PJM Baseline Reliability Assessment 2020 - 2035 Period

PJM

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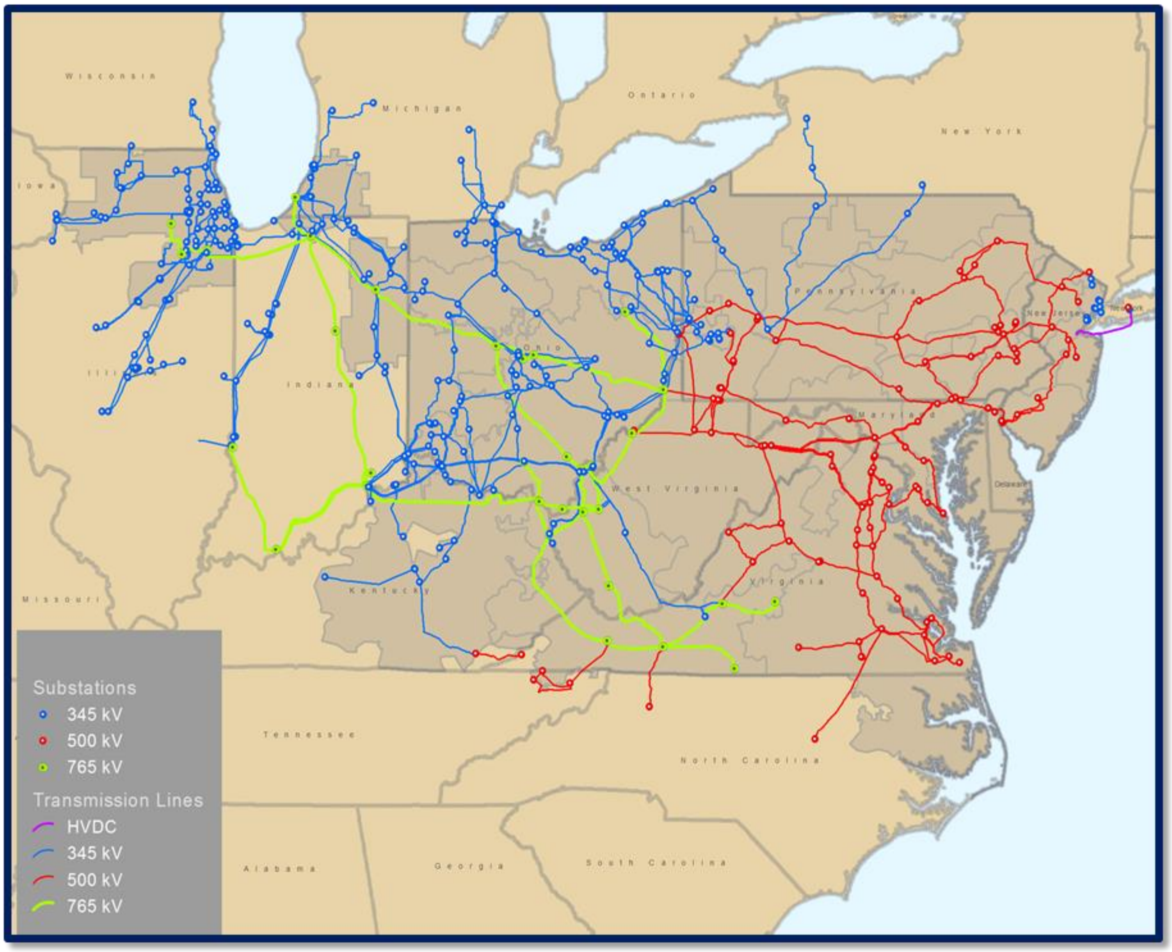
Contents

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 2020 through 2035 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 2020, PJM completed 594 system impact studies to accommodate new generation, merchant transmission, and long term firm transmission service. The 2020 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 participated in several inter-regional studies as part of the 2020 RTEP.

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 2020 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 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

- N4251.14 modeling issue and related short circuit investigation (DEOK)

Operating guideline and other sensitivity studies

- High Voltage issues at East Windsor 500 and 230 kV (JCPL)

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 2020 through 2035 as the 2020 "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 2025 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 2020. 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 2025 were updated with current assumptions to validate the on-going need for identified upgrades and to ensure continued compliance with reliability criteria.
For the 2020 RTEP cycle, PJM has studied 22 generator deactivation notifications resulting in over 4,400 MW of existing generation deactivating in 2020 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 2020 RTEP cycle. The scope of the deactivation notification analysis was significant and included a review of system impacts in years 2020 through 2025. 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 2020 RTEP that are required to achieve compliance having an estimated cost of at least $10 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

AEC

- Rebuild the Corson-Court 69 kV line to achieve ratings equivalent to 795 ACSR conductor or better - 6/1/2025 - $13.20M

Penelec

- 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

PJM SOUTH

Dominion

- Install 2nd Chickahominy 500/230 kV transformer - 6/1/2023 - $22.00M
- 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
- Expand the Northern Neck terminal from a 230 kV, 4-breaker ring bus to a 6-breaker ring bus. - 6/1/2023 - $5.00M
- Expand the Lanexa terminal from a 6-breaker ring bus to a breaker-and-a-half arrangement. - 6/1/2023 - $4.00M

PJM WEST

AEP

- Construct a 345 kV ring bus at Dunton Lake to serve SDI load at 345 kV via two circuits - 6/1/2016 - $23.40M
- Rebuild and convert the existing 17.6 miles East Leipsic-New Liberty 34.5 kV circuit to 138 kV using 795 ACSR - 6/1/2025 - $31.35M
- Rebuild approximately 8.9 miles of 69 kV line between Newcomerstown and Salt Fork Switch with 556 ACSR conductor. - 6/1/2025 - $15.89M
- Rebuild approximately 9 miles of the Rob Park - Harlan 69 kV line - 6/1/2025 - $20.90M
- Construct a 2.4 mile double circuit 138 kV line to connect Lake Head into the 138 kV network; Build a new 138/69 kV transformer station to feed Lakehead; Rebuild the 8.4 mile Pletcher – Buchanan Hydro line and the 1.2 mile Buchanan South 69 kV Radial tap – 6/1/2024 – $36.2M
- Rebuild 4.23 miles of 69 kV line between Sawmill and Lazelle station, using 795 ACSR 26/7 conductor – 6/1/2025 – $12M
- Rebuild 7.5 miles of double circuit 69kV line between East Ottoville Switch and Kalida Station (combining with the new Roselms to Kalida 69 kV circuit) – 6/1/2025 – $23.6M
- Build 9.4 miles of single circuit 69 kV line from Roselms to near East Ottoville 69 kV Switch – 6/1/2025 – $13.7M
- Rebuild approximately 12.3 miles of remaining Lark conductor on the double circuit line between Haviland and East Lima with 1033 54/7 ACSR conductor – 12/1/2024 – $25.9M
- Rebuild approximately 4.0 miles of existing 69 kV line between West Mount Vernon and Mount Vernon stations. Replace the existing 138/69 kV transformer at West Mount Vernon with a larger 90 MVA unit along with existing 69 kV breaker 'C' – 6/1/2025 – $12.9M
- Rebuild Fleming station in the clear; Replace 138/69kV Fleming Transformer #1 with 138/69 kV 130 MVA transformer with high side 138 kV CB; Install a 5 breaker 69 kV ring bus on the low side of the transformer, replace 69 kV circuit switcher AA, replace 69/12kV transformer #3 with 69/12 kV 30 MVA transformer, replace 12 kV CB A and D. Retire existing Fleming substation – 12/1/2025 – $21.1M
- Replace the Meigs 69 kV 4/0 Cu station riser towards Gavin and rebuild the section of the Meigs – Hemlock 69 kV circuit from Meigs to approximately structure #40 (~4 miles) replacing the line conductor 4/0 ACSR with the line conductor size 556.5 ACSR – 6/1/2025 – $12.1M
- Rebuild ~5.44 miles of 69 kV line from Lock Lane to Point Pleasant – 6/1/2025 – $13.5M
- Rebuild the existing Cabin Creek - Kelly Creek 46 kV line (to structure 366-44), approximately 4.4 miles. This section is double circuit with the existing Cabin Creek - London 46 kV line so a double circuit rebuild would be required – 6/1/2025 – $20.9M

APS

- At Shingletown Substation (APS Zone) convert the 230 kV station to a six breaker ring bus. Re-use and re-install the existing capacitor. Install SCADA control. Install new wave traps on Shawville and Dale Summit line exits. - 12/31/2025 - $11.65M

- Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV Line. Upgrade terminal equipment at Yukon and replace line relaying at Mitchell and Charleroi - 6/1/2023 - $24.50M

- 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

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 2020 through 2025 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 2026 through 2035 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 2020 through 2035 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 2020 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 2020 RTEP, a year 8 (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 2025 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 2025 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.

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

Table 3. **Analysis Type Summary**

Modeling Assumptions & Critical System Conditions

PJM selected a range of forecast demand levels for the year 2025.

- 2025 90/10 Summer Peak
- 2025 50/50 Summer Peak
- 2025 Light Load Reliability Analysis (50% of 50/50 Summer Peak)
- 2025 Winter Reliability Analysis

In addition to the analysis of the 2025 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 2025 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/2020-load-report.ashx?la=en

The 2025 summer peak analysis used the 2025 summer model from the 2019 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, 2025 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 2025 case (note these are in addition to the reactive power associated with the generation noted above).

2025			
Area Name	Static	Dynamic	Total
AE	1158	450	1608
AEP	14502	650	15152
AP	5153	1760	6913
BGE	6306	0	6306
CE	8477	1800	10277
DAY	1346	0	1346
DEO&K	838	0	838
DLCO	292	0	292
DP&L	1473	375	1848
DVP	9633	1750	11383
EKPC	1358	0	1358
FE	6609	1614	8223
JCPL	4733	55	4788
METED	1177	500	1677
PECO	4691	700	5391
PENELEC	2281	674	2955
PEPCO	1287	0	1287
PJM*	0	0	0
PPL	3596	0	3596
PSEG	9235	0	9235
RECO	0	0	0
UGI	66	0	66
Grand Total	**84212**	**10328**	**94539**

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 2025 summer period. A 2025, 2019 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.

2025 RTEP Interchange		
Source	**Sink**	**Total (MW)**
PJM	NYISO	817
PJM	LGEE	-475.5
PJM	DEI	-156
PJM	WEC	90
PJM	LAGN	-100
PJM	CPLE	30
PJM	DUK	-100
PJM	TVA	400
PJM	EEI	0
PJM	AMIL	-1805
PJM	OMUA	0
PJM	MEC	454
PJM	SMT	-285
Total		**-1130.5**

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 19,000 Single contingencies were defined, including contingencies involving the loss of facilities in neighboring systems.
- Over 15,000 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 376,000,000 combinations.

PJM's 2020 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 2020 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 2025 90/10 summer peak scenario, thermal and voltage analysis of a 2025 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 2025 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 2025 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 2025 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 2025 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 2025 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 2025 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 2025 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.

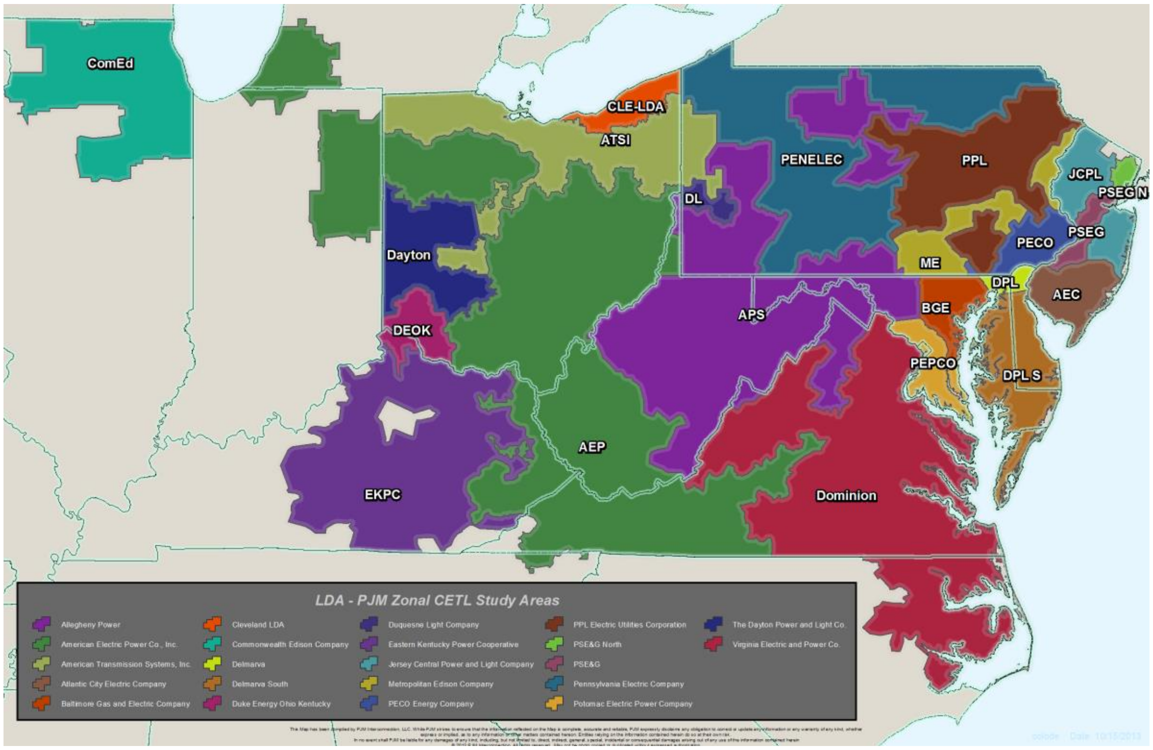
Load Deliverability Analysis

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 2025 Load Deliverability test used the 2025 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 2025 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 2025 winter reliability analysis. This analysis included Generator Deliverability Studies, as well as Load Deliverability studies using a 2025 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 2025 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 2020-2025

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 2020 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 2025 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 2020 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 2020 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 2020, PJM performed a significant reliability review of years 2020 through 2025. As part of the 2020 RTEP, PJM performed system wide assessment of normal system, single contingency, multiple contingency, N-1-1, generator deliverability and load deliverability testing for year 2020 through 2025 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.

2021 Retool

- B2753.9 Summer Study (AEP)
- B1570.4 scope change (AEP)
- B2697.1 and B2697.2 scope change (AEP)
- B2279 scope change (AEP)
- Jackson 230/115 kV transformer retirement (ME)

2022 Retool

- B3099 Summer study (AEP)
- B3100 Winter study (AEP)
- B3116 Summer study (AEP)
- B3040.6 Summer study (AEP)

2023 Retool

- B3036 Winter study (AEP)
- B3087 Winter Study (AEP)

2024 Retool

- Kincaid RAS removal (ComEd)
- Customer X(400 MW load interconnection) (Nipsco)
- Menges Ditch load connection to East Elkhart (AEP) station (Nipsco)
- B3157 Winter study (AEP)
- B3160 Summer study (AEP)
- B3156 Summer study (AEP)
- B3158 Winer study (AEP)
- B3159 Summer study (AEP)
- B3131 Winer study (AEP)
- B3085 status review (AEP)
- B2594 Cancelation (AEP)

2025 Retool

- B3161 Scope change (Dom)
- Recent deactivations and newly signed ISA (DEOK)
- S1533 Cancelation (RMU/ComEd)
- Multiple cap bank size reductions (AEP)
- Jackson 230/115 kV transformer retirement (ME)

- Dickerson Deactivation (PepCo)
- Chalk Point Deactivation (PepCo)
- Dresden Deactivation (ComEd)

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 2020 RTEP also included a review of the fifteen year planning horizon through 2035. The analyses conducted as part of the review included normal system, single, and multiple (tower) contingency analysis of the 2025 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 2026 through 2035 (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.

<table>
<tr><th>Analysis Type</th><th>Monitored Flowgates</th><th>Contingencies Considered</th><th>Years Considered</th></tr>
<tr><td>Load Deliverability</td><td rowspan="2">Any BES element loaded at 75% or greater in the 2025 analysis</td><td>normal system, single, double circuit tower line</td><td rowspan="2">2026 through 2035</td></tr>
<tr><td>Generation Deliverability</td><td>normal system, single</td></tr>
</table>

Table 7. **15 Year Planning Analysis**

Load forecasts for the years 2026 through 2035 from the 2020 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 2026 through 2035.

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 2020 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.

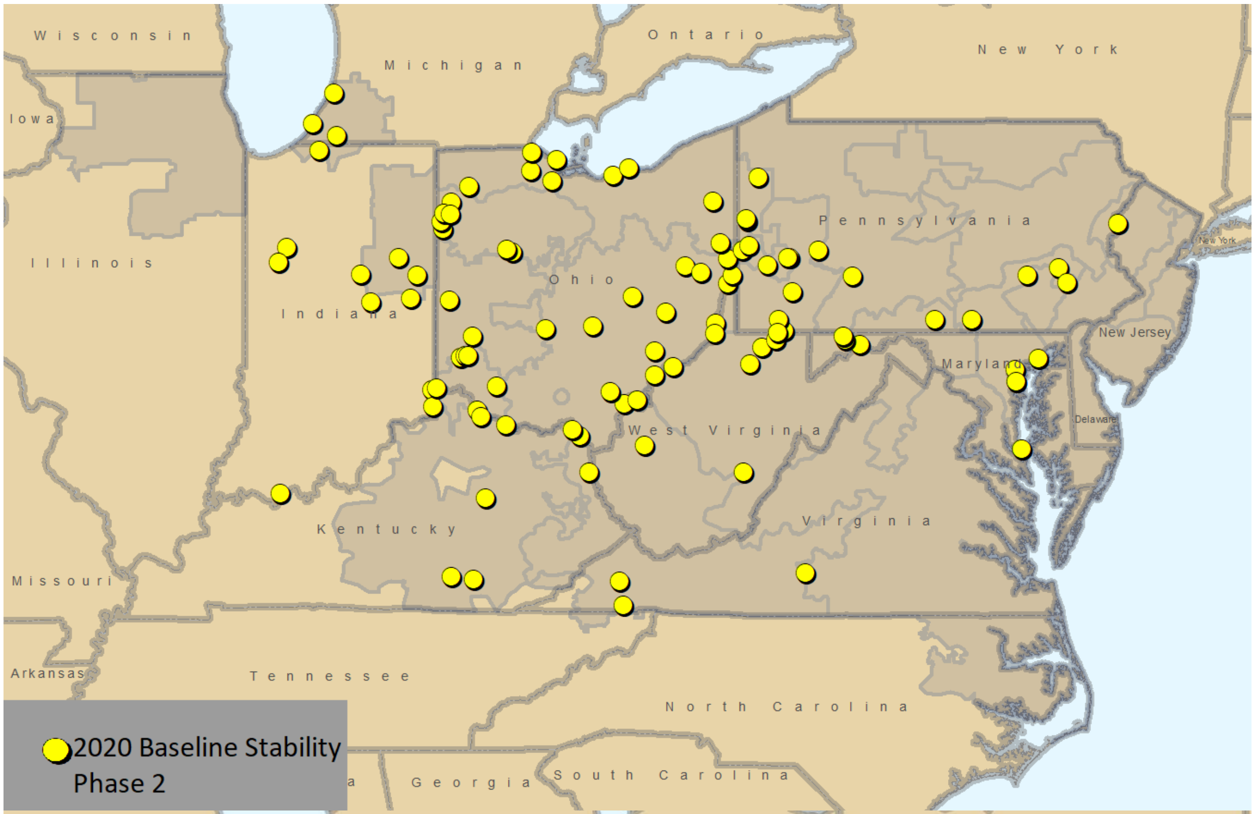
Stability Assessment

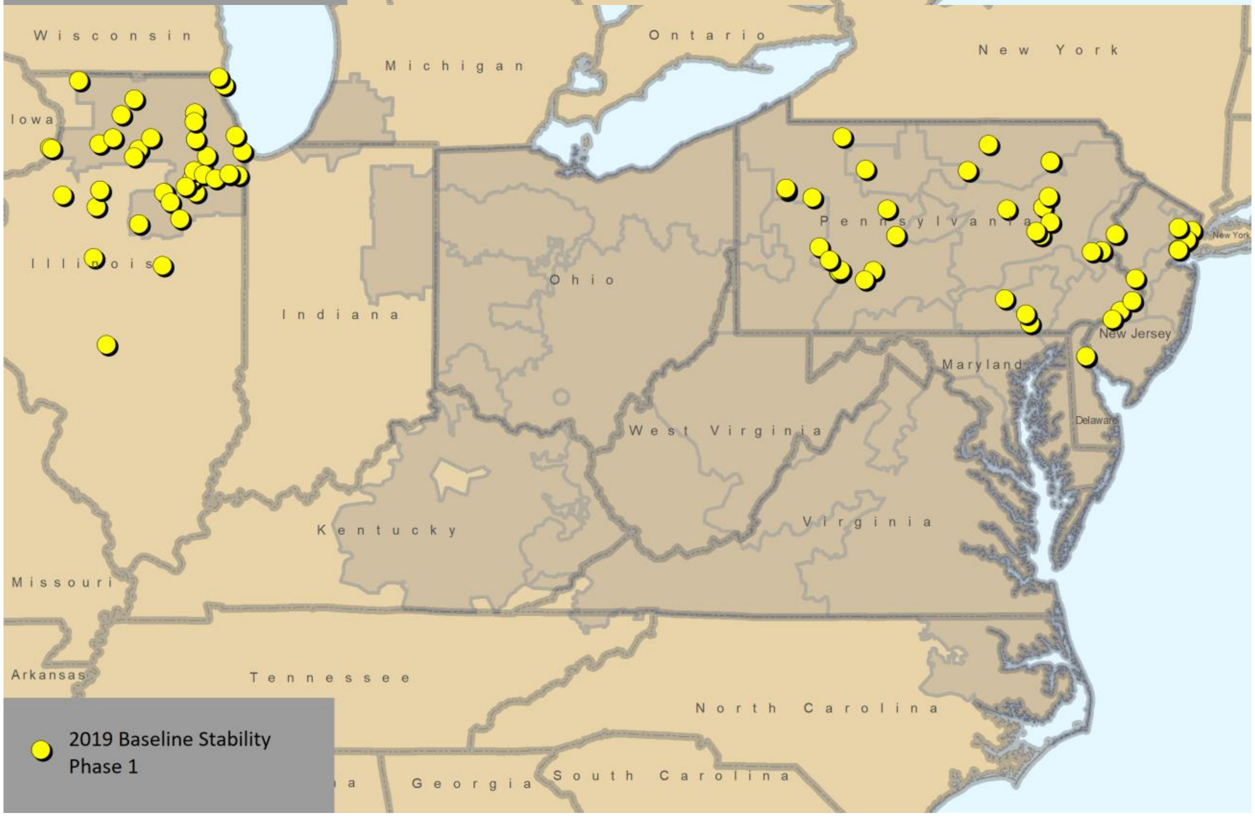
PJM performs multiple tiers of analysis to ensure the system will remain stable and have satisfactory dynamic performance for disturbances that are consistent with Table 1 of the NERC TPL-001-4 standards. Collectively, the studies performed assess system dynamic performance over a wide range of load 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	2019 RTEP
Annual baseline stability analysis of 1/3 of existing stations	100

