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PSEG
Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

December 8, 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, ER16040337
++
Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff
BPU Docket No. _______________

Irene Kim Asbury, Esquire
Secretary of the Board
Board of Public Utilities
44 South Clinton Ave.
3rd Floor, Suite 314
Trenton, New Jersey 08625-0350

Dear Secretary Asbury:

Enclosed for filing on behalf of Jersey Central Power & Light Company ("JCP&L"), Atlantic City Electric Company ("ACE"), Public Service Electric and Gas Company ("PSE&G"), and Rockland Electric Company ("RECO") (collectively, the "EDCs"), enclosed please find an original and ten copies of tariff sheets and supporting exhibits that reflect changes to the PJM Open Access Transmission Tariff ("OATT") made in response to the annual formula rate update 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 Orders dated October 22, 2003 (BPU Docket No. EO03050394) and October 22, 2004 (BPU Docket No. EO04040288), the Board of Public Utilities (“Board” or “BPU”) 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 Agreement (“SMA”).

The EDCs' pro-forma tariff sheets, included as Attachment 1a (PSE&G), Attachment 2a (JCP&L), Attachment 3a (ACE), and Attachment 4a (RECO), propose effective dates of January 1, 2018, and specifically reflect changes to BGS rates applicable to Basic Generation Service – Residential Small Commercial Pricing (“BGS-RSCP”), and Commercial and Industrial Energy Pricing ("BGS-CIEP") customers resulting from the MAIT annual formula rate update filed with FERC on or about October 13, 2017. The specific additional PJM transmission charges related to the MAIT filing are found in Schedule 12 of the PJM OATT. On July 29, 2017, PJM updated its Schedule 12 Transmission Enhancement Worksheet, which, along with Schedule 12 of the PJM OATT, is utilized in developing this filing and incorporates the formula rate updates referenced herein. Because BGS suppliers will begin paying these increased transmission charges in January 2018, the EDCs request a waiver of the 30-day filing requirement.

These Schedule 12 charges, also defined as Transmission Enhancement Charges ("TECs") in 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.

Request for Board Approval

The EDCs respectfully request approval to implement these revised tariff rates effective January 1, 2018. In support of this request, the EDCs have included pro-forma tariff sheets as noted above. The BGS 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 determinants for calculation of the PJM charges are set forth in Schedule 12 of the PJM OATT and on the Formula Rates page of the PJM website. Copies of all formula rate updates are attached, but can also be found on the PJM website at: http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx.

The translation of the transmission zone rate impact to the BGS rates of each of the EDCs, assuming implementation on January 1, 2018, is included as Attachments 1, 2, 3, and 4 for PSE&G, JCP&L, ACE, and RECO, respectively. Attachment 5 shows the cost impact for the January through December 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 MAIT projects posted on the PJM website. Attachment 6 provides excerpts of the Schedule 12 OATT indicating the responsible share of projects. Attachment 7 provides the formula rate update for MAIT.

The EDCs also request that BGS Suppliers be compensated for the changes to the OATT resulting from the implementation of the MAIT annual formula update effective on January 1, 2018. 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 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

C Thomas Walker, NJBPU
Stacy Peterson, NJBPU
Stefanie Brand, Division of Rate Counsel
Service List (via Electronic Mail Server)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket No.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket No.

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Attachment 1 – PSE&G Tariffs and Rate Translation

Attachment 1a
Pro-forma PSE&G Tariff Sheets

Attachment 1b
PSE&G Translation of MAIT Schedule 12 (Transmission Enhancement)
Charge into Customer Rates

Attachment 1a

Pro-forma PSE&G 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	$0.114497	$0.122369	$0.114551	$0.122426
RS – in excess of 600 kWh	0.114497	0.122369	0.123669	0.132171
RHS – first 600 kWh	0.092635	0.099004	0.087739	0.093771
RHS – in excess of 600 kWh	0.092635	0.099004	0.099931	0.106801
RLM On-Peak	0.195519	0.208961	0.206957	0.221185
RLM Off-Peak	0.054503	0.058250	0.050739	0.054227
WH	0.054424	0.058166	0.051835	0.055399
WHS	0.054891	0.058665	0.051426	0.054962
HS	0.092624	0.098992	0.093503	0.099931
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	$ 7.24 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 8.0209
Charge including New Jersey Sales and Use Tax (SUT)	$ 8.5723

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
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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	$ 7.24 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 8.0209
Charge including New Jersey Sales and Use Tax (SUT)	$ 8.5723

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.

Attachment 1b
PSE&G Translation of NITS Charge into
Customer Rates

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission Projects

TEC Charges for Jan 2018 - December 2018		$830,671.31	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	7.24	/MW/month
converted to $/MW/yr =	$	86.88	/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	$ 0.027717	$ 0.016650	$ 0.029100	$ -	$ -	$ 0.016008	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000028**	**$ 0.000017**	**$ 0.000029**	**$ -**	**$ -**	**$ 0.000016**	**$ -**	**$ -**

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	$	578,517		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0225	/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	$	(63,954)		unrounded	= (7) - (4)

Attachment 2 – JCP&L Tariffs and Rate Translation

Attachment 2a
Pro-forma JCP&L Tariff Sheets

Attachment 2b
JCP&L Translation of MAIT Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 2a

Pro-forma JCP&L Tariff Sheets

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 January 1, 2018, 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 **$0.000030** per KWH

3) BGS Reconciliation Charge per KWH: ($0.000207) (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 January 1, 2018, 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	**$0.000030**
GP	**$0.000020**
GT	**$0.000019**
GT – High Tension Service	**$0.000004**

4) BGS Reconciliation Charge per KWH: $0.002032 (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.

Attachment 2b
JCP&L Translation of MAIT Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 2b

Jersey Central Power & Light Company
Proposed MAIT Project Transmission Enhancement Charge (MAIT-TEC Surcharge) effective January 1, 2018
To reflect proposed MAIT Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2018

2018 Average Monthly MAIT-TEC Costs Allocated to JCP&L Zone	$	45,067.52	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5721.0	
MAIT-Transmission Enhancement Rate ($/MW-month)	$	7.88	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective January 1, 2018 MAIT-TEC Surcharge ($/kWh)	Effective January 1, 2018 MAIT-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	466,490	16,572,627,418	$ 0.000028	$ 0.000030
Primary	348.5	32,944	1,730,276,418	$ 0.000019	$ 0.000020
Transmission @ 34.5 kV	293.5	27,745	1,581,370,077	$ 0.000018	$ 0.000019
Transmission @ 230 kV	15.5	1,465	341,655,635	$ 0.000004	$ 0.000004
Total	5592.3	528,644	20,225,929,548		

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

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,159,224	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		16,830,967	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,688	MW
4	MAIT-Transmission Enhancement Costs to RSCP Suppliers	$	443,188	= Line 3 x $7.88 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.03	= Line 4 / Line 2

Attachment 3 – ACE Tariffs and Rate Translation

Attachment 3a
Pro-forma ACE Tariff Sheets

Attachment 3b
ACE Translation of PSE&G Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 3a
Pro-forma ACE Tariff Sheets

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	0.000031	0.000026	0.000028	0.000017	0.000014	0.000013	-	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	0.002181	0.001767	0.001878	0.001206	0.000994	0.000846	-	0.000742

Date of Issue: **Effective Date:**

Issued by:

Attachment 3b
ACE Translation of MAIT Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Atlantic City Electric Company
Proposed MAIT Projects Transmission Enhancement Charge (BG&E Project-TEC Surcharge) effective Jan 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective Jan 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	16,215
	$	16,215
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	6.38

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$	118,906	4,171,964,933	$	0.000029	$	0.000029	$	0.000031
MGS Secondary	359	$	27,456	1,152,950,462	$	0.000024	$	0.000024	$	0.000026
MGS Primary	8	$	629	24,456,016	$	0.000026	$	0.000026	$	0.000028
AGS Secondary	393	$	30,115	1,917,585,029	$	0.000016	$	0.000016	$	0.000017
AGS Primary	94	$	7,199	571,955,641	$	0.000013	$	0.000013	$	0.000014
TGS	146	$	11,186	920,786,585	$	0.000012	$	0.000012	$	0.000013
SPL/CSL	0	$	-	73,240,385	$	-	$	-	$	-
DDC	2	$	126	12,621,752	$	0.000010	$	0.000010	$	0.000011
	2,554	$	195,616	8,845,560,805						

Attachment 4 – RECO Tariffs and Rate Translation

Attachment 4a
Pro-forma RECO Tariff Sheets

Attachment 4b
RECO Translation of PSE&G Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 4a

Pro-forma RECO Tariff Sheets

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	0.948 ¢ per kWh	0.948 ¢ 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 ....@	0.590 ¢ per kWh	0.590 ¢ per kWh
Primary Voltage Service Only All kWh ....@	0.527 ¢ per kWh	0.527 ¢ 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.

