PJM Baseline Reliability Assessment 2021 - 2036 Period

PJM

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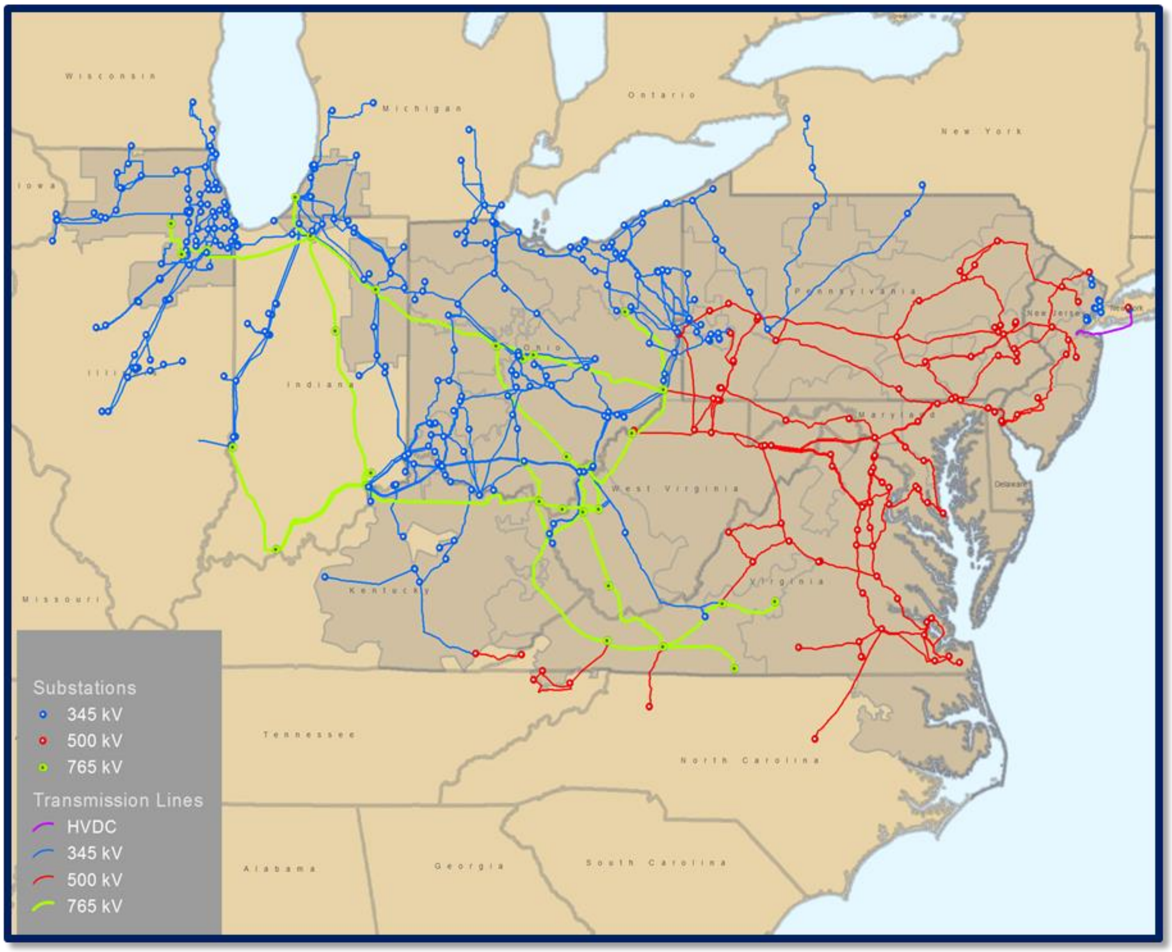
Contents

Introduction

The PJM system covers more than 369,000 square miles in 13 states and the District of Columbia. Serving approximately 65 million people, the PJM system includes major U.S. load centers from the western border of Illinois to the Atlantic coast including the metropolitan areas of Baltimore, Chicago, Cleveland, Columbus, Dayton, Newark, Norfolk, Philadelphia, Pittsburgh, Richmond, and Washington D.C. PJM dispatches more than 180,000 megawatts of generation capacity over more than 84,000 miles of transmission lines – a system that serves nearly 21 percent of the U.S. economy. The PJM system is electrically continuous and consists of multiple electrical service territories. PJM's Bulk Electric System (BES) includes a robust network of 765kV, 500kV, 345kV, 230kV, 161kV, 138kV, and 115kV facilities. The map below depicts the PJM service territory footprint overlaid with PJM high voltage lines operated at 345 kV and above.



Map 1. Existing PJM 345 kV, 500 kV, and 765 kV Network

As a Federal Energy Regulatory Commission (FERC) approved Regional Transmission Organization (RTO), one of PJM's core functions encompasses regional transmission planning. PJM is also a North American Electric Reliability Corporation (NERC) registered Reliability Coordinator, Planning Coordinator, and Transmission Planner. PJM's annual planning process is known as the PJM Regional Transmission Expansion Plan (RTEP). The RTEP process is established in the PJM Operating Agreement – Schedule 6 – Regional Transmission Expansion Planning Protocol. The RTEP processes and procedures are described in detail in the PJM Regional Transmission Planning Process Manuals. PJM Manual 14B – PJM Region Transmission Planning process contains the process used to complete the annual baseline reliability assessment.

PJM's Regional Transmission Expansion Plan (RTEP) identifies transmission upgrades and enhancements that are required to preserve the reliability of the transmission system. The PJM system is planned such that it can be operated to applicable System Operating Limits (SOL) while supplying projected customer demands and projected firm transmission service over a range of forecast system demands under contingency conditions that have a reasonable probability of occurrence. PJM reliability planning encompasses a comprehensive series of detailed analyses that ensure reliability and compliance under the most stringent of the applicable NERC, Regional Entity (RFC or SERC as applicable), PJM, and local criteria. To accomplish this each year, a baseline assessment is completed for applicable facilities over the near term (1-5 years) and longer term (years 6-15). All Bulk Electric System (BES) facilities are included in the RTEP baseline assessment process as required by NERC Standards.

PJM is registered with the North American Electric Reliability Corporation (NERC) as the Reliability Coordinator (RC), Interchange Authority (IA), Transmission Operator (TOP), Balancing Authority (BA), Planning Coordinator (PC), Transmission Planner (TP), Transmission Service Provider (TSP), and Resource Planner (RP). There are multiple transmission zones within PJM. Table 1 lists individual transmission zones in the PJM footprint. A few smaller PJM transmission owners are modeled within another larger PJM transmission area and are not explicitly listed on this table. A few examples of this are Neptune Regional Transmission System LLC, Linden VFT LLC, and Essential Power/Rock Springs.

AP	Allegheny Power System, Inc.
AE	Atlantic Electric
AEP	American Electric Power Co., Inc.
ATSI	American Transmission Systems, Inc.
BG&E	Baltimore Gas & Electric Co.
CE	Commonwealth Energy System
DAY	Dayton Power and Light Co
DEO&K	Duke Energy Ohio and Kentucky
DLCO	Duquesne Light Co
DP&L	Delmarva Power and Light Co
EKPC	Eastern Kentucky Power Cooperative
ITCI	ITC Interconnection
JCP&L	Jersey Central Power and Light
METED	Metropolitan Edison Co
OVEC	Ohio Valley Electric Corporation
PECO	PECO Energy Co.
PENELEC	Pennsylvania Electric Co
PEPCO	Potomac Electric Power Co.
PPL	PPL Electric Utilities
PSE&G	Public Service Electric and Gas Company
RECO	Rockland Electric Company
UGI	UGI Utilities Inc.
DVP	Virginia Power (Dominion)

Table 1. **PJM area Transmission Zones**

PJM is interconnected with neighboring systems and has over 100 BES transmission ties to these adjacent systems. Table 2 lists PJM's neighboring systems and associated entities. PJM coordinates planning analyses with adjacent Planning Coordinators and Transmission Planners to ensure that contingencies on adjacent systems are studied as part of PJMs RTEP process.

ALTE	Alliant Gas and Electric – East
ALTW	Alliant Gas and Electric – West
AMIL	Ameren Illinois
AMMO	Ameren Missouri
BREC	Big Rivers Electric Corporation
CPLE	Carolina Power and Light Company - East
CPLW	Carolina Power and Light Company - West
DEI	Duke Energy Indiana
DUKE	Duke Energy Carolinas
IPL	Indianapolis Power and Light Company
ITCT	International Transmission Company
LAGN	Louisiana Generating Company
LGEE	LGE Energy
LIPA	Long Island Power Authority
MEC	MidAmerican Energy
METC	Michigan Electric Transmission Co.
National Grid	National Grid
NIPS	Northern Indiana Public Service Company
NYISO	New York ISO
OMU	Owensboro Municipal Utilities
ORU	Orange & Rockland
SMT	Brookfield/Smoky Mountain Hydropower LLC
SIGE	Southern Indiana Gas & Electric Company
TVA	Tennessee Valley Authority
WEC	Wisconsin Electric Power Company

Table 2. **PJM Neighboring Systems**

The PJM RTEP process requires that cost responsibility for facility enhancements be established. In order to establish a starting point for development of Regional Transmission Expansion Plans and determine cost responsibility for expansion facilities, a 'baseline' assessment of system adequacy and security is necessary. The purpose of this assessment is threefold:

1. To identify areas where the system as planned under previous assessments does not meet the applicable reliability criteria and standards as a result of load increases on the system or changes to methodologies associated with the analyses.
2. To develop and recommend facility expansion plans which will bring areas where the system does not meet performance requirements specified in an applicable standard into compliance. These plans include cost estimates and required in-service dates.
3. To establish what will be included as baseline costs in the allocation of the costs of expansion for those generation and merchant transmission projects proposing to connect to the PJM system.

The system as planned is evaluated for its compliance with all applicable reliability standards to accommodate the forecast demand, committed resources, and commitments for firm transmission services for a specified time frame. Areas that are found to not meet applicable reliability criteria are identified and enhancement plans are developed to achieve compliance within an identified timeframe. The lead time necessary to implement the system enhancement is considered as part of the overall plan. In addition, the status and progress of each upgrade is tracked closely to ensure that the required in-service dates are met.

The 'baseline' assessment and the resulting expansion plans serve as the base system for the conduct of Interconnection Feasibility Studies and System Impact Studies associated with new generation, merchant transmission and long term firm transmission service. The interconnection process is described by Manual 14A: Generation and Transmission Interconnection Process. This report details the results of the 'baseline' assessment from 2021 through 2036 for the PJM footprint.

Executive Summary

PJM is responsible for the development of a Regional Transmission Expansion Plan (RTEP) for the PJM system that will meet the needs of the region in a reliable, economic and environmentally acceptable manner. As further described in following portions of this assessment, the PJM RTEP combines a broad set of analysis into a single plan. The annual RTEP process consists of a baseline reliability review, analysis to identify the transmission needs associated with both generation interconnection and merchant transmission, review of conditions experienced in real time operations, inter-regional reliability analysis, and many other special studies. The RTEP incorporates the unique needs identified by in-depth thermal, stability, short circuit, and voltage reliability analysis. PJM ensures a robust and comprehensive annual RTEP by incorporating all of these diverse needs into a single plan.

The annual RTEP planning assessment includes a comprehensive review of PJM Bulk Electric System (BES) facilities as required by NERC standards TPL-001-4. PJM maintains a series of power flow, short circuit and stability cases that represent a range of critical system conditions for a range of forecast demand levels and study years. The annual RTEP baseline analysis performs the following tests at a minimum to ensure NERC TPL compliance:

1) Thermal Analysis
   a) Normal system (all facilities in service), single, and multiple contingency analysis as required by NERC TPL standards
   b) Generation deliverability analysis, as described in PJM Manual 14B Section 2 RTEP Process
   c) Common mode outage procedure analysis, as described in PJM Manual 14B Section 2 RTEP Process
   d) Load deliverability analysis, as described in PJM Manual 14B Section 2 RTEP Process
   e) N-1-1 analysis
   f) Light Load Reliability Analysis
   g) Winter Reliability Analysis
   h) 15 Year Analysis
   i) Transfer Limit Analysis
2) Short Circuit fault duty analysis
3) Voltage Analysis
   a) Voltage limit testing, including voltage magnitude and voltage drop monitoring for many of the test methods listed above for the thermal analysis
   b) Voltage collapse, including non-convergent events
   c) PV analysis, including Transfer Limits
4) Stability Analysis
   a) Transient stability (short and long term)
   b) Small signal stability (oscillations)
   c) Voltage Stability
   d) Nuclear Plant Interface Requirements (NPIR)

PJM also studies, requests for new generation, merchant transmission, and long term firm transmission service. The process for studying these requests is described in PJM Manual 14A. In Calendar year 2021, PJM completed 594 system impact studies to accommodate new generation, merchant transmission, and long term firm transmission service. The 2021 RTEP includes any upgrades associated with the queue projects that are required to maintain the reliability of the PJM system.

1) New Services Queue Analysis
   a) Generation interconnection
   b) Merchant transmission
   c) Yearly long term firm transmission service

Information related to the generation, merchant transmission, and yearly long term firm transmission service request queues can be found on the PJM website at the following link.

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Information that is posted on the PJM website includes the status of the New Services Queues, as well as the technical study reports. The technical reports include the feasibility, impact, and facility study reports. PJM agreements such as interconnection service agreements (ISA) and interconnection construction service agreements (CSA) are also posted on the website.

PJM coordinates inter-regional activities with neighboring systems pursuant to PJM's Tariff and interregional agreements. PJM annually participates in a wide range of inter-regional groups and committees. Several significant efforts in 2021 are listed below.

1) Inter-regional planning groups
   a) Independent System Operator / Regional Transmission Organization (ISO/RTO) Council (IRC)
   b) Eastern Interconnection Planning Collaborative (EIPC): Planning Coordinators of the Eastern Interconnection
      i) 2020 High Renewables Study
      ii) State of the Grid Report
   c) Joint Operating Agreement with New York ISO (NYISO) and Joint Operating Agreement with Mid-Continent ISO (MISO)
      i) Joint ISO/RTO Planning Committee (JIPC) activities pursuant to the PJM/NYISO/ISO-NE Northeast Planning Coordination Protocol
         (1) Interregional Planning Stakeholder Advisory Committee (IPSAC) – Reliability Interconnection Queue and Market Efficiency Analysis
      ii) Joint RTO Planning Committee (JRPC) activities pursuant to the MISO/PJM Joint Operating Agreement
         (1) Interregional Planning Stakeholder Advisory Committee (IPSAC) – Reliability and Market Efficiency Analysis
   d) Southeastern Regional Transmission Planning: (SERTP)
      i) Joint Operating Agreement with Duke Energy Progress (DEP)

ii) Joint Operating Agreement with Tennessee Valley Authority (TVA)

e) Joint Reliability Coordination Agreement between PJM and TVA

f) North Carolina Transmission Planning Collaborative (NCTPC) planning and data sharing agreement

2) North American Electric Reliability Corporation (NERC) and Eastern Interconnection Reliability Assessment Group (ERAG) related activities

i) SERC Reliability Corporation and associated committees and working groups

ii) RFC Reliability Corporation and associated committees and working groups

PJM Planning also coordinates with PJM Operations to review operational performance issues. In addition, sensitivity studies may be requested by stakeholders. Examples of these studies include:

Additional Studies

- PJM-NYISO transfer limit study
- Chestnut Solar oscillation event analysis (Dominion)
- Homer City RAS update evaluation (Penelec)

Operating guideline and other sensitivity studies

- Washington (Beverly) N-1-1 stability issue evaluation (AEP)

The RTEP assesses the needs of the system, at peak load for year one, two, three four and year 5 in the near term and over the longer term (up to 15 years) to identify baseline transmission enhancements that require more time to implement. Additionally, PJM evaluates an off peak load seasonal assessment for year 5 PJM also is responsible for recommending the assignment of any transmission expansion costs to the appropriate parties. In order to carry out these responsibilities, it is necessary to establish a starting point or 'baseline' from which the need and responsibility for enhancements can be determined.

As the NERC registered Planning Coordinator, PJM is the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems for both the near term and longer term. The planned network upgrades required by the RTEP serve as a central repository for the BES related reliability plans of the individual PJM transmission owners. By integrating the individual plans into a single plan, the RTEP is able to provide a robust reliability plan for the PJM Bulk Electric System.

In order to establish the long term plan, PJM has defined the fifteen (15) year period from 2021 through 2036 as the 2021 "baseline" planning period. This assessment is inclusive of the previous years' baseline assessments, models, and required upgrades. As such, the existing system plus any planned modifications to the transmission system including reactive resources that are scheduled to be in service prior to the 2026 summer peak period were chosen as the base system for the near-term assessment. This ensures the system as planned remains compliant with

reliability standards. Appendix A represents a snapshot of all upgrades identified in RTEP evaluations prior to 2021. These identified upgrades, when added to the previously existing system, function as the base system for future models. In addition, assessments for delivery years prior to 2026 were updated with current assumptions to validate the on-going need for identified upgrades and to ensure continued compliance with reliability criteria.
For the 2021 RTEP cycle, PJM has studied 22 generator deactivation notifications resulting in over 4,400 MW of existing generation deactivating in 2021 or some point in the near term planning horizon. In order to establish a model which accurately included all expected generation retirements, PJM performed many sets of analysis to study the effects of these generation retirements on the system. Baseline transmission upgrades were identified as a result of these deactivations. The upgrades resulting from the deactivations were examined in the basecase before approving new RTEP upgrades for any of the standard RTEP analysis for the 2021 RTEP cycle. The scope of the deactivation notification analysis was significant and included a review of system impacts in years 2021 through 2026. The scope and results of the generation deactivation analysis is discussed in subsequent sections of this report.

All new generation and merchant transmission projects that executed an Interconnection Service Agreement were also included in this baseline system along with any associated transmission enhancements as identified in the System Impact Studies associated with those requests. Queued generation, merchant transmission, and firm transmission service is studied and subsequently included in the basecase for the New Services Queue studies. The process for these studies is detailed in PJM manual 14A. PJM manual 14B attachments A-I describe the analysis that is performed to ensure the reliability of new generation, merchant transmission, and firm transmission service. Any supplemental transmission enhancements independent of those associated with new generation or merchant transmission projects were also included. All firm transmission service currently committed for the period was represented.

PJM has conducted a comprehensive assessment of the ability of the PJM system to meet all applicable reliability planning criteria. The applicable reliability planning criteria are listed below:

- NERC Planning Standards
  http://www.nerc.com/pa/Stand/Pages/default.aspx
- RFC Reliability Standards
  https://rfirst.org/ProgramAreas/Standards/Regional/Pages/Regional.aspx
- SERC Reliability Corporation
  http://www.serc1.org/Application/HomePageView.aspx
- PJM Reliability Planning Criteria as contained in PJM Regional Transmission Planning Process Manuals http://www.pjm.com/library/manuals.aspx
- Transmission Owner Reliability Planning Criteria as filed in their respective FERC Form 715 filing http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx

In completing this assessment, PJM has documented all conditions where the system did not meet applicable reliability criteria and identified the system reinforcements required to bring the system into compliance along with estimated cost and lead-time to implement them.

Those areas that were found to not meet applicable reliability standards establish the need for reinforcement in those areas independent of any future interconnection projects not included in the baseline analysis. The resulting system with the identified reinforcements to bring the system into compliance, is anticipated to be used in evaluating the impact of the projects in queues AF1 and AF2 that qualify and elect to proceed with the system impact studies. The extent to which reinforcements identified in the baseline assessment are advanced, deferred, modified or eliminated will be used in determining cost responsibility for the final plans in the RTEP.

It should be recognized that the reinforcements identified in this baseline analysis may be modified, advanced, deferred or eliminated as a result of future system assumptions. Future assumptions include generation projects, merchant transmission projects, generation retirements, or transmission service being added to or removed from the system. The development of the RTEP for PJM is an ongoing process, which includes the conduct of system impact studies and development of plans to accommodate the new interconnection projects. Upon completion of the system impact studies some projects may elect not to proceed. When it is determined which projects will commit to proceed, PJM develops a new baseline RTEP to meet the needs of the region, including the accommodation of all new projects committed to connect, during the next 5 year period.

Key Findings

Inclusive of the baseline upgrades identified in the Results Section of this assessment, PJM assesses its system as being compliant with the thermal, reactive, short circuit, and stability requirements of all applicable standards including NERC Standards TPL-001-4 for both the near term and longer term. The results section of this assessment includes all planned upgrades needed to meet the performance requirements of Table 1 in each respective TPL standard throughout the planning horizon.

The reinforcements identified as part of the 2021 RTEP that are required to achieve compliance having an estimated cost of at least $5 million are described below. The required in-service date of these upgrades is also included. A complete list of projects along with detailed descriptions of the conditions that are driving the need for them, are described in the Results section and Appendix A of this report. PJM staff from the Infrastructure Coordination group coordinates with the transmission owners and generation or merchant transmission developers to monitor project schedules for implementation of these reinforcements and coordinate any required outage activities to ensure these reinforcements are completed by their required in-service dates. The cost estimates below are based on those provided by the responsible entities and discussed at the monthly Transmission Expansion Advisory Committee (TEAC) meetings during the calendar year.

PJM MID ATLANTIC

ME

- Rebuild approx. 3.6 miles of 875 (N. Boyertown - W. Boyertown). Upgrade terminal equipment (circuit breaker, disconnect switches, substation conductor) and relays at N. Boyertown and W. Boyertown substation - 6/1/2026 - $8.79M
- Rebuild approx. 3.6 miles of 875 (N. Boyertown - W. Boyertown). Upgrade terminal equipment (circuit breaker, disconnect switches, substation conductor) and relays at N. Boyertown and W. Boyertown substation - 6/1/2026 - $8.79M

PENELEC

- East Towanda – North Meshoppen 115 kV Line: Rebuild 2.5 miles of 636 ACSR with 1113 ACSS conductor using single circuit construction. Upgrade all terminal equipment to the rating of 1113 ACSS - 6/1/2026 - $6.66M
- East Towanda – North Meshoppen 115 kV Line: Rebuild 2.5 miles of 636 ACSR with 1113 ACSS conductor using single circuit construction. Upgrade all terminal equipment to the rating of 1113 ACSS - 6/1/2026 - $6.66M

PPL

- Reconductor the 14.2 miles of the existing Juniata - Cumberland 230kV line with 1272 ACSS/TW HS285 "Pheasant" conductor. - 12/1/2023 - $8.99M

PJM WEST

AEP

- Allen Substation: Rebuild Allen Station to the northwest of its current footprint utilizing a standard air-insulated substation with equipment raised by 7' concrete platforms and control house raised by a 10' platform to mitigate flooding concerns. Install five 69 kV 3000A 40 kA circuit breakers in a ring bus (operated at 46kV) configuration with a 13.2 MVAR capacitor bank. Existing Allen station will be retired (Does not include the distribution cost) Distribution Scope of Work: Install 69/46kV-12kV 20 MVA transformer along with 2-12kV breakers on 7' concrete platforms (Conversion of S2405.1) - 12/1/2026 - $10.55M
- Bring the Logan - Sprigg #2 138kV circuit in and out of Tin Branch station by constructing approximately 1.75 miles of new overhead double circuit 138kV line. Double circuit T3 series lattice towers will be used along with 795,000cm ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD and one shield wire will be OPGW - 11/1/2026 - $8.58M
- Construct a 138kV single bus station (Tin Branch) consisting of a 138kV box bay with a distribution transformer and 12kV distribution bay. Two 138kV lines will feed this station (from Logan and Sprigg Stations), and distribution will have one 12kV feed. Install two 138 kV circuit breakers on the line exits. Install 138 kV circuit switcher for the new transformer - 11/1/2026 - $5.58M
- Construct a new 138/46/12 kV Argyle station to replace Dehue station. Install a 138kV ring bus using a breaker-and-a-half configuration, with an autotransformer with a 46kV feed and a distribution transformer with a 12kV distribution bay. Two 138kV lines will feed this station (from Logan and Wyoming Stations). There will also be a 46kV feed from this station to Becco Station. Distribution will have two 12kV feeds. Retire Dehue station in its entirety - 11/1/2026 - $10.00M
- Logan - Wyoming No. 1 circuit in and out of the proposed Argyle Station. Double circuit T3 series lattice towers will be used along with 795,000cm ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD and one shield wire will be OPGW - 11/1/2026 - $7.70M
- Rebuild ~9 mi 69kV line from new Skeggs branch station to Coal Creek 69kV line. 6-wire the short double circuit section between Whetstone Branch and Str. 340-28 to convert the line to single circuit. Retire Garden Creek to Whetstone Branch 69kV line section. - 6/1/2023 - $26.25M
- Rebuild approximately 10 miles of 46 kV line between Becco and the new Argyle substation. Retire approximately 16 miles of 46 kV line between the new Argyle substation and Chauncey station - 11/1/2026 - $33.71M
- Rebuild approximately 2.3 miles of the existing North Van Wert Sw - Van Wert 69 kV line utilizing 556 ACSR conductor. - 6/1/2026 - $6.20M
- Rebuild approximately 3.1 miles of the overloaded conductor on the existing Oertels Corner - North Portsmouth 69 kV line utilizing 556 ACSR . - 6/1/2026 - $8.00M
- Rebuild approximately 3.5 miles of overloaded 69 kV line between North Delphos-East Delphos-Elida Road switch. This includes approximately 1.1 miles of double circuit line that makes up a portion of the North Delphos-South Delphos 69 kV line and the North Delphos-East Delphos 69 kV line. Approximately 2.4 miles of single circuit line will also be rebuilt between the double circuit portion to East Delphos station and from East Delphos to Elida Road Switch. - 6/1/2026 - $8.43M
- Rebuild Prestonsburg - Thelma 46kV circuit, approximately 14 miles. Retire Jenny Wiley SS. - 12/1/2026 - $33.01M
- Rebuild Skeggs Branch substation in the clear as Coronado substation. Establish New 138 kV

and 69 kV Buses. Install 138/69 kV 130 MVA transformer, 138 kV circuit switcher and 69 kV breaker. Retire Existing Skeggs Branch substation. - 6/1/2023 - $6.32M

APS

- Reconductor the Charleroi-Union 138 kV line and upgrade terminal equipment at Charleroi - 6/1/2022 - $11.00M
- Reconductor the existing 556.5 ACSR line segments on the Messick Road-Ridgeley WC4 138 kV line with 954 45/7 ACSR to achieve 308/376 MVA SN/SE and 349/445 MVA WN/WE ratings. Replace the remote end equipment for the Messick Road-Ridgeley WC4 138 kV line. - 6/1/2026 - $11.20M

ATSI

- Install a second 345/138 kV transformer at Hayes, 448 MVA nameplate rating. Add one 345 kV circuit breaker (3000A) to provide transformer high side connection between breaker B-18 and the new breaker. Connect the new transformer low side to the 138 kV bus. Add one 138 kV circuit breaker (3000A) at Hayes 138 kV substation between B-42 and the new breaker. Relocate the existing 138 kV No. 1 capacitor bank between B-42 and the new breaker. Protection Per FE standard. - 6/1/2026 - $7.59M
- Reconductor Leroy Center-Pinegrove 138 kV line - 6/1/2022 - $16.00M

Objective and Scope

The objectives of this assessment were as follows:

a) To identify system reinforcements as required to ensure compliance with NERC standards TPL-001-4.

b) To identify areas where the system as planned for the near term period 2021 through 2026 would not meet applicable reliability standards.

c) To develop and recommend preliminary facility expansion plans, including cost estimates and required in service dates, to ensure all areas meet applicable reliability criteria.

d) To identify areas where the system as planned for the longer term period 2027 through 2036 that would not meet applicable reliability criteria, and where appropriate, develop expansion plans. These plans include required in service dates of the facilities needed to bring those areas into compliance. This longer term planning is in consideration of larger scope projects that may require long lead time to implement.

e) To establish what will be included as baseline expansion costs for the allocation of the costs of expansion for those projects included in New Services Queues.

The scope of this assessment included analysis for the period 2021 through 2036 to ensure the system would meet all applicable reliability planning criteria. These assessments include baseline thermal, baseline voltage, thermal and voltage Load Deliverability, generation deliverability, and baseline stability analysis. The baseline thermal and voltage analysis encompasses an exhaustive analysis of all BES facilities for compliance with NERC P0 – P7 (TPL-001-4) events. In addition, consistent with NERC standard TPL-001-4, a number of extreme events as defined in Table 1 of TPL-001-4 were evaluated for risk and consequences to the system. Results of this study are not documented in this report due to their sensitive nature, and can be found in the 2021 Extreme Event Report.

The PJM Load Deliverability testing methods are described in Manual 14B, section 2. The tests ensure that an area of the transmission system that is experiencing higher than normal load levels (90/10) with higher than normal internal generation unavailability has the transmission capability to import energy to meet the transmission system reliability criteria. The generation deliverability testing ensures sufficient transmission capability so that generation can be ramped to full output so that excess energy can be exported to an area that is experiencing a capacity deficiency. PJM also performed a stability analysis consistent with NERC and local transmission owner criteria to ensure the system is stable for critical system conditions including fault conditions that include multi-phase faults and faults with delayed clearing and light load conditions.

Analytical testing is performed annually on a range of study years and system conditions to satisfy NERC standards. Every year analysis is performed on the 5 year out case, while the other nearer term cases (years 0 through 4) are retooled to be studied for specific projects as changes to system conditions warrant. Additional analysis is also performed for the longer term to identify marginal conditions that may require long lead time solutions. Currently as part of the RTEP a year 7 or year 8 case is studied in detail as part of the annual RTEP. During the 2021 RTEP, a year 7 (2028 study year) was studied.

PJM Generator Deliverability testing, which simulates higher than normal generation availability in an area, is performed at 50/50 load levels. PJM Load Deliverability testing, which is performed on 27 Locational Deliverability Areas (LDA's) within PJM's footprint, simulates an internal generation deficiency within the LDA (which simulates higher than expected forced outage conditions) being tested with the area at 90/10 load levels. Single and multiple contingency analyses were also performed on a shoulder peak case as described in subsequent sections of this document.

The combination of these tests includes simulation of various system conditions over a range of forecast system demands and generation availability scenarios that simulate planned and forced outage conditions. This analysis is performed for both the near term and longer term.

The continued need for the system reinforcements previously identified in prior RTEP Baseline Assessment Reports and the queue A through AE2 System Impact Studies associated with projects that have executed an Interconnection Service Agreement were evaluated. Any previously identified reinforcements that are no longer required were documented and removed from the list of RTEP Reinforcements. PJM adjusts required in-service dates based on updated forecasts that can affect the modeling of the system conditions. In the event that changing system conditions delay the need for a baseline upgrade beyond the 5 year planning horizon, PJM will re-evaluate the need for that upgrade. When evaluating the continued need for previous reinforcements, analysis is performed to test for system performance associated with all applicable reliability criteria including that specified under all event categories listed in Table 1 of TPL-001-4.

Analysis methodology

PJM completed a robust series of analysis over a broad spectrum of system conditions encompassing a range of study years and forecast demand levels. The following sections detail the assumptions of the modeling and analysis. The analysis sub-sections are grouped by the analysis type. The modeling assumptions of the 2026 cases and analysis are discussed in detail. The modeling assumptions for the retool cases are not discussed in detail but followed the same procedure as the 2026 case, which can be found in PJM Manual 14B, Attachment H The modeling assumptions of all of the cases follow the procedure in PJM Manual 14B, Attachment B. All study year cases model all normal (NERC TPL P0) operating procedures in place. PJM Manual 3 – Transmission Operations contains all PJM operating procedures that are applicable to PJM planning studies.

<table>
<tr><th>Analysis Type</th><th>NERC Contingency Category from Table 1 of TPL Standard</th><th>Applicable Limits Monitored</th><th>Monitored Elements</th><th>Contingencies Considered</th></tr>
<tr><td>normal system (no contingency)</td><td>P0</td><td rowspan="6">All System Operating Limits, including the most limiting thermal, voltage limit (magnitude and deviation), voltage collapse</td><td rowspan="8">All BES & select lower voltage facilities, all ties to neighboring systems regardless of voltage</td><td rowspan="8">Normal system, All BES & select lower voltage facilities. N-1-1 considers all possible combinations of single contingencies</td></tr>
<tr><td>single contingency</td><td>P1, P2</td></tr>
<tr><td>multiple contingency</td><td>P3, P4, P5, P6, P7</td></tr>
<tr><td>Load Deliverability</td><td>P1, P2</td></tr>
<tr><td>Light Load Reliability analysis</td><td>P0, P1, P2, P3, P4, P5, P6, P7</td></tr>
<tr><td>N-1-1 analysis</td><td>P3, P6</td></tr>
<tr><td>generation deliverability</td><td>P1, P2</td><td rowspan="2">thermal, voltage collapse</td></tr>
<tr><td>common mode outage procedure</td><td>P3, P4, P5, P6, P7</td></tr>
</table>

Table 3. **Analysis Type Summary**

Modeling Assumptions & Critical System Conditions

PJM selected a range of forecast demand levels for the year 2026.

- 2026 90/10 Summer Peak
- 2026 50/50 Summer Peak
- 2026 Light Load Reliability Analysis (50% of 50/50 Summer Peak)
- 2026 Winter Reliability Analysis

In addition to the analysis of the 2026 system, as part of this assessment, PJM also performed analysis of multiple critical system conditions in the near term and longer term planning horizons. The assessments of the critical system conditions within these study years will be discussed in subsequent sections of this document.

The load forecast from the 2026 PJM Load Forecast Report was used and can be found on the PJM website at the following address:

https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx

The 2026 summer peak analysis used the 2026 summer model from the 2020 series MMWG (Multiregional Model Working Group) case. The model was updated according to the procedures in PJM Manual 14B, Attachment H. The case build is a collaborative process that involves PJM, PJM transmission owners, and neighboring entities. The case was reviewed with all PJM transmission owners to ensure that all existing and planned facilities were modeled. All future transmission upgrades with a required in-service date up to and including June 1, 2026 were modeled as in service. The list of future upgrades along with a schedule for implementation is contained in Appendix A.

All existing generation was modeled in the base case. Future generation that had an executed Interconnection Service Agreement (ISA) was modeled along with any upgrades required to maintain the reliability of the PJM system including the future generation. Future merchant transmission facilities that had an executed Interconnection Service Agreement (FSA) were modeled along with any upgrades required to maintain the reliability of the PJM system including the future merchant transmission. Information regarding all of these projects can be found on the PJM website at the address below.

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Adequate Reactive Power resources were included in the base model to ensure system voltage performance. Some of the reactive power resources modeled are existing and in-service equipment while some are planned with a future implementation date. A list of the planned reactive upgrades along with a schedule for implementation is contained in Appendix A. Table 4 below is a summary of the reactive power resources included in the 2026 case (note these are in addition to the reactive power associated with the generation noted above).

2026			
Area Name	Static	Dynamic	Total
AE	1115	450	1565
AEP	14060	650	14710
AP	5274	1760	7034
BGE	9463	0	9463
CE	8548	1800	10348
DAY	1333	0	1033
DEO&K	838	0	838
DLCO	292	0	292
DP&L	1511	375	1885
DVP	9766	1750	11516
EKPC	1346	0	1346
FE	6878	1614	8492
JCPL	4762	40	4802
METED	1169	500	1669
PECO	4767	700	5467
PENELEC	2307	674	2981
PEPCO	1305	0	1305
PJM*	0	0	0
PPL	3679	0	3679
PSEG	8903	0	8903
RECO	0	0	0
UGI	66	0	66
Grand Total	87382	10313	97394

Table 4. **Reactive Power Resources in base case Static MVAR: Capacitor Banks, Switched Shunts; Dynamic MVAR: SVCs, Synchronous Condensers, and Dynamic Switched Shunts.**

The interchange targets in Table 5 below represents the net sum of all existing and planned yearly long-term firm transmission service commitments between PJM and neighboring systems for the 2026 summer period. A 2026, 2020 Series, MMWG case was used as a starting point for the modeling, all PJM firm transactions were included in the RTEP base case modeling. The base dispatch is set as defined in PJM Manual 14B, Attachment B.