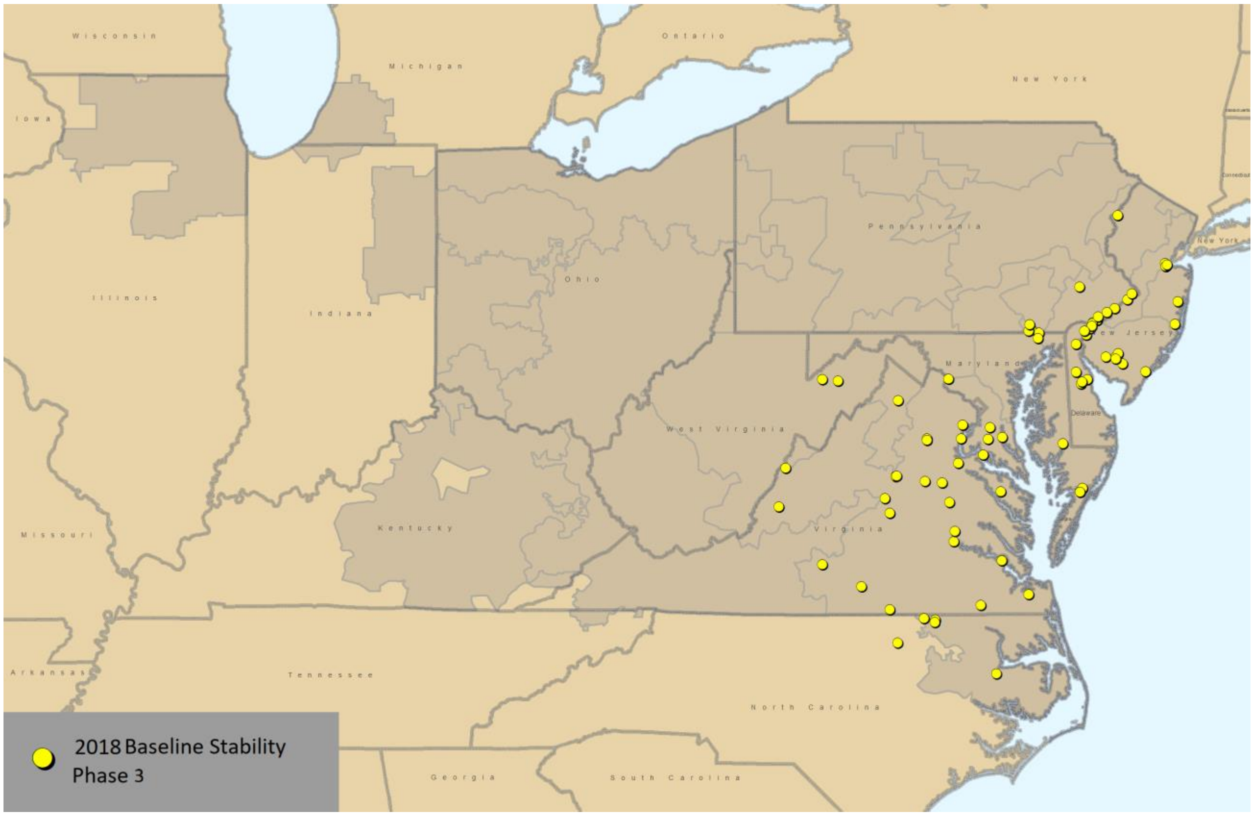
New Services Queue stability analysis	123
Total	**223**

Table 8. **Number of Generation Stations Studied for Stability as Part of the 2019 RTEP**


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


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

,



Map 3. Three-Year Baseline Stability Cycle

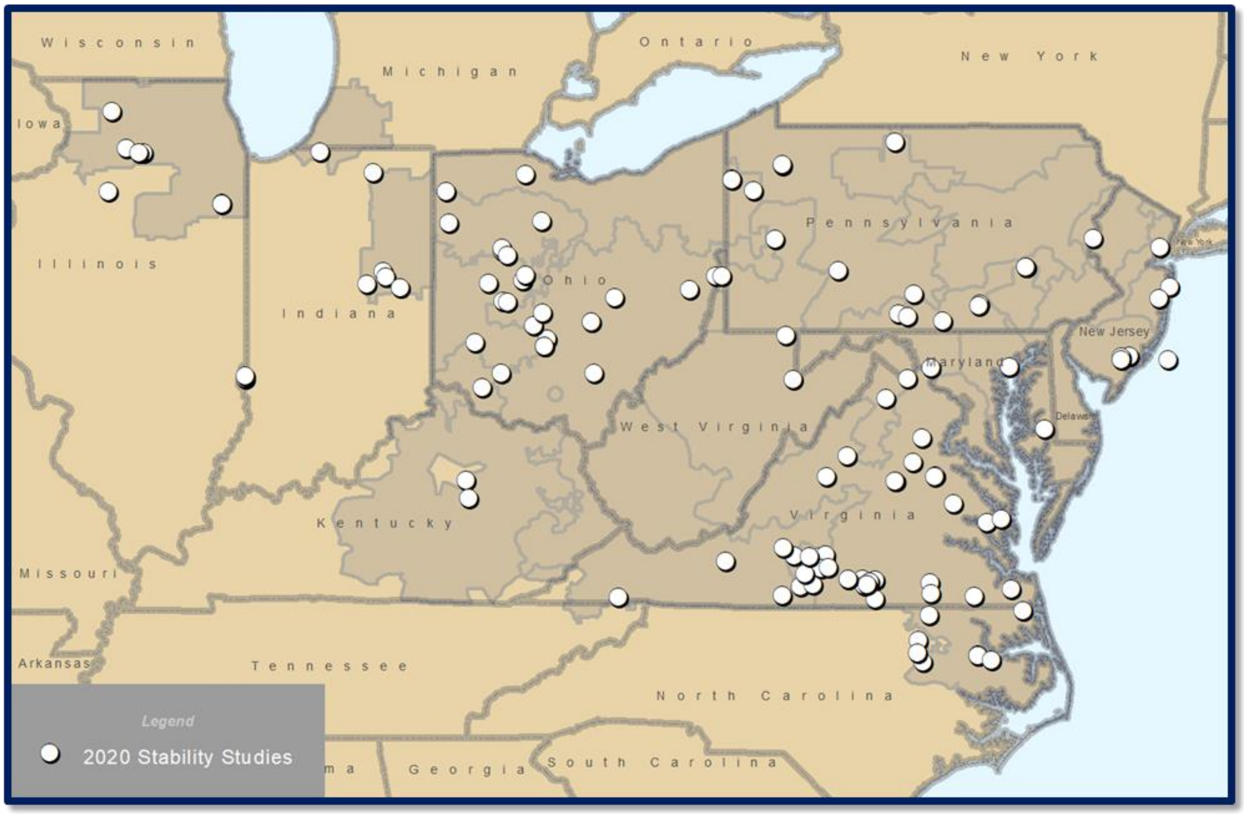
Good engineering practices as related to ensuring adequate system dynamic performance for the Bulk Electric System starts with proper base case models. PJM uses full ERAG MMWG models as a starting point for the dynamic stability analysis. All known transmission system as well as generation model changes 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 2020 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 2020

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 2020 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 2020 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 75plants was performed in 2020 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 2020 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 2020 new dynamic models per TOs request.

In addition to the NPIR stability studied, PJM also performed NPIR voltage studies. As part of the 2020 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 2020 RTEP

The results of the baseline assessment for the 2020 – 2035 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 2020.

PJM found the following areas of the PJM system to not meet reliability criteria during the assessment of the 2020 – 2035 study periods. These baseline upgrades were all identified as part of the 2020 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 b2779.6

- Overview of Reliability Problem
  - Criteria Violation: Greater than 300 MW consequential load loss
  - Criteria Test: Load Loss Limit (PJM Criteria)
- Overview of Reliability Solution
  - Description of Upgrade: Construct a 345 kV ring bus at Dunton Lake to serve SDI load at 345 kV via two circuits
  - Upgrade In-Service Date: 6/1/2016
  - Estimated Upgrade Cost: $23.40M
  - Construction Responsibility: AEP

2) Baseline Upgrade b2779.7

- Overview of Reliability Problem
  - Criteria Violation: Greater than 300 MW consequential load loss
  - Criteria Test: Load Loss Limit (PJM Criteria)
- Overview of Reliability Solution
  - Description of Upgrade: Retire Collingwood 345 kV station

- Upgrade In-Service Date: 6/1/2016
- Estimated Upgrade Cost: $1.40M
- Construction Responsibility: AEP

3) Baseline Upgrade b3011.8

- Overview of Reliability Problem
  - Criteria Violation: Overduty of Dravosburg "Z-78 Logans" breaker
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade 138 kV breaker “Z-78 Logans” at Dravosburg.
  - Upgrade In-Service Date: 6/1/2021
  - Estimated Upgrade Cost: $0.65M
  - Construction Responsibility: DL

4) Baseline Upgrade b3098.1

- Overview of Reliability Problem
  - Criteria Violation: End of Life
  - Criteria Test: Dominion FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Balcony Falls Substation
  - Upgrade In-Service Date: 6/1/2019
  - Estimated Upgrade Cost: $9.00M
  - Construction Responsibility: Dominion

5) Baseline Upgrade b3110.3

- Overview of Reliability Problem
  - Criteria Violation: Overstress of the Clifton 230 kV "201182" and "XT2011" breakers
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Clifton 230kV breakers “201182” and “XT2011” with 63kA breakers
  - Upgrade In-Service Date: 12/31/2021
  - Estimated Upgrade Cost: $0.93M
  - Construction Responsibility: Dominion

6) Baseline Upgrade b3213

- Overview of Reliability Problem
  - Criteria Violation: Overload of Chickahominy 500/230 kV Transformer
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Install 2nd Chickahominy 500/230 kV transformer

- Upgrade In-Service Date: 6/1/2023
- Estimated Upgrade Cost: $22.00M
- Construction Responsibility: Dominion

7) Baseline Upgrade b3213.1

- Overview of Reliability Problem
  - Criteria Violation: Overstressed breakers
  - Criteria Test: criteria test
- Overview of Reliability Solution
  - Description of Upgrade: Replace the eight (8) Chickahominy 230kV breakers with 63kA breakers: “SC122”, “205022”, 209122”, 210222-2”, “28722”, “H222”, “21922”, “287T2129”
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $3.76M
  - Construction Responsibility: Dominion

8) Baseline Upgrade b3214

- Overview of Reliability Problem
  - Criteria Violation: Overload of Yukon to Smithton #62 138 kV line and overload of Smithton #62 - Shepler Hill Junction 138 kV line
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV Line. Upgrade terminal equipment at Yukon and replace line relaying at Mitchell and Charleroi
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $24.50M
  - Construction Responsibility: APS

9) Baseline Upgrade b3215

- Overview of Reliability Problem
  - Criteria Violation: Overload of Yukon to AA2-161 (Robbins) 138kV line
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade terminal equipment at Yukon to increase rating on Yukon – AA2-161 (Robbins) 138 kV line
  - Upgrade In-Service Date: 6/1/2021
  - Estimated Upgrade Cost: $0.40M
  - Construction Responsibility: APS

10) Baseline Upgrade b3216

- Overview of Reliability Problem
  - Criteria Violation: Overload of Yukon to AA2 – 161 (Wycoff Jct) 161kV line

- Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade terminal equipment at Yukon to increase rating on Yukon – AA2-161 (Wycoff jct) 138 kV line
  - Upgrade In-Service Date: 6/1/2021
  - Estimated Upgrade Cost: $1.40M
  - Construction Responsibility: APS

11) Baseline Upgrade b3218

- Overview of Reliability Problem
  - Criteria Violation: Overdutied Breakers
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date:
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: APS

12) Baseline Upgrade b3221

- Overview of Reliability Problem
  - Criteria Violation: Overload of Steel City 500/230 kV transformer #1
  - Criteria Test: Summer Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace terminal equipment (bus conductor) on the 230 kV side of the Steel City 500/230 kV transformer #1
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.09M
  - Construction Responsibility: PPL

13) Baseline Upgrade b3222

- Overview of Reliability Problem
  - Criteria Violation: Post contingency voltage violation on the 69 kV system along the Limestone – Lock Haven – Renovo path
  - Criteria Test: Baseline N-1
- Overview of Reliability Solution
  - Description of Upgrade: Install one (1) 7.2 MVAR fixed cap bank on the Lock Haven-Reno 69 kV line and one (1) 7.2 MVAR fixed cap bank on the Lock Haven-Flemington 69 kV line near the Flemington 69/12kV substation.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $1.90M

- Construction Responsibility: PPL

14) Baseline Upgrade b3223.1

- Overview of Reliability Problem
    - Criteria Violation: N-1-1 Vmag and Vdrop violations, N-1-1 thermal and >300MW Load Loss in the Northern Neck area
    - Criteria Test: N-1-1 Thermal & Voltage, >300 MW Load Loss
- Overview of Reliability Solution
    - Description of Upgrade: 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).
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $14.00M
    - Construction Responsibility: Dominion

15) Baseline Upgrade b3223.2

- Overview of Reliability Problem
    - Criteria Violation: N-1-1 Vmag and Vdrop violations, N-1-1 thermal and >300MW Load Loss in the Northern Neck area
    - Criteria Test: N-1-1 Thermal & Voltage, >300 MW Load Loss
- Overview of Reliability Solution
    - Description of Upgrade: Expand the Northern Neck terminal from a 230kV, 4-breaker ring bus to a 6-breaker ring bus.
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $5.00M
    - Construction Responsibility: Dominion

16) Baseline Upgrade b3223.3

- Overview of Reliability Problem
    - Criteria Violation: N-1-1 Vmag and Vdrop violations, N-1-1 thermal and >300MW Load Loss in the Northern Neck area
    - Criteria Test: N-1-1 Thermal & Voltage, >300 MW Load Loss
- Overview of Reliability Solution
    - Description of Upgrade: Expand the Lanexa terminal from a 6-breaker ring bus to a breaker-and-a-half arrangement.
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $4.00M
    - Construction Responsibility: Dominion

17) Baseline Upgrade b3224

- Overview of Reliability Problem
    - Criteria Violation: Overload of Mt. Pleasant - Middletown Tap 138 kV line

- Criteria Test: Winter Generator Deliverability and Winter N-1 Thermal Overload

- Overview of Reliability Solution
  - Description of Upgrade: Replace a disconnect switch and reconductor a short span of Mt. Pleasant - Middletown Tap line
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.43M
  - Construction Responsibility: DPL

18) Baseline Upgrade b3226
- Overview of Reliability Problem
  - Criteria Violation: Post contingency voltage violation at Peermont and Swainton 69 kV stations
  - Criteria Test: Summer N-1 Voltage Magnitude and Voltage Drop
- Overview of Reliability Solution
  - Description of Upgrade: Add 10 MVAR 69 kV capacitor bank at Swainton substation
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $2.90M
  - Construction Responsibility: AEC

19) Baseline Upgrade b3227
- Overview of Reliability Problem
  - Criteria Violation: Overload of Corson-Court 69 kV line for outage of Corson-Middle 138 kV line during maintenance of Corson-England 138 kV line
  - Criteria Test: Intermediate Load N-1-1 Thermal Overload
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the Corson-Court 69 kV line to achieve ratings equivalent to 795 ACSR conductor or better
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $13.20M
  - Construction Responsibility: AEC

20) Baseline Upgrade b3228
- Overview of Reliability Problem
  - Criteria Violation: BGE 110552 Westport Center Circuit Overloaded for tower Contingency L/o 2344/2345
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace two relays at Center Substation to increase ratings on the 110552 circuit
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.03M
  - Construction Responsibility: BGE

21) Baseline Upgrade b3229.1

- Overview of Reliability Problem
  - Criteria Violation: In the 2020 RTEP 2025 Winter N-1-1 analysis the loss of the Milesburg - Moshannon 230 kV line followed by the loss of the Shingletown #82 230-46 kV transformer results in a voltage drop violation at the Shingeltown 230 kV bus of 12.5%.
  - Criteria Test: N-1-1 Voltage Drop
- Overview of Reliability Solution
  - Description of Upgrade: At Shingletown Substation (APS Zone) convert the 230 kV station to a six breaker ring bus. Re-use and re-install the existing capacitor. Install SCADA control. Install new wave traps on Shawville and Dale Summit line exits.
  - Upgrade In-Service Date: 12/31/2025
  - Estimated Upgrade Cost: $11.65M
  - Construction Responsibility: APS

22) Baseline Upgrade b3229.2

- Overview of Reliability Problem
  - Criteria Violation: In the 2020 RTEP 2025 Winter N-1-1 analysis the loss of the Milesburg - Moshannon 230 kV line followed by the loss of the Shingletown #82 230-46 kV transformer results in a voltage drop violation at the Shingeltown 230 kV bus of 12.5%.
  - Criteria Test: N-1-1 Voltage Drop
- Overview of Reliability Solution
  - Description of Upgrade:

    At Shawville Substation (PN Zone) replace the wave trap and substation conductor.
  - Upgrade In-Service Date: 12/31/2025
  - Estimated Upgrade Cost: $0.29M
  - Construction Responsibility: PENELEC

23) Baseline Upgrade b3229.3

- Overview of Reliability Problem
  - Criteria Violation: In the 2020 RTEP 2025 Winter N-1-1 analysis the loss of the Milesburg - Moshannon 230 kV line followed by the loss of the Shingletown #82 230-46 kV transformer results in a voltage drop violation at the Shingeltown 230 kV bus of 12.5%.
  - Criteria Test: N-1-1 Voltage Drop
- Overview of Reliability Solution
  - Description of Upgrade: At Lewistown Substation (PN Zone) install direct transfer trip relaying to be compatible with the new Shingletown ring bus relaying.
  - Upgrade In-Service Date: 12/31/2025
  - Estimated Upgrade Cost: $0.29M
  - Construction Responsibility: PENELEC

