November 1, 2023

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re:  
PJM Interconnection, L.L.C.
Revisions to PJM OATT, Operating Agreement, and RAA Docket No. ER24-____-000

PJM Interconnection, L.L.C.
Revisions to PJM CTOA Docket No. ER24-285-000

Pursuant to Section 205 of the Federal Power Act,1 PJM Interconnection, L.L.C. (“PJM”), FirstEnergy Pennsylvania Electric Company (“FE PA”), and Keystone Appalachian Transmission Company (“KATCo”) together submit modifications to the PJM Governing Agreements2 in connection with the integration of FE PA and KATCo into PJM as a result of FirstEnergy Corp.’s (“FirstEnergy’s”) proposed internal corporate reorganization (the “Transaction”).3 Specifically, PJM is submitting modifications to the PJM Open Access Transmission Tariff (“PJM OATT”), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“PJM OA”), the Reliability Assurance Agreement (“PJM RAA”), and the Consolidated Transmission Owners Agreement (“PJM CTOA”) (together, the “PJM Governing Agreements”).4

The purpose of this filing is to revise the PJM Governing Agreements to reflect the fact that, upon the anticipated closing of the Transaction on January 1, 2024, FE PA will own and operate the distribution facilities of Metropolitan Edison Company (“MetEd”), Pennsylvania Electric Company (“Penelec”), West Penn Power Company (“West Penn”), and Pennsylvania Power Company (“Penn Power”) in the MetEd, Penelec, Allegheny Power (“APS”), and ATSI Transmission Zones in PJM, and KATCo will own and operate West Penn transmission assets in the APS Transmission Zone in PJM.

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2 Unless otherwise defined in this letter, a capitalized term shall have the meaning set forth in the PJM Governing Agreements.
3 The Transaction has been approved by the Commission. See FirstEnergy Corp., et al., 184 FERC ¶ 61,094 (2023).
4 The PJM CTOA modifications are filed by PJM on behalf of the PJM Transmission Owners Agreement Administrative Committee. Due to eTariff restrictions, the proposed revisions to the PJM Governing Agreements will be filed separately using the same transmittal letter with specified attachments corresponding to each filing.
FE PA and KATCo anticipate that the Transaction will close on January 1, 2024, but the exact date is not known at this time. Out of an abundance of caution, PJM requests an open-ended effective date for the attached PJM Governing Agreement sections. Thus, a 12/31/9998 effective date is being used for eTariff purposes. FE PA, KATCo and/or PJM will make additional filings with the Commission no later than thirty (30) days after the closing date of the FE PA and KATCo Transaction.

I. BACKGROUND

PJM is a Commission-approved Regional Transmission Organization (‘‘RTO’’). PJM is a transmission provider under, and the administrator of, the PJM OATT. As the transmission provider, PJM operates energy and capacity markets, plans regional transmission expansion improvements to maintain grid reliability and relieve congestion, and conducts the day-to-day operations of the transmission system in the PJM region.

FE PA is a newly formed Pennsylvania corporation, and KATCo is a standalone transmission company and wholly owned subsidiary of FirstEnergy incorporated in the Commonwealth of Virginia. The Transaction is a comprehensive internal corporate reorganization that will separate the transmission and distributions functions among MetEd, Penelec, Penn Power, West Penn, KATCo, the Ohio Edison Company, Mid-Atlantic Interstate Transmission, LLC (“MAIT”), FirstEnergy Pennsylvania Holding Company LLC, and FE PA within the Commonwealth of Pennsylvania. Upon consummation of the Transaction, FE PA will own and operate all of the distribution assets previously owned and operated by MetEd, Penelec, West Penn and Penn Power, and KATCo will own and operate the transmission assets previously owned and operated by West Penn in PJM. As a result, FE PA will serve as the singular operating company for FirstEnergy’s distribution utilities in Pennsylvania.

II. DESCRIPTION OF FILING

A. PJM’s Revisions to the PJM OATT, PJM OA, PJM RAA, and PJM CTOA

PJM’s revisions to the PJM OATT, PJM OA, PJM RAA, and PJM CTOA are needed to reflect the fact that, as of the closing date of the Transaction, FE PA will own and operate distribution facilities in the MetEd, Penelec, APS, and ATSI Transmission Zones in PJM, and KATCo will own and operate the transmission facilities in the APS Transmission Zone in PJM. As discussed below, these changes are both nominal and ministerial in that, where needed, they simply remove references to MetEd, Penelec, Penn Power, and West Penn, and add references to FE PA and KATCo, respectively. The revisions do not change any rates, revenue recovery, or cost allocation for the impacted FirstEnergy affiliates.

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1. **PJM OATT Revisions**

   a. **PJM OATT, Table of Contents, Attachment H-5, Attachment H-5A, Attachment H-6, and Attachment H-6A**

   PJM is revising the PJM OATT Table of Contents headings for Attachments H-5 and H-5A by replacing the corporate name of MetEd with that of FE PA, which will own and operate distribution facilities in the MetEd Transmission Zone. PJM is also revising the Table of Contents headings for Attachments H-6 and H-6A by replacing the corporate name of Penelec with that of FE PA, which will own and operate distribution facilities in the Penelec Transmission Zone.

   b. **PJM OATT, Table of Contents, Attachment H-11A, Attachment H-34, Attachment H-34A, and Attachment H-34B**

   PJM is revising the PJM OATT Table of Contents headings for Attachment H-11 to add an “H” that was inadvertently omitted so the heading correctly reads “Attachment H-11A.” PJM is also revising the Table of Contents headings to add Attachment H-34 (Keystone Appalachian Transmission Company – Annual Transmission Rate), Attachment H-34A (Keystone Appalachian Transmission Company – Formula Rate Template), and Attachment H-34B (Keystone Appalachian Transmission Company – Formula Rate Implementation Protocols). These additions are to simply reference the existing attachments in the PJM OATT. PJM is not proposing any changes to KATCo’s annual transmission rate, formula rate template, or formula rate implementation protocols in this filing.

   KATCo was established in anticipation of transferring West Penn’s jurisdictional transmission assets to a separate transmission-only entity. In 2020, KATCo proposed revisions to the PJM OATT to implement a formula rate and associated protocols to establish Network Integration Transmission Service (“NITS”) and Transmission Enhancement Charge revenue requirements for transmission service that KATCo expected to provide in the PJM APS Zone, effective January 1, 2021.\(^6\) On May 4, 2023, the Commission accepted KATCo’s Offer of Settlement and Settlement Agreement addressing the true-ups and annual updates of the revenue requirement for the respective rate year included in the settled formula rate template and protocols included in Attachments H-34A and H-34B of the PJM OATT.\(^7\)

c. **PJM OATT, Attachment H-5**

   Attachment H-5 sets forth the annual transmission rates for MetEd for NITS. PJM is revising Attachment H-5 to replace references to MetEd with FE PA, to reflect that FE PA will own and operate MetEd’s distribution facilities and provide NITS for deliveries that utilize

\(^6\) *See Keystone Appalachian Transmission Co., Revisions to PJM Tariff, Docket No. ER21-265-000, at pp. 2-3 (filed Oct. 30, 2020).*

\(^7\) *Monongahela Power Co., Keystone Appalachian Transmission Co., 183 FERC 61,087 (2023).*
distribution facilities at voltage below 69 kilovolts (“kV”) located in the MetEd transmission zone.

d.   **PJM OATT, Attachment H-5A**

Attachment H-5A sets forth the rates, or Other Supporting Facilities Charges (“OSFCs”), for deliveries that utilize MetEd’s distribution facilities at voltages below 69 kV. PJM is revising Attachment H-5A to replace references to MetEd with FE PA, to reflect that FE PA will own and operate MetEd’s distribution facilities at voltages below 69 kV in the MetEd Transmission Zone.

e.   **PJM OATT, Attachment H-6**

Attachment H-6 sets forth the annual transmission rates for Penelec for NITS. PJM is revising Attachment H-6 to replace references to Penelec with FE PA, to reflect that FE PA will own and operate Penelec’s distribution facilities and provide NITS for deliveries that utilize distribution facilities at voltage below 46 kV located in the Penelec Transmission Zone.

f.   **PJM OATT, Attachment H-6A**

Attachment H-6A sets forth the rates, or OSFCs, for deliveries that utilize Penelec’s distribution facilities at voltages below 46 kV. PJM is revising Attachment H-6A to replace references to Penelec with FE PA, to reflect that FE PA will own and operate Penelec’s distribution facilities at voltages below 46 kV in the Penelec Transmission Zone.

g.   **PJM OATT, Attachment H-11A**

Attachment H-11A sets forth the OSFC for service at or below 115 kV in the APS Transmission Zone and Formula Rate for NITS for Monongahela Power (“Mon Power”), the Potomac Edison Company (“Potomac Edison”), and West Penn (referred to as the “South FirstEnergy Operating Companies”). PJM is revising references to West Penn as it relates to the OSFC and replacing those references with FE PA. PJM is also revising the heading for the Formula Rate to separate it from the OSFC heading and to create a standalone Formula Rate heading. PJM notes that West Penn remains referenced in the Formula Rate heading in Attachment H-11A solely to ensure the continued effectuation of its formula rate true-ups.

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8 On October 27, 2023, West Penn filed proposed revisions to the OSFC language in Attachment H-11A to the PJM OATT. See West Penn Power Company Tariff Filing, Docket No. ER24-231-000. The proposed revisions are currently under review by the Commission in that docket. To avoid confusion, the revisions proposed in the October 27, 2023 filing are also reflected in the attached PJM Governing Agreement revisions to Attachment H-11A.

9 To clarify, Attachment H-11A has been divided into two separate headers, one for the OSFC and one for the Formula Rate.
h. *PJM OATT, Schedule 12 – Appendix and PJM OATT, Schedule 12 – Appendix A*

PJM is revising Schedule 12 – Appendix and Schedule 12 – Appendix A by adding new sections to reflect that KATCo will own and operate West Penn’s transmission assets in the APS Transmission Zone, and will be the transmission owner for purposes of these schedules. In corresponding revisions, PJM is also removing references to West Penn from the headings for the existing Schedule 12 – Appendix and Schedule 12 – Appendix A sections for APS, and removing West Penn’s assets from the existing Schedule 12 – Appendix and Schedule 12 – Appendix A sections, respectively.\(^\text{10}\)

i. *PJM OATT, Attachment H-28B*

Attachment H-28B provides MAIT’s Formula Rate Implementation Protocols. PJM is revising Attachment H-28B to replace a reference to MetEd and Penelec to reflect that FE PA will own and operate all of MetEd and Penelec’s distribution assets and facilities, including ground leases.

j. *PJM OATT, Attachment J*

PJM Transmission Zones are listed in Attachment J to the PJM OATT. PJM is revising Attachment J for the sole purpose of clarifying in footnotes that FE PA is the successor-in-interest to Penelec and MetEd, but all references to the Penelec or MetEd Transmission Zones in the PJM OATT remain unchanged.

k. *PJM OATT, Attachment L*

Transmission Owners in PJM are listed in Attachment L to the PJM OATT. The PJM OATT defines “Transmission Owner” as: “[e]ach entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the Tariff.”\(^\text{11}\) KATCo will meet this definition as of the Transaction consummation date. Thus, PJM is revising Attachment L to the PJM OATT by removing the reference to West Penn in the definition of APS and adding KATCo to the list of PJM Transmission Owners.

l. *PJM OATT, Attachment M-1*

The purpose of Attachment M-1 is to provide PJM members serving load in a FirstEnergy Electric Distribution Company (“EDC”) service area an understanding of how each hour of an operating day’s Total Hourly Energy Obligation is developed. PJM is revising

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\(^\text{10}\) All of West Penn’s transmission assets have been moved to newly-created KATCo tables in Schedule 12 – Appendix and Schedule 12 – Appendix A, respectively. However, those assets built and owned in part by West Penn and in part by Mon Power or Potomac Edison are listed in both the existing Schedule 12 – Appendix and Schedule 12 – Appendix A sections for APS and the new sections for KATCo.

\(^\text{11}\) PJM OATT, Section 1.45F.
Attachment M-1 to add a reference to FE PA reflecting that it will operate in the ATSI, Penelec, MetEd, and APS PJM Transmission Zones. PJM is also revising Attachment M-1 to replace references to Penn Power, Penelec, MetEd, and West Penn with references to FE PA and the appropriate FirstEnergy EDC service areas.

m. **PJM OATT, Attachment M-2**

The purpose of Attachment M-2 is to establish procedures and methodologies under which FirstEnergy will determine the Peak Load Contribution and Network Service Peak Load in accordance with the PJM OATT, PJM OA, PJM RAA or other relevant PJM documents each PJM Planning Year for each retail and wholesale LSE serving load in the FirstEnergy EDC’s service areas. PJM is revising Attachment M-2 to add a reference to FE PA reflecting that it will operate in the ATSI, Penelec, MetEd, and APS PJM Transmission Zones. PJM is also revising Attachment M-2 to replace references to Penn Power, Penelec, MetEd, and West Penn with references to FE PA and the appropriate FirstEnergy EDC service areas.

2. **PJM OA Revisions**

a. **PJM OA, Schedule 12**

PJM is revising PJM OA, Schedule 12 by including FE PA and KATCo as PJM Members, and removing MetEd, Penelec, Penn Power, and West Penn as PJM Members. FE PA and KATCo signed Schedule 4 of the PJM OA and PJM countersigned, in accordance with Section 11.6(e) of the PJM OA.

3. **PJM RAA Revisions**

a. **PJM RAA, Schedule 15**

PJM is revising PJM RAA, Schedule 15 for the sole purpose of clarifying in footnotes that FE PA is the successor-in-interest to Penelec and MetEd, but all references to the Penelec and MetEd Zones in the RAA remain unchanged.

b. **PJM RAA, Schedule 17**

PJM is revising PJM RAA, Schedule 17 by including FE PA as a party to the RAA, and removing MetEd, Penelec, Penn Power, and West Penn as parties to the RAA.

4. **PJM CTOA Revisions**

a. **Addition of KATCo to List of PJM Transmission Owners**

As of the Transaction consummation date, KATCo will be a PJM Transmission Owner because, on that date, the KATCo transmission facilities will: (i) be within the PJM Region; (ii) meet the definition of transmission facilities in Section 1.27 of the PJM CTOA; and (iii) have
been integrated, to the satisfaction of PJM, with the Transmission System of the PJM Region and integrated into the planning and operation of such.\textsuperscript{12}

In preparation for KATCo’s integration on the Transaction consummation date, KATCo has executed the PJM CTOA; and PJM hereby submits for filing, as part of the PJM CTOA, a signature page to the PJM CTOA executed by KATCo. In addition, Attachment A to the PJM CTOA lists the Transmission Owners in the PJM Region.\textsuperscript{13} Therefore, PJM also submits for filing a revised Attachment A to the PJM CTOA removing West Penn from the definition of APS and adding KATCo to the list of PJM Transmission Owners.

\section*{III. OTHER RELATED FUTURE FILINGS AND MILESTONES}

FE PA, KATCo and/or PJM will make additional filings with the Commission no later than thirty (30) days after the closing date of the FE PA and KATCo Transaction. These additional filings will address modifications to existing service agreements under the PJM OATT that are necessary to reflect the fact that, as of Transaction consummation date, FE PA will own and operate all of distribution facilities previously owned by MetEd, Penelec, West Penn, and Penn Power in the MetEd, Penelec, APS, and ATSI Transmission Zones in PJM, and KATCo will own and operate the former West Penn transmission facilities in the APS Transmission Zone in PJM.

\section*{IV. ADDITIONAL INFORMATION}

\subsection*{A. Proposed Effective Date and Request for Waivers}

FE PA and KATCo anticipate that the Transaction will close on January 1, 2024, but the exact date is not known at this time. Out of an abundance of caution, PJM requests an open-ended effective date for the attached PJM Governing Agreement sections. Thus, a 12/31/9998 effective date is being used for eTariff purposes. FE PA, KATCo and/or PJM will make additional filings with the Commission no later than thirty (30) days after the closing date of the FE PA and KATCo Transaction.

To the extent necessary, PJM requests waiver of the Commission’s notice requirements to allow these changes to become effective on the date the Transaction is consummated. The parties to the Transaction expect the Transaction to close on or about January 1, 2024, and, therefore, request an order by December 29, 2023 to facilitate an orderly closing.

\textsuperscript{12} PJM CTOA, Section 1.27.
\textsuperscript{13} PJM CTOA, Section 1.28.
B. Communications

Please place the names of the following persons on the official service list established by the Secretary in this proceeding:

Craig Glazer*
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W, Suite 600
Washington, D.C. 20005
(202) 423-4743
craig.glazer@pjm.com

Steven R. Pincus*
Managing Counsel, Sr. Director
PJM Interconnection, L.L.C.
2750 Monroe Blvd
Audubon, PA 19403-2497
(610) 666-4370
steven.pincus@pjm.com

Morgan E. Parke*
Associate General Counsel
Anne M. Rericha
Attorney V
FirstEnergy Service Company
76 S. Main Street
Akron, OH 44308
(330) 374-6650
mparke@firstenergycorp.com
arericha@firstenergycorp.com

Nicholas A. Giannasca
Jonathan A. Namazi*
Davis Wright Tremaine LLP
1251 Avenue of the Americas
21st Floor
New York, NY 10020
(212) 603-6406
nicholasgiannasca@dwt.com
jonathannamazi@dwt.com

* Designated to receive service. PJM respectfully requests waiver of Rule 2010 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.2010, to permit more than two individuals to receive service in this proceeding.

C. List of Documents Submitted with Filing

Together with this filing letter, PJM submits the following:

1. **Attachment A** Marked Revised PJM OATT, PJM OA, and PJM RAA

2. **Attachment B** Clean Revised PJM OATT, PJM OA, and PJM RAA
D. Service

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM region by posting this filing electronically. In accordance with the Commission’s regulations, PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://pjm.com/library/filing-order with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM region alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC’s eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission’s regulations and Order No. 714.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Steven R Pincus
Steven R. Pincus
Managing Counsel,
Sr. Director
PJM Interconnection, L.L.C.
2750 Monroe Blvd
Audubon, PA 19403-2497
(610) 666-4370
steven.pincus@pjm.com

On Behalf of PJM Interconnection, L.L.C.

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14 See 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).
15 PJM already maintains, updates and regularly uses e-mail lists for all PJM Members and affected state commissions.
Attachment A
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1.27 Long-Term Firm Point-To-Point Transmission Service
1.28 MAAC
1.29 MAAC Control Zone
1.30 NERC
1.31 Network Upgrades
1.32 Office of the Interconnection
1.33 Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement
1.34 Part I
1.35 Part II
1.36 Part III
1.37 Part IV
1.38 Part VI
1.39 PJM Interchange Energy Market
1.40 PJM Manuals
1.41 PJM Region
1.42 PJM West Region
1.43 Point(s) of Delivery
1.44 Point(s) of Receipt
1.45 Project Financing
1.46 Project Finance Entity
1.47 Reasonable Efforts
1.48 Receiving Party
1.49 Regional Transmission Expansion Plan
1.50 Schedule and Scope of Work
1.51 Security
1.52 Service Agreement
1.53 State
1.54 Transmission System
1.55 VACAR

ATTACHMENT GG - APPENDIX III – GENERAL TERMS AND CONDITIONS

1.0 Effective Date and Term
1.1 Effective Date
1.2 Term
1.3 Survival

2.0 Facilitation by Transmission Provider

3.0 Construction Obligations
3.1 Direct Assignment Facilities or Customer-Funded Upgrades
3.2 Scope of Applicable Technical Requirements and Standards

4.0 Tax Liability
4.1 New Service Customer Payments Taxable
4.2 Income Tax Gross-Up
4.3 Private Letter Ruling
4.4 Refund
4.5 Contests
4.6 Taxes Other Than Income Taxes
4.7 Tax Status

5.0 Safety
5.1 General
5.2 Environmental Releases

6.0 Schedule Of Work
6.1 Standard Option
6.2 Option to Build
6.3 Revisions to Schedule and Scope of Work
6.4 Suspension

7.0 Suspension of Work Upon Default
7.1 Notification and Correction of Defects

8.0 Transmission Outages
8.1 Outages; Coordination

9.0 Security, Billing and Payments
9.1 Adjustments to Security
9.2 Invoice
9.3 Final Invoice
9.4 Disputes
9.5 Interest
9.6 No Waiver

10.0 Assignment
10.1 Assignment with Prior Consent
10.2 Assignment Without Prior Consent
10.3 Successors and Assigns

11.0 Insurance
11.1 Required Coverages
11.2 Additional Insureds
11.3 Other Required Terms
11.4 No Limitation of Liability
11.5 Self-Insurance
11.6 Notices: Certificates of Insurance
11.7 Subcontractor Insurance
11.8 Reporting Incidents

12.0 Indemnity
12.1 Indemnity
12.2 Indemnity Procedures
12.3 Indemnified Person
12.4 Amount Owing
12.5 Limitation on Damages
12.6 Limitation of Liability in Event of Breach
12.7 Limited Liability in Emergency Conditions

13.0 Breach, Cure And Default
13.1 Breach
13.2 Notice of Breach
13.3 Cure and Default
13.4 Right to Compel Performance
13.5 Remedies Cumulative
14.0 Termination
14.1 Termination
14.2 Cancellation By New Service Customer
14.3 Survival of Rights
14.4 Filing at FERC
15.0 Force Majeure
15.1 Notice
15.2 Duration of Force Majeure
15.3 Obligation to Make Payments
16.0 Confidentiality
16.1 Term
16.2 Scope
16.3 Release of Confidential Information
16.4 Rights
16.5 No Warranties
16.6 Standard of Care
16.7 Order of Disclosure
16.8 Termination of Upgrade Construction Service Agreement
16.9 Remedies
16.10 Disclosure to FERC or its Staff
16.11 No Party Shall Disclose Confidential Information of Party
16.12 Information that is Public Domain
16.13 Return or Destruction of Confidential Information
17.0 Information Access And Audit Rights
17.1 Information Access
17.2 Reporting of Non-Force Majeure Events
17.3 Audit Rights
17.4 Waiver
17.5 Amendments and Rights under the Federal Power Act
17.6 Regulatory Requirements
18.0 Representation and Warranties
18.1 General
19.0 Inspection and Testing of Completed Facilities
19.1 Coordination
19.2 Inspection and Testing
19.3 Review of Inspection and Testing by Transmission Owner
19.4 Notification and Correction of Defects
19.5 Notification of Results
20.0 Energization of Completed Facilities
21.0 Transmission Owner’s Acceptance of Facilities Constructed by New Service Customer
22.0 Transfer of Title to Certain Facilities Constructed By New Service Customer
23.0  Liens
ATTACHMENT HH – RATES, TERMS, AND CONDITIONS OF SERVICE FOR PJMSETTLEMENT, INC.

ATTACHMENT II – MTEP PROJECT COST RECOVERY FOR ATSI ZONE

ATTACHMENT JJ – MTEP PROJECT COST RECOVERY FOR DEOK ZONE

ATTACHMENT KK - FORM OF DESIGNATED ENTITY AGREEMENT

ATTACHMENT LL - FORM OF INTERCONNECTION COORDINATION AGREEMENT

ATTACHMENT MM – FORM OF PSEUDO-TIE AGREEMENT – WITH NATIVE BA AS PARTY

ATTACHMENT MM-1 – FORM OF SYSTEM MODIFICATION COST REIMBURSEMENT AGREEMENT – PSEUDO-TIE INTO PJM

ATTACHMENT NN – FORM OF PSEUDO-TIE AGREEMENT WITHOUT NATIVE BA AS PARTY

ATTACHMENT OO – FORM OF DYNAMIC SCHEDULE AGREEMENT INTO THE PJM REGION

ATTACHMENT PP – FORM OF FIRM TRANSMISSION FEASIBILITY STUDY AGREEMENT
### SCHEDULE 12 – APPENDIX

(14) Monongahela Power Company— and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>b0216</strong> Install -100/+525 MVAR dynamic reactive device at Black Oak</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td><strong>b0218</strong> Install third Wylie Ridge 500/345 kV transformer</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>AEC (11.83%) / DPL (19.40%) / Dominion (13.81%) / JCPL (15.56%) / PECO (39.40%)</td>
</tr>
<tr>
<td><strong>b0220</strong> Upgrade coolers on Wylie Ridge 500/345 kV #7</td>
<td></td>
<td>AEC (11.83%) / DPL (19.40%) / Dominion (13.81%) / JCPL (15.56%) / PECO (39.40%)</td>
</tr>
<tr>
<td><strong>b0229</strong> Install fourth Bedington 500/138 kV</td>
<td></td>
<td>APS (50.98%) / BGE (13.42%) / DPL (2.03%) / Dominion (14.50%) / ME (1.43%) / PEPCO (17.64%)</td>
</tr>
<tr>
<td><strong>b0230</strong> Install fourth Meadowbrook 500/138 kV</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>APS (79.16%) / BGE (3.61%) / DPL (0.86%) / Dominion (11.75%) / ME (0.67%) / PEPCO (3.95%)</td>
</tr>
</tbody>
</table>

* Neptune Regional Transmission System, LLC
## Required Transmission Enhancements

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<thead>
<tr>
<th>Requirement ID</th>
<th>Description</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b0238</td>
<td>Reconductor Doubs – Dickerson and Doubs – Aqueduct 1200 MVA</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>BGE (16.66%) / Dominion (33.66%) / PEPCO (49.68%)</td>
</tr>
<tr>
<td>b0240</td>
<td>Open the Black Oak #3 500/138 kV transformer for the loss of Hatfield – Back Oak 500 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0245</td>
<td>Replacement of the existing 954 ACSR conductor on the Bedington – Nipetown 138 kV line with high temperature/low sag conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0246</td>
<td>Rebuild of the Double Tollgate – Old Chapel 138 kV line with 954 ACSR conductor</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0273</td>
<td>Open both North Shenandoah #3 transformer and Strasburg – Edinburgh 138 kV line for the loss of Mount Storm – Meadowbrook 572 500 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0322</td>
<td>Convert Lime Kiln substation to 230 kV operation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0323</td>
<td>Replace the North Shenandoah 138/115 kV transformer</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>APS (100%)</td>
</tr>
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</table>
## Required Transmission Enhancements

<table>
<thead>
<tr>
<th>B0328.2</th>
<th>Build new Meadow Brook – Loudoun 500 kV circuit (20 of 50 miles)</th>
<th>As specified under the procedures detailed in Attachment H-18B, Section 1.b</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Annual Revenue Requirement</strong></td>
<td></td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td><strong>DFAX Allocation:</strong></td>
<td></td>
<td>AEC (1.85%) / BGE (21.49%) / DPL (3.91%) / Dominion (28.86%) / ME (2.97%) / PECO (5.73%) / PEPCO (35.19%)</td>
</tr>
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<table>
<thead>
<tr>
<th>B0343</th>
<th>Replace Doubs 500/230 kV transformer #2</th>
<th>As specified under the procedures detailed in Attachment H-18B, Section 1.b</th>
</tr>
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<tbody>
<tr>
<td><strong>Annual Revenue Requirement</strong></td>
<td></td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.85%) / BGE (21.49%) / DPL (3.91%) / Dominion (28.86%) / ME (2.97%) / PECO (5.74%) / PEPCO (35.19%)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>B0344</th>
<th>Replace Doubs 500/230 kV transformer #3</th>
<th>As specified under the procedures detailed in Attachment H-18B, Section 1.b</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Annual Revenue Requirement</strong></td>
<td></td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.86%) / BGE (21.50%) / DPL (3.91%) / Dominion (28.82%) / ME (2.97%) / PECO (5.74%) / PEPCO (35.20%)</td>
</tr>
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<table>
<thead>
<tr>
<th>B0345</th>
<th>Replace Doubs 500/230 kV transformer #4</th>
<th>As specified under the procedures detailed in Attachment H-18B, Section 1.b</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Annual Revenue Requirement</strong></td>
<td></td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.85%) / BGE (21.49%) / DPL (3.90%) / Dominion (28.83%) / ME (2.98%) / PECO (5.75%) / PEPCO (35.20%)</td>
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<th>Annual Revenue Requirement</th>
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</thead>
<tbody>
<tr>
<td><strong>b0347.1</strong> Build new Mt. Storm – 502 Junction 500 kV circuit</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td><strong>b0347.2</strong> Build new Mt. Storm – Meadow Brook 500 kV circuit</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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<tbody>
<tr>
<td>b0347.4</td>
<td>Upgrade Meadow Brook 500 kV substation</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
</tr>
</tbody>
</table>

**Load-Ratio Share Allocation:**
AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)

**DFAX Allocation:**
APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)

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</table>
| **b0347.5** Replace Harrison 500 kV breaker HL-3 | | **Load-Ratio Share Allocation:**  
AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENNELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)  
**DFAX Allocation:**  
APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%) |
| **b0347.6** Upgrade (per ABB inspection) breaker HL-6 | | **Load-Ratio Share Allocation:**  
AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENNELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)  
**DFAX Allocation:**  
APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%) |

* Neptune Regional Transmission System, LLC
### Monongahela Power Company, The Potomac Edison Company, West Penn Power Company, all doing business as Allegheny Power (cont.)

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<tbody>
<tr>
<td>b0347.7 Upgrade (per ABB inspection) breaker HL-7</td>
<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt;AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PEPCO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td><strong>DFAX Allocation:</strong>&lt;br&gt;APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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<tr>
<td>b0347.8 Upgrade (per ABB inspection) breaker HL-8</td>
<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt;AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PEPCO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td><strong>DFAX Allocation:</strong>&lt;br&gt;APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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<tbody>
<tr>
<td>Upgrade (per ABB inspection) breaker HL-10</td>
<td>b0347.9</td>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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DFAX Allocation: APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)

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<tbody>
<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3</td>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.46%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PLL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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</tr>
<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4</td>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.46%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PLL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<tbody>
<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6</td>
<td>Load-Ratio Share Allocation:</td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
</tr>
<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7</td>
<td>Load-Ratio Share Allocation:</td>
<td>APS (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7</td>
<td>DFAX Allocation:</td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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*Neptune Regional Transmission System, LLC*
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<th>Upgrade (per ABB Inspection)</th>
<th>Hatfield 500 kV breakers HFL-9</th>
<th>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELCO (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</th>
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<tr>
<td>Upgrade (per ABB inspection)</td>
<td>Harrison 500 kV breaker 'HL-3'</td>
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<tr>
<td></td>
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<td><strong>DFAX Allocation:</strong> APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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*Neptune Regional Transmission System, LLC*

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<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
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<td>b0347.17 Replace Meadow Brook 138 kV breaker ‘MD-10’</td>
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<td>b0347.18 Replace Meadow Brook 138 kV breaker ‘MD-11’</td>
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<td>APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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DFAX Allocation:
APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)

Load-Ratio Share Allocation:
AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)

DFAX Allocation:
APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)

*Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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*Neptune Regional Transmission System, LLC

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<td>DL (1.71%) / DPL (2.60%) /</td>
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<td>Dominion (13.32%) / EKPC</td>
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<td>OVEC (0.08%) / PECO (5.40%) /</td>
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<td>(3.67%) / PPL (4.72%) / PSEG</td>
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<td>Dominion (56.77%) / PEPCO</td>
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<td></td>
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<td>(13.39%)</td>
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| Replace Meadow Brook 138 kV breaker ‘MD-15’ |                             | Load-Ratio Share Allocation: |
|                                            |                            | AEC (1.65%) / AEP (13.68%) / |
|                                            |                            | APS (5.76%) / ATSI (8.04%) / |
|                                            |                            | BGE (4.11%) / ComEd (13.39%) |
|                                            |                            | Dayton (2.12%) / DEOK (3.25%) |
|                                            |                            | DL (1.71%) / DPL (2.60%) /   |
|                                            |                            | Dominion (13.32%) / EKPC     |
|                                            |                            | (1.89%) / JCPL (3.86%) / ME  |
|                                            |                            | (1.90%) / NEPTUNE* (0.42%) / |
|                                            |                            | OVEC (0.08%) / PECO (5.40%) /|
|                                            |                            | PENELEC (1.78%) / PEPCO      |
|                                            |                            | (3.67%) / PPL (4.72%) / PSEG |
|                                            |                            | (6.39%) / RE (0.26%)         |
| **DFAX Allocation:**              |                            | APS (22.57%) / BGE (7.27%) / |
|                                    |                            | Dominion (56.77%) / PEPCO    |
|                                    |                            | (13.39%)                     |

*Neptune Regional Transmission System, LLC

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<td>Replace Meadow Brook 138 kV breaker ‘MD-17’</td>
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<td>APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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*Neptune Regional Transmission System, LLC
Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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<td>Replace Meadow Brook 138 kV breaker ‘MD-18’</td>
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<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<td>Replace Meadow Brook 138 kV breaker ‘MD-22#1 CAP’</td>
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| **b0347.27** Replace Meadow Brook 138 kV breaker ‘MD-4’ | | **Load-Ratio Share Allocation:**  
  AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%) |
| **b0347.28** Replace Meadow Brook 138 kV breaker ‘MD-5’ | | **DFAX Allocation:**  
  APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%) |

*Neptune Regional Transmission System, LLC
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<td>b0347.30 Replace Meadowbrook 138 kV breaker ‘MD-7’</td>
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<td>DFX Allocation: APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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<td><strong>b0347.31</strong> Replace Meadowbrook 138 kV breaker ‘MD-8’</td>
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<td><strong>b0347.32</strong> Replace Meadowbrook 138 kV breaker ‘MD-9’</td>
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<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt;AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)&lt;br&gt;<strong>DFAX Allocation:</strong>&lt;br&gt;APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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*Neptune Regional Transmission System, LLC*
Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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<td>b0347.33  Replace Meadow Brook 138 kV breaker ‘MD-1’</td>
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<td>b0347.34  Replace Meadow Brook 138 kV breaker ‘MD-2’</td>
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<tr>
<td>b0348     Upgrade Stonewall – Inwood 138 kV with 954 ACSR conductor</td>
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<tr>
<td>b0373     Convert Doubs – Monocacy 138 kV facilities to 230 kV operation</td>
<td>AEC (1.82%) / APS (76.84%) / DPL (2.64%) / JCPL (4.53%) / ME (9.15%) / NEPTUNE* (0.42%) / PPL (4.60%)</td>
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| b0393     Replace terminal equipment at Harrison 500 kV and Belmont 500 kV |                         | **Load-Ratio Share Allocation:**  
AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)  
**DFAX Allocation:**  
APS (1.47%) / Dayton (0.26%) / DEOK (0.44%) / DL (9.95%) / Dominion (87.75%) / EKPC (0.13%) |

* Neptune Regional Transmission System, LLC
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<td>b0407.2 Replace Marlowe 138 kV breaker “MBO”</td>
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<td>APS (100%)</td>
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<td>b0407.3 Replace Marlowe 138 kV breaker “BMA”</td>
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<td>b0407.4 Replace Marlowe 138 kV breaker “BMR”</td>
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<td>b0407.5 Replace Marlowe 138 kV breaker “WC-1”</td>
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<td>Required Transmission Enhancements</td>
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<td>b0407.8 Replace Marlowe 138 kV breaker “138 kV bus tie”</td>
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<td>b0408.1 Replace Trissler 138 kV breaker “Belmont 604”</td>
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<td>b0408.2 Replace Trissler 138 kV breaker “Edgelawn 90”</td>
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<td>b0409.1 Replace Weirton 138 kV breaker “Wylie Ridge 210”</td>
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<td>b0409.2 Replace Weirton 138 kV breaker “Wylie Ridge 216”</td>
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<td>b0410 Replace Glen Falls 138 kV breaker “McAlpin 30”</td>
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Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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<th>DFAX Allocation:</th>
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<td>b0419</td>
<td>Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0420</td>
<td>Operating Procedure to open the Black Oak 500/138 kV transformer #3 for the loss of Hatfield – Ronco 500 kV and the Hatfield #3 Generation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0445</td>
<td>Upgrade substation equipment and reconductor the Tidd – Mahans Lane – Weirton 138 kV circuit with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>

* Neptune Regional Transmission System, LLC
<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)</td>
<td>As specified under the procedures detailed in Attachment H-19B</td>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>DFX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE* (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)</td>
</tr>
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*Neptune Regional Transmission System, LLC
Construct a Welton Spring to Kemptown 765 kV line (APS equipment)

As specified under the procedures detailed in Attachment H-19B

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<th>Required Transmission Enhancements</th>
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<tr>
<td>b0492</td>
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<tr>
<td><strong>Load-Ratio Share Allocation:</strong></td>
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<tr>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<td><strong>DFAX Allocation:</strong></td>
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<tr>
<td>AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE* (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)</td>
<td></td>
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<tr>
<td>b0492.3</td>
<td></td>
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<tr>
<td>Replace Eastalco 230 kV breaker D-26</td>
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<td>APS (100%)</td>
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<tr>
<td>b0492.4</td>
<td></td>
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<tr>
<td>Replace Eastalco 230 kV breaker D-28</td>
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<td>APS (100%)</td>
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<th>Annual Revenue Requirement</th>
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<tbody>
<tr>
<td>Replace Eastalco 230 kV breaker D-31</td>
<td>APS (100%)</td>
<td></td>
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<tr>
<td>Replace existing Kammer 765/500 kV transformer with a new larger transformer</td>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (5.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<tr>
<td>Reconductor the Powell Mountain – Sutton 138 kV line</td>
<td>APS (100%)</td>
<td></td>
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<tr>
<td>Install a 28.61 MVAR capacitor on Sutton 138 kV</td>
<td>APS (100%)</td>
<td></td>
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<tr>
<td>Replace Doubs circuit breaker DJ1</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Doubs circuit breaker DJ7</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Doubs circuit breaker DJ10</td>
<td>APS (100%)</td>
<td></td>
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<tr>
<td>Replace Doubs circuit breaker DJ11</td>
<td>APS (100%)</td>
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<tr>
<td>Replace Doubs circuit breaker DJ12</td>
<td>APS (100%)</td>
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</tr>
<tr>
<td>Replace Doubs circuit breaker DJ13</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Doubs circuit breaker DJ20</td>
<td>APS (100%)</td>
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* Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
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<tbody>
<tr>
<td>Replace Doubs circuit breaker DJ21</td>
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<td>APS (100%)</td>
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<tr>
<td>Remove instantaneous reclose from Eastalco circuit breaker D-26</td>
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<td>APS (100%)</td>
</tr>
<tr>
<td>Install 200 MVAR capacitor at Meadow Brook 500 kV substation</td>
<td>Load-Ratio Share Allocation:</td>
<td>APS (22.57%) / BGE (7.27%) / DOMINION (56.77%) / PEPCO (13.39%)</td>
</tr>
<tr>
<td>Install 250 MVAR capacitor at Kemptown 500 kV substation</td>
<td>Load-Ratio Share Allocation:</td>
<td>APS (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE* (1.12%) / PEPCO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)</td>
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<table>
<thead>
<tr>
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<th>Annual Revenue Requirement</th>
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<tbody>
<tr>
<td>b0572.1 Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
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<tr>
<td>b0572.2 Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
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<tr>
<td>b0573 Reconfigure circuits in Butler – Cabot 138 kV area</td>
<td>APS (100%)</td>
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</table>
| b0577 Replace Fort Martin 500 kV breaker FL-1 | **Load-Ratio Share Allocation:**  
AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PEPCO (5.40%) / PENELEC (1.78%) / PPL (6.39%) / RE (0.26%)  
**DFAX Allocation:**  
APS (100%) | |

*Neptune Regional Transmission System, LLC

<table>
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<tbody>
<tr>
<td>b0588 Install a 40.8 MVAR 138 kV capacitor at Grassy Falls</td>
<td>APS (100%)</td>
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<tr>
<td>b0589 Replace five 138 kV breakers at Cecil</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0591 Install a 25.2 MVAR capacitor at Seneca Caverns 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0674 Construct new Osage – Whiteley 138 kV circuit</td>
<td>APS (97.68%) / DL (0.96%) / PENELEC (1.09%) / ECP** (0.01%) / PSEG (0.25%) / RE (0.01%)</td>
<td></td>
</tr>
<tr>
<td>b0674.1 Replace the Osage 138 kV breaker ‘CollinsF126’</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0675.1 Convert Monocacy - Walkersville 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
<td></td>
</tr>
<tr>
<td>b0675.2 Convert Walkersville - Catoctin 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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</tr>
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*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.
### Required Transmission Enhancements

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Annual Revenue Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Convert Ringgold - Catoctin 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
</tr>
<tr>
<td>Convert Catoctin - Carroll 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
</tr>
<tr>
<td>Convert portion of Ringgold Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
</tr>
<tr>
<td>Convert Catoctin Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
</tr>
<tr>
<td>Convert portion of Carroll Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
</tr>
<tr>
<td>Convert Monocacy Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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</tbody>
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*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C.

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
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<tbody>
<tr>
<td><strong>b0675.9</strong> Convert Walkersville Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
<td></td>
</tr>
<tr>
<td><strong>b0676.1</strong> Reconductor Doubs - Lime Kiln (#207) 230 kV</td>
<td>AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)</td>
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<tr>
<td><strong>b0676.2</strong> Reconductor Doubs - Lime Kiln (#231) 230 kV</td>
<td>AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)</td>
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<tr>
<td><strong>b0677</strong> Reconductor Double Toll Gate – Riverton with 954 ACSR</td>
<td>APS (100%)</td>
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<tr>
<td><strong>b0678</strong> Reconductor Glen Falls - Oak Mound 138 kV with 954 ACSR</td>
<td>APS (100%)</td>
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<tr>
<td><strong>b0679</strong> Reconductor Grand Point – Letterkenny with 954 ACSR</td>
<td>APS (100%)</td>
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<tr>
<td><strong>b0680</strong> Reconductor Greene – Letterkenny with 954 ACSR</td>
<td>APS (100%)</td>
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*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C.
Monongahela Power Company—The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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<tr>
<td>b0685 Replace Ringgold 230/138 kV #3 with larger transformer</td>
<td>APS (71.93%) / JCPL (4.17%) / ME (6.79%) / NEPTUNE* (0.38%) / PECO (4.05%) / PENELEC (5.88%) / ECP** (0.18%) / PSEG (6.37%) / RE (0.25%)</td>
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<tr>
<td>b0797 Advance n0321 (Replace Doubs Circuit Breaker DJ2)</td>
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<td>APS (100%)</td>
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<tr>
<td>b0798 Advance n0322 (Replace Doubs Circuit Breaker DJ3)</td>
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<tr>
<td>b0799 Advance n0323 (Replace Doubs Circuit Breaker DJ6)</td>
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<tr>
<td>b0800 Advance n0327 (Replace Doubs Circuit Breaker DJ16)</td>
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</tr>
<tr>
<td>b0941 Replace Opequon 138 kV breaker 'BUSTIE'</td>
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<td>APS (100%)</td>
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<tr>
<td>b0956 Replace Pruntytown 138 kV breaker 'P-9'</td>
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<tr>
<td>b0957 Replace Pruntytown 138 kV breaker 'P-12'</td>
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<tr>
<td>b0958 Replace Pruntytown 138 kV breaker 'P-15'</td>
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**East Coast Power, L.L.C.

