s)	2017 TEAC Review
34	n5323	Reconductor the Lee County-Byron 345 kV line, upgrade station conductor and replace bus disconnect switches at Byron.				J594 (MISO)	$6.50	ComEd	10/12/2017
35	n5324	Reconductor the AB1-122 Tap-Dresden 345 kV line.	AB1-122				$20.00	ComEd	10/12/2017
36	n5326	Build a second Nelson-Electric Jct 345 kV line.				J577 (MISO)	$300.00	ComEd	10/12/2017
37	n5327	Construct a new nine circuit breaker 138 kV switching station physically configured in a breaker and half bus arrangement at or near the existing Ormet 138 kV station site.	AB2-093				$13.00	AEP	10/12/2017
38	n5335	Existing limit is conductor. Reconductor Cherry Valley-Garden Pr 345 kV line.			AA1-120		$25.00	AEP	10/12/2017
39	n5336	Existing limit is conductor. Reconductor Garden PR-Silver Lake 345 kV line.			AA1-120		$25.00	AEP	10/12/2017
40	n5337	Rebuild of 8.3 miles of 138 kV line from Burroak-Plymouth.			AA1-120		$10.40	AEP	10/12/2017
41	n5338	Replace circuit breaker 7-8 and circuit breaker 8-9 at Nelson.			AA1-120		$6.00	AEP	10/12/2017
42	n5339	Rebuild Eugene-Cayuga complete line (3.17 miles) with steel structures and larger conductor – (2)1272ACSR45X7: 3028A rating at 100C.			AA1-120		$18.60	AEP	10/12/2017
43	n5341	Mitigate sag limits on 345 kV line 11212 Loretto-Wilton Center.			AA1-120		$30.00	AEP	10/12/2017
44	n5344	Rating is 1334/1656. Additional capacity would require replacing two MODs at Electric Junction for a cost of $0.5 million.			AA1-120		$5.00	AEP	10/12/2017
45	n5346	For Pontiac-Loretto (Line 8012), mitigate sag on the 345 kV line.			AA1-120		$12.00	AEP	10/12/2017
46	n5349	Upgrade station conductor at ESS H471 on L0404.			AA1-120		$57.50	AEP	10/12/2017
47	n5350.1	AEP end: Replace the Eugene Wave trap (3000A). New Ratings after mitigation is complete: S/N 1,916 MVA, S/E2194.			AA1-120		$57.90	AEP	10/12/2017
	n5350.2	Ameren End: Build a new 345 kV line from Bunsonville-Eugene.			AA1-120			AEP	10/12/2017
48	n5352	To accommodate the interconnection on the Kammer-Vassell 765 kV circuit a new three circuit breaker 765 kV switching station physically configured in a breaker and half bus arrangement but operated as a ring-bus will be constructed 40 miles east of the Kammer 765 kV substation.	AB2-067				$25.00	AEP	10/12/2017
49	n5358	28 miles of 345 kV Reconductoring of Wempleton to Byron line and substation conductor.			AB1-185		$56.10	ComEd	10/12/2017
50	n5359	26.7 miles of 345 kV Reconductoring from Silver lake to GardenPR and substation conductor.			AB1-185		$54.10	ComEd	10/12/2017
51	n5360	13.8 miles of 345 kV Reconductoring from Cherry Valley to GardenPR.			AB1-185		$27.00	ComEd	10/12/2017
52	n5362	40 miles of 345 kV Reconductoring of Nelson to Cardova.			AB1-185		$80.00	ComEd	10/12/2017
53	n5365	10.4 miles of 138 kV reconductoring of rockfalls line..			AB1-185		$10.40	ComEd	10/12/2017
54	n5368	26.9 miles of 138 kV Reconductoring from Normandy to Kewanee line.			AB1-185		$26.90	ComEd	10/12/2017
55	n5369	5.4 miles of 138 kV Reconductoring of Normandy line.			AB1-185		$5.40	ComEd	10/12/2017

Table 11.5: Western Subregion – Network Projects (Continued)

Map ID	Project ID	Project	Western Subregion – Network Projects: Generation Interconnection	Merchant Transmission Interconnection	Auction Revenue Rights Request	Adjacent RTO Interconnection	Cost ($M)	TO Zone(s)	2017 TEAC Review
56	n5370	13.6 miles of 345 kV reconductoring of Electric Junction to Lombard.			AB1-185		$27.20	ComEd	10/12/2017
57	n5371	6.7 miles of 345 kV reconductoring Byron to Cherry Valley line.			AB1-185		$13.40	ComEd	10/12/2017
58	n5384	8.8 miles of 138 kV reconductoring of Plano West to Sandwich line.			AB1-185		$8.80	ComEd	10/12/2017
59	n5385	12.5 miles of 138 kV reconductoring of Nelson to O-029 line.			AB1-185		$12.50	ComEd	10/12/2017
60	n5387	7.9 miles of 345 kV reconductoring from Nelson to ESSH471.			AB1-185		$15.80	ComEd	10/12/2017
61	n5390	11 miles of 138 kV reconductoring at Garden Plain to ESSH71 line.			AB1-185		$11.00	ComEd	10/12/2017
62	n5392	19.472 miles 345 kV reconductoring of Byron-lee Co Energy Center and substation conductor.			AB1-185		$39.04	ComEd	10/12/2017
63	n5393	5.4 miles of 138 kV reconductoring to O-029 to Normandy line.			AB1-185		$5.40	ComEd	10/12/2017
64	n5394	17.9 miles of 138 kV reconductoring to Normandy to Annawan.			AB1-185		$17.90	ComEd	10/12/2017
65	n5396	6.7 miles of 138 kV reconductoring from Byron to Cherry Valley.			AB1-185		$13.40	ComEd	10/12/2017
66	n5398	Install Additional Auto transformer at Nelson; B-nelson2M.			AB1-185		$15.00	ComEd	10/12/2017
67	n5417	Construct a new three-circuit breaker 345 kV switching station along the Desoto-Fall Creek 345 kV line.	AB2-028				$5.55	AEP	10/12/2017
68	n5457	Reconductor/rebuild the AEP portion of the Adkins-Beatty 345 kV line.	AC1-069				$26.00	Dayton	10/12/2017
69	n5473	Reconductor the Nottingham-Yager 138 kV line.	AC1-103				$30.45	AEP	10/12/2017

Map 11.7: Western Subregion– Network Projects



11.1.4 — Supplemental Projects

Prior to FERC Order No. 890 in 2008, Supplemental Projects were referred to as Transmission Owner Initiated or TOI Projects. A Supplemental project is not required for compliance with system reliability, operational performance or economic criteria, as determined by PJM. Supplemental projects frequently address aging infrastructure, provide support to serve underlying systems and add connections to new, large load customers. PJM reviews Supplemental projects 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.

Transmission owners submitted a number of Supplemental projects throughout 2017. Projects with cost estimates greater than $5 million are listed in **Table 11.6** and shown on **Map 11.8**.

Table 11.6: Western Subregion – Supplemental Projects

Western Subregion – Supplemental Projects						
Map ID	**Project ID**	**Project**	**Projected Date**	**Cost ($M)**	**TO Zone(s)**	**2017 TEAC Review**
1	s1185.1	Construct 138 kV Britton Station, tapping the existing Davidson-Dublin underground circuit to serve new customer owned station and load.	6/30/2017	$18.10	AEP	1/5/2017
	s1185.2	Build a new 138 kV overhead circuit from Britton to Davidson.	6/30/2017		AEP	1/5/2017
	s1185.3	Reconfigure Davidson Station to improve reliability.	12/31/2017		AEP	1/5/2017
	s1185.4	Remote end work at Dublin, Bethel Road and Roberts stations.	6/30/2017		AEP	1/5/2017
2	s1187	Construct McConville station to serve distribution load on the Brookville-Graves Mill 138 kV line.	6/30/2017	$7.40	AEP	1/5/2017
3	s1189	Construct 138 kV Sumac Station to serve the new customer station and load adjacent to Amlin station. Construct Cole 345/138 kV station by tapping the Beatty-Hayden 345 kV circuit. String a 138 kV circuit from Cole to Amlin on existing towers, providing a second source to Amlin.	6/30/2018	$42.10	AEP	1/5/2017
4	s1190	Install a new Clouse 138/69 kV station at the intersection of the West Lancaster-Zanesville 138 kV line and the South Fultonham-New Lexington 69 kV line.	12/15/2017	$18.10	AEP	1/5/2017
5	s1191	Rebuild the Corridor-Jug Street 345 kV line as a double circuit line with one side served at 345 kV and the other at 138 kV to provide a third source to Jug Street station.	12/1/2019	$17.00	AEP	1/5/2017
6	s1192	Construct new Marriett 138/12 kV Station, which is tapped into the Twelve Pole Creek-Tri-State 138 kV line.	7/1/2017	$7.24	AEP	1/5/2017
7	s1194	Build 69 kV line between Lincoln and a new 138/69 kV Berrywood station to provide loop service.	12/1/2018	$38.70	AEP	1/5/2017
8	s1195	Tap the existing Hadley-McKinley 69 kV circuit and construct a new 69 kV double circuit extension to a new Melita 69 kV station, retiring Webster station and converting existing 34.5 kV transmission lines from Hillcrest to Melita (formerly Webster).	12/13/2017	$24.00	AEP	1/5/2017
9	s1200.1	Construct a new 138/12 kV Aviation station and approximately 4.7 miles of new 138 kV line from Waynedale Station and a newly established Dalman Road switching station.	12/31/2017	$11.60	AEP	1/5/2017
	s1200.2	Waynedale Station will be upgraded with modifications to the 138 kV and 12 kV systems.	12/31/2017		AEP	1/5/2017
10	s1201	Rebuild West Mount Vernon-South Kenton 138 kV Line between West Mount Vernon and North Waldo (477ACSR).	12/1/2020	$70.30	AEP	1/5/2017
11	s1204	Install 765 kV circuit breaker at Wilton Center 765 kV substation on line 11215 (Wilton Center-Dumont 765 kV line) shunt inductor.	6/1/2018	$5.80	ComEd	3/9/2017
12	s1206	Rebuild Sterling 138 kV station in the clear.	12/1/2018	$9.00	AEP	1/5/2017

Table 11.6: Western Subregion – Supplemental Projects (Continued)

Map ID	Project ID	Project	Projected Date	Cost ($M)	TO Zone(s)	2017 TEAC Review
			Western Subregion – Supplemental Projects			
13	s1210	Loop the Clark-Urbana 138 kV line (~5 miles) and East Springfield-Tangy 138 kV line (~3,5 miles) into the existing 69 kV Broadview Substation with 336 ASCR conductor; Add two 138/69 kV transformers at Broadview substation.	12/31/2019	$32.00	ATSI	1/5/2017
14	s1211	Network a radial line with multiple customer service points; Build a new 69 kV line from Hanville to Carriage substation (approximately 12 miles) with 477 ACSR conductor; Rebuild Hanville into a four breaker ring substation and Carriage into a five	5/8/2017	$27.00	ATSI	1/5/2017
15	s1212.1	Rebuild approximately 1.5 miles of 69 kV iine from Ravenna to Sumner tap as double circuit (477 ACSR).	8/10/2017	$19.00	ATSI	1/5/2017
	s1212.2	Build a new single circuit 69 kV line, approximately 6 miles, from Sumner radial tap to Campbellsport substation (477 ACSR).	7/27/2017		ATSI	1/5/2017
	s1212.3	Rebuild approximately 2.5 miles of 69 kV as double circuit (477 ACSR) to loop the Ravenna-West Ravenna 69 kV Line into Campbellsport.	11/10/2017		ATSI	1/5/2017
	s1212.4	Expand Campbells port to a six-breaker ring bus.	11/10/2017		ATSI	1/5/2017
16	s1213	Convert Aurora into six-breaker 69 kV ring bus	4/30/2017	$6.00	ATSI	1/5/2017
17	s1214	Expand Bingham 69 kV substation for a five-breaker ring configuration; Add 2-14.4 MVAR capacitor bank; Allow for future ring bus expansion to six breakers and cap bank(s); Relay terminal end upgrades required	12/31/2017	$7.00	ATSI	1/5/2017
18	s1215	Expand Dublin substation for a four-breaker ring configuration and reconfigure for a line-load-line-load lay-out; Relay upgrades required at terminal ends	12/31/2017	$6.00	ATSI	1/5/2017
19	s1216	Expand Ontario 138 kV substation for a four-breaker ring configuration and reconfigure for a line-load-line-load lay-out; Relay terminal end upgrades are also required	12/31/2017	$5.00	ATSI	1/5/2017
20	s1220	Rebuild approximately 4 miles of 69 kV line to a double circuit (336 ACSR) on existing ROW; Expand Chittenden substation to a five-circuit breaker ring bus and create the following lines: Chittenden-Darrow 69 kV and Darrow-West Akron 69 kV, Chittenden-Hudson Municipal	12/31/2018	$10.50	ATSI	1/5/2017
21	s1222.1	Mayfield 138 kV: Install four 138 kV breakers in open bay positions on the Q1, Q2,Q3 and Q4 138 kV lines	12/31/2017	$29.00	ATSI	1/5/2017
	s1222.2	Harding 138 kV: Install four 138 kV breakers in open bay positions on the Q11, Q12, Q13 and Q14 138 kV lines	6/1/2018		ATSI	1/5/2017
	s1222.3	Juniper 138 kV: Install two 138 kV breakers in open bay positions on the Q2 and Q4 138 kV lines	12/31/2018		ATSI	1/5/2017
	s1222.4	Jennings 138 kV: Install one 138 kV breaker in open bay position on the Q13 138 kV line	3/29/2018		ATSI	1/5/2017
	s1222.5	Fox 138 kV: Install four 138 kV breakers in open bay positions on the Q11, Q12, Q13 and Q14 138 kV lines	12/31/2018		ATSI	1/5/2017
	s1222.6	Northfield 138 kV: Install two 138 kV breakers in open bay positions on the Q1 and Q3 138 kV lines	12/31/2018		ATSI	1/5/2017
	s1222.7	Fowles 138 kV: Install two 138 kV breakers in open bay positions on the Q2 and Q4 138 kV lines	6/1/2018		ATSI	1/5/2017
	s1222.8	Ivy 138 kV: Install one 138 kV breaker in the open bay position on the Q14 138 kV line	12/31/2017		ATSI	1/5/2017
22	s1223.1	Rehab Cedar Street-Frisco East and West 69 kV Circuits (approximately 13 pole miles) for improved reliability and to extend life.	12/31/2017	$15.70	ATSI	1/5/2017
	s1223.2	Includes inspect and treat grillage foundations, replace select poles, insulators and conductor.	12/31/2017		ATSI	1/5/2017
	s1223.3	Remove mixed conductor types and sizes, replace all with 336 ACSR	12/31/2017		ATSI	1/5/2017
23	s1224.1	Galion-Leaside 69 kV Line: Rebuild the Galion-Leaside 69 kV circuit, approximately 13 miles, and replace 7 line switches; Reconductor with 477 ACSR, replacing multiple conductor types.	10/20/2017	$15.00	ATSI	1/5/2017
	s1224.2	Crestline Substation: Replace 69 kV disconnect switches A8, A10 & A29 and upgrade main bus conductor.	4/11/2017		ATSI	1/5/2017
	s1224.3	Leaside Substation: Replace 69 kV line relaying on B20 to Galion.	12/31/2017		ATSI	1/5/2017