24) Baseline Upgrade b3230

- Overview of Reliability Problem
  - Criteria Violation: In the 2020 RTEP 2025 summer N-1-1 analysis the loss of the Dutch Fork 138 kV capacitor followed by the Enon 138 kV capacitor the voltage must be adjustable back to the N-0 values

  - (0.95 p.u.) post contingency.
  - Criteria Test: ATSI 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: At Enon Substation install a second 138 kV, 28.8 MVAR nameplate, capacitor and the associated 138 kV capacitor switcher.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $1.84M
  - Construction Responsibility: APS

25) Baseline Upgrade b3231

- Overview of Reliability Problem
  - Criteria Violation: The Huntingdon 46 kV breaker # 2 is overdutied
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace the existing No. 2 cap bank breaker at Huntingdon substation with a new breaker with higher interrupting capability.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.80M
  - Construction Responsibility: PENELEC

26) Baseline Upgrade b3232

- Overview of Reliability Problem
  - Criteria Violation: Three Altoona 46 kV breakers are overdutied. The Altoona #1 (BUS_SECT and ALH_HOLI) breakers and Altoona #2 (WMSBURG) breaker.
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace the existing Williamsburg, ALH (Hollidaysburg) and bus section breaker at the Altoona substation with a new breaker with higher interrupting capability.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $1.70M
  - Construction Responsibility: PENELEC

27) Baseline Upgrade b3233

- Overview of Reliability Problem
  - Criteria Violation: Post contingency high voltage violations along the Rockwood – Mayersdale North 115 kV line
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $4.90M

- Construction Responsibility: PENELEC

28) Baseline Upgrade b3234

- Overview of Reliability Problem
  - Criteria Violation: High Voltages, based on ATSI TO Criteria, observed for voltage magnitude analysis of the Light load case in the area of Pine 138 kV
  - Criteria Test: ATSI 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $3.80M
  - Construction Responsibility: ATSI

29) Baseline Upgrade b3235

- Overview of Reliability Problem
  - Criteria Violation: High Voltage, based on ATSI TO Criteria, observed for voltage magnitude analysis of the Light load case at Tangy 138 kV for the loss of the Gavin – Flatlick 765 kV line.
  - Criteria Test: ATSI 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $3.70M
  - Construction Responsibility: ATSI

30) Baseline Upgrade b3236

- Overview of Reliability Problem
  - Criteria Violation: High Voltage, based on ATSI TO Criteria, observed for voltage magnitude analysis of the Light load case around Broadview, Tech + and Morefiel138 kV busses for the loss of the Edgewood – Urbana 69 kV line.
  - Criteria Test: ATSI 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Extend the 138 kV Bus by adding two new breakers and associated equipment and install a 75 MVAR Reactor
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $4.50M
  - Construction Responsibility: ATSI

31) Baseline Upgrade b3237

- Overview of Reliability Problem
  - Criteria Violation: Post contingency voltage violation on the 46 kV system along the Hill Valley – Mount Union – Mapleton path.

- Criteria Test: Baseline N-1
- Overview of Reliability Solution
  - Description of Upgrade: Install two 46 kV 6.12 MVAR capacitors effective at Mt Union.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $4.00M
  - Construction Responsibility: PENELEC

32) Baseline Upgrade b3238

- Overview of Reliability Problem
  - Criteria Violation: Seven(7) existing 40kA Whippany 34.5 kV breakers (X76, B37 (O769), D4, F6, P142, 320BY77 and A157) are overdutied
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace (7) overdutied 34.5 kV breakers with 50 kA rated equipment.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $8.67M
  - Construction Responsibility: JCPL

33) Baseline Upgrade b3239

- Overview of Reliability Problem
  - Criteria Violation: Fourteen (14) existing 40kA Freneau 34.5 kV breakers (M139A, M139B, C211, B29 (V100, W101, Z104, O15, S45, F32, E31, BK1A, BK1B, BK2A and BK2B) are overdutied
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace (14) overdutied 34.5 kV breakers with 63 kA rated equipment.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $5.70M
  - Construction Responsibility: JCPL

34) Baseline Upgrade b3240

- Overview of Reliability Problem
  - Criteria Violation: In the 2020 RTEP 2025 Winter Generator Deliverability analysis a stuck breaker of the BDL3 or BDL4 500 kV breakers at Bedington substation results in a thermal violation on the Cherry Run - Morgan 138 kV line at 103.4%.
  - Criteria Test: Winter Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Cherry Run and Morgan terminals to make the Transmission Line the limiting component.

    Morgan: Wave Trap

    Cherry Run: Substation conductor, relays, CT

    - Upgrade In-Service Date: 12/1/2025
    - Estimated Upgrade Cost: $0.23M
    - Construction Responsibility: APS

35) Baseline Upgrade b3241

- Overview of Reliability Problem
    - Criteria Violation: In the 2020 RTEP 2025 Summer Basecase analysis a bus contingency at Junction 138 kV substation results in a low voltage violation at multiple substations. (Baker 138 kV substation at 88% pu.)
    - Criteria Test: : N-1 and N-1-1 Summer Voltage Magnitude/Drop; TO Criteria: Voltage Magnitude/Drop
- Overview of Reliability Solution
    - Description of Upgrade: 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.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $2.85M
    - Construction Responsibility: APS

36) Baseline Upgrade b3242

- Overview of Reliability Problem
    - Criteria Violation: In the 2020 RTEP 2025 Summer Basecase analysis an N-1-1 contingency on the Bartonville - Meadowbrook and Feagans Mill - Millville 138 kV lines results in a low voltage violation at multiple substations (Stonewall 138 kV substation at 89% pu.)
    - Criteria Test: : N-1-1 Summer Voltage Magnitude; TO Criteria: Voltage Magnitude/Drop
- Overview of Reliability Solution
    - Description of Upgrade: 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.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $13.30M
    - Construction Responsibility: APS

37) Baseline Upgrade b3243

- Overview of Reliability Problem
    - Criteria Violation: Overload of Bass - Spy Run1 34.5kV line
    - Criteria Test: N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Replace risers at Bass 34.5kV station
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.10M
    - Construction Responsibility: AEP

38) Baseline Upgrade b3244

- Overview of Reliability Problem

  - Criteria Violation: Overload of Harlan - Robinson Park 69kV line
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild approximately 9 miles of the Rob Park - Harlan 69 kV line
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $20.90M
  - Construction Responsibility: AEP

39) Baseline Upgrade b3245

- Overview of Reliability Problem
  - Criteria Violation: Post contingency voltage drop violation on the Williams 115 kV substation.
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $23.20M
  - Construction Responsibility: PENELEC

40) Baseline Upgrade b3246.1

- Overview of Reliability Problem
  - Criteria Violation: Multiple load drop violations in the Manassas area greater than 300 MW
  - Criteria Test: N-1-1 Load Drop
- Overview of Reliability Solution
  - Description of Upgrade: Convert 115kV Line #172 Liberty-Lomar and 115kV Line #197 Cannon Branch-Lomar to 230kV to provide a new 230kV source between Cannon Branch and Liberty. The majority of 115kV Line #172 Liberty-Lomar and Line #197 Cannon Branch-Lomar is adequate for 230kV operation. Rebuild 0.36 mile segment between Lomar and Cannon Branch junction. Lines to have a summer rating of 1047MVA/1047MVA (SN/SE)
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $10.00M
  - Construction Responsibility: Dominion

41) Baseline Upgrade b3246.2

- Overview of Reliability Problem
  - Criteria Violation: Multiple load drop violations in the Manassas area greater than 300 MW
  - Criteria Test: N-1-1 Load Drop
- Overview of Reliability Solution
  - Description of Upgrade: Perform substation work for the 115kV to 230kV Line conversion at Liberty, Wellington, Godwin, Pioneer, Sandlot and Cannon Branch.

- Upgrade In-Service Date: 6/1/2023
- Estimated Upgrade Cost: $21.00M
- Construction Responsibility: Dominion

42) Baseline Upgrade b3246.3

- Overview of Reliability Problem
  - Criteria Violation: Multiple load drop violations in the Manassas area greater than 300 MW
  - Criteria Test: N-1-1 Load Drop
- Overview of Reliability Solution
  - Description of Upgrade: 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)
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $10.00M
  - Construction Responsibility: Dominion

43) Baseline Upgrade b3246.4

- Overview of Reliability Problem
  - Criteria Violation: Multiple load drop violations in the Manassas area greater than 300 MW
  - Criteria Test: N-1-1 Load Drop
- Overview of Reliability Solution
  - Description of Upgrade: Perform substation work at Cannon Branch, Brickyard and Winters Branch for the 230kV Line #2011 extension.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $4.00M
  - Construction Responsibility: Dominion

44) Baseline Upgrade b3246.5

- Overview of Reliability Problem
  - Criteria Violation: Multiple load drop violations in the Manassas area greater than 300 MW
  - Criteria Test: N-1-1 Load Drop
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Gainesville 230kV 40kA breaker “216192” with a 50kA breaker.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: Dominion

45) Baseline Upgrade b3247

- Overview of Reliability Problem
  - Criteria Violation: Loss of 500kV Line #514 from Doubs to Goose Creek

    - Criteria Test: End of Life Criteria
- Overview of Reliability Solution
    - Description of Upgrade: 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.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $7.60M
    - Construction Responsibility: Dominion

46) Baseline Upgrade b3248

- Overview of Reliability Problem
    - Criteria Violation: Voltage drop violation at Wolf Lake, Albion, Philips, Brimfield, North Kendallville and Kendallville 69 kV buses
    - Criteria Test: N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Install a low side 69 kV circuit breaker at Albion 138/69 kV transformer 1
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.40M
    - Construction Responsibility: AEP

47) Baseline Upgrade b3253

- Overview of Reliability Problem
    - Criteria Violation: Voltage magnitude and voltage drop violations at Mill Street, Sugar Hill, Friendship, Central Portsmouth, Cornerstone Station, Ruhlman, Rosemount, Sciotoville, Millbrook Park, Oertels Corners, Siloam, South Shore 69 kV buses and South Lucasville 138 kV bus
    - Criteria Test: N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Install a 3000A 40 kA 138 kV breaker on high side of 138/69 kV transformer #5 at Millbrook Park station. The transformer and associated bus protection will be upgraded accordingly.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.63M
    - Construction Responsibility: AEP

48) Baseline Upgrade b3255

- Overview of Reliability Problem
    - Criteria Violation: Upgrade 795 AAC risers at Sand Hill 138 kV station towards Cricket Switch with 1272 AAC
    - Criteria Test: N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Upgrade 795 AAC risers at Sand Hill 138 kV station towards Cricket Switch with 1272 AAC
    - Upgrade In-Service Date: 6/1/2025

    - Estimated Upgrade Cost: $0.04M
    - Construction Responsibility: AEP

49) Baseline Upgrade b3256

- Overview of Reliability Problem
    - Criteria Violation: Upgrade 500 MCM Cu risers at Tidd 138 kV station towards Wheeling Steel; replace with 1272 AAC conductor
    - Criteria Test: N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Upgrade 500 MCM Cu risers at Tidd 138 kV station towards Wheeling Steel; replace with 1272 AAC conductor
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.07M
    - Construction Responsibility: AEP

50) Baseline Upgrade b3257

- Overview of Reliability Problem
    - Criteria Violation: Overload of Twin Branch 1 - Twin Branch 2 34.5 kV
    - Criteria Test: N-1 and N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Replace two spans of 336.4 26/7 ACSR on Twin Branch-AM General #2 34.5 kV circuit
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.14M
    - Construction Responsibility: AEP

51) Baseline Upgrade b3258

- Overview of Reliability Problem
    - Criteria Violation: Overload of Easton - North Canton 69kV line and voltage drop violations at Belden Village and Wayview 69 kV buses.
    - Criteria Test: N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Install a 3000A 63 kA 138 kV breaker on high side of 138/69 kV transformer #2 at Wagenhals station. The transformer and associated bus protection will be upgraded accordingly.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $1.10M
    - Construction Responsibility: AEP

52) Baseline Upgrade b3259

- Overview of Reliability Problem
    - Criteria Violation: Voltage drop violations at BILLIAR, North Fredericksburg, Shreve, Big Prairie, PAINTVSS, Drake Valley and LOUDNVL 69 kV buses
    - Criteria Test: N-1-1

- Overview of Reliability Solution
    - Description of Upgrade: At West Millersburg station, replace the 138 kV MOAB on the West Millersburg - Wooster 138 kV line with a 3000A 40 kA breaker.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.68M
    - Construction Responsibility: AEP

53) Baseline Upgrade b3260

- Overview of Reliability Problem
    - Criteria Violation: In the 2020 RTEP 2025 FERC 715 analysis breaker 501-B-251 at Greenfield substation was identfied as over its Short Circuit capability
    - Criteria Test: FERC 715 Short Circuit
- Overview of Reliability Solution
    - Description of Upgrade: Replace the existing breaker 501-B-251 with a new 69 kV breaker with a higher (40 kA) interrupting capability
    - Upgrade In-Service Date: 12/1/2021
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: ATSI

54) Baseline Upgrade b3261

- Overview of Reliability Problem
    - Criteria Violation: Overstress of the Tanners creek 345 kV “R1” breaker
    - Criteria Test: Short Circuit
- Overview of Reliability Solution
    - Description of Upgrade: Upgrade Circuit breaker 'R1' at Tanners Creek 345kV - Install TRV capacitor to increase the rating from 50kA to 63kA
    - Upgrade In-Service Date: 12/31/2020
    - Estimated Upgrade Cost: $0.05M
    - Construction Responsibility: AEP

55) Baseline Upgrade b3262

- Overview of Reliability Problem
    - Criteria Violation: Low voltage and voltage drop around Harrisonburg area
    - Criteria Test: Dominion FERC 715 Criteria - radial post contingency
- Overview of Reliability Solution
    - Description of Upgrade: Install a second 115kV 33.67MVar cap bank at Harrisonburg substation along with a 115kV breaker.
    - Upgrade In-Service Date: 12/31/2025
    - Estimated Upgrade Cost: $1.25M
    - Construction Responsibility: Dominion

56) Baseline Upgrade b3263

- Overview of Reliability Problem
    - Criteria Violation: Low voltage and voltage drop around James River DP area
    - Criteria Test: Dominion FERC 715 Criteria - radial post contingency & N-1-1
- Overview of Reliability Solution
    - Description of Upgrade: Cut existing 115kV Line#5 between Bremo and Cunningham substations and loop in and out of Fork Union Substation.
    - Upgrade In-Service Date: 12/31/2025
    - Estimated Upgrade Cost: $2.50M
    - Construction Responsibility: Dominion

57) Baseline Upgrade b3264

- Overview of Reliability Problem
    - Criteria Violation: 5 Taps on 115kV Line#117 (Dooms to Dupont-Waynesboro)
    - Criteria Test: Number of taps on a network transmission line
- Overview of Reliability Solution
    - Description of Upgrade: Install 115kV breaker at Stuarts Draft station and section 115kV Line#117 into two 115kV lines.
    - Upgrade In-Service Date: 12/31/2025
    - Estimated Upgrade Cost: $5.00M
    - Construction Responsibility: Dominion

58) Baseline Upgrade b3265

- Overview of Reliability Problem
    - Criteria Violation: The Arsenal - Riazzi (Z-101) 138 kV line exceeds its normal rating as a result of an N-2 failure of underground cables (Z-47 and Z-48) in a common trench
    - Criteria Test: N-2 underground cable common trench failure
- Overview of Reliability Solution
    - Description of Upgrade: Implement slow circulation on existing underground 138 kV high pressure fluid filled (HPFF) cable between Arsenal and Riazzi substations.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $2.40M
    - Construction Responsibility: DL

59) Baseline Upgrade b3266

- Overview of Reliability Problem
    - Criteria Violation: The Clay Village- Clay Village T 69 KV line section is overloaded
    - Criteria Test: EKPC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Upgrade the metering CT associated with the Clay Village-Clay Village T 69 kV line section to increase the line ratings.
    - Upgrade In-Service Date: 12/1/2021

- Estimated Upgrade Cost: $0.03M
- Construction Responsibility: EKPC

60) Baseline Upgrade b3267

- Overview of Reliability Problem
  - Criteria Violation: Low voltage at the Brodhead distribution substation of 0.89 PU
  - Criteria Test: EKPC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 4/0 ACSR Norwood-Shopville 69 kV line section using 556 ACSR/TW.
  - Upgrade In-Service Date: 12/1/2021
  - Estimated Upgrade Cost: $3.79M
  - Construction Responsibility: EKPC

61) Baseline Upgrade b3268

- Overview of Reliability Problem
  - Criteria Violation: Voltage drop around Midway and Red Hill areas
  - Criteria Test: Dominion FERC 715 Criteria - radial post contingency
- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date: 12/31/2025
  - Estimated Upgrade Cost: $3.00M
  - Construction Responsibility: Dominion

62) Baseline Upgrade b3269

- Overview of Reliability Problem
  - Criteria Violation: Overload of the GEN TIRE-Newcomerstown, The GREENR- MILL ST SS, New Philadelphia – New PHILA 34.5kV and GREERZ – GREER 69 kV branches
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $2.02M
  - Construction Responsibility: AEP

63) Baseline Upgrade b3270

- Overview of Reliability Problem
  - Criteria Violation: Overload of the AM General #2– AM General #1, AM General #2– Twin Branch2, Beiger – Virgil S, BEIGER-Kline, CAP AV – AM General #1, Dodge SS -12th St, 12th ST – Virgil, Dragoon – Railroad, Grape Rd – South Bend 34.5kV lines and Kline and South Ben 138/69/34.5 kV transformers

- Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: 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.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $4.89M
    - Construction Responsibility: AEP

64) Baseline Upgrade b3270.1

- Overview of Reliability Problem
    - Criteria Violation: Overstress of Dragoon 34.5 kV "B", "C" and "D" breakers
    - Criteria Test: Short Circuit
- Overview of Reliability Solution
    - Description of Upgrade: Replace Dragoon 34.5 kV Breakers "B", "C" and "D" with 40 kA breakers.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $2.00M
    - Construction Responsibility: AEP

65) Baseline Upgrade b3271

- Overview of Reliability Problem
    - Criteria Violation: Overload of the Fremont Center – Holran - Maple GR – Riverview 69 kV line
    - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: 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.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $1.76M
    - Construction Responsibility: AEP

66) Baseline Upgrade b3272

- Overview of Reliability Problem
    - Criteria Violation: Overload of the Days Inn - Rockhill, Days Inn – South Side, Exc&L PM – South Side, Exc&L PM – Sterling1 34.5kV lines
    - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Install two 138 kV circuit switchers on the high side of 138/34.5 kV transformers #1 & #2 at Rockhill station.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $1.47M

- Construction Responsibility: AEP

67) Baseline Upgrade b3273.1

- Overview of Reliability Problem
  - Criteria Violation: 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
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild and convert the existing 17.6 miles East Leipsic-New Liberty 34.5 kV circuit to 138 kV using 795 ACSR
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $31.35M
  - Construction Responsibility: AEP

68) Baseline Upgrade b3273.2

- Overview of Reliability Problem
  - Criteria Violation: 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
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Convert the existing 34.5 kV equipment to 138 kV and expanded the existing McComb station to the north and east to allow for new equipment to be installed. Install two new 138 kV box bays to allow for line positions and two new 138/12 kV transformers.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.87M
  - Construction Responsibility: AEP

69) Baseline Upgrade b3273.3

- Overview of Reliability Problem
  - Criteria Violation: 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
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Expand the existing East Leipsic 138 kV station to the north to allow for another 138 kV line exit to be installed. The new line exit will involve installing a new 138 kV circuit breaker, disconnect switches and new dead end structure along with extending existing 138 kV bus work.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $1.30M
  - Construction Responsibility: AEP

70) Baseline Upgrade b3273.4

- Overview of Reliability Problem
    - Criteria Violation: 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
    - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Add one 138 kV circuit breaker and disconnect switches in order to add an additional line position at New Liberty 138 kV station. Install line relaying potential devices and retire the 34.5 kV breaker F.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.90M
    - Construction Responsibility: AEP

71) Baseline Upgrade b3274

- Overview of Reliability Problem
    - Criteria Violation: The West Newcomerstown-KimBLTN-SaltFork 69 kV line are overloaded
    - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild approximately 8.9 miles of 69 kV line between Newcomerstown and Salt Fork Switch with 556 ACSR conductor.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $15.89M
    - Construction Responsibility: AEP

72) Baseline Upgrade b3275.1

- Overview of Reliability Problem
    - Criteria Violation: The Conner RN-Columbi-Natrium 69 kV line and Kammer-Cresaps-McElroy 69 kV line are overloaded
    - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild Kammer Station-Cresaps Switch 69 kV, approximately 0.5 miles.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.93M
    - Construction Responsibility: AEP

73) Baseline Upgrade b3275.2

- Overview of Reliability Problem
    - Criteria Violation: The Conner RN-Columbi-Natrium 69 kV line and Kammer-Cresaps-McElroy 69 kV line are overloaded
    - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild Cresaps Switch-McElroy Station 69 kV, approximately 0.67 miles.