2026 RTEP Interchange		
Source	**Sink**	**Total (MW)**
PJM	NYISO	1115
PJM	LGEE	-159
PJM	DEI	-156
PJM	WEC	94
PJM	LAGN	-100
PJM	CPLE	105
PJM	DUK	-100
PJM	TVA	500
PJM	EEI	0
PJM	AMIL	-918
PJM	OMUA	0
PJM	MEC	454
PJM	SMT	-285
Total		550

Table 5. **Net Yearly Long Term Firm Interchange**

In all cases, where the physical design of connections or breaker arrangements resulted in the outage of more than the faulted facility when the fault was cleared, the additional facilities were also outaged in the load flow. That is, the breaker arrangements and system topology are used to develop and maintain the contingency files. For example, if a transformer is tapped off a line without a breaker, both the line and transformer were outaged as a single contingency event.

In addition, approved operating procedures were utilized as applicable. These operating procedures include the use of control devices such as Phase Angle Regulators (PARs) to manage flows on the system. Also, the expected operation of Remedial Action Schemes (RAS) were modeled and additionally tested where applicable. A complete listing of applicable remedial action schemes and operating procedures can be found in the Transmission Operation Manual (M-03) at the following link:

https://www.pjm.com/library/manuals.aspx

Contingencies Considered

The thermal and voltage analysis used a set of contingencies as required by NERC TPL standards. PJM's rationale was to define and select a comprehensive set that includes every possible BES contingency. Every possible single and multiple contingency loss of PJM BES elements is as described on Table 1 of NERC TPL standards was defined in contingency files and included in the assessment. No single or multiple BES contingencies were excluded from this assessment. The contingency set also included an inclusive set of single contingencies of non-BES elements that are modeled in the base case. A set of multiple facility contingencies involving non-BES facilities was included in the contingency set. A complete set of multiple facility contingencies involving non-BES facilities was not included in the contingency set given that issues on non-BES facilities are not expected to propagate to the BES system.

Contingency analysis takes into account the removal of all elements that the protection system and other automatic controls are expected to disconnect without operator intervention. This includes tripping of generators and transmission elements when protection equipment may exceed its performance capabilities.

In addition to the contingencies studied within PJM's footprint, analysis includes contingencies located in areas outside of PJM's footprint. PJM worked with its neighboring ISO's and RTO's to identify off-system contingencies that could affect PJM's system. All contingencies identified by these entities have been included in PJM's RTEP analysis.

- Over 21,000 Single contingencies were defined, including contingencies involving the loss of facilities in neighboring systems.
- Over 16,000 Multiple Facility Contingencies were defined, including contingencies involving the loss of facilities in neighboring systems.
- The N-1-1 analysis considers every possible combination of single contingencies, a total of over 441,000,000 combinations.

PJM's 2021 analysis focused on contingencies as defined by TPL-001-4 Table 1 – Steady State & Stability Performance Planning Events.

Planned Outages in the Transmission Planning Horizon

Although there are situations in which outages are planned and scheduled more than 12 months in advance, more often outages are submitted no more than one year in advance of the planned outage. Most maintenance plans are developed, and therefore the associated outages are planned with less lead time. In cases where outages are scheduled less than one year out, the lead time makes it impractical for inclusion in planning studies under the TPL timeframe. Outages planned with a lead time of less than one year are evaluated by PJM Operations.

PJM performed additional analysis of planned maintenance outages in the planning horizon by studying certain combinations of scheduled maintenance outages as reported through PJM's eDART, outage coordination software used by PJM operations. To increase the conservatism of the simulation, planned outages of BES equipment were studied on a Summer Peak case, which reflects a higher load than the historical maintenance outage season, and therefore a more conservative test. PJM Planning notified PJM operations of the results of this analysis. The results of this analysis are documented in the PJM Maintenance Outage Analysis report, which is published annually. This report also includes the analysis of known outages of generation or Transmission Facilities with duration of at least six months.

Planned outages are typically not scheduled at peak demand levels. In addition to the targeted maintenance outage analysis described above, the deliverability tests are performed at peak demand levels, which produce more severe results and impacts than studies performed at off peak demand levels.

Monitored Facilities

All cases used for this assessment model all PJM Bulk Electric System facilities. The specific facilities monitored for each analysis is described in detail in subsequent sections of this document. PJM also monitored every tie line to neighboring systems regardless of voltage. Over 20,000 individually modeled BES facilities are monitored in the analysis that supports this assessment. In addition to all BES elements, PJM monitors lower voltage, non-BES, facilities that are monitored by PJM operations. As part of the 2021 RTEP, PJM expanded its monitored facility list to include BES facilities in the MISO footprint. PJM also completed several joint studies of neighboring systems as described in the scope contained in the Executive Summary above.

Analysis of Near-Term

As part of the near-term assessment, PJM evaluated a range of critical system conditions. The range of system conditions included thermal and voltage analysis of a 2026 90/10 summer peak scenario, thermal and voltage analysis of a 2026 50/50 summer peak scenario, and thermal and voltage analysis of a light load scenario. The thermal analysis included applicable thermal limit checking. The voltage limit analysis included checking applicable voltage magnitude and voltage drop limits. PV analysis is an important part of the RTEP analysis and is performed for selected scenarios. The methodology for selecting the PV scenarios is discussed in a subsequent section of this document.

Analysis is performed for planning events listed in Table 1 of TPL-001-4 to ensure that all performance requirements are met, or upgrades to the system are implemented to address required performance issues.

The forecast demand level, analysis type, and mapping to TPL standards are summarized in tables in this section. In addition, a summary of the analysis type, contingencies considered, monitored elements, and monitored limits are summarized in the Analysis Methodology Section. Stability tests are detailed in a subsequent section of this document.

Normal System (All Facilities in Service) Analysis

The 2026 90/10 summer peak, 50/50 summer peak, light load and shoulder peak cases were evaluated for system performance under normal conditions. These models use data consistent with information provided in MOD-032 and MOD-033 standards. The normal system analysis as defined in P0 on Table 1 of NERC TPL-001-4 does not include a contingency event. Rather, all facilities are assumed to be in-service. Every BES facility and select lower voltage facilities in PJM were monitored for thermal limits, voltage limits, and voltage stability. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Single Contingency Analysis

The 2026 50/50 summer peak, 90/10 summer peak and light load cases were evaluated for system performance following the loss of a single element. The single elements included all of the P1 and P2 events defined on Table 1 of NERC TPL-001-4. Every BES facility and select lower voltage facilities were monitored for thermal limits, voltage limits, and voltage collapse. Additionally select off-system contingencies which may affect PJM's system were included in the single contingency analysis. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Common Mode Contingency Analysis

The 2026 50/50 summer peak and light load cases were evaluated for system performance following the loss of two or more (multiple) elements. The multiple elements included all common mode events defined in Table 1 of NERC TPL-001-4. Every BES facility and select lower voltage facilities were monitored for thermal limits, voltage limits, and voltage stability. Additionally select off-system contingencies which may affect PJM's system were included in the Common Mode contingency analysis. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

N-1-1 Analysis

The purpose of the N-1-1 analysis is to determine if all monitored facilities can be operated within normal thermal and voltage limits after an actual N-1 contingency and within the applicable emergency thermal and voltage limits after an additional simulated contingency. The 2026 50/50 summer peak was evaluated for system performance following a single contingency, followed by manual system adjustments, followed by another single contingency. The N-1-1 analysis monitored all BES facilities. The set of single contingencies that was used to compile the contingency pairs included all single contingencies in PJM regardless of voltage, all PJM tie lines regardless of voltage, and selected contingencies in neighboring systems. The contingency pairs that were considered included every possible combination of single contingencies, a total of over 376,000,000 combinations. The N-1-1 analysis also analyzed the contingency pairs in both possible orders to assess every combination and order of event. Reinforcements were developed for areas where the system failed to meet the applicable normal rating after the first contingency or the applicable emergency rating after the second contingency.

The N-1-1 analysis also assessed applicable voltage magnitude and voltage drop limits. For voltage magnitude and voltage drop testing, PJM screened for potential voltage violations. Voltage violations include exceeding the normal low voltage limit after the first contingency, emergency low limit after the second contingency, or exceeding the emergency voltage drop limit after the second contingency. Reinforcements were developed for areas where voltage violations were identified.

Deliverability Analysis

The 2026 base case was also used to analyze the capability of PJM's transmission system, including all PJM BES elements. To maintain reliability in a competitive capacity market, a resource must be deliverable to the overall network. PJM has developed the Load Deliverability and Generator Deliverability test methods for evaluating the adequacy of network capability for each of these deliverability requirements. Common mode outage analysis uses a procedure similar to Generator Deliverability to assess the impact of P3, P4, P5, P6 and P7 contingencies, as defined in PJM Manual 14B, Addendum 2.

A broad range of critical system conditions are established and analyzed through the deliverability test methods. The Generator Deliverability test establishes a critical stressed generation dispatch for every flowgate (monitored element and contingency pair) that could potentially be overloaded by the test. For every monitored facility, a critical stressed dispatch is created for all normal (all facilities in service) and single contingency conditions that could potentially overload the facility. This method results in the analysis of a large number of critical system conditions.

The load deliverability test procedure evaluates multiple critical system conditions though the evaluation of 27 individual stressed Locational Deliverability Areas, one thermal and one voltage case, for each of the defined Locational Deliverability Areas (LDA's) resulting in a minimum of 54 cases. The Locational Deliverability Areas are defined in Manual 14B – Attachment C. The load deliverability cases model stressed 90/10 summer peak loads in the LDA under study in each of the cases. A Capacity Emergency Transfer Objective (CETO) is identified. The CETO is the amount of energy an LDA will need to be able to import so that the area is not expected to have a loss of load event more frequently than one event in 25 years. A Capacity Emergency Transfer Limit (CETL) is calculated for each LDA (i.e. 54 cases) to determine the energy that can be imported into the area under test. In each case, the CETL ("the limit") is compared to the target Capacity Emergency Transfer Objective (CETO). Through this method, a large number of critical system conditions are also developed as part of the Load Deliverability Analysis. The system is planned to ensure that each of the LDAs meet the CETO at a minimum. System reinforcements were developed for any condition where the calculated import capability into any LDA would not meet the CETO.

Generator Deliverability Analysis

The PJM Generation Deliverability procedure was used to determine if the PJM transmission system, including all PJM BES elements, was adequate to deliver all PJM capacity resources to the network. Generator Deliverability analysis is performed to ensure that capacity resources within a given electrical area will, in aggregate, be able to be exported to other areas of PJM that are experiencing a capacity emergency. PJM utilizes the Generator Deliverability procedure to study the normal system and single contingencies under a stressed generation dispatch. Every BES facility and select lower voltage facilities were monitored for thermal limits and voltage stability. The stressed generation dispatch is unique to each monitored element and contingency pair under study. The Generator Deliverability procedure is defined in PJM Manual 14B Attachment C.

PJM performed the Generator Deliverability test on the 2026 50/50 summer peak model. The Generator Deliverability test examined system performance under normal and single contingency conditions. The contingency set included a complete set of single contingencies as defined by P1 and P2.1 in Table 1 of TPL-001-4.

The 2026 generator deliverability analysis tested a large number of critical system conditions. Every facility was monitored for applicable thermal limits for both the normal system and following the loss of every possible contingency. This process considers every one of the 19,000+ possible single contingencies for each monitored facility. As described in PJM Manual 14B, Attachment C a stressed dispatch was also developed and applied to each potentially overloaded flowgate to determine if an overload could be simulated. Through the method of applying a stressed dispatch to every possible single flowgate, the Generator Deliverability test identifies a large number of critical system conditions.

Reinforcements were developed for areas where the system failed to meet thermal limits or demonstrated a voltage collapse. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Common Mode Outage Analysis

Common mode outage analysis procedures are similar to the generation deliverability analysis procedure; however this analysis focuses specifically on the loss of multiple elements. The common mode outage analysis studies all events listed as P4, P5 and P7 under a stressed generation dispatch. Over 15,000 multiple contingency events were analyzed. Every BES facility and select lower voltage facilities were monitored for thermal limits and voltage stability. The stressed generation dispatch is unique to each monitored element and contingency pair under study. The common mode outage procedure is defined in Addendum 2 of PJM Manual 14B.

Reinforcements were developed for areas where the system failed to meet thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

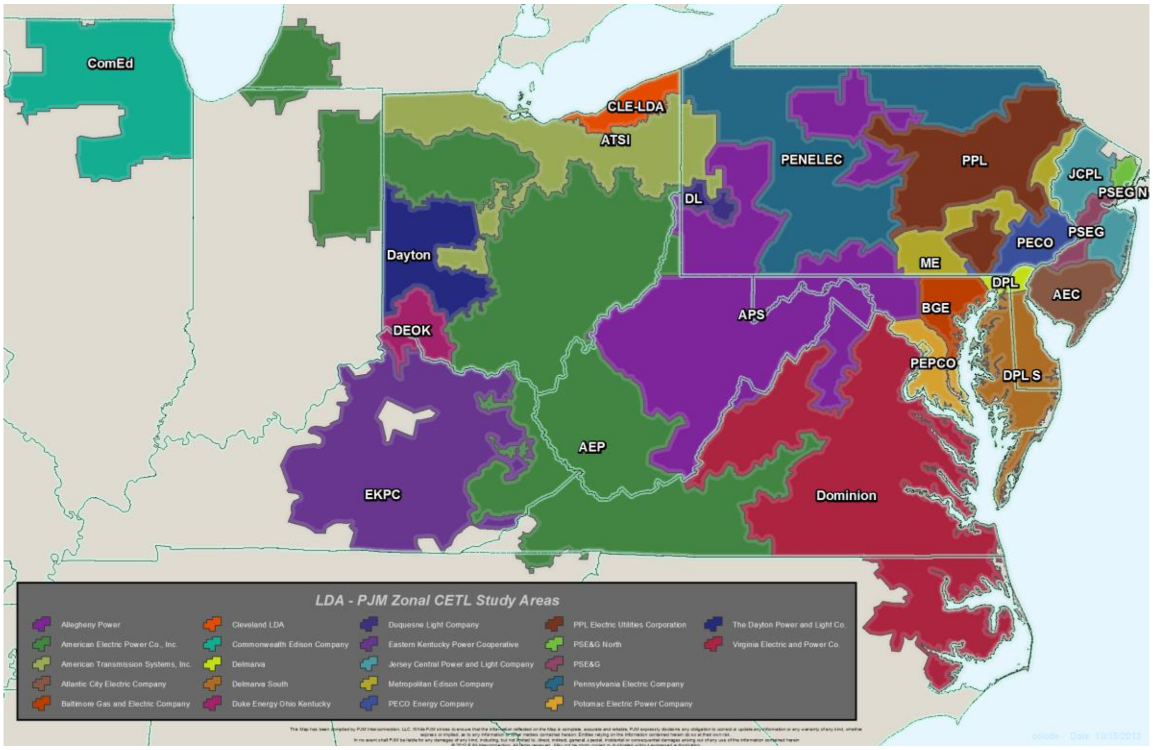
Load Deliverability Analysis

The Load Deliverability test procedures were used to determine if the Capacity Emergency Transfer Limit (CETL) for each of the various electrical areas of PJM is greater than each respective area's Capacity Emergency Transfer Objective (CETO).

There are currently 27 Locational Deliverability areas defined in PJM. The electrical areas within each of the 27 Locational Deliverability areas are described in table 6 and Map 2.

LDA	Description
EMAAC	Global area - PJM 500, JCPL, PECO, PSEG, AE, DPL, RECO
SWMAAC	Global area - BGE and PEPCO
MAAC	Global area - PJM 500, Penelec, Meted, JCPL, PPL, PECO, PSEG, BGE, Pepco, AE, DPL, UGI, RECO
PPL	PPL & UGI
PJM WEST	APS, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC, Cleveland, OVEC
WMAAC	PJM 500, Penelec, Meted, PPL, UGI
PENELEC	Pennsylvania Electric
METED	Metropolitan Edison
JCPL	Jersey Central Power and Light
PECO	PECO
PSEG	Public Service Electric and Gas
BGE	Baltimore Gas and Electric
PEPCO	Potomac Electric Power Company
AE	Atlantic City Electric
DPL	Delmarva Power and Light
DPLSOUTH	Southern Portion of DPL
PSNORTH	Northern Portion of PSEG
VAP	Dominion Virginia Power
APS	Allegheny Power
AEP	American Electric Power
DAYTON	Dayton Power and Light
DLCO	Duquesne Light Company
ComEd	Commonwealth Edison
ATSI	American Transmission Systems, Incorporated
DEO&K	Duke Energy Ohio and Kentucky
EKPC	Eastern Kentucky Power Cooperative
Cleveland	Cleveland Area

Table 6. **PJM Locational Deliverability Areas (LDA)**



Map 2. PJM Load Deliverability Areas

The 2026 Load Deliverability test used the 2026 summer peak base case as a starting point. From that starting point, 27 individual thermal Load Deliverability cases were built following the Load Deliverability thermal procedure as defined in PJM Manual 14B Attachment C. In addition, 27 individual voltage Load Deliverability cases were built following the Load Deliverability voltage procedure defined in PJM Manual 14B, Attachment C. This process developed one thermal and one voltage study case for each of the 27 Locational Deliverability Areas (LDA) resulting in 54 cases. These studies cover critical system conditions with load levels in the cases set to a 90/10 summer peak for the respective LDA under study and a 50/50 summer load level for all other areas. Modeling of specific system conditions such as load, reactive resources, and phase angle regulator settings were modeled as specified in PJM Manual 14B, Attachment G for the Load Deliverability tests. Manual 14B, Attachment C also specifies a procedure to dispatch generation in both the area assumed to be under a capacity emergency and the areas assumed not to be under a capacity emergency.

Capacity emergency transfer objectives (CETO's) for each of the 27 LDA's were used to set the target net interchange for the LDA under study in each of the thermal and voltage cases.

A thermal Load Deliverability study was then performed on each of the 27 thermal Load Deliverability cases. The thermal Load Deliverability study of each LDA monitored the respective LDA under study and tested system performance of the normal system and all single contingencies. Reinforcements were developed for areas where the system failed to meet thermal limits. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

A voltage Load Deliverability study was then performed on each of the 27 voltage Load Deliverability cases. The voltage Load Deliverability study of each LDA monitored the respective LDA under study and tested system performance of the normal system and all single contingencies. Critical system conditions were analyzed and reinforcements were developed for areas where the system failed to meet voltage magnitude limits, voltage drop limits, or demonstrated a voltage collapse. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Light Load Reliability Analysis

PJM also performed a year 2026 light load reliability analysis. The 50% of 50/50 summer peak demand level was chosen as being representative of a stressed light load condition. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level. In addition to the generation dispatch, the Light Load Reliability Analysis procedure also requires that PJM set interchanges within PJM and neighboring regions to their historical values.

The starting point power flow is the same power flow case set up for the baseline analysis, with adjustment to the model for the light load demand level, interchange, and accompanying generation dispatch. The flowgates ultimately used in the light load reliability analysis were determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. The contingencies used for light load reliability analysis included single and multiple contingencies, with the exception of the N-1-1criteria. Normal system conditions (P0) were also studied. All BES facilities and all non-BES facilities in the PJM real-time congestion management control facility list were monitored.

Winter Reliability Analysis

PJM also performed a year 2026 winter reliability analysis. This analysis included Generator Deliverability Studies, as well as Load Deliverability studies using a 2026 RTEP case with winter loadings and winter transmission line ratings. PJM focused these studies on Locational Deliverability Areas which had a Winter Loss of Load Expectation greater than 50%.

Voltage Stability

PV analysis was used to study a set of contingencies from the 2026 Load Deliverability voltage studies that were very severe or non-convergent. A set of single contingencies was selected for further study in the PV analysis. The methodology used to select the contingencies was to choose 500 kV or above contingencies that did not converge in a Load Deliverability voltage test. Also, contingencies that created a severe voltage drop or severe low magnitude violation on the BES were selected.

A PV analysis was then run on each of the selected contingencies. The analysis monitored all PJM facilities while simulating a transfer from all PJM generation outside the CETO area to all generation inside the CETO area where the contingency was identified. Typical to a PV analysis, the transfer was backed off until each contingency solved, and was then incrementally increased until a voltage collapse was simulated.

Retool Analysis of the Near-Term 2021-2026

Retool analysis is analysis that is performed during the current assessment to verify analysis that was performed in previous assessment. The retool analysis of the near-term was performed to verify the RTEP for the near-term due to forecasted changes in system conditions. Due to the recent overall net decrease in the projected load forecast for the PJM system, the retool work performed by PJM was a significant part of the 2021 RTEP. The retool analysis of the near-term included Generator Deliverability, Load Deliverability, common mode outage, and N-1-1 analysis. The methodologies for each of these analyses was performed as described in the detailed 2026 method descriptions in previous sections of this document. Through this approach, an extensive set of critical system conditions were analyzed. The conditions studies are summarized below.

Cases and contingency files for each year under study were updated in coordination with the Transmission Owners to reflect the most recent planned and existing facilities. The updated 2021 PJM load forecast was used to determine the load in the individual cases. The modeling updates included a review of the modeling of existing and planned facilities.

The retool analysis performed as part of the 2021 RTEP included the following groups of analysis. This analysis was in addition to the work performed as part of the near term and long term assessments required by the TPL standards. As a result of the significant generation deactivation notifications received throughout 2021, PJM performed a significant reliability review of years 2021 through 2026. As part of the 2021 RTEP, PJM performed system wide assessment of normal system, single contingency, multiple contingency, N-1-1, generator deliverability and load deliverability testing for year 2021 through 2026 summer peak models as needed for the widespread generation deactivations. PJM completed studies and developed system reinforcements related to generation deactivation requests for each year in the near-term in addition to the specific retool efforts outlined below. System enhancements, including an implementation schedule, were developed for every system performance issue that was identified as a result of the generation deactivation notifications. The system enhancements required as a result of the generation deactivations are described in more detail in the results section of this report. In addition to deactivation related retool studies PJM continually validates that previously identified system enhancements are still necessary.

2022 Retool

- B2611, B2883, B2603 Summer Studies (AEP)
- B2668 additional scope Summer Study (AEP)
- B2743/B2752 retool study (Multiple TOs)

2023 Retool

- B3139, B3140, B3141, B3220 cancellation Summer Studies (AEP)

- B2743/B2752 retool study (Multiple TOs)

2024 Retool

- S1851, S1996 Summer Studies (AEP)
- B3139, B3140, B3141, B3220 cancellation Summer Studies (AEP)
- B3333 Summer Study (AEP)
- S2188, S2342 Scope change Summer Study (AEP)
- S2583 without B3150 and S2153 Summer Study (AEP)
- B2743/B2752 retool study (Multiple TOs)

2025 Retool

- B3907 Winter Study (EKPC)
- B3094 Summer Study (EKPC)
- B2604, B1880, B3286, B2611, B2883, B2603 Summer Studies (AEP)
- S1412, S1851, S1996, S2179 Summer Studies (AEP)
- B3131, B3278 Winter Studies (AEP)
- B2743/B2752 retool study (Multiple TOs)

2026 Retool

- B3682, B3678, B3680 Summer Studies (ATSI)
- S1795, S1953, S2267.2, S2388, S22289, S2595, S2597, S2447-S2460, S2547, S2548, S2545, S2546, S2553 Summer Studies(ATSI)
- Y3-092 Summer Study (ATSI)
- B3683, B3681 Summer Studies (APS)
- S2549, S2550, S2551, S2543 Summer Studies (APS)
- B2743/B2752 retool study (Multiple TOs)

15 Year Planning and Analysis of the Longer-Term System

The purpose of the long term review is to simulate system trends to identify problems which may require longer lead time solutions. This enables PJM to take appropriate action when system issues may require initiation of a reinforcement project in anticipation of potential violations in the longer term. System issues uncovered that are amenable to shorter lead time remedies will be addressed as they enter into the near-term horizon. The detailed description of the 15 year planning process is described in PJM Manual 14B.

The 2021 RTEP also included a review of the fifteen year planning horizon through 2036. The analyses conducted as part of the review included normal system, single, and multiple (tower) contingency analysis of the 2026 50/50 Summer Peak case as summarized in Table 7. Following the 15 year procedure, the calculated loading on every flowgate was then scaled by a factor consistent with the forecasted load growth to determine a facility loading in years 2027 through 2036 (years 6 through 15). Both the Generator Deliverability and Load Deliverability procedures were used to establish the critical system conditions under which the system was evaluated.

Analysis Type	Monitored Flowgates	Contingencies Considered	Years Considered
Load Deliverability	Any BES element loaded at 75% or greater in the 2026 analysis	normal system, single, double circuit tower line	2027 through 2036
Generation Deliverability		normal system, single	

Table 7. **15 Year Planning Analysis**

Load forecasts for the years 2026 through 2036 from the 2021 PJM Load Forecast Report were used to generate load growth scaling factors for each of the highest loaded flowgates in each year. The DC scaling factors were then used to calculate a loading for each flowgate for each year 2027 through 2036.

Analysis of the Longer-Term System

PJM evaluated a 2028 (year 8) 50/50 Summer Peak case. One purpose of this evaluation was to identify any thermal or voltage reliability criteria violations in year 2028 that would require a longer term lead time to resolve. The evaluation of the 2028 Summer Peak case did not identify any reliability criteria violations that would require a longer lead time solution. In addition, this targeted analysis of 2028 summer conditions was benchmarked for consistency to the 2028 results from the 15 year analysis procedure.

Verification of Planned Reinforcements

Analysis was performed to verify that all planned reinforcements that were identified as part of the 2021 RTEP and all previously identified reinforcements acceptably resolved all criteria violations throughout the planning horizon. Analysis was also performed to verify that no new potential criteria violations were created as a result of implementing the required system reinforcements.

New Services Queue Analysis

Analysis for customer requests in the New Services Queue was performed for several different types of New Service Requests: Generator interconnection, long term firm transmission service, ARR requests, and Merchant transmission requests. The reliability of the requests is determined through two separate technical studies, the feasibility study and system impact study.

The feasibility study is the first study that is performed and is an initial look at the effect of the New Service Request on the transmission system. This study includes generator deliverability analysis that is performed on a summer peak load case to analyze the normal system and all single and multiple contingencies (Excluding N-1-1). Additionally Short Circuit analysis is performed.

If a developer elects to move forward and executes a System Impact Study Agreement PJM performs a more detailed study of the impact of the proposed request. The system impact study includes thermal analysis (AC Generator Deliverability) of the normal system and all single and multiple contingencies (Excluding N-1-1) as well as short circuit and stability assessments. Additionally, and as required based on the type of request made, load deliverability analysis may also be performed.

As part of the system impact study process, steady state voltage studies are performed for all interconnection projects. The steady state voltage studies included a check of the applicable voltage magnitude limits under normal and contingency conditions. The voltage of every BES facility was monitored. The contingencies included in the steady state voltage analysis included all multiple contingencies except N-1-1contingencies.

Specific results of interconnection studies can be found at:

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Short Circuit Assessment

PJM conducts short circuit analysis annually to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and transmission facilities in service which could impact the study area. Short circuit analysis is performed consistent with the following industry standards:

1) ANSI/IEEE 551-2006 —IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems
    a) This standard is used to provide short circuit current information for breakers and power system equipment used to sense and interrupt fault currents.
2) ANSI/IEEE C37.04-1999 —IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers

   a) This standard is used to establish the rating structure for circuit breakers and equipment associated with breakers.
3) ANSI/IEEE C37.010-1999 —IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis
   a) This standard is used to calculate the fault current on breakers that are rated on a Symmetrical Current Basis taking into consideration reclosing duration, X/R ratio differences, temperature conditions, etc.
4) ANSI/IEEE C37.5-1979 —IEEE Guide for Calculation of Fault Currents for Applications of AC High-Voltage Circuit Breakers Rated on a Total Current Basis
   a) This standard is used to calculate the fault current on breakers that are rated on a Total Current Basis.

Each of these standards is used jointly with transmission owners' methodologies as a basis to calculate fault currents on all BES breakers. By using these standards, single phase to ground and three phase fault currents are calculated and compared to the breaker interrupting capability, provided by the transmission owners, for each BES breaker within the PJM footprint. All breakers whose calculated fault currents exceed breaker interrupting capabilities are considered overdutied and reported to transmission owners for confirmation. All breakers are used in specific short circuit cases which help to identify the cause and year breakers are likely to become overdutied.

Short circuit cases are built consistent with a 2 year planning representation and a 5 year planning representation. The 2 year planning case consists of the current system in addition to all facilities planned to be in-service within the next year. The 5 year planning case uses the 2 year planning case as its base model and it is updated to include all system upgrades, generation projects, and merchant transmission projects planned to be in-service within 5 years. The 5 year planning case is similar to the 5 year PJM RTEP load flow basecase.

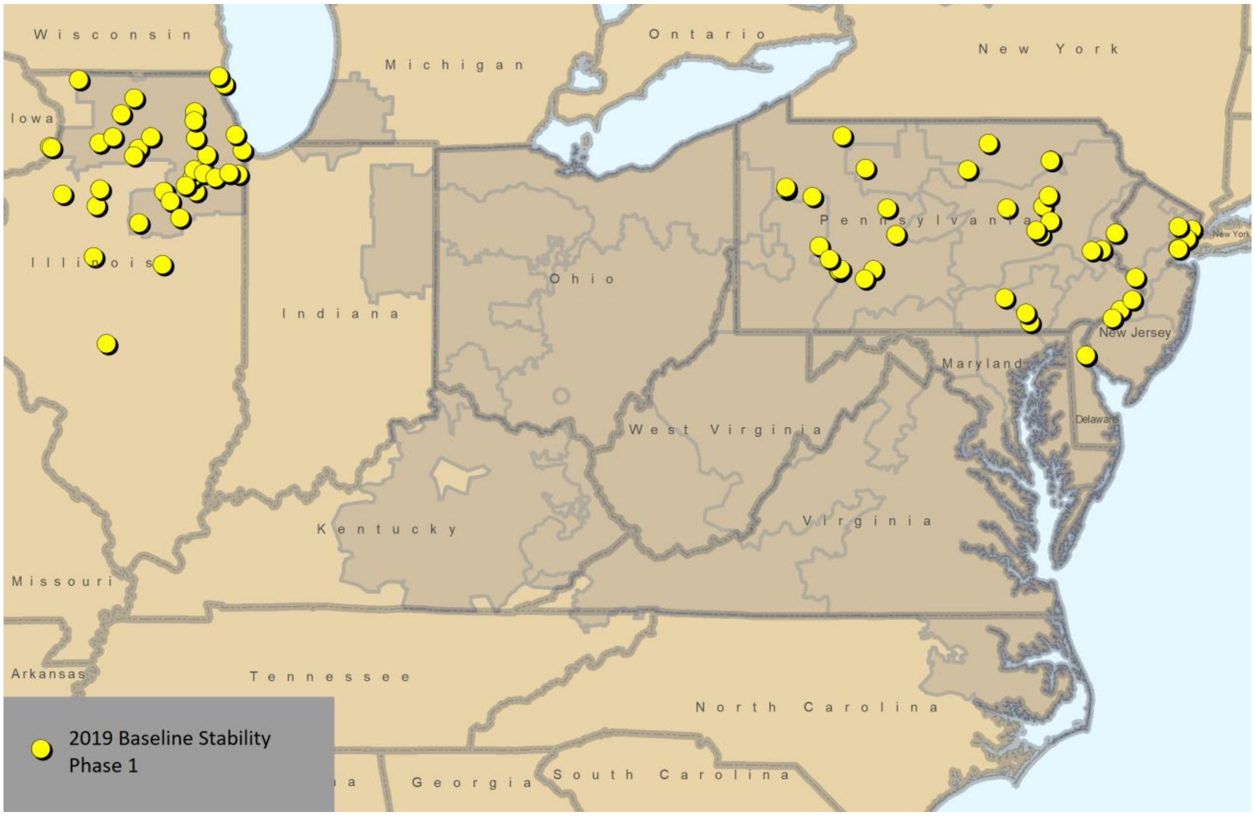
Once an overdutied breaker is confirmed breaker replacement and reinforcements along with cost estimates are determined. Breaker replacements and reinforcements, along with a schedule for implementation, were presented at monthly TEAC stakeholder meetings and are contained in the results section of this document.