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<tr>
<td>b0956 Replace Pruntytown 138 kV breaker 'P-9'</td>
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<tr>
<td>b0957 Replace Pruntytown 138 kV breaker 'P-12'</td>
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<td>APS (100%)</td>
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<tr>
<td>b0958 Replace Pruntytown 138 kV breaker 'P-15'</td>
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Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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<tr>
<td>Replace Pruntytown 138 kV breaker 'P-2'</td>
<td>APS (100%)</td>
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<tr>
<td>Replace Pruntytown 138 kV breaker 'P-5'</td>
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<tr>
<td>Replace Pruntytown 138 kV breaker 'P-11'</td>
<td>APS (100%)</td>
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<tr>
<td>Replace Pruntytown 138 kV breaker 'P-8'</td>
<td>APS (100%)</td>
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<tr>
<td>Replace Pruntytown 138 kV breaker 'P-14'</td>
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<tr>
<td>Replace Ringgold 138 kV breaker '#3 XFMR BANK'</td>
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<tr>
<td>Replace Rivesville 138 kV breaker '#8 XFMR BANK'</td>
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<tr>
<td>Replace Belmont 138 kV breaker 'B-16'</td>
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<tr>
<td>Replace Belmont 138 kV breaker 'B-17'</td>
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<tr>
<td>Replace Rivesville 138 kV breaker '#10 XFMR BANK'</td>
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<tr>
<td>Replace Belmont 138 kV breaker 'B-14'</td>
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### Required Transmission Enhancements — Annual Revenue Requirement — Responsible Customer(s)

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<td>b0972</td>
<td>Belmont 138 kV breaker 'B-16'</td>
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<td>APS (100%)</td>
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<tr>
<td>b0977</td>
<td>Belmont 138 kV breaker 'B-17'</td>
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<td>APS (100%)</td>
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<tr>
<td>b0984</td>
<td>Rivesville 138 kV breaker '#10 XFRM BANK'</td>
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<td>APS (100%)</td>
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<td>b0985</td>
<td>Belmont 138 kV breaker 'B-14'</td>
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<td>APS (100%)</td>
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### Required Transmission Enhancements

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<th>Responsible Customer(s)</th>
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<tbody>
<tr>
<td>b0989</td>
<td>Replace Edgelawn 138 kV breaker 'GOFF RUN #632'</td>
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<td>APS (100%)</td>
</tr>
<tr>
<td>b0991</td>
<td>Change reclosing on Belmont 138 kV breaker 'B-7'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0992</td>
<td>Change reclosing on Belmont 138 kV breaker 'B-12'</td>
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<td>APS (100%)</td>
</tr>
<tr>
<td>b0993</td>
<td>Change reclosing on Belmont 138 kV breaker 'B-9'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0994</td>
<td>Change reclosing on Belmont 138 kV breaker 'B-19'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0995</td>
<td>Change reclosing on Belmont 138 kV breaker 'B-21'</td>
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<td>APS (100%)</td>
</tr>
<tr>
<td>b0996</td>
<td>Change reclosing on Willow Island 138 kV breaker 'FAIRVIEW #84'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0999</td>
<td>Replace Redbud 138 kV breaker 'BUS TIE'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1022.1</td>
<td>Reconfigure the Peters to Bethel Park 138 kV line and Elrama to Woodville 138 kV line to create a 138 kV path from Woodville to Peters and a 138 kV path from Elrama to Bethel Park</td>
<td>APS (96.98%) / DL (3.02%)</td>
<td></td>
</tr>
<tr>
<td>b1023.3</td>
<td>Construct a new 502 Junction - Osage 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Required Transmission Enhancements — Annual Revenue Requirement — Responsible Customer(s)

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<tbody>
<tr>
<td>b0999</td>
<td>Replace Redbud 138 kV breaker ‘BUS TIE’</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1022.1</td>
<td>Reconfigure the Peters to Bethel Park 138 kV line and Elrama to Woodville 138 kV line to create a 138 kV path from Woodville to Peters and a 138 kV path from Elrama to Bethel Park</td>
<td>APS (96.98%) / DL (3.02%)</td>
</tr>
<tr>
<td>b1023.3</td>
<td>Construct a new 502 Junction – Osage 138 kV line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
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</tr>
<tr>
<td>-----------------------------------</td>
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</tr>
<tr>
<td>b1023.4  Construct Braddock 138 kV breaker station that connects the Charleroi - Gordon 138 kV line, Washington - Franklin 138 kV line and the Washington - Vanceville 138 kV line including a 66 MVAR capacitor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1028    Raise three structures on the Osage - Collins Ferry 138 kV line to increase the line rating</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1128    Reconductor the Edgewater – Vasco Tap; Edgewater – Loyalhanna 138 kV lines with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1129    Reconductor the East Waynesboro – Ringgold 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1131    Upgrade Double Tollgate – Meadowbrook MDT Terminal Equipment</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1132    Upgrade Double Tollgate-Meadowbrook MBG terminal equipment</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1133    Upgrade terminal equipment at Springdale</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1135    Reconductor the Bartonville – Meadowbrook 138 kV line with high temperature conductor</td>
<td></td>
<td>APS (100%)</td>
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Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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<tbody>
<tr>
<td><strong>b1137</strong> Reconductor the Eastgate – Luxor 138 kV; Eastgate – Sony 138 kV line with 954 ACSR</td>
<td>APS (78.59%) / PENELEC (14.08%) / ECP** (0.23%) / PSEG (6.83%) / RE (0.27%)</td>
<td></td>
</tr>
<tr>
<td><strong>b1138</strong> Reconductor the King Farm – Sony 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b1139</strong> Reconductor the Yukon – Waltz Mills 138 kV line with high temperature conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b1140</strong> Reconductor the Bracken Junction – Luxor 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b1141</strong> Reconductor the Sewickley – Waltz Mills Tap 138 kV line with high temperature conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b1142</strong> Reconductor the Bartonville – Stephenson 138 kV; Stonewall – Stephenson 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b1143</strong> Reconductor the Youngwood – Yukon 138 kV line with high temperature conductor</td>
<td></td>
<td>APS (89.92%) / PENELEC (10.08%)</td>
</tr>
<tr>
<td><strong>b1144</strong> Reconductor the Bull Creek Junction – Cabot 138 kV line with high temperature conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
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**East Coast Power, L.L.C.
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<tbody>
<tr>
<td>b1145</td>
<td>Reconductor the Lawson Junction – Cabot 138 kV line with high temperature conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1146</td>
<td>Replace Layton - Smithton #61 138 kV line structures to increase line rating</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1147</td>
<td>Replace Smith – Yukon 138 kV line structures to increase line rating</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1148</td>
<td>Reconductor the Loyalhanna – Luxor 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1149</td>
<td>Reconductor the Luxor – Stony Springs Junction 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1150</td>
<td>Upgrade terminal equipment at Social Hall</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1151</td>
<td>Reconductor the Greenwood – Redbud 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1152</td>
<td>Reconductor Grand Point – South Chambersburg</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1153</td>
<td>Replace Double Toll Gate 138 kV breaker ‘DRB-2’</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1154</td>
<td>Replace Double Toll Gate 138 kV breaker ‘DT 138 kV OCB’</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
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<tr>
<td>b1166 Replace Wylie Ridge 138 kV breaker ‘W-9’</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1167 Replace Reid 138 kV breaker ‘RI-2’</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1171.1 Install the second Black Oak 500/138 kV transformer, two 138 kV breaker, and related substation work</td>
<td>BGE (20.76%) / DPL (3.14%) / Dominion (39.55%) / ME (2.71%) / PECO (3.36%) / PEPCO (30.48%)</td>
<td></td>
</tr>
<tr>
<td>b1171.3 Install six 500 kV breakers and remove BOL1 500 kV breaker at Black Oak</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td></td>
</tr>
<tr>
<td>b1200 Reconductor Double Toll Gate – Greenwood 138 kV with 954 ACSR conductor</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1221.1 Convert Carbon Center from 138 kV to a 230 kV ring bus</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1221.2 Construct Bear Run 230 kV substation with 230/138 kV transformer</td>
<td>APS (100%)</td>
<td></td>
</tr>
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<tr>
<td>b1221.3 Loop Carbon Center Junction – Williamette line into Bear Run</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1221.4 Carbon Center – Carbon Center Junction &amp; Carbon Center Junction – Bear Run conversion from 138 kV to 230 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1230 Reconducto Willow-Eureka &amp; Eureka-St Mary 138 kV lines</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1232 Reconducto Nipetown – Reid 138 kV with 1033 ACCR</td>
<td>AEC (1.40%) / APS (75.74%) / DPL (1.92%) / JCPL (2.92%) / ME (6.10%) / NEPTUNE* (0.27%) / PECO (4.40%) / PENELEC (3.26%) / PPL (3.99%)</td>
<td></td>
</tr>
<tr>
<td>b1233.1 Upgrade terminal equipment at Washington</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1234 Replace structures between Ridgeway and Paper city</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1235 Reconducto the Albright – Black Oak AFA 138 kV line with 795 ACSS/TW</td>
<td>APS (30.25%) / BGE (16.10%) / Dominion (30.51%) / PEPCO (23.14%)</td>
<td></td>
</tr>
<tr>
<td>b1237 Upgrade terminal equipment at Albright, replace bus and line side breaker disconnects and leads, replace breaker risers, upgrade RTU and line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1238 Install a 138 kV 44 MVAR capacitor at Edgelawn substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>

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<tbody>
<tr>
<td>b1239 Install a 138 kV 44 MVAR capacitor at Ridgeway substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1240 Install a 138 kV 44 MVAR capacitor at Elko Substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1241 Upgrade terminal equipment at Washington substation on the GE Plastics/DuPont terminal</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1242 Replace structures between Collins Ferry and West Run</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1384 Reconductor approximately 2.17 miles of Bedington – Shepherdstown 138 kV with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1385 Reconductor Halfway – Paramount 138 kV with 1033 ACCR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1386 Reconductor Double Tollgate – Meadow Brook 138 kV ckt 2 with 1033 ACCR</td>
<td></td>
<td>APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)</td>
</tr>
<tr>
<td>b1387 Reconductor Double Tollgate – Meadow Brook 138 kV</td>
<td></td>
<td>APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)</td>
</tr>
<tr>
<td>b1388 Reconductor Feagans Mill – Millville 138 kV with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
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</table>

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<tbody>
<tr>
<td>b1389 Reconductor Bens Run – St. Mary’s 138 kV with 954 ACSR</td>
<td>AEP (12.40%) / APS (17.80%) / DL (69.80%)</td>
<td></td>
</tr>
<tr>
<td>b1390 Replace Bus Tie Breaker at Opequon</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1391 Replace Line Trap at Gore</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1392 Replace structure on Belmont – Trissler 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1393 Replace structures Kingwood – Pruntytown 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1395 Upgrade Terminal Equipment at Kittanning</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1401 Change reclosing on Pruntytown 138 kV breaker ‘P-16’ to 1 shot at 15 seconds</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1402 Change reclosing on Rivesville 138 kV breaker ‘Pruntytown #34’ to 1 shot at 15 seconds</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
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</table>
| Replace the Weirton 138 kV breaker ‘Tidd 224’ with a 40 kA breaker | APS (100%) | Load-Ratio Share Allocation:  
AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%) |
| Terminal Equipment upgrade at Doubs substation | | |

* Neptune Regional Transmission System, LLC
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<tbody>
<tr>
<td>b1507.3 Mt. Storm – Doubs transmission line rebuild in Maryland – Total line mileage for APS is 2.71 miles</td>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1510 Install 59.4 MVAR capacitor at Waverly</td>
<td>DFX Allocation: APS (16.11%) / BGE (13.32%) / Dominion (55.42%) / PEPCO (15.15%)</td>
<td>APS (100%)</td>
</tr>
</tbody>
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<table>
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</tr>
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<tbody>
<tr>
<td>b1803</td>
<td>Build a 300 MVAR Switched Shunt at Doubs 500 kV and increase (~50 MVAR) in size the existing Switched Shunt at Doubs 500 kV</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td>b1804</td>
<td>Install a new 600 MVAR SVC at Meadowbrook 500 kV</td>
<td>APS (16.11%) / BGE (13.32%) / Dominion (55.42%) / PEPCO (15.15%)</td>
</tr>
<tr>
<td>b1816.1</td>
<td>Replace relaying at the Mt. Airy substation on the Carroll - Mt. Airy 230 kV line</td>
<td>APS (100%)</td>
</tr>
</tbody>
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### Required Transmission Enhancements

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<tbody>
<tr>
<td>b1816.2</td>
<td>Adjust the control settings of all existing capacitors at Mt Airy 34.5 kV, Monocacy 138 kV, Ringgold 138 kV served by Potomac Edison's Eastern 230 kV network to ensure that all units will be on during the identified N-1-1 contingencies</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1816.3</td>
<td>Replace existing unidirectional LTC controller on the No. 4, 230/138 kV transformer at Carroll substation with a bidirectional unit</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1816.4</td>
<td>Isolate and bypass the 138 kV reactor at Germantown Substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1816.6</td>
<td>Replace 336.4 ACSR conductor on the Catoctin - Carroll 138 kV line using 556.5 ACSR (26/7) or equivalent on existing structures (12.7 miles), 800 A wave traps at Carroll and Catoctin with 1200 A units, and 556.5 ACSR SCCIR (Sub-conductor) line risers and bus traps with 795 ACSR or equivalent</td>
<td></td>
<td>APS (100%)</td>
</tr>
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<tr>
<td>b1822 Replace the 1200 A wave trap, line risers, breaker risers with 1600 A capacity terminal equipment at Reid 138 kV SS</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1823 Replace the 800 A wave trap with a 1200 A wave trap at Millville 138 kV substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1824 Reconductor Grant Point - Guilford 138 kV line approximately 8 miles of 556 ACSR with 795 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1826 Change the CT ratio at Double Toll Gate 138 kV SS on MDT line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1827 Change the CT ratio at Double Toll Gate 138 kV SS on MBG line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1828.1 Reconductor the Bartonville – Stephenson 3.03 mile 138 kV line of 556 ACSR with 795 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
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<tr>
<td>b1828.2</td>
<td>Reconductor the Stonewall – Stephenson 2.08 mile 138 kV line of 556 ACSR with 795 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1829</td>
<td>Replace the existing 138 kV 556.5 ACSR substation conductor risers with 954 ACSR at the Redbud 138 kV substation, including but not limited to the line side disconnect leads</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1830</td>
<td>Replace 1200 A wave trap and 1024 ACAR breaker risers at Halfway 138 kV substation, and replace 1024 ACAR breaker risers at Paramount 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1832</td>
<td>Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 1 (207) 230 kV line terminal</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1833</td>
<td>Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 2 (231) 230 kV line terminal</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
**Monongahela Power Company**—and** The Potomac Edison Company**, and** West Penn Power Company**, all-doing business as Allegheny Power (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
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</tr>
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<tbody>
<tr>
<td>Reconductor 14.3 miles of 556 ACSR with 795 ACSR from Old Chapel to Millville 138 kV and upgrade line risers at Old Chapel 138 kV and Millville 138 kV and replace 1200 A wave trap at Millville 138 kV</td>
<td>APS (37.68%) / Dominion (34.46%) / PEPCO (13.69%) / BGE (11.45%) / ME (2.01%) / PENELEC (0.53%) / DL (0.18%)</td>
<td>b1835</td>
</tr>
<tr>
<td>Replace 1200 A wave trap with 1600 A wave trap at Reid 138 kV SS</td>
<td>APS (100%)</td>
<td>b1836</td>
</tr>
<tr>
<td>Replace 750 CU breaker risers with 795 ACSR at Marlowe 138 kV and replace 1200 A wave traps with 1600 A wave traps at Marlowe 138 kV and Bedington 138 kV</td>
<td>APS (100%)</td>
<td>b1837</td>
</tr>
<tr>
<td>Replace the 1200 A Bedington 138 kV line air switch and the 1200 A 138 kV bus tie air switch at Nipetown 138 kV with 1600 A switches</td>
<td>APS (100%)</td>
<td>b1838</td>
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<tr>
<td>b1840 Construct a 138 kV line between Buckhannon and Weston 138 kV substations</td>
<td></td>
<td>APS (100%)</td>
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<tr>
<td>b1902 Replace line trap at Stonewall on the Stephenson 138 kV line terminal</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1942 Change the CT ratio at Millville to improve the Millville – Old Chapel 138 kV line ratings</td>
<td></td>
<td>APS (100%)</td>
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<tr>
<td>b1987 Reconductor the Osage-Collins Ferry 138 kV line with 795 ACSS. Upgrade terminal equipment at Osage and Collins Ferry</td>
<td></td>
<td>APS (100%)</td>
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<tr>
<td>Raise structures between Lake Lynn and West Run to eliminate the clearance de-rates on the West Run – Lake Lynn 138 kV line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Raise structures between Collins Ferry and West Run to eliminate the clearance de-rates on the Collins Ferry - West Run 138 kV line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Weirt 138 kV breaker 'S-TORONTO226' with 63 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Revise the reclosing of Weirt 138 kV breaker '2&amp;5 XFMR'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Ridgeley 138 kV breaker '#2 XFMR OCB'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Revise the reclosing of Ridgeley 138 kV breaker 'AR3' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Revise the reclosing of Ridgeley 138 kV breaker 'RC1'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Ridgeley 138 kV breaker 'WC4' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Ridgeley 138 kV breaker '1 XFMR OCB' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Requirement ID</td>
<td>Action Description</td>
<td>Annual Revenue Requirement</td>
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<tr>
<td>----------------</td>
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</tr>
<tr>
<td>b2106</td>
<td>Replace Wylie Ridge 345 kV breaker 'WK-1' with 63 kA rated breaker</td>
<td></td>
</tr>
<tr>
<td>b2107</td>
<td>Replace Wylie Ridge 345 kV breaker 'WK-2' with 63 kA rated breaker</td>
<td></td>
</tr>
<tr>
<td>b2108</td>
<td>Replace Wylie Ridge 345 kV breaker 'WK-3' with 63 kA rated breaker</td>
<td></td>
</tr>
<tr>
<td>b2109</td>
<td>Replace Wylie Ridge 345 kV breaker 'WK-4' with 63 kA rated breaker</td>
<td></td>
</tr>
<tr>
<td>b2110</td>
<td>Replace Wylie Ridge 345 kV breaker 'WK-5' with 63 kA rated breaker</td>
<td></td>
</tr>
<tr>
<td>b2111</td>
<td>Replace Wylie Ridge 138 kV breaker 'WK-6' with 63 kA rated breaker</td>
<td></td>
</tr>
<tr>
<td>b2112</td>
<td>Replace Weirton 138 kV breaker 'NO 6 XFRMR' with 63 kA rated breaker</td>
<td></td>
</tr>
<tr>
<td>b2113</td>
<td>Replace Armstrong 138 kV breaker 'Bus-Tie' (Status On-Hold pending retirement)</td>
<td></td>
</tr>
<tr>
<td>b2114</td>
<td>Replace Armstrong 138 kV breaker 'Bus-Tie' (Status On-Hold pending retirement)</td>
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<tr>
<td>b2124.1 Add a new 138 kV line exit</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2124.2 Construct a 138 kV ring bus and install a 138/69 kV autotransformer</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2124.4 Construct approximately 5.5 miles of 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2165 Replace 800A wave trap at Stonewall with a 1200 A wave trap</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2166 Reconductor the Millville – Sleepy Hollow 138 kV 4.25 miles of 556 ACSR with 795 ACSR, upgrade line risers at Sleepy Hollow, and change 1200 A CT tap at Millville to 800</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2168 For Grassy Falls 138 kV Capacitor bank adjust turn-on voltage to 1.0 pu with a high limit of 1.04 pu, For Crupperneck and Powell Mountain 138 kV Capacitor Banks adjust turn-on voltage to 1.01 pu with a high limit of 1.035 pu</td>
<td></td>
<td>APS (100%)</td>
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<tr>
<td>b2171 Replace/Raise structures on the Parsons-William 138 kV line section to eliminate clearance de-rate</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2172 Replace/Raise structures on the Parsons - Loughs Lane 138 kV line section to eliminate clearance de-rate</td>
<td></td>
<td>APS (100%)</td>
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**Keystone Appalachian Transmission Company**

**Required Transmission Enhancements**  
**Annual Revenue Requirement**  
**Responsible Customer(s)**

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<th>Description</th>
<th>Load-Ratio Share Allocation:</th>
<th>DFAX Allocation:</th>
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<tbody>
<tr>
<td>b0347.1</td>
<td>Build new Mt. Storm – 502 Junction 500 kV circuit</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
</tr>
<tr>
<td>b0347.3</td>
<td>Build new 502 Junction 500 kV substation</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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*Neptune Regional Transmission System, LLC*
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<tr>
<td>b0347.10 Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1</td>
<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt;AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELIC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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<tr>
<td>b0347.11 Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3</td>
<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt;AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELIC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<td><strong>Load-Ratio Share Allocation:</strong></td>
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<td>AEC (1.65%) / AEP (13.68%) / APS</td>
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<td>(5.76%) / ATSI (8.04%) / BGE</td>
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<td>(4.11%) / ComEd (13.39%) / Dayton</td>
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<td>(2.12%) / DEOK (3.25%) / DL</td>
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<td>(1.71%) / DPL (2.60%) / Dominion</td>
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<tr>
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<tr>
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<td><strong>DFAX Allocation:</strong></td>
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</tr>
<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7</td>
</tr>
<tr>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<tr>
<td>DFAX Allocation: APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9</td>
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<tr>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<tr>
<td>DFAX Allocation: APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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<tr>
<td>Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'</td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<tr>
<td>b0406.1 Replace Mitchell 138 kV breaker “#4 bank”</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0406.2 Replace Mitchell 138 kV breaker “#5 bank”</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0406.3 Replace Mitchell 138 kV breaker “#2 transf”</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0406.4 Replace Mitchell 138 kV breaker “#3 bank”</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0406.5 Replace Mitchell 138 kV breaker “Charlerio #2”</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0406.6 Replace Mitchell 138 kV breaker “Charlerio #1”</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0406.7 Replace Mitchell 138 kV breaker “Shepler Hill Jct”</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0406.8 Replace Mitchell 138 kV breaker “Union Jct”</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0406.9 Replace Mitchell 138 kV breaker “#1-2 138 kV bus tie”</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0417 Recondor Mitchell – Shepler Hill Junction 138 kV with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0418 Install a breaker failure auto-restoration scheme at Cabot 500 kV for the failure of the #6 breaker</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td></td>
</tr>
<tr>
<td>b0460 Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency</td>
<td></td>
<td>APS (100%)</td>
</tr>
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<tr>
<td>b0535. Install a 44 MVAR capacitor on Dutch Fork 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0584. Install 33 MVAR 138 kV capacitor at Necessity 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0585. Increase Cecil 138 kV capacitor size to 44 MVAR, replace five 138 kV breakers at Cecil due to increased short circuit fault duty as a result of the addition of the Prexy substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0586. Increase Whiteley 138 kV capacitor size to 44 MVAR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0587. Reconductor AP portion of Tidd – Carnegie 138 kV and Carnegie – Weirton 138 kV with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0590. Replace #1 and #2 breakers at Charleroi 138 kV</td>
<td>APS (100%)</td>
<td></td>
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Keystone Appalachian Transmission Company (cont.)

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<tr>
<td>b0673 Rebuild Elko – Carbon Center Junction using 230 kV construction</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0681 Replace 600/5 CT’s at Franklin 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0682 Replace 600/5 CT’s at Whiteley 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0684 Reconductor Guilford – South Chambersburg with 954 ACSR</td>
<td>APS (100%)</td>
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<tbody>
<tr>
<td>Install a third Cabot 500/138 kV transformer</td>
<td>APS (74.36%) / DL (2.73%) PENELEC (22.91%)</td>
<td></td>
</tr>
<tr>
<td>Replace Butler 138 kV breaker '1 BANK'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Butler 138 kV breaker '2 BANK'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-8'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-3'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-1'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-5'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-2'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-19'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-4'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-9'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-11'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-13'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Charleroi 138 kV breaker '1 XFMR BANK'</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>
### Keystone Appalachian Transmission Company (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-7'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Charleroi 138 kV breaker '2 XFMR BANK'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-18'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-10'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138E'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138C'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138F'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138G'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138V'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Armstrong 138 kV breaker 'BROOKVILLE'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138P'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138U'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138D'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138R'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-12'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-17'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-14'</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
## Keystone Appalachian Transmission Company (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace Armstrong 138 kV breaker 'RESERVE BUS'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Yukon 138 kV breaker 'Y-16'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Springdale 138 kV breaker '138T'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Change reclosing on Cabot 138 kV breaker 'C-9'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Change reclosing on Cabot 138 kV breaker 'C-4'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Change reclosing on Cabot 138 kV breaker 'C-1'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Add static capacitors at Smith 138 kV</td>
<td>APS (96.98%) / DL (3.02%)</td>
<td></td>
</tr>
<tr>
<td>Add static capacitors at North Fayette 138 kV</td>
<td>APS (96.98%) / DL (3.02%)</td>
<td></td>
</tr>
<tr>
<td>Add static capacitors at South Fayette 138 kV</td>
<td>APS (96.98%) / DL (3.02%)</td>
<td></td>
</tr>
<tr>
<td>Add static capacitors at Manifold 138 kV</td>
<td>APS (96.98%) / DL (3.02%)</td>
<td></td>
</tr>
<tr>
<td>Add static capacitors at Houston 138 kV</td>
<td>APS (96.98%) / DL (3.02%)</td>
<td></td>
</tr>
<tr>
<td>Install a 500/138 kV transformer at 502 Junction</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Construct a new Franklin - 502 Junction 138 kV line including a rebuild of the Whiteley - Franklin 138 kV line to double circuit</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Increase the size of the shunt capacitors at Enon 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Peters 138 kV breaker 'Bethel OCB'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Peters 138 kV breaker 'Cecil OCB'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Peters 138 kV breaker 'Union JetOCB'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Cecil 138 kV breaker 'Enlow OCB'</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>
### Keystone Appalachian Transmission Company (cont.)

**Required Transmission Enhancements**  |  **Annual Revenue Requirement**  |  **Responsible Customer(s)**
--- | --- | ---
| b1165 | Replace Cecil 138 kV breaker ‘South Fayette’ | APS (100%) |
| b1243 | Install a 138 kV capacitor at Potter Substation | APS (100%) |
| b1261 | Replace Butler 138 kV breaker ‘1-2 BUS 138’ | APS (100%) |
| b1383 | Install 2nd 500/138 kV transformer at 502 Junction | APS (93.27%) / DL (5.39%) / PENELEC (1.34%) |
| b1403 | Change reclosing on Yukon 138 kV breaker ‘Y21 Shepler’ to 1 shot at 15 seconds | APS (100%) |
| b1404 | Replace the Kiski Valley 138 kV breaker ‘Vandergrift’ with a 40 kA breaker | APS (100%) |
| b1405 | Change reclosing on Armstrong 138 kV breaker ‘GARETTRJCT’ at 1 shot at 15 seconds | APS (100%) |
| b1406 | Change reclosing on Armstrong 138 kV breaker ‘KITTANNING’ to 1 shot at 15 seconds | APS (100%) |
| b1407 | Change reclosing on Armstrong 138 kV breaker ‘BURMA’ to 1 shot at 15 seconds | APS (100%) |
| b1409 | Replace the Cabot 138 kV breaker ‘C9 Kiski Valley’ with a 40 kA breaker | APS (100%) |
**Keystone Appalachian Transmission Company (cont.)**

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b1672 Install a 230 kV breaker at Carbon Center</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1825 Replace the 800 Amp line trap at Butler 138 kV Sub on the Cabot East 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1839 Install additional 33 MVAR capacitors at Grand Point 138 kV SS and Guildford 138 kV SS</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1941 Loop the Homer City-Handsome Lake 345 kV line into the Armstrong substation and install a 345/138 kV transformer at Armstrong</td>
<td></td>
<td>APS (67.86%) / PENELEC (32.14%)</td>
</tr>
<tr>
<td>b1964 Convert Moshannon substation to a 4 breaker 230 kV ring bus</td>
<td></td>
<td>APS (41.06%) / DPL (6.68%) / JCPL (5.48%) / ME (10.70%) / NEPTUNE* (0.53%) / PECO (15.53%) / PPL (20.02%)</td>
</tr>
<tr>
<td>b1965 Install a 44 MVAR 138 kV capacitor at Luxor substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1986 Upgrade the AP portion of the Elrama – Mitchell 138 kV line by replace breaker risers on the Mitchell 138 kV bus on the Elrama terminal</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2102 Replace Armstrong 138 kV breaker 'GARETTRJCT' with 40 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2103 Replace Armstrong 138 kV breaker 'BURMA' with 40 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2104 Replace Armstrong 138 kV breaker 'KITTANNING' with 40 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2105 Replace Armstrong 138 kV breaker 'KISSINGERJCT' with 40 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>

*Neptune Regional Transmission System, LLC*
Keystone Appalachian Transmission Company (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b2124.3 Add new 138 kV line exit and install a 138/25 kV transformer</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2124.5 Convert approximately 7.5 miles of 69 kV to 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2156 Install a 75 MVAR 230 kV capacitor at Shingletown Substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2169 Replace/Raise structures on the Yukon-Smithton 138 kV line section to eliminate clearance de-rate</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2170 Replace/Raise structures on the Smithton-Shepler Hill Jct 138 kV line section to eliminate clearance de-rate</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
SCHEDULE 12 – APPENDIX A

(14) Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b2117 Reconductor 0.33 miles of the Parkersburg - Belpre line and upgrade Parkersburg terminal equipment</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2118 Add 44 MVAR Cap at New Martinsville</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2142 Replace Weirton 138 kV breaker “Wylie Ridge 210” with 63 kA breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2143 Replace Weirton 138 kV breaker “Wylie Ridge 216” with 63 kA breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2214 Albright Substation: Install a new control building in the switchyard and relocate controls and SCADA equipment from the generating station building to the new control center</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2215 Rivesville Switching Station: Relocate controls and SCADA equipment from the generating station building to new control building</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
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<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b2216 Willow Island: Install a new 138 kV cross bus at Belmont Substation and reconnect and reconfigure the 138 kV lines to facilitate removal of the equipment at Willow Island switching station</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2235 130 MVAR reactor at Monocacy 230 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2260 Install a 32.4 MVAR capacitor at Bartonville</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2261 Install a 33 MVAR capacitor at Damascus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2267 Replace 1000 Cu substation conductor and 1200 amp wave trap at Marlowe</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2268 Reconductor 6.8 miles of 138kV 336 ACSR with 336 ACSS from Double Toll Gate to Riverton</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2299 Reconductor from Collins Ferry - West Run 138 kV with 556 ACSS</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2300 Reconductor from Lake Lynn - West Run 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2342 Construct a new 138 kV switching station (Shuman Hill substation), which is next the Mobley 138 kV substation and install a 31.7 MVAR capacitor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2343 Install a 31.7 MVAR capacitor at West Union 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
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<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b2433.1 Install breaker and a half 138 kV substation (Waldo Run) with 4 breakers to accommodate service to MarkWest Sherwood Facility including metering which is cut into Glen Falls Lamberton 138 kV line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2433.2 Install a 70 MVAR SVC at the new WaldoRun 138 kV substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2433.3 Install two 31.7 MVAR capacitors at the new WaldoRun 138 kV substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2424 Replace the Weirton 138 kV breaker 'WYLIE RID210' with 63 kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2425 Replace the Weirton 138 kV breaker 'WYLIE RID216' with 63 kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>
Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

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<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>b2426 Replace the Oak Grove 138 kV breaker 'OG1' with 63 kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2427 Replace the Oak Grove 138 kV breaker 'OG2' with 63 kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2428 Replace the Oak Grove 138 kV breaker 'OG3' with 63 kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2429 Replace the Oak Grove 138 kV breaker 'OG4' with 63 kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2430 Replace the Oak Grove 138 kV breaker 'OG5' with 63 kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2431 Replace the Oak Grove 138 kV breaker 'OG6' with 63 kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2432 Replace the Ridgeley 138 kV breaker 'RC1' with a 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2472 Replace the Ringgold 138 kV breaker ‘RCM1’ with 40kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2473 Replace the Ringgold 138 kV breaker ‘#4 XMFR’ with 40kA breakers</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2475 Construct a new line between Oak Mound 138 kV substation and Waldo Run 138 kV substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2545.1 Construct a new 138 kV substation (Shuman Hill substation) connected to the Fairview –Willow Island (84) 138 kV line</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>

Required Transmission Enhancements

<table>
<thead>
<tr>
<th>Required Item</th>
<th>Action</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b2666.1</td>
<td>Replace Yukon 138 kV breaker “Y-11(CHARL1)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.2</td>
<td>Replace Yukon 138 kV breaker “Y-13(BETHEL)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.3</td>
<td>Replace Yukon 138 kV breaker “Y-18(CHARL2)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.4</td>
<td>Replace Yukon 138 kV breaker “Y-19(CHARL2)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.5</td>
<td>Replace Yukon 138 kV breaker “Y-4(4B-2BUS)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.6</td>
<td>Replace Yukon 138 kV breaker “Y-5(LAYTON)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.7</td>
<td>Replace Yukon 138 kV breaker “Y-8(HUNTING)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.8</td>
<td>Replace Yukon 138 kV breaker “Y-9(SPRINGD)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.9</td>
<td>Replace Yukon 138 kV breaker “Y-10(CHRL-SP)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.10</td>
<td>Replace Yukon 138 kV breaker “Y-12(1-1BUS)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.11</td>
<td>Replace Yukon 138 kV breaker “Y-14(1-1BUS)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-----------------------------</td>
<td>-------------------------</td>
</tr>
<tr>
<td>b2545.2 Install a ring bus station with five active positions and two 52.8 MVAR capacitors with 0.941 mH reactors</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2545.3 Install a +90/-30 MVAR SVC protected by a 138 kV breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2545.4 Remove the 31.7 MVAR capacitor bank at Mobley 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2548 Eliminate clearance de-rate on Wylie Ridge – Smith 138 kV line and upgrade terminals at Smith 138 kV, new line ratings 294 MVA (Rate A)/350 MVA (Rate B)</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2672 Change CT Ratio at Seneca Caverns from 120/1 to 160/1 and adjust relay settings accordingly</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2688.3 Carroll Substation: Replace the Germantown 138 kV wave trap, upgrade the bus conductor and adjust CT ratios</td>
<td>AEP (12.91%) / APS (19.04%) / ATSI (1.24%) / ComEd (0.35%) / Dayton (1.45%) / DEOK (2.30%) / DL (1.11%) / Dominion (44.85%) / EKPC (0.78%) / PEPCO (15.85%) / RECO (0.12%)</td>
<td></td>
</tr>
<tr>
<td>b2700 Remove existing Black Oak SPS</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2743.6 Reconfigure the Ringgold 230 kV substation to double bus double breaker scheme</td>
<td>AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)</td>
<td></td>
</tr>
</tbody>
</table>
### Required Transmission Enhancements

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Description</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b2743.6.1</td>
<td>Replace the two Ringgold 230/138 kV transformers</td>
<td>AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)</td>
<td></td>
</tr>
<tr>
<td>b2743.7</td>
<td>Rebuild/Reconductor the Ringgold – Catoctin 138 kV circuit and upgrade terminal equipment on both ends</td>
<td>AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)</td>
<td></td>
</tr>
<tr>
<td>b2747.1</td>
<td>Relocate the FirstEnergy Pratts 138 kV terminal CVTs at Gordonsville substation to allow for the installation of a new motor operated switch being installed by Dominion</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2764</td>
<td>Upgrade Fairview 138 kV breaker risers and disconnect leads; Replace 500 CU breaker risers and 556 ACSR disconnect leads with 795 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2964.1</td>
<td>Replace terminal equipment at Pruntytown and Glen Falls 138 kV station</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2964.2</td>
<td>Reconductor approximately 8.3 miles of the McAlpin - White Hall Junction 138 kV circuit</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>
Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements | Annual Revenue Requirement | Responsible Customer(s)  
--- | --- | ---  
**b2970** | Ringgold – Catoctin Solution | APS (100%)  
**b2970.1** | Install two new 230 kV positions at Ringgold for 230/138 kV transformers | APS (100%)  
**b2970.2** | Install new 230 kV position for Ringgold – Catoctin 230 kV line | APS (100%)  
**b2970.3** | Install one new 230 kV breaker at Catoctin substation | APS (100%)  
**b2970.4** | Install new 230/138 kV transformer at Catoctin substation. Convert Ringgold – Catoctin 138 kV line to 230 kV operation | APS (100%)
### Required Transmission Enhancements

<table>
<thead>
<tr>
<th>Requirement ID</th>
<th>Description</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b2970.5</td>
<td>Convert Garfield 138/12.5 kV substation to 230/12.5 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2996</td>
<td>Construct new Flint Run 500/138 kV substation</td>
<td></td>
<td>See sub-IDs for cost allocations</td>
</tr>
<tr>
<td></td>
<td>Construct a new 500/138 kV substation as a 4-breaker ring bus with expansion plans for double-breaker-double-bus on the 500 kV bus and breaker-and-a-half on the 138 kV bus to provide EHV source to the Marcellus shale load growth area. Projected load growth of additional 160 MVA to current plan of 280 MVA, for a total load of 440 MVA served from Waldo Run substation. Construct additional 3-breaker string at Waldo Run 138 kV bus. Relocate the Sherwood #2 line terminal to the new string. Construct two single circuit Flint Run - Waldo Run 138 kV lines using 795 ACSR (approximately 3 miles). After terminal relocation on new 3-breaker string at Waldo Run, terminate new Flint Run 138 kV lines onto the two open terminals</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2996.2</td>
<td>Loop the Belmont – Harrison 500 kV line into and out of the new Flint Run 500 kV substation (less than 1 mile). Replace primary relaying and carrier sets on Belmont and Harrison 500 kV remote end substations</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2996.3</td>
<td>Upgrade two (2) existing 138 kV breakers (Rider 50 and #1/4 transformer breaker) at Glen Falls with 63 kA 3000A units</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
<td></td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-----------------------------</td>
<td>-------------------------</td>
<td></td>
</tr>
<tr>
<td>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 wave trap, circuit breaker and disconnects will be replaced</td>
<td></td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b3010 Replace terminal equipment at Keystone and Cabot 500 kV buses. At Keystone, bus tubing and conductor, a wave trap, and meter will be replaced. At Cabot, a wave trap and bus conductor will be replaced</td>
<td></td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b3011.1 Construct new Route 51 substation and connect 10 138 kV lines to new substation</td>
<td></td>
<td>DL (100%)</td>
<td></td>
</tr>
<tr>
<td>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)</td>
<td></td>
<td>APS (22.82%) / DL (77.18%)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>---</td>
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<td>-------------------------</td>
</tr>
<tr>
<td>b3011.3</td>
<td>Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #1 138 kV line</td>
<td>DL (100%)</td>
<td></td>
</tr>
<tr>
<td>b3011.4</td>
<td>Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #2 138 kV line</td>
<td>DL (100%)</td>
<td></td>
</tr>
<tr>
<td>b3011.5</td>
<td>Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #3 138 kV line</td>
<td>APS (22.82%) / DL (77.18%)</td>
<td></td>
</tr>
<tr>
<td>b3011.6</td>
<td>Upgrade remote end relays for Yukon—Allenport—Iron Bridge 138 kV line</td>
<td>DL (100%)</td>
<td></td>
</tr>
<tr>
<td>b3012.1</td>
<td>Construct two new 138 kV ties with the single-structure from APS’s new substation to Duquesne’s new substation. The estimated line length is approximately 4.7 miles. The line is planned to use multiple ACSS conductors per phase</td>
<td>ATS (38.21%) / DL (61.79%)</td>
<td></td>
</tr>
<tr>
<td>b3012.3</td>
<td>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 reconducted portion. Install a new line terminal at APS Route 51 substation</td>
<td>DL (100%)</td>
<td></td>
</tr>
</tbody>
</table>
Monongahela Power Company, and The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
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</tr>
</thead>
<tbody>
<tr>
<td>b3028 Upgrade substation disconnect leads at William 138 kV substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b3051.1 Ronceverte cap bank and terminal upgrades</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b3052 Install a 138 kV capacitor (29.7 MVAR effective) at West Winchester 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b3079 Replace the Wylie Ridge 500/345 kV transformer #7</td>
<td>ATSI (72.30%) / DL (27.70%)</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Requirement</th>
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<tbody>
<tr>
<td><strong>b3068</strong> Reconduct 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 bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b3069</strong> Reconduct the Westraver—Route 51 138 kV line (5.63 miles) and replace line switches at Westraver 138 kV bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b3070</strong> Reconduct the Yukon—Route 51 #1 138 kV line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b3071</strong> Reconduct the Yukon—Route 51 #2 138 kV line (8 miles) and replace relays at Yukon 138 kV bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b3072</strong> Reconduct the Yukon—Route 51 #3 138 kV line (8 miles) and replace relays at Yukon 138 kV bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b3074</strong> Reconduct the 138 kV bus at Armstrong substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b3075</strong> Replace the 500/138 kV transformer breaker and reconduct 138 kV bus at Cabot substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b3076</strong> Reconduct the Edgewater—Loyalhanna 138 kV line (0.67 mile)</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b3079</strong> Replace the Wylie Ridge 500/345 kV transformer #7</td>
<td></td>
<td>ATSI (72.30%) / DL (27.70%)</td>
</tr>
<tr>
<td><strong>b3083</strong> Reconduct the 138 kV bus at Butler and reconduct the 138 kV bus and replace line trap at Karns City</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
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<tbody>
<tr>
<td>b3128 Relocate 34.5 kV lines from generating station roof R. Paul Smith 138 kV station</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3240 Upgrade Cherry Run and Morgan terminals to make the transmission line the limiting component</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3241 Install 138 kV, 36 MVAR capacitor and a 5 uF reactor protected by a 138 kV capacitor switcher. Install a breaker on the 138 kV Junction terminal. Install a 138 kV 3.5 uF reactor on the existing Hardy 138 kV capacitor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3242 Reconfigure Stonewall 138 kV substation from its current configuration to a six-breaker, breaker-and-a-half layout and add two (2) 36 MVAR capacitors with capacitor switchers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3683 Reconductor the existing 556.5 ACSR line segments on the Messick Road – Ridgeley 138 kV line with 954 45/7 ACSR to achieve 308/376 MVA SN/SE and 349/445 MVA WN/WE ratings. Replace the remote end equipment for the line. The total length of the line is 5.02 miles</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3701 Replace terminal equipment at French's Mill and Junction 138 kV substations</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>

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<tr>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>b3743</strong></td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>At Bedington substation:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replace substation conductor,</td>
<td></td>
<td></td>
</tr>
<tr>
<td>wave trap, Current Transformers</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(CT's) and upgrade relaying</td>
<td></td>
<td></td>
</tr>
<tr>
<td>At Cherry Run substation:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replace substation conductor,</td>
<td></td>
<td></td>
</tr>
<tr>
<td>wave trap, CT's, disconnect</td>
<td></td>
<td></td>
</tr>
<tr>
<td>switches, circuit breaker and</td>
<td></td>
<td></td>
</tr>
<tr>
<td>upgrade relaying</td>
<td></td>
<td></td>
</tr>
<tr>
<td>At Marlowe substation:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Replace substation conductor,</td>
<td></td>
<td></td>
</tr>
<tr>
<td>wave trap, CT's and upgrade</td>
<td></td>
<td></td>
</tr>
<tr>
<td>relaying</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>b3746</strong></td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Install redundant relaying at</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meadow Brook 500 kV substation</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>b3747</strong></td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Install redundant relaying at</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bedington 500 kV substation</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>b3772</strong></td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor 27.3 miles of the</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Messick Road – Morgan 138 kV line</td>
<td></td>
<td></td>
</tr>
<tr>
<td>from 556 ACSR to 954 ACSR. At</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Messick Road substation, replace</td>
<td></td>
<td></td>
</tr>
<tr>
<td>138 kV wave trap, circuit breaker,</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CT's, disconnect switch, and</td>
<td></td>
<td></td>
</tr>
<tr>
<td>substation conductor and upgrade</td>
<td></td>
<td></td>
</tr>
<tr>
<td>relaying. At Morgan substation,</td>
<td></td>
<td></td>
</tr>
<tr>
<td>upgrade relaying</td>
<td></td>
<td></td>
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</tbody>
</table>
**SCHEDULE 12 – APPENDIX A**

(33) **Keystone Appalachian Transmission Company**

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
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</tr>
</thead>
<tbody>
<tr>
<td>b2120 Six-Wire Lake Lynn - Lardin 138 kV circuits</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2174.8 Replace relays at Mitchell substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2174.9 Replace primary relay at Piney Fork substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2174.10 Perform relay setting changes at Bethel Park substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2213 Armstrong Substation: Relocate 138 kV controls from the generating station building to new control building</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2300 Reconductor from Lake Lynn - West Run 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2341 Install 39.6 MVAR Capacitor at Shaffers Corner 138 kV Substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2362 Install a 250 MVAR SVC at Squab Hollow 230 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2362.1 Install a 230 kV breaker at Squab Hollow 230 kV substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2363 Convert the Shingletown 230 kV bus into a 6 breaker ring bus</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2364 Install a new 230/138 kV transformer at Squab Hollow 230 kV substation. Loop the Forest - Elko 230 kV line into Squab Hollow. Loop the Brookville - Elko 138 kV line into Squab Hollow</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2412 Install a 44 MVAR 138 kV capacitor at the Hempfield 138 kV substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>
### Keystone Appalachian Transmission Company (cont.)

<table>
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<tr>
<th>Required Transmission Enhancements</th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>b2440</strong> Replace the Cabot 138kV breaker 'C9-KISKI VLY' with 63kA</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2546</strong> Install a 51.8 MVAR (rated) 138 kV capacitor at Nyswaner 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2547.1</strong> Construct a new 138 kV six breaker ring bus Hillman substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2547.2</strong> Loop Smith- Imperial 138 kV line into the new Hillman substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2547.3</strong> Install +125/-75 MVAR SVC at Hillman substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2547.4</strong> Install two 31.7 MVAR 138 kV capacitors</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2548</strong> Eliminate clearance de-rate on Wylie Ridge – Smith 138 kV line and upgrade terminals at Smith 138 kV, new line ratings 294 MVA (Rate A)/350 MVA (Rate B)</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2612.1</strong> Relocate All Dam 6 138 kV line and the 138 kV line to AE units 1&amp;2</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2612.2</strong> Install 138 kV, 3000A bus-tie breaker in the open bus-tie position next to the Shaffers corner 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2612.3</strong> Install a 6-pole manual switch, foundation, control cable, and all associated facilities</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2666</strong> Yukon 138 kV Breaker Replacement</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2666.1</strong> Replace Yukon 138 kV breaker “Y-11(CHARL1)” with an 80 kA breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
### Keystone Appalachian Transmission Company (cont.)

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<tr>
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<th>Description</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b2666.2</td>
<td>Replace Yukon 138 kV breaker “Y-13(BETHEL)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.3</td>
<td>Replace Yukon 138 kV breaker “Y-18(CHARL2)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.4</td>
<td>Replace Yukon 138 kV breaker “Y-19(CHARL2)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.5</td>
<td>Replace Yukon 138 kV breaker “Y-4(4B-2BUS)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.6</td>
<td>Replace Yukon 138 kV breaker “Y-5(LAYTON)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.7</td>
<td>Replace Yukon 138 kV breaker “Y-8(HUNTING)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.8</td>
<td>Replace Yukon 138 kV breaker “Y-9(SPRINGD)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.9</td>
<td>Replace Yukon 138 kV breaker “Y-10(CHRL-SP)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.10</td>
<td>Replace Yukon 138 kV breaker “Y-12(1-BUS)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.11</td>
<td>Replace Yukon 138 kV breaker “Y-14(4-BUS)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.12</td>
<td>Replace Yukon 138 kV breaker “Y-2(1B-BETHE)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.13</td>
<td>Replace Yukon 138 kV breaker “Y-21(SHEP)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.14</td>
<td>Replace Yukon 138 kV breaker “Y-22(SHEPHJT)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
### Keystone Appalachian Transmission Company (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>b2689.3</strong> Upgrade terminal equipment at structure 27A</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2696</strong> Upgrade 138 kV substation equipment at Butler, Shanor Manor and Krendale substations. New rating of line will be 353 MVA summer normal/422 MVA emergency</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2763</strong> Replace the breaker risers and wave trap at Bredinville 138 kV substation on the Cabrey Junction 138 kV terminal</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2965</strong> Reconductor the Charleroi – Allenport 138 kV line with 954 ACSR conductor. Replace breaker risers at Charleroi and Allenport</td>
<td></td>
<td>APS (37.15%) / DL (62.85%)</td>
</tr>
<tr>
<td><strong>b2966</strong> Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV line with 795 ACSS conductor. Replace Line Disconnect Switch at Yukon</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2966.1</strong> Reconductor the Yukon - Smithton - Shepler Hill Jct 138 kV line and replace terminal equipment as necessary to achieve required rating</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2967</strong> 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</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
### Keystone Appalachian Transmission Company (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>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 reconducted for this project. The total length of the line is 7.75 miles</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace four Yukon 500/138 kV transformers with three transformers with higher rating and reconfigure 500 kV bus</td>
<td></td>
<td>APS (63.21%) / DL (36.79%)</td>
</tr>
<tr>
<td>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 wave trap, circuit breaker and disconnects will be replaced</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace terminal equipment at Keystone and Cabot 500 kV buses. At Keystone, bus tubing and conductor, a wave trap, and meter will be replaced. At Cabot, a wave trap and bus conductor will be replaced</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Construct new Route 51 substation and connect 10 138 kV lines to new substation</td>
<td></td>
<td>DL (100%)</td>
</tr>
<tr>
<td>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)</td>
<td></td>
<td>APS (22.82%) / DL (77.18%)</td>
</tr>
<tr>
<td>Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #1 138 kV line</td>
<td></td>
<td>DL (100%)</td>
</tr>
<tr>
<td>Requirement Reference</td>
<td>Description</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>-----------------------</td>
<td>-----------------------------------------------------------------------------</td>
<td>-------------------------------</td>
</tr>
<tr>
<td>b3011.4</td>
<td>Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #2 138 kV line</td>
<td>DL (100%)</td>
</tr>
<tr>
<td>b3011.5</td>
<td>Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #3 138 kV line</td>
<td>APS (22.82%) / DL (77.18%)</td>
</tr>
<tr>
<td>b3011.6</td>
<td>Upgrade remote end relays for Yukon – Allenport – Iron Bridge 138 kV line</td>
<td>DL (100%)</td>
</tr>
<tr>
<td>b3012.1</td>
<td>Construct two new 138 kV ties with the single structure from APS’s new substation to Duquesne’s new substation. The estimated line length is approximately 4.7 miles. The line is planned to use multiple ACSS conductors per phase</td>
<td>ATSI (38.21%) / DL (61.79%)</td>
</tr>
<tr>
<td>b3012.3</td>
<td>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 reconducted portion. Install a new line terminal at APS Route 51 substation</td>
<td>DL (100%)</td>
</tr>
<tr>
<td>b3013</td>
<td>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</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3015.6</td>
<td>Reconductor Elrama to Mitchell 138 kV line – AP portion. 4.2 miles total. 2x 795 ACSS/TW 20/7</td>
<td>DL (100%)</td>
</tr>
<tr>
<td>b3015.8</td>
<td>Upgrade terminal equipment at Mitchell for Mitchell – Elrama 138 kV line</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
**Keystone Appalachian Transmission Company (cont.)**

<table>
<thead>
<tr>
<th>Requirement Code</th>
<th>Description</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b3064.3</td>
<td>Upgrade line relaying at Piney Fork and Bethel Park for Piney Fork – Elrama 138 kV line and Bethel Park – Elrama 138 kV</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3068</td>
<td>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</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3069</td>
<td>Reconductor the Westraver – Route 51 138 kV line (5.63 miles) and replace line switches at Westraver 138 kV bus</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3070</td>
<td>Reconductor the Yukon – Route 51 #1 138 kV line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV bus</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3071</td>
<td>Reconductor the Yukon – Route 51 #2 138 kV line (8 miles) and replace relays at Yukon 138 kV bus</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3072</td>
<td>Reconductor the Yukon – Route 51 #3 138 kV line (8 miles) and replace relays at Yukon 138 kV bus</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3074</td>
<td>Reconductor the 138 kV bus at Armstrong substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3075</td>
<td>Replace the 500/138 kV transformer breaker and reconductor 138 kV bus at Cabot substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3076</td>
<td>Reconductor the Edgewater – Loyalhanna 138 kV line (0.67 mile)</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3083</td>
<td>Reconductor the 138 kV bus at Butler and reconductor the 138 kV bus and replace line trap at Karns City</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3214.1</td>
<td>Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV Line. Upgrade terminal equipment at Yukon and replace line relaying at Mitchell and Charleroi</td>
<td>APS (12.21%) / DL (87.79%)</td>
</tr>
<tr>
<td>b3214.2</td>
<td>Reconductor the Smithton – Shepler Hill Jct 138 kV Line</td>
<td>APS (4.74%) / DL (95.26%)</td>
</tr>
<tr>
<td>b3230</td>
<td>At Enon substation install a second 138 kV, 28.8 MVAR nameplate, capacitor and the associated 138 kV capacitor switch</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
## Keystone Appalachian Transmission Company (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b3318 Reconductor the Shanor Manor - Butler 138 kV line with an upgraded circuit breaker at Butler 138 kV station</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3325 Reconductor the Charleroi - Union 138 kV line and upgrade terminal equipment at Charleroi 138 kV station</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3681 Upgrade the Shingletown #82 230/46 kV Transformer circuit by installing a 230 kV breaker and disconnect switches, removing existing 230 kV switches, replacing 46 kV disconnect switches, replacing limiting substation conductor, and installing/replacing relays</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3710 Reconductor AA2-161 to Yukon 138 kV Lines #1 and #2 with 954 ACSS conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3738 Replace limiting terminal equipment on Charleroi – Dry Run 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3739 Replace limiting terminal equipment on Dry Run – Mitchell 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3740 Replace limiting terminal equipment on Glen Falls – Bridgeport 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3741 Replace limiting terminal equipment on Yukon - Charleroi #1 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3742 Replace limiting terminal equipment on Yukon - Charleroi #2 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3744 Replace one span of 1272 ACSR from Krendale substation to structure 35 (approximately 630 feet) Replace one span of 1272 ACSR from Shanor Manor to structure 21 (approximately 148 feet) Replace 1272 ACSR risers at Krendale and Shanor Manor substations Replace 1272 ACSR substation conductor at Krendale substation Replace relaying at Krendale substation Revise relay settings at Butler and Shanor Manor substations</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Keystone Appalachian Transmission Company (cont.)

Required Transmission Enhancements | Annual Revenue Requirement | Responsible Customer(s)
--- | --- | ---
b3745 | Install redundant relaying at Carbon Center 230 kV substation | APS (100%)
b3761 | Install 138 kV breaker on the Ridgway 138/46 kV #2 Transformer | APS (100%)
b3773 | Install 33 MVAR switched capacitor, 138 kV breaker, and associated relaying at McConnellsburg 138 kV substation | APS (100%)
ATTACHMENT H-5

**Annual Transmission Rates -- FirstEnergy Pennsylvania Electric Company (MetEd Zone) Metropolitan Edison Company**
for Network Integration Transmission Service

1. The transmission revenue requirement and the rate for Network Integration Transmission Service in the Metropolitan Edison Company (“Met-Ed”) Zone is based on the facilities owned and costs incurred by Mid-Atlantic Interstate Transmission, LLC (“MAIT”), calculated pursuant to the formula shown in Attachment H-28. Attachment H-5A sets forth the rates for deliveries that utilize Met-Ed FirstEnergy Pennsylvania Electric Company’s distribution facilities at voltages below 69 kV located in the MetEd Zone.

2. In addition to the rate set forth in section 1 of this attachment, the Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse the Transmission Owners for any amounts payable by them as sales, excise, “Btu,” carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.
ATTACHMENT H-5A

Other Supporting Facilities Charges -- FirstEnergy Pennsylvania Electric Company (MetEd Zone) Metropolitan Edison Company

As provided in Attachment H-5, section 1, service utilizing facilities at voltages below 69 kV to serve certain Pennsylvania Municipal Utilities and Cooperatives will be provided at the rates set forth below (“Other Supporting Facilities Charges” or “OSFCs”).

