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PSEG Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

October 24, 2017

In the Matter of the Provision of Basic Generation Service
for Year Two of the Post-Transition Period
\- and -
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2015
-and-
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2016
-and-
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2017

BPU Docket Nos. EO03050394, ER14040370, ER15040482, and ER16040337

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Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff Docket No. ________________

Irene Kim Asbury
Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 9th Fl
Post Office Box 350
Trenton, NJ 08625-0350

Dear Secretary Asbury:

Enclosed for filing on behalf of Jersey Central Power & Light Company, Public Service Electric and Gas Company, Rockland Electric Company and Atlantic City Electric Company (collectively, the "EDCs") please find an original and 10 copies of tariff sheets and supporting exhibits proposed by each of the EDCs and revised to reflect changes to the PJM Open Access Transmission Tariff ("OATT") made in response to the formula rate filing made by Mid-Atlantic Interstate Transmission, LLC ("MAIT") in Federal Energy Regulatory Commission ("FERC") Docket No. ER17-211-000 and ER17-211-001.

Background

In its Order dated October 22, 2003 (BPU Docket No. EO03050394), the New Jersey Board of Public Utilities ("Board") authorized the EDCs to recover FERC-approved changes in firm transmission service-related charges. The Board has also authorized recovery of FERC-approved changes in firm transmission service-related charges in subsequent orders approving the Basic Generation Service ("BGS") supply procurement process and the associated Supplier Master Agreements ("SMAs"). Furthermore, by subsequent Orders, the BPU has approved Section 15.9 of the Supplier Master Agreements ("SMAs") filed by the EDCs, which authorize the EDCs to increase or decrease the rates paid to suppliers for FERC-approved rates and changes to Firm Transmission Service once approved by the Board.

The Transmission Enhancement Charges ("TECs") detailed in Schedule 12 of the PJM OATT were implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (again, as defined in the PJM OATT) that are requested by PJM for reliability or economic purposes. TECs are recovered by PJM through an additional transmission charge in the transmission zones assigned cost responsibility for Required Transmission Enhancement projects.

In turn, the EDCs file with the Board to recover costs associated with TECs from BGS customer and to pay BGS suppliers for TEC charges assigned to them by PJM for the load they serve in the respective EDC service territories.[1] BGS Suppliers began paying these increased transmission charges in July 2017.[2]

Request for Board Approval

The EDCs request Board approval to implement the attached, revised BGS-RSCP and BGS-CIEP tariff rates effective December 1, 2017. In support of this request, the EDCs have included pro-forma tariff sheets shown in Attachment 1. The proposed BGS tariff rates have been modified in accordance with the Board-approved methodology contained in each EDC's Company-Specific Addendum in the above-referenced BGS proceedings and in conformance with each EDC's Board-approved BGS tariff sheets. The attached pro-forma tariff sheets propose an effective date of December 1, 2017 and will remain in effect until changed. The BGS-RSCP and BGS-CIEP rates included in the amended tariff sheets for each EDC are revised to reflect costs effective on July 1, 2017 for TECs resulting from FERC tariff Filings. These rates are based on the FERC-authorized (and PJM implemented) rates for transmission services, including recent cost reallocations implemented by PJM.[3]

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[1] The EDCs pay suppliers subject to the conditions of the Board-approved SMAs.

[2] *Mid-Atlantic Interstate Transmission. LLC* 158 FERC ¶ 62,185, (Docket Nos. ER17-211-000 and ER17-211-001), FERC Letter Order Accepting and Suspending Filing, Subject to Refund, and Establishing Hearing and Settlement Judge Procedures, March 10, 2017.

[3] *Id.*

Attachment 2 shows the cost impact for the 2017/2018 period for each of the EDCs. These costs were allocated to the various transmission zones using the cost information from the formula rates for the projects covered by the Filings, as posted on the PJM website. The translation of the transmission zone rate impact to the BGS rates of each of the EDCs assuming implementation on December 1, 2017 is included as Attachment 3. Copies of the Filings and all formula rate updates are included as Attachment 4, and can also be found on the PJM website at http://www.pjm.com/markets-and-operations/transmission-service/formula-rates.aspx.

The EDCs also request that the BGS Suppliers be compensated for the changes to the OATT resulting from the implementation of the formula rate effective July 1, 2017. Suppliers will be compensated subject to the terms and conditions of the applicable SMAs. Any differences between payments to BGS-RSCP and BGS-CIEP Suppliers and charges to customers will flow through BGS Reconciliation Charges. This treatment is consistent with the previously-approved mechanisms.

This filing satisfies the requirements of ¶¶ 15.9 (a)(i) and (ii) of the BGS-RSCP and BGS-CIEP SMAs, which mandate that BGS-RSCP and BGS-CIEP Suppliers be notified of rate increases for firm transmission service, and that the EDCs file for and obtain Board approval of an increase in retail rates commensurate with the FERC-implemented rate increase.

We thank the Board for all courtesies extended.

Respectfully submitted,

Attachments

cc: Thomas Walker, NJBPU
Stacy Peterson, NJBPU
Stefanie Brand, Division of Rate Counsel
Service List (Electronic)

Attachment 1A
Public Service Electric and Gas Company Tariff Sheets

Attachment 1B
Jersey Central Power and Light Tariff Sheets

Attachment 1C
Rockland Electric Company Tariff Sheets

Attachment 1D
Atlantic City Electric Company Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 75**
Superseding
B.P.U.N.J. No. 15 ELECTRIC **XXX Revised Sheet No. 75**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	$0.114498	$0.122370	$0.114552	$0.122427
RS – in excess of 600 kWh	0.114498	0.122370	0.123670	0.132172
RHS – first 600 kWh	0.092636	0.099005	0.087740	0.093772
RHS – in excess of 600 kWh	0.092636	0.099005	0.099932	0.106802
RLM On-Peak	0.195521	0.208963	0.206959	0.221187
RLM Off-Peak	0.054505	0.058252	0.050741	0.054229
WH	0.054424	0.058166	0.051835	0.055399
WHS	0.054891	0.058665	0.051426	0.054962
HS	0.092625	0.098993	0.093504	0.099932
BPL	0.051712	0.055267	0.046936	0.050163
BPL-POF	0.051712	0.055267	0.046936	0.050163
PSAL	0.051712	0.055267	0.046936	0.050163

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 15 ELECTRIC **XXX Revised Sheet No. 79**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September ....$ 5.7899
Charge including New Jersey Sales and Use Tax (SUT) ....$ 6.1880

Charge applicable in the months of October through May...$ 5.7899
Charge including New Jersey Sales and Use Tax (SUT) ....$ 6.1880

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC ....$ 92,569.05 per MW per year
PJM Reallocation..$ 0.00 per MW per year
PJM Seams Elimination Cost Assignment Charges ....$ 0.00 per MW per month
PJM Reliability Must Run Charge..$ 0.00 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $102.26 per MW per month
Virginia Electric and Power Company ....$ 84.08 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....$ 11.32 per MW per month
PPL Electric Utilities Corporation..$ 52.22 per MW per month
American Electric Power Service Corporation ....$ 28.18 per MW per month
Atlantic City Electric Company. ....$ 11.09 per MW per month
Delmarva Power and Light Company...$ 0.33 per MW per month
Potomac Electric Power Company. ....$ 3.24 per MW per month
Baltimore Gas and Electric Company…………………………………$ 6.91 per MW per month
Mid Atlantic Interstate Transmission………………………………… $ 7.70 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months...$ 8.0214
Charge including New Jersey Sales and Use Tax (SUT) ....$ 8.5729

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC .... $ 92,569.05 per MW per year
PJM Reallocation.. $ 0.00 per MW per year
PJM Seams Elimination Cost Assignment Charges .... $ 0.00 per MW per month
PJM Reliability Must Run Charge.. $ 0.00 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $102.26 per MW per month
Virginia Electric and Power Company .... $ 84.08 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. .... $ 11.32 per MW per month
PPL Electric Utilities Corporation.. $ 52.22 per MW per month
American Electric Power Service Corporation .... $ 28.18 per MW per month
Atlantic City Electric Company. .... $ 11.09 per MW per month
Delmarva Power and Light Company... $ 0.33 per MW per month
Potomac Electric Power Company. .... $ 3.24 per MW per month
Baltimore Gas and Electric Company………………………………$ 6.91 per MW per month
Mid Atlantic Interstate Transmission………………………………… $ 7.70 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months.. $ 8.0214
Charge including New Jersey Sales and Use Tax (SUT) .... $ 8.5729

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED. Effective September 1, 2017, a RMR surcharge of **$0.000131** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective September 1, 2017, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

AEP-East-TEC surcharge of **$0.000111** per KWH
PATH-TEC surcharge of **$0.000046** per KWH
VEPCO-TEC surcharge of **$0.000342** per KWH
PSEG-TEC surcharge of **$0.001752** per KWH
TRAILCO-TEC surcharge of **$0.000461** per KWH
PEPCO-TEC surcharge of **$0.000015** per KWH
ACE-TEC surcharge of **$0.000084** per KWH
Delmarva-TEC surcharge of **$0.000001** per KWH
PPL-TEC surcharge of **$0.000211** per KWH
BG&E-TEC surcharge of **$0.000031** per KWH

Effective December 1, 2017, the following TEC surcharge (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

MAIT-TEC surcharge of **$0.000033** per KWH

3) BGS Reconciliation Charge per KWH: ($0.002331) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-up.

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

3) BGS Transmission Charge per KWH: (Continued)

Effective September 1, 2017, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	AEP-East-TEC	PATH-TEC	VEPCO-TEC	PSEG-TEC
GS and GST	**$0.000111**	**$0.000046**	**$0.000342**	**$0.001752**
GP	**$0.000068**	**$0.000028**	**$0.000211**	**$0.001077**
GT	**$0.000060**	**$0.000025**	**$0.000186**	**$0.000952**
GT – High Tension Service	**$0.000014**	**$0.000005**	**$0.000044**	**$0.000222**

	TRAILCO-TEC	PEPCO-TEC	ACE-TEC
GS and GST	**$0.000461**	**$0.000015**	**$0.000084**
GP	**$0.000283**	**$0.000009**	**$0.000052**
GT	**$0.000251**	**$0.000007**	**$0.000046**
GT – High Tension Service	**$0.000059**	**$0.000002**	**$0.000011**

	Delmarva-TEC	PPL-TEC	BG&E-TEC
GS and GST	**$0.000001**	**$0.000211**	**$0.000031**
GP	**$0.000001**	**$0.000129**	**$0.000019**
GT	**$0.000001**	**$0.000114**	**$0.000017**
GT – High Tension Service	**$0.000000**	**$0.000027**	**$0.000004**

Effective December 1, 2017, the following TEC surcharge (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	MAIT-TEC
GS and GST	**$0.000033**
GP	**$0.000021**
GT	**$0.000019**
GT – High Tension Service	**$0.000004**

4) BGS Reconciliation Charge per KWH: ($0.000885) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-up.

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charge

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
First 250 kWh ...... @	1.208 ¢ per kWh	1.208 ¢ per kWh
Over 250 kWh ..... @	1.208 ¢ per kWh	1.208 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

All kWh	0.878 ¢ per kWh	0.878 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges as described in General Information Section Nos. 33, 34, and 35, respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges (Continued)

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	0.519 ¢ per kWh	0.519 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.458 ¢ per kWh	0.458 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Surcharges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges as described in General Information Section Nos. 33, 34, and 35, respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY HEATING SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charge

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday ......@	0.810 ¢ per kWh	0.810 ¢ per kWh
Off-Peak All other kWh ......@	0.810 ¢ per kWh	0.810 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

All kWh .....@	0.461 ¢ per kWh	0.461 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges, as described in General Information Section Nos. 33, 34, and 35, respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 5
RESIDENTIAL SPACE HEATING SERVICE (Continued)

RATE - MONTHLY (Continued)

(3) Transmission Charge

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
First 250 kWh ... @	0.793 ¢ per kWh	0.793 ¢ per kWh
Next 450 kWh ... @	0.793 ¢ per kWh	0.793 ¢ per kWh
Over 700 kWh ... @	0.793 ¢ per kWh	0.793 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

All kWh ... @	0.604 ¢ per kWh	0.604 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges as described in General Information Section Nos. 33, 34, and 35, respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

		Primary	High Voltage Distribution
Demand Charge			
Period I	All kW @	$1.91 per kW	$1.91 per kW
Period II	All kW @	0.50 per kW	0.50 per kW
Period III	All kW @	1.74 per kW	1.74 per kW
Period IV	All kW @	0.50 per kW	0.50 per kW
Usage Charge			
Period I	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh
Period II	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh
Period III	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh
Period IV	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

		Primary	High Voltage Distribution
All Periods	All kWh @	0.322 ¢ per kWh	0.322 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, and Securitization Charges as described in General Information Section Nos. 33, 34, and 35 respectively, shall be assessed on all kWh delivered hereunder.

(Continued)

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

SPECIAL PROVISIONS

(A) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 3.289 ¢ per kWh during the billing months of October through May and 5.316 ¢ per kWh during the summer billing months and a Transmission Charge of 0.551 ¢ per kWh and a Transmission Surcharge of 0.322 ¢ per kWh during all billing months.

When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.93 per year per kW of space heating capacity. This provision applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit.

All usage under this Special Provision shall also be subject to Parts (4), (5), and (6) of RATE – MONTHLY. This Special Provision is not available to those customers taking high voltage distribution service.

This special provision is closed to new customers effective August 1, 2014.

(B) Budget Billing Plan

Any condominium association or cooperative housing corporation who takes service hereunder and any other customer taking service under Special Provision B of this Service Classification may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 8 of this tariff.

(Continued)

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 60b

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000160 per kWh

This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

Transmission Enhancement Charge

This charge reflects Transmission Enhancement Charges ("TECs"), implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (as defined in Schedule 12 of the PJM OATT) that are requested by PJM for reliability or economic purposes and approved by the Federal Energy Regulatory Commission (FERC). The TEC charge (in $ per kWh by Rate Schedule), including administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT, is delineated in the following table.