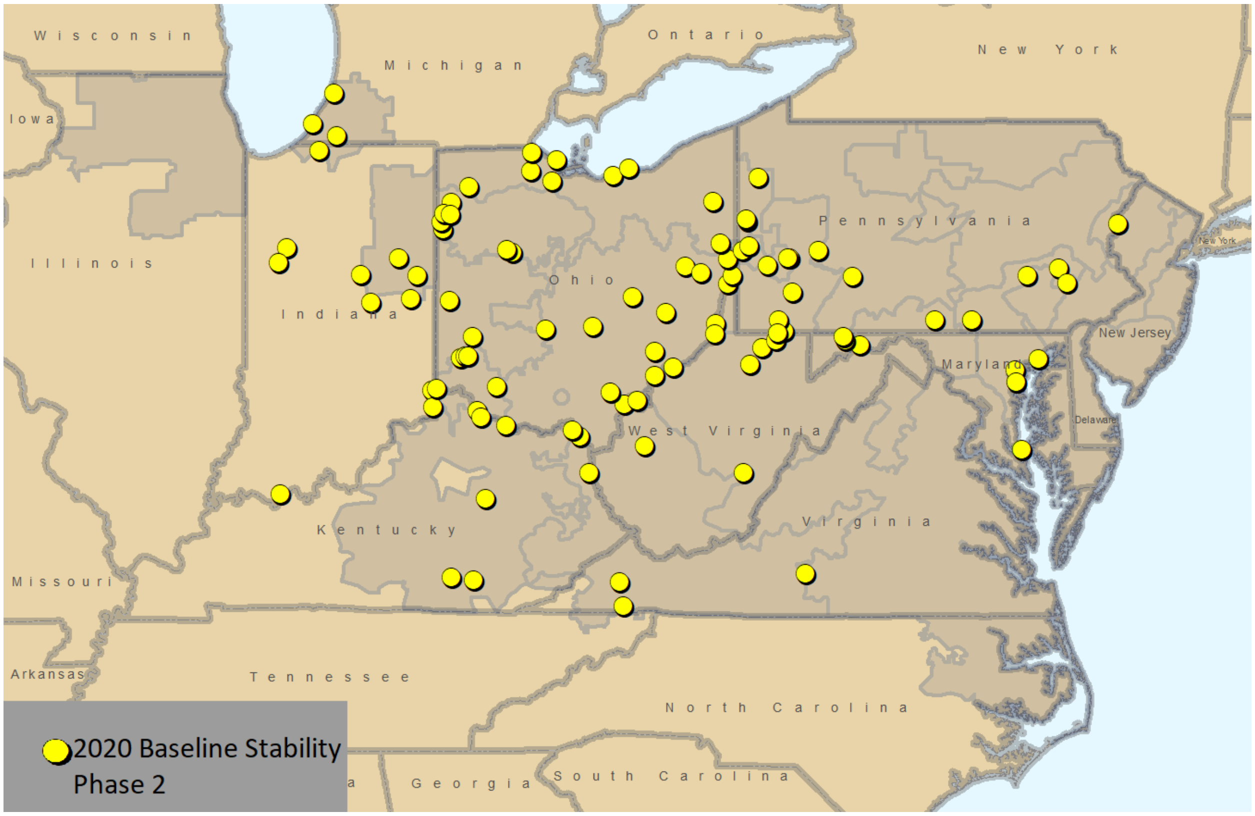
Stability Assessment

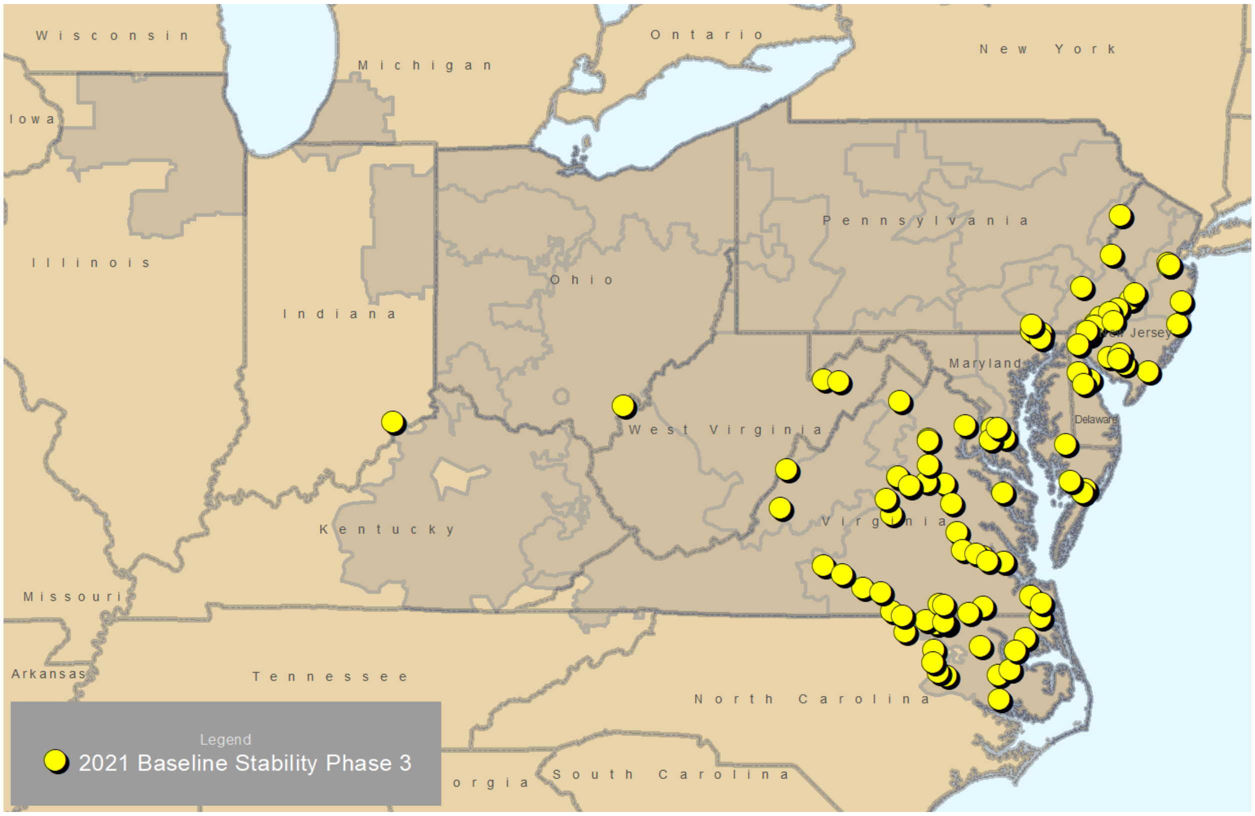
PJM performs multiple tiers of analysis to ensure the system will remain stable and have satisfactory dynamic performance for disturbances that are consistent with Table 1 of the NERC TPL-001-4 standards. Collectively, the studies performed assess system dynamic performance over a wide range of load levels. Whenever system dynamic performance does not meet criteria, appropriate reinforcements are incorporated in the system plans and design. These measures include the installation of PSS (Power System Stabilizer), Excitation system refinements, dynamic or static reactive supports for wind generation plants, relaying and breaker configuration modifications.

Stability Studies	**2021 RTEP**
Annual baseline stability analysis of 1/3 of existing stations	107
New Services Queue stability analysis	119
Total	**226**

Table 8. **Number of Generation Stations Studied for Stability as Part of the 2021 RTEP**


Wisconsin
Michigan
Ontario
New York
Iowa
Illinois
Indiana
Ohio
Pennsylvania
New Jersey
Maryland
Delaware
West Virginia
Virginia
Kentucky
Missouri
Arkansas
Tennessee
North Carolina
Georgia
South Carolina
2019 Baseline Stability Phase 1


Wisconsin
Michigan
Ontario
New York
Iowa
Illinois
Indiana
Ohio
Pennsylvania
New Jersey
Maryland
Delaware
West Virginia
Virginia
Kentucky
Missouri
Arkansas
Tennessee
North Carolina
Georgia
South Carolina
2020 Baseline Stability Phase 2



Map 3. Three-Year Baseline Stability Cycle

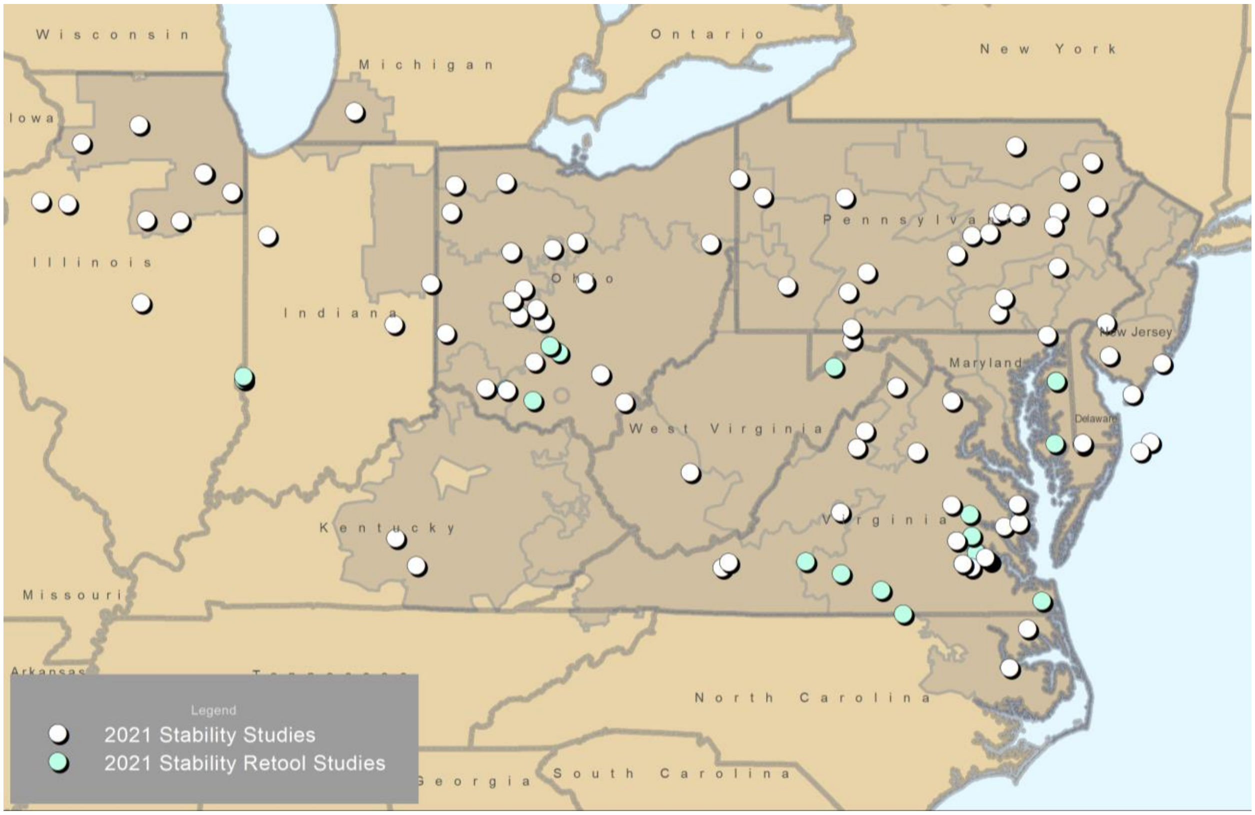
Good engineering practices as related to ensuring adequate system dynamic performance for the Bulk Electric System starts with proper base case models. PJM uses full ERAG MMWG models as a starting point for the dynamic stability analysis. All known transmission system as well as generation model changes available from approved system plans are incorporated. Step response simulations are conducted to detect and correct any modeling errors. Case initialization results are carefully analyzed to make sure that all the initial conditions are satisfactory. A 20 second no fault simulation is performed to ensure proper parameters are used in the models.

As part of the 2021 RTEP, several tiers of system stability analysis were performed. The first tier of this analysis includes PJM's annual comprehensive transient stability assessment of generating stations in the system. The annual analysis is performed for one third of the PJM footprint each year.

The annual baseline analysis includes an evaluation of the system under light load conditions as well as peak load conditions. PJM's rationale for choosing a light load case is that the light load system conditions are found to be the most challenging and severe from a transient stability perspective. The analysis also includes an evaluation of the system under summer peak loading (50/50) conditions.

PJM incorporates dynamic load models in peak load stability study to consider the behaviors of dynamic loads including induction motor loads. Various contingencies near load centers and generation stations are studied to ensure PJM system meets dynamic voltage recovery criteria as well as transient stability and damping criteria. In addition PJM evaluates the impact of dynamic load models on the system performance under a stressed power transfer condition across PJM eastern interface.

All PJM stability studies start by testing the system for a major transmission line switching operation. This examines the system under system normal conditions, as specified in TPL-001-4. The system response is verified by monitoring generating unit angle curves over a 20 second time frame. This test also provides the information to verify that all dynamic parameters are correctly initiating and responding properly. The stability test procedure includes a simulation of all applicable disturbances on all outlets of generating plants for multiple contingency (P3-P7) conditions. Additionally, all existing Remedial Action Schemes and their controlling actions are evaluated to ensure their effectiveness. A visual depiction of the coverage of the three latest baseline stability study cycles is shown in Map 3 above.



Map 4. Locations of proposed generation studied for stability in 2021

A second tier of PJM's stability assessment includes stability analysis for all proposed generator interconnections that exceed 20 MWs. New generator interconnections represent a significant modification to the system that could affect stability. In 2021 as part of the generation interconnection process, PJM completed transient stability analysis for 172 proposed generator interconnections within the PJM footprint. The locations of these proposed generators are shown in Map 4. In this analysis P0, P1, P2, P3, P4, P5, P6 and P7 conditions were analyzed for disturbances on all generating plant outlets as well as on transmission lines at a minimum, one bus away and more than one bus away from the point of interconnection if warranted by the system topology. In general, the analysis associated with proposed generation additions identifies any potential transient stability concerns among the generators electrically close to the portion of the system being modified. The proposed generation interconnections span all transmission system voltage levels and are widespread throughout PJM's footprint. Hence, the resulting stability analysis covers broad sections of PJM's Bulk Electric System. Solutions to the identified problems are developed and implemented prior to the proposed generation being placed in service.

As depicted in Map 4, the locations of the proposed generation additions are dispersed throughout the PJM footprint. In addition to monitoring the stability of the proposed generation, existing generation within several layers of the interconnection bus are also monitored. The transient stability analysis that is run for proposed generation interconnections not only ensures that the proposed unit will remain stable but also ensures that the transient stability of existing generation at nearby buses will not be compromised. It is important to note that the relative queue position is respected for this analysis, so that potential transient stability concerns are identified for the proposed unit and nearby existing generation. This ensures that violations will be allocated to the correct project based on queue order. The results of this analysis and any required upgrades or other mitigation measures needed, are identified in the System Impact Study for each New Service Request and are posted on the PJM web at the following address:

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

A third tier of PJM's stability analysis includes ad-hoc studies that were performed in 2021 and occur annually to support PJM operations.

The transient stability analysis performed by PJM is done with forward looking cases representing the system as planned in future years. Given the continued load growth within the PJM footprint and the on-going transmission system reinforcements that are identified as part of the regional transmission expansion plan, the transient stability of the system is expected to continue to improve.

As a result of PJM integrating each of these tiers of stability assessment, PJM has ensured its compliance to all applicable standards including the assessments required by Table 1 of the NERC TPL001-4 standard.

Based on PJM's knowledge and evaluation of current and forecasted system conditions, stability related upgrades would not require a lead time during the longer-term (year 6 and beyond) time frame, therefore stability analysis is not performed beyond 5 years out.

N-1-1 Stability Assessment

N-1-1 stability study for 75 plants was performed in 2021 RTEP. Critical contingency pairs which may lead to potential stability issues were applied to the study. RAS or specific operation guidelines were also implemented if necessary. Comprehensive time-domain simulations for N-1-1 contingencies were conducted to ensure those plants comply with PJM stability criteria. PJM will continue to conduct N-1-1 stability study for selected plants on a rotating basis.

Critical contingency pairs which may lead to potential stability issues were applied to the study. RAS or specific operation guidelines were also implemented if necessary. Comprehensive time-domain simulations for N-1-1 contingencies were conducted to ensure those plants comply with PJM stability criteria. No transient stability issues and damping violations were identified during the study.

NPIR Plant Specific Stability & Voltage Assessment

PJM has a total of 17 plants that fit the criteria for NPIR stability study. All 17 of those plants were studied as part of the 2021 RTEP. PJM will continue to study these 17 plants annually as part of future RTEPs. RAS or specific operation guidelines were implemented if necessary. Also, several nuclear plant NPIR studies were performed to verify and validate 2021 new dynamic models per TOs request.

In addition to the NPIR stability studied, PJM also performed NPIR voltage studies. As part of the 2021 RTEP, all 17 PJM nuclear plants were studied to ensure these plants comply with voltage monitoring criteria. Voltage magnitude and voltage drop were monitored under selected contingencies. Study results have been sent to NGOs.

Results of 2021 RTEP

The results of the baseline assessment for the 2021 – 2036 periods are presented below. This report, containing all corrective reinforcements, is provided to applicable regional entities annually in compliance with TPL-001-4. All of the upgrades below were presented to the TEAC stakeholder committee at one of the monthly TEAC stakeholder meetings in 2021.

PJM found the following areas of the PJM system to not meet reliability criteria during the assessment of the 2021 – 2036 study periods. These baseline upgrades were all identified as part of the 2021 RTEP. The list of required upgrades contains a summary of the system deficiencies and the associated action needed to achieve required system performance. This includes deficiencies identified in multiple sensitivity studies. The expected required in-service date of each upgrade is also included. PJM continuously evaluates the lead times of these plans with respect to the expected required in-service dates. System enhancements and corrective action plans are reviewed in subsequent annual studies for continued validity and implementation status of identified system facilities and operating procedures. Additionally, results include all recommended upgrades where short circuit analysis shows that existing breakers exceed their equipment rating.

Upgrades identified and established in previous RTEP cycles are detailed in Appendix A.

The most up to date information concerning in-service dates and schedule for implementation can be found at the following link: https://www.pjm.com/planning/project-construction.aspx. With the exception of the baseline upgrades noted below, all other areas of the system were found to meet applicable reliability criteria.

1) Baseline Upgrade b3278.1

- Overview of Reliability Problem
    - Criteria Violation: The Meadowview's 138/69/34.5 kV TR#2 is overloaded; voltage violations on the existing Glade, Owens Drive, Medallion, Hillman Highway, Arrowhead and Damascus 69KV busses.
    - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
    - Description of Upgrade: Saltville Station: Replace H.S. MOAB Switches on the high side of the 138/69/34.5 kV T1 with a H.S. Circuit Switcher.
    - Upgrade In-Service Date: 12/1/2025
    - Estimated Upgrade Cost: $0.72M
    - Construction Responsibility: AEP

2) Baseline Upgrade b3311

- Overview of Reliability Problem
    - Criteria Violation: Voltage magnitude violations identified at West Hellam 115 kV, Prospect 115 kV, Yorkana 115 kV, Redfront 115kV, Yoe 115 kV, and Windsor 115 kV buses
    - Criteria Test: N-1-1 Voltage Magnitude
- Overview of Reliability Solution

    - Description of Upgrade: Install a 120.75 kV 79.4 MVAR capacitor bank at Yorkana 115 kV
    - Upgrade In-Service Date: 5/31/2022
    - Estimated Upgrade Cost: $2.20M
    - Construction Responsibility: ME

3) Baseline Upgrade b3317

- Overview of Reliability Problem
    - Criteria Violation: Existing instabilities at 138kV STA16 Waukegan
    - Criteria Test: Stability
- Overview of Reliability Solution
    - Description of Upgrade: Modify backup relay clearing times at the 138 kV STA16 Waukegan station.
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $0.26M
    - Construction Responsibility: ComEd

4) Baseline Upgrade b3318

- Overview of Reliability Problem
    - Criteria Violation: Overload of Shanor Manor - Butler 138 KV line
    - Criteria Test: Gen Deliv - SP
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor the Shanor Manor - Butler 138 kV line with an upgraded circuit breaker at Butler
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $1.50M
    - Construction Responsibility: APS

5) Baseline Upgrade b3322

- Overview of Reliability Problem
    - Criteria Violation: Overload of Shanor Manor - Krendale 138 KV line
    - Criteria Test: Gen Deliv - SP
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor the small section of Shanor Manor - Krendale 138 kV line with relay replacement at Butler and Krendale
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $1.75M
    - Construction Responsibility: APS

6) Baseline Upgrade b3323

- Overview of Reliability Problem
    - Criteria Violation: Overload of Leroy Center - Pinegrove 138 KV line

- Criteria Test: Gen Deliv - SP
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor Leroy Center-Pinegrove 138 kV line
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $16.00M
  - Construction Responsibility: ATSI

7) Baseline Upgrade b3324

- Overview of Reliability Problem
  - Criteria Violation: Overload of Olive - New Carisle 138 KV line
  - Criteria Test: Gen Deliv - SP
- Overview of Reliability Solution
  - Description of Upgrade: Replace the bus section at Olive
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $0.10M
  - Construction Responsibility: AEP

8) Baseline Upgrade b3325

- Overview of Reliability Problem
  - Criteria Violation: Overload of Charleroi - Union 138 KV line
  - Criteria Test: Gen Deliv - SP
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor the Charleroi-Union 138 kV line and upgrade terminal equipment at Charleroi
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $11.00M
  - Construction Responsibility: APS

9) Baseline Upgrade b3333.1

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Skeggs Branch substation in the clear as Coronado substation. Establish New 138 kV and 69 kV Buses. Install 138/69 kV 130 MVA transformer, 138 kV circuit switcher and 69 kV breaker. Retire Existing Skeggs Branch substation.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $6.32M
  - Construction Responsibility: AEP

10) Baseline Upgrade b3333.10

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: At Whetstone Branch substation, Replace 69KV 600A 2 Way POP Switch with 69KV 1200A 2 Way POP Switch. Remove 69KV to Skeggs Branch (Switch "22" POP).
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.57M
  - Construction Responsibility: AEP

11) Baseline Upgrade b3333.11

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: At Garden Creek substation, remove 69 kV Richlands (via Coal Creek) line (Circuit Breaker F and disconnect switches) and update relay settings.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.14M
  - Construction Responsibility: AEP

12) Baseline Upgrade b3333.12

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Remote end work at Clinch River substation
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.08M
  - Construction Responsibility: AEP

13) Baseline Upgrade b3333.13

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Remote end work at Clinchfield substation.

- Upgrade In-Service Date: 6/1/2023
- Estimated Upgrade Cost: $0.08M
- Construction Responsibility: AEP

14) Baseline Upgrade b3333.2

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: New ~1.2 mi 138kV extension to new Skeggs Branch substation location.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $4.62M
  - Construction Responsibility: AEP

15) Baseline Upgrade b3333.3

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Install 46.1 MVAR Cap bank at Whitewood substation along with a 138 kV breaker.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $1.05M
  - Construction Responsibility: AEP

16) Baseline Upgrade b3333.4

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild ~9 mi 69kV line from new Skeggs branch station to Coal Creek 69kV line. 6-wire the short double circuit section between Whetstone Branch and Str. 340-28 to convert the line to single circuit. Retire Garden Creek to Whetstone Branch 69kV line section.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $26.25M
  - Construction Responsibility: AEP

17) Baseline Upgrade b3333.5

- Overview of Reliability Problem
  - Criteria Violation:

    - Criteria Test:
  - Overview of Reliability Solution
    - Description of Upgrade: Retire Knox Creek SS.
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $0.06M
    - Construction Responsibility: AEP

18) Baseline Upgrade b3333.6
  - Overview of Reliability Problem
    - Criteria Violation:
    - Criteria Test:
  - Overview of Reliability Solution
    - Description of Upgrade: Retire Horn Mountain SS. This will be served directly from 69kV bus at New Skeggs branch Substation.
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $0.05M
    - Construction Responsibility: AEP

19) Baseline Upgrade b3333.7
  - Overview of Reliability Problem
    - Criteria Violation:
    - Criteria Test:
  - Overview of Reliability Solution
    - Description of Upgrade: At Clell SS, replace two 600A POP Switches and Poles with single 2 Way 1200A POP Switch and Pole.
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $0.34M
    - Construction Responsibility: AEP

20) Baseline Upgrade b3333.8
  - Overview of Reliability Problem
    - Criteria Violation:
    - Criteria Test:
  - Overview of Reliability Solution
    - Description of Upgrade: At Permac, replace 600A Switch and structure with 2 Way 1200A POP Pole Switch and pole.
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $0.31M
    - Construction Responsibility: AEP

21) Baseline Upgrade b3333.9

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: At Marvin SS, replace 600 A Switch and structure with 2 Way 1200 A POP Pole Switch and pole.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.31M
  - Construction Responsibility: AEP

22) Baseline Upgrade b3346.1

- Overview of Reliability Problem
  - Criteria Violation: the North Delphos – East Delphos 69kV line and the East Delphos – Elida Road 69kV line are overloaded ; . The North Delphos – East Delphos 69kV line and the Delphos – South Delphos are overload
  - Criteria Test: AEP 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild approximately 3.5 miles of overloaded 69 kV line between North Delphos-East Delphos-Elida Road switch. This includes approximately 1.1 miles of double circuit line that makes up a portion of the North Delphos-South Delphos 69 kV line and the North Delphos-East Delphos 69 kV line. Approximately 2.4 miles of single circuit line will also be rebuilt between the double circuit portion to East Delphos station and from East Delphos to Elida Road Switch.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $8.43M
  - Construction Responsibility: AEP

23) Baseline Upgrade b3346.2

- Overview of Reliability Problem
  - Criteria Violation: the North Delphos – East Delphos 69kV line and the East Delphos – Elida Road 69kV line are overloaded ; . The North Delphos – East Delphos 69kV line and the Delphos – South Delphos are overload
  - Criteria Test: AEP 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace the line entrance spans at South Delphos to eliminate the overloaded 4/0 Copper and 4/0 ACSR conductor.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $0.44M
  - Construction Responsibility: AEP

24) Baseline Upgrade b3348.1

- Overview of Reliability Problem
  - Criteria Violation: the Becco – Slagle 46kV line, the Dehue – Pine Gap 46kV line and Dehue – Slagle 46kV line are overload;Low voltage and voltage drop violations at

Three Fork, Toney Fork, Cyclone, Pardee, Crane,, Latrobe, Becco, Slagle, Dehue 46kV buses
    - Criteria Test: AEP 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Construct a 138kV single bus station (Tin Branch) consisting of a 138kV box bay with a distribution transformer and 12kV distribution bay. Two 138kV lines will feed this station (from Logan and Sprigg Stations), and distribution will have one 12kV feed. Install two 138 kV circuit breakers on the line exits. Install 138 kV circuit switcher for the new transformer
    - Upgrade In-Service Date: 11/1/2026
    - Estimated Upgrade Cost: $5.58M
    - Construction Responsibility: AEP

25) Baseline Upgrade b3348.2

- Overview of Reliability Problem
    - Criteria Violation: the Becco – Slagle 46kV line, the Dehue – Pine Gap 46kV line and Dehue – Slagle 46kV line are overload;Low voltage and voltage drop violations at Three Fork, Toney Fork, Cyclone, Pardee, Crane,, Latrobe, Becco, Slagle, Dehue 46kV buses
    - Criteria Test: AEP 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Construct a new 138/46/12 kV Argyle station to replace Dehue station. Install a 138kV ring bus using a breaker-and-a-half configuration, with an autotransformer with a 46kV feed and a distribution transformer with a 12kV distribution bay. Two 138kV lines will feed this station (from Logan and Wyoming Stations). There will also be a 46kV feed from this station to Becco Station. Distribution will have two 12kV feeds. Retire Dehue station in its entirety
    - Upgrade In-Service Date: 11/1/2026
    - Estimated Upgrade Cost: $10.00M
    - Construction Responsibility: AEP

26) Baseline Upgrade b3348.3

- Overview of Reliability Problem
    - Criteria Violation: the Becco – Slagle 46kV line, the Dehue – Pine Gap 46kV line and Dehue – Slagle 46kV line are overload;Low voltage and voltage drop violations at Three Fork, Toney Fork, Cyclone, Pardee, Crane,, Latrobe, Becco, Slagle, Dehue 46kV buses
    - Criteria Test: AEP 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Bring the Logan - Sprigg #2 138kV circuit in and out of Tin Branch station by constructing approximately 1.75 miles of new overhead double circuit 138kV line. Double circuit T3 series lattice towers will be used along with 795,000cm ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD and one shield wire will be OPGW
    - Upgrade In-Service Date: 11/1/2026
    - Estimated Upgrade Cost: $8.58M

- Construction Responsibility: AEP

27) Baseline Upgrade b3348.4

- Overview of Reliability Problem
  - Criteria Violation: the Becco – Slagle 46kV line, the Dehue – Pine Gap 46kV line and Dehue – Slagle 46kV line are overload;Low voltage and voltage drop violations at Three Fork, Toney Fork, Cyclone, Pardee, Crane,, Latrobe, Becco, Slagle, Dehue 46kV buses
  - Criteria Test: AEP 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Logan - Wyoming No. 1 circuit in and out of the proposed Argyle Station. Double circuit T3 series lattice towers will be used along with 795,000cm ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD and one shield wire will be OPGW
  - Upgrade In-Service Date: 11/1/2026
  - Estimated Upgrade Cost: $7.70M
  - Construction Responsibility: AEP

28) Baseline Upgrade b3348.5

- Overview of Reliability Problem
  - Criteria Violation: the Becco – Slagle 46kV line, the Dehue – Pine Gap 46kV line and Dehue – Slagle 46kV line are overload;Low voltage and voltage drop violations at Three Fork, Toney Fork, Cyclone, Pardee, Crane,, Latrobe, Becco, Slagle, Dehue 46kV buses
  - Criteria Test: AEP 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild approximately 10 miles of 46 kV line between Becco and the new Argyle substation. Retire approximately 16 miles of 46 kV line between the new Argyle substation and Chauncey station
  - Upgrade In-Service Date: 11/1/2026
  - Estimated Upgrade Cost: $33.71M
  - Construction Responsibility: AEP

29) Baseline Upgrade b3348.6

- Overview of Reliability Problem
  - Criteria Violation: the Becco – Slagle 46kV line, the Dehue – Pine Gap 46kV line and Dehue – Slagle 46kV line are overload;Low voltage and voltage drop violations at Three Fork, Toney Fork, Cyclone, Pardee, Crane,, Latrobe, Becco, Slagle, Dehue 46kV buses
  - Criteria Test: AEP 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Adjust relay settings due to new line terminations and retirements at Logan, Wyoming, Sprigg, Becco, and Chauncey stations
  - Upgrade In-Service Date: 11/1/2026
  - Estimated Upgrade Cost: $0.23M

- Construction Responsibility: AEP

30) Baseline Upgrade b3349

- Overview of Reliability Problem
  - Criteria Violation: the 69kV risers between 69kV Bus #2 and 69kV winding of TR#3 are overloaded (AEP-SC1, AEP-SC2, AEP-SC3, AEP-SC4, AEP-SC5, AEP-SC6)
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace Bellefonte 69kV risers on the section between Benllefonte TR#3 and 69kV Bus #2.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $0.54M
  - Construction Responsibility: AEP

31) Baseline Upgrade b3351

- Overview of Reliability Problem
  - Criteria Violation: overload of the Monterey-Huntington Court 69 kV line section
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace the 69 kV, in-line switches at Monterey 69kV Substation.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

32) Baseline Upgrade b3352

- Overview of Reliability Problem
  - Criteria Violation: the Kenova - 47th street line section is overloaded
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace MOAB W, MOAB Y, line and bus side jumpers of both W and Y at 47th Street 69kV station. Upgrade the 69kV Strain bus between MOABs W and Y to 795 KCM AAC. Change the connectors on the tap to MOAB X1 to accommodate the larger 795 KCM AAC.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

33) Baseline Upgrade b3353.1

- Overview of Reliability Problem
  - Criteria Violation: the Stanville - Allen line section is overloaded
  - Criteria Test: AEP 715 criteria

- Overview of Reliability Solution
  - Description of Upgrade: Allen Substation: Rebuild Allen Station to the northwest of its current footprint utilizing a standard air-insulated substation with equipment raised by 7’ concrete platforms and control house raised by a 10’ platform to mitigate flooding concerns. Install five 69 kV 3000A 40 kA circuit breakers in a ring bus (operated at 46kV) configuration with a 13.2 MVAR capacitor bank. Existing Allen station will be retired (Does not include the distribution cost) Distribution Scope of Work: Install 69/46kV-12kV 20 MVA transformer along with 2-12kV breakers on 7’ concrete platforms (Conversion of S2405.1)
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $10.55M
  - Construction Responsibility: AEP

34) Baseline Upgrade b3353.2

- Overview of Reliability Problem
  - Criteria Violation: the Stanville - Allen line section is overloaded
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Allen – East Prestonsburg: A 0.20 mile segment of this 46 kV line will be relocated to the new station. (SN/SE/WN/WE: 53/61/67/73MVA). (Conversion of S2405.2)
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $0.33M
  - Construction Responsibility: AEP

35) Baseline Upgrade b3353.3

- Overview of Reliability Problem
  - Criteria Violation: the Stanville - Allen line section is overloaded
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: McKinney – Allen: The new line extension will walk around the south and east sides of the existing Allen Station to the new Allen Station being built in the clear. A short segment of new single circuit 69kV line and a short segment of new double circuit 69kV line (both operated at 46 kV) will be added to the line to tie into the new Allen Station bays. (Conversion of S2405.3)
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $1.95M
  - Construction Responsibility: AEP

36) Baseline Upgrade b3353.4

- Overview of Reliability Problem
  - Criteria Violation: the Stanville - Allen line section is overloaded
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution

- Description of Upgrade: Stanville – Allen: A segment of this line will have to be relocated to the new station (SN/SE/WN/WE: 50/50/63/63MVA). (Conversion of S2405.4)
- Upgrade In-Service Date: 12/1/2026
- Estimated Upgrade Cost: $0.17M
- Construction Responsibility: AEP

37) Baseline Upgrade b3353.5

- Overview of Reliability Problem
  - Criteria Violation: the Stanville - Allen line section is overloaded
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Allen – Prestonsburg: 0.25 mile segment of this existing single circuit will be relocated. The relocated line segment will require construction of one custom self-supporting double circuit dead end structure and single circuit suspension structure. A short segment of new double circuit 69kV line (energized at 46 kV) will be added to tie into the new Allen Station bays which will carry Allen – Prestonsburg 46kV and Allen – East Prestonsburg 46kV lines. A temporary 0.15 mile section double circuit line will be constructed to keep Allen – Prestonsburg and Allen – East Prestonsburg 46kV lines energized during construction. (Conversion of S2405.5)
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $2.66M
  - Construction Responsibility: AEP

38) Baseline Upgrade b3353.6

- Overview of Reliability Problem
  - Criteria Violation: the Stanville - Allen line section is overloaded
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Remote End Remote end work will be required at Prestonsburg, Stanville, and McKinney stations. (Conversion of S2405.6)
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $0.34M
  - Construction Responsibility: AEP

39) Baseline Upgrade b3358

- Overview of Reliability Problem
  - Criteria Violation: Voltage deviation issues of greater than 8 % have been identified at Slate Mills, Lattaville, and Mill (SCP) stations
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Install a 69 kV 11.5 MVAR capacitor at Biers Run station
  - Upgrade In-Service Date: 6/1/2026

- Estimated Upgrade Cost: $0.85M
- Construction Responsibility: AEP

40) Baseline Upgrade b3359

- Overview of Reliability Problem
  - Criteria Violation: ~2.3 miles of existing 4/0 Cu conductor on N. Van Wert Sw - Van Wert 69 kV line is overloading (101%)
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild approximately 2.3 miles of the existing North Van Wert Sw - Van Wert 69 kV line utilizing 556 ACSR conductor.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $6.20M
  - Construction Responsibility: AEP

41) Baseline Upgrade b3360

- Overview of Reliability Problem
  - Criteria Violation: In 2026 RTEP Winter case, the 46kV winding of the Thelma TR#1 is overload
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace Thelma Transformer #1 with a 138/69/46kV 130/130/90 MVA transformer and replace 46kV risers and relaying towards Kenwood substation. Existing TR#1 to be used as spare
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $3.54M
  - Construction Responsibility: AEP

42) Baseline Upgrade b3361

- Overview of Reliability Problem
  - Criteria Violation: In 2026 RTEP Winter case, voltage magnitude and voltage drop violations at Mckinney, Salsbury, Allen, East Prestonsburg, Prestonsburg, Middle Creek, Kenwood 46kV buses are identified
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Prestonsburg - Thelma 46kV circuit, approximately 14 miles. Retire Jenny Wiley SS.
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $33.01M
  - Construction Responsibility: AEP

43) Baseline Upgrade b3362

- Overview of Reliability Problem

- Criteria Violation: In 2026 RTEP Summer case, ~3.1 miles of existing 1/0 ASCR conductor on the Oertels Corner - North Portsmouth 69 kV line is overloading (120%)
- Criteria Test: AEP 715 criteria

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild approximately 3.1 miles of the overloaded conductor on the existing Oertels Corner - North Portsmouth 69 kV line utilizing 556 ACSR .
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $8.00M
  - Construction Responsibility: AEP

44) Baseline Upgrade b3370

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: (FG# GD-S444)
  - Criteria Test: Summer Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade terminal equipment on the Loretto - Fruitland 69 kV circuit: Replace the 477 ACSR stranded bus on the 6711 line terminal inside Loretto substation and the 500 SDCU stranded bus on the 6711 line terminal inside Fruitland substation with 954 ACSR conductor
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $0.80M
  - Construction Responsibility: DPL

45) Baseline Upgrade b3371

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: (FG# ME-T1 and ME-T2)
  - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild approx. 3.6 miles of 875 (N. Boyertown - W. Boyertown). Upgrade terminal equipment (circuit breaker, disconnect switches, substation conductor) and relays at N. Boyertown and W. Boyertown substation
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $8.79M
  - Construction Responsibility: ME

46) Baseline Upgrade b3372

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: GD-S13
  - Criteria Test: Summer Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: East Towanda – North Meshoppen 115 kV Line: Rebuild 2.5 miles of 636 ACSR with 1113 ACSS conductor using single circuit construction.