	Summer Months*	Other Months
All kWh .....@	0.576 ¢ per kWh	0.576 ¢ 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)

DRAFT

SERVICE CLASSIFICATION NO. 4
PUBLIC STREET LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Luminaire Charges (Continued)

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge	Transmission Charge
Post Top Luminaires					
16,000	Sodium Vapor-Offset	150	199	$23.00	$0.48
Off-Roadway Luminaires					
27,500	Sodium Vapor	250	311	$ 19.19	$ 0.75
46,000	Sodium Vapor	400	488	27.00	1.18
Post-Top Luminaires					
4,000	Mercury Vapor	100	130	$ 11.75	$ 0.31
7,900	Mercury Vapor	175	215	14.39	0.52
7,900	Merc. Vapor-Offset	175	215	16.90	0.52

The above Transmission Charges apply to all customers taking Basic Generation Service from the Company. Transmission charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. Transmission 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. A Transmission Surcharge, to recover Reliability Must Run Charges, of 0.001 ¢ per kWh will also apply to all customers taking Basic Generation Service from the Company.

(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 ... @	0.632 ¢ per kWh	0.632 ¢ 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. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Distribution and Transmission Charges (Continued)

(b) Distribution and Transmission Charges for Service Type C

The above Transmission Charges apply to all customers taking Basic Generation Service from the Company. Transmission charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. Transmission 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. A Transmission Surcharge, to recover Reliability Must Run Charges, of 0.001 ¢ per kWh will also apply to all customers taking Basic Generation Service from the Company.

(2) 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. For service type A, B, or C if not metered, the charges shall be applied to the kWh estimated as follows:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

* See Monthly Burn Hours Table.

(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 @	0.383 ¢ per kWh	0.383 ¢ 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 0.383 ¢ 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)

Attachment 4b

RECO Translation of PSE&G Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (MAIT) effective January 1, 2018
To reflect FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2018 to December 2018

2018 Average Monthly MAIT-TEC Costs Allocated to RECO	$	1,902	(1)
2018 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	4.32	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $1,902 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	262.5	59.69%	$	13,623	692,439,000	$	0.00002	$	0.00002
SC2 Secondary	124.6	28.32%	$	6,464	528,990,000	$	0.00001	$	0.00001
SC2 Primary	13.9	3.15%	$	720	65,159,000	$	0.00001	$	0.00001
SC3	0.1	0.01%	$	3	275,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.7	0.85%	$	194	14,763,000	$	0.00001	$	0.00001
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	35.1	7.97%	$	1,819	227,701,000	$	0.00001	$	0.00001
Total	439.8 (2)	100.00%	$	22,823	1,541,318,000				

(1) Attachment 2 - Cost Allocation of MAIT Schedule 12 Charges to RECO Zone for January 2018 to December 2018
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		405	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	20,982.30	= Line 3 x $4.32 * 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 January 1, 2018
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)
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
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)
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)
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)	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00012	0.00008	0.00007	0.00008	0.00000	0.00008	0.00000	0.00005
BG&E- TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00004)	(0.00003)	(0.00002)	(0.00003)	0.00000	(0.00003)	0.00000	(0.00002)
PEPCO - TEC	(7)	0.00001	0.00001	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00021	0.00013	0.00010	0.00013	0.00000	0.00014	0.00000	0.00008
PSE&G - TEC	(9)	0.00774	0.00481	0.00435	0.00469	0.00000	0.00516	0.00000	0.00314
TrAILCo - TEC	(10)	0.00041	0.00025	0.00020	0.00026	0.00000	0.00027	0.00000	0.00016
VEPCo - TEC	(11)	0.00035	0.00022	0.00020	0.00021	0.00000	0.00023	0.00000	0.00014
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Total ($/kWh and excl SUT)		$0.00890	$0.00553	$0.00495	$0.00540	$0.00001	$0.00592	$0.00001	$0.00359
Total (¢/kWh and excl SUT)		0.890 ¢	0.553 ¢	0.495 ¢	0.540 ¢	0.001 ¢	0.592 ¢	0.001 ¢	0.359 ¢

(B) Transmission Surcharge rates by Transmission Project and Service Class (including SUT) **6.625%**

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00013	0.00009	0.00007	0.00009	0.00000	0.00009	0.00000	0.00005
BG&E- TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00004)	(0.00003)	(0.00002)	(0.00003)	0.00000	(0.00003)	0.00000	(0.00002)
PEPCO - TEC	(7)	0.00001	0.00001	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00022	0.00014	0.00011	0.00014	0.00000	0.00015	0.00000	0.00009
PSE&G - TEC	(9)	0.00825	0.00513	0.00464	0.00500	0.00000	0.00550	0.00000	0.00335
TrAILCo - TEC	(10)	0.00044	0.00027	0.00021	0.00028	0.00000	0.00029	0.00000	0.00017
VEPCo - TEC	(11)	0.00037	0.00023	0.00021	0.00022	0.00000	0.00025	0.00000	0.00015
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Total ($/kWh and incl SUT)		$0.00948	$0.00590	$0.00527	$0.00576	$0.00001	$0.00632	$0.00001	$0.00383
Total (¢/kWh and incl SUT)		0.948 ¢	0.590 ¢	0.527 ¢	0.576 ¢	0.001 ¢	0.632 ¢	0.001 ¢	0.383 ¢

Notes:

(1) RMR rates based on allocations by transmission zone.
(2) ACE-TEC rates pursuant to the Board's Order dated August 23, 2017 in Docket No. ER17060671.
(3) AEP-East-TEC rates calculated in Attachment 5 filed separately.
(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 calculated in Attachment 5 filed separately.
(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 calculated in Attachment 5 filed separately.
(10) TrAILCo-TEC rates pursuant to the Board's Order dated August 23, 2017 in Docket No. ER17060671.
(11) VEPCo-TEC rates calculated in Attachment 5 filed separately.
(12) MAIT-TEC rates calculated in Attachment 5 of the joint filing.