Table 11.6: Western Subregion – Supplemental Projects (Continued)

Map ID	Project ID	Project	Projected Date	Cost ($M)	TO Zone(s)	2017 TEAC Review
			Western Subregion – Supplemental Projects			
24	s1236	Reroute a 1 mile section of feeder to a different path into the Morgan 138 kV substation. Install three 138 kV breakers, replace one aging breaker. Reconfigure to a ring bus.	6/1/2019	$5.37	DEO&K	1/5/2017
25	s1250	Build approximately 1 mile of 69 kV line from near Bekaert to the LGE/KU Simpsonville-Shelbyville 69 kV line and a 69 kV switching station at the connection point.	12/1/2019	$5.10	EKPC	1/5/2017
26	s1278	At Dumont station, replace the existing 765/345 kV 500 MVA transformer T1 with new 765/345 kV/34.5 750 MVA transformer T3 and a spare T3SP 765/345 kV/34.5 750 MVA transformer along with associated equipment and protection.	12/29/2017	$43.74	AEP	5/4/2017
27	s1279.1	Construct two 138/12 kV distribution stations, Bootjack and Marquette, to replace Silver Lake 34.5 kV and Springville 69 kV stations.	12/1/2019	$36.78	AEP	5/4/2017
	s1279.2	Cut the existing Olive-Bosserman line into New Carlisle station.	12/1/2019		AEP	5/4/2017
	s1279.3	Rebuild sections of the LaPorte Junction-New Carlisle/New Buffalo 34.5 kV line to 138 kV to establish Bootjack-Olive 138 kV circuit utilizing 795 ACSR conductor (251 MVA rating).	12/1/2019		AEP	5/4/2017
	s1279.4	Install a three way phase over phase switch, called Kuchar, near Liquid Carbonics station and construct a new 138 kV line between Bootjack and Kuchar.	12/1/2019		AEP	5/4/2017
	s1279.5	Construct a 138 kV extension to Marquette station by tapping the Bosserman-Liquid Carbonics 138 kV line utilizing 795 ACSR conductor (251 MVA rating).	12/1/2019		AEP	5/4/2017
28	s1284	Rebuild the 138 kV Line 13304 (Rock Falls-Normandy) 11 miles of wood H frame construction with steel poles.	12/31/2018	$13.20	ComEd	5/31/2017
29	s1287	Install a 138/69 kV transformer and a 138/13 kV transformer at Mitchell 138 kV substation. Replace related circuit breaker and insulators.	6/30/2018	$5.52	DEO&K	5/31/2017
30	s1290.1	Rebuild ~3.5 miles of the Carbondale-Dunn Hollow 46 kV line section with 795 ACSR conductor. This section of line is currently comprises of a mix of 2/0, 3/0, and 4/0 Copper conductor. The line portion to Montgomery station is of newer construction with larger conductor.	6/1/2021	$9.40	AEP	5/31/2017
	s1290.2	Retire the Smithers switch structure. Smithers load will be served out of Carbondale station via a new transformer. Replace existing Dunn Hollow switching structure with new 3-way phase over phase structure	6/1/2021		AEP	5/31/2017
31	s1291	Rebuild Peakland-Dearington 69 kV circuit (~4.4 miles) utilizing 795 26/7 ACSR conductor. A portion of this line shares a common tower with the Dearington-Blackwater 34.5 kV circuit. This line is currently comprises 4/0 Copper, 1/0 Copper and 336 ACSR conductor.	12/1/2018	$12.70	AEP	5/31/2017
32	s1295.1	Pipers Gap: Install five 138 kV circuit breakers (40 kA 3000A).	6/1/2021	$35.00	AEP	5/31/2017
	s1295.2	Jacksons Ferry: Install one 138 kV circuit breakers.	6/1/2021		AEP	5/31/2017
	s1295.3	Jacksons Ferry-Pipers Gap 138 kV: Construct a new 138 kV line (~10 miles) from Jacksons Ferry-Pipers Gap utilizing 1033.5 ACSR conductor.	6/1/2021		AEP	5/31/2017
33	s1297.1	Rebuild remaining 13.8 miles of Almena to Hartford 69 kV line using 795 ACSR conductor (90 MVA rating).	6/1/2021	$143.00	AEP	5/31/2017
	s1297.2	Rebuild remaining 21.2 miles of Riverside-South Haven 69V line using 795 ACSR conductor (90 MVA rating).	6/1/2021		AEP	5/31/2017
	s1297.3	At Hartford station, replace transformer 138/69 kV 1 with a 90 MVA unit and replace 69 kV circuit breaker H and G with 3000A 40 kA breakers.	6/1/2021		AEP	5/31/2017
	s1297.4	At Riverside station, replace Transformer 5 with a new 90MVA 138/69 kV transformer, replace 69 kV circuit breaker L and 138 kV circuit breaker R with 3000A 40 kA breakers.	6/1/2021		AEP	5/31/2017
	s1297.5	At Main Street station, rebuild the entire station on existing property at the site and install a 90 MVA transformer with 3000A 40 kA breakers.	6/1/2021		AEP	5/31/2017

Table 11.6: Western Subregion – Supplemental Projects (Continued)

			Western Subregion – Supplemental Projects			
Map ID	Project ID	Project	Projected Date	Cost ($M)	TO Zone(s)	2017 TEAC Review
33	s1297.6	At Hickory Creek station, rebuild the 34.5 kV yard, replace the 138 kV circuit breakers with 3000A 40 kA breakers, replace the existing 138/34.5 kV transformers No. 1 and No. 3 with a single 138/69/34.5 kV 90 MVA bank and move the distribution feeds from 34.5 kV to 138 kV.	6/1/2021	$143.00	AEP	5/31/2017
	s1297.7	At South Haven station, retire bus tie circuit breaker A and install two new 69 kV 3000A 40 kA breakers towards Riverside and Hartford remote end stations.	6/1/2021		AEP	5/31/2017
	s1297.8	At the Covert FBEC hard tap location, install a new phase-over-phase switch (vector switch) with load splitting capability.	6/1/2021		AEP	5/31/2017
34	s1298.1	Rebuild 69 kV line from West Rockaway Switch-St. Stephen's Switch 10.6 miles) using 795 ACSR Drake conductor.	6/1/2021	$21.75	AEP	5/31/2017
	s1298.2	Rebuild Hinesville-Howard 6.1 miles using 795 ACSR Drake conductor.	6/1/2021		AEP	5/31/2017
	s1298.3	New 138 kV protection at existing South Tiffin transformer.	6/1/2021		AEP	5/31/2017
	s1298.4	Replace 69 kV circuit breakers A & B at Chatfield.	6/1/2021		AEP	5/31/2017
35	s1301.1	At Chadwick 138 kV station, install two 138 kV circuit breakers in place of the MOAB switches "V" and "Y".	6/7/2017	$9.84	AEP	5/31/2017
	s1301.2	Replace 69 kV circuit breakers C and D with 3000A 40 kA breakers.	6/7/2017		AEP	5/31/2017
	s1301.3	At Leach station, replace 69 kV breaker E with a 3000A 40 kA breaker.	6/7/2017		AEP	5/31/2017
	s1301.4	At England Hill, replace 69 kV circuit breakers A and B with 3000A 40 kA breakers.	6/7/2017		AEP	5/31/2017
	s1301.5	At Kenova, replace 69 kV circuit breaker C with a 3000A 40 kA breaker.	6/7/2017		AEP	5/31/2017
36	s1302.1	Retire West 40 kV Station and North Galloway 40 kV switch.	12/1/2017	$22.30	AEP	5/31/2017
	s1302.2	Rebuild portions of the West-Wilson Road 40 kV line as 69 kV with 1033 ACSR conductor (125 MVA rating) to match the rest of the 69 kV through path and connect at Nautilus station.	12/1/2017		AEP	5/31/2017
	s1302.3	Reconnect the rebuilt portion of the 40 kV line to the Trabue-Galloway Road line to create a 69 kV loop through Nautilus and Blair stations.	12/1/2017		AEP	5/31/2017
	s1302.4	Retire remainder of the West-Wilson Road 40 kV line.	12/1/2017		AEP	5/31/2017
	s1302.5	Retire a portion of the Trabue-Galloway Road 40 kV line.	12/1/2017		AEP	5/31/2017
37	s1303.1	Install New 69 kV T-Line exits at North Wellsville 69 kV substation and revised relay settings.	9/1/2017	$12.90	AEP	5/31/2017
	s1303.2	Rebuild Calcutta-North Wellsville 69 kV line section (6.4 miles) with the 1234 ACSR/TW conductor (90 MVA rating, non-conductor limited) to match the rest of the circuit, utilizing mostly single-circuit steel poles.	9/1/2017		AEP	5/31/2017
38	s1309.1	Replace and convert the existing Gravel Pit 34.5/12 kV station with a 138/12 kV station.	12/1/2018	$17.24	AEP	5/31/2017
	s1309.2	Construct two single circuit 138 kV lines (795 ACSR conductor, 251 MVA rating), approximately 6 miles total and tap the Jackson Road-New Carlisle 138 kV line (Edison-Kankakee 138 kV circuit).	12/1/2018		AEP	5/31/2017
	s1309.3	Retire the 34.5 kV tap line that at present is utilized to serve Gravel Pit station from the Jackson Road-Kankakee 34.5 kV circuit. In addition, retire Gravel Pit station.	12/1/2018		AEP	5/31/2017
	s1309.4	Retire Bowman Creek 34.5 kV switch.	12/1/2018		AEP	5/31/2017
	s1309.5	De-energize sections of the Jackson Road-New Carlisle 138 kV line (Edison-Kankakee 138 kV circuit).	12/1/2018		AEP	5/31/2017
39	s1313.1	North Blacksburg-Matt Funk 138 kV line relaying/fiber.	6/1/2018	$37.50	AEP	5/31/2017
	s1313.2	North Blacksburg-Celanese 138 kV line relaying.	6/1/2018		AEP	5/31/2017
	s1313.3	Glen Lyn-Catawba-Cloverdale 138 kV line relaying/fiber.	6/1/2018		AEP	5/31/2017

Table 11.6: Western Subregion – Supplemental Projects (Continued)