Upgrade all terminal equipment to the rating of 1113 ACSS

- Upgrade In-Service Date: 6/1/2026
- Estimated Upgrade Cost: $6.66M
- Construction Responsibility: PENELEC

47) Baseline Upgrade b3373

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: (FG# , PN-T1 and PN-T2)
    - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
    - Description of Upgrade: Replace the relay panels at Bethlehem 33 46 kV substation on the Cambria Prison line
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $0.30M
    - Construction Responsibility: PENELEC

48) Baseline Upgrade b3374

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: (FG# JCPL-SC1, JCPL-SC2, JCPL-SC3, JCPL-SC4 and JCPL-SC5)
    - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
    - Description of Upgrade: Replace Five Atlantic 34.5 kV breakers (J36, BK1A, BK1B, BK3A and BK3B) with 63kA rated breakers and associated equipment
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $3.50M
    - Construction Responsibility: JCPL

49) Baseline Upgrade b3375

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: (FG# JCPL-SC6, JCPL-SC7, JCPL-SC8, JCPL-SC9, JCPL-SC10 and JCPL-SC11)
    - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
    - Description of Upgrade: Replace Six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) with 40 kA rated breakers and associated equipment..
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $4.20M
    - Construction Responsibility: JCPL

50) Baseline Upgrade b3376

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: (FG# JCPL-SC12)
    - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
    - Description of Upgrade: Replace One Freneau 34.5 kV breaker (BK6) with 63 kA rated breakers and associated equipment
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $0.70M
    - Construction Responsibility: JCPL

51) Baseline Upgrade b3663

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: FG# GD-S485, GD-S674 and GD-S486
    - Criteria Test: Summer Generator Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Replace a 0.76 mile length of the Croydon-Burlington 230 kV line conductor. The existing conductor is 1590 kcmil ACSR and will be replaced by 1622 kcmil ACSS/TW.
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $0.79M
    - Construction Responsibility: PECO

52) Baseline Upgrade b3668

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: (FG# N2-ST1, N2-ST2)
    - Criteria Test: Summer N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Upgrade Windy Edge 115 kV Substation Conductor to increase ratings of the Windy Edge - Chesco Park 110501 circuit
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $0.50M
    - Construction Responsibility: BGE

53) Baseline Upgrade b3669.1

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: (FG# GD-W248)
    - Criteria Test: Winter Generator Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Replace terminal equipment (Stranded Bus, Disconnect Switch, and Circuit Breaker) at Church Substation (Townsend-Church 138 kV)
    - Upgrade In-Service Date: 6/1/2026

- Estimated Upgrade Cost: $1.00M
- Construction Responsibility: DPL

54) Baseline Upgrade b3669.2

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: (FG# GD-W248)
  - Criteria Test: Winter Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace terminal equipment (Circuit Breaker) at Townsend Substation (Townsend-Church 138 kV)
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $0.45M
  - Construction Responsibility: DPL

55) Baseline Upgrade b3670

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: (FG# GD-S444)
  - Criteria Test: Summer Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade terminal equipment on the Loretto - Fruitland 69 kV circuit: Replace the 477 ACSR stranded bus on the 6711 line terminal inside Loretto substation and the 500 SDCU stranded bus on the 6711 line terminal inside Fruitland substation with 954 ACSR conductor
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $0.80M
  - Construction Responsibility: DPL

56) Baseline Upgrade b3671

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: (FG# ME-T1 and ME-T2)
  - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild approx. 3.6 miles of 875 (N. Boyertown - W. Boyertown). Upgrade terminal equipment (circuit breaker, disconnect switches, substation conductor) and relays at N. Boyertown and W. Boyertown substation
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $8.79M
  - Construction Responsibility: ME

57) Baseline Upgrade b3672

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: GD-S13

- Criteria Test: Summer Generator Deliverability

- Overview of Reliability Solution
    - Description of Upgrade: East Towanda – North Meshoppen 115 kV Line: Rebuild 2.5 miles of 636 ACSR with 1113 ACSS conductor using single circuit construction. Upgrade all terminal equipment to the rating of 1113 ACSS
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $6.66M
    - Construction Responsibility: PENELEC

58) Baseline Upgrade b3673

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: (FG# , PN-T1 and PN-T2)
    - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
    - Description of Upgrade: Replace the relay panels at Bethlehem 33 46 kV substation on the Cambria Prison line
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $0.30M
    - Construction Responsibility: PENELEC

59) Baseline Upgrade b3674

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: (FG# JCPL-SC1, JCPL-SC2, JCPL-SC3, JCPL-SC4 and JCPL-SC5)
    - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
    - Description of Upgrade: Replace Five Atlantic 34.5 kV breakers (J36, BK1A, BK1B, BK3A and BK3B) with 63kA rated breakers and associated equipment
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $3.50M
    - Construction Responsibility: JCPL

60) Baseline Upgrade b3675

- Overview of Reliability Problem
    - Criteria Violation: 2021 Window 1: (FG# JCPL-SC6, JCPL-SC7, JCPL-SC8, JCPL-SC9, JCPL-SC10 and JCPL-SC11)
    - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
    - Description of Upgrade: Replace Six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) with 40 kA rated breakers and associated equipment..
    - Upgrade In-Service Date: 6/1/2026

  - Estimated Upgrade Cost: $4.20M
  - Construction Responsibility: JCPL

61) Baseline Upgrade b3676

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: (FG# JCPL-SC12)
  - Criteria Test: First Energy FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Replace One Freneau 34.5 kV breaker (BK6) with 63 kA rated breakers and associated equipment
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $0.70M
  - Construction Responsibility: JCPL

62) Baseline Upgrade b3678

- Overview of Reliability Problem
  - Criteria Violation: High voltage at Galion 69 kV substation
  - Criteria Test: 2026 Light Load RTEP case N-1
- Overview of Reliability Solution
  - Description of Upgrade: Expand 138 kV substation; Install 100 MVAr reactor, associated breaker and relaying
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $1.70M
  - Construction Responsibility: ATSI

63) Baseline Upgrade b3679

- Overview of Reliability Problem
  - Criteria Violation: High voltage at West freemont 69 kV substation
  - Criteria Test: 2026 Light Load RTEP case N-1
- Overview of Reliability Solution
  - Description of Upgrade: Replace West Fremont 138/69 kV TR2 with a transformer having additional high-side taps
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $2.90M
  - Construction Responsibility: ATSI

64) Baseline Upgrade b3680

- Overview of Reliability Problem
  - Criteria Violation: Ashtabula-Sanborn Q3 138 kV line overloaded
  - Criteria Test: 2026 Summer RTEP case N-1-1
- Overview of Reliability Solution

- Description of Upgrade: At Sanborn, replace limiting substation conductors on Ashtabula 138 kV exit to make transmission line conductor the limiting element
- Upgrade In-Service Date: 6/1/2026
- Estimated Upgrade Cost: $0.30M
- Construction Responsibility: ATSI

65) Baseline Upgrade b3681

- Overview of Reliability Problem
    - Criteria Violation: Voltage drop at Shingletown 230 kV substation
    - Criteria Test: 2026 Summer RTEP case N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Upgrade the Shingletown #82 230-46 kV Transformer Circuit by installing a 230 kV breaker and disconnect switches, removing existing 230 kV switches, replacing 46 kV disconnect switches, replacing limiting substation conductor, and installing/replacing relays.
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $1.66M
    - Construction Responsibility: APS

66) Baseline Upgrade b3682

- Overview of Reliability Problem
    - Criteria Violation: Hayes 345/138 kV transformer # 1 is overloaded
    - Criteria Test: 2026 Summer Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Install a second 345/138 kV transformer at Hayes, 448 MVA nameplate rating. Add one 345 kV circuit breaker (3000A) to provide transformer high side connection between breaker B-18 and the new breaker. Connect the new transformer low side to the 138 kV bus. Add one 138 kV circuit breaker (3000A) at Hayes 138 kV substation between B-42 and the new breaker. Relocate the existing 138 kV No. 1 capacitor bank between B-42 and the new breaker. Protection Per FE standard.
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $7.59M
    - Construction Responsibility: ATSI

67) Baseline Upgrade b3683

- Overview of Reliability Problem
    - Criteria Violation: Generation Deliverability violation
    - Criteria Test: 2026 SUM RTEP case
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor the existing 556.5 ACSR line segments on the Messick Road-Ridgeley WC4 138 kV line with 954 45/7 ACSR to achieve 308/376 MVA SN/SE and 349/445 MVA WN/WE ratings. Replace the remote end equipment for the Messick Road-Ridgeley WC4 138 kV line.

- Upgrade In-Service Date: 6/1/2026
- Estimated Upgrade Cost: $11.20M
- Construction Responsibility: APS

68) Baseline Upgrade b3688

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: (FG# GD-W30)
  - Criteria Test: Winter Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace the 4/0 SDCU stranded bus with 954 ACSR and a 600 A disconnect switch with a 1200 A disconnect switch on the 6716 line terminal inside Todd substation (on the Preston – Todd 69 kV circuit).
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $0.75M
  - Construction Responsibility: DPL

69) Baseline Upgrade b3697

- Overview of Reliability Problem
  - Criteria Violation: Congestion
  - Criteria Test: Market Efficiency
- Overview of Reliability Solution
  - Description of Upgrade: Replace station conductor and metering inside Whitpain and Plymouth substations to increase the ratings of the 220-13/220-14 Whitpain-Plymouth 230 kV line facilities.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.62M
  - Construction Responsibility: PECO

70) Baseline Upgrade b3698

- Overview of Reliability Problem
  - Criteria Violation: Congestion
  - Criteria Test: Market Efficiency
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor the 14.2 miles of the existing Juniata - Cumberland 230kV line with 1272 ACSS/TW HS285 "Pheasant" conductor.
  - Upgrade In-Service Date: 12/1/2023
  - Estimated Upgrade Cost: $8.99M
  - Construction Responsibility: PPL

71) Baseline Upgrade b3699.2

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: (FG# GD-W248)

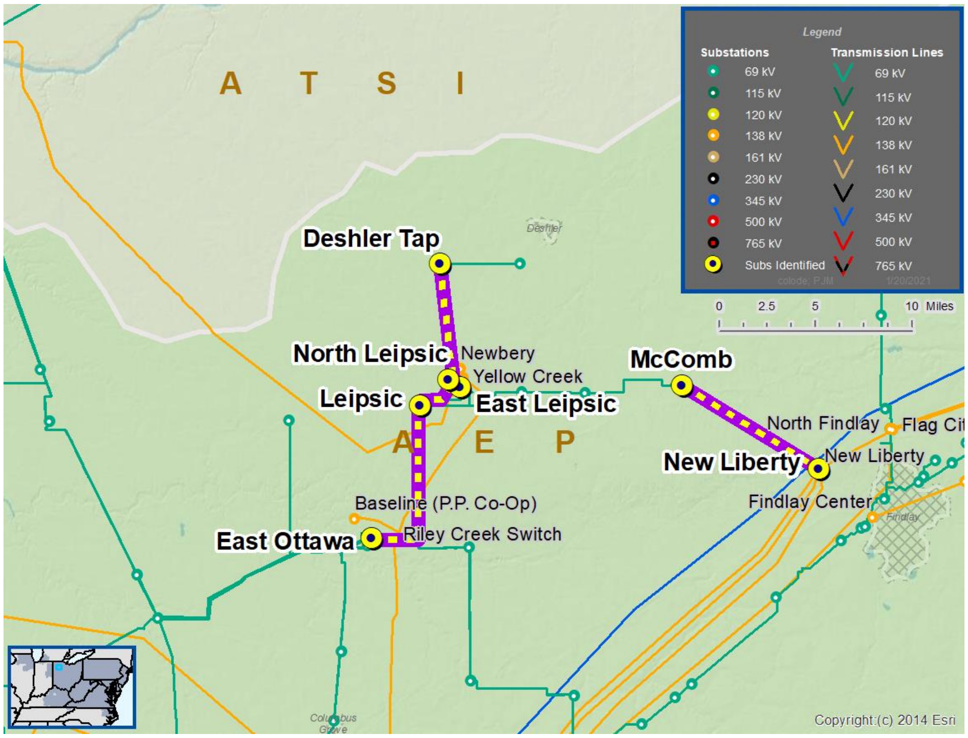
    - Criteria Test: Winter Generator Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Replace terminal equipment (Circuit Breaker) at Townsend Substation (Townsend-Church 138 kV)
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $0.45M
    - Construction Responsibility: DPL

Baseline Project b3273: Leipsic Area Improvements

AEP Transmission Zone

For 2020 Window 1, the East Ottawa-Leipsic-Deshler Tap 69 kV line, East Leipsic-North Leipsic 69 kV line, East Leipsic 138/69 kV transformer, Cairo-East Lima 69 kV line and McComb OP-New Liberty 34.5 kV line are overloaded for a tower contingency and multiple N-1-1 contingency pairs. These issues were identified through AEP's FERC 715 Planning Criteria.

Map 5. Leipsic Area



The recommended solution, solicited through the competitive proposal window, is to rebuild and convert the existing 17.6-mile East Leipsic-New Liberty 34.5 kV circuit to 138 kV using 795 ACSR. The project will also convert the existing 34.5 kV equipment to 138 kV and expand the existing McComb station to the north and east to allow for new equipment to be installed, including two new 138 kV box bays to allow for line positions and two new 138/12 kV transformers. The solution will expand the existing East Leipsic station to the north to allow for another 138 kV line exit to be installed, which involves installing a new 138 kV circuit breaker, disconnect switches and new dead-end structure, along with extending the existing 138kV bus. At New Liberty station, the project will retire 34.5 kV breaker F and install one 138 kV circuit breaker, disconnect switches and line relaying potential devices to add an additional line position. In addition to resolving the identified violations from the proposal window, the project also addresses the needs reviewed with stakeholders at the March 2020 SRRTEP-West meeting for the M-3 process need number AEP-2020-OH020. The estimated cost for this project is $34.418 million, with a required in-service date of June 2025. The projected in-service date is January 2024, and the local transmission owner, AEP, will be designated to complete this work.

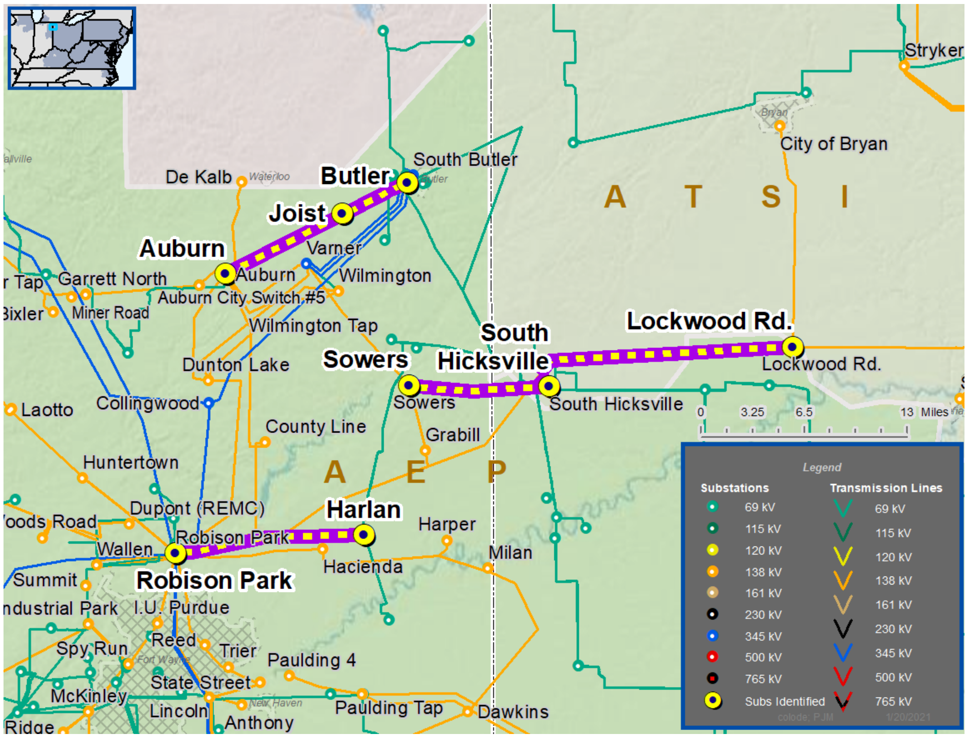
Baseline Project b3244: Rob Park-Harlan 69 kV Rebuild

AEP Transmission Zone

The Harlan-Robinson Park 69 kV line is overloaded for the N-1-1 contingency pair of the loss of Sowers-South Hicksville-Lockwood 138 kV line with South Hicksville 138/69 kV transformer and the loss of the Auburn-Joist-Butler 69 kV line. These issues were identified through AEP's FERC 715 Planning Criteria, and were excluded from the competitive proposal window through the below 200 kV exemption.

Map 6. Rob Park-Harlan 69 kV

The recommended solution is to rebuild approximately 9 miles of the Rob Park-Harlan 69 kV line. The estimated cost for this project is $20.9 million, with a required in-service date of June 2025. The projected in-service date is June



2023, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3246: Manassas Area Improvements

Dominion Transmission Zone

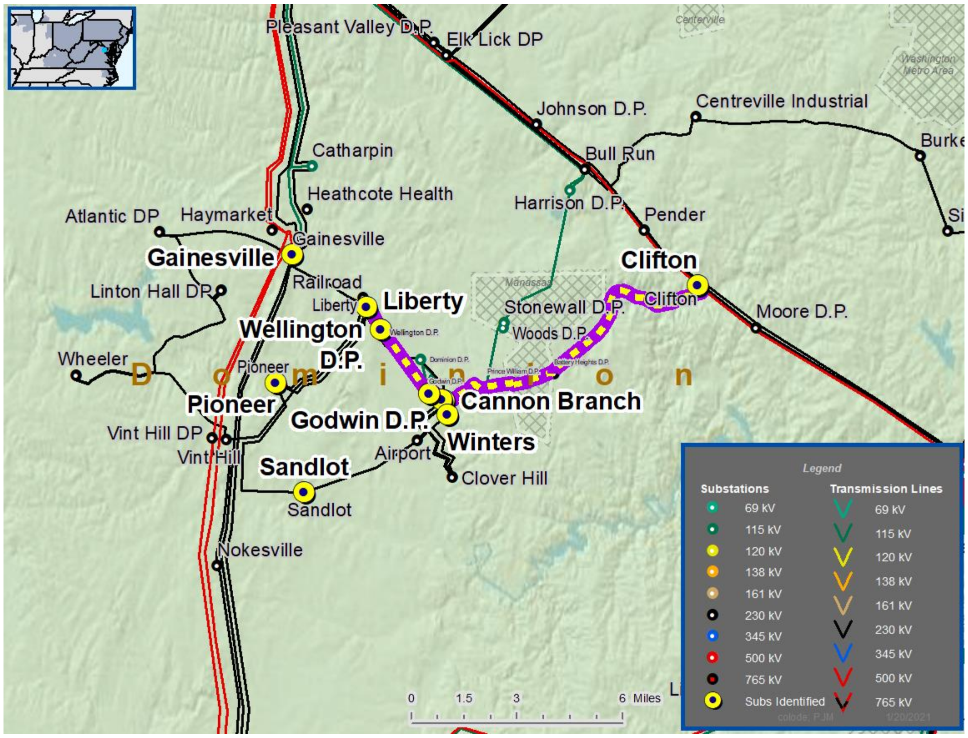
The Manassas area of northern Virginia in the Dominion territory is experiencing significant load growth due to the introduction of multiple new load locations and increases to existing load. The original introduction of new load was identified with smaller magnitudes of new load. However, subsequent increases in that new load have resulted in a magnitude of load significantly greater than was originally reviewed.

The original introduction of load in this area had commitments by customers to connect load as was studied by PJM in the do-no-harm tests. PJM and Dominion discussed with the stakeholders that there was a potential to have a significant increase in load at a later date. However, this additional load was not confirmed, during initial discussion with the customers, through the process Dominion employs to determine if new load is to be served, and how that service would be provided. Based on evolving information from the customers since the summer of 2019, the load increases in the load pocket identified in the violations discussed below and which were posted in the list of reliability violations for 2020 Window 1, are now expected to exceed 500 MW.

The results of both the winter and summer 2025 RTEP N-1-1 analysis showed that load drop violations will occur for the following contingency pairs and as a result of reverse-power relay schemes to prevent feeding the 230 kV system in the area from the 115 kV system:

- The loss of Cannon Branch-Winters Branch and Pioneer-Sandlot 230 kV lines
- The loss of Cannon Branch-Winters Branch and Cloverhill-Sandlot 230 kV lines
- The loss of Cannon Branch-Winters Branch and Liberty-Pioneer 230 kV lines
- The loss of Cannon Branch-Liberty and Liberty-Pioneer 230 kV lines

Due to the significant increase in load over the near term, and the interaction of the reverse-power relay scheme, the load drop violations are now anticipated to occur in the 2022/2023 time frame. Additionally, due to the expected arrival of future load growth in this area, integrated plans need to be considered to address the growth potential that has been evident in this area of the system. As a result, the recommended solution to address these issues was designated immediate need to address the near-term violation of dropping more than 300 MW in the 2022/2023 time frame, as well as those violations seen in 2025.



Map 7. Manassas Area

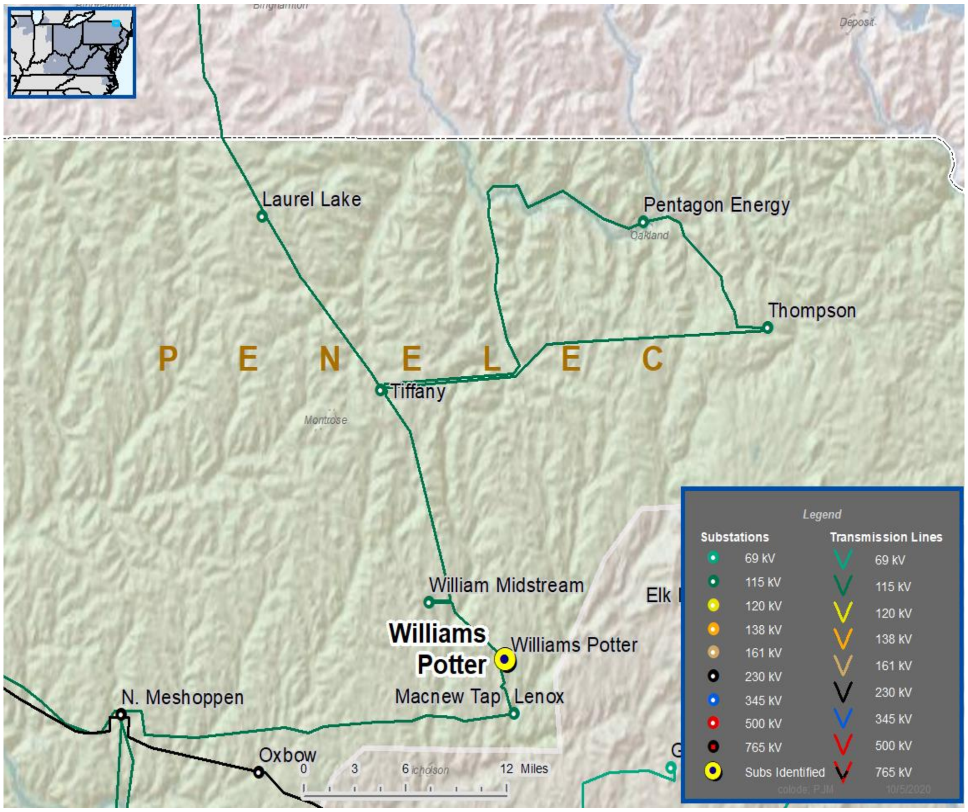
The recommended solution is to convert the Liberty-Lomar and Cannon Branch-Lomar 115 kV lines to 230 kV to provide a new 230 kV source between Cannon Branch and Liberty. A wreck and rebuild will be required on a 0.36-mile segment of the line between Lomar and Cannon Branch junction. Substation work will be required at Liberty, Wellington, Godwin, Pioneer, Sandlot, Cannon Branch, Brickyard and Winters Branch. The project will extend Cannon Branch-Clifton to Winters Branch by removing the existing line termination at Cannon Branch and extending the line to Brickyard, creating a Brickyard-Clifton line and extending a new line between Brickyard and Winters Branch. Substation work will be required at Cannon Branch, Brickyard and Winters Branch. Additionally, the overdutied Gainesville 230 kV 40 kA breaker 216192 will be replaced with a 50 kA breaker. The estimated cost for this project is $45.5 million, with a required and projected in-service date of June 2023. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3245: Warriner Pond 115 kV

PENELEC Transmission Zone

In the 2025 RTEP winter case, the Williams 115 kV bus has a voltage drop issue for a line fault stuck breaker contingency loss of the Williams-Tiffany-Laurel lake-Westover 115 kV circuit. These issues were excluded from the competitive proposal window through the below 200 kV exemption.

Map 8. Williams and Tiffany 115 kV Area



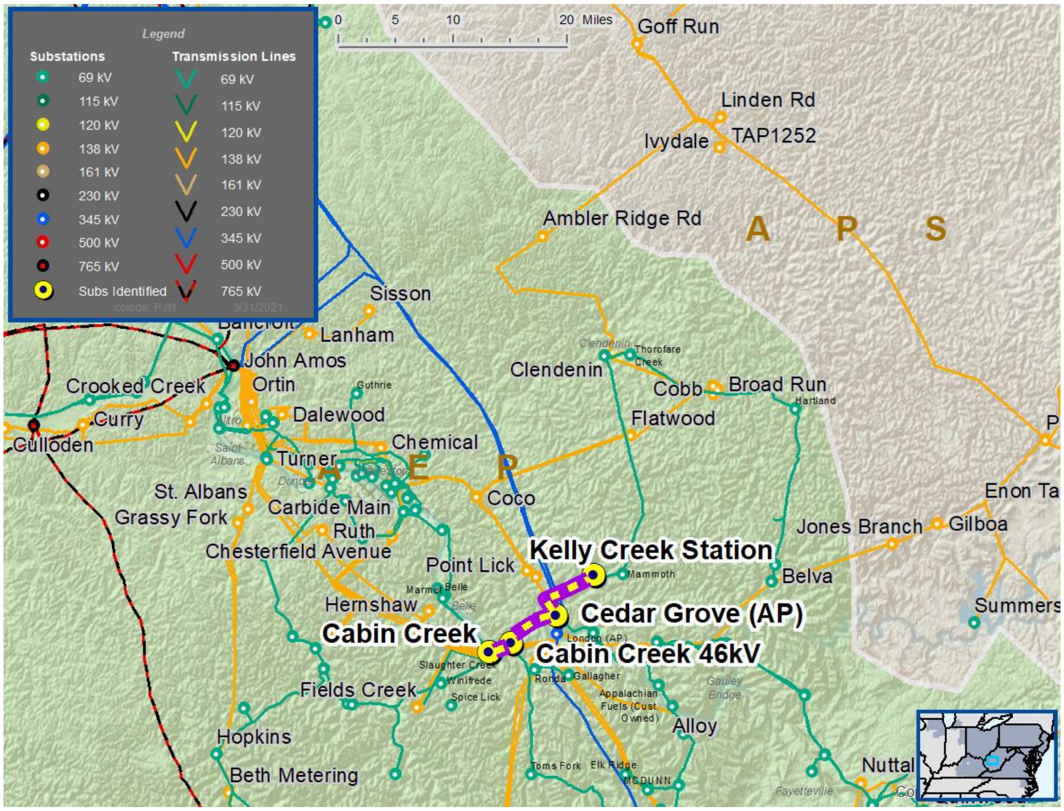
The recommended solution is to construct a new breaker-and-a-half Warriner Pond 115 kV substation near Tiffany substation. All transmission assets and lines will be relocated from Tiffany to the new substation. The two distribution transformers will be fed via two dedicated 115 kV feeds to the existing Tiffany substation. The estimated cost for this project is $23.2 million, with a required and projected in-service date of June 2025. The local transmission owner, PENELEC, will be designated to complete this work.

Baseline Project b3280: Cabin Creek-Kelly Creek Rebuild

AEP Transmission Zone

In the summer 2025 RTEP case, the Cabin Creek-Kelly Creek 46 kV line is overloaded for an N-1-1 138 kV contingency pair. These issues were identified through AEP's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV exemption.

Map 9. b3280: Cabin Creek-Kelly Creek Rebuild



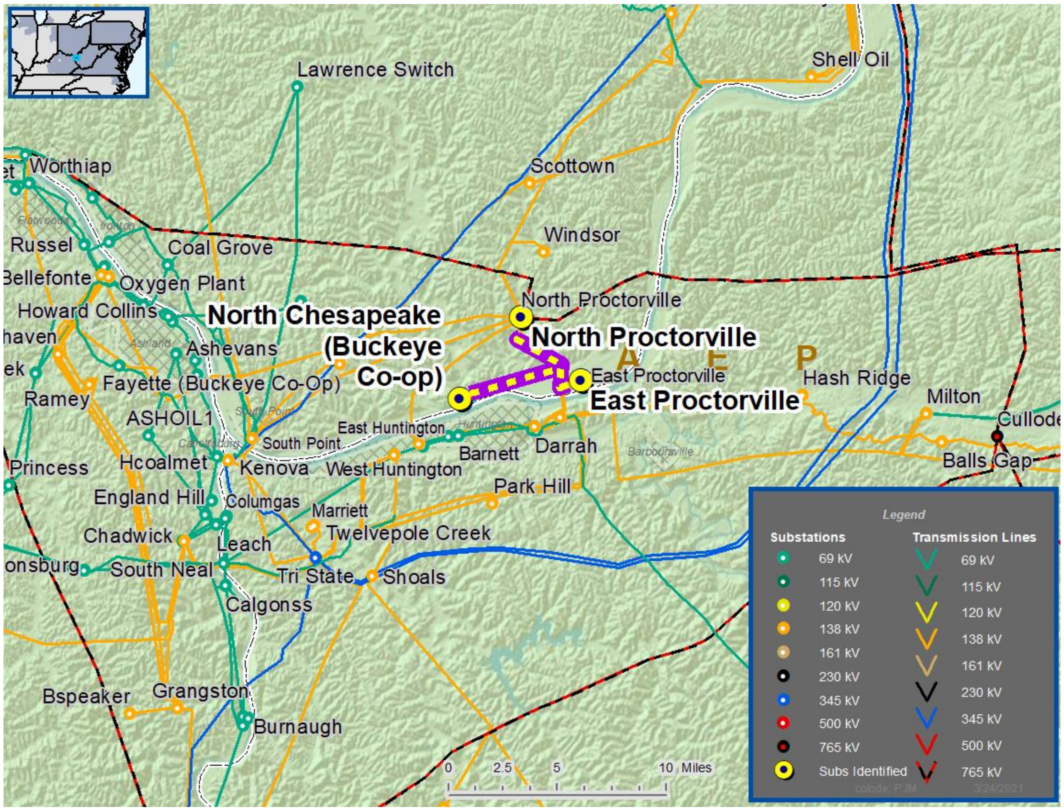
The recommended solution is to rebuild the existing Cabin Creek-Kelly Creek 46 kV line (approximately 4.4 miles to structure 366-44). The section is double circuit with the existing Cabin Creek-London 46 kV line so a double-circuit rebuild would be required. The estimated cost for this project is $17.9 million, with a required and projected in-service date of June 2025. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3282: East Huntington-North Proctorville 138 kV

AEP Transmission Zone

In the summer 2025 RTEP case, the Fulks-Johnson Lane 34.5 kV line is overloaded and in the summer and winter 2025 RTEP cases, there are voltage violations at East Huntington 138 kV buses, 23rd Street, 24th Street, 26th Street, BASF, East Huntington, Johnson Lane, Fulks, Connor Street, Inco Fur and Connor F 34.5 kV buses due to an N-1-1 scenario. These issues were identified through AEP's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below 200 kV and substation equipment exemptions.

Map 10. b3282: East Huntington-North Proctorville 138 kV



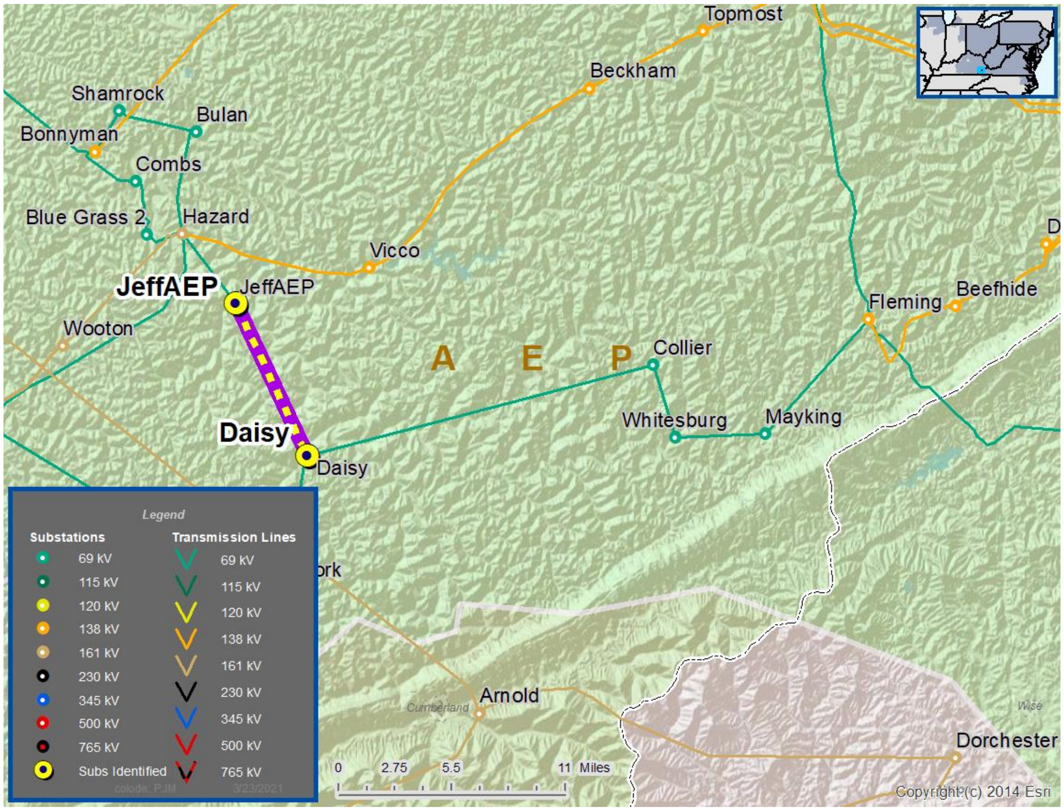
The recommended solution is to install a second 138 kV circuit utilizing 795 ACSR conductor on the open position of the existing double circuit towers from East Huntington-North Proctorville. Remove the existing 34.5 kV line from East Huntington-North Chesapeake and rebuild this section to 138 kV served from a new phase-over-phase switch off the new East Huntington-North Proctorville 138 kV No. 2 line. Additionally, 40 kA 138 kV breakers will be installed at North Proctorville and East Huntington. The existing 34/12 kV North Chesapeake station will be converted to a 138/12 kV station. The estimated cost for this project is $10.4 million, with a required and projected in-service date of June 2025. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3307: Fleming Station Ring Bus

AEP Transmission Zone

In the winter 2025 RTEP case, the Jeff-Daisy 69 kV line is overloaded and there are voltage violations at Weeksbury, Reedy Coal, Mayking, Daisy, Fleming, Collier, Golden Oaks, Slemp and Whitesburg 69 kV buses for the loss of multiple N-1-1 contingency pairs. These issues were identified through AEP's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV exemption.