- Upgrade In-Service Date: 6/1/2025
- Estimated Upgrade Cost: $1.25M
- Construction Responsibility: AEP

74) Baseline Upgrade b3275.3

- Overview of Reliability Problem
  - Criteria Violation: The Conner RN-Columbi-Natrium 69 kV line and Kammer-Cresaps-McElroy 69 kV line are overloaded
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace a single span of 4/0 ACSR from Moundsville-Natrium str 93L to Carbon Tap switch 69kV located between Colombia Carbon and Conner Run stations. Remainder of line is 336 ACSR.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.01M
  - Construction Responsibility: AEP

75) Baseline Upgrade b3275.4

- Overview of Reliability Problem
  - Criteria Violation: The Conner RN-Columbi-Natrium 69 kV line and Kammer-Cresaps-McElroy 69 kV line are overloaded
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild from Colombia Carbon to Columbia Carbon Tap str 93N 69 kV, approximately 0.72 miles. The remainder of the line between Colombia Carbon Tap structure 93N and Natrium station is 336 ACSR and will remain.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $1.08M
  - Construction Responsibility: AEP

76) Baseline Upgrade b3275.5

- Overview of Reliability Problem
  - Criteria Violation: The Conner RN-Columbi-Natrium 69 kV line and Kammer-Cresaps-McElroy 69 kV line are overloaded
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Cresaps 69 kV 3-Way Phase-Over-Phase Switch and structure with a new 1200 A 3-Way Switch and Steel Pole.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.71M
  - Construction Responsibility: AEP

77) Baseline Upgrade b3275.6

- Overview of Reliability Problem
  - Criteria Violation: The Conner RN-Columbi-Natrium 69 kV line and Kammer-Cresaps-McElroy 69 kV line are overloaded
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace 477 MCM Alum bus and risers at McElroy 69 kV station.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.33M
  - Construction Responsibility: AEP

78) Baseline Upgrade b3275.7

- Overview of Reliability Problem
  - Criteria Violation: The Conner RN-Columbi-Natrium 69 kV line and Kammer-Cresaps-McElroy 69 kV line are overloaded
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace Natrium 138 kV bus existing between CB-BT1 and along the 138 kV Main Bus # 1 dropping to CBH1 from the 500MCM conductors to a 1272 KCM AAC conductor. Replace the dead end clamp and strain insulators.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.29M
  - Construction Responsibility: AEP

79) Baseline Upgrade b3276.1

- Overview of Reliability Problem
  - Criteria Violation: The East Lancaster-Lancaster 69 kV line and Lancaster-South Lancaster 69 kV line, Ralston-Lancaster Junction 69 kV line are overloaded
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 2/0 Copper section of the Lancaster-South Lancaster 69 kV line, approximately 2.9 miles of the 3.2 mile total length with 556 ACSR conductor. The remaining section has 336 ACSR conductor.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $5.37M
  - Construction Responsibility: AEP

80) Baseline Upgrade b3276.2

- Overview of Reliability Problem
  - Criteria Violation: The East Lancaster-Lancaster 69 kV line and Lancaster-South Lancaster 69 kV line, Ralston-Lancaster Junction 69 kV line are overloaded
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution

- Description of Upgrade: Rebuild the 1/0 Copper section of the line between Lancaster Junction and Ralston station 69 kV, approximately 2.3 miles of the 3.1 mile total length.
- Upgrade In-Service Date: 6/1/2025
- Estimated Upgrade Cost: $4.58M
- Construction Responsibility: AEP

81) Baseline Upgrade b3276.3

- Overview of Reliability Problem
  - Criteria Violation: The East Lancaster-Lancaster 69 kV line and Lancaster-South Lancaster 69 kV line, Ralston-Lancaster Junction 69 kV line are overloaded
  - Criteria Test: AEP FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 2/0 Copper portion of the line between East Lancaster Tap and Lancaster 69 kV, approximately 0.81 miles.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $1.20M
  - Construction Responsibility: AEP

82) Baseline Upgrade b3277

- Overview of Reliability Problem
  - Criteria Violation: Breaker Over Duty
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace the existing East Akron 138 kV breaker B-22 with 3000A continuous, 40 KA momentary current interrupting rating circuit breaker.
  - Upgrade In-Service Date: 6/1/2021
  - Estimated Upgrade Cost: $0.55M
  - Construction Responsibility: ATSI

83) Baseline Upgrade b3300

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230kV Line #2172
  - Criteria Test: N-1 thermal, Generation Deliverability, N-1-1 thermal, TO Criteria
- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $2.32M
  - Construction Responsibility: Dominion

84) Baseline Upgrade b3301

- Overview of Reliability Problem

- Criteria Violation: Overload of 230kV Line #2210
- Criteria Test: N-1 thermal, Generation Deliverability, N-1-1 thermal, TO Criteria

- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $2.26M
  - Construction Responsibility: Dominion

85) Baseline Upgrade b3302

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230kV Line #2213
  - Criteria Test: N-1-1 thermal summer
- Overview of Reliability Solution
  - Description of Upgrade: 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.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $1.75M
  - Construction Responsibility: Dominion

86) Baseline Upgrade b3303.1

- Overview of Reliability Problem
  - Criteria Violation: >300 MW load loss
  - Criteria Test: N-1-1 >300 MW load loss summer and winter
- Overview of Reliability Solution
  - Description of Upgrade: Extend a new single circuit 230KV line (#9250) from Farmwell Substation to Nimbus Substation.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $5.65M
  - Construction Responsibility: Dominion

87) Baseline Upgrade b3303.2

- Overview of Reliability Problem
  - Criteria Violation: >300 MW load loss
  - Criteria Test: N-1-1 >300 MW load loss summer and winter
- Overview of Reliability Solution
  - Description of Upgrade: Remove Beaumeade 230kV Line #2152 line switch.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.05M
  - Construction Responsibility: Dominion

88) Baseline Upgrade b3304

- Overview of Reliability Problem
    - Criteria Violation: >300 MW load loss
    - Criteria Test: Common mode & N-1-1 >300 MW load loss winter
- Overview of Reliability Solution
    - Description of Upgrade: Midlothian Area 300 MW Load Drop Relief Area Improvements
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $6.22M
    - Construction Responsibility: Dominion

89) Baseline Upgrade b3304.1

- Overview of Reliability Problem
    - Criteria Violation: >300 MW load loss
    - Criteria Test: Common mode & N-1-1 >300 MW load loss winter
- Overview of Reliability Solution
    - Description of Upgrade: Cut 230kV Line #2066 at Trabue junction
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: Dominion

90) Baseline Upgrade b3304.2

- Overview of Reliability Problem
    - Criteria Violation: >300 MW load loss
    - Criteria Test: Common mode & N-1-1 >300 MW load loss winter
- Overview of Reliability Solution
    - Description of Upgrade: 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;
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: Dominion

91) Baseline Upgrade b3304.3

- Overview of Reliability Problem
    - Criteria Violation: >300 MW load loss
    - Criteria Test: Common mode & N-1-1 >300 MW load loss winter
- Overview of Reliability Solution
    - Description of Upgrade: 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

- Upgrade In-Service Date: 6/1/2025
- Estimated Upgrade Cost: $0.00M
- Construction Responsibility: Dominion

92) Baseline Upgrade b3304.4

- Overview of Reliability Problem
  - Criteria Violation: >300 MW load loss
  - Criteria Test: Common mode & N-1-1 >300 MW load loss winter
- Overview of Reliability Solution
  - Description of Upgrade: Create new line terminations at Midlothian for the new Midlothian-Trabue lines.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

93) Baseline Upgrade b3305

- Overview of Reliability Problem
  - Criteria Violation: FG# GD-S480 and GD-S483
  - Criteria Test: Summer Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace Pumphrey 230/115kV transformer
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $4.69M
  - Construction Responsibility: BGE

94) Baseline Upgrade b3306

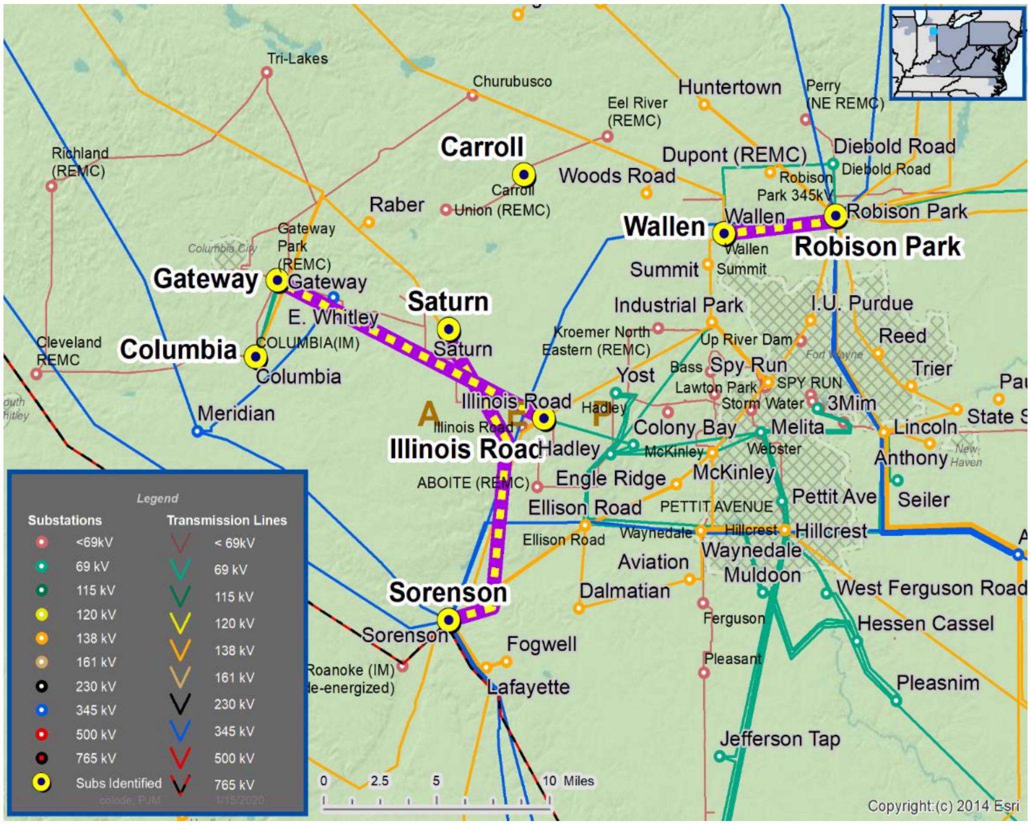
- Overview of Reliability Problem
  - Criteria Violation: FG# N2-SVM52 to N2-SVM55 and N2-WVM15 to N2-WVM19
  - Criteria Test: Summer and Winter N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Install a second 125 MVAR 345 kV shunt reactor and associated equipment at Pierce Brook Substation. Install a 345 kV breaker on the high side of the #1 345/230 kV transformer
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $8.08M
  - Construction Responsibility: PENELEC

Baseline Project b3151: Western Fort Wayne Area Improvements

AEP Transmission Zone

AEP FERC 715 Transmission Owner Criteria violations were identified in the western Fort Wayne, Indiana area. N-1 and N-1-1 thermal and voltage analysis identified multiple TO criteria violations for contingencies in the Carroll, Sorenson, Columbia and Whitley stations.

PJM worked closely with AEP to evaluate the thermal and voltage violations, and after confirming the validity of the violations, developed the following recommended solution.



Map 5. Western Fort Wayne Area

The recommended solution: Baseline Project b3151 addresses the thermal and voltage criteria violations when fully completed. The solution rebuilds the 30-mile Gateway-Wallen 34.5 kV circuit as the 27-mile Gateway-Wallen 69 kV circuit, including the retirement of 3 miles of the Columbia-Whitley 34.5 kV line. At the Gateway station, replace the 34.5 kV equipment with a 69 kV circuit breaker for the new Whitley line.

Rebuild Whitley as a 69 kV station, and replace the Union and Eel River 34.5 kV switches with 69 kV switches. Install a 69 kV switch at the Woodland station.

Replace Carrol and Churubusco 34.5 kV stations with the 69 kV Snapper station. Rebuild the 2.5-mile Columbia-Gateway 69 kV line. Rebuild Columbia as a 138/69 kV station with a 4-breaker ring bus.

Rebuild the 13-mile Columbia-Richland 69 kV line, rebuild 0.5 miles of Whitely-Columbia City 1 and Whitley-Columbia City 2 lines as 69 kV. Rebuild the 0.6-mile double circuit section of the Rob Park-South Hicksville/Rob Park-Diebiold Rd. as 69 kV.

The recommended solution addresses the baseline needs in the area. The estimated cost for this project is $113 million, and the projected in-service date is March 2022. The local transmission owner, AEP, will be designated to complete this work.

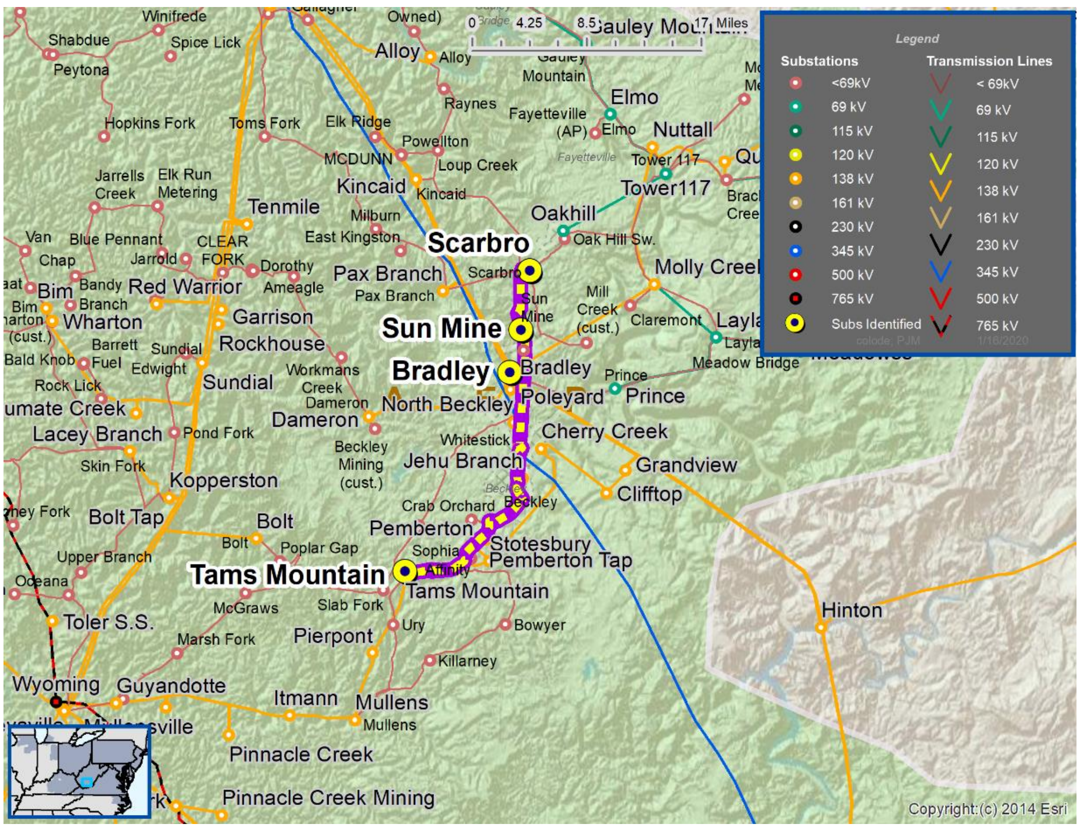
Baseline Project b3148: Rebuild Bradley-Scarbro 46kV Line

AEP Transmission Zone

AEP FERC 715 N-1-1 thermal and voltage violations are identified on the Bradley-Sun 46 kV line section and Tams Mountain-Glen White 46 kV line section for N-1-1 contingencies in the 2021 Winter RTEP Case.

Additionally, voltage magnitude violations are seen at the Beckley 46 kV, Whitestick 46 kV, Bradley 46 kV and Mt. Hope 46 kV substations. Voltage drop violations are seen at the Sun 46 kV station, Mt. Hope 46 kV station, Bradley 46 kV station, Whitestick 46 kV station, and Beckley 46 kV stations.

Additionally, Bradley-Scarbro 46 kV circuit has equipment material/condition/performance/risk issues shown in Supplemental Need AEP-2019-AP049.



Map 6. Bradley-Scarbro 46 kV

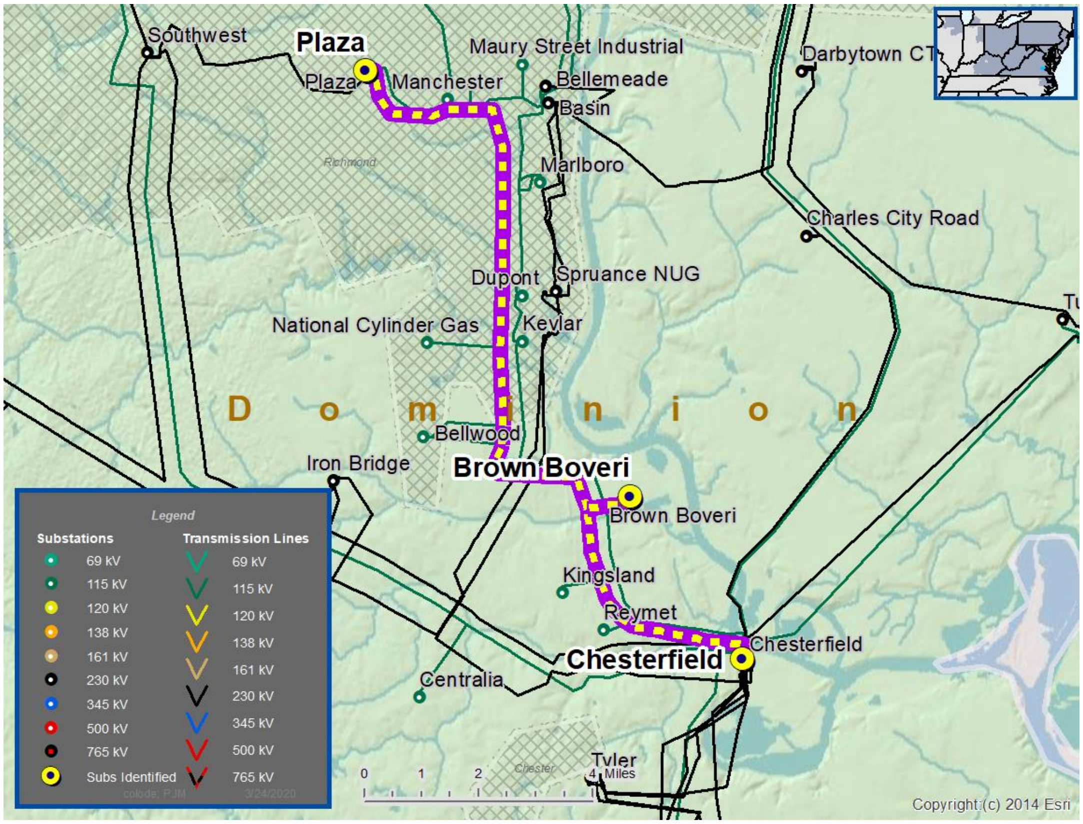
The recommended solution is to rebuild the 46 kV Bradley-Scarbro line (~7.8 miles). The new 46 kV line will be built with 795 ACSR (120 MVA) and 69 kV standards. Additional work includes Bradley remote-end station work, replace 46 kV bus, and install new 12 MVAR capacitor bank. The switch at Sun station will be replaced with a 2-way SCADA-controlled MOAB switch. Remote-end work and associated equipment at Scarbro station is required for this solution.