Attachment 5 – PJM Schedule 12 (Transmission Enhancement) Charges

Attachment 5
MAIT Project Charges

Attachment 5 - Transmission Enhancement Charges for January 2018 - December 2018
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*	**Jan-Dec 2018 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	$ 1,722,473.00	6.71%	16.85%	22.67%	0.34%	$115,578	$290,237	$390,485	$5,856	$802,156
Replace wave trap at Kestone 500kV Sub	b0284.3	$ -	1.70%	3.78%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 100 MVAR Cap Banks at Jack's Mountain 500 kV Sub	b0369	$ -	1.70%	3.78%	6.22%	0.25%	$0	$0	$0	$0	$0
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549	$ 456,461.00	1.70%	3.78%	6.22%	0.25%	$7,760	$17,254	$28,392	$1,141	$54,547
Install 25 MVAR capacitor at Saxton 115 kV Sub	b0551	$ 187,275.00	8.58%	18.16%	26.13%	0.97%	$16,068	$34,009	$48,935	$1,817	$100,829
Install 50 MVAR capacitor at Altoona 230 kV Sub	b0552	$ 150,010.00	8.58%	18.16%	26.13%	0.97%	$12,871	$27,242	$39,198	$1,455	$80,765
Install 50 MVAR capacitor at Raystoon 230 kV Sub	b0553	$ 132,043.00	8.58%	18.16%	26.13%	0.97%	$11,329	$23,979	$34,503	$1,281	$71,092
Install 75 MVAR capacitor at East Towanda 230 kV Sub	b0557	$ 309,489.00	8.58%	18.16%	26.13%	0.97%	$26,554	$56,203	$80,869	$3,002	$166,629
Relocate the Erie South 345 kV Line Terminal	b1993	$ 1,570,347.00	0.00%	5.14%	12.10%	0.48%	$0	$80,716	$190,012	$7,538	$278,265
Conver Lewis Run-Farmers Valley to 230kV using 1033.5 Conductor	b1994	$ 15,407.00	0.00%	8.64%	13.55%	0.54%	$0	$1,331	$2,088	$83	$3,502
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1	$ 260,294.00	1.70%	3.78%	6.22%	0.25%	$4,425	$9,839	$16,190	$651	$31,105
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1_dfax	$ 302,983.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
							$194,585	**$540,810**	**$830,671**	**$22,824**	**$1,588,890**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2018**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (12 months)**
PSE&G	$ 69,222.61	9,566.9	$ 7.24	$ 830,671
JCP&L	$ 45,067.52	5,721.0	$ 7.88	$ 540,810
ACE	$ 16,215.44	2,540.8	$ 6.38	$ 194,585
RE	$ 1,901.97	401.7	$ 4.73	$ 22,824
Total Impact on NJ Zones	**$ 132,407.54**			**$ 1,588,890**
Notes on calculations >>>			= (k) * (l)	= (k) *12

Notes:
1) 2018 allocation share percentages are from PJM OATT

Attachment 6 – Cost Allocations

Attachment 6 – Responsible Customer Shares for MAIT Schedule 12 Projects
Source – 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%)

* Neptune Regional Transmission System, LLC
** 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%)

* Neptune Regional Transmission System, LLC
** 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%)

* Neptune Regional Transmission System, LLC

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

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%)

* 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)
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%)

* 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)
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.
***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)
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%)

* 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)
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%)

* 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)
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 7

MAIT Formula Rate for January 1, 2018 to December 31, 2018

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2018

Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]					$ 157,048,022
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 451	(page 4, line 29)	-	TP	1.00000	-
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)	1,397,264	TP	1.00000	1,397,264
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	6,458,031	TP	1.00000	6,458,031
8	TOTAL REVENUE CREDITS (sum lines 2-7)		11,616,383			11,616,383
9	True-up Adjustment with Interest	Attachment 13, Line 28				-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)				$ 145,431,639

Line No.					Total
	DIVISOR				
11	1 Coincident Peak (CP) (MW)			(Note A)	5,786.8
12	Average 12 CPs (MW)			(Note CC)	5,063.5

Line No.			Total
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)	25,131.56

Line No.			Peak Rate Total	Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	28,721.33	28,721.33
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	2,393.44	2,393.44
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	552.33	552.33
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	110.47	78.90
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	6.90	3.28

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2018

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)	1,219,721,068	TP	1.00000	1,219,721,068
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)	40,516,028	W/S	1.00000	40,516,028
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	1.00000	-
6	TOTAL GROSS PLANT (sum lines 1-5)		1,260,237,097	GP=	100.000%	1,260,237,097
	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)	353,676,488	TP	1.00000	353,676,488
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)	6,319,769	W/S	1.00000	6,319,769
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	1.00000	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		359,996,256			359,996,256
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	-			
14	Transmission	(line 2- line 8)	866,044,581			866,044,581
15	Distribution	(line 3 - line 9)	-			
16	General & Intangible	(line 4 - line 10)	34,196,260			34,196,260
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		900,240,840	NP=	100.000%	900,240,840
	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)	(253,565,471)	NP	1.00000	(253,565,471)
21	Account No. 283 (enter negative)	Attachment 5, Line 3, Col. 3 (Notes F & Y & DD)	(2,593,026)	NP	1.00000	(2,593,026)
22	Account No. 190	Attachment 5, Line 3, Col. 4 (Notes F & Y & DD)	4,674,302	NP	1.00000	4,674,302
23	Account No. 255 (enter negative)	Attachment 5, Line 3, Col. 5 (Notes F & Y & DD)	-	NP	1.00000	-
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 9, Col. G (Note Y)	-	DA	1.00000	-
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 10, Col. G (Note Y)	-	DA	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)	5,397,056	DA	1.00000	5,397,056
28	Unamortized Abandoned Plant	Attachment 17, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
29	TOTAL ADJUSTMENTS (sum lines 19-28)		(246,087,138)			(246,087,138)
30	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 1, Col. D) (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)	6,809,443			6,675,428
33	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 2, Col. D) (Note Y)	-	TE	0.98040	-
34	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. D) (Notes B & Y)	545,482	GP	1.00000	545,482
35	TOTAL WORKING CAPITAL (sum lines 32 - 34)		7,354,925			7,220,911
36	RATE BASE (sum lines 18, 29, 30, & 35)		661,508,628			661,374,613

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2018

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 (Attachment 20, page 1, line 112)	54,706,299	TE	0.98040	53,634,183
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	5,466,499	DA	1.00000	5,466,499
5	A&G	323.197.b (Attachment 20, page 2, line 197)	1,141,284	W/S	1.00000	1,141,284
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	0.98040	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 9	(1,372,039)	DA	1.00000	(1,372,039)
10	Common	356.1	-	CE	1.00000	-
11	Account 407.3 Amortization of Regulatory Assets	Attachment 16a, 16b, 16c, Line 15, Col. 5	2,574,514	DA	1.00000	2,574,514
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	5,466,499	DA	1.00000	5,466,499
14	Total Account 566 (sum lines 12 & 13, ties to 321.97.b)		5,466,499			5,466,499
15	TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)		57,050,057			55,977,941
	DEPRECIATION AND AMORTIZATION EXPENSE					
16	Transmission	336.7.b (Note U)	27,133,954	TP	1.00000	27,133,954
17	General & Intangible	336.1.f & 336.10.f (Note U)	845,385	W/S	1.00000	845,385
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)		27,979,340			27,979,340
	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)	60,727	GP	1.00000	60,727
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)		60,727			60,727
	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)) =		49.36%			
	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)		(170,383)			
33	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]		130,585			
34	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]		-			
35	Income Tax Calculation = line 30 * line 40		24,161,211	NA		24,156,316
36	ITC adjustment (line 31 * line 32)		(291,220)	NP	1.00000	(291,220)
37	Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)		223,197	DA	1.00000	223,197
38	(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)		-	DA	1.00000	-
39	Total Income Taxes	sum lines 35 through 38	24,093,188			24,088,293
40	RETURN	[Rate Base (page 2, line 36) * Rate of Return (page 4, line 25)]	48,951,638.45	NA		48,941,721
41	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 15, 20, 28, 39, 40)	158,134,950			157,048,022
42	ADDITIONAL INCENTIVE REVENUE	Attachment 11, page 2, line 4, col 11 (Note AA)	0			0
43	GROSS REV. REQUIREMENT	(line 41 + line 42)	158,134,950			157,048,022

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2018

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)						1,219,721,068		
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)						1,219,721,068		
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)						54,706,299		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,072,116		
8	Included transmission expenses (line 6 less line 7)						53,634,183		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.98040		
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=	0.98040		
	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)		276,923,077	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)		562,476,500	50%	0.1030		0.0515		
25	Total (sum lines 22-24)		839,399,577				0.0740	=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) (Attachment 21, line 1z)			-		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			(300.19.b) (Attachment 21, line 2z)			3,761,088		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)			(330.x.n) (Attachment 21, line 3z)			1,397,264		