	Rate Class							
	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/CSL	DDC
VEPCo	0.000421	0.000332	0.000349	0.000233	0.000196	0.000150	-	0.000140
TrAILCo	0.000588	0.000492	0.000531	0.000325	0.000261	0.000250	-	0.000206
PSE&G	0.000633	0.000499	0.000524	0.000349	0.000294	0.000226	-	0.000211
PATH	0.000056	0.000044	0.000046	0.000031	0.000026	0.000020	-	0.000018
PPL	0.000238	0.000199	0.000215	0.000131	0.000105	0.000102	-	0.000083
Pepco	0.000021	0.000018	0.000019	0.000012	0.000010	0.000010	-	0.000007
MAIT	0.000032	0.000027	0.000029	0.000017	0.000014	0.000014	-	0.000011
JCP&L	0.000003	0.000003	0.000003	0.000002	0.000002	0.000001	-	0.000001
Delmarva	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
BG&E	0.000073	0.000061	0.000066	0.000041	0.000032	0.000031	-	0.000026
AEP - East	0.000116	0.000092	0.000096	0.000064	0.000053	0.000042	-	0.000038
Total	0.002182	0.001768	0.001879	0.001206	0.000994	0.000847	-	0.000742

Date of Issue: **Effective Date:**

Issued by:

Attachment 2

Cost Allocation of 2017 MAIT Schedule 12 Charges

Attachment 2 - Transmission Enhancement Charges for July 2017 - December 2017
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project					
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**July 2017-Dec 2017 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**	
Install 230kV series reactor and 2-100MVAR PLC switched capacitors at Hunterstown	b0215	$ 1,824,693.35	6.71%	16.85%	22.67%	0.34%	$122,437	$307,461	$413,658	$6,204	$849,760	
Replace wave trap at Kestone 500kV Sub	b0284.3	$ 10,703.36	1.70%	3.78%	0.00%	0.00%	$182	$405	$0	$0	$587	
Install 100 MVAR Cap Banks at Jack's Mountain 500 kV Sub	b0369	$ 524,464.42	1.70%	3.78%	6.22%	0.25%	$8,916	$19,825	$32,622	$1,311	$62,673	
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549	$ 485,007.07	1.70%	3.78%	6.22%	0.25%	$8,245	$18,333	$30,167	$1,213	$57,958	
Install 25 MVAR capacitor at Saxton 115 kV Sub	b0551	$ 198,313.37	8.58%	18.16%	26.13%	0.97%	$17,015	$36,014	$51,819	$1,924	$106,772	
Install 50 MVAR capacitor at Altoona 230 kV Sub	b0552	$ 156,456.58	8.58%	18.16%	26.13%	0.97%	$13,424	$28,413	$40,882	$1,518	$84,236	
Install 50 MVAR capacitor at Raystoon 230 kV Sub	b0553	$ 139,823.31	8.58%	18.16%	26.13%	0.97%	$11,997	$25,392	$36,536	$1,356	$75,281	
Install 75 MVAR capacitor at East Towanda 230 kV Sub	b0557	$ 328,223.63	8.58%	18.16%	26.13%	0.97%	$28,162	$59,605	$85,765	$3,184	$176,716	
Relocate the Erie South 345 kV Line Terminal	b1993	$ 1,648,747.99	0.00%	5.14%	12.10%	0.48%	$0	$84,746	$199,499	$7,914	$292,158	
Conver Lewis Run-Farmers Valley to 230kV using 1033.5 Conductor	b1994	$ 7,402.85	0.00%	8.64%	13.55%	0.54%	$0	$640	$1,003	$40	$1,683	
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1	$ 227,060.41	1.70%	3.78%	6.22%	0.25%	$3,860	$8,583	$14,123	$568	$27,134	ME
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1_dfax	$ 227,060.41	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0	
							$214,238	**$589,415**	**$906,074**	**$25,231**	**$1,734,957**	
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)	

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2017TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2017 Impact (6 months)**	**2018 Impact (6 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 75,506.16	9,800.3	$ 7.70	$ 453,037	$ 453,037	$ 906,074
JCP&L	$ 49,117.93	5,954.8	$ 8.25	$ 294,708	$ 294,708	$ 589,415
ACE	$ 17,853.13	2,673.4	$ 6.68	$ 107,119	$ 107,119	$ 214,238
RE	$ 2,102.55	402.0	$ 5.23	$ 12,615	$ 12,615	$ 25,231
Total Impact on NJ Zones	**$ 144,579.77**			**$ 867,479**	**$ 867,479**	**$ 1,734,957**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2017 allocation share percentages are from PJM OATT

SCHEDULE 12 – APPENDIX

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0215	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown		AEC (6.71%) / APS (3.97%) / DPL (9.10%) / JCPL (16.85%) / ME (10.53%) / Neptune* (1.69%) / PECO (19.00%) / PPL (7.55%) / PSEG (22.67%) / RE (0.34%) / UGI (0.95%) / ECP** (0.64%)
b0404.1	Replace South Reading 230 kV breaker 107252		ME (100%)
b0404.2	Replace South Reading 230 kV breaker 100652		ME (100%)
b0575.1	Rebuild Hunterstown – Texas Eastern Tap 115 kV		ME (100%)
b0575.2	Rebuild Texas Eastern Tap – Gardners 115 kV and associated upgrades at Gardners including disconnect switches		ME (100%)
b0650	Reconductor Jackson – JE Baker – Taxville 115 kV line		ME (100%)
b0652	Install bus tie circuit breaker on Yorkana 115 kV bus and expand the Yorkana 230 kV ring bus by one breaker so that the Yorkana 230/115 kV banks 1, 3, and 4 cannot be lost for either B-14 breaker fault or a 230 kV line or bank fault with a stuck breaker		ME (100%)

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

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0653	Construct a 230 kV Bernville station by tapping the North Temple – North Lebanon 230 kV line. Install a 230/69 kV transformer at existing Bernville 69 kV station		ME (100%)
b1000	Replace Portland 115kV breaker '95312'		ME (100%)
b1001	Replace Portland 115kV breaker '92712'		ME (100%)
b1002	Replace Hunterstown 115 kV breaker '96392'		ME (100%)
b1003	Replace Hunterstown 115 kV breaker '96292'		ME (100%)
b1004	Replace Hunterstown 115 kV breaker '99192'		ME (100%)
b1061	Replace existing Yorkana 230/115 kV transformer banks 1 and 4 with a single, larger transformer similar to transformer bank #3		ME (100%)
b1061.1	Replace the Yorkana 115 kV breaker '97282'		ME (100%)
b1061.2	Replace the Yorkana 115 kV breaker 'B282'		ME (100%)
b1302	Replace the limiting bus conductor and wave trap at the Jackson 115 kV terminal of the Jackson – JE Baker Tap 115 kV line		ME (100%)
b1365	Reconductor the Middletown – Collins 115 kV (975) line 0.32 miles of 336 ACSR		ME (100%)

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

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1366	Reconductor the Collins – Cly – Newberry 115 kV (975) line 5 miles with 795 ACSR		ME (100%)
b1727	Reconductor 2.4 miles of existing 556 and 795 ACSR from Harley Davidson to Pleasureville 115 kV with 795 ACSS to raise the ratings		ME (100%)
b1800	Install a 500 MVAR SVC at the existing Hunterstown 500kV substation		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1801	Build a 250 MVAR SVC at Altoona 230 kV		AEC (6.47%) / AEP (2.58%) / APS (6.88%) / BGE (6.57%) / DPL (12.39%) / Dominion (14.89%) / JCPL (8.14%) / ME (6.21%) / Neptune* (0.82%) / PECO (21.56%) / PPL (4.89%) / PSEG (8.18%) / RE (0.33%) / ECP** (0.09%)

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1816.5	Replace SCCIR (Sub-conductor) at Hunterstown Substation on the No. 1, 230/115 kV transformer		ME (100%)
b1999	Replace limiting wave trap, circuit breaker, substation conductor, relay and current transformer components at Northwood		ME (100%)
b2000	Replace limiting wave trap on the Glendon - Hosensack line		ME (100%)
b2001	Replace limiting circuit breaker and substation conductor transformer components at Portland 230kV		ME (100%)
b2002	Northwood 230/115 kV Transformer upgrade		ME (100%)
b2023	Construct a new North Temple - Riverview - Cartech 69 kV line (4.7 miles) with 795 ACSR		ME (100%)
b2024	Upgrade 4/0 substation conductors at Middletown 69 kV		ME (100%)
b2025	Upgrade 4/0 and 350 Cu substation conductors at the Middletown Junction terminal of the Middletown Junction - Wood Street Tap 69 kV line		ME (100%)
b2026	Upgrade an OC protection relay at the Baldy 69 kV substation		ME (100%)
b2148	Install a 115 kV 28.8 MVAR capacitor at Pleasureville substation		ME (100%)

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2149	Upgrade substation riser on the Smith St. - York Inc. 115 kV line		ME (100%)
b2150	Upgrade York Haven structure 115 kV bus conductor on Middletown Jct. - Zions View 115 kV		ME (100%)

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SCHEDULE 12 – APPENDIX

(7) Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.1	Build 500 kV substation in PENELEC – Tap the Keystone – Juniata and Conemaugh – Juniata 500 kV, connect the circuits with a breaker and half scheme, and install new 400 MVAR capacitor		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0284.3	Replace wave trap and upgrade a bus section at Keystone 500 kV – on the Keystone – Airydale 500 kV		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
***Hudson Transmission Partners, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0285.1	Replace wave trap at Keystone 500 kV – on the Keystone – Conemaugh 500 kV		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0285.2	Replace wave trap and relay at Conemaugh 500 kV – on the Conemaugh – Keystone 500 kV		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
***Hudson Transmission Partners, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0349	Upgrade Rolling Meadows-Gore Jct 115 kV		PENELEC (100%)
b0360	Construction of a ring bus on the 345 kV side of Wayne substation		PENELEC (100%)
b0365	Add a 50 MVAR, 230 kV cap bank at Altoona 230 kV		PENELEC (100%)
b0369	Install 100 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)
b0370	Install 500 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)

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** East Coast Power, L.L.C.
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Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0376	Install 300 MVAR capacitor at Conemaugh 500 kV substation		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0442	Spare Keystone 500/230 kV transformer		PENELEC (100%)
b0515	Replace Lewistown circuit breaker 1LY Yeagertown		PENELEC (100%)
b0516	Replace Lewistown circuit breaker 2LY Yeagertown		PENELEC (100%)
b0517	Replace Shawville bus section circuit breaker		PENELEC (100%)
b0518	Replace Homer City circuit breaker 201 Johnstown		PENELEC (100%)

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Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0519	Replace Keystone circuit breaker 4 Transformer - 20		PENELEC (100%)
b0549	Install 250 MVAR capacitor at Keystone 500 kV		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0550	Install 25 MVAR capacitor at Lewis Run 115 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0551	Install 25 MVAR capacitor at Saxton 115 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0552	Install 50 MVAR capacitor at Altoona 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
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Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0553	Install 50 MVAR capacitor at Raystown 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0555	Install 100 MVAR capacitor at Johnstown 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0556	Install 50 MVAR capacitor at Grover 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0557	Install 75 MVAR capacitor at East Towanda 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0563	Install 25 MVAR capacitor at Farmers Valley 115 kV substation		PENELEC (100%)
b0564	Install 10 MVAR capacitor at Ridgeway 115 kV substation		PENELEC (100%)

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Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0654	Reconfigure the Cambria Slope 115 kV and Wilmore Junction 115 kV stations to eliminate Wilmore Junction 115 kV 3-terminal line		PENELEC (100%)
b0655	Reconfigure and expand the Glade 230 kV ring bus to eliminate the Glade Tap 230 kV 3-terminal line		PENELEC (100%)
b0656	Add three breakers to form a ring bus at Altoona 230 kV		PENELEC (100%)
b0794	Upgrade the Homer City 230 kV breaker 'Pierce Road'		PENELEC (100%)
b1005	Replace Glory 115 kV breaker '#7 XFMR'		PENELEC (100%)
b1006	Replace Shawville 115 kV breaker 'NO.14 XFMR'		PENELEC (100%)
b1007	Replace Shawville 115 kV breaker 'NO.15 XFMR'		PENELEC (100%)
b1008	Replace Shawville 115 kV breaker '#1B XFMR'		PENELEC (100%)
b1009	Replace Shawville 115 kV breaker '#2B XFMR'		PENELEC (100%)
b1010	Replace Shawville 115 kV breaker 'Dubois'		PENELEC (100%)

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

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1011	Replace Shawville 115 kV breaker 'Philipsburg'		PENELEC (100%)
b1012	Replace Shawville 115 kV breaker 'Garman'		PENELEC (100%)
b1059	Replace a CRS relay at Hooversville 115 kV station		PENELEC (100%)
b1060	Replace a CRS relay at Rachel Hill 115 kV station		PENELEC (100%)
b1153	Upgrade Conemaugh 500/230 kV transformer and add a new line from Conemaugh-Seward 230 kV		AEC (3.74%) / APS (6.26%) / BGE (16.82%) / DL (0.32%) / JCPL (12.57%) / ME (6.89%) / PECO (11.53%) / PEPCO (0.55%) / PPL (15.42%) / PSEG (20.52%) / RE (0.72%) / NEPTUNE* (1.70%) / ECP** (2.96%)
b1153.1	Revise the reclosing on the Shelocta 115 kV breaker 'Lucerne'		PENELEC (100%)
b1169	Replace Shawville 115 kV breaker '#1A XFMR'		PENELEC (100%)
b1170	Replace Shawville 115 kV breaker '#2A XFMR'		PENELEC (100%)
b1277	Build a new Osterburg East – Bedford North 115 kV Line, 5.7 miles of 795 ACSR		PENELEC (100%)
b1278	Install 25 MVAR Capacitor Bank at Somerset 115 kV		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1367	Replace the Cambria Slope 115/46 kV 50 MVA transformer with 75 MVA		PENELEC (100%)
b1368	Replace the Claysburg 115/46 kV 30 MVA transformer with 75 MVA		PENELEC (100%)
b1369	Replace the 4/0 CU substation conductor with 795 ACSR on the Westfall S21 Tap 46 kV line		PENELEC (100%)
b1370	Install a 3rd 115/46 kV transformer at Westfall		PENELEC (100%)
b1371	Reconductor 2.6 miels of the Claysburg – HCR 46 kV line with 636 ACSR		PENELEC (100%)
b1372	Replace 4/0 CU substation conductor with 795 ACSR on the Hollidaysburg – HCR 46 kV		PENELEC (100%)
b1373	Re-configure the Erie West 345 kV substation, add a new circuit breaker and relocate the Ashtabula line exit		PENELEC (100%)
b1374	Replace wave traps at Raritan River and Deep Run 115 kV substations with higher rated equipment for both B2 and C3 circuits		PENELEC (100%)
b1535	Reconductor 0.8 miles of the Gore Junction – ESG Tap 115 kV line with 795 ACSS		PENELEC (100%)