Goldboro, Pennsylvania 0.092¢ per kWh
Lewisberry, Pennsylvania 0.276¢ per kWh
Royalton, Pennsylvania 0.068¢ per kWh
Allegheny Electric Cooperative, Inc. $6.69/kW/month*

* The rate of $6.69/kW/month shall apply to all Allegheny Electric Cooperative, Inc. delivery points for delivery by FirstEnergy Pennsylvania Electric Company located in the MetEd Zone Metropolitan Edison Company at 13.2 kV and shall be phased in over time in accordance with an applicable service agreement entitled an “Interconnection Agreement for Wholesale Load” (“Service Agreement”) between the Parties on file with the Federal Energy Regulatory Commission. The OSFC in the Service Agreement is also referred to as a “Monthly Distribution Charge.”
Monthly Distribution Charge ($/kW)

The Monthly Distribution Charge ("MDC") of $6.69/kW/month shall be phased in over time in accordance with the following table, which assumes an effective date of October 1, 2022 for the Service Agreement:

<table>
<thead>
<tr>
<th>Calendar Year/Quarter</th>
<th>% of MDC</th>
<th>MDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022 Q4</td>
<td>55%</td>
<td>$3.67/kW/month</td>
</tr>
<tr>
<td>2023 Calendar Year</td>
<td>60%</td>
<td>$4.01/kW/month</td>
</tr>
<tr>
<td>2024 Calendar Year</td>
<td>60%</td>
<td>$4.01/kW/month</td>
</tr>
<tr>
<td>2025 Calendar Year</td>
<td>60%</td>
<td>$4.01/kW/month</td>
</tr>
<tr>
<td>2026 and thereafter</td>
<td>100%</td>
<td>$6.69/kW/month</td>
</tr>
</tbody>
</table>

The above table shall be adjusted by mutual agreement of the Parties if the effective date of the Service Agreement is established by FERC at a date subsequent to October 1, 2022 in order to give effect to the Parties’ intent to have a phase-in of the MDC over the course of three (3) years with 100% of the MDC to apply no later than the fourth (4th) anniversary of the effective date of the Service Agreement. Notwithstanding section 13.1 of the Service Agreement, the Parties agree not to exercise rights afforded them by Sections 205 and 206 of the Federal Power Act to alter the MDC during the ten-year period beginning with the effective date of the Service Agreement as established by FERC.
ATTACHMENT H-6


1. The transmission revenue requirement and the rate for Network Integration Transmission Service in the Pennsylvania Electric Company (“Penelec”) Zone is based on the facilities owned and costs incurred by Mid-Atlantic Interstate Transmission, LLC (“MAIT”), calculated pursuant to the formula shown in Attachment H-28. Attachment H-6A sets forth the rates for deliveries that utilize FirstEnergy Pennsylvania Electric Company Penelec’s distribution facilities at voltages below 46 kV located in the Penelec Zone.

2. In addition to the rate set forth in section 1 of this attachment, the Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse the Transmission Owners for any amounts payable by them as sales, excise, “Btu,” carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.
ATTACHMENT H-6A

Other Supporting Facilities Charges -- FirstEnergy Pennsylvania Electric Company
(Penelec Zone) Pennsylvania Electric Company

As provided in Attachment H-6, Paragraph 1, service utilizing facilities at voltages below 46 kV to serve certain Pennsylvania Municipal Utilities and Cooperatives will be provided at the rates set forth below (“Other Supporting Facilities Charges” or “OSFCs”).

<table>
<thead>
<tr>
<th>Location</th>
<th>Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Berlin, Pennsylvania</td>
<td>0.175¢ per kWh</td>
</tr>
<tr>
<td>East Conemaugh, Pennsylvania</td>
<td>0.113¢ per kWh</td>
</tr>
<tr>
<td>Girard, Pennsylvania</td>
<td>0.057¢ per kWh</td>
</tr>
<tr>
<td>Hooversville, Pennsylvania</td>
<td>0.213¢ per kWh</td>
</tr>
<tr>
<td>Smethport, Pennsylvania</td>
<td>0.147¢ per kWh</td>
</tr>
<tr>
<td>Summerhill, Pennsylvania</td>
<td>0.283¢ per kWh</td>
</tr>
<tr>
<td>Allegheny Electric Cooperative, Inc.</td>
<td>$2.66/kW/month*</td>
</tr>
<tr>
<td>Allegheny Electric Cooperative, Inc.</td>
<td>$8.72/kW/month**</td>
</tr>
</tbody>
</table>

* The rate of $2.66/kW/month shall apply to all Allegheny Electric Cooperative, Inc. delivery points for delivery by FirstEnergy Pennsylvania Electric Company located in the Penelec Zone Pennsylvania Electric Company at 23 kV or 34.5 kV and shall be phased in over time in accordance with an applicable service agreement entitled an “Interconnection Agreement for Wholesale Load” (“Service Agreement”) between the Parties on file with the Federal Energy Regulatory Commission. The OSFC in the Service Agreement is also referred to as a “Monthly Distribution Charge.”

** The rate of $8.72/kW/month shall apply to all Allegheny Electric Cooperative, Inc. delivery points for delivery by FirstEnergy Pennsylvania Electric Company located in the Penelec Zone Pennsylvania Electric Company at 12.5 kV and shall be phased in over time in accordance with an applicable service agreement entitled an “Interconnection Agreement for Wholesale Load” (“Service Agreement”) between the Parties on file with the Federal Energy Regulatory Commission. The OSFC in the Service Agreement is also referred to as a “Monthly Distribution Charge.”
## Monthly Distribution Charges ($/kW)

The Monthly Distribution Charge ("MDC") of $2.66/kW/month shall be phased in over time in accordance with the following table, which assumes an effective date of October 1, 2022 for the Service Agreement:

<table>
<thead>
<tr>
<th>Calendar Year/Quarter</th>
<th>% of MDC</th>
<th>MDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022 Q4</td>
<td>55%</td>
<td>$1.46/kW/month</td>
</tr>
<tr>
<td>2023 Calendar Year</td>
<td>60%</td>
<td>$1.59/kW/month</td>
</tr>
<tr>
<td>2024 Calendar Year</td>
<td>60%</td>
<td>$1.59/kW/month</td>
</tr>
<tr>
<td>2025 Calendar Year</td>
<td>60%</td>
<td>$1.59/kW/month</td>
</tr>
<tr>
<td>2026 and thereafter</td>
<td>100%</td>
<td>$2.66/kW/month</td>
</tr>
</tbody>
</table>

The MDC of $8.72/kW/month shall be phased in over time in accordance with the following table, which assumes an effective date of October 1, 2022 for the Service Agreement:

<table>
<thead>
<tr>
<th>Calendar Year/Quarter</th>
<th>% of MDC</th>
<th>MDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022 Q4</td>
<td>55%</td>
<td>$4.79/kW/month</td>
</tr>
<tr>
<td>2023 Calendar Year</td>
<td>60%</td>
<td>$5.23/kW/month</td>
</tr>
<tr>
<td>2024 Calendar Year</td>
<td>60%</td>
<td>$5.23/kW/month</td>
</tr>
<tr>
<td>2025 Calendar Year</td>
<td>60%</td>
<td>$5.23/kW/month</td>
</tr>
<tr>
<td>2026 and thereafter</td>
<td>100%</td>
<td>$8.72/kW/month</td>
</tr>
</tbody>
</table>

The above tables shall be adjusted by mutual agreement of the Parties if the effective date of the Service Agreement is established by FERC at a date subsequent to October 1, 2022 in order to give effect to the Parties' intent to have the phase-ins of the MDCs over the course of three (3) years with 100% of the MDCs to apply no later than the fourth (4th) anniversary of the effective date of the Service Agreement. Notwithstanding section 13.1 of the Service Agreement, the Parties agree not to exercise rights afforded them by Sections 205 and 206 of the Federal Power Act to alter the MDCs during the ten-year period beginning with the effective date of the Service Agreement as established by FERC.
ATTACHMENT H-11A


Service Below 115 kV in the Allegheny Power Zone (Other Supporting Facilities Charges)

As provided in Attachment H-11, service utilizing facilities at voltages below 115 kV owned by one of the South FirstEnergy Operating Companies designated in the table below to transmit energy to and from a customer within the Allegheny Power Zone will be provided at the rates set forth below (“Other Supporting Facilities Charges”).

<table>
<thead>
<tr>
<th>Customer/Interconnection Point/Customer Facility</th>
<th>South FirstEnergy Operating Company</th>
<th>Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>All Dams Generation, LLC (Allegheny River Lock and Dam No. 5)</td>
<td>West Penn Power Company First Energy Pennsylvania Electric Company</td>
<td>$4,320.00/mo.</td>
</tr>
<tr>
<td>Harrison Rural Electrification Association, Inc. (Barnetts Run, Chiefton, Dola, Oral Lake, Crystal Lake, Buckhannon, Milford Rd.)</td>
<td>Monongahela Power Company</td>
<td>$13,047.00/mo.</td>
</tr>
<tr>
<td>Thurmont Municipal Light Company (Main Street, Moser Road (Primary) and Moser Road (Back-Up))</td>
<td>The Potomac Edison Company</td>
<td>$11,529.18/mo.</td>
</tr>
</tbody>
</table>

Service At or Above 115 kV in the Allegheny Power Zone by SFC

See attached formula rate.
* The reference to West Penn Power Company is solely to ensure the continued effectuation of the formula rate true-up.
### Formula Rate - Non-Levelized

<table>
<thead>
<tr>
<th>Line No.</th>
<th>SPC Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Net Revenue Requirement with incentive projects - MP</td>
</tr>
<tr>
<td>2</td>
<td>Net Revenue Requirement with incentive projects - PE</td>
</tr>
<tr>
<td>3</td>
<td>Net Revenue Requirement with incentive projects - WPP</td>
</tr>
<tr>
<td>4</td>
<td>TOTAL NET REVENUE REQUIREMENT</td>
</tr>
</tbody>
</table>

### DIVISOR

| 5 | 1 Coincident Peak (CP) (MW)            | (Note A) |
| 6 | Average 12 CPs (MW)                   | (Note B) |
| 7 | Annual Rate ($/MW/Yr)                | (line 4 / line 5) |

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>Point-to-Point Rate ($/MW/Year)</td>
</tr>
<tr>
<td>9</td>
<td>Point-to-Point Rate ($/MW/Month)</td>
</tr>
<tr>
<td>10</td>
<td>Point-to-Point Rate ($/MW/Week)</td>
</tr>
<tr>
<td>11</td>
<td>Point-to-Point Rate ($/MW/Day)</td>
</tr>
<tr>
<td>12</td>
<td>Point-to-Point Rate ($/MW/h)</td>
</tr>
</tbody>
</table>

### Notes

A  As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT. Includes CP for the AP Zone.
B  Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve-month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.
### Schedule 1A Rate Calculation Summary

<table>
<thead>
<tr>
<th></th>
<th>Description</th>
<th>Line(s)</th>
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<td>2</td>
<td>Revenue Credits for Sched 1A - Note A</td>
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<td>3</td>
<td>Net Schedule 1A Expenses (Line 1 - Line 2)</td>
<td>Attachment 1, Line 3</td>
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<td>4</td>
<td>Annual MWh in AP Zone - Note B</td>
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<td>Schedule 1A rate $/MWh (Line 3/Line 4)</td>
<td>Attachment 1, Line 5</td>
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</table>

**Total**

---

**Note:**

A. Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of AP Zone during the year used to calculate rates under Attachment H-11A.

B. Load expressed in MWh consistent with load used for billing under Schedule 1A for the AP Zone. Data from RTO settlement systems for the calendar year prior to the rate year.
Transmission Enhancement Charge (TEC) Summary

<table>
<thead>
<tr>
<th>Line No.</th>
<th>(1) Project Name</th>
<th>(2) RTEP Project Number</th>
<th>(3) Net Revenue Requirement with True-up</th>
<th>Note A</th>
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<tbody>
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Note A  Net Revenue Requirement with True-up is sourced from Attachment 11, Col. 15. PJM to bill each project utilizing the respective Net revenue requirement with true-up on Col. 3.
<table>
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<tr>
<th>Line No.</th>
<th>Project Name (A)</th>
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Note A: (A) Revenue Requirement is sourced from Attachment 16 Col. R. PJM to bill each project utilizing the respective Revenue Requirement reflected on Col. 3
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<td>Account No. 454</td>
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<td>4</td>
<td>Account No. 456</td>
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<td>5</td>
<td>Section 30.9 credits</td>
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<td>6</td>
<td>Other Revenue credits</td>
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<td>7</td>
<td>TEC Revenue</td>
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<td>8</td>
<td>TOTAL REVENUE CREDITS (sum Lines 2-7)</td>
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<td>9</td>
<td>True-up Adjustment with Interest</td>
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<td>NET REVENUE REQUIREMENT</td>
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## MON POWER

### Form 1 Data Utilizing FERC Form 1 Data

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<th>Line No.</th>
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<th>Source</th>
<th>Company Total</th>
<th>Allocator</th>
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<td>3</td>
<td>Distribution</td>
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<td>TOTAL GROSS PLANT (sum Lines 1-5)</td>
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<table>
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<td>21</td>
<td>Account No. 283 (enter negative)</td>
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<td>RATE BASE (sum Lines 18, 28, 29, &amp; 34)</td>
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### Attachment H-11A

**Page 143**

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**Formula Rate - Non-Levelized**

**Rate Formula Template**

**Utilizing FERC Form 1 Data**

**MON POWER**

### SUPPORTING CALCULATIONS AND NOTES

<table>
<thead>
<tr>
<th>Line</th>
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<th>TRANSMISSION PLANT INCLUDED IN ISO RATES</th>
<th>(1)</th>
<th>(2)</th>
<th>(3)</th>
<th>(4)</th>
<th>(5)</th>
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<td>Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1)</td>
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<td>100%</td>
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**TRANSMISSION EXPENSES**

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<th>(3)</th>
<th>(4)</th>
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<td>Less transmission expenses included in OATT Ancillary Services (Attachment 20, Line 2 plus Line 3 and Line 4, Col. C) (Note K)</td>
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<td>Included transmission expenses (Line 6 less Line 7)</td>
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<td>Percentage of transmission expenses after adjustment (Line 8 divided by Line 6)</td>
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**WAGES & SALARY ALLOCATOR**

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**COMMON PLANT ALLOCATOR (CE)** (Note N)

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**ANNUAL ALLOCATION FACTOR CALCULATION** (Note A)

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<th>(6)</th>
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**RETURN (R)**

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**REVENUE CREDITS** (Note AA)

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**OTHER REVENUE CREDITS**

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<th>(4)</th>
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</tr>
<tr>
<td>41</td>
<td></td>
<td>SECTION 30.9 CREDITS</td>
<td>FERC Form No. 1, 310.1.s.a</td>
<td></td>
<td></td>
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<tr>
<td>42</td>
<td></td>
<td>OTHER REVENUE CREDITS</td>
<td>FERC Form No. 1, 310.1.s.a</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>43</td>
<td></td>
<td>a. Labor Related Revenues</td>
<td>W&amp;S</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tbody>
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---

*Note: TP = Total Plant, TE = Total Expenses, W&S = Wages and Salaries*
<table>
<thead>
<tr>
<th>Item</th>
<th>Code</th>
<th>Amount</th>
<th>%</th>
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</thead>
<tbody>
<tr>
<td>Plant Related Revenues</td>
<td>GP</td>
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<td>-</td>
</tr>
<tr>
<td>Transmission Related Revenues</td>
<td>TP</td>
<td>0.00000</td>
<td>-</td>
</tr>
<tr>
<td>Other</td>
<td>DA</td>
<td>1.00000</td>
<td>-</td>
</tr>
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</table>
To the extent transmission assets are transferred to KATCo, a proration factor will be applied on a percent of the transmission function based upon transmission records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. 

In conjunction with the transfer, certain regulatory agreements may provide for the taxation of the buyer or seller of the transmission assets, and the tax liabilities will be capitalized. The amount capitalized will be amortized over the economic life of the assets, and any excess or deficient tax paid in respect of such transfer shall be provided for in the financial reporting. 

For the 12 months ended December 31, 2021, the excess or deficient deferred taxes attributed to the transmission function will be based upon transmission records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes.
### Schedule 1A Rate Calculation

<table>
<thead>
<tr>
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<th>Description</th>
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<tbody>
<tr>
<td>1</td>
<td>$ - Attachment H-11A, Page 4, Line 7</td>
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<tr>
<td>2</td>
<td>Revenue Credits for Sched 1A - Note A</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>$ - Net Schedule 1A Expenses (Line 1 - Line 2)</td>
<td></td>
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<tr>
<td>4</td>
<td>Annual MWh in AP Zone - Note B</td>
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<tr>
<td>5</td>
<td>#DIV/0! Schedule 1A rate $/MWh (Line 3/Line 4)</td>
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**Note:**

A. Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of AP Zone during the year used to calculate rates under Attachment H-11A.

B. Load expressed in MWh consistent with load used for billing under Schedule 1A for the AP Zone. Data from RTO settlement systems for the calendar year prior to the rate year.
### ROE Calculation

**Return Calculation**

<p>| | | | | |</p>
<table>
<thead>
<tr>
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<tr>
<td>1</td>
<td>Rate Base</td>
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<tr>
<td>2</td>
<td>Preferred Dividends</td>
<td>enter positive</td>
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<tr>
<td></td>
<td>Common Stock</td>
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<tr>
<td>3</td>
<td>Proprietary Capital</td>
<td>Attachment H-11A, page 4, Line 33, Col. 5</td>
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<tr>
<td>4</td>
<td>Less Preferred Stock</td>
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<td>5</td>
<td>Less Accumulated Other Comprehensive Income Account 219</td>
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<td>Less Account 216.1, Renaissance Adj, AGC adj &amp; Goodwill</td>
<td>Attachment H-11A, page 4, Line 33, Col. 5</td>
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<tr>
<td>7</td>
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<td>Capitalization</td>
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<td>Long Term Debt</td>
<td>Attachment H-11A, page 4, Line 31, Col. 5</td>
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<tr>
<td>9</td>
<td>Preferred Stock</td>
<td>Attachment H-11A, page 4, Line 31, Col. 5</td>
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<tr>
<td>10</td>
<td>Common Stock</td>
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<td>Total Capitalization</td>
<td>Attachment H-11A, page 4, Line 31, Col. 5</td>
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<tr>
<td></td>
<td>Debt %</td>
<td>Total Long Term Debt</td>
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<tr>
<td>12</td>
<td>Preferred %</td>
<td>Preferred Stock</td>
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<tr>
<td>13</td>
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<td>Common Stock</td>
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<td>14</td>
<td>Debt Cost</td>
<td>Total Long Term Debt</td>
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<td>Preferred Cost</td>
<td>Preferred Stock</td>
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<td>17</td>
<td>Weighted Cost of Debt</td>
<td>Total Long Term Debt (WCLTD)</td>
<td>(Line 12 * Line 15)</td>
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<td>Weighted Cost of Preferred</td>
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<td>20</td>
<td>Rate of Return on Rate Base (ROR)</td>
<td>(Sum Lines 18 to 20)</td>
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<tr>
<td>21</td>
<td>Investment Return = Rate Base * Rate of Return</td>
<td>(Line 1 * Line 21)</td>
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#### Income Taxes

**Income Tax Rates**

<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
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<tr>
<td>23</td>
<td>T = \left(1 - \text{SIT}\right) / \left(1 - \text{FIT}\right)</td>
<td>Attachment H-11A, page 3, Line 30, Col. 3</td>
<td>0.00%</td>
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<tr>
<td>24</td>
<td>CIT = \left(1 - \text{T}\right) / \left(1 - \text{WCLTD/R}\right)</td>
<td>Calculated</td>
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<tr>
<td>25</td>
<td>1 / (1 - T)</td>
<td>Attachment H-11A, page 3, Line 32, Col. 3</td>
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<td>26</td>
<td>Amortized Investment Tax Credit (266.8.f)</td>
<td>Attachment H-11A, page 3, Line 33, Col. 3</td>
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<td>27</td>
<td>Tax Effect of Permanent Differences and AFUDC Equity</td>
<td>Attachment H-11A, page 3, Line 33, Col. 3</td>
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<tr>
<td>28</td>
<td>(Excess)/Deficient Deferred Income Taxes</td>
<td>Attachment H-11A, page 3, Line 33, Col. 3</td>
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<tr>
<td>29</td>
<td>Income Tax Calculation</td>
<td>(line 22 * line 24)</td>
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<td>31</td>
<td>Permanent Differences and AFUDC Equity Tax Adjustment</td>
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<td>32</td>
<td>(Excess)/Deficient Deferred Income Tax Adjustment</td>
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<tr>
<td>33</td>
<td>Total Income Taxes</td>
<td>Sum lines 29 to 32</td>
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#### Return and Taxes

<p>| | | |</p>
<table>
<thead>
<tr>
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<tr>
<td>34</td>
<td>Return and Income taxes with ROE</td>
<td>(Line 22 + Line 33)</td>
</tr>
<tr>
<td>35</td>
<td>Return with ROE</td>
<td>Attachment H-11A, page 3, Line 41, Col. 5</td>
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<td>36</td>
<td>Income Tax with ROE</td>
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</table>
ATTACHMENT H-28B
Mid-Atlantic Interstate Transmission, LLC
Formula Rate Implementation Protocols

ANNUAL TRUE-UP, INFORMATION EXCHANGE,
AND CHALLENGE PROCEDURES

Definitions

“Actual Transmission Revenue Requirement” or “ATRR” means the actual net transmission revenue requirement calculated and posted on the PJM website no later than June 1 of each year subsequent to calendar year 2017 for the immediately preceding calendar year in accordance with MAIT’s Formula Rate and based upon MAIT’s actual costs and expenditures.

“Annual Update” means MAIT’s ATRR for the preceding calendar year, as well as the True-up for the prior Rate Year, as posted on or before June 1 of each year.

“Formal Challenge” means a written challenge to an Annual Update or Projected Transmission Revenue Requirement submitted to the Federal Energy Regulatory Commission (the “Commission” or “FERC”) as provided in Section IV below.

“Formula Rate” means these protocols (to be included as Attachment H-28B of the PJM Interconnection, L.L.C. (“PJM”), FERC Electric Tariff (“PJM Tariff”)) and the Formula Rate Template.

“Formula Rate Template” means the collection of formulas and worksheets, unpopulated with any data, to be included as Attachment H-28A of the PJM Tariff.

“Interested Parties” include, but are not limited to, customers under the PJM Tariff, state utility regulatory commissions, the Organization of PJM States, Inc., consumer advocacy agencies, and state attorneys general.

“Preliminary Challenge” means a written challenge to the Annual Update or Projected Transmission Revenue Requirement submitted to MAIT as provided in Section IV below.

“Projected Transmission Revenue Requirement” or “PTRR” means the projected net transmission revenue requirement calculated for the forthcoming Rate Year, as well as, where applicable, the most recently calculated True-up, with interest, to be posted on the PJM website no later than October 5 of each year for rates effective the next calendar year starting January 1.

“Publication Date” means the date on which the Annual Update is posted.

“Rate Year” means the twelve consecutive month period that begins on January 1 and continues through December 31.
“True-up” means the difference between the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) and the ATRR for the same Rate Year, which shall be provided in the Annual Update on or before June 1 of the year subsequent to the Rate Year. The True-up will be a component of the PTRR.

**Section I. Applicability**

The following procedures shall apply to the Mid-Atlantic Interstate Transmission, LLC (“MAIT”) calculation of its Actual Transmission Revenue Requirement, True-up, and Projected Transmission Revenue Requirement.

**Section II. Annual Update and Projected Transmission Revenue Requirement**

A. On or before June 1 of each year subsequent to calendar year 2017, MAIT shall determine its Annual Update for the immediately preceding calendar year under Attachment H-28A and Section VII of these protocols, including calculation of the True-up to be included in MAIT’s PTRR for the subsequent Rate Year.

B. On or before June 1 of each year subsequent to calendar year 2017, MAIT shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website. Within two (2) days of such posting, PJM shall provide notice of such posting via an e-mail exploder list.

C. On or before September 1, MAIT shall, upon request, provide any Interested Party with:

1. information showing (a) each transmission project forecasted to be placed into service in the following Rate Year that is expected to have a direct cost of $1,000,000 (one million dollars) or greater, and a breakdown of the projected direct costs of each such project in as much detail as is reasonably available; and (b) purchases of categories of capital equipment (e.g., switches, transformers, relays, etc.) aggregating $3,000,000 (three million dollars) or greater that are forecasted to enter service during the following Rate Year, either through the use of such capital equipment in projects forecasted to be placed in service during the following Rate Year or as spare plant that MAIT determines to be needed for the safe and reliable operation of the transmission system in accordance with Good Utility Practice during the following Rate Year; and

2. a statement setting forth the basis for MAIT’s determination that each such transmission project or capital equipment purchase, as applicable, is needed for service during the following Rate Year (which statement may be based on a determination that the placement of the project or equipment purchases into service during the following Rate Year, as described below, is needed as part of a larger multi-year transmission project or equipment purchase project, as applicable). MAIT’s provision of such information shall be subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC’s Model Protective Order.
D. MAIT shall provide: (1) to PJM, MAIT’s PTRR for rates to be effective the following Rate Year, by October 5, and (2) upon request, to any Interested Party by October 5, (a) a list of the transmission projects and capital equipment purchases included in the PTRR capital projections, which shall be projects and capital equipment forecasted to enter service through projects in service or as spare plant during the Rate Year that is the subject to the PTRR; (b) a copy of the approved budget and/or construction plan pursuant to which such projects and equipment purchases have been undertaken; (c) a statement setting forth the basis for MAIT’s determination that each such transmission project or capital equipment purchase, as applicable, is needed for service during the following Rate Year (which statement may be based on a determination that the placement of the project or equipment purchase into service during the following Rate Year is needed as part of a larger multi-year transmission project or equipment purchase project, as applicable). With respect to the information referenced in clause (1), on October 5, MAIT shall provide via an email exploder list: (i) its PTRR for rates to be effective the following Rate Year; and (ii) notice of such posting. With respect to the information described in clause (2), MAIT’s provision of such information shall be subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC’s Model Protective Order.

E. If the date for posting the Annual Update or PTRR falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual Update occurs shall be that year’s Publication Date. Any delay in the Publication Date or in the posting of the PTRR will result in an equivalent extension of time for the submission of information requests discussed in Section III of these protocols.

F. The ATRR shall:

1. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas and links intact;

2. Be based on MAIT’s FERC Form No. 1 for the prior calendar year;

3. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the ATRR that are not otherwise available in the FERC Form No. 1, subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC’s Model Protective Order;

4. Provide sufficient information to enable Interested Parties to replicate the calculation of the ATRR results from the FERC Form No. 1;

5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1;

6. Identify and, to the extent not explained in a worksheet included in the ATRR, explain, all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in the FERC Form No. 1;
7. Provide underlying data for Formula Rate inputs that provide greater granularity than is required for the FERC Form No. 1;

8. With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate (“Accounting Change”):
   a. Identify any Accounting Change, including:
      i. the initial implementation of an accounting standard or policy;
      ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
      iii. correction of errors and prior period adjustments that affect the ATRR and True-up calculation;
      iv. the implementation of new estimation methods or policies that change prior estimates; and
      v. changes to income tax elections;
   b. Identify items included in the ATRR at an amount other than on a historic cost basis (e.g., fair value adjustments);
   c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the ATRR;
   d. Provide, for each item identified pursuant to items II.F.8.a - II.F.8.c above, a narrative explanation of the individual impact of such change on the ATRR.

9. It is the intent of the Formula Rate, including the supporting explanations and allocation described therein, that each input to the Formula Rate will be either taken directly from FERC Form No. 1 or reconcilable to FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

G. The Projected Transmission Revenue Requirement shall:

1. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas and links intact;

2. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the PTRR;
3. Provide sufficient information to enable Interested Parties to replicate the calculation of the PTRR;

4. With respect to any Accounting Change:
   a. Identify any Accounting Change, including:
      i. the initial implementation of an accounting standard or policy;
      ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
      iii. correction of errors and prior period adjustments that affect the PTRR calculation;
      iv. the implementation of new estimation methods or policies that change prior estimates; and
      v. changes to income tax elections.
   b. Identify items included in the PTRR at an amount other than on a historic cost basis (e.g., fair value adjustments);
   c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the PTRR; and
   d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these protocols, a narrative explanation of the individual impact of such change on the PTRR.

H. MAIT shall hold an open meeting among Interested Parties (“Annual Update Meeting”), to be conducted via Internet webcast, no earlier than ten (10) business days following the Publication Date and no later than June 25. No fewer than seven (7) days prior to such Annual Update Meeting, MAIT shall provide notice on PJM’s website of the time, date, and webcast registration information of the Annual Update Meeting, and PJM shall provide notice of the posting via an e-mail exploder list. The Annual Update Meeting shall: (i) permit MAIT to explain and clarify its ATRR and True-up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from MAIT about the ATRR and True-up.

I. MAIT shall hold an open meeting among Interested Parties (“Annual Projected Rate Meeting”), to be conducted via Internet webcast, no earlier than ten (10) business days following the posting of the PTRR (as described in Section II.C of these protocols) and no later than November 30. No fewer than seven (7) days prior to such Annual Projected Rate Meeting, MAIT shall provide notice on PJM’s website of the time, date, and webcast registration information of the Annual Projected Rate Meeting, and PJM shall provide notice of the posting via an e-mail exploder list. The Annual Projected Rate Meeting shall: (i) permit MAIT to explain and clarify its PTRR and
(ii) provide Interested Parties an opportunity to seek information and clarifications from MAIT about the PTRR.

J. Each year MAIT shall endeavor to (a) coordinate with other Transmission Owners in PJM using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and (b) hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

Section III. Information Exchange Procedures

Each Annual Update and PTRR shall be subject to the following information exchange procedures (“Information Exchange Procedures”):

A. Interested Parties shall have until January 5 following the Publication Date (unless such period is extended with the written consent of MAIT or by FERC order) to serve reasonable information and document requests on MAIT (“Information Exchange Period”). If January 5 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

1. the extent or effect of an Accounting Change;
2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols, or includes data not properly recorded in accordance with these protocols;
3. the proper application of the Formula Rate and procedures in these protocols;
4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR or PTRR;
5. the prudence of actual costs and expenditures included in the ATRR or the reasonableness of projected costs and expenditures included in the PTRR, information concerning which may include MAIT’s utilized procurement methods and cost control methodologies, and the basis for and reasonableness of allocating all or any portion of such costs and expenditures to wholesale transmission service;
6. whether transmission projects or equipment purchases underlying the costs and expenditures included in the ATRR or PTRR are needed for service during the Rate Year (including as part of a larger multi-year transmission project or equipment purchase program, as applicable);
7. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or
8. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.
The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

B. MAIT shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. MAIT shall respond to all information and document requests by no later than February 15 following the Publication Date, unless the Information Exchange Period is extended by MAIT or FERC.

C. MAIT will serve all information requests from Interested Parties and MAIT’s response(s) to such requests upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such information requests or responses, as needed, under non-disclosure agreements that are based on FERC’s Model Protective Order.

D. MAIT shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege in any proceeding addressing MAIT’s Annual Update or PTRR, and such responses may be included in any Formal Challenge or other submittal addressing MAIT’s Annual Update or PTRR.

E. MAIT will provide, upon the request of any Interested Party, the Ground Lease Calculation worksheet filed with the Pennsylvania Public Utility Commission for the applicable Rate Year, provided such request is timely made consistent with the Review Period set forth in Section IV.A below. MAIT shall not claim any privilege precludes the provision of such Ground Lease Calculation worksheet. MAIT agrees to include in its FERC Form 1 the amount of base rent in Account No. 567 associated with the Ground Leases with FirstEnergy Pennsylvania Electric CompanyMet-Ed and Penelec, respectively.

Section IV. Challenge Procedures

A. Interested Parties shall have until March 5 following the Publication Date (unless such period is extended with the written consent of MAIT or by FERC order) (“Review Period”), to review the inputs, supporting explanations, allocations and calculations and to notify MAIT in writing, which may be made consistent with the Review Period set forth in Section IV.A below. MAIT shall not claim any privilege precludes the provision of such Ground Lease Calculation worksheet. MAIT agrees to include in its FERC Form 1 the amount of base rent in Account No. 567 associated with the Ground Leases with FirstEnergy Pennsylvania Electric CompanyMet-Ed and Penelec, respectively.

B. Preliminary Challenges shall be subject to the resolution procedures and limitations in this Section IV and shall satisfy all of the following requirements.

1. A party submitting a Preliminary Challenge to MAIT must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and
provide an appropriate explanation and documents to support its challenge.

2. MAIT shall make a good faith effort to respond to any Preliminary Challenge within twenty (20) business days of notification of such challenge.

3. MAIT, and where applicable, PJM, shall appoint a senior representative to work with the party that submitted the Preliminary Challenge (or its representative) toward a resolution of the challenge.

4. If MAIT disagrees with such challenge, MAIT will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.

5. No Preliminary Challenge may be submitted after March 5, and MAIT must respond to all Preliminary Challenges by no later than April 5 unless the Review Period is extended by MAIT or FERC, or as provided in Section IV.A above.

6. MAIT will serve all Preliminary Challenges from Interested Parties and MAIT’s response(s) to such Preliminary Challenges upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such Preliminary Challenges or responses, as needed, under non-disclosure agreements that are based on the FERC’s Model Protective Order.

C. Formal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

1. A Formal Challenge shall:
   a. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;
   b. Explain how the action or inaction violates the filed rate formula or protocols;
   c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:
      (i) the extent or effect of an Accounting Change;
      (ii) whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols;
      (iii) the proper application of the Formula Rate and procedures in these protocols;
      (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the ATRR or PTRR;
      (v) the prudence of actual costs and expenditures included in the ATRR;
      (vi) the reasonableness of any projection that forms a basis of the PTRR;
whether transmission projects or equipment purchases underlying the costs and expenditures included in the ATRR or PTRR are needed for service during the Rate Year (including as part of a larger multi-year transmission project or equipment purchase program, as applicable);

the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the challenged action or inaction;

e. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Preliminary Challenge procedures described in these protocols to dispute the challenged action or inaction raised by the Formal Challenge, and, if not, describe why not.

2. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on MAIT. Service to MAIT must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on MAIT’s Informational Filing required under Section VI of these protocols.

D. Preliminary and Formal Challenges shall be limited to all issues that may be necessary to determine:

1. the extent or effect of an Accounting Change;

2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols, or includes data not properly recorded in accordance with these protocols;

3. the proper application of the Formula Rate and procedures in these protocols;

4. the accuracy of data and consistency with the formula rate of the calculations shown in the ATRR and PTRR;
5. the prudence of actual costs and expenditures included in the ATRR;

6. the reasonableness of any projection that forms a basis of the PTRR;

7. whether transmission projects or equipment purchases underlying the costs and expenditures included in the ATRR or PTRR are needed for service during the Rate Year (including as part of a larger multi-year transmission project or equipment purchase program, as applicable);

8. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

E. Any changes or adjustments to the ATRR and PTRR resulting from the information exchange and Preliminary Challenge processes that are agreed to by MAIT will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by MAIT on or before December 1 will be reflected in the PTRR for the upcoming Rate Year. Any changes or adjustments agreed to by MAIT after December 1 will be reflected in the following year’s Annual Update, as discussed in Section V of these protocols.

F. An Interested Party shall have until May 5 following the Review Period (unless such date is extended with the written consent of MAIT to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with FERC, which shall be served on MAIT on the date of such filing as specified in Section IV.C.2 above. A Formal Challenge shall be filed in the same docket as MAIT’s Informational Filing discussed in Section VI of these protocols. MAIT shall respond to the Formal Challenge by the deadline established by FERC. An Interested Party may not pursue a Formal Challenge unless it submitted a Preliminary Challenge on some issue (which may be different from the Formal Challenge issue) during the applicable Review Period.

G. In any proceeding initiated by FERC concerning the Annual Update or PTRR or in response to a Formal Challenge, MAIT shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these protocols and that it followed the applicable requirements and procedures in the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

H. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of MAIT to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

I. No party shall seek to modify the Formula Rate under the challenge procedures set forth in these protocols and the Annual Update and PTRR shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing. MAIT may, at its discretion
and at a time of its choosing, make a limited filing pursuant to Section 205 to modify stated values in the Formula Rate for (a) amortization and depreciation rates, (b) Post-Employment Benefits Other Than Pensions rates, or (c) the weighting of the ADIT balance in rate base to ensure MAIT’s compliance with the IRS regulations for normalization under IRS Section 1.167(l)-1(h)(6). The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

J. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 shall first raise the matter with MAIT in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Changes to Actual Transmission Revenue Requirement or Projected Transmission Revenue Requirement

A. Except as provided in Section IV.E of these protocols, any changes to the data inputs, including but not limited to revisions to MAIT’s FERC Form No. 1, or as the result of any FERC proceeding to consider the ATRR or PTRR, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the PTRR for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols.

B. In the event that MAIT identifies an error in the Annual Update (or its FERC Form No. 1 or successor form which is used as an input to the Formula Rate), or if MAIT is required by applicable law or a court or a regulatory body to correct such error, MAIT shall correct the error in good faith and without regard to whether the correction increases or decreases MAIT’s revenue requirements. MAIT shall implement the correction in the next Annual Update following the identification of the error or the order of a court or regulatory body. Nothing in these protocols should or may be construed as preventing Interested Parties from protesting such correction.

Section VI. Informational Filings

A. By June 1 of each year, MAIT shall submit to FERC in a new docket an informational filing (“Informational Filing”) of its PTRR for the Rate Year, including its ATRR and True-up reflected in that PTRR. This Informational Filing must include information that is reasonably necessary to determine:

1. that input data under the Formula Rate are properly recorded in any underlying work papers;
2. that MAIT has properly applied the Formula Rate and these procedures;
3. the accuracy of data and the consistency with the Formula Rate of the transmission revenue requirement and rates under review;
4. the extent of Accounting Changes that affect Formula Rate inputs; and
5. the reasonableness of projected costs and the prudence of actual costs.

The Informational Filing must also describe any corrections or adjustments made during the period since the Publication Date, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Preliminary or Formal Challenge procedures.

Finally, the Informational Filing shall include for the applicable Rate Year the following information related to affiliate cost allocation: a detailed description of the methodologies used to allocate and directly assign costs between MAIT and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; the magnitude of such costs that have been allocated or directly assigned between MAIT and each affiliate by service category or function; and a copy of any service agreement between MAIT and any MAIT affiliate that went into effect during the Rate Year.

Within five (5) days of such Informational Filing, PJM shall provide notice of the Informational Filing via an e-mail exploder list and by posting the docket number assigned to MAIT’s Informational Filing on the PJM website, subject to the protection of any confidential information contained in the Informational Filing, as needed, under nondisclosure agreements that are based on FERC’s Model Protective Order.

B. Any challenges to the implementation of the MAIT formula rate must be made through the challenge procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VII. Calculation of True-up

The True-up will be determined in the following manner:

A. As part of the Annual Update for each Rate Year, MAIT shall determine the difference between the revenues collected by PJM based on the PTRR for the Rate Year (net of the True-up from the prior year) and the ATRR for the same Rate Year based on actual cost data as reflected in its FERC Form No. 1. The True-up will be determined as follows:

i. The ATRR for the previous Rate Year as determined using MAIT’s completed FERC Form No. 1 report shall be compared to the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) for that same Rate Year (“True-up Year”) to determine any excess or shortfall in the revenues collected by PJM in the True-up Year. The revenue excess or shortfall determined by this comparison shall constitute the “True-up.”

ii. Interest on any True-up shall be based on the interest rate equal to: (i) MAIT’s actual short-term debt costs capped at the interest rate determined by 18 C.F.R. § 35.19a; or (ii) the interest rate determined by 18 C.F.R. § 35.19, if MAIT does not have short term debt. Interest rates will be used to calculate the time value of money for the period that the
True-up exists. The interest rate to be applied to the True-up will be determined using the average rate for the twenty (20) months preceding September of the current year.

B. MAIT will post on PJM’s website all information relating to the True-up as part of the Annual Update. As provided in Section II.B. of these Protocols, MAIT shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website on or before June 1 of each year subsequent to calendar year 2017.

Section VIII. Formula Rate Inputs

A. Stated inputs to the Formula Rate Template: For (i) rate of return on common equity; (ii) “Post-Employment Benefits other than Pension” pursuant to Statement of Financial Accounting Standards No. 106, Employers’ Accounting for Postretirement Benefits Other Than Pensions (“PBOP”) charges; and (iii) depreciation and/or amortization rates, the values shall be stated values to be used in the Formula Rate until changed pursuant to a Federal Power Act section 205 or section 206 filing. These stated-value inputs are specified in Attachment 9, respectively, of the Formula Rate Template.

B. Unpopulated Formula Rate line items: With respect to line items in the Formula Rate that are not currently populated with non-zero numerical values because FERC policy requires prior authorization for recovery of the underlying costs or because, due to the nature of the associated functional activities, such costs are not considered part of MAIT’s transmission-related revenue requirement (but not line items that are zero values in a particular Rate Year for the sole reason that no such costs or revenues were incurred or revenues received or projected to be incurred or received during the Rate Year), such line items shall not be populated with non-zero values except as may be authorized following a Federal Power Act section 205 filing or required under Federal Power Act section 206.
### FULL NAME

- Pennsylvania Electric Company*
- Allegheny Power
- PPL Electric Utilities Corporation
- Metropolitan Edison Company**
- Jersey Central Power and Light Company
- Public Service Electric and Gas Company
- Atlantic City Electric Company
- PECO Energy Company
- Baltimore Gas and Electric Company
- Delmarva Power and Light Company
- Potomac Electric Power Company
- Rockland Electric Company
- Commonwealth Edison Company
- AEP East Zone
- The Dayton Power and Light Company
- Duquesne Light Company
- Virginia Electric and Power Company
- American Transmission Systems, Incorporated
- Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.
- East Kentucky Power Cooperative, Inc.
- Ohio Valley Electric Corporation

### SHORT NAME

- PENELEC
- APS
- PPL
- ME
- JCPL
- PSEG
- AEC
- PECO
- BGE
- DPL
- PEPCO
- RE
- ComEd
- AEP
- Dayton
- DL
- Dominion
- ATSI
- DEOK
- EKPC
- OVEC
* FirstEnergy Pennsylvania Electric Company ("FE PA") is the successor-in-interest to Pennsylvania Electric Company, but all references to the Pennsylvania Electric Company or PENELEC Zone remain unchanged.

** FirstEnergy Pennsylvania Electric Company ("FE PA") is the successor-in-interest to Metropolitan Edison Company, but all references to the Metropolitan Edison Company, MetEd, or ME Zone remain unchanged.
ATTACHMENT L
List of Transmission Owners

Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Atlantic City Electric Company
Baltimore Gas and Electric Company
Delmarva Power & Light Company
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
East Kentucky Power Cooperative, Inc.
Essential Power Rock Springs, LLC
Hudson Transmission Partners, LLC
ITC Interconnection LLC
Jersey Central Power & Light Company
Mid-Atlantic Interstate Transmission, LLC
Neptune Regional Transmission System, LLC
Old Dominion Electric Cooperative
PECO Energy Company
Pennsylvania Power & Light Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company
Trans-Allegheny Interstate Line Company
Transource West Virginia, LLC
UGI Utilities, Inc.
Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.
The Dayton Power and Light Company
Duquesne Light Company
Virginia Electric and Power Company
Linden VFT, LLC
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Hamilton, OH
Southern Maryland Electric Cooperative, Inc.
Ohio Valley Electric Cooperative
AMP Transmission, LLC
Silver Run Electric, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
Wabash Valley Power Association, Inc.
Keystone Appalachian Transmission Company
ATTACHMENT M-1 (FirstEnergy Zones)
FirstEnergy Procedure for Determining a Load Serving Entity’s Hourly Energy Obligations

Purpose

The purpose of this Attachment M-1 is to give PJM members serving load in a FirstEnergy Zone(s) the understanding of how each hour of an operating day’s Total Hourly Energy Obligation (“THEO”) is developed, in accordance with the PJM Open Access Transmission Tariff, the PJM Operating Agreement, Reliability Assurance Agreement or other relevant PJM documents (the “PJM Documents”) and submitted to PJM. Attachment M-1 pertains to both wholesale and retail Load Serving Entities (“LSEs”) serving load in the following FirstEnergy Electric Distribution Companies (“EDC”) Zones (the “FirstEnergy Zones”): Ohio Edison Company, The Toledo Edison Company, The Cleveland Electric Illuminating Company (together “ATSI Ohio”), FirstEnergy Pennsylvania Electric Power Company (“FE PAPenn Power”) operating in the separate ATSI, Penelec, Metropolitan Edison Company (“Met-Ed”), Pennsylvania Electric Company (“Penelec”), and Allegheny Power PJM transmission zones. Jersey Central Power & Light Company (“JCP&L”), Monongahela Power Company (“Mon Power”), West Penn Power Company (“West Penn Power”), and The Potomac Edison Company (“Potomac Edison MD” and “Potomac Edison WV”). —Attachment M-1 is not intended to supersede or replace any contractual arrangement(s) between FirstEnergy (or its affiliated FirstEnergy EDC) and the applicable LSE that otherwise governs the calculations. Such contractual arrangement(s) shall prevail unless silent on a particular issue or calculation.

Attachment M-1 is divided into three main sections. The first section titled “Terms” defines terms specific to this Attachment M-1 that are not found in the PJM Documents. The second section titled “Wholesale” describes processes for determining the THEO for wholesale LSEs such as municipal electric utilities or electric cooperatives. The final section titled “Retail” describes processes for determining the THEO for retail LSEs such as retail generation service providers serving retail customers or retail suppliers providing provider of last resort services.

FirstEnergy performs the THEO calculation and subsequently uploads this data to PJM systems (such as PJM’s InSchedule eSuite application or its successor) on behalf of retail LSEs and wholesale LSEs serving load in each FirstEnergy Zone, unless otherwise agreed.

Questions concerning the methodologies described in this Attachment M-1 may be submitted by visiting the Supplier Support section of the FirstEnergy corporate website located here: https://www.firstenergycorp.com/supplierservices.

Section I: Terms

Unaccounted for Energy – Energy that is remaining after comparing: (a) the FirstEnergy Zone load determined by summing physical generation delivered to a FirstEnergy Zone plus net imports/exports of energy into/out of a FirstEnergy Zone to: (b) the sum of all wholesale and retail customers’ metered load, whether interval metered or estimated, including contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC, in
any given hour. Unaccounted for Energy is not allocated to wholesale LSEs unless otherwise specified in their contracts/agreements with FirstEnergy. The methodology for determining Unaccounted for Energy for an LSE providing service to retail customers receiving distribution service from a FirstEnergy EDC shall be set forth in state-approved retail tariffs.

Losses – The following loss factors shall apply for each FirstEnergy Zone. Loss factors will be applied according to location (FirstEnergy Zone) and service voltage of each meter point. For wholesale LSEs, all of the loss factors specified herein shall apply, unless otherwise established by contract and filed with FERC. For retail LSEs, the Transmission Load loss factors specified herein shall apply, however for lower service voltages, the loss factors specified in state-approved retail tariffs shall apply.

<table>
<thead>
<tr>
<th>Service Voltage</th>
<th>ATSI Ohio</th>
<th>Penn Power FE PA (Penn Power, ATSI Zone)</th>
<th>FE PA (Met-Ed Zone)</th>
<th>FE PA (Penelec Zone)</th>
<th>JCP&amp;L</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Load</td>
<td>1.01486</td>
<td>1.01486</td>
<td>1.02100</td>
<td>1.04070</td>
<td>1.03900</td>
</tr>
<tr>
<td>Subtransmission Source</td>
<td>1.02786</td>
<td>1.02786</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Subtransmission Load</td>
<td>1.02886</td>
<td>1.02886</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary Load</td>
<td>1.05786</td>
<td>1.05786</td>
<td>1.03740</td>
<td>1.06060</td>
<td>1.06100</td>
</tr>
<tr>
<td>Secondary Load</td>
<td>1.09486</td>
<td>1.08960</td>
<td>1.07180</td>
<td>1.09450</td>
<td>1.11800</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Service Voltage</th>
<th>West Penn Power FE PA (West Penn Power, Allegheny Power Zone)</th>
<th>Potomac Edison MD</th>
<th>Potomac Edison WV</th>
<th>Mon Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Load</td>
<td>1.02184</td>
<td>1.02245</td>
<td>1.02245</td>
<td>1.02233</td>
</tr>
<tr>
<td>Subtransmission Source</td>
<td>1.04282</td>
<td></td>
<td>1.02646</td>
<td></td>
</tr>
<tr>
<td>Subtransmission w/Tran Charge</td>
<td>1.03578</td>
<td>1.03742</td>
<td>1.03807</td>
<td>1.03390</td>
</tr>
<tr>
<td>Primary Source</td>
<td>1.06383</td>
<td>1.07542</td>
<td>1.07691</td>
<td>1.06071</td>
</tr>
<tr>
<td>Primary Load</td>
<td>1.09434</td>
<td>1.09513</td>
<td>1.09705</td>
<td>1.09033</td>
</tr>
</tbody>
</table>

Transmission Load — For Mon Power, Potomac Edison MD, Potomac Edison WV and -FE PA (West Penn Power, Allegheny Power Zone)West Penn Power, 138 kV and above. For JCP&L and FE PA—(Penelec and Met-Ed Zones), 34.5 kV and above. For ATSI Ohio and FE PA (Penn Power, ATSI Zone), 69 kV and above.
Subtransmission Source - For Potomac Edison WV, ATSI Ohio and **FE PA** (Penn Power, **ATSI Zone**), service at source of subtransmission bus.

Subtransmission w/Tran Charge - For **FE PA** (West Penn Power, **Allegheny Power Zone**), service on low side of subtransmission to primary transformer.