Additionally, PJM is recommending the retirement of the Mt. Hope station, transferring load to the existing Sun station. The estimated cost for this project is $27.7 million, and the projected in-service date is June 2021. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3161: Chesterfield-Plaza Transmission Line
Dominion Transmission Zone

Dominion FERC 715 Transmission Owner Planning Criteria limits the number of direct-connect loads (tapped facilities) to four facilities. The Chesterfield-Plaza line exceeds this limit, as the line currently serves five tap stations: National Cylinder Gas, Bellwood, Brown Boveri, Kingsland and Reymet.

Additionally, the Brown Boveri tap line, with a length of 1.1 miles, exceeds Dominion’s requirement of a terminal station for tap lines longer than one mile.



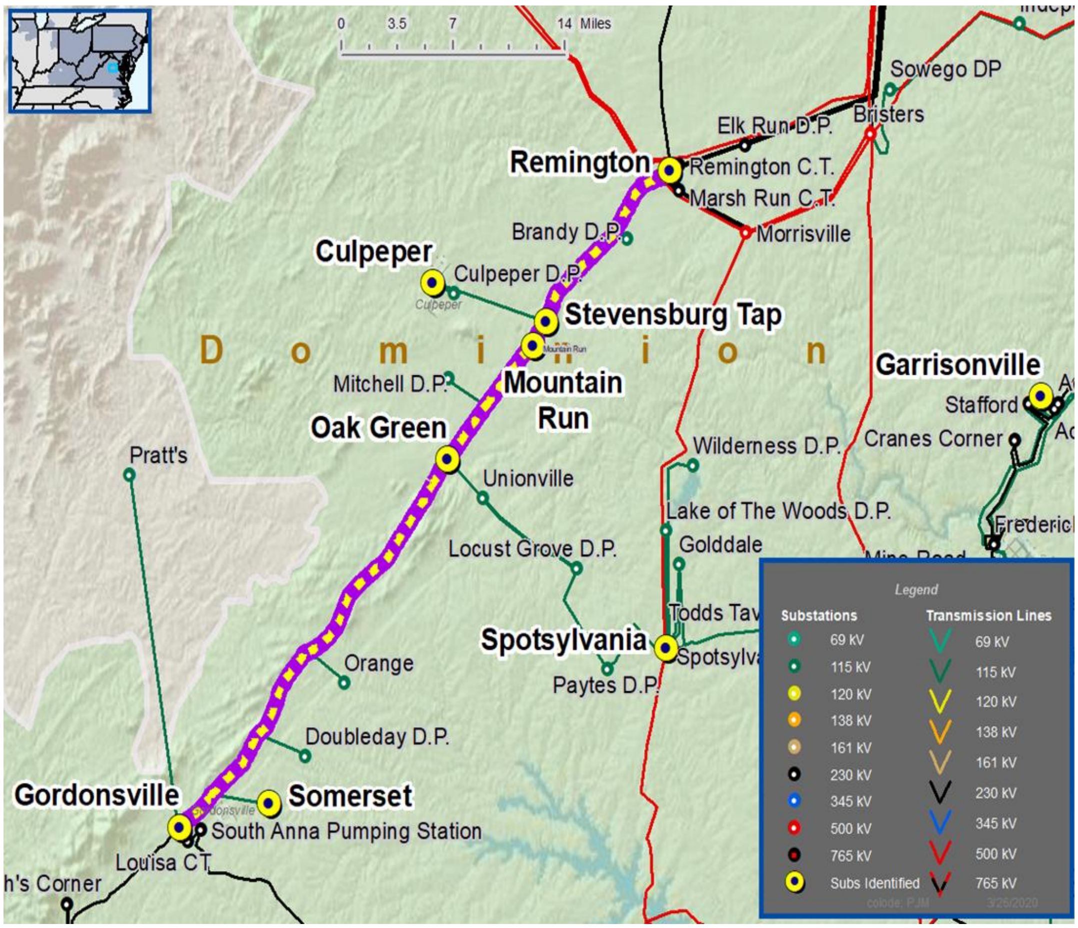
Map 7. Chesterfield-Plaza 115 kV

The recommended solution is to split the Chesterfield-Plaza 115 kV by rebuilding the Brown Boveri tap line as a double-circuit loop in-and-out of the station, and install a 115 kV breaker at Brown Boveri. Site expansion is also required for the project in order to accommodate the new site layout.

The estimated cost for this project is $5.3 million, with a required in-service date of June 2024, and the projected in-service date is December 2023. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3162: Spotsylvania-Oak Green and Culpeper 115 kV Delivery
Dominion Transmission Zone

Dominion FERC 715 Transmission Owner Planning Criteria violations were identified at Spotsylvania-Oak Green 115 kV for the N-1-1 loss of multiple circuits. The voltage at Culpeper also drops below 85 percent at Culpeper for the N-1-1 loss of multiple circuits.



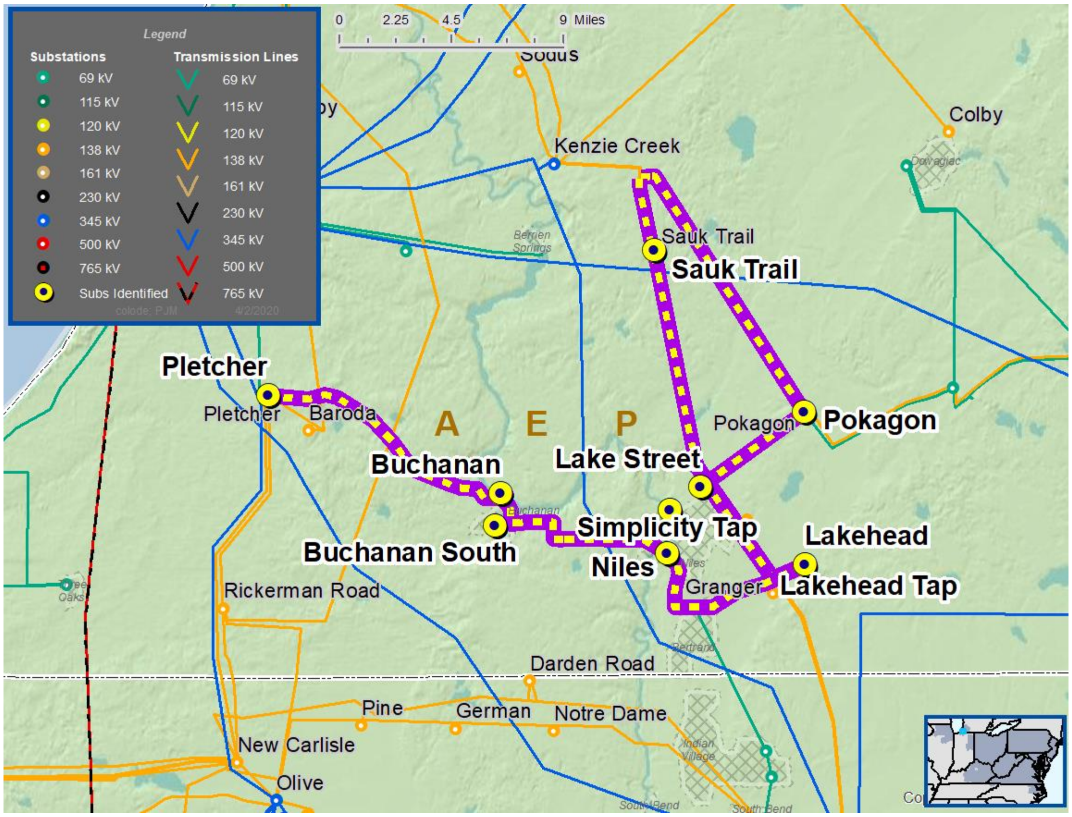
Map 8. Spotsylvania-Oak Green and Culpeper 115 kV

The recommended solution is to acquire land and build a new 230 kV switching station (Stevensburg) with a 224 MVA, 230/115 kV transformer. The Gordonsville-Remington, Remington-Mt. Run and Mt. Run-Oak Green 115 kV lines will be cut and connected to the new Stevensburg station.

The estimated cost for this project is $22 million, with a required in-service date of June 2024, and the projected in-service date is December 2023. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3160: Niles Area Improvements
AEP Transmission Zone

AEP FERC 715 Transmission Owner Planning Criteria violations were identified in the Niles area. Niles-Simplicity 34.5 kV is overloaded for multiple N-1 contingencies. There are multiple identified N-1-1 thermal and voltage issues in the Niles area.



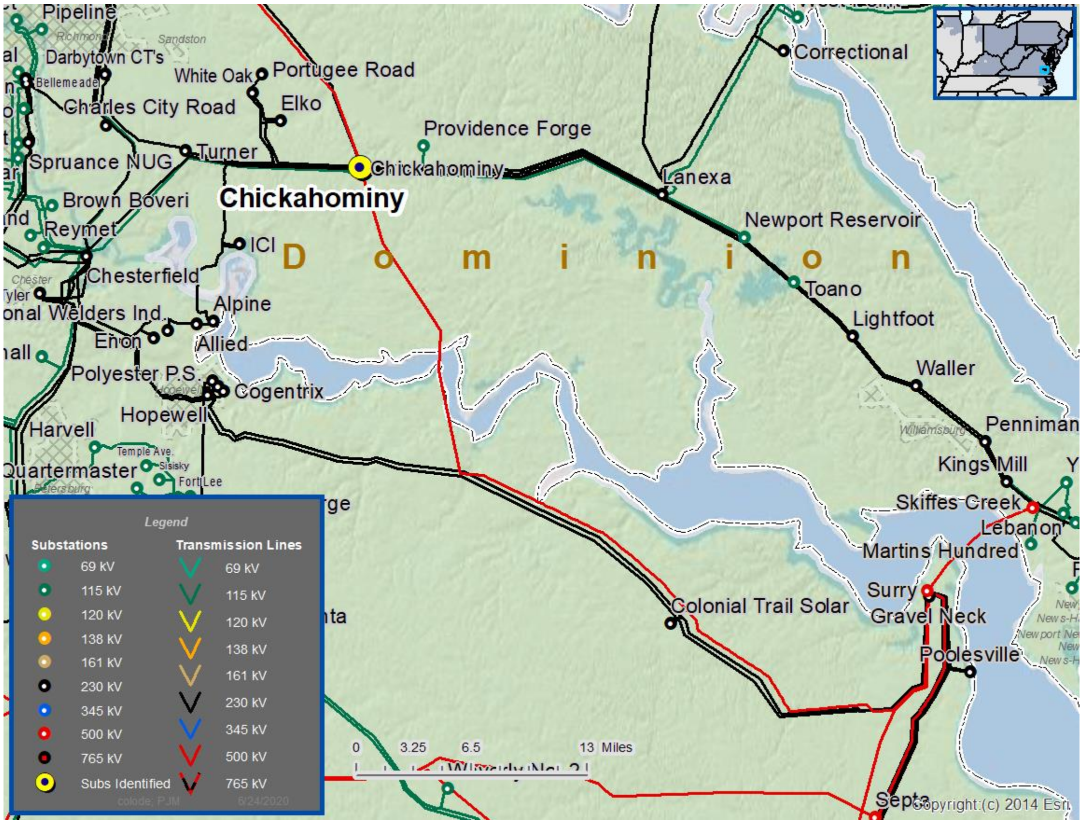
Map 9. Niles Area Improvements

The recommended solution is to construct approximately 2.4 miles of a new double-circuit 138 kV extension, using 1033 ACSR, which will connect Lake Head to the 138 kV network. The solution will also retire approximately 2.5 miles of Niles-Simplicity 34.5 kV and approximately 4.6 miles of Lakehead 69 kV tap lines, and build a new 138/69 kV drop-down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV MOAB. Approximately 8.4 miles of Pletcher-Buchanan Hydro 69 kV line will be rebuilt as the 9 mile Pletcher-Buchanan South 69 kV line using 795 ACSR, and approximately 1.2 miles of Buchanan South 69 kV radial tap will be rebuilt using 795 ACSR. The solution will also install a phase-over-phase switch at Buchanan South station with two line MOABs.

The total estimated cost for this project is $36.2 million, with a required in-service date of June 2024, and a projected in-service date is June 2022. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3213: Second Chickahominy 500/230 kV Transformer
Dominion Transmission Zone

Due to the deactivation of the Chesterfield 5 and 6 units, the Chickahominy 500/230 kV transformer is overloaded for an N-1 contingency.



Map 10. Chickahominy 500/230 kV Transformer

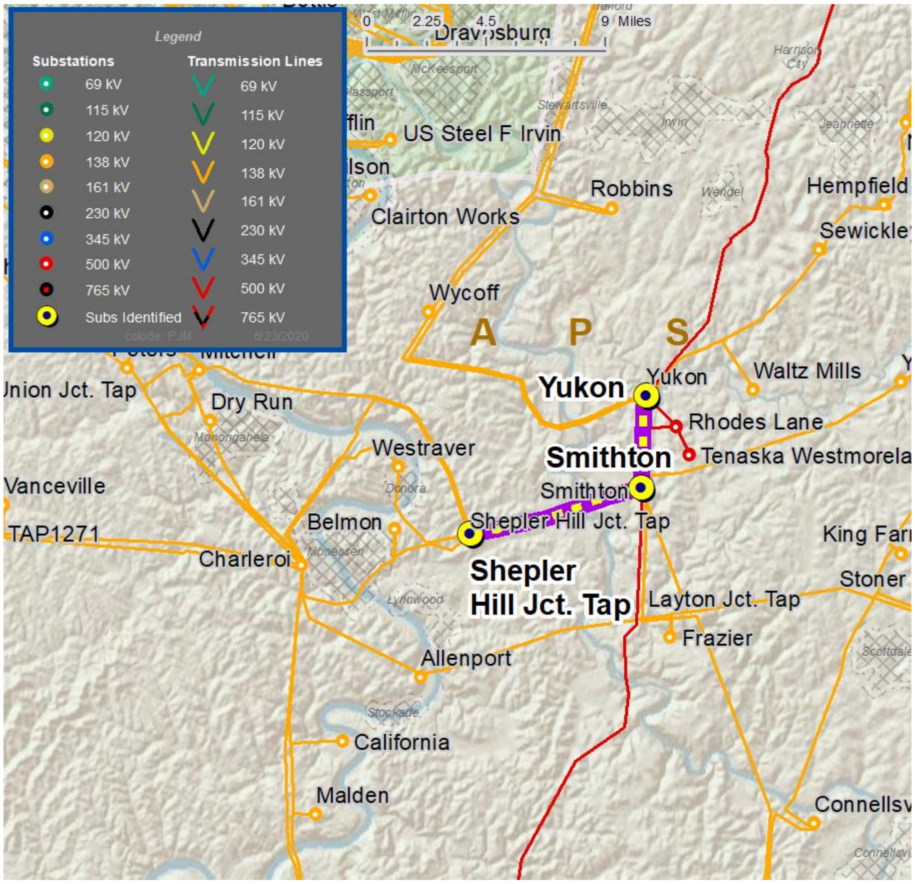
The recommended solution is to install a second Chickahominy 500/230 kV transformer. The estimated cost for this project is $22 million, with a required and projected in-service date of June 2023. The local transmission owner, Dominion, will be designated to complete this work.

Beaver Valley Reinstatement Baselines

The Beaver Valley nuclear units, totaling 1,811 MW capacity, withdrew their deactivation request in March 2020. The reinstatement study has determined that the following scope of work is either still needed to maintain reliability or will be completed due to work progression.

Baseline Project b3012: Yukon-Smithton-Shepler Hill Jct 138 kV
APS Transmission Zone

The original project scope for baseline b2966 was previously canceled due to the scope change for baseline b3012 (driven by the Beaver Valley, Davis Besse and Perry nuclear deactivation notifications), which eliminated the need for the project. However, the Beaver Valley reinstatement study determined the scope of work is still needed to maintain reliability, and so the scope of work was reassigned to a new baseline b3214. The Yukon-Smithton and Smithton-Shepler Hill Jct 138 kV circuits are overloaded as a result of multiple tower contingencies.



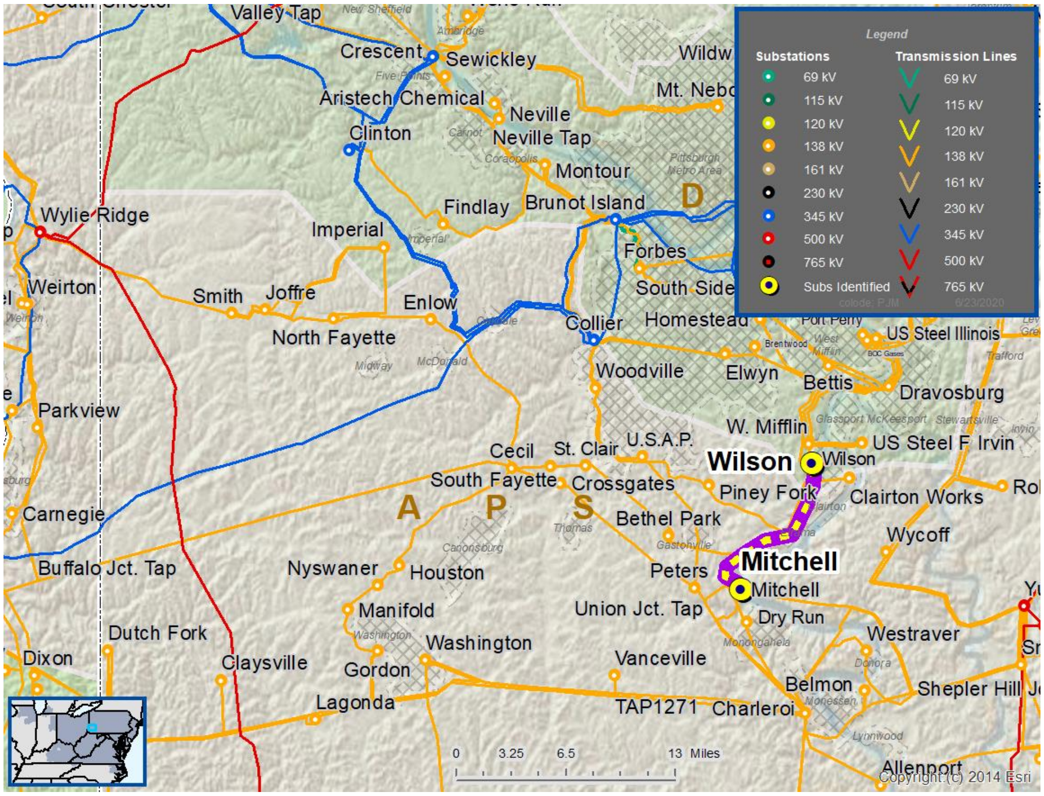
Map 11. Yukon-Smithton-Shepler Hill Jct 138 kV

The recommended solution is to reconductor Yukon-Smithton-Shepler Hill Jct 138 kV, upgrade the terminal equipment at Yukon 138 kV, and replace line relaying at Mitchell and Charleroi 138 kV. The estimated cost for this project is $21.4 million, with a required and projected in-service date of June 2023. The local transmission owner, APS, will be designated to complete this work.

Baseline Project b3217: Wilson-Mitchell 138 kV

DLCO Transmission Zone

The Beaver Valley reinstatement study determined that several baseline projects will remain due to work progression, and baseline b3015.5 project scope is one such upgrade. However, due to a component of the overall upgrade no longer being required, and its potential impact on cost allocation, the baseline was reassigned to the new baseline b3217. The Wylie Ridge 500/345 kV transformer and multiple 138 kV facilities in APS and DLCO transmission zones are overloaded for various contingencies in the zones.