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

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1607	Reconductor the New Baltimore - Bedford North 115 kV		PENELEC (100%)
b1608	Construct a new 345/115 kV substation and loop the Mansfield - Everts 115 kV		APS (8.61%) / PECO (1.72%) / PENELEC (89.67%)
b1609	Construct Four Mile Junction 230/115 kV substation. Loop the Erie South - Erie East 230 kV line, Buffalo Road - Corry East and Buffalo Road - Erie South 115 kV lines		APS (4.86%) / PENELEC (95.14%)
b1610	Install a new 230 kV breaker at Yeagertown		PENELEC (100%)
b1713	Install a 345 kV breaker at Erie West and relocate Ashtabula 345 kV line		PENELEC (100%)
b1769	Install a 75 MVAR cap bank on the Four Mile 230 kV bus		PENELEC (100%)
b1770	Install a 50 MVAR cap bank on the Buffalo Road 115 kV bus		PENELEC (100%)
b1802	Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 kV		AEC (6.47%) / AEP (2.58%) / APS (6.88%) / BGE (6.57%) / / DPL (12.39%) / Dominion (14.89%) / JCPL (8.14%) / ME (6.21%) / NEPTUNE* (0.82%) / PECO (21.56%) / PPL (4.89%) / PSEG (8.18%) / RE (0.33%) / ECP** (0.09%)

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

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1821	Replace the Erie South 115 kV breaker 'Union City'		PENELEC (100%)
b1943	Construct a 115 kV ring bus at Claysburg Substation. Bedford North and Saxton lines will no longer share a common breaker		PENELEC (100%)
b1944	Reconductor Eclipse substation 115 kV bus with 1033 kcmil conductor		PENELEC (100%)
b1945	Install second 230/115 kV autotransformer at Johnstown		PENELEC (100%)
b1966	Replace the 1200 Amp Line trap at Lewistown on the Raystown-Lewistown 230 kV line and replace substation conductor at Lewistown		PENELEC (100%)
b1967	Replace the Blairsville 138/115 kV transformer		PENELEC (100%)
b1990	Install a 25 MVAR 115 kV Capacitor at Grandview		PENELEC (100%)
b1991	Construct Farmers Valley 345/230 kV and 230/115 kV substation. Loop the Homer City-Stolle Road 345 kV line into Farmers Valley		PENELEC (100%)
b1992	Reconductor Cambria Slope-Summit 115kV with 795 ACSS Conductor		PENELEC (100%)

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

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1993	Relocate the Erie South 345 kV line terminal		APS (10.09%) / ECP** (0.45%) / HTP (0.49%) / JCPL (5.14%) / Neptune* (0.54%) / PENELEC (70.71%) / PSEG (12.10%) / RE (0.48%)
b1994	Convert Lewis Run-Farmers Valley to 230 kV using 1033.5 ACSR conductor. Project to be completed in conjunction with new Farmers Valley 345/230 kV transformation		APS (33.20%) / ECP** (0.44%) / HTP (0.44%) / JCPL (8.64%) / ME (5.52%) / Neptune (0.86%) / PENELEC (36.81%) / PSEG (13.55%) / RE (0.54%)
b1995	Change CT Ratio at Claysburg		PENELEC (100%)
b1996.1	Replace 600 Amp Disconnect Switches on Ridgeway-Whetstone 115 kV line with 1200 Amp Disconnects		PENELEC (100%)
b1996.2	Reconductor Ridgway and Whetstone 115 kV Bus		PENELEC (100%)
b1996.3	Replace Wave Trap at Ridgway		PENELEC (100%)
b1996.4	Change CT Ratio at Ridgway		PENELEC (100%)
b1997	Replace 600 Amp Disconnect Switches on Dubois-Harvey Run-Whetstone 115 kV line with 1200 Amp Disconnects		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1998	Install a 75 MVAR 115 kV Capacitor at Shawville		PENELEC (100%)
b2016	Reconductor bus at Wayne 115 kV station		PENELEC (100%)

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

SCHEDULE 12 – APPENDIX A

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2006.1.1	Loop the 2026 (TMI – Hosensack 500 kV) line in to the Lauschtown		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (4*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: BGE (17.43%) / ME (20.22%) / PPL (62.35%)
b2006.2.1	Upgrade relay at South Reading on the 1072 230 V line		ME (100%)
b2006.4	Replace the South Reading 69 kV '81342' breaker with 40kA breaker		ME (100%)
b2006.5	Replace the South Reading 69 kV '82842' breaker with 40kA breaker		ME (100%)
b2452	Install 2nd Hunterstown 230/115 kV transformer		APS (8.30%) / BGE (14.70%) / DEOK (0.48%) / Dominion (36.92%) / ME (23.85%) / PEPCO (15.75%)

Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2452.1	Reconductor Hunterstown - Oxford 115 kV line		APS (8.30%) / BGE (14.70%) / DEOK (0.48%) / Dominion (36.92%) / ME (23.85%) / PEPCO (15.75%)
b2452.3	Replace the Hunterstown 115 kV breaker ‘96192’ with 40 kA		ME (100%)
b2588	Install a 36.6 MVAR 115 kV capacitor at North Bangor substation		ME (100%)
b2637	Convert Middletown Junction 230 kV substation to nine bay double breaker configuration.		ME (100%)
b2644	Install a 28.8 MVAR 115 kV capacitor at the Mountain substation		ME (100%)
b2688.1	Lincoln Substation: Upgrade the bus conductor and replace CTs.		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%)
b2688.2	Germantown Substation: Replace 138/115 kV transformer with a 135/180/224 MVA bank. Replace Lincoln 115 kV breaker, install new 138 kV breaker, upgrade bus conductor and adjust/replace CTs.		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%)

Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2743.4	Upgrade terminal equipment at Hunterstown 500 kV on the Conemaugh – Hunterstown 500 kV circuit		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*%)
b2752.4	Upgrade terminal equipment and required relay communication at TMI 500 kV: on the Beach Bottom – TMI 500 kV circuit		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*%)
b2749	*Replace relay at West Boyertown 69 kV station on the West Boyertown – North Boyertown 69 kV circuit*		*ME (100%)*
b2765	*Upgrade bus conductor at Gardners 115 kv substation; Upgrade bus conductor and adjust CT ratios at Carlisle Pike 115 kV*		*ME (100%)*
b2814	Install a 3rd 230/69 kV 224 MVA Transformer at Lyons and install new terminal equipment for existing Lyons - East Penn(865) 69 kV Line		ME (100%)

SCHEDULE 12 – APPENDIX A

(7) Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2212	Shawville Substation: Relocate 230 kV and 115 kV controls from the generating station building to new control building		PENELEC (100%)
b2293	Replace the Erie South 115 kV breaker 'Buffalo Rd' with 40kA breaker		PENELEC (100%)
b2294	Replace the Johnstown 115 kV breaker 'Bon Aire' with 40kA breaker		PENELEC (100%)
b2302	Replace the Erie South 115 kV breaker 'French #2' with 40kA breaker		PENELEC (100%)
b2304	Replace the substation conductor and switch at South Troy 115 kV substation		PENELEC (100%)
b2371	Install 75 MVAR capacitor at the Erie East 230 kV substation		PENELEC (100%)
b2441	Install +250/-100 MVAR SVC at the Erie South 230 kV station		PENELEC (100%)
b2442	Install three 230 kV breakers on the 230 kV side of the Lewistown #1, #2 and #3 transformers		PENELEC (100%)
b2450	Construct a new 115 kV line from Central City West to Bedford North		PENELEC (100%)
b2463	Rebuild and reconductor 115 kV line from East Towanda to S. Troy and upgrade terminal equipment at East Towanda, Tennessee Gas and South Troy		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2494	Construct Warren 230 kV ring bus and install a second Warren 230/115 kV transformer		PENELEC (100%)
b2552.1	Reconductor the North Meshoppen – Oxbow-Lackawanna 230 kV circuit and upgrade terminal equipment (MAIT portion)		PENELEC (100%)
b2573	Replace the Warren 115 kV ‘B12’ breaker with a 40kA breaker		PENELEC (100%)
b2587	Reconfigure Pierce Brook 345 kV station to a ring bus and install a 125 MVAR shunt reactor at the station		PENELEC (100%)
b2621	Replace relays at East Towanda and East Sayre 115 kV substations (158/191 MVA SN/SE)		PENELEC (100%)
b2677	Replace wave trap, bus conductor and relay at Hilltop 115 kV substation. Replace relays at Prospect and Cooper substations		PENELEC (100%)
b2678	Convert the East Towanda 115 kV substation to breaker and half configuration		PENELEC (100%)
b2679	Install a 115 kV Venango Jct. line breaker at Edinboro South		PENELEC (100%)
b2680	Install a 115 kV breaker on Hooversville #1 115/23 kV transformer		PENELEC (100%)
b2681	Install a 115 kV breaker on the Eclipse #2 115/34.5 kV transformer		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2682	Install two 21.6 MVAR capacitors at the Shade Gap 115 kV substation		PENELEC (100%)
b2683	Install a 36 MVAR 115 kV capacitor and associated equipment at Morgan Street substation		PENELEC (100%)
b2684	Install a 36 MVAR 115 kV capacitor at Central City West substation		PENELEC (100%)
b2685	Install a second 115 kV 3000A bus tie breaker at Hooversville substation		PENELEC (100%)
b2735	*Replace the Warren 115 kV 'NO. 2 XFMR' breaker with 40kA breaker*		*PENELEC (100%)*
b2736	*Replace the Warren 115 kV 'Warren #1' breaker with 40kA breaker*		*PENELEC (100%)*
b2737	*Replace the Warren 115 kV 'A TX #1' breaker with 40kA breaker*		*PENELEC (100%)*
b2738	*Replace the Warren 115 kV 'A TX #2' breaker with 40kA breaker*		*PENELEC (100%)*
b2739	*Replace the Warren 115 kV 'Warren #2' breaker with 40kA breaker*		*PENELEC (100%)*
b2740	*Revise the reclosing of the Hooversville 115 kV 'Ralphton' breaker*		*PENELEC (100%)*
b2741	*Revise the reclosing of the Hooversville 115 kV 'Statler Hill' breaker*		*PENELEC (100%)*

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

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

b2743.2	Tie in new Rice substation to Conemaugh – Hunterstown 500 kV		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*%)
b2743.3	Upgrade terminal equipment at Conemaugh 500 kV on the Conemaugh – Hunterstown 500 kV circuit		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*%)
b2748	*Install two 28 MVAR capacitors at Tiffany 115 kV substation*		*PENELEC (100%)*
b2767	*Construct a new 345 kV breaker string with three (3) 345 kV breakers at Homer City and move the North autotransformer connection to this new breaker string*		*PENELEC (100%)*
b2803	Reconductor 3.7 miles of the Bethlehem – Leretto 46 kV circuit and replace terminal equipment at Summit 46 kV		PENELEC (100%)
b2804	Install a new relay and replace 4/0 CU bus conductor at Huntingdon 46 kV station, on the Huntingdon – C tap 46 kV circuit		PENELEC (100%)
b2805	Install a new relay and replace 4/0 CU & 250 CU substation conductor at Hollidaysburg 46 kV station, on the Hollidaysburg – HCR Tap 46 kV circuit		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2806	Install a new relay and replace meter at the Raystown 46 kV substation, on the Raystown – Smithfield 46 kV circuit		PENELEC (100%)
b2807	Replace the CHPV and CRS relay, and adjust the IAC overcurrent relay trip setting; or replace the relay at Eldorado 46 kV substation, on the Eldorado – Gallitzin 46 kV circuit		PENELEC (100%)
b2808	Adjust the JBC overcurrent relay trip setting at Raystown 46 kV, and replace relay and 4/0 CU bus conductor at Huntingdon 46 kV substations, on the Raystown – Huntingdon 46 kV circuit		PENELEC (100%)

Attachment 3A
Translation of 2017 Schedule 12 Charges into Rates – PSE&G

Attachment 3B
Translation of 2017 Schedule 12 Charges into Rates – JCP&L

Attachment 3C
Translation of 2017 Schedule 12 Charges into Rates – RECO

Attachment 3D
Translation of 2017 Schedule 12 Charges into Rates – ACE

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for July 2017 - December 2017
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission Projects

TEC Charges for July 2017 - December 2017	$	906,073.91	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,800.3	
Term (Months)		12	
OATT rate	$	7.70	/MW/month
converted to $/MW/yr =	$	92.40	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,892.6	25.5	73.1	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,201,596	133,056	218,246	1,283	27	15,197	158,968	296,268
Energy charge								
in $/MWh	$ 0.029478	$ 0.017708	$ 0.030949	$ -	$ -	$ 0.017025	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000029**	**$ 0.000018**	**$ 0.000031**	**$ -**	**$ -**	**$ 0.000017**	**$ -**	**$ -**
Current Energy Charge								
in $/MWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
in $/kWh - rounded to 6 places	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Variance Energy Charge								
in $/MWh	**$ 0.02948**	**$ 0.01771**	**$ 0.03095**	**$ -**	**$ -**	**$ 0.01703**	**$ -**	**$ -**
in $/kWh - rounded to 6 places	**0.000029**	**0.000018**	**0.000031**	**0**	**0**	**0.000017**	**0**	**0**
% difference	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,658.80	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		23,949,599	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,728,145	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	615,273		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0239	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.02	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	514,563		unrounded	= (6) * (3)
8	Difference due to rounding	$	(100,710)		unrounded	= (7) - (4)

Jersey Central Power & Light Company
Proposed MAIT Project Transmission Enhancement Charge (MAIT-TEC Surcharge) effective December 1, 2017
To reflect proposed MAIT Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective July 2017 - December 2017