Map 11. b3307: Fleming Station Ring Bus



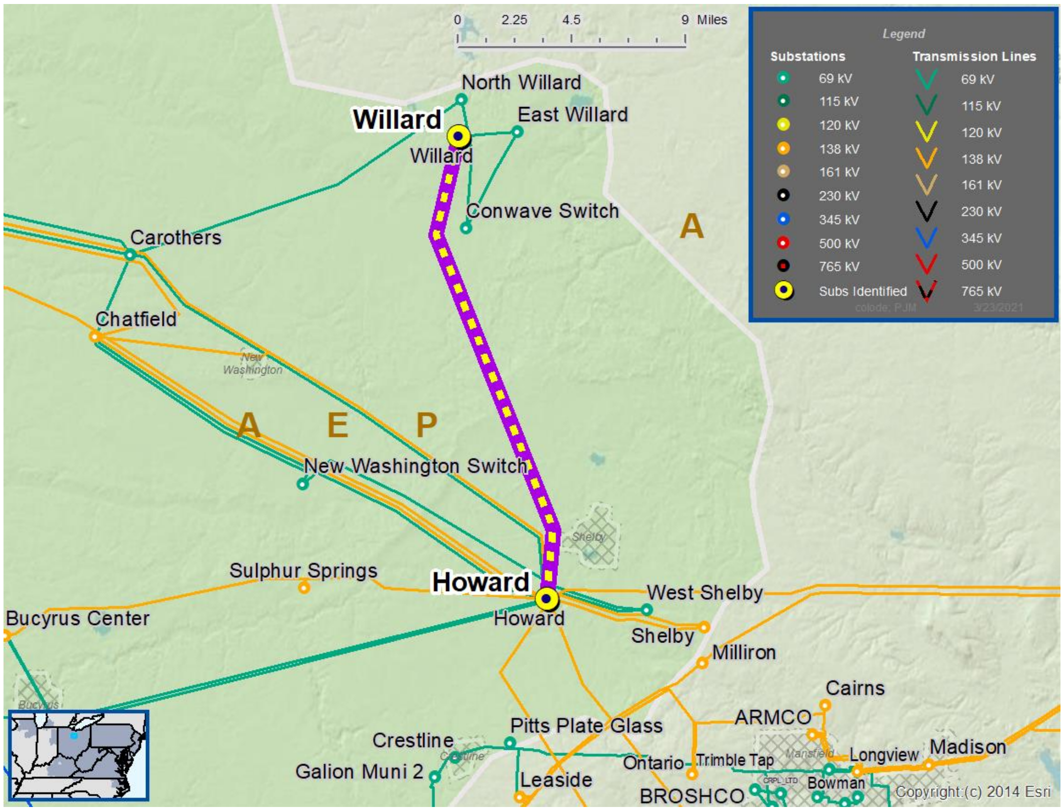
The recommended solution is to retire the existing Fleming substation and rebuild the station in the clear as new Jackhorn 138/69 kV substation. The project will include the replacement of the 138/69 kV Fleming Transformer No. 1 with a 130 MVA transformer with high side 138 kV circuit breaker. Additionally, a 5-breaker 69 kV ring bus will be installed on the low side of the transformer, and the 69 kV circuit switcher AA, the 69/12 kV transformer No. 3 and 12 kV circuit breakers A and D will be replaced. The estimated cost for this project is $21.1 million, with a required and projected in-service date of December 2025. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3310: Howard-Willard 69 kV Rebuild

AEP Transmission Zone

In the summer 2025 RTEP case, the Howard-Willard 69 kV line is overloaded for multiple N-1 and N-1-1 contingencies in the Willard area. These issues were identified through AEP's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV exemption.

Map 12. b3310: Howard-Willard 69 kV Rebuild



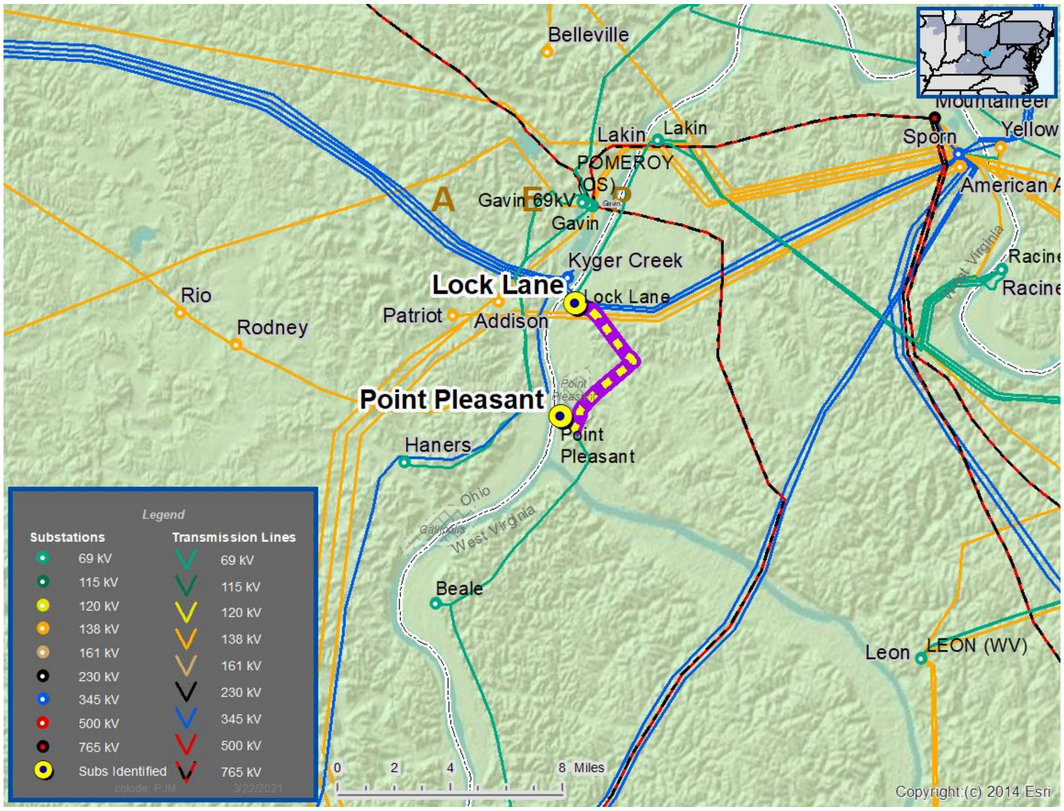
The recommended solution is to rebuild 10.5 miles of the Howard-Willard 69 kV line with 556 ACSR conductor. Additionally, the relays at Howard and Willard 69 kV substations will be upgraded. The estimated cost for this project is $19.46 million, with a required and projected in-service date of June 2025. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3284: Lock Lane-Point Pleasant Rebuild

AEP Transmission Zone

In the summer and winter 2025 RTEP cases, the Lock Lane-Point Pleasant 69 kV line is overloaded in the event of an N-1-1 scenario. This issue was identified through AEP's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV exemption.

Map 13. b3284: Lock Lane-Point Pleasant Rebuild



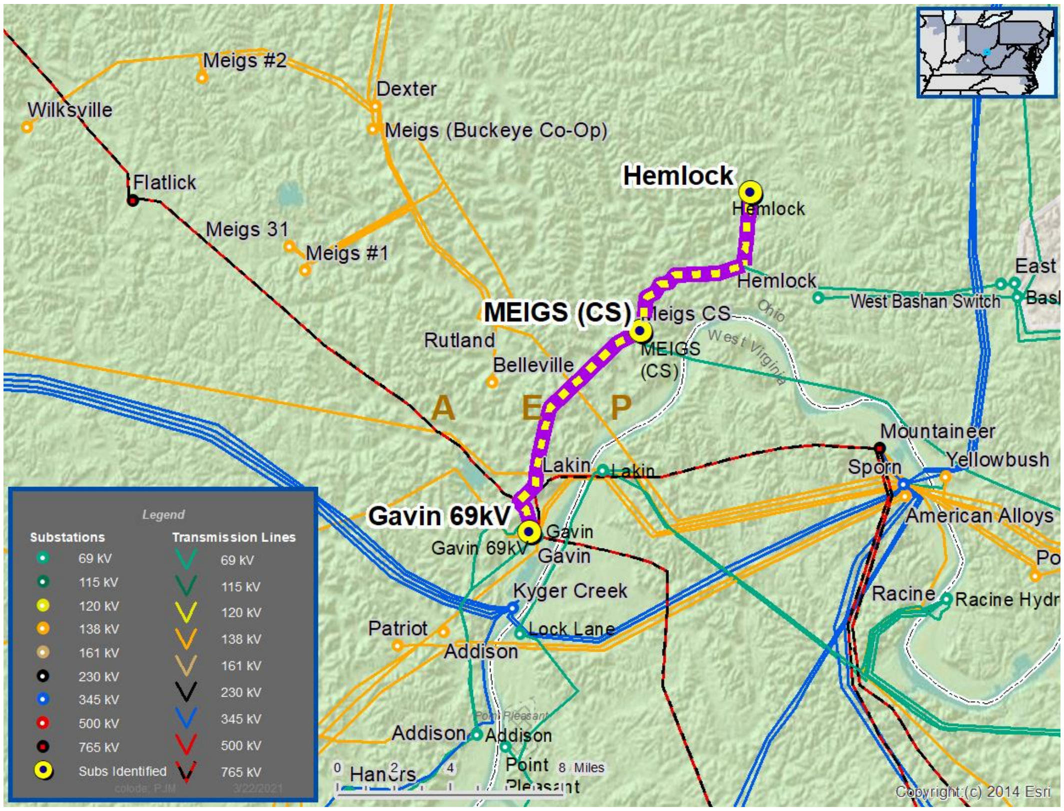
The recommended solution is to rebuild approximately 5.44 miles of 69 kV line from Lock Lane to Point Pleasant. The estimated cost for this project is $13.5 million, with a required and projected in-service date of June 2025. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3285: Meigs Area Upgrades

AEP Transmission Zone

In the summer and winter 2025 RTEP cases, the Meigs-Gavin and Meigs-Hemlock 69 kV lines are overloaded for the loss of multiple N-1-1 contingency pairs. These issues were identified through AEP's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV exemption.

Map 14. b3285: Meigs Area Upgrades



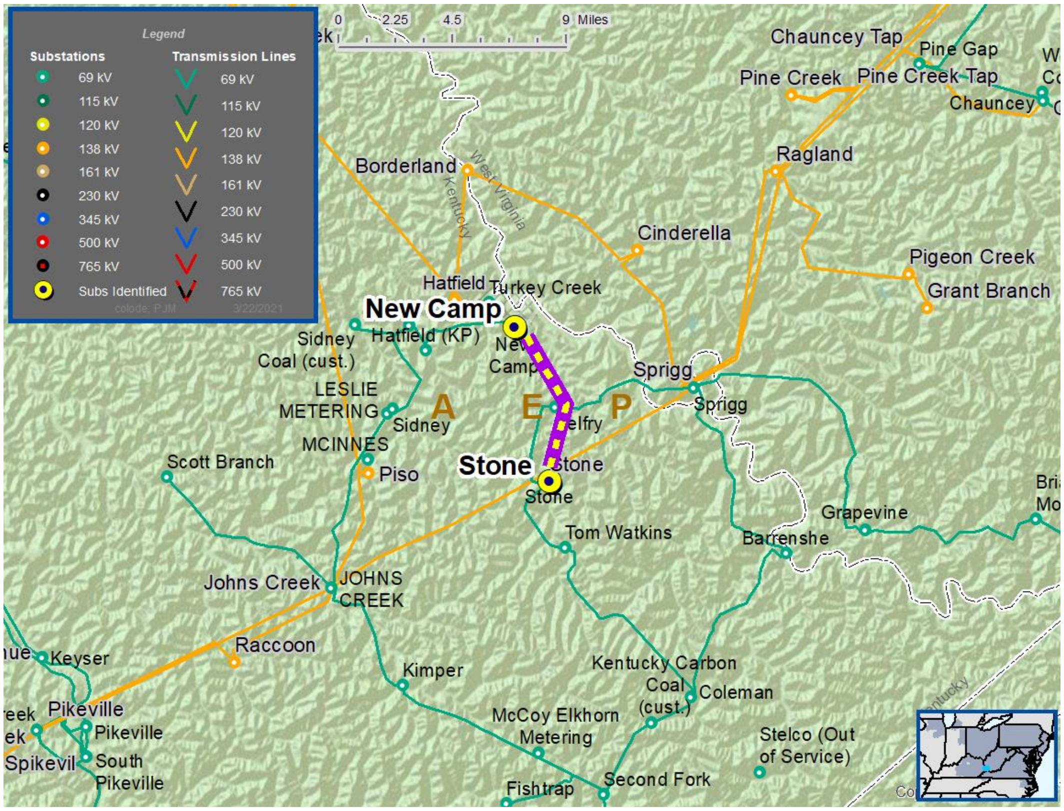
The recommended solution is to replace the Meigs 69 kV 4/0 Cu station riser towards Gavin and rebuild a section of the Meigs- Hemlock 69 kV circuit (approximately 4 miles) replacing the line conductor 4/0 ACSR with the line conductor size 556.5 ACSR. The estimated cost for this project is $12.14 million, with a required in-service date of June 2025. The projected in-service date is September 2024, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3288: New Camp-Stone 69 kV

AEP Transmission Zone

In the winter 2025 RTEP case, voltage drop violations at New Camp 69 kV were identified in the event of an N-1-1 scenario. These issues were identified through AEP's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV exemption.

Map 15. b3288: New Camp-Stone 69 kV



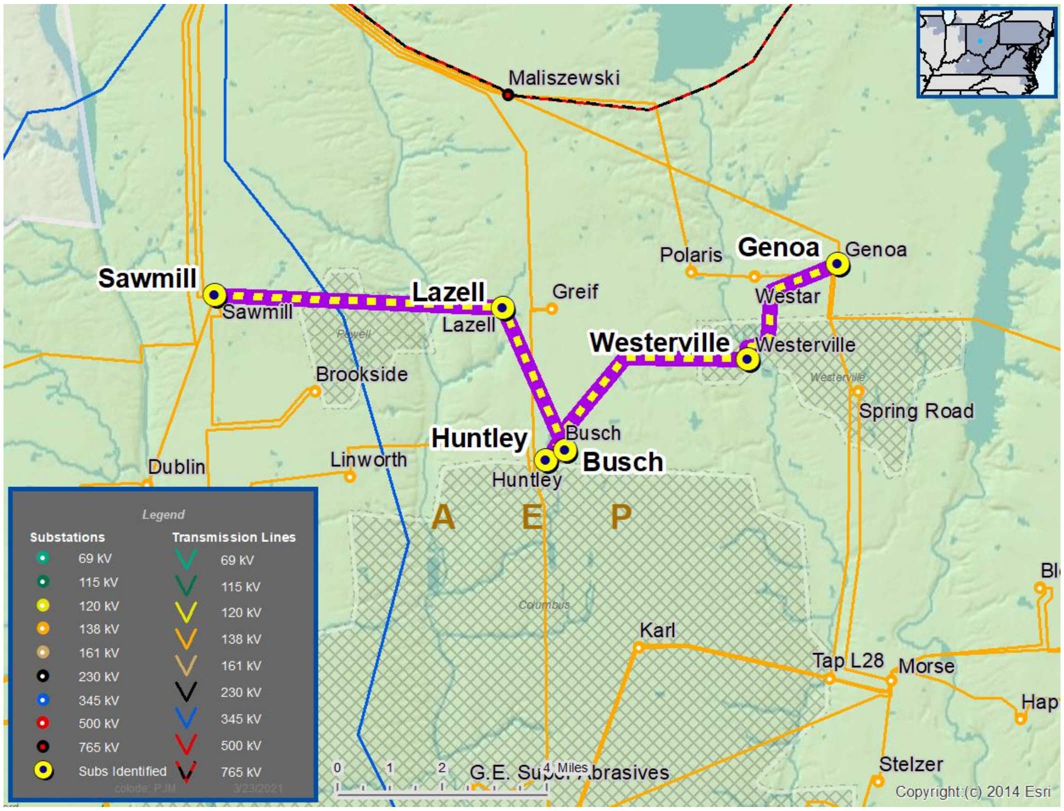
The recommended solution is to construct two new greenfield lines (approximately 2.75 miles of 69 kV transmission line between the Orinoco and Stone stations, and approximately 3.25 mi of 69 kV transmission line between the Orinoco and New Camp stations). At the Stone substation, circuit breaker A will remain in place and be utilized as the transformer T1 low side breaker, and circuit breaker B will remain in place and be utilized as new Hatfield (via Orinoco and New Camp) 69 kV line breaker. The project will add a new 40 kA 69 kV circuit breaker E for the Coleman line exit. The project includes the reconfiguration of the New Camp tap which includes access road improvements/installation, temporary wire and permanent wire work along with installation of dead end structures. At the New Camp substation, the project will rebuild the 69 kV bus, add 69 kV MOAB W and replace the 69 kV ground switch Z1 with a 69 kV circuit switcher on the New Camp transformer. The estimated cost for this project is $21.47 million, with a required and projected in-service date of December 2025. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3297: North Columbus 69 kV line Rebuilds

AEP Transmission Zone

In the summer 2025 RTEP case, the Sawmill-Lazelle and Westerville-Genoa 69 kV lines along with station equipment at Lazelle, Westerville and Genoa are overloaded for multiple N-1-1 contingency scenarios. These issues were identified through AEP's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV and substation equipment exemptions.

Map 16. b3297: North Columbus 69 kV Line Rebuilds



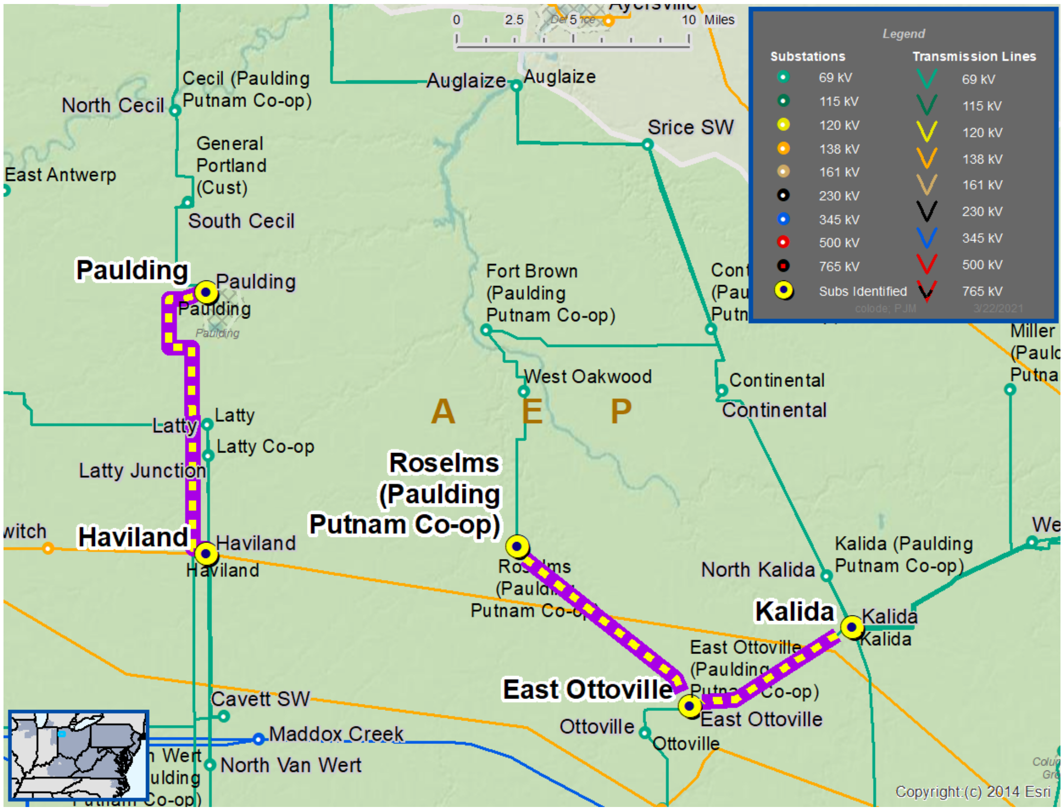
The recommended solution is to rebuild 4.23 miles of 69 kV line between Sawmill and Lazelle stations and 1.94 miles of 69kV line between Westerville and Genoa stations using 795 ACSR 26/7 conductor. The project will also replace risers and switchers at Lazelle, Westerville and Genoa 69 kV stations, and upgrade associated relaying accordingly. The estimated cost for this project is $19.8 million, with a required and projected in-service date of June 2025. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3290: Roselms-Kalida 69 kV

AEP Transmission Zone

In the summer 2025 RTEP case, the Haviland-Paulding 69 kV circuit is overloaded for the loss of multiple N-1-1 contingency pairs. In the summer and winter 2025 RTEP cases, the same N-1-1 contingency pair causes voltage drop violations at Roselms, West Oakwood, Fort Brown, Continental, Auglaize, Sherwood and Mark Center 69 kV buses. These issues were identified through AEP’s FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV exemption.

Map 17. b3290: Roselms-Kalida 69 kV



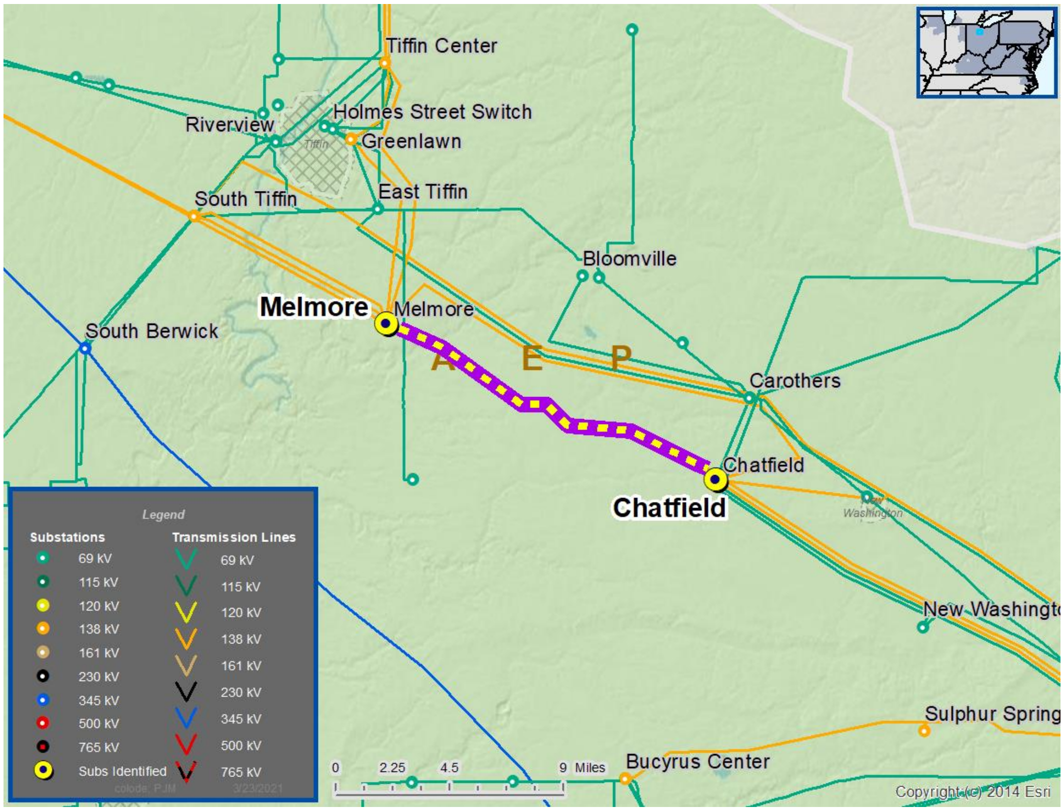
The recommended solution is to build 9.4 miles of single circuit 69 kV line from Roselms to near East Ottoville 69 kV Switch. The project also includes rebuilding 7.5 miles of the double circuit 69 kV line between East Ottoville Switch and Kalida Station, which will be combined with the new Roselms to Kalida 69 kV circuit. At the Roselms Switch, a new three-way 69 kV, 1200 A phase-over-phase switch with sectionalizing capability will be installed. At Kalida station, the new line from Roselms Switch will be terminated, and the CS XT2 will be moved from the high side of the T2 transformer to the high side of the T1 transformer. Additionally, the existing T2 transformer will be removed. The estimated cost for this project is $38.9 million, with a required and in-service date of June 2025. The projected in-service date is October 2024, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3249: Chatfield-Melmore 138 kV Rebuild

AEP Transmission Zone

In the summer 2025 RTEP case, the Chatfield-Melmore 138 kV line is overloaded due to a line with stuck breaker contingency. This issue was identified through AEP's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV exemption.

Map 18. b3249: Chatfield-Melmore 138 kV Rebuild



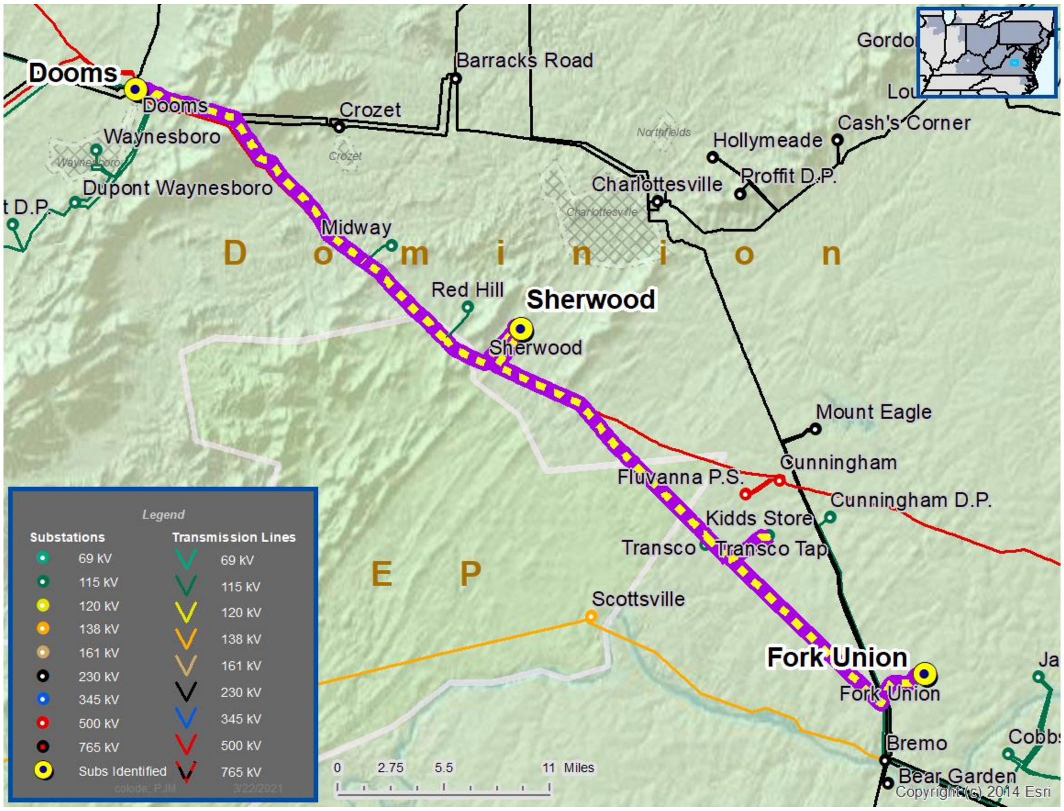
The recommended solution is to rebuild the Chatfield-Melmore 138 kV line (approximately 10 miles) to 1033 ACSR conductor. The estimated cost for this project is $27.2 million, with a required and projected in-service date of June 2025. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3268: Midway and Red Hill Area

Dominion Transmission Zone

In the winter 2025 RTEP cases, the Midway-Red Hill area is experiencing voltage drop violations in the event of a bus or breaker failure. These issues were identified through Dominion's FERC 715 Planning Criteria, and excluded from the competitive proposal window through the below-200 kV exemption.

Map 19. b3268: Midway & Red Hill Area



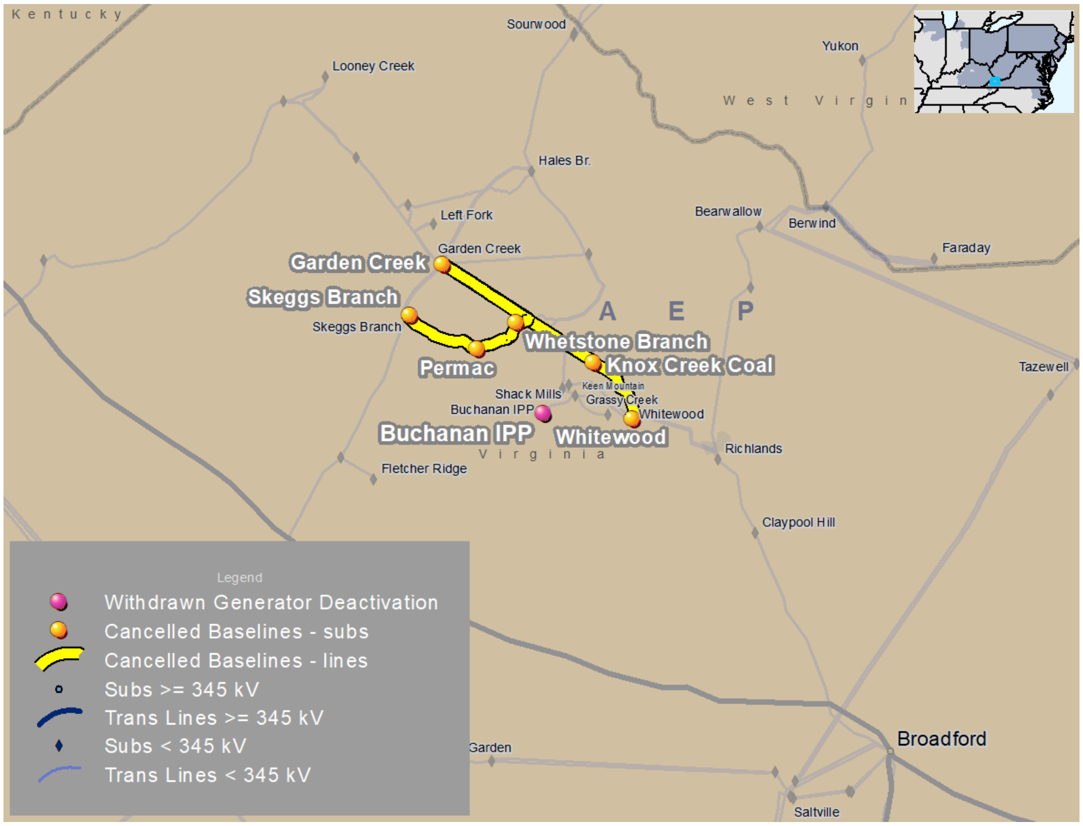
The recommended solution is to build a 230 kV switching station called Walnut Creek and operate it at 115 kV at the junction where both Fork Union-Sherwood line No. 91 and Dooms-Sherwood line No. 39 115 kV lines start to share a common structure. The station arrangement will be a new 115 kV four-breaker ring bus station with an additional 115 kV 33.67 MVAR capacitor bank. The estimated cost for this project is $12 million, with a required and projected in-service date of December 2025. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3333: Skeggs Branch Area Improvements

AEP Transmission Zone

The deactivation of Buchanan 1 and 2, which have a requested deactivation date of June 1, 2023, results in the overload of the Garden Creek-Whetstone, Whetstone-Knox Creek and Knox Creek-Coal Creek 69 kV lines for various N-1 outage combinations. The Richland, Whitewood, Shack Mills, Grassy Creek, Buchanan and Keen Mountain 138 kV buses also become radial for various N-1 outage combinations, and, as a result, these radial-connected 138 kV buses (and 69 kV buses through Richland 138 kV bus) have voltage magnitude and drop violations. The violations from the deactivation study were initially resolved by existing baseline projects b3139-b3141 and b3220. However, there are supplemental needs identified in the area, so a new holistic alternative is being recommended in lieu of the previously identified projects.

Map 20. b3333: Skeggs Branch Area Improvements



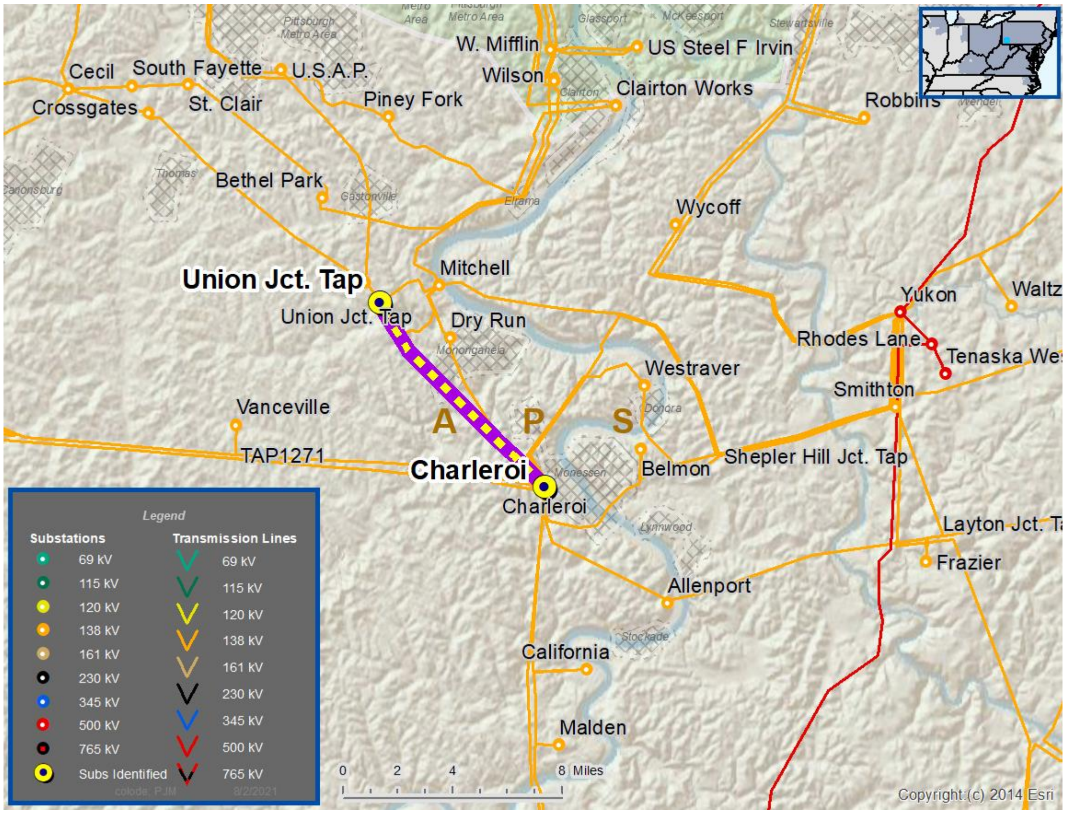
The recommended solution is to rebuild the Skeggs Branch substation in the clear as Coronado substation (the existing Skeggs Branch substation will be retired), by establishing new 138 kV and 69 kV buses, and installing a 138/69 kV 130 MVA transformer, 138 kV circuit switcher and a 69 kV breaker. Approximately 1.2 miles of 138 kV extension will be built to the Coronado substation, and a 46.1 MVAR capacitor bank and 138 kV circuit breaker will be installed at the Whitewood substation. The project will rebuild approximately 9 miles of 69 kV line from the Coronado station to the Coal Creek 69 kV line, and six-wire the short double circuit section between Whetstone Branch and structure 340-28 to convert the line to a single circuit. The Garden Creek to Whetstone Branch 69 kV line section, along with the Knox Creek and Horn Mountain 69 kV switching stations, will be retired. At the Clell 69 kV switching station, two 600 A phase-over-phase (POP) switches and poles will be replaced with a single two-way 1200 A POP switch and pole. At Permac and Marvin 69 kV switching stations, a 600 A switch and structure will be replaced with a two-way 1200 A POP pole switch and pole. At Whetstone Branch 69 kV substation, a 600 A two-way POP switch will be replaced with a 1200 A two-way POP switch, and the No. 22 POP switch to Skeggs Branch will be removed. At Garden Creek 69 kV substation, the Richlands (via Coal Creek) 69 kV line (circuit breaker F and disconnect switches) will be removed and relay settings will be updated. The project also includes remote-end work at Clinch River and Clinchfield 69 kV substations. The estimated cost for this project is $40.17 million, with a required in-service date of June 2023. The projected in-service date is December 2023, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3325: Charleroi-Union Jct. 138 kV

APS Transmission Zone

The deactivation of Waukegan 7 and 8 and Will County 4, which have a requested deactivation date of May 31, 2022, results in the overload of the Charleroi-Union Jct. 138 kV line for an N-2 outage.