Map ID	Project ID	Project	Projected Date	Cost ($M)	TO Zone(s)	2017 TEAC Review
			Western Subregion – Supplemental Projects			
39	s1313.4	Glen Lyn-Peters MT. 138 kV relaying/fiber.	6/1/2018	$37.50	AEP	5/31/2017
	s1313.5	North Blacksburg-Lane 69 kV relaying/fiber.	6/1/2018		AEP	5/31/2017
	s1313.6	North Blacksburg-Blacksburg 69 kV relaying/fiber.	6/1/2018		AEP	5/31/2017
	s1313.7	Lane-Merrimac 69 kV relaying/fiber.	6/1/2018		AEP	5/31/2017
	s1313.8	Merrimac-North Blacksburg 69 kV relaying/fiber	6/1/2018	$37.50	AEP	5/31/2017
	s1313.9	North Blacksburg Station: Install 3000A 40 kA 138 kV circuit breakers and switchers on the transformers.	6/1/2018		AEP	5/31/2017
	s1313.10	Glen Lyn 138 kV Station: Replace two 138 kV circuit breakers with 3000A 40 kA breakers.	6/1/2018		AEP	5/31/2017
	s1313.11	Merrimac 69 kV Station: Replace two 69 kV circuit breakers with 3000A 40 kA breakers	6/1/2018		AEP	5/31/2017
	s1313.12	Catawba 138 kV Station: Install two 3000A 40 kA 138 kV circuit breakers, two 138 kV switchers on the transformers, and three 3000A 40 kA 69 kV circuit breakers.	6/1/2018		AEP	5/31/2017
40	s1316	Rebuild approximately 8 miles of 69 kV line between Albion and Kendallville stations (starting at structure 32) using 795 ACSR conductor (128 MVA rating) on the existing circuit centerline.	6/1/2018	$7.63	AEP	5/31/2017
41	s1319	Purchase transmission lines owned by Century Aluminum, which has shut down. Century Aluminum has retired and planned to scrap the lines.	3/31/2018	$5.22	AEP	5/31/2017
42	s1323	Rebuild 16.62 miles of the Hocking-Poston 138 kV line with 1033 ACSR (296 MVA rating) on steel poles.	12/1/2017	$17.10	AEP	5/31/2017
43	s1324.1	Replace 138/34.5 kV transformer with a 138/69-34.5 kV transformer, replace 34.5 kV circuit breaker F and add a new 69 kV breaker at Jackson Road station.	12/1/2018	$32.00	AEP	5/31/2017
	s1324.2	Rebuild and convert ~13 miles of 34.5 kV line between Jackson Road and Marshall (NIPSCO) to 69 kV utilizing 556 ACSR conductor (102 MVA rating).	12/1/2018		AEP	5/31/2017
	s1324.3	Convert Quinn to 69 kV.	12/1/2018		AEP	5/31/2017
	s1324.4	Construct Vintage 69 kV station to replace Lapaz.	12/1/2018		AEP	5/31/2017
	s1324.5	Install 69 kV tie line metering at Marshall station.	12/1/2018		AEP	5/31/2017
44	s1325	Jug Street 138 kV Station will be expanded and modified into a two ring bus configuration to serve up to five additional 50 MVA, 138/34.5 kV customer transformers.	6/1/2017	$9.10	AEP	5/31/2017
45	s1326.1	Replace existing Kankakee transformer No. 1 with a 138/69/34.5 kV 130 MVA transformer.	12/1/2017	$5.00	AEP	5/31/2017
	s1326.2	Replace 34.5 kV circuit breakers H, I, D and F with new 1200A 25 kA circuit breakers along with associated equipment and protection.	12/1/2017		AEP	5/31/2017
46	s1334.1	Add three 138 kV 3000A 63 kA circuit breakers at Karl Road to create a ring bus and cut in the other side of the existing double circuit tower line.	12/31/2019	$14.50	AEP	5/31/2017
	s1334.2	Replace circuit breakers at Karl Road, Morse Road, and Clinton stations with 3000A 63 kA circuit breakers.	12/31/2019		AEP	5/31/2017
47	s1335.1	Construct a new 34.5 kV Tulip Road station with one circuit breaker on the West Side line exit.	12/1/2017	$7.48	AEP	5/31/2017
	s1335.2	Terminate New Carlisle, West Side, Scrap Metals, and Edco lines into the new station.	12/1/2017		AEP	5/31/2017
	s1335.3	Remote end work at New Carlisle station due to breaker addition at Tulip Road.	12/1/2017		AEP	5/31/2017
48	s1336	Rebuild approximately 65 miles of 138 kV double circuit tower line between Twin Branch and Robison Park stations using 795 ACSR overhead conductor (251 MVA rating).	6/1/2020	$98.70	AEP	5/31/2017

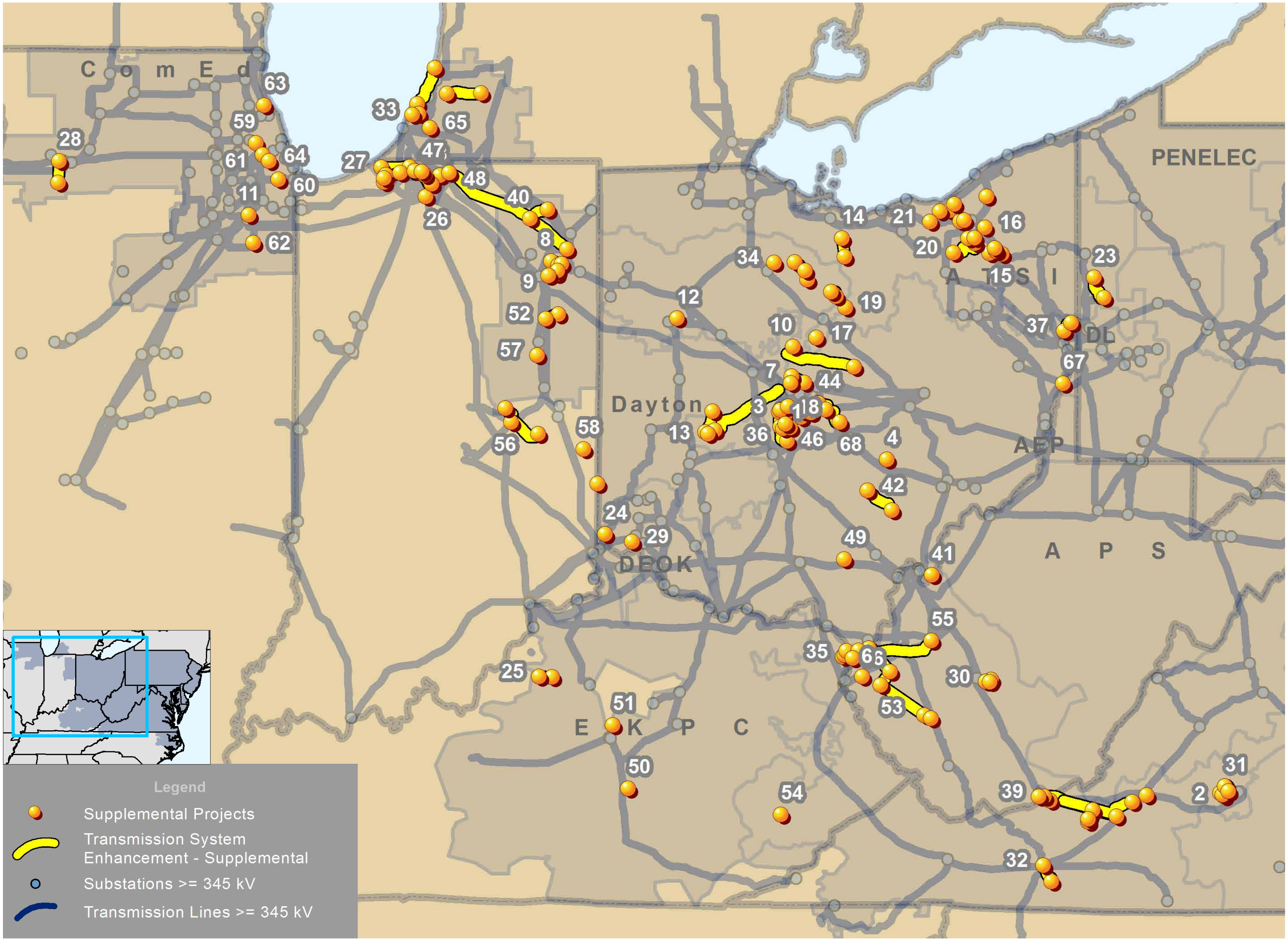
Table 11.6: Western Subregion – Supplemental Projects (Continued)

			Western Subregion – Supplemental Projects			
Map ID	**Project ID**	**Project**	**Projected Date**	**Cost ($M)**	**TO Zone(s)**	**2017 TEAC Review**
49	s1342	Rebuild the around 6 miles line from Rhodes to Heppner and from Heppner to Lick with 1033 ACSR build for future 138 kV conversion.	3/1/2018	$7.00	AEP	5/31/2017
50	s1360	Construct a new Broughtontown 69-26.4 kV,12/16/20 MVA distribution substation and associated 69 KV tap line (7.4 miles). 30 Year net present value (NPV) $20.4 million.	12/1/2021	$8.02	EKPC	6/30/2017
51	s1361	Construct a new Pekin Pike 69-13.2 kV, 12/16/20 MVA distribution substation and 6.4 mile 69 kV tap line. 30 Year NPV $15.6 million.	12/1/2019	$8.21	EKPC	6/30/2017
52	s1372.1	Retire the old Liberty Center REMC switch and install a new 69 kV 1200A 3-way phase-over-phase switch at Meridian Road.	3/1/2018	$10.56	AEP	9/11/2017
	s1372.2	Replace Bluffton and Liberty Center line switches with 1200A 61 kA one-way GOAB's. Rebuild the full 6.43 miles of the Liberty Center-Bluffton 69 kV circuit utilizing 795 26/7 ACSR (129 MVA rating).	3/1/2018		AEP	9/11/2017
	s1372.3	Retire line from the old Liberty Center Switch to structure 5 and build 0.58 miles using 4/0 ACSR from the new Liberty Center Switch to structure 5.	3/1/2018		AEP	9/11/2017
53	s1377.1	Retire 69/12 kV Sheridan station. Rebuild on property near existing station as 138/34.5 kV station. Install two 138 kV line circuit breakers, one 138/34.5 kV transformer, one 138 kV circuit switcher, one 138 kV cap bank, and distribution line exits with breakers.	12/1/2020	$88.10	AEP	12/18/2017
	s1377.2	Midkiff: Install a motorized phase-over-phase switch outside Midkiff Station to maintain 138 kV service.	12/1/2020		AEP	12/18/2017
	s1377.3	Lavalette: Install 138 kV MOAB facing West Huntington. Replace high-speed ground switch/MOAB combo on transformer No. 1 with a circuit switcher.	12/1/2020		AEP	12/18/2017
	s1377.4	Stone Branch: Replace high-speed ground switch/MOAB combo on XFRs No. 1 and No. 2 with circuit switchers. Install 138 kV MOABs facing Midkiff and Chapman.	12/1/2020		AEP	12/18/2017
	s1377.5	Chapman: Retire Trace Fork S.S. and four-way switch and replace with Chapman Switching Station located ~1 mile away. Install four 138 kV 3000A 40 kA circuit breaker ring bus at new Chapman.	12/1/2020		AEP	12/18/2017
	s1377.6	Darrah: Retire 69 kV circuit breakers H and M.	12/1/2020		AEP	12/18/2017
	s1377.7	Construct an 8-mile 138 kV double circuit line between Sheridan and Midkiff utilizing 1033.5 ACSR (375/464 MVA winter ratings) and OPGW.	12/1/2020		AEP	12/18/2017
	s1377.8	Construct a 17-mile 138 kV line between Midkiff and Stone Branch utilizing 1033.5 ACSR (375/464 MVA winter ratings) and OPGW.	12/1/2020		AEP	12/18/2017
	s1377.9	Construct 138 kV double circuit line from Chapman to existing 138 kV Stone Branch-Trace Fork line utilizing 1033.5 ACSR (375/464 MVA winter ratings). Install OPGW on new line sections.	12/1/2020		AEP	12/18/2017
	s1377.10	Construct 138 kV double circuit line from Chapman to existing 138 kV Logan-Hopkins line utilizing 1590 ACSR (493/624 MVA winter ratings) to match the existing Logan-Hopkins line capabilities. Install OPGW on new line sections.	12/1/2020		AEP	12/18/2017
	s1377.11	Retire Darrah-Sheridan 69 kV line.	12/1/2020		AEP	12/18/2017
54	s1412.1	Install a new 3000A 40 kA 138 kV circuit breaker at Hazard station on the line exit towards Beckham station. Add a 138 kV circuit switcher to the high side of transformer No. 4 at Hazard station.	12/31/2019	$20.00	AEP	12/18/2017
	s1412.2	Replace 138 kV capacitor bank and switcher BB with a new switcher and 43.2 MVAR capacitor bank at Hazard station.	12/31/2019		AEP	12/18/2017
	s1412.3	Replace 138/69 kV transformers No. 1 and No. 2 with new 138/69 kV 130 MVA transformers with 138 kV circuit switchers on the high side and 3000A 40 kA 69 kV breakers on the low side at Hazard station.	12/31/2019		AEP	12/18/2017
	s1412.4	Replace 69 kV circuit breakers S, E, and F with 3000A 40 kA 69 kV circuit breakers and with a bus tie 3000A 69 kV circuit breaker being installed between the existing 69 kV box bays at Hazard station.	12/31/2019		AEP	12/18/2017
	s1412.5	Replace 69 kV capacitor bank and switcher CC with a new switcher and 28.8 MVAR capacitor bank and retire the 69 kV capacitor bank and switcher AA at Hazard station.	12/31/2019		AEP	12/18/2017
	s1412.6	Replace the 161 kV circuit breaker M towards Wooton with a 161 kV 3000A 40 kA breaker.	12/31/2019		AEP	12/18/2017

Table 11.6: Western Subregion – Supplemental Projects (Continued)