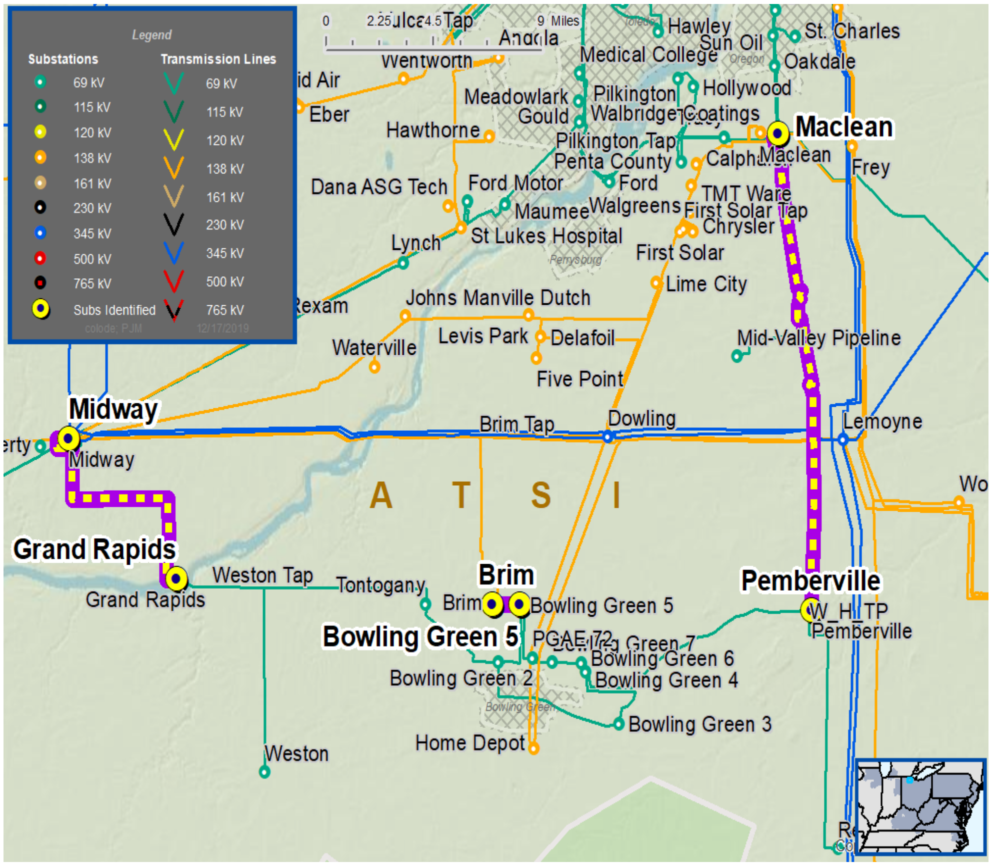


Map 12. **Wilson-Mitchell 138 kV**

The recommended solution is to reconductor the DLCO portion (4.2 miles) of the Wilson-Mitchell 138 kV circuit. The total estimated cost for this project is $7.5 million, with a required and projected in-service date of June 2021. The local transmission owner, DLCO, will be designated to complete this work.

Baseline Project b3159: New AMPT 138/69 kV Substation in Bowling Green Area
AMPT Transmission Zone

There are multiple AMP Transmission FERC Form 715 Transmission Owner Planning Criteria thermal overloads and voltage violations on the 69 kV system in the Bowling Green and Pemberville area for multiple N-1-1 contingencies.



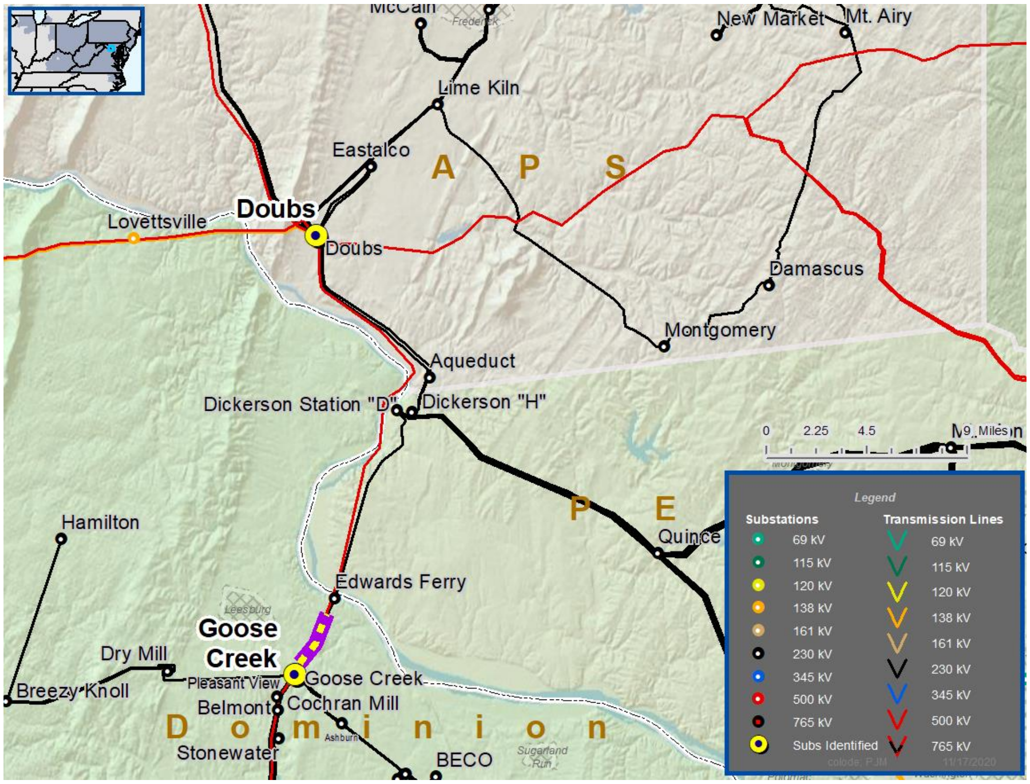
Map 13. Bowling Green and Pemberville Area

The recommended solution is to establish a new 138/69 kV substation with one 138 kV circuit breaker, one 138/69 kV 130 MVA transformer, and three 69 kV circuit breakers. The project will also construct a 0.15 mile 138 kV 795 ACSR transmission line between Brim 138/69 kV substation (First Energy) and the newly proposed AMPT substation. The Bowling Green Sub No. 5-Bowling Green Sub No. 2 69 kV line will be looped in and out of the newly established substation. The total estimated cost for this project is $5.7 million, with a required and projected in-service date of June 2024. The transmission owner, AMPT, will be designated to complete this work.

Baseline Project b3247: Doubs-Goose Creek 500 kV Rebuild
Dominion Transmission Zone

The First Energy to Dominion tie line, Doubs-Goose Creek 500 kV, is an approximately 18-mile long line, 3 miles of which is Dominion owned. The line is primarily constructed on weathering COR-TEN® steel lattice structures. Third-party assessment has determined that the towers have corroded to a point where they exhibit premature thinning of structure members and packout at joints. If left unaddressed, these issues could result in failure of the structures and potentially collapse for the line. This issue was identified through Dominion's end of life criteria (Dominion FERC Form 715 Transmission Owner Planning Criteria). The remainder of the line rebuild is a solution identified by APS through the M-3 process.

Map 1.



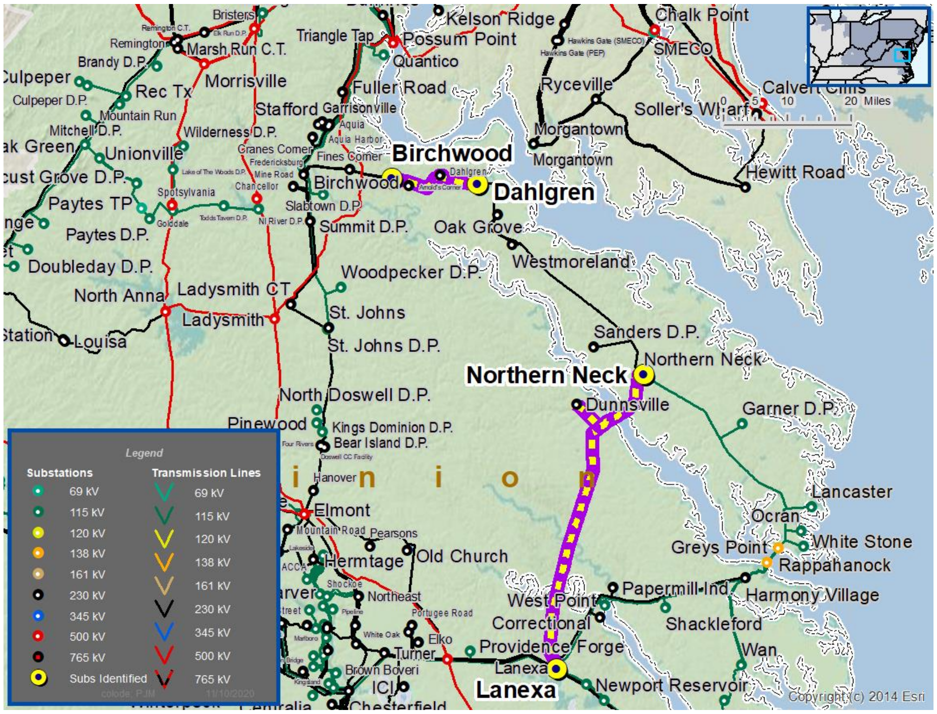
Map 14. Doubs-Goose Creek 500 kV

The recommended solution, solicited through the 2020 Window 2, is to replace Dominion's portion of the Doubs-Goose Creek 500 kV line, consisting of 13 COR-TEN® towers, with galvanized steel towers, to reconductor the 3-mile section with 3-1351.5 ACSR 45/7 and upgrade the line terminal equipment at Goose Creek substation to support the 500 kV line rebuild. The estimated cost for this project is $7.6 million, with a required and projected in-service date of June 2025. The local transmission owner, Dominion, will be designated to complete this work. While not a baseline upgrade requiring Board approval, it should be noted that through the Attachment M-3 process, Allegheny Power has also introduced a need for the remainder of the Doubs-Goose Creek line, not covered in the work to be performed under this baseline upgrade, to address the similar issues associated with the equipment structures and line for the Allegheny Power portion of the Doubs-Goose Creek 500 kV line.

Baseline Project b3223: Northern Neck Area
Dominion Transmission Zone

There are various N-1-1 voltage magnitude and drop violations in the Northern Neck area. Also, the Rappahannock-Whitestone and Harmony Village-Greys Point 115 kV circuits are overloaded for an N-1-1 contingency. Both the voltage and thermal violations were identified in the 2025 RTEP winter case.

There is currently an operating procedure in the Northern Neck area to mitigate thermal overloads on the Neck-Harmony Village 115 kV circuit. The operating procedure also helps to control and mitigate voltage. However, continued use of the operating procedure results in a PJM planning criteria violation of dropping over 300 MW in the 2022/2023 time frame based on the 2020 PJM load forecast.

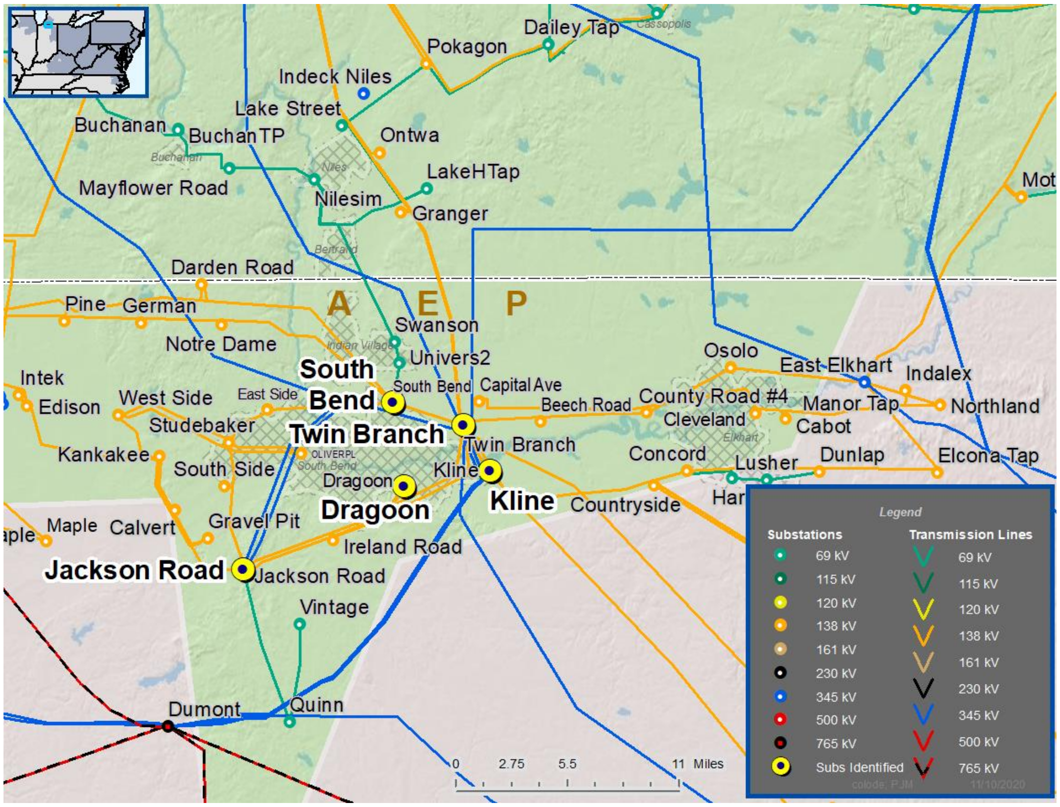


Map 15. Northern Neck Area

The recommended solution is to install a second Lanexa-Northern Neck 230 kV circuit, expand the Northern Neck 230 kV terminal from a four-breaker ring bus to a six-breaker ring bus, and expand the Lanexa 230 kV terminal from a six-breaker ring bus to a breaker-and-a-half arrangement. Increases in load and a shift in the load profile in Dominion to better match the winter peaking condition in Dominion has resulted in the increase in the magnitude of the load in this area of Dominion at an accelerated rate, leading to exceeding 300 MW load loss in a timeframe requiring that this project be designated as immediate-need. This project has an estimated cost of $23 million and a required and projected in-service date of June 2023. Given the configuration of the facilities in the area, and the need to serve load from these facilities, the local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3270: Dragoon 138 kV
AEP Transmission Zone

For 2020 Window 1, the following facilities were overloaded under multiple N-1-1 contingencies. The overloads were identified in both the 2025 RTEP summer and winter cases.



Map 16. Dragoon 138 kV

The recommended solution, solicited through the competitive proposal window, is to install 1.7 miles of 795 ASCR 138 kV conductor along the other side of Dragoon Tap 138 kV line, which is currently a double circuit tower with one position open. Additionally, the recommended solution will install a second 138/34.5 kV transformer and a high-side circuit switcher on the current transformer at Dragoon station, along with two 138 kV line breakers on the Dragoon-Jackson and Dragoon-Twin Branch 138 kV lines. The solution drives the Dragoon 34.5 kV circuit breakers B, C and D into an overdutied condition, so the breakers will be replaced with 40 kA breakers. The estimated cost for this project is $6.89 million, with a required and projected in-service date of June 2025. The local transmission owner, AEP, 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 2020 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 12/31/2020.

1) Baseline Upgrade b0866

- Replace Chalk Point 230 kV breaker (6C) with 80 Ka breaker - 6/1/2012 - $2.00M

2) Baseline Upgrade b1205

- Siegfried-East Palmerton #1 69 kV Line- Install new 69 kV LSAB, Sectionalize, and Transfer Treichlers Substation - 5/31/2014 - $0.27M

3) Baseline Upgrade b1270

- Reconductor Bath - Trebein 138kV - 6/1/2015 - $1.30M

4) Baseline Upgrade b1273

- Add 2nd Bath 345/138kV Xfr - 6/1/2015 - $7.00M

5) Baseline Upgrade b1274

- Add 2nd Trebein 138/69kV Xfr - 6/1/2015 - $5.30M

6) Baseline Upgrade b1275

- Add 2nd W. Milton 138/69kV Xfr - 6/1/2015 - $8.80M

7) Baseline Upgrade b1276

- Add 2nd W. Milton 345/138 Xfr - 6/1/2015 - $5.50M

8) Baseline Upgrade b1570

- Add a 345/69 kV transformer at Dayton's Peoria 345 kV bus - 6/1/2014 - $16.00M

9) Baseline Upgrade b1570.1

- Add/reconductor Peoria - Darby 69 kV line - 6/1/2014 - $0.00M

10) Baseline Upgrade b1570.2

- Add / reconductor Peoria - Union REA 69 kV line - 6/1/2014 - $0.00M

11) Baseline Upgrade b1570.3

- Reconductor Union REA - Honda MT 69 kV line - 6/1/2014 - $0.00M

12) Baseline Upgrade b1570.4

- Add a 345 kV breaker at Marysville station and a 0.1 mile 345 kV line extension from Marysville to the new 345/69 kV Dayton transformer. - 6/1/2021 - $3.84M

13) Baseline Upgrade b1572

- Construct a new 138 kV line from West Milton to Eldean - 6/1/2014 - $16.00M

14) 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

15) Baseline Upgrade b1696.1

- Replace the Idylwood 230 kV '25112' breaker with 50 kA breaker - 6/1/2017 - $0.35M

16) Baseline Upgrade b1696.2

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

17) Baseline Upgrade b1880

- Rebuild the 15 miles of the Moseley - Roanoke 138 kV line. This project would consist of rebuilding both circuits on the double circuit line - 6/1/2016 - $30.00M

18) Baseline Upgrade b2003

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

19) 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

20) 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

21) Baseline Upgrade b2334

- Install a 69 kV, 22.96 MVAR capacitor bank at the Owen County substation - 6/1/2017 - $0.36M

22) 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

23) Baseline Upgrade b2396.1

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

24) 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

25) Baseline Upgrade b2443.6

- Install a second 500/230 kV transformer at Possum Point substation and replace bus work and associated equipment as needed. - 6/1/2023 - $23.08M

26) Baseline Upgrade b2443.7

- Replace 19 - 63 kA 230 kV breakers with 19 – 80 kA 230 kV breakers - 6/1/2023 - $19.00M

27) Baseline Upgrade b2496

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

28) 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

29) Baseline Upgrade b2505

- Install structures in river to remove the 115 kV #65 line (Whitestone - Harmony Village 115 kV) from bridge and improve reliability of the line - 5/31/2016 - $105.00M

30) 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 - $10.80M

31) 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

32) Baseline Upgrade b2586

- Upgrade the V74 34.5 kV transmission line between Allenhurst and Elberon Substations - 6/1/2018 - $16.00M

33) 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

34) 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

35) Baseline Upgrade b2603

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

36) Baseline Upgrade b2604

- Bellefonte Transformer Addition - 6/1/2019 - $5.21M

37) Baseline Upgrade b2611

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

38) Baseline Upgrade b2611.1

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

39) 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

40) 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

41) Baseline Upgrade b2633

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

42) Baseline Upgrade b2633.4

- Add a new 500 kV bay at Hope Creek (Expansion of Hope Creek substation) - 4/1/2019 - $46.70M

43) Baseline Upgrade b2633.5

- Add a new 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation - 4/1/2019 - $58.30M

44) Baseline Upgrade b2633.91

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

45) Baseline Upgrade b2633.92

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

46) Baseline Upgrade b2651

- Rebuild Buggs Island - Plywood 115 kV Line #127 (25.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV. The line should be rebuilt for 230 kV and operated at 115 kV. - 12/31/2021 - $42.41M

47) 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

48) Baseline Upgrade b2656

- Reconductor the Leon - Airport Road 69 kV line section (5.72 miles) using 556.5 MCM ACTW conductor - 12/1/2018 - $1.65M

49) Baseline Upgrade b2668

- Reconductor Dequine - Meadow Lake 345 kV circuit #1 utilizing dual 954 ACSR 54/7 cardinal conductor - 6/1/2020 - $5.10M

50) Baseline Upgrade b2670

- Replace switches at Elk Garden and Lebanon 138 kV substations (on the Elk Garden-Lebanon 138 kV circuit). - 6/1/2020 - $4.80M

51) Baseline Upgrade b2671

- Replace/upgrade/add terminal equipment at Bradley, Mullensville, Pinnacle Creek, Itmann, and Tams Mountain 138 kV substations. Sag study on Mullens – Wyoming and Mullens – Tams Mt. 138 kV circuits - 6/1/2020 - $5.36M

52) Baseline Upgrade b2675

- Install 26.4 MVAR capacitor and associated terminal equipment at Lincoln Park 138 kV substation - 6/1/2020 - $1.00M

53) Baseline Upgrade b2680

- Install a 115 kV breaker on Hooversville #1 115/23 kV transformer - 6/1/2020 - $0.73M

54) Baseline Upgrade b2685

- Install a second 115 kV 3000A bus tie breaker at Hooversville substation - 6/1/2020 - $1.42M

55) Baseline Upgrade b2697.1

- Mitigate violations identified by sag study to operate Fieldale-Thornton-Franklin 138 kV overhead line conductor at its max. operating temperature. 6 potential line crossings to be addressed. - 6/1/2019 - $1.30M