Map 21. b3325: Charleroi-Union Jct. 138 kV



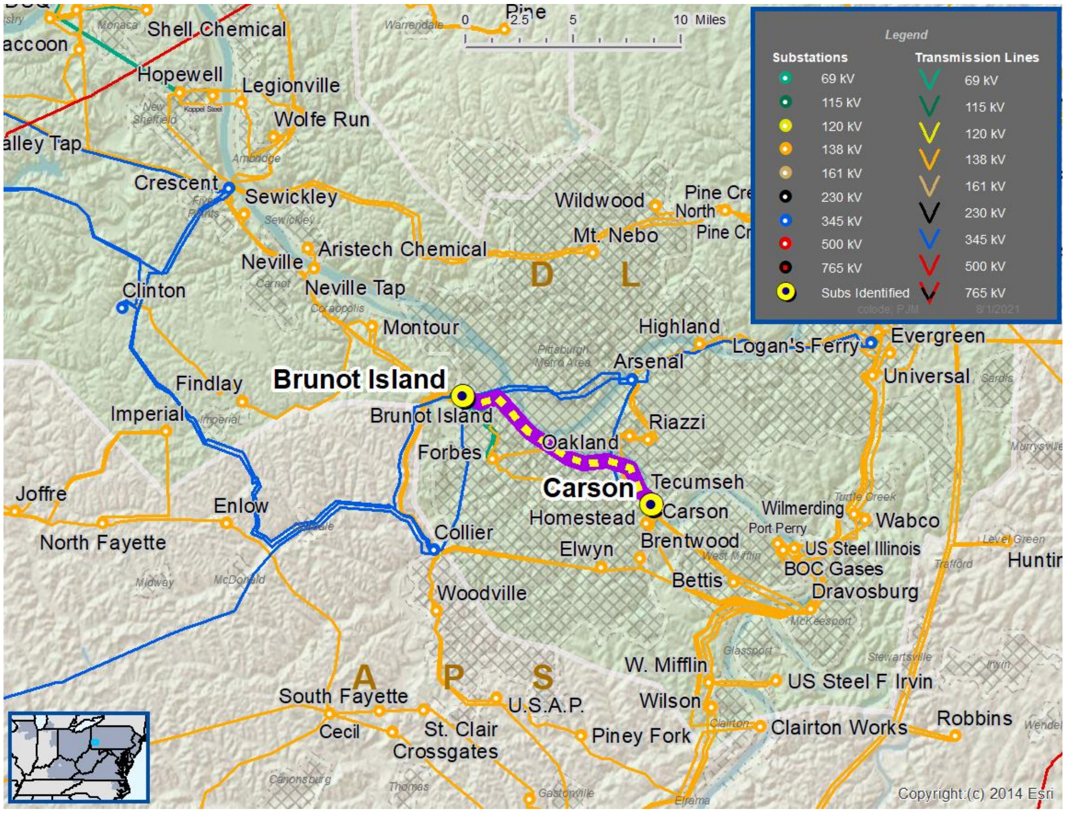
The recommended solution is to reconductor the Charleroi-Union Jct. 138 kV line and upgrade the terminal equipment at Charleroi 138 kV. The estimated cost for this project is $11 million, with a required in-service date of June 2022. The projected in-service date is June 2023, and operating measures have been identified to mitigate reliability impacts in the interim. The local transmission owner, APS, will be designated to complete this work.

Baseline Project b3319: Brunot Island-Carson 345 kV

DL Transmission Zone

The deactivation of Cheswick 1, which has a requested deactivation date of April 1, 2022, results in the overload of the Brunot Island-Carson 345 kV cable for an N-2 underground common trench failure outage. The criteria used to identify the overload is part of Duquesne Light Company's FERC 715 Planning Criteria.

Map 22. b3319: Brunot Island-Carson 345 kV



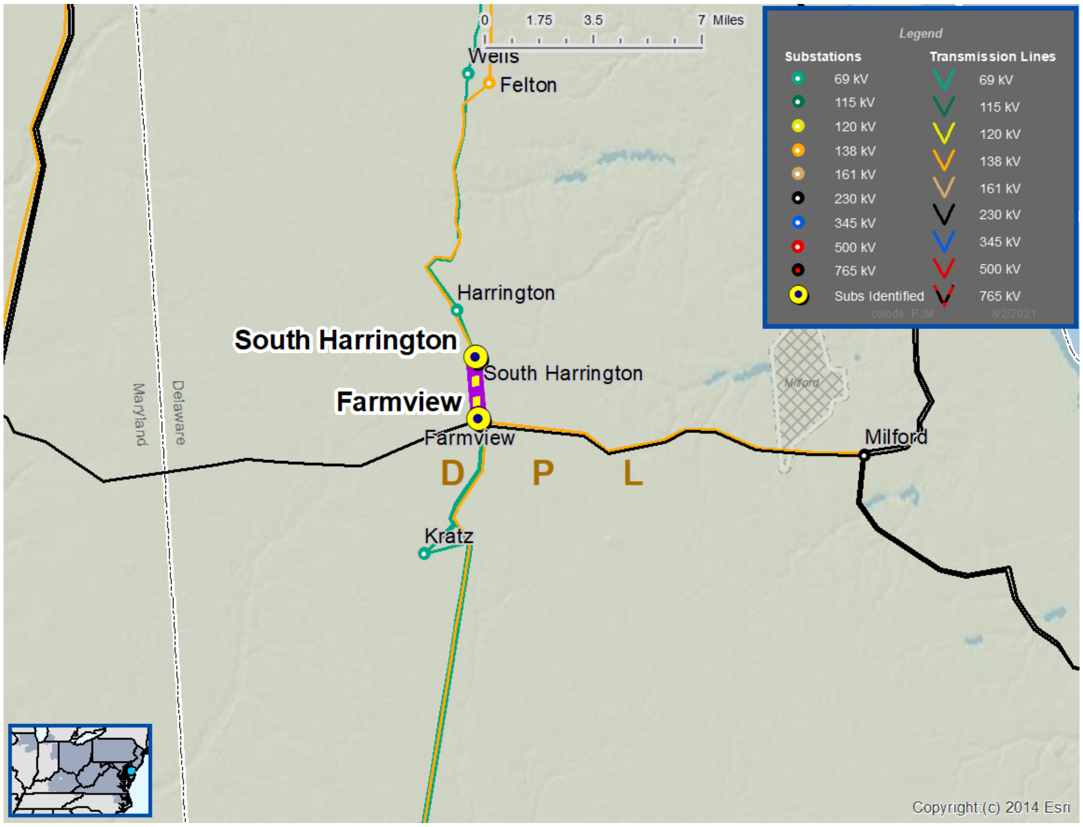
The recommended solution is to add forced cooling to increase the normal rating of the Brunot Island-Carson 345 kV High-Pressure Fluid Filled (HPFF) underground cable circuit. The estimated cost for this project is $22 million, with a required in-service date of June 2022. The projected in-service date is December 2024, and operating measures have been identified to mitigate reliability impacts in the interim. The local transmission owner, DL, will be designated to complete this work.

Baseline Project b3330: Farmview-S. Harrington 138 kV

DPL Transmission Zone

The deactivation of Indian River 4, which has a requested deactivation date of May 31, 2022, results in the overload of the Farmview-S. Harrington 138 kV line for various N-1 outage combinations.

Map 23. b3330: Farmview-S. Harrington 138 kV



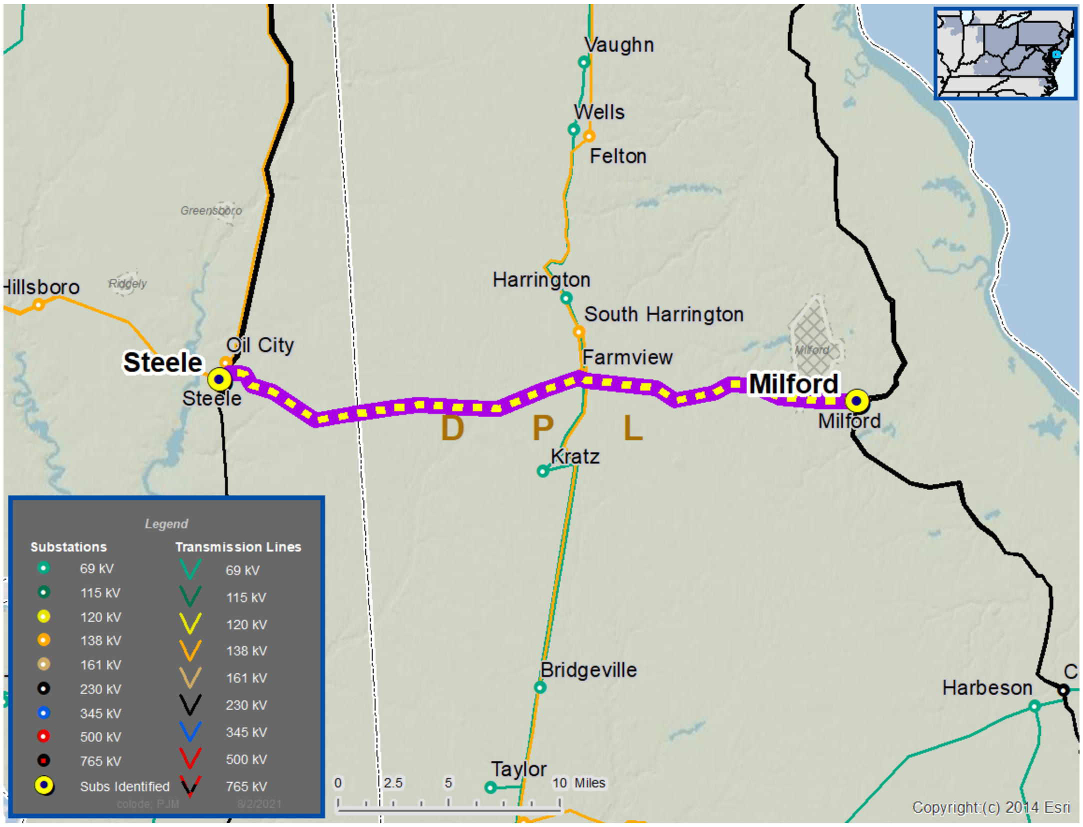
The recommended solution is to rebuild the Farmview-S. Harrington 138 kV line. The estimated cost for this project is $16.9 million, with a required in-service date of June 2022. The projected in-service date is June 2026, and operating measures are not available in the interim. PJM Planning/Operations and DPL are continuing to investigate mitigation. The local transmission owner, DPL, will be designated to complete this work.

Baseline Project b3332: Steele-Milford 230 kV

DPL Transmission Zone

The deactivation of Indian River 4, which has a requested deactivation date of May 31, 2022, results in the overload of the Steele-Milford 230 kV line for various N-1 outage combinations.

Map 24. b3332: Steele-Milford 230 kV



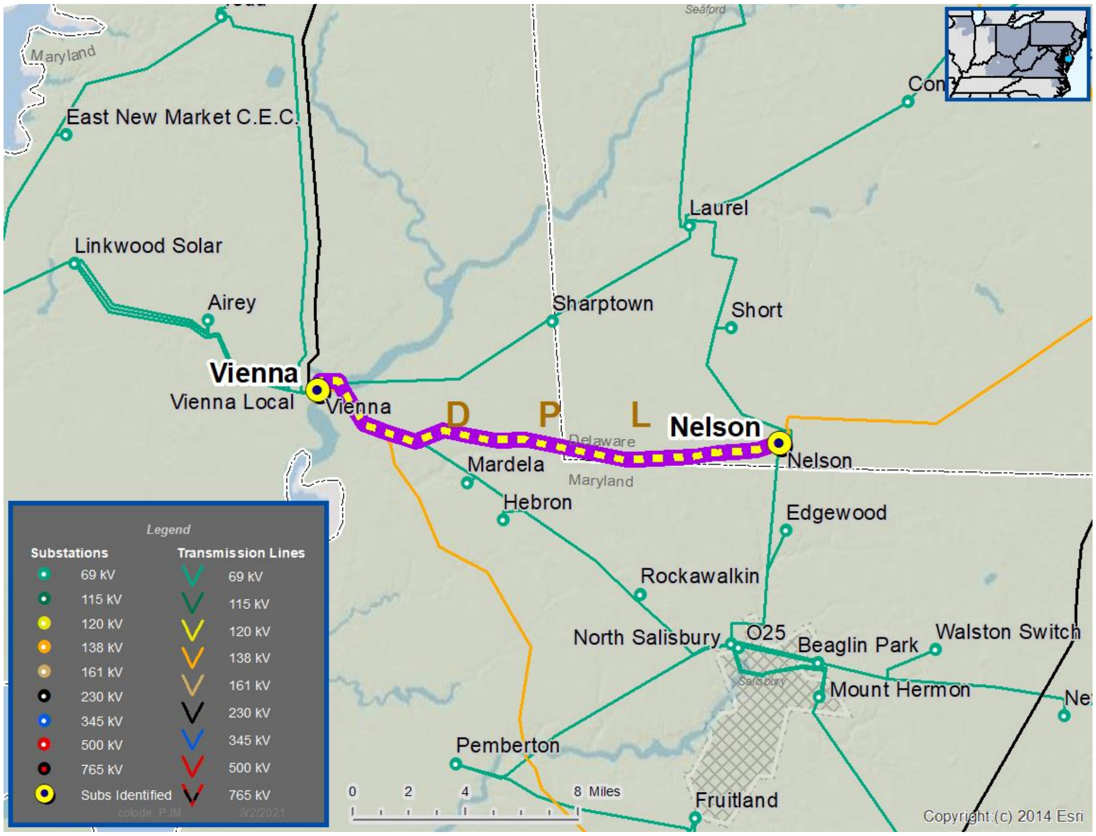
The recommended solution is to rebuild the Steele-Milford 230 kV line. The estimated cost for this project is $63 million, with a required in-service date of June 2022. The projected in-service date is June 2027, and operating measures are not available in the interim. PJM Planning/Operations and DPL are continuing to investigate mitigation. The local transmission owner, DPL, will be designated to complete this work.

Baseline Project b3326: Vienna-Nelson 138 kV

DPL Transmission Zone

The deactivation of Indian River 4, which has a requested deactivation date of May 31, 2022, results in the overload of the Vienna-Nelson 138 kV line for an N-2 and various N-1 outage combinations.

Map 25. b3326: Vienna-Nelson 138 k



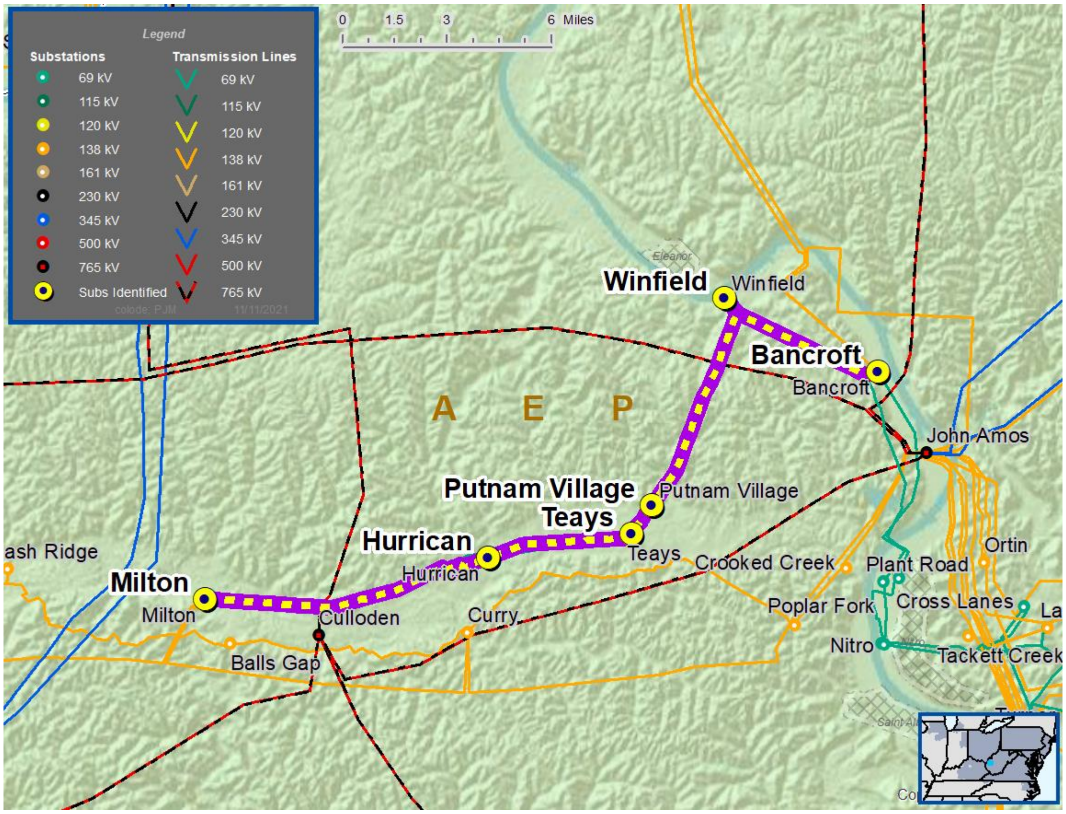
The recommended solution is to rebuild the Vienna-Nelson 138 kV line. The estimated cost for this project is $31.25 million, with a required in-service date of June 2022. The projected in-service date is June 2026, and operating measures are not available in the interim. PJM Planning/Operations and DPL are continuing to investigate mitigation. The local transmission owner, DPL, will be designated to complete this work.

Baseline Project b3347: Bancroft-Milton 69 kV

AEP Transmission Zone

In the 2026 Light Load RTEP case, the Bancroft-Putnam Village, Putnam Village-Winfield, Putnam Village-Teays and the Hurrican-Milton 69 kV lines are overloaded for an N-1 outage combination. The Hurrican-Teays 69 kV line is also overloaded for various N-1 outage combinations.

Map 26. b3347: Bancroft-Milton 69 kV



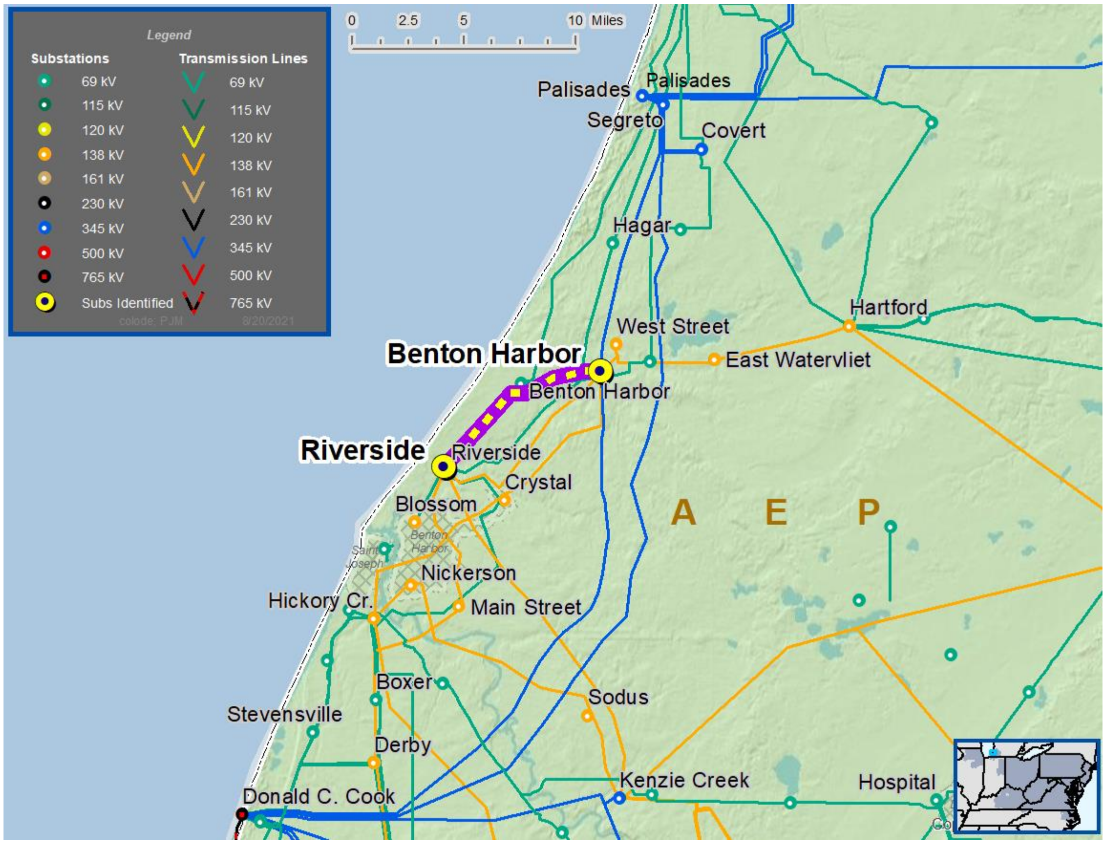
The recommended solution, solicited through the 2021 Window 1 competitive proposal process, is to rebuild approximately 20 miles of line between Bancroft and Milton 69 kV stations with 556 ACSR conductor. The project includes the replacement of jumpers around Hurrican and Teays switches with 556 ACSR, and update of relay settings at Winfield, Bancroft, Milton and Putnam Village 69 kV stations to coordinate with remote ends on the line rebuild. The estimated cost for this project is $56.73 million, with a required in-service of November 2026. The projected in-service date is June 2026, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3336: Benton Harbor-Riverside 138 kV

AEP Transmission Zone

The deactivation of Zimmer 1, which has a requested deactivation date of May 31, 2022, results in the overload of the Benton Harbor-Riverside 138 kV line for an N-2 outage.

Map 27. b3336: Benton Harbor-Riverside 138 kV



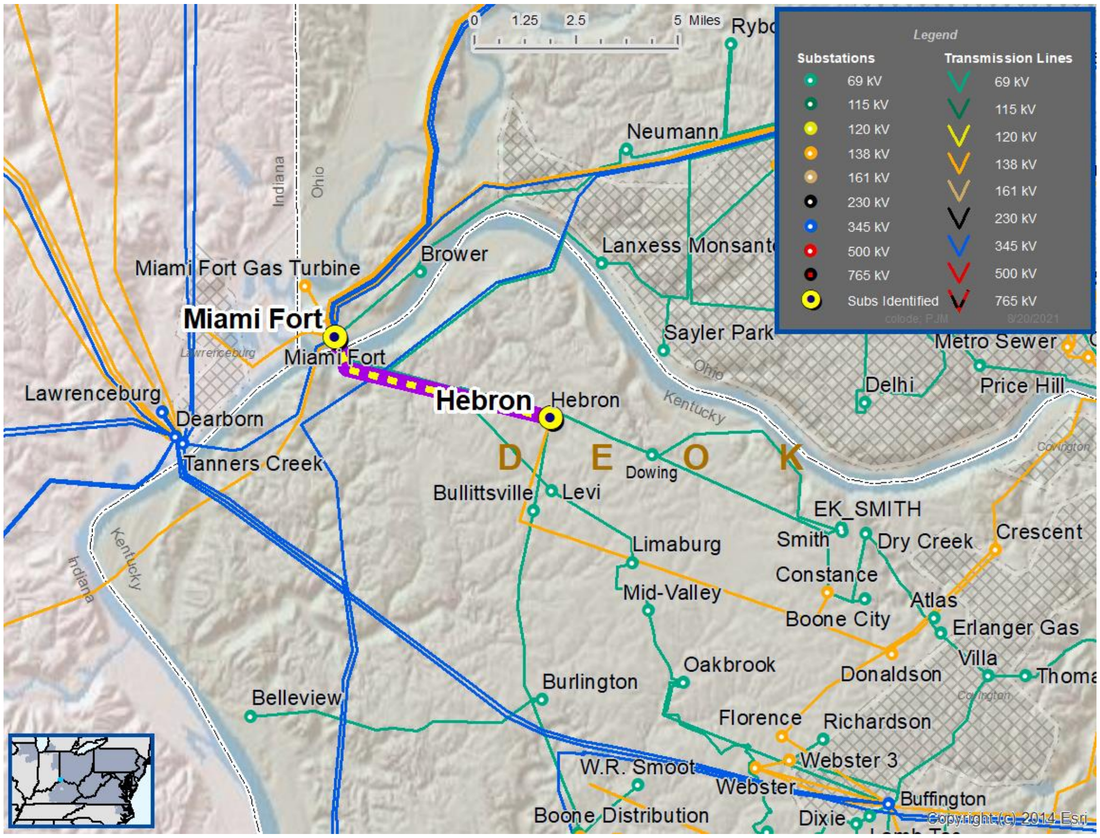
The recommended solution was previously a supplemental solution, which has been converted to a baseline project, and is to rebuild the Benton Harbor-Riverside 138 kV double circuit extension (6 miles). The estimated cost for this project is $14.9 million, with a required in-service date of June 2022. The projected in-service date is November 2021, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3334: Miami Fort-Hebron Tap 138 kV

DEOK Transmission Zone

The deactivation of Zimmer 1, which has a requested deactivation date of May 31, 2022, results in the overload of the Miami Fort-Hebron Tap 138 kV line for an N-2 outage.

Map 28. b3334: Miami Fort-Hebron Tap 138 kV



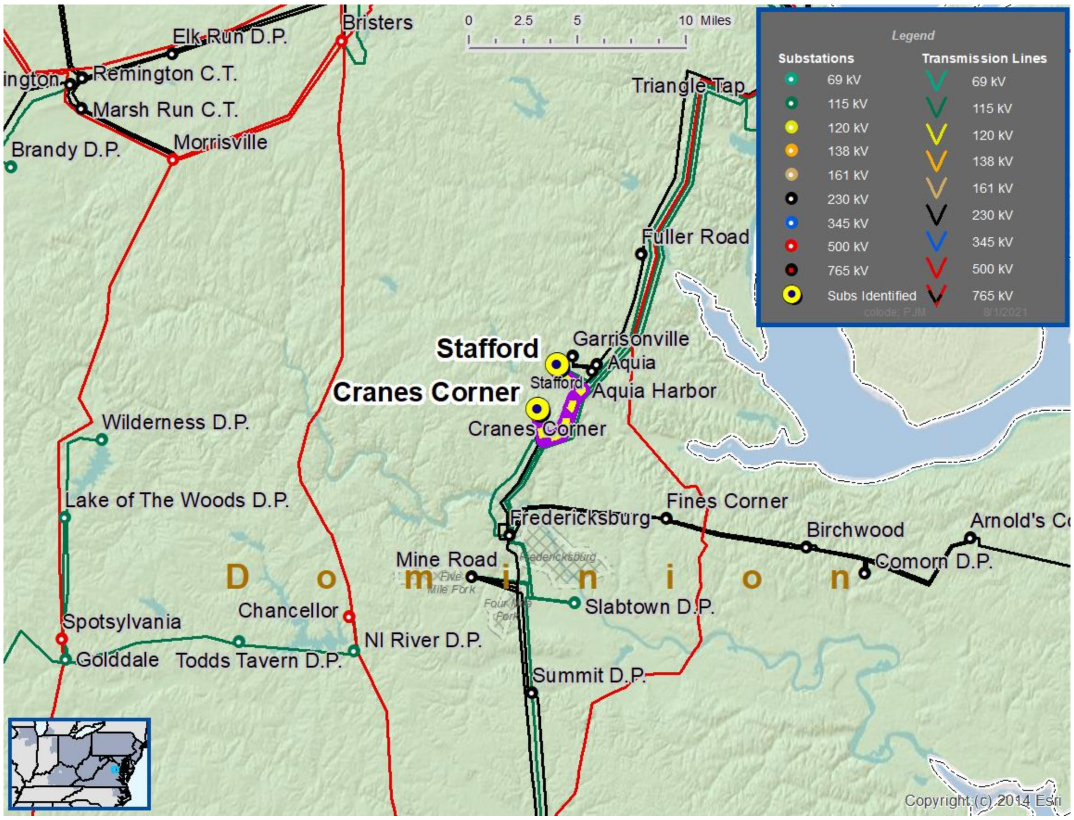
The recommended solution is to rebuild the section of Miami Fort-Hebron Tap 138 kV line. The estimated cost for this project is $44.3 million, with a required in-service date of June 2022. The projected in-service date is June 2025 and operating measures have been identified to mitigate reliability impacts in interim. The local transmission owner, DEOK, will be designated to complete this work.

Baseline Project b3321: Cranes Corner-Stafford 230 kV

Dominion Transmission Zone

The deactivation of Morgantown 1 and 2, which have a requested deactivation date of May 31, 2022, results in the overload of the Cranes Corner-Stafford 230 kV line for an N-1 outage.

Map 29. b3321: Cranes Corner-Stafford 230 kV



The recommended solution is to rebuild the Cranes Corner-Stafford 230 kV line. The estimated cost for this project is $19.6 million, with a required in-service date of June 2022. The projected in-service date is December 2023, and operating measures have been identified to mitigate reliability impacts in interim. The local transmission owner, Dominion, will be designated to complete this work.

Appendix A - Previously Identified RTEP Baseline Upgrades

Appendix A contains all currently required baseline upgrades that were identified in previous RTEP assessments. This appendix also contains expected required in-service dates for facilities. PJM continuously evaluates the lead times of these plans with respect to the expected required in-service dates. The continuing need for these required system facilities was evaluated as part of the 2021 RTEP assessment and will be evaluated in future RTEP assessments. This list of upgrades represents a snapshot of all required planned facilities in the RTEP as of 12/31/2021.