Map ID	Project ID	Project	Projected Date	Cost ($M)	TO Zone(s)	2017 TEAC Review
			Western Subregion – Supplemental Projects			
54	s1412.7	Add a 3000A 40 kA 138 kV circuit breaker to the low side of 161/138 kV transformer No. 3 at Hazard station.	12/31/2019	$20.00	AEP	12/18/2017
	s1412.8	Address Safety and access issues associated with existing equipment platforms and drainage issues at the station at Hazard station.	12/31/2019		AEP	12/18/2017
55	s1416.1	Tap the Amos-West Huntington 138 kV line utilizing 1033.5 ACSR conductor (167 MVA rating) and extend 3.6 miles in and out of the new Balls Gap Station.	12/1/2017	$12.10	AEP	12/18/2017
	s1416.2	Construct a new 138-34.5 kV Station. Install a 138/34.5 kV 30 MVA transformer, high side circuit switcher and two 138 kV 40 kA circuit breakers.	12/1/2017		AEP	12/18/2017
56	s1419.1	At Fall Creek 138 kV station, install six 138 kV 3000A 63 kA breakers to complete a breaker-and-a-half arrangement for all line exits at the station.	12/31/2017	$7.70	AEP	12/18/2017
	s1419.2	Reroute and terminate the Delco and Pendleton 138 kV lines to Fall Creek station exit locations.	12/31/2017		AEP	12/18/2017
	s1419.3	Reroute and terminate the Madison and New Castle lines to Fall Creek station exit locations.	12/31/2017		AEP	12/18/2017
57	s1423	Rebuild the 17.6 mile Bosman-Hartford City 34.5 kV line utilizing 795 ACSR 26/7 (64 MVA rating). This line will be built to 69 kV standards but operated at 34.5 kV.	8/31/2018	$13.60	AEP	12/18/2017
58	s1426.1	Rebuild College Corner 138 kV station in the clear at the existing station site with ten 3000A 40 kA circuit breakers in a breaker and a half arrangement to terminate seven line positions. Replace the control house with a new DICM.	11/30/2018	$13.80	AEP	12/18/2017
	s1426.2	At Richmond station, replace 138 kV breaker C with a 3000A 40 kA model and replace MOAB's U, V, W, and Y with 3000A MOAB switches.	11/30/2018		AEP	12/18/2017
59	s1439	Add 5 138 kV circuit breachers and reconfigure Bellwood 138 kV substation bus from a straight bus to a ring bus to create 2 new line bays. Extend two new 138 kV lines from Bellwood for 3.3 miles to a new customer substation.	12/1/2018	$12.00	ComEd	12/18/2017
60	s1440	Replace Blue Island 345/138 kV transformer 82. Remove tertiary cap bank and install 115 MVAr 138 kV bus cap.	12/1/2018	$12.00	ComEd	12/18/2017
61	s1442	Remove McCook 345/138 kV Transformer 84 tertiary capacitor banks and install 138 kV 115 MVar capacitor banks	12/1/2018	$6.00	ComEd	12/18/2017
62	s1444	Expand Davis Creek 345 kV straight busses to breaker and half.	12/1/2018	$34.00	ComEd	12/14/2017
63	s1445.1	Install three 345 kV breakers at Northbrook and allow independent operation of the transmission lines and transformers.	12/1/2019	$8.50	ComEd	12/14/2017
	s1445.2	Retire SPOG 3-34, requiring switching to be performed in a specified order.	12/1/2019		ComEd	12/14/2017
64	s1446	Replace Bedford Park open air 345 kV bus with indoor GIS.	12/1/2020	$28.00	ComEd	12/14/2017
65	s1448	At Kenzie Creek station, retire 345 kV MOABS 'W' and 'Y'. Install three 345 kV 5000A 63 kA breakers in a ring bus configuration. Set up station to allow for future 'B' and 'C' breaker strings.	12/31/2018	$7.40	AEP	12/14/2017
66	s1449	At Tri State station, replace circuit breaker "H" with a 345 kV 63 kA breaker. Install 4 new 345 kV 63 kA breakers in a new breaker and a half string configuration. Replace transformers 1 & 2 with 345-138 450 MVA units.	12/1/2018	$9.00	AEP	12/14/2017
67	s1451	At Tidd station, replace 345/138 kV transformer, install 138 kV series reactor, install new 345 kV 3-breaker string with new relay panels and SCADA. Reconductor the tie line from the 345 and 138 kV yard at Tidd.	12/1/2018	$7.80	AEP	12/14/2017
68	s1373	Establish a new 138 kV, breaker and a half station with 12 circuit breakers (Babbitt Station). Cut existing Jug Street-Kirk 138 kV circuit and run two single pole line extensions to the new Babbitt Station.	8/31/2018	$22.67	AEP	9/11/2017

Map 11.8: Western Subregion – Supplemental Projects



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

11.2: Southern PJM Summary

11.2.1 — RTEP Context

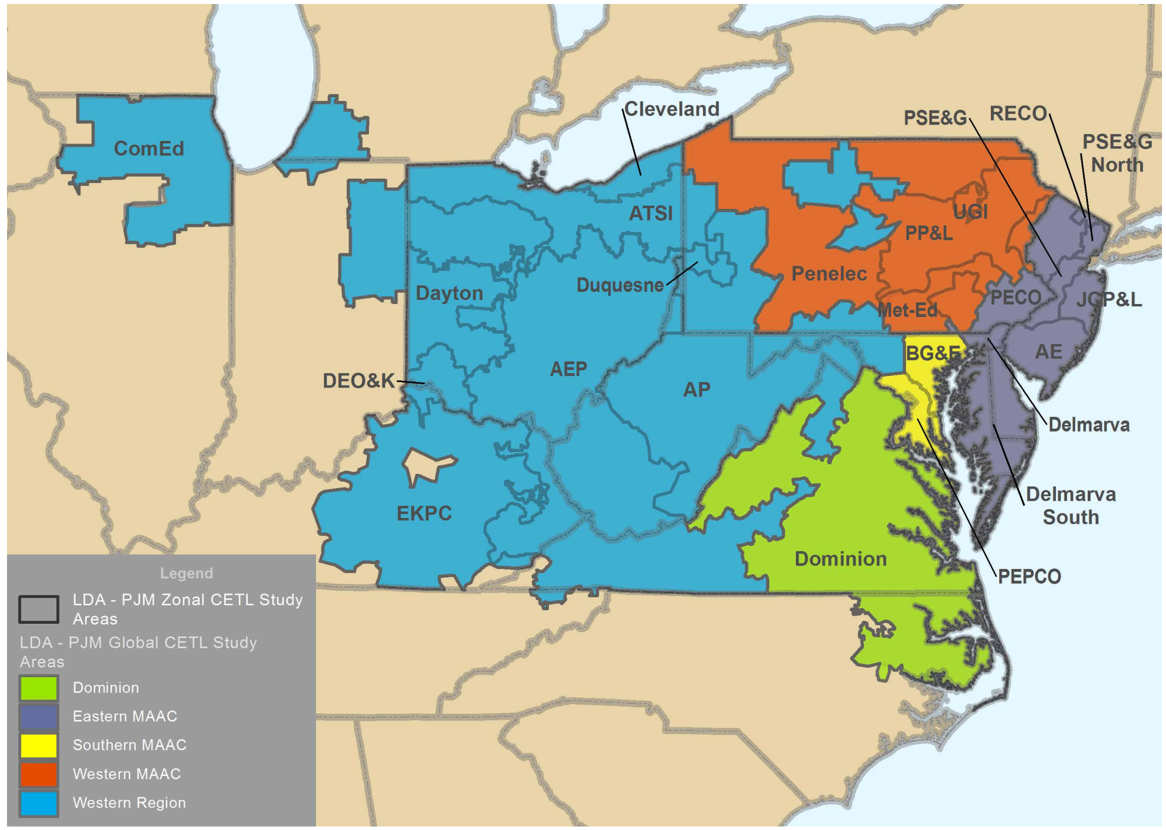
PJM operates the bulk electric system transmission facilities (and others monitored at lower voltage levels) throughout PJM's southern subregion, shown in **Map 11.9**, and includes that of Dominion Virginia Power (Dominion) which operates in Virginia and northeastern North Carolina.

A 15-year long-term planning horizon allows PJM to consider the aggregate effects of many drivers. At 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 identifies one optimal, comprehensive set of solutions to resolve baseline reliability criteria violations, operational performance issues and congestion constraints as well as Network reinforcements to accommodate generator interconnection and other new queued service requests. Specific system enhancements are justified to deliver needed power to distant load centers as well to meet local, subregional needs.

Stakeholder Participation

Subregional RTEP committees increase the opportunity for direct stakeholder participation in the planning process from initial assumption setting stages through review of planning analyses, violations and alternative transmission expansion plans. Each subregional RTEP committee provides a more local forum for surfacing and considering planning issues. Interested parties can access PJM Southern Subregional RTEP Committee information from PJM's website: http://www.pjm.com/committees-and-groups/committees/srrtep-s.aspx.

Map 11.9: Locational Deliverability Areas



11.2.2 — Baseline Projects

Baseline transmission projects are system enhancements identified through analysis of operational performance issues, market efficiency studies and conventional NERC criteria tests that include the following:

- Base case thermal and voltage analysis
- Load deliverability thermal and voltages analysis
- Generation deliverability thermal analysis
- N-1-1 thermal and voltage analysis
- Common mode contingency analysis
- Short circuit analysis
- Baseline stability analysis
- Transmission owner criteria tests

Contingency analysis includes all bulk electric system facilities, tie lines to neighboring systems, critical neighboring system facilities and lower voltage facilities operated by PJM.

Baseline projects with cost estimates greater than $5 million approved by the PJM Board in 2017, are listed in **Table 11.7** and shown on **Map 11.10**.

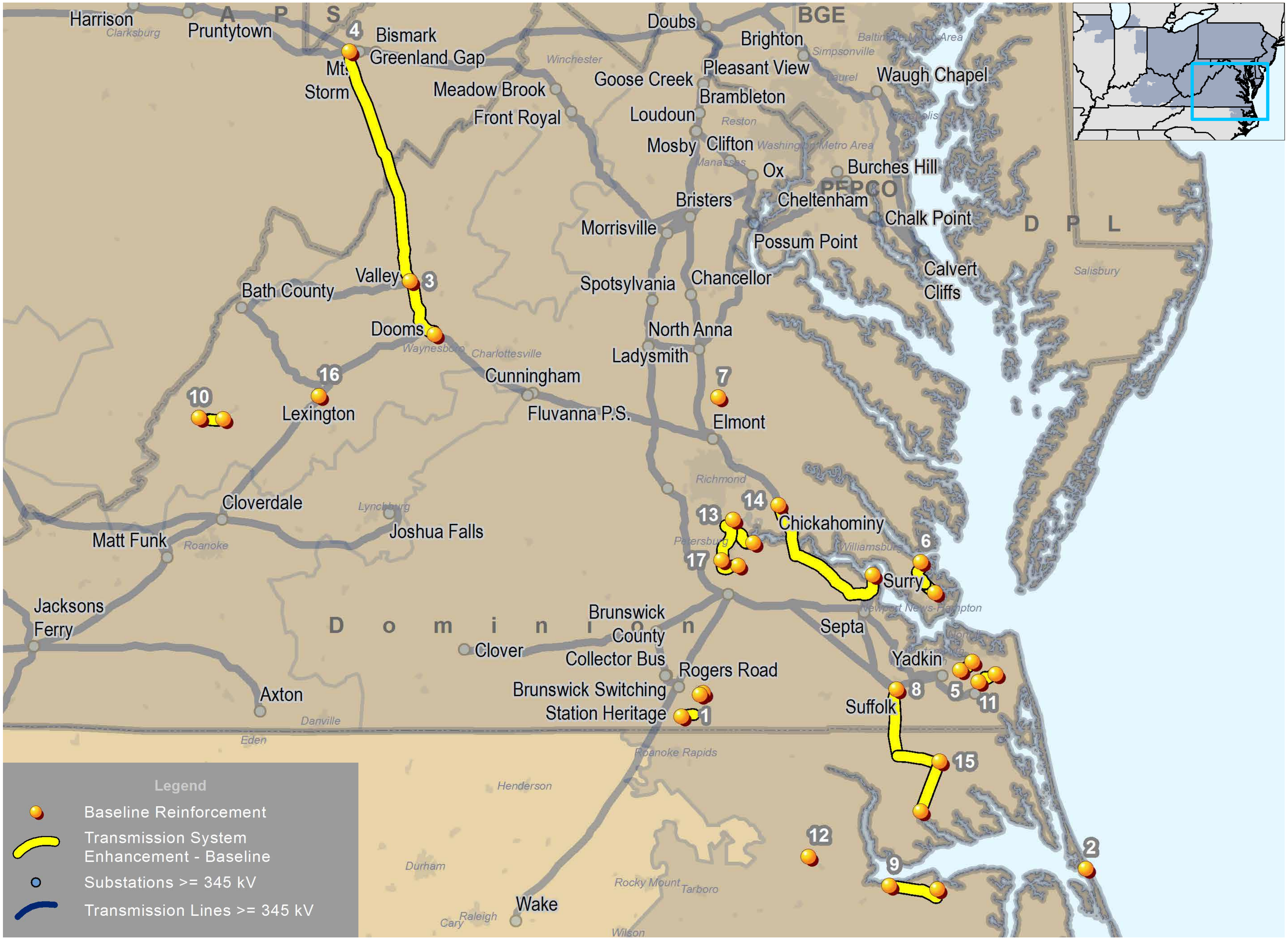
Table 11.7: Southern Subregion – Baseline Projects

			Southern Subregion – Baseline Projects								
Map ID	Project ID	Project	Baseline Load Growth/ Deliverability & Reliability	Congestion Relief-Economic	Operational Performance	Short Circuit	TO Criteria Violation	Required Date	Cost ($M)	Designated Entity	2017 TEAC Review
1	b2649.1	Rebuild of 1.7 mile tap to Metcalf and Belfield DP (MEC) due to poor condition. The existing summer rating of the tap is 48 MVA and existing conductor is 4/0 ACSR on wood H-frames. The proposed new rating is 176 MVA using 636 ACSR conductor.					▲	12/31/2019	$38.78	Dominion	6/9/2017
	b2649.2	Rebuild of 4.1 mile tap to Brinks DP (MEC) due to wood poles built in 1962. The existing summer rating of the tap is 48 MVA and existing conductor is 4/0 ACSR and 393.6 ACSR on wood H-frames. The proposed new rating is 176 MVA using 636 ACSR conductor.					▲	12/31/2019		Dominion	6/9/2017
2	b2757	Install a +/-125 MVAR STATCOM at Colington 115 kV.					▲	6/1/2017	$30.00	Dominion	10/6/2016
3	b2758	Rebuild Line No. 549 Dooms-Valley 500 kV.					▲	6/1/2016	$58.16	Dominion	10/6/2016
4	b2759	Rebuild Line No. 550 Mt. Storm-Valley 500 kV.					▲	6/1/2016	$225.00	Dominion	10/6/2016
5	b2800	The 7 mile section from Dozier to Thompsons Corner of line No. 120 will be rebuilt to current standards using 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115 kV. Line is proposed to be rebuilt on single circuit steel monopole structure.					▲	12/30/2021	$6.50	Dominion	6/9/2017
6	b2801	Line No. 76 and No. 79 Yorktown to Peninsula will be rebuilt to current standard using 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115 kV. Proposed structure for rebuild is double circuit steel monopole structure.					▲	12/30/2020	$22.00	Dominion	6/9/2017

Table 11.7: Southern Subregion – Baseline Projects (Continued)