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

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. Per the Settlement Agreement in docket number ER17-211-000, beginning in calendar year 2019, the equity component of MAIT's capital structure to be used in calculating charges under the formula rate shall be the lower of (i) MAIT's actual equity component as calculated in accordance with Attachment 8 or (ii) 60%.
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). No change in ROE may be made absent a filing with FERC under Section 205 or Section 206 of the Federal Power Act. Per the Settlement Agreement in Docket No. ER17-211-000, MAIT's stated ROE is set to 10.30% (9.8% base ROE plus 50 basis point adder for RTO participation).
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	$	1,072,116	Attachment H-28A, Page 4, Line 7
2	$	103,341	Revenue Credits for Sched 1A - Note A
3	$	968,775	Net Schedule 1A Expenses (Line 1 - Line 2)
4		28,891,661	Annual MWh in Met-Ed and Penelec Zones - Note B
5	$	0.0335	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	661,374,613
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	786,068,470
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	223,591,970
7	Common Stock		Attachment 8, Line 14, Col. 6	562,476,500
	Capitalization			
8	Long Term Debt		Attachment H-28A, page 4, Line 22, Col. 3	276,923,077
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	562,476,500
11	Total Capitalization		Attachment H-28A, page 4, Line 25, Col. 3	839,399,577
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	10.30%	0.1030
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)	0.0515
21	Rate of Return on Rate Base (ROR)		(Sum Lines 18 to 20)	**0.0740**
22	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 21)**	**48,941,721**
	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	49.36%
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	(170,382.72)
27	Tax Effect of Permanent Differences and AFUDC Equity		Attachment H-28A, page 3, Line 33, Col. 3	130,585.00
28	(Excess)/Deficient Deferred Income Taxes		Attachment H-28A, page 3, Line 34, Col. 3	-
29	Income Tax Calculation		(line 22 * line 24)	24,156,315.91
30	ITC adjustment		(line 25 * line 26)	(291,220.16)
31	Permanent Differences and AFUDC Equity Tax Adjustment		Attachment H-28A, page 3, Line 37, Col. 3	223,197.42
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	24,088,293.18
	Increased Return and Taxes			
34	Return and Income taxes with increase in ROE		(Line 22 + Line 33)	73,030,014.55
35	Return without incentive adder		Attachment H-28A, Page 3, Line 40, Col. 5	48,941,721.38
36	Income Tax without incentive adder		Attachment H-28A, Page 3, Line 39, Col. 5	24,088,293.18
37	Return and Income taxes without increase in ROE		Line 35 + Line 36	73,030,014.55
38	Return and Income taxes with increase in ROE		Line 34	73,030,014.55
39	Incremental Return and incomes taxes for increase in ROE		Line 38 - Line 37	-
40	Rate Base		Line 1	661,374,613.18
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 12/31/2018

			[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2017	-	1,133,031,967	-	-	35,818,555	-	1,168,850,522
2	January	2018	-	1,135,039,334	-	-	37,384,342	-	1,172,423,677
3	February	2018	-	1,137,852,749	-	-	37,578,294	-	1,175,431,043
4	March	2018	-	1,141,895,513	-	-	39,035,332	-	1,180,930,845
5	April	2018	-	1,146,135,029	-	-	39,210,019	-	1,185,345,048
6	May	2018	-	1,213,816,117	-	-	39,408,566	-	1,253,224,684
7	June	2018	-	1,238,268,761	-	-	39,540,996	-	1,277,809,757
8	July	2018	-	1,245,391,101	-	-	39,837,486	-	1,285,228,587
9	August	2018	-	1,251,552,217	-	-	40,291,625	-	1,291,843,842
10	September	2018	-	1,258,243,444	-	-	42,140,943	-	1,300,384,387
11	October	2018	-	1,269,621,583	-	-	43,833,835	-	1,313,455,419
12	November	2018	-	1,280,819,355	-	-	44,351,087	-	1,325,170,443
13	December	2018	-	1,404,706,717	-	-	48,277,288	-	1,452,984,005
14	**13-month Average**	**[A] [C]**	**-**	**1,219,721,068**	**-**	**-**	**40,516,028**	**-**	**1,260,237,097**

			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	2017		1,133,036,067			35,818,555		1,168,854,622
16	January	2018		1,135,043,435			37,384,342		1,172,427,777
17	February	2018		1,137,856,849			37,578,294		1,175,435,143
18	March	2018		1,141,899,614			39,035,332		1,180,934,946
19	April	2018		1,146,139,130			39,210,019		1,185,349,149
20	May	2018		1,213,820,218			39,408,566		1,253,228,784
21	June	2018		1,238,272,861			39,540,996		1,277,813,857
22	July	2018		1,245,395,202			39,837,486		1,285,232,688
23	August	2018		1,251,556,317			40,291,625		1,291,847,942
24	September	2018		1,258,247,544			42,140,943		1,300,388,487
25	October	2018		1,269,625,684			43,833,835		1,313,459,519
26	November	2018		1,280,823,456			44,351,087		1,325,174,543
27	December	2018		1,404,710,818			48,277,288		1,452,988,106
28	13-month Average		-	1,219,725,169	-	-	40,516,028	-	1,260,241,197

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	2017		4,100				
30	January	2018		4,100				
31	February	2018		4,100				
32	March	2018		4,100				
33	April	2018		4,100				
34	May	2018		4,100				
35	June	2018		4,100				
36	July	2018		4,100				
37	August	2018		4,100				
38	September	2018		4,100				
39	October	2018		4,100				
40	November	2018		4,100				
41	December	2018		4,100				
42	13-month Average			4,100	-	-	-	-

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

[D] Met-Ed retained 34.5kV lines

Accumulated Depreciation Calculation

For the 12 months ended 12/31/2018

			[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2017	-	357,773,407	-	-	6,298,607	-	364,072,014
2	January	2018	-	359,096,733	-	-	6,259,209	-	365,355,942
3	February	2018	-	359,771,111	-	-	6,298,266	-	366,069,376
4	March	2018	-	359,038,620	-	-	6,256,940	-	365,295,560
5	April	2018	-	358,097,781	-	-	6,299,077	-	364,396,858
6	May	2018	-	353,434,789	-	-	6,350,954	-	359,785,744
7	June	2018	-	352,642,169	-	-	6,407,689	-	359,049,858
8	July	2018	-	353,244,176	-	-	6,454,349	-	359,698,525
9	August	2018	-	353,153,749	-	-	6,491,737	-	359,645,486
10	September	2018	-	352,123,155	-	-	6,442,051	-	358,565,206
11	October	2018	-	350,325,833	-	-	6,299,916	-	356,625,749
12	November	2018	-	348,641,504	-	-	6,237,886	-	354,879,390
13	December	2018	-	340,451,312	-	-	6,060,313	-	346,511,625
14	**13-month Average**	**[A] [C]**	**-**	**353,676,488**	**-**	**-**	**6,319,769**	**-**	**359,996,256**

			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	2017		357,775,364			6,298,607		364,073,971
16	January	2018		359,098,681			6,259,209		365,357,890
17	February	2018		359,773,049			6,298,266		366,071,315
18	March	2018		359,040,549			6,256,940		365,297,489
19	April	2018		358,099,701			6,299,077		364,398,778
20	May	2018		353,436,699			6,350,954		359,787,654
21	June	2018		352,644,069			6,407,689		359,051,759
22	July	2018		353,246,067			6,454,349		359,700,416
23	August	2018		353,155,631			6,491,737		359,647,367
24	September	2018		352,125,027			6,442,051		358,567,078
25	October	2018		350,327,695			6,299,916		356,627,611
26	November	2018		348,643,357			6,237,886		354,881,243
27	December	2018		340,453,156			6,060,313		346,513,469
28	13-month Average		-	353,678,388	-	-	6,319,769	-	359,998,157

Reserve for Depreciation of Asset Retirement Costs

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
		[B]		Company Records				
29	December	2017		1,958				
30	January	2018		1,948				
31	February	2018		1,939				
32	March	2018		1,929				
33	April	2018		1,920				
34	May	2018		1,910				
35	June	2018		1,901				
36	July	2018		1,891				
37	August	2018		1,882				
38	September	2018		1,872				
39	October	2018		1,863				
40	November	2018		1,853				
41	December	2018		1,844				
42	13-month Average			1,901	-	-	-	-