Subtransmission Load - For Mon Power, Potomac Edison MD, Potomac Edison WV, and **FE PA** (West Penn Power, **Allegheny Power Zone**), 23 kV to 69 kV. For ATSI Ohio and **FE PA** (Penn Power, **ATSI Zone**), 23 kV to 34.5 kV.

Primary Source - For Mon Power and Potomac Edison WV, service at source of primary bus.

Primary Load - For Mon Power, Potomac Edison MD, Potomac Edison WV, **FE PA** (West Penn Power, **Allegheny Power Zone; and Penn Power, ATSI Zone**), and ATSI Ohio, and **Penn Power**, 1 kV to 15 kV. For **FE PA** (**Penelec and Met-Ed Zones**) and JCP&L, 1 kV to 34.5 kV.

Secondary Load - For all FirstEnergy **EDC** Zones, below 1 kV.

**Section II: Wholesale**

The FirstEnergy EDCs are required to determine the THEO for each wholesale LSE operating in their respective FirstEnergy Zones and submit this information to PJM per practices under the PJM Documents. The following procedures and methodologies describe how THEO is determined.

Note: A wholesale LSE’s THEO is determined in accordance with current and approved contractual obligations between FirstEnergy EDCs and the respective wholesale LSE. Should the current and approved agreements be silent on procedural matters regarding the determination and submittal of a wholesale LSE’s THEO, the PJM Documents shall be used to establish such procedures including those outlined below.

FirstEnergy uses the following equation to determine a wholesale LSE’s THEO in a FirstEnergy Zone. If the wholesale LSE serves load in more than one FirstEnergy Zone, the THEO is determined separately for each FirstEnergy Zone.

\[
\text{THEO} = \sum_{x=1}^{n} (\text{Wholesale LSE’s Interconnection Hourly Meter Reading} \times (1.0 + \text{Applicable Loss Factor}))
\]

where:

\[
\text{THEO} = \text{The wholesale LSE’s hourly energy consumption in any given hour of the previous operating day in a FirstEnergy Zone}
\]

\[
x = \text{A specific Meter* included in the determination of the wholesale LSE’s hourly energy consumption in a FirstEnergy Zone}
\]
\[ n = \text{The total number of Meters aggregated to determine the wholesale LSE’s THEO} \]

* For purposes of this document, the term “Meter” refers to the billing quality metering devices and related equipment owned by FirstEnergy and/or the wholesale LSE, located at or near the interconnection point (the “Interconnection”) between the FirstEnergy distribution or transmission system and the wholesale LSE system, and used to measure the wholesale LSE’s THEO.

Wholesale LSE’s Interconnection Hourly Meter Reading (WIMR) = The quantity of energy consumed by the wholesale LSE at an individual wholesale LSE’s Interconnection as shown on the Meter in a given hour, with an adjustment for certain behind-the-meter generation if applicable. Specifically, WIMR shall equal the actual interconnection point meter readings of the wholesale LSE plus the metered output of any generation resources that met all of the following three criteria during the given hour: (1) the resource was operating behind the interconnection meter, (2) the resource was participating in PJM markets or other wholesale markets, and (3) the output of the resource was wheeled across the wholesale LSE’s system to the FirstEnergy distribution or transmission system.

Applicable Loss Factor (ALF) = The contractually or otherwise mutually determined loss factor as specified herein or as otherwise filed with FERC in effect to account for losses across the applicable distribution and transmission system to the LSE’s system.

In the case where the actual WIMR is not obtained by FirstEnergy from one or more of the Meters in time to use in the calculation of the wholesale LSE’s THEO, FirstEnergy will use an estimated WIMR in place of an actual WIMR for any missing hour(s) of Meter data.

The derivation of an estimated WIMR will be determined on a case-by-case basis and be dependent on the reason for and the duration of the event triggering the need for an estimated WIMR. FirstEnergy’s WIMR methodology will take into account appropriate variables such as the history of the Interconnection Meter readings; load growth; the season of the year; temperature and any other variable(s) that could significantly affect the accuracy of the WIMR.

The following chart illustrates possible cases and outcomes of using this methodology to estimate the WIMR to be provided to PJM. The methodology used to generate a WIMR in a particular case is dependent on the reason the actual WIMR was not received.

<table>
<thead>
<tr>
<th>Case</th>
<th>Reason</th>
<th>Primary (Day After Reconciliation Estimate)</th>
<th>Secondary (60-Day Reconciliation Estimate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Short-term communication outage (&lt;59 days)</td>
<td>Profile generated in FE Settlement System*</td>
<td>Not applicable if actual Meter data received</td>
</tr>
<tr>
<td>2</td>
<td>Long-term communication error (&gt;=59 days)</td>
<td>Profile generated in FE Settlement System*</td>
<td>Not applicable if actual Meter data received via handheld device or manual entry</td>
</tr>
<tr>
<td></td>
<td>Short-term Meter/metering equipment malfunction (&lt; 59 days)</td>
<td>Profile generated in FE Settlement System*</td>
<td>Estimate in Meter Data Management System*</td>
</tr>
<tr>
<td>---</td>
<td>-------------------------------------------------</td>
<td>--------------------------------------------</td>
<td>---------------------------------------------</td>
</tr>
<tr>
<td>4</td>
<td>Long-term Meter/metering equipment malfunction (&gt;= 59 days)</td>
<td>Estimate in Meter Data Management System*</td>
<td>Estimate in Meter Data Management System*</td>
</tr>
</tbody>
</table>

* If the FE Settlement or Data Management System(s) data are not available or may not be accurate, data obtained from the wholesale LSE’s Meter, SCADA or other accurate source will be used. Regardless of estimating methodology or data source, FirstEnergy will coordinate the estimate(s) of the wholesale LSE’s THEO with the affected wholesale LSE.

**Section III: Retail**

The THEO for an LSE providing service to retail customers receiving distribution service from a FirstEnergy EDC shall adhere to the following:

A. Where retail customers are interval metered and interval meter data is used for retail billing, interval meter data will be utilized for the THEO calculations.

B. Where interval meter readings are not received in time for PJM settlement deadlines, estimates will be developed using customer specific profiles.

C. Where retail customers do not have installed interval metering or use interval metering for billing, profiles will be utilized to distribute load into hourly values spanning the retail customer’s billing period.

D. All retail customer load will be grossed up for applicable transmission and distribution losses.

E. Unaccounted For Energy for each hour will be allocated to LSEs based on their load ratio share of metered load, unless such approach is prohibited by the applicable regulatory body. The FirstEnergy EDC will provide monthly, on an informational basis, the Unaccounted For Energy hourly percentages that were applied to LSEs’ hourly loads.

FirstEnergy does not determine the THEO for retail consumers of wholesale LSEs like municipal electric utilities and electric cooperatives.

Additional implementation details related to the determination of the THEO for retail LSEs and the process for submitting data for sub-account customers will be provided in the manual titled "Supplier Energy Obligation" posted under the "Supplier Registration" tab of the Supplier Support section of the FirstEnergy corporate website located here: https://www.firstenergycorp.com/supplierservices. The Manual may reflect differences based on the state utility commission requirements applicable to each FirstEnergy EDC, to the extent such requirements are not inconsistent with the requirements stated in this Attachment M-1.
ATTACHMENT M-2 (FirstEnergy Zones)
FirstEnergy Procedure for Determining a Load Serving Entity’s
Peak Load Contribution (PLC) and Network Service Peak Load (NSPL)

PURPOSE

The purpose of this Attachment M-2 is to establish the procedures and methodologies under which FirstEnergy will determine the PLC and NSPL, as defined/specified in the PJM Open Access Transmission Tariff, the PJM Operating Agreement, Reliability Assurance Agreement or other relevant PJM documents (the “PJM Documents”) each PJM Planning Year for each retail and wholesale Load Serving Entity (“LSE”) serving load in the following FirstEnergy Electric Distribution Companies (“EDCs”) Zones (the “FirstEnergy Zones”): Ohio Edison Company, The Toledo Edison Company, The Cleveland Electric Illuminating Company (together, “ATSI Ohio”), Pennsylvania Power Company (“Penn Power”), Metropolitan Edison Company (“MetEd”), FirstEnergy Pennsylvania Electric Company (“FE PA Penelec”) operating in the separate ATSI, Penelec, MetEd, and Allegheny Power PJM transmission zones, Jersey Central Power & Light Company (“JCP&L”), Monongahela Power Company (“Mon Power”), West Penn Power Company (“West Penn Power”), and The Potomac Edison Company (“Potomac Edison MD” and “Potomac Edison WV”). Attachment M-2 is not intended to supersede or replace any contractual arrangement(s) between FirstEnergy (or its affiliated FirstEnergy EDC) and the applicable LSE that otherwise governs the calculations. Such contractual arrangement(s) shall prevail unless silent on a particular issue or calculation.

Questions concerning the methodologies described in this Attachment M-2 may be submitted by visiting the Supplier Support section of the FirstEnergy corporate website located here: https://www.firstenergycorp.com/supplierservices.

SECTION I: TERMS


Losses - The following loss factors shall apply for each FirstEnergy Zone. Loss factors will be applied according to location (FirstEnergy Zone) and service voltage of each meter point. For wholesale LSEs, all of the loss factors specified herein shall apply, unless otherwise established by contract and filed with FERC. For retail LSEs, the Transmission Load loss factors specified herein shall apply, however for lower service voltages, the loss factors specified in state-approved retail tariffs shall apply.

<table>
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<tr>
<th>Service Voltage</th>
<th>ATSI Ohio</th>
<th>Penn Power</th>
<th>FE PA (Met-Ed Zone)</th>
<th>FE PA (Penelec Zone)</th>
<th>JCP&amp;L</th>
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<td>FE PA (Penn Power)</td>
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<td>Subtransmission Load</td>
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<th>Service Voltage</th>
<th>FE PA (West Penn Power, Allegheny Power Zone)</th>
<th>Potomac Edison MD</th>
<th>Potomac Edison WV</th>
<th>Mon Power</th>
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</table>

Transmission Load — For Mon Power, Potomac Edison MD, Potomac Edison WV and FE PA (West Penn Power, Allegheny Power Zone), 138 kV and above. For FE PA (Penelec and Met-Ed Zones) and JCP&L, 34.5 kV and above. For ATSI Ohio and FE PA (Penn Power, ATSI Zone), 69 kV and above.

Subtransmission Source - For Potomac Edison WV, For ATSI Ohio and FE PA (Penn Power, ATSI Zone), service at source of subtransmission bus.

Subtransmission w/Tran Charge - For FE PA (West Penn Power, Allegheny Power Zone), service on low side of subtransmission to primary transformer.

Subtransmission Load - For Mon Power, Potomac Edison MD, Potomac Edison WV and FE PA (West Penn Power, Allegheny Power Zone), 23 kV to 69 kV. For ATSI Ohio and Penn Power, 23 kV to 34.5 kV.

Primary Source - For Mon Power and Potomac Edison WV, service at source of primary bus.

Primary Load - For Mon Power, Potomac Edison MD, Potomac Edison WV, FE PA (West Penn Power, Allegheny Power Zone; and Penn Power, ATSI Zone) and ATSI Ohio and Penn Power, 1 kV to 15 kV. For FE PA (Penelec and MetEd Zones) and JCP&L, 1 kV to 34.5 KV.

Secondary Load - For all FirstEnergy EDC Zones, below 1 kV.
SECTION II: WHOLESALE

Under the PJM Documents, the FirstEnergy EDCs are required to determine the PLC and NSPL for each wholesale LSE operating in their respective FirstEnergy Zones.

This Attachment M-2 supplements and clarifies the procedures and methodologies under which FirstEnergy will determine the PLC and NSPL for all wholesale LSEs with load located in one or more FirstEnergy Zone. Unless specified otherwise, this Attachment M-2 does not amend or replace any existing contracts or agreements between FirstEnergy and any wholesale LSE.

The PLC and NSPL values for each FirstEnergy Zone in which the wholesale LSE serves load will be calculated separately and will be based on the hourly reading obtained from billing quality metering and related equipment (“Meters”) owned by FirstEnergy or the wholesale LSE located at or near the interconnection point between the FirstEnergy distribution or transmission system, and the wholesale LSE system. Furthermore, all calculations in this Attachment M-2 will be done consistent with the requirements of the PJM Documents.

PLC Calculation

The calculation of PLC for each wholesale LSE, with load located in any of the FirstEnergy Zones, is as follows:

1. Determine the wholesale LSE’s load contribution to the total FirstEnergy Zone load at the time of the high 5 peak hours for the PJM region (“High 5 Hours”) as determined by PJM. This load is grossed up for contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC.

   If a PJM Demand Response Event (“DR Event”) occurred within the applicable FirstEnergy Zone in which the wholesale LSE serves load during one or more of the High 5 Hours, then add back the PJM-determined load reduction to each of the corresponding wholesale LSE’s loads for those DR Events affecting the High 5 Hours.

   The result is the wholesale LSE’s unrestricted PJM High 5 loads.

2. Average the wholesale LSE’s 5 unrestricted PJM High 5 loads.

3. Multiply the wholesale LSE’s average unrestricted PJM High 5 load by the ratio of (a) the appropriate FirstEnergy Zone’s weather-normalized peak to (b) the average of the FirstEnergy unrestricted loads during the PJM High 5 Hours.

Note: PJM determines the weather-normalized peak for each Transmission Zone. Where a Transmission Zone comprises more than one FirstEnergy Zone, each FirstEnergy Zone’s weather-normalized peak is determined on a load ratio share basis (including PJM add-backs, if
any) using the High 5 Hours. This ensures that the weather normalization ratio is the same value for each FirstEnergy Zone in those cases where a Transmission Zone comprises more than one FirstEnergy Zone.

4. This determines the wholesale LSE’s PLC for that FirstEnergy Zone, which is posted to the wholesale LSE’s PJM RPM account.

5. Numeric Example:

FirstEnergy Zone load during PJM High 5 Hour 1: 1,000 MW
FirstEnergy Zone load during PJM High 5 Hour 2: 1,100 MW
FirstEnergy Zone load during PJM High 5 Hour 3: 850 MW
FirstEnergy Zone load during PJM High 5 Hour 4: 1,250 MW
FirstEnergy Zone load during PJM High 5 Hour 5: 1,175 MW

Step 1: Determine/compute wholesale LSE’s load during the High 5 Hours from Meters (grossed up for contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC):

Wholesale LSE’s load during PJM High 5 Hour 1: 85 MW
Wholesale LSE’s load during PJM High 5 Hour 2: 86 MW
Wholesale LSE’s load during PJM High 5 Hour 3: 70 MW
Wholesale LSE’s load during PJM High 5 Hour 4: 98 MW
Wholesale LSE’s load during PJM High 5 Hour 5: 90 MW

Step 2: Perform add-backs for High 5 DR Events, if any.

Wholesale LSE’s PJM-determined add-back during PJM High 5 Hour 4: 5 MW
Wholesale LSE’s unrestricted load during PJM High 5 Hour 4: 98 + 5 = 103 MW

Step 3: Calculate wholesale LSE’s average unrestricted load

\[(85 + 86 + 70 + 103 + 90) / 5 = 86.8 \text{ MW}\]

Step 4: Determine FirstEnergy Zone weather normalization ratio

Note: Any FirstEnergy or other LSE add-backs would also be included in determining the unrestricted FirstEnergy Zone loads.

Unrestricted FirstEnergy Zone load during PJM High 5 Hour 1: 1,000 MW
Unrestricted FirstEnergy Zone load during PJM High 5 Hour 2: 1,100 MW
Unrestricted FirstEnergy Zone load during PJM High 5 Hour 3: 850 MW
Unrestricted FirstEnergy Zone load during PJM High 5 Hour 4: 1,255 MW
Unrestricted FirstEnergy Zone load during PJM High 5 Hour 5: 1,175 MW

FirstEnergy Zone weather-normalized peak load: 950 MW
950 / ((1000 + 1100 + 850 + 1255 + 1175) / 5) = 0.883

Step 5: Determine PLC for wholesale LSE for that FirstEnergy Zone:

0.883 * 86.8 = 76.6 MW

**NSPL Calculation**

The NSPL calculation for a wholesale LSE is simply the wholesale LSE’s metered load at the time of the Transmission Zone peak as determined by PJM and as grossed up for contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC.

Numeric Example:

Transmission Zone peak occurred on August 1, 201X, during Hour Ending 1700.

Wholesale LSE’s load on August 1, 201X, during Hour Ending 1700 (including contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC): 90 MW

Wholesale LSE’s NSPL = 90 MW

Note: Unlike the calculation of PLC, add-backs are not considered in determining the wholesale LSE’s NSPL.

**SECTION III: RETAIL**

The PLC and NSPL for an LSE providing service to retail customers receiving distribution service from a FirstEnergy EDC shall be determined in accordance with the following:

1. On a customer-by-customer basis, PLCs will be determined based on the customer load during the High 5 Hours.

   a. Where interval meters are utilized for retail customer billing, load values for the High 5 Hours will be determined using customer-specific interval meter data.
   b. Where interval meters are not utilized for retail customer billing, load values for the High 5 Hours will be determined from profiled data.
   c. All data will be grossed up for applicable distribution and transmission losses.
   d. If a DR Event occurred in the FirstEnergy Zone in which the retail LSE serves load during one or more of the High 5 Hours, then the PJM-determined
load reduction for each customer will be added back to the customer's load value for the corresponding hour.
e. PLCs will be scaled by the Daily Scaling Factor (“DSF”) before submittal to PJM.

2. On a customer-by-customer basis, NSPLs will be determined by:
   
a. selecting the hours in which the 5 peak loads occurred during the season in which the respective Transmission Zone peak, as reported by PJM, occurred (i.e., Summer season from June 1 to September 30, or Winter season from December 1 to March 31);
b. determining the average load values of each retail load customer during these 5 peak hours;
c. grossing up all data for transmission and, as applicable, distribution losses; and
   
d. scaling that average load value to the Transmission Zone peak as reported by PJM.

In lieu of a PLC DSF, a separate and distinct NSPL daily scaling factor is determined for each Transmission Zone and applied to each NSPL to ensure that the sum of all NSPL values reported to PJM matches the respective Transmission Zone target. For NSPL, there is no add-back for DR Events.

FirstEnergy does not determine PLCs and NSPLs for the retail consumers of wholesale LSEs like municipal electric utilities and electric cooperatives.

Additional implementation details related to the determination of the PLC and NSPL for each retail customer will be provided in the manual titled "Supplier Capacity Manual" under the "Supplier Registration" tab of the Supplier Support section of the FirstEnergy corporate website located here: https://www.firstenergycorp.com/supplierservices. The Manual may reflect differences based on the state utility commission requirements applicable to each FirstEnergy Zone, to the extent such requirements are not inconsistent with the requirements stated in this Attachment M-2.
Section(s) of the
PJM Operating Agreement

(Marked / Redline Format)
SCHEDULE 12 -
PJM MEMBER LIST

7 Bridges Solar, LLC
AC Energy, LLC
Acciona Energy North America Corporation (AENAC)
ACT Commodities Inc.
Advanced Energy Economy Inc.
AEP Appalachian Transmission Company, Inc.
AEP Energy Partners, Inc.
AEP Energy, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP Retail Energy Partners, LLC
AEP West Virginia Transmission Company, Inc.
AES Energy Storage, LLC
AES ES Holdings, LLC
Aesir Power, LLC
AES Integrated Energy, LLC
AES Laurel Mountain, LLC
AES Ohio Generation, LLC
AES Solutions Management, LLC
AEUG Madison Solar, LLC
Affirmed Energy LLC
Aggressive Energy LLC
Agile Energy Trading LLC
Agway Energy Services, LLC
Air Products & Chemicals, Inc.
Alabama Power Company
Alameda Solar I, LLC
Alegría Fund, LP
Algonquin Energy Services, Inc.
All American Power and Gas, LLC
All Choice Energy MidAmerica LLC dba Raava Energy
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, LLC
ALLETE, Inc. d/b/a Minnesota Power
Alliant Energy Corporate Services, Inc.
Alliant Energy Resources, LLC
Alpaca Energy LLC
Alpha Gas and Electric, LLC
Alphataraxia Palladium LLC
Alternative Transmission Inc.
Altop Energy Trading LLC
Altop Energy Trading MidAtlantic LLC
Altrock LLC
Altro Power LLC
Altus Power, Inc.
Amazand, LLC
Amazon Energy LLC
Ambit Northeast, LLC
American Municipal Power, Inc.
American Power & Gas of IL, LLC
American Power & Gas of MD, LLC
American Power & Gas of NJ, LLC
American Power & Gas of Ohio, LLC
American Power & Gas of Pennsylvania, LLC
American PowerNet Management, L.P.
American Transmission Systems Inc.
Ames Energy, LLC
AMP Transmission, LLC
Anbaric Development Partners, LLC
AM Trading Solutions, LLC
AP Gas & Electric (IL), LLC
AP Gas & Electric (MD), LLC
AP Gas & Electric (OH), LLC
AP Gas and Electric (NJ), LLC
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Apogee Energy Trading LLC
Appalachian Power Company
Appian Way Energy Partners MidAtlantic, LLC
Approved Energy II LLC
Aquenergy Systems LLC
Archer Energy, LLC
Armada Power, LLC
Armenia Mountain Wind, LLC
Aspen Generating, LLC
Aspen Gen Funding, LLC
Aspire Power Ventures, LP
Associated Electric Cooperative, Inc.
Astral Energy LLC
Atlantic City Electric Company
Atlantic Energy MD, LLC
ATNV Energy, LP
Aurora Energy Research LLC
Automated Algorithms, LLC
Avangrid Networks, Inc.
Avangrid Renewables, LLC
Axpo U.S. LLC
Baltimore Gas and Electric Company
Baltimore Power Company LLC
Bancroft Energy LLC
Barclays Capital Services Corporation
Bath County Energy, LLC
Battery Utility of Ohio, LLC
Bazinga, LLC
Beaver Dam Energy LLC
Beech Ridge Energy LLC
Beech Ridge Energy II LLC
Beech Ridge Energy Storage LLC
Bellflower Solar 1, LLC
Bernards Solar, LLC
BIF II Safe Harbor Holding LLC
BIF III Holtwood LLC
Big Bend Trading, LLC
Big Level Wind LLC
Big Plain Solar, LLC
Big Rivers Electric Corporation
Big Sandy Peaker Plant, LLC
Big Savage, LLC
Big Sky Wind, LLC
Birchwood Power Partners, L.P.
Birdsboro Power LLC
Bishop Hill Energy LLC
BITH Solar I, LLC
Bitter Ridge Wind Farm, LLC
BJ Energy, LLC
Black Oak Capital, LLC
Blackout Power Trading Inc.
Black Rock Wind Force, LLC
Blackstone Wind Farm II, LLC
Blackstone Wind Farm, LLC
Blooming Grove Wind Energy Center LLC
Blossom Solar, LLC
Blue Harvest Solar Park LLC
Blue Ridge Power Agency, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Columbia, PA
Borough of Lavallette, New Jersey
Borough of Madison, New Jersey
Borough of Milltown
Borough of Mont Alto
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights
Borough of South River, New Jersey
Boston Energy Group, Inc.
Boston Energy Trading and Marketing LLC
Bowfin KeyCon Energy, LLC
Bowfin KeyCon Power, LLC
BP Energy Company
BP Energy Retail Company LLC
BP Energy Holding Company LLC
Brandon Shores LLC
BREG Aggregator LLC
Brick Standard LLC
Brookfield Energy Marketing, LP
Brookfield Power Piney & Deep Creek LLC
Brookfield Renewable Energy Marketing US LLC
Brookfield Renewable Trading and Marketing LP
Bruce Power Inc.
Brunner Island, LLC
Buckeye Power, Inc.
C4GT LLC
Caden Energix Axton LLC
Calpine Bethlehem, LLC
Calpine Energy Services, L.P.
Calpine Energy Solutions, LLC
Calpine Mid Atlantic Marketing, LLC
Calvert Cliffs Nuclear Power Plant, LLC
Cambria Wind LLC
Camden Plant Holding, L.L.C.
Camden Solar LLC
Camp Grove Wind Farm, LLC
Capacity Markets Partners, LLC
Cape May County Municipal Utilities Authority
Carolina Power Partners, LLC
Carroll County Energy LLC
Castleton Commodities Merchant Trading L.P.
Catalyst Power & Gas LLC
CCI U.S. Power Trading LLC
Central Electric Power Cooperative, Inc.
Central Transmission, LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy, LLC
Champion Energy Marketing LLC
Champion Energy Services, LLC
Chesapeake Transmission LLC
Chief Conemaugh Power, LLC
Chief Conemaugh Power II, LLC
Chief Keystone Power, LLC
Chief Keystone Power II, LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Cinnamon Bay, LLC
Citadel FNGE Ltd.
Citigroup Energy Inc.
Citizens’ Electric Company of Lewisburg, PA
City of Batavia, Illinois
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Geneva (The)
City of Hamilton
City of Rochelle
City Power & Gas, LLC
CleanChoice Energy, Inc.
Clean Energy Future – Lordstown, LLC
Clearview Electric Inc.
Clearview Solar I, LLC
Cleveland-Cliffs Steel Corporation
Cleveland-Cliffs Steel LLC
Cleveland Electric Illuminating Company
Click Energy, LLC
CL-Viaduct Holding LLC
CMS Energy Resource Management Company
Comity Inc.
Coaltrain Energy LP
Coastal Strategies, LLC
COI Energy Services, Inc.
Collegiate Clean Energy, LLC
Commonwealth Chesapeake Company, LLC
Commonwealth Edison Company
Community Energy, Inc.
ConocoPhillips Company
Consolidated Edison Company of New York, Inc.
Constellation Energy Generation, LLC
Constellation NewEnergy, Inc.
Consumer Protection and Advocate Division of the Tennessee Attorney General
Consumers Energy Company
Convergent Energy and Power LP
Cordova Energy Company LLC
Cork Oak Solar LLC
Cornerstone Gas, L.L.C.
Corona Power LLC
Cottontail Solar 1, LLC
Cottontail Solar 2, LLC
Cottontail Solar 3, LLC
Cottontail Solar 4, LLC
Cottontail Solar 5, LLC
Cottontail Solar 6, LLC
Cottontail Solar 7, LLC
Cottontail Solar 8, LLC
County of Frederick, VA
Covanta Energy Marketing LLC
Covanta Union, LLC
CP Energy Marketing (US) Inc.
CPV Backbone Solar, LLC
CPV Fairview, LLC
CPV Keasbey, LLC
CPV Maple Hill Solar, LLC
CPV MARYLAND, LLC
CPV Power Holdings, LP
CPV Retail Energy LP
CPV Shore, LLC
CPV Three Rivers, LLC
CPV Rogue's Wind, LLC
Crescent Ridge LLC
Crete Energy Venture, LLC
Crossroads Solar I, LLC
Cube Hydro Partners, LLC
Current Energy and Renewables Inc.
Customized Energy Solutions, Ltd.
CWP Energy Inc.
Cypress Creek Renewables, LLC
Danske Commodities US LLC
Darby Energy, LLLP
Darby Power, LLC
Dart Container Corporation of Pennsylvania
David Energy Supply, LLC
Dayton Power & Light Company (The)
DC Energy LLC
DC Energy Mid-Atlantic, LLC
DCO Energy, LLC
Decatur Energy Center, LLC
Delaware Division of the Public Advocate
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy, LLC
Diamond Energy East, LLC
Diamond Retail Energy, LLC
Diamond State Generation Partners, LLC
Direct Energy Business, LLC
Direct Energy Business Marketing, LLC
Direct Energy Services, LLC
Discount Power, Inc.
Divine Power, Inc.
Dominion Energy Generation Marketing, Inc.
Dominion Energy South Carolina, Inc.
Domtar Paper Company, LLC
Doral Renewables LLC
Doswell Limited Partnership
DPL Energy Resources, LLC
Drake Power, LLC
DTE Atlantic, LLC
DTE Energy Trading, Inc.
DTN, LLC
Duke-American Transmission Company, LLC
Duke Energy Business Services, LLC
Duke Energy Carolinas, LLC
Duke Energy Florida, LLC
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Progress, LLC
Duke Energy Renewable Services, LLC
Duquesne Light Company
Duquesne Light Energy, LLC
Duquesne Power LLC
DV Trading, LLC
DXT Commodities North America Inc.
Dynamix Energy Services Company, LLC
Dynasty Energy California Inc.
Dynasty Power Inc.
Dynegy Energy Services, LLC
Dynegy Marketing and Trade, LLC
Dynegy Power Marketing, LLC
Eagle Creek Hydro Holdings, LLC
Eagle Point Power Generation LLC
East Coast Power Linden Holdings L.L.C.
Eastern Generation, LLC
Eastern Shore Solar LLC
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
Ebensburg Power Company
eCcap Network, LLC
EcoGrove Wind, LLC
EcoPlus Power, LLC
EDF Trading North America, LLC
Edgecombe Solar LLC
EDP Renewables North America, LLC
EF Kenilworth LLC
EFS Parlin Holdings, LLC
Electranet REP I, LLC
Elgin Energy Center, LLC
Eligo Energy, LLC
Elk Hill Solar 1, LLC
Elk Hill Solar 2, LLC
Elk Run Storage LLC
Elliot Bay Energy Trading, LLC
Elmagin Power Fund LLC
Elm Line LLC
Elmwood Park Power, LLC
Elwood Energy LLC
Emera Energy Services, Inc.
Emporia Hydropower Limited Partnership
Endurance Energy Midwest LLC
Enel Green Power Hilltopper Wind, LLC
Enel Trading North America, LLC
Enel X North America, Inc.
Energo Power & Gas LLC dba Energo
Energy Authority, Inc. (The)
Energy Center Dover LLC
Energy Cooperative Association of Pennsylvania
Energy Cooperative of America, Inc.
Energy Harbor LLC
EnergyMark, LLC
Energy Plus Holdings LLC
Energy Power Investment Company, LLC
Energy Service Providers, Inc.
Energy Technology Savings, Inc.
Energy Transfer Retail Power, LLC
EnerPenn USA, LLC
Enerwise Global Technologies, LLC
Engelhart CTP (US) LLC
ENGIE Energy Marketing NA, Inc.
ENGIE Power & Gas LLC
ENGIE Resources LLC
EnPowered USA Inc.
Entergrid Fund I LLC
EPP Renewable Energy, LLC
ESC Harrison County Power, LLC
Essential Power OPP, LLC
Essential Power Rock Springs, LLC
ETC Endure Energy L.L.C.
Evergreen Gas & Electric, LLC
Evergy Kansas Central, Inc.
Evergy Metro, Inc.
Everyday Energy, LLC
Exelon Business Services Company, LLC
Fairless Energy, L.L.C.
Fantods LLC
Fermata Energy, LLC
Fern Solar LLC
FirstEnergy Pennsylvania Electric Company
First Point Power, LLC
FiTran Fund LP
Five Elements Energy LLC
Five Forks Solar, LLC
Florida Power & Light Company
Forest Investment Group, LLC
Forked River Power LLC
Fowler Ridge Wind Farm LLC
Fowler Ridge II Wind Farm LLC
Fowler Ridge III Wind Farm LLC
Fowler Ridge IV Wind Farm LLC
Foxhound Solar, LLC
FP East Capital Partners LLC
Franklin Power LLC
Frasier Solar, LLC
Freepoint Commodities LLC
Freepoint Energy Solutions LLC
Fresh Air Energy XVIII, LLC
Fresh Air Energy XXXV, LLC
G&G Energy, Inc.
G&S Wantage Solar, LLC
Galilean Electricae LLC
Gallus Capital LLC
Galt Power, Inc.
Gavin Power, LLC
GBE Energy Marketing Inc.
GDF SUEZ Energy Resources NA, Inc.
Geenex Solar LLC
Genbright LLC
Gen IV Investment Opportunities, LLC
GenOn Energy Management, LLC
GenOn Mid-Atlantic, LLC
GenOn Power Midwest, LP
GenOn REMA, LLC
Gen Ops, LLC
Geodesic 2 LLC
Georgia Power Company
Gerdau Ameristeel Energy, Inc
GlidePath Power Operations LLC
Goldin LLC
Grand Ridge Energy LLC
Grand Ridge Energy II LLC
Grand Ridge Energy III LLC
Grand Ridge Energy IV LLC
Grand Ridge Energy Storage, LLC
Grange Solar, LLC
Granger Energy of Honey Brook, LLC
Grantham Energy Corporation
Grasshopper Energy LLC
Grays Ferry Cogeneration Partnership
Great American Gas & Electric, LLC
Great American Power, LLC
Great Barrington Energy Fund LP
Great Cove Solar I LLC
Great Cove Solar II LLC
Great Falls Hydroelectric Company Limited Partnership
Green Energy NE LLC
Greenlight Energy Inc.
Green Mountain Energy Company
Green River Holdings, LLC
Greensville County Solar Project, LLC
GRG ENERGY LLC
GridBeyond US, LLC
Gridforce Energy Management, LLC
Gridmatic Inc.
Gridmatic Panicum LLC
Grid Power Direct, LLC
Group628, LLC
GSG, LLC
GSG 6, LLC
Guernsey Power Station LLC
Guidehouse Inc.
Gunvor USA LLC
Guzman Energy LLC
H.A. Wagner LLC
H.Q. Energy Services (U.S.), Inc.
Hagerstown Light Department
Half Moon Ventures, LLC
Hamilton Liberty LLC
Hamilton Patriot LLC
Hammond Solar, LLC
Handsome Lake Energy, LLC
Harborside Energy, LLC
Hardin Solar Energy LLC
Hardin Wind LLC
Harrison REA, Inc. – Clarkesburg, WV
Hartree Partners, LP
Harts Mill Solar, LLC
Harvey Solar I, LLC
Hawks Nest Hydro LLC
Hazle Spindle, LLC
Hazleton Generation LLC
HD Project One, LLC
Headwaters Wind Farm LLC
Headwaters Wind Farm II LLC
Hecate Energy Highland LLC
Helix Ironwood, LLC
Hemlock Solar, LLC
Hemsworth Capital LP
Hemsworth Capital Midwest LP
Heritage Power Marketing, LLC
Hexis Energy Trading, LLC
Hickory Run Energy, LLC
Highland North LLC
High Point Solar LLC
High Trail Wind Farm LLC
Hillcrest Solar I, LLC
Hill Top Energy Center, LLC
Holcim (US), Inc.
Holocene Finance, LLC
Homer City Generation, LP
Hoosier Energy REC, Inc.
Horizon Power and Light, LLC
H-P Energy Resources, LLC
Hudson Energy Services LLC
Hudson Transmission Partners, LLC
Hummel Station, LLC
HXNAir Solar One, LLC
Icetec.com, Inc.
Icetec Energy Services, Inc.
IDT Energy, Inc.
IHG Core Holdings, Ltd.
IHS Global Inc.
Illinois Citizens Utility Board
Illinois Municipal Electric Agency
Illinois Power Marketing Company
IMG Midstream LLC
In Commodities US LLC
Indeck Niles, LLC
Independence Energy Group, LLC
Independent Energy Consultants, Inc.
Indiana Michigan Power Company
Indiana Municipal Power Agency
Indiana Office of Utility Consumer Counselor (IN OUCC)
Inerci Capital Inc.
Inertia Power I, LLC
Ingenco Wholesale Power, LLC
Innergex Renewable USA LLC
Innoventive Power LLC
Inspire Energy Holdings, LLC
Intelligent Generation LLC
International Paper Company
Interstate Gas Supply, LLC
Interstate Power and Light Company
Invenergy Energy Management LLC
Invenergy LLC
Invenergy Nelson Expansion LLC
Invenergy Nelson LLC
IPKeys Power Partners, Inc.
IR Energy Management LLC
ISO 1, LLC
ITC Mid-Atlantic Development LLC
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jackson Generation, LLC
Jane Street Energy Trading, LLC
Janus Power LLC
J. Aron & Company LLC
Jersey-Atlantic Wind, LLC
Jersey Central Power & Light Company
Jersey Green Energy, LLC
Josco Energy IL LLC
Josco Energy USA, LLC
JP Morgan Ventures Energy Corporation
Jupiter Power LLC
Just Energy Limited
Just Energy Solutions Inc.
KDC Solar Green Power LLC
Kendall Power Company LLC
Keni Energy LLC
Kentucky Municipal Energy Agency
Kentucky Power Company
Kestrel Acquisition, LLC
KeyCon Power Holdings LLC
Keystone Appalachian Transmission Company
Keystone-Conemaugh Projects, LLC
KeyTex Energy LLC
KeyTex Energy Solutions LLC
KFW Energy, LLC
Kimberly-Clark Corporation
Kincaid Generation, LLC
Kingsport Power Company
Kiwi Energy NY LLC
KMC Thermo, LLC
KOREnergy, Ltd.
Kuehne Chemical Company, Inc.
kWantix Trading Fund I, LLP
Lackawanna Energy Center LLC
Lafayette Power LLC
Lancaster County Solid Waste Management Authority
Landaj Investment, LLC
Land O’Lakes, Inc.
Lantar Energy LLC
Lawrenceberg Power, LLC
Lanyard Power Holdings, LLC
LCP Energy LP
Leapfrog Power, Inc.
Lee County Generating Station, LLC
Leeward Asset Management, LLC
Legacy Energy Group, LLC (The)
Lehigh Portland Cement Company
Letterkenny Industrial Development Authority – PA
Lexington Chenoa Wind Farm LLC
Liberty Electric Power, LLC
Liberty Madison Storage LLC
Lightstone Marketing LLC
Lily Pond Solar, LLC
Lincoln Generating Facility, LLC
Linden VFT LLC
LM Power, LLC
LMBE Project Company LLC
Lone Tree Wind, LLC
Long Island Lighting Company d/b/a LIPA
Long Ridge Energy Generation LLC
Longview Power, LLC
Louisville Gas and Electric Company/Kentucky Utilities Company
Lower Electric, LLC
LQA, LLC
LSP University Park, LLC
LTSTE Investments, LLC
Lyons Solar, LLC
Macquarie Energy LLC
Macquarie Energy Trading LLC
MAG Energy Solution, Inc.
Mahoning Creek Hydroelectric Company, LLC
Major Energy Electric Services, LLC
Manatee Transmission LLC
Maple Analytics, LLC
Marginal Unit, Inc.
Marina Energy, LLC
Martins Creek, LLC
Marubeni Power International, Inc.
Maryland Office of People’s Counsel
Maryland Solar LLC
Mattawoman Energy, LLC
MC Project Company LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm, LLC
Meadow Lake Wind Farm II, LLC
Meadow Lake Wind Farm III, LLC
Meadow Lake Wind Farm IV, LLC
Meadow Lake Wind Farm V, LLC
Meadow Lake Wind Farm VI LLC
MeadWestvaco Corporation
Median Energy Corp.
Median Energy IL LLC
Median Energy PA LLC
Mehoopany Wind Energy LLC
Mendota Hills, LLC
Mercuria Energy America, LLC
Mercuria SJAK Trading, LLC
Merrill Lynch Commodities, Inc.
Messer LLCsouth
Messer Energy Services, Inc.
MeterGenius, Inc.

**Metropolitan Edison Company**

MFT Energy US 1 LLC
Miami Valley Lighting, LLC
Mianus River Energy, LLC
Michigan Department of Attorney General, Environment, Natural Resources & Agriculture Division
Michigan Public Power Agency
MidAmerican Energy Company
MidAmerican Energy Services, LLC
Mid-Atlantic Interstate Transmission, LLC
MidAtlantic Power Partners, LLC
Middlesex County Utilities Authorities
Midwest Energy Trading East LLC
Midwest Generation, LLC
Milan Energy LLC
Milford Solar LLC
Mississippi Power Company
Mitsui Bussan Commodities Ltd.
Mitsui & Co. Energy Marketing and Services (USA), Inc.
Monongahela Power Company d/b/a Allegheny Power
Monterey MA LLC
Montour, LLC
Montpelier Generating Station, LLC
Monument Generating Station, LLC
Morgan Stanley Capital Group Inc.
Morgan Stanley Services Group Inc.
Morris Cogeneration, L.L.C
Mosaic Power, LLC
Moundsville Power, LLC
Moxie Freedom LLC
MP2 Energy LLC
MP2 Energy NE LLC dba Shell Energy Solutions
MPCF I, LLC
MPower Energy NJ LLC
Mt. Carmel Cogen, Inc.
National Gas & Electric, LLC
Nautilus Power, LLC
Nautilus Solar Energy, LLC
NDC Partners, LLC
NedPower Mount Storm, LLC
NEPM II, LLC
Neptune Regional Transmission System, LLC
Newark Energy Center, LLC
New Covert Generating Company, LLC
New Creek Wind LLC
New Jersey Division of the Ratepayer Advocate
New Jersey Transit Corporation
New Wave Energy, LLC
New York Power Authority
New York State Electric & Gas Corporation
Newark Bay Cogeneration Partnership, L.P.
New Road Power, LLC
NextEra Energy Bluff Point, LLC
NextEra Energy Marketing, LLC
NextEra Energy Services Illinois, LLC
NextEra Energy Services New Jersey, LLC
NextEra Energy Transmission, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
NextPower III US Holdco Inc.
Nexus Energy Inc.
NG Renewables Energy Marketing, LLC
NJR Clean Energy Ventures Corporation
NJR Clean Energy Ventures II Corporation
NJR Clean Energy Ventures III Corporation
Nodal Exchange, LLC
Nordic Energy Services LLC
North 301 Solar, LLC
North American Power and Gas, LLC
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
North Hanover Solar W2-082, LLC
Northampton Generating Company, L.P.
Northeastern REMC
Northeast Maryland Waste Disposal Authority
Northern Illinois Municipal Power Agency
Northern Indiana Public Service Company
Northern States Power Company
Northern Virginia Electric Cooperative - NOVEC
NorthPoint Energy Solutions, Inc.
Northstar Trading Ltd.
Northwest Ohio Wind, LLC
NRG Curtailment Solutions, Inc.
NRG Power Marketing, LLC
NRGStream LLC
NTE Ohio, LLC
nTherm, LLC
NuEnergen, LLC
Oak Trail Solar, LLC
OCI Solar Power, LLC
Octopus Energy LLC
Office of the Attorney General, Kentucky
Office of the People’s Counsel for the District of Columbia
O.H. Hutchings CT, LLC
Ohio Consumer’s Counsel
Ohio Edison Company
Ohio Power Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
Old Mission Energy Trading LLC
Olympus Power, LLC
One Energy Enterprises LLC
Ontario Power Generation Energy Trading, Inc.
Ontario Power Generation Inc.
Ontelaunee Power Operating Company, LLC
Open Road Renewables, LLC
Oregon Clean Energy, LLC
Orennia US LLC
Orsted Onshore North America, LLC
Osaka Gas USA Corporation
Owensboro Municipal Utilities
Oxbow Creek Energy LLC
Pacific Summit Energy LLC
Palladium Energy, LLC
Palm Energy LLC
Palmco Power DC, LLC
PALMco Power DE, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power PA, LLC
PALMco Power VA, LLC
Panther Creek Power Operating, LLC
Park Power LLC
Parkway Generation Operating LLC
PATH Allegheny Transmission Company, LLC
PATH West Virginia Transmission Company, LLC
Patton Wind Farm, LLC
Paulding Wind Farm II LLC
Paulding Wind Farm III LLC
Paulding Wind Farm IV LLC
Pay Less Energy, LLC
PBF Power Marketing, LLC
Peak Energy Capital LP
Peakstone Energy, LLC
PECO Energy Company
Pedricktown Cogeneration Company LP
Pegasus Energy Futures LLC
PEI Power LLC
PEI Power II, LLC
Peninsula Power, LLC
PennCat Corporation
Pennoni Associates Inc.
Pennsylvania Electric Company
Pennsylvania Grain Processing LLC
Pennsylvania Office of Consumer Advocate
Pennsylvania Power Company
Pennsylvania Renewable Resources, Associates
Perast Fund LP
Pharentram Energy Services, Ltd.
Philadelphia Energy Solutions Refining and Marketing LLC
Phillips 66 Energy Trading LLC
Piedmont Energy Fund, L.P.
Pine Gate Mid-Atlantic, LLC
Pinesburg Solar LLC
Pinnacle Power LLC
Pixelle Specialty Solutions LLC
Plains Solar, LLC
Plant-E Corp.
Polaris Power Services LLC
Potomac Edison Company (The) d/b/a Allegheny Power
Potomac Electric Power Company
Potomac Energy Center, LLC
Power Analytics Software, Inc.
Power Engineers, Incorporated
Power Supply Services, LLC
Power Up Energy, LLC
Powervine Energy, LLC
PPL Electric Utilities Corporation dba PPL Utilities
Prairieland Energy, Inc.
Praxair, Inc.
Precept Power LLC
Procter & Gamble Paper Products Company (The)
Prospect Power, LLC
Providence Heights Wind, LLC
Provision Power and Gas, LLC
PSEG Energy Resources & Trade LLC
PSEG Energy Solutions LLC
PSEG Nuclear LLC
Public Service Electric and Gas Company
Public Staff – North Carolina Utilities Commission
Pure Energy, Inc.
Pure Energy USA IL, LLC
Pure Energy USA, LLC
Quattro Energy LP
Radford’s Run Wind Farm, LLC
Rainbow Energy Marketing Corporation
Rainbow Energy Ventures LLC
Rausch Creek Electric Power Holdings, LLC
Realgy, LLC
Recurrent Energy, LLC
Red Oak Power, LLC
Red Wolf TX2, LLC
Refinitiv US LLC
Reliant Energy Northeast, LLC
Renaissance Power & Gas, Inc.
Renergy Inc.
Renewable Energy Aggregators Inc.
Rensselaer Generating LLC
RES America Developments Inc.
ResCom Energy, LLC
Residents Energy, LLC
Respond Power, LLC
Rhei Energy Partners LP
Richfield Solar Energy LLC
Richland-Stryker Generation LLC
RI-Corp. Development, Inc.
River Bay Commodities, LLC
RiverCrest Power-South, LLC
Riverside Generating Company, L.L.C.
Riverstart Solar Park LLC
Rochester Gas and Electric Corporation
Rockfish Solar LLC
Rockland Electric Company
Rocky Road Power, LLC
Rodan Energy Solutions (USA) Inc.
Rolling Hills Generating, L.L.C.
Rose Gold Solar, LLC
Roseton Generating LLC
Roth Rock Wind Farm, LLC
Roundtop Energy LLC
Royal Bank of Canada
RPA Energy, Inc.
RTP Controls, Inc
RTR Energy Solutions LLC
Rushmore Energy, LLC (new)
RWE Clean Energy Solutions, Inc.
RWE Clean Energy Wholesale Services, Inc.
RWE Renewables Americas, LLC
Safe Harbor Water Power Corporation
Sanitas Power, LLC
Santanna Energy Services
Saracen Energy East LP
Saracen Energy Midwest LP
Saracen Energy West LP
Saracen Power LP
Saugatuck River Power Trading LLC
S.C. Energy Partners LLC
Schuylkill Energy Resources, Inc.
Scout Storage LLC
Scrubgrass Generating Company, L.P.
Scylla Energy LLC
Seneca Generation, LLC
Seneca Trading LLC
SESCO ENTERPRISES LLC
Seven Islands Environmental Solutions, LLC
Severn River Power LLC
Seward Generation, LLC
SFE Energy, Inc.
Shell Energy North America (U.S.), L.P.
Shepard’s Neck Point LLC
Shipley Choice LLC
Sidney, LLC
Siemens Industry, Inc.
Silver Run Electric, LLC
S.J. Energy Partners, Inc.
SmartEnergy Holdings, LLC
Smar testEnergy US LLC
Smart Wires Inc.
SociVolta Inc.
Solios Power Mid-Atlantic Trading LLC
Sol Madison Solar, LLC
Southampton Solar LLC
South Bay Energy Corp.
Southeastern Chester County Refuse Authority
Southeastern Power Administration
Southern Indian Gas and Electric Company d/b/a Vectren Power Supply Inc.
Southern Maryland Electric Cooperative, Inc.
Southern Power Company
South Field Energy LLC
South Jersey Energy Company
Spark Energy, LLC
Spartacus Energy Services LLC
Spotlight Power LLC
sPower Energy Marketing, LLC
Spring Energy RRH, LLC dba Spring Power & Gas
Spruance Operating Services, LLC
Spruce Power Trading, LLC
Standard Gas & Electric, LLC
Star Jasmine Houston LLC
STATARB INVESTMENTS LLC
Sterling Partners Energy Investors LLC
St. Joseph Energy Center, LLC
Stones DR, LLC
Stoney Creek Wind Farm, LLC
Stream Energy Columbia, LLC
Stream Energy Delaware, LLC
Stream Energy Illinois, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
Stream Ohio Gas & Electric, LLC
Strom Power, LLC
Summer Energy Midwest, LLC
Summit Farms Solar, LLC
SunCoke Energy, Inc
Sunflower Solar LLC
SunSea Energy LLC
Sunshaw Power Trading, LLC
Sun Tribe Development LLC
Susquehanna Nuclear, LLC
Sustaining Power Solutions LLC
Syncarpha Solar, LLC
SYSO Inc.
Tait Electric Generating Station, LLC
Talen Energy Marketing, LLC
Tangent Energy Solutions, Inc.
Tatanka Wind Power, LLC
TC Energy Marketing Inc.
TEC Energy Inc.
TEC Trading, Inc.
Tenaska Pennsylvania Partners, LLC
Tenaska Power Management, LLC
Tenaska Power Services Co.
Tenaska Virginia Partners, L.P.
Tennessee Valley Authority (The)
TerraForm IWG Acquisition Holdings II, LLC
Texas Retail Energy, LLC
Teza Technologies LLC
The Hartz Group
The Highlands Energy Group, LLC
Think Energy, LLC
Thordin ApS
Thurmont Municipal Light Company
Tidal Energy Marketing (U.S.) L.L.C.
Tilton Energy LLC
Timber Road Solar Park LLC
TimberRock Consulting LLC
Tios Capital, LLC
Titan Gas and Power
Todd Solar LLC
Toledo Edison Company (The)
Tomorrow Energy Corp
Town of Berlin, Maryland
Town of Williamsport
Town Square Energy East, LLC
Tradewind Energy, Inc.
Trafigura Trading LLC
TrailStone Energy Marketing, LLC
Trans-Allegheny Interstate Line Company
TransAlta Energy Marketing (US) Inc.
Transource Energy, LLC
Transource Maryland, LLC
Transource Pennsylvania, LLC
Transource West Virginia, LLC
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Tri Global Energy, LLC
TrueLight Commodities, LLC
Trustees of the University of Pennsylvania
Tupelo Solar I, LLC
TWE Myrtle Solar Project, LLC
Twin Eagle Resource Management, LLC
Tyne Hill Investments LP
Tyr Energy, LLC
UGI Development Company
UGI Energy Services, LLC
UGI Utilities, Inc.
Uncia Energy LP – Series B
Union Electric Company d/b/a Ameren Missouri
Union Ridge Solar, LLC
University Park Energy, LLC
UN-School House Holding LLC
Urban Grid Solar Projects, LLC
V3 Commodities Group, LLC
VCIOM, LLC
VECO Power Trading, LLC
Velocity American Energy Master I, LP
Verde Energy USA DC, LLC
Verde Energy USA Illinois, LLC
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verde Energy USA, Inc.
Vineland Municipal Electric Utility
Virginia Division of Consumer Counsel
Virginia Electric and Power Company
Virginia Solar 2017 Projects LLC
Virginia State Corporation Commission
Viribus Fund LP
Viridian Energy Ohio LLC
Viridian Energy PA, LLC
Viridity Energy Solutions Inc.
Vista Energy Marketing, L.P.
Vitol, Inc.
Voltus, Inc.
Wabash Valley Power Association, Inc.
Volunteer Energy Services, Inc.
Walden Renewables Development LLC
Walnut Ridge Wind, LLC
Walleye Power, LLC
Waterford Power, LLC
Waverly Solar, LLC
Wellsboro Electric Company
West Deptford Energy, LLC
Western Reserve Energy Services, LLC
West Penn Power Company d/b/a Allegheny Power
West Virginia Consumer Advocate Division
WGL Energy Services, Inc.
Wheelabrator Baltimore, L.P.
Wheelabrator Falls Inc.
Wheelabrator Frackville Energy Company, Inc.
Wheelabrator Gloucester Company, L.P.
Wheelabrator Portsmouth, Inc.
Wheeling Power Company
White Peak Energy LLC
Whitetail Solar 1, LLC
Whitetail Solar 2, LLC
Whitetail Solar 3, LLC
Whitmore Solar, LLC
Whitney Hill Wind Power, LLC
Wildcat Wind Farm I, LLC
Wilkinson Solar LLC
Wolley Battery Utility, LLC
Wisconsin Power and Light Company
WM Renewable Energy, LLC
Wolf Hills Energy, LLC
Wolf Run Energy LLC
Wolverine Holdings, L.P.
Wolverine Power Supply Cooperative, Inc.
Wolverine Trading, LLC
WP&G Holdings, LLC
WPPI Energy
Wrigley Capital LLC
Wyandot Solar LLC
XO Energy MA, LP
XO Energy MA2, LP
XO Energy MA3, LP
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
XOOM Energy Ohio, LLC
XOOM Enegy Washington D.C., LLC
Xoom Energy, LLC
Yankee Street, LLC
Yellow Jacket Energy, LLC
Yes Energy LLC
York County Solid Waste and Refuse Authority
York Generation Company LLC
York Haven Power Company, LLC
Zongyi Solar America Co. Ltd.
Section(s) of the
Reliability Assurance
Agreement

(Marked / Redlined
Format)
## Schedule 15
### Zones Within the PJM Region

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<th>SHORT NAME</th>
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<td>Allegheny Power</td>
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<td>PPL Group</td>
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<td>Metropolitan Edison Company**</td>
<td>MetEd</td>
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<td>Jersey Central Power and Light Company</td>
<td>JCPL</td>
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<td>Public Service Electric and Gas Company</td>
<td>PSEG</td>
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<td>Baltimore Gas and Electric Company</td>
<td>BGE</td>
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<td>DPL</td>
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<td>PEPICO</td>
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<td>Commonwealth Edison Company</td>
<td>ComEd</td>
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<td>AEP East Zone</td>
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<td>The Dayton Power and Light Company</td>
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<td>Virginia Electric and Power Company</td>
<td>Dominion</td>
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<td>Duquesne Light Company</td>
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<td>American Transmission Systems, Incorporated</td>
<td>ATSI</td>
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<td>Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.</td>
<td>DEOK</td>
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<td>East Kentucky Power Cooperative, Inc.</td>
<td>EKPC</td>
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<tr>
<td>Ohio Valley Electric Corporation</td>
<td>OVEC</td>
</tr>
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</table>
* FirstEnergy Pennsylvania Electric Company ("FE PA") is the successor-in-interest to Pennsylvania Electric Company, but all references to the Pennsylvania Electric Company or Penelec Zone remain unchanged.