Map ID	Project ID	Project	Southern Subregion – Baseline Projects: Baseline Load Growth/ Deliverability & Reliability	Congestion Relief-Economic	Operational Performance	Short Circuit	TO Criteria Violation	Required Date	Cost ($M)	Designated Entity	2017 TEAC Review
7	b2815	Build a new Pinewood 115 kV switching station at the tap serving North Doswell DP with a 115 kV four breaker ring bus.					▲	6/1/2017	$12.80	Dominion	12/1/2016
8	b2871	Rebuild 230 kV line No. 247 from Swamp to Suffolk (31 miles) to current standards with a summer emergency rating of 1047 MVA at 230 kV.					▲	12/30/2022	$31.00	Dominion	5/4/2017
9	b2876	Rebuild line No. 101 from Mackeys-Creswell 115 kV, 14 miles, with double circuit structures. Install one circuit with provisions for a second circuit. The conductor used will be at current standards with a summer emergency rating of 262 MVA at 115 kV.					▲	12/30/2022	$40.00	Dominion	8/29/2017
10	b2877	Rebuild line No. 112 from Fudge Hollow-Lowmoor 138 kV (5.16 miles) to current standards with a summer emergency rating of 314 MVA at 138 kV..					▲	10/31/2020	$8.00	Dominion	6/9/2017
11	b2899	Rebuild 230 kV line no. 231 Landstown to Thrasher, to current standard with a summer emergency rating of 1046 MVA. Proposed conductor is 2-636 ACSR.					▲	12/1/2020	$22.00	Dominion	7/13/2017
12	b2900	Build a new 230-115 kV switching station connecting to 230 kV network Line No. 2014 (Earleys-Everetts). Provide a 115 kV source from the new station to serve Windsor DP.					▲	12/30/2022	$11.50	Dominion	8/29/2017
13	b2922	Rebuild 8 of 11 miles of 230 kV Lines No. 211 and No. 228 to current standard with a summer emergency rating of 1046 MVA for rebuilt section. Proposed conductor is 2-636 ACSR.					▲	12/1/2020	$28.10	Dominion	8/10/2017
14	b2928	Rebuild four structures of 500 kV Line No. 567 from Chickahominy to Surry using galvanized steel and replace the river crossing conductor with 3-1534 ACSR. This will increase the Line No. 567 Line Rating from 1,954 MVA to 2,600 MVA.					▲	12/30/2017	$41.00	Dominion	9/14/2017
15	b2929	Rebuild 230 kV Line No. 2144 from Winfall to Swamp (4.3 miles) to current standards with a standard conductor (bundled 636 ACSR) having a summer emergency rating of 1047 MVA at 230 kV.					▲	12/30/2022	$6.00	Dominion	9/14/2017
16	b2960	Replace fixed series capacitors on 500 kV line No. 547 at Lexington and on 500 kV line No. 548 at Valley.					▲	4/1/2020	$28.90	Dominion	11/2/2017
17	b2961	Rebuild approximately 3 miles of line No. 205 and line No. 2003 from Chesterfield to Locks and Poe respectively.					▲	12/31/2022	$9.50	Dominion	11/2/2017

Map 11.10: Southern Subregion – Baseline Projects



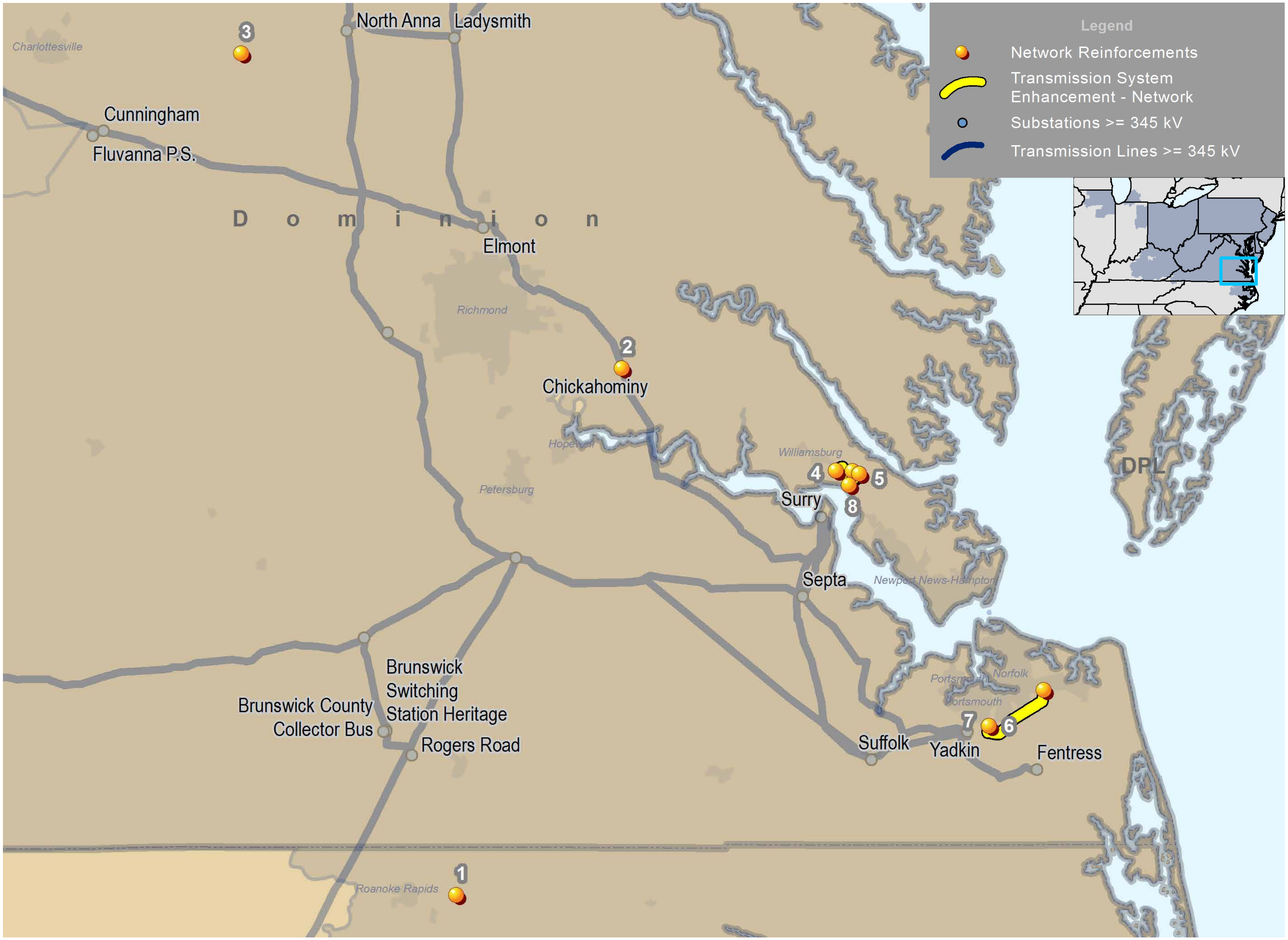
11.2.3 — Network Projects

PJM's RTEP also includes system reinforcements identified through interconnection process system impact studies. These Network projects are necessary to interconnect new generation, merchant transmission facilities and other new services. Direct connection Network projects are transmission enhancements that deliver power to a defined point of interconnection. Non-direct connection Network projects mitigate transmission system impacts beyond the point of interconnection. Network projects with cost estimates greater than $5 million approved by the PJM Board in 2017, are listed in **Table 11.8** and shown on **Map 11.11**.

Table 11.8: Southern Subregion– Network Projects

			Southern Subregion – Network Projects						
Map ID	Project ID	Project	Generation Interconnection	Merchant Transmission Interconnection	Auction Revenue Rights Request	Adjacent RTO Interconnection	Cost ($M)	TO Zone(s)	2017 TEAC Review
1	n5191	Build a three breaker ring bus at Occoneechee 115 kV substation	AA2-053				$5.57	Dominion	10/12/2017
2	n5212	Add three new 500 kV breakers and associated equipment to the exiting Chickahominy 500 kV substation	AB2-068				$6.50	Dominion	10/12/2017
3	n5409	Build New AB2-158 Switching Substation (interconnection substation)	AB2-158				$6.30	Dominion	10/12/2017
4	n5460	Wreck and rebuild the Penniman-Waller 230 kV line. New Rating 1047 MVA	AC1-159				$13.00	Dominion	10/12/2017
5	n5461	Wreck and rebuild the Kings Mill-Penniman 230 kV line. New Rating 1047 MVA	AC1-159				$6.80	Dominion	10/12/2017
6	n5462	Add a third Chesapeake 230/115 kV transformer	AC1-159				$7.00	Dominion	10/12/2017
7	n5463	Wreck and rebuild 11 miles Chesapeake-Greenwich 230 kV line	AC1-159				$21.20	Dominion	10/12/2017
8	n5465	Wreck and rebuild the Skiff Creek-Kings Mill 230 kV line. New Rating 1047 MVA	AC1-107				$8.40	Dominion	10/12/2017

Map 11.11: Southern Subregion – Network Projects



11.2.4 — Supplemental Projects

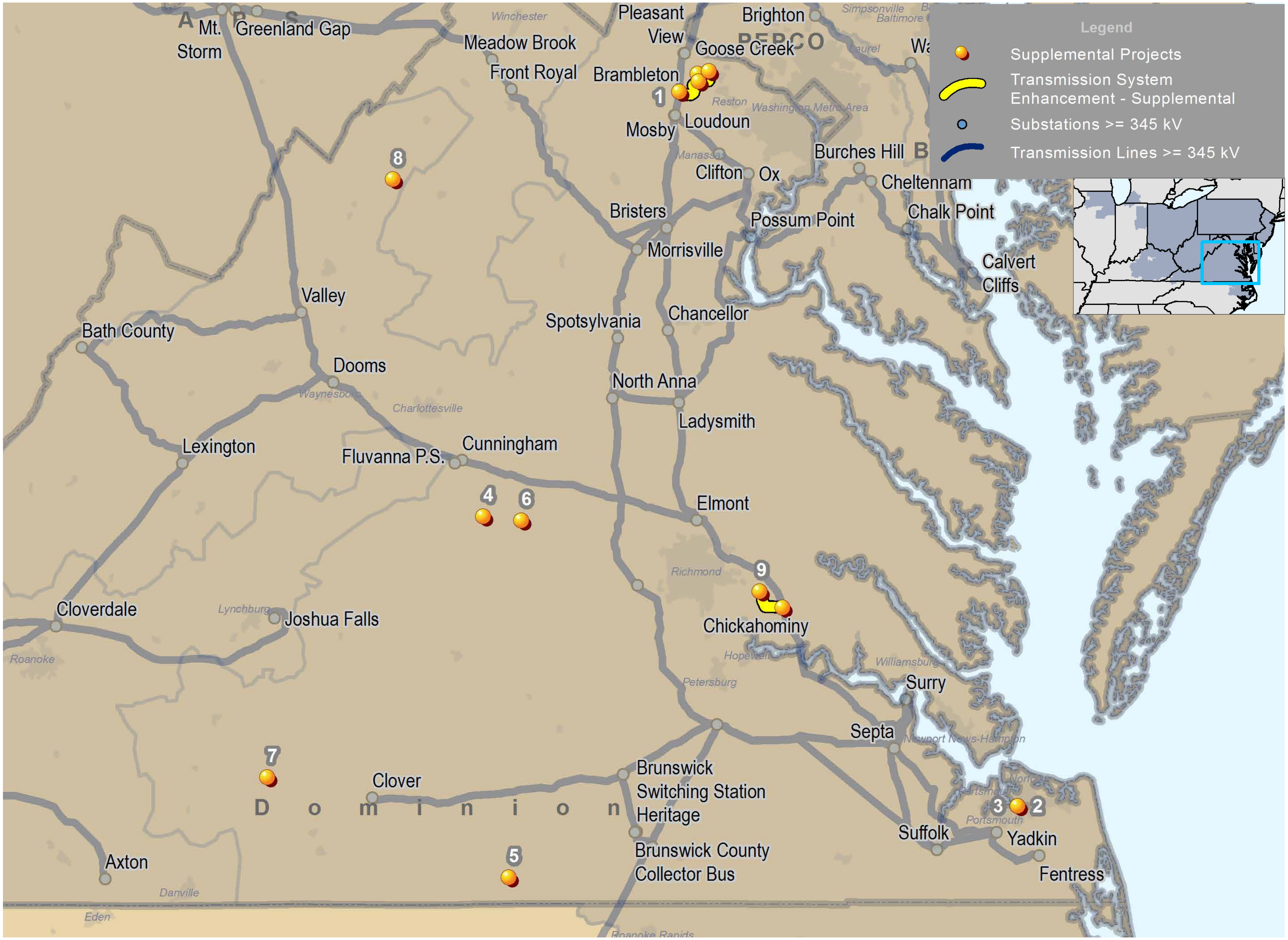
Prior to FERC Order No. 890 in 2008, Supplemental projects were referred to as transmission owner initiated or TOI projects. A Supplemental project is not required for compliance with system reliability, operational performance or economic criteria, as determined by PJM. Supplemental projects frequently address aging infrastructure, provide support to serve underlying systems and add connections to new, large load customers. PJM reviews Supplemental projects 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.

Transmission owners submitted a number of Supplemental projects throughout 2017. Projects with cost estimates greater than $5 million are listed in **Table 11.9** and shown on **Map 11.12**.