2017/2018 Average Monthly MAIT-TEC Costs Allocated to JCP&L Zone	$	49,117.93	(1)
2017 JCP&L Zone Transmission Peak Load (MW)		5954.8	
MAIT-Transmission Enhancement Rate ($/MW-month)	$	8.25	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective December 1, 2017 MAIT-TEC Surcharge ($/kWh)	MAIT-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5168.8	511,616	16,578,051,257	$ 0.000031	$ 0.000033
Primary	351.1	34,752	1,731,612,273	$ 0.000020	$ 0.000021
Transmission @ 34.5 kV	287.0	28,408	1,583,073,774	$ 0.000018	$ 0.000019
Transmission @ 230 kV	14.0	1,386	342,007,406	$ 0.000004	$ 0.000004
Total	5820.9	576,162	20,234,744,710		

(1) Cost Allocation of MAIT Project Schedule 12 Charges to JCP&L Zone for 2017/2018
(2) Based on 12 months MAIT Project costs from July 2017 through December 2017
(3) December 2017 through November 2018

<u>BGS-RSCP Supplier Payment Adjustment</u>

Line No.				
1	BGS-RSCP Eligible Sales July through June @ Customer		15,159,224	MWH
2	BGS-RSCP Eligible Sales July through June @ Transmission Node		16,830,967	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,943	MW
4	MAIT-Transmission Enhancement Costs to RSCP Suppliers	$	489,305	= Line 3 x $8.25 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.03	= Line 4 / Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (MAIT) effective December 1, 2017

To reflect FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2017 to December 2017

2017/2018 Average Monthly MAIT-TEC Costs Allocated to RECO	$	2,103	(1)
2017 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	4.78	
SUT		6.875%	

	Col. 1	Col. 2		Col.3=Col.2 x $2,103 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales June 2017- May2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	262.5	59.69%	$	15,060	696,227,000	$	0.00002	$	0.00002
SC2 Secondary	124.6	28.32%	$	7,146	538,141,000	$	0.00001	$	0.00001
SC2 Primary	13.9	3.15%	$	796	77,417,000	$	0.00001	$	0.00001
SC3	0.1	0.01%	$	4	266,000	$	0.00002	$	0.00002
SC4	0.0	0.00%	$	-	6,467,000	$	-	$	-
SC5	3.7	0.85%	$	214	14,953,000	$	0.00001	$	0.00001
SC6	0.0	0.00%	$	-	5,575,000	$	-	$	-
SC7	35.1	7.97%	$	2,011	236,391,000	$	0.00001	$	0.00001
Total	439.8 (2)	100.00%	$	25,231	1,575,437,000				

(1) Attachment 2 - Cost Allocation of MAIT Schedule 12 Charges to RECO Zone for July 2017 to December 2017

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,287,617	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,198,532	MWH
3	BGS-RSCP Eligible Transmission Obligation		405	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	23,216.52	= Line 3 x $4.78 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.02	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting proposed changes effective December 1, 2017
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved BG&E Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT)

(A) Transmission Surcharge rates by Transmission Project and Service Class (excluding SUT)

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00012	0.00007	0.00006	0.00006	0.00000	0.00008	0.00000	0.00004
BG&E- TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(4)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(5)	0.00005	0.00003	0.00002	0.00002	0.00000	0.00003	0.00000	0.00002
PEPCO - TEC	(6)	0.00001	0.00001	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(7)	0.00021	0.00013	0.00010	0.00013	0.00000	0.00014	0.00000	0.00008
PSE&G - TEC	(8)	0.00699	0.00413	0.00370	0.00361	0.00000	0.00483	0.00000	0.00255
TrAILCo - TEC	(9)	0.00041	0.00025	0.00020	0.00026	0.00000	0.00027	0.00000	0.00016
VEPCo - TEC	(10)	0.00035	0.00020	0.00018	0.00018	0.00000	0.00024	0.00000	0.00013
MAIT -TEC	(11)	0.00002	0.00001	0.00001	0.00002	0.00000	0.00001	0.00000	0.00001
Total ($/kWh and excl SUT)		$0.00823	$0.00487	$0.00430	$0.00432	$0.00000	$0.00565	$0.00000	$0.00301
Total (¢/kWh and excl SUT)		0.823 ¢	0.487 ¢	0.430 ¢	0.432 ¢	0.000 ¢	0.565 ¢	0.000 ¢	0.301 ¢

(B) Transmission Surcharge rates by Transmission Project and Service Class (including SUT) **6.875%**

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00013	0.00007	0.00006	0.00006	0.00000	0.00009	0.00000	0.00004
BG&E- TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(4)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(5)	0.00005	0.00003	0.00002	0.00002	0.00000	0.00003	0.00000	0.00002
PEPCO - TEC	(6)	0.00001	0.00001	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(7)	0.00022	0.00014	0.00011	0.00014	0.00000	0.00015	0.00000	0.00009
PSE&G - TEC	(8)	0.00747	0.00441	0.00395	0.00386	0.00000	0.00516	0.00000	0.00273
TrAILCo - TEC	(9)	0.00044	0.00027	0.00021	0.00028	0.00000	0.00029	0.00000	0.00017
VEPCo - TEC	(10)	0.00037	0.00021	0.00019	0.00019	0.00000	0.00026	0.00000	0.00014
MAIT -TEC	(11)	0.00002	0.00001	0.00001	0.00002	0.00000	0.00001	0.00000	0.00001
Total ($/kWh and incl SUT)		$0.00878	$0.00519	$0.00458	$0.00461	$0.00000	$0.00604	$0.00000	$0.00322
Total (¢/kWh and incl SUT)		0.878 ¢	0.519 ¢	0.458 ¢	0.461 ¢	0.000 ¢	0.604 ¢	0.000 ¢	0.322 ¢

Notes:

(1) RMR rates based on allocations by transmission zone. For RECO, the estimated allocation is zero percent for calendar year 2017.
(2) ACE-TEC rates pursuant to the Board's Order dated August 23, 2017 in Docket No. ER17060671.
(3) AEP-East-TEC rates pursuant to the Board's Order dated July 26, 2017 in Docket No. ER17050499.
(4) BG&E-TEC rates pursuant to the Board's Order dated August 23, 2017 in Docket No. ER17060671.
(5) Delmarva-TEC rates pursuant to the Board's Order dated August 23, 2017 in Docket No. ER17060671.
(6) PATH-TEC rates pursuant to the Board's Order dated July 26, 2017 in Docket No. ER17050499.
(7) PEPCO-TEC rates pursuant to the Board's Order dated August 23, 2017 in Docket No. ER17060671.
(8) PPL-TEC rates pursuant to the Board's Order dated August 23, 2017 in Docket No. ER17060671.
(9) PSE&G-TEC rates pursuant to the Board's Order dated July 26, 2017 in Docket No. ER17050499.
(10) TrAILCo-TEC rates pursuant to the Board's Order dated August 23, 2017 in Docket No. ER17060671.
(11) VEPCo-TEC rates pursuant to the Board's Order dated July 26, 2017 in Docket No. ER17050499.
(12) MAIT-TEC rates calculated in Attachment 5 of the joint filing

Atlantic City Electric Company
Proposed MAIT Projects Transmission Enhancement Charge (BG&E Project-TEC Surcharge) effective December 1, 2017
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective December 1, 2017

Transmission Enhancement Costs Allocated to ACE Zone (2017)	$ 17,853
	$ 17,853
2017 ACE Zone Transmission Peak Load (MW)	2,673
Transmission Enhancement Rate ($/MW-Month)	$ 6.68

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06875 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$ 124,421	4,171,964,933	$ 0.000030	$ 0.000030	$ 0.000032
MGS Secondary	359	$ 28,729	1,152,950,462	$ 0.000025	$ 0.000025	$ 0.000027
MGS Primary	8	$ 658	24,456,016	$ 0.000027	$ 0.000027	$ 0.000029
AGS Secondary	393	$ 31,512	1,917,585,029	$ 0.000016	$ 0.000016	$ 0.000017
AGS Primary	94	$ 7,533	571,955,641	$ 0.000013	$ 0.000013	$ 0.000014
TGS	146	$ 11,704	920,786,585	$ 0.000013	$ 0.000013	$ 0.000014
SPL/CSL	0	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 132	12,621,752	$ 0.000010	$ 0.000010	$ 0.000011
	2,554	$ 204,690	8,845,560,805			

Attachment 4

MAIT Formula Rate Filing

Attachment 4

Formula Rate - Non-Levelized | Rate Formula Template | Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]					$ 143,997,614
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 451	(page 4, line 29)	81,960	TP	1.00000	81,960
3	Account No. 454	(page 4, line 30)	3,761,088	TP	1.00000	3,761,088
4	Account No. 456	(page 4, line 31)	1,131,260	TP	1.00000	1,131,260
5	Revenues from Grandfathered Interzonal Transactions		-	TP	1.00000	-
6	Revenues from service provided by the ISO at a discount		-	TP	1.00000	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	6,587,323	TP	1.00000	6,587,323
8	TOTAL REVENUE CREDITS (sum lines 2-7)		11,561,631			11,561,631
9	True-up Adjustment with Interest	Attachment 13, Line 28				-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)				$ 132,435,983

Line No.	DIVISOR			Total
11	1 Coincident Peak (CP) (MW)		(Note A)	5,856.8
12	Average 12 CPs (MW)		(Note CC)	5,007.7

Line No.			Total
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)	22,612.39

Line No.			Peak Rate Total	Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	26,446.29	26,446.29
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	2,203.86	2,203.86
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	508.58	508.58
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	101.72	72.65
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	6.36	3.02

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	-	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,087,577,419	TP	1.00000	1,087,577,419
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	-	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	9,647,707	W/S	1.00000	9,647,707
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	1.00000	-
6	TOTAL GROSS PLANT (sum lines 1-5)		1,097,225,126	GP=	100.000%	1,097,225,126
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	-	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	353,829,652	TP	1.00000	353,829,652
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	-	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	8,019,670	W/S	1.00000	8,019,670
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	1.00000	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		361,849,322			361,849,322
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	-			
14	Transmission	(line 2- line 8)	733,747,768			733,747,768
15	Distribution	(line 3 - line 9)	-			
16	General & Intangible	(line 4 - line 10)	1,628,037			1,628,037
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		735,375,804	NP=	100.000%	735,375,804
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 3, Col. 1 (Notes F & Y & DD)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 3, Col. 2 (Notes F & Y & DD)	(215,319,716)	NP	1.00000	(215,319,716)
21	Account No. 283 (enter negative)	Attachment 5, Line 3, Col. 3 (Notes F & Y & DD)	(7,823,609)	NP	1.00000	(7,823,609)
22	Account No. 190	Attachment 5, Line 3, Col. 4 (Notes F & Y & DD)	4,852,135	NP	1.00000	4,852,135
23	Account No. 255 (enter negative)	Attachment 5, Line 3, Col. 5 (Notes F & Y & DD)	(2,478,998)	NP	1.00000	(2,478,998)
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 6, Col. 6 (Note Y)	-	NP	1.00000	-
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 9, Col. 6 (Note Y)	-	W/S	1.00000	-
26	CWIP	216.b (Notes X & Z)	-	DA	1.00000	-
27	Unamortized Regulatory Asset	Attachment 16a, 16b, 16c, line 15, Col. 7 (Notes X)	17,420,142	DA	1.00000	17,420,142
28	Unamortized Abandoned Plant	Attachment 17, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
29	TOTAL ADJUSTMENTS (sum lines 19-28)		(203,350,045)			(203,350,045)
30	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)	-	TP	1.00000	-
31	WORKING CAPITAL (Note H)					
32	CWC	1/8*(Page 3, Line 15 minus Page 3, Lines 11 & 12)	6,626,171			6,374,546
33	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)	-	TE	0.96015	-
34	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)	-	GP	1.00000	-
35	TOTAL WORKING CAPITAL (sum lines 32 - 34)		6,626,171			6,374,546
36	RATE BASE (sum lines 18, 29, 30, & 35)		538,651,930			538,400,306

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	50,513,663	TE	0.96015	48,500,665
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		-	DA	1.00000	-
3	Less Account 565	321.96.b	-	DA	1.00000	-
4	Less Account 566	321.97.b	5,814,771	DA	1.00000	5,814,771
5	A&G	323.197.b	3,750,202	W/S	1.00000	3,750,202
6	Less FERC Annual Fees		-	W/S	1.00000	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		-	W/S	1.00000	-
8	Plus Transmission Related Reg. Comm. Exp. (Note I)		-	TE	0.96015	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 9	(1,254,497)	DA	1.00000	(1,254,497)
10	Common	356.1	-	CE	1.00000	-
11	Account 407.3 Amortization of Regulatory Assets	Attachment 16a, 16b, 16c, Line 15, Col. 5	3,816,534	DA	1.00000	3,816,534
12	Account 566 Amortization of Regulatory Assets	321.97.b (notes)	-	DA	1.00000	-
13	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 12	5,814,771	DA	1.00000	5,814,771
14	Total Account 566 (sum lines 12 & 13, ties to 321.97.b)		5,814,771			5,814,771
15	TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)		56,825,903			54,812,905
	DEPRECIATION AND AMORTIZATION EXPENSE					
16	Transmission	336.7.b (Note U)	24,550,792	TP	1.00000	24,550,792
17	General & Intangible	336.1.f & 336.10.f (Note U)	243,800	W/S	1.00000	243,800
18	Common	336.11.b (Note U)	-	CE	1.00000	-
19	Amortization of Abandoned Plant	Attachment 17, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
20	TOTAL DEPRECIATION (sum lines 16 -19)		24,794,592			24,794,592
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
21	Payroll	263.i (Attachment 7, line 1z)	-	W/S	1.00000	-
22	Highway and vehicle	263.i (Attachment 7, line 2z)	-	W/S	1.00000	-
23	PLANT RELATED					
24	Property	263.i (Attachment 7, line 3z)	-	GP	1.00000	-
25	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
26	Other	263.i (Attachment 7, line 5z)	-	GP	1.00000	-
27	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	1.00000	-
28	TOTAL OTHER TAXES (sum lines 21 - 27)		-			-
	INCOME TAXES	(Note K)				
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		41.49%			
30	CIT=(T/1-T) * (1-(WCLTD/R)) =		50.33%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
31	1 / (1 - T) = (from line 29)		1.7092			
32	Amortized Investment Tax Credit (266.8.f) (enter negative)		(99,685)			
33	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]		1,072,591			
34	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]		-			
35	Income Tax Calculation = line 30 * line 40		21,011,007	NA		21,001,192
36	ITC adjustment (line 31 * line 32)		(170,383)	NP	1.00000	(170,383)
37	Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)		1,833,285	DA	1.00000	1,833,285
38	(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)		-	DA	1.00000	-
39	Total Income Taxes	sum lines 35 through 38	22,673,908			22,664,093
40	RETURN	[Rate Base (page 2, line 36) * Rate of Return (page 4, line 25)]	41,745,524.60	NA		41,726,024
41	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 15, 20, 28, 39, 40)	146,039,928			143,997,614
42	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)	0			0
43	GROSS REV. REQUIREMENT	(line 41 + line 42)	146,039,928			143,997,614