** FirstEnergy Pennsylvania Electric Company ("FE PA") is the successor-in-interest to Metropolitan Edison Company, but all references to the Metropolitan Edison Company or MetEd Zone remain unchanged.
SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Energy, Inc.
AEP Retail Energy Partners LLC
AES Ohio Generation, LLC
AES Solutions Management, LLC
Aggressive Energy LLC
Agway Energy Services, LLC
Algonquin Energy Services Inc.
All American Power and Gas, LLC
All Choice Mid America LLC dba Raava Energy
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, L.L.C.
Alpaca Energy LLC
Alpha Gas and Electric LLC
Ambit Northeast, LLC
American Electric Power Service Corporation on behalf of its affiliates:
   Appalachian Power Company
   Indiana Michigan Power Company
   Kentucky Power Company
   Kingsport Power Company
   Ohio Power Company
   Wheeling Power Company.
American Municipal Power, Inc.
American Power & Gas of IL, LLC
American Power & Gas of MD, LLC
American Power & Gas of NJ, LLC
American Power & Gas of Ohio, LLC
American Power & Gas of Pennsylvania, LLC
American PowerNet Management, L.P.
American Transmission Systems, Inc.
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Approved Energy II LLC
Archer Energy, LLC
Astral Energy LLC
Atlantic City Electric Company
Atlantic Energy MD, LLC
Avangrid Renewables, LLC
Axpo U.S. LLC
Baltimore Gas and Electric Company
Baltimore Power Company LLC
Barclays Capital Services, Inc
Bativa, IL (City of)
BBPC LLC d/b/a Great Eastern Energy
Blackstone Wind Farm, LLC
Blue Ridge Power Agency, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Columbia, PA
Borough of Lavallette, New Jersey
Borough of Milltown
Borough of Mont Alto, PA
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights, New Jersey
Borough of South River, New Jersey
Boston Energy Trading and Marketing LLC
BP Energy Company
BP Energy Retail Company LLC
Brookfield Renewable Energy Marketing US LLC
BTG Pactual Commodities (US) LLC
Buckeye Power, Inc.
Calpine Energy Service, L.P.
Calpine Energy Solutions, LLC
Catalyst Power
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy Marketing LLC
Champion Energy, LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Citigroup Energy Inc.
Citizens' Electric Company of Lewisburg, PA
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of New Martinsville - WV
City of Rochelle
CleanChoice Energy, Inc.
Clearview Electric, Inc.
Cleveland Electric Illuminating Company
Click Energy, LLC
CMS Resource Management Company
Collegiate Clean Energy, LLC
Commonwealth Edison Company
ConocoPhillips Company
Constellation Energy Generation, LLC
Constellation NewEnergy, Inc.
Convanta Energy Marketing LLC
CPV Retail Energy LP
Current Energy and Renewables Inc.
David Energy Supply, LLC
Dayton Power & Light Company (The)
DC Energy LLC
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy LLC
Diamond Energy East, LLC
Direct Energy Business, LLC
Direct Energy Business Marketing, LLC
Direct Energy Services, LLC
Discount Power, Inc.
DPL Energy Resources, Inc.
DTE Atlantic, LLC
DTE Energy Trading, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Duquesne Light Energy, LLC
DXT Commodities North America Inc.
Dynegy Energy Services, LLC
Dynegy Marketing and Trade, LLC
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
EcoPlus Power, LLC
EDF Trading North America, LLC
Eligio Energy, LLC
Enel Trading North America, LLC
Energetix, Inc.
Energy Cooperative Association of Pennsylvania (The)
Energy Cooperative of America, Inc.
Energy Harbor LLC
EnergyMark, LLC
Energy Plus Holdings LLC
Energy Services Providers, Inc.
Energy Technology Savings, Inc.
Energy Transfer Retail Power, LLC
EnerPenn USA, LLC
Engie Energy Marketing NA, Inc.
EnPowered USA Inc.
Evergreen Gas & Electric, LLC
Everyday Energy, LLC

FirstEnergy Pennsylvania Electric Company
First Point Power, LLC
Freepoint Energy Solutions LLC
Front Royal (Town of)
Galt Power Inc.
GenOn Power Midwest, LP
Gerdau Ameristeel Energy, Inc.
Great American Gas & Electric, LLC
Great American Power, LLC
Greenlight Energy Inc.
Green Mountain Energy Company
Grid Power Direct, LLC
Hagerstown Light Department
Harborside Energy, LLC
Harrison REA, Inc. - Clarksburg, WV
Hartee Parnters, LP
Holcim (US) Inc.
Hoosier Energy REC, Inc.
Horizon Power and Light LLC
Hudson Energy Services, LLC
IDT Energy, Inc.
Illinois Municipal Electric Agency
Illinois Power Marketing Company
Inspire Energy Holdings, LLC
Interstate Gas Supply, LLC
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
J. Aron & Company LLC
Jersey Central Power & Light Company
Josco Energy USA, LLC
Just Energy Limited
Just Energy Solutions Inc.
Kentucky Municipal Energy Agency
Kiwi Energy NY LLC
Kuehne Chemical Company, Inc.
Land O’Lakes, Inc.
Lower Electric, LLC
Macquarie Cook Energy LLC
Major Energy Electric Services LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm LLC
Meadow Lake Wind Farm II LLC
Meadow Lake Wind Farm III LLC
Meadow Lake Wind Farm IV LLC
MeadWestvaco Corporation
Median Energy Corp.
Median Energy PA LLC
Mega Energy Holdings, LLC
Mercuria Energy America, Inc.
Messer Energy Services, Inc.
MeterGenius Inc.
**Metropolitan Edison Company**
MidAmerican Energy Company
MidAmerican Energy Services, LLC
Morgan Stanley Capital Group, Inc.
Morgan Stanley Services Group Inc.
MP2 Energy NE, LLC dba Shell Energy Solutions
MPower NJ LLC
National Gas & Electric, LLC
NextEra Energy Marketing, LLC
Nextera Energy Services New Jersey, LLC
Nextera Energy Services, Illinois, LLC
Nordic Energy Services LLC
North American Power and Gas LLC.
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northeastern REMC
Northern States Power Company
Northern Virginia Electric Cooperative – NOVEC
NRG Power Marketing, L.L.C.
nTherm, LLC
Octopus Energy LLC
Ohio Edison Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
Palmco Power DC, LLC
Palmco Power DE, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power PA, LLC
PALMco Power VA, LLC
Park Power LLC
Pay Less Energy, LLC
PBF Power Marketing LLC
PECO Energy Company
**Pennsylvania Electric Company**
Pennsylvania Grain Processing LLC
**Pennsylvania Power Company**
PEPCO Energy Services, Inc.
Pinnacle Power LLC
Plymouth Rock Energy, LLC
Polaris Power Services LLC
Potomac Electric Power Company
Power UP Energy, LLC
Powervine Energy, LLC
PPL Electric Utilities Corporation d/b/a PPL Utilities
Prairieland Energy, Inc.
Provision Power and Gas, LLC
PSEG Energy Resources & Trade LLC
PSEG Energy Solutions LLC
Public Service Electric and Gas Company
Pure Energy USA IL, LLC
Pure Energy USA, LLC
Realg, LLC
Red Oak Power, LLC
Renaissance Power & Gas, Inc.
ResCom Energy, LLC
Residents Energy, L.L.C.
Respond Power LLC
Riverside Generating Company, LLC
Rolling Hills Generating, LLC
RPA Energy, Inc.
Rushmore Energy, LLC (new)
RWE Clean Energy Solutions, Inc.
RWE Clean Energy Wholesale Services, Inc.
S.J. Energy Partners, Inc.
Santanna Energy Services
Seward Generation, LLC
SFE Energy, Inc.
Shipley Choice LLC
Smarest Energy US LLC
Solios Power Mid-Atlantic Trading LLC
South Bay Energy Corp.
South Jersey Energy Company
Southeastern Power Administration
Southern Indiana Gas & Electric
Southern Maryland Electric Cooperative, Inc.
Spark Energy, LLC
Spring Energy RRH, LLC dba Spring Power & Gas
Standard Gas & Electric, LLC
Stream Energy Columbia, LLC
Stream Energy Delaware, LLC
Stream Energy Illinois, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
Stream Ohio Gas & Electric, LLC
Summer Energy Midwest, LLC
SunSea Energy LLC
Talen Energy Marketing, LLC
Tenaska Power Services Co.
Texas Retail Energy, LLC
Think Energy, LLC
Thurmont Municipal Light Company
Titan Gas and Power
Toledo Edison Company (The)
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**SCHEDULE 12 – APPENDIX**

(14) Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
</table>
| **b0216** Install -100/+525 MVAR dynamic reactive device at Black Oak | As specified under the procedures detailed in Attachment H-18B, Section 1.b | **Load-Ratio Share Allocation:**
| | | AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUN* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%) |
| **b0218** Install third Wylie Ridge 500/345 kV transformer | As specified under the procedures detailed in Attachment H-18B, Section 1.b | **DFAx Allocation:**
| | | AEC (11.83%) / DPL (19.40%) / Dominion (42.56%) / PEPCO (16.12%) |
| **b0220** Upgrade coolers on Wylie Ridge 500/345 kV #7 | | AEC (11.83%) / DPL (19.40%) / Dominion (13.81%) / JCPL (15.56%) / PECO (39.40%) |
| **b0229** Install fourth Bedington 500/138 kV | | APS (50.98%) / BGE (13.42%) / DPL (2.03%) / Dominion (14.50%) / ME (1.43%) / PEPCO (17.64%) |
| **b0230** Install fourth Meadowbrook 500/138 kV | As specified under the procedures detailed in Attachment H-18B, Section 1.b | APS (79.16%) / BGE (3.61%) / DPL (0.86%) / Dominion (11.75%) / ME (0.67%) / PEPCO (3.95%) |

* Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
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</tr>
</thead>
<tbody>
<tr>
<td>b0238 Reconductor Doubs – Dickerson and Doubs – Aqueduct 1200 MVA</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>BGE (16.66%) / Dominion (33.66%) / PEPCO (49.68%)</td>
</tr>
<tr>
<td>b0240 Open the Black Oak #3 500/138 kV transformer for the loss of Hatfield – Back Oak 500 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0245 Replacement of the existing 954 ACSR conductor on the Bedington – Nipetown 138 kV line with high temperature/low sag conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0246 Rebuild of the Double Tollgate – Old Chapel 138 kV line with 954 ACSR conductor</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0273 Open both North Shenandoah #3 transformer and Strasburg – Edinburgh 138 kV line for the loss of Mount Storm – Meadowbrook 572 500 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0322 Convert Lime Kiln substation to 230 kV operation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0323 Replace the North Shenandoah 138/115 kV transformer</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>b0328.2</strong> Build new Meadow Brook – Loudoun 500 kV circuit (20 of 50 miles)</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt; AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td><strong>b0334</strong> Replace Doubs 500/230 kV transformer #2</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td><strong>DFAX Allocation:</strong>&lt;br&gt; APS (2.49%) / BGE (7.42%) / Dominion (78.37%) / PEPCO (11.72%)</td>
</tr>
<tr>
<td><strong>b0344</strong> Replace Doubs 500/230 kV transformer #3</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>AEC (1.86%) / BGE (21.50%) / DPL (3.91%) / Dominion (28.82%) / ME (2.97%) / PECO (5.74%) / PEPCO (35.20%)</td>
</tr>
<tr>
<td><strong>b0345</strong> Replace Doubs 500/230 kV transformer #4</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>AEC (1.85%) / BGE (21.49%) / DPL (3.90%) / Dominion (28.83%) / ME (2.98%) / PECO (5.75%) / PEPCO (35.20%)</td>
</tr>
</tbody>
</table>

* Neptune Regional Transmission System, LLC
<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Load-Ratio Share Allocation:</th>
</tr>
</thead>
<tbody>
<tr>
<td>b0347.1 Build new Mt. Storm – 502 Junction 500 kV circuit</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td>b0347.2 Build new Mt. Storm – Meadow Brook 500 kV circuit</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
</tr>
</tbody>
</table>

DFAX Allocation:
- APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)

* Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

<table>
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<tr>
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<th>Annual Revenue Requirement</th>
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<tbody>
<tr>
<td>b0347.4</td>
<td>Upgrade Meadow Brook 500 kV substation</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
</tr>
<tr>
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<td></td>
<td><strong>Load-Ratio Share Allocation:</strong></td>
</tr>
<tr>
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<td></td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<tr>
<td></td>
<td></td>
<td><strong>DFAX Allocation:</strong></td>
</tr>
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<td></td>
<td></td>
<td>APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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* Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
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<td>Upgrade (per ABB inspection) breaker HL-7</td>
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<td>Upgrade (per ABB inspection) breaker HL-8</td>
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*Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<td>Upgrade (per ABB inspection) breaker HL-10</td>
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**Load-Ratio Share Allocation:**
- AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)

**DFAX Allocation:**
- APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)

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<td>APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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<td><strong>b0347.18</strong> Replace Meadow Brook 138 kV breaker ‘MD-11’</td>
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<td>APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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<td>Replace Meadow Brook 138 kV breaker ‘MD-12’</td>
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<td><strong>b0347.20</strong></td>
<td>Replace Meadow Brook 138 kV breaker ‘MD-13’</td>
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**DFAX Allocation:**
APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)
### Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<td><strong>b0347.22</strong> Replace Meadow Brook 138 kV breaker ‘MD-15’</td>
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*Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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| Replace Meadow Brook 138 kV breaker ‘MD-16’ |                             | Load-Ratio Share Allocation:  
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|                                                   |                             | BGE (4.11%) / ComEd (13.39%) /  
|                                                   |                             | Dayton (2.12%) / DEOK (3.25%) /  
|                                                   |                             | DL (1.71%) / DPL (2.60%) /  
|                                                   |                             | Dominion (13.32%) / EKPC  
|                                                   |                             | (1.89%) / JCPL (3.86%) / ME  
|                                                   |                             | (1.90%) / NEPTUNE* (0.42%) /  
|                                                   |                             | OVEC (0.08%) / PECO (5.40%) /  
|                                                   |                             | PENELEC (1.78%) / PEPCO  
|                                                   |                             | (3.67%) / PPL (4.72%) / PSEG  
|                                                   |                             | (6.39%) / RE (0.26%)  
|                                                   |                             | DFAX Allocation:  
|                                                   |                             | APS (22.57%) / BGE (7.27%) /  
|                                                   |                             | Dominion (56.77%) / PEPCO  
|                                                   |                             | (13.39%)  |

| Replace Meadow Brook 138 kV breaker ‘MD-17’ |                             | Load-Ratio Share Allocation:  
|                                            |                             | AEC (1.65%) / AEP (13.68%) /  
|                                            |                             | APS (5.76%) / ATSI (8.04%) /  
|                                            |                             | BGE (4.11%) / ComEd (13.39%) /  
|                                            |                             | Dayton (2.12%) / DEOK (3.25%) /  
|                                            |                             | DL (1.71%) / DPL (2.60%) /  
|                                            |                             | Dominion (13.32%) / EKPC  
|                                            |                             | (1.89%) / JCPL (3.86%) / ME  
|                                            |                             | (1.90%) / NEPTUNE* (0.42%) /  
|                                            |                             | OVEC (0.08%) / PECO (5.40%) /  
|                                            |                             | PENELEC (1.78%) / PEPCO  
|                                            |                             | (3.67%) / PPL (4.72%) / PSEG  
|                                            |                             | (6.39%) / RE (0.26%)  
|                                            |                             | DFAX Allocation:  
|                                            |                             | APS (22.57%) / BGE (7.27%) /  
|                                            |                             | Dominion (56.77%) / PEPCO  
|                                            |                             | (13.39%)  |

*Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<td>b0347.26 Replace Meadow Brook 138 kV breaker ‘MD-22#1 CAP’</td>
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<td>DFAX Allocation: APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tr>
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| Replace Meadow Brook 138 kV breaker ‘MD-4’ | **b0347.27** | **Load-Ratio Share Allocation:**
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**DFAX Allocation:**
APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)

| Replace Meadow Brook 138 kV breaker ‘MD-5’ | **b0347.28** | **Load-Ratio Share Allocation:**
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**DFAX Allocation:**
APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)

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Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<td>APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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<td>b0347.32 Replace Meadowbrook 138 kV breaker ‘MD-9’</td>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td>APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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<td>b0347.34 Replace Meadow Brook 138 kV breaker ‘MD-2’</td>
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<td>APS (100%)</td>
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<td>b0348 Upgrade Stonewall – Inwood 138 kV with 954 ACSR conductor</td>
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<td>APS (100%)</td>
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<td>b0373 Convert Doubs – Monocacy 138 kV facilities to 230 kV operation</td>
<td>AEC (1.82%) / APS (76.84%) / DPL (2.64%) / JCPL (4.53%) / ME (9.15%) / NEPTUNE* (0.42%) / PPL (4.60%)</td>
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<tr>
<td>b0393 Replace terminal equipment at Harrison 500 kV and Belmont 500 kV</td>
<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt;AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)&lt;br&gt;&lt;br&gt;&lt;br&gt;<strong>DFAX Allocation:</strong>&lt;br&gt;APS (1.47%) / Dayton (0.26%) / DEOK (0.44%) / DL (9.95%) / Dominion (87.75%) / EKPC (0.13%)</td>
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</table>

* Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b0407.1 Replace Marlowe 138 kV breaker “#1 transf”</td>
<td>APS (100%)</td>
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<tr>
<td>b0407.2 Replace Marlowe 138 kV breaker “MBO”</td>
<td>APS (100%)</td>
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<tr>
<td>b0407.3 Replace Marlowe 138 kV breaker “BMA”</td>
<td>APS (100%)</td>
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<td>b0407.4 Replace Marlowe 138 kV breaker “BMR”</td>
<td>APS (100%)</td>
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<tr>
<td>b0407.5 Replace Marlowe 138 kV breaker “WC-1”</td>
<td>APS (100%)</td>
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<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
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<tr>
<td>b0407.6 Replace Marlowe 138 kV breaker “R11”</td>
<td>APS (100%)</td>
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<tr>
<td>b0407.7 Replace Marlowe 138 kV breaker “W”</td>
<td>APS (100%)</td>
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<tr>
<td>b0407.8 Replace Marlowe 138 kV breaker “138 kV bus tie”</td>
<td>APS (100%)</td>
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<tr>
<td>b0408.1 Replace Trissler 138 kV breaker “Belmont 604”</td>
<td>APS (100%)</td>
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<tr>
<td>b0408.2 Replace Trissler 138 kV breaker “Edgelawn 90”</td>
<td>APS (100%)</td>
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<tr>
<td>b0409.1 Replace Weirton 138 kV breaker “Wylie Ridge 210”</td>
<td>APS (100%)</td>
<td></td>
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<tr>
<td>b0409.2 Replace Weirton 138 kV breaker “Wylie Ridge 216”</td>
<td>APS (100%)</td>
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<tr>
<td>b0410 Replace Glen Falls 138 kV breaker “McAlpin 30”</td>
<td>APS (100%)</td>
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<tr>
<td>Code</td>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
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<tr>
<td>b0419</td>
<td>Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers</td>
<td></td>
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<tr>
<td>b0420</td>
<td>Operating Procedure to open the Black Oak 500/138 kV transformer #3 for the loss of Hatfield – Ronco 500 kV and the Hatfield #3 Generation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0445</td>
<td>Upgrade substation equipment and reconductor the Tidd – Mahans Lane – Weirton 138 kV circuit with 954 ACSR</td>
<td>APS (100%)</td>
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</tbody>
</table>

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<tbody>
<tr>
<td>b0460 Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency</td>
<td>APS (100%)</td>
<td></td>
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</table>
| b0491 Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment) | As specified under the procedures detailed in Attachment H-19B | Load-Ratio Share Allocation:
AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%) |
|                                      |                           | DFX Allocation:
AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE* (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%) |

*Neptune Regional Transmission System, LLC
### Required Transmission Enhancements

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Description</th>
<th>Load-Ratio Share Allocation:</th>
<th>DFAX Allocation:</th>
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<tbody>
<tr>
<td>b0492</td>
<td>Construct a Welton Spring to Kemptown 765 kV line (APS equipment)</td>
<td>As specified under the procedures detailed in Attachment H-19B</td>
<td>AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE* (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)</td>
</tr>
<tr>
<td>b0492.3</td>
<td>Replace Eastalco 230 kV breaker D-26</td>
<td>APS (100%)</td>
<td>AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE* (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)</td>
</tr>
<tr>
<td>b0492.4</td>
<td>Replace Eastalco 230 kV breaker D-28</td>
<td>APS (100%)</td>
<td>AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE* (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)</td>
</tr>
</tbody>
</table>

*Neptune Regional Transmission System, LLC
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
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<tbody>
<tr>
<td>b0492.5 Replace Eastalco 230 kV breaker D-31</td>
<td>APS (100%)</td>
<td>Load-Ratio Share Allocation: AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (5.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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<tr>
<td>b0495 Replace existing Kammer 765/500 kV transformer with a new larger transformer</td>
<td>APS (100%)</td>
<td>DFAX Allocation: AEP (0.13%) / APS (0.13%) / BGE (15.93%) / Dayton (0.04%) / DEOK (0.06%) / Dominion (64.90%) / EKPC (0.02%) / PEPCO (18.79%)</td>
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<tr>
<td>b0533 Reconductor the Powell Mountain – Sutton 138 kV line</td>
<td>APS (100%)</td>
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<tr>
<td>b0534 Install a 28.61 MVAR capacitor on Sutton 138 kV</td>
<td>APS (100%)</td>
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<tr>
<td>b0536 Replace Doubs circuit breaker DJ1</td>
<td>APS (100%)</td>
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<tr>
<td>b0537 Replace Doubs circuit breaker DJ7</td>
<td>APS (100%)</td>
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<tr>
<td>b0538 Replace Doubs circuit breaker DJ10</td>
<td>APS (100%)</td>
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</tr>
<tr>
<td>b0539 Replace Doubs circuit breaker DJ11</td>
<td>APS (100%)</td>
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<tr>
<td>b0540 Replace Doubs circuit breaker DJ12</td>
<td>APS (100%)</td>
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<tr>
<td>b0541 Replace Doubs circuit breaker DJ13</td>
<td>APS (100%)</td>
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<tr>
<td>b0542 Replace Doubs circuit breaker DJ20</td>
<td>APS (100%)</td>
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</table>

* Neptune Regional Transmission System, LLC
# Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<th>Required Transmission Enhancements</th>
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</thead>
<tbody>
<tr>
<td>Replace Doubs circuit breaker DJ21</td>
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<td>APS (100%)</td>
</tr>
<tr>
<td>Remove instantaneous reclose from Eastalco circuit breaker D-26</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Install 200 MVAR capacitor at Meadow Brook 500 kV substation</td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / COMED (13.39%) / DAYTON (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / DOMINION (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td></td>
</tr>
<tr>
<td>Install 250 MVAR capacitor at Kemptown 500 kV substation</td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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* Neptune Regional Transmission System, LLC
**Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)**

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<tr>
<td>b0572.1</td>
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<td>APS (100%)</td>
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<tr>
<td>Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR</td>
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<td>APS (100%)</td>
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<tr>
<td>b0572.2</td>
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<td>APS (100%)</td>
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<tr>
<td>Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR</td>
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<td>APS (100%)</td>
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<tr>
<td>b0573</td>
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<td>APS (100%)</td>
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<tr>
<td>Reconfigure circuits in Butler – Cabot 138 kV area</td>
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<td>b0577</td>
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<td><strong>Load-Ratio Share Allocation:</strong></td>
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<tr>
<td>Replace Fort Martin 500 kV breaker FL-1</td>
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<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
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**DFAx Allocation:**
APS (100%)

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<tbody>
<tr>
<td><strong>b0588</strong> Install a 40.8 MVAR 138 kV capacitor at Grassy Falls</td>
<td></td>
<td>APS (100%)</td>
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<tr>
<td><strong>b0589</strong> Replace five 138 kV breakers at Cecil</td>
<td></td>
<td>APS (100%)</td>
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<tr>
<td><strong>b0591</strong> Install a 25.2 MVAR capacitor at Seneca Caverns 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b0674</strong> Construct new Osage – Whiteley 138 kV circuit</td>
<td>APS (97.68%) / DL (0.96%) / PENELEC (1.09%) / ECP** (0.01%) / PSEG (0.25%) / RE (0.01%)</td>
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<tr>
<td><strong>b0674.1</strong> Replace the Osage 138 kV breaker ‘CollinsF126’</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b0675.1</strong> Convert Monocacy - Walkersville 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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<tr>
<td><strong>b0675.2</strong> Convert Walkersville - Catoctin 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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<tr>
<td><strong>b0675.3</strong> Convert Ringgold - Catoctin 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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<tr>
<td><strong>b0675.4</strong> Convert Catoctin - Carroll 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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<tr>
<td><strong>b0675.5</strong> Convert portion of Ringgold Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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<tr>
<td><strong>b0675.6</strong> Convert Catoctin Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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<tr>
<td><strong>b0675.7</strong> Convert portion of Carroll Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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<tr>
<td><strong>b0675.8</strong> Convert Monocacy Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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<tr>
<td>b0675.9 Convert Walkersville Substation from 138 kV to 230 kV</td>
<td>AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.07%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)</td>
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<tr>
<td>b0676.1 Reconductor Doubs - Lime Kiln (#207) 230 kV</td>
<td>AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.83%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)</td>
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<tr>
<td>b0676.2 Reconductor Doubs - Lime Kiln (#231) 230 kV</td>
<td>AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.83%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)</td>
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<tr>
<td>b0677 Reconductor Double Toll Gate – Riverton with 954 ACSR</td>
<td>APS (100%)</td>
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<tr>
<td>b0678 Reconductor Glen Falls - Oak Mound 138 kV with 954 ACSR</td>
<td>APS (100%)</td>
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<tr>
<td>b0679 Reconductor Grand Point – Letterkenny with 954 ACSR</td>
<td>APS (100%)</td>
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<tr>
<td>b0680 Reconductor Greene – Letterkenny with 954 ACSR</td>
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<tbody>
<tr>
<td>b0685 Replace Ringgold 230/138 kV #3 with larger transformer</td>
<td>APS (71.93%) / JCPL (4.17%) / ME (6.79%) / NEPTUNE* (0.38%) / PECO (4.05%) / PENELEC (5.88%) / ECP** (0.18%) / PSEG (6.37%) / RE (0.25%)</td>
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<tr>
<td>b0797 Advance n0321 (Replace Doubs Circuit Breaker DJ2)</td>
<td>APS (100%)</td>
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<tr>
<td>b0798 Advance n0322 (Replace Doubs Circuit Breaker DJ3)</td>
<td>APS (100%)</td>
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<tr>
<td>b0799 Advance n0323 (Replace Doubs Circuit Breaker DJ6)</td>
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<tr>
<td>b0800 Advance n0327 (Replace Doubs Circuit Breaker DJ16)</td>
<td>APS (100%)</td>
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<tr>
<td>b0941 Replace Opequon 138 kV breaker 'BUSTIE'</td>
<td>APS (100%)</td>
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</tr>
<tr>
<td>b0956 Replace Pruntytown 138 kV breaker 'P-9'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0957 Replace Pruntytown 138 kV breaker 'P-12'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0958 Replace Pruntytown 138 kV breaker 'P-15'</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>

*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.
### Required Transmission Enhancements

<table>
<thead>
<tr>
<th>B0960</th>
<th>Replace Pruntytown 138 kV breaker 'P-2'</th>
<th>APS (100%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>B0961</td>
<td>Replace Pruntytown 138 kV breaker 'P-5'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>B0964</td>
<td>Replace Pruntytown 138 kV breaker 'P-11'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>B0966</td>
<td>Replace Pruntytown 138 kV breaker 'P-8'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>B0967</td>
<td>Replace Pruntytown 138 kV breaker 'P-14'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>B0968</td>
<td>Replace Ringgold 138 kV breaker '#3 XFMR BANK'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>B0970</td>
<td>Replace Rivesville 138 kV breaker '#8 XFMR BANK'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>B0972</td>
<td>Replace Belmont 138 kV breaker 'B-16'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>B0977</td>
<td>Replace Belmont 138 kV breaker 'B-17'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>B0984</td>
<td>Replace Rivesville 138 kV breaker '#10 XFMR BANK'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>B0985</td>
<td>Replace Belmont 138 kV breaker 'B-14'</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b0989 Replace Edgelawn 138 kV breaker 'GOFF RUN #632'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0991 Change reclosing on Belmont 138 kV breaker 'B-7'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0992 Change reclosing on Belmont 138 kV breaker 'B-12'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0993 Change reclosing on Belmont 138 kV breaker 'B-9'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0994 Change reclosing on Belmont 138 kV breaker 'B-19'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0995 Change reclosing on Belmont 138 kV breaker 'B-21'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0996 Change reclosing on Willow Island 138 kV breaker 'FAIRVIEW #84'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0999 Replace Redbud 138 kV breaker 'BUS TIE'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1022.1 Reconfigure the Peters to Bethel Park 138 kV line and Elrama to Woodville 138 kV line to create a 138 kV path from Woodville to Peters and a 138 kV path from Elrama to Bethel Park</td>
<td></td>
<td>APS (96.98%) / DL (3.02%)</td>
</tr>
<tr>
<td>b1023.3 Construct a new 502 Junction - Osage 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>-----------------------------------</td>
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</tr>
<tr>
<td>b1023.4 Construct Braddock 138 kV breaker station that connects the Charleroi - Gordon 138 kV line, Washington - Franklin 138 kV line and the Washington - Vanceville 138 kV line including a 66 MVAR capacitor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1028 Raise three structures on the Osage - Collins Ferry 138 kV line to increase the line rating</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1128 Reconduct the Edgewater – Vasco Tap; Edgewater – Loyalhanna 138 kV lines with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1129 Reconduct the East Waynesboro – Ringgold 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1131 Upgrade Double Tollgate – Meadowbrook MDT Terminal Equipment</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1132 Upgrade Double Tollgate-Meadowbrook MBG terminal equipment</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1133 Upgrade terminal equipment at Springdale</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1135 Reconduct the Bartonville – Meadowbrook 138 kV line with high temperature conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
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Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tr>
<td>b1137 Reconductor the Eastgate – Luxor 138 kV; Eastgate – Sony 138 kV line with 954 ACSR</td>
<td>APS (78.59%) / PENELEC (14.08%) / ECP** (0.23%) / PSEG (6.83%) / RE (0.27%)</td>
<td></td>
</tr>
<tr>
<td>b1138 Reconductor the King Farm – Sony 138 kV line with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1139 Reconductor the Yukon – Waltz Mills 138 kV line with high temperature conductor</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1140 Reconductor the Bracken Junction – Luxor 138 kV line with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1141 Reconductor the Sewickley – Waltz Mills Tap 138 kV line with high temperature conductor</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1142 Reconductor the Bartonville – Stephenson 138 kV; Stonewall – Stephenson 138 kV line with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1143 Reconductor the Youngwood – Yukon 138 kV line with high temperature conductor</td>
<td>APS (89.92%) / PENELEC (10.08%)</td>
<td></td>
</tr>
<tr>
<td>b1144 Reconductor the Bull Creek Junction – Cabot 138 kV line with high temperature conductor</td>
<td>APS (100%)</td>
<td></td>
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<tr>
<td>b1145 Reconductor the Lawson Junction – Cabot 138 kV line with high temperature conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1146 Replace Layton - Smithton #61 138 kV line structures to increase line rating</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1147 Replace Smith – Yukon 138 kV line structures to increase line rating</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1148 Reconductor the Loyalhanna – Luxor 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1149 Reconductor the Luxor – Stony Springs Junction 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1150 Upgrade terminal equipment at Social Hall</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1151 Reconductor the Greenwood – Redbud 138 kV line with 954 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1152 Reconductor Grand Point – South Chambersburg</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1162 Replace Double Toll Gate 138 kV breaker ‘DRB-2’</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1163 Replace Double Toll Gate 138 kV breaker ‘DT 138 kV OCB’</td>
<td></td>
<td>APS (100%)</td>
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</tbody>
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### Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tbody>
<tr>
<td><strong>b1166</strong> Replace Wylie Ridge 138 kV breaker ‘W-9’</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b1167</strong> Replace Reid 138 kV breaker ‘RI-2’</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b1171.1</strong> Install the second Black Oak 500/138 kV transformer, two 138 kV breaker, and related substation work</td>
<td></td>
<td>BGE (20.76%) / DPL (3.14%) / Dominion (39.55%) / ME (2.71%) / PECO (3.36%) / PEPCO (30.48%)</td>
</tr>
<tr>
<td><strong>b1171.3</strong> Install six 500 kV breakers and remove BOL1 500 kV breaker at Black Oak</td>
<td></td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td><strong>b1200</strong> Reconductor Double Toll Gate – Greenwood 138 kV with 954 ACSR conductor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b1221.1</strong> Convert Carbon Center from 138 kV to a 230 kV ring bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b1221.2</strong> Construct Bear Run 230 kV substation with 230/138 kV transformer</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>

*Neptune Regional Transmission System, LLC*
## Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<th>Required Transmission Enhancements</th>
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</tr>
</thead>
<tbody>
<tr>
<td>b1221.3 Loop Carbon Center Junction – Williamette line into Bear Run</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1221.4 Carbon Center – Carbon Center Junction &amp; Carbon Center Junction – Bear Run conversion from 138 kV to 230 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1230 Reconductor Willow-Eureka &amp; Eureka-St Mary 138 kV lines</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1232 Reconductor Nipetown – Reid 138 kV with 1033 ACCR</td>
<td>AEC (1.40%) / APS (75.74%) / DPL (1.92%) / JCP (2.92%) / ME (6.10%) / Neptune* (0.27%) / PECO (4.40%) / PENELEC (3.26%) / PPL (3.99%)</td>
<td></td>
</tr>
<tr>
<td>b1233.1 Upgrade terminal equipment at Washington</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1234 Replace structures between Ridgeway and Paper city</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1235 Reconductor the Albright – Black Oak AFA 138 kV line with 795 ACSS/TW</td>
<td>APS (30.25%) / BGE (16.10%) / Dominion (30.51%) / PEPCO (23.14%)</td>
<td></td>
</tr>
<tr>
<td>b1237 Upgrade terminal equipment at Albright, replace bus and line side breaker disconnects and leads, replace breaker risers, upgrade RTU and line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1238 Install a 138 kV 44 MVAR capacitor at Edgelawn substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>

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Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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</thead>
<tbody>
<tr>
<td>b1239 Install a 138 kV 44 MVAR capacitor at Ridgeway substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1240 Install a 138 kV 44 MVAR capacitor at Elko Substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1241 Upgrade terminal equipment at Washington substation on the GE Plastics/DuPont terminal</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1242 Replace structures between Collins Ferry and West Run</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1384 Reconductor approximately 2.17 miles of Bedington – Shepherdstown 138 kV with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1385 Reconductor Halfway – Paramount 138 kV with 1033 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1386 Reconductor Double Tollgate – Meadow Brook 138 kV ckt 2 with 1033 ACSR</td>
<td>APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)</td>
<td></td>
</tr>
<tr>
<td>b1387 Reconductor Double Tollgate – Meadow Brook 138 kV</td>
<td>APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)</td>
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</tr>
<tr>
<td>b1388 Reconductor Feagans Mill – Millville 138 kV with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>----------------------------------------------------------------------</td>
<td>----------------------------------------------------------</td>
<td>-------------------------</td>
</tr>
<tr>
<td>b1389 Reconductors Bens Run – St. Mary’s 138 kV with 954 ACSR</td>
<td>AEP (12.40%) / APS (17.80%) / DL (69.80%)</td>
<td></td>
</tr>
<tr>
<td>b1390 Replace Bus Tie Breaker at Opequon</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1391 Replace Line Trap at Gore</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1392 Replace structure on Belmont – Trissler 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1393 Replace structures Kingwood – Pruntytown 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1395 Upgrade Terminal Equipment at Kittanning</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1401 Change reclosing on Pruntytown 138 kV breaker ‘P-16’ to 1 shot</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>at 15 seconds</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b1402 Change reclosing on Rivesville 138 kV breaker ‘Pruntytown #34’</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>to 1 shot at 15 seconds</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>------------------------------------------------------------------------</td>
<td>----------------------------</td>
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</tr>
<tr>
<td>Replace the Weirton 138 kV breaker ‘Tidd 224’ with a 40 kA breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Terminal Equipment upgrade at Doubs substation</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Load-Ratio Share Allocation:**
- AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%) |

**DFAX Allocation:**
- APS (16.11%) / BGE (13.32%) / Dominion (55.42%) / PEPCO (15.15%) |

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Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tr>
<td>b1507.3 Mt. Storm – Doubs transmission line rebuild in Maryland – Total line mileage for APS is 2.71 miles</td>
<td></td>
<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt;AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td>b1510 Install 59.4 MVAR capacitor at Waverly</td>
<td></td>
<td><strong>DFAX Allocation:</strong>&lt;br&gt;APS (16.11%) / BGE (13.32%) / Dominion (55.42%) / PEPCO (15.15%)</td>
</tr>
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<tr>
<td><strong>b1803</strong></td>
<td></td>
<td><strong>Load-Ratio Share Allocation:</strong></td>
</tr>
<tr>
<td>Build a 300 MVAR Switched Shunt at Doubs 500 kV and increase (~50 MVAR) in size the existing Switched Shunt at Doubs 500 kV</td>
<td></td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td><strong>b1804</strong></td>
<td></td>
<td><strong>DFAX Allocation:</strong></td>
</tr>
<tr>
<td>Install a new 600 MVAR SVC at Meadowbrook 500 kV</td>
<td></td>
<td>APS (16.11%) / BGE (13.32%) / Dominion (55.42%) / PEPCO (15.15%)</td>
</tr>
<tr>
<td><strong>b1816.1</strong></td>
<td></td>
<td><strong>Load-Ratio Share Allocation:</strong></td>
</tr>
<tr>
<td>Replace relaying at the Mt. Airy substation on the Carroll - Mt. Airy 230 kV line</td>
<td></td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>DFAX Allocation:</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td>APS (22.57%) / BGE (7.27%) / Dominion (56.77%) / PEPCO (13.39%)</td>
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Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tbody>
<tr>
<td>b1816.2 Adjust the control settings of all existing capacitors at Mt Airy 34.5 kV, Monocacy 138 kV, Ringgold 138 kV served by Potomac Edison's Eastern 230 kV network to ensure that all units will be on during the identified N-1-1 contingencies</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1816.3 Replace existing unidirectional LTC controller on the No. 4, 230/138 kV transformer at Carroll substation with a bidirectional unit</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1816.4 Isolate and bypass the 138 kV reactor at Germantown Substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1816.6 Replace 336.4 ACSR conductor on the Catoctin - Carroll 138 kV line using 556.5 ACSR (26/7) or equivalent on existing structures (12.7 miles), 800 A wave traps at Carroll and Catoctin with 1200 A units, and 556.5 ACSR SCCIR (Sub-conductor) line risers and bus traps with 795 ACSR or equivalent</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>-----------------------------------</td>
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</tr>
<tr>
<td>b1822</td>
<td>Replace the 1200 A wave trap, line risers, breaker risers with 1600 A capacity terminal equipment at Reid 138 kV SS</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1823</td>
<td>Replace the 800 A wave trap with a 1200 A wave trap at Millville 138 kV substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1824</td>
<td>Reconductor Grant Point - Guilford 138 kV line approximately 8 miles of 556 ACSR with 795 ACSR</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1826</td>
<td>Change the CT ratio at Double Toll Gate 138 kV SS on MDT line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1827</td>
<td>Change the CT ratio at Double Toll Gate 138 kV SS on MBG line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1828.1</td>
<td>Reconductor the Bartonville – Stephenson 3.03 mile 138 kV line of 556 ACSR with 795 ACSR</td>
<td>APS (100%)</td>
</tr>
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### Required Transmission Enhancements

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<tbody>
<tr>
<td>b1828.2</td>
<td>Reconductor the Stonewall – Stephenson 2.08 mile 138 kV line of 556 ACSR with 795 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1829</td>
<td>Replace the existing 138 kV 556.5 ACSR substation conductor risers with 954 ACSR at the Redbud 138 kV substation, including but not limited to the line side disconnect leads</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1830</td>
<td>Replace 1200 A wave trap and 1024 ACAR breaker risers at Halfway 138 kV substation, and replace 1024 ACAR breaker risers at Paramount 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1832</td>
<td>Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 1 (207) 230 kV line terminal</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1833</td>
<td>Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 2 (231) 230 kV line terminal</td>
<td></td>
<td>APS (100%)</td>
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### Required Transmission Enhancements

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</thead>
<tbody>
<tr>
<td>b1835</td>
<td>Reconductor 14.3 miles of 556 ACSR with 795 ACSR from Old Chapel to Millville 138 kV and upgrade line risers at Old Chapel 138 kV and Millville 138 kV and replace 1200 A wave trap at Millville 138 kV</td>
<td>APS (37.68%) / Dominion (34.46%) / PEPCO (13.69%) / BGE (11.45%) / ME (2.01%) / PENELEC (0.53%) / DL (0.18%)</td>
</tr>
<tr>
<td>b1836</td>
<td>Replace 1200 A wave trap with 1600 A wave trap at Reid 138 kV SS</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1837</td>
<td>Replace 750 CU breaker risers with 795 ACSR at Marlowe 138 kV and replace 1200 A wave traps with 1600 A wave traps at Marlowe 138 kV and Bedington 138 kV</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1838</td>
<td>Replace the 1200 A Bedington 138 kV line air switch and the 1200 A 138 kV bus tie air switch at Nipetown 138 kV with 1600 A switches</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tr>
<th>Required Transmission Enhancements</th>
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<tbody>
<tr>
<td>b1840</td>
<td>Construct a 138 kV line between Buckhannon and Weston 138 kV substations</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1902</td>
<td>Replace line trap at Stonewall on the Stephenson 138 kV line terminal</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1942</td>
<td>Change the CT ratio at Millville to improve the Millville – Old Chapel 138 kV line ratings</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1987</td>
<td>Reconductor the Osage-Collins Ferry 138 kV line with 795 ACSS. Upgrade terminal equipment at Osage and Collins Ferry</td>
<td>APS (100%)</td>
</tr>
</tbody>
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<tbody>
<tr>
<td>Raise structures between Lake Lynn and West Run to eliminate the clearance de-rates on the West Run – Lake Lynn 138 kV line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Raise structures between Collins Ferry and West Run to eliminate the clearance de-rates on the Collins Ferry - West Run 138 kV line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Weirt 138 kV breaker 'S-TORONTO226' with 63 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Revise the reclosing of Weirt 138 kV breaker '2&amp;5 XFMR'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Ridgeley 138 kV breaker '2 XFMR OCB'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Revise the reclosing of Ridgeley 138 kV breaker 'AR3' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Revise the reclosing of Ridgeley 138 kV breaker 'RC1'</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Ridgeley 138 kV breaker 'WC4' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Ridgeley 138 kV breaker '1 XFMR OCB' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
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</tr>
<tr>
<td><strong>b2106</strong> Replace Wylie Ridge 345 kV breaker 'WK-1' with 63 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2107</strong> Replace Wylie Ridge 345 kV breaker 'WK-2' with 63 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2108</strong> Replace Wylie Ridge 345 kV breaker 'WK-3' with 63 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2109</strong> Replace Wylie Ridge 345 kV breaker 'WK-4' with 63 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2110</strong> Replace Wylie Ridge 345 kV breaker 'WK-5' with 63 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2111</strong> Replace Wylie Ridge 138 kV breaker 'WK-7' with 63 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2112</strong> Replace Wylie Ridge 345 kV breaker 'WK-5'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2113</strong> Replace Weirton 138 kV breaker 'NO 6 XFMR' with 63 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2114</strong> Replace Armstrong 138 kV breaker 'Bus-Tie' (Status On-Hold pending retirement)</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tbody>
<tr>
<td>b2124.1 Add a new 138 kV line exit</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2124.2 Construct a 138 kV ring bus and install a 138/69 kV autotransformer</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2124.4 Construct approximately 5.5 miles of 138 kV line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2165 Replace 800A wave trap at Stonewall with a 1200 A wave trap</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2166 Reconductor the Millville – Sleepy Hollow 138 kV 4.25 miles of 556 ACSR with 795 ACSR, upgrade line risers at Sleepy Hollow, and change 1200 A CT tap at Millville to 800</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b2168 For Grassy Falls 138 kV Capacitor bank adjust turn-on voltage to 1.0 pu with a high limit of 1.04 pu, For Crupperneck and Powell Mountain 138 kV Capacitor Banks adjust turn-on voltage to 1.01 pu with a high limit of 1.035 pu</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
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<td>Responsible Customer(s)</td>
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<tr>
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</tr>
<tr>
<td>b2171 Replace/Raise structures on the Parsons-William 138 kV line section to eliminate clearance de-rate</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2172 Replace/Raise structures on the Parsons - Loughs Lane 138 kV line section to eliminate clearance de-rate</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
### Required Transmission Enhancements

<table>
<thead>
<tr>
<th>Scheduled Enhancement</th>
<th>Description</th>
<th>Load-Ratio Share Allocation</th>
<th>DFAX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>b0347.1</strong></td>
<td>Build new Mt. Storm – 502 Junction 500 kV circuit</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
</tr>
<tr>
<td><strong>b0347.3</strong></td>
<td>Build new 502 Junction 500 kV substation</td>
<td>As specified under the procedures detailed in Attachment H-18B, Section 1.b</td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
</tr>
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</tr>
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<tbody>
<tr>
<td>b0347.10</td>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
</tr>
<tr>
<td>b0347.11</td>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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<tbody>
<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4</td>
<td><strong>Load-Ratio Share Allocation:</strong></td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6</td>
<td><strong>DFAX Allocation:</strong></td>
<td>APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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<tbody>
<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7</td>
<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt;AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)&lt;br&gt;&lt;br&gt;<strong>DFAX Allocation:</strong>&lt;br&gt;APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)&lt;br&gt;</td>
<td></td>
</tr>
<tr>
<td>Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9</td>
<td><strong>Load-Ratio Share Allocation:</strong>&lt;br&gt;AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)&lt;br&gt;&lt;br&gt;<strong>DFAX Allocation:</strong>&lt;br&gt;APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)&lt;br&gt;</td>
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* Neptune Regional Transmission System, LLC
### Keystone Appalachian Transmission Company (cont.)

