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PSEG
Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

February 13, 2018

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
and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2018

Docket Nos. EO03050394, ER14040370, ER15040485, ER16040337, ER17040335
++
Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff Docket No.

New Jersey Board of Public Utilities
Office of the Secretary
Attn: Aida Camacho
44 South Clinton Avenue, 3rd Floor, Suite 314
Trenton, New Jersey 08625-0350

Dear Ms. Camacho:

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"), please find an original and ten copies of revised tariff sheets and supporting exhibits to modify the initial filings made by the EDCs on January 12, 2018, and June 22, 2017, in the above-captioned dockets (the "Filings").

A. Purpose of Revised Tariff Sheet Filing

The attached revised tariff sheets and supporting exhibits listed below incorporate changes to the PJM Open Access Transmission Tariff ("OATT") pursuant to Federal Energy Regulatory Commission ("FERC") Orders issued on December 15, 2017, in Docket Nos. EL17-84-000 and EL17-90-000 ("HTP and Linden VFT Orders"). PJM implemented these changes in the OATT effective January 1, 2018. The changes to the PJM OATT were made as a result of a change in Hudson Transmission Partners' ("HTP") and Linden VFT's responsibility for certain transmission cost allocations resulting from the conversion of Firm to Non-Firm Transmission Withdrawal Rights.

The PJM tariff revisions remove HTP and Linden VFT as parties responsible for cost allocation under Schedule 12 of the PJM. The tariff revisions reallocate the HTP and Linden VFT transmission costs to other entities in PJM. As a result, the Transmission Enhancement Charges in Schedule 12 have been adjusted to reflect the revised cost allocation.

While FERC has ruled on these matters through the issuance of the HTP and Linden VFT Orders, the cost reallocation being implemented pursuant to the HTP and Linden VFT Orders are subject to ongoing challenges before FERC.

B. Updated Tariff Sheets

The following tariff sheets and supporting documentation are attached to this filing.

- Attachment 1 (Derivation of PSE&G NITS Charge)
- Attachment 2a (Pro-forma PSE&G Tariff Sheets)
- Attachment 2b (PSE&G Translation of NITS Charge into Customer Rates)
- Attachment 2c (PSE&G Translation of VEPCo TEC into Customer Rates)
- Attachment 2d (PSE&G Translation of PATH TEC into Customer Rates)
- Attachment 2e (PSE&G Translation of TrailCo TEC into Customer Rates)
- Attachment 2f (PSE&G Translation of Delmarva TEC into Customer Rates)
- Attachment 2g (PSE&G Translation of ACE TEC into Customer Rates)
- Attachment 2h (PSE&G Translation of PEPCO TEC into Customer Rates)
- Attachment 2i (PSE&G Translation of PPL TEC into Customer Rates)
- Attachment 2j (PSE&G Translation of AEP East TEC into Customer Rates)
- Attachment 2k (PSE&G Translation of BG&E TEC into Customer Rates)
- Attachment 2l (PSE&G Translation of MAIT TEC into Customer Rates)
- Attachment 2m (PSE&G Translation of PECO TEC into Customer Rates)
- Attachment 3a (Pro-forma JCPL Tariff Sheets)
- Attachment 3b (JCP&L –Translation of PSE&G TEC into Customer Rates)

- Attachment 3c (JCP&L Translation of VEPCo TEC into Customer Rates)
- Attachment 3d (JCP&L Translation of PATH TEC into Customer Rates)
- Attachment 3e (JCP&L Translation of TrailCo TEC into Customer Rates)
- Attachment 3f (JCP&L Translation of Delmarva TEC into Customer Rates)
- Attachment 3g (JCP&L Translation of ACE TEC into Customer Rates)
- Attachment 3h (JCP&L Translation of PEPCO TEC into Customer Rates)
- Attachment 3i (JCP&L Translation of PPL TEC into Customer Rates)
- Attachment 3j (JCP&L Translation of AEP East TEC into Customer Rates)
- Attachment 3k (JCP&L Translation of BG&E TEC into Customer Rate)
- Attachment 3l (JCP&L Translation of MAIT TEC into Customer Rates)
- Attachment 3m (JCP&L Translation of PECO TEC into Customer Rates)
- Attachment 4a (ACE Pro-forma Tariff Sheets)
- Attachment 4b (ACE – Translation of PSE&G TEC into Customer Rates)
- Attachment 4c (ACE Translation of VEPCo TEC into Customer Rates)
- Attachment 4d (ACE Translation of PATH TEC into Customer Rates)
- Attachment 4e (ACE Translation of TrailCo TEC into Customer Rates)
- Attachment 4f (ACE Translation of Delmarva TEC into Customer Rates)
- Attachment 4g (N/A)
- Attachment 4h (ACE Translation of PEPCO TEC into Customer Rates)
- Attachment 4i (ACE Translation of PPL TEC into Customer Rates)
- Attachment 4j (ACE Translation of AEP East TEC into Customer Rates)
- Attachment 4k (ACE Translation of BG&E TEC into Customer Rates)
- Attachment 4l (ACE Translation of MAIT TEC into Customer Rates)
- Attachment 4m (ACE Translation of PECO TEC into Customer Rates)
- Attachment 5a (RECO Pro-forma Tariff Sheets)
- Attachment 5b (RECO –Translation of PSE&G TEC into Customer Rates)
- Attachment 5c (RECO Translation of VEPCo TEC into Customer Rates)
- Attachment 5d (RECO Translation of PATH TEC into Customer Rates)
- Attachment 5e (RECO Translation of TrailCo TEC into Customer Rates)
- Attachment 5f (RECO Translation of Delmarva TEC into Customer Rates)
- Attachment 5g (RECO Translation of ACE TEC into Customer Rates)
- Attachment 5h (RECO Translation of PEPCO TEC into Customer Rates)
- Attachment 5i (RECO Translation of PPL TEC into Customer Rates)
- Attachment 5j (RECO Translation of AEP East TEC into Customer Rates)
- Attachment 5k (RECO Translation of BG&E TEC into Customer Rates)
- Attachment 5l (RECO Translation of MAIT TEC into Customer Rates)
- Attachment 5m (RECO Translation of PECO TEC into Customer Rates)
- Attachment 6a (PSE&G Transmission Enhancement Charges)
- Attachment 6b (VEPCo Transmission Enhancement Charges)
- Attachment 6c (PATH Transmission Enhancement Charges)
- Attachment 6d (TrailCo Transmission Enhancement Charges)

- Attachment 6e (Delmarva Transmission Enhancement Charges)
- Attachment 6f (ACE Transmission Enhancement Charges)
- Attachment 6g (PEPCO Transmission Enhancement Charges)
- Attachment 6h (PPL Transmission Enhancement Charges)
- Attachment 6i (AEP East Transmission Enhancement Charges)
- Attachment 6j (BG&E Transmission Enhancement Charges)
- Attachment 6k (MAIT Transmission Enhancement Charges)
- Attachment 6l (PECO Transmission Enhancement Charges)
- Attachment 7a (PSE&G OATT)
- Attachment 7b (VEPCo OATT)
- Attachment 7c (PATH OATT)
- Attachment 7d (TrailCo OATT)
- Attachment 7e (Delmarva OATT)
- Attachment 7f (ACE OATT)
- Attachment 7g (PEPCO OATT)
- Attachment 7h (PPL OATT)
- Attachment 7i (AEP OATT)
- Attachment 7j (BG&E OATT)
- Attachment 7k (MAIT OATT)
- Attachment 7l (PECO OATT)
- Attachment 8 HTP FERC Order
- Attachment 9 Linden VFT FERC Order
- Attachment 10 (PSE&G FERC Formula Rate filing)

C. Request for Authority to Collect Adjusted Rate and to Pay Suppliers

The EDCs respectfully reiterate the requests for approval set forth in the 2017 Filings as if incorporated herein. More specifically, the EDCs request approval to implement the attached tariff sheets effective January 1, 2018.

Also, the EDCs respectfully request that the Board issue a waiver of the 30-day filing requirement that would otherwise apply to this submission, because Basic Generation Service ("BGS") suppliers began paying these revised transmission charges for transmission service effective January 1, 2018 pursuant to the PJM OATT changes implementing the HTP and Linden VFT FERC Orders. The EDCs hereby also seek authority from the Board to remit payment to suppliers for the increased charges they incur.

Under the Supplier Master Agreement ("SMA"), EDCs are permitted to recover increases in Firm Transmission Service charges from BGS customers subject to Board approval. SMA, Section 15.9. After collecting such charges, EDCs are required to remit payment of the increased charges to suppliers upon, among other things, the issuance of a "FERC Final Order" approving the Firm Transmission Service increase. In addition, in a recent order, the Board noted that it has the authority to direct the EDCs to pay suppliers prior to the issuance of a FERC Final Order. (In the Matter of the Provision of Basic Generation Service (BGS) for the Period Beginning June 1, 2018, Docket No. ER17040335).

We note that the HTP and Linden VFT rate adjustments in the attached tariffs are intended to implement adjustments to Transmission Enhancement Charges ("TECs") rather than the Firm Transmission Rate. Thus, there will not be a FERC Final Order approving a Firm Transmission Rate.

The EDCs specifically request that the Board find that upon the EDCs collection of the increase due to the Linden and VFT cost reallocations, the EDCs be authorized to remit to BGS suppliers the cost increases collected due to the cost reallocations. Any difference between the payments to the BGS suppliers and charges to customers would flow through each EDC's BGS Reconciliation Charge.

Prompt payment to suppliers of PJM initiated cost reallocations is important to the continued success of the BGS auction process which benefits customers. BGS suppliers have a reasonable expectation that they will be paid for increased charges imposed by PJM. Payment to the suppliers for the HTP and Linden VFT Orders related charges will help ensure that BGS suppliers, when establishing their bid prices, can rely upon the provision of the SMA that permits BGS suppliers to be made whole for increased PJM charges.

D. Conclusion

For the foregoing reasons, the EDCs respectfully request that the Board accept the tariff revision proposed herein and the Board authorize the EDCs to remit payment to suppliers for the increased charges they incur due to the PJM implemented cost reallocation arising from the change in HTP's and Linden's VFT responsibility for Transmission Enhancement Charges.

We thank the Board for all courtesies extended.

Respectfully submitted,

Attachments

C Thomas Walker, NJBPU
Stacy Peterson, NJBPU
Stefanie Brand, Division of Rate Counsel
Attached Service List (email only)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE

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Attachment 1 (Derivation of PSE&G NITS Charge)

Attachment 1 - PSE&G Network Integration Service Calculation.

Derived Network Integration Service Rate Applicable to PSE&G customers - Effective January 1, 2018 through December 31, 2018

Line #	Description	Rate		Source
(1)	Transmission Service Annual Revenue Requirement	$ 1,248,819,352.00		Page 4 of Attachment 11 -Line 164
(2)	Total Schedule 12 TEC Included in above	$ (480,678,136.00)		Attachment 6a Column (a)
(3)	PSE&G Customer Share of Schedule 12 TEC	$ 290,871,138.50		Attachment 6a Column (h)
(4)	Total Transmission Costs Borne by PSE&G customers	$ 1,059,012,354.50		=(1) +(2) +(3)
(5)	2018 PSE&G Network Service Peak	9,566.9	MW	Page 4 of Attachment 11 - -Line 165
(6)	2018 Derived Network Integration Transmission Service Rate	$ 110,695.46	per MW-year	
	Resulting 2018 BGS Firm Transmission Service Supplier Rate	$ 303.28	per MW-day	= (6)/365

Attachment 2a (Pro-forma PSE&G Tariff Sheets)
Attachment 2b (PSE&G Translation of NITS Charge into Customer Rates)
Attachment 2c (PSE&G Translation of VEPCo TEC into Customer Rates)
Attachment 2d (PSE&G Translation of PATH TEC into Customer Rates)
Attachment 2e (PSE&G Translation of TrailCo TEC into Customer Rates)
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Attachment 2l (PSE&G Translation of MAIT TEC into Customer Rates)
Attachment 2m (PSE&G Translation of PECO TEC into Customer Rates)

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	$0.116437	$0.124151	$0.116491	$0.124209
RS – in excess of 600 kWh	0.116437	0.124151	0.125609	0.133931
RHS – first 600 kWh	0.094068	0.100300	0.089172	0.095080
RHS – in excess of 600 kWh	0.094068	0.100300	0.101364	0.108079
RLM On-Peak	0.197431	0.210511	0.208869	0.222707
RLM Off-Peak	0.056415	0.060152	0.052651	0.056139
WH	0.054424	0.058030	0.051835	0.055269
WHS	0.054891	0.058528	0.051426	0.054833
HS	0.093607	0.099808	0.094486	0.100746
BPL	0.051712	0.055138	0.046936	0.050046
BPL-POF	0.051712	0.055138	0.046936	0.050046
PSAL	0.051712	0.055138	0.046936	0.050046

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) ....$ 6.1735

Charge applicable in the months of October through May..$ 5.7899
Charge including New Jersey Sales and Use Tax (SUT) ....$ 6.1735

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 ....$110,695.46 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.. $ 2.82 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $103.21 per MW per month
Virginia Electric and Power Company .... $ 85.19 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....($10.35) per MW per month
PPL Electric Utilities Corporation.. $ 53.83 per MW per month
American Electric Power Service Corporation .... $ 31.39 per MW per month
Atlantic City Electric Company. .... $ 11.43 per MW per month
Delmarva Power and Light Company... $ 0.34 per MW per month
Potomac Electric Power Company. .... $ 3.33 per MW per month
Baltimore Gas and Electric Company……………………………….$ 7.10 per MW per month
Mid Atlantic Interstate Transmission………………………………..$ 7.29 per MW per month
PECO Energy Company... $ 14.31 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months .... $ 9.5343
Charge including New Jersey Sales and Use Tax (SUT) $10.1659

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).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 83**
Superseding
B.P.U.N.J. No. 15 ELECTRIC **XXX Revised Sheet No. 83**

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 ....$110,695.46 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.. $ 2.82 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $103.21 per MW per month
Virginia Electric and Power Company .... $ 85.19 per MW per month
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PPL Electric Utilities Corporation... $ 53.83 per MW per month
American Electric Power Service Corporation .... $ 31.39 per MW per month
Atlantic City Electric Company. .... $ 11.43 per MW per month
Delmarva Power and Light Company.. $ 0.34 per MW per month
Potomac Electric Power Company. .... $ 3.33 per MW per month
Baltimore Gas and Electric Company………………………………$ 7.10 per MW per month
Mid Atlantic Interstate Transmission………………………………. $ 7.29 per MW per month
PECO Energy Company..$ 14.31 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months .... $ 9.5343
Charge including New Jersey Sales and Use Tax (SUT) $10.1659

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.

Network Integration Service Calculation - BGS-RSCP
NITS Charges for January 2018 - December 2018

		Effective 1/1/18 - 12/31/18					
PSE&G Annual Transmission Service Revenue Requirement	$	1,248,819,352.00					
Total Schedule 12 TEC Included in above	$	(480,678,136.00)					
PSE&G Customer Share of Schedule 12 NITS	$	290,871,138.50					
NITS Charges for Jan 2018 - Dec 2018	$	1,059,012,354.50					
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.90					
Term (Months)		12					
OATT rate	$	9,224.62	/MW/month	all values show w/o NJ SUT			
converted to $/MW/yr =	$	110,695.46	/MW/yr	**Jan 18 - Dec 18 NITS Charge**			
	$	82,474.75	/MW/yr	**2015 - 2017 Weighted Average of:**	**$ 72,688.29**	**$ 82,516.44**	**$ 92,569.05**
	$	95,441.90	/MW/yr	**2016- 2018 Weighted Average of:**	**$ 82,516.44**	**$ 92,569.05**	**$ 110,695.46**
	$	90,038.92	/MW/yr	**Jan 18 - Dec 18 Weighted Average**			
Resulting Increase in Transmission Rate	$	20,656.53	/MW/yr				
Resulting Increase in Transmission Rate	$	1,721.38	/MW/month				

	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	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0
Change in energy charge								
in $/MWh	$ 6.5899	$ 3.9588	$ 6.9188	$ -	$ -	$ 3.8060	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.006590**	**$ 0.003959**	**$ 0.006919**	**$ -**	**$ -**	**$ 0.003806**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,658.8	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,949,599	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,728,145	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 137,547,734		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$ 5.3462	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 5.35	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 137,645,573		unrounded	= (6) * (3)
8	Difference due to rounding	$ 97,839		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for VEPCO Projects

TEC Charges for Jan 2018 - Dec 2018	$ 9,780,204.37		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,566.9		
Term (Months)	12		
OATT rate	$ 85.19	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$ 1,022.28	/MW/yr	

	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	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0
Change in energy charge								
in $/MWh	$ 0.3261	$ 0.1959	$ 0.3424	$ -	$ -	$ 0.1884	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000326**	**$ 0.000196**	**$ 0.000342**	**$ -**	**$ -**	**$ 0.000188**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,658.8	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,949,599.4	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,728,144.5	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 6,807,158		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.2646	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.26	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 6,689,318		unrounded	= (6) * (3)
8	Difference due to rounding	$ (117,840)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for PATH Project

TEC Charges for Jan 2018 - Dec 2018	$	(1,188,300.57)	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	(10.35)	/MW/month
Resulting Increase in Transmission Rate	$	(124.20)	/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	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0
Change in energy charge								
in $/MWh	$ (0.0396)	$ (0.0238)	$ (0.0416)	$ -	$ -	$ (0.0229)	$ -	$ -
in $/kWh - rounded to 6 places	**$ (0.000040)**	**$ (0.000024)**	**$ (0.000042)**	**$ -**	**$ -**	**$ (0.000023)**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,658.8	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,949,599	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,728,145	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	(827,023)		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	(0.0321)	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	(0.03)	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	(771,844)		unrounded	= (6) * (3)
8	Difference due to rounding	$	55,179		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Project

TEC Charges for June 2017 - May 2018	$ 11,848,797.55	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,566.9	
Term (Months)	12	
OATT rate	$ 103.21	/MW/month
converted to $/MW/yr =	$ 1,238.52	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3892.6	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	$ 0.395117	$ 0.237361	$ 0.414835	$ -	$ -	$ 0.228200	$ -	$ -
in $/kWh - rounded to 6 places	**0.000395**	**0.000237**	**0.000415**	**0**	**0**	**0.000228**	**0**	**0**

Line #					
1	Total BGS-RSCP eligbile Trans Obl	6658.8	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	$ 8,247,057		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.3205	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.32	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 8,233,006		unrounded	= (6) * (3)
8	Difference due to rounding	$ (14,051)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for Delmarva Projects

TEC Charges for June 2017 - May 2018	$	39,063.59	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	0.34	/MW/month
converted to $/MW/yr =	$	4.08	/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	$	0.001302	$ 0.000782	$ 0.001367	$ -	$ -	$ 0.000752	$ -	$ -
in $/kWh - rounded to 6 places		**0.000001**	**0.000001**	**0.000001**	**0**	**0**	**0.000001**	**0**	**0**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,658.8	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	$	27,168		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0011	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	-	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	-		unrounded	= (6) * (3)
8	Difference due to rounding	$	(27,168)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for ACE Projects

TEC Charges for June 2017 - May 2018	$ 1,311,840.95	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,566.9	
Term (Months)	12	
OATT rate	$ 11.43	/MW/month
converted to $/MW/yr =	$ 137.16	/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	$ 0.043757	$ 0.026287	$ 0.045941	$ -	$ -	$ 0.025272	$ -	$ -
in $/kWh - rounded to 6 places	**0.000044**	**0.000026**	**0.000046**	**0**	**0**	**0.000025**	**0**	**0**

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	$ 913,321		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0355	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.04	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 1,029,126		unrounded	= (6) * (3)
8	Difference due to rounding	$ 115,805		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for PEPCO Projects

TEC Charges for June 2017 - May 2018	$	382,400.18	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	3.33	/MW/month
converted to $/MW/yr =	$	39.96	/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	$ 0.012748	$ 0.007658	$ 0.013384	$ -	$ -	$ 0.007363	$ -	$ -
in $/kWh - rounded to 6 places	**0.000013**	**0.000008**	**0.000013**	**0**	**0**	**0.000007**	**0**	**0**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,658.8	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	$	266,086		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0103	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.01	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	257,281		unrounded	= (6) * (3)
8	Difference due to rounding	$	(8,804)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for PPL Projects

TEC Charges for June 2017 - May 2018	$ 6,179,594.11	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,566.9	
Term (Months)	12	
OATT rate	$ 53.83	/MW/month
converted to $/MW/yr =	$ 645.96	/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	$ 0.206077	$ 0.123797	$ 0.216360	$ -	$ -	$ 0.119019	$ -	$ -
in $/kWh - rounded to 6 places	**0.000206**	**0.000124**	**0.000216**	**0**	**0**	**0.000119**	**0**	**0**

Line #					
1	Total BGS-RSCP eligbile Trans Obl	6,658.8 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	$ 4,301,318		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.1672	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.17	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 4,373,785		unrounded	= (6) * (3)
8	Difference due to rounding	$ 72,466		unrounded	= (7) - (4)

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

TEC Charges for January 2018 - December 2018	$	3,603,405	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	31.39	/MW/month
converted to $/MW/yr =	$	376.68	/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	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0
Energy Charge								
in $/MWh	$ 0.120170	$ 0.072190	$ 0.126167	$ -	$ -	$ 0.069404	$ -	$ -
in $/kWh - rounded to 6 places	**0.00012**	**0.000072**	**0.000126**	**0**	**0**	**0.000069**	**0**	**0**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6658.8	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	$	2,508,237		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0975	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.10	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	2,572,814		unrounded	= (6) * (3)
8	Difference due to rounding	$	64,578		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for BG&E - Initial Year

TEC Charges for June 2017 - May 2018	$	815,288.16	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	7.10	/MW/month
converted to $/MW/yr =	$	85.20	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,892.60	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	$ 0.027181	$ 0.016328	$ 0.028537	$ -	$ -	$ 0.015698	$ -	$ -
in $/kWh - rounded to 6 places	**0.000027**	**0.000016**	**0.000029**	**0**	**0**	**0.000016**	**0**	**0**

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	$ 567,330		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0221	/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	$ (52,767)		unrounded	= (7) - (4)

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		$836,767.34	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	7.29	/MW/month
converted to $/MW/yr =	$	87.48	/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	$ 0.027908	$ 0.016765	$ 0.029301	$ -	$ -	$ 0.016118	$ -	$ -
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	$	582,512		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0226	/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	$	(67,949)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for December 2017 - May 2018
Calculation of costs and monthly PJM charges for PECO Energy Company Transmission Projects

TEC Charges for December 2017 - May 2018		$1,642,725.00	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	14.31	/MW/month
converted to $/MW/yr =	$	171.72	/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	$ 0.054783	$ 0.032910	$ 0.057517	$ -	$ -	$ 0.031640	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000055**	**$ 0.000033**	**$ 0.000058**	**$ -**	**$ -**	**$ 0.000032**	**$ -**	**$ -**

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	$	1,143,449		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0444	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.04	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	1,029,126		unrounded	= (6) * (3)
8	Difference due to rounding	$	(114,323)		unrounded	= (7) - (4)

Attachment 3a (Pro-forma JCPL Tariff Sheets)
Attachment 3b (JCP&L –Translation of PSE&G TEC into Customer Rates)
Attachment 3c (JCP&L Translation of VEPCo TEC into Customer Rates)
Attachment 3d (JCP&L Translation of PATH TEC into Customer Rates)
Attachment 3e (JCP&L Translation of TrailCo TEC into Customer Rates)
Attachment 3f (JCP&L Translation of Delmarva TEC into Customer Rates)
Attachment 3g (JCP&LTranslation of ACE TEC into Customer Rates)
Attachment 3h (JCP&L Translation of PEPCO TEC into Customer Rates)
Attachment 3i (JCP&L Translation of PPL TEC into Customer Rates)
Attachment 3j (JCP&L Translation of AEP East TEC into Customer Rates)
Attachment 3k (JCP&L Translation of BG&E TEC into Customer Rate)
Attachment 3l (JCP&L Translation of MAIT TEC into Customer Rates)
Attachment 3m (JCP&L Translation of PECO TEC into Customer Rates)

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 36
BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 36**

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 (BL England) 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 January 1, 2018, a RMR (Yorktown) surcharge of **$0.000011** 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 January 1, 2018, 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:

PSEG-TEC surcharge of **$0.001525** per KWH
VEPCO-TEC surcharge of **$0.000325** per KWH
PATH-TEC surcharge of **($0.000039)** per KWH
TRAILCO-TEC surcharge of **$0.000431** per KWH
Delmarva-TEC surcharge of **$0.000001** per KWH
ACE-TEC surcharge of **$0.000082** per KWH
PEPCO-TEC surcharge of **$0.000014** per KWH
PPL-TEC surcharge of **$0.000203** per KWH
AEP-East-TEC surcharge of **$0.000115** per KWH
BG&E-TEC surcharge of **$0.000031** per KWH
MAIT-TEC surcharge of **$0.000030** per KWH
PECO-TEC surcharge of **$0.000051** per KWH

3) BGS Reconciliation Charge per KWH: $0.001862 (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 January 1, 2018, 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:

	PSEG-TEC	VEPCO-TEC	PATH-TEC
GS and GST	**$0.001525**	**$0.000325**	**($0.000039)**
GP	**$0.001031**	**$0.000220**	**($0.000027)**
GT	**$0.000950**	**$0.000203**	**($0.000025)**
GT – High Tension Service	**$0.000232**	**$0.000049**	**($0.000006)**

	TRAILCO-TEC	Delmarva-TEC	ACE-TEC
GS and GST	**$0.000431**	**$0.000001**	**$0.000082**
GP	**$0.000291**	**$0.000001**	**$0.000055**
GT	**$0.000269**	**$0.000001**	**$0.000051**
GT – High Tension Service	**$0.000066**	**$0.000000**	**$0.000013**

	PEPCO-TEC	PPL-TEC	AEP-East-TEC
GS and GST	**$0.000014**	**$0.000203**	**$0.000115**
GP	**$0.000010**	**$0.000138**	**$0.000078**
GT	**$0.000009**	**$0.000127**	**$0.000071**
GT – High Tension Service	**$0.000002**	**$0.000031**	**$0.000017**

	BG&E-TEC	MAIT-TEC	PECO-TEC
GS and GST	**$0.000031**	**$0.000030**	**$0.000051**
GP	**$0.000020**	**$0.000020**	**$0.000034**
GT	**$0.000019**	**$0.000019**	**$0.000032**
GT – High Tension Service	**$0.000004**	**$0.000004**	**$0.000007**

4) BGS Reconciliation Charge per KWH: ($0.001552) (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 3b

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

2018 Average Monthly PSEG-TEC Costs Allocated to JCP&L Zone	$	2,290,000.29	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PSEG-Transmission Enhancement Rate ($/MW-month)	$	400.28	

				Effective January 1, 2018:			
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)		PSEG-TEC Surcharge ($/kWh)		PSEG-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	23,703,604	16,572,627,418	$	0.001430	$	0.001525
Primary	348.5	1,673,970	1,730,276,418	$	0.000967	$	0.001031
Transmission @ 34.5 kV	293.5	1,409,785	1,581,370,077	$	0.000891	$	0.000950
Transmission @ 230 kV	15.5	74,452	341,655,635	$	0.000218	$	0.000232
Total	5592.3	26,861,811	20,225,929,548				

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

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

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	PSEG-Transmission Enhancement Costs to RSCP Suppliers	$	22,519,577	= Line 3 x $400.28 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	1.34	= Line 4 / Line 2

Attachment 3c

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

2018 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$	487,651.85	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$	85.24	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective January 1, 2018: VEPCO-TEC Surcharge ($/kWh)	VEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	5,047,644	16,572,627,418	$ 0.000305	$ 0.000325
Primary	348.5	356,469	1,730,276,418	$ 0.000206	$ 0.000220
Transmission @ 34.5 kV	293.5	300,211	1,581,370,077	$ 0.000190	$ 0.000203
Transmission @ 230 kV	15.5	15,854	341,655,635	$ 0.000046	$ 0.000049
Total	5592.3	5,720,179	20,225,929,548		

(1) Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months VEPCO 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	VEPCO-Transmission Enhancement Costs to RSCP Suppliers	$	4,795,507	= Line 3 x $85.24 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.28	= Line 4 / Line 2

Attachment 3d

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

2018 Average Monthly PATH-TEC Costs Allocated to JCP&L Zone	$	(59,161.93)	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PATH-Transmission Enhancement Rate ($/MW-month)	$	(10.34)	

				Effective January 1, 2018:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PATH-TEC Surcharge ($/kWh)	PATH-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	(612,380)	16,572,627,418	$ (0.000037)	$ (0.000039)
Primary	348.5	(43,247)	1,730,276,418	$ (0.000025)	$ (0.000027)
Transmission @ 34.5 kV	293.5	(36,422)	1,581,370,077	$ (0.000023)	$ (0.000025)
Transmission @ 230 kV	15.5	(1,923)	341,655,635	$ (0.000006)	$ (0.000006)
Total	5592.3	(693,972)	20,225,929,548		

(1) Cost Allocation of PATH Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months PATH 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	PATH-Transmission Enhancement Costs to RSCP Suppliers	$	(581,791)	= Line 3 x ($10.34) x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	(0.03)	= Line 4 / Line 2

Attachment 3e

Jersey Central Power & Light Company
Proposed TRAILCO Project Transmission Enhancement Charge (TRAILCO-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved TRAILCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2017 - May 2018

2017/2018 Average Monthly TRAILCO-TEC Costs Allocated to JCP&L Zone	$	647,244.84	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
TRAILCO-Transmission Enhancement Rate ($/MW-month)	$	113.13	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective January 1, 2018:** TRAILCO-TEC Surcharge ($/kWh)	TRAILCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	6,699,578	16,572,627,418	$ 0.000404	$ 0.000431
Primary	348.5	473,130	1,730,276,418	$ 0.000273	$ 0.000291
Transmission @ 34.5 kV	293.5	398,461	1,581,370,077	$ 0.000252	$ 0.000269
Transmission @ 230 kV	15.5	21,043	341,655,635	$ 0.000062	$ 0.000066
Total	5592.3	7,592,213	20,225,929,548		

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

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

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	TRAILCO-Transmission Enhancement Costs to RSCP Suppliers	$	6,364,925	= Line 3 x $113.13 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.38	= Line 4 / Line 2

Attachment 3f

Jersey Central Power & Light Company
Proposed DELMARVA Project Transmission Enhancement Charge (DELMARVA-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved DELMARVA Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2017 - May 2018

2017/2018 Average Monthly DELMARVA Costs Allocated to JCP&L Zone	$	1,994.86	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
DELMARVA-Transmission Enhancement Rate ($/MW-month)	$	0.34	

Effective January 1, 2018:

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	DELMARVA-TEC Surcharge ($/kWh)	DELMARVA-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	20,056	16,572,627,418	$ 0.000001	$ 0.000001
Primary	348.5	1,416	1,730,276,418	$ 0.000001	$ 0.000001
Transmission @ 34.5 kV	293.5	1,193	1,581,370,077	$ 0.000001	$ 0.000001
Transmission @ 230 kV	15.5	63	341,655,635	$ -	$ -
Total	5592.3	22,729	20,225,929,548		

(1) Cost Allocation of DELMARVA Project Schedule 12 Charges to JCP&L Zone for 2017/2018
(2) Based on 12 months DELMARVA Project costs from June 2017 through May 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	DELMARVA-Transmission Enhancement Costs to RSCP Suppliers	$	19,055	= Line 3 x $0.34 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	-	= Line 4 / Line 2

Attachment 3g

Jersey Central Power & Light Company
Proposed ACE Project Transmission Enhancement Charge (ACE-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2017 - May 2018

2017/2018 Average Monthly ACE-TEC Costs Allocated to JCP&L Zone	$	124,045.25	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
ACE-Transmission Enhancement Rate ($/MW-month)	$	21.68	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective January 1, 2018: ACE-TEC Surcharge ($/kWh)	ACE-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	1,283,982	16,572,627,418	$ 0.000077	$ 0.000082
Primary	348.5	90,676	1,730,276,418	$ 0.000052	$ 0.000055
Transmission @ 34.5 kV	293.5	76,366	1,581,370,077	$ 0.000048	$ 0.000051
Transmission @ 230 kV	15.5	4,033	341,655,635	$ 0.000012	$ 0.000013
Total	5592.3	1,455,057	20,225,929,548		

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

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

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	ACE-Transmission Enhancement Costs to RSCP Suppliers	$	1,219,846	= Line 3 x $21.68 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.07	= Line 4 / Line 2

Attachment 3h

Jersey Central Power & Light Company
Proposed PEPCO Project Transmission Enhancement Charge (PEPCO-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved PEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2017 - May 2018

2017/2018 Average Monthly PEPCO-TEC Costs Allocated to JCP&L Zone	$	21,060.24	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PEPCO-Transmission Enhancement Rate ($/MW-month)	$	3.68	

				Effective January 1, 2018:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PEPCO-TEC Surcharge ($/kWh)	PEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	217,993	16,572,627,418	$ 0.000013	$ 0.000014
Primary	348.5	15,395	1,730,276,418	$ 0.000009	$ 0.000010
Transmission @ 34.5 kV	293.5	12,965	1,581,370,077	$ 0.000008	$ 0.000009
Transmission @ 230 kV	15.5	685	341,655,635	$ 0.000002	$ 0.000002
Total	5592.3	247,038	20,225,929,548		

/'(1) Cost Allocation of PEPCO Project Schedule 12 Charges to JCP&L Zone for 2017/2018
(2) Based on 12 months PEPCO Project costs from June 2017 through May 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	PEPCO-Transmission Enhancement Costs to RSCP Suppliers	$	207,104	= Line 3 x $3.68 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.01	= Line 4 / Line 2

Attachment 3i

Jersey Central Power & Light Company
Proposed PPL Project Transmission Enhancement Charge (PPL-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved PPL Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2017 - May 2018

2017/2018 Average Monthly PPL-TEC Costs Allocated to JCP&L Zone	$	304,757.39	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PPL-Transmission Enhancement Rate ($/MW-month)	$	53.27	

				Effective January 1, 2018:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PPL-TEC Surcharge ($/kWh)	PPL-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	3,154,519	16,572,627,418	$ 0.000190	$ 0.000203
Primary	348.5	222,775	1,730,276,418	$ 0.000129	$ 0.000138
Transmission @ 34.5 kV	293.5	187,617	1,581,370,077	$ 0.000119	$ 0.000127
Transmission @ 230 kV	15.5	9,908	341,655,635	$ 0.000029	$ 0.000031
Total	5592.3	3,574,819	20,225,929,548		

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

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

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	PPL-Transmission Enhancement Costs to RSCP Suppliers	$	2,996,946	= Line 3 x $53.27 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.18	= Line 4 / Line 2

Attachment 3j

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

2018 Average Monthly AEP-East-TEC Costs Allocated to JCP&L Zone	$	173,291.37	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
AEP-East-Transmission Enhancement Rate ($/MW-month)	$	30.29	

Effective January 1, 2018:

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	AEP-East-TEC Surcharge ($/kWh)		AEP-East-TEC Surcharge w/ SUT($/kWh)	
Secondary (excluding lighting)	4934.8	1,793,725	16,572,627,418	$	0.000108	$	0.000115
Primary	348.5	126,674	1,730,276,418	$	0.000073	$	0.000078
Transmission @ 34.5 kV	293.5	106,683	1,581,370,077	$	0.000067	$	0.000071
Transmission @ 230 kV	15.5	5,634	341,655,635	$	0.000016	$	0.000017
Total	5592.3	2,032,716	20,225,929,548				

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

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

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	AEP-East-Transmission Enhancement Costs to RSCP Suppliers	$	1,704,126	= Line 3 x $30.29 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.10	= Line 4 / Line 2

Attachment 3k

Jersey Central Power & Light Company
Proposed BG&E Project Transmission Enhancement Charge (BG&E-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved BG&E Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2017 - May 2018

2017/2018 Average Monthly BG&E-TEC Costs Allocated to JCP&L Zone	$	46,000.45	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
BG&E-Transmission Enhancement Rate ($/MW-month)	$	8.04	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective January 1, 2018: BG&E-TEC Surcharge ($/kWh)		BG&E-TEC Surcharge w/ SUT($/kWh)	
Secondary (excluding lighting)	4934.8	476,147	16,572,627,418	$	0.000029	$	0.000031
Primary	348.5	33,626	1,730,276,418	$	0.000019	$	0.000020
Transmission @ 34.5 kV	293.5	28,319	1,581,370,077	$	0.000018	$	0.000019
Transmission @ 230 kV	15.5	1,496	341,655,635	$	0.000004	$	0.000004
Total	5592.3	539,587	20,225,929,548				

(1) Cost Allocation of BG&E Project Schedule 12 Charges to JCP&L Zone for 2017/2018
(2) Based on 12 months BG&E Project costs from June 2017 through May 2018
(3) January 2018 through December 2018

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

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	BG&E-Transmission Enhancement Costs to RSCP Suppliers	$	452,363	= Line 3 x $8.04 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.03	= Line 4 / Line 2

Attachment 3l

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

2018 Average Monthly MAIT-TEC Costs Allocated to JCP&L Zone	$	45,358.84	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
MAIT-Transmission Enhancement Rate ($/MW-month)	$	7.93	

				Effective January 1, 2018:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	MAIT-TEC Surcharge ($/kWh)	MAIT-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	469,506	16,572,627,418	$ 0.000028	$ 0.000030
Primary	348.5	33,157	1,730,276,418	$ 0.000019	$ 0.000020
Transmission @ 34.5 kV	293.5	27,924	1,581,370,077	$ 0.000018	$ 0.000019
Transmission @ 230 kV	15.5	1,475	341,655,635	$ 0.000004	$ 0.000004
Total	5592.3	532,061	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	$	446,053	= Line 3 x $7.93 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.03	= Line 4 / Line 2

Attachment 3m

Jersey Central Power & Light Company
Proposed PECO Project Transmission Enhancement Charge (PECO-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved PECO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for December 2017 - May 2018

2018 Average Monthly PECO-TEC Costs Allocated to JCP&L Zone	$	76,144.19	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PECO-Transmission Enhancement Rate ($/MW-month)	$	13.31	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective January 1, 2018:** PECO-TEC Surcharge ($/kWh)	PECO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	788,162	16,572,627,418	$ 0.000048	$ 0.000051
Primary	348.5	55,661	1,730,276,418	$ 0.000032	$ 0.000034
Transmission @ 34.5 kV	293.5	46,876	1,581,370,077	$ 0.000030	$ 0.000032
Transmission @ 230 kV	15.5	2,476	341,655,635	$ 0.000007	$ 0.000007
Total	5592.3	893,175	20,225,929,548		

(1) Cost Allocation of PECO Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months PECO Project costs from December 2017 through May 2018
(3) January 2018 through December 2018

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

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	PECO-Transmission Enhancement Costs to RSCP Suppliers	$	748,792	= Line 3 x $13.31 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.04	= Line 4 / Line 2

Attachment 4a (ACE Pro-forma Tariff Sheets)
Attachment 4b (ACE – Translation of PSE&G TEC into Customer Rates)
Attachment 4c (ACE Translation of VEPCo TEC into Customer Rates)
Attachment 4d (ACE Translation of PATH TEC into Customer Rates)
Attachment 4e (ACE Translation of TrailCo TEC into Customer Rates)
Attachment 4f (ACE Translation of Delmarva TEC into Customer Rates)
Attachment 4g (N/A)
Attachment 4h (ACE Translation of PEPCO TEC into Customer Rates)
Attachment 4i (ACE Translation of PPL TEC into Customer Rates)
Attachment 4j (ACE Translation of AEP East TEC into Customer Rates)
Attachment 4k (ACE Translation of BG&E TEC into Customer Rates)
Attachment 4l (ACE Translation of MAIT TEC into Customer Rates)
Attachment 4m (ACE Translation of PECO TEC into Customer Rates)

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	0.000413	0.000344	0.000372	0.000228	0.000181	0.000175	-	0.000145
TrAILCo	0.000574	0.000480	0.000518	0.000317	0.000253	0.000244	-	0.000202
PSE&G	0.000581	0.000486	0.000525	0.000321	0.000257	0.000248	-	0.000204
PATH	(0.000049)	(0.000042)	(0.000045)	(0.000027)	(0.000021)	(0.000021)	-	(0.000017)
PPL	0.000244	0.000204	0.000220	0.000134	0.000108	0.000103	-	0.000085
PECO	0.000194	0.000162	0.000176	0.000108	0.000086	0.000083		0.000068
Pepco	0.000022	0.000019	0.000020	0.000013	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	0.000001	0.000001	-	0.000001
Delmarva	0.000002	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
BG&E	0.000077	0.000064	0.000069	0.000043	0.000034	0.000033	-	0.000027
AEP - East	0.000128	0.000107	0.000115	0.000070	0.000057	0.000054	-	0.000045
Total	0.002220	0.001854	0.002002	0.001227	0.000981	0.000944	-	0.000779

Date of Issue: **Effective Date:**

Issued by:

Atlantic City Electric Company
Proposed PSE&G Projects Transmission Enhancement Charge (PSE&G-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)	$	309,588
	$	309,588
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	121.85

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 ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$ 2,270,171	4,171,964,933	$ 0.000544	$ 0.000545	$ 0.000581
MGS Secondary	359	$ 524,192	1,152,950,462	$ 0.000455	$ 0.000456	$ 0.000486
MGS Primary	8	$ 12,011	24,456,016	$ 0.000491	$ 0.000492	$ 0.000525
AGS Secondary	393	$ 574,954	1,917,585,029	$ 0.000300	$ 0.000301	$ 0.000321
AGS Primary	94	$ 137,450	571,955,641	$ 0.000240	$ 0.000241	$ 0.000257
TGS	146	$ 213,556	920,786,585	$ 0.000232	$ 0.000233	$ 0.000248
SPL/CSL	0	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 2,413	12,621,752	$ 0.000191	$ 0.000191	$ 0.000204
	2,554	$ 3,734,746	8,845,560,805			

Attachment 4c

Atlantic City Electric Company
Proposed VEPCO Projects Transmission Enhancement Charge (VEPCO-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)	$	219,443
	$	219,443
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	86.37

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 ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$ 1,609,145	4,171,964,933	$ 0.000386	$ 0.000387	$ 0.000413
MGS Secondary	359	$ 371,558	1,152,950,462	$ 0.000322	$ 0.000323	$ 0.000344
MGS Primary	8	$ 8,514	24,456,016	$ 0.000348	$ 0.000349	$ 0.000372
AGS Secondary	393	$ 407,540	1,917,585,029	$ 0.000213	$ 0.000214	$ 0.000228
AGS Primary	94	$ 97,427	571,955,641	$ 0.000170	$ 0.000170	$ 0.000181
TGS	146	$ 151,373	920,786,585	$ 0.000164	$ 0.000164	$ 0.000175
SPL/CSL	0	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 1,710	12,621,752	$ 0.000136	$ 0.000136	$ 0.000145
	2,554	$ 2,647,267	8,845,560,805			

Atlantic City Electric Company
Proposed PATH Projects Transmission Enhancement Charge (PATH-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)	$	(26,259)
	$	(26,259)
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	(10.33)

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 ($/kWh)		Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$	(192,554)	4,171,964,933	$	(0.000046)	$	(0.000046)	$	(0.000049)
MGS Secondary	359	$	(44,462)	1,152,950,462	$	(0.000039)	$	(0.000039)	$	(0.000042)
MGS Primary	8	$	(1,019)	24,456,016	$	(0.000042)	$	(0.000042)	$	(0.000045)
AGS Secondary	393	$	(48,767)	1,917,585,029	$	(0.000025)	$	(0.000025)	$	(0.000027)
AGS Primary	94	$	(11,658)	571,955,641	$	(0.000020)	$	(0.000020)	$	(0.000021)
TGS	146	$	(18,114)	920,786,585	$	(0.000020)	$	(0.000020)	$	(0.000021)
SPL/CSL	0	$	-	73,240,385	$	-	$	-	$	-
DDC	2	$	(205)	12,621,752	$	(0.000016)	$	(0.000016)	$	(0.000017)
	2,554	$	(316,778)	8,845,560,805						

Atlantic City Electric Company
Proposed TrAIL CO Projects Transmission Enhancement Charge (TrAIL Co Project-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	305,736
	$	305,736
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	120.33

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$ 2,241,922	4,171,964,933	$ 0.000537	$ 0.000538	$ 0.000574
MGS Secondary	359	$ 517,669	1,152,950,462	$ 0.000449	$ 0.000450	$ 0.000480
MGS Primary	8	$ 11,862	24,456,016	$ 0.000485	$ 0.000486	$ 0.000518
AGS Secondary	393	$ 567,800	1,917,585,029	$ 0.000296	$ 0.000297	$ 0.000317
AGS Primary	94	$ 135,740	571,955,641	$ 0.000237	$ 0.000237	$ 0.000253
TGS	146	$ 210,899	920,786,585	$ 0.000229	$ 0.000229	$ 0.000244
SPL/CSL	0	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 2,383	12,621,752	$ 0.000189	$ 0.000189	$ 0.000202
	2,554	$ 3,688,274	8,845,560,805			

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	863
	$	863
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	0.34

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$ 6,330	4,171,964,933	$ 0.000002	$ 0.000002	$ 0.000002
MGS Secondary	359	$ 1,462	1,152,950,462	$ 0.000001	$ 0.000001	$ 0.000001
MGS Primary	8	$ 33	24,456,016	$ 0.000001	$ 0.000001	$ 0.000001
AGS Secondary	393	$ 1,603	1,917,585,029	$ 0.000001	$ 0.000001	$ 0.000001
AGS Primary	94	$ 383	571,955,641	$ 0.000001	$ 0.000001	$ 0.000001
TGS	146	$ 595	920,786,585	$ 0.000001	$ 0.000001	$ 0.000001
SPL/CSL	0	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 7	12,621,752	$ 0.000001	$ 0.000001	$ 0.000001
	2,554	$ 10,414	$ 8,845,560,805			