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

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 (enter negative)	Acct. No. 282 (enter negative)	Acct. No. 283 (enter negative)	Acct. No. 190	Acct. No. 255 (enter negative)	Total
					[C]	[D]	[E]	[F]	
1	December 31	2017		-	(243,630,934)	(2,773,555)	4,623,150	-	(241,781,340)
2	December 31	2018		-	(263,500,008)	(2,412,496)	4,725,455	-	(261,187,049)
3	**Begin/End Average**		**[A]**	**-**	**(253,565,471)**	**(2,593,026)**	**4,674,302**	**-**	**(251,484,194)**

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	2017			245,190,307	12,289,649	12,085,507	2,429,155	271,994,617
5	December 31	2018			302,359,277	10,073,458	13,369,023	2,329,470	328,131,228
6	Begin/End Average			-	273,774,792	11,181,553	12,727,265	2,379,313	300,062,923

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	Other: [H]	Other: [H]	Normalization [G]
2017	-	-	1,559,372		-	-	-
2018	-	-	2,056,652		-	-	36,802,617

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

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Other: [H]	Other: [H]	Normalization [G]
2017	-	-	9,516,093		-	-	-
2018	-	-	8,368,159		-	-	(707,196)

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

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Other: [H]	Other: [H]	Normalization [G]
2017	-	-	-	7,462,357	-	-	-
2018	-	-	-	8,443,185	-	-	200,383

[F] See Attachment H-28A, page 5, note K; 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).

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

[H] Include any additional adjustments to ADIT items as may be recognized in the future to be proper for PTRR/ATRR calculation purposes.

ADIT Normalization Calculation

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
	2018 Quarterly Activity and Balances							
Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
4,623,150	67,572	4,690,722	82,324	4,773,046	35,965	4,809,011	116,827	4,925,838
Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
4,623,150	**51,096**		**41,726**		**9,164**		**320**	
Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
243,630,934	13,123,446	256,754,381	15,988,411	272,742,792	6,984,895	279,727,687	22,689,297	302,416,984
Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
243,630,934	**9,923,483**		**8,103,715**		**1,779,713**		**62,162**	
Beginning 283 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
2,773,555	(238,478)	2,535,077	(290,540)	2,244,537	(126,929)	2,117,608	(412,308)	1,705,300
Beginning 283 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
2,773,555	**(180,329)**		**(147,260)**		**(32,341)**		**(1,130)**	

ADIT Normalization Calculation

2018 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, CIAC and Other 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**					
102,305	**4,725,455**	13,369,023	8,643,567	8,443,185	**200,383**	4,725,455
Pro-rated Total	**Pro-rated Ending 282**					
19,869,073	**263,500,008**	302,359,277	38,859,269	2,056,652	**36,802,617**	263,500,008
Pro-rated Total	**Pro-rated Ending 283**					
(361,059)	**2,412,496**	10,073,458	7,660,962	8,368,159	**(707,196)**	2,412,496

ADIT Detail

For the 12 months ended 12/31/2018

	COLUMN A	COLUMN B	COLUMN C	COLUMN D
		BALANCE AS OF 12-31-17	BALANCE AS OF 12-31-18	AVERAGE BALANCE
	ACCOUNT 255:			
	Investment Tax Credit	2,429,155	2,329,470	2,379,313
1	TOTAL ACCOUNT 255	2,429,155	2,329,470	
	ACCOUNT 282:			
	263A Capitalized Overheads	24,990,314	28,883,136	26,936,725
	263A Miscellaneous	2,258,977	1,993,504	2,126,240
	Accelerated Depreciation	188,440,777	244,154,364	216,297,571
	AFUDC	3,336,884	3,595,356	3,466,120
	AFUDC Equity (FAS109)	1,559,372	2,056,652	1,808,012
	Capitalized Tree Trimming	4,315,138	4,200,696	4,257,917
	Casualty Loss	2,865,380	763,983	1,814,682
	Other	(4,195,910)	(4,740,657)	(4,468,283)
	Pension and Capitalized Benefits	(1,963,650)	(1,581,423)	(1,772,536)
	Tax Repairs	11,724,554	13,289,552	12,507,053
	FAS109 Related to Property	11,858,472	9,744,113	10,801,292
2	TOTAL ACCOUNT 282	245,190,307	302,359,277	

ADIT Detail

For the 12 months ended 12/31/2018

	COLUMN A	COLUMN B	COLUMN C	COLUMN D
		BALANCE AS OF 12-31-17	BALANCE AS OF 12-31-18	AVERAGE BALANCE
	ACCOUNT 283:			
	AFUDC Equity Flow Thru (Gross up)	1,105,925	1,458,602	1,282,264
	Property FAS109	8,410,168	6,909,557	7,659,862
	Deferred Storm Costs	327,581	218,387	272,984
	Vegetation Management	1,734,731	1,486,912	1,610,822
	Start-up Costs	711,243	0	355,622
3	TOTAL ACCOUNT 283	12,289,649	10,073,458	

ADIT Detail

For the 12 months ended 12/31/2018

	COLUMN A	COLUMN B	COLUMN C	COLUMN D
		BALANCE AS OF 12-31-17	BALANCE AS OF 12-31-18	AVERAGE BALANCE
	ACCOUNT 190:			
	Capitalized Interest	2,900,365	3,273,750	3,087,057
	Contribution in Aid of Construction	7,462,357	8,443,185	7,952,771
	Investment Tax Credit	1,722,785	1,652,088	1,687,437
4	TOTAL ACCOUNT 190	12,085,507	13,369,023	

1	**Calculation of PBOP Expenses**		
2	**MAIT**	**Amount**	**Source**
3	Total FirstEnergy PBOP expenses	(108,686,300)	FirstEnergy 2015 Actuarial Study
4	Labor dollars (FirstEnergy)	2,024,261,894	FirstEnergy 2015 Actual: Company Records
5	cost per labor dollar (line 3 / line 4)	-$0.0537	
6	labor (labor not capitalized) current year	14,029,594	MAIT Labor: Company Records
7	PBOP Expense for current year (line 5 * line 6)	-$753,274	
8	PBOP expense in Account 926 for current year	618,765	MAIT Account 926: Company Records
9	PBOP Adjustment for Attachment H-28A, page 3, line 9 (line 7 - line 8)	(1,372,039)	

10 Lines 3-4 cannot change absent a Section 205 or 206 filing approved or accepted by FERC in a separate proceeding

For the 12 months ended 12/31/2018

Taxes Other than Income Calculation

		[A]	Dec 31, 2018
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	60,727
3b			-
3c			-
3z	**Property Taxes**		60,727
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]		$60,727.00

Notes:

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

Capital Structure Calculation

For the 12 months ended 12/31/2018

				[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	2017		782,921,751				223,591,970	559,329,781	-
2	January	2018		786,595,554				223,591,970	563,003,584	-
3	February	2018		790,341,684				223,591,970	566,749,714	-
4	March	2018		782,924,362				223,591,970	559,332,392	-
5	April	2018		786,904,847				223,591,970	563,312,877	-
6	May	2018		791,545,425				223,591,970	567,953,455	450,000,000
7	June	2018		783,957,994				223,591,970	560,366,024	450,000,000
8	July	2018		787,428,123				223,591,970	563,836,153	450,000,000
9	August	2018		790,951,999				223,591,970	567,360,029	450,000,000
10	September	2018		783,284,923				223,591,970	559,692,953	450,000,000
11	October	2018		786,980,184				223,591,970	563,388,214	450,000,000
12	November	2018		790,646,180				223,591,970	567,054,210	450,000,000
13	December	2018		774,407,086				223,591,970	550,815,116	450,000,000
14	13-month Average			786,068,470	-	-	-	223,591,970	562,476,500	276,923,077

Notes:

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

Stated Value Inputs For the 12 months ended 12/31/2018

Formula Rate Protocols
Section VIII.A

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

MAIT's stated ROE is set to: 10.3%

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	2.90%
390.2	1.24%
391.1	0.63%
391.2	18.82%
392	4.84%
393	0.01%
394	4.62%
395	0.00%
396	0.47%
397	1.80%
398	0.32%
303	14.29%

4. Net Plant Allocator
If the Net Plant (NP) allocator becomes anything other than 1.000 (or 100%), MAIT must make a Section 205 filing to seek approval of any new depreciation or amortization rates applicable to production and/or distribution plant accounts.