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Mid-Atlantic Interstate Transmission, LLC

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (page 2, line 2, column 3)						1,087,577,419		
2	Less transmission plant excluded from ISO rates (Note M)						-		
3	Less transmission plant included in OATT Ancillary Services (Note N)						-		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,087,577,419		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)						50,513,663		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						2,012,998		
8	Included transmission expenses (line 6 less line 7)						48,500,665		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.96015		
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.96015		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	-	0.00	-				
13	Transmission	354.21.b	-	1.00	-				
14	Distribution	354.23.b	-	0.00	-		W&S Allocator		
15	Other	354.24,25,26.b	-	0.00	-		($ / Allocation)		
16	Total (sum lines 12-15)		-		-	=	1.00000	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)								
			$		% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	-						
18	Gas	201.3.d	-		1.00000	*	1.00000	=	1.00000
19	Water	201.3.e	-						
20	Total (sum lines 17 - 19)		-						
	RETURN (R)						$		
21		Preferred Dividends (118.29c) (positive number)					-		
			$	(Note C) %	Cost (Note P)		Weighted		
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)		-	50%	0.0450		0.0225	=WCLTD	
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000		
24	Common Stock (Attachment 8, Line 14, Col. 6) (Note X)		-	50%	0.1100		0.0550		
25	Total (sum lines 22-24)		-				0.0775	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)					
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-		
27	b. Bundled Sales for Resale included in Divisor on page 1						-		
28	Total of (a)-(b)						-		
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)			(300.17.b)			81,960		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			(300.19.b)			3,761,088		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)			(330.x.n)			1,131,260		

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Mid-Atlantic Interstate Transmission, LLC

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
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 combined CPs for Met-Ed and Penelec zones.
B	Prepayments shall exclude prepayments of income taxes.
C	In its order approving the transfer of Penelec's and Met-Ed's transmission assets to MAIT, the Commission approved MAIT's commitment to apply a 50 percent equity/50 percent debt capital structure for ratemaking purposes for a two-year transition period. Pennsylvania Electric, 154 FERC ¶ 61,109 at P 51. Consequently, for the first two years (i.e., calendar years 2017 and 2018) the hypothetical capital structure will be used instead of the actual calculation. The capital structure will remain 50% equity and 50% debt until calendar year 2019, in which case actual capital structure will prevail and be utilized for all subsequent filings.
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Amounts to be included will be January 1, 2017 and thereafter.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. 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.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 15, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". 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.f) multiplied by (1/1-T) (page 3, line 31).

Inputs	FIT =	35.00%	
	SIT=	9.99%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	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.
M	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).
N	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.
O	Enter dollar amounts
P	Debt cost rate will be set at 4.5% until such time as debt is issued by MAIT. Once debt is issued, the long-term debt cost rate will be the weighted average of the rates for all outstanding debt instruments, calculated within Attachment 10, col. j. Consistent with Note C, there will be no preferred stock cost, consistent with MAIT's commitment to use a hypothetical 50%/50% capital structure until calendar year 2019. Thereafter, Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 28 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.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They 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 it own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Page 4, Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Met-Ed's and Penelec's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of Met-Ed's and Penelec's 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.
DD	Includes transmission-related balance only.

Schedule 1A Rate Calculation

1	$ 2,012,998	Attachment H-28A, Page 4, Line 7
2	$ 99,456	Revenue Credits for Sched 1A - Note A
3	$ 1,913,542	Net Schedule 1A Expenses (Line 1 - Line 2)
4	31,756,497	Annual MWh in Met-Ed and Penelec Zones - Note B
5	$ 0.0603	Schedule 1A rate $/MWh (Line 3/ Line 4)

Note:

A Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of Met-Ed's and Penelec's zones during the year used to calculate rates under Attachment H-28A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the Met-Ed and Penelec zones. Data from RTO settlement systems for the calendar year prior to the rate year.

Incentive ROE Calculation

			Source Reference	
Return Calculation				
1	Rate Base		Attachment H-28A, page 2, Line 36, Col. 5	538,400,306
2	Preferred Dividends	enter positive	Attachment H-28A, page 4, Line 21, Col. 6	0
	Common Stock			
3	Proprietary Capital		Attachment 8, Line 14, Col. 1	0
4	Less Preferred Stock		Attachment 8, Line 14, Col. 2	0
5	Less Accumulated Other Comprehensive Income Account 219		Attachment 8, Line 14, Col. 4	0
6	Less Account 216.1 & Goodwill		Attachment 8, Line 14, Col. 3 & 5	0
7	Common Stock		Attachment 8, Line 14, Col. 6	0
	Capitalization			
8	Long Term Debt		Attachment H-28A, page 4, Line 22, Col. 3	0
9	Preferred Stock		Attachment H-28A, page 4, Line 23, Col. 3	0
10	Common Stock		Attachment H-28A, page 4, Line 24, Col. 3	0
11	Total Capitalization		Attachment H-28A, page 4, Line 25, Col. 3	0
12	Debt %	Total Long Term Debt	Attachment H-28A, page 4, Line 22, Col. 4	50.0000%
13	Preferred %	Preferred Stock	Attachment H-28A, page 4, Line 23, Col. 4	0.0000%
14	Common %	Common Stock	Attachment H-28A, page 4, Line 24, Col. 4	50.0000%
15	Debt Cost	Total Long Term Debt	Attachment H-28A, page 4, Line 22, Col. 5	0.0450
16	Preferred Cost	Preferred Stock	Attachment H-28A, page 4, Line 23, Col. 5	0.0000
17	Common Cost	Common Stock	11.00%	0.1100
18	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 12 * Line 15)	0.0225
19	Weighted Cost of Preferred	Preferred Stock	(Line 13 * Line 16)	0.0000
20	Weighted Cost of Common	Common Stock	(Line 14 * Line 17)	0.0550
21	Rate of Return on Rate Base (ROR)		(Sum Lines 18 to 20)	**0.0775**
22	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 21)**	**41,726,024**
Income Taxes				
	Income Tax Rates			
23	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		Attachment H-28A, page 3, Line 29, Col. 3	41.49%
24	CIT=(T/1-T) * (1-(WCLTD/R)) =		Calculated	50.33%
25	1 / (1 - T) = (from line 23)		Attachment H-28A, page 3, Line 31, Col.3	1.7092
26	Amortized Investment Tax Credit (266.8.f) (enter negative)		Attachment H-28A, page 3, Line 32, Col. 3	(99,685.00)
27	Tax Effect of Permanent Differences and AFUDC Equity		Attachment H-28A, page 3, Line 33, Col. 3	1,072,590.60
28	(Excess)/Deficient Deferred Income Taxes		Attachment H-28A, page 3, Line 34, Col. 3	-
29	Income Tax Calculation		(line 22 * line 24)	21,001,191.65
30	ITC adjustment		(line 25 * line 26)	(170,382.78)
31	Permanent Differences and AFUDC Equity Tax Adjustment		Attachment H-28A, page 3, Line 37, Col. 3	1,833,284.51
32	(Excess)/Deficient Deferred Income Tax Adjustment		Attachment H-28A, page 3, Line 38, Col. 3	-
33	Total Income Taxes		Sum lines 29 to 32	22,664,093.38
Increased Return and Taxes				
34	Return and Income taxes with increase in ROE		(Line 22 + Line 33)	64,390,117.06
35	Return without incentive adder		Attachment H-28A, Page 3, Line 40, Col. 5	41,726,023.68
36	Income Tax without incentive adder		Attachment H-28A, Page 3, Line 39, Col. 5	22,664,093.38
37	Return and Income taxes <u>without</u> increase in ROE		Line 35 + Line 36	64,390,117.06
38	Return and Income taxes with increase in ROE		Line 34	64,390,117.06
39	Incremental Return and incomes taxes for increase in ROE		Line 38 - Line 37	-
40	Rate Base		Line 1	538,400,305.56
41	Incremental Return and incomes taxes for increase in ROE divided by rate base		Line 39 / Line 40	-

Notes:

Line 17 to include an incentive ROE that is used only to determine the increase in return and incomes taxes associated with a specific increase in ROE. Any actual ROE incentive must be approved by the Commission. Until an ROE incentive is approved, line 17 will reflect the current ROE.

Gross Plant Calculation

For the 12 months ended 12/31/2017

			[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2016	-	1,043,480,023	-	-	9,668,705	-	1,053,148,728
2	January	2017	-	1,045,873,067	-	-	9,668,705	-	1,055,541,772
3	February	2017	-	1,048,170,472	-	-	9,665,298	-	1,057,835,771
4	March	2017	-	1,051,462,998	-	-	9,658,635	-	1,061,121,633
5	April	2017	-	1,056,535,437	-	-	9,653,272	-	1,066,188,710
6	May	2017	-	1,068,758,806	-	-	9,648,639	-	1,078,407,446
7	June	2017	-	1,090,156,064	-	-	9,643,754	-	1,099,799,818
8	July	2017	-	1,094,456,332	-	-	9,643,169	-	1,104,099,501
9	August	2017	-	1,105,641,193	-	-	9,642,241	-	1,115,283,433
10	September	2017	-	1,112,737,682	-	-	9,637,649	-	1,122,375,331
11	October	2017	-	1,126,051,190	-	-	9,634,103	-	1,135,685,294
12	November	2017	-	1,131,126,851	-	-	9,630,231	-	1,140,757,082
13	December	2017	-	1,164,056,338	-	-	9,625,788	-	1,173,682,125
14	**13-month Average**	[A] [C]	**-**	**1,087,577,419**	**-**	**-**	**9,647,707**	**-**	**1,097,225,126**

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
		[B]	205.46.g	207.58.g	207.75.g	205.5.g	207.99.g	356.1	
15	December	2016		1,043,488,099			9,668,705		1,053,156,804
16	January	2017		1,045,881,143			9,668,705		1,055,549,848
17	February	2017		1,048,178,549			9,665,298		1,057,843,847
18	March	2017		1,051,471,075			9,658,635		1,061,129,709
19	April	2017		1,056,543,514			9,653,272		1,066,196,786
20	May	2017		1,068,766,883			9,648,639		1,078,415,522
21	June	2017		1,090,164,141			9,643,754		1,099,807,894
22	July	2017		1,094,464,408			9,643,169		1,104,107,577
23	August	2017		1,105,649,269			9,642,241		1,115,291,510
24	September	2017		1,112,745,759			9,637,649		1,122,383,408
25	October	2017		1,126,059,267			9,634,103		1,135,693,370
26	November	2017		1,131,134,927			9,630,231		1,140,765,158
27	December	2017		1,164,064,414			9,625,788		1,173,690,202
28	13-month Average		-	1,087,585,496	-	-	9,647,707	-	1,097,233,203

Asset Retirement Costs

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
		[B]	205.44.g	207.57.g	207.74.g	company records	207.98.g	company records
29	December	2016		8,076				
30	January	2017		8,076				
31	February	2017		8,076				
32	March	2017		8,076				
33	April	2017		8,076				
34	May	2017		8,076				
35	June	2017		8,076				
36	July	2017		8,076				
37	August	2017		8,076				
38	September	2017		8,076				
39	October	2017		8,076				
40	November	2017		8,076				
41	December	2017		8,076				
42	13-month Average			8,076	-	-	-	-

Notes:

[A] Included on Attachment H-28A, page 2, lines 1-6, Col. 3

[B] Reference for December balances as would be reported in FERC Form 1.

[C] Balance excludes Asset Retirements Costs

Accumulated Depreciation Calculation

For the 12 months ended 12/31/2017

			[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2016	-	348,366,245	-	-	7,906,343	-	356,272,588
2	January	2017	-	348,760,257	-	-	7,906,762	-	356,667,019
3	February	2017	-	350,189,710	-	-	7,929,024	-	358,118,734
4	March	2017	-	351,361,535	-	-	7,951,359	-	359,312,893
5	April	2017	-	352,505,180	-	-	7,973,645	-	360,478,826
6	May	2017	-	353,159,538	-	-	7,995,902	-	361,155,440
7	June	2017	-	354,083,179	-	-	8,018,154	-	362,101,333
8	July	2017	-	354,956,842	-	-	8,040,289	-	362,997,131
9	August	2017	-	355,856,164	-	-	8,062,431	-	363,918,595
10	September	2017	-	356,550,992	-	-	8,084,660	-	364,635,653
11	October	2017	-	357,224,413	-	-	8,106,854	-	365,331,267
12	November	2017	-	358,000,192	-	-	8,129,047	-	366,129,239
13	December	2017	-	358,771,222	-	-	8,151,244	-	366,922,467
14	**13-month Average**	**[A] [C]**	**-**	**353,829,652**	**-**	**-**	**8,019,670**	**-**	**361,849,322**

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
		[B]	219.20-24.c	219.25.c	219.26.c	200.21.c	219.28.c	356.1	
15	December	2016		348,370,877			7,906,343		356,277,220
16	January	2017		348,764,577			7,906,762		356,671,339
17	February	2017		350,194,042			7,929,024		358,123,066
18	March	2017		351,365,880			7,951,359		359,317,238
19	April	2017		352,509,538			7,973,645		360,483,184
20	May	2017		353,163,909			7,995,902		361,159,811
21	June	2017		354,087,562			8,018,154		362,105,716
22	July	2017		354,961,237			8,040,289		363,001,526
23	August	2017		355,860,573			8,062,431		363,923,003
24	September	2017		356,555,413			8,084,660		364,640,073
25	October	2017		357,228,847			8,106,854		365,335,700
26	November	2017		358,004,638			8,129,047		366,133,684
27	December	2017		358,775,681			8,151,244		366,926,925
28	13-month Average		-	353,834,059	-	-	8,019,670	-	361,853,730

Reserve for Depreciation of Asset Retirement Costs

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
		[B]		Company Records				
29	December	2016		4,632				
30	January	2017		4,320				
31	February	2017		4,332				
32	March	2017		4,345				
33	April	2017		4,358				
34	May	2017		4,370				
35	June	2017		4,383				
36	July	2017		4,395				
37	August	2017		4,408				
38	September	2017		4,421				
39	October	2017		4,433				
40	November	2017		4,446				
41	December	2017		4,458				
42	13-month Average			4,408	-	-	-	-

Notes:

[A] Included on Attachment H-28A, page 2, lines 7-11, Col. 3

[B] Reference for December balances as would be reported in FERC Form 1.