Attachment 4g (N/A)

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	12,042
	$	12,042
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	4.74

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$	88,304	4,171,964,933	$	0.000021	$	0.000021	$	0.000022
MGS Secondary	359	$	20,390	1,152,950,462	$	0.000018	$	0.000018	$	0.000019
MGS Primary	8	$	467	24,456,016	$	0.000019	$	0.000019	$	0.000020
AGS Secondary	393	$	22,364	1,917,585,029	$	0.000012	$	0.000012	$	0.000013
AGS Primary	94	$	5,346	571,955,641	$	0.000009	$	0.000009	$	0.000010
TGS	146	$	8,307	920,786,585	$	0.000009	$	0.000009	$	0.000010
SPL/CSL	0	$	-	73,240,385	$	-	$	-	$	-
DDC	2	$	94	12,621,752	$	0.000007	$	0.000007	$	0.000007
	2,554	$	145,272	8,845,560,805						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	130,091
	$	130,091
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	51.20

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$ 953,940	4,171,964,933	$ 0.000229	$ 0.000229	$ 0.000244
MGS Secondary	359	$ 220,269	1,152,950,462	$ 0.000191	$ 0.000191	$ 0.000204
MGS Primary	8	$ 5,047	24,456,016	$ 0.000206	$ 0.000206	$ 0.000220
AGS Secondary	393	$ 241,599	1,917,585,029	$ 0.000126	$ 0.000126	$ 0.000134
AGS Primary	94	$ 57,757	571,955,641	$ 0.000101	$ 0.000101	$ 0.000108
TGS	146	$ 89,738	920,786,585	$ 0.000097	$ 0.000097	$ 0.000103
SPL/CSL	0	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 1,014	12,621,752	$ 0.000080	$ 0.000080	$ 0.000085
	2,554	$ 1,569,364	8,845,560,805			

Atlantic City Electric Company
Proposed AEP Projects Transmission Enhancement Charge (AEP 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)	$	68,037
	$	68,037
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	26.78

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	$	498,908.36	4,171,964,933	$	0.000120	$	0.000120	$	0.000128
MGS Secondary	359	$	115,200	1,152,950,462	$	0.000100	$	0.000100	$	0.000107
MGS Primary	8	$	2,640	24,456,016	$	0.000108	$	0.000108	$	0.000115
AGS Secondary	393	$	126,356	1,917,585,029	$	0.000066	$	0.000066	$	0.000070
AGS Primary	94	$	30,207	571,955,641	$	0.000053	$	0.000053	$	0.000057
TGS	146	$	46,933	920,786,585	$	0.000051	$	0.000051	$	0.000054
SPL/CSL	0	$	-	73,240,385	$	-	$	-	$	-
DDC	2	$	530	12,621,752	$	0.000042	$	0.000042	$	0.000045
	2,554	$	820,774	8,845,560,805						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	41,086
	$	41,086
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	16.17

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$	301,281	4,171,964,933	$	0.000072	$	0.000072	$	0.000077
MGS Secondary	359	$	69,567	1,152,950,462	$	0.000060	$	0.000060	$	0.000064
MGS Primary	8	$	1,594	24,456,016	$	0.000065	$	0.000065	$	0.000069
AGS Secondary	393	$	76,304	1,917,585,029	$	0.000040	$	0.000040	$	0.000043
AGS Primary	94	$	18,241	571,955,641	$	0.000032	$	0.000032	$	0.000034
TGS	146	$	28,342	920,786,585	$	0.000031	$	0.000031	$	0.000033
SPL/CSL	0	$	-	73,240,385	$	-	$	-	$	-
DDC	2	$	320	12,621,752	$	0.000025	$	0.000025	$	0.000027
	2,554	$	495,649	8,845,560,805						

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)	$ 16,288
	$ 16,288
2018 ACE Zone Transmission Peak Load (MW)	2,541
Transmission Enhancement Rate ($/MW-Month)	$ 6.41

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	$ 119,437	4,171,964,933	$ 0.000029	$ 0.000029	$ 0.000031
MGS Secondary	359	$ 27,579	1,152,950,462	$ 0.000024	$ 0.000024	$ 0.000026
MGS Primary	8	$ 632	24,456,016	$ 0.000026	$ 0.000026	$ 0.000028
AGS Secondary	393	$ 30,249	1,917,585,029	$ 0.000016	$ 0.000016	$ 0.000017
AGS Primary	94	$ 7,231	571,955,641	$ 0.000013	$ 0.000013	$ 0.000014
TGS	146	$ 11,235	920,786,585	$ 0.000012	$ 0.000012	$ 0.000013
SPL/CSL	0	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 127	12,621,752	$ 0.000010	$ 0.000010	$ 0.000011
	2,554	$ 196,491	8,845,560,805			

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	103,821
	$	103,821
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	40.86

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 ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$ 761,307	4,171,964,933	$ 0.000182	$ 0.000182	$ 0.000194
MGS Secondary	359	$ 175,789	1,152,950,462	$ 0.000152	$ 0.000152	$ 0.000162
MGS Primary	8	$ 4,028	24,456,016	$ 0.000165	$ 0.000165	$ 0.000176
AGS Secondary	393	$ 192,812	1,917,585,029	$ 0.000101	$ 0.000101	$ 0.000108
AGS Primary	94	$ 46,094	571,955,641	$ 0.000081	$ 0.000081	$ 0.000086
TGS	146	$ 71,616	920,786,585	$ 0.000078	$ 0.000078	$ 0.000083
SPL/CSL	-	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 809	12,621,752	$ 0.000064	$ 0.000064	$ 0.000068
	2,554	$ 1,252,456	8,845,560,805			

Attachment 5a (RECO Pro-forma Tariff Sheets)
Attachment 5b (RECO –Translation of PSE&G TEC into Customer Rates)
Attachment 5c (RECO Translation of VEPCo TEC into Customer Rates)
Attachment 5d (RECO Translation of PATH TEC into Customer Rates)
Attachment 5e (RECO Translation of TrailCo TEC into Customer Rates)
Attachment 5f (RECO Translation of Delmarva TEC into Customer Rates)
Attachment 5g (RECO Translation of ACE TEC into Customer Rates)
Attachment 5h (RECO Translation of PEPCO TEC into Customer Rates)
Attachment 5i (RECO Translation of PPL TEC into Customer Rates)
Attachment 5j (RECO Translation of AEP East TEC into Customer Rates)
Attachment 5k (RECO Translation of BG&E TEC into Customer Rates)
Attachment 5l (RECO Translation of MAIT TEC into Customer Rates)
Attachment 5m (RECO Translation of PECO TEC into Customer Rates)

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges

(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
All kWh .... @	1.583 ¢ per kWh	1.583 ¢ 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 .... @	0.985 ¢ per kWh	0.985 ¢ 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 ....@	0.593 ¢ per kWh	0.593 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.575 ¢ per kWh	0.575 ¢ 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 ......@	1.583 ¢ per kWh	1.583 ¢ per kWh
Off-Peak All other kWh ......@	1.583 ¢ per kWh	1.583 ¢ 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 .....@	0.624 ¢ per kWh	0.624 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE - MONTHLY (Continued)

(3) Transmission Charge

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

	Summer Months*	Other Months
All kWh ……….. @	1.583 ¢ per kWh	1.583 ¢ 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 ……….. @	0.631 ¢ per kWh	0.631 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

		Primary	High Voltage Distribution
Demand Charge			
Period I	All kW @	$2.55 per kW	$2.55 per kW
Period II	All kW @	0.67 per kW	0.67 per kW
Period III	All kW @	2.55 per kW	2.55 per kW
Period IV	All kW @	0.67 per kW	0.67 per kW
Usage Charge			
Period I	All kWh @	0.421 ¢ per kWh	0.421 ¢ per kWh
Period II	All kWh @	0.421 ¢ per kWh	0.421 ¢ per kWh
Period III	All kWh @	0.421 ¢ per kWh	0.421 ¢ per kWh
Period IV	All kWh @	0.421 ¢ per kWh	0.421 ¢ 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 @	0.368 ¢ per kWh	0.368 ¢ 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 3.281 ¢ per kWh during the billing months of October through May and 5.304 ¢ per kWh during the summer billing months, a Transmission Charge of 0.421 ¢ per kWh and a Transmission Surcharge of 0.368 ¢ per kWh during all billing months. The applicability of Transmission Charges and the Transmission Surcharge is described in Part (3) of RATE – MONTHLY.

When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.87 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)

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

2018 Average Monthly PSE&G-TEC Costs Allocated to RECO	$	734,039	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	1,675.55	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $734,039 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	5,331,157	692,439,000	$	0.00770	$	0.00821
SC2 Secondary	122.2	27.89%	$	2,456,339	528,990,000	$	0.00464	$	0.00495
SC2 Primary	14.5	3.32%	$	292,084	65,159,000	$	0.00448	$	0.00478
SC3	0.1	0.02%	$	1,339	275,000	$	0.00487	$	0.00519
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	72,756	14,763,000	$	0.00493	$	0.00526
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	654,788	227,701,000	$	0.00288	$	0.00307
Total	438.1 (2)	100.00%	$	8,808,463	1,541,318,000				

(1) Attachment 4 - Cost Allocation of PSE&G Project Schedule 12 Charges to RECO Zone for January 2018 through 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		406	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	8,153,695.50	= Line 3 x $1675.55 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	6.93	= Line 4/Line 2

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

2018 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	33,851	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	77.27	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $33,851 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$ 245,849	692,439,000	$ 0.00036	$ 0.00038
SC2 Secondary	122.2	27.89%	$ 113,275	528,990,000	$ 0.00021	$ 0.00022
SC2 Primary	14.5	3.32%	$ 13,470	65,159,000	$ 0.00021	$ 0.00022
SC3	0.1	0.02%	$ 62	275,000	$ 0.00023	$ 0.00025
SC4	0.0	0.00%	$ -	6,441,000	$ -	$ -
SC5	3.6	0.83%	$ 3,355	14,763,000	$ 0.00023	$ 0.00025
SC6	0.0	0.00%	$ -	5,550,000	$ -	$ -
SC7	32.6	7.43%	$ 30,196	227,701,000	$ 0.00013	$ 0.00014
Total	438.1 (2)	100.00%	$ 406,207	1,541,318,000		

(1) Attachment 4 - Cost Allocation of VEPCo Schedule 12 Charges to RECO Zone for January 2018 through 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		406	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	376,017.46	= Line 3 x $77.27 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.32	= Line 4/Line 2

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

2018 Average Monthly PATH-TEC Costs Allocated to RECO	$	(4,113)	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	(9.39)	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $-4,113 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	(29,871)	692,439,000	$	(0.00004)	$	(0.00004)
SC2 Secondary	122.2	27.89%	$	(13,763)	528,990,000	$	(0.00003)	$	(0.00003)
SC2 Primary	14.5	3.32%	$	(1,637)	65,159,000	$	(0.00003)	$	(0.00003)
SC3	0.1	0.02%	$	(8)	275,000	$	(0.00003)	$	(0.00003)
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	(408)	14,763,000	$	(0.00003)	$	(0.00003)
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	(3,669)	227,701,000	$	(0.00002)	$	(0.00002)
Total	438.1 (2)	100.00%	$	(49,356)	1,541,318,000				

(1) Attachment 4 - Cost Allocation of PATH Project Schedule 12 Charges to RECO Zone for January 2018 through 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		406	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	(45,694.37)	= Line 3 x $-9.39 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	(0.04)	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (TrAILCo) effective January 1, 2018
To reflect FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2017 to May 2018

2017/2018 Average Monthly TrAILCo-TEC Costs Allocated to RECO	$	40,505	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	92.46	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $40,505 x 12		Col. 4	Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07	
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales June 2017- May2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	294,182	692,439,000	$	0.00042	$	0.00045
SC2 Secondary	122.2	27.89%	$	135,545	528,990,000	$	0.00026	$	0.00028
SC2 Primary	14.5	3.32%	$	16,118	65,159,000	$	0.00025	$	0.00027
SC3	0.1	0.02%	$	74	275,000	$	0.00027	$	0.00029
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	4,015	14,763,000	$	0.00027	$	0.00029
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	36,132	227,701,000	$	0.00016	$	0.00017
Total	438.1 (2)	100.00%	$	486,066	1,541,318,000				

(1) Attachment 2 - Cost Allocation of TrAILCo Schedule 12 Charges to RECO Zone for June 2017 to May 2018
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		403	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	447,169.21	= Line 3 x $92.46 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.38	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (Delmarva) effective January 1, 2018
To reflect FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2017 to May 2018

2017/2018 Average Monthly Delmarva-TEC Costs Allocated to RECO	$	135	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	0.31	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $135 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales June 2017- May2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	982	692,439,000	$	-	$	-
SC2 Secondary	122.2	27.89%	$	452	528,990,000	$	-	$	-
SC2 Primary	14.5	3.32%	$	54	65,159,000	$	-	$	-
SC3	0.1	0.02%	$	-	275,000	$	-	$	-
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	13	14,763,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	121	227,701,000	$	-	$	-
Total	438.1 (2)	100.00%	$	1,622	1,541,318,000				

(1) Attachment 2 - Cost Allocation of Delmarva Schedule 12 Charges to RECO Zone for June 2017 to May 2018
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		403	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	1,499.27	= Line 3 x $0.31 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	-	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective January 1, 2018
To reflect FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2017 to May 2018

2017/2018 Average Monthly ACE-TEC Costs Allocated to RECO	$	3,532	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	8.06	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $3,532 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales June 2017- May2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	25,649	692,439,000	$	0.00004	$	0.00004
SC2 Secondary	122.2	27.89%	$	11,818	528,990,000	$	0.00002	$	0.00002
SC2 Primary	14.5	3.32%	$	1,405	65,159,000	$	0.00002	$	0.00002
SC3	0.1	0.02%	$	6	275,000	$	0.00002	$	0.00002
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	350	14,763,000	$	0.00002	$	0.00002
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	3,150	227,701,000	$	0.00001	$	0.00001
Total	438.1 (2)	100.00%	$	42,378	1,541,318,000				

(1) Attachment 2 - Cost Allocation of ACE Schedule 12 Charges to RECO Zone for June 2017 to May 2018
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		406	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	39,222.22	= Line 3 x $8.06 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.03	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PEPCO) effective January 1, 2018
To reflect FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2017 to May 2018

2017/2018 Average Monthly PEPCO-TEC Costs Allocated to RECO	$	855	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	1.95	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $855 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales June 2017- May2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	6,212	692,439,000	$	0.00001	$	0.00001
SC2 Secondary	122.2	27.89%	$	2,862	528,990,000	$	0.00001	$	0.00001
SC2 Primary	14.5	3.32%	$	340	65,159,000	$	0.00001	$	0.00001
SC3	0.1	0.02%	$	2	275,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	85	14,763,000	$	0.00001	$	0.00001
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	763	227,701,000	$	-	$	-
Total	438.1 (2)	100.00%	$	10,264	1,541,318,000				

(1) Attachment 2 - Cost Allocation of PEPCO Schedule 12 Charges to RECO Zone for June 2017 to May 2018
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.					
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		403	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	9,430.89	= Line 3 x $1.95 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PPL) effective January 1, 2017
To reflect FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2017 to May 2018

2017/2018 Average Monthly PPL-TEC Costs Allocated to RECO	$	21,278	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	48.57	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $21,278 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales June 2017- May2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	154,538	692,439,000	$	0.00022	$	0.00023
SC2 Secondary	122.2	27.89%	$	71,204	528,990,000	$	0.00013	$	0.00014
SC2 Primary	14.5	3.32%	$	8,467	65,159,000	$	0.00013	$	0.00014
SC3	0.1	0.02%	$	39	275,000	$	0.00014	$	0.00015
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	2,109	14,763,000	$	0.00014	$	0.00015
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	18,981	227,701,000	$	0.00008	$	0.00009
Total	438.1 (2)	100.00%	$	255,338	1,541,318,000				

(1) Attachment 2 - Cost Allocation of PPL Schedule 12 Charges to RECO Zone for June 2017 to May 2018
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		403	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	234,901.67	= Line 3 x $48.57 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.20	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP East) effective January 1, 2018

To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2018 to December 2018

2018 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	12,368	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	28.23	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $12,368 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	89,823	692,439,000	$	0.00013	$	0.00014
SC2 Secondary	122.2	27.89%	$	41,386	528,990,000	$	0.00008	$	0.00009
SC2 Primary	14.5	3.32%	$	4,921	65,159,000	$	0.00008	$	0.00009
SC3	0.1	0.02%	$	23	275,000	$	0.00008	$	0.00009
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	1,226	14,763,000	$	0.00008	$	0.00009
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	11,032	227,701,000	$	0.00005	$	0.00005
Total	438.1 (2)	100.00%	$	148,411	1,541,318,000				

(1) Attachment 2 - Cost Allocation of AEP East Schedule 12 Charges to RECO Zone for January 2018 through 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		406	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	137,375.09	= Line 3 x $28.23 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.12	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (BG&E) effective January 1, 2018
To reflect FERC-approved BG&E Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2017 to May 2018

2017/2018 Average Monthly BG&E-TEC Costs Allocated to RECO	$	2,534	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	5.78	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $2,534 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales June 2017- May2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	18,402	692,439,000	$	0.00003	$	0.00003
SC2 Secondary	122.2	27.89%	$	8,479	528,990,000	$	0.00002	$	0.00002
SC2 Primary	14.5	3.32%	$	1,008	65,159,000	$	0.00002	$	0.00002
SC3	0.1	0.02%	$	5	275,000	$	0.00002	$	0.00002
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	251	14,763,000	$	0.00002	$	0.00002
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	2,260	227,701,000	$	0.00001	$	0.00001
Total	438.1 (2)	100.00%	$	30,405	1,541,318,000				

(1) Attachment 2 - Cost Allocation of BG&E Schedule 12 Charges to RECO Zone for June 2017 to May 2018
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		403	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	27,954.12	= Line 3 x $5.78 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.02	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting 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	$	1,914	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	4.37	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $1,914 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	13,904	692,439,000	$	0.00002	$	0.00002
SC2 Secondary	122.2	27.89%	$	6,406	528,990,000	$	0.00001	$	0.00001
SC2 Primary	14.5	3.32%	$	762	65,159,000	$	0.00001	$	0.00001
SC3	0.1	0.02%	$	3	275,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	190	14,763,000	$	0.00001	$	0.00001
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	1,708	227,701,000	$	0.00001	$	0.00001
Total	438.1 (2)	100.00%	$	22,973	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		406	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	21,265.64	= Line 3 x $4.37 * 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 changes in Transmission Enhancement Charges (PECO) effective January 1, 2018
To reflect FERC-approved PECO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period December 2017 to May 2018

2018 Average Monthly PECO-TEC Costs Allocated to RECO	$	5,310	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	12.12	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $5,310 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$	38,563	692,439,000	$	0.00006	$	0.00006
SC2 Secondary	122.2	27.89%	$	17,768	528,990,000	$	0.00003	$	0.00003
SC2 Primary	14.5	3.32%	$	2,113	65,159,000	$	0.00003	$	0.00003
SC3	0.1	0.02%	$	10	275,000	$	0.00004	$	0.00004
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.6	0.83%	$	526	14,763,000	$	0.00004	$	0.00004
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	32.6	7.43%	$	4,736	227,701,000	$	0.00002	$	0.00002
Total	438.1 (2)	100.00%	$	63,716	1,541,318,000				

(1) Attachment 2 - Cost Allocation of PECO 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		406	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	58,979.31	= Line 3 x $12.12 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.05	= 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)
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved BG&E Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT
FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PECO 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	$0.00001
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00013	0.00008	0.00008	0.00008	0.00000	0.00008	0.00000	0.00005
BG&E- TEC	(4)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00004)	(0.00003)	(0.00003)	(0.00003)	0.00000	(0.00003)	0.00000	(0.00002)
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00022	0.00013	0.00013	0.00014	0.00000	0.00014	0.00000	0.00008
PSE&G - TEC	(9)	0.00770	0.00464	0.00448	0.00487	0.00000	0.00493	0.00000	0.00288
TrAILCo - TEC	(10)	0.00042	0.00026	0.00025	0.00027	0.00000	0.00027	0.00000	0.00016
VEPCo - TEC	(11)	0.00036	0.00021	0.00021	0.00023	0.00000	0.00023	0.00000	0.00013
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
JCP&L -TEC	(13)	0.00029	0.00017	0.00017	0.00018	0.00000	0.00018	0.00000	0.00011
PECO -TEC	(14)	0.00006	0.00003	0.00003	0.00004	0.00000	0.00004	0.00000	0.00002
Total ($/kWh and excl SUT)		$0.00925	$0.00556	$0.00539	$0.00585	$0.00001	$0.00591	$0.00001	$0.00345
Total (¢/kWh and excl SUT)		0.925 ¢	0.556 ¢	0.539 ¢	0.585 ¢	0.001 ¢	0.591 ¢	0.001 ¢	0.345 ¢

(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	$0.00001
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00014	0.00009	0.00009	0.00009	0.00000	0.00009	0.00000	0.00005
BG&E- TEC	(4)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00004)	(0.00003)	(0.00003)	(0.00003)	0.00000	(0.00003)	0.00000	(0.00002)
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00023	0.00014	0.00014	0.00015	0.00000	0.00015	0.00000	0.00009
PSE&G - TEC	(9)	0.00821	0.00495	0.00478	0.00519	0.00000	0.00526	0.00000	0.00307
TrAILCo - TEC	(10)	0.00045	0.00028	0.00027	0.00029	0.00000	0.00029	0.00000	0.00017
VEPCo - TEC	(11)	0.00038	0.00022	0.00022	0.00025	0.00000	0.00025	0.00000	0.00014
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
JCP&L -TEC	(13)	0.00031	0.00018	0.00018	0.00019	0.00000	0.00019	0.00000	0.00012
PECO -TEC	(14)	0.00006	0.00003	0.00003	0.00004	0.00000	0.00004	0.00000	0.00002
Total ($/kWh and incl SUT)		$0.00985	$0.00593	$0.00575	$0.00624	$0.00001	$0.00631	$0.00001	$0.00368
Total (¢/kWh and incl SUT)		0.985 ¢	0.593 ¢	0.575 ¢	0.624 ¢	0.001 ¢	0.631 ¢	0.001 ¢	0.368 ¢

Notes:

(1) RMR rates based on allocations by transmission zone.
(2) ACE-TEC rates rates calculated in Attachment 5 filed separately.
(3) AEP-East-TEC rates calculated in Attachment 5 filed separately.
(4) BG&E-TEC rates calculated in Attachment 5 filed separately.
(5) Delmarva-TEC rates calculated in Attachment 5 filed separately.
(6) PATH-TEC rates calculated in Attachment 5 filed separately.
(7) PEPCO-TEC rates rates calculated in Attachment 5 filed separately.
(8) PPL-TEC rates rates calculated in Attachment 5 filed separately.
(9) PSE&G-TEC rates calculated in Attachment 5 filed separately.
(10) TrAILCo-TEC rates rates calculated in Attachment 5 filed separately.
(11) VEPCo-TEC rates calculated in Attachment 5 filed separately.
(12) MAIT-TEC rates calculated in Attachment 5 filed separately.
(13) JCP&L-TEC rates calculated in Attachment 5 filed separately.
(14) PECO-TEC rates calculated in Attachment 5 of the joint filing.

Attachment 6a (PSE&G Transmission Enhancement Charges)
Attachment 6b (VEPCo Transmission Enhancement Charges)
Attachment 6c (PATH Transmission Enhancement Charges)
Attachment 6d (TrailCo Transmission Enhancement Charges)
Attachment 6e (Delmarva Transmission Enhancement Charges)
Attachment 6f (ACE Transmission Enhancement Charges)
Attachment 6g (PEPCO Transmission Enhancement Charges)
Attachment 6h (PPL Transmission Enhancement Charges)
Attachment 6i (AEP East Transmission Enhancement Charges)
Attachment 6j (BG&E Transmission Enhancement Charges)
Attachment 6k (MAIT Transmission Enhancement Charges)
Attachment 6l (PECO Transmission Enhancement Charges)

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for PSE&G 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	JCP&L Zone Share	PSE&G Zone Share1,2	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								
Replace all derated Branchburg 500/230 kava transformers	b0130	$ 1,877,462.00	1.36%	47.76%	50.88%	0.00%	$25,533	$896,676	$955,253	$0	$1,877,462
Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	b0134	$ 763,586.00	0.00%	51.11%	45.96%	2.93%	$0	$390,269	$350,944	$22,373	$763,586
Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	b0145	$ 8,165,842.00	0.00%	73.45%	21.78%	4.77%	$0	$5,997,811	$1,778,520	$389,511	$8,165,842
Install 230-138kV transformer at Metuchen substation	b0161	$ 2,535,989.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$2,530,917	$5,072	$2,535,989
Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	b0169	$ 1,551,830.00	1.76%	26.50%	60.89%	0.00%	$27,312	$411,235	$944,909	$0	$1,383,456
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 678,523.00	0.00%	42.95%	38.36%	0.79%	$0	$291,426	$260,281	$5,360	$557,067
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 2,664.00	1.66%	3.74%	6.26%	0.26%	$44	$100	$167	$7	$318
Replace both 230/138 kV transformers at Roseland	b0274	$ 2,067,525.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$2,067,525	$0	$2,067,525
Branchburg 400 MVAR Capacitor	b0290	$ 7,661,319.00	1.66%	3.74%	6.26%	0.26%	$127,178	$286,533	$479,599	$19,919	$913,229
Inst Conemaugh 250 MVAR Cap	b0376	$ 294,411.00	1.66%	3.74%	6.26%	0.26%	$4,887	$11,011	$18,430	$765	$35,094
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 2,074,869.00	47.01%	7.04%	22.31%	0.00%	$975,396	$146,071	$462,903	$0	$1,584,370
Saddle Brook - Athenia Upgrade Cable	b0472	$ 1,518,454.00	0.00%	0.00%	96.40%	3.60%	$0	$0	$1,463,790	$54,664	$1,518,454
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489	$ 83,726,646.00	1.66%	3.74%	6.26%	0.26%	$1,389,862	$3,131,377	$5,241,288	$217,689	$9,980,216
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project) (In Service)	b0489.4	$ 4,655,898.00	5.14%	33.04%	41.10%	1.53%	$239,313	$1,538,309	$1,913,574	$71,235	$3,762,431
Susquehanna Roseland Breakers (In-Service)	b0489.5-.15	$ 635,009.00	1.66%	3.74%	6.26%	0.26%	$10,541	$23,749	$39,752	$1,651	$75,693
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 2,633,067.00	1.66%	3.74%	6.26%	0.26%	$43,709	$98,477	$164,830	$6,846	$313,862
Branchburg-Somerville-Flagtown Reconductor	b0664-b0665	$ 1,963,330.00	0.00%	36.35%	43.24%	1.61%	$0	$713,670	$848,944	$31,610	$1,594,224
Somerville -Bridgewater Reconductor	b0668	$ 676,946.00	0.00%	39.41%	38.76%	1.45%	$0	$266,784	$262,384	$9,816	$538,984
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 935,200.00	0.00%	9.92%	83.73%	3.12%	$0	$92,772	$783,043	$29,178	$904,993
New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	b0814	$ 4,903,080.00	0.00%	23.49%	67.03%	2.50%	$0	$1,151,733	$3,286,535	$122,577	$4,560,845
Reconductor South Mahwah 345 kV J-3410 Circuit	b1017	$ 2,128,153.00	0.00%	29.27%	65.42%	2.55%	$0	$622,910	$1,392,238	$54,268	$2,069,416

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for PSE&G 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 *per PJM Open Access Transmission Tariff*	JCP&L Zone Share	PSE&G Zone Share1,2	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
Reconductor South Mahwah 345 kV K-3411 Circuit	b1018	$ 2,209,709.00	0.00%	29.44%	65.26%	2.55%	$0	$650,538	$1,442,056	$56,348	$2,148,942
West Orange Conversion (North Central Reliability)	b1154	$ 40,101,459.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$38,569,583	$1,531,876	$40,101,459
Branchburg-Middlesex Sw Rack	b1155	$ 6,761,094.00	0.00%	4.61%	91.75%	3.64%	$0	$311,686	$6,203,304	$246,104	$6,761,094
Conversion	b1156	$ 38,998,661.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$37,508,912	$1,489,749	$38,998,661
Reconf Kearny Loop in P2216	b1589	$ 1,639,441.00	0.00%	0.00%	77.16%	3.08%	$0	$0	$1,264,993	$50,495	$1,315,487
230kV Lawrence Switching Station Upgrade	b1228	$ 2,299,055.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$2,211,231	$87,824	$2,299,055
Ridge Rd 69kV Breaker Station	b1255	$ 1,698,080.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$1,633,213	$64,867	$1,698,080
Northeast Grid Reliability Project	b1304.1-b1304.4	$ 43,961,786.00	0.28%	1.43%	85.73%	3.40%	$123,093	$628,654	$37,688,439	$1,494,701	$39,934,886
Mickleton-Gloucester-Camden	b1398-b1398.7	$ 51,110,727.00	0.00%	13.03%	31.99%	1.27%	$0	$6,659,728	$16,350,322	$649,106	$23,659,156
Aldene-Springfield Rd. Conv	b1399	$ 8,012,066.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$7,706,005	$306,061	$8,012,066
Replace Salem 500 kV breakers	b1410-b1415	$ 1,643,978.00	1.66%	3.74%	6.26%	0.26%	$27,290	$61,485	$102,913	$4,274	$195,962
Uprate Eagle Point-Gloucester 230 kV Circuit	b1588	$ 1,360,297.00	0.00%	10.48%	55.03%	2.19%	$0	$142,559	$748,571	$29,791	$920,921
Upgrade Camden Richmon 230kV	b1590	$ 1,274,565.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
New Cox's Corner-Lumberton 230kV Circuit	b1787	$ 4,013,704.00	4.97%	44.34%	48.23%	1.93%	$199,481	$1,779,676	$1,935,809	$77,464	$3,992,431
Build Mickleton-Gloucester Corridor Ultimate Design	b2139	$ 2,314,572.00	0.00%	0.00%	61.11%	2.44%	$0	$0	$1,414,435	$56,476	$1,470,911
Reconfigure Brunswick New 69kV	b2146	$ 10,815,286.00	0.00%	0.00%	96.16%	3.84%	$0	$0	$10,399,979	$415,307	$10,815,286
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10	$ 11,117,605.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$11,117,605	$0	$11,117,605
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10	$ 11,117,605.00	1.66%	3.74%	6.26%	0.26%	$184,552	$415,798	$695,962	$28,906	$1,325,219
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 3,723,348.50	0.00%	0.00%	100.00%	0.00%	$0	$0	$3,723,349	$0	$3,723,349
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 3,723,348.50	1.66%	3.74%	6.26%	0.26%	$61,808	$139,253	$233,082	$9,681	$443,823
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 2,819,272.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$2,819,272	$0	$2,819,272
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 2,819,272.00	1.66%	3.74%	6.26%	0.26%	$46,800	$105,441	$176,486	$7,330	$336,057
Construct New Bayway-Bayonne 345kV Circuit	b2436.33	$ 19,138,377.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$19,138,377	$0	$19,138,377
Construct New North Ave-Bayonne 345kV Circuit	b2436.34	$ 13,179,230.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$13,179,230	$0	$13,179,230
Construct North Ave-Airport 345kV Circuit and Substation Upgrades	b2436.50	$ 6,293,352.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$6,293,352	$0	$6,293,352
Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (CWIP)	b2436.60	$ 5,234,688.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$5,032,106	$202,582	$5,234,688
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (CWIP)	b2436.70	$ 10,406,460.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$10,406,460	$0	$10,406,460

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for PSE&G 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	**PJM Upgrade ID**	**Jan - Dec 2018 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1,2**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81	$ 2,769,919.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$2,662,724	$107,196	$2,769,920
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81	$ 2,769,919.50	1.66%	3.74%	6.26%	0.26%	$45,981	$103,595	$173,397	$7,202	$330,174
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83	$ 2,769,765.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$2,662,575	$107,190	$2,769,765
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83	$ 2,769,765.00	1.66%	3.74%	6.26%	0.26%	$45,978	$103,589	$173,387	$7,201	$330,156
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84	$ 2,744,165.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$2,637,966	$106,199	$2,744,166
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84	$ 2,744,165.50	1.66%	3.74%	6.26%	0.26%	$45,553	$102,632	$171,785	$7,135	$327,105
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85	$ 2,744,165.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$2,637,966	$106,199	$2,744,166
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85	$ 2,744,165.50	1.66%	3.74%	6.26%	0.26%	$45,553	$102,632	$171,785	$7,135	$327,105
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 2,038,208.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$1,959,329	$78,879	$2,038,208
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 2,038,208.00	1.66%	3.74%	6.26%	0.26%	$33,834	$76,229	$127,592	$5,299	$242,954
New Bergen 345/230 kV transformer and any associated substation upgrades	b2437.10	$ 3,191,830.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$3,068,306	$123,524	$3,191,830
New Bergen 345/138 kV transformer #1 and any associated substation upgrades	b2437.11	$ 3,201,998.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$3,201,998	$0	$3,201,998
New Bayway 345/138 kV transformer #1 and any associated substation upgrades	b2437.20	$ 1,818,772.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$1,748,386	$70,386	$1,818,772
New Bayway 345/138 kV transformer #2 and any associated substation upgrades	b2437.21	$ 1,820,116.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$1,749,678	$70,438	$1,820,116
New Linden 345/230 kV transformer and any associated substation upgrades	b2437.30	$ 3,907,406.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$3,756,189	$151,217	$3,907,406
Install two 175 MVAR Re at Hptcg	b2702	$ 684,363.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$684,363	$0	$684,363
Install two 175 MVAR Re at Hptcg	b2702	$ 684,363.00	1.66%	3.74%	6.26%	0.26%	$11,360	$25,595	$42,841	$1,779	$81,576
Totals		**$ 480,678,136.00**					**$3,715,060**	**$27,480,003**	**$290,871,139**	**$8,808,462**	**$330,874,664**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) +

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for PSE&G 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	**PJM Upgrade ID**	**Jan - Dec 2018 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1,2**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								

	(k)	(l)	(m)	(n)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2018**	**2018 Trans. Peak Load [2]**	**Rate in \$/MW-mo. [1]**	**2018 Impact (12 months)**
PSE&G	$ 24,239,261.54	9,566.9	$ 2,533.66	$ 290,871,139
JCP&L	$ 2,290,000.29	5,721.0	$ 400.28	$ 27,480,003
ACE	$ 309,588.34	2,540.8	$ 121.85	$ 3,715,060
RE	$ 734,038.51	401.7	$ 1,827.33	$ 8,808,462
Total Impact on NJ Zones	**$ 27,572,888.67**	**18,230.4**		**$ 330,874,664**
Notes on calculations >>>			= (k) / (l)	= (k) *12

(o)

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2018
2) Data on PJM website

Attachment 6b - PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for VEPCO Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan - Dec 2018 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix: ACE Zone Share *per PJM Open Access Transmission Tariff*	(c) JCP&L Zone Share	(d) PSE&G Zone Share1	(e) RE Zone Share	(f) Estimated New Jersey EDC Zone Charges by Project: ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
Upgrade Mt Storm - Doubs 500kV	b0217	$211,650.75	1.66%	3.74%	6.26%	0.26%	$3,513	$7,916	$13,249	$550	$25,229
Loudoun 150 MVA capacitor @ 500 kV	b0222	$192,360.93	1.66%	3.74%	6.26%	0.26%	$3,193	$7,194	$12,042	$500	$22,929
500 kV breakers and bus work at Suffolk	b0231	$2,565,634.68	1.66%	3.74%	6.26%	0.26%	$42,590	$95,955	$160,609	$6,671	$305,824
Meadowbrook-Loudon 500kV circuit	b0328.1	$29,611,630.39	1.66%	3.74%	6.26%	0.26%	$491,553	$1,107,475	$1,853,688	$76,990	$3,529,706
Upgrade Mt. Storm 500 KV Substation	b0328.3	$1,766,913.75	1.66%	3.74%	6.26%	0.26%	$29,331	$66,083	$110,609	$4,594	$210,616
Upgrade Loudoun 500 KV Substation	b0328.4	$402,111.03	1.66%	3.74%	6.26%	0.26%	$6,675	$15,039	$25,172	$1,045	$47,932
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B	$21,035,930.06	1.66%	3.74%	6.26%	0.26%	$349,196	$786,744	$1,316,849	$54,693	$2,507,483
500/230 KV transformer at Bristers, new 230 Bristers - Gainsville circuit	b0227	$2,411,792.43	0.71%	0.00%	0.00%	0.00%	$17,124	$0	$0	$0	$17,124
Rebuild Mt Storm-Doubs 500 KV circuit	b1507	$42,296,858.25	1.66%	3.74%	6.26%	0.26%	$702,128	$1,581,902	$2,647,783	$109,972	$5,041,786
Replace wave traps on Dooms-Lexington 500KV circuit	b0457	$13,249.20	1.66%	3.74%	6.26%	0.26%	$220	$496	$829	$34	$1,579
Morrisville H1T573	b1647	$2,022.98	1.66%	3.74%	6.26%	0.26%	$34	$76	$127	$5	$241
Morrisville H2T545	b1648	$2,022.98	1.66%	3.74%	6.26%	0.26%	$34	$76	$127	$5	$241
Morrisville H1T580	b1649	$106,738.70	1.66%	3.74%	6.26%	0.26%	$1,772	$3,992	$6,682	$278	$12,723
Morrisville H2T569	b1650	$106,738.70	1.66%	3.74%	6.26%	0.26%	$1,772	$3,992	$6,682	$278	$12,723
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784	$9,129.30	1.66%	3.74%	6.26%	0.26%	$152	$341	$571	$24	$1,088
Reconductor the Dickerson-Pleasant View 230 KV circuit	b0467.2	$669,979.57	1.75%	0.71%	0.00%	0.00%	$11,725	$4,757	$0	$0	$16,481
Install 500/230 kV transformer and two 230 kV breakers at Brambleton	b1188.6	$2,146,442.64	0.22%	0.00%	0.00%	0.00%	$4,722	$0	$0	$0	$4,722
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188	($1,122,569.06)	1.66%	3.74%	6.26%	0.26%	-$18,635	-$41,984	-$70,273	-$2,919	-$133,810
500 kV breaker at Brambleton	b1698.1	($39,426.03)	1.66%	3.74%	6.26%	0.26%	-$654	-$1,475	-$2,468	-$103	-$4,700
Install 2 500kV breakers at Chancellor 500 kV	b0756.1	$524,946.62	1.66%	3.74%	6.26%	0.26%	$8,714	$19,633	$32,862	$1,365	$62,574
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797	$2,330,730.17	1.66%	3.74%	6.26%	0.26%	$38,690	$87,169	$145,904	$6,060	$277,823
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798	$15,158,173.95	1.66%	3.74%	6.26%	0.26%	$251,626	$566,916	$948,902	$39,411	$1,806,854
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799	$3,426,019.27	1.66%	3.74%	6.26%	0.26%	$56,872	$128,133	$214,469	$8,908	$408,381
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805	$4,802,360.00	1.66%	3.74%	6.26%	0.26%	$79,719	$179,608	$300,628	$12,486	$572,441
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1	$1,420,331.79	1.66%	3.74%	6.26%	0.26%	$23,578	$53,120	$88,913	$3,693	$169,304
Rebuild Lexington-Dooms 500 kV Line	b1908	$18,179,893.07	1.66%	3.74%	6.26%	0.26%	$301,786	$679,928	$1,138,061	$47,268	$2,167,043

Attachment 6b - PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for VEPCO 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** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share**	**PSE&G Zone Share1**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Surry 500 kV Station Work	b1905.2	$237,723.18	1.66%	3.74%	6.26%	0.26%	$3,946	$8,891	$14,881	$618	$28,337
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837	$90,493.38	1.66%	3.74%	6.26%	0.26%	$1,502	$3,384	$5,665	$235	$10,787
Uprate Section between Possum and Dumfries Substation	b1328	$520,887.02	0.66%	0.00%	0.00%	0.00%	$3,438	$0	$0	$0	$3,438
Rebuild Loudoun - Brambleto 500kV	b1694	$8,953,178.18	1.66%	3.74%	6.26%	0.26%	$148,623	$334,849	$560,469	$23,278	$1,067,219
R/P Midlothian 500kV 3 breaker Ring Bus	b2471	$588,596.80	1.66%	3.74%	6.26%	0.26%	$9,771	$22,014	$36,846	$1,530	$70,161
Surry to Skiffes Creek 500kV Line	b1905.1	$1,171,270.50	1.66%	3.74%	6.26%	0.26%	$19,443	$43,806	$73,322	$3,045	$139,615
Install Breaker and half scheme with minimum of eight 230kV Breakers	b1696	$615,636.33	0.46%	0.64%	0.00%	0.00%	$2,832	$3,940	$0	$0	$6,772
Build a second Loudon - Brambleton 500kV line	b2373	$11,245,190.14	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Carson Rogers 500kV Ckt	b2744	$2,188,583.17	1.66%	3.74%	6.26%	0.26%	$36,330	$81,853	$137,005	$5,690	$260,879
Totals		**$173,843,224.82**					**$2,633,313**	**$5,851,822**	**$9,780,204**	**$406,207**	**$18,671,546**
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**	**2018 Trans. Peak Load [2]**	**Rate in \$/MW-mo. [1]**	**2018 Impact (12 months)**
	PSE&G	$ 815,017.03	9,566.9	$ 85.19	$ 9,780,204
	JCP&L	$ 487,651.85	5,721.0	$ 85.24	$ 5,851,822
	ACE	$ 219,442.75	2,540.8	$ 86.37	$ 2,633,313
	RE	$ 33,850.55	401.7	$ 84.27	$ 406,207
	Total Impact on NJ Zones	**$ 1,555,962.18**	**18,230.4**		**$18,671,546**
Notes on calculations >>>				= (k) / (l)	= (k) *12

Attachment 6c PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for PATH Project

			(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**	**JCP&L Zone Share**	**PSE&G Zone Share[1]** *per PJM Open Access Transmission Tariff*	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Amos-Bedington 765 kV Circuit (AEP)	b0490	$	(11,779,517.00)	1.66%	3.74%	6.26%	0.26%	-$195,540	-$440,554	-$737,398	-$30,627	-$1,404,118
Amos-Bedington 765 kV Circuit (APS)	b0491	Included above		1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	(7,202,920.21)	1.66%	3.74%	6.26%	0.26%	-$119,568	-$269,389	-$450,903	-$18,728	-$858,588
Totals		**$**	**(18,982,437.21)**					**-$315,108**	**-$709,943**	**-$1,188,301**	**-$49,354**	**-$2,262,707**
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**	**2018 Trans. Peak Load[2]**	**Rate in $/MW-mo.[1]**	**2018 Impact (12 months)**
PSE&G	$	(99,025.05)	9,566.9	($10.35)	$ (1,188,301)
JCP&L	$	(59,161.93)	5,721.0	($10.34)	$ (709,943)
ACE	$	(26,259.04)	2,540.8	($10.33)	$ (315,108)
RE	$	(4,112.86)	401.7	($10.24)	$ (49,354)
Total Impact on NJ Zones	**$**	**(188,558.88)**	**18,230.4**		**$ (2,262,707)**
Notes on calculations >>>				= (k) / (l)	= (k) *12