1) Baseline Upgrade b0866
   - Replace Chalk Point 230 kV breaker (6C) with 80 Ka breaker - 6/1/2012 - $2.00M
2) Baseline Upgrade b1270
   - Reconductor Bath - Trebein 138kV - 6/1/2015 - $1.30M
3) Baseline Upgrade b1273
   - Add 2nd Bath 345/138kV Xfr - 6/1/2015 - $7.00M
4) Baseline Upgrade b1274
   - Add 2nd Trebein 138/69kV Xfr - 6/1/2015 - $5.30M
5) Baseline Upgrade b1275
   - Add 2nd W. Milton 138/69kV Xfr - 6/1/2015 - $8.80M
6) Baseline Upgrade b1276
   - Add 2nd W. Milton 345/138 Xfr - 6/1/2015 - $5.50M
7) Baseline Upgrade b1570
   - Add a 345/69 kV transformer at Dayton's Peoria 345 kV bus - 6/1/2014 - $16.00M
8) Baseline Upgrade b1570.1
   - Add/reconductor Peoria - Darby 69 kV line - 6/1/2014 - $0.00M
9) Baseline Upgrade b1570.2
   - Add / reconductor Peoria - Union REA 69 kV line - 6/1/2014 - $0.00M
10) Baseline Upgrade b1570.3
   - Reconductor Union REA - Honda MT 69 kV line - 6/1/2014 - $0.00M
11) Baseline Upgrade b1572
   - Construct a new 138 kV line from West Milton to Eldean - 6/1/2014 - $16.00M
12) Baseline Upgrade b1696
   - Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV - 5/1/2016 - $159.00M
13) Baseline Upgrade b1696.1
   - Replace the Idylwood 230 kV '25112' breaker with 50 kA breaker - 6/1/2017 - $0.35M

14) Baseline Upgrade b1696.2

- Replace the Idylwood 230 kV ’209712’ breaker with 50 kA breaker - 6/1/2017 - $0.35M

15) Baseline Upgrade b2003

- Construct a Whippany to Montville 230 kV line (6.4 miles) - 6/1/2015 - $80.60M

16) Baseline Upgrade b2220

- Install two 115 kV breakers at Chestnut Hill and remove sag limitations on the Pumphrey - Frederick Rd 115 kV circuits 110527 and 110528 to obtain a 125 deg. Celsius rating (161/210 MVA) - 6/1/2017 - $10.30M

17) Baseline Upgrade b2257

- Rebuild the Pokagon - Corey 69 kV line as a double circuit 138 kV line with one side at 69 kV and the other side as an express circuit between Pokagon and Corey stations - 6/1/2017 - $84.70M

18) Baseline Upgrade b2361

- Construct a 230kV UG line approx. 4.5 miles from Idylwood to Tysons. Tysons Substation will be rebuilt, within its existing footprint, with a 6-breaker ring bus using GIS equipment. - 6/1/2017 - $181.79M

19) Baseline Upgrade b2396.1

- Install a tie breaker at Mays Chapel 115 kV substation - 6/1/2018 - $5.83M

20) Baseline Upgrade b2436.90

- Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades - 6/1/2015 - $40.21M

21) Baseline Upgrade b2496

- Replace Franklin 115/34.5 kV transformer #2 with 90 MVA transformer - 6/1/2015 - $3.00M

22) Baseline Upgrade b2501.4

- Build 2 new 69 kV exits to reinforce 69 kV facilities and upgrade conductor between Irish Run 69 kV Switch and Bowerstown 69 kV Switch - 6/1/2014 - $30.54M

23) Baseline Upgrade b2555

- Updated scope: Reconductor 0.3 miles of Tiltonsville-Windsor 138 kV into Tiltonsville station with 795 ACSS; string the vacant side of the 3.8 mile middle section using 556 ACSR and operate in a six wire configuration; rebuild the 0.9 mile section crossing from Ohio into the Windsor station in West Virginia, using 795 ACSS. - 6/1/2019 - $2.00M

24) Baseline Upgrade b2568

- Reconductor Northwest – Northwest #2 115kV 110574 substation tie circuit with 2167 ACSR to achieve ratings of 400/462 MVA SN/SE - 6/1/2019 - $4.10M

25) Baseline Upgrade b2597

- Rebuild approximately 1 mi. section of Dragoon-Virgil Street 34.5 kV line between Dragoon and Dodge Tap switch and replace Dodge switch MOAB to increase thermal capability of Dragoon-Dodge Tap branch - 6/1/2019 - $2.15M

26) Baseline Upgrade b2598

- Rebuild approximately 1 mile section of the Kline-Virgil Street 34.5 kV line between Kline and Virgil Street tap. Replace MOAB switches at Beiger, risers at Kline, switches and bus at Virgil Street. - 6/1/2019 - $1.69M

27) Baseline Upgrade b2603

- Boone Area Improvements - 6/1/2019 - $43.18M

28) Baseline Upgrade b2611

- Skin Fork Area Improvements - 6/1/2019 - $25.98M

29) Baseline Upgrade b2611.1

- New 138/46 kV station near Skin Fork and other components - 6/1/2019 - $0.00M

30) Baseline Upgrade b2611.2

- Construct 3.2 miles of 1033 ACSR double circuit from new Station to cut into Sundial-Baileysville 138 kV line - 6/1/2019 - $0.11M

31) Baseline Upgrade b2626

- Rebuild the 115 kV Line No.34 (Skiffes Creek - Yorktown) and the double circuit portion of 115kV Line No.61 to current standards with a summer emergency rating of 353 MVA at 115 kV. Rebuild the 2.5 mile tap line to Fort Eustis as Double Circuit line to loop line No.34 in and out of Fort Eustis station to current standard with a summer emergency rating of 393 MVA at 115 kV. Install a 115 kV breaker in line No.34 at Fort Eustis station. - 12/31/2018 - $16.92M

32) Baseline Upgrade b2633

- Artificial Island Solution - 4/1/2019 - $0.00M

33) Baseline Upgrade b2633.91

- Implement changes to the tap settings for the two Salem units' step up transformers - 4/1/2019 - $0.01M

34) Baseline Upgrade b2633.92

- Implement changes to the tap settings for the Hope Creek unit's step up transformers - 4/1/2019 - $0.01M

35) Baseline Upgrade b2652

- Rebuild Greatbridge - Hickory 115 kV Line #16 and Greatbridge - Chesapeak E.C. to current standard with summer emergency rating of 353 MVA at 115 kV. - 12/1/2021 - $27.80M

36) Baseline Upgrade b2708

- Replace the Oceanview 230/34.5 kV transformer #1 - 6/1/2020 - $4.07M

37) Baseline Upgrade b2743.1

- Tap the Conemaugh - Hunterstown 500 kV line & create new Rice 500 kV & 230 kV stations. Install two 500/230 kV transformers, operated together. - 6/1/2020 - $43.10M

38) Baseline Upgrade b2743.2

- Tie in new Rice substation to Conemaugh-Hunterstown 500 kV - 6/1/2020 - $14.30M

39) Baseline Upgrade b2743.3

- Upgrade terminal equipment at Conemaugh 500 kV: on the Conemaugh - Hunterstown 500 kV circuit - 6/1/2020 - $0.35M

40) Baseline Upgrade b2743.4

- Upgrade terminal equipment at Hunterstown 500 kV: on the Conemaugh - Hunterstown 500 kV circuit - 6/1/2020 - $0.20M

41) Baseline Upgrade b2743.5

- Build new 230 kV double circuit line between Rice and Ringgold 230 kV, operated as a single circuit. - 6/1/2020 - $93.40M

42) Baseline Upgrade b2743.6

- Reconfigure the Ringgold 230 kV substation to double bus double breaker scheme - 6/1/2020 - $7.87M

43) Baseline Upgrade b2743.6.1

- Replace the two Ringgold 230/138 kV transformers - 6/1/2020 - $6.26M

44) Baseline Upgrade b2743.7

- Rebuild/Reconductor the Ringgold - Catoctin 138 kV circuit and upgrade terminal equipment on both ends - 6/1/2020 - $47.22M

45) Baseline Upgrade b2743.8

- Replace Ringgold Substation 138 kV breakers '138 BUS TIE' and 'RCM0' with 40 kA breakers - 6/1/2020 - $0.71M

46) Baseline Upgrade b2752.1

- Tap the Peach Bottom – TMI 500 kV line & create new Furnace Run 500 kV & 230 kV stations. Install two 500/230 kV transformers, operated together. - 6/1/2020 - $39.80M

47) Baseline Upgrade b2752.2

- Tie in new Furnace Run substation to Peach Bottom-TMI 500 kV - 6/1/2020 - $10.50M

48) Baseline Upgrade b2752.3

- Upgrade terminal equipment and required relay communication at Peach Bottom 500 kV: on the Peach Bottom - TMI 500 kV circuit - 6/1/2020 - $1.70M

49) Baseline Upgrade b2752.4

- Upgrade terminal equipment and required relay communication at TMI 500 kV: on the Peach Bottom - TMI 500 kV circuit - 6/1/2020 - $2.00M

50) Baseline Upgrade b2752.5

- Build new 230 kV double circuit line between Furnace Run and Conastone 230 kV, operated as a single circuit. - 6/1/2020 - $51.12M

51) Baseline Upgrade b2752.6

- Conastone 230 kV substation tie-in work (install a new circuit breaker at Conastone 230 kV and upgrade any required terminal equipment to terminate the new circuit) - 6/1/2020 - $6.14M

52) Baseline Upgrade b2752.7

- Reconductor/Rebuild the two Conastone - Northwest 230 kV lines and upgrade terminal equipment on both ends - 6/1/2020 - $52.14M

53) Baseline Upgrade b2752.8

- Replace the Conastone 230kV '2322 B5' breaker with a 63kA breaker - 6/1/2020 - $1.51M

54) Baseline Upgrade b2752.9

- Replace the Conastone 230kV '2322 B6' breaker with a 63kA breaker - 6/1/2020 - $1.51M

55) Baseline Upgrade b2753.7

- Retire line sections (Dilles Bottom - Bellaire and Moundsville - Dilles Bottom 69 kV lines) south of First Energy 138 kV line corridor, near “Point A”. Tie George Washington - Moundsville 69 kV circuit to George Washington - West Bellaire 69 kV circuit. - 5/31/2020 - $5.52M

56) Baseline Upgrade b2759

- Rebuild Line #550 Mt. Storm – Valley 500kV - 6/1/2016 - $410.00M

57) Baseline Upgrade b2760

- Perform a Sag Study of the Saltville - Tazewell 138 kV line to increase the thermal rating of the line - 6/1/2021 - $0.10M

58) Baseline Upgrade b2761.1

- Replace and relocate the Hazard 161/138 kV Transformer and circuit breaker 'M'. Upgrade protection scheme on the new Transformer including installation of low side breaker. - 6/1/2021 - $2.30M

59) Baseline Upgrade b2765

- Upgrade bus conductor at Gardners 115 kV substation; Upgrade bus conductor and adjust CT ratios at Carlisle Pike 115 kV - 6/1/2021 - $1.20M

60) Baseline Upgrade b2767

- Install one new 345 kV breaker and relocate the Homer City-Mainesburg 345 kV line terminal and Homer City 345/230 kV North transformer terminal - 6/1/2021 - $5.40M

61) Baseline Upgrade b2777

- Reconductor the entire Dequine - Eugene 345 kV circuit #1 - 6/1/2021 - $22.19M

62) Baseline Upgrade b2779.4

- Loop the 138 kV circuits in-and-out of the new SDI Varner station, resulting in a direct circuit to Auburn, Sowers and Wilmington. String approximately 3 miles of the open side of circuit between Collingwood and Dunton Lake with new conductor, thus establishing a second 345 kV feed (utilizing 9 miles of existing 138 kV feed constructed as 345 kV) - 6/1/2016 - $0.00M

63) Baseline Upgrade b2779.6

- Construct a 345 kV ring bus at Dunton Lake to serve SDI load at 345 kV via two circuits - 6/1/2016 - $23.40M

64) Baseline Upgrade b2779.7

- Retire Collingwood 345 kV station - 6/1/2016 - $1.40M

65) Baseline Upgrade b2791

- Rebuild Tiffin-Howard, new transformer at Chatfield - 6/1/2021 - $20.39M

66) Baseline Upgrade b2791.3

- New 138/69kV transformer with 138kV & 69kV protection at Chatfield station. - 6/1/2021 - $0.00M

67) Baseline Upgrade b2791.4

- New 138kV & 69kV protection at existing Chatfield transformer. - 6/1/2021 - $2.50M

68) Baseline Upgrade b2793

- Energize the spare Fremont Center 138/69 kV 130 MVA transformer #3. Reduces overloaded facilities to 46% loading. - 6/1/2021 - $1.30M

69) Baseline Upgrade b2794

- Construct new 138/69/34 kV station and one(1)34 kV circuit (designed for 69 kV) from new station to Decliff station, approximately 5.5 miles, with 556 ACSR conductor (51 MVA rating). - 6/1/2021 - $28.90M

70) Baseline Upgrade b2821

- Replace Morse 138 kV breakers '103', '104', '105', and '106' with 63 kA breakers - 6/1/2019 - $4.00M

71) Baseline Upgrade b2832

- Six wire the Kyger Creek to Sporn 345 kV circuits #1 and #2 and convert them to one circuit and replace structures outside of the Kyger Creek station to complete the six-wire scope. - 12/1/2021 - $0.30M

72) Baseline Upgrade b2833

- Reconductor the Maddox Creek - East Lima 345 kV circuit with 2-954 ACSS Cardinal conductor - 12/1/2021 - $18.20M

73) Baseline Upgrade b2834

- Reconductor and string open position and sixwire 6.2 miles of the Chemical - Capitol Hill 138 kV circuit - 12/1/2021 - $7.30M

74) Baseline Upgrade b2838

- Build a new 230/69 kV substation by tapping the Montour - Susquehanna 230 kV double circuits and Berwick - Hunlock & Berwick - Colombia 69 kV circuits - 6/1/2017 - $57.00M

75) Baseline Upgrade b2881

- Rebuild ~1.7 miles of the Dunn Hollow – London 46kV line section utilizing 795 26/7 ACSR conductor (58 MVA rating, non-conductor limited, 55%). - 6/1/2021 - $4.00M

76) Baseline Upgrade b2883

- Rebuild the Craneco – Pardee – Three Forks – Skin Fork 46kV line section (approximately 7.2 miles) utilizing 795 26/7 ACSR conductor (108 MVA rating, 43%) - 6/1/2021 - $16.60M

77) Baseline Upgrade b2889.2

- Retire Byllesby – Wythe 69 kV line: 13.77 miles of 1/0 CU (~4 miles currently in national forest). - 6/1/2021 - $0.00M

78) Baseline Upgrade b2889.3

- Retire 13.53 miles of Galax–Wythe 69 kV line (1/0 CU section) 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 69 kV, creating a new Galax – Byllesby 69 kV circuit. - 6/1/2021 - $0.00M

79) Baseline Upgrade b2889.5

- Install one 138/69 kV (90 MVA) transformer, one 138 kV circuit switcher, two 138 kV (40kA 3000A) breakers, establish a 69 kV bus, install three 69 kV(40kA 3000A) breakers at Jubal Early station - 6/1/2021 - $0.00M

80) Baseline Upgrade b2891

- Rebuild the Midland Switch to East Findlay 34.5 kV line (3.31 miles) with 795 ACSR (63 MVA rating) to match other conductor in the area. - 6/1/2021 - $13.40M

81) Baseline Upgrade b2900

- Build a new 230-115kV switching station connecting to 230kV network Line #2014 (Earleys – Everetts). Provide a 115kV source from the new station to serve Windsor DP. - 12/30/2022 - $15.50M

82) Baseline Upgrade b2902

- Rebuild the Brodhead - Three Links Jct. 69 kV line section (8.2 miles) using 556.5 MCM ACTW wire. - 12/1/2018 - $5.33M

83) Baseline Upgrade b2914

- Rebuild Tharp Tap-KU Elizabethtown 69kV line section to 795 MCM (2.11 miles). - 12/1/2024 - $1.22M

84) Baseline Upgrade b2921

- New TVA 161kV 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 161kV switching station at point of interconnection with TVA. - 6/1/2018 - $20.20M

85) Baseline Upgrade b2932

- Replace terminal equipment at Tanners Creek on Tanners Creek Dearborn 345 kV line. - 6/1/2021 - $1.50M

86) Baseline Upgrade b2933

- Third Source for Springfield Rd. and Stanley Terrace Stations - 6/1/2018 - $0.00M

87) Baseline Upgrade b2933.31

- Construct a 69 kV network between Front Street, Springfield and Stanley Terrace (Front Street - Springfield) - 6/1/2018 - $39.66M

88) Baseline Upgrade b2935

- Third Supply for Runnemede 69kV and Woodbury 69kV - 6/1/2018 - $90.60M

89) Baseline Upgrade 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 - $0.00M

90) Baseline Upgrade b2935.2

- Build a new line between Hilltop and Woodbury 69 kV providing the 3rd supply - 6/1/2018 - $0.00M

91) Baseline Upgrade b2937

- Replace the existing 636 ACSR 138 kV Bus at Fletchers Ridge with a larger 954 ACSR conductor. - 6/1/2022 - $0.63M

92) Baseline Upgrade b2938

- Perform a sag mitigations on the Broadford – Wolf Hills 138kV circuit to allow the line to operate to a higher maximum temperature. - 6/1/2022 - $2.60M

93) Baseline Upgrade b2940

- Upgrade the distance relay on the Wayne Co – Wayne Co KY 161kV line to increase the line winter rating would be 167/167 - 12/1/2022 - $0.00M

94) Baseline Upgrade b2945.1

- Rebuild the BL England – Middle Tap 138kV line to 2000A on double circuited steel poles and new foundations - 6/1/2022 - $52.20M

95) Baseline Upgrade b2945.2

- Re-conductor BL England – Merion 138kV (1.9miles) line - 6/1/2022 - $3.73M

96) Baseline Upgrade b2945.3

- Re-conductor Merion – Corson 138kV (8miles) line - 6/1/2022 - $8.36M

97) Baseline Upgrade b2946

- Convert existing Preston 69 kV Substation to DPL’s current design standard of a 3-breaker ring bus. - 6/1/2022 - $8.00M

98) Baseline Upgrade b2947.1

- Upgrade terminal equipment at DPL's Naamans Substation (Darley-Naamans 69 kV) - 6/1/2022 - $0.15M

99) Baseline Upgrade b2947.2

- Re-conductor 0.11 mile section of Darley-Naamans 69 kV circuit - 6/1/2022 - $0.20M

100) Baseline Upgrade b2948

- Upgrade terminal equipment at DPL's Silverside Road Substation (Dupont Edge Moor – Silver R. 69 kV) - 6/1/2022 - $0.15M

101) Baseline Upgrade b2950

- Upgrade limiting 115 kV switches on the 115 kV side of the 230/115 kV Northwood substation and adjust setting on limiting ZR relay - 6/1/2022 - $0.25M

102) Baseline Upgrade b2952

- Replace the North Meshoppen #3 230/115kV transformer eliminating the old reactor and installing two breakers to complete a 230kV ring bus at North Meshoppen - 6/1/2022 - $11.60M

103) Baseline Upgrade b2961

- Rebuild approximately 3 miles of Line #205 & Line #2003 from Chesterfield to and including 4 structures past Tyler Sub. - 12/31/2022 - $11.07M

104) Baseline Upgrade b2963

- Reconductor the Woodbridge to Occoquan 230kV line segment of Line 2001 with 1047 MVA conductor and replace line terminal equipment at Possum Point, Woodbridge, and Occoquan - 6/1/2022 - $4.70M

105) Baseline Upgrade b2964.1

- Replace terminal equipment at Pruntytown and Glen Falls 138 kV station. - 6/1/2022 - $0.00M

106) Baseline Upgrade b2964.2

- Reconductor approximately 8.3 miles of the McAlpin - White Hall Junction 138 kV circuit - 6/1/2022 - $13.25M

107) Baseline Upgrade 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 - $6.96M

108) Baseline Upgrade b2969

- Replace terminal equipment on Maddox Creek - East Lima 345kV circuit - 6/1/2022 - $1.48M

109) Baseline Upgrade b2970

- Ringgold - Catoctin Solution - 6/1/2020 - $0.00M

110) Baseline Upgrade b2970.1

- Install two new 230 kV positions at Ringgold for 230/138 kV transformers. - 6/1/2020 - $3.20M

111) Baseline Upgrade b2970.2

- Install new 230 kV position for the Catoctin 230 kV line at Ringgold. - 6/1/2020 - $1.60M

112) Baseline Upgrade b2970.3

- Install one new 230 kV breaker at Catoctin substation. - 6/1/2020 - $7.60M

113) Baseline Upgrade b2970.4

- Install new 230 / 138 kV transformer at Catoctin substation. Convert Ringgold-Catoctin 138 kV Line to 230 kV operation. - 6/1/2020 - $0.90M

114) Baseline Upgrade b2970.5

- Convert Garfield 138/12.5 kV substation to 230/12.5 kV - 6/1/2020 - $2.20M

115) Baseline Upgrade b2977

- Portion of 2017_1-6A - 6/1/2021 - $9.17M

116) Baseline Upgrade b2977.3

- Install new 345KV breaker B and move the Buffington-Pierce 345kV feeder to the B-C junction. Install a new tower at the first tower outside the station for Buffington-Pierce 345kV line. - 6/1/2021 - $3.12M

117) Baseline Upgrade b2977.4

- Remove breaker A and move the Pierce 345/138kV transformer #17 feed to the C-D junction. - 6/1/2021 - $1.50M

118) Baseline Upgrade b2978

- Install 2-125 MVAR STATCOMs at Rawlings and 1-125 MVAR STATCOM at Clover 500 kV Substations - 5/31/2021 - $47.00M

119) Baseline Upgrade b2980

- Rebuild 115kV Line #43 between Staunton and Harrisonburg (22.8 miles) to current standards with a summer emergency rating of 261 MVA at 115kV - 10/31/2022 - $39.60M

120) Baseline Upgrade b2981

- Rebuild 115 kV Line No.29 segment between Fredericksburg and Aquia Harbor to current 230 kV standards (operating at 115 kV) utilizing steel H-frame structures with 2-636 ACSR to provide a normal continuous summer rating of 524 MVA at 115 kV (1047 MVA at 230 kV) - 12/31/2022 - $19.24M

121) Baseline Upgrade b2983

- Convert Kuller Road to a 69/13kV station - 6/1/2018 - $81.09M

122) Baseline Upgrade b2983.2

- Construct a 69kV network between Kuller Road, Passaic, Paterson, and Harvey (new Clifton area switching station). - 6/1/2018 - $0.00M

123) Baseline Upgrade b2984

- Reconfigure the bus at Glory and install a 50.4 MVAR 115 kV capacitor - 6/1/2021 - $13.46M

124) Baseline Upgrade b2985

- Replace the 230 kV CB #225 at Linwood Substation (PECO) with a double circuit breaker (back to back circuit breakers in one device). - 6/1/2022 - $1.40M

125) Baseline Upgrade b2986.1

- Roseland-Branchburg 230kV corridor rebuild - 6/1/2018 - $0.00M

126) Baseline Upgrade b2986.11

- Roseland-Branchburg 230kV corridor rebuild (Roseland - Readington) - 6/1/2018 - $289.04M

127) Baseline Upgrade b2986.12

- Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) - 6/1/2018 - $64.93M

128) Baseline Upgrade b2986.2

- Branchburg-Pleasant Valley 230kV corridor rebuild - 6/1/2018 - $0.00M

129) Baseline Upgrade b2986.22

- Branchburg-Pleasant Valley 230kV corridor rebuild (East Flemington - Pleasant Valley) - 6/1/2018 - $102.45M

130) Baseline Upgrade b2986.23

- Branchburg-Pleasant Valley 230kV corridor rebuild (Pleasant Valley - Rocktown) - 6/1/2018 - $18.92M

131) Baseline Upgrade b2986.24

- Branchburg-Pleasant Valley 230kV corridor rebuild (the PSEG portion of Rocktown - Buckingham) - 6/1/2018 - $4.30M

132) Baseline Upgrade b2987

- Install a 30 MVAR capacitor bank at DPL's Cool Springs 69 kV Substation. The capacitor bank would be installed in two separate 15 MVAR stages allowing DPL operational flexibility - 6/1/2022 - $3.00M

133) Baseline Upgrade b2996

- New Flint Run 500-138 kV substation - 6/1/2019 - $0.00M

134) Baseline Upgrade b2996.2

- Loop the Belmont-Harrison 500 kV line into and out of the new Flint Run 500 kV substation (less than 1 mile). Replace primary relaying and carrier sets on Belmont and Harrison 500 kV Remote End Substations. - 6/1/2019 - $16.60M

135) Baseline Upgrade b3004

- Construct a 230/69/13kV station by tapping the Mercer - Kuser Rd 230kV circuit - 6/1/2018 - $65.40M

136) Baseline Upgrade b3004.4

- Install 18 MVAR capacitor bank at Clinton Ave 69 kV - 6/1/2018 - $0.00M

137) Baseline Upgrade b3005

- Reconductor 3.1 mile 556 ACSR portion of Cabot to Butler 138 kV with 556 ACSS and upgrade terminal equipment. 3.1 miles of line will be reconductored for this project. The total length of the line is 7.75 miles. - 6/1/2021 - $5.88M

138) Baseline Upgrade b3006

- Replace four Yukon 500/138 kV transformers with three transformers with higher rating and reconfigure 500 kV bus - 6/1/2021 - $101.21M

139) Baseline Upgrade b3007.1

- Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - AP portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Social Hall, meters, relays, bus conductor, a wavetrap, circuit breaker and disconnects will be replaced. - 6/1/2021 - $4.42M

140) Baseline Upgrade b3007.2

- Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - PENELEC portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Blairsville East, the wave trap and breaker disconnects will be replaced. - 6/1/2021 - $7.00M

141) Baseline Upgrade b3010

- Replace terminal equipment at Keystone and Cabot 500 kV buses. At Keystone, bus tubing and conductor, a wavetrap, and meter will be replaced. At Cabot, a wavetrap and bus conductor will be replaced. - 6/1/2021 - $0.78M

142) Baseline Upgrade b3011.1

- Construct new Route 51 substation and connect 10 138 kV lines to new substation - 6/1/2021 - $36.34M

143) Baseline Upgrade b3011.6

- Upgrade remote end relays for Yukon –Allenport – Iron Bridge 138 kV line - 6/1/2021 - $1.97M

144) Baseline Upgrade b3012.1

- Construct two new 138 kV ties with the single structure from APS's new substation to DUQ's new substation. The estimated line length is approximately 4.7 miles. The line is planned to use multiple ACSS conductors per phase. - 6/1/2021 - $23.10M

145) Baseline Upgrade b3012.3

- Construct a new Elrama - Route 51 138 kV No.3 line: reconductor 4.7 miles of the existing line, and construct 1.5 miles of a new line to the reconductored portion. Install a new line terminal at APS Route 51 substation. - 6/1/2020 - $18.10M

146) Baseline Upgrade b3013

- Reconductor Vasco Tap to Edgewater Tap 138 kV line. 4.4 miles. The new conductor will be 336 ACSS replacing the existing 336 ACSR conductor. - 6/1/2021 - $5.88M

147) Baseline Upgrade b3014

- Replace the existing Shelocta 230/115 kV transformer and construct a 230 kV ring bus - 6/1/2021 - $7.35M

148) Baseline Upgrade b3015.8

- Upgrade terminal equipment at Mitchell for Mitchell – Elrama 138 kV line - 6/1/2021 - $2.00M

149) Baseline Upgrade b3017.1

- Rebuild Glade to Warren 230 kV line with hi-temp conductor and substation terminal upgrades. 11.53 miles. New conductor will be 1033 ACSS. Existing conductor is 1033 ACSR. - 6/1/2021 - $42.40M

150) Baseline Upgrade b3017.2

- Glade substation terminal upgrades. Replace bus conductor, wave traps, and relaying. - 6/1/2021 - $0.05M

151) Baseline Upgrade b3017.3

- Warren substation terminal upgrades. Replace bus conductor, wave traps, and relaying. - 6/1/2021 - $0.05M

152) Baseline Upgrade b3019

- Rebuild 500kV Line #552 Bristers to Chancellor – 21.6 miles long - 6/1/2018 - $62.15M

153) Baseline Upgrade b3019.1

- Update the nameplate for Morrisville 500 kV breaker "H1T594" to be 50 kA - 6/1/2018 - $0.00M

154) Baseline Upgrade b3019.2

- Update the nameplate for Morrisville 500 kV breaker "H1T545" to be 50 kA - 6/1/2018 - $0.00M

155) Baseline Upgrade b3020

- Rebuild 500kV Line #574 Ladysmith to Elmont - 26.2 miles long - 6/1/2018 - $91.32M

156) Baseline Upgrade b3021

- Rebuild 500kV Line #581 Ladysmith to Chancellor - 15.2 miles long - 6/1/2018 - $44.38M

157) Baseline Upgrade b3023

- Replace West Wharton 115kV breakers 'G943A' and 'G943B' with 40kA breakers - 6/1/2020 - $0.50M

158) Baseline Upgrade b3025

- Construct two (2) new 69/13kV stations in the Doremus area and relocate the Doremus load to the new stations - 6/1/2018 - $155.00M

159) Baseline Upgrade b3025.1

- Install a new 69/13 kV station (Vauxhall) with a ring bus configuration - 6/1/2018 - $0.00M

160) Baseline Upgrade b3025.2

- Install a new 69/13 kV station (area of 19th Ave) with a ring bus configuration - 6/1/2018 - $0.00M

161) Baseline Upgrade b3025.3

- Construct a 69kV network between Stanley Terrace, Springfield Road, McCarter, Federal Square, and the two new stations (Vauxhall & area of 19th Ave) - 6/1/2018 - $0.00M

162) Baseline Upgrade b3026

- Re-conductor the entire 230 kV Line No.274 (Pleasant View – Ashburn – Beaumeade) using a higher capacity conductor with an approximate rating of 1572 MVA. - 6/1/2021 - $10.00M

163) Baseline Upgrade b3029

- Install 69 kV underground transmission line from Harings Corner Station terminating at Closter Station (about 3 miles). - 5/31/2020 - $22.00M

164) Baseline Upgrade b3029.1

- Reconfigure Closter Station to accommodate the UG transmission line from Harings Corner Station - 5/31/2020 - $0.00M

165) Baseline Upgrade b3029.2

- Loop in the existing 751 Line (Sparkill - Cresskill 69 kV) into Closter 69 kV station - 5/31/2020 - $0.00M

166) Baseline Upgrade b3031

- Transfer load off of the Leroy Center-Mayfield Q2 138 kV line by reconfiguring the Pawnee Substation primary source, via the existing switches, from the Leroy Center-Mayfield Q2 138 kV line to the Leroy Center-Mayfield Q1 138 kV line. - 6/1/2021 - $0.10M

167) Baseline Upgrade b3033

- Ottawa-Lakeview 138 kV Reconductor and Substation Upgrades - 12/1/2023 - $20.00M

168) Baseline Upgrade b3034

- Lakeview-Greenfield 138 kV Reconductor and Substation Upgrades - 12/1/2023 - $4.80M

169) Baseline Upgrade b3037

- Upgrades at the Natrium substation - 6/1/2023 - $1.10M

170) Baseline Upgrade b3039

- Line Swaps at Muskingum 138 kV Station - 12/1/2023 - $0.10M

171) Baseline Upgrade b3040.2

- Rebuild existing Ripley - Ravenswood 69 kV circuit (~9 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor - 6/1/2022 - $23.60M

172) Baseline Upgrade b3041

- Peach Bottom - Furnace Run 500kV Terminal Equipment - 6/1/2021 - $3.50M

173) Baseline Upgrade b3042

- Replace substation conductor at Raritan River 230 kV substation on the Kilmer line terminal - 6/1/2023 - $0.05M

174) Baseline Upgrade b3043

- Install one 115 kV 36 MVAR capacitor at Westfall 115 kV substation - 6/1/2023 - $3.20M

175) Baseline Upgrade b3050

- Install redundant relay to Port Union 138 kV Bus#2 - 6/1/2023 - $0.39M

176) Baseline Upgrade b3052

- Install a 138 kV capacitor (29.7 MVAR effective) at West Winchester 138 kV. - 6/1/2018 - $2.61M

177) Baseline Upgrade b3053

- Upgrade terminal equipment on Gibson - Petersburg 345kV - 10/29/2018 - $4.30M

178) Baseline Upgrade b3054

- Install a battery storage device at Grasonville Substation * Rebuild Wye Mills - Stevensville 69 kV Line * Construct a new 69 kV line from Wye Mills to Grasonville. - 12/1/2023 - $0.00M

179) Baseline Upgrade b3055

- Install spare 230/69 kV transformer at Davis Substation - 6/1/2023 - $0.54M

180) Baseline Upgrade b3056

- Partial Rebuild 230 kV Line #2113 Waller to Lightfoot - 6/1/2018 - $9.00M

181) Baseline Upgrade b3057

- Rebuild 6.1 miles of Waller-Skiffess Creek 230 kV Line (#2154) between Waller and Kings Mill to current standards with a minimum summer emergency rating of 1047 MVA utilizing single circuit steel structures. Remove this 6.1 mile section of Line #58 between Waller and Kings Mill. Rebuild the 1.6 miles of Line #2154 and #19 between Kings Mill and Skiffes Creek to current standards with a minimum summer emergency rating of 1047 MVA at 230 kV for Line #2154 and 261 MVA at 115 kV for Line #19, utilizing double circuit steel structures. - 6/1/2018 - $18.36M

182) Baseline Upgrade b3058

- Partial Rebuild of 230 kV lines between Clifton and Johnson DP (#265, #200 and #2051) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA. - 6/1/2018 - $11.50M

183) Baseline Upgrade b3059

- Rebuild Line #2173 Loudoun to Elklick - 12/31/2022 - $13.50M

184) Baseline Upgrade b3060

- Rebuild 4.6 mile Elk Lick-Bull Run 230 kV Line (#295) and the portion (3.85 miles) of the Clifton-Walney 230kV Line (#265) which shares structures with line #295 - 10/30/2018 - $15.50M

185) Baseline Upgrade b3064.3

- Upgrade line relaying at Piney Fork and Bethel Park for Piney Fork – Elrama 138 kV line and Bethel Park – Elrama 138 kV line. - 6/1/2021 - $0.60M

186) Baseline Upgrade b3066

- Reconductor the Cranberry - Jackson 138 kV line (2.1 miles), reconductor 138 kV bus at Cranberryand replace 138 kv line switches at Jackson - 6/1/2022 - $2.90M

187) Baseline Upgrade b3067

- Reconductor the Jackson - Maple 138 kV line (4.7 miles), replace line switches at Jackson 138 kV and replace the line traps and relays at Maple 138 kV - 6/1/2022 - $7.10M

188) Baseline Upgrade b3068

- Reconductor the Yukon - Westraver 138 kV line (2.8 miles), replace the line drops and relays at Yukon 138 kV and replace switches at Westraver 138 kV - 6/1/2022 - $2.50M

189) Baseline Upgrade b3069

- Reconductor the Westraver - Route 51 138 kV line (5.63 miles) and replace line switches at Westraver 138 kV - 6/1/2022 - $7.50M

190) Baseline Upgrade b3070

- Reconductor the Yukon - Route 51 #1 138 kV line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV - 6/1/2022 - $10.00M

191) Baseline Upgrade b3071

- Reconductor the Yukon - Route 51 #2 138 kV line (8 miles) and replace relays at Yukon 138 kV - 6/1/2022 - $10.00M

192) Baseline Upgrade b3072

- Reconductor the Yukon - Route 51 #3 138 kV line (8 miles) and replace relays at Yukon 138 kV - 6/1/2022 - $10.00M

193) Baseline Upgrade b3073

- Replace the Blairsville East 138/115 kV transformer and associated equipment such as breaker disconnects and bus conductor - 6/1/2022 - $2.10M

194) Baseline Upgrade b3074

- Replace Substation conductor on the 345/138 kV transformer at Armstrong substation - 6/1/2022 - $0.10M

195) Baseline Upgrade b3075

- Replace substation conductor and 138 kV circuit breaker on the #1 transformer (500/138 kV) at Cabot substation - 6/1/2022 - $0.30M

196) Baseline Upgrade b3076

- Reconductor the Edgewater - Loyalhanna 138 kV line (0.67 miles) - 6/1/2022 - $2.00M

197) Baseline Upgrade b3077

- Reconductor the Franklin Pike - Wayne 115 kV line (6.78 miles) - 6/1/2022 - $11.40M

198) Baseline Upgrade b3078

- Reconductor 138 kV bus and replace the line trap, relays at Morgan Street. Reconductor 138 kV bus at Venango Junction - 6/1/2022 - $1.00M

199) Baseline Upgrade b3079

- Replace the Wylie Ridge 500/345 kV transformer #7 - 6/1/2022 - $6.37M

200) Baseline Upgrade b3080

- Reconductor 138 kV bus at Seneca - 6/1/2022 - $0.07M

201) Baseline Upgrade b3081

- Replace 138 kV breaker and substation conductor at Krendale - 6/1/2022 - $0.30M

202) Baseline Upgrade b3082

- Construct a 4-breaker 115 kV ring bus at Franklin Pike - 6/1/2022 - $8.00M

203) Baseline Upgrade b3083

- Replace substation conductor at Butler (138 kV) Replace substation conductor and line trap at Karns City (138 kV) - 6/1/2022 - $0.20M

204) Baseline Upgrade b3085

- Reconductor Kammer - George Washington 138 kV line (~0.08 miles). Replace the wave trap at Kammer 138 kV. - 6/1/2022 - $0.50M

205) Baseline Upgrade b3086.1

- Rebuild New Liberty – Findlay 34 kV Line Str's 1 – 37 (1.5 miles), utilizing 795 26/7 ACSR conductor - 6/1/2022 - $3.40M

206) Baseline Upgrade b3086.2

- Rebuild New Liberty – North Baltimore 34 kV Line Str's 1-11 (0.5 miles), utilizing 795 26/7 ACSR conductor - 6/1/2022 - $1.80M

207) Baseline Upgrade b3086.4

- North Findlay Station: Install a 138 kV 3000 A 63 kA line breaker and low side 34.5 kV 2000 A 40 kA breaker, high side 138 kV circuit switcher on T1 - 6/1/2022 - $1.70M

208) Baseline Upgrade b3086.5

- Ebersole Station: Install second 90 MVA 138/69/34 kV transformer. Install two low side (69 kV) 2000A 40kA breakers for T1 and T2. - 6/1/2022 - $3.75M

209) Baseline Upgrade b3087.1

- Construct a new greenfield station to the west (~1.5 mi.) of the existing Fords Branch Station potentially in/near the new Kentucky Enterprise Industrial Park. . This new station will consist of 4 -138 kV breaker ring bus and two 30 MVA 138/34.5 kV transformers. The existing Fords Branch Station will be retired. - 12/1/2018 - $3.40M

210) Baseline Upgrade b3087.2

- Construct approximately 5 miles of new double circuit 138 kV line in order to loop the new Fords Branch station into the existing Beaver Creek – Cedar Creek 138 kV circuit. - 12/1/2018 - $19.90M

211) Baseline Upgrade b3087.3

- Remote end work will be required at Cedar Creek Station. - 12/1/2018 - $0.50M

212) Baseline Upgrade b3087.4

- Install 28.8MVar switching shunt at the new Fords Branch substation - 12/1/2023 - $0.50M

213) Baseline Upgrade b3089

- Rebuild 230kV Line #224 between Lanexa and Northern Neck utilizing double circuit structures to current 230kV standards. Only one circuit is to be installed on the structures with this project with a minimum summer emergency rating of 1047 MVA. - 6/1/2018 - $86.00M