[C] Balance excludes reserve for depreciation of asset retirement costs

ADIT Calculation

For the 12 months ended 12/31/2017

ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below

				[1]	[2]	[3]	[4]	[5]	[6]
				Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
				(enter negative)	**(enter negative)**	**(enter negative)**		**(enter negative)**	
					[C]	[D]	[E]	[F]	
1	December 31	2016		-	(210,176,662)	(7,542,754)	4,832,355	(2,528,840)	(215,415,901)
2	December 31	2017		-	(220,462,770)	(8,104,463)	4,871,915	(2,429,155)	(226,124,474)
3	**Begin/End Average**		**[A]**	**-**	**(215,319,716)**	**(7,823,609)**	**4,852,135**	**(2,478,998)**	**(220,770,187)**

ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjustments from notes below)

				Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
			[B]	273.8.k	275.2.k	277.9.k	234.8.c	267.h	
4	December 31	2016			224,133,175	17,608,719	16,609,862	2,528,840	260,880,596
5	December 31	2017			254,677,204	18,913,733	16,729,320	2,429,155	292,749,412
6	Begin/End Average			-	239,405,190	18,261,226	16,669,591	2,478,998	276,815,004

Notes:

[A] Beginning/Ending Average with adjustments for FAS143, FAS106, FAS109, CIACs and normalization to populate Appendix H-28A, page 2, lines 19-23, col. 3 for accounts 281, 282, 283, 190, and 255, respectively

[B] Reference for December balances as would be reported in FERC Form 1.

[C] FERC Account No. 282 is adjusted for the following items.

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [G]
2016	-	-	13,956,513		-
2017	-	-	13,439,403		20,775,031

[D] FERC Account No. 283 is adjusted for the following items.

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [G]
2016	-	-	10,065,965		-
2017	-	-	9,674,777		1,134,493

[E] FERC Account No. 190 is adjusted for the following items:

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [G]
2016	-	-	-	11,777,507	-
2017	-	-	-	11,777,507	79,899

[F] Based on prior elections and IRS rulings, the 3% Investment Tax Credit ("ITC") and the 4% ITC may be used to reduce rate base as well as utilizing amortization of the tax credits against taxable income.
As a result, only the 3% and 4% values in FERC Form 1 column (h) on page 267 should be reported under Acct. No. 255.

[G] Taken from Attachment 5a, page 2, col. 4

ADIT Normalization Calculation

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
	2017 Quarterly Activity and Balances							
Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
4,832,355	17,187	4,849,542	37,264	4,886,806	29,747	4,916,554	35,260	4,951,814
Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
4,832,355	**12,996**		**18,887**		**7,579**		**97**	
Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
210,176,662	4,468,939	214,645,601	9,689,158	224,334,758	7,734,840	232,069,599	9,168,203	241,237,802
Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
210,176,662	**3,379,252**		**4,910,943**		**1,970,795**		**25,118**	
Beginning 283 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
7,542,754	244,042	7,786,796	529,110	8,315,907	422,388	8,738,294	500,662	9,238,956
Beginning 283 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
7,542,754	**184,536**		**268,179**		**107,622**		**1,372**	

ADIT Normalization Calculation

2017 Activity		[1] FERC Form 1 - Year-End (sourced from Attachment 5, page 1, line 5)	[2] Prorated year-end less FERC Form 1 Year-end	[3] Sum of FAS143, FAS106, FAS109, and CIAC from Attachment 5, page 1, notes	[4] Total Normalization to Attachment 5 (col. 2 - col. 3)	[5] Ending Balance for formula rate (col. 1 - col. 3. - col. 4)
Pro-rated Total	**Pro-rated Ending 190**					
39,559	**4,871,915**	16,729,320	11,857,406	11,777,507	**79,899**	4,871,915
Pro-rated Total	**Pro-rated Ending 282**					
10,286,109	**220,462,770**	254,677,204	34,214,434	13,439,403	**20,775,031**	220,462,770
Pro-rated Total	**Pro-rated Ending 283**					
561,709	**8,104,463**	18,913,733	10,809,269	9,674,777	**1,134,493**	8,104,463

1	**Calculation of PBOP Expenses**	
2	**MAIT**	
3	Total FirstEnergy PBOP expenses	(108,686,300)
4	Labor dollars (FirstEnergy)	2,024,261,894
5	cost per labor dollar (line 3 / line 4)	-$0.0537
6	labor (labor not capitalized) current year	11,489,713
7	PBOP Expense for current year (line 5 * line 6)	-$616,904
8	PBOP expense in all O&M and A&G accounts for current year	637,593
9	PBOP Adjustment for Attachment H-28A, page 3, line 9 (line 7 - line 8)	(1,254,497)
10	Lines 3-4 cannot change absent approval or acceptance by FERC in a separate proceeding	

For the 12 months ended 12/31/2017

Taxes Other than Income Calculation

		[A]	Dec 31, 2017
1	**Payroll Taxes**		
1a	FICA	263.i	-
1b	Federal Unemployment Tax	263.i	-
1c	Pennsylvania Unemployment Tax	263.i	-
1z	**Payroll Taxes Total**		-
2	**Highway and Vehicle Taxes**		
2a	Federal Excise Tax	263.i	-
2z	**Highway and Vehicle Taxes**		-
3	**Property Taxes**		
3a	Property Tax	263.i	-
3b			-
3c			-
3z	**Property Taxes**		-
4	**Gross Receipts Tax**		
4a	Gross Receipts Tax	263.i	-
4z	**Gross Receipts Tax**		-
5	**Other Taxes**		
5a	Sales & Use Tax	263.i	-
5b	Capital Stock Tax/Franchise	263.i	-
5c			-
5z	**Other Taxes**		-
6z	**Payments in lieu of taxes**		
7	Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]		$0.00

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Capital Structure Calculation

For the 12 months ended 12/31/2017

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Proprietary Capital	**Preferred Stock**	**Account 216.1**	**Account 219**	**Goodwill**	**Common Stock**	**Long Term Debt**
			[A]	112.16.c	112.3.d	112.12.c	112.15.c	233.5.f	(1) - (2) - (3) - (4) - (5)	112.24.c
1	December	2016		-	-	-	-	-	-	-
2	January	2017							-	-
3	February	2017							-	-
4	March	2017							-	-
5	April	2017							-	-
6	May	2017							-	-
7	June	2017							-	-
8	July	2017							-	-
9	August	2017							-	-
10	September	2017							-	-
11	October	2017							-	-
12	November	2017							-	-
13	December	2017							-	-
14	13-month Average			-	-	-	-	-	-	-

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Stated Value Inputs
For the 12 months ended 12/31/2017

Formula Rate Protocols
Section VIII.A

1. Rate of Return on Common Equity ("ROE")

MAIT's stated ROE is set to: 11.0%

2. Postretirement Benefits Other Than Pension ("PBOP")
**sometimes referred to as Other Post Employment Benefits, or "OPEB"*

Total FirstEnergy PBOP expenses	(108,686,300)
Labor dollars (FirstEnergy)	2,024,261,894

3. Depreciation Rates

FERC Account	Depr %
352	1.28%
353	2.05%
354	1.39%
355	2.32%
356	2.68%
356.1	1.27%
358	2.52%
359	0.87%
390	1.81%
397	2.81%
303	14.29%

Debt Cost Calculation

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED 12/31/2017

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	t=N	Issue Date	Maturity Date	ORIGINAL ISSUANCE (table 2, col. cc)	Net Proceeds At Issuance (table 2, col. hh)	Net Amount Outstanding at t=N	Months Outstanding at t=N	Average Net Outstanding in Year* z* ((col e. * col. F)/12)	Weighted Outstanding Ratios (col. g/col. g total)	Effective Cost Rate (Table 2, Col. ll)	Weighted Debt Cost at t = N (h) * (i)	
	Long Term Debt 12/31/2017											
	First Mortgage Bonds:											
(1)	x.xx%, Senior Unsecured Notes	xx/xx/xxxx	xx/xx/xxxx	$ -	$ -	$ -	12	$ -	#DIV/0!	#VALUE!	#DIV/0!	
(2)	x.xx%, Senior Unsecured Notes	xx/xx/xxxx	xx/xx/xxxx	$ -	$ -	$ -	12	$ -	#DIV/0!	#VALUE!	#DIV/0!	
	Total			$ -		$ -		$ -	#DIV/0!		#DIV/0!	**

t = time

The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.

The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.

* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).

Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).

** This Total Weighted Average Debt Cost will be shown on page 4, line 22, column 5 of formula rate Attachment H-28A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED 12/31/2017

		(aa)	(bb)	(cc)	(dd)	(ee)	(ff)	(gg)	(hh)	(ii)	(jj)	(kk)	(ll)
	Long Term Debt Affiliate	Issue Date	Maturity Date	Amount Issued	(Discount) Premium at Issuance	Issuance Expense	Loss/Gain on Reacquired Debt	Less Related ADIT	Net Proceeds + col. ee + col. ff)	Net Proceeds Ratio ((col. cc / col. hh)*100)	Coupon Rate	Annual Interest (col. cc * col. jj)	Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
(1)	x.xx%, Senior Unsecured Notes	xx/xx/xxxx	xx/xx/xxxx	$ -	$ -	0	-	xxx	$ -	#DIV/0!	0.00000	$ -	#VALUE!
(2)	x.xx%, Senior Unsecured Notes	xx/xx/xxxx	xx/xx/xxxx	-	0	0			$ -	#DIV/0!	0	$ -	#VALUE!
												-	
	TOTALS			$ -	-	$ -	-	xxx	$ -			$ -	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation

Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_o equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-28A

	(1)	(2)	(3)	(4)
Line No.		**Reference**	**Transmission**	**Allocator**
1	Gross Transmission Plant - Total	Attach. H-28A, p. 2, line 2, col. 5 (Note A)	$ 1,087,577,419	
2	Net Transmission Plant - Total	Attach. H-28A, p. 2, line 14, col. 5 (Note B)	$ 733,747,768	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-28A, p. 3, line 15, col. 5	$ 54,812,905	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	5.039908%	5.039908%
	GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE			
5	Total G, I, & C depreciation expense	Attach. H-28A, p. 3, lines 17 & 18, col. 5	$ 243,800	
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)	0.022417%	0.022417%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach. H-28A, p. 3, line 28, col. 5	$ -	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)	0.000000%	0.000000%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**		**5.062325%**
	INCOME TAXES			
10	Total Income Taxes	Attach. H-28A, p. 3, line 39, col. 5	$ 22,664,093	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)	3.088813%	3.088813%
	RETURN			
12	Return on Rate Base	Attach. H-28A, p. 3, line 40, col. 5	$ 41,726,024	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)	5.686699%	5.686699%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**8.775511%**

Columns 5-9 (page 1) only applies with incentive ROE project(s) (Note F)

(5)	(6)	(7)	(8)	(9)
Line No.		**Reference**	**Transmission**	**Allocator**
	INCOME TAXES			
10b	Total Income Taxes	Attachment 2, line 33	$ 22,664,093	
11b	Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)	3.088813%	3.088813%
	RETURN			
12b	Return on Rate Base	Attachment 2, line 22	$ 41,726,024	
13b	Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)	5.686699%	5.686699%
14b	**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		**8.775511%**
15	**Additional Annual Allocation Factor for Return**	**Line 14 b, col. 9 less line 14, col. 4**		**0.00000%**