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2018
2) Data on PJM website

Attachment 6d PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for Allegheny TrAILCo 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	**PJM Upgrade ID**	**June 2017-May 2018 Annual Revenue Requirement**	**ACE Zone Share[1]**	**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**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 142,698,296.88	1.66%	3.74%	6.26%	0.26%	$2,368,792	$5,336,916	$8,932,913	$371,016	$17,009,637
Wylie Ridge [2]	b0218	$ 2,884,641.73	11.83%	15.56%	0.00%	0.00%	$341,253	$448,850	$0	$0	$790,103
Black Oak	b0216	$ 5,754,277.45	1.66%	3.74%	6.26%	0.26%	$95,521	$215,210	$360,218	$14,961	$685,910
Meadowbrook 200 MVAR capacitor	b0559	$ 794,379.64	1.66%	3.74%	6.26%	0.26%	$13,187	$29,710	$49,728	$2,065	$94,690
Replace Kammer 765/500 kV TXfmr	b0495	$ 4,802,279.44	1.66%	3.74%	6.26%	0.26%	$79,718	$179,605	$300,623	$12,486	$572,432
Doubs TXfmr 2	b0343	$ 635,524.86	1.85%	0.00%	0.00%	0.00%	$11,757	$0	$0	$0	$11,757
Doubs TXfmr 3	b0344	$ 582,767.79	1.86%	0.00%	0.00%	0.00%	$10,839	$0	$0	$0	$10,839
Doubs TXfmr 4	b0345	$ 717,765.46	1.85%	0.00%	0.00%	0.00%	$13,279	$0	$0	$0	$13,279
New Osage 138KV Ckt	b0674	$ 2,451,582.02	0.00%	0.00%	0.25%	0.01%	$0	$0	$6,129	$245	$6,374
Cap at Grover 230	b0556	$ 121,286.39	8.64%	18.30%	26.32%	0.98%	$10,479	$22,195	$31,923	$1,189	$65,786
Upgrade transformer 500/230	b1153	$ 3,743,231.50	3.86%	12.95%	21.15%	0.74%	$144,489	$484,748	$791,693	$27,700	$1,448,631
Build a 300 MVAR Switched Shunt at Doubs 500kV	b1803	$ 662,641.57	1.66%	3.74%	6.26%	0.26%	$11,000	$24,783	$41,481	$1,723	$78,987
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800	$ 5,875,239.81	1.66%	3.74%	6.26%	0.26%	$97,529	$219,734	$367,790	$15,276	$700,329
Install a new 600 MVAR SVC at Meadowbrook 500 kV	b1804	$ 8,162,156.68	1.66%	3.78%	6.26%	0.26%	$135,492	$308,530	$510,951	$21,222	$976,194
Build 250 MVAR svc at Altoona 230kV	b1801	$ 4,701,915.58	6.48%	8.15%	8.19%	0.33%	$304,684	$383,206	$385,087	$15,516	$1,088,493
Convert Moshannon sub to 4 breaker 230 kv ring bus	b1964	$ 1,087,213.05	0.00%	5.48%	0.00%	0.00%	$0	$59,579	$0	$0	$59,579
Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 kV	b1802	$ 204,394.75	6.48%	8.15%	8.19%	0.33%	$13,245	$16,658	$16,740	$675	$47,317
Install 100 MVAR capacitor at Johnstown 230 kV substation	b0555	$ 203,348.58	8.64%	18.30%	26.32%	0.98%	$17,569	$37,213	$53,521	$1,993	$110,296
Install 300 MVAR capacitor at Conemaugh 500 kV substation	b0376	$ -	1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
							$3,668,832	**$7,766,938**	**$11,848,798**	**$486,065**	**$23,770,634**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2017 Impact (7 months)**	**2018 Impact (5 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 987,399.80	9,566.9	$ 103.21	$ 6,911,799	$ 4,936,999	$ 11,848,798
JCP&L	$ 647,244.84	5,721.0	$ 113.13	$ 4,530,714	$ 3,236,224	$ 7,766,938
ACE	$ 305,736.04	2,540.8	$ 120.33	$ 2,140,152	$ 1,528,680	$ 3,668,832
RE	$ 40,505.45	401.7	$ 100.84	$ 283,538	$ 202,527	$ 486,065
Total Impact on NJ Zones	**$ 1,980,886.13**			**$ 13,866,203**	**$ 9,904,431**	**$ 23,770,634**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6e PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for Delmarva 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*	**June 2017-May 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**[1]	**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**
			per PJM Open Access Transmission Tariff								
Replace line trap-Keeney	b0272.1	$ 25,760	1.66%	3.74%	6.26%	0.26%	$428	$963	$1,613	$67	$3,071
Add two breakers-Keeney	b0751	$ 598,259	1.66%	3.74%	6.26%	0.26%	$9,931	$22,375	$37,451	$1,555	$71,312
Totals							**$10,359**	**$23,338**	**$39,064**	**$1,622**	**$74,383**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2017 Impact (7 months)**	**2018 Impact (5 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 3,255.30	9,566.9	$ 0.34	$ 22,787	$ 16,276	$ 39,064
JCP&L	$ 1,944.86	5,721.0	$ 0.34	$ 13,614	$ 9,724	$ 23,338
ACE	$ 863.23	2,540.8	$ 0.34	$ 6,043	$ 4,316	$ 10,359
RE	$ 135.20	401.7	$ 0.34	$ 946	$ 676	$ 1,622
Total Impact on NJ Zones	**$ 6,198.59**			**$ 43,390**	**$ 30,993**	**$ 74,383**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for ACE 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*		**June 2017 - May 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**
Upgrade AE portion of Delco Tap	b0265	$	573,925	89.87%	9.48%	0.00%	0.00%	$515,786	$54,408	$0	$0	$570,194
Replace Monroe 230/69 kV TXfmrs	b0276	$	877,862	91.46%	0.00%	8.31%	0.23%	$802,893	$0	$72,950	$2,019	$877,862
Reconductor Union - Corson 138 kV	b0211	$	1,496,892	65.23%	25.87%	6.35%	0.00%	$976,423	$387,246	$95,053	$0	$1,458,721
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$	2,998,498	1.66%	3.74%	6.26%	0.26%	$49,775	$112,144	$187,706	$7,796	$357,421
New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$	2,138,040	65.23%	25.87%	6.35%	0.00%	$1,394,643	$553,111	$135,766	$0	$2,083,520
Reconductor the existing Mickleton – Goucestr 230 kV circuit (AE portion)	b1398.5	$	534,416	0.00%	13.03%	31.99%	1.27%	$0	$69,634	$170,960	$6,787	$247,381
	b1398.5.3.1	$	1,670,931	0.00%	13.03%	31.99%	1.27%	$0	$217,722	$534,531	$21,221	$773,474
Upgrade the Mill T2 138/69 kV Transformer	b1600	$	1,980,620	89.21%	4.76%	5.80%	0.23%	$1,766,911	$94,278	$114,876	$4,555	$1,980,620
								$5,506,431	**$1,488,543**	**$1,311,841**	**$42,379**	**$8,349,194**
Notes on calculations >>>								= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

		(k)	(l)		(m)		(n)		(o)		(p)
Zonal Cost Allocation for New Jersey Zones		**Average Monthly Impact on Zone Customers in 17/18**	**2018TX Peak Load** *per PJM website*		**Rate in $/MW-mo.**		**2017 Impact (7 months)**		**2018 Impact (5 months)**		**2017-2018 Impact (12 months)**
PSE&G	$	109,320.08	9,566.9	$	11.43	$	765,241	$	546,600	$	1,311,841
JCP&L	$	124,045.25	5,721.0	$	21.68	$	868,317	$	620,226	$	1,488,543
ACE	$	458,869.27	2,540.8	$	180.60	$	3,212,085	$	2,294,346	$	5,506,431
RE	$	3,531.54	401.7	$	8.79	$	24,721	$	17,658	$	42,379
Total Impact on NJ Zones	**$**	**695,766.15**				**$**	**4,870,363**	**$**	**3,478,831**	**$**	**8,349,194**
Notes on calculations >>>					= (k) * (l)		= (k) * 7		= (k) * 5		= (n) * (o)

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

Attachment 6g PJM Schedule 12 - Transmission Enhancement Charges for June 2017 to May 2018
Calculation of costs and monthly PJM charges for PEPCO 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*	**June 2017-May 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**
Reconductor 23035 for Dickerson-Quince	b0367.1-2	$ 3,134,708	1.78%	2.67%	3.82%	0.00%	$55,798	$83,697	$119,746	$0	$259,240
Replace 230 1A breaker	b0512.7	$ 298,286	1.66%	3.74%	6.26%	0.26%	$4,952	$11,156	$18,673	$776	$35,556
Replace 230 1B breaker	b0512.8	$ 298,286	1.66%	3.74%	6.26%	0.26%	$4,952	$11,156	$18,673	$776	$35,556
Replace 230 2A breaker	b0512.9	$ 298,286	1.66%	3.74%	6.26%	0.26%	$4,952	$11,156	$18,673	$776	$35,556
Replace 230 3A breaker	b0512.12	$ 301,090	1.66%	3.74%	6.26%	0.26%	$4,998	$11,261	$18,848	$783	$35,890
Ritchie-Benning 230 lines	b0526	$ 8,942,285	0.77%	1.39%	2.10%	0.08%	$68,856	$124,298	$187,788	$7,154	$388,095
Totals							**$144,506**	**$252,723**	**$382,400**	**$10,263**	**$789,893**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2017 Impact (7 months)**	**2018 Impact (5 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 31,866.68	9,566.9	$ 3.33	$ 223,067	$ 159,333	$ 382,400
JCP&L	$ 21,060.24	5,721.0	$ 3.68	$ 147,422	$ 105,301	$ 252,723
ACE	$ 12,042.18	2,540.8	$ 4.74	$ 84,295	$ 60,211	$ 144,506
RE	$ 855.27	401.7	$ 2.13	$ 5,987	$ 4,276	$ 10,263
Total Impact on NJ Zones	**$ 65,824.38**			**$ 460,771**	**$ 329,122**	**$ 789,893**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6h PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for PPL 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*	**June 2017- May 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
New 500 KV Susquehana-Roseland Line	b0487	$ 94,007,965.00	1.66%	3.74%	6.26%	0.26%	$1,560,532	$3,515,898	$5,884,899	$244,421	$11,205,749
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$ 10,646.00	1.66%	3.74%	6.26%	0.26%	$177	$398	$666	$28	$1,269
Replace wavetrap at Hosensack 500KV Sub	b0172.1	$ 7,634.00	1.66%	3.74%	6.26%	0.26%	$127	$286	$478	$20	$910
Replace wavetraps at Juniata 500KV Sub	b0284.2	$ 15,445.00	1.66%	3.74%	6.26%	0.26%	$256	$578	$967	$40	$1,841
New S-R additions < 500kV[2]	b0487.1	$ 2,146,064.00	0.00%	0.00%	5.14%	0.19%	$0	$0	$110,308	$4,078	$114,385
New substation and transformers Middletown	b0468	$ 3,068,630.00	0.00%	4.56%	5.94%	0.22%	$0	$139,930	$182,277	$6,751	$328,957
Totals							**$1,561,092**	**$3,657,089**	**$6,179,594**	**$255,337**	**$11,653,112**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2018 Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2017 Impact (7 months)**	**2018 Impact (5 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 514,966.18	9,566.9	$ 53.83	$ 3,604,763	$ 2,574,831	$ 6,179,594
JCP&L	$ 304,757.39	5,721.0	$ 53.27	$ 2,133,302	$ 1,523,787	$ 3,657,089
ACE	$ 130,091.00	2,540.8	$ 51.20	$ 910,637	$ 650,455	$ 1,561,092
RE	$ 21,278.08	401.7	$ 52.97	$ 148,947	$ 106,390	$ 255,337
Total Impact on NJ Zones	**$ 971,092.65**			**$ 6,797,649**	**$ 4,855,463**	**$ 11,653,112**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6i PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for AEP -East 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
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 939,995	1.66%	3.74%	6.26%	0.26%	$15,604	$35,156	$58,844	$2,444	$112,047
Rockport Reactor Bank	b1465.2	$ 1,965,688	1.66%	3.74%	6.26%	0.26%	$32,630	$73,517	$123,052	$5,111	$234,310
Transpose Rockport- Sullivan 765KV line	b1465.3	$ 2,981,701	1.66%	3.74%	6.26%	0.26%	$49,496	$111,516	$186,654	$7,752	$355,419
Switching changes Sullivan 765KV station	b1465.4	$ 2,615,476	1.66%	3.74%	6.26%	0.26%	$43,417	$97,819	$163,729	$6,800	$311,765
765kV circuit breaker at Wyoming station	b1661	$ 554,795	1.66%	3.74%	6.26%	0.26%	$9,210	$20,749	$34,730	$1,442	$66,132
Term Tsfmr #2 @ SW Lima - new bay position	b1957	$ 2,150,455	0.00%	0.00%	4.54%	0.18%	$0	$0	$97,631	$3,871	$101,501
Reconductor/Rebuild Sporn-Waterford-Muskingham River 345 kV Line	b2017	$ 14,018,439	0.00%	1.39%	2.00%	0.08%	$0	$194,856	$280,369	$11,215	$486,440
Add four 765 kV Breakers at Kammar	b1962	$ 2,845,266	1.66%	3.74%	6.26%	0.26%	$47,231	$106,413	$178,114	$7,398	$339,156
Ft. Wayne Relocate	b1659.14	$ 12,058,807	1.66%	3.74%	6.26%	0.26%	$200,176	$450,999	$754,881	$31,353	$1,437,410
Sorenson 765/500kV Transformer	b1659	$ 7,781,244	0.00%	0.00%	0.92%	0.04%	$0	$0	$71,587	$3,112	$74,700
Sorenson Work 765kV	b1659.13	$ 9,894,917	1.66%	3.74%	6.26%	0.26%	$164,256	$370,070	$619,422	$25,727	$1,179,474
Baker Station 765/500kV Transformer	b1495	$ 7,581,997	0.41%	0.90%	1.48%	0.06%	$31,086	$68,238	$112,214	$4,549	$216,087
Cloverdale 765/500kV Transformer	b1660	$ (2,621,574)	1.66%	3.74%	6.26%	0.26%	($43,518)	($98,047)	($164,111)	($6,816)	($312,492)
Cloverdale 500kV Station	b1660.1	$ (868,486)	1.66%	3.74%	6.26%	0.26%	($14,417)	($32,481)	($54,367)	($2,258)	($103,524)
Jacksons-Ferry 765kV Breakers	b1663.2	$ 1,245,257	1.66%	3.74%	6.26%	0.26%	$20,671	$46,573	$77,953	$3,238	$148,435
Reconductor Cloverdale-Lexington 500kV	b1797.1	$ 5,600,310	1.66%	3.74%	6.26%	0.26%	$92,965	$209,452	$350,579	$14,561	$667,557
Reconductor West Bellaire	b1970	$ 2,845,706	0.00%	1.68%	2.88%	0.11%	$0	$47,808	$81,956	$3,130	$132,894
Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station	b1465.1	$ 4,244,665	0.71%	1.58%	2.63%	0.10%	$30,137	$67,066	$111,635	$4,245	$213,082
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230	$ 1,488,438	1.66%	3.74%	6.26%	0.26%	$24,708	$55,668	$93,176	$3,870	$177,422
Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station	b2423	$ 1,238,544	1.66%	3.74%	6.26%	0.26%	$20,560	$46,322	$77,533	$3,220	$147,634
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.1	$ 4,862,568	1.66%	3.74%	6.26%	0.26%	$80,719	$181,860	$304,397	$12,643	$579,618
Install 300 MVAR shunt line reactor	b2687.2	$ 693,717	1.66%	3.74%	6.26%	0.26%	$11,516	$25,945	$43,427	$1,804	$82,691
Totals							**$816,447**	**$2,079,496**	**$3,603,405**	**$148,410**	**$6,647,759**
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	$ 300,283.72	9,566.9	$ 31.39	$ 3,603,405
JCP&L	$ 173,291.37	5,721.0	$ 30.29	$ 2,079,496
ACE	$ 68,037.27	2,540.8	$ 26.78	$ 816,447
RE	$ 12,367.52	401.7	$ 30.79	$ 148,410
Total Impact on NJ Zones	**$ 553,979.89**			**$ 6,647,759**
Notes on calculations >>>			= (k) * (l)	= (k) *12

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

Attachment 6j PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for BG&E

		(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*	**June 2017 - May 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 a second Conastone – Graceton 230 kV circuit	b0497	$ 5,234,913	9.03%	9.67%	14.11%	0.52%	$472,713	$506,216	$738,646	$27,222	$1,744,797
install new 500 kV transmission from Possum Point to Calvert Cliffs	b0512	$ 1,224,312	1.66%	3.74%	6.26%	0.26%	$20,324	$45,789	$76,642	$3,183	$145,938
		$ -					$0	$0	$0	$0	$0
Totals							**$493,036**	**$552,005**	**$815,288**	**$30,405**	**$1,890,734**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2017 Impact (7 months)**	**2018 Impact (5 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 67,940.68	9,566.9	$ 7.10	$ 475,585	$ 339,703	$ 815,288
JCP&L	$ 46,000.45	5,721.0	$ 8.04	$ 322,003	$ 230,002	$ 552,005
ACE	$ 41,086.35	2,540.8	$ 16.17	$ 287,604	$ 205,432	$ 493,036
RE	$ 2,533.73	401.7	$ 6.31	$ 17,736	$ 12,669	$ 30,405
Total Impact on NJ Zones	**$ 157,561.21**			**$ 1,102,928**	**$ 787,806**	**$ 1,890,734**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6k - 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]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]** *per PJM Open Access Transmission Tariff*	**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	6.75%	16.96%	22.82%	0.34%	$116,267	$292,131	$393,068	$5,856	$807,323
Replace wave trap at Kestone 500kV Sub	b0284.3	$	-	1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
Install 100 MVAR Cap Banks at Jack's Mountain 500 kV Sub	b0369	$	-	1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549	$	456,461.00	1.66%	3.74%	6.26%	0.26%	$7,577	$17,072	$28,574	$1,187	$54,410
Install 25 MVAR capacitor at Saxton 115 kV Sub	b0551	$	187,275.00	8.64%	18.30%	26.32%	0.98%	$16,181	$34,271	$49,291	$1,835	$101,578
Install 50 MVAR capacitor at Altoona 230 kV Sub	b0552	$	150,010.00	8.64%	18.30%	26.32%	0.98%	$12,961	$27,452	$39,483	$1,470	$81,365
Install 50 MVAR capacitor at Raystoon 230 kV Sub	b0553	$	132,043.00	8.64%	18.30%	26.32%	0.98%	$11,409	$24,164	$34,754	$1,294	$71,620
Install 75 MVAR capacitor at East Towanda 230 kV Sub	b0557	$	309,489.00	8.64%	18.30%	26.32%	0.98%	$26,740	$56,636	$81,458	$3,033	$167,867
Relocate the Erie South 345 kV Line Terminal	b1993	$	1,570,347.00	0.00%	5.19%	12.21%	0.48%	$0	$81,501	$191,739	$7,538	$280,778
Conver Lewis Run-Farmers Valley to 230kV using 1033.5 Conductor	b1994	$	15,407.00	0.00%	8.72%	13.67%	0.54%	$0	$1,343	$2,106	$83	$3,533
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1	$	260,294.00	1.66%	3.74%	6.26%	0.26%	$4,321	$9,735	$16,294	$677	$31,027
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
								$195,455	**$544,306**	**$836,767**	**$22,973**	**$1,599,502**
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	$	69,730.61	9,566.9	$	7.29	$	836,767
JCP&L	$	45,358.84	5,721.0	$	7.93	$	544,306
ACE	$	16,287.90	2,540.8	$	6.41	$	195,455
RE	$	1,914.44	401.7	$	4.77	$	22,973
Total Impact on NJ Zones	**$**	**133,291.79**				**$**	**1,599,502**

Notes on calculations >>> = (k) * (l) = (k) *12

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

Attachment 6I - Transmission Enhancement Charges for December 2017 - May 2018
Calculation of costs and monthly PJM charges for PECO Energy Company 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*		**2017/2018 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 a new 500 kV Center Point substation in PECO by tapping the Elroy – Whitpain 500 kV circuit.	b0269	$	5,680,503.12	1.66%	3.74%	6.26%	0.26%	$94,296	$212,451	$355,599	$14,769	$677,116
Add a new 230 kV circuit between Whitpain and Heaton substations	b0269.1	$	2,840,251.56	8.25%	0.00%	0.00%	0.00%	$234,321	$0	$0	$0	$234,321
Upgrade terminal equip. on the Richmond-Waneeta 230 kV line to emergency rating of 1162 MVA	b1591	$	2,795,183.59	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Add a new 500kV brkr. at Whitpain bet. #3 transfmr. and 5029 line	b0269.6	$	531,022.51	1.66%	3.74%	6.26%	0.26%	$8,815	$19,860	$33,242	$1,381	$63,298
Replace 2-500 kV circt brkrs and 2 wave traps at Elroy subs to increase rating of Elroy - Hosensack 500kV	b0171.1	$	727,138.28	1.66%	3.74%	6.26%	0.26%	$12,070	$27,195	$45,519	$1,891	$86,675
Upgrade the portion of the Camden - Richmond 230 kV to a six wire conductor and replace term equip	b1590.1-b1590.2	$	729,239.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Increase the rating of lines 220-39 and 220-43 (Linwood-Chicester 230kV lines) and install reactors.	b1900	$	252,171.13	0.00%	6.07%	21.01%	0.84%	$0	$15,307	$52,981	$2,118	$70,406
Rebuild Bryn Mawr-Plymouth Meeting 138 kV line (130-35 Line)	b0727	$	3,381,918.62	1.25%	0.00%	0.00%	0.00%	$42,274	$0	$0	$0	$42,274
Install a 3rd Emilie 230/138 kV trfmr	b2140	$	2,994,166.28	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Recndr Chichester - Saville 138 kV line and upgrade term equip	b1182	$	3,137,736.52	0.00%	5.12%	14.31%	0.57%	$0	$160,652	$449,010	$17,885	$627,547
Loop the 2026 kV Line to Laushtown Substation	b1717	$	2,012,578.19	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Add a second 230/138 kV trans at Chichester. Add an inductor in series with the parallel tranfmrs	b1178	$	1,411,308.89	0.00%	4.17%	12.18%	0.48%	$0	$58,852	$171,897	$6,774	$237,523
Increase Bradford - Planebrook 230 kV Ckt.220-31 line rating. Replace terminal equipment	b0790	$	302,577.18	0.00%	17.46%	34.00%	1.32%	$0	$52,830	$102,876	$3,994	$159,700
Reconductor the North Wales - Hartman 230 kV circuit	b0506	$	384,967.68	8.58%	0.00%	0.00%	0.00%	$33,030	$0	$0	$0	$33,030
Reconductor the North Wales - Whitpain 230 kV circuit	b0505	$	422,395.48	8.58%	0.00%	0.00%	0.00%	$36,242	$0	$0	$0	$36,242
Increase Bradford - Planebrook 230 kV Ckt.220-02 line rating. Replace terminal equipment	b0789	$	414,111.72	0.73%	17.52%	33.83%	1.32%	$3,023	$72,552	$140,094	$5,466	$221,136
Install 161MVAR capacitor at Planebrook 230kV substation	b0206	$	551,433.67	14.20%	0.00%	3.47%	0.00%	$78,304	$0	$19,135	$0	$97,438
Install 161MVAR capacitor at Newlinville 230kV substation	b0207	$	743,830.62	14.20%	0.00%	3.47%	0.00%	$105,624	$0	$25,811	$0	$131,435

Attachment 6l - Transmission Enhancement Charges for December 2017 - May 2018
Calculation of costs and monthly PJM charges for PECO Energy Company 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*	**2017/2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Install 2% series reactor at Chichester substation on the Chichester - Mickleton 230kV circuit	b0209	$ 421,701.95	65.23%	25.87%	6.35%	0.00%	$275,076	$109,094	$26,778	$0	$410,949
Upgrade Chichester - Delco Tap 230kV and the PECO portion of the Delco Tap - Mickleton 230kV cicuit	b0264	$ 359,162.60	89.87%	9.48%	0.00%	0.00%	$322,779	$34,049	$0	$0	$356,828
Reconductor Buckingham - Pleasant Valley 230kV; same impedance as existing line; ratings of 760MVA normal/882MVA emergency	b0357	$ 398,227.92	0.00%	37.89%	55.19%	2.37%	$0	$150,889	$219,782	$9,438	$380,109
							$1,245,854	**$913,730**	**$1,642,725**	**$63,716**	**$3,866,026**
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	$ 136,893.75	9,566.9	$ 14.31	$ 1,642,725
JCP&L	$ 76,144.19	5,721.0	$ 13.31	$ 913,730
ACE	$ 103,821.21	2,540.8	$ 40.86	$ 1,245,854
RE	$ 5,309.70	401.7	$ 13.22	$ 63,716
Total Impact on NJ Zones	**$ 322,168.85**			**$ 3,866,026**
Notes on calculations >>>			= (k) * (l)	= (k) *12

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

Attachment 7a (PSE&G OATT)

SCHEDULE 12 – APPENDIX

(12) Public Service Electric and Gas Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0025	Convert the Bergen-Leonia 138 Kv circuit to 230 kV circuit.		PSEG (100%)
b0090	Add 150 MVAR capacitor at Camden 230 kV		PSEG (100%)
b0121	Add 150 MVAR capacitor at Aldene 230 kV		PSEG (100%)
b0122	Bypass the Essex 138 kV series reactors		PSEG (100%)
b0125	Add Special Protection Scheme at Bridgewater to automatically open 230 kV breaker for outage of Branchburg – Deans 500 kV and Deans 500/230 kV #1 transformer		PSEG (100%)
b0126	Replace wavetrap on Branchburg – Flagtown 230 kV		PSEG (100%)
b0127	Replace terminal equipment to increase Brunswick – Adams – Bennetts Lane 230 kV to conductor rating		PSEG (100%)
b0129	Replace wavetrap on Flagtown – Somerville 230 kV		PSEG (100%)
b0130	Replace all derated Branchburg 500/230 kV transformers		AEC (1.36%) / JCPL (47.76%) / PSEG (50.88%)
b0134	Upgrade or Retension PSEG portion of Kittatinny – Newton 230 kVcircuit		JCPL (51.11%) / PSEG (45.96%) / RE (2.93%)

The Annual Revenue Requirement for all Public Service Electric and Gas Company Projects (Required Transmission Enhancements) in this Section 12 shall be as specified in Attachment 7 of Attachment H-10A and under the procedures detailed in Attachment H-10B.

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0145	Build new Essex – Aldene 230 kV cable connected through a phase angle regulator at Essex		PSEG (21.78%) / JCPL (73.45%) /RE (4.77%)
b0157	Add 100MVAR capacitor at West Orange 138kV substation		PSEG (100%)
b0158	Close the Sunnymeade "C" and "F" bus tie		PSEG (100%)
b0159	Make the Bayonne reactor permanent installation		PSEG (100%)
b0160	Relocate the X-2250 circuit from Hudson 1-6 bus to Hudson 7-12 bus		PSEG (100%)
b0161	Install 230/138kV transformer at Metuchen substation		PSEG (99.80%) / RE (0.20%)
b0162	Upgrade the Edison – Meadow Rd 138kV "Q" circuit		PSEG (100%)
b0163	Upgrade the Edison – Meadow Rd 138kV "R" circuit		PSEG (100%)
b0169	Build a new 230 kV section from Branchburg – Flagtown and move the Flagtown – Somerville 230 kV circuit to the new section		AEC (1.76%) / JCPL (26.50%) / Neptune* (10.85%) / PSEG (60.89%)
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS		JCLP (42.95%) / Neptune* (17.90%) / PSEG (38.36%) RE (0.79%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0172.2	Replace wave trap at Branchburg 500kV substation		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0184	Replace Hudson 230kV circuit breakers #1-2		PSEG (100%)
b0185	Replace Deans 230kV circuit breakers #9-10		PSEG (100%)
b0186	Replace Essex 230kV circuit breaker #5-6		PSEG (100%)
b1082	Install 230/138 kV transformer at Bergen substation		PENELEC (16.52%) / PSEG (80.29%) / RE (3.19%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0201	Branchburg substation: replace wave trap on Branchburg – Readington 230 kV circuit		PSEG (100%)
b0213.1	Replace New Freedom 230 kV breaker BS2-6		PSEG (100%)
b0213.3	Replace New Freedom 230 kV breaker BS2-8		PSEG (100%)
b0274	Replace both 230/138 kV transformers at Roseland		PSEG (100%)
b0275	Upgrade the two 138 kV circuits between Roseland and West Orange		PSEG (100%)
b0278	Install 228 MVAR capacitor at Roseland 230 kV substation		PSEG (100%)
b0290	Install 400 MVAR capacitor in the Branchburg 500 kV vicinity		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0358	Reconductor the PSEG portion of Buckingham – Pleasant Valley 230 kV, replace wave trap and metering transformer		PSEG (100%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0368	Reconductor Tosco – G22_MTX 230 kV circuit with 1033 bundled ACSS		PSEG (100%)
b0371	Make the Metuchen 138 kV bus solid and upgrade 6 breakers at the Metuchen substation		PSEG (100%)
b0372	Make the Athenia 138 kV bus solid and upgrade 2 breakers at the Athenia substation		PSEG (100%)
b0395	Replace Hudson 230 kV breaker BS4-5		PSEG (100%)
b0396	Replace Hudson 230 kV breaker BS1-6		PSEG (100%)
b0397	Replace Hudson 230 kV breaker BS3-4		PSEG (100%)
b0398	Replace Hudson 230 kV breaker BS5-6		PSEG (100%)
b0401.1	Replace Roseland 230 kV breaker BS6-7		PSEG (100%)
b0401.2	Replace Roseland 138 kV breaker O-1315		PSEG (100%)
b0401.3	Replace Roseland 138 kV breaker S-1319		PSEG (100%)
b0401.4	Replace Roseland 138 kV breaker T-1320		PSEG (100%)
b0401.5	Replace Roseland 138 kV breaker G-1307		PSEG (100%)
b0401.6	Replace Roseland 138 kV breaker P-1316		PSEG (100%)
b0401.7	Replace Roseland 138 kV breaker 220-4		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0401.8	Replace W. Orange 138 kV breaker 132-4		PSEG (100%)
b0411	Install 4th 500/230 kV transformer at New Freedom		AEC (47.01%) / JCPL (7.04%) / Neptune* (0.28%) / PECO (23.36%) / PSEG (22.31%)
b0423	Reconductor Readington (2555) – Branchburg (4962) 230 kV circuit w/1590 ACSS		PSEG (100%)
b0424	Replace Readington wavetrap on Readington (2555) – Roseland (5017) 230 kV circuit		PSEG (100%)
b0425	Reconductor Linden (4996) – Tosco (5190) 230 kV circuit w/1590 ACSS (Assumes operating at 220 degrees C)		PSEG (100%)
b0426	Reconductor Tosco (5190) – G22_MTX5 (90220) 230 kV circuit w/1590 ACSS (Assumes operation at 220 degrees C)		PSEG (100%)
b0427	Reconductor Athenia (4954) – Saddle Brook (5020) 230 kV circuit river section		PSEG (100%)
b0428	Replace Roseland wavetrap on Roseland (5019) – West Caldwell "G" (5089) 138 kV circuit		PSEG (100%)
b0429	Reconductor Kittatinny (2553) – Newton (2535) 230 kV circuit w/1590 ACSS		JCPL (42.63%) / Neptune* (3.65%) / PSEG (51.45%) / RE (2.27%)
b0439	Spare Deans 500/230 kV transformer		PSEG (100%)
b0446.1	Upgrade Bayway 138 kV breaker #2-3		PSEG (100%)
b0446.2	Upgrade Bayway 138 kV breaker #3-4		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0446.3	Upgrade Bayway 138 kV breaker #6-7		PSEG (100%)
b0446.4	Upgrade the breaker associated with TX 132-5 on Linden 138 kV		PSEG (100%)
b0470	Install 138 kV breaker at Roseland and close the Roseland 138 kV buses		PSEG (100%)
b0471	Replace the wave traps at both Lawrence and Pleasant Valley on the Lawrence – Pleasant Vallen 230 kV circuit		PSEG (100%)
b0472	Increase the emergency rating of Saddle Brook – Athenia 230 kV by 25% by adding forced cooling		PSEG (96.40%) / RE (3.60%)
b0473	Move the 150 MVAR mobile capacitor from Aldene 230 kV to Lawrence 230 kV substation		PSEG (100%)
b0489	Build new 500 kV transmission facilities from Pennsylvania – New Jersey border at Bushkill to Roseland		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)†

* Neptune Regional Transmission System, LLC

†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project

††Cost allocations associated with below 500 kV elements of the project

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b489.1	Replace Athenia 230 kV breaker 31H		PSEG (100%)
b489.2	Replace Bergen 230 kV breaker 10H		PSEG (100%)
b489.3	Replace Saddlebrook 230 kV breaker 21P		PSEG (100%)
b0489.4	Install two Roseland 500/230 kV transformers as part of the Susquehanna – Roseland 500 kV project		AEC (5.14%) / ComEd (0.29%) / Dayton (0.03%) / DPL (1.78%) / JCPL (33.04%) / Neptune* (6.38%) / PECO (10.14%) / PENELEC (0.57%) / PSEG (41.10%) / RE (1.53%) ††
b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.6	Replace Roseland 230 kV breaker '51H' with 80 kA		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.8	Replace Roseland 230 kV breaker '31H' with 80 kA		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0489.9	Replace Roseland 230 kV breaker '11H' with 80 kA		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0489.10	Replace Roseland 230 kV breaker '21H'		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.11	Replace Roseland 230 kV breaker '32H'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0489.12	Replace Roseland 230 kV breaker '12H'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.13	Replace Roseland 230 kV breaker '52H'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0489.14	Replace Roseland 230 kV breaker '41H'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.15	Replace Roseland 230 kV breaker '72H'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0498	Loop the 5021 circuit into New Freedom 500 kV substation		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0498.1	Upgrade the 20H circuit breaker		PSEG (100%)
b0498.2	Upgrade the 22H circuit breaker		PSEG (100%)
b0498.3	Upgrade the 30H circuit breaker		PSEG (100%)
b0498.4	Upgrade the 32H circuit breaker		PSEG (100%)
b0498.5	Upgrade the 40H circuit breaker		PSEG (100%)
b0498.6	Upgrade the 42H circuit breaker		PSEG (100%)
b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV substation		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0578	Replace Essex 138 kV breaker 4LM (C1355 line to ECRRF)		PSEG (100%)
b0579	Replace Essex 138 kV breaker 1LM (220-1 TX)		PSEG (100%)
b0580	Replace Essex 138 kV breaker 1BM (BS1-3 tie)		PSEG (100%)
b0581	Replace Essex 138 kV breaker 2BM (BS3-4 tie)		PSEG (100%)
b0582	Replace Linden 138 kV breaker 3 (132-7 TX)		PSEG (100%)
b0592	Replace Metuchen 138 kV breaker '2-2 Transfer'		PSEG (100%)
b0664	Reconductor with 2x1033 ACSS conductor		JCPL (36.35%) / NEPTUNE* (18.80%) / PSEG (43.24%) / RE (1.61%)
b0665	Reconductor with 2x1033 ACSS conductor		JCPL (36.35%) / NEPTUNE* (18.80%) / PSEG (43.24%) / RE (1.61%)
b0668	Reconductor with 2x1033 ACSS conductor		JCPL (39.41%) / NEPTUNE* (20.38%) / PSEG (38.76%) / RE (1.45%)
b0671	Replace terminal equipment at both ends of line		PSEG (100%)
b0743	Add a bus tie breaker at Roseland 138 kV		PSEG (100%)
b0812	Increase operating temperature on line for one year to get 925E MVA rating		PSEG (100%)
b0813	Reconductor Hudson – South Waterfront 230 kV circuit		BGE (1.25%) / JCPL (9.92%) / NEPTUNE* (0.87%) / PEPCO (1.11%) / PSEG (83.73%) / RE (3.12%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814	New Essex – Kearney 138 kV circuit and Kearney 138 kV bus tie		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.1	Replace Kearny 138 kV breaker '1-SHT' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.2	Replace Kearny 138 kV breaker '15HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.3	Replace Kearny 138 kV breaker '14HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.4	Replace Kearny 138 kV breaker '10HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.5	Replace Kearny 138 kV breaker '2HT' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.6	Replace Kearny 138 kV breaker '22HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.7	Replace Kearny 138 kV breaker '4HT' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.8	Replace Kearny 138 kV breaker '25HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.9	Replace Essex 138 kV breaker '2LM' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814.10	Replace Essex 138 kV breaker '1BT' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.11	Replace Essex 138 kV breaker '2PM' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.12	Replace Marion 138 kV breaker '2HM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.13	Replace Marion 138 kV breaker '2LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.14	Replace Marion 138 kV breaker '1LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.15	Replace Marion 138 kV breaker '6PM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.16	Replace Marion 138 kV breaker '3PM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.17	Replace Marion 138 kV breaker '4LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814.18	Replace Marion 138 kV breaker '3LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.19	Replace Marion 138 kV breaker '1HM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.20	Replace Marion 138 kV breaker '2PM3' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.21	Replace Marion 138 kV breaker '2PM1' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.22	Replace ECRR 138 kV breaker '903'		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.23	Replace Foundry 138 kV breaker '21P'		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.24	Change the contact parting time on Essex 138 kV breaker '3LM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.25	Change the contact parting time on Essex 138 kV breaker '2BM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0814.26	Change the contact parting time on Essex 138 kV breaker '1BM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.27	Change the contact parting time on Essex 138 kV breaker '3PM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.28	Change the contact parting time on Essex 138 kV breaker '4LM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.29	Change the contact parting time on Essex 138 kV breaker '1PM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.30	Change the contact parting time on Essex 138 kV breaker '1LM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0829	Build Branchburg to Roseland 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0829.6	Replace Branchburg 500 kV breaker 91X		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0829.9	Replace Branchburg 230 kV breaker 102H		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0829.11	Replace Branchburg 230 kV breaker 32H		PSEG (100%)
b0829.12	Replace Branchburg 230 kV breaker 52H		PSEG (100%)
b0830	Build Roseland - Hudson 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0830.1	Replace Roseland 230 kV breaker '82H' with 80 kA		PSEG (100%
b0830.2	Replace Roseland 230 kV breaker '91H' with 80 kA		PSEG (100%)
b0830.3	Replace Roseland 230 kV breaker '22H' with 80 kA		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0831	Replace 138/13 kV transformers with 230/13 kV units as part of Branchburg – Hudson 500 kV project		ComEd (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
b0832	Build Hudson 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0833	Build Roseland 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0834	Convert the E-1305/F-1306 to one 230 kV circuit as part of Branchburg – Hudson 500 kV project		ComEd (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
b0835	Build Hudson 230 kV transmission lines as part of Roseland – Hudson 500 kV project as part of Branchburg – Hudson 500 kV project		ComEd (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
b0836	Install transformation at new Hudson 500 kV switching station and perform Hudson 230 kV and 345 kV station work as part of Branchburg – Hudson 500 kV project		ComEd (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
b0882	Replace Hudson 230 kV breaker 1HA with 80 kA		PSEG (100%)
b0883	Replace Hudson 230 kV breaker 2HA with 80 kA		PSEG (100%)
b0884	Replace Hudson 230 kV breaker 3HB with 80 kA		PSEG (100%)
b0885	Replace Hudson 230 kV breaker 4HA with 80 kA		PSEG (100%)
b0886	Replace Hudson 230 kV breaker 4HB with 80 kA		PSEG (100%)
b0889	Replace Bergen 230 kV breaker '21H'		PSEG (100%)
b0890	Upgrade New Freedom 230 kV breaker '21H'		PSEG (100%)
b0891	Upgrade New Freedom 230 kV breaker '31H'		PSEG (100%)
b0899	Replace ECRR 138 kV breaker 901		PSEG (100%)
b0900	Replace ECRR 138 kV breaker 902		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1013	Replace Linden 138 kV breaker '7PB'		PSEG (100%)
b1017	Reconductor South Mahwah - Waldwick 345 kV J-3410 circuit		JCPL (29.27%) / NEPTUNE* (2.76%) / PSEG (65.42%) / RE (2.55%)
b1018	Reconductor South Mahwah - Waldwick 345 kV K-3411 circuit		JCPL (29.44%) / NEPTUNE* (2.76%) / PSEG (65.25%) / RE (2.55%)
b1019.1	Replace wave trap, line disconnect and ground switch at Roseland on the F-2206 circuit		PSEG (100%)
b1019.2	Replace wave trap, line disconnect and ground switch at Roseland on the B-2258 circuit		PSEG (100%)
b1019.3	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.4	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the B-2258 circuit		PSEG (100%)
b1019.5	Replace wave trap, line disconnect and ground switch at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.6	Replace line disconnect and ground switch at Cedar Grove on the K-2263 circuit		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1019.7	Replace 2-4 and 4-5 section disconnect and ground switches at Clifton on the B-2258 circuit		PSEG (100%)
b1019.8	Replace 1-2 and 2-3 section disconnect and ground switches at Clifton on the K-2263 circuit		PSEG (100%)
b1019.9	Replace line, ground, 230 kV main bus disconnects at Athenia on the B-2258 circuit		PSEG (100%)
b1019.10	Replace wave trap, line, ground 230 kV breaker disconnect and 230 kV main bus disconnects at Athenia on the K-2263 circuit		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1082.1	Replace Bergen 138 kV breaker '30P' with 80 kA		PSEG (100%)
b1082.2	Replace Bergen 138 kV breaker '80P' with 80 kA		PSEG (100%)
b1082.3	Replace Bergen 138 kV breaker '70P' with 80 kA		PSEG (100%)
b1082.4	Replace Bergen 138 kV breaker '90P' with 63 kA		PSEG (100%)
b1082.5	Replace Bergen 138 kV breaker '50P' with 63 kA		PSEG (100%)
b1082.6	Replace Bergen 230 kV breaker '12H' with 80 kA		PSEG (100%)
b1082.7	Replace Bergen 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1082.8	Replace Bergen 230 kV breaker '11H' with 80 kA		PSEG (100%)
b1082.9	Replace Bergen 230 kV breaker '20H' with 80 kA		PSEG (100%)
b1098	Re-configure the Bayway 138 kV substation and install three new 138 kV breakers		PSEG (100%)
b1099	Build a new 230 kV substation by tapping the Aldene – Essex circuit and install three 230/26 kV transformers, and serve some of the Newark area load from the new station		PSEG (100%)
b1100	Build a new 138 kV circuit from Bayonne to Marion		PSEG (100%)
b1101	Re-configure the Cedar Grove substation with breaker and half scheme and build a new 69 kV circuit from Cedar Grove to Hinchman		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1154	Convert the West Orange 138 kV substation, the two Roseland – West Orange 138 kV circuits, and the Roseland – Sewaren 138 kV circuit from 138 kV to 230 kV		PSEG (96.18%) / RE (3.82%)
b1155	Build a new 230 kV circuit from Branchburg to Middlesex Sw. Rack. Build a new 230 kV substation at Middlesex		JCPL (4.61%) / PSEG (91.75%) / RE (3.64%)
b1155.3	Replace Branchburg 230 kV breaker '81H' with 63 kA		PSEG (100%)
b1155.4	Replace Branchburg 230 kV breaker '72H' with 63 kA		PSEG (100%)
b1155.5	Replace Branchburg 230 kV breaker '61H' with 63 kA		PSEG (100%)
b1155.6	Replace Branchburg 230 kV breaker '41H' with 63 kA		PSEG (100%)
b1156	Convert the Burlington, Camden, and Cuthbert Blvd 138 kV substations, the 138 kV circuits from Burlington to Camden, and the 138 kV circuit from Camden to Cuthbert Blvd. from 138 kV to 230 kV		PSEG (96.18%) / RE (3.82%)
b1156.13	Replace Camden 230 kV breaker '22H' with 80 kA		PSEG (100%)
b1156.14	Replace Camden 230 kV breaker '32H' with 80 kA		PSEG (100%)
b1156.15	Replace Camden 230 kV breaker '21H' with 80 kA		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1156.16	Replace New Freedom 230 kV breaker '50H' with 63 kA		PSEG (100%)
b1156.17	Replace New Freedom 230 kV breaker '41H' with 63 kA		PSEG (100%)
b1156.18	Replace New Freedom 230 kV breaker '51H' with 63 kA		PSEG (100%)
b1156.19	Rebuild Camden 230 kV to 80 kA		PSEG (100%)
b1156.20	Rebuild Burlington 230 kV to 80 kA		PSEG (100%)
b1197.1	Reconductor the PSEG portion of the Burlington – Croydon circuit with 1590 ACSS		PSEG (100%)
b1228	Re-configure the Lawrence 230 kV substation to breaker and half		PSEG (96.18%) / RE (3.82%)
b1255	Build a new 69 kV substation (Ridge Road) and build new 69 kV circuits from Montgomery – Ridge Road – Penns Neck/Dow Jones		PSEG (96.18%) / RE (3.82%)
b1304.1	Convert the existing ‘D1304’ and ‘G1307’ 138 kV circuits between Roseland – Kearny – Hudson to 230 kV operation		AEC (0.28%) / BGE (1.18%) / ComEd (2.83%) / Dayton (0.16%) / JCPL (1.43%) / Neptune (0.09%) / PENELEC (3.63%) / PEPCO (1.27%) / PSEG (85.73%) / RE (3.40%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.2	Expand existing Bergen 230 kV substation and reconfigure the Athenia 230 kV substation to breaker and a half scheme		AEC (0.28%) / BGE (1.18%) / ComEd (2.83%) / Dayton (0.16%) / JCPL (1.43%) / Neptune (0.09%) / PENELEC (3.63%) / PEPCO (1.27%) / PSEG (85.73%) / RE (3.40%)
b1304.3	Build second 230 kV underground cable from Bergen to Athenia		AEC (0.28%) / BGE (1.18%) / ComEd (2.83%) / Dayton (0.16%) / JCPL (1.43%) / Neptune (0.09%) / PENELEC (3.63%) / PEPCO (1.27%) / PSEG (85.73%) / RE (3.40%)
b1304.4	Build second 230 kV underground cable from Hudson to South Waterfront		AEC (0.28%) / BGE (1.18%) / ComEd (2.83%) / Dayton (0.16%) / JCPL (1.43%) / Neptune (0.09%) / PENELEC (3.63%) / PEPCO (1.27%) / PSEG (85.73%) / RE (3.40%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.5	Replace Athenia 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1304.6	Replace Athenia 230 kV breaker '41H' with 80 kA		PSEG (100%)
b1304.7	Replace South Waterfront 230 kV breaker '12H' with 80 kA		PSEG (100%)
b1304.8	Replace South Waterfront 230 kV breaker '22H' with 80 kA		PSEG (100%)
b1304.9	Replace South Waterfront 230 kV breaker '32H' with 80 kA		PSEG (100%)
b1304.10	Replace South Waterfront 230 kV breaker '52H' with 80 kA		PSEG (100%)
b1304.11	Replace South Waterfront 230 kV breaker '62H' with 80 kA		PSEG (100%)
b1304.12	Replace South Waterfront 230 kV breaker '72H' with 80 kA		PSEG (100%)
b1304.13	Replace South Waterfront 230 kV breaker '82H' with 80 kA		PSEG (100%)
b1304.14	Replace Essex 230 kV breaker '20H' with 80 kA		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.15	Replace Essex 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1304.16	Replace Essex 230 kV breaker '10H' with 80 kA		PSEG (100%)
b1304.17	Replace Essex 230 kV breaker '11H' with 80 kA		PSEG (100%)
b1304.18	Replace Essex 230 kV breaker '11HL' with 80 kA		PSEG (100%)
b1304.19	Replace Newport R 230 kV breaker '23H' with 63 kA		PSEG (100%)
b1304.20	Rebuild Athenia 230 kV substation to 80 kA		PSEG (100%)
b1304.21	Rebuild Bergen 230 kV substation to 80 kA		PSEG (100%)
b1398	Build two new parallel underground circuits from Gloucester to Camden		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)
b1398.1	Install shunt reactor at Gloucester to offset cable charging		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)
b1398.2	Reconfigure the Cuthbert station to breaker and a half scheme		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)
b1398.3	Build a second 230 kV parallel overhead circuit from Mickelton – Gloucester		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1398.4	Reconductor the existing Mickleton – Gloucester 230 kV circuit (PSEG portion)		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)
b1398.7	Reconductor the Camden – Richmond 230 kV circuit (PSEG portion) and upgrade terminal equipments at Camden substations		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)
b1398.15	Replace Gloucester 230 kV breaker '21H' with 63 kA		PSEG (100%)
b1398.16	Replace Gloucester 230 kV breaker '51H' with 63 kA		PSEG (100%)
b1398.17	Replace Gloucester 230 kV breaker '56H' with 63 kA		PSEG (100%)
b1398.18	Replace Gloucester 230 kV breaker '26H' with 63 kA		PSEG (100%)
b1398.19	Replace Gloucester 230 kV breaker '71H' with 63 kA		PSEG (100%)
b1399	Convert the 138 kV path from Aldene – Springfield Rd. – West Orange to 230 kV		PSEG (96.18%) / RE (3.82%)
b1400	Install 230 kV circuit breakers at Bennetts Ln. “F” and “X” buses		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1410	Replace Salem 500 kV breaker ‘11X’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1411	Replace Salem 500 kV breaker ‘12X’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1412	Replace Salem 500 kV breaker ‘20X’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1413	Replace Salem 500 kV breaker ‘21X’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1414	Replace Salem 500 kV breaker ‘31X’		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1415	Replace Salem 500 kV breaker ‘32X’		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1539	Replace Tosco 230 kV breaker 'CB1' with 63 kA		PSEG (100%)
b1540	Replace Tosco 230 kV breaker 'CB2' with 63 kA		PSEG (100%)
b1541	Open the Hudson 230 kV bus tie		PSEG (100%)
b1588	Reconductor the Eagle Point - Gloucester 230 kV circuit #1 and #2 with higher conductor rating		JCPL (10.48%) / Neptune* (1.00%) / PECO (31.30%) / PSEG (55.03%) / RE (2.19%)
b1589	Re-configure the Kearny 230 kV substation and loop the P-2216-1 (Essex - NJT Meadows) 230 kV circuit		ATSI (10.02%) / PENELEC (9.74%) / PSEG (77.16%) / RE (3.08%)
b1590	Upgrade the PSEG portion of the Camden Richmond 230 kV circuit to six wire conductor and replace terminal equipment at Camden		BGE (3.06%) / ME (0.83%) / PECO (91.70%) / PEPCO (1.94%) / PPL (2.47%)
b1749	Advance n1237 (Replace Essex 230 kV breaker '22H' with 80kA)		PSEG (100%)
b1750	Advance n0666.5 (Replace Hudson 230 kV breaker '1HB' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)
b1751	Advance n0666.3 (Replace Hudson 230 kV breaker '2HA' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1752	Advance n0666.10 (Replace Hudson 230 kV breaker '2HB' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)
b1753	Marion 138 kV breaker '7PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1754	Marion 138 kV breaker '3PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1755	Marion 138 kV breaker '6PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1787	Build a second 230 kV circuit from Cox's Corner - Lumberton		AEC (4.97%) / JCPL (44.34%) / NEPTUNE* (0.53%) / PSEG (48.23%) / RE (1.93%)
b2034	Install a reactor along the Kearny - Essex 138 kV line		PSEG (100%)
b2035	Replace Sewaren 138 kV breaker '11P'		PSEG (100%)
b2036	Replace Sewaren 138 kV breaker '21P'		PSEG (100%)
b2037	Replace PVSC 138 kV breaker '452'		PSEG (100%)
b2038	Replace PVSC 138 kV breaker '552'		PSEG (100%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2039	Replace Bayonne 138 kV breaker ‘11P’		PSEG (100%)
b2139	Reconductor the Mickleton - Gloucester 230 kV parallel circuits with double bundle conductor		PSEG (61.11%) / PECO (36.45%) / RE (2.44%)
b2146	Re-configure the Brunswick 230 kV and 69 kV substations		PSEG (96.16%) / RE (3.84%)
b2151	Construct Jackson Rd. 69 kV substation and loop the Cedar Grove - Hinchmans Ave into Jackson Rd. and construct Hawthorne 69 kV substation and build 69 kV circuit from Hinchmans Ave - Hawthorne - Fair Lawn		PSEG (100%)
b2159	Reconfigure the Linden, Bayway, North Ave, and Passaic Valley S.C. 138 kV substations. Construct and loop new 138 kV circuit to new airport station		PSEG (96.16%) / RE (3.84%)

*Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

(12) Public Service Electric and Gas Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2218	Rebuild 4 miles of overhead line from Edison - Meadow Rd - Metuchen (Q 1317)		PSEG (100%)
b2239	50 MVAR reactor at Saddlebrook 230 kV		PSEG (100%)
b2240	50 MVAR reactor at Athenia 230 kV		PSEG (100%)
b2241	50 MVAR reactor at Bergen 230 kV		PSEG (100%)
b2242	50 MVAR reactor at Hudson 230 kV		PSEG (100%)
b2243	Two 50 MVAR reactors at Stanley Terrace 230 kV		PSEG (100%)
b2244	50 MVAR reactor at West Orange 230 kV		PSEG (100%)
b2245	50 MVAR reactor at Aldene 230 kV		PSEG (100%)
b2246	150 MVAR reactor at Camden 230 kV		PSEG (100%)
b2247	150 MVAR reactor at Gloucester 230 kV		PSEG (100%)
b2248	50 MVAR reactor at Clarksville 230 kV		PSEG (100%)
b2249	50 MVAR reactor at Hinchmans 230 kV		PSEG (100%)
b2250	50 MVAR reactor at Beaverbrook 230 kV		PSEG (100%)
b2251	50 MVAR reactor at Cox's Corner 230 kV		PSEG (100%)

*Neptune Regional Transmission System, LLC

The Annual Revenue Requirement for all Public Service Electric and Gas Company Projects (Required Transmission Enhancements) in this Section 12 shall be as specified in Attachment 7 of Attachment H-10A and under the procedures detailed in Attachment H-10B.