5. Land Rights
If Land Rights (Account 350) are acquired by MAIT, it must make a Section 205 filing to establish the appropriate depreciation rate.

Debt Cost Calculation

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED 12/31/2018

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	t=N Long Term Debt 12/31/2018 First Mortgage Bonds:	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)	
(1)	4.50%, Senior Unsecured Notes	5/15/2018	5/15/2028	$ 450,000,000	$ 450,000,000	$ 450,000,000	7.5	##############	100.00%	4.50%	4.50%	
	Total			$ 450,000,000		$ 450,000,000		$ 281,250,000	100.000%		4.50%	**

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 12/31/2018

		(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. cc + col. dd + 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)	4.50%, Senior Unsecured Notes	5/15/2018	5/15/2028	$ 450,000,000	$ -	0	-	xxx	$ 450,000,000	100.0000	0.04500	$ 20,250,000	4.50%
												-	
	TOTALS			$ 450,000,000	-	$ -	-	xxx	$ 450,000,000			$ 20,250,000	

* 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)	$ 1,219,721,068	
2	Net Transmission Plant - Total	Attach. H-28A, p. 2, line 14, col. 5 (Note B)	$ 866,044,581	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-28A, p. 3, line 15, col. 5	$ 55,977,941	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	4.589405%	4.589405%
	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	$ 845,385	
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)	0.069310%	0.069310%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach. H-28A, p. 3, line 28, col. 5	$ 60,727	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)	0.004979%	0.004979%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**		**4.663694%**
	INCOME TAXES			
10	Total Income Taxes	Attach. H-28A, p. 3, line 39, col. 5	$ 24,088,293	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)	2.781415%	2.781415%
	RETURN			
12	Return on Rate Base	Attach. H-28A, p. 3, line 40, col. 5	$ 48,941,721	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)	5.651178%	5.651178%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**8.432593%**

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	$ 24,088,293	
11b	Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)	2.781415%	2.781415%
	RETURN			
12b	Return on Rate Base	Attachment 2, line 22	$ 48,941,721	
13b	Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)	5.651178%	5.651178%
14b	**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		**8.432593%**
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	4.663694%	$589,371	$ 10,364,958	8.432593%	$874,035	$ 259,067	$1,722,473	0	$1,722,473		$1,722,473
2b	Install 250 MVAR capacitor at Keystone 500 kV	b0549	$ 3.207.134	4.663694%	$149.571	$ 2.859.667	8.432593%	$241.144	$ 65.746	$456.461	0	$456.461		$456.461
2c	Install 25 MVAR capacitor at Lewis Run 115 kV substation	b0550	$ -	4.663694%	$0	$ -	8.432593%	$0	$ -	$0	0	$0		$0
2d	Install 25 MVAR capacitor at Saxton 115 kV substation	b0551	$ 1.380.393	4.663694%	$64.377	$ 1.125.106	8.432593%	$94.876	$ 28.022	$187.275	0	$187.275		$187.275
2e	Install 50 MVAR capacitor at Altoona 230 kV substation	b0552	$ 1.038.335	4.663694%	$48,425	$ 952,250	8.432593%	$80.299	$ 21,286	$150.010	0	$150.010		$150.010
2f	Install 50 MVAR capacitor at Raystown 230 kV substation	b0553	$ 927.947	4.663694%	$43.277	$ 827.069	8.432593%	$69.743	$ 19.023	$132.043	0	$132.043		$132.043
2g	Install 75 MVAR capacitor at East Towanda 230 kV substation	b0557	$ 2,177,814	4.663694%	$101,567	$ 1,941,433	8.432593%	$163,713	$ 44,210	$309,489	0	$309,489		$309,489
2h	Relocate the Erie South 345 kV line terminal	b1993	$ 10.675.225	4.663694%	$497.860	$ 10.110.506	8.432593%	$852.578	$ 219.910	$1.570.347	0	$1.570.347		$1.570.347
2i	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	$ 102,703	4.663694%	$4,790	$ 100,207	8.432593%	$8,450	$ 2,167	$15,407	0	$15,407		$15,407
2j	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	$ 1,975,998	4.663694%	$92,154	$ 1,923,717	8.432593%	$162,219	$ 48,610	$302,983	0	$302,983		$302,983
2k	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	$ 1,698,653	4.663694%	$79,220	$ 1,651,774	8.432593%	$139,287	$ 41,787	$260,294	0	$260,294		$260,294
2l	Install 2nd Hunterstown 230/115 kV transformer	b2452	$ 6.063.115	4.663694%	$282.765	$ 5.924.423	8.432593%	$499.583	$ 133.389	$915.736	0	$915.736		$915.736
2m	Reconductor Hunterstown - Oxford 115 kV line	b2452.1	$ 2,884,049	4.663694%	$134,503	$ 2,817,160	8.432593%	$237,560	$ 63,449	$435,512	0	$435,512		$435,512
3	Transmission Enhancement Credit taken to Attachment H-28A Page 1, Line 7											6,458,031.09		
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-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
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	Install 250 MVAR capacitor at Keystone 500 kV	b0549	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134	$ 3,207,134
2c	Install 25 MVAR capacitor at Lewis Run 115 kV substation	b0550	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2d	Install 25 MVAR capacitor at Saxton 115 kV substation	b0551	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393	$ 1,380,393
2e	Install 50 MVAR capacitor at Altoona 230 kV substation	b0552	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335	$ 1,038,335
2f	Install 50 MVAR capacitor at Raystown 230 kV substation	b0553	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947	$ 927,947
2g	Install 75 MVAR capacitor at East Towanda 230 kV substation	b0557	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814	$ 2,177,814
2h	Relocate the Erie South 345 kV line terminal	b1993	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225	$ 10,675,225
2i	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	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703	$ 102,703
2j	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_DFAX_Allocati	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998	$ 1,975,998
2k	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_Sh	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653	$ 1,698,653
2l	Install 2nd Hunterstown 230/115 kV transformer	b2452	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115	$ 6,063,115
2m	Reconductor Hunterstown - Oxford 115 kV line	b2452.1	$ 2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049	$2,884,049