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-28A

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**Additional Incentive Annual Allocation Factor for Return (Note F)**	**Total Annual Revenue Requirement**	**True-up Adjustment**	**Net Revenue Requirement with True-up**
			(Note C & H)	(Page 1, line 9)	(Col. 3 * Col. 4)	(Note D & H)	Page 1, line 14	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8, & 9)	(Col. 6 * Page 1, line 15, Col. 9)	(Sum Col. 10 & 11)	(Note G)	(Sum Col. 12 & 13)
2a	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown	b0215	$ 12,637,431	5.062325%	$639,748	$ 10,550,703	8.775511%	$925,878	$ 259,067	$1,824,693	0	$1,824,693		$1,824,693
2b	Replace wave trap and upgrade a bus section at Keystone 500 kV – on the Keystone – Airydale 500 kV	b0284.3	$ 67,817	5.062325%	$3,433	$ 66,695	8.775511%	$5,853	$ 1,417	$10,703	0	$10,703		$10,703
2c	Replace wave trap at Keystone 500 kV – on the Keystone – Conemaugh 500 kV	b0285.1	$ -	5.062325%	$0	$ -	8.775511%	$0	$ -	$0	0	$0		$0
2d	Replace wave trap and relay at Conemaugh 500 kV – on the Conemaugh – Keystone 500 kV	b0285.2	$ -	5.062325%	$0	$ -	8.775511%	$0	$0.00	$0	0	$0		$0
2e	Install 100 MVAR Dynamic Reactive Device at Airydale 500 kV substation	b0369	$ 3,323,047	5.062325%	$168,223	$ 3,268,064	8.775511%	$286,789	$69,451.67	$524,464	0	$524,464		$524,464
2f	Install 250 MVAR capacitor at Keystone 500 kV	b0549	$ 3,207,134	5.062325%	$162,356	$ 2,927,525	8.775511%	$256,905	$65,746.25	$485,007	0	$485,007		$485,007
2g	Install 25 MVAR capacitor at Lewis Run 115 kV substation	b0550	$ -	5.062325%	$0	$ -	8.775511%	$0	$0.00	$0	0	$0		$0
2h	Install 25 MVAR capacitor at Saxton 115 kV substation	b0551	$ 1,380,393	5.062325%	$69,880	$ 1,144,223	8.775511%	$100,411	$28,021.98	$198,313	0	$198,313		$198,313
2i	Install 50 MVAR capacitor at Altoona 230 kV substation	b0552	$ 1,038,335	5.062325%	$52,564	$ 941,334	8.775511%	$82,607	$21,285.86	$156,457	0	$156,457		$156,457
2j	Install 50 MVAR capacitor at Raystown 230 kV substation	b0553	$ 927,947	5.062325%	$46,976	$ 841,258	8.775511%	$73,825	$19,022.91	$139,823	0	$139,823		$139,823
2k	Install 75 MVAR capacitor at East Towanda 230 kV substation	b0557	$ 2,177,814	5.062325%	$110,248	$ 1,980,124	8.775511%	$173,766	$44,209.63	$328,224	0	$328,224		$328,224
2l	Relocate the Erie South 345 kV line terminal	b1993	$ 10,525,319	5.062325%	$532,826	$ 10,245,563	8.775511%	$899,101	$216,821.58	$1,648,748	0	$1,648,748		$1,648,748
2m	Convert Lewis Run-Farmers Valley to 230 kV using 1033.5 ACSR conductor. Project to be completed in conjunction with new Farmers Valley 345/230 kV transformation	b1994	$ 45,262	5.062325%	$2,291	$ 48,192	8.775511%	$4,229	$882.49	$7,403	0	$7,403		$7,403
2n	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_DFAX_Allocation	$ 1,396,065	5.062325%	$70,673	$ 1,384,617	8.775511%	$121,507	$34,879.81	$227,060	0	$227,060		$227,060
2o	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_Load_Ratio Share Allocation	$ 1,396,065	5.062325%	$70,673	$ 1,384,617	8.775511%	$121,507	$34,879.81	$227,060	0	$227,060		$227,060
2p	Install 2nd Hunterstown 230/115 kV transformer	b2452	$ 3,178,583	5.062325%	$160,910	$ 3,154,631	8.775511%	$276,835	$70,987.42	$508,733	0	$508,733		$508,733
2q	Reconductor Hunterstown - Oxford 115 kV line	b2452.1	$ 1,878,434	5.062325%	$95,092	$ 1,864,206	8.775511%	$163,594	$41,947.26	$300,633	0	$300,633		$300,633
3	Transmission Enhancement Credit taken to Attachment H-28A Page 1, Line 7											6,587,322.67		
4	Additional Incentive Revenue taken to Attachment H-28A Page 3, Line 42										$0.00			

Notes
A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-28A.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-28A.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above. This value includes subsequent capital investments required to maintain the project in-service.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-28A, page 3, line 16.
F Any actual ROE incentive must be approved by the Commission
G True-up adjustment is calculated on the project true-up schedule, attachment 12, column i
H Based on a 13-month average

TEC Worksheet Support
Net Plant Detail

Line No.	Project Name	RTEP Project Number	Project Gross Plant (Note A)	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
2a	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown	b0215	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431	$ 12,637,431
2b	Replace wave trap and upgrade a bus section at Keystone 500 kV – on the Keystone – Airydale 500 kV	b0284.3	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817	$ 67,817
2c	Replace wave trap at Keystone 500 kV – on the Keystone – Conemaugh 500 kV	b0285.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2d	Replace wave trap and relay at Conemaugh 500 kV – on the Conemaugh – Keystone 500 kV	b0285.2	$ -	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2e	Install 100 MVAR Dynamic Reactive Device at Airydale 500 kV substation	b0369	$ 3,323,047	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60	$3,323,046.60
2f	Install 250 MVAR capacitor at Keystone 500 kV	b0549	$ 3,207,134	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25	$3,207,134.25
2g	Install 25 MVAR capacitor at Lewis Run 115 kV substation	b0550	$ -	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2h	Install 25 MVAR capacitor at Saxton 115 kV substation	b0551	$ 1,380,393	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10	$1,380,393.10
2i	Install 50 MVAR capacitor at Altoona 230 kV substation	b0552	$ 1,038,335	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66	$1,038,334.66
2j	Install 50 MVAR capacitor at Raystown 230 kV substation	b0553	$ 927,947	$927,946.84	$927,946.84	$927,946.84	$927,946.84	$927,946.84	$927,946.84	$927,946.84	$927,946.84	$927,946.84	$927,946.84	$927,946.84	$927,946.84	$927,946.84
2k	Install 75 MVAR capacitor at East Towanda 230 kV substation	b0557	$ 2,177,814	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37	$2,177,814.37
2l	Relocate the Erie South 345 kV line terminal	b1993	$ 10,525,319	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44	$10,525,319.44
2m	Convert Lewis Run-Farmers Valley to 230 kV using 1033.5 ACSR conductor. Project to be completed in conjunction with new Farmers Valley 345/230 kV transformation	b1994	$ 45,262	-$20,739.21	-$20,739.18	-$20,739.18	-$20,739.18	-$20,739.18	-$20,739.18	-$20,739.18	-$20,739.18	-$20,739.18	$193,763.21	$193,763.21	$193,763.21	$193,763.21
2n	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_DFAX_Allocation	$ 1,396,065	$0.00	$0.00	$0.00	$0.00	$0.00	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68
2o	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_Load_Ratio_Share_Allocation	$ 1,396,065	$0.00	$0.00	$0.00	$0.00	$0.00	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68	$2,268,605.68
2p	Install 2nd Hunterstown 230/115 kV transformer	b2452	$ 3,178,583	$99,060.23	$99,060.23	$99,060.23	$99,060.23	$99,060.23	$5,103,285.05	$5,103,285.13	$5,103,285.13	$5,103,285.05	$5,103,285.05	$5,103,285.05	$5,103,285.05	$5,103,285.05
2q	Reconductor Hunterstown - Oxford 115 kV line	b2452.1	$ 1,878,434	$69,825.25	$69,825.25	$69,825.25	$69,825.25	$69,825.25	$3,008,814.43	$3,008,814.48	$3,008,814.48	$3,008,814.43	$3,008,814.43	$3,008,814.43	$3,008,814.43	$3,008,814.43

NOTE
[A Project Gross Plant is the total capital investment for the project, including subsequent capital investments required to maintain the project in-service. Utilizing a 13-month average.

TEC Worksheet Support
Net Plant Detail

Accumulated Depreciation	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Project Net Plant
(Note B)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note B & C)
$2,086,728.23	$ 1,957,195	$ 1,978,784	$ 2,000,372	$ 2,021,961	$ 2,043,550	$ 2,065,139	$ 2,086,728	$ 2,108,317	$ 2,129,906	$ 2,151,495	$ 2,173,084	$ 2,194,673	$ 2,216,262	$10,550,703.24
$1,122.09	$ 413	$ 532	$ 650	$ 768	$ 886	$ 1,004	$ 1,122	$ 1,240	$ 1,358	$ 1,476	$ 1,595	$ 1,713	$ 1,831	$66,695.18
$0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.00
$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$54,982.58	$20,256.74	$26,044.38	$31,832.02	$37,619.66	$43,407.30	$49,194.94	$54,982.58	$60,770.21	$66,557.85	$72,345.49	$78,133.13	$83,920.77	$89,708.41	$3,268,064.03
$279,609.53	$246,736.41	$252,215.26	$257,694.12	$263,172.97	$268,651.82	$274,130.68	$279,609.53	$285,088.39	$290,567.24	$296,046.10	$301,524.95	$307,003.81	$312,482.66	$2,927,524.72
$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$236,170.26	$222,159.27	$224,494.43	$226,829.60	$229,164.76	$231,499.93	$233,835.09	$236,170.26	$238,505.42	$240,840.59	$243,175.75	$245,510.92	$247,846.08	$250,181.25	$1,144,222.84
$97,000.92	$86,357.99	$88,131.81	$89,905.63	$91,679.45	$93,453.27	$95,227.10	$97,000.92	$98,774.74	$100,548.56	$102,322.38	$104,096.20	$105,870.03	$107,643.85	$941,333.74
$86,688.52	$77,177.06	$78,762.30	$80,347.55	$81,932.79	$83,518.03	$85,103.27	$86,688.52	$88,273.76	$89,859.00	$91,444.24	$93,029.49	$94,614.73	$96,199.97	$841,258.32
$197,690.86	$175,586.04	$179,270.18	$182,954.32	$186,638.45	$190,322.59	$194,006.72	$197,690.86	$201,375.00	$205,059.13	$208,743.27	$212,427.40	$216,111.54	$219,795.68	$1,980,123.51
$279,756.45	$171,345.66	$189,414.13	$207,482.59	$225,551.06	$243,619.52	$261,687.99	$279,756.45	$297,824.92	$315,893.38	$333,961.85	$352,030.31	$370,098.78	$388,167.24	$10,245,562.99
-$2,930.19	-$2,943.49	-$2,979.96	-$3,016.43	-$3,052.89	-$3,089.36	-$3,125.83	-$3,162.29	-$3,198.76	-$3,235.22	-$3,083.11	-$2,742.41	-$2,401.71	-$2,061.01	$48,191.74
$11,447.73	$0.00	$0.00	$0.00	$0.00	$0.00	$2,325.32	$6,975.96	$11,626.60	$16,277.25	$20,927.89	$25,578.53	$30,229.17	$34,879.81	$1,384,617.30
$11,447.73	$0.00	$0.00	$0.00	$0.00	$0.00	$2,325.32	$6,975.96	$11,626.60	$16,277.25	$20,927.89	$25,578.53	$30,229.17	$34,879.81	$1,384,617.30
$23,952.64	$279.81	$461.42	$643.03	$824.64	$1,006.25	$5,775.07	$15,131.09	$24,487.11	$33,843.14	$43,199.16	$52,555.18	$61,911.20	$71,267.23	$3,154,630.57
$14,227.57	$196.36	$324.37	$452.39	$580.40	$708.41	$3,530.50	$9,046.66	$14,562.82	$20,078.98	$25,595.14	$31,111.30	$36,627.46	$42,143.62	$1,864,206.42

NOTE

[B] Utilizing a 13-month average.

[C] Taken to Attachment 11, Page 2, Col. 6

[D] Company records

TEC - True-up
To be completed after Attachment 11 for the True-up Year is updated using actual data

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.		**Project Name**	**RTEP Project Number**	**Actual Revenues for Appendix D**	**Projected Annual Revenue Requirement**	**% of Total Revenue Requirement**	**Revenue Received**	**Actual Annual Revenue Requirement**	**True-up Adjustment Principal Over/(Under)**	**Applicable Interest Rate on Over/(Under)**	**Total True-up Adjustment with Interest Over(Under)**
					Projected Attachment 11 p 2 of 2, col. 14	Col d, line 2 / Col. d, line 3	Col c, line 1 * Col e	Actual Attachment 11 p 2 of 2, col. 14	Col. f - Col. G	Col. H line 2x / Col. H line 3 * Col. J line 4	Col. h + Col. i
1	[A]	Actual RTEP Credit Revenues for true-up year		0							
2a		Project 1			-	-	-	-	-	#DIV/0!	#DIV/0!
2b		Project 2				-	-		-	#DIV/0!	#DIV/0!
2c		Project 3				-	-		-	#DIV/0!	#DIV/0!
3		Subtotal			-			-	-		#DIV/0!
4		Total Interest (Sourced from Attachment 13a, line 30)									-

NOTE
[A] Amount included in revenues reported on pages 328-330 of FERC Form 1.

Net Revenue Requirement True-up with Interest

	Reconciliation Revenue Requirement For Year 2015 Available May 1, 2016		2015 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2014		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				

An over or under collection will be recovered prorata over 2015, held for 2016 and returned prorate over 2017

	Calculation of Interest					Monthly		
3	January	Year 2015	-	0.0000%	12	-		-
4	February	Year 2015	-	0.0000%	11	-		-
5	March	Year 2015	-	0.0000%	10	-		-
6	April	Year 2015	-	0.0000%	9	-		-
7	May	Year 2015	-	0.0000%	8	-		-
8	June	Year 2015	-	0.0000%	7	-		-
9	July	Year 2015	-	0.0000%	6	-		-
10	August	Year 2015	-	0.0000%	5	-		-
11	September	Year 2015	-	0.0000%	4	-		-
12	October	Year 2015	-	0.0000%	3	-		-
13	November	Year 2015	-	0.0000%	2	-		-
14	December	Year 2015	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2016	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2017	-	0.0000%		-	-	-
17	February	Year 2017	-	0.0000%		-	-	-
18	March	Year 2017	-	0.0000%		-	-	-
19	April	Year 2017	-	0.0000%		-	-	-
20	May	Year 2017	-	0.0000%		-	-	-
21	June	Year 2017	-	0.0000%		-	-	-
22	July	Year 2017	-	0.0000%		-	-	-
23	August	Year 2017	-	0.0000%		-	-	-
24	September	Year 2017	-	0.0000%		-	-	-
25	October	Year 2017	-	0.0000%		-	-	-
26	November	Year 2017	-	0.0000%		-	-	-
27	December	Year 2017	-	0.0000%		-	-	-
						-		

28	True-Up with Interest	$ -
29	Less Over (Under) Recovery	$ -
30	Total Interest	$ -

[A] 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

TEC Revenue Requirement True-up with Interest

	TEC Reconciliation Revenue Requirement For Year 2015 Available May 1, 2016		TEC 2015 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2014		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				
	An over or under collection will be recovered prorata over 2015, held for 2016 and returned prorate over 2017							
	Calculation of Interest					Monthly		
3	January	Year 2015	-	0.0000%	12	-		-
4	February	Year 2015	-	0.0000%	11	-		-
5	March	Year 2015	-	0.0000%	10	-		-
6	April	Year 2015	-	0.0000%	9	-		-
7	May	Year 2015	-	0.0000%	8	-		-
8	June	Year 2015	-	0.0000%	7	-		-
9	July	Year 2015	-	0.0000%	6	-		-
10	August	Year 2015	-	0.0000%	5	-		-
11	September	Year 2015	-	0.0000%	4	-		-
12	October	Year 2015	-	0.0000%	3	-		-
13	November	Year 2015	-	0.0000%	2	-		-
14	December	Year 2015	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2016	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2017	-	0.0000%		-	-	-
17	February	Year 2017	-	0.0000%		-	-	-
18	March	Year 2017	-	0.0000%		-	-	-
19	April	Year 2017	-	0.0000%		-	-	-
20	May	Year 2017	-	0.0000%		-	-	-
21	June	Year 2017	-	0.0000%		-	-	-
22	July	Year 2017	-	0.0000%		-	-	-
23	August	Year 2017	-	0.0000%		-	-	-
24	September	Year 2017	-	0.0000%		-	-	-
25	October	Year 2017	-	0.0000%		-	-	-
26	November	Year 2017	-	0.0000%		-	-	-
27	December	Year 2017	-	0.0000%		-	-	-
						-		