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2276	Eliminate the Sewaren 138 kV bus by installing a new 230 kV bay at Sewaren 230 kV		PSEG (100%)
b2276.1	Convert the two 138 kV circuits from Sewaren – Metuchen to 230 kV circuits including Lafayette and Woodbridge substation		PSEG (100%)
b2276.2	Reconfigure the Metuchen 230 kV station to accommodate the two converted circuits		PSEG (100%)
b2290	Replace disconnect switches at Kilmer, Lake Nilson and Greenbrook 230 kV substations on the Raritian River - Middlesex (I-1023) circuit		PSEG (100%)
b2291	Replace circuit switcher at Lake Nelson 230 kV substation on the Raritian River - Middlesex (W-1037) circuit		PSEG (100%)
b2295	Replace the Salem 500 kV breaker 10X with 63kA breaker		PSEG (100%)
b2421	Install all 69kV lines to interconnect Plainfield, Greenbrook, and Bridgewater stations and establish the 69kV network		PSEG (100%)
b2421.1	Install two 18MVAR capacitors at Plainfield and S. Second St substation		PSEG (100%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2421.2	Install a second four (4) breaker 69kV ring bus at Bridgewater Switching Station		PSEG (100%)
b2436.10	Convert the Bergen – Marion 138 kV path to double circuit 345 kV and associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: PSEG (*100*%)
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: *PSEG (100%)*

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: *PSEG (100%)*
b2436.33	Construct a new Bayway – Bayonne 345 kV circuit and any associated substation upgrades		*PSEG (100%)*
b2436.34	Construct a new North Ave – Bayonne 345 kV circuit and any associated substation upgrades		*PSEG (100%)*

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.50	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades		*PSEG (100%)*
b2436.60	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades		*PSEG (96.13%) / RE (3.87%)*
b2436.70	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades		*PSEG (100%)*
b2436.81	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: PSEG (*96.13*%) / RE (*3.87*%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.83	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: PSEG (*96.13*%) / RE (*3.87*%)
b2436.84	Convert the Bayway – Linden “W” 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: *PSEG (96.13%) / RE (3.87%)*

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.85	Convert the Bayway – Linden “M” 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: *PSEG (96.13%) / RE (3.87%)*
b2436.90	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: PSEG (*96.13*%) / RE (*3.87*%)
b2436.91	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades		PSEG (100%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades		PSEG (*96.13*%) / RE (*3.87*%)
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades		*PSEG (100%)*
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades		PSEG (*96.13*%) / RE (*3.87*%)
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades		PSEG (*96.13*%) / RE (*3.87*%)
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades		PSEG (*96.13*%) / RE (*3.87*%)
b2437.33	New Bayonne 345/69 kV transformer and any associated substation upgrades		PSEG (100%)
b2438	Install two reactors at Tosco 230 kV		PSEG (100.00%)
b2439	Replace the Tosco 138kV breaker 'CB1/2 (CBT)' with 63kA		PSEG (100.00%)
b2474	Rebuild Athenia 138 kV to 80kA		PSEG (100%)
b2589	Install a 100 MVAR 230 kV shunt reactor at Mercer station		PSEG (100%)
b2590	Install two 75 MVAR 230 kV capacitors at Sewaren station		PSEG (100%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2633.3	Install an SVC at New Freedom 500 kV substation		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.4	Add a new 500 kV bay at Hope Creek (Expansion of Hope Creek substation)		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2633.5	Add a new 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.8	Implement high speed relaying utilizing OPGW on Salem – Orchard 500 kV, Hope Creek – New Freedom 500 kV, New Freedom - Salem 500 kV, Hope Creek – Salem 500 kV, and New Freedom – Orchard 500 kV lines		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2633.91	Implement changes to the tap settings for the two Salem units' step up transformers		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.92	Implement changes to the tap settings for the Hope Creek unit's step up transformers		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2702	Install a 350 MVAR reactor at Roseland 500 kV		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: PSEG (100%)
b2703	Install a 100 MVAR reactor at Bergen 230 kV		PSEG (100%)
b2704	Install a 150 MVAR reactor at Essex 230 kV		PSEG (100%)
b2705	Install a 200 MVAR reactor (variable) at Bergen 345 kV		PSEG (100%)
b2706	Install a 200 MVAR reactor (variable) at Bayway 345 kV		PSEG (100%)
b2707	Install a 100 MVAR reactor at Bayonne 345 kV		PSEG (100%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2712	Replace the Bergen 138 kV ‘40P’breaker with 80kA breaker		PSEG (100%)
b2713	Replace the Bergen 138 kV ‘90P’ breaker with 80kA breaker		PSEG (100%)
b2722	Reconductor the 1 mile Bergen – Bergen GT 138 kV circuit (B-1302)		PSEG (100%)
b2755	Build a third 345 kV source into Newark Airport		PSEG (100%)
b2810.1	Install second 230/69 kV transformer at Cedar Grove		PSEG (100%)
b2810.2	Build a new 69 kV circuit from Cedar Grove to Great Notch		PSEG (100%)
b2811	Build 69 kV circuit from Locust Street to Delair		PSEG (100%)
b2812	Construct River Road to Tonnelle Avenue 69kV Circuit		PSEG (100%)
b2825.1	Install 2X50 MVAR shunt reactors at Kearny 230 kV substation		PSEG (100%)
b2825.2	Increase the size of the Hudson 230 kV, 2X50 MVAR shunt reactors to 2X100 MVAR		PSEG (100%)
b2825.3	Install 2X100 MVAR shunt reactors at Bayway 345 kV substation		PSEG (100%)
b2825.4	Install 2X100 MVAR shunt reactors at Linden 345 kV substation		PSEG (100%)
b2835	Convert the R-1318 and Q1317 (Edison – Metuchen) 138 kV circuits to one 230 kV circuit		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2836	Convert the N-1340 and T-1372/D-1330 (Brunswick – Trenton) 138 kV circuits to 230 kV circuits		PSEG (100%)
b2837	Convert the F-1358/Z1326 and K1363/Y-1325 (Trenton – Burlington) 138 kV circuits to 230 kV circuits		PSEG (100%)
b2870	Build new 138/26 kV Newark GIS station in a building (layout #1A) located adjacent to the existing Newark Switch and demolish the existing Newark Switch		PSEG (100%)

Attachment 7b (VEPCo OATT)

SCHEDULE 12 – APPENDIX

(20) Virginia Electric and Power Company

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

b0217	Upgrade Mt. Storm - Doubs 500kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0222	Install 150 MVAR capacitor at Loudoun 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
*** Hudson Transmission Partners, LLC
*** The Annual Revenue Requirement for all Virginia Electric and Power Company projects in this Section 20 shall be as specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0223	Install 150 MVAR capacitor at Asburn 230 kV		Dominion (100%)
b0224	Install 150 MVAR capacitor at Dranesville 230 kV		Dominion (100%)
b0225	Install 33 MVAR capacitor at Possum Pt. 115 kV		Dominion (100%)
b0226	Install 500/230 kV transformer at Clifton and Clifton 500 kV 150 MVAR capacitor	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	APS (3.69%) / BGE (3.54%) / Dominion (85.73%) / PEPCO (7.04%)
b0227	Install 500/230 kV transformer at Bristers; build new 230 kV Bristers-Gainsville circuit, upgrade two Loudoun-Brambleton circuits		AEC (0.71%) / APS (3.36%) / BGE (10.93%) / DPL (1.66%) / Dominion (67.38%) / ME (0.89%) / PECO (2.33%) / PEPCO (12.20%) / PPL (0.54%)
b0227.1	Loudoun Sub – upgrade 6-230 kV breakers		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0231	Install 500 kV breakers & 500 kV bus work at Suffolk		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0231.2	Install 500/230 kV Transformer, 230 kV breakers, & 230 kV bus work at Suffolk		Dominion (100%)
b0232	Install 150 MVAR capacitor at Lynnhaven 230 kV		Dominion (100%)
b0233	Install 150 MVAR capacitor at Landstown 230 kV		Dominion (100%)
b0234	Install 150 MVAR capacitor at Greenwich 230 kV		Dominion (100%)
b0235	Install 150 MVAR capacitor at Fentress 230 kV		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0307	Reconductor Endless Caverns – Mt. Jackson 115 kV		Dominion (100%)
b0308	Replace L breaker and switches at Endless Caverns 115 kV		Dominion (100%)
b0309	Install SPS at Earleys 115 kV		Dominion (100%)
b0310	Reconductor Club House – South Hill and Chase City – South Hill 115 kV		Dominion (100%)
b0311	Reconductor Idylwood to Arlington 230 kV		Dominion (100%)
b0312	Reconductor Gallows to Ox 230 kV		Dominion (100%)
b0325	Install a 2nd Everetts 230/115 kV transformer		Dominion (100%)
b0326	Uprate/resag Remington-Brandywine-Culppr 115 kV		Dominion (100%)
b0327	Build 2nd Harrisonburg – Valley 230 kV		APS (19.79%) / Dominion (76.18%) / PEPCO (4.03%)
b0328.1	Build new Meadow Brook – Loudoun 500 kV circuit (30 of 50 miles)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0328.3	Upgrade Mt. Storm 500 kV substation		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0328.4	Upgrade Loudoun 500 kV substation		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		Dominion (100%)††
b0329.1	Replace Thole Street 115 kV breaker '48T196'		Dominion (100%)
b0329.2	Replace Chesapeake 115 kV breaker 'T242'		Dominion (100%)
b0329.3	Replace Chesapeake 115 kV breaker '8722'		Dominion (100%)
b0329.4	Replace Chesapeake 115 kV breaker '16422'		Dominion (100%)
b0330	Install Crewe 115 kV breaker and shift load from line 158 to 98		Dominion (100%)
b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165)		Dominion (100%)

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†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project
††Cost allocations associated with below 500 kV elements of the project

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0332	Uprate/resag Chesapeake – Cradock 115 kV		Dominion (100%)
b0333	Replace wave trap on Elmont – Replace (Line #231)		Dominion (100%)
b0334	Uprate/resag Iron Bridge-Walmsley-Southwest 230 kV		Dominion (100%)
b0335	Build Chase City – Clarksville 115 kV		Dominion (100%)
b0336	Reconductor one span of Chesapeake – Dozier 115 kV close to Dozier substation		Dominion (100%)
b0337	Build Lexington 230 kV ring bus		Dominion (100%)
b0338	Replace Gordonsville 230/115 kV transformer for larger one		Dominion (100%)
b0339	Install Breaker at Dooms 230 kV Sub		Dominion (100%)
b0340	Reconductor one span Peninsula – Magruder 115 kV close to Magruder substation		Dominion (100%)
b0341	Install a breaker at Northern Neck 115 kV		Dominion (100%)
b0342	Replace Trowbridge 230/115 kV transformer		Dominion (100%)
b0403	2nd Dooms 500/230 kV transformer addition		APS (3.35%) / BGE (4.22%) / DPL (1.10%) / Dominion (83.94%) / PEPCO (7.39%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0412	Retension Pruntytown – Mt. Storm 500 kV to a 3502 MVA rating		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0450	Install 150 MVAR Capacitor at Fredricksburg 230 kV		Dominion (100%)
b0451	Install 25 MVAR Capacitor at Somerset 115 kV		Dominion (100%)
b0452	Install 150 MVAR Capacitor at Northwest 230 kV		Dominion (100%)
b0453.1	Convert Remingtion – Sowego 115 kV to 230 kV		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.2	Add Sowego – Gainsville 230 kV		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.3	Add Sowego 230/115 kV transformer		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0454	Reconductor 2.4 miles of Newport News – Chuckatuck 230 kV		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0455	Add 2nd Endless Caverns 230/115 kV transformer		APS (32.70%) / BGE (7.01%) / DPL (1.80%) / Dominion (50.82%) / PEPCO (7.67%)
b0456	Reconductor 9.4 miles of Edinburg – Mt. Jackson 115 kV		APS (33.69%) / BGE (12.18%) / Dominion (40.08%) / PEPCO (14.05%)
b0457	Replace both wave traps on Dooms – Lexington 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0467.2	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.70%) / BGE (22.13%) / DPL (3.70%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.54%) / PEPCO (41.86%) / PPL (2.07%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0492.6	Replace Mount Storm 500 kV breaker 55072		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0492.7	Replace Mount Storm 500 kV breaker 55172		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0492.8	Replace Mount Storm 500 kV breaker H1172-2		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0492.9	Replace Mount Storm 500 kV breaker G2T550		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0492.10	Replace Mount Storm 500 kV breaker G2T554		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0492.11	Replace Mount Storm 500 kV breaker G1T551		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.12	Upgrade nameplate rating of Mount Storm 500 kV breakers 55472, 57272, SX172, G3TSX1, G1TH11, G3T572, and SX22		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.5	Advance n0716 (Ox - Replace 230kV breaker L242)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.6	Advance n0717 (Possum Point - Replace 230kV breaker SC192)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0583	Install dual primary protection schemes on Gosport lines 62 and 51 at the remote terminals (Chesapeake on the 62 line and Reeves Ave on the 51 line)		Dominion (100%)
b0756	Install a second 500/115 kV autotransformer at Chancellor 500 kV		Dominion (100%)
b0756.1	Install two 500 kV breakers at Chancellor 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0757	Reconductor one mile of Chesapeake – Reeves Avenue 115 kV line		Dominion (100%)
b0758	Install a second Fredericksburg 230/115 kV autotransformer		Dominion (100%)
b0760	Build 115 kV line from Kitty Hawk to Colington 115 kV (Colington on the existing line and Nag's Head and Light House DP on new line)		Dominion (100%)
b0761	Install a second 230/115 kV transformer at Possum Point		Dominion (100%)
b0762	Build a new Elko station and transfer load from Turner and Providence Forge stations		Dominion (100%)
b0763	Rebuild 17.5 miles of the line for a new summer rating of 262 MVA		Dominion (100%)
b0764	Increase the rating on 2.56 miles of the line between Greenwich and Thompson Corner; new rating to be 257 MVA		Dominion (100%)
b0765	Add a second Bull Run 230/115 kV autotransformer		Dominion (100%)
b0766	Increase the rating of the line between Loudoun and Cedar Grove to at least 150 MVA		Dominion (100%)
b0767	Extend the line from Old Church – Chickahominy 230 kV		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0768	Loop line #251 Idylwood – Arlington into the GIS sub		Dominion (100%)
b0769	Re-tension 15 miles of the line for a new summer rating of 216 MVA		Dominion (100%)
b0770	Add a second 230/115 kV autotransformer at Lanexa		Dominion (100%)
b0770.1	Replace Lanexa 115 kV breaker '8532'		Dominion (100%)
b0770.2	Replace Lanexa 115 kV breaker '9232'		Dominion (100%)
b0771	Build a parallel Chickahominy – Lanexa 230 kV line		Dominion (100%)
b0772	Install a second Elmont 230/115 kV autotransformer		Dominion (100%)
b0772.1	Replace Elmont 115 kV breaker '7392'		Dominion (100%)
b0774	Install a 33 MVAR capacitor at Bremo 115 kV		Dominion (100%)
b0775	Reconductor the Greenwich – Virginia Beach line to bring it up to a summer rating of 261 MVA; Reconductor the Greenwich – Amphibious Base line to bring it up to 291 MVA		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0776	Re-build Trowbridge – Winfall 115 kV		Dominion (100%)
b0777	Terminate the Thelma – Carolina 230 kV circuit into Lakeview 230 kV		Dominion (100%)
b0778	Install 29.7 MVAR capacitor at Lebanon 115 kV		Dominion (100%)
b0779	Build a new 230 kV line from Yorktown to Hayes but operate at 115 kV initially		Dominion (100%)
b0780	Reconductor Chesapeake – Yadkin 115 kV line		Dominion (100%)
b0781	Reconductor and replace terminal equipment on line 17 and replace the wave trap on line 88		Dominion (100%)
b0782	Install a new 115 kV capacitor at Dupont Waynesboro substation		Dominion (100%)
b0784	Replace wave traps on North Anna to Ladysmith 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0785	Rebuild the Chase City – Crewe 115 kV line		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0786	Reconductor the Moran DP – Crewe 115 kV segment		Dominion (100%)
b0787	Upgrade the Chase City – Twitty's Creek 115 kV segment		Dominion (100%)
b0788	Reconductor the line from Farmville – Pamplin 115 kV		Dominion (100%)
b0793	Close switch 145T183 to network the lines. Rebuild the section of the line #145 between Possum Point – Minnieville DP 115 kV		Dominion (100%)
b0815	Replace Elmont 230 kV breaker '22192'		Dominion (100%)
b0816	Replace Elmont 230 kV breaker '21692'		Dominion (100%)
b0817	Replace Elmont 230 kV breaker '200992'		Dominion (100%)
b0818	Replace Elmont 230 kV breaker '2009T2032'		Dominion (100%)
b0837	At Mt. Storm, replace the existing MOD on the 500 kV side of the transformer with a circuit breaker		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0888	Replace Loudoun 230 kV Cap breaker 'SC352'		Dominion (100%)
b0892	Replace Chesapeake 115 kV breaker SX522		Dominion (100%)
b0893	Replace Chesapeake 115 kV breaker T202		Dominion (100%)
b0894	Replace Possum Point 115 kV breaker SX-32		Dominion (100%)
b0895	Replace Possum Point 115 kV breaker L92-1		Dominion (100%)
b0896	Replace Possum Point 115 kV breaker L92-2		Dominion (100%)
b0897	Replace Suffolk 115 kV breaker T202		Dominion (100%)
b0898	Replace Peninsula 115 kV breaker SC202		Dominion (100%)
b0921	Reconductor Brambleton - Cochran Mill 230 kV line with 201 Yukon conductor		Dominion (100%)
b0923	Install 50-100 MVAR variable reactor banks at Carson 230 kV		Dominion (100%)
b0924	Install 50-100 MVAR variable reactor banks at Dooms 230 kV		Dominion (100%)
b0925	Install 50-100 MVAR variable reactor banks at Garrisonville 230 kV		Dominion (100%)
b0926	Install 50-100 MVAR variable reactor banks at Hamilton 230 kV		Dominion (100%)
b0927	Install 50-100 MVAR variable reactor banks at Yadkin 230 kV		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0928	Install 50-100 MVAR variable reactor banks at Carolina, Dooms, Everetts, Idylwood, N. Alexandria, N. Anna, Suffolk and Valley 230 kV substations		Dominion (100%)
b1056	Build a 2nd Shawboro – Elizabeth City 230kV line		Dominion (100%)
b1058	Add a third 230/115 kV transformer at Suffolk substation		Dominion (100%)
b1058.1	Replace Suffolk 115 kV breaker 'T122' with a 40 kA breaker		Dominion (100%)
b1058.2	Convert Suffolk 115 kV straight bus to a ring bus for the three 230/115 kV transformers and three 115 kV lines		Dominion (100%)
b1071	Rebuild the existing 115 kV corridor between Landstown - Va Beach Substation for a double circuit arrangement (230 kV & 115 kV)		Dominion (100%)
b1076	Replace existing North Anna 500-230kV transformer with larger unit		Dominion (100%)
b1087	Replace Cannon Branch 230-115 kV with larger transformer		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1088	Build new Radnor Heights Sub, add new underground circuit from Ballston - Radnor Heights, Tap the Glebe - Davis line and create circuits from Davis - Radnor Heights and Glebe - Radnor Heights		Dominion (100%)
b1089	Install 2nd Burke to Sideburn 230 kV underground cable		Dominion (100%)
b1090	Install a 150 MVAR 230 kV capacitor and one 230 kV breaker at Northwest		Dominion (100%)
b1095	Reconductor Chase City 115 kV bus and add a new tie breaker		Dominion (100%)
b1096	Construct 10 mile double ckt. 230kV tower line from Loudoun to Middleburg		Dominion (100%)
b1102	Replace Bremo 115 kV breaker ‘9122’		Dominion (100%)
b1103	Replace Bremo 115 kV breaker ‘822’		Dominion (100%)
b1172	Build a 4-6 mile long 230 kV line from Hopewell to Bull Hill (Ft Lee) and install a 230-115 kV Tx		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1188	Build new Brambleton 500 kV three breaker ring bus connected to the Loudoun to Pleasant View 500 kV line		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1188.1	Replace Loudoun 230 kV breaker '200852' with a 63 kA breaker		Dominion (100%)
b1188.2	Replace Loudoun 230 kV breaker '2008T2094' with a 63 kA breaker		Dominion (100%)
b1188.3	Replace Loudoun 230 kV breaker '204552' with a 63 kA breaker		Dominion (100%)
b1188.4	Replace Loudoun 230 kV breaker '209452' with a 63 kA breaker		Dominion (100%)
b1188.5	Replace Loudoun 230 kV breaker 'WT2045' with a 63 kA breaker		Dominion (100%)
b1188.6	Install one 500/230 kV transformer and two 230 kV breakers at Brambleton		AEC (0.22%) / BGE (7.90%) / DPL (0.59%) / Dominion (75.58%) / ME (0.22%) / PECO (0.73%) / PEPCO (14.76%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1224	Install 2nd Clover 500/230 kV transformer and a 150 MVAr capacitor		BGE (7.56%) / DPL (1.03%) / Dominion (78.21%) / ME (0.77%) / PECO (1.39%) / PEPCO (11.04%)
b1225	Replace Yorktown 115 kV breaker ‘L982-1’		Dominion (100%)
b1226	Replace Yorktown 115 kV breaker ‘L982-2’		Dominion (100%)
b1279	Line #69 Uprate – Increase rating on Locks – Purdy 115 kV to serve additional load at the Reams delivery point		Dominion (100%)
b1306	Reconfigure 115 kV bus at Endless Caverns substation such that the existing two 230/115 kV transformers at Endless Caverns operate in		Dominion (100%)
b1307	Install a 2nd 230/115 kV transformer at Northern Neck Substation		Dominion (100%)
b1308	Improve LSE’s power factor factor in zone to .973 PF, adjust LTC’s at Gordonsville and Remington, move existing shunt capacitor banks		Dominion (100%)
b1309	Install a 230 kV line from Lakeside to Northwest utilizing the idle line and 60 line ROW’s and reconductor the existing 221 line between Elmont and Northwest		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1310	Install a 115 kV breaker at Broadnax substation on the South Hill side of Broadnax		Dominion (100%)
b1311	Install a 230 kV 3000 amp breaker at Cranes Corner substation to sectionalize the 2104 line into two lines		Dominion (100%)
b1312	Loop the 2054 line in and out of Hollymeade and place a 230 kV breaker at Hollymeade. This creates two lines: Charlottesville - Hollymeade		Dominion (100%)
b1313	Resag wire to 125C from Chesterfield – Shockoe and replace line switch 1799 with 1200 amp switch. The new rating would be 231 MVA.		Dominion (100%)
b1314	Rebuild the 6.8 mile line #100 from Chesterfield to Harrowgate 115 kV for a minimum 300 MBA rating		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1315	Convert line #64 Trowbridge to Winfall to 230 kV and install a 230 kV capacitor bank at Winfall		Dominion (100%)
b1316	Rebuild 10.7 miles of 115 kV line #80, Battleboro – Heartsease DP		Dominion (100%)
b1317	LSE load power factor on the #47 line will need to meet MOA requirements of .973 in 2015 to further resolve this issue through at least 2019		Dominion (100%)
b1318	Install a 115 kV bus tie breaker at Acca substation between the Line #60 and Line #95 breakers		Dominion (100%)
b1319	Resag line #222 to 150 C and upgrade any associated equipment to a 2000A rating to achieve a 706 MVA summer line rating		Dominion (100%)
b1320	Install a 230 kV, 150 MVAR capacitor bank at Southwest substation		Dominion (100%)
b1321	Build a new 230 kV line North Anna – Oak Green and install a 224 MVA 230/115 kV transformer at Oak Green		BGE (0.85%) / Dominion (97.96%) / PEPCO (1.19%)
b1322	Rebuild the 39 Line (Dooms – Sherwood) and the 91 Line (Sherwood – Bremo)		Dominion (100%)
b1323	Install a 224 MVA 230/115 kV transformer at Staunton. Rebuild the 115 kV line #43 section Staunton - Verona		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1324	Install a 115 kV capacitor bank at Oak Ridge. Install a capacitor bank at New Bohemia. Upgrade 230/34.5 kV transformer #3 at Kings Fork		Dominion (100%)
b1325	Rebuild 15 miles of line #2020 Winfall – Elizabeth City with a minimum 900 MVA rating		Dominion (100%)
b1326	Install a third 168 MVA 230/115 kV transformer at Kitty Hawk with a normally open 230 kV breaker and a low side 115 kV breaker		Dominion (100%)
b1327	Rebuild the 20 mile section of line #22 between Kerr Dam – Eatons Ferry substations		Dominion (100%)
b1328	Uprate the 3.63 mile line section between Possum and Dumfries substations, replace the 1600 amp wave trap at Possum Point		AEC (0.66%) / APS (3.59%) / DPL (0.91%) / Dominion (92.94%) / PECO (1.90%)
b1329	Install line-tie breakers at Sterling Park substation and BECO substation		Dominion (100%)
b1330	Install a five breaker ring bus at the expanded Dulles substation to accommodate the existing Dulles Arrangement and support the Metrorail		Dominion (100%)
b1331	Build a 230 kV line from Shawboro to Aydlett tap and connect Aydlett to the new line		Dominion (100%)
b1332	Build Cannon Branch to Nokesville 230 kV line		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1333	Advance n1728 (Replace Possum Point 230 kV breaker H9T237 with an 80 kA breaker)		Dominion (100%)
b1334	Advance n1748 (Replace Ox 230 kV breaker 22042 with a 63 kA breaker)		Dominion (100%)
b1335	Advance n1749 (Replace Ox 230 kV breaker 220T2603 with a 63 kA breaker)		Dominion (100%)
b1336	Advance n1750 (Replace Ox 230 kV breaker 24842 with a 63 kA breaker)		Dominion (100%)
b1337	Advance n1751 (Replace Ox 230 kV breaker 248T2013 with a 63 kA breaker)		Dominion (100%)
b1503.1	Loop Line #2095 in and out of Waxpool approximately 1.5 miles		Dominion (100%)
b1503.2	Construct a new 230kV line from Brambleton to BECO Substation of approximately 11 miles with approximately 10 miles utilizing the vacant side of existing Line #2095 structures		Dominion (100%)
b1503.3	Install a one 230 kV breaker, Future 230 kV ring-bus at Waxpool Substation		Dominion (100%)
b1503.4	The new Brambleton - BECO line will feed Shellhorn Substation load and Greenway TX's #2&3 load		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1506.1	At Gainesville Substation, create two 115 kV straight-buses with a normally open tie-breaker		Dominion (100%)
b1506.2	Upgrade Line 124 (radial from Loudoun) to a minimum continuous rating of 500 MVA and network it into the 115 kV bus feeding NOVEC's DP at Gainesville		Dominion (100%)
b1506.3	Install two additional 230 kV breakers in the ring at Gainesville (may require substation expansion) to accommodate conversion of NOVEC's Gainesville to Wheeler line		Dominion (100%)
b1506.4	Convert NOVEC's Gainesville-Wheeler line from 115 kV to 230 kV (will require Gainsville DP Upgrade replacement of three transformers total at Atlantic and Wheeler Substations)		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1507	Rebuild Mt Storm – Doubs 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1508.1	Build a 2nd 230 kV Line Harrisonburg to Endless Caverns		APS (37.05%) / Dominion (62.95%)
b1508.2	Install a 3rd 230-115 kV Tx at Endless Caverns		APS (37.05%) / Dominion (62.95%)
b1508.3	Upgrade a 115 kV shunt capacitor banks at Merck and Edinburg		APS (37.05%) / Dominion (62.95%)
b1536	Advance n1752 (Replace OX 230 breaker 24342 with an (63kA breaker)		Dominion (100%)
b1537	Advance n1753 (Replace OX 230 breaker 243T2097 with an 63kA breaker)		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements   Annual Revenue Requirement   Responsible Customer(s)

b1538	Replace Loudoun 230 kV breaker '29552'		Dominion (100%)
b1571	Replace Acca 115 kV breaker '6072' with 40 kA		Dominion (100%)
b1647	Upgrade the name plate rating at Morrisville 500kV breaker 'H1T573' with 50kA breaker		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1648	Upgrade name plate rating at Morrisville 500kV breaker 'H2T545' with 50kA breaker		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1649	Replace Morrisville 500kV breaker ‘H1T580’ with 50kA breaker		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1650	Replace Morrisville 500kV breaker ‘H2T569’ with 50kA breaker		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1651	Replace Loudoun 230kV breaker ‘295T2030’ with 63kA breaker		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1652	Replace Ox 230kV breaker ‘209742’ with 63kA breaker		Dominion (100%)
b1653	Replace Clifton 230kV breaker ‘26582’ with 63kA breaker		Dominion (100%)
b1654	Replace Clifton 230kV breaker ‘26682’ with 63kA breaker		Dominion (100%)
b1655	Replace Clifton 230kV breaker ‘205182’ with 63kA breaker		Dominion (100%)
b1656	Replace Clifton 230kV breaker ‘265T266’ with 63kA breaker		Dominion (100%)
b1657	Replace Clifton 230kV breaker ‘2051T2063’ with 63kA breaker		Dominion (100%)
b1694	Rebuild Loudoun - Brambleton 500 kV Rebuild Loudoun - Brambleton 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1696	Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV		AEC (0.46%) / APS (4.18%) / BGE (2.02%) / DPL (0.80%) / Dominion (88.45%) / JCPL (0.64%) / ME (0.50%) / NEPTUNE* (0.06%) / PECO (1.55%) / PEPCO (1.34%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1697	Build a 2nd Clark - Idylwood 230 kV line and install 230 kV gas-hybrid breakers at Clark		AEC (1.35%) / APS (15.65%) / BGE (10.53%) / DPL (2.59%) / Dominion (46.97%) / JCPL (2.36%) / ME (1.91%) / NEPTUNE* (0.23%) / PECO (4.48%) / PEPCO (11.23%) / PSEG (2.59%) / RE (0.11%)
b1698	Install a 2nd 500/230 kV transformer at Brambleton		APS (4.21%) / BGE (13.28%) / DPL (1.09%) / Dominion (59.38%) / PEPCO (22.04%)
b1698.1	Install a 500 kV breaker at Brambleton		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1698.6	Replace Brambleton 230 kV breaker '2094T2095'		Dominion (100%)
b1699	Reconfigure Line #203 to feed Edwards Ferry sub radial from Pleasant View 230 kV and install new breaker bay at Pleasant View Sub		Dominion (100%)
b1700	Install a 230/115 kV transformer at the new Liberty substation to relieve Gainesville Transformer #3		Dominion (100%)
b1701	Reconductor line #2104 (Fredericksburg - Cranes Corner 230 kV)		APS (8.66%) / BGE (10.95%) / Dominion (63.30%) / PEPCO (17.09%)
b1724	Install a 2nd 138/115 kV transformer at Edinburg		Dominion (100%)
b1728	Replace the 115/34.5 kV transformer #1 at Hickory with a 230/34.5 kV transformer		Dominion (100%)
b1729	Add 4 breaker ring bus at Burton 115 kV substation and construct a 115 kV line approximately 3.5 miles from Oakwood 115 kV substation to Burton 115 kV substation		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1730	Install a 230/115 kV transformer at a new Liberty substation		Dominion (100%)
b1731	Uprate or rebuild Four Rivers – Kings Dominion 115 kV line or Install capacitors or convert load from 115 kV system to 230 kV system		Dominion (100%)
b1790	Split Wharton 115 kV capacitor bank into two smaller units and add additional reactive support in area by correcting power factor at Pantego 115 kV DP and FivePoints 115 kV DP to minimum of 0.973		Dominion (100%)
b1791	Wreck and rebuild 2.1 mile section of Line #11 section between Gordonsville and Somerset		APS (5.83%) / BGE (6.25%) / Dominion (78.38%) / PEPCO (9.54%)
b1792	Rebuild line #33 Halifax to Chase City, 26 miles. Install 230 kV 4 breaker ring bus		Dominion (100%)
b1793	Wreck and rebuild remaining section of Line #22, 19.5 miles and replace two pole H frame construction built in 1930		Dominion (100%)
b1794	Split 230 kV Line #2056 (Hornertown - Rocky Mount) and double tap line to Battleboro Substation. Expand station, install a 230 kV 3 breaker ring bus and install a 230/115 kV transformer		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1795	Reconductor segment of Line #54 (Carolina to Woodland 115 kV) to a minimum of 300 MVA		Dominion (100%)
b1796	Install 115 kV 25 MVAR capacitor bank at Kitty Hawk Substation		Dominion (100%)
b1797	Wreck and rebuild 7 miles of the Dominion owned section of Cloverdale - Lexington 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1798	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1799	Build 150 MVAR Switched Shunt at Pleasant View 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1805	Install a 250 MVAR SVC at the existing Mt. Storm 500kV substation		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1809	Replace Brambleton 230 kV Breaker ‘22702’		Dominion (100%)
b1810	Replace Brambleton 230 kV Breaker ‘227T2094’		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.1	Surry to Skiffes Creek 500 kV Line (7 miles overhead)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1905.2	Surry 500 kV Station Work		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1905.3	Skiffes Creek 500-230 kV Tx and Switching Station		Dominion (99.84%) / PEPCO (0.16%)
b1905.4	New Skiffes Creek - Whealton 230 kV line		Dominion (99.84%) / PEPCO (0.16%)
b1905.5	Whealton 230 kV breakers		Dominion (99.84%) / PEPCO (0.16%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.6	Yorktown 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.7	Lanexa 115 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.8	Surry 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.9	Kings Mill, Peninmen, Toano, Waller, Warwick		Dominion (99.84%) / PEPCO (0.16%)
b1906.1	At Yadkin 500 kV, install six 500 kV breakers		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1906.2	Install a 2nd 230/115 kV TX at Yadkin		Dominion (100%)
b1906.3	Install a 2nd 230/115 kV TX at Chesapeake		Dominion (100%)
b1906.4	Uprate Yadkin – Chesapeake 115 kV		Dominion (100%)
b1906.5	Install a third 500/230 kV TX at Yadkin		Dominion (100%)
b1907	Install a 3rd 500/230 kV TX at Clover		APS (5.83%) / BGE (4.74%) / Dominion (81.79%) / PEPCO (7.64%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1908	Rebuild Lexington – Dooms 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1909	Uprate Bremo – Midlothian 230 kV to its maximum operating temperature		APS (6.31%) / BGE (3.81%) / Dominion (81. 90%) / PEPCO (7.98%)
b1910	Build a Suffolk – Yadkin 230 kV line (14 miles) and install 4 breakers		Dominion (100%)
b1911	Add a second Valley 500/230 kV TX		APS (14.85%) / BGE (3.10%) / Dominion (74.12%) / PEPCO (7.93%)
b1912	Install a 500 MVAR SVC at Landstown 230 kV		DEOK (0.46%) / Dominion (99.54%)
b2053	Rebuild 28 mile line		AEP (100%)
b2125	Install four additional 230 kV 100 MVAR variable shunt reactor banks at Clifton, Gallows Road, Garrisonville, and Virginia Hills substations		Dominion (100%)
b2126	Install two additional 230 kV 100 MVAR variable shunt reactor banks at Churchland and Shawboro substations		Dominion (100%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2181	Add a motor to an existing switch at Prince George to allow for Sectionalizing scheme for line #2124 and allow for Brickhouse DP to be re-energized from the 115 kV source		Dominion (100%)
b2182	Install 230kV 4-breaker ring at Enterprise 230 kV to isolate load from transmission system when substation initially built		Dominion (100%)
b2183	Add a motor to an existing switch at Keene Mill to allow for a sectionalizing scheme		Dominion (100%)
b2184	Install a 230 kV breaker at Tarboro to split line #229. Each will feed an autotransformer at Tarboro. Install switches on each autotransformer		Dominion (100%)
b2185	Uprate Line #69 segment Reams DP to Purdy (19 miles) from 41 MVA to 162 MVA by replacing 5 structures and re-sagging the line from 50C to 75C		Dominion (100%)
b2186	Install a 2nd 230-115kV transformer at Earleys connected to the existing 115kV and 230kV ring busses. Add a 115 kV breaker and 230kV breaker to the ring busses		Dominion (100%)
b2187	Install 4 - 230kV breakers at Shellhorn 230 kV to isolate load		Dominion (100%)

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

SCHEDULE 12 – APPENDIX A

(20) Virginia Electric and Power Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1698.7	Replace Loudoun 230 kV breaker ‘203052’ with 63kA rating		Dominion (100%)
b1696.1	Replace the Idylwood 230 kV ‘25112’ breaker with 50kA breaker		Dominion (100%)
b1696.2	Replace the Idylwood 230 kV ‘209712’ breaker with 50kA breaker		Dominion (100%)
b1793.1	Remove the Carolina 22 SPS to include relay logic changes, minor control wiring, relay resets and SCADA programming upon completion of project		Dominion (100%)
b2281	Additional Temporary SPS at Bath County		Dominion (100%)
b2350	Reconductor 211 feet of 545.5 ACAR conductor on 59 Line Elmont - Greenwood DP 115 kV to achieve a summer emergency rating of 906 amps or greater		Dominion (100%)
b2358	Install a 230 kV 54 MVAR capacitor bank on the 2016 line at Harmony Village Substation		Dominion (100%)
b2359	Wreck and rebuild approximately 1.3 miles of existing 230 kV line between Cochran Mill - X4-039 Switching Station		Dominion (100%)
b2360	Build a new 39 mile 230 kV transmission line from Dooms - Lexington on existing right-of-way		Dominion (100%)
b2361	Construct 230 kV OH line along existing Line #2035 corridor, approx. 2.4 miles from Idylwood - Dulles Toll Road (DTR) and 2.1 miles on new right-of-way along DTR to new Scott's Run Substation		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2368	Replace the Brambleton 230 kV breaker '209502' with 63kA breaker		Dominion (100%)
b2369	Replace the Brambleton 230 kV breaker '213702' with 63kA breaker		Dominion (100%)
b2370	Replace the Brambleton 230 kV breaker 'H302' with 63kA breaker		Dominion (100%)
b2373	Build a 2nd Loudoun - Brambleton 500 kV line within the existing ROW. The Loudoun - Brambleton 230 kV line will be relocated as an underbuild on the new 500 kV line		Dominion (100%)
b2397	Replace the Beaumeade 230 kV breaker '2079T2116' with 63kA		Dominion (100%)
b2398	Replace the Beaumeade 230 kV breaker '2079T2130' with 63kA		Dominion (100%)
b2399	Replace the Beaumeade 230 kV breaker '208192' with 63kA		Dominion (100%)
b2400	Replace the Beaumeade 230 kV breaker '209592' with 63kA		Dominion (100%)
b2401	Replace the Beaumeade 230 kV breaker '211692' with 63kA		Dominion (100%)
b2402	Replace the Beaumeade 230 kV breaker '227T2130' with 63kA		Dominion (100%)
b2403	Replace the Beaumeade 230 kV breaker '274T2130' with 63kA		Dominion (100%)

The Annual Revenue Requirement for all Virginia Electric and Power Company projects in this Section 20 shall be as specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B.

*Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2404	Replace the Beaumeade 230 kV breaker '227T2095' with 63kA		Dominion (100%)
b2405	Replace the Pleasant view 230 kV breaker '203T274' with 63kA		Dominion (100%)
b2443	Construct new underground 230 kV line from Glebe to Station C, rebuild Glebe Substation, construct 230 kV high side bus at Station C with option to install 800 MVA PAR		Dominion (97.11%) / ME (0.18%) / PEPCO (2.71%)
b2443.1	Replace the Idylwood 230 kV breaker ‘203512’ with 50kA		Dominion (100%)
b2443.2	Replace the Ox 230 kV breaker ‘206342’ with 63kA breaker		Dominion (100%)
b2443.3	Glebe – Station C PAR		**DFAX Allocation:** Dominion (22.57%) / PEPCO (77.43%)
b2457	Replace 24 115 kV wood h-frames with 230 kV Dominion pole H-frame structures on the Clubhouse – Purdy 115 kV line		Dominion (100%)
b2458.1	Replace 12 wood H-frame structures with steel H-frame structures and install shunts on all conductor splices on Carolina – Woodland 115 kV		Dominion (100%)
b2458.2	Upgrade all line switches and substation components at Carolina 115 kV to meet or exceed new conductor rating of 174 MVA		Dominion (100%)
b2458.3	Replace 14 wood H-frame structures on Carolina – Woodland 115 kV		Dominion (100%)
b2458.4	Replace 2.5 miles of static wire on Carolina – Woodland 115 kV		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2458.5	Replace 4.5 miles of conductor between Carolina 115 kV and Jackson DP 115 kV with min. 300 MVA summer STE rating; Replace 8 wood H-frame structures located between Carolina and Jackson DP with steel H-frames		Dominion (100%)
b2460.1	Replace Hanover 230 kV substation line switches with 3000A switches		Dominion (100%)
b2460.2	Replace wave traps at Four River 230 kV and Elmont 230 kV substations with 3000A wave traps		Dominion (100%)
b2461	Wreck and rebuild existing Remington CT – Warrenton 230 kV (approx. 12 miles) as a double-circuit 230 kV line		Dominion (100%)
b2461.1	Construct a new 230 kV line approximately 6 miles from NOVEC’s Wheeler Substation a new 230 kV switching station in Vint Hill area		Dominion (100%)
b2461.2	Convert NOVEC’s Gainesville – Wheeler line (approximately 6 miles) to 230 kV		Dominion (100%)
b2461.3	Complete a Vint Hill – Wheeler – Loudoun 230 kV networked line		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2471	Replace Midlothian 500 kV breaker 563T576 and motor operated switches with 3 breaker 500 kV ring bus. Terminate Lines # 563 Carson – Midlothian, #576 Midlothian –North Anna, Transformer #2 in new ring		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: Dominion (100%)
b2504	Rebuild 115 kV Line #32 from Halifax-South Boston (6 miles) for min. of 240 MVA and transfer Welco tap to Line #32. Moving Welco to Line #32 requires disabling auto-sectionalizing scheme		Dominion (100%)
b2505	Install structures in river to remove the 115 kV #65 line (Whitestone-Harmony Village 115 kV) from bridge and improve reliability of the line		Dominion (100%)
b2542	Replace the Loudoun 500 kV 'H2T502' breaker with a 50kA breaker		Dominion (100%)
b2543	Replace the Loudoun 500 kV 'H2T584' breaker with a 50kA breaker		Dominion (100%)
b2565	Reconductor wave trap at Carver Substation with a 2000A wave trap		Dominion (100%)
b2566	Reconductor 1.14 miles of existing line between ACCA and Hermitage and upgrade associated terminal equipment		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2582	Rebuild the Elmont – Cunningham 500 kV line		Dominion (100%)
b2583	Install 500 kV breaker at Ox Substation to remove Ox Tx#1 from H1T561 breaker failure outage.		Dominion (100%)
b2584	Relocate the Bremo load (transformer #5) to #2028 (Bremo-Charlottesville 230 kV) line and Cartersville distribution station to #2027 (Bremo-Midlothian 230 kV) line		Dominion (100%)
b2585	Reconductor 7.63 miles of existing line between Cranes and Stafford, upgrade associated line switches at Stafford		**DFAX Allocation:** PEPCO (100%)
b2620	Wreck and rebuild the Chesapeake – Deep Creek – Bowers Hill – Hodges Ferry 115 kV line; minimum rating 239 MVA normal/emergency, 275 MVA load dump rating		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2622	Rebuild Line #47 between Kings Dominion 115 kV and Fredericksburg 115 kV to current standards with summer emergency rating of 353 MVA at 115 kV		Dominion (100%)
b2623	Rebuild Line #4 between Bremo and Structure 8474 (4.5 miles) to current standards with a summer emergency rating of 261 MVA at 115 kV		Dominion (100%)
b2624	Rebuild 115 kV Lines #18 and #145 between Possum Point Generating Station and NOVEC's Smoketown DP (approx. 8.35 miles) to current 230 kV standards with a normal continuous summer rating of 524 MVA at 115 kV		Dominion (100%)
b2625	Rebuild 115 kV Line #48 between Thole Street and Structure 48/71 to current standard. The remaining line to Sewells Point is 2007 vintage. Rebuild 115 kV Line #107 line, Sewells Point to Oakwood, between structure 107/17 and 107/56 to current standard.		Dominion (100%)
b2626	Rebuild 115 kV Line #34 between Skiffes Creek and Yorktown and the double circuit portion of 115 kV Line #61 to current standards with a summer emergency rating of 353 MVA at 115 kV		Dominion (100%)
b2627	Rebuild 115 kV Line #1 between Crewe 115 kV and Fort Pickett DP 115 kV (12.2 miles) to current standards with summer emergency rating of 261 MVA at 115 kV		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2628	Rebuild 115 kV Line #82 Everetts – Voice of America (20.8 miles) to current standards with a summer emergency rating of 261 MVA at 115 kV		Dominion (100%)
b2629	Rebuild the 115 kV Lines #27 and #67 lines from Greenwich 115 kV to Burton 115 kV Structure 27/280 to current standard with a summer emergency rating of 262 MVA at 115 kV		Dominion (100%)
b2630	Install circuit switchers on Gravel Neck Power Station GSU units #4 and #5. Install two 230 kV CCVT's on Lines #2407 and #2408 for loss of source sensing		Dominion (100%)
b2636	Install three 230 kV bus breakers and 230 kV, 100 MVAR Variable Shunt Reactor at Dahlgren to provide line protection during maintenance, remove the operational hazard and provide voltage reduction during light load conditions		Dominion (100%)
b2647	Rebuild Boydton Plank Rd – Kerr Dam 115 kV Line #38 (8.3 miles) to current standards with summer emergency rating of 353 MVA at 115 kV.		Dominion (100%)
b2648	Rebuild Carolina – Kerr Dam 115 kV Line #90 (38.7 miles) to current standards with summer emergency rating of 353 MVA 115 kV.		Dominion (100%)
b2649	Rebuild Clubhouse – Carolina 115 kV Line #130 (17.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV.		Dominion (100%)
b2650	Rebuild Twittys Creek – Pamplin 115 kV Line #154 (17.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV.		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2651	Rebuild Buggs Island – Plywood 115 kV Line #127 (25.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV. The line should be rebuilt for 230 kV and operated at 115 kV.		Dominion (100%)
b2652	Rebuild Greatbridge – Hickory 115 kV Line #16 and Greatbridge – Chesapeake E.C. to current standard with summer emergency rating of 353 MVA at 115 kV.		Dominion (100%)
b2653.1	Build 20 mile 115 kV line from Pantego to Trowbridge with summer emergency rating of 353 MVA.		Dominion (100%)
b2653.2	Install 115 kV four-breaker ring bus at Pantego		Dominion (100%)
b2653.3	Install 115 kV breaker at Trowbridge		Dominion (100%)
b2654.1	Build 15 mile 115 kV line from Scotland Neck to S Justice Branch with summer emergency rating of 353 MVA. New line will be routed to allow HEMC to convert Dawson's Crossroads RP from 34.5 kV to 115 kV.		Dominion (100%)
b2654.2	Install 115 kV three-breaker ring bus at S Justice Branch		Dominion (100%)
b2654.3	Install 115 kV breaker at Scotland Neck		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2665	Rebuild the Cunningham – Dooms 500 kV line		Dominion (100%)
b2686	Pratts Area Improvement		Dominion (100%)
b2686.1	Build a 230 kV line from Remington Substation to Gordonsville Substation utilizing existing ROW		Dominion (100%)
b2686.11	Upgrading sections of the Gordonsville – Somerset 115 kV circuit		Dominion (100%)
b2686.12	Upgrading sections of the Somerset – Doubleday 115 kV circuit		Dominion (100%)
b2686.13	Upgrading sections of the Orange – Somerset 115 kV circuit		Dominion (100%)
b2686.14	Upgrading sections of the Mitchell – Mt. Run 115 kV circuit		Dominion (100%)
b2686.2	Install a 3rd 230/115 kV transformer at Gordonsville Substation		Dominion (100%)

*Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2686.3	Upgrade Line 2088 between Gordonsville Substation and Louisa CT Station		Dominion (100%)
b2717.1	De-energize Davis – Rosslyn #179 and #180 69 kV lines		Dominion (100%)
b2717.2	Remove splicing and stop joints in manholes		Dominion (100%)
b2717.3	Evacuate and dispose of insulating fluid from various reservoirs and cables		Dominion (100%)
b2717.4	Remove all cable along the approx. 2.5 mile route, swab and cap-off conduits for future use, leave existing communication fiber in place		Dominion (100%)
b2719.1	Expand Perth substation and add a 115 kV four breaker ring		Dominion (100%)
b2719.2	Extend the Hickory Grove DP tap 0.28 miles to Perth and terminate it at Perth		Dominion (100%)
b2719.3	Split Line #31 at Perth and terminate it into the new ring bus with 2 breakers separating each of the line terminals to prevent a breaker failure from taking out both 115 kV lines		Dominion (100%)
b2720	Replace the Loudoun 500 kV 'H1T569' breakers with 50kA breaker		Dominion (100%)
b2729	Optimal Capacitors Configuration: New 175 MVAR capacitor at Brambleton, new 175 MVAR capacitor at Ashburn, new 300 MVAR capacitor at Shelhorm, new 150 MVAR capacitor at Liberty		AEC (1.97%) / BGE (14.46%) / Dominion (35.33%) / DPL (3.78%) / JCPL (3.33%) / ME (2.53%) / Neptune (0.63%) / PECO (6.30%) / PEPCO (20.36%) / PPL (3.97%) / PSEG (7.34%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2744	Rebuild the Carson – Rogers Rd 500 kV circuit		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: Dominion (100%)
b2745	Rebuild 21.32 miles of existing line between Chesterfield – Lakeside 230 kV		Dominion (100%)
b2746.1	Rebuild Line #137 Ridge Rd – Kerr Dam 115 kV, 8.0 miles, for 346 MVA summer emergency rating		Dominion (100%)
b2746.2	Rebuild Line #1009 Ridge Rd – Chase City 115 kV, 9.5 miles, for 346 MVA summer emergency rating		Dominion (100%)
b2746.3	Install a second 4.8 MVAR capacitor bank on the 13.8 kV bus of each transformer at Ridge Rd		Dominion (100%)
b2747	Install a Motor Operated Switch and SCADA control between Dominion's Gordonsville 115 kV bus and FirstEnergy's 115 kV line		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2757	Install a +/-125 MVAr Statcom at Colington 230 kV		Dominion (100%)
b2758	Rebuild Line #549 Dooms – Valley 500kV		Dominion (100%)
b2759	Rebuild Line #550 Mt. Storm – Valley 500kV		Dominion (100%)
b2802	Rebuild Line #171 from Chase City – Boydton Plank Road tap by removing end-of-life facilities and installing 9.4 miles of new conductor. The conductor used will be at current standards with a summer emergency rating of 393 MVA at 115kV		Dominion (100%)
b2815	Build a new Pinewood 115kV switching station at the tap serving North Doswell DP with a 115kV four breaker ring bus		Dominion (100%)
b2842	Update the nameplate for Mount Storm 500 kV "57272" to be 50kA breaker		Dominion (100%)
b2843	Replace the Mount Storm 500 kV "G2TY" with 50kA breaker		Dominion (100%)
b2844	Replace the Mount Storm 500 kV "G2TZ" with 50kA breaker		Dominion (100%)
b2845	Update the nameplate for Mount Storm 500 kV "G3TSX1" to be 50kA breaker		Dominion (100%)
b2846	Update the nameplate for Mount Storm 500 kV "SX172" to be 50kA breaker		Dominion (100%)
b2847	Update the nameplate for Mount Storm 500 kV "Y72" to be 50kA breaker		Dominion (100%)
b2848	Replace the Mount Storm 500 kV "Z72" with 50kA breaker		Dominion (100%)
b2871	Rebuild 230 kV line #247 from Swamp to Suffolk (31 miles) to current standards with a summer emergency rating of 1047 MVA at 230 kV		Dominion (100%)

Attachment 7c (PATH OATT)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.66%*) / AEP (*14.16%*) / APS (*5.73%*) / ATSI (*7.88%*) / BGE (*4.22%*) / ComEd (*13.31%*) / Dayton (*2.11%*) / DEOK (*3.29%*) / DL (*1.75%*) / DPL (*2.50%*) / Dominion (*12.86%*) / EKPC (*1.87%*) / JCPL (*3.74%*) / ME (*1.90%*) / NEPTUNE* (*0.44%*) / PECO (*5.34%*) / PENELEC (*1.89%*) / PEPCO (*3.99%*) / PPL (*4.84%*) / PSEG (*6.26%*) / RE (*0.26%*)
b0492	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.66%*) / AEP (*14.16%*) / APS (*5.73%*) / ATSI (*7.88%*) / BGE (*4.22%*) / ComEd (*13.31%*) / Dayton (*2.11%*) / DEOK (*3.29%*) / DL (*1.75%*) / DPL (*2.50%*) / Dominion (*12.86%*) / EKPC (*1.87%*) / JCPL (*3.74%*) / ME (*1.90%*) / NEPTUNE* (*0.44%*) / PECO (*5.34%*) / PENELEC (*1.89%*) / PEPCO (*3.99%*) / PPL (*4.84%*) / PSEG (*6.26%*) / RE (*0.26%*)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0541	Replace Doubs circuit breaker DJ13		APS (100%)
b0542	Replace Doubs circuit breaker DJ20		APS (100%)
b0543	Replace Doubs circuit breaker DJ21		APS (100%)
b0544	Remove instantaneous reclose from Eastalco circuit breaker D-26		APS (100%)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX

(17) AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0318	Install a 765/138 kV transformer at Amos		AEP (99.00%) / PEPCO (1.00%)
b0324	Replace entrance conductors, wave traps, and risers at the Tidd 345 kV station on the Tidd – Canton Central 345 kV circuit		AEP (100%)
b0447	Replace Cook 345 kV breaker M2		AEP (100%)
b0448	Replace Cook 345 kV breaker N2		AEP (100%)
b0490	Construct an Amos – Bedington 765 kV circuit (AEP equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

* Neptune Regional Transmission System, LLC

Attachment 7d (TrailCo OATT)

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0216	Install -100/+525 MVAR dynamic reactive device at Black Oak	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0218	Install third Wylie Ridge 500/345kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (11.83%) / DPL (19.40%) / Dominion (13.81%) / JCPL (15.56%) / PECO (39.40%)
b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7		AEC (11.83%) / DPL (19.40%) / Dominion (13.81%) / JCPL (15.56%) / PECO (39.40%)
b0229	Install fourth Bedington 500/138 kV		APS (50.98%) / BGE (13.42%) / DPL (2.03%) / Dominion (14.50%) / ME (1.43%) / PEPCO (17.64%)
b0230	Install fourth Meadowbrook 500/138 kV	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (79.16%) / BGE (3.61%) / DPL (0.86%) / Dominion (11.75%) / ME (0.67%) / PEPCO (3.95%)

* Neptune Regional Transmission System, LLC

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

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

* Neptune Regional Transmission System, LLC

†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project

††Cost allocations associated with below 500 kV elements of the project

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0328.2	Build new Meadow Brook – Loudoun 500 kV circuit (20 of 50 miles)	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0343	Replace Doubs 500/230 kV transformer #2	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.91%) / Dominion (28.86%) / ME (2.97%) / PECO (5.73%) / PEPCO (35.19%)
b0344	Replace Doubs 500/230 kV transformer #3	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.86%) / BGE (21.50%) / DPL (3.91%) / Dominion (28.82%) / ME (2.97%) / PECO (5.74%) / PEPCO (35.20%)
b0345	Replace Doubs 500/230 kV transformer #4	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.90%) / Dominion (28.83%) / ME (2.98%) / PECO (5.75%) / PEPCO (35.20%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.1	Build new Mt. Storm – 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.2	Build new Mt. Storm – Meadow Brook 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.3	Build new 502 Junction 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.4	Upgrade Meadow Brook 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.5	Replace Harrison 500 kV breaker HL-3		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0347.6	Upgrade (per ABB inspection) breaker HL-6		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.17	Replace Meadow Brook 138 kV breaker 'MD-10'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.18	Replace Meadow Brook 138 kV breaker 'MD-11'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.19	Replace Meadow Brook 138 kV breaker 'MD-12'		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0347.20	Replace Meadow Brook 138 kV breaker 'MD-13'		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.21	Replace Meadow Brook 138 kV breaker 'MD-14'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.22	Replace Meadow Brook 138 kV breaker 'MD-15'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.23	Replace Meadow Brook 138 kV breaker 'MD-16'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.24	Replace Meadow Brook 138 kV breaker 'MD-17'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.25	Replace Meadow Brook 138 kV breaker 'MD-18'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.26	Replace Meadow Brook 138 kV breaker 'MD-22#1 CAP'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.27	Replace Meadow Brook 138 kV breaker 'MD-4'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.28	Replace Meadow Brook 138 kV breaker 'MD-5'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.29	Replace Meadowbrook 138 kV breaker 'MD-6'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.30	Replace Meadowbrook 138 kV breaker 'MD-7'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0347.31	Replace Meadowbrook 138 kV breaker 'MD-8'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.32	Replace Meadowbrook 138 kV breaker 'MD-9'		AEC (*1.66%*) / AEP (*14.16%*) / APS (*5.73%*) / ATSI (*7.88%*) / BGE (*4.22%*) / ComEd (*13.31%*) / Dayton (*2.11%*) / DEOK (*3.29%*) / DL (*1.75%*) / DPL (*2.50%*) / Dominion (*12.86%*) / EKPC (*1.87%*) / JCPL (*3.74%*) / ME (*1.90%*) / NEPTUNE* (*0.44%*) / PECO (*5.34%*) / PENELEC (*1.89%*) / PEPCO (*3.99%*) / PPL (*4.84%*) / PSEG (*6.26%*) / RE (*0.26%*)
b0347.33	Replace Meadow Brook 138kV breaker 'MD-1'		APS (100%)
b0347.34	Replace Meadow Brook 138kV breaker 'MD-2'		APS (100%)
b0348	Upgrade Stonewall – Inwood 138 kV with 954 ACSR conductor		APS (100%)
b0373	Convert Doubs – Monocacy 138 kV facilities to 230 kV operation		AEC (1.82%) / APS (76.84%) / DPL (2.64%) / JCPL (4.53%) / ME (9.15%) / Neptune* (0.42%) / PPL (4.60%)
b0393	Replace terminal equipment at Harrison 500 kV and Belmont 500 kV		AEC (*1.66%*) / AEP (*14.16%*) / APS (*5.73%*) / ATSI (*7.88%*) / BGE (*4.22%*) / ComEd (*13.31%*) / Dayton (*2.11%*) / DEOK (*3.29%*) / DL (*1.75%*) / DPL (*2.50%*) / Dominion (*12.86%*) / EKPC (*1.87%*) / JCPL (*3.74%*) / ME (*1.90%*) / NEPTUNE* (*0.44%*) / PECO (*5.34%*) / PENELEC (*1.89%*) / PEPCO (*3.99%*) / PPL (*4.84%*) / PSEG (*6.26%*) / RE (*0.26%*)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0406.1	Replace Mitchell 138 kV breaker “#4 bank”		APS (100%)
b0406.2	Replace Mitchell 138 kV breaker “#5 bank”		APS (100%)
b0406.3	Replace Mitchell 138 kV breaker “#2 transf”		APS (100%)
b0406.4	Replace Mitchell 138 kV breaker “#3 bank”		APS (100%)
b0406.5	Replace Mitchell 138 kV breaker “Charlerio #2”		APS (100%)
b0406.6	Replace Mitchell 138 kV breaker “Charlerio #1”		APS (100%)
b0406.7	Replace Mitchell 138 kV breaker “Shepler Hill Jct”		APS (100%)
b0406.8	Replace Mitchell 138 kV breaker “Union Jct”		APS (100%)
b0406.9	Replace Mitchell 138 kV breaker “#1-2 138 kV bus tie”		APS (100%)
b0407.1	Replace Marlowe 138 kV breaker “#1 transf”		APS (100%)
b0407.2	Replace Marlowe 138 kV breaker “MBO”		APS (100%)
b0407.3	Replace Marlowe 138 kV breaker “BMA”		APS (100%)
b0407.4	Replace Marlowe 138 kV breaker “BMR”		APS (100%)
b0407.5	Replace Marlowe 138 kV breaker “WC-1”		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0407.6	Replace Marlowe 138 kV breaker “R11”		APS (100%)
b0407.7	Replace Marlowe 138 kV breaker “W”		APS (100%)
b0407.8	Replace Marlowe 138 kV breaker “138 kV bus tie”		APS (100%)
b0408.1	Replace Trissler 138 kV breaker “Belmont 604”		APS (100%)
b0408.2	Replace Trissler 138 kV breaker “Edgelawn 90”		APS (100%)
b0409.1	Replace Weirton 138 kV breaker “Wylie Ridge 210”		APS (100%)
b0409.2	Replace Weirton 138 kV breaker “Wylie Ridge 216”		APS (100%)
b0410	Replace Glen Falls 138 kV breaker “McAlpin 30”		APS (100%)
b0417	Reconductor Mitchell – Shepler Hill Junction 138kV with 954 ACSR		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0418	Install a breaker failure auto-restoration scheme at Cabot 500 kV for the failure of the #6 breaker		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0419	Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0420	Operating Procedure to open the Black Oak 500/138 kV transformer #3 for the loss of Hatfield – Ronco 500 kV and the Hatfield #3 Generation		APS (100%)
b0445	Upgrade substation equipment and reconductor the Tidd – Mahans Lane – Weirton 138kV circuit with 954 ACSR		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.66%*) / AEP (*14.16%*) / APS (*5.73%*) / ATSI (*7.88%*) / BGE (*4.22%*) / ComEd (*13.31%*) / Dayton (*2.11%*) / DEOK (*3.29%*) / DL (*1.75%*) / DPL (*2.50%*) / Dominion (*12.86%*) / EKPC (*1.87%*) / JCPL (*3.74%*) / ME (*1.90%*) / NEPTUNE* (*0.44%*) / PECO (*5.34%*) / PENELEC (*1.89%*) / PEPCO (*3.99%*) / PPL (*4.84%*) / PSEG (*6.26%*) / RE (*0.26%*)
b0492	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.66%*) / AEP (*14.16%*) / APS (*5.73%*) / ATSI (*7.88%*) / BGE (*4.22%*) / ComEd (*13.31%*) / Dayton (*2.11%*) / DEOK (*3.29%*) / DL (*1.75%*) / DPL (*2.50%*) / Dominion (*12.86%*) / EKPC (*1.87%*) / JCPL (*3.74%*) / ME (*1.90%*) / NEPTUNE* (*0.44%*) / PECO (*5.34%*) / PENELEC (*1.89%*) / PEPCO (*3.99%*) / PPL (*4.84%*) / PSEG (*6.26%*) / RE (*0.26%*)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0492.5	Replace Eastalco 230 kV breaker D-31		APS (100%)
b0495	Replace existing Kammer 765/500 kV transformer with a new larger transformer		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0533	Reconductor the Powell Mountain – Sutton 138 kV line		APS (100%)
b0534	Install a 28.61 MVAR capacitor on Sutton 138 kV		APS (100%)
b0535	Install a 44 MVAR capacitor on Dutch Fork 138 kV		APS (100%)
b0536	Replace Doubs circuit breaker DJ1		APS (100%)
b0537	Replace Doubs circuit breaker DJ7		APS (100%)
b0538	Replace Doubs circuit breaker DJ10		APS (100%)
b0572.1	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0572.2	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0573	Reconfigure circuits in Butler – Cabot 138 kV area		APS (100%)
b0577	Replace Fort Martin 500 kV breaker FL-1		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0584	Install 33 MVAR 138 kV capacitor at Necessity 138 kV		APS (100%)
b0585	Increase Cecil 138 kV capacitor size to 44 MVAR, replace five 138 kV breakers at Cecil due to increased short circuit fault duty as a result of the addition of the Prexy substation		APS (100%)
b0586	Increase Whiteley 138 kV capacitor size to 44 MVAR		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0587	Reconductor AP portion of Tidd – Carnegie 138 kV and Carnegie – Weirton 138 kV with 954 ACSR		APS (100%)
b0588	Install a 40.8 MVAR 138 kV capacitor at Grassy Falls		APS (100%)
b0589	Replace five 138 kV breakers at Cecil		APS (100%)
b0590	Replace #1 and #2 breakers at Charleroi 138 kV		APS (100%)
b0591	Install a 25.2 MVAR capacitor at Seneca Caverns 138 kV		APS (100%)
b0673	Rebuild Elko – Carbon Center Junction using 230 kV construction		APS (100%)
b0674	Construct new Osage – Whiteley 138 kV circuit		APS (97.69%) / DL (0.96%) / PENELEC (1.09%) / PSEG (0.25%) / RE (0.01%)
b0674.1	Replace the Osage 138 kV breaker 'CollinsF126'		APS (100%)
b0675.1	Convert Monocacy - Walkersville 138 kV to 230 kV		AEC (1.02%) / APS (82.01%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.2	Convert Walkersville - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (82.01%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0675.3	Convert Ringgold - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (82.01%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.4	Convert Catoctin - Carroll 138 kV to 230 kV		AEC (1.02%) / APS (82.01%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.5	Convert portion of Ringgold Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.01%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.6	Convert Catoctin Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.01%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.7	Convert portion of Carroll Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.01%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.8	Convert Monocacy Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.01%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0675.9	Convert Walkersville Substation from 138 kV to 230 kV		AEC (1.02%) / APS (82.01%) / DPL (0.85%) / JCPL (1.75%) / ME (6.38%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV		AEC (0.64%) / APS (86.77%) / DPL (0.53%) / JCPL (1.93%) / ME (4.05%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%)
b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV		AEC (0.64%) / APS (86.77%) / DPL (0.53%) / JCPL (1.93%) / ME (4.05%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%)
b0677	Reconductor Double Toll Gate – Riverton with 954 ACSR		APS (100%)
b0678	Reconductor Glen Falls - Oak Mound 138kV with 954 ACSR		APS (100%)
b0679	Reconductor Grand Point – Letterkenny with 954 ACSR		APS (100%)
b0680	Reconductor Greene – Letterkenny with 954 ACSR		APS (100%)
b0681	Replace 600/5 CT's at Franklin 138 kV		APS (100%)
b0682	Replace 600/5 CT's at Whiteley 138 kV		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0684	Reconductor Guilford – South Chambersburg with 954 ACSR		APS (100%)
b0685	Replace Ringgold 230/138 kV #3 with larger transformer		APS (72.06%) / JCPL (4.18%) / ME (6.80%) / NEPTUNE* (0.38%) / PECO (4.06%) / PENELEC (5.89%) / PSEG (6.38%) / RE (0.25%)
b0704	Install a third Cabot 500/138 kV transformer		APS (74.36%) / DL (2.73%) PENELEC (22.91%)
b0797	Advance n0321 (Replace Doubs Circuit Breaker DJ2)		APS(100%)
b0798	Advance n0322 (Replace Doubs Circuit Breaker DJ3)		APS(100%)
b0799	Advance n0323 (Replace Doubs Circuit Breaker DJ6)		APS(100%)
b0800	Advance n0327 (Replace Doubs Circuit Breaker DJ16)		APS(100%)
b0941	Replace Opequon 138 kV breaker 'BUSTIE'		APS(100%)
b0942	Replace Butler 138 kV breaker '#1 BANK'		APS(100%)
b0943	Replace Butler 138 kV breaker '#2 BANK'		APS(100%)
b0944	Replace Yukon 138 kV breaker 'Y-8'		APS(100%)
b0945	Replace Yukon 138 kV breaker 'Y-3'		APS(100%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0946	Replace Yukon 138 kV breaker 'Y-1'		APS(100%)
b0947	Replace Yukon 138 kV breaker 'Y-5'		APS(100%)
b0948	Replace Yukon 138 kV breaker 'Y-2'		APS(100%)
b0949	Replace Yukon 138 kV breaker 'Y-19'		APS(100%)
b0950	Replace Yukon 138 kV breaker 'Y-4'		APS(100%)
b0951	Replace Yukon 138 kV breaker 'Y-9'		APS(100%)
b0952	Replace Yukon 138 kV breaker 'Y-11'		APS(100%)
b0953	Replace Yukon 138 kV breaker 'Y-13'		APS(100%)
b0954	Replace Charleroi 138 kV breaker '#1 XFMR BANK'		APS(100%)
b0955	Replace Yukon 138 kV breaker 'Y-7'		APS(100%)
b0956	Replace Pruntytown 138 kV breaker 'P-9'		APS(100%)
b0957	Replace Pruntytown 138 kV breaker 'P-12'		APS(100%)
b0958	Replace Pruntytown 138 kV breaker 'P-15'		APS(100%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0959	Replace Charleroi 138 kV breaker '#2 XFMR BANK'		APS(100%)
b0960	Replace Pruntytown 138 kV breaker 'P-2'		APS(100%)
b0961	Replace Pruntytown 138 kV breaker 'P-5'		APS(100%)
b0962	Replace Yukon 138 kV breaker 'Y-18'		APS(100%)
b0963	Replace Yukon 138 kV breaker 'Y-10'		APS(100%)
b0964	Replace Pruntytown 138 kV breaker 'P-11'		APS(100%)
b0965	Replace Springdale 138 kV breaker '138E'		APS(100%)
b0966	Replace Pruntytown 138 kV breaker 'P-8'		APS(100%)
b0967	Replace Pruntytown 138 kV breaker 'P-14'		APS(100%)
b0968	Replace Ringgold 138 kV breaker '#3 XFMR BANK'		APS(100%)
b0969	Replace Springdale 138 kV breaker '138C'		APS(100%)
b0970	Replace Rivesville 138 kV breaker '#8 XFMR BANK'		APS(100%)
b0971	Replace Springdale 138 kV breaker '138F'		APS(100%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0972	Replace Belmont 138 kV breaker 'B-16'		APS(100%)
b0973	Replace Springdale 138 kV breaker '138G'		APS(100%)
b0974	Replace Springdale 138 kV breaker '138V'		APS(100%)
b0975	Replace Armstrong 138 kV breaker 'BROOKVILLE'		APS(100%)
b0976	Replace Springdale 138 kV breaker '138P'		APS(100%)
b0977	Replace Belmont 138 kV breaker 'B-17'		APS(100%)
b0978	Replace Springdale 138 kV breaker '138U'		APS(100%)
b0979	Replace Springdale 138 kV breaker '138D'		APS(100%)
b0980	Replace Springdale 138 kV breaker '138R'		APS(100%)
b0981	Replace Yukon 138 kV breaker 'Y-12'		APS(100%)
b0982	Replace Yukon 138 kV breaker 'Y-17'		APS(100%)
b0983	Replace Yukon 138 kV breaker 'Y-14'		APS(100%)
b0984	Replace Rivesville 138 kV breaker '#10 XFMR BANK'		APS(100%)
b0985	Replace Belmont 138 kV breaker 'B-14'		APS(100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0986	Replace Armstrong 138 kV breaker 'RESERVE BUS'		APS(100%)
b0987	Replace Yukon 138 kV breaker 'Y-16'		APS(100%)
b0988	Replace Springdale 138 kV breaker '138T'		APS(100%)
b0989	Replace Edgelawn 138 kV breaker 'GOFF RUN #632'		APS(100%)
b0990	Change reclosing on Cabot 138 kV breaker 'C-9'		APS(100%)
b0991	Change reclosing on Belmont 138 kV breaker 'B-7'		APS(100%)
b0992	Change reclosing on Belmont 138 kV breaker 'B-12'		APS(100%)
b0993	Change reclosing on Belmont 138 kV breaker 'B-9'		APS(100%)
b0994	Change reclosing on Belmont 138 kV breaker 'B-19'		APS(100%)
b0995	Change reclosing on Belmont 138 kV breaker 'B-21'		APS(100%)
b0996	Change reclosing on Willow Island 138 kV breaker 'FAIRVIEW #84'		APS(100%)
b0997	Change reclosing on Cabot 138 kV breaker 'C-4'		APS(100%)
b0998	Change reclosing on Cabot 138 kV breaker 'C-1'		APS(100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0999	Replace Redbud 138 kV breaker 'BUS TIE'		APS(100%)
b1022.1	Reconfigure the Peters to Bethel Park 138 kV line and Elrama to Woodville 138 kV line to create a 138 kV path from Woodville to Peters and a 138 kV path from Elrama to Bethel Park		APS (96.98%) / DL (3.02%)
b1022.3	Add static capacitors at Smith 138 kV		APS (96.98%) / DL (3.02%)
b1022.4	Add static capacitors at North Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.5	Add static capacitors at South Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.6	Add static capacitors at Manifold 138 kV		APS (96.98%) / DL (3.02%)
b1022.7	Add static capacitors at Houston 138 kV		APS (96.98%) / DL (3.02%)
b1023.1	Install a 500/138 kV transformer at 502 Junction		APS (100%)
b1023.2	Construct a new Franklin - 502 Junction 138 kV line including a rebuild of the Whiteley - Franklin 138 kV line to double circuit		APS (100%)
b1023.3	Construct a new 502 Junction - Osage 138 kV line		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1023.4	Construct Braddock 138 kV breaker station that connects the Charleroi - Gordon 138 kV line, Washington - Franklin 138 kV line and the Washington - Vanceville 138 kV line including a 66 MVAR capacitor		APS (100%)
b1027	Increase the size of the shunt capacitors at Enon 138 kV		APS (100%)
b1028	Raise three structures on the Osage - Collins Ferry 138 kV line to increase the line rating		APS (100%)
b1128	Reconductor the Edgewater – Vasco Tap; Edgewater – Loyalhanna 138 kV lines with 954 ACSR		APS (100%)
b1129	Reconductor the East Waynesboro – Ringgold 138 kV line with 954 ACSR		APS (100%)
b1131	Upgrade Double Tollgate – Meadowbrook MDT Terminal Equipment		APS (100%)
b1132	Upgrade Double Tollgate-Meadowbrook MBG terminal equipment		APS (100%)
b1133	Upgrade terminal equipment at Springdale		APS (100%)
b1135	Reconductor the Bartonville – Meadowbrook 138 kV line with high temperature conductor		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1137	Reconductor the Eastgate – Luxor 138 kV; Eastgate – Sony 138 kV line with 954 ACSR		APS (78.77%) / PENELEC (14.11%) / PSEG (6.85%) / RE (0.27%)
b1138	Reconductor the King Farm – Sony 138 kV line with 954 ACSR		APS (100%)
b1139	Reconductor the Yukon – Waltz Mills 138 kV line with high temperature conductor		APS (100%)
b1140	Reconductor the Bracken Junction – Luxor 138 kV line with 954 ACSR		APS (100%)
b1141	Reconductor the Sewickley – Waltz Mills Tap 138 kV line with high temperature conductor		APS (100%)
b1142	Reconductor the Bartonsville – Stephenson 138 kV; Stonewall – Stephenson 138 kV line with 954 ACSR		APS (100%)
b1143	Reconductor the Youngwood – Yukon 138 kV line with high temperature conductor		APS (89.92%) / PENELEC (10.08%)
b1144	Reconductor the Bull Creek Junction – Cabot 138 kV line with high temperature conductor		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1145	Reconductor the Lawson Junction – Cabot 138 kV line with high temperature conductor		APS (100%)
b1146	Replace Layton - Smithton #61 138 kV line structures to increase line rating		APS (100%)
b1147	Replace Smith – Yukon 138 kV line structures to increase line rating		APS (100%)
b1148	Reconductor the Loyalhanna – Luxor 138 kV line with 954 ACSR		APS (100%)
b1149	Reconductor the Luxor – Stony Springs Junction 138 kV line with 954 ACSR		APS (100%)
b1150	Upgrade terminal equipment at Social Hall		APS (100%)
b1151	Reconductor the Greenwood – Redbud 138 kV line with 954 ACSR		APS (100%)
b1152	Reconductor Grand Point – South Chambersburg		APS (100%)
b1159	Replace Peters 138 kV breaker 'Bethel P OCB'		APS (100%)
b1160	Replace Peters 138 kV breaker 'Cecil OCB'		APS (100%)
b1161	Replace Peters 138 kV breaker 'Union JctOCB'		APS (100%)
b1162	Replace Double Toll Gate 138 kV breaker 'DRB-2'		APS (100%)
b1163	Replace Double Toll Gate 138 kV breaker 'DT 138 kV OCB'		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1164	Replace Cecil 138 kV breaker ‘Enlow OCB’		APS (100%)
b1165	Replace Cecil 138 kV breaker ‘South Fayette’		APS (100%)
b1166	Replace Wylie Ridge 138 kV breaker ‘W-9’		APS (100%)
b1167	Replace Reid 138 kV breaker ‘RI-2’		APS (100%)
b1171.1	Install the second Black Oak 500/138 kV transformer, two 138 kV breaker, and related substation work		BGE (20.76%) / DPL (3.14%) / Dominion (39.55%) / ME (2.71%) / PECO (3.36%) / PEPCO (30.48%)
b1171.3	Install six 500 kV breakers and remove BOL1 500 kV breaker at Black Oak		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1200	Reconductor Double Toll Gate – Greenwood 138 kV with 954 ACSR conductor		APS (100%)
b1221.1	Convert Carbon Center from 138 kV to a 230 kV ring bus		APS (100%)
b1221.2	Construct Bear Run 230 kV substation with 230/138 kV transformer		APS (100%)

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1239	Install a 138 kV 44 MVAR capacitor at Ridgeway substation		APS (100%)
b1240	Install a 138 kV 44 MVAR capacitor at Elko Substation		APS (100%)
b1241	Upgrade terminal equipment at Washington substation on the GE Plastics/DuPont terminal		APS (100%)
b1242	Replace structures between Collins Ferry and West Run		APS (100%)
b1243	Install a 138 kV capacitor at Potter Substation		APS (100%)
b1261	Replace Butler 138 kV breaker ‘1-2 BUS 138’		APS (100%)
b1383	Install 2nd 500/138 kV transformer at 502 Junction		APS (93.27%) / DL (5.39%) / PENELEC (1.34%)
b1384	Reconductor approximately 2.17 miles of Bedington – Shepherdstown 138 kV with 954 ACSR		APS (100%)
b1385	Reconductor Halfway – Paramount 138 kV with 1033 ACCR		APS (100%)
b1386	Reconductor Double Tollgate – Meadow Brook 138 kV ckt 2 with 1033 ACCR		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)
b1387	Reconductor Double Tollgate – Meadow Brook 138 kV		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)
b1388	Reconductor Feagans Mill – Millville 138 kV with 954 ACSR		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1389	Reconductor Bens Run – St. Mary's 138 kV with 954 ACSR		AEP (12.40%) / APS (17.80%) / DL (69.80%)
b1390	Replace Bus Tie Breaker at Opequon		APS (100%)
b1391	Replace Line Trap at Gore		APS (100%)
b1392	Replace structure on Belmont – Trissler 138 kV line		APS (100%)
b1393	Replace structures Kingwood – Pruntytown 138 kV line		APS (100%)
b1395	Upgrade Terminal Equipment at Kittanning		APS (100%)
b1401	Change reclosing on Pruntytown 138 kV breaker 'P-16' to 1 shot at 15 seconds		APS (100%)
b1402	Change reclosing on Rivesville 138 kV breaker 'Pruntytown #34' to 1 shot at 15 seconds		APS (100%)
b1403	Change reclosing on Yukon 138 kV breaker 'Y21 Shepler' to 1 shot at 15 seconds		APS (100%)
b1404	Replace the Kiski Valley 138 kV breaker 'Vandergrift' with a 40 kA breaker		APS (100%)
b1405	Change reclosing on Armstrong 138 kV breaker 'GARETTRJCT' at 1 shot at 15 seconds		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1406	Change reclosing on Armstrong 138 kV breaker 'KITTANNING' to 1 shot at 15 seconds		APS (100%)
b1407	Change reclosing on Armstrong 138 kV breaker 'BURMA' to 1 shot at 15 seconds		APS (100%)
b1408	Replace the Weirton 138 kV breaker 'Tidd 224' with a 40 kA breaker		APS (100%)
b1409	Replace the Cabot 138 kV breaker 'C9 Kiski Valley' with a 40 kA breaker		APS (100%)
b1507.2	Terminal Equipment upgrade at Doubs substation		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1507.3	Mt. Storm – Doubs transmission line rebuild in Maryland – Total line mileage for APS is 2.71 miles		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1510	Install 59.4 MVAR capacitor at Waverly		APS (100%)
b1672	Install a 230 kV breaker at Carbon Center		APS (100%)
b0539	Replace Doubs circuit breaker DJ11		APS (100%)
b0540	Replace Doubs circuit breaker DJ12		APS (100%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0541	Replace Doubs circuit breaker DJ13		APS (100%)
b0542	Replace Doubs circuit breaker DJ20		APS (100%)
b0543	Replace Doubs circuit breaker DJ21		APS (100%)
b0544	Remove instantaneous reclose from Eastalco circuit breaker D-26		APS (100%)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		AEC (*1.66%*) / AEP (*14.16%*) / APS (*5.73%*) / ATSI (*7.88%*) / BGE (*4.22%*) / ComEd (*13.31%*) / Dayton (*2.11%*) / DEOK (*3.29%*) / DL (*1.75%*) / DPL (*2.50%*) / Dominion (*12.86%*) / EKPC (*1.87%*) / JCPL (*3.74%*) / ME (*1.90%*) / NEPTUNE* (*0.44%*) / PECO (*5.34%*) / PENELEC (*1.89%*) / PEPCO (*3.99%*) / PPL (*4.84%*) / PSEG (*6.26%*) / RE (*0.26%*)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (*1.66%*) / AEP (*14.16%*) / APS (*5.73%*) / ATSI (*7.88%*) / BGE (*4.22%*) / ComEd (*13.31%*) / Dayton (*2.11%*) / DEOK (*3.29%*) / DL (*1.75%*) / DPL (*2.50%*) / Dominion (*12.86%*) / EKPC (*1.87%*) / JCPL (*3.74%*) / ME (*1.90%*) / NEPTUNE* (*0.44%*) / PECO (*5.34%*) / PENELEC (*1.89%*) / PEPCO (*3.99%*) / PPL (*4.84%*) / PSEG (*6.26%*) / RE (*0.26%*)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1803	Build a 300 MVAR Switched Shunt at Doubs 500 kV and increase (~50 MVAR) in size the existing Switched Shunt at Doubs 500 kV		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1804	Install a new 600 MVAR SVC at Meadowbrook 500kV		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1816.1	Replace relaying at the Mt. Airy substation on the Carroll - Mt. Airy 230 kV line		APS (100%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1816.2	Adjust the control settings of all existing capacitors at Mt Airy 34.5kV, Monocacy 138kV, Ringgold 138kV served by Potomac Edison's Eastern 230 kV network to ensure that all units will be on during the identified N-1-1 contingencies		APS (100%)
b1816.3	Replace existing unidirectional LTC controller on the No. 4, 230/138 kV transformer at Carroll substation with a bidirectional unit		APS (100%)
b1816.4	Isolate and bypass the 138 kV reactor at Germantown Substation		APS (100%)
b1816.6	Replace 336.4 ACSR conductor on the Catoctin - Carroll 138 kV line using 556.5 ACSR (26/7) or equivalent on existing structures (12.7 miles), 800 A wave traps at Carroll and Catoctin with 1200 A units, and 556.5 ACSR SCCIR (Sub-conductor) line risers and bus traps with 795 ACSR or equivalent		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1822	Replace the 1200 A wave trap, line risers, breaker risers with 1600 A capacity terminal equipment at Reid 138 kV SS		APS (100%)
b1823	Replace the 800 A wave trap with a 1200 A wave trap at Millville 138 kV substation		APS (100%)
b1824	Reconductor Grant Point - Guilford 138kV line approximately 8 miles of 556 ACSR with 795 ACSR		APS (100%)
b1825	Replace the 800 Amp line trap at Butler 138 kV Sub on the Cabot East 138 kV line		APS (100%)
b1826	Change the CT ratio at Double Toll Gate 138 kV SS on MDT line		APS (100%)
b1827	Change the CT ratio at Double Toll Gate 138 kV SS on MBG line		APS (100%)
b1828.1	Reconductor the Bartonville – Stephenson 3.03 mile 138 kV line of 556 ACSR with 795 ACSR		APS (100%)