Table 11.9: Southern Subregion – Supplemental Projects

			Southern Subregion – Supplemental Projects			
Map ID	**Project ID**	**Project**	**Projected Date**	**Cost ($M)**	**TO Zone(s)**	**2017 TEAC Review**
1	s1238	Interconnect new Roundtable substation by cutting and extending both Line No. 2149 (Enterprise-Waxpool) and Line No. 2137 (Brambleton-BECO). Terminate the lines into a six-breaker 230 kV ring bus. Install a 230 kV circuit switcher, high side switches and necessary bus work for the new transformers and high side switches for future transformers.	9/1/2018	$9.35	Dominion	1/5/2017
2	s1271.1	New Reeves Ave 230 kV configuration: Install three 230 kV breakers to form a 4-breaker ring bus.	11/30/2017	$5.2	Dominion	5/4/2017
	s1271.2	115 kV configuration: Install 115 kV breakers on high side of transformer No. 2, No. 3, and No. 6.	12/30/2018		Dominion	5/4/2017
3	s1272	Replace Transformer No. 4 and Transformer No. 5 with new 168MVA (nameplate rating) transformers.	1/31/2018	$8.70	Dominion	5/4/2017
4	s1374	Replace Bremo 138-115 kV transformer No. 8 with a 225 MVA transformer.	7/31/2018	$7.00	Dominion	10/30/2017
5	s1389	Rebuild Beechwood (MEC), 115 kV line No. 90 (to be No. 1004), 4.51 miles.	12/1/2018	$7.00	Dominion	6/9/2017
6	s1390	Rebuild Columbia (CVEC), 115 kV line No. 4, 4.00 miles.	12/1/2019	$5.00	Dominion	6/9/2017
7	s1391	Rebuild Hickory Grove (MEC), 115 kV line No. 31 (to be No. 1022), 8.25 miles.	12/1/2020	$12.30	Dominion	6/9/2017
8	s1399	Rebuild Mt. Jackson (SVEC), 115 kV line No. 128, 0.05 mile.	12/1/2021	$10.00	Dominion	6/9/2017
9	s1452	Install a 230 kV switching station and delivery point by tapping the 230 kV Line No. 2091 (Chickahominy-White Oak) in and out of the proposed customer site.	10/25/2018	$11.00	Dominion	12/14/2017

Map 11.12: Southern Subregion – Supplemental Projects



Section 12: 2016 Load Deliverability Review

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

12.0: Load Deliverability Area Margin Analysis

12.0.1 — RTEP Context

PJM revisited the 2016 RTEP Load Deliverability analyses during 2017 to determine any changes to locational deliverability area (LDA) Capacity Emergency Transfer Objective (CETO) and Capacity Emergency Transfer Limit (CETL) values caused by system topology changes identified during the 2016 RTEP cycle. The objective is to provide stakeholders a sense of system margin before another CETL might be encountered after the ones solved by approved projects identified during a prior RTEP cycle. To do so, PJM conducted studies to identify limiting facilities identified for LDAs with less than 150 percent margin.

As described in **Book 2, Section 4.2.2**, CETO is the emergency import capability, expressed in megawatts, required of a PJM LDA to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency. CETL is part of load deliverability analysis to determine the maximum capability of the transmission system to deliver power to an LDA experiencing a localized capacity emergency.

12.0.2 — Results

The 2016 load deliverability review conducted in 2017 incorporated updated 2020 Summer Peak RTEP base case study assumptions:

- 2017 PJM load forecast report
- PJM Board approved projects and TO Supplemental projects
- Generation model deactivation and interconnection project changes
- Transmission service

The results of the 2017 analysis are shown in **Table 12.1** reflects the limiting facilities identified for LDAs with a CETL to CETO margin less than 150 percent. Although studies revealed two LDAs with margins less than 150 percent, none qualified as reliability criteria violations given that their CETL values were still greater than respective CETOs.

Table 12.1: 2017 CETO and CETL Review with 2016 RTEP Projects

Area	CETO (MW)	2020/21 CETL (MW)	2020/2021 Margin	Limiting Facility	Violation Type
AE	1,140	> 1,793	>150%		None
AEP	-170	> 0	*		None
APS	2,020	> 3,463	>150%		None
ATSI	4,660	9,889	212%	South Canton-Harmon 345 kV line for the loss of the Hanna-Canton Central 345 kV line	Thermal
BGE	4,410	6,244	142%	Howard-Pumphrey 230 kV line pre-contingency (Base Case)	Thermal
Cleveland	3,540	5,605	158%	Low Voltage at Hayes for the loss of the Hayes-Davis Besse 345 kV line	Voltage
ComEd	640	4,064	635%	Eugene-Dequin 345 kV line for the loss of the Greentown-Jefferson 765 kV line	Thermal

*Note: LDA has adequate internal resources to meet the reliability criterion.

Table 12.1: 2017 CETO and CETL Review with 2016 RTEP Projects (Continued)

Area	CETO (MW)	2020/21 CETL (MW)	2020/2021 Margin	Limiting Facility	Violation Type
DAYTON	2,550	3,401	133%	Sugar Creek-Ohio 138 kV line for loss of Ohio-College Corner 138 kV	Thermal
DEO&K	3,650	5,072	139%	Tanner-Miami Fort 345 kV line for the loss of the Terminal-South Bend 345 kV line	Thermal
DLCO	1,530	> 2,554	>150%		None
DPL	910	> 1,808	>150%		None
DPL SOUTH	1,230	1,872	152%	Red Lion-Cedar Creek 230 kV for the loss of Cartanza-Milford 230 kV	Thermal
EKPC	560	> 840	>150%		None
EMAAC	3,650	8,800	241%	Low Voltage at Cochranville 230 kV for loss of Keeney-Rock Springs 500 kV; low voltage at Hotpacong 500 kV Substation and Roseland 500 kV Substation for loss of Branchburg-Hopatcong 500 kV	Voltage
JCPL	3,430	> 5,145	> 150%		None
MAAC	-7,000	4,218	*	Sandy Spring 2334-High Ridge 230 kV for loss of Sandy Spring 2314-Burtonsville 230 kV	Thermal
Met-Ed	770	> 2,167	> 150%		None
PECO	2,690	> 4,035	>150%		None
PENELEC	-210	>383	*		None
PEPCO	1,540	7,625	495%	Voltage drop at High Ridge 230 kV station for the loss of Burches Hill-Possum Point 500 kV line	Voltage
PJM WEST	2,350	> 3,525	>150%		None
PLGRP	-1,010	7,084	*	Wescosville 500/138 kV transformer pre-contingency (Base Case)	Thermal
PSE&G	5,900	8,001	136%	Roseland-Cedar Grove 230 kV for loss of Roseland-Williams Pipeline 230 kV/low voltage at Hotpacong 500 kV Substation and Roseland 500 kV Substation for loss of Branchburg-Hopatcong 500 kV	Thermal/Voltage
PSE&G NORTH	2,620	4,264	163%	Roseland-Cedar Grove 230 kV for loss of Roseland-Williams Pipeline 230 kV/low voltage at Hotpacong 500 kV Substation and Roseland 500 kV Substation for loss of Branchburg-Hopatcong 500 kV	Thermal/Voltage
SWMAAC	2,900	9,802	338%	Graceton-Bagley 230 kV circuit No. 1 and No. 2 for the loss of the one or the other	Thermal
VAP	-3,010	> -928	*		None
WMAAC	-10,140	> -5,070	*		None

*Note: LDA has adequate internal resources to meet the reliability criterion.

Appendix 1: TO Zones and Locational Deliverability Areas

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

The terms *Transmission Owner Zone* and *Locational Deliverability Area* as used in this report are defined below and shown on **Map 1**. They are provided for the convenience of the reader based on definitions from other sources.

A transmission owner (TO) is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a TO. Schedule 16 of the Reliability Assurance Agreement (RAA) defines the distinct zones that the PJM control area comprises: http://www.pjm.com/directory/merged-tariffs/raa.pdf. They are restated in **Table 1**, below, for ease of reference.

A Locational Deliverability Area (LDA) is an electrically cohesive area defined by transmission zones, parts of zones, or combination of zones. LDAs are used as part of PJM's RTEP process load deliverability test.

Map 1: Locational Deliverability Areas

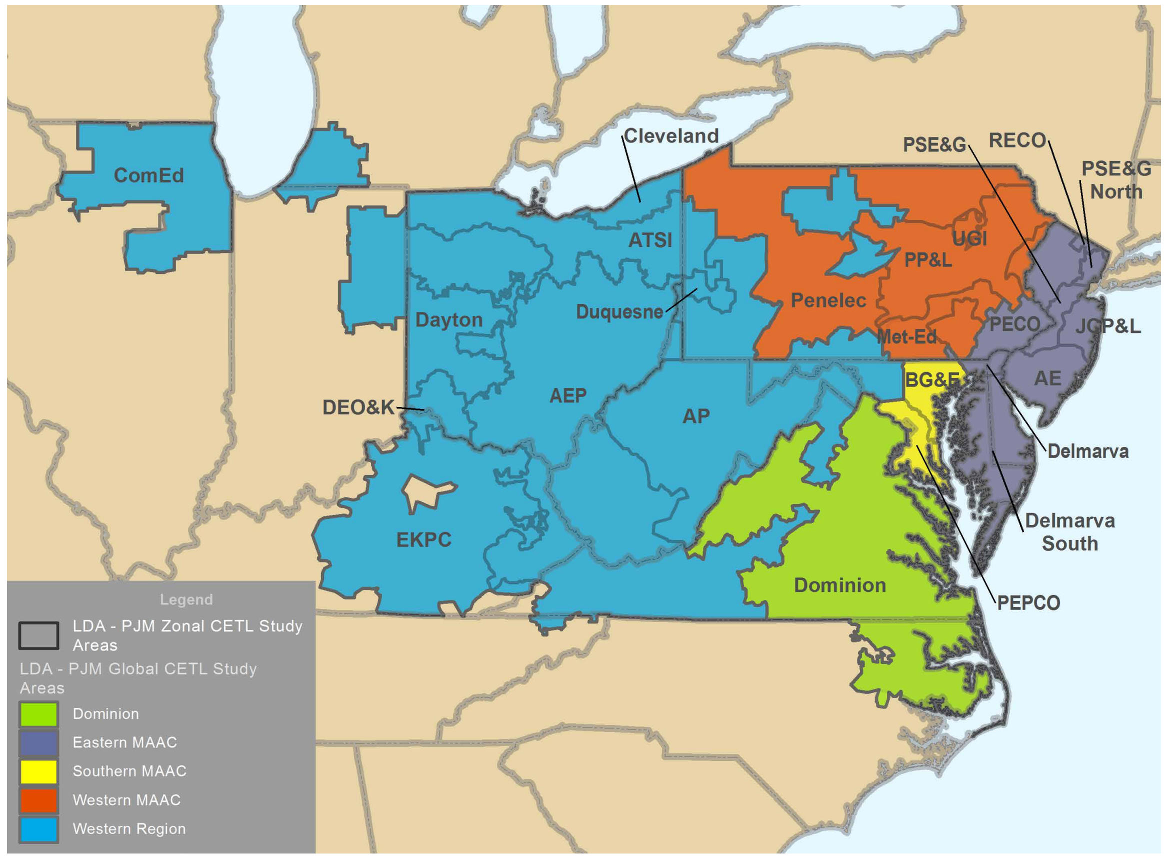


Table 1: Locational Deliverability Areas

Entity Name	TO Zone	LDA	Description
AE	▲	▲	Atlantic Electric
AEP	▲	▲	American Electric Power
APS	▲	▲	Allegheny Power
ATSI	▲	▲	American Transmission Systems, Incorporated
BGE	▲	▲	Baltimore Gas and Electric
Cleveland	n/a	▲	Cleveland Area
ComEd	▲	▲	Commonwealth Edison
DAYTON	▲	▲	Dayton Power and Light
DEO&K	▲	▲	Duke Energy Ohio and Kentucky
DLCO	▲	▲	Duquesne Light Company
Dominion	▲	▲	Dominion Virginia Power
DPL	▲	▲	Delmarva Power and Light
Delmarva South	n/a	▲	Southern Portion of DPL
Eastern Mid-Atlantic	n/a	▲	Global area – JCPL, PECO, PSE&G, AE, DPL, RECO
EKPC	▲	▲	East Kentucky Power Cooperative
JCPL	▲	▲	Jersey Central Power and Light
Met-Ed	▲	▲	Metropolitan Edison
Mid-Atlantic	n/a	▲	Global area – Penelec, Met-Ed, JCPL, PPL, PECO, PSE&G, BGE, PEPCO, AE, DPL, RECO
PECO	▲	▲	PECO
PENELEC	▲	▲	Pennsylvania Electric
PEPCO	▲	▲	Potomac Electric Power Company
PPL	▲	▲	PPL Electric Utilities Corporation, UGI
PSE&G	▲	▲	Public Service Electric and Gas
PSE&G North	n/a	▲	Northern Portion of PSE&G
Southern Mid-Atlantic	n/a	▲	Global area – BGE and PEPCO
Western Mid-Atlantic	n/a	▲	Global Area – Penelec, Met-Ed, PPL
Western PJM	n/a	▲	Global Area – APS, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC

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

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Glossary

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

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

- Mxx – PJM Manual – http://www.pjm.com/library/manuals.aspx
- NERC – North American Electric Reliability Council – http://www.nerc.com/
- OA – PJM Operating Agreement – http://www.pjm.com/media/documents/merged-tariffs/oa.pdf
- OATT – PJM Open Access Transmission Tariff – http://www.pjm.com/media/documents/merged-tariffs/oatt.pdf
- RAA – Reliability Assurance Agreement – http://www.pjm.com/media/documents/merged-tariffs/raa.pdf

Term	Reference	Acronym	Definition
Adequacy	NERC		Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency. "Resources" refers to a combination of electricity generation and transmission facilities, which produce and deliver electricity, and "demand response" programs, which reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
Ancillary Service	OATT		Ancillary services are those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Annual Demand Resources			Demand resources can be called on an unlimited number of times any day of the delivery year, unless otherwise on an approved maintenance outage. Product type ceases to exist following the commencement of Capacity Performance rules.
Attachment Facilities	OATT		Attachment facilities are necessary to physically connect a customer facility to the transmission system or interconnected distribution facilities.
Auction Revenue Right	OA	ARR	An Auction Revenue Right is a financial instrument entitling its holder to auction revenue from financial transmission rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the annual FTR auction.
Available Transfer Capability	NERC	ATC	The available transfer capability is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Base Capacity Resource	M18		Base capacity resources are capacity resources that are not capable of sustained, predictable operation throughout the entire delivery year. These resources will only be procured through the 2019/2020 Delivery Year, at which point all resources will be Capacity Performance Resources starting with the 2020/2021 Delivery Year. See "Capacity Performance."