56) Baseline Upgrade b2697.2

- Replace terminal equipment at AEP's Danville and East Danville substations to improve thermal capacity of Danville - East Danville 138 kV circuit - 6/1/2019 - $1.40M

57) Baseline Upgrade b2708

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

58) Baseline Upgrade b2709

- Replace the Deep Run 230/34.5 kV #1 - 6/1/2020 - $3.90M

59) Baseline Upgrade b2727

- Replace the South Canton 138 kV breakers 'K', 'J','J1', and 'J2' with 80 kA breakers. - 6/1/2018 - $1.20M

60) Baseline Upgrade b2733

- Replace South Canton 138 kV breakers 'L' and 'L2' with 80 kA rated breakers - 6/1/2021 - $0.78M

61) 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

62) Baseline Upgrade b2743.2

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

63) Baseline Upgrade b2743.3

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

64) Baseline Upgrade b2743.4

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

65) 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

66) Baseline Upgrade b2743.6

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

67) Baseline Upgrade b2743.6.1

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

68) Baseline Upgrade b2743.7

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

69) Baseline Upgrade b2743.8

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

70) 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

71) Baseline Upgrade b2752.2

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

72) 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

73) 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

74) 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

75) 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

76) 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

77) Baseline Upgrade b2752.8

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

78) Baseline Upgrade b2752.9

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

79) Baseline Upgrade b2753.3

- Holloway Station – Connect two 138kV 6-wired ckts from “Point A” (currently de-energized and owned by First Energy) in ckt positions previously designated Burger #1 & Burger #2. Install interconnection settlement metering on both circuits exiting Holloway station. - 5/31/2020 - $2.00M

80) 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

81) Baseline Upgrade b2753.9

- Remove/Open Kammer 345/138 kV transformer #301 - 9/13/2021 - $0.00M

82) Baseline Upgrade b2759

- Rebuild Line #550 Mt. Storm – Valley 500kV - 6/1/2016 - $288.19M

83) 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

84) 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

85) Baseline Upgrade b2761.2

- Perform a Sag Study of the Hazard – Wooten 161 kV line to increase the thermal rating of the line - 6/1/2021 - $0.00M

86) Baseline Upgrade b2761.3

- Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating). Replace line relaying and associated termination equipment. - 6/1/2021 - $16.48M

87) Baseline Upgrade b2764

- Upgrade Fairview Substation 138 kV breaker risers and disconnect leads; Replace 500 CU breaker risers and 556 ACSR disconnect leads with 795 ACSR - 6/1/2021 - $0.03M

88) 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

89) 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

90) Baseline Upgrade b2776

- Reconductor the entire Dequine - Meadow Lake 345 kV circuit #2 - 6/1/2021 - $6.60M

91) Baseline Upgrade b2777

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

92) Baseline Upgrade b2778

- Add 2nd 345/138 kV transformer at Chamberlin substation - 6/2/2021 - $4.00M

93) Baseline Upgrade b2779.1

- Construct a new 138 kV station, Sowers, tapping into the Grabill-South Hicksville 138 kV line - 6/1/2016 - $10.10M

94) Baseline Upgrade b2779.2

- Reconstruct sections of the Butler-N.Hicksville (9.6miles) and Auburn-Butler (9 miles) 69 kV circuits as 138 kV double circuit and extend the 138 kV line from Sowers station (3.5miles) - 6/1/2016 - $45.10M

95) Baseline Upgrade b2779.3

- Construct a new 345/138 kV SDI Varner Station which will serve a portion of the SDI load from the 138 kV system. Serve Wilmington Tap from new Varner 138 kV station, and install ddadditional breakers at South Butler 138 kV station to comply with AEP Interconnection Guidelines. - 6/1/2016 - $37.60M

96) 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 - $14.80M

97) Baseline Upgrade b2783

- Rebuild the Davis - Fayette 69kv line section to 556.5 MCM (3.15 miles) - 12/1/2021 - $1.30M

98) Baseline Upgrade b2787

- Reconductor 0.53 miles (14 spans) of the Kaiser Jct-Air Force Jct Sw section of the Kaiser-Heath 69 kV circuit/line with 336 ACSR to match the rest of the circuit (73 MVA rating, 78% loading). - 6/1/2021 - $1.10M

99) Baseline Upgrade b2788

- Install a new 3-way 69kV line switch to provide service to AEP's Barnesville distribution station. Remove a portion of the #1 copper T-Line from the 69kV through-path. - 6/1/2021 - $5.00M

100) Baseline Upgrade b2789

- Rebuild the Brues-Glendale Heights 69kV line section (5 miles) with 795 ACSR (128 MVA rating, 43% loading) - 6/1/2021 - $5.00M

101) Baseline Upgrade b2791

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

102) Baseline Upgrade b2791.2

- Rebuild Tiffin-Howard 69kV line from St. Stephen's Switch to Hinesville (14.7 miles) using 795 ACSR Drake conductor (90 MVA rating, non-conductor limited, 38% loading). - 6/1/2021 - $18.63M

103) Baseline Upgrade b2791.3

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

104) Baseline Upgrade b2791.4

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

105) Baseline Upgrade b2792

- Replace the Elliott transformer with a 130 MVA unit. Reconductor 0.42 miles of the Elliott – Ohio University 69 kV line with 556 ACSR to match the rest of the line conductor (102 MVA rating, 73% loading) and rebuild 4 miles of the Clark Street – Strouds Run 69 kV with 556 ACSR conductor (102 MVA rating, 76% loading). - 6/1/2021 - $12.65M

106) 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

107) 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

108) Baseline Upgrade b2795

- Install a 34.5 kV 4.8 MVAR capacitor bank at Killbuck 34.5kV station. - 6/1/2021 - $4.80M

109) Baseline Upgrade b2799

- Rebuild Valley-Almena, Almena-Hartford, Riverside-South Haven 69kV lines. New line exit at Valley Station. New transformers at Almena and Hartford - 6/1/2021 - $62.50M

110) Baseline Upgrade b2799.2

- Rebuild 3.2 miles of Almena to Hartford 69kV line using 795 ACSR conductor (90 MVA rating). - 6/1/2021 - $33.38M

111) Baseline Upgrade b2799.3

- Rebuild 3.8 miles of Riverside – South Haven 69V line using 795 ACSR conductor (90 MVA rating). - 6/1/2021 - $39.90M

112) Baseline Upgrade b2799.4

- At Valley station, add new 138kV line exit with a 3000 A 40 kA breaker for the new 138 kV line to Almena and replace CB D with a 3000 A 40 kA breaker. - 6/1/2021 - $0.67M

113) Baseline Upgrade b2799.5

- At Almena station, install a 90MVA 138kV/69kV transformer with low side 3000 A 40 kA breaker and establish a new 138kV line exit towards Valley. - 6/1/2021 - $1.57M

114) Baseline Upgrade b2800

- The 7 mile section from Dozier to Thompsons Corner of line #120 will be rebuilt to current standardsusing 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115kV. Line is proposed to be rebuilt on single circuit steel monopole structures. - 6/1/2017 - $12.60M

115) Baseline Upgrade b2816.1

- Modify the Crane – Windy Edge 110591 & 110592 115 kV circuits by terminating Windy Edge Circuits 110591 & 110592 into Northeast Substation with the addition of new 115kV breaker positions at Northeast sub - 6/1/2018 - $5.48M

116) Baseline Upgrade b2816.2

- Modify the Crane – Windy Edge 110591 & 110592 115 kV circuits by terminating Crane Circuits 110591 & 110592 into Northeast Substation with the addition of new 115kV breaker positions at Northeast sub - 6/1/2018 - $5.16M

117) Baseline Upgrade b2821

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

118) Baseline Upgrade b2827

- Upgrade the current 5% impedance 1200A line reactor, which connects the 4SPURLOCK - 4SPUR-KENT-R and 4SPUR-KENT-R - 4KENTON 138kV line sections, to a 6.5% impedance 1600A line reactor - 6/1/2021 - $0.43M

119) Baseline Upgrade b2828

- Install 10% reactors at Miami Fort 138 kV to limit current - 6/1/2021 - $0.95M

120) Baseline Upgrade b2831.1

- Upgrade Tanner Creek to Miami Fort 345 kV line (AEP portion) - 12/1/2021 - $0.64M

121) Baseline Upgrade b2831.2

- Rebuild the Tanner Creek – Miami Fort 345kV line (DEOK portion) - 12/1/2021 - $22.70M

122) 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 - $3.00M

123) Baseline Upgrade b2833

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

124) 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

125) Baseline Upgrade b2837

- Convert the F-1358/Z1326 and K1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits - 6/1/2017 - $0.00M

126) Baseline Upgrade b2837.1

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) - 6/1/2017 - $40.33M

127) Baseline Upgrade b2837.10

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) - 6/1/2017 - $42.02M

128) Baseline Upgrade b2837.11

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) - 6/1/2017 - $49.11M

129) Baseline Upgrade b2837.2

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) - 6/1/2017 - $12.42M

130) Baseline Upgrade b2837.3

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) - 6/1/2017 - $10.03M

131) Baseline Upgrade b2837.4

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) - 6/1/2017 - $45.64M

132) Baseline Upgrade b2837.5

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) - 6/1/2017 - $49.11M

133) Baseline Upgrade b2837.6

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) - 6/1/2017 - $40.33M

134) Baseline Upgrade b2837.7

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) - 6/1/2017 - $12.42M

135) Baseline Upgrade b2837.8

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) - 6/1/2017 - $10.03M

136) Baseline Upgrade b2837.9

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) - 6/1/2017 - $3.62M

137) 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

138) Baseline Upgrade b2870

- Build new 138/26 kV Newark GIS station in a building (layout #1A) located adjacent to the existing Newark Switch and demolish the existing Newark Switch - 6/1/2017 - $275.00M

139) Baseline Upgrade b2871

- Rebuild 230kV line #247 from Swamp to Suffolk (31 miles) to current standards with a summer emergency rating of 1047 MVA at 230kV. - 12/30/2022 - $31.00M

140) Baseline Upgrade b2872

- Replace the South Canton 138 kV breaker 'K2' with an 80 kA breaker . - 6/1/2019 - $0.60M

141) Baseline Upgrade b2873

- Replace the South Canton 138 kV breaker "M" with a 80 kA breaker - 6/1/2022 - $0.60M

142) Baseline Upgrade b2874

- Replace the South Canton 138 kV breaker "M2" with a 80 kA breaker - 6/1/2022 - $0.60M

143) Baseline Upgrade b2876

- Rebuild Line #101 from Mackeys - Creswell 115 kV, 14 miles, with double circuit structures. Install one circuit with provisions for a second circuit. The conductor used will be at current standards with a summer emergency rating of 262 MVA at 115kV. - 12/30/2022 - $27.50M

144) Baseline Upgrade b2877

- Rebuild Line #112 from Fudge Hollow - Lowmoor 138 kV (5.16 miles) to current standards with a summer emergency rating of 314 MVA at 138kV. - 10/31/2020 - $16.23M

145) 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 - $11.30M

146) Baseline Upgrade b2882

- Rebuild Reusens-Peakland Switch 69kV line. Replace Peakland Switch. - 6/1/2021 - $2.90M

147) Baseline Upgrade b2882.1

- Rebuild the Reusens - Peakland Switch 69 kV line (approximately 0.8 miles) utilizing 795 ACSR conductor (86 MVA rating, non-conductor limited, 67%) - 6/1/2021 - $11.80M

148) Baseline Upgrade b2882.2

- Replace existing Peakland S.S with new 3 way switch phase over phase structure. - 6/1/2021 - $0.70M

149) 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

150) Baseline Upgrade b2887

- Add 2-138kV CB's and relocate 2-138kV circuit exits to different bays at Morse Road. Eliminate 3 terminal line by terminating Genoa-Morse circuit at Morse Road. - 12/31/2019 - $3.00M

151) Baseline Upgrade b2889

- Expand Cliffview station - 6/1/2021 - $32.00M

152) Baseline Upgrade b2889.1

- Rebuild Cliffview station in the clear as Wolf Glade 138/69 kV station. Build a 138 kV bus. Install one 138/69 kV (130 MVA) transformer, five 138 kV (40kA 3000A) breakers and three 69 kV (40kA 3000A) breakers. - 6/1/2021 - $0.00M

153) 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

154) 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

155) Baseline Upgrade b2889.4

- Tap the existing Pipers Gap – Jubal Early 138 kV line section. Construct double circuit in/out (~2 miles) to the new Wolf Glade 138/69 kV station, utilizing 795 26/7 ACSR conductor. - 6/1/2021 - $0.00M

156) 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

157) Baseline Upgrade b2889.6

- Extend the existing double circuit Cliffview 69 kV line (0.5 mile) to the new Wolf Glade Station. - 6/1/2021 - $0.00M

158) Baseline Upgrade b2890.1

- Rebuild 23.55 miles of the East Cambridge – Smyrna 34.5 kV circuit with 795 ACSR conductor (128 MVA rating) and convert to 69 kV. - 6/1/2021 - $34.00M

159) Baseline Upgrade b2890.2

- East Cambridge: Install a 2000 A 69 kV 40 kA circuit breaker for the East Cambridge – Smyrna 69 kV circuit. -

6/1/2021 - $0.54M

160) Baseline Upgrade b2890.3

- Old Washington: Install 69 kV 2000 A two way phase over phase switch. - 6/1/2021 - $0.51M

161) Baseline Upgrade b2890.4

- Antrim Switch: Install 69 kV 2000 A two way phase over phase switch. - 6/1/2021 - $2.50M

162) 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

163) Baseline Upgrade b2894

- Replace Todhunter 138 kV breakers ‘931’, ‘919’, and ‘913’ with 80 kA breakers - 6/1/2021 - $2.03M

164) Baseline Upgrade b2895

- Replace Dicks Creek 138 kV breaker ‘963’ with 63 kA breaker - 6/1/2019 - $0.40M

165) Baseline Upgrade b2899

- Rebuild 230kV Line #231 to current standard with a summer emergency rating of 1046 MVA. Proposed conductor is 2-636 ACSR. - 12/1/2020 - $19.00M

166) 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

167) Baseline Upgrade b2901

- Reconductor the Port Union – Mulhauser 138kV line with 954ASCR bringing the summer ratings to A/B/C=300/300/300 MVA. - 6/1/2021 - $11.08M

168) 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 - $4.82M

169) Baseline Upgrade b2907

- Upgrade the metering CT associated with the Clay Village - KU Clay Village 69 kV Tap line section to 600 A; at least 64 MVA Winter LTE; Upgrade the distance relay associated with the Clay Village - KU Clay Village 69 kV Tap line section to at least 64 MVA Winter LTE. - 12/1/2024 - $0.13M

170) Baseline Upgrade b2914

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

171) Baseline Upgrade b2915

- Resize the Sideview 69 kV capacitor bank from 6.12 MVAR to 9.18 MVAR. - 12/1/2023 - $0.07M

172) 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 - $18.10M

173) Baseline Upgrade b2931

- Upgrade substation equipment at Pontiac Midpoint station to increase capacity on Pontiac-Brokaw 345 kV line. - 6/1/2021 - $5.50M

174) Baseline Upgrade b2932

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

175) Baseline Upgrade b2933

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

176) Baseline Upgrade b2933.1

- Construct a 230/69 kV station at Springfield. - 6/1/2018 - $51.93M

177) Baseline Upgrade b2933.2

- Construct a 230/69 kV station at Stanley Terrace - 6/1/2018 - $45.30M

178) Baseline Upgrade b2933.31

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

179) Baseline Upgrade b2933.32

- Construct a 69 kV network between Front Street, Springfield and Stanley Terrace (Springfield – Stanley Terrace) - 6/1/2018 - $52.60M

180) Baseline Upgrade b2935

- Third Supply for Runnemede 69kV and Woodbury 69kV - 6/1/2018 - $89.20M

181) 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

182) Baseline Upgrade b2935.2

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

183) 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

184) 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

185) 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

186) Baseline Upgrade b2941

- Build an indoor new Elk Grove 138kV GIS substation at the point where Rolling Meadows & Schaumburg tap off from the main lines, between Landmeier and Busse. The four 345 kV circuits in the ROW will be diverted into Gas Insulated Bus (GIB) and go through the basement of the building to provide clearance for the above ground portion of the building. - 12/31/2017 - $107.68M

187) Baseline Upgrade b2943

- Perform a LIDAR study on the Clifty Creek - Dearborn 345 kV line to increase the Summer Emergency rating above 1023MVA). - 6/1/2018 - $0.17M

188) 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 - $22.64M

189) Baseline Upgrade b2945.2

- Re-conductor BL England – Merion 138kV (1.9miles) line - 6/1/2022 - $3.92M

190) Baseline Upgrade b2945.3

- Re-conductor Merion – Corson 138kV (8miles) line - 6/1/2022 - $9.85M

191) Baseline Upgrade b2946

- Convert existing Preston 69 kV Substation to DPL's current design standard of a 3-breaker ring bus. - 6/1/2022 - $5.00M

192) Baseline Upgrade b2947.1

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

193) Baseline Upgrade b2947.2

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

194) Baseline Upgrade b2948

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

195) 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

196) 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 - $6.80M

197) Baseline Upgrade b2955

- Wreck and re-build the VFT – Warinanco – Aldene 230 kV circuit with paired conductor. - 6/1/2018 - $90.40M

198) Baseline Upgrade b2956

- Replace existing cable on Cedar Grove-Jackson Rd. with 5000kcmil XLPE cable. - 6/1/2018 - $69.80M

199) 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

200) 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

201) Baseline Upgrade b2964.1

- Replace terminal equipment at Pruntytown and Glen Falls 138 kV station. - 6/1/2022 - $0.26M

202) Baseline Upgrade b2964.2

- Reconductor approximately 8.3 miles of the McAlpin - White Hall Junction 138 kV circuit - 6/1/2022 - $3.79M

203) 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

204) Baseline Upgrade b2968

- Upgrade existing 345kV terminal equipment at Tanners Creek station on Tanners Creek - Miami Fort 345kV line - 6/1/2022 - $1.20M

205) Baseline Upgrade b2969

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

206) Baseline Upgrade b2970

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

207) Baseline Upgrade b2970.1

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

208) Baseline Upgrade b2970.2

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

209) Baseline Upgrade b2970.3

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

210) 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

211) Baseline Upgrade b2970.5

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

212) Baseline Upgrade b2976

- Upgrade terminal equipment at Tanners Creek 345kV station. Upgrade 345kV Bus and Risers at Tanners Creek for the Dearborn circuit. - 6/1/2021 - $0.60M

213) Baseline Upgrade b2977

- Portion of 2017_1-6A - 6/1/2021 - $8.47M

214) Baseline Upgrade b2977.1

- Install a new 345kV breaker “1422” so Pierce 345/138KV transformer #18 is now fed in a double breaker, double bus configuration. - 6/1/2021 - $0.00M

215) Baseline Upgrade b2977.2

- Remove X-533 No. 2 to the first tower outside the station. Install a new first tower for X-533 No.2. - 6/1/2021 - $0.00M

216) 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 - $0.00M

217) Baseline Upgrade b2977.4

- Remove breaker A and move the Pierce 345/138kV transformer #17 feed to the C-D junction. - 6/1/2021 - $0.00M

218) Baseline Upgrade b2977.5

- Replace breaker 822 at Beckjord 138kV substation to increase the rating from Pierce to Beckjord 138kV to 603MVA. - 6/1/2021 - $0.00M

219) 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

220) 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

221) 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

222) Baseline Upgrade b2982

- Construct a 230/69kV station at Hillsdale Substation and tie to Paramus and Dumont at 69kV. - 6/1/2018 - $99.06M

223) Baseline Upgrade b2982.1

- Install a 69kV ring bus and one (1) 230/69kV transformer at Hillsdale. - 6/1/2018 - $0.00M

224) Baseline Upgrade b2982.2

- Construct a 69kV network between Paramus, Dumont, and Hillsdale Substation using existing 69kV circuits - 6/1/2018 - $0.00M

225) Baseline Upgrade b2983

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

226) Baseline Upgrade b2983.1

- Install 69kV ring bus and two (2) 69/13kV transformers at Kuller Road. - 6/1/2018 - $0.00M

227) 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

228) Baseline Upgrade b2984

- Reconfigure the bus at Glory and install a 50.4 MVAR 115 kV capacitor - 6/1/2021 - $8.70M

229) 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

230) Baseline Upgrade b2986.1

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

231) Baseline Upgrade b2986.11

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

232) Baseline Upgrade b2986.12

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

233) Baseline Upgrade b2986.2

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

234) Baseline Upgrade b2986.21

- Branchburg-Pleasant Valley 230kV corridor rebuild (Branchburg - East Flemington) - 6/1/2018 - $66.36M