214) Baseline Upgrade b3090

- Convert the OH portion (approx. 1500 Feet) of 230 kV Lines #248 & #2023 to UG and convert Glebe substation to GIS. - 1/1/2021 - $120.00M

215) Baseline Upgrade b3094

- Move 69 kV 12.0 MVAR capacitor bank from Greenbriar to Bullitt Co 69kV substation - 6/1/2018 - $0.40M

216) Baseline Upgrade b3095

- Rebuild Lakin – Racine Tap 69 kV line section (9.2 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor - 12/1/2022 - $23.90M

217) Baseline Upgrade b3096

- Rebuild 230 kV line No.2063 (Clifton – Ox) and part of 230 kV line No.2164 (Clifton – Keene Mill) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA. - 6/1/2019 - $22.00M

218) Baseline Upgrade b3098

- Rebuild 9.8 miles of 115kV Line #141 between Balcony Falls and Skimmer and 3.8 miles of 115kV Line #28 between Balcony Falls and Cushaw to current standards with a minimum rating of 261 MVA. - 6/1/2019 - $30.90M

219) Baseline Upgrade b3098.1

- Rebuild Balcony Falls Substation - 6/1/2019 - $9.00M

220) Baseline Upgrade b3099

- Install a 138 kV 3000A 40 kA circuit switcher on the high side of the existing 138/34.5 kV transformer #5 and a 138 kV 3000A 40 kA circuit switcher transformer #7 at Holston station - 6/1/2022 - $0.70M

221) Baseline Upgrade b3100

- Relocate 138 kV circuit breaker W between 138 kV bus #1 extension and bus #2 at Chemical station. Install a new 138 kV circuit breaker between bus #1 and bus #1 extension. - 12/1/2022 - $0.70M

222) Baseline Upgrade b3101

- Rebuild the 1/0 Cu. conductor sections (~1.5 miles) of the Fort Robinson - Moccasin Gap 69 kV line section (~5 miles) utilizing 556 ACSR conductor and upgrade existing relay trip limit (WN/WE: 63 MVA , line limited by remaining conductor sections). - 12/1/2023 - $3.00M

223) Baseline Upgrade b3103.3

- Retire 138 kV breaker L at Delaware station and re-purpose 138 kV breaker M for the Jay line. - 6/1/2022 - $0.18M

224) Baseline Upgrade b3103.4

- Retire all 34.5 kV equipment at Hartford City station. Re-purpose breaker M for the Bosman line 69 kV exit. - 6/1/2022 - $0.88M

225) Baseline Upgrade b3103.5

- Rebuild the 138 kV portion of Jay station as a 6 breaker, breaker and a half station re-using the existing breakers “A”, “B” and “G”. Rebuild the 69 kV portion of this station as a 6 breaker ring bus re-using the 2 existing 69 kV breakers. Install a new 138/69kV transformer. - 6/1/2022 - $18.73M

226) Baseline Upgrade b3103.6

- Rebuild the 69 kV Hartford City – Armstrong Cork line but instead of terminating it into Armstrong Cork, terminate it into Jay station. - 6/1/2022 - $21.12M

227) Baseline Upgrade b3103.7

- Build a new 69 kV line from Armstrong Cork – Jay station. - 6/1/2022 - $2.35M

228) Baseline Upgrade b3104

- Perform a sag study on the Polaris - Westerville 138 kV line (~ 3.6 miles) to increase the Summer Emergency rating to 310 MVA. - 6/1/2020 - $0.50M

229) Baseline Upgrade b3108.1

- Install 100 MVAR reactor at Miami 138 kV substation - 6/1/2019 - $5.00M

230) Baseline Upgrade b3108.2

- Install 100 MVAR reactor at Sugarcreek 138 kV substation - 6/1/2019 - $5.00M

231) Baseline Upgrade b3108.3

- Install 100 MVAR reactor at Hutchings 138 kV substation - 6/1/2019 - $5.00M

232) Baseline Upgrade b3109

- Rebuild 5.2 mile Bethel-Sawmill 138 kV line including ADSS. - 6/1/2019 - $34.50M

233) Baseline Upgrade b3110.1

- Rebuild Line #2008 between Loudoun to Dulles Junction using single circuit conductor at current 230 kV northern Virginia standards with minimum summer ratings of 1200 MVA. Cut and loop Line #265 (Clifton – Sully) into Bull Run Substation. Add three (3) 230 kV breakers at Bull Run to accommodate the new line and upgrade the substation. - 6/1/2019 - $14.00M

234) Baseline Upgrade b3110.2

- Replace the Bull Run 230 kV breakers “200T244” and “200T295” with 50 kA breakers. - 6/1/2019 - $0.54M

235) Baseline Upgrade b3110.3

- Replace the Clifton 230kV breakers “201182” and “XT2011” with 63kA breakers - 12/31/2021 - $0.93M

236) Baseline Upgrade b3112

- Construct a single circuit 138 kV line (~3.5 miles) from Amlin to Dublin using 1033 ACSR Curlew (296 MVA SN), convert Dublin Station into a ring configuration, and re-terminating the Britton UG cable to Dublin Station. - 6/1/2020 - $39.29M

237) Baseline Upgrade b3114

- Rebuild the 18.6 mile section of 115kV Line #81 which includes 1.7 miles of double circuit Line #81 with 230kV Line #2056 and 1.3 miles of double circuit Line #81 with 230kV Line

#239. This segment of Line #81 will be rebuilt to current standards with a minimum rating of 261 MVA. This segment of Line #239 will be rebuilt to current standards with a minimum rating of 1046 MVA. Line #2056 rating will not change. - 6/1/2019 - $25.00M

238) Baseline Upgrade b3115

- Provide new station service to control building from 230 kV bus (served from plant facilities presently). - 9/30/2019 - $1.50M

239) Baseline Upgrade b3116

- Replace existing Mullens 138/46 kV 30 MVA transformer No.4 and associated protective equipment with a new 138/46 kV 90 MVA transformer and associated protective equipment. Install required high side transformer protection by replacing the existing ground switch MOAB with a new 138 kV high side circuit breaker. - 12/1/2022 - $4.00M

240) Baseline Upgrade b3118.1

- Expand existing Chadwick station and install a second 138/69 kV transformer at a new 138 kV bus tied into the Bellefonte – Grangston 138 kV circuit. The 69 kV bus will be reconfigured into a ring bus arrangement to tie the new transformer into the existing 69 kV via installation of four 3000A 63 kA 69 kV circuit breakers. - 6/1/2022 - $9.30M

241) Baseline Upgrade b3118.10

- Replace 69 kV line risers (towards Chadwick) at Leach station - 6/1/2022 - $0.10M

242) Baseline Upgrade b3118.2

- Perform 138 kV remote end work at Grangston station. - 6/1/2022 - $0.50M

243) Baseline Upgrade b3118.3

- Perform 138 kV remote end work at Bellefonte station. - 6/1/2022 - $0.50M

244) Baseline Upgrade b3118.4

- Relocate the Chadwick – Leach 69 kV circuit within Chadwick station. - 6/1/2022 - $0.50M

245) Baseline Upgrade b3118.5

- Terminate the Bellefonte – Grangston 138 kV circuit to the Chadwick 138 kV bus - 6/1/2022 - $1.10M

246) Baseline Upgrade b3118.6

- Chadwick – Tri-State #2 138 kV circuit will be reconfigured within the station to terminate into the newly established 138 kV bus #2 at Chadwick due to construability aspects. - 6/1/2022 - $0.10M

247) Baseline Upgrade b3118.7

- Reconductor Chadwick-Leach and Chadwick-England Hill 69 kV lines with 795 ACSS conductor. Perform a LiDAR survey and a sag study to confirm that the reconductored circuits would maintain acceptable clearances. - 6/1/2022 - $3.30M

248) Baseline Upgrade b3118.8

- Replace 20 kA 69 kV circuit breaker ‘F’ at South Neal station with a new 3000A 40 kA 69 kV circuit breaker. Replace line risers towards Leach station. - 6/1/2022 - $0.00M

249) Baseline Upgrade b3118.9

- Rebuild 336 ACSR portion of Leach - Miller S.S 69 kV line section (~0.3 miles) with 795 ACSS conductor. - 6/1/2022 - $1.50M

250) Baseline Upgrade b3119.1

- Rebuild the Jay – Pennville 138 kV line as double circuit 138/69 kV. Build a new 9.8 mile single circuit 69 kV line from near Pennville station to North Portland station - 6/1/2022 - $38.10M

251) Baseline Upgrade b3119.2

- Install three (3) 69 kV breakers to create the “U” string and add a low side breaker on the Jay transformer 2 - 6/1/2022 - $3.40M

252) Baseline Upgrade b3119.3

- Install two (2) 69 kV breakers at North Portland station to complete the ring and allow for the new line. - 6/1/2022 - $1.90M

253) Baseline Upgrade b3121

- Rebuild Clubhouse-Lakeview 230 kV Line #254 with single-circuit wood pole equivalent structures at the current 230 kV standard with a minimum rating of 1047 MVA. - 6/1/2019 - $23.67M

254) Baseline Upgrade b3122

- Rebuild Hathaway-Rocky Mount (Duke Energy Progress) 230 kV Line #2181 and Line #2058 with double circuit steel structures using double circuit conductor at current 230 kV standards with a minimum rating of 1047 MVA. - 6/1/2019 - $13.00M

255) Baseline Upgrade b3123

- At Sammis 345 kV station: Install a new control building in the switchyard, construct a new station access road, install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and separate all protection and controls schemes - 6/1/2022 - $8.00M

256) Baseline Upgrade b3124

- Separate metering, station power, and communication at Bruce Mansfield 345 kV station - 12/31/2020 - $0.93M

257) Baseline Upgrade b3125

- At Davis Bessie 345 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and separate all protection and controls schemes - 5/31/2020 - $1.80M

258) Baseline Upgrade b3126

- At Perry 345 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and construct a new station access road - 6/1/2021 - $0.60M

259) Baseline Upgrade b3127

- At Bay Shore 138 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and construct a new station access road. - 12/31/2021 - $1.50M

260) Baseline Upgrade b3128

- Relocate 34.5 kV lines from generating station roof R. Paul Smith 138 kV station - 12/31/2021 - $0.40M

261) Baseline Upgrade b3130

- Construct seven new 34.5 kV circuits on existing pole lines (total of 53.5 miles), Rebuild/Reconductor two 34.5 kV circuits (total of 5.5 miles) and install a 2nd 115/34.5 kV transformer (Werner) - 6/1/2016 - $223.00M

262) Baseline Upgrade b3130.1

- Construct a new 34.5 kV circuit from Oceanview to Allenhurst 34.5 kV (3.9 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

263) Baseline Upgrade b3130.10

- Install 2nd 115-34.5 kV Transformer at Werner Substation - (replaces B1690) - 6/1/2016 - $0.00M

264) Baseline Upgrade b3130.2

- Construct a new 34.5 kV circuit from Atlantic to Red Bank 34.5 kV (10.3 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

265) Baseline Upgrade b3130.3

- Construct a new 34.5 kV circuit from Freneau to Taylor Lane 34.5 kV (10.7 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

266) Baseline Upgrade b3130.4

- Construct a new 34.5 kV circuit from Keyport to Belford 34.5 kV (5.6 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

267) Baseline Upgrade b3130.5

- Construct a new 34.5 kV circuit from Red Bank to Belford 34.5 kV (5.7 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

268) Baseline Upgrade b3130.6

- Construct a new 34.5 kV circuit from Werner to Clark Street (7.3 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

269) Baseline Upgrade b3130.7

- Construct a new 34.5 kV circuit from Atlantic to Freneau (13.3 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

270) Baseline Upgrade b3130.8

- Rebuild/Reconductor the Atlantic to Camp Woods Switch Point (3.5 Miles) 34.5 kV circuit - (replaces B1690) - 6/1/2016 - $0.00M

271) Baseline Upgrade b3130.9

- Rebuild/Reconductor the Allenhurst to Elberon (2.0 Miles) 34.5 kV circuit - (replaces B1690) - 6/1/2016 - $0.00M

272) Baseline Upgrade b3131

- At East Lima and Haviland.The Haviland – East Lima 138kV line is overloaded for multiple contingencies in winter generator deliverability test and basecase analysis test. 138 kV stations, replace line relays and wavetrap on the East Lima-Haviland 138 kV facility.In addition, replace 500 MCM Cu Risers and Bus conductors at Haviland 138 kV - 12/1/2024 - $1.35M

273) Baseline Upgrade b3132

- Rebuild 3.11 miles of the LaPorte Junction – New Buffalo 69 kV line with 795 ACSR - 6/1/2022 - $12.30M

274) Baseline Upgrade b3133

- Move the existing Botkins 69 kV capacitor from the Sidney-Botkins side of the existing breaker at Botkins to the Botkins-Jackson Center side. This will keep the capacitor in-service for the loss of Sidney-Botkins. This reduces the voltage drop to less than 3% and also resolves the overload on the Blue Jacket Tap-Huntsville 69 kV line. - 6/1/2024 - $0.20M

275) Baseline Upgrade b3134

- Build a new single circuit 69 kV overhead from Kellam sub to new Bayview substation (21 miles) and create a line terminal at Belle Haven delivery point (three-breaker ring bus) - 6/1/2019 - $22.00M

276) Baseline Upgrade b3134.1

- Reconfigure the Belle Haven 69 kV bus to three-breaker ring bus and create a line terminal for the new 69 kV circuit to Bayview - 6/1/2019 - $0.00M

277) Baseline Upgrade b3134.2

- Build a new single circuit 69 kV overhead from Kellam sub to new Bayview Substation (21 miles) - 6/1/2019 - $0.00M

278) Baseline Upgrade b3135

- Install back-up relay on the 138 kV bus at Corson substation - 6/1/2019 - $0.30M

279) Baseline Upgrade b3136

- Replace bus conductor at Smith 115 kV substation - 6/1/2024 - $0.24M

280) Baseline Upgrade b3137

- Rebuild 20 miles of the East Towanda - North Meshoppen 115 kV line - 6/1/2024 - $58.60M

281) Baseline Upgrade b3138

- Move 2 MVA load from the Roxborough to Bala substation. Adjust the tap setting on the Master 138/69 kV transformer No.2 - 6/1/2024 - $0.00M

282) Baseline Upgrade b3142

- Rebuild Michigan City-Trail Creek - Bosserman 138 kV (10.7 mi) - 1/1/2023 - $33.26M

283) Baseline Upgrade b3143.1

- Reconductor the Silverside – Darley 69 kV circuit - 6/1/2024 - $1.39M

284) Baseline Upgrade b3143.2

- Reconductor the Darley – Naamans 69 kV circuit - 6/1/2024 - $2.09M

285) Baseline Upgrade b3143.3

- Replace three (3) existing 1200 A disconnect switches with 2000 A disconnect switches and install three (3) new 2000 A disconnect switches at Silverside 69 kV station - 6/1/2024 - $0.48M

286) Baseline Upgrade b3143.4

- Replace two (2) 1200 A disconnect switches with 2000 A disconnect switches, replace existing 954 ACSR and 500 SDCU stranded bus with (2) 954 ACSR stranded bus. Reconfigure four (4) CTs from 1200 A to 2000 A and install two (2) new 2000 A disconnect switches, new (2) 954 ACSR stranded bus at Naamans 69 kV station - 6/1/2024 - $0.60M

287) Baseline Upgrade b3143.5

- Replace four (4) 1200 A disconnect switches with 2000 A disconnect switces. Replace existing 954 ACSR and 1272 MCM AL stranded bus with (2) 954 ACSR stranded bus. Reconfigure eight (8) CTs from 1200 A to 2000 A and install Four (4) new 2000 A (310 MVA SE / 351 MVA WE) disconnect switches, new (2) 954 ACSR (331 MVA SE / 369 MVA WE) stranded bus at Darley 69 kV station - 6/1/2024 - $0.95M

288) Baseline Upgrade b3144

- Upgrade bus conductor and relay panels Jackson Road – Nanty Glo 46 kV SJN line - 6/1/2024 - $1.50M

289) Baseline Upgrade b3144.1

- Upgrade line relaying and substation conductor on the 46 kV Nanty Glo line exit at Jackson Road substation - 6/1/2024 - $0.00M

290) Baseline Upgrade b3144.2

- Upgrade line relaying and substation conductor on the 46 kV Jackson Road line exit at Nanty Glo substation - 6/1/2024 - $0.00M

291) Baseline Upgrade b3145

- Rebuild the Hunterstown - Lincoln 115 kV line (No.962) (~2.6 mi.). Upgrade limiting terminal equipment at Hunterstown and Lincoln. - 6/1/2023 - $7.21M

292) Baseline Upgrade b3149

- Rebuild the 2.3 mile Decatur – South Decatur 69 kV line using 556 ACSR in order to alleviate the overloads. - 6/1/2024 - $9.30M

293) Baseline Upgrade b3150

- Rebuild Ferguson 69/12 kV station in the clear as the 138/12 kV Bear station and connect it to a ~1 mile double circuit 138 kV extension from the Aviation – Ellison Rd 138 kV line to remove the load from the 69 kV line. - 6/1/2024 - $6.40M

294) Baseline Upgrade b3151.1

- Rebuild the ~30 mile Gateway – Wallen 34.5 kV circuit as the ~27 mile Gateway – Wallen 69 kV circuit. - 6/1/2024 - $43.30M

295) Baseline Upgrade b3151.10

- Rebuild the 2.5 mile Columbia – Gateway 69 kV line. - 6/1/2024 - $6.20M

296) Baseline Upgrade b3151.11

- Rebuild Columbia station in the clear as a 138/69 kV station with two (2) 138/69 kV transformers and 4-breaker ring buses on the high and low side. Station will reuse 69 kV breakers “J” & “K” and 138 kV breaker “D”. - 6/1/2024 - $15.00M

297) Baseline Upgrade b3151.12

- Rebuild the 13 mile Columbia – Richland 69 kV line. - 6/1/2024 - $29.30M

298) Baseline Upgrade b3151.13

- Rebuild the 0.5 mile Whitley – Columbia City No.1 line as 69 kV. - 6/1/2024 - $1.00M

299) Baseline Upgrade b3151.14

- Rebuild the 0.5 mile Whitley – Columbia City No.2 line as 69 kV. - 6/1/2024 - $0.70M

300) Baseline Upgrade b3151.15

- Rebuild the 0.6 mile double circuit section of the Rob Park – South Hicksville / Rob Park – Diebold Road as 69 kV - 6/1/2024 - $1.00M

301) Baseline Upgrade b3151.2

- Retire the ~3 miles Columbia – Whitley 34.5 kV line. - 6/1/2024 - $0.50M

302) Baseline Upgrade b3151.3

- At Gateway station, remove all 34.5 kV equipment and install one (1) 69 kV circuit breaker for the new Whitley line entrance. - 6/1/2024 - $1.00M

303) Baseline Upgrade b3151.4

- Rebuild Whitley as a 69 kV station with two (2) line and one (1) bus tie circuit breakers. -

6/1/2024 - $4.20M

304) Baseline Upgrade b3151.5

- Replace the Union 34.5 kV switch with a 69 kV switch structure. - 6/1/2024 - $0.60M

305) Baseline Upgrade b3151.6

- Replace the Eel River 34.5 kV switch with a 69 kV switch structure. - 6/1/2024 - $0.60M

306) Baseline Upgrade b3151.7

- Install a 69 kV Bobay switch at Woodland Station. - 6/1/2024 - $0.60M

307) Baseline Upgrade b3151.8

- Replace Carroll and Churubusco 34.5 kV stations with the 69 kV Snapper station. Snapper will have two (2) line circuit breakers, one (1) bus tie circuit breaker and a 14.4 MVAR cap bank - 6/1/2024 - $8.70M

308) Baseline Upgrade b3151.9

- Remove 34.5 kV circuit breaker "AD" at Wallen station. - 6/1/2024 - $0.30M

309) Baseline Upgrade b3152

- Reconductor the 8.4 mile section of the Leroy Center - Mayfield Q1 line between Leroy Center and Pawnee Tap to achieve a rating of at least 160 MVA / 192 MVA (SN/SE). - 6/1/2022 - $14.10M

310) Baseline Upgrade b3153

- Construct a greenfield 0.3 mile 138 kV double circuit line tapping the Beaver-Black River (ATSI) 138 kV line; Install five (5) monopole 138 kV double circuit steel structures with concrete foundations and string 1590 ACSR conductor.
  Expand the Amherst No.2 substation with the installation of three (3) 138 kV circuit breakers; one (1) 138/69/12 kV 130 MVA transformers; two (2) 69 kV circuit breaker.
  Install one (1) 69 kV breaker towards Nordson. - 6/1/2020 - $9.10M

311) Baseline Upgrade b3154

- Install one (1) 13.2 MVAR 46 kV capacitor at the Logan substation - 6/1/2024 - $1.70M

312) Baseline Upgrade b3155

- Rebuild approximately 12 miles of Wye Mills - Stevensville line to achieve needed ampacity - 12/1/2023 - $22.00M

313) Baseline Upgrade b3156

- Replace line relaying and fault detector on the Wylie Ridge terminal at Smith 138 kV Substation - 6/1/2022 - $0.85M

314) Baseline Upgrade b3157

- Replace line relaying and fault detector relaying at Messick Rd. and Morgan 138 kV substations; Replace wave trap at Morgan 138 kV substation - 12/1/2024 - $0.23M

315) Baseline Upgrade b3159

- Build a new 138/69 kV substation. Install one (1) 138 kV circuit breaker, one (1) 138/69 kV 130 MVA transformer, three (3) 69 kV circuit breakers. Build a 0.15 mile 138 kV 795 ACSR transmission line between the FE Brim 138/69 kV substation and the newly proposed AMPT substation (three steel poles). Loop the Bowling Green Sub No.5 – Bowling Green Sub No.2 69 kV lines in and out of the newly established substation. Complete the remote end terminal work at BG substations #2 and #5 to accommodate the new substation. - 6/1/2024 - $10.10M

316) Baseline Upgrade b3161.1

- Install two, 2000 Amp, 115kV line switches. Extend Reymet fence and bus to allow installation of risers to Line #53 (Chesterfield-Kevlar 115 kV). - 6/1/2024 - $3.00M

317) Baseline Upgrade b3162

- Acquire land and build a new 230 kV switching station (Stevensburg) with a 224 MVA, 230/115 kV transformer. Gordonsville-Remington 230 kV (Line #2199) will be cut and connected to the new station. Remington-Mt. Run 115 kV (Line #70) and Mt. Run-Oak Green 115 kV (Line #2) will also be cut and connected to the new station. - 6/1/2024 - $22.00M

318) Baseline Upgrade b3208

- Retire approximately 38 miles of the 44 mile Clifford-Scottsville 46 kV circuit. Build new 138 kV "in and out" to two new Distribution stations to serve the load formerly served by Phoenix, Shipman, Schuyler (AEP), and Rockfish stations. Construct new 138 kV lines from Joshua Falls-Riverville (~10 mi.) and Riverville-Gladstone (~5 mi.). Install required station upgrades at Joshua Falls, Riverville and Gladstone stations to accommodate the new 138 kV circuits. Rebuild Reusen – Monroe 69 kV (~4 mi.) - 12/1/2022 - $85.00M

319) Baseline Upgrade b3209

- Rebuild the 10.5 mile Berne – South Decatur 69 kV line using 556 ACSR in order to alleviate the overload and address a deteriorating asset. - 6/1/2022 - $16.60M

320) Baseline Upgrade b3210

- Replace approx. 0.7 miles Beatty - Galloway 69 kV line with 4000 kcmil XLPE cable - 6/1/2023 - $5.30M

321) Baseline Upgrade b3211

- Rebuild the 1.3 mile section of 500 kV Line No.569 (Loudoun - Morrisville) with single-circuit 500 kV structures at the current 500 kV standard. This will increase the rating of the line to 3424 MVA. - 6/1/2019 - $4.50M

322) Baseline Upgrade b3213

- Install 2nd Chickahominy 500/230 kV transformerRelocate the Chickahominy – Elmont 500kV line #557 to terminate in a new bay at Chickahominy substation and relocate the Chesterfield – Lanexa 115kV line #92 to allow for the expansion of the Chickahominy substation • Add three new 500 kV breakers with 50kA interrupting rating and associated equipment - 6/1/2023 - $22.00M

323) Baseline Upgrade b3214

- Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV Line. Upgrade terminal equipment at Yukon and replace line relaying at Mitchell and Charleroi - 6/1/2022 - $24.50M

324) Baseline Upgrade b3218

- At Oak Mound 138 kV substation, replace the 138 kV bus tie and Waldo Run #2 breakers with 40 kA, 3000 amp units. Install CTs as 2000/5 MR. - - $0.00M

325) Baseline Upgrade b3223.1

- Install a 2nd 230kV circuit with a minimum summer emergency rating of 1047 MVA between Lanexa and Northern Neck Substations. The 2nd circuit will utilize the vacant arms on the double-circuit structures that are being installed on the Line #224 (Lanexa-Northern Neck) End-of-Life rebuild project (b3089). - 6/1/2023 - $14.00M

326) Baseline Upgrade b3223.2

- Expand the Northern Neck terminal from a 230kV, 4-breaker ring bus to a 6-breaker ring bus. - 6/1/2023 - $5.00M

327) Baseline Upgrade b3223.3

- Expand the Lanexa terminal from a 6-breaker ring bus to a breaker-and-a-half arrangement. - 6/1/2023 - $4.00M

328) Baseline Upgrade b3230

- At Enon Substation install a second 138 kV, 28.8 MVAR nameplate, capacitor and the associated 138 kV capacitor switcher. - 6/1/2025 - $1.84M

329) Baseline Upgrade b3231

- Replace the existing No. 2 cap bank breaker at Huntingdon substation with a new breaker with higher interrupting capability. - 6/1/2025 - $0.80M

330) Baseline Upgrade b3232

- Replace the existing Williamsburg, ALH (Hollidaysburg) and bus section breaker at the Altoona substation with a new breaker with higher interrupting capability. - 6/1/2025 - $1.70M

331) Baseline Upgrade b3233

- Install one 34 MVAR 115 kV shunt reactor and breaker. Install one 115 kV circuit breaker to expand the substation to a 4 breaker ring bus. - 6/1/2025 - $4.90M

332) Baseline Upgrade b3234

- Extend both the east and west 138 kV buses at Pine substation, and install one 138 kV breaker, associated disconnect switches, and one 100 MVAR reactor. - 6/1/2025 - $3.80M

333) Baseline Upgrade b3235

- Extend 138 kV bus work to the west of Tangy substation for the addition of the 100 MVAR reactor bay and one 138 kV 40 kA circuit breaker. - 6/1/2025 - $3.70M

334) Baseline Upgrade b3236

- Extend the 138 kV Bus by adding two new breakers and associated equipment and install a 75 MVAR Reactor - 6/1/2025 - $4.50M

335) Baseline Upgrade b3237

- Install two 46 kV 6.12 MVAR capacitors effective at Mt Union. - 6/1/2025 - $4.00M

336) Baseline Upgrade b3238

- Replace (7) overdutied 34.5 kV breakers with 50 kA rated equipment at the Whippany substation. - 6/1/2025 - $3.47M

337) Baseline Upgrade b3239

- Replace (14) overdutied 34.5 kV breakers with 63 kA rated equipment. - 6/1/2025 - $8.50M

338) Baseline Upgrade b3240

- Upgrade Cherry Run and Morgan terminals to make the Transmission Line the limiting component.

  Morgan: Wave Trap

  Cherry Run: Substation conductor, relays, CT - 6/1/2024 - $0.60M

339) Baseline Upgrade b3241

- Install 138 kV, 36 MVAR capacitor and a 5 uF reactor protected by a 138 kV capacitor switcher. Install a breaker on the 138 kV Junction terminal. Install a 138 kV 3.5 uF reactor on the existing Hardy 138 kV capacitor. - 6/1/2025 - $2.85M

340) Baseline Upgrade b3242

- Reconfigure Stonewall 138 kV substation from its current configuration to a six-breaker breaker-and-a-half layout and add two 36 MVAR capacitors with capacitor switchers. - 6/1/2025 - $13.30M

341) Baseline Upgrade b3245

- Construct a new breaker-and-a-half substation near Tiffany substation. All transmission assets and lines will be relocated to the new substation. The two distribution transformers will be fed via two dedication 115 kV feeds to the existing Tiffany substation. - 6/1/2025 - $23.20M

342) Baseline Upgrade b3246.1

- Convert 115 kV Line #172 Liberty-Lomar and 115 kV Line #197 Cannon Branch-Lomar to 230 kV to provide a new 230 kV source between Cannon Branch and Liberty. The majority of 115 kV Line #172 Liberty-Lomar and Line #197 Cannon Branch-Lomar is adequate for 230 kV operation. Lines to have a summer rating of 1047 MVA/1047 MVA (SN/SE) - 6/1/2023 - $8.00M

343) Baseline Upgrade b3246.2

- Perform substation work for the 115 kV to 230 kV Line conversion at Liberty, Wellington, Godwin, Pioneer, Sandlot and Cannon Branch. - 6/1/2023 - $16.00M

344) Baseline Upgrade b3246.3

- Extend 230kV Line #2011 Cannon Branch – Clifton to Winters Branch by removing the existing Line #2011 termination at Cannon Branch and extending the line to Brickyard creating 230kV Line #2011 Brickyard-Clifton. Extend a new 230kV line between Brickyard and Winters Branch with a summer rating of 1572MVA/1572MVA (SN/SE) - 6/1/2023 - $10.00M

345) Baseline Upgrade b3246.4

- Perform substation work at Cannon Branch, Brickyard and Winters Branch for the 230kV Line #2011 extension. - 6/1/2023 - $4.00M

346) Baseline Upgrade b3246.5

- Replace the Gainesville 230kV 40kA breaker “216192” with a 50kA breaker. - 6/1/2023 - $0.50M

347) Baseline Upgrade b3247

- Replace 13 towers with galvanized steel towers on Doubs - Goose Creek 500 kV. Reconductor 3 mile section with 3-1351.5 ACSR 45/7. Upgrade line terminal equipment at Goose Creek substation to support the 500 kV line rebuild. - 6/1/2025 - $7.60M

348) Baseline Upgrade b3260

- Replace the existing breaker 501-B-251 with a new 69 kV breaker with a higher (40 kA) interrupting capability - 12/1/2021 - $0.00M

349) Baseline Upgrade b3261

- Upgrade Circuit breaker 'R1' at Tanners Creek 345kV - Install TRV capacitor to increase the rating from 50kA to 63kA - 12/31/2020 - $0.05M

350) Baseline Upgrade b3262

- Install a second 115kV 33.67MVar cap bank at Harrisonburg substation along with a 115kV breaker. - 12/1/2025 - $1.25M

351) Baseline Upgrade b3263

- Cut existing 115kV Line#5 between Bremo and Cunningham substations and loop in and out of Fork Union Substation. - 12/1/2025 - $2.50M

352) Baseline Upgrade b3264

- Install 115kV breaker at Stuarts Draft station and sectionalize 115kV Line#117 into two 115kV lines. - 6/1/2025 - $5.00M

353) Baseline Upgrade b3266

- Upgrade the metering CT associated with the Clay Village-Clay Village T 69 kV line section to increase the line ratings. - 12/1/2021 - $0.03M

354) Baseline Upgrade b3267

- Rebuild the 4/0 ACSR Norwood-Shopville 69 kV line section using 556 ACSR/TW. - 12/1/2021 - $3.75M

355) Baseline Upgrade b3268

- Build a switching station at the junction of 115kV line #39 and 115kV line #91 with a 115kV capacitor bank. The switching station will built with 230kV structures but will operate at 115kV. - 12/1/2025 - $3.00M

356) Baseline Upgrade b3269

- At West New Philadelphia station, add a high side 138 kV breaker on the 138/69 kV transformer #2 along with a 138 kV breaker on the line towards Newcomerstown. - 6/1/2025 - $2.02M

357) Baseline Upgrade b3270

- Install 1.7 miles of 795 ASCR 138kV conductor along the other side of Dragoon Tap 138 kV line, which is currently double circuit tower with one position open. Additionally, install a 2nd 138/34.5 kV transformer at Dragoon, install a high side circuit switcher on the current transformer at Dragoon Station, and install 2-138 kV line breakers on the Dragoon-Jackson 138 kV and Dragoon-Twin Branch 138 kV lines. - 6/1/2025 - $4.89M

358) Baseline Upgrade b3270.1

- Replace Dragoon 34.5 kV Breakers "B", "C" and "D" with 40 kA breakers. - 6/1/2025 - $2.00M

359) Baseline Upgrade b3271

- Install a 138 kV circuit breaker at Fremont station on line towards Fremont Center and install a 9.6 MVAR 69 kV capacitor bank at Bloom Road station. - 6/1/2025 - $1.76M

360) Baseline Upgrade b3272

- Install two 138 kV circuit switchers on the high side of 138/34.5 kV transformers #1 & #2 at Rockhill station. - 6/1/2025 - $1.47M

361) Baseline Upgrade b3277

- Replace the existing East Akron 138 kV breaker B-22 with 3000A continuous, 40 KA momentary current interrupting rating circuit breaker. - 6/1/2021 - $0.55M

362) Baseline Upgrade b3300

- Reconductor 230kV Line #2172 from Brambleton to Evergreen Mills along with upgrading the line leads at Brambleton to achieve a summer emergency rating of 1574 MVA. - 6/1/2025 - $2.32M

363) Baseline Upgrade b3301

- Reconductor 230kV Line #2210 from Brambleton to Evergreen Mills along with upgrading the line leads at Brambleton to achieve a summer emergency rating of 1574 MVA. - 6/1/2025 - $2.26M

364) Baseline Upgrade b3302

- Reconductor 230kV Line #2213 from Cabin Run to Yardley Ridge along with upgrading the line leads at Yardley to achieve a summer emergency rating of 1574 MVA. - 6/1/2025 - $1.75M

365) Baseline Upgrade b3303.1

- Extend a new single circuit 230KV line (#9250) from Farmwell Substation to Nimbus Substation. - 6/1/2025 - $5.65M

366) Baseline Upgrade b3303.2

- Remove Beaumeade 230kV Line #2152 line switch. - 6/1/2025 - $0.05M

367) Baseline Upgrade b3304

- Midlothian Area 300 MW Load Drop Relief Area Improvements - 6/1/2025 - $6.22M

368) Baseline Upgrade b3304.1

- Cut 230kV Line #2066 at Trabue junction - 6/1/2025 - $0.00M

369) Baseline Upgrade b3304.2

- Reconductor idle 230kV Line #242 (radial from Midlothian to Trabue junction) to allow a minimum summer rating of 1047 MVA and connect to the section of 230kV Line #2066 between Trabue junction and Winterpock; re-number 230kV Line #242 structures to #2066; - 6/1/2025 - $0.00M

370) Baseline Upgrade b3304.3

- Use the section of idle 115kV Line #153, between Midlothian and Trabue junction to connect to the section of (former) 230kV Line #2066 between Trabue junction and Trabue to create new Midlothian-Trabue lines with new line numbers #2218 and #2219 - 6/1/2025 - $0.00M

371) Baseline Upgrade b3304.4

- Create new line terminations at Midlothian for the new Midlothian-Trabue lines. - 6/1/2025 - $0.00M

372) Baseline Upgrade b3306

- Install a second 125 MVAR 345 kV shunt reactor and associated equipment at Pierce Brook Substation. Install a 345 kV breaker on the high side of the #1 345/230 kV transformer - 6/1/2025 - $8.08M

Revision History:

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Approver: Sami Abdulsalam, Manager Transmission Planning