Term	Reference	Acronym	Definition
Baseline Upgrades	M14B		In developing the RTEP, PJM tests the baseline adequacy of the transmission system to deliver energy and capacity resources to each load in the PJM region. The system (as planned to accommodate forecast demand, committed resources and commitments for firm transmission service for a specified time frame) is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, nuclear plant licensee requirements, PJM reliability standards and PJM design standards. Areas not in compliance with the standards are identified, and enhancement plans to achieve compliance are developed. Baseline expansion plans serve as the base system for conducting feasibility studies and system impact studies for all proposed requests for generation and merchant transmission interconnection and for long-term firm transmission service.
Behind-The-Meter Generation	OATT	BTM	Behind-the-meter generation delivers energy to load without using the transmission system or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of PJM), provided, however, that behind-the-meter generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a capacity resource, or (ii) in an hour, any portion of the output of such generating unit(s) that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.
Bilateral Transaction	OA		A bilateral transaction is a contractual arrangement between two entities (one or both being PJM members) for the sale and delivery of a service.
Bulk Electric System	NERC; M14B	BES	ReliabilityFirst defines the bulk electric system as all: Individual generation resources larger than 20 MVA or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher, lines operated at voltages of 100 kV or higher, associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment). The ReliabilityFirst BES excludes: (1) Radial facilities connected to load-serving facilities or individual generation resources smaller than 20 MVA or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher; (2) the balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and step-up transformer), which would include relays and systems that automatically trip a unit for boiler, turbine, environmental, and/or other plant restrictions; and (3) all other facilities operated at voltages below 100 kV.
Capacity Emergency	M13		A capacity emergency is a system condition where operating capacity plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet the total of its demand, firm sales and regulating requirements.
Capacity Emergency Transfer Limit	RAA, M14B, M18	CETL	The capacity emergency transfer limit is part of load deliverability analysis to determine the maximum limit, expressed in megawatts, of a study area's import capability, under the conditions specified in the load deliverability criteria.
Capacity Emergency Transfer Objective	RAA; M14B, M18, M20	CETO	The CETO is the emergency import capability, expressed in megawatts, required of a PJM subregion-area to satisfy established reliability criteria.
Capacity Interconnection Rights	OATT	CIRs	Capacity interconnection rights are rights to input generation as a 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 2020/2021 Delivery Year. See "Base Capacity Resource" and "Capacity Performance Resource."
Capacity Performance Resource	M18		Capacity Performance Resources are capable of sustained, predictable operation throughout the entire delivery year. All resources will be Capacity Performance Resources starting with the 2020/2021 Delivery Year. See "Capacity Performance."
Capacity Resource	RAA. M14A, M14B		Capacity resources are megawatts of net capacity from existing or planned generation capacity resources or load reduction capability provided by demand resources or interruptible load for reliability (ILR) in the region PJM serves.
Clean Air Interstate Rule		CAIR	The Clean Air Interstate Rule is an Environmental Protection Agency, or EPA, rule regarding the interstate transport of soot and smog.
Clean Power Plan		CPP	The Clean Power Plan is an EPA rule regarding carbon pollution from power plants.
Coincident Peak	M19		The coincident peak is a zone's contribution to the RTO or higher level locational deliverability area (LDA) peak load.
Combined Cycle (Turbine)		CC/CCT	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 combustion turbine is a generating unit in which a combustion turbine engine is the prime mover.

Term	Reference	Acronym	Definition
Consolidated Transmission Owners Agreement	PJM.com	CTOA	The Consolidated Transmission Owners Agreement is an agreement between transmission owners, which PJM is a signatory to, establishing the rights and commitments of all parties involved.
Contingency			A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Coordinated System Plan		CSP	A Coordinated System Plan (CSP) contains the results of coordinated PJM-MISO studies required to assure the reliable, efficient, and effective operation of the transmission system. The CSP also includes the study results for interconnection requests and long-term firm transmission service requests. Further description of CSP development can be found in the PJM-MISO Joint Operating Agreement.
Cost of New Entry	M18	CONE	The cost of new entry is a Reliability Pricing Model (RPM) capacity market parameter defined as the levelized annual cost in ICAP $/MW-day of a reference combustion turbine to be built in a specific locational deliverability area (LDA).
Cross-State Air Pollution Rule		CSAPR	The Cross-State Air Pollution Rule is an EPA rule regarding reduction in air pollution related to power plant emissions.
Deactivation	M14D		Deactivation encompasses retiring or mothballing a generating unit, governed by the PJM Open Access Transmission Tariff. Any generator owner, or designated agent, who wishes to retire a unit from PJM operations must initiate a deactivation request in writing no less than 90 days in advance of the planned deactivation date.
Deliverability	RAA, M14B, M18		Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver energy from generation facilities to wherever it is needed to ensure, only, that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) generation deliverability and (2) load deliverability.
Demand Resource	M18	DR	See "load management."
Designated Entity			A designated entity can be an existing transmission owner or nonincumbent transmission developer, designated by PJM with the responsibility to construct, own, operate, maintain and finance immediate need reliability projects, short-term projects, long-lead projects, or economic-based enhancements or expansions.
Designated Entity Agreement	OATT	DEA	When a project is designated as a greenfield project that is not reserved for the transmission owner, execution of a Designated Entity Agreement is required. 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			Distributed solar generation is not connected to PJM and does not participate in PJM markets. These resources do not go through the full interconnection queue process. The output of these resources is netted directly with the load. PJM does not receive metered production data from any of these resources.
Distribution Factor		DFAX	A distribution factor is the portion of an imposed power transfer flows across a specified transmission facility or interface.
Diversity	M18		Diversity is the number of megawatts that account for the difference between a transmission owner zone's forecasted peak load at the time of its own peak and its coincident load at the time of the PJM peak.
Eastern Interconnection Planning Collaborative		EIPC	The Eastern Interconnection Planning Collaborative represents an interconnection-wide transmission planning coordination effort among Planning Authorities in the Eastern Interconnection. EIPC consists of 20 Planning Coordinators comprising approximately 95 percent of the Eastern Interconnection electricity demand. EIPC coordinates transmission analysis of regional transmission plans to ensure their coordination and also provides the resources to conduct analysis of emerging issues affecting the grid.
Eastern Interconnection Reliability Assessment Group		ERAG	The ERAG is a group whose purpose is to further augment the reliability of the bulk power system in the Eastern Interconnection through periodic studies of seasonal and longer-term transmission system conditions.
Eastern MAAC	M14B	EMAAC	Eastern MAAC is a term used in PJM deliverability analysis to refer to the portion of PJM that includes AE, DPL, JCPL, PECO, PSE&G and Rockland.
Effective Forced Outage Rate on Demand	M22	EFORd	EFORd is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. See Manual 22: Generator Resource Performance Indices for the equation.
Electrical Distribution Company		EDC	An electrical distribution company owns and/or operates electrical distribution facilities for the delivery of electrical energy to end-use customers.

Term	Reference	Acronym	Definition
End-use characteristics	M19		End-use characteristics are the measures of electrical equipment and appliance efficiency used in residential and commercial settings. These are represented in forecast models as part of heating, cooling and other applications.
Energy Efficiency Programs		EE	Energy efficiency programs are incentives or requirements at the state or federal level that promote energy conservation and wise use of energy resources.
Energy Resource	M14A, M14B	OATT	An energy resource is a generating facility that is not a capacity resource.
Extended Summer Demand Resources			Extended summer demand resources can be called on as many times as needed from 10 a.m. to 10 p.m. any day from June through October and during the following May of that delivery year. Product type ceased to exist following the commencement of Capacity Performance rules.
Extra High Voltage		EHV	Extra high voltage transmission equipment operates at 230 kV and above.
Facilities Study Agreement	M14A	FSA	A facilities study agreement is an agreement between the interconnection customer/developer and PJM to identify the scope of facility additions and upgrades to be included in the interconnection study.
Fault			A physical condition that results in the failure of a component or facility of the transmission system to transmit electrical power in the manner for which it was designed.
Federal Energy Regulatory Commission		FERC	FERC is an independent agency that regulates the interstate transmission of electricity, natural gas and oil.
Financial Transmission Right	M6	FTR	A financial transmission right is a financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm Transmission Service	OATT		Firm transmission service is intended to be available at all times to the maximum extent practical. Service availability is subject to system emergency conditions, unanticipated facility failure or other unanticipated events and is governed by Part II of the OATT.
Flexible Alternating Current Transmission System		FACTS	FACTS is a system composed of static equipment used for the AC transmission of electrical energy, meant to enhance controllability and increase power transfer capability of the network. It is generally a power electronics-based system.
Fixed Series Capacitor		FSC	A fixed series capacitor is a grouping of capacitors used to reduce transfer reactance's on bulk transmission corridors.
Flowgate			A flowgate is a specific combination of a monitored facility and contingency impacting that monitored facility.
Generation Deliverability	M14B		Generation deliverability is the ability of the transmission system to export capacity resources from one electrical area to the remainder of PJM. The generator deliverability test for reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the transmission system is capable of delivering the aggregate system generating capacity at peak load with all firm transmission uses modeled.
Generator Step-up Transformer		GSU	A GSU transformer "steps-up" generator power output voltage level to a suitable grid level voltage for transmission of electricity to load centers.
Geomagnetically Induced Current		GIC	A manifestation at ground level of space weather, these currents impact the normal operation of electrical conductor systems.
Good Utility Practice	OATT		Good Utility Practice is any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be practices, methods or acts generally accepted in the region.
Group/Gang Operated Air Break		GOAB	A group/gang operated air break is the portion of a circuit breaker that opens and closes to allow current to flow through or not. This particular type of break uses air as a dielectric medium, as opposed to others which use gas, oil or air contained within a vacuum. "Gang operated" refers to a mechanical linkage that opens and closes the disconnect.
Horizontal Directional Drilling		HDD	Horizontal directional drilling technology for laying transmission cable employs a long, flexible drill bit to bore horizontally underground. Horizontal directional drilling is a trenchless method in which no surface excavation is required except for drill entry and exit points, which minimizes surface restoration, ecological disturbances and environmental impacts. By contrast, jet-plowing techniques affect the riverbed over the length of the installation.

Term	Reference	Acronym	Definition
Independent State Agencies Committee	PJM.com	ISAC	The ISAC is a voluntary, stand-alone committee that consists of members from regulatory and other state agencies representing all of the states and the District of Columbia within the service territory of PJM. The ISAC is an independent committee that is not controlled or directed by PJM, the PJM Board or PJM members. The purpose of the ISAC is to provide PJM with inputs and scenarios for transmission planning studies.
Independent System Operator		ISO	An independent system operator is an entity that is authorized to operate an electric transmission system and is independent of any influence from the owner(s) of that electric transmission system. See also “RTO.”
Installed Capacity		ICAP	Installed capacity is valued based on the summer net dependable rating of the unit as determined in accordance with PJM, rules and procedures of the determination of generating capacity.
Interconnected Reliability Operating Limit	M14B	IROL	The interconnected reliability operating limit is a system operating limit that, if violated, could lead to instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk electric system.
Interconnection Construction Service Agreement	M14C	ICSA	The ICSA is companion agreement to the ISA and is necessary for projects that require the construction of Interconnection Facilities as defined in the ISA. The ICSA details the project scope, construction responsibilities of the involved parties, ownership of transmission and customer interconnect facilities and the schedule of major construction work.
Interconnection Coordination Agreement	OATT	ICA	An interconnection coordination agreement is an agreement between transmission owners and/or transmission developers outlining the schedules and responsibilities of each party involved.
Interconnection Service Agreement	M14A	ISA	An interconnection service agreement is 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.
Interregional Market Efficiency Project		IMEP	Interregional proposals are designed to address congestion and its associated costs along the MISO-PJM border within the context of the PJM-MISO JOA as identified in long-term market efficiency simulation results
Joint RTO Planning Committee		JRPC	The JRPC is the decision-making body for PJM-MISO coordinated system planning as governed by the PJM-MISO JOA.
Light Load Reliability Analysis	M14B		Light load reliability analysis ensures that the transmission system is capable of delivering the system generating capacity during a light load situation (50 percent of 50/50 summer peak demand level).
Limited Demand Resources			Limited demand resources can be called on up to 10 times from noon to 8 p.m. on weekdays, other than NERC holidays, from June through September. Product type ceases to exist following the commencement of Capacity Performance rules.
Load			Load is demand for electricity at a given time, expressed in megawatts.
Load Analysis Subcommittee	M19	LAS	The Load Analysis Subcommittee is responsible for technical analysis and coordination of information related to the electric peak demand and energy forecasts, interruptible load resources for capacity credit and weather, and peak load studies. The LAS reports to the Planning Committee (PC).
Load Deliverability	M14B		Load deliverability is the ability of the transmission system to deliver energy from the aggregate of available capacity resources in one PJM electrical area and adjacent non-PJM areas to another PJM electrical area that is experiencing a capacity deficiency.
Load Management	M18	LM	Load management is the ability to interrupt retail customer load 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.
Local Distribution Company		LDC	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	M14B	LDA	Locational deliverability areas are electrically cohesive load areas historically defined by transmission owner service territories and larger geographical zones comprising a number of those service areas.
Locational Marginal Price		LMP	The locational marginal price is the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.
Loss-of-Load Expectation	M14B	LOLE	Loss-of-load expectation defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, during only one day in 10 years.