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</tr>
</thead>
<tbody>
<tr>
<td><strong>b0347.16</strong> Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'</td>
<td></td>
<td><strong>Load-Ratio Share Allocation:</strong> AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>DFAX Allocation:</strong> APS (28.94%) / BGE (13.78%) / Dominion (32.18%) / PEPCO (25.10%)</td>
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**Keystone Appalachian Transmission Company (cont.)**

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<tbody>
<tr>
<td>b0406.1  Replace Mitchell 138 kV breaker “#4 bank”</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0406.2  Replace Mitchell 138 kV breaker “#5 bank”</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0406.3  Replace Mitchell 138 kV breaker “#2 transf”</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0406.4  Replace Mitchell 138 kV breaker “#3 bank”</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0406.5  Replace Mitchell 138 kV breaker “Charlerio #2”</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0406.6  Replace Mitchell 138 kV breaker “Charlerio #1”</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0406.7  Replace Mitchell 138 kV breaker “Shepler Hill Jct”</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0406.8  Replace Mitchell 138 kV breaker “Union Jct”</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0406.9  Replace Mitchell 138 kV breaker “#1-2 138 kV bus tie”</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0417  Recondorctor Mitchell – Shepler Hill Junction 138 kV with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0418  Install a breaker failure auto-restoration scheme at Cabot 500 kV for the failure of the #6 breaker</td>
<td>AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / DPL (2.60%) / Dominion (13.32%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PEPCO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%)</td>
<td></td>
</tr>
<tr>
<td>b0460  Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency</td>
<td>APS (100%)</td>
<td></td>
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<tbody>
<tr>
<td>b0535</td>
<td>Install a 44 MVAR capacitor on Dutch Fork 138 kV</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0584</td>
<td>Install 33 MVAR 138 kV capacitor at Necessity 138 kV</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0585</td>
<td>Increase Cecil 138 kV capacitor size to 44 MVAR, replace five 138 kV breakers at Cecil due to increased short circuit fault duty as a result of the addition of the Prexy substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0586</td>
<td>Increase Whiteley 138 kV capacitor size to 44 MVAR</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0587</td>
<td>Recondutor AP portion of Tidd – Carnegie 138 kV and Carnegie – Weirton 138 kV with 954 ACSR</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0590</td>
<td>Replace #1 and #2 breakers at Charleroi 138 kV</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>

* Neptune Regional Transmission System, LLC
Keystone Appalachian Transmission Company (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
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</tr>
</thead>
<tbody>
<tr>
<td>b0673 Rebuild Elko – Carbon Center Junction using 230 kV construction</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0681 Replace 600/5 CT’s at Franklin 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0682 Replace 600/5 CT’s at Whiteley 138 kV</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b0684 Reconductor Guilford – South Chambersburg with 954 ACSR</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>
Keystone Appalachian Transmission Company (cont.)

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</tr>
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<tbody>
<tr>
<td>b0704 Install a third Cabot 500/138 kV transformer</td>
<td>APS (74.36%) / DL (2.73%) PENELEC (22.91%)</td>
<td></td>
</tr>
<tr>
<td>b0942 Replace Butler 138 kV breaker '1 BANK'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0943 Replace Butler 138 kV breaker '2 BANK'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0944 Replace Yukon 138 kV breaker 'Y-8'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0945 Replace Yukon 138 kV breaker 'Y-3'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0946 Replace Yukon 138 kV breaker 'Y-1'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0947 Replace Yukon 138 kV breaker 'Y-5'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0948 Replace Yukon 138 kV breaker 'Y-2'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0949 Replace Yukon 138 kV breaker 'Y-19'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0950 Replace Yukon 138 kV breaker 'Y-4'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0951 Replace Yukon 138 kV breaker 'Y-9'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0952 Replace Yukon 138 kV breaker 'Y-11'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0953 Replace Yukon 138 kV breaker 'Y-13'</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0954 Replace Charleroi 138 kV breaker '#1 XFMR BANK'</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
### Required Transmission Enhancements

<table>
<thead>
<tr>
<th>Code</th>
<th>Description</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b0955</td>
<td>Replace Yukon 138 kV breaker 'Y-7'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0959</td>
<td>Replace Charleroi 138 kV breaker '2 XFMR BANK'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0962</td>
<td>Replace Yukon 138 kV breaker 'Y-18'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0963</td>
<td>Replace Yukon 138 kV breaker 'Y-10'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0965</td>
<td>Replace Springdale 138 kV breaker '138E'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0969</td>
<td>Replace Springdale 138 kV breaker '138C'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0971</td>
<td>Replace Springdale 138 kV breaker '138F'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0973</td>
<td>Replace Springdale 138 kV breaker '138G'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0974</td>
<td>Replace Springdale 138 kV breaker '138V'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0975</td>
<td>Replace Armstrong 138 kV breaker 'BROOKVILLE'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0976</td>
<td>Replace Springdale 138 kV breaker '138P'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0978</td>
<td>Replace Springdale 138 kV breaker '138U'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0979</td>
<td>Replace Springdale 138 kV breaker '138D'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0980</td>
<td>Replace Springdale 138 kV breaker '138R'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0981</td>
<td>Replace Yukon 138 kV breaker 'Y-12'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0982</td>
<td>Replace Yukon 138 kV breaker 'Y-17'</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b0983</td>
<td>Replace Yukon 138 kV breaker 'Y-14'</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Keystone Appalachian Transmission Company (cont.)

Required Transmission Enhancements | Annual Revenue Requirement | Responsible Customer(s)
--- | --- | ---
b0986 | Replace Armstrong 138 kV breaker 'RESERVE BUS' | APS (100%)
b0987 | Replace Yukon 138 kV breaker 'Y-16' | APS (100%)
b0988 | Replace Springdale 138 kV breaker '138T' | APS (100%)
b0990 | Change reclosing on Cabot 138 kV breaker 'C-9' | APS (100%)
b0997 | Change reclosing on Cabot 138 kV breaker 'C-4' | APS (100%)
b0998 | Change reclosing on Cabot 138 kV breaker 'C-1' | APS (100%)
b1022.3 | Add static capacitors at Smith 138 kV | APS (96.98%) / DL (3.02%)
b1022.4 | Add static capacitors at North Fayette 138 kV | APS (96.98%) / DL (3.02%)
b1022.5 | Add static capacitors at South Fayette 138 kV | APS (96.98%) / DL (3.02%)
b1022.6 | Add static capacitors at Manifold 138 kV | APS (96.98%) / DL (3.02%)
b1022.7 | Add static capacitors at Houston 138 kV | APS (96.98%) / DL (3.02%)
b1023.1 | Install a 500/138 kV transformer at 502 Junction | APS (100%)
b1023.2 | Construct a new Franklin - 502 Junction 138 kV line including a rebuild of the Whiteley - Franklin 138 kV line to double circuit | APS (100%)
b1027 | Increase the size of the shunt capacitors at Enon 138 kV | APS (100%)
b1159 | Replace Peters 138 kV breaker ‘Bethel P OCB’ | APS (100%)
b1160 | Replace Peters 138 kV breaker ‘Cecil OCB’ | APS (100%)
b1161 | Replace Peters 138 kV breaker ‘Union JctOCB’ | APS (100%)
b1164 | Replace Cecil 138 kV breaker ‘Enlow OCB’ | APS (100%)
### Keystone Appalachian Transmission Company (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
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</tr>
</thead>
<tbody>
<tr>
<td>b1165 Replace Cecil 138 kV breaker ‘South Fayette’</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1243 Install a 138 kV capacitor at Potter Substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1261 Replace Butler 138 kV breaker ‘1-2 BUS 138’</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1383 Install 2nd 500/138 kV transformer at 502 Junction</td>
<td>APS (93.27%) / DL (5.39%) / PENELEC (1.34%)</td>
<td></td>
</tr>
<tr>
<td>b1403 Change reclosing on Yukon 138 kV breaker ‘Y21 Shepler’ to 1 shot at 15 seconds</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b1404 Replace the Kiski Valley 138 kV breaker ‘Vandergrift’ with a 40 kA breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1405 Change reclosing on Armstrong 138 kV breaker ‘GARETTRJCT’ at 1 shot at 15 seconds</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1406 Change reclosing on Armstrong 138 kV breaker ‘KITTANNING’ to 1 shot at 15 seconds</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1407 Change reclosing on Armstrong 138 kV breaker ‘BURMA’ to 1 shot at 15 seconds</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>b1409 Replace the Cabot 138 kV breaker ‘C9 Kiski Valley’ with a 40 kA breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-----------------------------</td>
<td>-------------------------</td>
</tr>
<tr>
<td>Install a 230 kV breaker at Carbon Center</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace the 800 Amp line trap at Butler 138 kV Sub on the Cabot East 138 kV line</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Install additional 33 MVAR capacitors at Grand Point 138 kV SS and Guildford 138 kV SS</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Loop the Homer City-Handsome Lake 345 kV line into the Armstrong substation and install a 345/138 kV transformer at Armstrong</td>
<td>APS (67.86%) / PENELEC (32.14%)</td>
<td></td>
</tr>
<tr>
<td>Convert Moshannon substation to a 4 breaker 230 kV ring bus</td>
<td>APS (41.06%) / DPL (6.68%) / JCPL (5.48%) / ME (10.70%) / NEPTUNE* (0.53%) / PECO (15.53%) / PPL (20.02%)</td>
<td></td>
</tr>
<tr>
<td>Install a 44 MVAR 138 kV capacitor at Luxor substation</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Upgrade the AP portion of the Elrama – Mitchell 138 kV line by replace breaker risers on the Mitchell 138 kV bus on the Elrama terminal</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Armstrong 138 kV breaker 'GARETTRJCT' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Armstrong 138 kV breaker 'BURMA' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Armstrong 138 kV breaker 'KITTANNING' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
<tr>
<td>Replace Armstrong 138 kV breaker 'KISSINGERJCT' with 40 kA rated breaker</td>
<td>APS (100%)</td>
<td></td>
</tr>
</tbody>
</table>

* Neptune Regional Transmission System, LLC
### Keystone Appalachian Transmission Company (cont.)

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<tr>
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<tbody>
<tr>
<td>b2124.3 Add new 138 kV line exit and install a 138/25 kV transformer</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2124.5 Convert approximately 7.5 miles of 69 kV to 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2156 Install a 75 MVAR 230 kV capacitor at Shingletown Substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2169 Replace/Raise structures on the Yukon-Smithton 138 kV line section to eliminate clearance de-rate</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2170 Replace/Raise structures on the Smithton-Shepler Hill Jct 138 kV line section to eliminate clearance de-rate</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
SCHEDULE 12 – APPENDIX A

(14) **Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power**

<table>
<thead>
<tr>
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<tbody>
<tr>
<td>b2117</td>
<td>Reconductor 0.33 miles of the Parkersburg - Belpre line and upgrade Parkersburg terminal equipment</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2118</td>
<td>Add 44 MVAR Cap at New Martinsville</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2142</td>
<td>Replace Weirton 138 kV breaker “Wylie Ridge 210” with 63 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2143</td>
<td>Replace Weirton 138 kV breaker “Wylie Ridge 216” with 63 kA breaker</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2214</td>
<td>Albright Substation: Install a new control building in the switchyard and relocate controls and SCADA equipment from the generating station building to the new control center</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2215</td>
<td>Rivesville Switching Station: Relocate controls and SCADA equipment from the generating station building to new control building</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tbody>
<tr>
<td>b2216 Willow Island: Install a new 138 kV cross bus at Belmont Substation and reconnect and reconfigure the 138 kV lines to facilitate removal of the equipment at Willow Island switching station</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2235 130 MVAR reactor at Monocacy 230 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2260 Install a 32.4 MVAR capacitor at Bartonville</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2261 Install a 33 MVAR capacitor at Damascus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2267 Replace 1000 Cu substation conductor and 1200 amp wave trap at Marlowe</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2268 Reconductor 6.8 miles of 138kV 336 ACSR with 336 ACSS from Double Toll Gate to Riverton</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2299 Reconductor from Collins Ferry - West Run 138 kV with 556 ACSS</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2300 Reconductor from Lake Lynn - West Run 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2342 Construct a new 138 kV switching station (Shuman Hill substation), which is next the Mobley 138 kV substation and install a 31.7 MVAR capacitor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2343 Install a 31.7 MVAR capacitor at West Union 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tbody>
<tr>
<td>b2433.1 Install breaker and a half 138 kV substation (Waldo Run) with 4 breakers to accommodate service to MarkWest Sherwood Facility including metering which is cut into Glen Falls Lamberton 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2433.2 Install a 70 MVAR SVC at the new WaldoRun 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2433.3 Install two 31.7 MVAR capacitors at the new WaldoRun 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2424 Replace the Weirton 138 kV breaker 'WYLIE RID210' with 63 kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2425 Replace the Weirton 138 kV breaker 'WYLIE RID216' with 63 kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
**Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)**

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<tbody>
<tr>
<td>b2426 Replace the Oak Grove 138 kV breaker 'OG1' with 63 kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2427 Replace the Oak Grove 138 kV breaker 'OG2' with 63 kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2428 Replace the Oak Grove 138 kV breaker 'OG3' with 63 kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2429 Replace the Oak Grove 138 kV breaker 'OG4' with 63 kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2430 Replace the Oak Grove 138 kV breaker 'OG5' with 63 kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2431 Replace the Oak Grove 138 kV breaker 'OG6' with 63 kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2432 Replace the Ridgeley 138 kV breaker 'RC1' with a 40 kA rated breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2472 Replace the Ringgold 138 kV breaker ‘RCM1’ with 40kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2473 Replace the Ringgold 138 kV breaker ‘#4 XMFR’ with 40kA breakers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2475 Construct a new line between Oak Mound 138 kV substation and Waldo Run 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2545.1 Construct a new 138 kV substation (Shuman Hill substation) connected to the Fairview –Willow Island (84) 138 kV line</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-----------------------------</td>
<td>------------------------</td>
</tr>
<tr>
<td><strong>b2545.2</strong> Install a ring bus station with five active positions and two 52.8 MVAR capacitors with 0.941 mH reactors</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2545.3</strong> Install a +90/-30 MVAR SVC protected by a 138 kV breaker</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2545.4</strong> Remove the 31.7 MVAR capacitor bank at Mobley 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2548</strong> Eliminate clearance de-rate on Wylie Ridge – Smith 138 kV line and upgrade terminals at Smith 138 kV, new line ratings 294 MVA (Rate A)/350 MVA (Rate B)</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2672</strong> Change CT Ratio at Seneca Caverns from 120/1 to 160/1 and adjust relay settings accordingly</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2688.3</strong> Carroll Substation: Replace the Germantown 138 kV wave trap, upgrade the bus conductor and adjust CT ratios</td>
<td>AEP (12.91%) / APS (19.04%) / ATSI (1.24%) / ComEd (0.35%) / Dayton (1.45%) / DEOK (2.30%) / DL (1.11%) / Dominion (44.85%) / EKPC (0.78%) / PEPCO (15.85%) / RECO (0.12%)</td>
<td></td>
</tr>
<tr>
<td><strong>b2700</strong> Remove existing Black Oak SPS</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2743.6</strong> Reconfigure the Ringgold 230 kV substation to double bus double breaker scheme</td>
<td>AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)</td>
<td></td>
</tr>
</tbody>
</table>
### Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tr>
<th>Required Transmission Enhancements</th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>b2743.6.1</strong> Replace the two Ringgold 230/138 kV transformers</td>
<td></td>
<td>AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)</td>
</tr>
<tr>
<td><strong>b2743.7</strong> Rebuild/Reconductor the Ringgold – Catoctin 138 kV circuit and upgrade terminal equipment on both ends</td>
<td></td>
<td>AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)</td>
</tr>
<tr>
<td><strong>b2747.1</strong> Relocate the FirstEnergy Pratts 138 kV terminal CVTs at Gordonsville substation to allow for the installation of a new motor operated switch being installed by Dominion</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2764</strong> Upgrade Fairview 138 kV breaker risers and disconnect leads; Replace 500 CU breaker risers and 556 ACSR disconnect leads with 795 ACSR</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2964.1</strong> Replace terminal equipment at Pruntytown and Glen Falls 138 kV station</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td><strong>b2964.2</strong> Reconductor approximately 8.3 miles of the McAlpin - White Hall Junction 138 kV circuit</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
### Required Transmission Enhancements

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Description</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b2970</td>
<td>Ringgold – Catoctin Solution</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2970.1</td>
<td>Install two new 230 kV positions at Ringgold for 230/138 kV transformers</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2970.2</td>
<td>Install new 230 kV position for Ringgold – Catoctin 230 kV line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2970.3</td>
<td>Install one new 230 kV breaker at Catoctin substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2970.4</td>
<td>Install new 230/138 kV transformer at Catoctin substation. Convert Ringgold – Catoctin 138 kV line to 230 kV operation</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
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<tbody>
<tr>
<td>b2970.5 Convert Garfield 138/12.5 kV substation to 230/12.5 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2996 Construct new Flint Run 500/138 kV substation</td>
<td></td>
<td>See sub-IDs for cost allocations</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2996.1 Construct a new 500/138 kV substation as a 4-breaker ring bus with expansion plans for double-breaker-double-bus on the 500 kV bus and breaker-and-a-half on the 138 kV bus to provide EHV source to the Marcellus shale load growth area. Projected load growth of additional 160 MVA to current plan of 280 MVA, for a total load of 440 MVA served from Waldo Run substation. Construct additional 3-breaker string at Waldo Run 138 kV bus. Relocate the Sherwood #2 line terminal to the new string. Construct two single circuit Flint Run - Waldo Run 138 kV lines using 795 ACSR (approximately 3 miles). After terminal relocation on new 3-breaker string at Waldo Run, terminate new Flint Run 138 kV lines onto the two open terminals</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2996.2 Loop the Belmont – Harrison 500 kV line into and out of the new Flint Run 500 kV substation (less than 1 mile). Replace primary relaying and carrier sets on Belmont and Harrison 500 kV remote end substations</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2996.3 Upgrade two (2) existing 138 kV breakers (Rider 50 and #1/4 transformer breaker) at Glen Falls with 63 kA 3000A units</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tr>
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<tbody>
<tr>
<td>b3028 Upgrade substation disconnect leads at William 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3051.1 Ronceverte cap bank and terminal upgrades</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3052 Install a 138 kV capacitor (29.7 MVAR effective) at West Winchester 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3079 Replace the Wylie Ridge 500/345 kV transformer #7</td>
<td></td>
<td>ATSI (72.30%) / DL (27.70%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tr>
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<tbody>
<tr>
<td>b3128 Relocate 34.5 kV lines from generating station roof R. Paul Smith 138 kV station</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3240 Upgrade Cherry Run and Morgan terminals to make the transmission line the limiting component</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3241 Install 138 kV, 36 MVAR capacitor and a 5 uF reactor protected by a 138 kV capacitor switcher. Install a breaker on the 138 kV Junction terminal. Install a 138 kV 3.5 uF reactor on the existing Hardy 138 kV capacitor</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3242 Reconfigure Stonewall 138 kV substation from its current configuration to a six-breaker, breaker-and-a-half layout and add two (2) 36 MVAR capacitors with capacitor switchers</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3683 Reconductor the existing 556.5 ACSR line segments on the Messick Road – Ridgeley 138 kV line with 954 45/7 ACSR to achieve 308/376 MVA SN/SE and 349/445 MVA WN/WE ratings. Replace the remote end equipment for the line. The total length of the line is 5.02 miles</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3701 Replace terminal equipment at French's Mill and Junction 138 kV substations</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power (cont.)

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<tbody>
<tr>
<td>At Bedington substation: Replace substation conductor, wave trap, Current Transformers (CT's) and upgrade relaying At Cherry Run substation: Replace substation conductor, wave trap, CT's, disconnect switches, circuit breaker and upgrade relaying At Marlowe substation: Replace substation conductor, wave trap, CT's and upgrade relaying</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Install redundant relaying at Meadow Brook 500 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Install redundant relaying at Bedington 500 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor 27.3 miles of the Messick Road – Morgan 138 kV line from 556 ACSR to 954 ACSR. At Messick Road substation, replace 138 kV wave trap, circuit breaker, CT's, disconnect switch, and substation conductor and upgrade relaying. At Morgan substation, upgrade relaying</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
### Keystone Appalachian Transmission Company

<table>
<thead>
<tr>
<th>Task Number</th>
<th>Description</th>
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</tr>
</thead>
<tbody>
<tr>
<td>b2120</td>
<td>Six-Wire Lake Lynn - Lardin 138 kV circuits</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2174.8</td>
<td>Replace relays at Mitchell substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2174.9</td>
<td>Replace primary relay at Piney Fork substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2174.10</td>
<td>Perform relay setting changes at Bethel Park substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2213</td>
<td>Armstrong Substation: Relocate 138 kV controls from the generating station building to new control building</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2300</td>
<td>Reconductor from Lake Lynn - West Run 138 kV</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2341</td>
<td>Install 39.6 MVAR Capacitor at Shaffers Corner 138 kV Substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2362</td>
<td>Install a 250 MVAR SVC at Squab Hollow 230 kV</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2362.1</td>
<td>Install a 230 kV breaker at Squab Hollow 230 kV Substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2363</td>
<td>Convert the Shingletown 230 kV bus into a 6 breaker ring bus</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2364</td>
<td>Install a new 230/138 kV transformer at Squab Hollow 230 kV substation. Loop the Forest - Elko 230 kV line into Squab Hollow. Loop the Brookville - Elko 138 kV line into Squab Hollow</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2412</td>
<td>Install a 44 MVAR 138 kV capacitor at the Hempfield 138 kV substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
<td>Annual Revenue Requirement</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>------------------------------------</td>
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</tr>
<tr>
<td>b2440</td>
<td>Replace the Cabot 138kV breaker ‘C9-KISKI VLY’ with 63kA</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2546</td>
<td>Install a 51.8 MVAR (rated) 138 kV capacitor at Nyswaner 138 kV substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2547.1</td>
<td>Construct a new 138 kV six breaker ring bus Hillman substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2547.2</td>
<td>Loop Smith- Imperial 138 kV line into the new Hillman substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2547.3</td>
<td>Install +125/-75 MVAR SVC at Hillman substation</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2547.4</td>
<td>Install two 31.7 MVAR 138 kV capacitors</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2548</td>
<td>Eliminate clearance de-rate on Wylie Ridge – Smith 138 kV line and upgrade terminals at Smith 138 kV, new line ratings 294 MVA (Rate A)/350 MVA (Rate B)</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2612.1</td>
<td>Relocate All Dam 6 138 kV line and the 138 kV line to AE units 1&amp;2</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2612.2</td>
<td>Install 138 kV, 3000A bus-tie breaker in the open bus-tie position next to the Shaffers corner 138 kV line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2612.3</td>
<td>Install a 6-pole manual switch, foundation, control cable, and all associated facilities</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666</td>
<td>Yukon 138 kV Breaker Replacement</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2666.1</td>
<td>Replace Yukon 138 kV breaker “Y-11(CHARL1)” with an 80 kA breaker</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
**Keystone Appalachian Transmission Company (cont.)**

<table>
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<tbody>
<tr>
<td>b2666.2 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-13(BETHEL)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.3 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-18(CHARL2)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.4 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-19(CHARL2)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.5 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-4(4B-2BUS)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.6 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-5(LAYTON)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.7 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-8(HUNTING)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.8 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-9(SPRINGD)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.9 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-10(CHRL-SP)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.10 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-12(1-1BUS)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.11 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-14(4-1BUS)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.12 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-2(1B-BETHE)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.13 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-21(SHEPJ)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b2666.14 Replace Yukon 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>breaker “Y-22(SHEPHJT)” with an 80 kA breaker</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Keystone Appalachian Transmission Company (cont.)

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<tbody>
<tr>
<td>b2689.3 Upgrade terminal equipment at structure 27A</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2696 Upgrade 138 kV substation equipment at Butler, Shanor Manor and Krendale substations. New rating of line will be 353 MVA summer normal/422 MVA emergency</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2763 Replace the breaker risers and wave trap at Bredinville 138 kV substation on the Cabrey Junction 138 kV terminal</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2965 Reconduct the Charleroi – Allenport 138 kV line with 954 ACSR conductor. Replace breaker risers at Charleroi and Allenport</td>
<td></td>
<td>APS (37.15%) / DL (62.85%)</td>
</tr>
<tr>
<td>b2966 Reconduct the Yukon – Smithton – Shepler Hill Jct 138 kV line with 795 ACSS conductor. Replace Line Disconnect Switch at Yukon</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b2966.1 Reconduct the Yukon - Smithton - Shepler Hill Jct 138 kV line and replace terminal equipment as necessary to achieve required rating</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>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</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Required Transmission Enhancements</td>
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</tr>
<tr>
<td>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 reconducted for this project. The total length of the line is 7.75 miles</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3006 Replace four Yukon 500/138 kV transformers with three transformers with higher rating and reconfigure 500 kV bus</td>
<td></td>
<td>APS (63.21%)/DL (36.79%)</td>
</tr>
<tr>
<td>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 wave trap, circuit breaker and disconnects will be replaced</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3010 Replace terminal equipment at Keystone and Cabot 500 kV buses. At Keystone, bus tubing and conductor, a wave trap, and meter will be replaced. At Cabot, a wave trap and bus conductor will be replaced</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3011.1 Construct new Route 51 substation and connect 10 138 kV lines to new substation</td>
<td></td>
<td>DL (100%)</td>
</tr>
<tr>
<td>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)</td>
<td></td>
<td>APS (22.82%)/DL (77.18%)</td>
</tr>
<tr>
<td>b3011.3 Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #1 138 kV line</td>
<td></td>
<td>DL (100%)</td>
</tr>
</tbody>
</table>
## Keystone Appalachian Transmission Company (cont.)

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<tbody>
<tr>
<td>b3011.4</td>
<td>Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #2 138 kV line</td>
<td>DL (100%)</td>
</tr>
<tr>
<td>b3011.5</td>
<td>Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #3 138 kV line</td>
<td>APS (22.82%) / DL (77.18%)</td>
</tr>
<tr>
<td>b3011.6</td>
<td>Upgrade remote end relays for Yukon – Allenport – Iron Bridge 138 kV line</td>
<td>DL (100%)</td>
</tr>
<tr>
<td>b3012.1</td>
<td>Construct two new 138 kV ties with the single structure from APS’s new substation to Duquesne’s new substation. The estimated line length is approximately 4.7 miles. The line is planned to use multiple ACSS conductors per phase</td>
<td>ATSI (38.21%) / DL (61.79%)</td>
</tr>
<tr>
<td>b3012.3</td>
<td>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 reconducted portion. Install a new line terminal at APS Route 51 substation</td>
<td>DL (100%)</td>
</tr>
<tr>
<td>b3013</td>
<td>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</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3015.6</td>
<td>Reconductor Elrama to Mitchell 138 kV line – AP portion. 4.2 miles total. 2x 795 ACSS/TW 20/7</td>
<td>DL (100%)</td>
</tr>
<tr>
<td>b3015.8</td>
<td>Upgrade terminal equipment at Mitchell for Mitchell – Elrama 138 kV line</td>
<td>APS (100%)</td>
</tr>
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<tr>
<td>Upgrade line relaying at Piney Fork and Bethel Park for Piney Fork – Elrama 138 kV line and Bethel Park – Elrama 138 kV</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor the Yukon – Weastraver 138 kV line (2.8 miles), replace the line drops and relays at Yukon 138 kV and replace switches at Weastraver 138 kV bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor the Weastraver – Route 51 138 kV line (5.63 miles) and replace line switches at Weastraver 138 kV bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor the Yukon – Route 51 #1 138 kV line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor the Yukon – Route 51 #2 138 kV line (8 miles) and replace relays at Yukon 138 kV bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor the Yukon – Route 51 #3 138 kV line (8 miles) and replace relays at Yukon 138 kV bus</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor the 138 kV bus at Armstrong substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Replace the 500/138 kV transformer breaker and reconductor 138 kV bus at Cabot substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor the Edgewater – Loyalhanna 138 kV line (0.67 mile)</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor the 138 kV bus at Butler and reconductor the 138 kV bus and replace line trap at Karns City</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV Line. Upgrade terminal equipment at Yukon and replace line relaying at Mitchell and Charleroi</td>
<td></td>
<td>APS (12.21%) / DL (87.79%)</td>
</tr>
<tr>
<td>Reconductor the Smithton – Shepler Hill Jct 138 kV Line</td>
<td></td>
<td>APS (4.74%) / DL (95.26%)</td>
</tr>
<tr>
<td>At Enon substation install a second 138 kV, 28.8 MVAR nameplate, capacitor and the associated 138 kV capacitor switcher</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>Requirement ID</td>
<td>Description</td>
<td>Responsible Customer(s)</td>
</tr>
<tr>
<td>----------------</td>
<td>-----------------------------------------------------------------------------</td>
<td>------------------------</td>
</tr>
<tr>
<td>b3318</td>
<td>Reconductor the Shanor Manor - Butler 138 kV line with an upgraded circuit breaker at Butler 138 kV station</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3325</td>
<td>Reconductor the Charleroi - Union 138 kV line and upgrade terminal equipment at Charleroi 138 kV station</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3681</td>
<td>Upgrade the Shingletown #82 230/46 kV Transformer circuit by installing a 230 kV breaker and disconnect switches, removing existing 230 kV switches, replacing 46 kV disconnect switches, replacing limiting substation conductor, and installing/replacing relays</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3710</td>
<td>Reconductor AA2-161 to Yukon 138 kV Lines #1 and #2 with 954 ACSS conductor</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3738</td>
<td>Replace limiting terminal equipment on Charleroi – Dry Run 138 kV line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3739</td>
<td>Replace limiting terminal equipment on Dry Run – Mitchell 138 kV line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3740</td>
<td>Replace limiting terminal equipment on Glen Falls –Bridgeport 138 kV line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3741</td>
<td>Replace limiting terminal equipment on Yukon - Charleroi #1 138 kV line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3742</td>
<td>Replace limiting terminal equipment on Yukon - Charleroi #2 138 kV line</td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3744</td>
<td>Replace one span of 1272 ACSR from Krendale substation to structure 35 (approximately 630 feet) Replace one span of 1272 ACSR from Shanor Manor to structure 21 (approximately 148 feet) Replace 1272 ACSR risers at Krendale and Shanor Manor substations Replace 1272 ACSR substation conductor at Krendale substation Replace relaying at Krendale substation Revise relay settings at Butler and Shanor Manor substations</td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
### Keystone Appalachian Transmission Company (cont.)

<table>
<thead>
<tr>
<th>Required Transmission Enhancements</th>
<th>Annual Revenue Requirement</th>
<th>Responsible Customer(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b3745 Install redundant relaying at Carbon Center 230 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3761 Install 138 kV breaker on the Ridgway 138/46 kV #2 Transformer</td>
<td></td>
<td>APS (100%)</td>
</tr>
<tr>
<td>b3773 Install 33 MVAR switched capacitor, 138 kV breaker, and associated relaying at McConnellsburg 138 kV substation</td>
<td></td>
<td>APS (100%)</td>
</tr>
</tbody>
</table>
ATTACHMENT H-5

Annual Transmission Rates -- FirstEnergy Pennsylvania Electric Company (MetEd Zone) for Network Integration Transmission Service

1. The transmission revenue requirement and the rate for Network Integration Transmission Service in the Metropolitan Edison Company (“MetEd”) Zone is based on the facilities owned and costs incurred by Mid-Atlantic Interstate Transmission, LLC (“MAIT”), calculated pursuant to the formula shown in Attachment H-28. Attachment H-5A sets forth the rates for deliveries that utilize FirstEnergy Pennsylvania Electric Company’s distribution facilities at voltages below 69 kV located in the MetEd Zone.

2. In addition to the rate set forth in section 1 of this attachment, the Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse the Transmission Owners for any amounts payable by them as sales, excise, “Btu,” carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.
## ATTACHMENT H-5A

**Other Supporting Facilities Charges -- FirstEnergy Pennsylvania Electric Company**  
*(MetEd Zone)*

As provided in Attachment H-5, section 1, service utilizing facilities at voltages below 69 kV to serve certain Pennsylvania Municipal Utilities and Cooperatives will be provided at the rates set forth below (“Other Supporting Facilities Charges” or “OSFCs”).

<table>
<thead>
<tr>
<th>Location</th>
<th>Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Goldsboro, Pennsylvania</td>
<td>0.092¢ per kWh</td>
</tr>
<tr>
<td>Lewisberry, Pennsylvania</td>
<td>0.276¢ per kWh</td>
</tr>
<tr>
<td>Royalton, Pennsylvania</td>
<td>0.068¢ per kWh</td>
</tr>
<tr>
<td>Allegheny Electric Cooperative, Inc.</td>
<td>$6.69/kW/month*</td>
</tr>
</tbody>
</table>

* The rate of $6.69/kW/month shall apply to all Allegheny Electric Cooperative, Inc. delivery points for delivery by FirstEnergy Pennsylvania Electric Company located in the MetEd Zone at 13.2 kV and shall be phased in over time in accordance with an applicable service agreement entitled an “Interconnection Agreement for Wholesale Load” (“Service Agreement”) between the Parties on file with the Federal Energy Regulatory Commission. The OSFC in the Service Agreement is also referred to as a “Monthly Distribution Charge.”
Monthly Distribution Charge ($/kW)

The Monthly Distribution Charge (“MDC”) of $6.69/kW/month shall be phased in over time in accordance with the following table, which assumes an effective date of October 1, 2022 for the Service Agreement:

<table>
<thead>
<tr>
<th>Calendar Year/Quarter</th>
<th>% of MDC</th>
<th>MDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022 Q4</td>
<td>55%</td>
<td>$3.67/kW/month</td>
</tr>
<tr>
<td>2023 Calendar Year</td>
<td>60%</td>
<td>$4.01/kW/month</td>
</tr>
<tr>
<td>2024 Calendar Year</td>
<td>60%</td>
<td>$4.01/kW/month</td>
</tr>
<tr>
<td>2025 Calendar Year</td>
<td>60%</td>
<td>$4.01/kW/month</td>
</tr>
<tr>
<td>2026 and thereafter</td>
<td>100%</td>
<td>$6.69/kW/month</td>
</tr>
</tbody>
</table>

The above table shall be adjusted by mutual agreement of the Parties if the effective date of the Service Agreement is established by FERC at a date subsequent to October 1, 2022 in order to give effect to the Parties’ intent to have a phase-in of the MDC over the course of three (3) years with 100% of the MDC to apply no later than the fourth (4th) anniversary of the effective date of the Service Agreement. Notwithstanding section 13.1 of the Service Agreement, the Parties agree not to exercise rights afforded them by Sections 205 and 206 of the Federal Power Act to alter the MDC during the ten-year period beginning with the effective date of the Service Agreement as established by FERC.
ATTACHMENT H-6

Annual Transmission Rates -- FirstEnergy Pennsylvania Electric Company (Penelec Zone) for Network Integration Transmission Service

1. The transmission revenue requirement and the rate for Network Integration Transmission Service in the Pennsylvania Electric Company (“Penelec”) Zone is based on the facilities owned and costs incurred by Mid-Atlantic Interstate Transmission, LLC (“MAIT”), calculated pursuant to the formula shown in Attachment H-28. Attachment H-6A sets forth the rates for deliveries that utilize FirstEnergy Pennsylvania Electric Company’s distribution facilities at voltages below 46 kV located in the Penelec Zone.

2. In addition to the rate set forth in section 1 of this attachment, the Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse the Transmission Owners for any amounts payable by them as sales, excise, “Btu,” carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.
ATTACHMENT H-6A

Other Supporting Facilities Charges -- FirstEnergy Pennsylvania Electric Company
(Penelec Zone)

As provided in Attachment H-6, Paragraph 1, service utilizing facilities at voltages below 46 kV to serve certain Pennsylvania Municipal Utilities and Cooperatives will be provided at the rates set forth below (“Other Supporting Facilities Charges” or “OSFCs”).

<table>
<thead>
<tr>
<th>Location</th>
<th>Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Berlin, Pennsylvania</td>
<td>0.175¢ per kWh</td>
</tr>
<tr>
<td>East Conemaugh, PA</td>
<td>0.113¢ per kWh</td>
</tr>
<tr>
<td>Girard, PA</td>
<td>0.057¢ per kWh</td>
</tr>
<tr>
<td>Hooversville, PA</td>
<td>0.213¢ per kWh</td>
</tr>
<tr>
<td>Smethport, PA</td>
<td>0.147¢ per kWh</td>
</tr>
<tr>
<td>Summerhill, PA</td>
<td>0.283¢ per kWh</td>
</tr>
<tr>
<td>Allegheny Electric Cooperative, Inc.</td>
<td>$2.66/kW/month*</td>
</tr>
<tr>
<td>Allegheny Electric Cooperative, Inc.</td>
<td>$8.72/kW/month**</td>
</tr>
</tbody>
</table>

* The rate of $2.66/kW/month shall apply to all Allegheny Electric Cooperative, Inc. delivery points for delivery by FirstEnergy Pennsylvania Electric Company located in the Penelec Zone at 23 kV or 34.5 kV and shall be phased in over time in accordance with an applicable service agreement entitled an “Interconnection Agreement for Wholesale Load” (“Service Agreement”) between the Parties on file with the Federal Energy Regulatory Commission. The OSFC in the Service Agreement is also referred to as a “Monthly Distribution Charge.”

** The rate of $8.72/kW/month shall apply to all Allegheny Electric Cooperative, Inc. delivery points for delivery by FirstEnergy Pennsylvania Electric Company located in the Penelec Zone at 12.5 kV and shall be phased in over time in accordance with an applicable service agreement entitled an “Interconnection Agreement for Wholesale Load” (“Service Agreement”) between the Parties on file with the Federal Energy Regulatory Commission. The OSFC in the Service Agreement is also referred to as a “Monthly Distribution Charge.”
Monthly Distribution Charges ($/kW)

The Monthly Distribution Charge ("MDC") of $2.66/kW/month shall be phased in over time in accordance with the following table, which assumes an effective date of October 1, 2022 for the Service Agreement:

<table>
<thead>
<tr>
<th>Calendar Year/Quarter</th>
<th>% of MDC</th>
<th>MDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022 Q4</td>
<td>55%</td>
<td>$1.46/kW/month</td>
</tr>
<tr>
<td>2023 Calendar Year</td>
<td>60%</td>
<td>$1.59/kW/month</td>
</tr>
<tr>
<td>2024 Calendar Year</td>
<td>60%</td>
<td>$1.59/kW/month</td>
</tr>
<tr>
<td>2025 Calendar Year</td>
<td>60%</td>
<td>$1.59/kW/month</td>
</tr>
<tr>
<td>2026 and thereafter</td>
<td>100%</td>
<td>$2.66/kW/month</td>
</tr>
</tbody>
</table>

The MDC of $8.72/kW/month shall be phased in over time in accordance with the following table, which assumes an effective date of October 1, 2022 for the Service Agreement:

<table>
<thead>
<tr>
<th>Calendar Year/Quarter</th>
<th>% of MDC</th>
<th>MDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022 Q4</td>
<td>55%</td>
<td>$4.79/kW/month</td>
</tr>
<tr>
<td>2023 Calendar Year</td>
<td>60%</td>
<td>$5.23/kW/month</td>
</tr>
<tr>
<td>2024 Calendar Year</td>
<td>60%</td>
<td>$5.23/kW/month</td>
</tr>
<tr>
<td>2025 Calendar Year</td>
<td>60%</td>
<td>$5.23/kW/month</td>
</tr>
<tr>
<td>2026 and thereafter</td>
<td>100%</td>
<td>$8.72/kW/month</td>
</tr>
</tbody>
</table>

The above tables shall be adjusted by mutual agreement of the Parties if the effective date of the Service Agreement is established by FERC at a date subsequent to October 1, 2022 in order to give effect to the Parties’ intent to have the phase-ins of the MDCs over the course of three (3) years with 100% of the MDCs to apply no later than the fourth (4th) anniversary of the effective date of the Service Agreement. Notwithstanding section 13.1 of the Service Agreement, the Parties agree not to exercise rights afforded them by Sections 205 and 206 of the Federal Power Act to alter the MDCs during the ten-year period beginning with the effective date of the Service Agreement as established by FERC.
ATTACHMENT H-11A


Service Below 115 kV in the Allegheny Power Zone (Other Supporting Facilities Charges)

As provided in Attachment H-11, service utilizing facilities at voltages below 115 kV owned by one of the Operating Companies designated in the table below to transmit energy to and from a customer within the Allegheny Power Zone will be provided at the rates set forth below (“Other Supporting Facilities Charges”).

<table>
<thead>
<tr>
<th>Customer/Interconnection Point/Customer Facility</th>
<th>Operating Company</th>
<th>Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>All Dams Generation, LLC (Allegheny River Lock and Dam No. 5)</td>
<td>FirstEnergy Pennsylvania Electric Company</td>
<td>$4,320.00/mo.</td>
</tr>
<tr>
<td>Harrison Rural Electrification Association, Inc. (Barnetts Run, Chiefton, Dola, Oral Lake, Crystal Lake, Buckhannon, Milford Rd.)</td>
<td>Monongahela Power Company</td>
<td>$13,047.00/mo.</td>
</tr>
<tr>
<td>Thurmont Municipal Light Company (Main Street, Moser Road (Primary) and Moser Road (Back-Up))</td>
<td>The Potomac Edison Company</td>
<td>$11,529.18/mo.</td>
</tr>
</tbody>
</table>

Service At or Above 115 kV in the Allegheny Power Zone by SFC

See attached formula rate.
* The reference to West Penn Power Company is solely to ensure the continued effectuation of the formula rate true-up.
### Formula Rate - Non-Levelized

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Formula</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Net Revenue Requirement with incentive projects - MP</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Net Revenue Requirement with incentive projects - PE</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Net Revenue Requirement with incentive projects - WPP</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>TOTAL NET REVENUE REQUIREMENT</td>
<td>$0.00</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Formula</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>1 Coincident Peak (CP) (MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Average 12 CPs (MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Annual Rate ($/MW/Yr)</td>
<td>(line 4 / line 5)</td>
<td>#DIV/0!</td>
</tr>
<tr>
<td>8</td>
<td>Point-to-Point Rate ($/MW/Year)</td>
<td>(line 4 / line 6)</td>
<td>#DIV/0!</td>
</tr>
<tr>
<td>9</td>
<td>Point-to-Point Rate ($/MW/Month)</td>
<td>(line 8/12)</td>
<td>#DIV/0!</td>
</tr>
<tr>
<td>10</td>
<td>Point-to-Point Rate ($/MW/Week)</td>
<td>(line 8/52)</td>
<td>#DIV/0!</td>
</tr>
<tr>
<td>11</td>
<td>Point-to-Point Rate ($/MW/Day)</td>
<td>(line 10/5; line 10/7)</td>
<td>#DIV/0!</td>
</tr>
<tr>
<td>12</td>
<td>Point-to-Point Rate ($/MW/h)</td>
<td>(line 8/160; line 8/8,760)</td>
<td>#DIV/0!</td>
</tr>
</tbody>
</table>

### SPC Summary

<table>
<thead>
<tr>
<th>Formula</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Notes

A. As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT. Includes CP for the AP Zone.

B. Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve-month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.
### Schedule 1A Rate Calculation Summary

<table>
<thead>
<tr>
<th></th>
<th>Description</th>
<th>Source</th>
<th>Calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Transmission expenses included in OATT Ancillary Services (Attachment H-11A, Page 4, Line 7)</td>
<td>Attachment 1, Line 2</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Revenue Credits for Sched 1A - Note A</td>
<td>Attachment 1, Line 2</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Net Schedule 1A Expenses (Line 1 - Line 2)</td>
<td>Attachment 1, Line 3</td>
<td>$ -</td>
</tr>
<tr>
<td>4</td>
<td>Annual MWh in AP Zone - Note B</td>
<td>Attachment 1, Line 4</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Schedule 1A rate $/MWh (Line 3/Line 4)</td>
<td>Attachment 1, Line 5</td>
<td>#DIV/0!</td>
</tr>
</tbody>
</table>

**Note:**
- A Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of AP Zone during the year used to calculate rates under Attachment H-11A.
- B Load expressed in MWh consistent with load used for billing under Schedule 1A for the AP Zone. Data from RTO settlement systems for the calendar year prior to the rate year.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>(1) Project Name</th>
<th>(2) RTEP Project Number</th>
<th>(3) Net Revenue Requirement with True-up (Note A)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note A  Net Revenue Requirement with True-up is sourced from Attachment 11, Col. 15. PJM to bill each project utilizing the respective Net revenue requirement with true-up on Col. 3
## Abandoned Plant Summary

For the 12 months ended 12/31/2021

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Project Name (A)</th>
<th>RTEP Project Number</th>
<th>Revenue Requirement (A)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.00</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.01</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.02</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>1.03</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.04</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.05</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.06</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.07</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.08</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.09</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.10</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note A: Revenue Requirement is sourced from Attachment 16 Col. R. PJM to bill each project utilizing the respective Revenue Requirement reflected on Col. 3
## Formula Rate - Non-Levelized

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>(1)</th>
<th>(2)</th>
<th>(3)</th>
<th>(4)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>GROSS REVENUE REQUIREMENT [page 3, Line 38, col 5]</td>
<td></td>
<td>Alloc</td>
<td>Total</td>
<td>Alloc</td>
</tr>
<tr>
<td></td>
<td>REVENUE CREDITS</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Account No. 451</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Account No. 454</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Account No. 456</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Section 30.9 credits</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Other Revenue credits</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>TEC Revenue</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>TOTAL REVENUE CREDITS (sum Lines 2-7)</td>
<td></td>
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<td>True-up Adjustment with Interest</td>
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**Rate Formula Template Utilizing FERC Form 1 Data**

For the 12 months ended 12/31/2021

**MON POWER**

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<td>TOTAL REVENUE CREDITS (sum Lines 2-7)</td>
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<tr>
<td>9</td>
<td>True-up Adjustment with Interest</td>
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## Formula Rate - Non-Levelized

### MON POWER

#### Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2021

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### Attachment H-11A

Page 2 of 5
### Supporting Calculations and Notes

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<td>7</td>
<td>Less transmission expenses included in OATT Ancillary Services (Attachment 20, Line 2 plus Line 3 and Line 4, Col. C) (Note K)</td>
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### Wages & Salary Allocator (W&S)

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### Annual Allocation Factor (Note A)

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**Return (R)**

### Revenue Credits (Note A)

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<td>Long Term Debt (112.18c) (Attachment 8, Line 14, Col. 3) (Note BB)</td>
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**Other Revenue Credits**

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To the extent transmission assets are transferred to KATCo, a proration factor will be applied on a percent of the transmission within the ROE range of the applicable data.

Excludes revenues unrelated to transmission services.

Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = \( \frac{\text{FIT}}{\text{SIT}+1} \) (percent of federal income tax deductible for state purposes).

The balanc of accounts 190, 281, 282, and 283 shall be adjusted for items listed on Attachment 5. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

Identified in Form 1 as being only transmission related.

As agreed to as part of the settlement of Docket No. ER21-253 and ER21-265, Cash Working Capital is a challengeable input that is capped at one-eighth of O&M and A&G allocated to transmission at page 3, Line 9, column 5 minus amortization of regulatory assets (page 3, Line 8, col. 5) unless supported by a fully-developed and reliable lead/lag study. Interested parties will not challenge the input for the cash working capital allowance for three (3) rate years following the effective date of the ultimately settled formula, provided that the CWC input lies not exceed the one-eighth cap. In no case shall the calculation include service company depreciation expense in the cash working capital base.

Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts and taxes non-functionalized to Transmission are not included in transmission revenue requirement in the Rate Formula Template since they are recovered elsewhere.

The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = \( \frac{\text{FIT}}{\text{SIT}+1} \) (percent of federal income tax deductible for state purposes). If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.1) multiplied by (1/(1-T)) (page 3, Line25).