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

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1835	Reconductor 14.3 miles of 556 ACSR with 795 ACSR from Old Chapel to Millville 138 kV and upgrade line risers at Old Chapel 138 kV and Millville 138 kV and replace 1200 A wave trap at Millville 138 kV		APS (37.68%) / Dominion (34.46%) / PEPCO (13.69%) / BGE (11.45%) / ME (2.01%) / PENELEC (0.53%) / DL (0.18%)
b1836	Replace 1200 A wave trap with 1600 A wave trap at Reid 138 kV SS		APS (100%)
b1837	Replace 750 CU breaker risers with 795 ACSR at Marlowe 138 kV and replace 1200 A wave traps with 1600 A wave traps at Marlowe 138 kV and Bedington 138 kV		APS (100%)
b1838	Replace the 1200 A Bedington 138 kV line air switch and the 1200 A 138 kV bus tie air switch at Nipetown 138 kV with 1600 A switches		APS (100%)
b1839	Install additional 33 MVAR capacitors at Grand Point 138 kV SS and Guildford 138 kV SS		APS (100%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1840	Construct a 138 kV line between Buckhannon and Weston 138 kV substations		APS (100%)
b1902	Replace line trap at Stonewall on the Stephenson 138 kV line terminal		APS (100%)
b1941	Loop the Homer City-Handsome Lake 345 kV line into the Armstrong substation and install a 345/138 kV transformer at Armstrong		APS (67.86%) / PENELEC (32.14%)
b1942	Change the CT ratio at Millville to improve the Millville – Old Chapel 138 kV line ratings		APS (100%)
b1964	Convert Moshannon substation to a 4 breaker 230 kV ring bus		APS (41.06%) / DPL (6.68%) / JCPL (5.48%) / ME (10.70%) / Neptune* (0.53%) / PECO (15.53%) / PPL (20.02%)
b1965	Install a 44 MVAR 138 kV capacitor at Luxor substation		APS (100%)
b1986	Upgrade the AP portion of the Elrama – Mitchell 138 kV line by replace breaker risers on the Mitchell 138 kV bus on the Elrama terminal		APS (100%)
b1987	Reconductor the Osage-Collins Ferry 138 kV line with 795 ACSS. Upgrade terminal equipment at Osage and Collins Ferry		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1988	Raise structures between Lake Lynn and West Run to eliminate the clearance de-rates on the West Run – Lake Lynn 138 kV line		APS (100%)
b1989	Raise structures between Collins Ferry and West Run to eliminate the clearance de-rates on the Collins Ferry - West Run 138 kV line		APS (100%)
b2095	Replace Weirt 138 kV breaker 'S-TORONTO226' with 63kA rated breaker		APS (100%)
b2096	Revise the reclosing of Weirt 138 kV breaker '2&5 XFMR'		APS (100%)
b2097	Replace Ridgeley 138 kV breaker '#2 XFMR OCB'		APS (100%)
b2098	Revise the reclosing of Ridgeley 138 kV breaker 'AR3' with 40kA rated breaker		APS (100%)
b2099	Revise the reclosing of Ridgeley 138 kV breaker 'RC1'		APS (100%)
b2100	Replace Ridgeley 138 kV breaker 'WC4' with 40kA rated breaker		APS (100%)
b2101	Replace Ridgeley 138 kV breaker '1 XFMR OCB' with 40kA rated breaker		APS (100%)
b2102	Replace Armstrong 138 kV breaker 'GARETTRJCT' with 40kA rated breaker		APS (100%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2103	Replace Armstrong 138 kV breaker 'BURMA' with 40kA rated breaker		APS (100%)
b2104	Replace Armstrong 138 kV breaker 'KITTANNING' with 40kA rated breaker		APS (100%)
b2105	Replace Armstrong 138 kV breaker 'KISSINGERJCT' with 40kA rated breaker		APS (100%)
b2106	Replace Wylie Ridge 345 kV breaker 'WK-1' with 63kA rated breaker		APS (100%)
b2107	Replace Wylie Ridge 345 kV breaker 'WK-2' with 63kA rated breaker		APS (100%)
b2108	Replace Wylie Ridge 345 kV breaker 'WK-3' with 63kA rated breaker		APS (100%)
b2109	Replace Wylie Ridge 345 kV breaker 'WK-4' with 63kA rated breaker		APS (100%)
b2110	Replace Wylie Ridge 345 kV breaker 'WK-6' with 63kA rated breaker		APS (100%)
b2111	Replace Wylie Ridge 138 kV breaker 'WK-7' with 63kA rated breaker		APS (100%)
b2112	Replace Wylie Ridge 345 kV breaker 'WK-5'		APS (100%)
b2113	Replace Weirton 138 kV breaker 'NO 6 XFMR' with 63kA rated breaker		APS (100%)
b2114	Replace Armstrong 138 kV breaker 'Bus-Tie' (Status On-Hold pending retirement)		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2124.1	Add a new 138 kV line exit		APS (100%)
b2124.2	Construct a 138 kV ring bus and install a 138/69 kV autotransformer		APS (100%)
b2124.3	Add new 138 kV line exit and install a 138/25 kV transformer		APS (100%)
b2124.4	Construct approximately 5.5 miles of 138 kV line		APS (100%)
b2124.5	Convert approximately 7.5 miles of 69 kV to 138 kV		APS (100%)
b2156	Install a 75 MVAR 230 kV capacitor at Shingletown Substation		APS (100%)
b2165	Replace 800A wave trap at Stonewall with a 1200 A wave trap		APS (100%)
b2166	Reconductor the Millville – Sleepy Hollow 138kV 4.25 miles of 556 ACSR with 795 ACSR, upgrade line risers at Sleepy Hollow, and change 1200 A CT tap at Millville to 800		APS (100%)
b2168	For Grassy Falls 138kV Capacitor bank adjust turn-on voltage to 1.0pu with a high limit of 1.04pu, For Crupperneck and Powell Mountain 138kV Capacitor Banks adjust turn-on voltage to 1.01pu with a high limit of 1.035pu		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2169	Replace/Raise structures on the Yukon-Smithton 138 kV line section to eliminate clearance de-rate		APS (100%)
b2170	Replace/Raise structures on the Smithton-Shepler Hill Jct 138 kV line section to eliminate clearance de-rate		APS (100%)
b2171	Replace/Raise structures on the Parsons-William 138 kV line section to eliminate clearance de-rate		APS (100%)
b2172	Replace/Raise structures on the Parsons - Loughs Lane 138 kV line section to eliminate clearance de-rate		APS (100%)

Attachment 7e (Delmarva OATT)

SCHEDULE 12 – APPENDIX

(3) Delmarva Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0144.1	Build new Red Lion – Milford – Indian River 230 kV circuit		DPL (100%)
b0144.2	Indian River Sub – 230 kV Terminal Position		DPL (100%)
b0144.3	Red Lion Sub – 230 kV Terminal Position		DPL (100%)
b0144.4	Milford Sub – (2) 230 kV Terminal Positions		DPL (100%)
b0144.5	Indian River – 138 kV Transmission Line to AT-20		DPL (100%)
b0144.6	Indian River – 138 & 69 kV Transmission Ckts. Undergrounding		DPL (100%)
b0144.7	Indian River – (2) 230 kV bus ties		DPL (100%)
b0148	Re-rate Glasgow – Mt. Pleasant 138 kV and North Seaford – South Harrington 138 kV		DPL (100%)
b0149	Complete structure work to increase rating of Cheswold – Jones REA 138 kV		DPL (100%)
b0221	Replace disconnect switch on Edgewood-N. Salisbury 69 kV		DPL (100%)
b0241.1	Keeny Sub – Replace overstressed breakers		DPL (100%)
b0241.2	Edgemoor Sub – Replace overstressed breakers		DPL (100%)
b0241.3	Red Lion Sub – Substation reconfigure to provide for second Red Lion 500/230 kV transformer		DPL (84.5%) / PECO (15.5%)
b0261	Replace 1200 Amp disconnect switch on the Red Lion – Reybold 138 kV circuit		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0262	Reconductor 0.5 miles of Christiana – Edgemoor 138 kV		DPL (100%)
b0263	Replace 1200 Amp wavetrap at Indian River on the Indian River – Frankford 138 kV line		DPL (100%)
b0272.1	Replace line trap and disconnect switch at Keeney 500 kV substation – 5025 Line Terminal Upgrade		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0282	Install 46 MVAR capacitors on the DPL distribution system		DPL (100%)
b0291	Replace 1600A disconnect switch at Harmony 230 kV and for the Harmony – Edgemoor 230 kV circuit, increase the operating temperature of the conductor		DPL (100%)
b0295	Raise conductor temperature of North Seaford – Pine Street – Dupont Seaford		DPL (100%)

*Neptune Regional Transmission System, LLC

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0296	Rehoboth/Cedar Neck Tap (6733-2) upgrade		DPL (100%)
b0320	Create a new 230 kV station that splits the 2nd Milford to Indian River 230 kV line, add a 230/69 kV transformer, and run a new 69 kV line down to Harbeson 69 kV		DPL (100%)
b0382	Cambridge Sub – Close through to Todd Substation		DPL (100%)
b0383	Wye Mills AT-1 and AT-2 138/69 kV Replacements		DPL (100%)
b0384	Replace Indian River AT-20 (400 MVA)		DPL (100%)
b0385	Oak Hall to New Church (13765) Upgrade		DPL (100%)
b0386	Cheswold/Kent (6768) Rebuild		DPL (100%)
b0387	N. Seaford – Add a 2nd 138/69 kV autotransformer		DPL (100%)
b0388	Hallwood/Parksley (6790-2) Upgrade		DPL (100%)
b0389	Indian River AT-1 and AT-2 138/69 kV Replacements		DPL (100%)
b0390	Rehoboth/Lewes (6751-1 and 6751-2) Upgrade		DPL (100%)
b0391	Kent/New Meredith (6704-2) Upgrade		DPL (100%)
b0392	East New Market Sub – Establish a 69 kV Bus Arrangement		DPL (100%)
b0415	Increase the temperature ratings of the Edgemoor – Christiana – New Castle 138 kV by replacing six transmission poles		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0437	Spare Keeney 500/230 kV transformer		DPL (100%)
b0441	Additional spare Keeney 500/230 kV transformer		DPL (100%)
b0480	Rebuild Lank – Five Points 69 kV		DPL (100%)
b0481	Replace wave trap at Indian River 138 kV on the Omar – Indian River 138 kV circuit		DPL (100%)
b0482	Rebuild Millsboro – Zoar REA 69 kV		DPL (100%)
b0483	Replace Church 138/69 kV transformer and add two breakers		DPL (100%)
b0483.1	Build Oak Hall – Wattsville 138 kV line		DPL (100%)
b0483.2	Add 138/69 kV transformer at Wattsville		DPL (100%)
b0483.3	Establish 138 kV bus position at Oak Hall		DPL (100%)
b0484	Re-tension Worcester – Berlin 69 kV for 125ºC		DPL (100%)
b0485	Re-tension Taylor – North Seaford 69 kV for 125ºC		DPL (100%)
b0494.1	Install a 2nd Red Lion 230/138 kV		DPL (100%)
b0494.2	Hares Corner – Relay Improvement		DPL (100%)
b0494.3	Reybold – Relay Improvement		DPL (100%)
b0494.4	New Castle – Relay Improvement		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0513	Rebuild the Ocean Bay – Maridel 69 kV line		DPL (100%)
b0527	Replace existing 12 MVAR capacitor at Bethany with a 30 MVAR capacitor		DPL (100%)
b0528	Replace existing 69/12 kV transformer at Bethany with a 138/12 kV transformer		DPL (100%)
b0529	Install an additional 8.4 MVAR capacitor at Grasonville 69 Kv		DPL (100%)
b0530	Replace existing 12 MVAR capacitor at Wye Mills with a 30 MVAR capacitor		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0531	Create a four breaker 138 kV ring bus at Wye Mills and add a second 138/69 kV transformer		DPL (100%)
b0566	Rebuild the Trappe Tap – Todd 69 kV line		DPL (100%)
b0567	Rebuild the Mt. Pleasant – Townsend 138 kV line		DPL (100%)
b0568	Install a third Indian River 230/138 kV transformer		DPL (100%)
b0725	Add a third Steele 230/138 kV transformer		DPL (100%)
b0732	Rebuild Vaugh – Wells 69 kV		DPL (100%)
b0733	Add a second 230/138 kV transformer at Harmony		DPL (97.06%) / PECO (2.94%)
b0734	Rebuild Church – Steele 138 kV		DPL (100%)
b0735	Rebuild Indian River – Omar – Bethany 138 kV		DPL (100%)
b0736	Rebuild Dupont Edgemoor – Edgemoor – Silverside 69 kV		DPL (69.65%) / PECO (17.30%) / PSEG (12.56%) / RE (0.49%)
b0737	Build a new Indian River – Bishop 138 kV line		DPL (100%)
b0750	Convert 138 kV network path from Vienna – Loretto – Piney - Grove to 230 kV, add 230/138 kV transformer to Loretto 230 kV		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0751	Add two additional breakers at Keeney 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0752	Replace two circuit breakers to bring the emergency rating up to 348 MVA		DPL (100%)
b0753	Add a second Loretto 230/138 kV transformer		DPL (100%)
b0754	Rebuild 10 miles of Glasgow to Mt. Pleasant 138 kV line to bring the normal rating to 298 MVA and the emergency rating to 333 MVA		DPL (100%)
b0792	Reconfigure Cecil Sub into 230 and 138 kV ring buses, add a 230/138 kV transformer, and operate the 34.5 kV bus normally open		DPL (100%)
b0873	Build 2nd Glasgow-Mt Pleasant 138 kV line		DPL (100%)
b0874	Reconfigure Brandywine substation		DPL (100%)

*Neptune Regional Transmission System, LLC

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0876	Install 50 MVAR SVC at 138th St 138 kV		DPL (100%)
b0877	Build a 2nd Vienna-Steele 230 kV line		DPL (100%)
b0879.1	Apply a special protection scheme (load drop at Stevensville and Grasonville)		DPL (100%)
b1246	Re-build the Townsend – Church 138 kV circuit		DPL (100%)
b1247	Re-build the Glasgow – Cecil 138 kV circuit		DPL (72.06%) / PECO (27.94%)
b1248	Install two 15 MVAR capacitor at Loretto 69 kV		DPL (100%)
b1249	Reconfigure the existing Sussex 69 kV capacitor		DPL (100%)
b1603	Upgrade 19 miles conductor of the Wattsville - Signepost - Stockton - Kenney 69 kV circuit		DPL (100%)
b1604	Replace CT at Reybold 138 kV substation		DPL (100%)
b1723	Replace strand bus and disconnect switch at Glasgow 138 kV substation		DPL (100%)
b1899.1	Install new variable reactors at Indian River and Nelson 138 kV		DPL (100%)

* Neptune Regional Transmission System, LLC

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-3.

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1899.2	Install new variable reactors at Cedar Creek 230 kV		DPL (100%)
b1899.3	Install new variable reactors at New Castle 138 kV and Easton 69 kV		DPL (100%)

SCHEDULE 12 – APPENDIX A

(3) Delmarva Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2288	Build a new 138kV line from Piney Grove - Wattsville		DPL (100%)
b2395	Reconductor the Harmony - Chapel St 138 kV circuit		DPL (100%)
b2569	Replace Terminal equipment at Silverside 69 kV substation		DPL (100%)
b2633.7	Implement high speed relaying utilizing OPGW on Red Lion – Hope Creek 500 kV line		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.10	Interconnect the new Silver Run 230 kV substation with existing Red Lion – Cartanza and Red Lion – Cedar Creek 230 kV lines		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)

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

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2695	Rebuild Worcester – Ocean Pine 69 kV ckt. 1 to 1400A capability summer emergency		DPL (100%)

Attachment 7f (ACE OATT)

SCHEDULE 12 – APPENDIX

(1) Atlantic City Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0135	Build new Cumberland – Dennis 230 kV circuit which replaces existing Cumberland – Corson 138 kV		AEC (100%)
b0136	Install Dennis 230/138 kV transformer, Dennis 150 MVAR SVC and 50 MVAR capacitor		AEC (100%)
b0137	Build new Dennis – Corson 138 kV circuit		AEC (100%)
b0138	Install Cardiff 230/138 kV transformer and a 50 MVAR capacitor at Cardiff		AEC (100%)
b0139	Build new Cardiff – Lewis 138 kV circuit		AEC (100%)
b0140	Reconductor Laurel – Woodstown 69 kV		AEC (100%)
b0141	Reconductor Monroe – North Central 69 kV		AEC (100%)
b0265	Upgrade AE portion of Delco Tap – Mickleton 230 kV circuit		AEC (89.87%) / JCPL (9.48%) / Neptune* (0.65%)
b0276	Replace both Monroe 230/69 kV transformers		AEC (91.46%) / PSEG (8.31%) / RE (0.23%)
b0276.1	Upgrade a strand bus at Monroe to increase the rating of transformer #2		AEC (100%)
b0277	Install a second Cumberland 230/138 kV transformer		AEC (100%)
b0281.1	Install 35 MVAR capacitor at Lake Ave 69 kV substation		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0281.2	Install 15 MVAR capacitor at Shipbottom 69 kV substation		AEC (100%)
b0281.3	Install 8 MVAR capacitors on the AE distribution system		AEC (100%)
b0142	Reconductor Landis – Minotola 138 kV		AEC (100%)
b0143	Reconductor Beckett – Paulsboro 69 kV		AEC (100%)
b0210	Install a new 500/230kV substation in AEC area. The high side will be tapped on the Salem - East Windsor 500kV circuit and the low side will be tapped on the Churchtown - Cumberland 230kV circuit.		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0210.1	Orchard – Cumberland – Install second 230 kV line		AEC (65.23%) / JCPL (25.87%) / Neptune * (2.55%) / PSEG (6.35%)††
b0210.2	Install a new 500/230kV substation in AEC area, the high side will be tapped on the Salem - East Windsor 500kV circuit and the low side will be tapped on the Churchtown - Cumberland 230kV circuit.		AEC (65.23%) / JCPL (25.87%) / Neptune* (2.55%) / PSEG (6.35%)††

* Neptune Regional Transmission System, LLC

†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project

††Cost allocations associated with below 500 kV elements of the project

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-1.

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0211	Reconductor Union - Corson 138kV circuit		AEC (65.23%) / JCPL (25.87%) / Neptune* (2.55%) / PSEG (6.35%)
b0212	Substation upgrades at Union and Corson 138kV		AEC (65.23%) / JCPL (25.87%) / Neptune* (2.55%) / PSEG (6.35%)
b0214	Install 50 MVAR capacitor at Cardiff 230kV substation		AEC (100%)
b0431	Monroe Upgrade New Freedom strand bus		AEC (100%)
b0576	Move the Monroe 230/69 kV to Mickleton		AEC (100%)
b0744	Upgrade a strand bus at Mill 138 kV		AEC (100%)
b0871	Install 35 MVAR capacitor at Motts Farm 69 kV		AEC (100%)
b1072	Modify the existing EMS load shedding scheme at Cedar to additionally sense the loss of both Cedar 230/69 kV transformers and shed load accordingly		AEC (100%)
b1127	Build a new Lincoln-Minitola 138 kV line		AEC (100%)
b1195.1	Upgrade the Corson sub T2 terminal		AEC (100%)
b1195.2	Upgrade the Corson sub T1 terminal		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1244	Install 10 MVAR capacitor at Peermont 69 kV substation		AEC (100%)
b1245	Rebuild the Newport-South Millville 69 kV line		AEC (100%)
b1250	Reconductor the Monroe – Glassboro 69 kV		AEC (100%)
b1250.1	Upgrade substation equipment at Glassboro		AEC (100%)
b1280	Sherman: Upgrade 138/69 kV transformers		AEC (100%)
b1396	Replace Lewis 138 kV breaker 'L'		AEC (100%)
b1398.5	Reconductor the existing Mickleton – Goucestr 230 kV circuit (AE portion)		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)
b1598	Reconductor Sherman Av – Carl's Corner 69kV circuit		AEC (100%)
b1599	Replace terminal equipments at Central North 69 kV substation		AEC (100%)
b1600	Upgrade the Mill T2 138/69 kV transformer		AEC (89.21%) / JCPL (4.76%) / PSEG (5.80%) / RE (0.23%)
b2157	Re-build 5.3 miles of the Corson - Tuckahoe 69 kV circuit		AEC (100%)

* Neptune Regional Transmission System, LLC

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-1.

Attachment 7g (PEPCO OATT)

SCHEDULE 12 – APPENDIX

(10) Potomac Electric Power Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0146	Installation of (2) new 230 kV circuit breakers at Quince Orchard substation on circuits 23028 and 23029		PEPCO (100%)
b0219	Install two new 230 kV circuits between Palmers Corner and Blue Plains		PEPCO (100%)
b0228	Upgrade Burtonsville – Sandy Springs 230 kV circuit		PEPCO (100%)
b0238.1	Modify Dickerson Station H 230 kV		PEPCO (100%)
b0251	Install 100 MVAR of 230 kV capacitors at Bells Mill		PEPCO (100%)
b0252	Install 100 MVAR of 230 kV capacitors at Bells Mill		PEPCO (100%)
b0288	Brighton Substation – add 2nd 1000 MVA 500/230 kV transformer, 2 500 kV circuit breakers and miscellaneous bus work		BGE (19.33%) / Dominion (17%) / PEPCO (63.67%)
b0319	Add a second 1000 MVA Bruches Hill 500/230 kV transformer		PEPCO (100%)
b0366	Install a 4th Ritchie 230/69 kV transformer		PEPCO (100%)

* Neptune Regional Transmission System, LLC

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-9.

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0367.1	Reconductor circuit "23035" for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (26.54%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (4.80%) / PEPCO (52.50%) / PPL (3.23%) / PSEG (3.82%)
b0367.2	Reconductor circuit "23033" for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (26.54%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (4.80%) / PEPCO (52.50%) / PPL (3.23%) / PSEG (3.82%)
b0375	Install 0.5% reactor at Dickerson on the Pleasant View – Dickerson 230 kV circuit		AEC (1.02%) / BGE (25.42%) / DPL (2.97%) / ME (1.72%) / PECO (3.47%) / PEPCO (65.40%)
b0467.1	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.70%) / BGE (22.13%) / DPL (3.70%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.54%) / PEPCO (41.86%) / PPL (2.07%)
b0478	Reconductor the four circuits from Burches Hill to Palmers Corner		APS (1.68%) / BGE (1.83%) / PEPCO (96.49%)
b0496	Replace existing 500/230 kV transformer at Brighton		APS (5.67%) / BGE (29.68%) / Dominion (10.91%) / PEPCO (53.74%)
b0499	Install third Burches Hill 500/230 kV transformer		APS (3.54%) / BGE (7.31%) / PEPCO (89.15%)

*Neptune Regional Transmission System, LLC

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-9.

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.7	Advance n0772 (Replace Chalk Point 230 kV breaker (1A) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.8	Advance n0773 (Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.9	Advance n0774 (Replace Chalk Point 230 kV breaker (2A) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.10	Advance n0775 (Replace Chalk Point 230 kV breaker (2B) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.11	Advance n0776 (Replace Chalk Point 230 kV breaker (2C) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.12	Advance n0777 (Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.13	Advance n0778 (Replace Chalk Point 230 kV breaker (3B) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.14	Advance n0779 (Replace Chalk Point 230 kV breaker (3C) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.15	Advance n0780 (Replace Chalk Point 230 kV breaker (4A) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.16	Advance n0781 (Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.17	Advance n0782 (Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.18	Advance n0783 (Replace Chalk Point 230 kV breaker (5B) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.19	Advance n0784 (Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.20	Advance n0785 (Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.21	Advance n0786 (Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.22	Advance n0787 (Replace Chalk Point 230 kV breaker (8A) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.23	Advance n0788 (Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.24	Advance n0789 (Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.25	Advance n0790 (Replace Chalk Point 230 Kv breaker (1C) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.26	Advance n0791 (Replace Chalk Point 230 Kv breaker (4C) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.27	Advance n0792 (Replace Chalk Point 230 Kv breaker (5C) with 80 kA breaker)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.28	Advance n0793 (Replace Chalk Point 230 Kv breaker (6C) with 80 kA breaker)		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0512.29	Advance n0794 (Replace Chalk Point 230 Kv breaker (7C) with 80 kA breaker)		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0526	Build two Ritchie – Benning Station A 230 kV lines		AEC (0.77%) / BGE (16.76%) / DPL (1.22%) / JCPL (1.39%) / ME (0.59%) / Neptune* (0.13%) / PECO (2.10%) / PEPCO (74.86%) / PSEG (2.10%) / RE (0.08%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0561	Install 300 MVAR capacitor at Dickerson Station “D” 230 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
b0562	Install 500 MVAR capacitor at Brighton 230 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
b0637	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0638	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0639	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0640	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0641	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0642	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0643	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0644	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0645	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0646	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0647	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0648	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0649	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0701	Expand Benning 230 kV station, add a new 250 MVA 230/69 kV transformer at Benning Station 'A', new 115 kV Benning switching station		BGE (30.57%) / PEPCO (69.43%)
b0702	Add a second 50 MVAR 230 kV shunt reactor at the Benning 230 kV substation		PEPCO (100%)
b0720	Upgrade terminal equipment on both lines		PEPCO (100%)
b0721	Upgrade Oak Grove – Ritchie 23061 230 kV line		PEPCO (100%)
b0722	Upgrade Oak Grove – Ritchie 23058 230 kV line		PEPCO (100%)
b0723	Upgrade Oak Grove – Ritchie 23059 230 kV line		PEPCO (100%)
b0724	Upgrade Oak Grove – Ritchie 23060 230 kV line		PEPCO (100%)
b0730	Add slow oil circulation to the four Bells Mill Road – Bethesda 138 kV lines, add slow oil circulation to the two Buzzard Point – Southwest 138 kV lines; increasing the thermal ratings of these six lines allows for greater adjustment of the O Street phase shifters		PEPCO (100%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0731	Implement an SPS to automatically shed load on the 34 kV Bells Mill Road bus for this N-2 condition. The SPS will be in effect for 2013 and 2014 until a third Bells Mill 230/34 kV is placed in-service in 2015		PEPCO (100%)
b0746	Upgrade circuit for 3,000 amps using the ACCR		AEC (0.73%) / BGE (31.05%) / DPL (1.45%) / PECO (2.46%) / PEPCO (62.88%) / PPL (1.43%)
b0747	Upgrade terminal equipment on both lines: Quince Orchard - Bells Mill 230 kV (030) and (028)		PEPCO (100%)
b0802	Advance n0259 (Replace Dickerson Station H Circuit Breaker 412A)		PEPCO (100%)
b0803	Advance n0260 (Replace Dickerson Station H Circuit Breaker 42A)		PEPCO (100%)
b0804	Advance n0261 (Replace Dickerson Station H Circuit Breaker 42C)		PEPCO (100%)
b0805	Advance n0262 (Replace Dickerson Station H Circuit Breaker 43A)		PEPCO (100%)
b0806	Advance n0264 (Replace Dickerson Station H Circuit Breaker 44A)		PEPCO (100%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0809	Advance n0267 (Replace Dickerson Station H Circuit Breaker 45B)		PEPCO (100%)
b0810	Advance n0270 (Replace Dickerson Station H Circuit Breaker 47A)		PEPCO (100%)
b0811	Advance n0726 (Replace Dickerson Station H Circuit Breaker SPARE)		PEPCO (100%)
b0845	Replace Chalk Point 230 kV breaker (1A) with 80 kA breaker		PEPCO (100%)
b0846	Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker		PEPCO (100%)
b0847	Replace Chalk Point 230 kV breaker (2A) with 80 kA breaker		PEPCO (100%)
b0848	Replace Chalk Point 230 kV breaker (2B) with 80 kA breaker		PEPCO (100%)
b0849	Replace Chalk Point 230 kV breaker (2C) with 80 kA breaker		PEPCO (100%)
b0850	Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker		PEPCO (100%)
b0851	Replace Chalk Point 230 kV breaker (3B) with 80 kA breaker		PEPCO (100%)
b0852	Replace Chalk Point 230 kV breaker (3C) with 80 kA breaker		PEPCO (100%)
b0853	Replace Chalk Point 230 kV breaker (4A) with 80 kA breaker		PEPCO (100%)
b0854	Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker		PEPCO (100%)
b0855	Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker		PEPCO (100%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0856	Replace Chalk Point 230 kV breaker (5B) with 80 kA breaker		PEPCO (100%)
b0857	Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker		PEPCO (100%)
b0858	Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		PEPCO (100%)
b0859	Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker		PEPCO (100%)
b0860	Replace Chalk Point 230 kV breaker (8A) with 80 kA breaker		PEPCO (100%)
b0861	Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker		PEPCO (100%)
b0862	Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker		PEPCO (100%)
b0863	Replace Chalk Point 230 kV breaker (1C) with 80 kA breaker		PEPCO (100%)
b1104	Replace Burtonsville 230 kV breaker ‘1C’		PEPCO (100%)
b1105	Replace Burtonsville 230 kV breaker ‘2C’		PEPCO (100%)
b1106	Replace Burtonsville 230 kV breaker ‘3C’		PEPCO (100%)
b1107	Replace Burtonsville 230 kV breaker ‘4C’		PEPCO (100%)
b1125	Convert the 138 kV line from Buzzard 138 - Ritchie 851 to a 230 kV line and Remove 230/138 kV Transformer at Ritchie and install a spare 230/138 kV transformer at Buzzard Pt		APS (4.74%) / PEPCO (95.26%)
b1126	Upgrade the 230 kV line from Buzzard 016 – Ritchie 059		APS (4.74%) / PEPCO (95.26%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1592	Reconductor the Oak Grove – Bowie 230 kV circuit and upgrade terminal equipments at Oak Grove and Bowie 230 kV substations		AEC (2.40%) / APS (3.83%) / BGE (65.87%) / DPL (4.44%) / JCPL (3.94%) / ME (2.16%) / Neptune* (0.39%) / PECO (8.37%) / PPL (2.84%) / PSEG (5.54%) / RE (0.22%)
b1593	Reconductor the Bowie - Burtonsville 230 kV circuit and upgrade terminal equipments at Bowie and Burtonsville 230 kV substations		AEC (2.40%) / APS (3.83%) / BGE (65.87%) / DPL (4.44%) / JCPL (3.94%) / ME (2.16%) / Neptune* (0.39%) / PECO (8.37%) / PPL (2.84%) / PSEG (5.54%) / RE (0.22%)
b1594	Reconductor the Oak Grove – Bowie 230 kV ‘23042’ circuit and upgrade terminal equipments at Oak Grove and Bowie 230 kV substations		AEC (2.39%) / APS (3.85%) / BGE (65.87%) / DPL (4.45%) / JCPL (3.94%) / ME (2.16%) / Neptune* (0.39%) / PECO (8.35%) / PPL (2.84%) / PSEG (5.54%) / RE (0.22%)
b1595	Reconductor the Bowie – Burtonsville 230 kV ‘23042’ circuit and upgrade terminal equipments at Oak Grove and Burtonsville 230 kV substations		AEC (2.39%) / APS (3.85%) / BGE (65.87%) / DPL (4.45%) / JCPL (3.94%) / ME (2.16%) / Neptune* (0.39%) / PECO (8.35%) / PPL (2.84%) / PSEG (5.54%) / RE (0.22%)
b1596	Reconductor the Dickerson station “H” – Quince Orchard 230 kV ‘23032’ circuit and upgrade terminal equipments at Dickerson station “H” and Quince Orchard 230 kV substations		AEC (0.80%) / BGE (33.68%) / DPL (2.09%) / PECO (3.07%) / PEPCO (60.36%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1597	Reconductor the Oak Grove - Aquasco 230 kV '23062' circuit and upgrade terminal equipments at Oak Grove and Aquasco 230 kV substations		AEC (1.44%) / BGE (48.60%) / DPL (2.52%) / PECO (5.00%) / PEPCO (42.44%)
b2008	Reconductor feeder 23032 and 23034 to high temp. conductor (10 miles)		BGE (33.05%) / DPL (1.38%) / PECO (1.35%) / PEPCO (64.22%) /
b2136	Reconductor the Morgantown - V3-017 230 kV '23086' circuit and replace terminal equipments at Morgantown		PEPCO (100%)
b2137	Reconductor the Morgantown - Talbert 230 kV '23085' circuit and replace terminal equipment at Morgantown		PEPCO (100%)
b2138	Replace terminal equipments at Hawkins 230 kV substation		PEPCO (100%)

Attachment 7h (PPL OATT)

SCHEDULE 12 – APPENDIX

(9) PPL Electric Utilities Corporation

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0074	Rebuild 12 miles of S. Akron – Berks 230 kV to double circuit, looping Met Ed's S. Lebanon – S. Reading line into Berks; replacement of S. Reading 230 kV breaker 107252		PPL (100%)
b0171.2	Replace wavetrap at Hosensack 500kV substation to increase rating of Elroy - Hosensack 500 kV		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0172.1	Replace wave trap at Alburtis 500kV substation		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.2	Replace two wave traps at Juniata 500 kV – on the two Juniata – Airydale 500 kV		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0284.4	Changes at Juniata 500 kV substation		PPL (100%)
b0293.1	Replace wavetrap at the Martins Creek 230 kV bus		PPL (100%)
b0293.2	Raise the operating temperature of the 2-1590 ACSR to 140C for the Martins Creek – Portland 230 kV circuit		PPL (100%)
b0440	Spare Juniata 500/230 kV transformer		PPL (100%)
b0468	Build a new substation with two 150 MVA transformers between Dauphin and Hummelstown 230/69 kV substations by sectionalizing the Middletown Junction – New Lebanon 230 kV line		JCPL (4.56%) / Neptune* (0.37%) / PECO (1.79%) / PENELEC (0.33%) / PPL (86.79%) / PSEG (5.94%) / RE (0.22%)

* Neptune Regional Transmission System, LLC

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0469	Install 130 MVAR capacitor at West Shore 230 kV line		PPL (100%)
b0487	Build new 500 kV transmission facilities from Susquehanna to Pennsylvania – New Jersey border at Bushkill		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0487.1	Install Lackawanna 500/230 kV transformer and upgrade 230 kV substation and switchyard		PENELEC (16.93%) / PPL (77.74%) / PSEG (5.14%) / RE (0.19%)
b0500.1	Conastone – Otter Creek 230 kV – Reconductor approximately 17.2 miles of 795 kcmil ACSR with new 795 kcmil ACSS operated at 160 deg C		AEC (6.31%) / DPL (8.70%) / JCPL (14.62%) / ME (10.65%) / Neptune* (1.38%) / PECO (15.75%) / PPL (21.14%) / PSEG (20.68%) / RE (0.77%)

*Neptune Regional Transmission System, LLC

The Annual Revenue Requirements associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-8G.

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0558	Install 250 MVAR capacitor at Juniata 500 kV substation		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0593	Eldred – Pine Grove 69 kV line Rebuild Part 2: 8 miles		PPL (100%)
b0595	Rebuild Lackawanna – Edella 69 kV line to double circuit		PPL (100%)
b0596	Reconductor and rebuild Stanton – Providence 69 kV #1 and #2 lines with 69 kV design; approximately 8 miles total		PPL (100%)
b0597	Reconductor Suburban – Providence 69 kV #1 and resectionalize the Suburban 69 kV lines		PPL (100%)
b0598	Reconductor Suburban Taps #1 and #2 for 69 kV line portions		PPL (100%)

* Neptune Regional Transmission System, LLC

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0600	Tripp Park Substation: 69 kV tap off Stanton – Providence 69 kV line #3 to new substation		PPL (100%)
b0601	Jessup Substation: New 138/69 kV tap off of Peckville – Jackson 138/69 kV line		PPL (100%)
b0604	Add 150 MVA, 230/138/69 transformer #6 to Harwood substation		PPL (100%)
b0605	Reconductor Stanton – Old Forge 69 kV line and resectionalize the Jenkins – Scranton 69 kV #1 and #2 lines		PPL (100%)
b0606	New 138 kV tap off Monroe – Jackson 138 kV #1 line to Bartonsville substation		PPL (100%)
b0607	New 138 kV taps off Monroe – Jackson 138 kV lines to Stroudsburg substation		PPL (100%)
b0608	New 138 kV tap off Siegfried – Jackson 138 kV #2 to transformer #2 at Gilbert substation		PPL (100%)
b0610	At South Farmersville substation, a new 69 kV tap off Nazareth – Quarry #2 to transformer #2		PPL (100%)
b0612	Rebuild Siegfried – North Bethlehem portion (6.7 miles) of Siegfried – Quarry 69 kV line		PPL (100%)
b0613	East Tannersville Substation: New 138 kV tap to new substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0614	Elroy substation expansion and new Elroy – Hatfield 138/69 kV double circuit lines (1.9 miles)		PPL (100%)
b0615	Reconductor and rebuild 12 miles of Seidersville – Quakerstown 138/69 kV and a new 75 MVA, 230/69 kV transformer #4		PPL (100%)
b0616	New Springfield 230/69 kV substation and transmission line connections		PPL (100%)
b0620	New 138 kV line and terminal at Monroe 230/138 substation		PPL (100%)
b0621	New 138 kV line and terminal at Siegfried 230/138 kV substation and add a second circuit to Siegfried – Jackson for 8.0 miles		PPL (100%)
b0622	138 kV yard upgrades and transmission line rearrangements at Jackson 138/69 kV substation		PPL (100%)
b0623	New West Shore – Whitehill Taps 138/69 kV double circuit line (1.3 miles)		PPL (100%)
b0624	Reconductor Cumberland – Wertzville 69 kV portion (3.7 miles) of Cumberland – West Shore 69 kV line		PPL (100%)
b0625	Reconductor Mt. Allen – Rossmoyne 69 kV portions (1.6 miles) of West Shore – Cumberland #3 and #4 lines		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0627	Replace UG cable from Walnut substation to Center City Harrisburg substation for higher ampacity (0.25 miles)		PPL (100%)
b0629	Lincoln substation: 69 kV tap to convert to modified Twin A		PPL (100%)
b0630	W. Hempfield – Donegal 69 kV line: Reconductor / rebuild from Landisville Tap – Mt. Joy (2 miles)		PPL (100%)
b0631	W. Hempfield – Donegal 69 kV line: Reconductor / rebuild to double circuit from Mt. Joy – Donegal (2 miles)		PPL (100%)
b0632	Terminate new S. Manheim – Donegal 69 kV circuit into S. Manheim 69 kV #3		PPL (100%)
b0634	Rebuild S. Manheim – Fuller 69 kV portion (1.0 mile) of S. Manheim – West Hempfield 69 kV #3 line into a 69 kV double circuit		PPL (100%)
b0635	Reconductor Fuller Tap – Landisville 69 kV (4.1 miles) into a 69 kV double circuit		PPL (100%)
b0703	Berks substation modification on Berks – South Akron 230 kV line. Modification will isolate the line fault on the South Akron line and will allow Berks transformer #2 to be energized by the South Lebanon 230 kV circuit		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0705	New Derry – Millville 69 kV line		PPL (100%)
b0707	Construct Bohemia – Twin Lakes 69 kV line, install a 10.9 MVAR capacitor bank near Bohemia 69 kV substation		PPL (100%)
b0708	New 69 kV double circuit from Jackson – Lake Naomi Tap		PPL (100%)
b0709	Install new 69 kV double circuit from Carlisle – West Carlisle		PPL (100%)
b0710	Install a third 69 kV line from Reese's Tap to Hershey substation		PPL (100%)
b0711	New 69 kV that taps West Shore – Cumberland 69 kV #1 to Whitehill 69 kV substation		PPL (100%)
b0712	Construct a new 69 kV line between Strassburg Tap and the Millwood – Engleside 69 kV #1 line		PPL (100%)
b0713	Construct a new 138 kV double circuit line between Dillersville Tap and the West Hempfield – Prince 138 kV line		PPL (100%)
b0714	Prepare Roseville Tap for 138 kV conversion		PPL (100%)
b0715	Transfer S. Akron – S. Manheim #1 and #2 lines from the S. Akron 69 kV Yard to the S. Akron 138 kV Yard; Install switches on S. Akron – S. Manheim 138 kV #1 and #2 lines		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0716	Add a second 69 kV line from Morgantown – Twin Valley		PPL (100%)
b0717	Rebuild existing Brunner Island – West Shore 230 kV line and add a second Brunner Island – West Shore 230 kV line		PPL (100%)
b0718	SPS scheme to drop 190 MVA of 69 kV radial load at West Shore and 56 MVA of 69 kV radial load at Cumberland		PPL (100%)
b0719	SPS scheme at Jenkins substation to open the Stanton #1 and Stanton #2 230 kV circuit breakers after the second contingency		PPL (100%)
b0791	Add a fourth 230/69 kV transformer at Stanton		PENELEC (9.55%) / PPL (90.45%)
b1074	Install motor operators on the Jenkins 230 kV '2W' disconnect switch and build out Jenkins Bay 3 and have MOD '3W' operated as normally open		PPL (100%)
b0881	Install motor operators on Susquehanna T21 - Susquehanna 230 kV line East CB at Susquehanna 230 kV switching station		PPL (100%)
b0908	Install motor operators at South Akron 230 kV		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0909	Convert Jenkins 230 kV yard into a 3-breaker ring bus		PPL (100%)
b0910	Install a second 230 kV line between Jenkins and Stanton		PPL (100%)
b0911	Install motor operators at Frackville 230 kV		PPL (100%)
b0912	Install 2, 10.8 MVAR capacitor banks at Scranton 69 kV		PPL (100%)
b0913	Extend Cando Tap to the Harwood-Jenkins #2 69 kV line		PPL (100%)
b0914	Build a 3rd 69 kV line from Harwood to Valmont Taps		PPL (100%)
b0915	Replace Walnut-Center City 69 kV cable		PPL (100%)
b0916	Reconductor Sunbury-Dalmatia 69 kV line		PPL (100%)
b1021	Install a new (#4) 138/69 kV transformer at Wescosville		PPL (100%)
b1196	Remove the Siegfried bus tie breaker and install a new breaker on the Martins Creek 230 kV line west bay to maintain two ties between the 230 kV buses		PPL (100%)
b1201	Rebuild the Hercules Tap to Double Circuit 69 kV		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1202	Mack-Macungie Double Tap, Single Feed Arrangement		PPL (100%)
b1203	Add the 2nd Circuit to the East Palmerton-Wagners-Lake Naomi 138/69 kV Tap		PPL (100%)
b1204	New Breinigsville 230-69 kV Substation		PPL (100%)
b1205	Siegfried-East Palmerton #1 69 kV Line- Install new 69 kV LSAB, Sectionalize, and Transfer Treichlers Substation		PPL (100%)
b1206	Siegfried-Quarry #1 & #2 69 kV Lines- Rebuild 3.3 mi from Quarry Substation to Macada Taps		PPL (100%)
b1209	Convert Neffsville Taps from 69 kV to 138 kV Operation		PPL (100%)
b1210	Convert Roseville Taps from 69 kV to 138 kV Operation (Part 1 – operate on the 69 kV system)		PPL (100%)
b1211	Convert Roseville Taps from 69 kV to 138 kV Operation (Part 2 – operate on the 138 kV system)		PPL (100%)
b1212	New 138 kV Taps to Flory Mill 138/69 kV Substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1213	Convert East Petersburg Taps from 69 kV to 138 kV operation, install two 10.8 MVAR capacitor banks		PPL (100%)
b1214	Terminate South Manheim-Donegal #2 at South Manheim, Reduce South Manheim 69 kV Capacitor Bank, Resectionalize 69 kV		PPL (100%)
b1215	Reconductor and rebuild 16 miles of Peckville-Varden 69 kV line and 4 miles of Blooming Grove-Honesdale 69 kV line		PPL (100%)
b1216	Build approximately 2.5 miles of new 69 kV transmission line to provide a “double tap – single feed” connection to Kimbles 69/12 kV substation		PPL (100%)
b1217	Provide a “double tap – single feed” connection to Tafton 69/12 kV substation		PPL (100%)
b1524	Build a new Pocono 230/69 kV substation		PPL (100%)
b1524.1	Build approximately 14 miles new 230 kV South Pocono – North Pocono line		PPL (100%)
b1524.2	Install MOLSABs at Mt. Pocono substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1525	Build new West Pocono 230/69 kV Substation		PPL (100%)
b1525.1	Build approximately 14 miles new 230 kV Jenkins-West Pocono 230 kV Line		PPL (100%)
b1525.2	Install Jenkins 3E 230 kV circuit breaker		PPL (100%)
b1526	Install a new Honeybrook – Twin Valley 69/138 kV tie		PPL (100%)
b1527	Construct a new 230/69 kV North Lancaster substation. The sub will be supplied from the SAKR-BERK 230kV Line		PPL (100%)
b1527.1	Construct new 69/138 kV transmission from North Lancaster 230/69 kV sub to Brecknock and Honeybrook areas		PPL (100%)
b1528	Install Motor-Operated switches on the Wescosville-Trexlertown #1 & #2 69 kV lines at East Texas Substation		PPL (100%)
b1529	Add a double breaker 230 kV bay 3 at Hosensack		PPL (100%)
b1530	Replace Lock Haven 69kV ring bus with standard breaker and half design		PPL (100%)
b1532	Install new 32.4 MVAR capacitor bank at Sunbury		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1533	Rebuild Lycoming-Lock Haven #1 and Lycoming-Lock Haven #2 69kV lines		PPL (100%)
b1534	Rebuild 1.4 miles of the Sunbury-Milton 69kV		PPL (100%)
b1601	Re-configure the Breinigsville 500 kV substation with addition two 500 kV circuit breakers		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)†
b1602	Re-configure the Elimsport 230 kV substation to breaker and half scheme and install 80 MVAR capacitor		PPL (100%)
b1740	Install a 90 MVAR cap bank on the Frackville 230 kV bus #207973		PPL (100%)
b1756	Install a 3rd West Shore 230/69 kV transformer		PPL (100%)
b1757	Install a 230 kV motor-operated air-break switch on the Clinton - Elimsport 230 kV line		PPL (100%)