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 (Note B)	Dec-17 (Note D)	Jan-18 (Note D)	Feb-18 (Note D)	Mar-18 (Note D)	Apr-18 (Note D)	May-18 (Note D)	Jun-18 (Note D)	Jul-18 (Note D)	Aug-18 (Note D)	Sep-18 (Note D)	Oct-18 (Note D)	Nov-18 (Note D)	Dec-18 (Note D)	Project Net Plant (Note B & C)
$2,272,473.08	$ 2,142,939	$ 2,164,528	$ 2,186,117	$ 2,207,706	$ 2,229,295	$ 2,250,884	$ 2,272,473	$ 2,294,062	$ 2,315,651	$ 2,337,240	$ 2,358,829	$ 2,380,418	$ 2,402,007	$10,364,958.39
$347,467.15	$ 314,594	$ 320,073	$ 325,552	$ 331,031	$ 336,509	$ 341,988	$ 347,467	$ 352,946	$ 358,425	$ 363,904	$ 369,383	$ 374,861	$ 380,340	$2,859,667.10
$0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.00
$255,286.61	$ 241,276	$ 243,611	$ 245,946	$ 248,281	$ 250,616	$ 252,951	$ 255,287	$ 257,622	$ 259,957	$ 262,292	$ 264,627	$ 266,962	$ 269,298	$1,125,106.49
$86,084.96	$ 75,442	$ 77,216	$ 78,990	$ 80,763	$ 82,537	$ 84,311	$ 86,085	$ 87,859	$ 89,633	$ 91,406	$ 93,180	$ 94,954	$ 96,728	$952,249.70
$100,878.00	$ 91,367	$ 92,952	$ 94,537	$ 96,122	$ 97,708	$ 99,293	$ 100,878	$ 102,463	$ 104,048	$ 105,634	$ 107,219	$ 108,804	$ 110,389	$827,068.84
$236,381.87	$ 214,277	$ 217,961	$ 221,645	$ 225,329	$ 229,014	$ 232,698	$ 236,382	$ 240,066	$ 243,750	$ 247,434	$ 251,118	$ 254,803	$ 258,487	$1,941,432.50
$564,719.49	$ 454,765	$ 473,090	$ 491,416	$ 509,742	$ 528,068	$ 546,394	$ 564,719	$ 583,045	$ 601,371	$ 619,697	$ 638,023	$ 656,349	$ 674,674	$10,110,505.51
$2,495.80	$ 1,412	$ 1,593	$ 1,773	$ 1,954	$ 2,135	$ 2,315	$ 2,496	$ 2,676	$ 2,857	$ 3,038	$ 3,218	$ 3,399	$ 3,579	$100,207.39
$52,280.69	$ 27,976	$ 32,027	$ 36,078	$ 40,128	$ 44,179	$ 48,230	$ 52,281	$ 56,331	$ 60,382	$ 64,433	$ 68,484	$ 72,535	$ 76,585	$1,923,717.13
$46,879.40	$ 25,986	$ 29,468	$ 32,950	$ 36,433	$ 39,915	$ 43,397	$ 46,879	$ 50,362	$ 53,844	$ 57,326	$ 60,808	$ 64,291	$ 67,773	$1,651,773.60
$138,691.98	$ 71,998	$ 83,113	$ 94,229	$ 105,345	$ 116,461	$ 127,576	$ 138,692	$ 149,808	$ 160,923	$ 172,039	$ 183,155	$ 194,271	$ 205,386	$5,924,423.26
$66,888.76	$35,164	$40,452	$45,739	$51,026	$56,314	$61,601	$66,889	$72,176	$77,464	$82,751	$88,038	$93,326	$98,613	$2,817,160.00

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

Line No.		(a) Project Name	(b) RTEP Project Number	(c) Actual Revenues for Appendix D	(d) Projected Annual Revenue Requirement	(e) % of Total Revenue Requirement	(f) Revenue Received	(g) Actual Annual Revenue Requirement	(h) True-up Adjustment Principal Over/(Under)	(i) Applicable Interest Rate on Over/(Under)	(j) 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

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G
		BALANCE AS	BALANCE AS	AVERAGE			
Line No.	Description	OF 12-31-17	OF 12-31-18	BALANCE			
1	Land Held for Future Use (214.x.d)	0	0	-	[redacted]		
2	Materials & Supplies (227.8.c & .16.c)	0	0	-			
3	Prepayments: Account 165 (111.57.c) - Note [A]	545,482	545,482	545,482			

Unfunded Reserves

		BALANCE AS	BALANCE AS	AVERAGE			TRANSMISSION TOTAL
Line No.	Description	OF 12-31-17	OF 12-31-18	BALANCE	ALLOCATION FACTOR		(Col D times Col F)
	Account 228.1						
4a	Property Insurance (Self insurance not covered by property insurance)	0	0	0	GP	1.00	0
4b	[Insert Item Included in Account 228.1 that are not allocated to transmission]	0	0	0	Other	0	0
4c	[Insert Item Included in Account 228.1 that are not allocated to transmission]	0	0	0	Other	0	0
4z	Total Account 228.1 (112.27.c)	0	0				0
	Account 228.2						
5a	Workman's Compensation	0	0	0	W/S	1.00	0
5b	Probable liabilities not covered by insurance for death or injuries to employees and others	0	0	0	W/S	1.00	0
5c	Probable liabilities not covered by insurance for damages to property neither owned nor held under lease by the utility	0	0	0	GP	1.00	0
5d	[Insert Item Included in Account 228.2 that are not allocated to transmission]	0	0	0	Other	0	0
5e	[Insert Item Included in Account 228.2 that are not allocated to transmission]	0	0	0	Other	0	0
5z	Total Account 228.2 (112.28.c)	0	0				0
	Account 228.3						
6a	Year-End Vacation Pay Accrual	0	0	0	W/S	1.00	0
6b	Year-End Deferred Compensation Accrual	0	0	0	W/S	1.00	0
6c	Year-End Sick Pay Accrual	0	0	0	W/S	1.00	0
6d	Year-End Incentive Compensation Accrual	0	0	0	W/S	1.00	0
6e	Year-End Severance Pay Accrual	0	0	0	W/S	1.00	0
6f	Year-End PBOP/OPEB Accrual not included in established trusts	0	0	0	W/S	1.00	0
6g	[Insert Item Included in Account 228.3 that are not allocated to transmission]	0	0	0	Other	0	0
6h	[Insert Item Included in Account 228.3 that are not allocated to transmission]	0	0	0	Other	0	0
6z	Total Account 228.3 (112.29.c)	0	0				0
	Account 228.4						
7a	Year-End Vacation Pay Accrual	0	0	0	W/S	1.00	0
7b	Year-End Deferred Compensation Accrual	0	0	0	W/S	1.00	0
7c	Year-End Sick Pay Accrual	0	0	0	W/S	1.00	0
7d	Year-End Incentive Compensation Accrual	0	0	0	W/S	1.00	0
7e	Year-End Severance Pay Accrual	0	0	0	W/S	1.00	0
7f	Year-End PBOP/OPEB Accrual not included in established trusts	0	0	0	W/S	1.00	0
7g	[Insert Item Included in Account 228.4 that are not allocated to transmission]	0	0	0	Other	0	0
7h	[Insert Item Included in Account 228.4 that are not allocated to transmission]	0	0	0	Other	0	0
7z	Total Account 228.4 (112.30.c)	0	0				0
	Account 242						
8a	Year-End Vacation Pay Accrual	0	0	0	W/S	1.00	0
8b	Year-End Deferred Compensation Accrual	0	0	0	W/S	1.00	0
8c	Year-End Sick Pay Accrual	0	0	0	W/S	1.00	0
8d	Year-End Incentive Compensation Accrual	0	0	0	W/S	1.00	0
8e	Year-End Severance Pay Accrual	0	0	0	W/S	1.00	0
8f	Year-End PBOP/OPEB Accrual not included in established trusts	0	0	0	W/S	1.00	0
8g	[Insert Item Included in Account 242 that are not allocated to transmission]	0	0	0	Other	0	0
8h	[Insert Item Included in Account 242 that are not allocated to transmission]	0	0	0	Other	0	0
8z	Total Account 242 (113.48.c)	0	0				0
9	Total Unfunded Reserves Plant-related (items with GP allocator) - Note [B]	0	0	0	GP	1.00	0
10	Total Unfunded Reserves Labor-related (items with W/S allocator) - Note [C]	0	0	0	W/S	1.00	0

Notes:

[A] Prepayments shall exclude prepayments of income taxes.
[B] Column G balance taken to Attachment H-28A, page 2, line 24, col. 3
[C] Column G balance taken to Attachment H-28A, page 2, line 25, col. 3

Income Tax Adjustments

	[1]	[2]	[3]	[4]	[5]	[6]
				Dec 31,	Dec 31,	
			Beg/End Average [C]	2017	2018	Reference
1	Tax adjustment for Permanent Differences & AFUDC Equity	[A]	130,585.00	111,170	$150,000	MAIT Company Records
2	Amortized Excess Deferred Taxes (enter negative)	[B]	-	-	$0	MAIT Company Records
3	Amortized Deficient Deferred Taxes	[B]	-	-	$0	MAIT Company Records