Inputs Required:

\[ \text{FIT} = \frac{\text{FIT}}{\text{SIT}+1} \]
\[ p = \frac{\text{FIT}}{\text{SIT}+1} \]

(0.00)

(0.00) (State Income Tax Rate or Composite SIT)

\( p \) = (percent of federal income tax deductible for state purposes)

K Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA, and related to generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

L Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

M Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

N Enter dollar amounts

O Debt cost rate = Attachment 10, Column (b) total. Preferred cost rate = preferred dividends (Line 30) / preferred outstanding (Line 32). No change in ROE may be made absent a filing with FERC under Section 205 or Section 206 of the Federal Power Act. The ROE consists of a base ROE of 9.95% and a 50 basis point adder for participation in an RTO as eligible and consistent with the terms of the Settlement Agreement in Docket No. ER21-253-000.

P Page 4, Line 37 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

Q Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

R Excludes revenues unrelated to transmission services.

S The revenues credited on page 1, Rates 2-6 do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on Line 7 is supported by its own reference.

T Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. FERC account 405 – Amortization of Other Electric Plant amounts are excluded unless approved and authorized by FERC.

U Page 4, Line 40, enter revenues from RTO settlements that are associated with NTIS and firm Point-to-Point Service for which the load is not included in the divisor to derive AP Zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects, unless provisions per settlement agreement section 2.23 requires inclusion.

V Calculate using a 13-month average balance.

W Includes only CWIP approved by the Commission for inclusion in rate base.

X Any actual ROE incentive must be approved by the Commission; therefore, Line will remain zero until a project(s) is granted a ROE incentive adder.

Y Sub-transmission includes assets below 100 kV, but which reside in transmission FERC accounts

Z To the extent transmission assets are transferred to KATCo, a proration factor will be applied on a percent of the transmission gross plant transferred

AA The SDCs shall utilize a W/S allocator to the extent that it aligns with distribution treatment, to become effective following the filing of the Settlement in Docket No. ER21-253 with a sunset of three years. After the sunset period, any revenue credits shall be credited to the formula rate template in the same manner as the underlying associated plant assets or expenses that generate the credits.

BB Calculates using a 13-month average balance. The Capitalization ratio for a capital component is the ratio of that component's capitalization to total company capitalization, subject to a total equity ceiling (i.e., preferred and common equity) of 56% Actual equity capitalization: 0.0% Equity Cap Not Triggered
## Schedule 1A Rate Calculation

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<td>Net Schedule 1A Expenses (Line 1 - Line 2)</td>
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<td>Annual MWh in AP Zone - Note B</td>
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<td>4</td>
<td>Schedule 1A rate $/MWh (Line 3/ Line 4)</td>
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**Note:**

A. Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of AP Zone during the year used to calculate rates under Attachment H-11A.

B. Load expressed in MWh consistent with load used for billing under Schedule 1A for the AP Zone. Data from RTO settlement systems for the calendar year prior to the rate year.
### ROE Calculation

**Return Calculation**

| Source Reference |  
|------------------|---|
| 1 Rate Base | Attachment H-11A, page 2, Line 35, Col. 5 #DIV/0! |
| 2 Preferred Dividends | enter positive Attachment H-11A, page 4, Line 30, Col. 6 0 |
| 3 Proprietary Capital | Attachment 8, Line 14, Col. 1 0 |
| 4 Less Preferred Stock | Attachment 8, Line 14, Col. 3 0 |
| 5 Less Accumulated Other Comprehensive Income Account 219 | Attachment 8, Line 14, Col. 6 0 |
| 6 Less Account 216.1, Renaissance Adj, AGC adj & Goodwill | Attachment 8, Line 14, Col. 2, 4, 5 & 7 0 |
| 7 Common Stock | Attachment 8, Line 14, Col. 8 0 |
| 8 Total Capitalization | Attachment H-11A, page 4, Line 34, Col. 3 0 |
| 9 Preferred Stock | Attachment H-11A, page 4, Line 32, Col. 3 0 |
| 10 Common Stock | Attachment H-11A, page 4, Line 33, Col. 3 0 |
| 11 Total Capitalization | Attachment H-11A, page 4, Line 34, Col. 3 0 |
| 12 Debt % | Attachment H-11A, page 4, Line 31, Col. 4 0.0000% |
| 13 Preferred % | Attachment H-11A, page 4, Line 32, Col. 4 0.0000% |
| 14 Common % | Attachment H-11A, page 4, Line 33, Col. 4 0.0000% |
| 15 Total Cost of Debt | Attachment H-11A, page 4, Line 31, Col. 5 #DIV/0! |
| 16 Preferred Cost | Attachment H-11A, page 4, Line 32, Col. 5 0.0000 |
| 17 Common Cost | Attachment H-11A, page 4, Line 33, Col. 5 0.1045 |
| 18 Weighted Cost of Debt (WCLTD) | Attachment H-11A, page 4, Line 34, Col. 3 #DIV/0! |
| 19 Preferred Stock | Attachment H-11A, page 4, Line 32, Col. 5 (Line 12 * Line 15) #DIV/0! |
| 20 Common Stock | Attachment H-11A, page 4, Line 33, Col. 5 (Line 13 * Line 16) 0.0000 |
| 21 Rate of Return on Rate Base (ROR) | (Sum Lines 18 to 20) #DIV/0! |
| 22 Investment Return = Rate Base * Rate of Return | (Line 1 * Line 21) #DIV/0! |

#### Income Taxes

**Income Tax Rates**

| Income Tax Rates |  
|------------------|---|
| 23 Income Tax Rates | Attachment H-11A, page 3, Line 30, Col. 3 0.00% |
| 24 Calculated | Attachment H-11A, page 3, Line 30, Col. 3 #DIV/0! |
| 25 1 / (1 - T) | Attachment H-11A, page 3, Line 32, Col. 3 - |
| 26 Amortized Investment Tax Credit (266.8.f) (enter negative) | Attachment H-11A, page 3, Line 33, Col. 3 - |
| 27 Tax Effect of Permanent Differences and AFUDC Equity | Attachment H-11A, page 3, Line 34, Col. 3 - |
| 28 (Excess)Deficient Deferred Income Taxes | Attachment H-11A, page 3, Line 35, Col. 3 - |
| 29 Income Tax Calculation | Attachment H-11A, page 3, Line 36, Col. 3 #DIV/0! |
| 30 ITC adjustment | Attachment H-11A, page 3, Line 37, Col. 5 - |
| 31 Permanent Differences and AFUDC Equity Tax Adjustment | Attachment H-11A, page 3, Line 38, Col. 5 - |
| 32 (Excess)Deficient Deferred Income Tax Adjustment | Attachment H-11A, page 3, Line 39, Col. 5 - |
| 33 Total Income Taxes | Sum lines 29 to 32 #DIV/0! |

### Return and Taxes

**Return and Income Taxes with ROE**

| Return and Taxes |  
|------------------|---|
| 34 Return and Income taxes with ROE | (Line 22 + Line 33) #DIV/0! |
| 35 Return with ROE | Attachment H-11A, page 3, Line 41, Col. 5 #DIV/0! |
| 36 Income Tax with ROE | Attachment H-11A, page 3, Line 46, Col. 5 #DIV/0! |
ATTACHMENT H-28B
Mid-Atlantic Interstate Transmission, LLC
Formula Rate Implementation Protocols

ANNUAL TRUE-UP, INFORMATION EXCHANGE,
AND CHALLENGE PROCEDURES

Definitions

“Actual Transmission Revenue Requirement” or “ATRR” means the actual net transmission revenue requirement calculated and posted on the PJM website no later than June 1 of each year subsequent to calendar year 2017 for the immediately preceding calendar year in accordance with MAIT’s Formula Rate and based upon MAIT’s actual costs and expenditures.

“Annual Update” means MAIT’s ATRR for the preceding calendar year, as well as the True-up for the prior Rate Year, as posted on or before June 1 of each year.

“Formal Challenge” means a written challenge to an Annual Update or Projected Transmission Revenue Requirement submitted to the Federal Energy Regulatory Commission (the “Commission” or “FERC”) as provided in Section IV below.

“Formula Rate” means these protocols (to be included as Attachment H-28B of the PJM Interconnection, L.L.C. (“PJM”), FERC Electric Tariff (“PJM Tariff”)) and the Formula Rate Template.

“Formula Rate Template” means the collection of formulas and worksheets, unpopulated with any data, to be included as Attachment H-28A of the PJM Tariff.

“Interested Parties” include, but are not limited to, customers under the PJM Tariff, state utility regulatory commissions, the Organization of PJM States, Inc., consumer advocacy agencies, and state attorneys general.

“Preliminary Challenge” means a written challenge to the Annual Update or Projected Transmission Revenue Requirement submitted to MAIT as provided in Section IV below.

“Projected Transmission Revenue Requirement” or “PTRR” means the projected net transmission revenue requirement calculated for the forthcoming Rate Year, as well as, where applicable, the most recently calculated True-up, with interest, to be posted on the PJM website no later than October 5 of each year for rates effective the next calendar year starting January 1.

“Publication Date” means the date on which the Annual Update is posted.

“Rate Year” means the twelve consecutive month period that begins on January 1 and continues through December 31.
“True-up” means the difference between the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) and the ATRR for the same Rate Year, which shall be provided in the Annual Update on or before June 1 of the year subsequent to the Rate Year. The True-up will be a component of the PTRR.

Section I. Applicability

The following procedures shall apply to the Mid-Atlantic Interstate Transmission, LLC (“MAIT”) calculation of its Actual Transmission Revenue Requirement, True-up, and Projected Transmission Revenue Requirement.

Section II. Annual Update and Projected Transmission Revenue Requirement

A. On or before June 1 of each year subsequent to calendar year 2017, MAIT shall determine its Annual Update for the immediately preceding calendar year under Attachment H-28A and Section VII of these protocols, including calculation of the True-up to be included in MAIT’s PTRR for the subsequent Rate Year.

B. On or before June 1 of each year subsequent to calendar year 2017, MAIT shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website. Within two (2) days of such posting, PJM shall provide notice of such posting via an e-mail exploder list.

C. On or before September 1, MAIT shall, upon request, provide any Interested Party with:

(1) information showing (a) each transmission project forecasted to be placed into service in the following Rate Year that is expected to have a direct cost of $1,000,000 (one million dollars) or greater, and a breakdown of the projected direct costs of each such project in as much detail as is reasonably available; and (b) purchases of categories of capital equipment (e.g., switches, transformers, relays, etc.) aggregating $3,000,000 (three million dollars) or greater that are forecasted to enter service during the following Rate Year, either through the use of such capital equipment in projects forecasted to be placed in service during the following Rate Year or as spare plant that MAIT determines to be needed for the safe and reliable operation of the transmission system in accordance with Good Utility Practice during the following Rate Year; and

(2) a statement setting forth the basis for MAIT’s determination that each such transmission project or capital equipment purchase, as applicable, is needed for service during the following Rate Year (which statement may be based on a determination that the placement of the project or equipment purchases into service during the following Rate Year, as described below, is needed as part of a larger multi-year transmission project or equipment purchase project, as applicable). MAIT’s provision of such information shall be subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC’s Model Protective Order.
D. MAIT shall provide: (1) to PJM, MAIT’s PTRR for rates to be effective the following Rate Year, by October 5, and (2) upon request, to any Interested Party by October 5. (a) a list of the transmission projects and capital equipment purchases included in the PTRR capital projections, which shall be projects and capital equipment forecasted to enter service through projects in service or as spare plant during the Rate Year that is the subject to the PTRR; (b) a copy of the approved budget and/or construction plan pursuant to which such projects and equipment purchases have been undertaken; (c) a statement setting forth the basis for MAIT’s determination that each such transmission project or capital equipment purchase, as applicable, is needed for service during the following Rate Year (which statement may be based on a determination that the placement of the project or equipment purchase into service during the following Rate Year is needed as part of a larger multi-year transmission project or equipment purchase project, as applicable). With respect to the information referenced in clause (1), on October 5, MAIT shall provide via an email exploder list: (i) its PTRR for rates to be effective the following Rate Year; and (ii) notice of such posting. With respect to the information described in clause (2), MAIT’s provision of such information shall be subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC’s Model Protective Order.

E. If the date for posting the Annual Update or PTRR falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual Update occurs shall be that year’s Publication Date. Any delay in the Publication Date or in the posting of the PTRR will result in an equivalent extension of time for the submission of information requests discussed in Section III of these protocols.

F. The ATRR shall:

1. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas and links intact;

2. Be based on MAIT’s FERC Form No. 1 for the prior calendar year;

3. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the ATRR that are not otherwise available in the FERC Form No. 1, subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC’s Model Protective Order;

4. Provide sufficient information to enable Interested Parties to replicate the calculation of the ATRR results from the FERC Form No. 1;

5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1;

6. Identify and, to the extent not explained in a worksheet included in the ATRR, explain, all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in the FERC Form No. 1;
7. Provide underlying data for Formula Rate inputs that provide greater granularity than is required for the FERC Form No. 1;

8. With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate (“Accounting Change”):

   a. Identify any Accounting Change, including:

      i. the initial implementation of an accounting standard or policy;
      ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
      iii. correction of errors and prior period adjustments that affect the ATRR and True-up calculation;
      iv. the implementation of new estimation methods or policies that change prior estimates; and
      v. changes to income tax elections;

   b. Identify items included in the ATRR at an amount other than on a historic cost basis (e.g., fair value adjustments);

   c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the ATRR;

   d. Provide, for each item identified pursuant to items II.F.8.a - II.F.8.c above, a narrative explanation of the individual impact of such change on the ATRR.

9. It is the intent of the Formula Rate, including the supporting explanations and allocation described therein, that each input to the Formula Rate will be either taken directly from FERC Form No. 1 or reconcilable to FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

G. The Projected Transmission Revenue Requirement shall:

   1. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas and links intact;

   2. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the PTRR;
3. Provide sufficient information to enable Interested Parties to replicate the calculation of the PTRR;

4. With respect to any Accounting Change:
   a. Identify any Accounting Change, including:
      i. the initial implementation of an accounting standard or policy;
      ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
      iii. correction of errors and prior period adjustments that affect the PTRR calculation;
      iv. the implementation of new estimation methods or policies that change prior estimates; and
      v. changes to income tax elections.
   b. Identify items included in the PTRR at an amount other than on a historic cost basis (e.g., fair value adjustments);
   c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the PTRR; and
   d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these protocols, a narrative explanation of the individual impact of such change on the PTRR.

H. MAIT shall hold an open meeting among Interested Parties (“Annual Update Meeting”), to be conducted via Internet webcast, no earlier than ten (10) business days following the Publication Date and no later than June 25. No fewer than seven (7) days prior to such Annual Update Meeting, MAIT shall provide notice on PJM’s website of the time, date, and webcast registration information of the Annual Update Meeting, and PJM shall provide notice of the posting via an e-mail exploder list. The Annual Update Meeting shall: (i) permit MAIT to explain and clarify its ATRR and True-up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from MAIT about the ATRR and True-up.

I. MAIT shall hold an open meeting among Interested Parties (“Annual Projected Rate Meeting”), to be conducted via Internet webcast, no earlier than ten (10) business days following the posting of the PTRR (as described in Section II.C of these protocols) and no later than November 30. No fewer than seven (7) days prior to such Annual Projected Rate Meeting, MAIT shall provide notice on PJM’s website of the time, date, and webcast registration information of the Annual Projected Rate Meeting, and PJM shall provide notice of the posting via an e-mail exploder list. The Annual Projected Rate Meeting shall: (i) permit MAIT to explain and clarify its PTRR and
(ii) provide Interested Parties an opportunity to seek information and clarifications from MAIT about the PTRR.

J. Each year MAIT shall endeavor to (a) coordinate with other Transmission Owners in PJM using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and (b) hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

Section III. Information Exchange Procedures

Each Annual Update and PTRR shall be subject to the following information exchange procedures (“Information Exchange Procedures”):

A. Interested Parties shall have until January 5 following the Publication Date (unless such period is extended with the written consent of MAIT or by FERC order) to serve reasonable information and document requests on MAIT (“Information Exchange Period”). If January 5 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

1. the extent or effect of an Accounting Change;
2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols, or includes data not properly recorded in accordance with these protocols;
3. the proper application of the Formula Rate and procedures in these protocols;
4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR or PTRR;
5. the prudence of actual costs and expenditures included in the ATRR or the reasonableness of projected costs and expenditures included in the PTRR, information concerning which may include MAIT’s utilized procurement methods and cost control methodologies, and the basis for and reasonableness of allocating all or any portion of such costs and expenditures to wholesale transmission service;
6. whether transmission projects or equipment purchases underlying the costs and expenditures included in the ATRR or PTRR are needed for service during the Rate Year (including as part of a larger multi-year transmission project or equipment purchase program, as applicable);
7. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or
8. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.
The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

B. MAIT shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. MAIT shall respond to all information and document requests by no later than February 15 following the Publication Date, unless the Information Exchange Period is extended by MAIT or FERC.

C. MAIT will serve all information requests from Interested Parties and MAIT’s response(s) to such requests upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such information requests or responses, as needed, under non-disclosure agreements that are based on FERC’s Model Protective Order.

D. MAIT shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege in any proceeding addressing MAIT’s Annual Update or PTRR, and such responses may be included in any Formal Challenge or other submittal addressing MAIT’s Annual Update or PTRR.

E. MAIT will provide, upon the request of any Interested Party, the Ground Lease Calculation worksheet filed with the Pennsylvania Public Utility Commission for the applicable Rate Year, provided such request is timely made consistent with the Review Period set forth in Section IV.A below. MAIT shall not claim any privilege precludes the provision of such Ground Lease Calculation worksheet. MAIT agrees to include in its FERC Form 1 the amount of base rent in Account No. 567 associated with the Ground Leases with FirstEnergy Pennsylvania Electric Company.

Section IV. Challenge Procedures

A. Interested Parties shall have until March 5 following the Publication Date (unless such period is extended with the written consent of MAIT or by FERC order) (“Review Period”), to review the inputs, supporting explanations, allocations and calculations and to notify MAIT in writing, which may be made electronically, of any specific Preliminary Challenges to the Annual Update or PTRR. If March 5 falls on a weekend or holiday recognized by FERC, the deadline for submitting all Preliminary Challenges shall be extended to the next business day. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update or PTRR shall bar pursuit of such issue with respect to that Annual Update or PTRR under the challenge procedures set forth in these protocols, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update or PTRR. This Section IV.A shall in no way affect a party’s rights under section 206 of the Federal Power Act as set forth in Section IV.I of these protocols.

B. Preliminary Challenges shall be subject to the resolution procedures and limitations in this Section IV and shall satisfy all of the following requirements.

1. A party submitting a Preliminary Challenge to MAIT must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and
provide an appropriate explanation and documents to support its challenge.

2. MAIT shall make a good faith effort to respond to any Preliminary Challenge within twenty (20) business days of notification of such challenge.

3. MAIT, and where applicable, PJM, shall appoint a senior representative to work with the party that submitted the Preliminary Challenge (or its representative) toward a resolution of the challenge.

4. If MAIT disagrees with such challenge, MAIT will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.

5. No Preliminary Challenge may be submitted after March 5, and MAIT must respond to all Preliminary Challenges by no later than April 5 unless the Review Period is extended by MAIT or FERC, or as provided in Section IV.A above.

6. MAIT will serve all Preliminary Challenges from Interested Parties and MAIT’s response(s) to such Preliminary Challenges upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such Preliminary Challenges or responses, as needed, under non-disclosure agreements that are based on the FERC’s Model Protective Order.

C. Formal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

1. A Formal Challenge shall:
   a. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;
   b. Explain how the action or inaction violates the filed rate formula or protocols;
   c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:
      (i) the extent or effect of an Accounting Change;
      (ii) whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols;
      (iii) the proper application of the Formula Rate and procedures in these protocols;
      (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the ATRR or PTRR;
      (v) the prudence of actual costs and expenditures included in the ATRR;
      (vi) the reasonableness of any projection that forms a basis of the PTRR;
whether transmission projects or equipment purchases underlying the costs and expenditures included in the ATRR or PTRR are needed for service during the Rate Year (including as part of a larger multi-year transmission project or equipment purchase program, as applicable);

(viii) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

(ix) any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the challenged action or inaction;

e. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Preliminary Challenge procedures described in these protocols to dispute the challenged action or inaction raised by the Formal Challenge, and, if not, describe why not.

2. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on MAIT. Service to MAIT must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on MAIT’s Informational Filing required under Section VI of these protocols.

D. Preliminary and Formal Challenges shall be limited to all issues that may be necessary to determine:

1. the extent or effect of an Accounting Change;

2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols, or includes data not properly recorded in accordance with these protocols;

3. the proper application of the Formula Rate and procedures in these protocols;

4. the accuracy of data and consistency with the formula rate of the calculations shown in the ATRR and PTRR;
5. the prudence of actual costs and expenditures included in the ATRR;

6. the reasonableness of any projection that forms a basis of the PTRR;

7. whether transmission projects or equipment purchases underlying the costs and expenditures included in the ATRR or PTRR are needed for service during the Rate Year (including as part of a larger multi-year transmission project or equipment purchase program, as applicable);

8. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

E. Any changes or adjustments to the ATRR and PTRR resulting from the information exchange and Preliminary Challenge processes that are agreed to by MAIT will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by MAIT on or before December 1 will be reflected in the PTRR for the upcoming Rate Year. Any changes or adjustments agreed to by MAIT after December 1 will be reflected in the following year’s Annual Update, as discussed in Section V of these protocols.

F. An Interested Party shall have until May 5 following the Review Period (unless such date is extended with the written consent of MAIT to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with FERC, which shall be served on MAIT on the date of such filing as specified in Section IV.C.2 above. A Formal Challenge shall be filed in the same docket as MAIT’s Informational Filing discussed in Section VI of these protocols. MAIT shall respond to the Formal Challenge by the deadline established by FERC. An Interested Party may not pursue a Formal Challenge unless it submitted a Preliminary Challenge on some issue (which may be different from the Formal Challenge issue) during the applicable Review Period.

G. In any proceeding initiated by FERC concerning the Annual Update or PTRR or in response to a Formal Challenge, MAIT shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these protocols and that it followed the applicable requirements and procedures in the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

H. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of MAIT to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

I. No party shall seek to modify the Formula Rate under the challenge procedures set forth in these protocols and the Annual Update and PTRR shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing. MAIT may, at its discretion
and at a time of its choosing, make a limited filing pursuant to Section 205 to modify stated values in the Formula Rate for (a) amortization and depreciation rates, (b) Post-Employment Benefits Other Than Pensions rates, or (c) the weighting of the ADIT balance in rate base to ensure MAIT’s compliance with the IRS regulations for normalization under IRS Section 1.167(l)-1(h)(6). The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

J. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 shall first raise the matter with MAIT in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Changes to Actual Transmission Revenue Requirement or Projected Transmission Revenue Requirement

A. Except as provided in Section IV.E of these protocols, any changes to the data inputs, including but not limited to revisions to MAIT’s FERC Form No. 1, or as the result of any FERC proceeding to consider the ATRR or PTRR, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the PTRR for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols.

B. In the event that MAIT identifies an error in the Annual Update (or its FERC Form No. 1 or successor form which is used as an input to the Formula Rate), or if MAIT is required by applicable law or a court or a regulatory body to correct such error, MAIT shall correct the error in good faith and without regard to whether the correction increases or decreases MAIT’s revenue requirements. MAIT shall implement the correction in the next Annual Update following the identification of the error or the order of a court or regulatory body. Nothing in these protocols should or may be construed as preventing Interested Parties from protesting such correction.

Section VI. Informational Filings

A. By June 1 of each year, MAIT shall submit to FERC in a new docket an informational filing (“Informational Filing”) of its PTRR for the Rate Year, including its ATRR and True-up reflected in that PTRR. This Informational Filing must include information that is reasonably necessary to determine:

1. that input data under the Formula Rate are properly recorded in any underlying work papers;
2. that MAIT has properly applied the Formula Rate and these procedures;
3. the accuracy of data and the consistency with the Formula Rate of the transmission revenue requirement and rates under review;
4. the extent of Accounting Changes that affect Formula Rate inputs; and
5. the reasonableness of projected costs and the prudence of actual costs.

The Informational Filing must also describe any corrections or adjustments made during the period since the Publication Date, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Preliminary or Formal Challenge procedures.

Finally, the Informational Filing shall include for the applicable Rate Year the following information related to affiliate cost allocation: a detailed description of the methodologies used to allocate and directly assign costs between MAIT and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; the magnitude of such costs that have been allocated or directly assigned between MAIT and each affiliate by service category or function; and a copy of any service agreement between MAIT and any MAIT affiliate that went into effect during the Rate Year.

Within five (5) days of such Informational Filing, PJM shall provide notice of the Informational Filing via an e-mail exploder list and by posting the docket number assigned to MAIT’s Informational Filing on the PJM website, subject to the protection of any confidential information contained in the Informational Filing, as needed, under nondisclosure agreements that are based on FERC’s Model Protective Order.

B. Any challenges to the implementation of the MAIT formula rate must be made through the challenge procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VII. Calculation of True-up

The True-up will be determined in the following manner:

A. As part of the Annual Update for each Rate Year, MAIT shall determine the difference between the revenues collected by PJM based on the PTRR for the Rate Year (net of the True-up from the prior year) and the ATRR for the same Rate Year based on actual cost data as reflected in its FERC Form No. 1. The True-up will be determined as follows:

i. The ATRR for the previous Rate Year as determined using MAIT’s completed FERC Form No. 1 report shall be compared to the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) for that same Rate Year (“True-up Year”) to determine any excess or shortfall in the revenues collected by PJM in the True-up Year. The revenue excess or shortfall determined by this comparison shall constitute the “True-up.”

ii. Interest on any True-up shall be based on the interest rate equal to: (i) MAIT’s actual short-term debt costs capped at the interest rate determined by 18 C.F.R. § 35.19a; or (ii) the interest rate determined by 18 C.F.R. § 35.19, if MAIT does not have short term debt. Interest rates will be used to calculate the time value of money for the period that the
True-up exists. The interest rate to be applied to the True-up will be determined using the average rate for the twenty (20) months preceding September of the current year.

B. MAIT will post on PJM’s website all information relating to the True-up as part of the Annual Update. As provided in Section II.B. of these Protocols, MAIT shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website on or before June 1 of each year subsequent to calendar year 2017.

Section VIII. Formula Rate Inputs

A. Stated inputs to the Formula Rate Template: For (i) rate of return on common equity; (ii) “Post-Employment Benefits other than Pension” pursuant to Statement of Financial Accounting Standards No. 106, Employers’ Accounting for Postretirement Benefits Other Than Pensions (“PBOP”) charges; and (iii) depreciation and/or amortization rates, the values shall be stated values to be used in the Formula Rate until changed pursuant to a Federal Power Act section 205 or section 206 filing. These stated-value inputs are specified in Attachment 9, respectively, of the Formula Rate Template.

B. Unpopulated Formula Rate line items: With respect to line items in the Formula Rate that are not currently populated with non-zero numerical values because FERC policy requires prior authorization for recovery of the underlying costs or because, due to the nature of the associated functional activities, such costs are not considered part of MAIT’s transmission-related revenue requirement (but not line items that are zero values in a particular Rate Year for the sole reason that no such costs or revenues were incurred or revenues received or projected to be incurred or received during the Rate Year), such line items shall not be populated with non-zero values except as may be authorized following a Federal Power Act section 205 filing or required under Federal Power Act section 206.
<table>
<thead>
<tr>
<th>FULL NAME</th>
<th>SHORT NAME</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pennsylvania Electric Company*</td>
<td>PENELEC</td>
</tr>
<tr>
<td>Allegheny Power</td>
<td>APS</td>
</tr>
<tr>
<td>PPL Electric Utilities Corporation</td>
<td>PPL</td>
</tr>
<tr>
<td>Metropolitan Edison Company**</td>
<td>ME</td>
</tr>
<tr>
<td>Jersey Central Power and Light Company</td>
<td>JCPPL</td>
</tr>
<tr>
<td>Public Service Electric and Gas Company</td>
<td>PSEG</td>
</tr>
<tr>
<td>Atlantic City Electric Company</td>
<td>AEC</td>
</tr>
<tr>
<td>PECO Energy Company</td>
<td>PECO</td>
</tr>
<tr>
<td>Baltimore Gas and Electric Company</td>
<td>BGE</td>
</tr>
<tr>
<td>Delmarva Power and Light Company</td>
<td>DPL</td>
</tr>
<tr>
<td>Potomac Electric Power Company</td>
<td>PEPCO</td>
</tr>
<tr>
<td>Rockland Electric Company</td>
<td>RE</td>
</tr>
<tr>
<td>Commonwealth Edison Company</td>
<td>ComEd</td>
</tr>
<tr>
<td>AEP East Zone</td>
<td>AEP</td>
</tr>
<tr>
<td>The Dayton Power and Light Company</td>
<td>Dayton</td>
</tr>
<tr>
<td>Duquesne Light Company</td>
<td>DL</td>
</tr>
<tr>
<td>Virginia Electric and Power Company</td>
<td>Dominion</td>
</tr>
<tr>
<td>American Transmission Systems, Incorporated</td>
<td>ATSI</td>
</tr>
<tr>
<td>Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.</td>
<td>DEOK</td>
</tr>
<tr>
<td>East Kentucky Power Cooperative, Inc.</td>
<td>EKPC</td>
</tr>
<tr>
<td>Ohio Valley Electric Corporation</td>
<td>OVEC</td>
</tr>
</tbody>
</table>
* FirstEnergy Pennsylvania Electric Company (“FE PA”) is the successor-in-interest to Pennsylvania Electric Company, but all references to the Pennsylvania Electric Company or PENELEC Zone remain unchanged.

** FirstEnergy Pennsylvania Electric Company (“FE PA”) is the successor-in-interest to Metropolitan Edison Company, but all references to the Metropolitan Edison Company, MetEd, or ME Zone remain unchanged.
ATTACHMENT L
List of Transmission Owners

Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Atlantic City Electric Company
Baltimore Gas and Electric Company
Delmarva Power & Light Company
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
East Kentucky Power Cooperative, Inc.
Essential Power Rock Springs, LLC
Hudson Transmission Partners, LLC
ITC Interconnection LLC
Jersey Central Power & Light Company
Mid-Atlantic Interstate Transmission, LLC
Neptune Regional Transmission System, LLC
Old Dominion Electric Cooperative
PECO Energy Company
Pennsylvania Power & Light Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company
Trans-Allegheny Interstate Line Company
Transource West Virginia, LLC
UGI Utilities, Inc.
Monongahela Power Company and The Potomac Edison Company, doing business as Allegheny Power
Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.
The Dayton Power and Light Company
Duquesne Light Company
Virginia Electric and Power Company
Linden VFT, LLC
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Hamilton, OH
Southern Maryland Electric Cooperative, Inc.
Ohio Valley Electric Cooperative
AMP Transmission, LLC
Silver Run Electric, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
Wabash Valley Power Association, Inc.
Keystone Appalachian Transmission Company
ATTACHMENT M-1 (FirstEnergy Zones)
FirstEnergy Procedure for Determining a
Load Serving Entity’s Hourly Energy Obligations

Purpose

The purpose of this Attachment M-1 is to give PJM members serving load in a FirstEnergy Zone(s) the understanding of how each hour of an operating day’s Total Hourly Energy Obligation (“THEO”) is developed, in accordance with the PJM Open Access Transmission Tariff, the PJM Operating Agreement, Reliability Assurance Agreement or other relevant PJM documents (the “PJM Documents”) and submitted to PJM. Attachment M-1 pertains to both wholesale and retail Load Serving Entities (“LSEs”) serving load in the following FirstEnergy Electric Distribution Companies (“EDC”) Zones (the “FirstEnergy Zones”): Ohio Edison Company, The Toledo Edison Company, The Cleveland Electric Illuminating Company (together “ATSI Ohio”), FirstEnergy Pennsylvania Electric Company (“FE PA”) operating in the separate ATSI, Penelec, MetEd, and Allegheny Power PJM transmission zones, Jersey Central Power & Light Company (“JCP&L”), Monongahela Power Company (“Mon Power”) and The Potomac Edison Company (“Potomac Edison MD” and “Potomac Edison WV”). Attachment M-1 is not intended to supersede or replace any contractual arrangement(s) between FirstEnergy (or its affiliated FirstEnergy EDC) and the applicable LSE that otherwise governs the calculations. Such contractual arrangement(s) shall prevail unless silent on a particular issue or calculation.

Attachment M-1 is divided into three main sections. The first section titled “Terms” defines terms specific to this Attachment M-1 that are not found in the PJM Documents. The second section titled “Wholesale” describes processes for determining the THEO for wholesale LSEs such as municipal electric utilities or electric cooperatives. The final section titled “Retail” describes processes for determining the THEO for retail LSEs such as retail generation service providers serving retail customers or retail suppliers providing provider of last resort services.

FirstEnergy performs the THEO calculation and subsequently uploads this data to PJM systems (such as PJM’s InSchedule eSuite application or its successor) on behalf of retail LSEs and wholesale LSEs serving load in each FirstEnergy Zone, unless otherwise agreed.

Questions concerning the methodologies described in this Attachment M-1 may be submitted by visiting the Supplier Support section of the FirstEnergy corporate website located here: https://www.firstenergycorp.com/supplierservices.

Section I: Terms

Unaccounted for Energy – Energy that is remaining after comparing: (a) the FirstEnergy Zone load determined by summing physical generation delivered to a FirstEnergy Zone plus net imports/exports of energy into/out of a FirstEnergy Zone to: (b) the sum of all wholesale and retail customers’ metered load, whether interval metered or estimated, including contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC, in any given hour. Unaccounted for Energy is not allocated to wholesale LSEs unless otherwise
specified in their contracts/agreements with FirstEnergy. The methodology for determining Unaccounted for Energy for an LSE providing service to retail customers receiving distribution service from a FirstEnergy EDC shall be set forth in state-approved retail tariffs.

Losses – The following loss factors shall apply for each FirstEnergy Zone. Loss factors will be applied according to location (FirstEnergy Zone) and service voltage of each meter point. For wholesale LSEs, all of the loss factors specified herein shall apply, unless otherwise established by contract and filed with FERC. For retail LSEs, the Transmission Load loss factors specified herein shall apply, however for lower service voltages, the loss factors specified in state-approved retail tariffs shall apply.

<table>
<thead>
<tr>
<th>Service Voltage</th>
<th>ATSI Ohio</th>
<th>FE PA (Penn Power, ATSI Zone)</th>
<th>FE PA (MetEd Zone)</th>
<th>FE PA (Penelec Zone)</th>
<th>JCP&amp;L</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Load</td>
<td>1.01486</td>
<td>1.01486</td>
<td>1.02100</td>
<td>1.04070</td>
<td>1.03900</td>
</tr>
<tr>
<td>Subtransmission Source</td>
<td>1.02786</td>
<td>1.02786</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Subtransmission Load</td>
<td>1.02886</td>
<td>1.02886</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary Load</td>
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<td>1.05786</td>
<td>1.03740</td>
<td>1.06060</td>
<td>1.06100</td>
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<tr>
<td>Secondary Load</td>
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<td>1.09450</td>
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<table>
<thead>
<tr>
<th>Service Voltage</th>
<th>FE PA (West Penn Power, Allegheny Power Zone)</th>
<th>Potomac Edison MD</th>
<th>Potomac Edison WV</th>
<th>Mon Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Load</td>
<td>1.02184</td>
<td>1.02245</td>
<td>1.02245</td>
<td>1.02233</td>
</tr>
<tr>
<td>Subtransmission Source</td>
<td></td>
<td></td>
<td>1.02646</td>
<td></td>
</tr>
<tr>
<td>Subtransmission w/Tran Charge</td>
<td>1.04282</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Subtransmission Load</td>
<td>1.03578</td>
<td>1.03742</td>
<td>1.03807</td>
<td>1.03390</td>
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<tr>
<td>Primary Source</td>
<td></td>
<td>1.03070</td>
<td>1.03378</td>
<td></td>
</tr>
<tr>
<td>Primary Load</td>
<td>1.06383</td>
<td>1.07542</td>
<td>1.07691</td>
<td>1.06071</td>
</tr>
<tr>
<td>Secondary Load</td>
<td>1.09434</td>
<td>1.09513</td>
<td>1.09705</td>
<td>1.09033</td>
</tr>
</tbody>
</table>

Transmission Load - For Mon Power, Potomac Edison MD, Potomac Edison WV and FE PA (West Penn Power, Allegheny Power Zone), 138 kV and above. For JCP&L and FE PA (Penelec and MetEd Zones), 34.5 kV and above. For ATSI Ohio and FE PA (Penn Power, ATSI Zone), 69 kV and above.

Subtransmission Source - For Potomac Edison WV, ATSI Ohio and FE PA (Penn Power, ATSI Zone), service at source of subtransmission bus.
Subtransmission w/Tran Charge - For FE PA (West Penn Power, Allegheny Power Zone), service on low side of subtransmission to primary transformer.

Subtransmission Load - For Mon Power, Potomac Edison MD, Potomac Edison WV, and FE PA (West Penn Power, Allegheny Power Zone), 23 kV to 69 kV. For ATSI Ohio and FE PA (Penn Power, ATSI Zone), 23 kV to 34.5 kV.

Primary Source - For Mon Power and Potomac Edison WV, service at source of primary bus.

Primary Load - For Mon Power, Potomac Edison MD, Potomac Edison WV, FE PA (West Penn Power, Allegheny Power Zone; and Penn Power, ATSI Zone), and ATSI Ohio, 1 kV to 15 kV. For FE PA (Penelec and MetEd Zones) and JCP&L, 1 kV to 34.5 KV.

Secondary Load - For all FirstEnergy EDC Zones, below 1 kV.

**Section II: Wholesale**

The FirstEnergy EDCs are required to determine the THEO for each wholesale LSE operating in their respective FirstEnergy Zones and submit this information to PJM per practices under the PJM Documents. The following procedures and methodologies describe how THEO is determined.

Note: A wholesale LSE’s THEO is determined in accordance with current and approved contractual obligations between FirstEnergy EDCs and the respective wholesale LSE. Should the current and approved agreements be silent on procedural matters regarding the determination and submittal of a wholesale LSE’s THEO, the PJM Documents shall be used to establish such procedures including those outlined below.

FirstEnergy uses the following equation to determine a wholesale LSE’s THEO in a FirstEnergy Zone. If the wholesale LSE serves load in more than one FirstEnergy Zone, the THEO is determined separately for each FirstEnergy Zone.

\[
\text{THEO} = \sum_{x=1}^{n} \left( \text{Wholesale LSE’s Interconnection Hourly Meter Reading} \times (1.0 + \text{Applicable Loss Factor}) \right)
\]

where:

\[ \text{THEO} = \text{The wholesale LSE’s hourly energy consumption in any given hour of the previous operating day in a FirstEnergy Zone} \]

\[ x = \text{A specific Meter* included in the determination of the wholesale LSE’s hourly energy consumption in a FirstEnergy Zone} \]

\[ n = \text{The total number of Meters aggregated to determine the wholesale LSE’s THEO} \]

* For purposes of this document, the term “Meter” refers to the billing quality metering devices and related equipment owned by FirstEnergy and/or the wholesale LSE, located at or near the
interconnection point (the “Interconnection”) between the FirstEnergy distribution or transmission system and the wholesale LSE system, and used to measure the wholesale LSE’s THEO.

Wholesale LSE’s Interconnection Hourly Meter Reading (WIMR) = The quantity of energy consumed by the wholesale LSE at an individual wholesale LSE’s Interconnection as shown on the Meter in a given hour, with an adjustment for certain behind-the-meter generation if applicable. Specifically, WIMR shall equal the actual interconnection point meter readings of the wholesale LSE plus the metered output of any generation resources that met all of the following three criteria during the given hour: (1) the resource was operating behind the interconnection meter, (2) the resource was participating in PJM markets or other wholesale markets, and (3) the output of the resource was wheeled across the wholesale LSE’s system to the FirstEnergy distribution or transmission system.

Applicable Loss Factor (ALF) = The contractually or otherwise mutually determined loss factor as specified herein or as otherwise filed with FERC in effect to account for losses across the applicable distribution and transmission system to the LSE’s system.

In the case where the actual WIMR is not obtained by FirstEnergy from one or more of the Meters in time to use in the calculation of the wholesale LSE’s THEO, FirstEnergy will use an estimated WIMR in place of an actual WIMR for any missing hour(s) of Meter data.

The derivation of an estimated WIMR will be determined on a case-by-case basis and be dependent on the reason for and the duration of the event triggering the need for an estimated WIMR. FirstEnergy’s WIMR methodology will take into account appropriate variables such as the history of the Interconnection Meter readings; load growth; the season of the year; temperature and any other variable(s) that could significantly affect the accuracy of the WIMR.

The following chart illustrates possible cases and outcomes of using this methodology to estimate the WIMR to be provided to PJM. The methodology used to generate a WIMR in a particular case is dependent on the reason the actual WIMR was not received.

<table>
<thead>
<tr>
<th>Case</th>
<th>Reason</th>
<th>Primary (Day After Reconciliation Estimate)</th>
<th>Secondary (60-Day Reconciliation Estimate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Short-term communication outage (&lt;59 days)</td>
<td>Profile generated in FE Settlement System*</td>
<td>Not applicable if actual Meter data received</td>
</tr>
<tr>
<td>2</td>
<td>Long-term communication error (&gt;=59 days)</td>
<td>Profile generated in FE Settlement System*</td>
<td>Not applicable if actual Meter data received via handheld device or manual entry</td>
</tr>
<tr>
<td>3</td>
<td>Short-term Meter/metering equipment malfunction (&lt; 59 days)</td>
<td>Profile generated in FE Settlement System*</td>
<td>Estimate in Meter Data Management System*</td>
</tr>
</tbody>
</table>
Long-term Meter/metering equipment malfunction (>= 59 days)

<table>
<thead>
<tr>
<th><strong>Estimate in Meter Data Management System</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>* Estimate in Meter Data Management System*</td>
</tr>
</tbody>
</table>

* If the FE Settlement or Data Management System(s) data are not available or may not be accurate, data obtained from the wholesale LSE’s Meter, SCADA or other accurate source will be used. Regardless of estimating methodology or data source, FirstEnergy will coordinate the estimate(s) of the wholesale LSE’s THEO with the affected wholesale LSE.

**Section III: Retail**

The THEO for an LSE providing service to retail customers receiving distribution service from a FirstEnergy EDC shall adhere to the following:

A. Where retail customers are interval metered and interval meter data is used for retail billing, interval meter data will be utilized for the THEO calculations.

B. Where interval meter readings are not received in time for PJM settlement deadlines, estimates will be developed using customer specific profiles.

C. Where retail customers do not have installed interval metering or use interval metering for billing, profiles will be utilized to distribute load into hourly values spanning the retail customer’s billing period.

D. All retail customer load will be grossed up for applicable transmission and distribution losses.

E. Unaccounted For Energy for each hour will be allocated to LSEs based on their load ratio share of metered load, unless such approach is prohibited by the applicable regulatory body. The FirstEnergy EDC will provide monthly, on an informational basis, the Unaccounted For Energy hourly percentages that were applied to LSEs’ hourly loads.

FirstEnergy does not determine the THEO for retail consumers of wholesale LSEs like municipal electric utilities and electric cooperatives.

Additional implementation details related to the determination of the THEO for retail LSEs and the process for submitting data for sub-account customers will be provided in the manual titled "Supplier Energy Obligation" posted under the "Supplier Registration" tab of the Supplier Support section of the FirstEnergy corporate website located here: https://www.firstenergycorp.com/supplierservices. The Manual may reflect differences based on the state utility commission requirements applicable to each FirstEnergy EDC, to the extent such requirements are not inconsistent with the requirements stated in this Attachment M-1.
ATTACHMENT M-2 (FirstEnergy Zones)

FirstEnergy Procedure for Determining a Load Serving Entity’s Peak Load Contribution (PLC) and Network Service Peak Load (NSPL)

PURPOSE

The purpose of this Attachment M-2 is to establish the procedures and methodologies under which FirstEnergy will determine the PLC and NSPL, as defined/specified in the PJM Open Access Transmission Tariff, the PJM Operating Agreement, Reliability Assurance Agreement or other relevant PJM documents (the “PJM Documents”) each PJM Planning Year for each retail and wholesale Load Serving Entity (“LSE”) serving load in the following FirstEnergy Electric Distribution Companies (“EDCs”) Zones (the “FirstEnergy Zones”): Ohio Edison Company, The Toledo Edison Company, The Cleveland Electric Illuminating Company (together, “ATSI Ohio”), FirstEnergy Pennsylvania Electric Company (“FE PA”) operating in the separate ATSI, Penelec, MetEd, and Allegheny Power PJM transmission zones, Jersey Central Power & Light Company (“JCP&L”), Monongahela Power Company (“Mon Power”) and The Potomac Edison Company (“Potomac Edison MD” and “Potomac Edison WV”). Attachment M-2 is not intended to supersede or replace any contractual arrangement(s) between FirstEnergy (or its affiliated FirstEnergy EDC) and the applicable LSE that otherwise governs the calculations. Such contractual arrangement(s) shall prevail unless silent on a particular issue or calculation.

Questions concerning the methodologies described in this Attachment M-2 may be submitted by visiting the Supplier Support section of the FirstEnergy corporate website located here: https://www.firstenergycorp.com/supplierservices.

SECTION I: TERMS


Losses - The following loss factors shall apply for each FirstEnergy Zone. Loss factors will be applied according to location (FirstEnergy Zone) and service voltage of each meter point. For wholesale LSEs, all of the loss factors specified herein shall apply, unless otherwise established by contract and filed with FERC. For retail LSEs, the Transmission Load loss factors specified herein shall apply, however for lower service voltages, the loss factors specified in state-approved retail tariffs shall apply.

<table>
<thead>
<tr>
<th>Service Voltage</th>
<th>ATSI Ohio</th>
<th>FE PA (Penn Power, ATSI Zone)</th>
<th>FE PA (MetEd Zone)</th>
<th>FE PA (Penelec Zone)</th>
<th>JCP&amp;L</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Load</td>
<td>1.01486</td>
<td>1.01486</td>
<td>1.02100</td>
<td>1.04070</td>
<td>1.03900</td>
</tr>
<tr>
<td>Service Voltage</td>
<td>FE PA (West Penn Power, Allegheny Power Zone)</td>
<td>Potomac Edison MD</td>
<td>Potomac Edison WV</td>
<td>Mon Power</td>
<td></td>
</tr>
<tr>
<td>-----------------</td>
<td>---------------------------------------------</td>
<td>-------------------</td>
<td>-------------------</td>
<td>-----------</td>
<td></td>
</tr>
<tr>
<td>Transmission Load</td>
<td>1.02184</td>
<td>1.02245</td>
<td>1.02245</td>
<td>1.02233</td>
<td></td>
</tr>
<tr>
<td>Subtransmission Source</td>
<td>1.04282</td>
<td>1.03578</td>
<td>1.03742</td>
<td>1.03807</td>
<td>1.03390</td>
</tr>
<tr>
<td>Subtransmission w/Tran Charge</td>
<td>1.03578</td>
<td>1.03742</td>
<td>1.03807</td>
<td>1.03390</td>
<td></td>
</tr>
<tr>
<td>Primary Source</td>
<td>1.06383</td>
<td>1.07542</td>
<td>1.07691</td>
<td>1.06071</td>
<td></td>
</tr>
<tr>
<td>Primary Load</td>
<td>1.09434</td>
<td>1.09513</td>
<td>1.09705</td>
<td>1.09033</td>
<td></td>
</tr>
</tbody>
</table>

Transmission Load - For Mon Power, Potomac Edison MD, Potomac Edison WV and FE PA (West Penn Power, Allegheny Power Zone), 138 kV and above. For FE PA (Penelec and MetEd Zones) and JCP&L, 34.5 kV and above. For ATSI Ohio and FE PA (Penn Power, ATSI Zone), 69 kV and above.

Subtransmission Source - For Potomac Edison WV, For ATSI Ohio and FE PA (Penn Power, ATSI Zone), service at source of subtransmission bus.

Subtransmission w/Tran Charge - For FE PA (West Penn Power, Allegheny Power Zone), service on low side of subtransmission to primary transformer.

Subtransmission Load - For Mon Power, Potomac Edison MD, Potomac Edison WV and FE PA (West Penn Power, Allegheny Power Zone), 23 kV to 69 kV. For ATSI Ohio and Penn Power, 23 kV to 34.5 kV.

Primary Source - For Mon Power and Potomac Edison WV, service at source of primary bus.

Primary Load - For Mon Power, Potomac Edison MD, Potomac Edison WV, FE PA (West Penn Power, Allegheny Power Zone; and Penn Power, ATSI Zone) and ATSI Ohio, 1 kV to 15 kV. For FE PA (Penelec and MetEd Zones) and JCP&L, 1 kV to 34.5 kV.

Secondary Load - For all FirstEnergy EDC Zones, below 1 kV.

SECTION II: WHOLESALE
Under the PJM Documents, the FirstEnergy EDCs are required to determine the PLC and NSPL for each wholesale LSE operating in their respective FirstEnergy Zones.

This Attachment M-2 supplements and clarifies the procedures and methodologies under which FirstEnergy will determine the PLC and NSPL for all wholesale LSEs with load located in one or more FirstEnergy Zone. Unless specified otherwise, this Attachment M-2 does not amend or replace any existing contracts or agreements between FirstEnergy and any wholesale LSE.

The PLC and NSPL values for each FirstEnergy Zone in which the wholesale LSE serves load will be calculated separately and will be based on the hourly reading obtained from billing quality metering and related equipment (“Meters”) owned by FirstEnergy or the wholesale LSE located at or near the interconnection point between the FirstEnergy distribution or transmission system, and the wholesale LSE system. Furthermore, all calculations in this Attachment M-2 will be done consistent with the requirements of the PJM Documents.

**PLC Calculation**

The calculation of PLC for each wholesale LSE, with load located in any of the FirstEnergy Zones, is as follows:

1. Determine the wholesale LSE’s load contribution to the total FirstEnergy Zone load at the time of the high 5 peak hours for the PJM region (“High 5 Hours”) as determined by PJM. This load is grossed up for contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC.