28	True-Up with Interest	$ -
29	Less Over (Under) Recovery	$ -
30	Total Interest	$ -

[A] 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

Other Rate Base Items

For the 12 months ended 12/31/2017

			[1]	[2]	[3]	[4]	[5]	[6]
			Land Held for Future Use	**Materials & Supplies**	**Prepayments (Account 165)**		**Total**	
		[A]	214.x.d	227.8.c & .16.c	111.57.c [C]			
1	December 31	2016	-	-	-		-	
2	December 31	2017	-	-	-		-	
3	Begin/End Average		-	-	-		-	

Unfunded Reserve - Plant Related

	FERC Acct No.		228.1	228.2	228.3	228.4	242	Total
		[A,D]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c	
4	December 31	2016	-	-	-	-	-	-
5	December 31	2017	-	-	-	-	-	-
6	Begin/End Average		-	-	-	-	-	-

Unfunded Reserve - Labor Related

	FERC Acct No.		228.1	228.2	228.3	228.4	242	Total
		[A,D]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c [B]	
7	December 31	2016	-	-	-	-	-	-
8	December 31	2017	-	-	-	-	-	-
9	Begin/End Average		-	-	-	-	-	-

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

[B] Values entered under FERC Account No. 242, classified as Unfunded Reserve - Labor Related, are limited to MAIT labor-related Vacation Accruals and Employee Incentive Compensation.

[C] Prepayments shall exclude prepayments of income taxes.

[D] Includes transmission-related balance only.

Income Tax Adjustments

	[1]	[2]	[3]	[4]	[5]
				Dec 31,	Dec 31,
			Beg/End Average [C]	2016	2017
1	Tax adjustment for Permanent Differences & AFUDC Equity	[A]	1,072,591	854,625	$1,290,556
2	Amortized Excess Deferred Taxes (enter negative)	[B]	-	-	$0
3	Amortized Deficient Deferred Taxes	[B]	-	-	$0

Notes:

[A] AFUDC equity component is the gross cumulative annual amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function.

[B] Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Amounts to be included will be January 1, 2017 and thereafter.

[C] Beg/End Average for line 1 included on Attachment H-28A, page 3, line 33; Beg/End Average for lines 2-3 taken to Attachment H-28A, page 3, line 34

Regulatory Asset - Deferred Storms

	[1]	[2]	[3] Months Remaining In Amortization Period	[4] BegInning Balance	[5] Amortization Expense (Company Records)	[6] Additions (Deductions)	[7] Ending Balance
1	**Monthly Balance**	Source					
2	December 2016	p232 (and Notes)	61				1,214,578.00
3	January	FERC Account 182.3	60	1,214,578	20,242.97	-	1,194,335.03
4	February	FERC Account 182.3	59	1,194,335	20,242.97	-	1,174,092.07
5	March	FERC Account 182.3	58	1,174,092	20,242.97	-	1,153,849.10
6	April	FERC Account 182.3	57	1,153,849	20,242.97	-	1,133,606.13
7	May	FERC Account 182.3	56	1,133,606	20,242.97	-	1,113,363.17
8	June	FERC Account 182.3	55	1,113,363	20,242.97	-	1,093,120.20
9	July	FERC Account 182.3	54	1,093,120	20,242.97	-	1,072,877.23
10	August	FERC Account 182.3	53	1,072,877	20,242.97	-	1,052,634.27
11	September	FERC Account 182.3	52	1,052,634	20,242.97	-	1,032,391.30
12	October	FERC Account 182.3	51	1,032,391	20,242.97	-	1,012,148.33
13	November	FERC Account 182.3	50	1,012,148	20,242.97	-	991,905.37
14	December 2017	p232 (and Notes)	49	991,905	20,242.97	-	971,662.40
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$242,915.60	-	$1,093,120.20
					Attachment H-28A, page 3, line 12		Attachment H-28A, page 2, Line 27

Regulatory Asset - Vegetation Management

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (Company Records)	Additions (Deductions)	Ending Balance
2	December 2016	p232 (and Notes)	85				16,963,581.30
3	January	FERC Account 182.3	84	16,963,581	201,947.40	-	16,761,633.90
4	February	FERC Account 182.3	83	16,761,634	201,947.40	-	16,559,686.51
5	March	FERC Account 182.3	82	16,559,687	201,947.40	-	16,357,739.11
6	April	FERC Account 182.3	81	16,357,739	201,947.40	-	16,155,791.71
7	May	FERC Account 182.3	80	16,155,792	201,947.40	-	15,953,844.32
8	June	FERC Account 182.3	79	15,953,844	201,947.40	-	15,751,896.92
9	July	FERC Account 182.3	78	15,751,897	201,947.40	-	15,549,949.53
10	August	FERC Account 182.3	77	15,549,950	201,947.40	-	15,348,002.13
11	September	FERC Account 182.3	76	15,348,002	201,947.40	-	15,146,054.73
12	October	FERC Account 182.3	75	15,146,055	201,947.40	-	14,944,107.34
13	November	FERC Account 182.3	74	14,944,107	201,947.40	-	14,742,159.94
14	December 2017	p232 (and Notes)	73	14,742,160	201,947.40	-	14,540,212.54
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$2,423,368.76	-	$15,751,896.92
					Attachment H-28A, page 3, line 12		Attachment H-28A, page 2, Line 27

Regulatory Asset - Start-up Costs

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Months Remaining In Amortization Period				
1	**Monthly Balance**	Source		BegInning Balance	Amortization Expense (Company Records)	Additions (Deductions)	Ending Balance
2	December 2016	p232 (and Notes)	13				1,150,250.00
3	January	FERC Account 182.3	12	1,150,250	95,854.17	-	1,054,395.83
4	February	FERC Account 182.3	11	1,054,396	95,854.17	-	958,541.67
5	March	FERC Account 182.3	10	958,542	95,854.17	-	862,687.50
6	April	FERC Account 182.3	9	862,688	95,854.17	-	766,833.33
7	May	FERC Account 182.3	8	766,833	95,854.17	-	670,979.17
8	June	FERC Account 182.3	7	670,979	95,854.17	-	575,125.00
9	July	FERC Account 182.3	6	575,125	95,854.17	-	479,270.83
10	August	FERC Account 182.3	5	479,271	95,854.17	-	383,416.67
11	September	FERC Account 182.3	4	383,417	95,854.17	-	287,562.50
12	October	FERC Account 182.3	3	287,563	95,854.17	-	191,708.33
13	November	FERC Account 182.3	2	191,708	95,854.17	-	95,854.17
14	December 2017	p232 (and Notes)	1	95,854	95,854.17	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$1,150,250.00	-	$575,125.00
					Attachment H-28A, page 3, line 12		Attachment H-28A, page 2, Line 27

Abandoned Plant

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
2	December 2016	p111.71.d (and Notes)	13				-
3	January	FERC Account 182.2	12	-	-	-	-
4	February	FERC Account 182.2	11	-	-	-	-
5	March	FERC Account 182.2	10	-	-	-	-
6	April	FERC Account 182.2	9	-	-	-	-
7	May	FERC Account 182.2	8	-	-	-	-
8	June	FERC Account 182.2	7	-	-	-	-
9	July	FERC Account 182.2	6	-	-	-	-
10	August	FERC Account 182.2	5	-	-	-	-
11	September	FERC Account 182.2	4	-	-	-	-
12	October	FERC Account 182.2	3	-	-	-	-
13	November	FERC Account 182.2	2	-	-	-	-
14	December 2017	p111.71.c (and Notes) Detail on p230b	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00		$0.00
					Attachment H-28A, page 3, Line 19		Attachment H-28A, page 2, Line 28

Note:

Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC and will be zero until the Commission accepts or approves recovery of the cost of abandoned plant

			CWIP
			[A]
			216.b
1	December	2016	
2	January	2017	
3	February	2017	
4	March	2017	
5	April	2017	
6	May	2017	
7	June	2017	
8	July	2017	
9	August	2017	
10	September	2017	
11	October	2017	
12	November	2017	
13	December	2017	
14	13-month Average		-

Notes:
[A] Includes only CWIP authorized by the Commission for inclusion in rate base.

Federal Income Tax Rate

Nominal Federal Income Tax Rate (entered on Attachment H-28A, page 5 of 5, Note K)	35.00%

State Income Tax Rate

	Pennsylvania	Combined Rate (entered on Attachment H-28A, page 5 of 5, Note K)
Nominal State Income Tax Rate	9.99%	
Times Apportionment Percentage	100.00%	
Combined State Income Tax Rate	9.990%	9.990%

Attachment 5

MAIT FERC Order

158 FERC ¶ 62,185
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

Mid-Atlantic Interstate Transmission, LLC
Docket Nos. ER17-211-000
ER17-211-001

Issued: March 10, 2017

Skadden, Arps, Slate Meagher & Flom LLP
1440 New York Avenue, N.W.
Washington, DC 20005

FirstEnergy Service Co.
76 South Main St.
Akron, OH 44308

Attention: Mike Naeve, Esq. and John S. Moot, Esq.
Counsel for Mid-Atlantic Interstate Transmission, LLC

Reference: Order Accepting and Suspending Filing, Subject to Refund, and Establishing Hearing and Settlement Judge Procedures

Dear Mr. Naeve and Mr. Moot:

On October 28, 2016, as amended on January 10, 2017, pursuant to section 205 of the Federal Power Act,[1] Mid-Atlantic Interstate Transmission, LLC (MAIT) submitted proposed tariff revisions intended to change the revenue requirements used to establish transmission rates charged in the Metropolitan Edison (MetEd) and Pennsylvania Electric Company (Penelec) Zone(s) under the PJM Open Access Transmission Tariff (Tariff) by replacing the current stated transmission rates with a new formula rate template and formula rate protocols. MAIT seeks an effective date for the proposed tariff revisions of February 1, 2017.

[1] 16 U.S.C. § 824d (2012).

MAIT's filing was noticed on October 28, 2016, with interventions and protests due on or before November 18, 2016. MAIT's response to a deficiency letter was noticed on January 10, 2017, with interventions and protests due on or before January 31, 2017. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[2] any notices of intervention and timely filed, unopposed motions to intervene serve to make the filer a party to this proceeding.[3]

Protestors challenge the filing on various grounds, disputing, among other things, the proposed formula rate protocols, formula rate template, and the application of Commission precedent. They assert that the proposed Tariff revisions will produce substantially excessive rates.

MAIT's proposed Tariff revisions raise issues of material fact that cannot be resolved based on the existing record and are more appropriately addressed in hearing and settlement judge procedures. Preliminary analysis indicates that MAIT's proposed Tariff revisions have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Additionally, in *West Texas Utilities Co.*, the Commission explained that, when its preliminary analysis indicates that proposed rates may be unjust and unreasonable, and may be substantially excessive, the Commission will generally impose a maximum suspension (i.e., five months).[4] In this proceeding, it appears that MAIT's proposed Tariff revisions may yield substantially excessive rates. Therefore, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), and pursuant to the authority delegated to the Director, Division of Electric Power Regulation – East, Office of Energy Market Regulation, in the Commission's February 3, 2017 Order Delegating Further Authority to Staff in Absence of Quorum,[5] MAIT's proposed Tariff revisions are accepted for filing, suspended for the maximum

[2] 18 C.F.R. § 385.214 (2016).

[3] The Chief Administrative Law Judge or presiding officer, as appropriate, may rule on any late and opposed motions to intervene. *See* 18 C.F.R. §§ 375.304(a), 385.102(a), 385.214(c) and (d), and 385.504(b)(12) (2016). *See also*, *Cities of Anaheim*, 101 FERC 61,392 at P 13 (2002) (Chief Administrative Law Judge may, but settlement judges may not, rule on motions to intervene).

[4] *W. Texas Util. Co.*, 18 FERC ¶ 61,189 at 61,374-75 (1982).

[5] *Agency Operations in the Absence of a Quorum*, 158 FERC ¶ 61,135 (2017).

five-month period, to become effective July 1, 2017, subject to refund, and set for hearing and settlement judge procedures.[6] Although this order directs that a public hearing shall be held concerning the justness and reasonableness of MAIT's proposed Tariff revisions, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed below.

While this matter is set for a trial-type evidentiary hearing, parties are encouraged to make every effort to settle their disputes before hearing procedures are commenced. To aid the parties in their settlement efforts, the hearing will be held in abeyance, and pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, the Chief Administrative Law Judge is directed to appoint a settlement judge in these proceedings within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding.[7] The Chief Judge, however, may not be able to designate the requested settlement judge based on workload requirements which determine judges' availability. If the participants decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the participants with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the participants' progress toward settlement.

If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Commission, 888 First Street, NE, Washington, DC 20426. Such a conference shall be held for the purpose of

[6] MAIT's entire filing is set for hearing. Issues to be explored at hearing are not limited to those noted here.

[7] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at 202-502-8500 within five days of this order. The Commission's website contains a list of the Commission's judges and a summary of their background and experience at http://www.ferc.gov/about/offices/oaljdr/oalj-dj.asp.

establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

The acceptance for filing herein shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in the filing; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against MAIT.

Consistent with Rule 1902 of the Commission's Rules of Practice and Procedure,[8] requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order.[9]

Sincerely,

Kurt M. Longo, Director
Division of Electric Power
Regulation – East

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[8] 18 C.F.R. § 385.1902 (2016).

[9] 18 C.F.R. § 385.713 (2016).

Document Content(s)