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] (Column 4 + Column 5)/2; 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]	[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 2017	p232 (and Notes)	37				789,475.70
3	January	FERC Account 182.3	36	789,476	21,929.88	-	767,545.82
4	February	FERC Account 182.3	35	767,546	21,929.88	-	745,615.94
5	March	FERC Account 182.3	34	745,616	21,929.88	-	723,686.06
6	April	FERC Account 182.3	33	723,686	21,929.88	-	701,756.18
7	May	FERC Account 182.3	32	701,756	21,929.88	-	679,826.30
8	June	FERC Account 182.3	31	679,826	21,929.88	-	657,896.42
9	July	FERC Account 182.3	30	657,896	21,929.88	-	635,966.54
10	August	FERC Account 182.3	29	635,967	21,929.88	-	614,036.66
11	September	FERC Account 182.3	28	614,037	21,929.88	-	592,106.78
12	October	FERC Account 182.3	27	592,107	21,929.88	-	570,176.89
13	November	FERC Account 182.3	26	570,177	21,929.88	-	548,247.01
14	December 2018	p232 (and Notes)	25	548,247	21,929.88	-	526,317.13
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$263,158.57		$657,896.42
					Attachment H-28A, page 3, line 11		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 2017	p232 (and Notes)	85				4,180,729.25
3	January	FERC Account 182.3	84	4,180,729	49,770.59	-	4,130,958.66
4	February	FERC Account 182.3	83	4,130,959	49,770.59	-	4,081,188.08
5	March	FERC Account 182.3	82	4,081,188	49,770.59	-	4,031,417.49
6	April	FERC Account 182.3	81	4,031,417	49,770.59	-	3,981,646.90
7	May	FERC Account 182.3	80	3,981,647	49,770.59	-	3,931,876.32
8	June	FERC Account 182.3	79	3,931,876	49,770.59	-	3,882,105.73
9	July	FERC Account 182.3	78	3,882,106	49,770.59	-	3,832,335.15
10	August	FERC Account 182.3	77	3,832,335	49,770.59	-	3,782,564.56
11	September	FERC Account 182.3	76	3,782,565	49,770.59	-	3,732,793.97
12	October	FERC Account 182.3	75	3,732,794	49,770.59	-	3,683,023.39
13	November	FERC Account 182.3	74	3,683,023	49,770.59	-	3,633,252.80
14	December 2018	p232 (and Notes)	73	3,633,253	49,770.59	-	3,583,482.21
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$597,247.04		$3,882,105.73
					Attachment H-28A, page 3, line 11		Attachment H-28A, page 2, Line 27

Regulatory Asset - Start-up Costs

	[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 2017	p232 (and Notes)	13				1,714,108.00
3	January	FERC Account 182.3	12	1,714,108	142,842.33	-	1,571,265.67
4	February	FERC Account 182.3	11	1,571,266	142,842.33	-	1,428,423.33
5	March	FERC Account 182.3	10	1,428,423	142,842.33	-	1,285,581.00
6	April	FERC Account 182.3	9	1,285,581	142,842.33	-	1,142,738.67
7	May	FERC Account 182.3	8	1,142,739	142,842.33	-	999,896.33
8	June	FERC Account 182.3	7	999,896	142,842.33	-	857,054.00
9	July	FERC Account 182.3	6	857,054	142,842.33	-	714,211.67
10	August	FERC Account 182.3	5	714,212	142,842.33	-	571,369.33
11	September	FERC Account 182.3	4	571,369	142,842.33	-	428,527.00
12	October	FERC Account 182.3	3	428,527	142,842.33	-	285,684.67
13	November	FERC Account 182.3	2	285,685	142,842.33	-	142,842.33
14	December 2018	p232 (and Notes)	1	142,842	142,842.33	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$1,714,108.00		$857,054.00
					Attachment H-28A, page 3, line 11		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 2017	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 2018	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	2017	
2	January	2018	
3	February	2018	
4	March	2018	
5	April	2018	
6	May	2018	
7	June	2018	
8	July	2018	
9	August	2018	
10	September	2018	
11	October	2018	
12	November	2018	
13	December	2018	
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%

Operation and Maintenance Expenses

Line No. [a]	Account Reference	Description	Account Balance [b]
82		***Operation***	
83	560	Operation Supervision and Engineering	$126,104
84			
85	561.1	Load Dispatch-Reliability	$933,350
86	561.2	Load Dispatch-Monitor and Operate Transmission System	$684,667
87	561.3	Load-Dispatch-Transmission Service and Scheduling	
88	561.4	Scheduling, System Control and Dispatch Services	
89	561.5	Reliability, Planning and Standards Development	$177,787
90	561.6	Transmission Service Studies	
91	561.7	Generation Interconnection Studies	
92	561.8	Reliability, Planning and Standards Development Services	
93	562	Station Expenses	$10,144
94	563	Overhead Lines Expense	$40,144
95	564	Underground Lines Expense	
96	565	Transmission of Electricity by Others	
97	566	Miscellaneous Transmission Expense	$5,466,499
98	567	Rents	$6,813,603
99		TOTAL Operation (Enter Total of Lines 83 thru 98)	$14,252,299
100		***Maintenance***	
101	568	Maintenance Supervision and Engineering	$920,386
102	569	Maintenance of Structures	
103	569.1	Maintenance of Computer Hardware	$7,428
104	569.2	Maintenance of Computer Software	$42,391
105	569.3	Maintenance of Communication Equipment	
106	569.4	Maintenance of Miscellaneous Regional Transmission Plant	
107	570	Maintenance of Station Equipment	$4,343,924
108	571	Maintenance of Overhead Lines	$34,849,899
109	572	Maintenance of Underground Lines	
110	573	Maintenance of Miscellaneous Transmission Plant	$289,973
111		TOTAL Maintenance (Total of lines 101 thru 110)	$40,454,001
112		**TOTAL Transmission Expenses (Total of lines 99 and 111) [c]**	**$54,706,299**

Notes:

[a] Line No. as would be reported in FERC Form 1, page 321

[b] December balances as would be reported in FERC Form 1

[c] Ties to Attachment H-28A, page 3, line 1, column 3

Above expenses do not include amounts for Met-Ed's 34.5 kV transmission lines

Administrative and General (A&G) Expenses

Line No. [d]	Account Reference	Description	Account Balance [e]
180		***Operation***	
181	920	Administrative and General Salaries	
182	921	Office Supplies and Expenses	
183	Less 922	Administrative Expenses Transferred - Credit	
184	923	Outside Services Employed	$2,140,681
185	924	Property Insurance	$156,334
186	925	Injuries and Damages	$603,043
187	926	Employee Pensions and Benefits	-$2,646,881
188	927	Franchise Requirements	
189	928	Regulatory Commission Expense	
190	Less 929	(Less) Duplicate Charges-Cr.	
191	930.1	General Advertising Expenses	
192	930.2	Miscellaneous General Expenses	$27,000
193	931	Rents	
194		**Total Operation (Enter Total of lines 181 thru 193)**	$280,177
195		***Maintenance***	
196	935	Maintenance of General Plant	$861,107
197		**TOTAL A&G Expenses (Total of lines 194 and 196) [f]**	**$1,141,284**

Notes:

[d] Line No. as would be reported in FERC Form 1, page 323

[e] December balances as would be reported in FERC Form 1

[f] Ties to Attachment H-28A, page 3, line 5, column 3

Above expenses do not include amounts for Met-Ed's 34.5 kV transmission lines

Revenue Credit Worksheet
(See Footnote T on Attachment H-28A, page 5)

				December 31, 2018	
1	Account 451 -- Miscellaneous Service Revenues		FERC Form 1 , page 300 and footnote data	Amount	Note S, page 5
1a					
1b					
1z		Account 451 Total		$0	
2	Account 454 -- Rent from Electric Property		FERC Form 1, pages 300 and 429		Note R, page 5
2a		Transmission Charge - TMI Unit 1		$1,998,563	
2b		Transmission Investment - Power Pool Agreement		$1,762,525	
2c					
2z		Account 454 Total		$3,761,088	
3	Account 456 -- Other Electric Revenues		FERC Form 1, page 330 and footnote data		Note V, page 5
3a		Point-to-point Revenues		$1,131,260	
3b		Seneca Transmission Facilities Charges		$266,004	
3c				$0	
3d					
3e					
3z		Account 456 Total		$1,397,264	