   If a PJM Demand Response Event (“DR Event”) occurred within the applicable FirstEnergy Zone in which the wholesale LSE serves load during one or more of the High 5 Hours, then add back the PJM-determined load reduction to each of the corresponding wholesale LSE’s loads for those DR Events affecting the High 5 Hours.

   The result is the wholesale LSE’s unrestricted PJM High 5 loads.

2. Average the wholesale LSE’s 5 unrestricted PJM High 5 loads.

3. Multiply the wholesale LSE’s average unrestricted PJM High 5 load by the ratio of (a) the appropriate FirstEnergy Zone’s weather-normalized peak to (b) the average of the FirstEnergy unrestricted loads during the PJM High 5 Hours.

Note: PJM determines the weather-normalized peak for each Transmission Zone. Where a Transmission Zone comprises more than one FirstEnergy Zone, each FirstEnergy Zone’s weather-normalized peak is determined on a load ratio share basis (including PJM add-backs, if any) using the High 5 Hours. This ensures that the weather normalization ratio is the same value for each FirstEnergy Zone in those cases where a Transmission Zone comprises more than one FirstEnergy Zone.
4. This determines the wholesale LSE’s PLC for that FirstEnergy Zone, which is posted to the wholesale LSE’s PJM RPM account.

5. Numeric Example:

FirstEnergy Zone load during PJM High 5 Hour 1: 1,000 MW
FirstEnergy Zone load during PJM High 5 Hour 2: 1,100 MW
FirstEnergy Zone load during PJM High 5 Hour 3: 850 MW
FirstEnergy Zone load during PJM High 5 Hour 4: 1,250 MW
FirstEnergy Zone load during PJM High 5 Hour 5: 1,175 MW

Step 1: Determine/compute wholesale LSE’s load during the High 5 Hours from Meters (grossed up for contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC):

Wholesale LSE’s load during PJM High 5 Hour 1: 85 MW
Wholesale LSE’s load during PJM High 5 Hour 2: 86 MW
Wholesale LSE’s load during PJM High 5 Hour 3: 70 MW
Wholesale LSE’s load during PJM High 5 Hour 4: 98 MW
Wholesale LSE’s load during PJM High 5 Hour 5: 90 MW

Step 2: Perform add-backs for High 5 DR Events, if any.

Wholesale LSE’s PJM-determined add-back during PJM High 5 Hour 4: 5 MW
Wholesale LSE’s unrestricted load during PJM High 5 Hour 4: 98 + 5 = 103 MW

Step 3: Calculate wholesale LSE’s average unrestricted load

\[
\frac{(85 + 86 + 70 + 103 + 90)}{5} = 86.8 \text{ MW}
\]

Step 4: Determine FirstEnergy Zone weather normalization ratio

Note: Any FirstEnergy or other LSE add-backs would also be included in determining the unrestricted FirstEnergy Zone loads.

Unrestricted FirstEnergy Zone load during PJM High 5 Hour 1: 1,000 MW
Unrestricted FirstEnergy Zone load during PJM High 5 Hour 2: 1,100 MW
Unrestricted FirstEnergy Zone load during PJM High 5 Hour 3: 850 MW
Unrestricted FirstEnergy Zone load during PJM High 5 Hour 4: 1,255 MW
Unrestricted FirstEnergy Zone load during PJM High 5 Hour 5: 1,175 MW

FirstEnergy Zone weather-normalized peak load: 950 MW

\[
950 \div ((1000 + 1100 + 850 + 1255 + 1175) \div 5) = 0.883
\]
Step 5: Determine PLC for wholesale LSE for that FirstEnergy Zone:

\[ 0.883 \times 86.8 = 76.6 \text{ MW} \]

**NSPL Calculation**

The NSPL calculation for a wholesale LSE is simply the wholesale LSE’s metered load at the time of the Transmission Zone peak as determined by PJM and as grossed up for contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC.

Numeric Example:

Transmission Zone peak occurred on August 1, 201X, during Hour Ending 1700.

Wholesale LSE’s load on August 1, 201X, during Hour Ending 1700 (including contractual or otherwise mutually agreed upon losses, as specified herein or as otherwise filed with FERC): 90 MW

Wholesale LSE’s NSPL = 90 MW

Note: Unlike the calculation of PLC, add-backs are not considered in determining the wholesale LSE’s NSPL.

**SECTION III: RETAIL**

The PLC and NSPL for an LSE providing service to retail customers receiving distribution service from a FirstEnergy EDC shall be determined in accordance with the following:

1. On a customer-by-customer basis, PLCs will be determined based on the customer load during the High 5 Hours.
   a. Where interval meters are utilized for retail customer billing, load values for the High 5 Hours will be determined using customer-specific interval meter data.
   b. Where interval meters are not utilized for retail customer billing, load values for the High 5 Hours will be determined from profiled data.
   c. All data will be grossed up for applicable distribution and transmission losses.
   d. If a DR Event occurred in the FirstEnergy Zone in which the retail LSE serves load during one or more of the High 5 Hours, then the PJM-determined load reduction for each customer will be added back to the customer's load value for the corresponding hour.
   e. PLCs will be scaled by the Daily Scaling Factor (“DSF”) before submittal to PJM.
2. On a customer-by-customer basis, NSPLs will be determined by:

   a. selecting the hours in which the 5 peak loads occurred during the season in which the respective Transmission Zone peak, as reported by PJM, occurred (i.e., Summer season from June 1 to September 30, or Winter season from December 1 to March 31);
   b. determining the average load values of each retail load customer during these 5 peak hours;
   c. grossing up all data for transmission and, as applicable, distribution losses; and
   d. scaling that average load value to the Transmission Zone peak as reported by PJM.

In lieu of a PLC DSF, a separate and distinct NSPL daily scaling factor is determined for each Transmission Zone and applied to each NSPL to ensure that the sum of all NSPL values reported to PJM matches the respective Transmission Zone target. For NSPL, there is no add-back for DR Events.

FirstEnergy does not determine PLCs and NSPLs for the retail consumers of wholesale LSEs like municipal electric utilities and electric cooperatives.

Additional implementation details related to the determination of the PLC and NSPL for each retail customer will be provided in the manual titled "Supplier Capacity Manual" under the "Supplier Registration" tab of the Supplier Support section of the FirstEnergy corporate website located here: https://www.firstenergycorp.com/supplierservices. The Manual may reflect differences based on the state utility commission requirements applicable to each FirstEnergy Zone, to the extent such requirements are not inconsistent with the requirements stated in this Attachment M-2.
Section(s) of the PJM Operating Agreement

(Clean Format)
SCHEDULE 12 -  
PJM MEMBER LIST

7 Bridges Solar, LLC  
AC Energy, LLC  
Acciona Energy North America Corporation (AENAC)  
ACT Commodities Inc.  
Advanced Energy Economy Inc.  
AEP Appalachian Transmission Company, Inc.  
AEP Energy Partners, Inc.  
AEP Energy, Inc.  
AEP Indiana Michigan Transmission Company, Inc.  
AEP Kentucky Transmission Company, Inc.  
AEP Ohio Transmission Company, Inc.  
AEP Retail Energy Partners, LLC  
AEP West Virginia Transmission Company, Inc.  
AES Energy Storage, LLC  
AES ES Holdings, LLC  
Aesir Power, LLC  
AES Integrated Energy, LLC  
AES Laurel Mountain, LLC  
AES Ohio Generation, LLC  
AES Solutions Management, LLC  
AEUG Madison Solar, LLC  
Affirmed Energy LLC  
Aggressive Energy LLC  
Agile Energy Trading LLC  
Agway Energy Services, LLC  
Air Products & Chemicals, Inc.  
Alabama Power Company  
Alameda Solar I, LLC  
Alegría Fund, LP  
Algonquin Energy Services, Inc.  
All American Power and Gas, LLC  
All Choice Energy MidAmerica LLC dba Raava Energy  
Allegheny Electric Cooperative, Inc.  
Allegheny Energy Supply Company, LLC  
ALLETE, Inc. d/b/a Minnesota Power  
Alliant Energy Corporate Services, Inc.  
Alliant Energy Resources, LLC  
Alpaca Energy LLC  
Alpha Gas and Electric, LLC  
Alphataraxia Palladium LLC  
Alternative Transmission Inc.  
Altop Energy Trading LLC  
Altop Energy Trading MidAtlantic LLC
Altrock LLC
Altro Power LLC
Altus Power, Inc.
Amazand, LLC
Amazon Energy LLC
Ambit Northeast, LLC
American Municipal Power, Inc.
American Power & Gas of IL, LLC
American Power & Gas of MD, LLC
American Power & Gas of NJ, LLC
American Power & Gas of Ohio, LLC
American Power & Gas of Pennsylvania, LLC
American PowerNet Management, L.P.
American Transmission Systems Inc.
Ames Energy, LLC
AMP Transmission, LLC
Anbaric Development Partners, LLC
AM Trading Solutions, LLC
AP Gas & Electric (IL), LLC
AP Gas & Electric (MD), LLC
AP Gas & Electric (OH), LLC
AP Gas and Electric (NJ), LLC
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Apogee Energy Trading LLC
Appalachian Power Company
Appian Way Energy Partners MidAtlantic, LLC
Approved Energy II LLC
Aquenergy Systems LLC
Archer Energy, LLC
Armada Power, LLC
Armenia Mountain Wind, LLC
Aspen Generating, LLC
Aspen Gen Funding, LLC
Aspire Power Ventures, LP
Associated Electric Cooperative, Inc.
Astral Energy LLC
Atlantic City Electric Company
Atlantic Energy MD, LLC
ATNV Energy, LP
Aurora Energy Research LLC
Automated Algorithms, LLC
Avangrid Networks, Inc.
Avangrid Renewables, LLC
Axpo U.S. LLC
Baltimore Gas and Electric Company
Baltimore Power Company LLC
Bancroft Energy LLC
Barclays Capital Services Corporation
Bath County Energy, LLC
Battery Utility of Ohio, LLC
Bazinga, LLC
Beaver Dam Energy LLC
Beech Ridge Energy LLC
Beech Ridge Energy II LLC
Beech Ridge Energy Storage LLC
Bellflower Solar 1, LLC
Bernards Solar, LLC
BIF II Safe Harbor Holding LLC
BIF III Holtwood LLC
Big Bend Trading, LLC
Big Level Wind LLC
Big Plain Solar, LLC
Big Rivers Electric Corporation
Big Sandy Peaker Plant, LLC
Big Savage, LLC
Big Sky Wind, LLC
Birchwood Power Partners, L.P.
Birdsboro Power LLC
Bishop Hill Energy LLC
BITH Solar I, LLC
Bitter Ridge Wind Farm, LLC
BJ Energy, LLC
Black Oak Capital, LLC
Blackout Power Trading Inc.
Black Rock Wind Force, LLC
Blackstone Wind Farm II, LLC
Blackstone Wind Farm, LLC
Blooming Grove Wind Energy Center LLC
Blossom Solar, LLC
Blue Harvest Solar Park LLC
Blue Ridge Power Agency, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Columbia, PA
Borough of Lavallette, New Jersey
Borough of Madison, New Jersey
Borough of Milltown
Borough of Mont Alto
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights
Borough of South River, New Jersey
Boston Energy Group, Inc.
Boston Energy Trading and Marketing LLC
Bowfin KeyCon Energy, LLC
Bowfin KeyCon Power, LLC
BP Energy Company
BP Energy Retail Company LLC
BP Energy Holding Company LLC
Brandon Shores LLC
BREG Aggregator LLC
Brick Standard LLC
Brookfield Energy Marketing, LP
Brookfield Power Piney & Deep Creek LLC
Brookfield Renewable Energy Marketing US LLC
Brookfield Renewable Trading and Marketing LP
Bruce Power Inc.
Brunner Island, LLC
Buckeye Power, Inc.
C4GT LLC
Caden Energix Axton LLC
Calpine Bethlehem, LLC
Calpine Energy Services, L.P.
Calpine Energy Solutions, LLC
Calpine Mid Atlantic Marketing, LLC
Calvert Cliffs Nuclear Power Plant, LLC
Cambria Wind LLC
Camden Plant Holding, L.L.C.
Camden Solar LLC
Camp Grove Wind Farm, LLC
Capacity Markets Partners, LLC
Cape May County Municipal Utilities Authority
Carolina Power Partners, LLC
Carroll County Energy LLC
Castleton Commodities Merchant Trading L.P.
Catalyst Power & Gas LLC
CCI U.S. Power Trading LLC
Central Electric Power Cooperative, Inc.
Central Transmission, LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy, LLC
Champion Energy Marketing LLC
Champion Energy Services, LLC
Chesapeake Transmission LLC
Chief Conemaugh Power, LLC
Cottontail Solar 3, LLC
Cottontail Solar 4, LLC
Cottontail Solar 5, LLC
Cottontail Solar 6, LLC
Cottontail Solar 7, LLC
Cottontail Solar 8, LLC
County of Frederick, VA
Covanta Energy Marketing LLC
Covanta Union, LLC
CP Energy Marketing (US) Inc.
CPV Backbone Solar, LLC
CPV Fairview, LLC
CPV Keasbey, LLC
CPV Maple Hill Solar, LLC
CPV MARYLAND, LLC
CPV Power Holdings, LP
CPV Retail Energy LP
CPV Shore, LLC
CPV Three Rivers, LLC
CPV Rogue's Wind, LLC
Crescent Ridge LLC
Crete Energy Venture, LLC
Crossroads Solar I, LLC
Cube Hydro Partners, LLC
Current Energy and Renewables Inc.
Customized Energy Solutions, Ltd.
CWP Energy Inc.
Cypress Creek Renewables, LLC
Danske Commodities US LLC
Darby Energy, LLLP
Darby Power, LLC
Dart Container Corporation of Pennsylvania
David Energy Supply, LLC
Dayton Power & Light Company (The)
DC Energy LLC
DC Energy Mid-Atlantic, LLC
DCO Energy, LLC
Decatur Energy Center, LLC
Delaware Division of the Public Advocate
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy, LLC
Diamond Energy East, LLC
Diamond Retail Energy, LLC
Diamond State Generation Partners, LLC
Direct Energy Business, LLC
Direct Energy Business Marketing, LLC
Direct Energy Services, LLC
Discount Power, Inc.
Divine Power, Inc.
Dominion Energy Generation Marketing, Inc.
Dominion Energy South Carolina, Inc.
Domtar Paper Company, LLC
Doral Renewables LLC
Doswell Limited Partnership
DPL Energy Resources, LLC
Drake Power, LLC
DTE Atlantic, LLC
DTE Energy Trading, Inc.
DTN, LLC
Duke-American Transmission Company, LLC
Duke Energy Business Services, LLC
Duke Energy Carolinas, LLC
Duke Energy Florida, LLC
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Progress, LLC
Duke Energy Renewable Services, LLC
Duquesne Light Company
Duquesne Light Energy, LLC
Duquesne Power LLC
DV Trading, LLC
DXT Commodities North America Inc.
Dynamix Energy Services Company, LLC
Dynasty Energy California Inc.
Dynasty Power Inc.
Dynegy Energy Services, LLC
Dynegy Marketing and Trade, LLC
Dynegy Power Marketing, LLC
Eagle Creek Hydro Holdings, LLC
Eagle Point Power Generation LLC
East Coast Power Linden Holdings L.L.C.
Eastern Generation, LLC
Eastern Shore Solar LLC
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
Ebensburg Power Company
eCap Network, LLC
EcoGrove Wind, LLC
EcoPlus Power, LLC
EDF Trading North America, LLC
Edgecombe Solar LLC
EDP Renewables North America, LLC
EF Kenilworth LLC
EFS Parlin Holdings, LLC
Electranet REP I, LLC
Elgin Energy Center, LLC
Eligo Energy, LLC
Elk Hill Solar 1, LLC
Elk Hill Solar 2, LLC
Elk Run Storage LLC
Elliot Bay Energy Trading, LLC
Elmagin Power Fund LLC
Elm Line LLC
Elmwood Park Power, LLC
Elwood Energy LLC
Emera Energy Services, Inc.
Emporia Hydropower Limited Partnership
Endurance Energy Midwest LLC
Enel Green Power Hilltopper Wind, LLC
Enel Trading North America, LLC
Enel X North America, Inc.
Energo Power & Gas LLC dba Energo
Energy Authority, Inc. (The)
Energy Center Dover LLC
Energy Cooperative Association of Pennsylvania
Energy Cooperative of America, Inc.
Energy Harbor LLC
EnergyMark, LLC
Energy Plus Holdings LLC
Energy Power Investment Company, LLC
Energy Service Providers, Inc.
Energy Technology Savings, Inc.
Energy Transfer Retail Power, LLC
EnerPenn USA, LLC
Enerwise Global Technologies, LLC
Engelhart CTP (US) LLC
ENGIE Energy Marketing NA, Inc.
ENGIE Power & Gas LLC
ENGIE Resources LLC
EnPowered USA Inc.
Entergrid Fund I LLC
EPP Renewable Energy, LLC
ESC Harrison County Power, LLC
Essential Power OPP, LLC
Essential Power Rock Springs, LLC
ETC Endure Energy L.L.C.
Evergreen Gas & Electric, LLC
Evergy Kansas Central, Inc.
Evergy Metro, Inc.
Everyday Energy, LLC
Exelon Business Services Company, LLC
Fairless Energy, L.L.C.
Fantods LLC
Fermata Energy, LLC
Fern Solar LLC
FirstEnergy Pennsylvania Electric Company
First Point Power, LLC
FiTran Fund LP
Five Elements Energy LLC
Five Forks Solar, LLC
Florida Power & Light Company
Forest Investment Group, LLC
Forked River Power LLC
Fowler Ridge Wind Farm LLC
Fowler Ridge II Wind Farm LLC
Fowler Ridge III Wind Farm LLC
Fowler Ridge IV Wind Farm LLC
Foxhound Solar, LLC
FP East Capital Partners LLC
Franklin Power LLC
Frasier Solar, LLC
Freepoint Commodities LLC
Freepoint Energy Solutions LLC
Fresh Air Energy XVIII, LLC
Fresh Air Energy XXXV, LLC
G&G Energy, Inc.
G&S Wantage Solar, LLC
Galilean Electricae LLC
Gallus Capital LLC
Galt Power, Inc.
Gavin Power, LLC
GBE Energy Marketing Inc.
GDF SUEZ Energy Resources NA, Inc.
Geenex Solar LLC
Genbright LLC
Gen IV Investment Opportunities, LLC
GenOn Energy Management, LLC
GenOn Mid-Atlantic, LLC
GenOn Power Midwest, LP
GenOn REMA, LLC
Gen Ops, LLC
Geodesic 2 LLC
Georgia Power Company
Gerdau Ameristeel Energy, Inc
GlidePath Power Operations LLC
Goldin LLC
Grand Ridge Energy LLC
Grand Ridge Energy II LLC
Grand Ridge Energy III LLC
Grand Ridge Energy IV LLC
Grand Ridge Energy Storage, LLC
Grange Solar, LLC
Granger Energy of Honey Brook, LLC
Grantham Energy Corporation
Grasshopper Energy LLC
Grays Ferry Cogeneration Partnership
Great American Gas & Electric, LLC
Great American Power, LLC
Great Barrington Energy Fund LP
Great Cove Solar I LLC
Great Cove Solar II LLC
Great Falls Hydroelectric Company Limited Partnership
Green Energy NE LLC
Greenlight Energy Inc.
Green Mountain Energy Company
Green River Holdings, LLC
Greensville County Solar Project, LLC
GRG ENERGY LLC
GridBeyond US, LLC
Gridforce Energy Management, LLC
Gridmatic Inc.
Gridmatic Panicum LLC
Grid Power Direct, LLC
Group628, LLC
GSG, LLC
GSG 6, LLC
Guernsey Power Station LLC
Guidehouse Inc.
Gunvor USA LLC
Guzman Energy LLC
H.A. Wagner LLC
H.Q. Energy Services (U.S.), Inc.
Hagerstown Light Department
Half Moon Ventures, LLC
Hamilton Liberty LLC
Hamilton Patriot LLC
Hammond Solar, LLC
Handsome Lake Energy, LLC
Harborside Energy, LLC
Hardin Solar Energy LLC
Hardin Wind LLC
Harrison REA, Inc. – Clarkesburg, WV
Hartree Partners, LP
Harts Mill Solar, LLC
Harvey Solar I, LLC
Hawks Nest Hydro LLC
Hazle Spindle, LLC
Hazleton Generation LLC
HD Project One, LLC
Headwaters Wind Farm LLC
Headwaters Wind Farm II LLC
Hecate Energy Highland LLC
Helix Ironwood, LLC
Hemlock Solar, LLC
Hemsworth Capital LP
Hemsworth Capital Midwest LP
Heritage Power Marketing, LLC
Hexis Energy Trading, LLC
Hickory Run Energy, LLC
Highland North LLC
High Point Solar LLC
High Trail Wind Farm LLC
Hillcrest Solar I, LLC
Hill Top Energy Center, LLC
Holcim (US), Inc.
Holocene Finance, LLC
Homer City Generation, LP
Hoosier Energy REC, Inc.
Horizon Power and Light, LLC
H-P Energy Resources, LLC
Hudson Energy Services LLC
Hudson Transmission Partners, LLC
Hummel Station, LLC
HXNAir Solar One, LLC
Icetec.com, Inc.
Icetec Energy Services, Inc.
IDT Energy, Inc.
IHG Core Holdings, Ltd.
IHS Global Inc.
Illinois Citizens Utility Board
Illinois Municipal Electric Agency
Illinois Power Marketing Company
IMG Midstream LLC
In Commodities US LLC
Indeck Niles, LLC
Independence Energy Group, LLC
Independent Energy Consultants, Inc.
Indiana Michigan Power Company
Indiana Municipal Power Agency
Indiana Office of Utility Consumer Counselor (IN OUCC)
Inerci Capital Inc.
Inertia Power I, LLC
Ingenco Wholesale Power, LLC
Innergex Renewable USA LLC
Innoventive Power LLC
Inspire Energy Holdings, LLC
Intelligent Generation LLC
International Paper Company
Interstate Gas Supply, LLC
Interstate Power and Light Company
Invenergy Energy Management LLC
Invenergy LLC
Invenergy Nelson Expansion LLC
Invenergy Nelson LLC
IPKeys Power Partners, Inc.
IR Energy Management LLC
ISO 1, LLC
ITC Mid-Atlantic Development LLC
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jackson Generation, LLC
Jane Street Energy Trading, LLC
Janus Power LLC
J. Aron & Company LLC
Jersey-Atlantic Wind, LLC
Jersey Central Power & Light Company
Jersey Green Energy, LLC
Josco Energy IL LLC
Josco Energy USA, LLC
JP Morgan Ventures Energy Corporation
Jupiter Power LLC
Just Energy Limited
Just Energy Solutions Inc.
KDC Solar Green Power LLC
Kendall Power Company LLC
Keni Energy LLC
Kentucky Municipal Energy Agency
Kentucky Power Company
Kestrel Acquisition, LLC
KeyCon Power Holdings LLC
Keystone Appalachian Transmission Company
Keystone-Conemaugh Projects, LLC
KeyTex Energy LLC
KeyTex Energy Solutions LLC
KFW Energy, LLC
Kimberly-Clark Corporation
Kincaid Generation, LLC
Kingsport Power Company
Kiwi Energy NY LLC
KMC Thermo, LLC
KOREnergy, Ltd.
Kuehne Chemical Company, Inc.
kWantix Trading Fund I,LLP
Lackawanna Energy Center LLC
Lafayette Power LLC
Lancaster County Solid Waste Management Authority
Landaj Investment, LLC
Land O’Lakes, Inc.
Lantar Energy LLC
Lawrenceberg Power, LLC
Lanyard Power Holdings, LLC
LCP Energy LP
Leapfrog Power, Inc.
Lee County Generating Station, LLC
Leeward Asset Management, LLC
Legacy Energy Group, LLC (The)
Lehigh Portland Cement Company
Letterkenny Industrial Development Authority – PA
Lexington Chenoa Wind Farm LLC
Liberty Electric Power, LLC
Liberty Madison Storage LLC
Lightstone Marketing LLC
Lily Pond Solar, LLC
Lincoln Generating Facility, LLC
Linden VFT LLC
LM Power, LLC
LMBE Project Company LLC
Lone Tree Wind, LLC
Long Island Lighting Company d/b/a LIPA
Long Ridge Energy Generation LLC
Longview Power, LLC
Louisville Gas and Electric Company/Kentucky Utilities Company
Lower Electric, LLC
LQA, LLC
LSP University Park, LLC
LTSTE Investments, LLC
Lyons Solar, LLC
Macquarie Energy LLC
Macquarie Energy Trading LLC
MAG Energy Solution, Inc.
Mahoning Creek Hydroelectric Company, LLC
Major Energy Electric Services, LLC
Manatee Transmission LLC
Maple Analytics, LLC
Marginal Unit, Inc.
Marina Energy, LLC
Martins Creek, LLC
Marubeni Power International, Inc.
Maryland Office of People’s Counsel
Maryland Solar LLC
Mattawoman Energy, LLC
MC Project Company LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm, LLC
Meadow Lake Wind Farm II, LLC
Meadow Lake Wind Farm III, LLC
Meadow Lake Wind Farm IV, LLC
Meadow Lake Wind Farm V, LLC
Meadow Lake Wind Farm VI LLC
MeadWestvaco Corporation
Median Energy Corp.
Median Energy IL LLC
Median Energy PA LLC
Mega Energy of Illinois, LLC
Mehoopany Wind Energy LLC
Mendota Hills, LLC
Mercuria Energy America, LLC
Mercuria SJAK Trading, LLC
Merrill Lynch Commodities, Inc.
Messer LLCsouth
Messer Energy Services, Inc.
MeterGenius, Inc.
MFT Energy US 1 LLC
Miami Valley Lighting, LLC
Mianus River Energy, LLC
Michigan Department of Attorney General, Environment, Natural Resources & Agriculture Division
Michigan Public Power Agency
MidAmerican Energy Company
MidAmerican Energy Services, LLC
Mid-Atlantic Interstate Transmission, LLC
MidAtlantic Power Partners, LLC
Middlesex County Utilities Authorities
Midwest Energy Trading East LLC
Midwest Generation, LLC
Milan Energy LLC
Milford Solar LLC
Mississippi Power Company
Mitsui Bussan Commodities Ltd.
Mitsui & Co. Energy Marketing and Services (USA), Inc.
Monongahela Power Company d/b/a Allegheny Power
Monterey MA LLC
Montour, LLC
Montpelier Generating Station, LLC
Monument Generating Station, LLC
Morgan Stanley Capital Group Inc.
Morgan Stanley Services Group Inc.
Morris Cogeneration, L.L.C
Mosaic Power, LLC
Moundsville Power, LLC
Moxie Freedom LLC
MP2 Energy LLC
MP2 Energy NE LLC dba Shell Energy Solutions
MPCF I, LLC
MPower Energy NJ LLC
Mt. Carmel Cogen, Inc.
National Gas & Electric, LLC
Nautilus Power, LLC
Nautilus Solar Energy, LLC
NDC Partners, LLC
NedPower Mount Storm, LLC
NEPM II, LLC
Neptune Regional Transmission System, LLC
Newark Energy Center, LLC
New Covert Generating Company, LLC
New Creek Wind LLC
New Jersey Division of the Ratepayer Advocate
New Jersey Transit Corporation
New Wave Energy, LLC
New York Power Authority
New York State Electric & Gas Corporation
Newark Bay Cogeneration Partnership, L.P.
New Road Power, LLC
NextEra Energy Bluff Point, LLC
NextEra Energy Marketing, LLC
NextEra Energy Services Illinois, LLC
NextEra Energy Services New Jersey, LLC
NextEra Energy Transmission, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
NextPower III US Holdco Inc.
Nexus Energy Inc.
NG Renewables Energy Marketing, LLC
NJR Clean Energy Ventures Corporation
NJR Clean Energy Ventures II Corporation
NJR Clean Energy Ventures III Corporation
Nodal Exchange, LLC
Nordic Energy Services LLC
North 301 Solar, LLC
North American Power and Gas, LLC
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
North Hanover Solar W2-082, LLC
Northampton Generating Company, L.P.
Northeastern REMC
Northeast Maryland Waste Disposal Authority
Northern Illinois Municipal Power Agency
Northern Indiana Public Service Company
Northern States Power Company
Northern Virginia Electric Cooperative - NOVEC
NorthPoint Energy Solutions, Inc.
Northstar Trading Ltd.
Northwest Ohio Wind, LLC
NRG Curtailment Solutions, Inc.
NRG Power Marketing, LLC
NRGStream LLC
NTE Ohio, LLC
nTherm, LLC
NuEnergen, LLC
Oak Trail Solar, LLC
OCI Solar Power, LLC
Octopus Energy LLC
Office of the Attorney General, Kentucky
Office of the People’s Counsel for the District of Columbia
O.H. Hutchings CT, LLC
Ohio Consumer’s Counsel
Ohio Edison Company
Ohio Power Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
Old Mission Energy Trading LLC
Olympus Power, LLC
One Energy Enterprises LLC
Ontario Power Generation Energy Trading, Inc.
Ontario Power Generation Inc.
Ontelaunee Power Operating Company, LLC
Open Road Renewables, LLC
Oregon Clean Energy, LLC
Orennia US LLC
Orsted Onshore North America, LLC
Osaka Gas USA Corporation
Owensboro Municipal Utilities
Oxbow Creek Energy LLC
Pacific Summit Energy LLC
Palladium Energy, LLC
Palm Energy LLC
Palmco Power DC, LLC
PALMco Power DE, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power PA, LLC
PALMco Power VA, LLC
Panther Creek Power Operating, LLC
Park Power LLC
Parkway Generation Operating LLC
PATH Allegheny Transmission Company, LLC
PATH West Virginia Transmission Company, LLC
Patton Wind Farm, LLC
Paulding Wind Farm II LLC
Paulding Wind Farm III LLC
Paulding Wind Farm IV LLC
Pay Less Energy, LLC
PBF Power Marketing, LLC
Peak Energy Capital LP
Peakstone Energy, LLC
PECO Energy Company
Pedricktown Cogeneration Company LP
Pegasus Energy Futures LLC
PEI Power LLC
PEI Power II, LLC
Peninsula Power, LLC
Penncat Corporation
Pennoni Associates Inc.
Pennsylvania Grain Processing LLC
Pennsylvania Office of Consumer Advocate
Pennsylvania Renewable Resources, Associates
Perast Fund LP
Pharentram Energy Services, Ltd.
Philadelphia Energy Solutions Refining and Marketing LLC
Phillips 66 Energy Trading LLC
Piedmont Energy Fund, L.P.
Pine Gate Mid-Atlantic, LLC
Pinesburg Solar LLC
Pinnacle Power LLC
Pixelle Specialty Solutions LLC
Plains Solar, LLC
Plant-E Corp.
Polaris Power Services LLC
Potomac Edison Company (The) d/b/a Allegheny Power
Potomac Electric Power Company
Potomac Energy Center, LLC
Power Analytics Software, Inc.
Power Engineers, Incorporated
Power Supply Services, LLC
Power Up Energy, LLC
Powervine Energy, LLC
PPL Electric Utilities Corporation dba PPL Utilities
Prairie Energy, Inc.
Praxair, Inc.
Precept Power LLC
Procter & Gamble Paper Products Company (The)
Prospect Power, LLC
Providence Heights Wind, LLC
Provision Power and Gas, LLC
PSEG Energy Resources & Trade LLC
PSEG Energy Solutions LLC
PSEG Nuclear LLC
Public Service Electric and Gas Company
Public Staff – North Carolina Utilities Commission
Pure Energy, Inc.
Pure Energy USA IL, LLC
Pure Energy USA, LLC
Quattro Energy LP
Radford’s Run Wind Farm, LLC
Rainbow Energy Marketing Corporation
Rainbow Energy Ventures LLC
Rausch Creek Electric Power Holdings, LLC
Realg NYC LLC
Recurrent Energy, LLC
Red Oak Power, LLC
Red Wolf TX2, LLC
Refinitiv US LLC
Reliant Energy Northeast, LLC
Renaissance Power & Gas, Inc.
Renergy Inc.
Renewable Energy Aggregators Inc.
Rensselaer Generating LLC
RES America Developments Inc.
ResCom Energy, LLC
Residents Energy, LLC
Respond Power, LLC
Rhei Energy Partners LP
Richfield Solar Energy LLC
Richland-Stryker Generation LLC
RI-Corp. Development, Inc.
River Bay Commodities, LLC
RiverCrest Power-South, LLC
Riverside Generating Company, L.L.C.
Riverstart Solar Park LLC
Rochester Gas and Electric Corporation
Rockfish Solar LLC
Rockland Electric Company
Rocky Road Power, LLC
Rodan Energy Solutions (USA) Inc.
Rolling Hills Generating, L.L.C.
Rose Gold Solar, LLC
Roseton Generating LLC
Roth Rock Wind Farm, LLC
Roundtop Energy LLC
Royal Bank of Canada
RPA Energy, Inc.
RTP Controls, Inc
RTR Energy Solutions LLC
Rushmore Energy, LLC (new)
RWE Clean Energy Solutions, Inc.
RWE Clean Energy Wholesale Services, Inc.
RWE Renewables Americas, LLC
Safe Harbor Water Power Corporation
Sanitas Power, LLC
Santanna Energy Services
Saracen Energy East LP
Saracen Energy Midwest LP
Saracen Energy West LP
Saracen Power LP
Saugatuck River Power Trading LLC
S.C. Energy Partners LLC
Schuykill Energy Resources, Inc.
Scout Storage LLC
Scrubgrass Generating Company, L.P.
Scylla Energy LLC
Seneca Generation, LLC
Seneca Trading LLC
SESCO ENTERPRISES LLC
Seven Islands Environmental Solutions, LLC
Severn River Power LLC
Seward Generation, LLC
SFE Energy, Inc.
Shell Energy North America (U.S.), L.P.
Shepard’s Neck Point LLC
Shipley Choice LLC
Sidney, LLC
Siemens Industry, Inc.
Silver Run Electric, LLC
S.J. Energy Partners, Inc.
SmartEnergy Holdings, LLC
SmarestEnergy US LLC
Smart Wires Inc.
SociVolta Inc.
Solios Power Mid-Atlantic Trading LLC
Sol Madison Solar, LLC
Southampton Solar LLC
South Bay Energy Corp.
Southeastern Chester County Refuse Authority
Southeastern Power Administration
Southern Indian Gas and Electric Company d/b/a Vectren Power Supply Inc.
Southern Maryland Electric Cooperative, Inc.
Southern Power Company
South Field Energy LLC
South Jersey Energy Company
Spark Energy, LLC
Spartacus Energy Services LLC
Spotlight Power LLC
sPower Energy Marketing, LLC
Spring Energy RRH, LLC dba Spring Power & Gas
Spruance Operating Services, LLC
Spruce Power Trading, LLC
Standard Gas & Electric, LLC
Star Jasmine Houston LLC
STATARB INVESTMENTS LLC
Sterling Partners Energy Investors LLC
St. Joseph Energy Center, LLC
Stones DR, LLC
Stoney Creek Wind Farm, LLC
Stream Energy Columbia, LLC
Stream Energy Delaware, LLC
Stream Energy Illinois, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
Stream Ohio Gas & Electric, LLC
Strom Power, LLC
Summer Energy Midwest, LLC
Summit Farms Solar, LLC
SunCoke Energy, Inc
Sunflower Solar LLC
SunSea Energy LLC
Sunshaw Power Trading, LLC
Sun Tribe Development LLC
Susquehanna Nuclear, LLC
Sustaining Power Solutions LLC
Syncarpha Solar, LLC
SYSO Inc.
Tait Electric Generating Station, LLC
Talen Energy Marketing, LLC
Tangent Energy Solutions, Inc.
Tatanka Wind Power, LLC
TC Energy Marketing Inc.
TEC Energy Inc.
TEC Trading, Inc.
Tenaska Pennsylvania Partners, LLC
Tenaska Power Management, LLC
Tenaska Power Services Co.
Tenaska Virginia Partners, L.P.
Tennessee Valley Authority (The)
TerraForm IWG Acquisition Holdings II, LLC
Texas Retail Energy, LLC
Teza Technologies LLC
The Hartz Group
The Highlands Energy Group, LLC
Think Energy, LLC
Thordin ApS
Thurmont Municipal Light Company
Tidal Energy Marketing (U.S.) L.L.C.
Tilton Energy LLC
Timber Road Solar Park LLC
TimberRock Consulting LLC
Tios Capital, LLC
Titan Gas and Power
Todd Solar LLC
Toledo Edison Company (The)
Tomorrow Energy Corp
Town of Berlin, Maryland
Town of Williamsport
Town Square Energy East, LLC
Tradewind Energy, Inc.
Trafigura Trading LLC
TrailStone Energy Marketing, LLC
Trans-Allegheny Interstate Line Company
TransAlta Energy Marketing (US) Inc.
Transource Energy, LLC
Transource Maryland, LLC
Transource Pennsylvania, LLC
Transource West Virginia, LLC
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Tri Global Energy, LLC
TrueLight Commodities, LLC
Trustees of the University of Pennsylvania
Tupelo Solar I, LLC
TWE Myrtle Solar Project, LLC
Twin Eagle Resource Management, LLC
Tyne Hill Investments LP
Tyr Energy, LLC
UGI Development Company
UGI Energy Services, LLC
UGI Utilities, Inc.
Uncia Energy LP – Series B
Union Electric Company d/b/a Ameren Missouri
Union Ridge Solar, LLC
University Park Energy, LLC
UN-School House Holding LLC
Urban Grid Solar Projects, LLC
V3 Commodities Group, LLC
VCIOM, LLC
VECO Power Trading, LLC
Velocity American Energy Master I, LP
Verde Energy USA DC, LLC
Verde Energy USA Illinois, LLC
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verde Energy USA, Inc.
Vineland Municipal Electric Utility
Virginia Division of Consumer Counsel
Virginia Electric and Power Company
Virginia Solar 2017 Projects LLC
Virginia State Corporation Commission
Viribus Fund LP
Viridian Energy Ohio LLC
Viridian Energy PA, LLC
Viridity Energy Solutions Inc.
Vista Energy Marketing, L.P.
Vitol, Inc.
Voltus, Inc.
Wabash Valley Power Association, Inc.
Volunteer Energy Services, Inc.
Walden Renewables Development LLC
Walnut Ridge Wind, LLC
Valleye Power, LLC
Waterford Power, LLC
Waverly Solar, LLC
Wellsboro Electric Company
West Deptford Energy, LLC
Western Reserve Energy Services, LLC
West Virginia Consumer Advocate Division
WGL Energy Services, Inc.
Wheelabrator Baltimore, L.P.
Wheelabrator Falls Inc.
Wheelabrator Frackville Energy Company, Inc.
Wheelabrator Gloucester Company, L.P.
Wheelabrator Portsmouth, Inc.
Wheeling Power Company
White Peak Energy LLC
Whitetail Solar 1, LLC
Whitetail Solar 2, LLC
Whitetail Solar 3, LLC
Whitmore Solar, LLC
Whitney Hill Wind Power, LLC
Wildcat Wind Farm I, LLC
Wilkinson Solar LLC
Willey Battery Utility, LLC
Wisconsin Power and Light Company
WM Renewable Energy, LLC
Wolf Hills Energy, LLC
Wolf Run Energy LLC
Wolverine Holdings, L.P.
Wolverine Power Supply Cooperative, Inc.
Wolverine Trading, LLC
WP&G Holdings, LLC
WPPI Energy
Wrigley Capital LLC
Wyandot Solar LLC
XO Energy MA, LP
XO Energy MA2, LP
XO Energy MA3, LP
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
XOOM Energy Ohio, LLC
XOOM Enegy Washington D.C., LLC
Xoom Energy, LLC
Yankee Street, LLC
Yellow Jacket Energy, LLC
Yes Energy LLC
York County Solid Waste and Refuse Authority
York Generation Company LLC
York Haven Power Company, LLC
Zongyi Solar America Co. Ltd.
Section(s) of the Reliability Assurance Agreement

(Clean Format)
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<td>Ohio Valley Electric Corporation</td>
<td>OVEC</td>
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* FirstEnergy Pennsylvania Electric Company (“FE PA”) is the successor-in-interest to Pennsylvania Electric Company, but all references to the Pennsylvania Electric Company or Penelec Zone remain unchanged.

** FirstEnergy Pennsylvania Electric Company (“FE PA”) is the successor-in-interest to Metropolitan Edison Company, but all references to the Metropolitan Edison Company or MetEd Zone remain unchanged.
SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Energy, Inc.
AEP Retail Energy Partners LLC
AES Ohio Generation, LLC
AES Solutions Management, LLC
Aggressive Energy LLC
Agway Energy Services, LLC
Algonquin Energy Services Inc.
All American Power and Gas, LLC
All Choice Mid America LLC dba Raava Energy
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, L.L.C.
Alpaca Energy LLC
Alpha Gas and Electric LLC
Ambit Northeast, LLC
American Electric Power Service Corporation on behalf of its affiliates:
  Appalachian Power Company
  Indiana Michigan Power Company
  Kentucky Power Company
  Kingsport Power Company
  Ohio Power Company
  Wheeling Power Company.
American Municipal Power, Inc.
American Power & Gas of IL, LLC
American Power & Gas of MD, LLC
American Power & Gas of NJ, LLC
American Power & Gas of Ohio, LLC
American Power & Gas of Pennsylvania, LLC
American PowerNet Management, L.P.
American Transmission Systems, Inc.
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Approved Energy II LLC
Archer Energy, LLC
Astral Energy LLC
Atlantic City Electric Company
Atlantic Energy MD, LLC
Avangrid Renewables, LLC
Axpo U.S. LLC
Baltimore Gas and Electric Company
Baltimore Power Company LLC
Barclays Capital Services, Inc
Bativa, IL (City of)
BBPC LLC d/b/a Great Eastern Energy
Blackstone Wind Farm, LLC
Blue Ridge Power Agency, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Columbia, PA
Borough of Lavallette, New Jersey
Borough of Milltown
Borough of Mont Alto, PA
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights, New Jersey
Borough of South River, New Jersey
Boston Energy Trading and Marketing LLC
BP Energy Company
BP Energy Retail Company LLC
Brookfield Renewable Energy Marketing US LLC
BTG Pactual Commodities (US) LLC
Buckeye Power, Inc.
Calpine Energy Service, L.P.
Calpine Energy Solutions, LLC
Catalyst Power
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy Marketing LLC
Champion Energy, LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Citigroup Energy Inc.
Citizens’ Electric Company of Lewisburg, PA
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of New Martinsville - WV
City of Rochelle
CleanChoice Energy, Inc.
Clearview Electric, Inc.
Cleveland Electric Illuminating Company
Click Energy, LLC
CMS Resource Management Company
Collegiate Clean Energy, LLC
Commonwealth Edison Company
ConocoPhillips Company
Constellation Energy Generation, LLC
Constellation NewEnergy, Inc.
Convanta Energy Marketing LLC
CPV Retail Energy LP
Current Energy and Renewables Inc.
David Energy Supply, LLC
Dayton Power & Light Company (The)
DC Energy LLC
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy LLC
Diamond Energy East, LLC
Direct Energy Business, LLC
Direct Energy Business Marketing, LLC
Direct Energy Services, LLC
Discount Power, Inc.
DPL Energy Resources, Inc.
DTE Atlantic, LLC
DTE Energy Trading, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Duquesne Light Energy, LLC
DXT Commodities North America Inc.
Dynegy Energy Services, LLC
Dynegy Marketing and Trade, LLC
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
EcoPlus Power, LLC
EDF Trading North America, LLC
Eligio Energy, LLC
Enel Trading North America, LLC
Energetix, Inc.
Energy Cooperative Association of Pennsylvania (The)
Energy Cooperative of America, Inc.
Energy Harbor LLC
EnergyMark, LLC
Energy Plus Holdings LLC
Energy Services Providers, Inc.
Energy Technology Savings, Inc.
Energy Transfer Retail Power, LLC
EnerPenn USA, LLC
Engie Energy Marketing NA, Inc.
EnPowered USA Inc.
Evergreen Gas & Electric, LLC
Everyday Energy, LLC
FirstEnergy Pennsylvania Electric Company
First Point Power, LLC  
Freepoint Energy Solutions LLC  
Front Royal (Town of)  
Galt Power Inc.  
GenOn Power Midwest, LP  
Gerdau Ameristeel Energy, Inc.  
Great American Gas & Electric, LLC  
Great American Power, LLC  
Greenlight Energy Inc.  
Green Mountain Energy Company  
Grid Power Direct, LLC  
Hagerstown Light Department  
Harborside Energy, LLC  
Harrison REA, Inc. - Clarksburg, WV  
Hartee Parnters, LP  
Holcim (US) Inc.  
Hoosier Energy REC, Inc.  
Horizon Power and Light LLC  
Hudson Energy Services, LLC  
IDT Energy, Inc.  
Illinois Municipal Electric Agency  
Illinois Power Marketing Company  
Inspire Energy Holdings, LLC  
Interstate Gas Supply, LLC  
J.P. Morgan Ventures Energy Corporation  
Jack Rich, Inc. d/b/a Anthracite Power & Light Company  
J. Aron & Company LLC  
Jersey Central Power & Light Company  
Josco Energy USA, LLC  
Just Energy Limited  
Just Energy Solutions Inc.  
Kentucky Municipal Energy Agency  
Kiwi Energy NY LLC  
Kuehne Chemical Company, Inc.  
Land O’Lakes, Inc.  
Lower Electric, LLC  
Macquarie Cook Energy LLC  
Major Energy Electric Services LLC  
MC Squared Energy Services, LLC  
Meadow Lake Wind Farm LLC  
Meadow Lake Wind Farm II LLC  
Meadow Lake Wind Farm III LLC  
Meadow Lake Wind Farm IV LLC  
MeadWestvaco Corporation  
Median Energy Corp.
Median Energy PA LLC
Mega Energy Holdings, LLC
Mercuria Energy America, Inc.
Messer Energy Services, Inc.
MeterGenius Inc.
MidAmerican Energy Company
MidAmerican Energy Services, LLC
Morgan Stanley Capital Group, Inc.
Morgan Stanley Services Group Inc.
MP2 Energy NE, LLC dba Shell Energy Solutions
MPower NJ LLC
National Gas & Electric, LLC
NextEra Energy Marketing, LLC
Nextera Energy Services New Jersey, LLC
Nextera Energy Services, Illinois, LLC
Nordic Energy Services LLC
North American Power and Gas LLC.
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northeastern REMC
Northern States Power Company
Northern Virginia Electric Cooperative – NOVEC
NRG Power Marketing, L.L.C.
nTherm, LLC
Octopus Energy LLC
Ohio Edison Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
Palmco Power DC, LLC
PALMco Power DE, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power PA, LLC
PALMco Power VA, LLC
Park Power LLC
Pay Less Energy, LLC
PBF Power Marketing LLC
PECO Energy Company
Pennsylvania Grain Processing LLC
PEPCO Energy Services, Inc.
Pinnacle Power LLC
Plymouth Rock Energy, LLC
Polaris Power Services LLC
Potomac Electric Power Company
Power UP Energy, LLC
Powervine Energy, LLC
PPL Electric Utilities Corporation d/b/a PPL Utilities
Prairieland Energy, Inc.
Provision Power and Gas, LLC
PSEG Energy Resources & Trade LLC
PSEG Energy Solutions LLC
Public Service Electric and Gas Company
Pure Energy USA IL, LLC
Pure Energy USA, LLC
Realgy, LLC
Red Oak Power, LLC
Renaissance Power & Gas, Inc.
ResCom Energy, LLC
Residents Energy, L.L.C.
Respond Power LLC
Riverside Generating Company, LLC
Rolling Hills Generating, LLC
RPA Energy, Inc.
Rushmore Energy, LLC (new)
RWE Clean Energy Solutions, Inc.
RWE Clean Energy Wholesale Services, Inc.
S.J. Energy Partners, Inc.
Santanna Energy Services
Seward Generation, LLC
SFE Energy, Inc.
Shipley Choice LLC
Smartest Energy US LLC
Solios Power Mid-Atlantic Trading LLC
South Bay Energy Corp.
South Jersey Energy Company
Southeastern Power Administration
Southern Indiana Gas & Electric
Southern Maryland Electric Cooperative, Inc.
Spark Energy, LLC
Spring Energy RRH, LLC dba Spring Power & Gas
Standard Gas & Electric, LLC
Stream Energy Columbia, LLC
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Stream Energy Illinois, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
Stream Ohio Gas & Electric, LLC
Summer Energy Midwest, LLC
SunSea Energy LLC
Talen Energy Marketing, LLC
Tenaska Power Services Co.
Texas Retail Energy, LLC
Think Energy, LLC
Thurmont Municipal Light Company
Titan Gas and Power
Toledo Edison Company (The)
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Town of Berlin, Maryland
Town of Williamsport
Town Square Energy East, LLC
TransAlta Energy Marketing (U.S.) Inc.
TransCanada Power Marketing Ltd.
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trustees of the University of Pennsylvania
Twin Eagle Resource Management, LLC
UGI Energy Services, LLC
UGI Utilities, Inc. - Electric Division
Verde Energy USA DC, LLC
Verde Energy USA Illinois, LLC
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verde Energy USA, Inc.
Vineland Municipal Electric Utility (City of Vineland)
Virginia Electric & Power Company
Viridian Energy PA LLC
Viridian Energy Ohio LLC
Vista Energy Marketing, L.P.
Volunteer Energy Services, Inc.
Wabash Valley Power Association, Inc.
Wellsboro Electric Company
WGL Energy Services, Inc.
Wolverine Holdings, L.P.
Wolverine Power Supply Cooperative, Inc.
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
XOOM Energy Ohio, LLC
Xoom Energy, LLC
York Generation Company, LLC