Term	Reference	Acronym	Definition
Market Participant			A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met 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	See "Reactive Power."
Merchant Transmission Facility	OATT		Merchant transmission facilities are AC or DC transmission facilities that are interconnected with or added to the transmission system in accordance with the PJM Open Access Transmission Tariff. These facilities are not existing facilities of the transmission system, transmission facilities included in the rate base of a public utility on which a regulated return is earned, transmission facilities included in previous RTEPs, or customer interconnection facilities.
Mercury and Air Toxins Standards		MATS	MATS is an EPA rule limiting the emissions of toxic air pollutants like mercury, arsenic and metals from power plant emissions.
Mid-Atlantic Subregion	M14B	MAAC	The PJM Mid-Atlantic Subregion encompasses 12 transmission owner zones: Atlantic Electric Company (AE), Baltimore Gas and Electric (BGE), Delmarva Power and Light (DPL), Jersey Central Power and Light (JCPL), Metropolitan Edison Company (Met-Ed), Neptune, PECO Energy (PECO), Pennsylvania Electric Company (PENELEC), PEPCO, PPL Electric Utilities Corporation (PPL), Public Service Electric and Gas (PSE&G) and Rockland Electric (Rockland). The Neptune Regional Transmission System interconnects with the Mid-Atlantic PJM transmission system at Sayreville substation in Northern New Jersey.
MISO Transmission Expansion Planning		MTEP	MTEP is the Midcontinent Independent System Operator (MISO) plan for enhancing the future of the power grid in their area.
Motor Operated Air-Break		MOAB	A motor-operated air-break is the portion of a circuit breaker that opens and closes to allow current to flow through or not. This particular type of break uses air as a dielectric medium, as opposed to others that use gas, oil or air contained within a vacuum. "Motor operated" refers to a remote-controlled motorized linkage that opens and closes the disconnect.
Multiregional Model Working Group		MMWG	The Multiregional Model Working Group reports to the 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.
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		Network reinforcements are modifications or additions to transmission-related facilities that are integrated with and support the transmission provider's overall transmission system for the general benefit of all users of such transmission system.
Non-Coincident Peak	M19	NCP	The non-coincident peak is a zone's individual peak load.
North American Electric Reliability Corporation	NERC	NERC	NERC is a FERC-appointed body whose mission is to ensure the reliability of the bulk power system.
Open Access Same-Time Information System		OASIS	The Open Access Same-Time Information System (OASIS) provides information by electronic means about available transmission capability for point-to-point service and a process for requesting transmission service on a non-discriminatory basis. OASIS enables transmission providers and transmission customers to communicate requests and responses to buy and sell available transmission capacity offered under the PJM Open Access Transmission Tariff.
Open Access Transmission Tariff	OATT	OATT	The OATT is a FERC-filed tariff specifying the terms of conditions under which PJM provides transmission service and carries out its generation and merchant transmission interconnection process.
Optical Grounding Wire Communications		OPGW	Optical grounding wire communications is a type of fiber optic cable used in the construction of electric power transmission and distribution lines that combines the functions of grounding and communications.
Optimal Power Flow		OPF	Optimal power flow is a tool used to determine optimal dispatch, subject to transmission constraints. Optimal often means most economical but may also mean minimum control change.
Organization of PJM States, Inc.		OPSI	OPSI 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.

Term	Reference	Acronym	Definition
PJM Manuals			PJM Manuals contain the instructions, rules, procedures and guidelines established by PJM for the operation, planning and accounting requirements of the region PJM serves and the PJM Interchange Energy Market.
PJM Member	OA, M33		A PJM member is any entity that has satisfied PJM requirements to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
Planning Committee	OA	PC	The Planning Committee was established under the operating agreement to review and recommend system planning strategies and policies, as well as planning and engineering designs for the PJM bulk power supply system.
Planning Cycle	M14B		The planning cycle is the annual RTEP process series of studies, analysis, assessments and related supporting functions.
Planning Horizon	M14B		The planning horizon is the future time period over which system transmission expansion plans are developed based on forecasted conditions.
Probabilistic Risk Assessment	M14B	PRA	PJM assesses risk exposure using a PRA risk management tool. The goal of the PRA model is to minimize asset service cost. PJM's PRA method integrates the economics of facility loss with the likelihood of that loss occurring. Incurring.
Reactive Power (expressed in MVAR)	M14A		Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is usually expressed as megavolt-ampere reactive (MVAR).
Regional Greenhouse Gas Initiative		RGGI	States and provinces in the Northeastern United States and Eastern Canada adopted the Regional Greenhouse Gas Initiative to reduce greenhouse gas emissions.
Regional RTEP Project	M14B, OA		A Regional RTEP Project is a transmission expansion or enhancement at a voltage level of 100 kV or higher.
Regional Transmission Expansion Plan	M14B	RTEP	The Regional Transmission Expansion Plan is prepared by PJM pursuant to Schedule 6 of the PJM Operating Agreement for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the region PJM serves.
Regional Transmission Organization	FERC	RTO	A regional transmission organization is an independent, FERC-approved organization of sufficient regional scope, which coordinates the interstate movement of electricity under FERC-approved tariffs by operating the transmission system and competitive wholesale electricity markets and ensuring reliability and efficiency through expansion planning and interregional coordination.
Reliability	NERC		A reliable bulk power system is one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity.
Reliability Assurance Agreement	RAA	RAA	The Reliability Assurance Agreement (RAA) among load-serving entities in the region PJM serves is intended to ensure that adequate capacity resources will be planned and made available to provide reliable service to loads within PJM, to assist other parties during emergencies and to coordinate planning of capacity resources consistent with the reliability principles and standards.
Reliability Must Run		RMR	A Reliability Must Run (RMR) generating unit is one slated to be retired by its owners but needed to be available to maintain reliability. Typically, it is requested to remain operational beyond its proposed retirement date until required transmission enhancements are completed.
Reliability Pricing Model		RPM	The Reliability Pricing Model is PJM's resource adequacy construct. The purpose of RPM is to develop a long-term pricing signal for capacity resources and load serving entity (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).
Renewable Integration Study		RIS	The RIS is an ongoing study to examine the reliability and market impacts of high wind and solar penetration in the PJM system to meet objectives of state policies regarding renewable resource production.
Renewable Portfolio Standard		RPS	The Renewable Portfolio Standard is a set of guidelines or requirements at the state or federal level requiring energy suppliers to provide specified amounts of electric energy from eligible renewable energy resources.

Term	Reference	Acronym	Definition
Right of First Refusal		ROFR or RFR	The right of first refusal is a contractual right that gives the holder the option to enter a business transaction with the owner of an asset, according to specified terms, before the owner is entitled to enter into that transaction with a third party.
Right-of-Way		ROW	A right-of-way is a corridor of land on which electric lines may be located. The transmission owner may own the land in fee; own an easement; or have certain franchise, prescription or license rights to construct and maintain lines.
Security	NERC		The ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits, or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by physical or cyberattacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.
Security Constrained Optimal Power Flow		SCOPF	The optimal power flow determines the ideal dispatch, subject to transmission constraints. Optimal usually means least cost (or most economical), but may also mean minimum control change. Security-constrained OPF, or SCOPF, adds contingencies. The SCOPF will seek a single dispatch that does not cause any overloads in the base case, nor any overloads during any of the contingencies.
Southern Subregion	M14B		The PJM Southern Subregion comprises one transmission owner zone – Dominion Virginia Power (Dominion).
Special Protection System	M03	SPS	A Special Protection System (SPS) – also known as a remedial action scheme – includes an assembly of protection devices designed to detect and initiate automatic action in response to abnormal or pre-defined system conditions. The intent of these schemes is generally to protect equipment from thermal overload or to protect against system instability following subsequent contingencies on the electric system. Redundant assemblies may be applied for the above functions on an individual facility – in such cases, each assembly is considered 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.
Static Synchronous Compensator		STATCOM	A shunt device of the Flexible AC Transmission System (FACTS) family using power electronics to control power flow and improve transient stability on power grids.
System Operating Limit	M14B	SOL	The value (such as MW, MVAR, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System operating limits are based upon certain operating criteria.
Static Var Compensation		SVC	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	M14B, OA		A PJM committee that facilitates the development and review of the subregional RTEP projects. The Subregional RTEP Committee is responsible for the initial review of the subregional RTEP projects, and for providing recommendations to the Transmission Expansion Advisory Committee (TEAC) concerning the subregional RTEP projects.
Subregional RTEP Project	M14B, OA		A subregional RTEP project is defined in the PJM Operating Agreement as a transmission expansion or enhancement rated below 230 kV.
Sub-Synchronous Resonance		SSR	Power system sub-synchronous resonance (SSR) is the build-up of mechanical oscillations in a turbine shaft arising from the electro-mechanical interaction between the turbine generator and the rest of the power system. This can lead to turbine shaft damage, even catastrophic loss. The term "sub-synchronous" refers to the fact that the oscillations a shaft can experience occur at levels below 60 Hz (cycles-per-second).
Supplemental Project	M14B, OA		"Supplemental project" replaces the term "Transmission Owner Initiated or TOI Project." A regional RTEP project or a subregional RTEP project that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.
Surge Impedance Loading		SIL	The megawatt loading of a transmission line at which a natural reactive power balance occurs. A line loaded below its SIL supplies reactive power to the system; a line above its SIL absorbs reactive power.
System Stability			Stability studies examine the grid's ability to return to a stable operating point following a system fault or similar disturbance. Such contingencies can cause a nearby generator's rotor'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 megawatt, system voltage, machine voltage, duration of the disturbance and system impedance. Transient stability examines this phenomenon over the first several seconds following a system disturbance.
Targeted Market Efficiency Project		TMEP	TMEP interregional projects address historical congestion on reciprocal coordinated flowgates – a set of specific flowgates subject to joint and common market (JCM) congestion management.

Term	Reference	Acronym	Definition
Temperature-Humidity Index	M19	THI	The 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 THI is defined as follows: *THI = Td – (0.55 – 0.55RH) * (Td - 58)*, where Td is the dry-bulb temperature and RH is the percentage of relative humidity, when Td is greater than or equal to 58.
Thyristor Controlled Series Compensator		TCSC	A thyristor controlled series compensator is a series capacitor bank that is shunted by a thyristor controlled reactor.
Topology	M14B		Topology is a geographically based or other diagrammatic representation of the physical features of an electrical system or portion of an electrical system – including transmission lines, transformers, substations, capacitors and other power system elements – that in aggregate constitute a transmission system model for power flow and economic analysis.
Transmission Customer	M14A, M14B, M2, OATT		A transmission customer is any eligible customer (or its designated agent) that (i) executes a service agreement or (ii) requests in writing that PJM file with the FERC, a proposed unexecuted service agreement to receive transmission service under Part II of the PJM OATT.
Transmission Expansion Advisory Committee	M14B	TEAC	The Transmission Expansion Advisory Committee was established by PJM to provide advice and recommendations to aid in the development of the Regional Transmission Expansion Plan (RTEP).
Transmission Loading Relief	M03	TLR	Transmission loading relief is a NERC procedure developed for the Eastern Interconnection to mitigate overloads on the transmission system by allowing reliability coordinators to request the curtailment of transactions that are causing parallel flows through their system.
Transmission Owner	M14B, OATT	TO	A transmission owner is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a transmission owner.
Transmission Owner Initiated		TOI	See "Supplemental Project."
Transmission Owner Upgrade	OA		A transmission owner upgrade is an improvement to, addition to, or replacement of a part of a transmission owner's existing facility and is not an entirely new transmission facility.
Transmission Provider	M14B, OATT		The transmission provider is PJM for all purposes in accordance with the PJM OATT.
Transmission Service Request	M02	TSR	A transmission service request is a request submitted by a PJM market participant for transmission service over PJM designated facilities. Typically, the request is for either short-term or long-term service, over a specific path for a specific megawatt amount. PJM evaluates each request and determines if it can be accommodated and, if the requestor so chooses, pursues needed upgrades to accommodate the request.
Transmission System	OATT		The transmission system comprises the transmission facilities operated by PJM used to provide transmission services. These facilities that transmit electricity: are within the PJM footprint; meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and have been demonstrated to the satisfaction of PJM to be integrated with the transmission system of PJM and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.
Unforced Capacity	RAA	UCAP	Unforced capacity is an entitlement to a specified number of summer-rated MW of capacity from a specific resource, on average, not experiencing a forced outage or 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 a UCSA govern the construction activities associated with the upgrade of capability along an existing PJM bulk electric system circuit in order to accommodate a merchant transmission interconnection request. Facilities constructed under a UCSA are not owned by a developer. All ownership rights of the physical facilities are retained by the respective transmission owner following the completion of construction. PJM and the developer execute a separate UCSA with each impacted transmission owner. A developer retains the right, but not the obligation (option to build), to design, procure, construct and install all or any portion of the direct assignment facilities and/or customer-funded upgrades.
Violation	M14B		A violation is a PJM planning study result that shows a specific system condition that is not in compliance with established NERC, ReliabilityFirst, SERC or PJM reliability criteria.
Weather Normalized Peak	M19		The weather normalized peak is an estimate of the seasonal peak load at normal peak day weather conditions.

Term	Reference	Acronym	Definition
Western Subregion	M14B, OA		The PJM Western Subregion comprises five transmission owner zones: Allegheny Power (AP), American Electric Power (AEP), American Transmission Systems Incorporated (ATSI), Commonwealth Edison (ComED), Dayton Power and Light (Dayton), Duke Energy Ohio and Kentucky (DEO&K), Duquesne Light Company (DLCO) and Eastern Kentucky Power Cooperative (EKPC).
Wheel			A wheel is the contracted third-party use of electrical facilities to transmit power whose origin and destination are outside the entity transmitting the power.
X-Effective Forced Outage Rate on Demand		XEFORd	XEFORd is a statistic that results from excluding events Outside Management Control (outages deemed not to be preventable by the operator) from the EFORd calculation. See “Effective Forced Outage Rate on Demand (EFORd).”
Zone/Control Zone	M14B		A zone/control zone is an area within the PJM control area, as set forth in the PJM Open Access Tariff and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that compose the PJM Control Area.