235) Baseline Upgrade b2986.22

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

236) Baseline Upgrade b2986.23

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

237) Baseline Upgrade b2986.24

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

238) 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 - $1.75M

239) Baseline Upgrade b2992.1

- Reconductor the Conastone to Graceton 230 kV 2323 & 2324 circuits. Replace 7 disconnect switches at Conastone Substation - 3/1/2021 - $23.10M

240) Baseline Upgrade b2992.2

- Add Bundle conductor on the Graceton-Bagley-Raphael Road 2305 & 2313 230kV circuits - 3/1/2021 - $24.00M

241) Baseline Upgrade b2992.4

- Reconductor the Raphael Road - Northeast 2315 & 2337 230kV circuits - 3/1/2021 - $9.75M

242) Baseline Upgrade b2996

- New Flint Run 500-138 kV substation - 6/1/2019 - $58.00M

243) Baseline Upgrade b2996.3

- Upgrade two (2) existing 138 kV breakers (Rider 50 and #1/4 transformer breaker) at Glen Falls with 63 kA, 3000 A units - 5/31/2020 - $0.90M

244) Baseline Upgrade b3000

- Replace South Canton 138kV breaker 'N' with an 80kA breaker - 6/1/2020 - $1.00M

245) Baseline Upgrade b3001

- Replace South Canton 138kV breaker 'N1' with an 80kA breaker - 6/1/2020 - $1.00M

246) Baseline Upgrade b3002

- Replace South Canton 138kV breaker 'N2' with an 80kA breaker - 6/1/2020 - $1.00M

247) Baseline Upgrade b3003

- Construct a 230/69kV station at Maywood - 6/1/2018 - $80.20M

248) Baseline Upgrade b3003.1

- Purchase properties at Maywood to accommodate new construction - 6/1/2018 - $0.00M

249) Baseline Upgrade b3003.2

- Extend Maywood 230kV bus and install one (1) 230kV breaker - 6/1/2018 - $0.00M

250) Baseline Upgrade b3003.3

- Install one (1) 230/69kV transformer at Maywood - 6/1/2018 - $0.00M

251) Baseline Upgrade b3003.4

- Install Maywood 69kV ring bus - 6/1/2018 - $0.00M

252) Baseline Upgrade b3003.5

- Construct a 69kV network between Spring Valley Road, Hasbrouck Heights, and Maywood - 6/1/2018 - $0.00M

253) Baseline Upgrade b3004

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

254) Baseline Upgrade b3004.1

- Install a new Clinton 230kV ring bus with one (1) 230/69kV transformer Mercer - Kuser Rd 230kV circuit - 6/1/2018 - $0.00M

255) Baseline Upgrade b3004.2

- Expand existing 69kV ring bus at Clinton Ave with two (2) additional 69kV breakers. - 6/1/2018 - $0.00M

256) Baseline Upgrade b3004.3

- Install two (2) 69/13kV transformers at Clinton Ave - 6/1/2018 - $0.00M

257) Baseline Upgrade b3004.4

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

258) 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

259) Baseline Upgrade b3006

- Replace four Yukon 500/138 kV transformers with three transformers with higher rating and reconfigure 500 kV bus - 6/1/2021 - $77.00M

260) 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

261) 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

262) Baseline Upgrade b3008

- Upgrade Blairsville East 138/115 kV transformer terminals. This project is an upgrade to the tap of the Seward – Shelocta 115 kV line into Blairsville substation. The project will replace the circuit breaker and adjust relay settings. - 6/1/2021 - $0.32M

263) Baseline Upgrade b3009

- Upgrade Blairsville East 115 kV terminal equipment. Replace 115 kV circuit breaker and disconnects. - 6/1/2021 - $0.26M

264) 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

265) Baseline Upgrade b3011.1

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

266) Baseline Upgrade b3011.2

- Upgrade terminal equipment at Yukon to increase rating on Yukon to Charleroi #2 138 kV line (New Yukon to Route 51 #4 138 kV line) - 6/1/2021 - $0.63M

267) Baseline Upgrade b3011.5

- Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #3 138 kV line - 6/1/2021 - $1.00M

268) Baseline Upgrade b3011.6

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

269) 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

270) Baseline Upgrade b3012.2

- Construct two new ties from a new First Energy substation to a new Duquesne substation by using two separate structures - Duquesne portion. - 6/1/2021 - $8.10M

271) 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

272) Baseline Upgrade b3012.4

- Establish the new tie line in place of the existing Elarama - Mitchell 138 kV line - 6/1/2021 - $1.00M

273) 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

274) Baseline Upgrade b3014

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

275) Baseline Upgrade b3015.1

- Construct new Elrama 138 kV substation and connect 7 138 kV lines to new substation - 6/1/2021 - $20.00M

276) Baseline Upgrade b3015.3

- Reconductor Dravosburg to West Mifflin 138 kV line. 3 miles - 6/1/2021 - $4.20M

277) Baseline Upgrade b3015.4

- Run new conductor on existing tower to establish the new Dravosburg-Elrama (Z-75) circuit. 10 miles - 6/1/2021 - $15.00M

278) Baseline Upgrade b3015.7

- Reconductor Wilson to West Mifflin 138 kV line. 2 miles. 795ACSS/TW 20/7 - 6/1/2021 - $3.60M

279) Baseline Upgrade b3015.8

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

280) 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

281) Baseline Upgrade b3017.2

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

282) Baseline Upgrade b3017.3

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

283) Baseline Upgrade b3018

- Rebuild Line #49 between New Road and Middleburg substations with single circuit steel structures to current 115kV standards with a minimum summer emergency rating of 261 MVA. - 12/31/2021 - $12.70M

284) Baseline Upgrade b3019

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

285) Baseline Upgrade b3019.1

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

286) Baseline Upgrade b3019.2

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

287) Baseline Upgrade b3020

- Rebuild 500kV Line #574 Ladysmith to Elmont - 26.2 miles long - 6/1/2018 - $65.50M

288) Baseline Upgrade b3021

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

289) Baseline Upgrade b3023

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

290) 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

291) Baseline Upgrade b3025.1

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

292) 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

293) 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

294) 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

295) Baseline Upgrade b3027.1

- Add a 2nd 500/230 kV 840 MVA transformer at Dominion's Ladysmith Substation - 6/1/2021 - $25.00M

296) Baseline Upgrade b3027.2

- Re-conductor Line #2089 between Ladysmith and Ladysmith CT Substations to increase the line rating from 1047 MVA to 1225 MVA. - 6/1/2021 - $5.00M

297) Baseline Upgrade B3027.3

- Replace the Ladysmith 500kV breaker "H1T581" with 50kA breaker - 6/1/2021 - $0.52M

298) Baseline Upgrade B3027.4

- Update the nameplate for Ladysmith 500kV breaker "H1T575" to be 50kA breaker - 6/1/2021 - $0.52M

299) Baseline Upgrade B3027.5

- Update the nameplate for Ladysmith 500kV breaker "568T574" (will be renumbered as "H2T568") to be 50kA breaker - 6/1/2021 - $0.00M

300) 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

301) Baseline Upgrade b3029.1

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

302) Baseline Upgrade b3029.2

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

303) 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

304) Baseline Upgrade b3033

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

305) Baseline Upgrade b3034

- Lakeview-Greenfield 138 kV Reconductor and Substation Upgrades - 12/1/2023 - $2.40M

306) Baseline Upgrade b3037

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

307) Baseline Upgrade b3038

- Reconductor the Capitol Hill - Coco 138 kV line section - 12/1/2023 - $3.80M

308) Baseline Upgrade b3039

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

309) Baseline Upgrade b3040

- Ravenswood - 6/1/2022 - $1.00M

310) Baseline Upgrade b3040.1

- Rebuild Ravenswood - Racine Tap 69 kV line section (~15 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor - 6/1/2022 - $39.20M

311) 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

312) Baseline Upgrade b3040.3

- Install new 3-way phase over phase switch at Sarah Lane station to replace the retired switch at Cottageville. - 6/1/2022 - $1.00M

313) Baseline Upgrade b3040.4

- Install new 138/12 kV 20 MVA transformer at Polymer station to transfer load from Mill Run Station to help address overload on the 69 kV network. - 6/1/2022 - $3.50M

314) Baseline Upgrade b3040.5

- Retire Mill Run station. - 6/1/2022 - $0.54M

315) Baseline Upgrade b3040.6

- Install 34.6 MVAR Cap Bank at South Buffalo station. - 6/1/2022 - $0.80M

316) Baseline Upgrade b3041

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

317) Baseline Upgrade b3042

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

318) Baseline Upgrade b3043

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

319) Baseline Upgrade b3045

- Increase the MOT of Liberty Church Tap-Bacon Creek Tap 69kV line 266.8 MCM conductor from 212°F to 266°F - 6/1/2020 - $0.25M

320) Baseline Upgrade b3046

- Increase the MOT of Summer Shade-JB Galloway Jct. 69kV line 266.8 MCM conductor to from 167°F to 212°F. - 6/1/2020 - $0.75M

321) Baseline Upgrade b3047

- Upgrade the existing 4/0 CU line jumpers with double 500 MCM CU associated with the Green Co-KU Green Co 69 KV line section. Also, replace the existing 600 A disconnect switches with 1200 A associated with the Green Co 161/69 KV transformer - 6/1/2020 - $0.25M

322) Baseline Upgrade b3048

- Replace 138 kV breakers 937, 941 and 945 at TODHunter station - 12/31/2020 - $1.90M

323) Baseline Upgrade b3050

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

324) Baseline Upgrade b3051.1

- Ronceverte Cap Bank and Terminal Upgrades - 6/1/2018 - $0.72M

325) Baseline Upgrade b3052

- Install a 138 kV capacitor (29.7 MVAR effective) at West Winchester 138 kV. - 6/1/2018 - $1.01M

326) Baseline Upgrade b3053

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

327) 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

328) Baseline Upgrade b3055

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

329) Baseline Upgrade b3056

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

330) 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

331) 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

332) Baseline Upgrade b3059

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

333) 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

334) Baseline Upgrade b3061

- Reconductor the West Mifflin - Dravosburg (Z-73) and Dravosburg - Elrama (Z-75) 138 kV lines - 6/1/2021 - $6.70M

335) Baseline Upgrade b3062

- Install 138 kV tie breaker at West Mifflin - 6/1/2021 - $4.40M

336) Baseline Upgrade b3063

- Reconductor the Wilson - Dravosburg (Z-72) 138 kV line (~5 miles) - 6/1/2021 - $6.60M

337) Baseline Upgrade b3064

- Expand Elrama 138 kV substation to loop in the existing USS Steel Clariton - Piney Fork 138 kV line - 6/1/2021 - $8.00M

338) Baseline Upgrade b3064.2

- Replace the West Mifflin 138 kV breakers “Z-94”, “Z-74”, “Z14”, and “Z-13” with 63 kA breakers - 6/1/2021 - $3.10M

339) 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

340) Baseline Upgrade b3065

- Install 138 kV tie breaker at Wilson - 6/1/2021 - $4.00M

341) 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

342) 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

343) 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

344) 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

345) 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

346) 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

347) 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

348) 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

349) Baseline Upgrade b3074

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

350) 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

351) Baseline Upgrade b3076

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

352) Baseline Upgrade b3077

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

353) 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

354) Baseline Upgrade b3079

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

355) Baseline Upgrade b3080

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

356) Baseline Upgrade b3081

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

357) Baseline Upgrade b3082

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

358) 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

359) Baseline Upgrade b3084

- Reconductor the Oakland - Panther Hollow 138 kV line (~1 mile) - 6/1/2021 - $6.80M

360) 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

361) 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

362) 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

363) 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

364) 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

365) 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

366) 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

367) Baseline Upgrade b3087.3

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

368) Baseline Upgrade b3087.4

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

369) 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

370) 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

371) Baseline Upgrade b3094

- Move 69 kV 12.0 MVAR capacitor bank from Greenbriar to Bullitt Co 69kV substation - 6/1/2018 - $0.30M

372) 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

373) 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

374) 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 -

$20.00M

375) 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

376) 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

377) 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

378) Baseline Upgrade b3102

- Replace existing 50 MVA 138/69 kV transformers #1 and #2 (both 1957 vintage) at Fremont station with new 130 MVA 138/69 kV transformers. - 12/1/2022 - $4.10M

379) Baseline Upgrade b3103.1

- Install a 138/69 kV transformer at Royerton station. Install a 69 kV bus with one 69 kV breaker toward Bosman station. Rebuild the 138 kV portion into a ring bus configuration built for future breaker and a half with four 138 kV breakers. - 6/1/2022 - $10.25M

380) Baseline Upgrade b3103.2

- Rebuild the Bosman/Strawboard station in the clear across the road to move it out of the flood plain and bring it up to 69kV standards. - 6/1/2022 - $4.47M

381) 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

382) 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

383) 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

384) 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

385) Baseline Upgrade b3103.7

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

386) Baseline Upgrade b3103.8

- Rebuild the 34.5 kV Delaware – Bosman line as the 69 kV Royerton – Strawboard line. Retire the line section from Royerton to Delaware stations. - 6/1/2022 - $12.78M

387) 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

388) Baseline Upgrade b3105

- Rebuild the Delaware – Hyatt 138 kV line (~ 4.3 miles) along with replacing conductors at both Hyatt and Delaware substations. - 6/1/2020 - $16.00M

389) Baseline Upgrade b3108.1

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

390) Baseline Upgrade b3108.2

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

391) Baseline Upgrade b3108.3

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

392) Baseline Upgrade b3109

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

393) 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

394) Baseline Upgrade b3110.2

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

395) 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

396) Baseline Upgrade b3114

- Rebuild the 18.6 mile section of 115 kV Line #81 which includes 1.7 miles of double circuit Line #81 and 230 kV Line #2056. This segment of line of 81 will be rebuilt to current standards with a minimum rating of 261 MVA. Line 2056 rating will not change. - 6/1/2019 - $25.00M

397) Baseline Upgrade b3115

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

398) 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

399) 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

400) Baseline Upgrade b3118.10

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

401) Baseline Upgrade b3118.2

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

402) Baseline Upgrade b3118.3

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

403) Baseline Upgrade b3118.4

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

404) Baseline Upgrade b3118.5

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

405) 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

406) 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

407) 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

408) 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

409) 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

410) 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

411) 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

412) Baseline Upgrade b3120

- Replace the Whitpain 230 kV breaker "125" with a 63 kA breaker. - 6/1/2021 - $0.60M

413) 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

414) 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

415) 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

416) Baseline Upgrade b3124

- Separate metering, station power, and communication at Bruce Mansfield 345 kV station - 12/31/2020 - $0.40M

417) 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

418) 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

419) 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

420) Baseline Upgrade b3128

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

421) Baseline Upgrade b3129

- At Conesville 138 kV station: Remove line leads to generating units, transfer plant AC service to existing station service feeds in Conesville 345/138 kV yard, and separate and reconfigure protection schemes - 12/31/2020 - $1.50M

422) 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

423) 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

424) Baseline Upgrade b3130.10

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

425) 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

426) 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

427) 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

428) 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

429) 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

430) 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

431) 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

432) Baseline Upgrade b3130.9

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

433) Baseline Upgrade b3131

- At East Lima and Haviland 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

434) Baseline Upgrade b3132

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

435) 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

436) 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

437) 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

438) 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

439) Baseline Upgrade b3135

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

440) Baseline Upgrade b3136

- Replace bus conductor at Smith 115 kV substation - 6/1/2024 - $0.15M

441) Baseline Upgrade b3137

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

442) 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

443) Baseline Upgrade b3139

- Rebuild the Garden Creek - Whetstone 69 kV line (approx. 4 mile) - 6/1/2023 - $14.00M

444) Baseline Upgrade b3140

- Rebuild the Whestone - Knox Creek 69 kV line (3.1 mile) - 6/1/2023 - $9.00M

445) Baseline Upgrade b3141

- Rebuild the Knox Creek - Coal Creek 69 kV line (2.9 mile) - 6/1/2023 - $9.00M

446) Baseline Upgrade b3142

- Rebuild Michigan City-Trail Creek - Bosserman 138 kV (10.7 mi) - 1/1/2023 - $24.69M

447) Baseline Upgrade b3143.1

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

448) Baseline Upgrade b3143.2

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

449) 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

450) 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

451) 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

452) Baseline Upgrade b3144

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

453) 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

454) 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

455) 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

456) Baseline Upgrade b3146

- Upgrade the Richmond 69 kV breaker "140" with 40 kA breaker - 6/1/2021 - $0.42M

457) Baseline Upgrade b3148.1

- Rebuild the 46 kV Bradley-Scarbro line to 96 kV standards using 795 ACSR to achieve a minimum rater of 120 MVA. Rebuild the new line adjacent to the existing one leaving the old line in service until the work is completed. - 12/1/2021 - $26.00M

458) Baseline Upgrade b3148.2

- Bradley remote end station work, replace 46 kV bus, install new 12 MVAR capacitor bank. - 12/1/2021 - $3.60M

459) Baseline Upgrade b3148.3

- Replace the existing switch at Sun substation with a 2-way SCADA-controlled MOAB switch - 12/1/2021 - $0.90M

460) Baseline Upgrade b3148.4

- Remote end work and associated equipment at Scarbro Station. - 12/1/2021 - $1.40M

461) Baseline Upgrade b3148.5

- Retire Mt. Hope Station and transfer load to existing Sun Station. - 12/1/2021 - $0.00M

462) 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

463) 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

464) 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

465) Baseline Upgrade b3151.10

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

466) 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

467) Baseline Upgrade b3151.12

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

468) Baseline Upgrade b3151.13

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

469) Baseline Upgrade b3151.14

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

470) 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

471) Baseline Upgrade b3151.2

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

472) 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

473) 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

474) Baseline Upgrade b3151.5

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

475) Baseline Upgrade b3151.6

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

476) Baseline Upgrade b3151.7

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

477) 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

478) Baseline Upgrade b3151.9

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

479) 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). - 6/1/2024 - $14.10M

480) 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

481) Baseline Upgrade b3154

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

482) Baseline Upgrade b3155

- Rebuild approximately 12 miles of Wye Mills - Stevensville line to achieve needed ampacity - 12/1/2023 - $15.00M

483) Baseline Upgrade b3156

- Replace line relaying and fault detector on the Wylie Ridge terminal at Smith 138 kV Substation - 6/1/2024 - $0.85M

484) 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

485) Baseline Upgrade b3158

- Replace line relays on the Ridgeley line terminal at Messick Rd. 138 kV substation - 12/1/2024 - $0.40M

486) 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. - 6/1/2024 - $5.70M

487) Baseline Upgrade b3160.1

- Construct a ~2.4 mile double circuit 138 kV extension using 1033 ACSR to connect Lake Head to the 138 kV network. - 6/1/2024 - $6.00M

488) Baseline Upgrade b3160.2

- Retire the ~2.5 mile 34.5 kV Niles – Simplicity Tap line. - 6/1/2024 - $1.20M

489) Baseline Upgrade b3160.3

- Retire the ~4.6 mile Lakehead 69 kV Tap - 6/1/2024 - $1.40M

490) Baseline Upgrade b3160.4

- Build new 138/69 kV drop down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV MOAB - 6/1/2024 - $4.00M

491) Baseline Upgrade b3160.5

- Rebuild the ~1.2 mile Buchanan South 69 kV Radial Tap using 795 ACSR - 6/1/2024 - $3.00M

492) Baseline Upgrade b3160.6

- Rebuild the ~8.4 mile 69 kV Pletcher – Buchanan Hydro line as the ~9 mile Pletcher – Buchanan South 69 kV line using 795 ACSR. - 6/1/2024 - $20.00M

493) Baseline Upgrade b3160.7

- Install a PoP switch at Buchanan South station with 2 line Moabs. - 6/1/2024 - $0.60M

494) 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

495) 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

496) Baseline Upgrade b3207

- Beatty-Adkins: Replace station conductor at Adkins station and perform a sag study on the line. Note that results from the sag study could cover a wide range of outcomes, from no work required to a complete rebuild. - 6/2/2020 - $1.50M

497) 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

498) 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

499) Baseline Upgrade b3210

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

500) 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

501) Baseline Upgrade b3220

- Install 14.4 MVAR Capacitor Bank at Whitewood 138 KV - 6/1/2023 - $1.20M

Revision History:

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Approver: Aaron Berner, Manager Transmission Planning