* Neptune Regional Transmission System, LLC

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1758	Rebuild 1.65 miles of Columbia - Danville 69 kV line		PPL (100%)
b1759	Install a 69 kV 16.2 MVAR Cap at Milton substation		PPL (100%)
b1760	Install motor operated devices on the existing disconnect switches that are located on each side of all four 230 kV CBs at Stanton		PPL (100%)
b1761	Build a new Paupack - North 230 kV line (Approximately 21 miles)		PPL (100%)
b1762	Replace 3.7 miles of the existing 230 kV Blooming Grove - Peckville line by building 8.4 miles of new 230 kV circuit onto the Lackawanna - Hopatcong tower-line		PPL (100%)
b1763	Re-terminate the Peckville - Jackson and the Peckville - Varden 69 kV lines from Peckville into Lackawanna		PPL (100%)
b1764	Build a new 230-69 kV substations (Paupack)		PPL (100%)
b1765	Install a 16.2 MVAR capacitor bank at Bohemia 69-12 kV substation		PPL (100%)
b1766	Reconductor/rebuild 3.3 miles of the Siegfried - Quarry #1 and #2 lines		PPL (100%)
b1767	Install 6 motor-operated disconnect switches at Quarry substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1788	Install a new 500 kV circuit breaker at Wescosville		PPL (100%)
b1890	Add a second 230/69 kV transformer at North Pocono (NE/Pocono Reliability Project)		PPL (100%)
b1891	Build a new 230/138 kV Yard at Lackawanna (138 kV conversion from Lackawanna to Jenkins)		PPL (100%)
b1892	Rebuild the Throop Taps for 138 kV operation (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1893	Swap the Staton - Old Forge and Stanton - Brookside 69 kV circuits at Stanton (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1894	Rebuild and re-conductor 2.5 miles of the Stanton - Avoca 69 kV line		PPL (100%)
b1895	Rebuild and re-conductor 4.9 miles of the Stanton - Providence #1 69 kV line		PPL (100%)
b1896	Install a second 230/138 kV transformer and expand the 138 kV yard at Monroe		PPL (100%)
b1897	Build a new 230/138 kV substation at Jenkins (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1898	Install a 69 kV Tie Line between Richfield and Dalmatia substations		PPL (100%)
b2004	Replace the CTs and switch in South Akron Bay 4 to increase the rating		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2005	Replace the CTs and switch in SAKR Bay 3 to increase the rating of the Millwood-South Akron 230 kV Line and of the rating in Bay 3		PPL (100%)
b2006	Install North Lancaster 500/230 kV substation (below 500 kV portion)		AEC (1.11%) / JCPL (9.68%) / ME (19.56%) / Neptune* (0.76%) / PECO (6.06%) / PPL (50.95%) / PSEG (11.43%) / RE (0.45%)
b2006.1	Install North Lancaster 500/230 kV substation (500 kV portion)		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b2007	Install a 90 MVAR capacitor bank at the Frackville 230 kV Substation		PPL (100%)
b2158	Install 10.8 MVAR capacitor at West Carlisle 69/12 kV substation		PPL (100%)

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

(9) PPL Electric Utilities Corporation

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

b1813.12	Replace the Blooming Grove 230 kV breaker 'Peckville'		PPL (100%)
b2223	Rebuild and reconductor 2.6 miles of the Sunbury - Dauphin 69 kV circuit		PPL (100%)
b2224	Add a 2nd 150 MVA 230/69 kV transformer at Springfield		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2237	150 MVAR shunt reactor at Alburtis 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PPL (100%)
b2238	100 MVAR shunt reactor at Elimsport 230 kV		PPL (100%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2269	Rebuild approximately 23.7 miles of the Susquehanna - Jenkins 230kV circuit. This replaces a temporary SPS that is already planned to mitigate the violation until this solution is implemented		PPL (100%)
b2282	Rebuild the Siegfried-Frackville 230 kV line		PPL (100%)
b2406.1	Rebuild Stanton-Providence 69 kV 2&3 9.5 miles with 795 SCSR		PPL (100%)
b2406.2	Reconductor 7 miles of the Lackawanna - Providence 69 kV #1 and #2 with 795 ACSR		PPL (100%)
b2406.3	Rebuild SUB2 Tap 1 (Lackawanna - Scranton 1) 69 kV 1.5 miles 556 ACSR		PPL (100%)
b2406.4	Rebuild SUB2 Tap 2 (Lackawanna - Scranton 1) 69 kV 1.6 miles 556 ACSR		PPL (100%)
b2406.5	Create Providence - Scranton 69 kV #1 and #2, 3.5 miles with 795 ACSR		PPL (100%)
b2406.6	Rebuild Providence 69 kV switchyard		PPL (100%)
b2406.7	Install 2 - 10.8 MVAR capacitors at EYNO 69 kV		PPL (100%)
b2406.8	Rebuild Stanton 230 kV yard		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2446	Replace wave trap and protective relays at Montour		PPL (100%)
b2447	Replace wave trap and protective relays at Montour		PPL (100%)
b2448	Install a 2nd Sunbury 900MVA 500-230kV transformer and associated equipment		PPL (100%)
b2552.2	Reconductor the North Meshoppen - Oxbow – Lackawanna 230 kV circuit and upgrade terminal equipment (PPL portion)		PENELEC (100%)
b2574	Replace the Sunbury 230 kV ‘MONTOUR NORT’ breaker with a 63kA breaker		PPL (100%)
b2690	Reconductor two spans of the Graceton – Safe Harbor 230 kV transmission line. Includes termination point upgrades		PPL (100%)
b2691	Reconductor three spans limiting Brunner Island – Yorkana 230 kV line, add 2 breakers to Brunner Island switchyard, upgrade associated terminal equipment		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2716	Add a 200 MVAR shunt reactor at Lackawanna 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PPL (100%)
b2754.1	Install 7 miles of optical ground wire (OPGW) between Gilbert and Springfield 230 kV substations		PPL (100%)
b2754.4	Use ~ 40 route miles of existing fibers on PPL 230 kV system to establish direct fiber circuits		PPL (100%)
b2754.5	Upgrade relaying at Martins Creek 230 kV		PPL (100%)
b2756	Install 2% reactors at Martins Creek 230 kV		PPL (100%)
b2813	Expand existing Lycoming 69 kV yard to double bus double breaker arrangement		PPL (100%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2824	Reconfigure/Expand the Lackawanna 500 kV substation by adding a third bay with three breakers		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PPL (100%)

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

Attachment 7i (AEP OATT)

SCHEDULE 12 – APPENDIX

(17) AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0318	Install a 765/138 kV transformer at Amos		AEP (99.00%) / PEPCO (1.00%)
b0324	Replace entrance conductors, wave traps, and risers at the Tidd 345 kV station on the Tidd – Canton Central 345 kV circuit		AEP (100%)
b0447	Replace Cook 345 kV breaker M2		AEP (100%)
b0448	Replace Cook 345 kV breaker N2		AEP (100%)
b0490	Construct an Amos – Bedington 765 kV circuit (AEP equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

* Neptune Regional Transmission System, LLC

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.2	Replace Amos 138 kV breaker ‘B’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0490.3	Replace Amos 138 kV breaker ‘B1’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.4	Replace Amos 138 kV breaker ‘C’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0490.5	Replace Amos 138 kV breaker ‘C1’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

* Neptune Regional Transmission System, LLC

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.6	Replace Amos 138 kV breaker ‘D’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0490.7	Replace Amos 138 kV breaker ‘D2’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.8	Replace Amos 138 kV breaker ‘E’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0490.9	Replace Amos 138 kV breaker ‘E2’		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0504	Add two advanced technology circuit breakers at Hanging Rock 765 kV to improve operational performance		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0570	Reconductor East Side Lima – Sterling 138 kV		AEP (41.99%) / ComEd (58.01%)
b0571	Reconductor West Millersport – Millersport 138 kV		AEP (73.83%) / ComEd (19.26%) / Dayton (6.91%)
b0748	Establish a new 69 kV circuit between the Canal Road and East Wooster stations, establish a new 69 kV circuit between the West Millersburg and Moreland Switch stations (via Shreve), add reactive support via cap banks		AEP (100%)
b0838	Hazard Area 138 kV and 69 kV Improvement Projects		AEP (100%)
b0839	Replace existing 450 MVA transformer at Twin Branch 345 / 138 kV with a 675 MVA transformer		AEP (99.73%) / Dayton (0.27%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0840	String a second 138 kV circuit on the open tower position between Twin Branch and East Elkhart		AEP (100%)
b0840.1	Establish a new 138/69-34.5kV Station to interconnect the existing 34.5kV network		AEP (100%)
b0917	Replace Baileysville 138 kV breaker 'P'		AEP (100%)
b0918	Replace Riverview 138 kV breaker '634'		AEP (100%)
b0919	Replace Torrey 138 kV breaker 'W'		AEP (100%)
b1032.1	Construct a new 345/138kV station on the Marquis-Bixby 345kV line near the intersection with Ross - Highland 69kV		AEP (89.97%) / Dayton (10.03%)
b1032.2	Construct two 138kV outlets to Delano 138kV station and to Camp Sherman station		AEP (89.97%) / Dayton (10.03%)
b1032.3	Convert Ross - Circleville 69kV to 138kV		AEP (89.97%) / Dayton (10.03%)
b1032.4	Install 138/69kV transformer at new station and connect in the Ross - Highland 69kV line		AEP (89.97%) / Dayton (10.03%)
b1033	Add a third delivery point from AEP's East Danville Station to the City of Danville.		AEP (100%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1034.1	Establish new South Canton - West Canton 138kV line (replacing Torrey - West Canton) and Wagenhals – Wayview 138kV		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.2	Loop the existing South Canton - Wayview 138kV circuit in-and-out of West Canton		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.3	Install a 345/138kV 450 MVA transformer at Canton Central		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.4	Rebuild/reconductor the Sunnyside - Torrey 138kV line		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.5	Disconnect/eliminate the West Canton 138kV terminal at Torrey Station		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.6	Replace all 138kV circuit breakers at South Canton Station and operate the station in a breaker and a half configuration		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.7	Replace all obsolete 138kV circuit breakers at the Torrey and Wagenhals stations		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1034.8	Install additional 138kV circuit breakers at the West Canton, South Canton, Canton Central, and Wagenhals stations to accommodate the new circuits		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1035	Establish a third 345kV breaker string in the West Millersport Station. Construct a new West Millersport – Gahanna 138kV circuit. Miscellaneous improvements to 138kV transmission system.		AEP (100%)
b1036	Upgrade terminal equipment at Poston Station and update remote end relays		AEP (100%)
b1037	Sag check Bonsack–Cloverdale 138 kV, Cloverdale–Centerville 138kV, Centerville–Ivy Hill 138kV, Ivy Hill–Reusens 138kV, Bonsack–Reusens 138kV and Reusens–Monel–Gomingo–Joshua Falls 138 kV.		AEP (100%)
b1038	Check the Crooksville - Muskingum 138 kV sag and perform the required work to improve the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1039	Perform a sag study for the Madison – Cross Street 138 kV line and perform the required work to improve the emergency rating		AEP (100%)
b1040	Rebuild an 0.065 mile section of the New Carlisle – Olive 138 kV line and change the 138 kV line switches at New Carlisle		AEP (100%)
b1041	Perform a sag study for the Moseley - Roanoke 138 kV to increase the emergency rating		AEP (100%)
b1042	Perform sag studies to raise the emergency rating of Amos – Poca 138kV		AEP (100%)
b1043	Perform sag studies to raise the emergency rating of Turner - Ruth 138kV		AEP (100%)
b1044	Perform sag studies to raise the emergency rating of Kenova – South Point 138kV		AEP (100%)
b1045	Perform sag studies of Tri State - Darrah 138 kV		AEP (100%)
b1046	Perform sag study of Scottsville – Bremo 138kV to raise the emergency rating		AEP (100%)
b1047	Perform sag study of Otter Switch - Altavista 138kV to raise the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1048	Reconductor the Bixby - Three C - Groves and Bixby - Groves 138 kV tower line		AEP (100%)
b1049	Upgrade the risers at the Riverside station to increase the rating of Benton Harbor – Riverside 138kV		AEP (100%)
b1050	Rebuilding and reconductor the Bixby – Pickerington Road - West Lancaster 138 kV line		AEP (100%)
b1051	Perform a sag study for the Kenzie Creek – Pokagon 138 kV line and perform the required work to improve the emergency rating		AEP (100%)
b1052	Unsix-wire the existing Hyatt - Sawmill 138 kV line to form two Hyatt - Sawmill 138 kV circuits		AEP (100%)
b1053	Perform a sag study and remediation of 32 miles between Claytor and Matt Funk.		AEP (100%)
b1091	Add 28.8 MVAR 138 kV capacitor bank at Huffman and 43.2 MVAR 138 kV Bank at Jubal Early and 52.8 MVAR 138 kV Bank at Progress Park Stations		AEP (100%)

* Neptune Regional Transmission System, LLC

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1092	Add 28.8 MVAR 138 kV capacitor bank at Sullivan Gardens and 52.8 MVAR 138 kV Bank at Reedy Creek Stations		AEP (100%)
b1093	Add a 43.2 MVAR capacitor bank at the Morgan Fork 138 kV Station		AEP (100%)
b1094	Add a 64.8 MVAR capacitor bank at the West Huntington 138 kV Station		AEP (100%)
b1108	Replace Ohio Central 138 kV breaker ‘C2’		AEP (100%)
b1109	Replace Ohio Central 138 kV breaker ‘D1’		AEP (100%)
b1110	Replace Sporn A 138 kV breaker ‘J’		AEP (100%)
b1111	Replace Sporn A 138 kV breaker ‘J2’		AEP (100%)
b1112	Replace Sporn A 138 kV breaker ‘L’		AEP (100%)
b1113	Replace Sporn A 138 kV breaker ‘L1’		AEP (100%)
b1114	Replace Sporn A 138 kV breaker ‘L2’		AEP (100%)
b1115	Replace Sporn A 138 kV breaker ‘N’		AEP (100%)
b1116	Replace Sporn A 138 kV breaker ‘N2’		AEP (100%)
b1227	Perform a sag study on Altavista – Leesville 138 kV circuit		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1231	Replace the existing 138/69-12 kV transformer at West Moulton Station with a 138/69 kV transformer and a 69/12 kV transformer		AEP (96.69%) / Dayton (3.31%)
b1375	Replace Roanoke 138 kV breaker ‘T’		AEP (100%)
b1376	Replace Roanoke 138 kV breaker ‘E’		AEP (100%)
b1377	Replace Roanoke 138 kV breaker ‘F’		AEP (100%)
b1378	Replace Roanoke 138 kV breaker ‘G’		AEP (100%)
b1379	Replace Roanoke 138 kV breaker ‘B’		AEP (100%)
b1380	Replace Roanoke 138 kV breaker ‘A’		AEP (100%)
b1381	Replace Olive 345 kV breaker ‘E’		AEP (100%)
b1382	Replace Olive 345 kV breaker ‘R2’		AEP (100%)
b1416	Perform a sag study on the Desoto – Deer Creek 138 kV line to increase the emergency rating		AEP (100%)
b1417	Perform a sag study on the Delaware – Madison 138 kV line to increase the emergency rating		AEP (100%)
b1418	Perform a sag study on the Rockhill – East Lima 138 kV line to increase the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1419	Perform a sag study on the Findlay Center – Fostoria Ctl 138 kV line to increase the emergency rating		AEP (100%)
b1420	A sag study will be required to increase the emergency rating for this line. Depending on the outcome of this study, more action may be required in order to increase the rating		AEP (100%)
b1421	Perform a sag study on the Sorenson – McKinley 138 kV line to increase the emergency rating		AEP (100%)
b1422	Perform a sag study on John Amos – St. Albans 138 kV line to allow for operation up to its conductor emergency rating		AEP (100%)
b1423	A sag study will be performed on the Chemical – Capitol Hill 138 kV line to determine if the emergency rating can be utilized		AEP (100%)
b1424	Perform a sag study for Benton Harbor – West Street – Hartford 138 kV line to improve the emergency rating		AEP (100%)
b1425	Perform a sag study for the East Monument – East Danville 138 kV line to allow for operation up to the conductor's maximum operating temperature		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1426	Perform a sag study for the Reusens – Graves 138 kV line to allow for operation up to the conductor's maximum operating temperature		AEP (100%)
b1427	Perform a sag study on Smith Mountain – Leesville – Altavista – Otter 138 kV and on Boones – Forest – New London – JohnsMT – Otter		AEP (100%)
b1428	Perform a sag study on Smith Mountain – Candlers Mountain 138 kV and Joshua Falls – Cloverdale 765 kV to allow for operation up to		AEP (100%)
b1429	Perform a sag study on Fremont – Clinch River 138 kV to allow for operation up to its conductor emergency ratings		AEP (100%)
b1430	Install a new 138 kV circuit breaker at Benton Harbor station and move the load from Watervliet 34.5 kV station to West street 138 kV		AEP (100%)
b1432	Perform a sag study on the Kenova – Tri State 138 kV line to allow for operation up to their conductor emergency rating		AEP (100%)
b1433	Replace risers in the West Huntington Station to increase the line ratings which would eliminate the overloads for the contingencies listed		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1434	Perform a sag study on the line from Desoto to Madison. Replace bus and risers at Daleville station and replace bus and risers at Madison		AEP (100%)
b1435	Replace the 2870 MCM ACSR riser at the Sporn station		AEP (100%)
b1436	Perform a sag study on the Sorenson – Illinois Road 138 kV line to increase the emergency MOT for this line. Replace bus and risers at Illinois Road		AEP (100%)
b1437	Perform sag study on Rock Cr. – Hummel Cr. 138 kV to increase the emergency MOT for the line, replace bus and risers at Huntington J., and replace relays for Hummel Cr. – Hunt – Soren. Line at Soren		AEP (100%)
b1438	Replacement of risers at McKinley and Industrial Park stations and performance of a sag study for the 4.53 miles of 795 ACSR section is expected to improve the Summer Emergency rating to 335 MVA		AEP (100%)
b1439	By replacing the risers at Lincoln both the Summar Normal and Summer Emergency ratings will improve to 268 MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1440	By replacing the breakers at Lincoln the Summer Emergency rating will improve to 251 MVA		AEP (100%)
b1441	Replacement of risers at South Side and performance of a sag study for the 1.91 miles of 795 ACSR section is expected to improve the Summer Emergency rating to 335 MVA		AEP (100%)
b1442	Replacement of 954 ACSR conductor with 1033 ACSR and performance of a sag study for the 4.54 miles of 2-636 ACSR section is expected		AEP (100%)
b1443	Station work at Thelma and Busseyville Stations will be performed to replace bus and risers		AEP (100%)
b1444	Perform electrical clearance studies on Clinch River – Clinchfield 139 kV line (a.k.a. sag studies) to determine if the emergency ratings can be utilized		AEP (100%)
b1445	Perform a sag study on the Addison (Buckeye CO-OP) – Thinever and North Crown City – Thivener 138 kV sag study and switch		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1446	Perform a sag study on the Parkersburg (Allegheny Power) – Belpre (AEP) 138 kV		AEP (100%)
b1447	Dexter – Elliot tap 138 kV sag check		AEP (100%)
b1448	Dexter – Meigs 138 kV Electrical Clearance Study		AEP (100%)
b1449	Meigs tap – Rutland 138 kV sag check		AEP (100%)
b1450	Muskingum – North Muskingum 138 kV sag check		AEP (100%)
b1451	North Newark – Sharp Road 138 kV sag check		AEP (100%)
b1452	North Zanesville – Zanesville 138 kV sag check		AEP (100%)
b1453	North Zanesville – Powelson and Ohio Central – Powelson 138 kV sag check		AEP (100%)
b1454	Perform an electrical clearance study on the Ross – Delano – Scioto Trail 138 kV line to determine if the emergency rating can be utilized		AEP (100%)
b1455	Perform a sag check on the Sunny – Canton Central – Wagenhals 138 kV line to determine if all circuits can be operated at their summer emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1456	The Tidd – West Bellaire 345 kV circuit has been de-rated to its normal rating and would need an electrical clearance study to determine if the emergency rating can be utilized		AEP (100%)
b1457	The Tiltonsville – Windsor 138 kV circuit has been derated to its normal rating and would need an electrical clearance study to determine if the emergency rating could be utilized		AEP (100%)
b1458	Install three new 345 kV breakers at Bixby to separate the Marquis 345 kV line and transformer #2. Operate Circleville – Harrison 138 kV and Harrison – Zuber 138 kV up to conductor emergency ratings		AEP (100%)
b1459	Several circuits have been de-rated to their normal conductor ratings and could benefit from electrical clearance studies to determine if the emergency rating could be utilized		AEP (100%)
b1460	Replace 2156 & 2874 risers		AEP (100%)
b1461	Replace meter, metering CTs and associated equipment at the Paden City feeder		AEP (100%)
b1462	Replace relays at both South Cadiz 138 kV and Tidd 138 kV		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1463	Reconductor the Bexley – Groves 138 kV circuit		AEP (100%)
b1464	Corner 138 kV upgrades		AEP (100%)
b1465.1	Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station		AEC (0.71%) / AEP (75.17%) / APS (1.25%) / BGE (1.81%) / ComEd (5.92%) / Dayton (0.86%) / DL (1.23%) / DPL (0.95%) / Dominion (3.90%) / JCPL (1.58%) / NEPTUNE (0.15%) / PECO (2.08%) / PEPCO (1.66%) / PSEG (2.63%) / RE (0.10%)
b1465.2	Replace the 100 MVAR 765 kV shunt reactor bank on Rockport – Jefferson 765 kV line with a 300 MVAR bank at Rockport Station		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1465.3	Transpose the Rockport – Sullivan 765 kV line and the Rockport – Jefferson 765 kV line		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1465.4	Make switching improvements at Sullivan and Jefferson 765 kV stations		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b1466.1	Create an in and out loop at Adams Station by removing the hard tap that currently exists		AEP (100%)
b1466.2	Upgrade the Adams transformer to 90 MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1466.3	At Seaman Station install a new 138 kV bus and two new 138 kV circuit breakers		AEP (100%)
b1466.4	Convert South Central Co-op's New Market 69 kV Station to 138 kV		AEP (100%)
b1466.5	The Seaman – Highland circuit is already built to 138 kV, but is currently operating at 69 kV, which would now increase to 138 kV		AEP (100%)
b1466.6	At Highland Station, install a new 138 kV bus, three new 138 kV circuit breakers and a new 138/69 kV 90 MVA transformer		AEP (100%)
b1466.7	Using one of the bays at Highland, build a 138 kV circuit from Hillsboro – Highland 138 kV, which is approximately 3 miles		AEP (100%)
b1467.1	Install a 14.4 MVAr Capacitor Bank at New Buffalo station		AEP (100%)
b1467.2	Reconfigure the 138 kV bus at LaPorte Junction station to eliminate a contingency resulting in loss of two 138 kV sources serving the LaPorte area		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1468.1	Expand Selma Parker Station and install a 138/69/34.5 kV transformer		AEP (100%)
b1468.2	Rebuild and convert 34.5 kV line to Winchester to 69 kV, including Farmland Station		AEP (100%)
b1468.3	Retire the 34.5 kV line from Haymond to Selma Wire		AEP (100%)
b1469.1	Conversion of the Newcomerstown – Cambridge 34.5 kV system to 69 kV operation		AEP (100%)
b1469.2	Expansion of the Derwent 69 kV Station (including reconfiguration of the 69 kV system)		AEP (100%)
b1469.3	Rebuild 11.8 miles of 69 kV line, and convert additional 34.5 kV stations to 69 kV operation		AEP (100%)
b1470.1	Build a new 138 kV double circuit off the Kanawha – Bailysville #2 138 kV circuit to Skin Fork Station		AEP (100%)
b1470.2	Install a new 138/46 kV transformer at Skin Fork		AEP (100%)
b1470.3	Replace 5 Moab's on the Kanawha – Baileysville line with breakers at the Sundial 138 kV station		AEP (100%)
b1471	Perform a sag study on the East Lima – For Lima – Rockhill 138 kV line to increase the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1472	Perform a sag study on the East Lima – Haviland 138 kV line to increase the emergency rating		AEP (100%)
b1473	Perform a sag study on the East New Concord – Muskingum River section of the Muskingum River – West Cambridge 138 kV circuit		AEP (100%)
b1474	Perform a sag study on the Ohio Central – Prep Plant tap 138 kV circuit		AEP (100%)
b1475	Perform a sag study on the S73 – North Delphos 138 kV line to increase the emergency rating		AEP (100%)
b1476	Perform a sag study on the S73 – T131 138 kV line to increase the emergency rating		AEP (100%)
b1477	The Natrium – North Martin 138 kV circuit would need an electrical clearance study among other equipment upgrades		AEP (100%)
b1478	Upgrade Strouds Run – Strounds Tap 138 kV relay and riser		AEP (100%)
b1479	West Hebron station upgrades		AEP (100%)
b1480	Perform upgrades and a sag study on the Corner – Layman 138 kV section of the Corner – Muskingum River 138 kV circuit		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1481	Perform a sag study on the West Lima – Eastown Road – Rockhill 138 kV line and replace the 138 kV risers at Rockhill station to increase the emergency rating		AEP (100%)
b1482	Perform a sag study for the Albion – Robison Park 138 kV line to increase its emergency rating		AEP (100%)
b1483	Sag study 1 mile of the Clinch River – Saltville 138 kV line and replace the risers and bus at Clinch River, Lebanon and Elk Garden Stations		AEP (100%)
b1484	Perform a sag study on the Hacienda – Harper 138 kV line to increase the emergency rating		AEP (100%)
b1485	Perform a sag study on the Jackson Road – Concord 183 kV line to increase the emergency rating		AEP (100%)
b1486	The Matt Funk – Poages Mill – Starkey 138 kV line requires		AEP (100%)
b1487	Perform a sag study on the New Carlisle – Trail Creek 138 kV line to increase the emergency rating		AEP (100%)
b1488	Perform a sag study on the Olive – LaPorte Junction 138 kV line to increase the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1489	A sag study must be performed for the 5.40 mile Tristate – Chadwick 138 kV line to determine if a higher emergency rating can be used		AEP (100%)
b1490.1	Establish a new 138/69 kV Butler Center station		AEP (100%)
b1490.2	Build a new 14 mile 138 kV line from Auburn station to Woods Road station VIA Butler Center station		AEP (100%)
b1490.3	Replace the existing 40 MVA 138/69 kV transformer at Auburn station with a 90 MVA 138/96 kV transformer		AEP (100%)
b1490.4	Improve the switching arrangement at Kendallville station		AEP (100%)
b1491	Replace bus and risers at Thelma and Busseyville stations and perform a sag study for the Big Sandy – Busseyville 138 kV line		AEP (100%)
b1492	Reconductor 0.65 miles of the Glen Lyn – Wythe 138 kV line with 3 – 1590 ACSR		AEP (100%)
b1493	Perform a sag study for the Bellfonte – Grantston 138 kV line to increase its emergency rating		AEP (100%)
b1494	Perform a sag study for the North Proctorville – Solida – Bellefonte 138 kV line to increase its emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1495	Add an additional 765/345 kV transformer at Baker Station		AEC (0.41%) / AEP (87.29%) / BGE (1.03%) / ComEd (3.39%) / Dayton (1.23%) / DL (1.46%) / DPL (0.54%) / JCPL (0.90%) / NEPTUNE (0.09%) / PECO (1.18%) / PEPCO (0.94%) / PSEG (1.48%) / RE (0.06%)
b1496	Replace 138 kV bus and risers at Johnson Mountain Station		AEP (100%)
b1497	Replace 138 kV bus and risers at Leesville Station		AEP (100%)
b1498	Replace 138 kV risers at Wurno Station		AEP (100%)
b1499	Perform a sag study on Sporn A – Gavin 138 kV to determine if the emergency rating can be improved		AEP (100%)
b1500	The North East Canton – Wagenhals 138 kV circuit would need an electrical clearance study to determine if the emergency rating can be utilized		AEP (100%)
b1501	The Moseley – Reusens 138 kV circuit requires a sag study to determine if the emergency rating can be utilized to address a thermal loading issue for a category C3		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1502	Reconductor the Conesville East – Conesville Prep Plant Tap 138 kV section of the Conesville – Ohio Central to fix Reliability N-1-1 thermal overloads		AEP (100%)
b1659	Establish Sorenson 345/138 kV station as a 765/345 kV station		AEP (93.67%) / ATSI (2.99%) / ComEd (2.07%) / PENELEC (0.31%) / PSEG (0.92%) / RE (0.04%)
b1659.1	Replace Sorenson 138 kV breaker 'L1'		AEP (100%)
b1659.2	Replace Sorenson 138 kV breaker 'L2' breaker		AEP (100%)
b1659.3	Replace Sorenson 138 kV breaker 'M1'		AEP (100%)
b1659.4	Replace Sorenson 138 kV breaker 'M2'		AEP (100%)
b1659.5	Replace Sorenson 138 kV breaker 'N1'		AEP (100%)
b1659.6	Replace Sorenson 138 kV breaker 'N2'		AEP (100%)
b1659.7	Replace Sorenson 138 kV breaker 'O1'		AEP (100%)
b1659.8	Replace Sorenson 138 kV breaker 'O2'		AEP (100%)
b1659.9	Replace Sorenson 138 kV breaker 'M'		AEP (100%)
b1659.10	Replace Sorenson 138 kV breaker 'N'		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1659.11	Replace Sorenson 138 kV breaker 'O'		AEP (100%)
b1659.12	Replace McKinley 138 kV breaker 'L1'		AEP (100%)
b1659.13	Establish 765 kV yard at Sorenson and install four 765 kV breakers		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1659.14	Build approximately 14 miles of 765 kV line from existing Dumont - Marysville line		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1660	Install a 765/500 kV transformer at Cloverdale		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1661	Install a 765 kV circuit breaker at Wyoming station		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1662	Rebuild 4 miles of 46 kV line to 138 kV from Pemberton to Cherry Creek		AEP (100%)
b1662.1	Circuit Breakers are installed at Cherry Creek (facing Pemberton) and at Pemberton (facing Tams Mtn. and Cherry Creek)		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1662.2	Install three 138 kV breakers at Grandview Station (facing Cherry Creek, Hinton, and Bradley Stations)		AEP (100%)
b1662.3	Remove Sullivan Switching Station (46 kV)		AEP (100%)
b1663	Install a new 765/138 kV transformer at Jackson Ferry substation		AEP (100%)
b1663.1	Establish a new 10 mile double circuit 138 kV line between Jackson Ferry and Wythe		AEP (100%)
b1663.2	Install 2 765 kV circuit breakers, breaker disconnect switches and associated bus work for the new 765 kV breakers, and new relays for the 765 kV breakers at Jackson's Ferry		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1664	Install switched capacitor banks at Kenwood 138 kV stations		AEP (100%)
b1665	Install a second 138/69 kV transformer at Thelma station		AEP (100%)
b1665.1	Construct a single circuit 69 kV line from West Paintsville to the new Paintsville station		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1665.2	Install new 7.2 MVAR, 46 kV bank at Kenwood Station		AEP (100%)
b1666	Build an 8 breaker 138 kV station tapping both circuits of the Fostoria - East Lima 138 kV line		AEP (90.65%) / Dayton (9.35%)
b1667	Establish Melmore as a switching station with both 138 kV circuits terminating at Melmore. Extend the double circuit 138 kV line from Melmore to Fremont Center		AEP (100%)
b1668	Revise the capacitor setting at Riverside 138 kV station		AEP (100%)
b1669	Capacitor setting changes at Ross 138 kV stations		AEP (100%)
b1670	Capacitor setting changes at Wooster 138 kV station		AEP (100%)
b1671	Install four 138 kV breakers in Danville area		AEP (100%)
b1676	Replace Natrium 138 kV breaker 'G (rehab)'		AEP (100%)
b1677	Replace Huntley 138 kV breaker '106'		AEP (100%)
b1678	Replace Kammer 138 kV breaker 'G'		AEP (100%)
b1679	Replace Kammer 138 kV breaker 'H'		AEP (100%)
b1680	Replace Kammer 138 kV breaker 'J'		AEP (100%)
b1681	Replace Kammer 138 kV breaker 'K'		AEP (100%)
b1682	Replace Kammer 138 kV breaker 'M'		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1683	Replace Kammer 138 kV breaker 'N'		AEP (100%)
b1684	Replace Clinch River 138 kV breaker 'E1'		AEP (100%)
b1685	Replace Lincoln 138 kV breaker 'D'		AEP (100%)
b1687	Advance s0251.7 (Replace Corrid 138 kV breaker '104S')		AEP (100%)
b1688	Advance s0251.8 (Replace Corrid 138 kV breaker '104C')		AEP (100%)
b1712.1	Perform sag study on Altavista - Leesville 138 kV line		Dominion (75.30%) / PEPCO (24.70%)
b1712.2	Rebuild the Altavista - Leesville 138 kV line		Dominion (75.30%) / PEPCO (24.70%)
b1733	Perform a sag study of the Bluff Point - Jauy 138 kV line. Upgrade breaker, wavetrap, and risers at the terminal ends		AEP (100%)
b1734	Perform a sag study of Randoph - Hodgins 138 kV line. Upgrade terminal equipment		AEP (100%)
b1735	Perform a sag study of R03 - Magely 138 kV line. Upgrade terminal equipment		AEP (100%)
b1736	Perform a sag study of the Industrial Park - Summit 138 kV line		AEP (100%)
b1737	Sag study of Newcomerstown - Hillview 138 kV line. Upgrade - terminal equipment		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1738	Perform a sag study of the Wolf Creek - Layman 138 kV line. -Upgrade terminal equipment including a 138 kV breaker and wavetrap		AEP (100%)
b1739	Perform a sag study of the Ohio Central - West Trinway 138 kV line		AEP (100%)
b1741	Replace Beatty 138 kV breaker '2C(IPP)'		AEP (100%)
b1742	Replace Beatty 138 kV breaker '1E'		AEP (100%)
b1743	Replace Beatty 138 kV breaker '2E'		AEP (100%)
b1744	Replace Beatty 138 kV breaker '3C'		AEP (100%)
b1745	Replace Beatty 138 kV breaker '2W'		AEP (100%)
b1746	Replace St. Claire 138 kV breaker '8'		AEP (100%)
b1747	Replace Cloverdale 138 kV breaker 'C'		AEP (100%)
b1748	Replace Cloverdale 138 kV breaker 'D1'		AEP (100%)
b1780	Install two 138kV breakers and two 138kV circuit switchers at South Princeton Station and one 138kV breaker and one 138kV circuit switcher at Switchback Station		AEP (100%)
b1781	Install three 138 kV breakers and a 138kV circuit switcher at Trail Fork Station in Pineville, WV		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1782	Install a 46kV Moab at Montgomery Station facing Carbondale (on the London - Carbondale 46 kV circuit)		AEP (100%)
b1783	Add two 138 kV Circuit Breakers and two 138 kV circuit switchers on the Lonesome Pine - South Bluefield 138 kV line		AEP (100%)
b1784	Install a 52.8 MVAR capacitor bank at the Clifford 138 kV station		AEP (100%)
b1811.1	Perform a sag study of 4 miles of the Waterford - Muskingum line		AEP (100%)
b1811.2	Rebuild 0.1 miles of Waterford - Muskingum 345 kV with 1590 ACSR		AEP (100%)
b1812	Reconductor the AEP portion of the South Canton - Harmon 345 kV with 954 ACSR and upgrade terminal equipment at South Canton. Expected rating is 1800 MVA S/N and 1800 MVA S/E		AEP (100%)
b1817	Install (3) 345 kV circuit breakers at East Elkhart station in ring bus designed as a breaker and half scheme		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1818	Expand the Allen station by installing a second 345/138 kV transformer and adding four 138 kV exits by cutting in the Lincoln - Sterling and Milan - Timber Switch 138 kV double circuit tower line		AEP (88.30%) / ATSI (8.86%) / Dayton (2.84%)
b1819	Rebuild the Robinson Park - Sorenson 138 kV line corridor as a 345 kV double circuit line with one side operated at 345 kV and one side at 138 kV		AEP (87.18%) / ATSI (10.06%) / Dayton (2.76%)
b1859	Perform a sag study for Hancock - Cave Spring - Roanoke 138 kV circuit to reach new SE ratings of 272MVA (Cave Spring-Hancock), 205MVA (Cave Spring-Sunscape), 245MVA (ROANO2-Sunscape)		AEP (100%)
b1860	Perform a sag study on the Crooksville - Spencer Ridge section (14.3 miles) of the Crooksville-Poston-Strouds Run 138 kV circuit to see if any remedial action needed to reach the SE rating (175MVA)		AEP (100%)
b1861	Reconductor 0.83 miles of the Dale - West Canton 138 kV Tie-line and upgrade risers at West Canton 138 kV		AEP (100%)
b1862	Perform a sag study on the Grant - Greentown 138 kV circuit and replace the relay CT at Grant 138 kV station to see if any remedial action needed to reach the new ratings of 251/286MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1863	Perform a sag study of the Kammer - Wayman SW 138 kV line to see if any remedial action needed to reach the new SE rating of 284MVA		AEP (100%)
b1864.1	Add two additional 345/138 kV transformers at Kammer		AEP (87.22%) / APS (8.22%) / ATSI (3.52%) / DL (1.04%)
b1864.2	Add second West Bellaire - Brues 138 kV circuit		AEP (87.22%) / APS (8.22%) / ATSI (3.52%) / DL (1.04%)
b1864.3	Replace Kammer 138 kV breaker 'E'		AEP (100%)
b1865	Perform a sag study on the Kanawha - Carbondale 138 kV line to see if any remedial action needed to reach the new ratings of 251/335MVA		AEP (100%)
b1866	Perform a sag study on the Clinch River-Lock Hart-Dorton 138kV line,increase the Relay Compliance Trip Limit at Clinch River on the C.R.-Dorton 138kV line to 310 and upgrade the risers with 1590ACSR		AEP (100%)
b1867	Perform a sag study on the Newcomerstown - South Coshocton 138 kV line to see if any remedial action is needed to reach the new SE rating of 179MVA		AEP (100%)
b1868	Perform sag study on the East Lima - new Liberty 138 kV line to see if any remedial action is needed to reach the new SE rating of 219MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1869	Perform a sag study of the Ohio Central - South Coshocton 138 kV circuit to see if any remedial action needed to reach the new SE ratings of 250MVA		AEP (100%)
b1870	Replace the Ohio Central transformer #1 345/138/12 kV 450 MVA for a 345/138/34.5 kV 675 MVA transformer		AEP (68.16%) / ATSI (25.27%) / Dayton (3.88%) / PENELEC (1.59%) / DEOK (1.10%)
b1871	Perform a sag study on the Central - West Coshocton 138 kV line (improving the emergency rating of this line to 254 MVA)		AEP (100%)
b1872	Add a 57.6 MVAr capacitor bank at East Elkhart 138 kv station in Indiana		AEP (100%)
b1873	Install two 138 kV circuit breakers at Cedar Creek Station and primary side circuit switcher on the 138/69/46 kV transformer		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1874	Install two 138 kV circuit breakers and one 138 kV circuit switcher at Magely 138 kV station in Indiana		AEP (100%)
b1875	Build 25 miles of new 138 kV line from Bradley Station through Tower 117 Station and terminating at McClung 138 kV station. Existing 69 kV distribution transformers will be replaced with 138 kV transformers		AEP (100%)
b1876	Install a 14.4 MVAr capacitor bank at Capital Avenue (AKA Currant Road) 34.5 kV bus		AEP (100%)
b1877	Relocate 138 kV Breaker G to the West Kingsport - Industry Drive 138 kV line and Remove 138 kV MOAB		AEP (100%)
b1878	Perform a sag study on the Lincoln - Robinson Park 138 kV line (Improve the emergency rating to 244 MVA)		AEP (100%)
b1879	Perform a sag study on the Hansonville - Meadowview 138 kV line (Improve the emergency rating to 245 MVA)		AEP (100%)
b1880	Rebuild the 15 miles of the Moseley - Roanoke 138 kV line. This project would consist of rebuilding both circuits on the double circuit line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1881	Replace existing 600 Amp switches, station risers and increase the CT ratios associated with breaker 'G' at Sterling 138 kV Station. It will increase the rating to 296 MVA S/N and 384 MVA S/E		AEP (100%)
b1882	Perform a sag study on the Bluff Point - Randolf 138 kV line to see if any remedial action needed to reach the new SE rating of 255 MVA		AEP (100%)
b1883	Switch the breaker position of transformer #1 and SW Lima at East Lima 345 kV bus		AEP (100%)
b1884	Perform a sag study on Strawton station - Fisher Body - Deer Creek 138 kV line to see if any remedial action needed to reach the new SE rating of 250 MVA		AEP (100%)
b1887	Establish a new 138/69 kV source at Carrollton and construct two new 69 kV lines from Carrollton to tie into the Dennison - Miller SW 69 kV line and to East Dover 69 kV station respectively		AEP (100%)
b1888	Install a 69 kV line breaker at Blue Pennant 69 kV Station facing Bim Station and 14.4 MVAr capacitor bank		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1889	Install a 43.2 MVAR capacitor bank at Hinton 138 kV station (APCO WV)		AEP (100%)
b1901	Rebuild the Ohio Central - West Trinway (4.84 miles) section of the Academia - Ohio Central 138 kV circuit. Upgrade the Ohio Central riser, Ohio Central switch and the West Trinway riser		AEP (100%)
b1904.1	Construct new 138/69 Michiana Station near Bridgman by tapping the new Carlisle - Main Street 138 kV and the Bridgman - Buchanan Hydro 69 kV line		AEP (100%)
b1904.2	Establish a new 138/12 kV New Galien station by tapping the Olive - Hickory Creek 138 kV line		AEP (100%)
b1904.3	Retire the existing Galien station and move its distribution load to New Galien station. Retire the Buchanan Hydro - New Carlisile 34.5 kV line		AEP (100%)
b1904.4	Implement an in and out scheme at Cook 69 kV by eliminating the Cook 69 kV tap point and by installing two new 69 kV circuit breakers		AEP (100%)
b1904.5	Rebuild the Bridgman - Cook 69 kV and the Derby - Cook 69 kV lines		AEP (100%)
b1946	Perform a sag study on the Brues – West Bellaire 138 kV line		AEP (100%)
b1947	A sag study of the Dequine - Meadowlake 345 kV line #1 line may improve the emergency rating to 1400 MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1948	Establish a new 765/345 interconnection at Sporn. Install a 765/345 kV transformer at Mountaineer and build ¾ mile of 345 kV to Sporn		ATSI (61.08%) / DL (21.87%) / Dominion (13.97%) / PENELEC (3.08%)
b1949	Perform a sag study on the Grant Tap – Deer Creek 138 kV line and replace bus and risers at Deer Creek station		AEP (100%)
b1950	Perform a sag study on the Kammer – Ormet 138 kV line of the conductor section		AEP (100%)
b1951	Perform a sag study of the Maddox- Convoy 345 kV line to improve the emergency rating to 1400 MVA		AEP (100%)
b1952	Perform a sag study of the Maddox – T130 345 kV line to improve the emergency rating to 1400 MVA		AEP (100%)
b1953	Perform a sag study of the Meadowlake - Olive 345 kV line to improve the emergency rating to 1400 MVA		AEP (100%)
b1954	Perform a sag study on the Milan - Harper 138 kV line and replace bus and switches at Milan Switch station		AEP (100%)
b1955	Perform a sag study of the R-049 - Tillman 138 kV line may improve the emergency rating to 245 MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1956	Perform a sag study of the Tillman - Dawkins 138 kV line may improve the emergency rating to 245 MVA		AEP (100%)
b1957	Terminate Transformer #2 at SW Lima in a new bay position		AEP (69.66%) / ATSI (23.19%) / PENELEC (2.43%) / PSEG (4.54%) / RE (0.18%)
b1958	Perform a sag study on the Brookside - Howard 138 kV line and replace bus and risers at AEP Howard station		AEP (100%)
b1960	Sag Study on 7.2 miles SE Canton-Canton Central 138kV ckt		AEP (100%)
b1961	Sag study on the Southeast Canton – Sunnyside 138kV line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1962	Add four 765 kV breakers at Kammer		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1963	Build approximately 1 mile of circuit comprising of 2-954 ACSR to get the rating of Waterford-Muskinum 345 kV higher		AEP (100%)
b1970	Reconductor 13 miles of the Kammer – West Bellaire 345kV circuit		APS (33.58%) / ATSI (32.28%) / DL (18.68%) / Dominion (6.02%) / JCPL (1.68%) / Neptune* (0.18%) / PENELEC (4.59%) / PSEG (2.88%) / RE (0.11%)
b1971	Perform a sag study to improve the emergency rating on the Bridgville – Chandlersville 138 kV line		AEP (100%)
b1972	Replace disconnect switch on the South Canton 765/345 kV transformer		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1973	Perform a sag study to improve the emergency rating on the Carrollton – Sunnyside 138 kV line		AEP (100%)
b1974	Perform a sag study to improve the emergency rating on the Bethel Church – West Dover 138 kV line		AEP (100%)
b1975	Replace a switch at South Millersburg switch station		AEP (100%)
b2017	Reconductor or rebuild Sporn - Waterford - Muskingum River 345 kV line		ATSI (37.10%) / AEP (34.41%) / DL (10.43%) / Dominion (6.20%) / APS (3.95%) / PENELEC (3.10%) / JCPL (1.39%) / Dayton (1.20%) / Neptune* (0.14%) / PSEG (2.00%) / RE (0.08%)
b2018	Loop Conesville - Bixby 345 kV circuit into Ohio Central		ATSI (58.58%) / AEP (14.16%) / APS (12.88%) / DL (7.93%) / PENELEC (5.73%) / Dayton (0.72%)
b2019	Establish Burger 345/138 kV station		AEP (93.74%) / APS (4.40%) / DL (1.11%) / ATSI (0.74%) / PENELEC (0.01%)
b2020	Rebuild Amos - Kanawah River 138 kV corridor		AEP (88.39%) / APS (7.12%) / ATSI (2.89%) / DEOK (1.58%) / PEPCO (0.02%)
b2021	Add 345/138 transformer at Sporn, Kanawah River & Muskingum River stations		AEP (91.92%) / DEOK (3.60%) / APS (2.19%) / ATSI (1.14%) / DL (1.08%) / PEPCO (0.04%) / BGE (0.03%)
b2021.1	Replace Kanawah 138 kV breaker 'L'		AEP (100%)
b2021.2	Replace Muskingum 138 kV breaker 'HG'		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2021.3	Replace Muskingum 138 kV breaker 'HJ'		AEP (100%)
b2021.4	Replace Muskingum 138 kV breaker 'HE'		AEP (100%)
b2021.5	Replace Muskingum 138 kV breaker 'HD'		AEP (100%)
b2021.6	Replace Muskingum 138 kV breaker 'HF'		AEP (100%)
b2021.7	Replace Muskingum 138 kV breaker 'HC'		AEP (100%)
b2021.8	Replace Sporn 138 kV breaker 'D1'		AEP (100%)
b2021.9	Replace Sporn 138 kV breaker 'D2'		AEP (100%)
b2021.10	Replace Sporn 138 kV breaker 'F1'		AEP (100%)
b2021.11	Replace Sporn 138 kV breaker 'F2'		AEP (100%)
b2021.12	Replace Sporn 138 kV breaker 'G'		AEP (100%)
b2021.13	Replace Sporn 138 kV breaker 'G2'		AEP (100%)
b2021.14	Replace Sporn 138 kV breaker 'N1'		AEP (100%)
b2021.15	Replace Kanawah 138 kV breaker 'M'		AEP (100%)
b2022	Terminate Tristate - Kyger Creek 345 kV line at Sporn		AEP (97.99%) / DEOK (2.01%)
b2027	Perform a sag study of the Tidd - Collier 345 kV line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2028	Perform a sag study on East Lima - North Woodcock 138 kV line to improve the rating		AEP (100%)
b2029	Perform a sag study on Bluebell - Canton Central 138 kV line to improve the rating		AEP (100%)
b2030	Install 345 kV circuit breakers at West Bellaire		AEP (100%)
b2031	Sag study on Tilton - W. Bellaire section 1 (795 ACSR), about 12 miles		AEP (100%)
b2032	Rebuild 138 kV Elliot tap - Poston line		ATSI (73.02%) / Dayton (19.39%) / DL (7.59%)
b2033	Perform a sag study of the Brues - W. Bellaire 138 kV line		AEP (100%)
b2046	Adjust tap settings for Muskingum River transformers		AEP (100%)
b2047	Replace relay at Greenlawn		AEP (100%)
b2048	Replace both 345/138 kV transformers with one bigger transformer		AEP (92.49%) / Dayton (7.51%)
b2049	Replace relay		AEP (100%)
b2050	Perform sag study		AEP (100%)
b2051	Install 3 138 kV breakers and a circuit switcher at Dorton station		AEP (100%)
b2052	Replace transformer		AEP (67.17%) / ATSI (27.37%) / Dayton (3.73%) / PENELEC (1.73%)
b2054	Perform a sag study of Sporn - Rutland 138 kV line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2069	Replace George Washington 138 kV breaker 'A' with 63kA rated breaker		AEP (100%)
b2070	Replace Harrison 138 kV breaker '6C' with 63kA rated breaker		AEP (100%)
b2071	Replace Lincoln 138 kV breaker 'L' with 63kA rated breaker		AEP (100%)
b2072	Replace Natrum 138 kV breaker 'I' with 63kA rated breaker		AEP (100%)
b2073	Replace Darrah 138 kV breaker 'B' with 63kA rated breaker		AEP (100%)
b2074	Replace Wyoming 138 kV breaker 'G' with 80kA rated breaker		AEP (100%)
b2075	Replace Wyoming 138 kV breaker 'G1' with 80kA rated breaker		AEP (100%)
b2076	Replace Wyoming 138 kV breaker 'G2' with 80kA rated breaker		AEP (100%)
b2077	Replace Wyoming 138 kV breaker 'H' with 80kA rated breaker		AEP (100%)
b2078	Replace Wyoming 138 kV breaker 'H1' with 80kA rated breaker		AEP (100%)
b2079	Replace Wyoming 138 kV breaker 'H2' with 80kA rated breaker		AEP (100%)
b2080	Replace Wyoming 138 kV breaker 'J' with 80kA rated breaker		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2081	Replace Wyoming 138 kV breaker 'J1' with 80kA rated breaker		AEP (100%)
b2082	Replace Wyoming 138 kV breaker 'J2' with 80kA rated breaker		AEP (100%)
b2083	Replace Natrum 138 kV breaker 'K' with 63kA rated breaker		AEP (100%)
b2084	Replace Tanner Creek 345 kV breaker 'P' with 63kA rated breaker		AEP (100%)
b2085	Replace Tanner Creek 345 kV breaker 'P2' with 63kA rated breaker		AEP (100%)
b2086	Replace Tanner Creek 345 kV breaker 'Q1' with 63kA rated breaker		AEP (100%)
b2087	Replace South Bend 138 kV breaker 'T' with 63kA rated breaker		AEP (100%)
b2088	Replace Tidd 138 kV breaker 'L' with 63kA rated breaker		AEP (100%)
b2089	Replace Tidd 138 kV breaker 'M2' with 63kA rated breaker		AEP (100%)
b2090	Replace McKinley 138 kV breaker 'A' with 40kA rated breaker		AEP (100%)
b2091	Replace West Lima 138 kV breaker 'M' with 63kA rated breaker		AEP (100%)
b2092	Replace George Washington 138 kV breaker 'B' with 63kA rated breaker		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2093	Replace Turner 138 kV breaker 'W' with 63kA rated breaker		AEP (100%)
b2135	Build a new 138 kV line from Falling Branch to Merrimac and add a 138/69 kV transformer at Merrimac Station		AEP (100%)
b2160	Add a fourth circuit breaker to the station being built for the U4-038 project (Conelley), rebuild U4-038 - Grant Tap line as double circuit tower line		AEP (100%)
b2161	Rebuild approximately 20 miles of the Allen - S073 double circuit 138 kV line (with one circuit from Allen - Tillman - Timber Switch - S073 and the other circuit from Allen - T-131 - S073) utilizing 1033 ACSR		AEP (100%)
b2162	Perform a sag study to improve the emergency rating of the Belpre - Degussa 138 kV line		AEP (100%)
b2163	Replace breaker and wavetrap at Jay 138 kV station		AEP (100%)

*Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

(17) AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1660.1	Cloverdale: install 6-765 kV breakers, incremental work for 2 additional breakers, reconfigure and relocate miscellaneous facilities, establish 500 kV station and 500 kV tie with 765 kV station		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (97.94%) / DEOK (0.54%) / Dominion (1.33%) / EKPC (0.19%)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1797.1	Reconductor the AEP portion of the Cloverdale - Lexington 500 kV line with 2-1780 ACSS		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (55.05%) / ATSI (2.77%) / Dayton (0.84%) / DEOK (2.06%) / Dominion (5.76%) / EKPC (0.72%) / PEPCO (32.80%)
b2055	Upgrade relay at Brues station		AEP (100%)
b2122.3	Upgrade terminal equipment at Howard on the Howard - Brookside 138 kV line to achieve ratings of 252/291 (SN/SE)		AEP (100%)
b2122.4	Perform a sag study on the Howard - Brookside 138 kV line		AEP (100%)
b2229	Install a 300 MVAR reactor at Dequine 345 kV		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2230	Replace existing 150 MVAR reactor at Amos 765 kV substation on Amos - N. Proctorville - Hanging Rock with 300 MVAR reactor		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)
b2231	Install 765 kV reactor breaker at Dumont 765 kV substation on the Dumont - Wilton Center line		AEP (100%)
b2232	Install 765 kV reactor breaker at Marysville 765 kV substation on the Marysville - Maliszewski line		AEP (100%)
b2233	Change transformer tap settings for the Baker 765/345 kV transformer		AEP (100%)
b2252	Loop the North Muskingum - Crooksville 138 kV line into AEP's Philo 138 kV station which lies approximately 0.4 miles from the line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2253	Install an 86.4 MVAR capacitor bank at Gorsuch 138 kV station in Ohio		AEP (100%)
b2254	Rebuild approximately 4.9 miles of Corner - Degussa 138 kV line in Ohio		AEP (100%)
b2255	Rebuild approximately 2.8 miles of Maliszewski - Polaris 138 kV line in Ohio		AEP (100%)
b2256	Upgrade approximately 36 miles of 138 kV through path facilities between Harrison 138 kV station and Ross 138 kV station in Ohio		AEP (100%)
b2257	Rebuild the Pokagon - Corey 69 kV line as a double circuit 138 kV line with one side at 69 kV and the other side as an express circuit between Pokagon and Corey stations		AEP (100%)
b2258	Rebuild 1.41 miles of #2 CU 46 kV line between Tams Mountain - Slab Fork to 138 kV standards. The line will be strung with 1033 ACSR		AEP (100%)
b2259	Install a new 138/69 kV transformer at George Washington 138/69 kV substation to provide support to the 69 kV system in the area		AEP (100%)
b2286	Rebuild 4.7 miles of Muskingum River - Wolf Creek 138 kV line and remove the 138/138 kV transformer at Wolf Creek Station		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2287	Loop in the Meadow Lake - Olive 345 kV circuit into Reynolds 765/345 kV station		AEP (100%)
b2344.1	Establish a new 138/12 kV station, transfer and consolidate load from its Nicholsville and Marcellus 34.5 kV stations at this new station		AEP (100%)
b2344.2	Tap the Hydramatic – Valley 138 kV circuit (~ structure 415), build a new 138 kV line (~3.75 miles) to this new station		AEP (100%)
b2344.3	From this station, construct a new 138 kV line (~1.95 miles) to REA's Marcellus station		AEP (100%)
b2344.4	From REA's Marcellus station construct new 138 kV line (~2.35 miles) to a tap point on Valley – Hydramatic 138 kV ckt (~structure 434)		AEP (100%)
b2344.5	Retire sections of the 138 kV line in between structure 415 and 434 (~ 2.65 miles)		AEP (100%)
b2344.6	Retire AEP's Marcellus 34.5/12 kV and Nicholsville 34.5/12 kV stations and also the Marcellus – Valley 34.5 kV line		AEP (100%)
b2345.1	Construct a new 69 kV line from Hartford to Keeler (~8 miles)		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2345.2	Rebuild the 34.5 kV lines between Keeler - Sister Lakes and Glenwood tap switch to 69 kV (~12 miles)		AEP (100%)
b2345.3	Implement in - out at Keeler and Sister Lakes 34.5 kV stations		AEP (100%)
b2345.4	Retire Glenwood tap switch and construct a new Rothadew station. These new lines will continue to operate at 34.5 kV		AEP (100%)
b2346	Perform a sag study for Howard - North Bellville - Millwood 138 kV line including terminal equipment upgrades		AEP (100%)
b2347	Replace the North Delphos 600A switch. Rebuild approximately 18.7 miles of 138 kV line North Delphos - S073. Reconductor the line and replace the existing tower structures		AEP (100%)
b2348	Construct a new 138 kV line from Richlands Station to intersect with the Hales Branch - Grassy Creek 138 kV circuit		AEP (100%)
b2374	Change the existing CT ratios of the existing equipment along Bearskin - Smith Mountain 138kV circuit		AEP (100%)
b2375	Change the existing CT ratios of the existing equipment along East Danville-Banister 138kV circuit		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2376	Replace the Turner 138 kV breaker 'D'		AEP (100%)
b2377	Replace the North Newark 138 kV breaker 'P'		AEP (100%)
b2378	Replace the Sporn 345 kV breaker 'DD'		AEP (100%)
b2379	Replace the Sporn 345 kV breaker 'DD2'		AEP (100%)
b2380	Replace the Muskingum 345 kV breaker 'SE'		AEP (100%)
b2381	Replace the East Lima 138 kV breaker 'E1'		AEP (100%)
b2382	Replace the Delco 138 kV breaker 'R'		AEP (100%)
b2383	Replace the Sporn 345 kV breaker 'AA2'		AEP (100%)
b2384	Replace the Sporn 345 kV breaker 'CC'		AEP (100%)
b2385	Replace the Sporn 345 kV breaker 'CC2'		AEP (100%)
b2386	Replace the Astor 138 kV breaker '102'		AEP (100%)
b2387	Replace the Muskingum 345 kV breaker 'SH'		AEP (100%)
b2388	Replace the Muskingum 345 kV breaker 'SI'		AEP (100%)
b2389	Replace the Hyatt 138 kV breaker '105N'		AEP (100%)
b2390	Replace the Muskingum 345 kV breaker 'SG'		AEP (100%)
b2391	Replace the Hyatt 138 kV breaker '101C'		AEP (100%)
b2392	Replace the Hyatt 138 kV breaker '104N'		AEP (100%)
b2393	Replace the Hyatt 138 kV breaker '104S'		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2394	Replace the Sporn 345 kV breaker 'CC1'		AEP (100%)
b2409	Install two 56.4 MVAR capacitor banks at the Melmore 138 kV station in Ohio		AEP (100%)
b2410	Convert Hogan Mullin 34.5 kV line to 138 kV, establish 138 kV line between Jones Creek and Strawton, rebuild existing Mullin Elwood 34.5 kV and terminate line into Strawton station, retire Mullin station		AEP (100%)
b2411	Rebuild the 3/0 ACSR portion of the Hadley - Kroemer Tap 69 kV line utilizing 795 ACSR conductor		AEP (100%)
b2423	Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2444	Willow - Eureka 138 kV line: Reconductor 0.26 mile of 4/0 CU with 336 ACSS		AEP (100%)
b2445	Complete a sag study of Tidd - Mahans Lake 138 kV line		AEP (100%)
b2449	Rebuild the 7-mile 345 kV line between Meadow Lake and Reynolds 345 kV stations		AEP (100%)
b2462	Add two 138 kV circuit breakers at Fremont station to fix tower contingency ‘408_2’		AEP (100%)
b2501	Construct a new 138/69 kV Yager station by tapping 2-138 kV FE circuits (Nottingham-Cloverdale, Nottingham-Harmon)		AEP (100%)
b2501.2	Build a new 138 kV line from new Yager station to Azalea station		AEP (100%)
b2501.3	Close the 138 kV loop back into Yager 138 kV by converting part of local 69 kV facilities to 138 kV		AEP (100%)
b2501.4	Build 2 new 69 kV exits to reinforce 69 kV facilities and upgrade conductor between Irish Run 69 kV Switch and Bowerstown 69 kV Switch		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2502.1	Construct new 138 kV switching station Nottingham tapping 6-138 kV FE circuits (Holloway-Brookside, Holloway-Harmon #1 and #2, Holloway-Reeds, Holloway-New Stacy, Holloway-Cloverdale). Exit a 138 kV circuit from new station to Freebyrd station		AEP (100%)
b2502.2	Convert Freebyrd 69 kV to 138 kV		AEP (100%)
b2502.3	Rebuild/convert Freebyrd-South Cadiz 69 kV circuit to 138 kV		AEP (100%)
b2502.4	Upgrade South Cadiz to 138 kV breaker and a half		AEP (100%)
b2530	Replace the Sporn 138 kV breaker 'G1' with 80kA breaker		AEP (100%)
b2531	Replace the Sporn 138 kV breaker 'D' with 80kA breaker		AEP (100%)
b2532	Replace the Sporn 138 kV breaker 'O1' with 80kA breaker		AEP (100%)
b2533	Replace the Sporn 138 kV breaker 'P2' with 80kA breaker		AEP (100%)
b2534	Replace the Sporn 138 kV breaker 'U' with 80kA breaker		AEP (100%)
b2535	Replace the Sporn 138 kV breaker 'O' with 80 kA breaker		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2536	Replace the Sporn 138 kV breaker ‘O2’ with 80 kA breaker		AEP (100%)
b2537	Replace the Robinson Park 138 kV breakers A1, A2, B1, B2, C1, C2, D1, D2, E1, E2, and F1 with 63 kA breakers		AEP (100%)
b2555	Reconductor 0.5 miles Tiltonsville – Windsor 138 kV and string the vacant side of the 4.5 mile section using 556 ACSR in a six wire configuration		AEP (100%)
b2556	Install two 138 kV prop structures to increase the maximum operating temperature of the Clinch River- Clinch Field 138 kV line		AEP (100%)
b2581	Temporary operating procedure for delay of upgrade b1464. Open the Corner 138 kV circuit breaker 86 for an overload of the Corner – Washington MP 138 kV line. The tower contingency loss of Belmont – Trissler 138 kV and Belmont – Edgelawn 138 kV should be added to Operational contingency		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2591	Construct a new 69 kV line approximately 2.5 miles from Colfax to Drewry's. Construct a new Drewry's station and install a new circuit breaker at Colfax station.		AEP (100%)
b2592	Rebuild existing East Coshocton – North Coshocton double circuit line which contains Newcomerstown – N. Coshocton 34.5 kV Circuit and Coshocton – North Coshocton 69 kV circuit		AEP (100%)
b2593	Rebuild existing West Bellaire – Glencoe 69 kV line with 138 kV & 69 kV circuits and install 138/69 kV transformer at Glencoe Switch		AEP (100%)
b2594	Rebuild 1.0 mile of Brantley – Bridge Street 69 kV Line with 1033 ACSR overhead conductor		AEP (100%)
b2595.1	Rebuild 7.82 mile Elkhorn City – Haysi S.S 69 kV line utilizing 1033 ACSR built to 138 kV standards		AEP (100%)
b2595.2	Rebuild 5.18 mile Moss – Haysi SS 69 kV line utilizing 1033 ACSR built to 138 kV standards		AEP (100%)
b2596	Move load from the 34.5 kV bus to the 138 kV bus by installing a new 138/12 kV XF at New Carlisle station in Indiana		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2597	Rebuild approximately 1 mi. section of Dragoon-Virgil Street 34.5 kV line between Dragoon and Dodge Tap switch and replace Dodge switch MOAB to increase thermal capability of Dragoon-Dodge Tap branch		AEP (100%)
b2598	Rebuild approximately 1 mile section of the Kline-Virgil Street 34.5 kV line between Kline and Virgil Street tap. Replace MOAB switches at Beiger, risers at Kline, switches and bus at Virgil Street.		AEP (100%)
b2599	Rebuild approximately 0.1 miles of 69 kV line between Albion and Albion tap		AEP (100%)
b2600	Rebuild Fremont – Pound line as 138 kV		AEP (100%)
b2601	Fremont Station Improvements		AEP (100%)
b2601.1	Replace MOAB towards Beaver Creek with 138 kV breaker		AEP (100%)
b2601.2	Replace MOAB towards Clinch River with 138 kV breaker		AEP (100%)
b2601.3	Replace 138 kV Breaker A with new bus-tie breaker		AEP (100%)
b2601.4	Re-use Breaker A as high side protection on transformer #1		AEP (100%)
b2601.5	Install two (2) circuit switchers on high side of transformers # 2 and 3 at Fremont Station		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2602.1	Install 138 kV breaker E2 at North Proctorville		AEP (100%)
b2602.2	Construct 2.5 Miles of 138 kV 1033 ACSR from East Huntington to Darrah 138 kV substations		AEP (100%)
b2602.3	Install breaker on new line exit at Darrah towards East Huntington		AEP (100%)
b2602.4	Install 138 kV breaker on new line at East Huntington towards Darrah		AEP (100%)
b2602.5	Install 138 kV breaker at East Huntington towards North Proctorville		AEP (100%)
b2603	Boone Area Improvements		AEP (100%)
b2603.1	Purchase approximately a 200X300 station site near Slaughter Creek 46 kV station (Wilbur Station)		AEP (100%)
b2603.2	Install 3 138 kV circuit breakers, Cabin Creek to Hernshaw 138 kV circuit		AEP (100%)
b2603.3	Construct 1 mi. of double circuit 138 kV line on Wilbur – Boone 46 kV line with 1590 ACSS 54/19 conductor @ 482 Degree design temp. and 1-159 12/7 ACSR and one 86 Sq.MM. 0.646” OPGW Static wires		AEP (100%)
b2604	Bellefonte Transformer Addition		AEP (100%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2605	Rebuild and reconductor Kammer – George Washington 69 kV circuit and George Washington – Moundsville ckt #1, designed for 138kV. Upgrade limiting equipment at remote ends and at tap stations		AEP (100%)
b2606	Convert Bane – Hammondsville from 23 kV to 69 kV operation		AEP (100%)
b2607	Pine Gap Relay Limit Increase		AEP (100%)
b2608	Richlands Relay Upgrade		AEP (100%)
b2609	Thorofare – Goff Run – Powell Mountain 138 kV Build		AEP (100%)
b2610	Rebuild Pax Branch – Scaraboro as 138 kV		AEP (100%)
b2611	Skin Fork Area Improvements		AEP (100%)
b2611.1	New 138/46 kV station near Skin Fork and other components		AEP (100%)
b2611.2	Construct 3.2 miles of 1033 ACSR double circuit from new Station to cut into Sundial-Baileysville 138 kV line		AEP (100%)
b2634.1	Replace metering BCT on Tanners Creek CB T2 with a slip over CT with higher thermal rating in order to remove 1193 MVA limit on facility (Miami Fort-Tanners Creek 345 kV line)		AEP (100%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2643	Replace the Darrah 138 kV breaker 'L' with 40kA rated breaker		AEP (100%)
b2645	Ohio Central 138 kV Loop		AEP (100%)
b2667	Replace the Muskingum 138 kV bus # 1 and 2		AEP (100%)
b2668	Reconductor Dequine to Meadow Lake 345 kV circuit #1 utilizing dual 954 ACSR 54/7 cardinal conductor		AEP (100%)
b2669	Install a second 345/138 kV transformer at Desoto		AEP (100%)
b2670	Replace switch at Elk Garden 138 kV substation (on the Elk Garden – Lebanon 138 kV circuit)		AEP (100%)
b2671	Replace/upgrade/add terminal equipment at Bradley, Mullensville, Pinnacle Creek, Itmann, and Tams Mountain 138 kV substations. Sag study on Mullens – Wyoming and Mullens – Tams Mt. 138 kV circuits		AEP (100%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2687.1	Install a +/- 450 MVAR SVC at Jacksons Ferry 765 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)

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

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2687.2	Install a 300 MVAR shunt line reactor on the Broadford end of the Broadford – Jacksons Ferry 765 kV line		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)
b2697.1	Mitigate violations identified by sag study to operate Fieldale-Thornton-Franklin 138 kV overhead line conductor at its max. operating temperature. 6 potential line crossings to be addressed.		AEP (100%)
b2697.2	Replace terminal equipment at AEP's Danville and East Danville substations to improve thermal capacity of Danville – East Danville 138 kV circuit		AEP (100%)

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2698	Replace relays at AEP's Cloverdale and Jackson's Ferry substations to improve the thermal capacity of Cloverdale – Jackson's Ferry 765 kV line		AEP (100%)
b2701.1	Construct Herlan station as breaker and a half configuration with 9-138 kV CB's on 4 strings and with 2-28.8 MVAR capacitor banks		AEP (100%)
b2701.2	Construct new 138 kV line from Herlan station to Blue Racer station. Estimated approx. 3.2 miles of 1234 ACSS/TW Yukon and OPGW		AEP (100%)
2701.3	Install 1-138 kV CB at Blue Racer to terminate new Herlan circuit		AEP (100%)
b2714	Rebuild/upgrade line between Glencoe and Willow Grove Switch 69 kV		AEP (100%)
b2715	Build approximately 11.5 miles of 34.5 kV line with 556.5 ACSR 26/7 Dove conductor on wood poles from Flushing station to Smyrna station		AEP (100%)
b2727	Replace the South Canton 138 kV breakers 'K', 'J', 'J1', and 'J2' with 80kA breakers		AEP (100%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2731	Convert the Sunnyside – East Sparta – Malvern 23 kV sub-transmission network to 69 kV. The lines are already built to 69 kV standards		AEP (100%)
b2733	Replace South Canton 138 kV breakers ‘L’ and ‘L2’ with 80 kA rated breakers		AEP (100%)
b2750.1	Retire Betsy Layne 138/69/43 kV station and replace it with the greenfield Stanville station about a half mile north of the existing Betsy Layne station		AEP (100%)
b2750.2	Relocate the Betsy Layne capacitor bank to the Stanville 69 kV bus and increase the size to 14.4 MVAR		AEP (100%)
b2753.1	Replace existing George Washington station 138 kV yard with GIS 138 kV breaker and a half yard in existing station footprint. Install 138 kV revenue metering for new IPP connection		AEP (100%)
b2753.2	Replace Dilles Bottom 69/4 kV Distribution station as breaker and a half 138 kV yard design including AEP Distribution facilities but initial configuration will constitute a 3 breaker ring bus		AEP (100%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2753.3	Connect two 138 kV 6-wired circuits from "Point A" (currently de-energized and owned by FirstEnergy) in circuit positions previously designated Burger #1 & Burger #2 138 kV. Install interconnection settlement metering on both circuits exiting Holloway		AEP (100%)
b2753.6	Build double circuit 138 kV line from Dilles Bottom to "Point A". Tie each new AEP circuit in with a 6-wired line at Point A. This will create a Dilles Bottom – Holloway 138 kV circuit and a George Washington – Holloway 138 kV circuit		AEP (100%)
b2753.7	Retire line sections (Dilles Bottom – Bellaire and Moundsville – Dilles Bottom 69 kV lines) south of FirstEnergy 138 kV line corridor, near "Point A". Tie George Washington – Moundsville 69 kV circuit to George Washington – West Bellaire 69 kV circuit		AEP (100%)
b2753.8	Rebuild existing 69 kV line as double circuit from George Washington – Dilles Bottom 138 kV. One circuit will cut into Dilles Bottom 138 kV initially and the other will go past with future plans to cut in		AEP (100%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2760	Perform a Sag Study of the Saltville – Tazewell 138 kV line to increase the thermal rating of the line		AEP (100%)
b2761.1	Replace the Hazard 161/138 kV transformer		AEP (100%)
b2761.2	Perform a Sag Study of the Hazard – Wooten 161 kV line to increase the thermal rating of the line		AEP (100%)
b2762	Perform a Sag Study of Nagel – West Kingsport 138 kV line to increase the thermal rating of the line		AEP (100%)
b2776	Reconductor the entire Dequine – Meadow Lake 345 kV circuit #2		AEP (100%)
b2777	Reconductor the entire Dequine – Eugene 345 kV circuit #1		AEP (100%)
b2779.1	Construct a new 138 kV station, Campbell Road, tapping into the Grabill – South Hicksville138 kV line		AEP (100%)
b2779.2	Reconstruct sections of the Butler-N.Hicksville and Auburn-Butler 69 kV circuits as 138 kV double circuit and extend 138 kV from Campbell Road station		AEP (100%)
b2779.3	Construct a new 345/138 kV SDI Wilmington Station which will be sourced from Collingwood 345 kV and serve the SDI load at 345 kV and 138 kV, respectively		AEP (100%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2779.4	Loop 138 kV circuits in-out of the new SDI Wilmington 138 kV station resulting in a direct circuit to Auburn 138 kV and an indirect circuit to Auburn and Rob Park via Dunton Lake, and a circuit to Campbell Road; Reconductor 138 kV line section between Dunton Lake – SDI Wilmington		AEP (100%)
b2779.5	Expand Auburn 138 kV bus		AEP (100%)
b2817	Replace Delaware 138 kV breaker ‘P’ with a 40 kA breaker		AEP (100%)
b2818	Replace West Huntington 138 kV breaker ‘F’ with a 40 kA breaker		AEP (100%)
b2819	Replace Madison 138 kV breaker ‘V’ with a 63 kA breaker		AEP (100%)
b2820	Replace Sterling 138 kV breaker ‘G’ with a 40 kA breaker		AEP (100%)
b2821	Replace Morse 138 kV breakers ‘103’, ‘104’, ‘105’, and ‘106’ with 63 kA breakers		AEP (100%)
b2822	Replace Clinton 138 kV breakers ‘105’ and ‘107’ with 63 kA breakers		AEP (100%)
b2826.1	Install 300 MVAR reactor at Ohio Central 345 kV substation		AEP (100%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2826.2	Install 300 MVAR reactor at West Bellaire 345 kV substation		AEP (100%)
b2831.1	Upgrade the Tanner Creek – Miami Fort 345 kV circuit (AEP portion)		**DFAX Allocation:** Dayton (34.34%) / DEOK (56.45%) / EKPC (9.21%)
b2832	Six wire the Kyger Creek – Sporn 345 kV circuits #1 and #2 and convert them to one circuit		AEP (100%)
b2833	Reconductor the Maddox Creek – East Lima 345 kV circuit with 2-954 ACSS Cardinal conductor		**DFAX Allocation:** Dayton (100%)
b2834	Reconductor and string open position and sixwire 6.2 miles of the Chemical – Capitol Hill 138 kV circuit		AEP (100%)
b2878	Upgrade the Clifty Creek 345 kV risers		AEP (100%)

Attachment 7j (BG&E OATT)

SCHEDULE 12 – APPENDIX

(2) Baltimore Gas and Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0152	Add (2) 230 kV Breakers at High Ridge and install two Northwest 230 kV 120 MVAR capacitors		BGE (100%)
b0244	Install a 4th Waugh Chapel 500/230kV transformer, terminate the transformer in a new 500 kV bay and operate the existing in-service spare transformer on standby		BGE (85.56%) / ME (0.83%) / PEPCO (13.61%)
b0298	Replace both Conastone 500/230 kV transformers with larger transformers	As specified in Attachment H-2A, Attachment 7, the Transmission Enhancement Charge Worksheet	BGE (75.85%) / Dominion (11.54%) / ME (4.73%) / PEPCO (7.88%)
b0298.1	Replace Conastone 230 kV breaker 500-3/2323		BGE (100%)
b0474	Add a fourth 230/115 kV transformer, two 230 kV circuit breakers and a 115 kV breaker at Waugh Chapel		BGE (100%)
b0475	Create two 230 kV ring buses at North West, add two 230/ 115 kV transformers at North West and create a new 115 kV station at North West		BGE (100%)
b0476	Rebuild High Ridge 230 kV substation to Breaker and Half configuration		BGE (100%)
b0477	Replace the Waugh Chapel 500/230 kV transformer #1 with three single phase transformers		BGE (90.56%) / ME (1.51%) / PECO (.92%) / PEPCO (4.01%) / PPL (3.00%)

* Neptune Regional Transmission System, LLC

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0497	Install a second Conastone – Graceton 230 kV circuit		AEC (9.03%) / DPL (16.90%) / JCPL (9.67%) / ME (1.48%) / Neptune* (0.95%) / PECO (30.88%) / PPL (16.46%) / PSEG (14.11%) / RE (0.52%)
b0497.1	Replace Conastone 230 kV breaker #4		BGE (100%)
b0497.2	Replace Conastone 230 kV breaker #7		BGE (100%)
b0500.2	Replace wavetrap and raise operating temperature on Conastone – Otter Creek 230 kV line to 165 deg		AEC (6.31%) / DPL (8.70 %) / JCPL (14.62%) / ME (10.65%) / Neptune* (1.38%) / PECO (15.75%) / PPL (21.14%) / PSEG (20.68%) / RE (0.77%)
b0512.33	MAPP Project Install new Hallowing Point – Calvert Cliffs 500 kV circuit and associated substation work at Calvert Cliffs substation		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*11.40*%) / ComEd (*6.13*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.43	MAPP Project Install new Hallowing Point – Calvert Cliffs 500 kV circuit and associated substation work at Calvert Cliffs substation		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*11.40*%) / ComEd (*6.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0729	Rebuild both Harford – Perryman 110615-A and 110616-A 115 kV circuits		BGE (100%)
b0749	Replace 230 kV breaker and associated CT's at Riverside 230 kV on 2345 line; replace all dead-end structures at Brandon Shores, Hawkins Point, Sollers Point and Riverside; Install a second conductor per phase on the spans entering each station		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0795	Install a 115 kV breaker at Chesaco Park		BGE (100%)
b0796	Install 2, 115 kV breakers at Gwynnbrook		BGE (100%)
b0819	Remove line drop limitations at the substation terminations for Gwynnbrook – Mays Chapel 115 kV		BGE (100%)
b0820	Remove line drop limitations at the substation terminations and replace switch for Delight – Gwynnbrook 115 kV		BGE (100%)
b0821	Remove line drop limitations at the substation terminations for Northwest – Delight 115 kV		BGE (100%)
b0822	Remove line drop limitations at the substation terminations for Gwynnbrook – Sudbrook 115 kV		BGE (100%)
b0823	Remove line drop limitations at the substation terminations for Windy Edge – Texas 115 kV		BGE (100%)
b0824	Remove line drop limitations at the substation terminations for Granite – Harrisonville 115 kV		BGE (100%)
b0825	Remove line drop limitations at the substation terminations for Harrison – Dolefield 115 kV		BGE (100%)

* Neptune Regional Transmission System, LLC

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0826	Remove line drop limitations at the substation terminations for Riverside – East Point 115 kV		BGE (100%)
b0827	Install an SPS for one year to trip a Mays Chapel 115 kV breaker one line 110579 for line overloads 110509		BGE (100%)
b0828	Disable the HS throwover at Harrisonville for one year		BGE (100%)
b0870	Rebuild each line (0.2 miles each) to increase the normal rating to 968 MVA and the emergency rating to 1227 MVA		BGE (100%)
b0906	Increase contact parting time on Wagner 115 kV breaker 32-3/2		BGE (100%)
b0907	Increase contact parting time on Wagner 115 kV breaker 34-1/3		BGE (100%)
b1016	Rebuild Graceton - Bagley 230 kV as double circuit line using 1590 ACSR. Terminate new line at Graceton with a new circuit breaker.		APS (2.02%) / BGE (75.22%) / Dominion (16.1%) / PEPCO (6.6%)
b1055	Upgrade wire drops at Center 115kV on the Center - Westport 115 kV circuit		BGE (100%)
b1029	Upgrade wire sections at Wagner on both 110534 and 110535 115 kV circuits. Reconfigure Lipins Corner substation		BGE (100%)

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-2.

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1030	Move the Hillen Rd substation from circuits 110507/110508 to circuits 110505/110506		BGE (100%)
b1031	Replace wire sections on Westport - Pumphrey 115 kV circuits #110521, 110524, 110525, and 110526		BGE (100%)
b1083	Upgrade wire sections of the Mays Chapel – Mt Washington circuits (110701 and 110703) to improve the rating to 260/300 SN/SE MVA		BGE (100%)
b1084	Extend circuit 110570 from Deer Park to Northwest, and retire the section of circuit 110560 from Deer Park to Deer Park tap and retire existing Deer Park Breaker		BGE (100%)
b1085	Upgrade substation wire conductors at Lipins Corner to improve the rating of Solley-Lipins Corner sections of circuits 110534 and 110535 to 275/311 MVA SN/SE		BGE (100%)
b1086	Build a new 115 kV switching station between Orchard St. and Monument St.		BGE (100%)
b1175	Apply SPS at Mt. Washington to delay load pick-up for one outage and for the other outage temporarily drop load		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1176	Transfer 6 MW of load from Mt. Washington – East Towson		BGE (100%)
b1251	Build a second Raphael – Bagley 230 kV		APS (4.42%) / BGE (66.95%) / ComEd (4.12%) / Dayton (0.49%) / Dominion (18.76%) / PENELEC (0.05%) / PEPCO (5.21%)
b1251.1	Re-build the existing Raphael – Bagley 230 kV		APS (4.42%) / BGE (66.95%) / ComEd (4.12%) / Dayton (0.49%) / Dominion (18.76%) / PENELEC (0.05%) / PEPCO (5.21%)
b1252	Upgrade terminal equipment (remove terminal limitation at Pumphrey Tap to bring the circuit to 790N/941E		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1253	Replace the existing Northeast 230/115 kV transformer #3 with 500 MVA		BGE (100%)
b1253.1	Replace the Northeast 230 kV breaker ‘2317/315’		BGE (100%)
b1253.2	Revise reclosing on Windy Edge 115 kV breaker ‘110515’		BGE (100%)
b1253.3	Revise reclosing on Windy Edge 115 kV breaker ‘110516’		BGE (100%)
b1253.4	Revise reclosing on Windy Edge 115 kV breaker ‘110517’		BGE (100%)
b1254	Build a new 500/230 kV substation (Emory Grove)		APS (4.07%) / BGE (53.19%) / ComEd (3.71%) / Dayton (0.50%) / Dominion (16.44%) / PENELEC (0.59%) / PEPCO (21.50%)
b1254.1	Bundle the Emory – North West 230 kV circuits		BGE (100%)
b1267	Rebuild existing Erdman 115 kV substation to a dual ring-bus configuration to enable termination of new circuits		BGE (100%)
b1267.1	Construct 115 kV double circuit underground line from existing Coldspring to Erdman substation		BGE (100%)
b1267.2	Replace Mays Chapel 115 kV breaker ‘110515A’		BGE (100%)
b1267.3	Replace Mays Chapel 115 kV breaker ‘110579C’		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1544	Advance the baseline upgrade B1252 to upgrade terminal equipment removing terminal limitation at Pumphrey Tap on BGE 230 kV circuit 2332-A		BGE (100%)
b1545	Upgrade terminal equipment at both Brandon Shores and Waugh Chapel removing terminal limitation on BGE 230 kV circuit 2343		BGE (100%)
b1546	Upgrade terminal equipment at Graceton removing terminal limitation on BGE portion of the 230 kV Graceton – Cooper circuit 2343		BGE (100%)
b1583	Replace Hazelwood 115 kV breaker '110602'		BGE (100%)
b1584	Replace Hazelwood 115 kV breaker '110604'		BGE (100%)
b1606.1	Moving the station supply connections of the Hazelwood 115/13kV station		BGE (100%)
b1606.2	Installing 115kV tie breakers at Melvale		BGE (100%)
b1785	Revise the reclosing for Pumphrey 115 kV breaker ‘110521 DR’		BGE (100%)
b1786	Revise the reclosing for Pumphrey 115 kV breaker ‘110526 DR’		BGE (100%)
b1789	Revise the reclosing for Pumphrey 115 kV breaker ‘110524DR’		BGE (100%)
b1806	Rebuild Wagner 115kV substation to 80kA		BGE (100%)

SCHEDULE 12 – APPENDIX A

(2) Baltimore Gas and Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2219	Install a 115 kV tie breaker at Wagner to create a separation from line 110535 and transformer 110-2		BGE (100%)
b2220	Install four 115 kV breakers at Chestnut Hill		BGE (100%)
b2221	Install an SPS to trip approximately 19 MW load at Green St. and Concord		BGE (100%)
b2307	Install a 230/115kV transformer at Raphael Rd and construct approximately 3 miles of 115kV line from Raphael Rd. to Joppatowne. Construct a 115kV three breaker ring at Joppatowne		BGE (100%)
b2308	Build approximately 3 miles of 115kV underground line from Bestgate tap to Waugh Chapel. Create two breaker bay at Waugh Chapel to accommodate the new underground circuit		BGE (100%)
b2396	Build a new Camp Small 115 kV station and install 30 MVAR capacitor		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2396.1	Install a tie breaker at Mays Chapel 115 kV substation		BGE (100%)
b2567	Upgrade the Riverside 115kV substation strain bus conductors on circuits 115012 and 115011 with double bundled 1272 ACSR to achieve ratings of 491/577 MVA SN/SE on both transformer leads		BGE (100%)
b2568	Reconductor Northwest – Northwest #2 115kV 110574 substation tie circuit with 2167 ACSR to achieve ratings of 400/462 MVA SN/SE		BGE (100%)
b2752.6	Conastone 230 kV substation tie-in work (install a new circuit breaker at Conastone 230 kV and upgrade any required terminal equipment to terminate the new circuit)		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%)
b2752.7	Reconductor/Rebuild the two Conastone – Northwest 230 kV lines and upgrade terminal equipment on both ends		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%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2766.1	Upgrade substation equipment at Conastone 500 kV to increase facility rating to 2826 MVA normal and 3525 MVA emergency		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (0.05%) / APS (11.40%) / BGE (22.83%) / Dayton (2.23%) / DEOK (4.28%) / DPL (0.20%) / EKPC (1.98%) / JCPL (11.06%) / NEPTUNE* (1.17%) / POSEIDON**** (0.64%) / PENELEC (0.06%) / PEPCO (19.38%) / PSEG (23.77%) / RECO (0.95%)

*Neptune Regional Transmission System, LLC
****Poseidon Transmission 1, LLC

Attachment 7k (MAIT 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 (6.75%) / APS (4.00%) / DPL (9.16%) / JCPL (16.96%) / ME (10.60%) / Neptune* (1.70%) / PECO (19.12%) / PPL (8.55%) / PSEG (22.82%) / RE (0.34%)
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

(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

(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 (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b1801	Build a 250 MVAR SVC at Altoona 230 kV		AEC (6.48%) / AEP (2.58%) / APS (6.89%) / BGE (6.58%) / DPL (12.40%) / Dominion (14.90%) / JCPL (8.15%) / ME (6.21%) / Neptune* (0.82%) / PECO (21.58%) / PPL (4.89%) / PSEG (8.19%) / RE (0.33%)

(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

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 (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0284.3	Replace wave trap and upgrade a bus section at Keystone 500 kV – on the Keystone – Airydale 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, 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 (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0285.2	Replace wave trap and relay at Conemaugh 500 kV – on the Conemaugh – Keystone 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, 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 (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0370	Install 500 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)

* Neptune Regional Transmission System, LLC

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 (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
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

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 (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0550	Install 25 MVAR capacitor at Lewis Run 115 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
b0551	Install 25 MVAR capacitor at Saxton 115 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
b0552	Install 50 MVAR capacitor at Altoona 230 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)

* Neptune Regional Transmission System, 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 (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
b0555	Install 100 MVAR capacitor at Johnstown 230 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
b0556	Install 50 MVAR capacitor at Grover 230 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
b0557	Install 75 MVAR capacitor at East Towanda 230 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
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

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%)

* Neptune Regional Transmission System, LLC

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 (3.86%) / APS (6.45%) / BGE (17.33%) / DL (0.33%) / JCPL (12.95%) / ME (7.10%) / PECO (11.88%) / PEPCO (0.57%) / PPL (15.89%) / PSEG (21.15%) / RE (0.74%) / NEPTUNE* (1.75%)
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

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 (6.48%) / AEP (2.58%) / APS (6.89%) / BGE (6.58%) / DPL (12.40%) / Dominion (14.90%) / JCPL (8.15%) / ME (6.21%) / NEPTUNE* (0.82%) / PECO (21.58%) / PPL (4.89%) / PSEG (8.19%) / RE (0.33%)

* Neptune Regional Transmission System, LLC

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

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 (10.19%) / JCPL (5.19%) / Neptune* (0.55%) / PENELEC (71.38%) / PSEG (12.21%) / 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 (33.49%) / JCPL (8.72%) / ME (5.57%) / Neptune (0.87%) / PENELEC (37.14%) / PSEG (13.67%) / 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

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 (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PPL (100%)
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%)

Attachment 7l (PECO OATT)

SCHEDULE 12 – APPENDIX

(8) PECO Energy Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0171.1	Replace two 500 kV circuit breakers and two wave traps at Elroy substation to increase rating of Elroy - Hosensack 500 kV		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0180	Replace Whitpain 230kV circuit breaker #165		PECO (100%)
b0181	Replace Whitpain 230kV circuit breaker #J105		PECO (100%)
b0182	Upgrade Plymouth Meeting 230kV circuit breaker #125		PECO (100%)
b0205	Install three 28.8Mvar capacitors at Planebrook 35kV substation		PECO (100%)
b0206	Install 161Mvar capacitor at Planebrook 230kV substation		AEC (14.20%) / DPL (24.39%) / PECO (57.94%) / PSEG (3.47%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0207	Install 161Mvar capacitor at Newlinville 230kV substation		AEC (14.20%) / DPL (24.39%) / PECO (57.94%) / PSEG (3.47%)
b0208	Install 161Mvar capacitor Heaton 230kV substation		AEC (14.20%) / DPL (24.39%) / PECO (57.94%) / PSEG (3.47%)
b0209	Install 2% series reactor at Chichester substation on the Chichester - Mickleton 230kV circuit		AEC (65.23%) / JCPL (25.87%)/ Neptune* (2.55%) / PSEG (6.35%)
b0264	Upgrade Chichester – Delco Tap 230 kV and the PECO portion of the Delco Tap – Mickleton 230 kV circuit		AEC (89.87%) / JCPL (9.48%) / Neptune* (0.65%)
b0266	Replace two wave traps and ammeter at Peach Bottom, and two wave traps and ammeter at Newlinville 230 kV substations		PECO (100%)
b0269	Install a new 500/230 kV substation in PECO, and tap the high side on the Elroy – Whitpain 500 kV and the low side on the North Wales – Perkiomen 230 kV circuit		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)†

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0269	Install a new 500/230 kV substation in PECO, and tap the high side on the Elroy – Whitpain 500 kV and the low side on the North Wales – Perkiomen 230 kV circuit		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.1	Add a new 230 kV circuit between Whitpain and Heaton substations		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.2	Reconductor the Whitpain 1 – Plymtg 1 230 kV circuit		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.3	Convert the Heaton bus to a ring bus		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.4	Reconductor the Heaton – Warminster 230 kV circuit		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.5	Reconductor Warminster – Buckingham 230 kV circuit		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††

* Neptune Regional Transmission System, LLC

†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project

††Cost allocations associated with below 500 kV elements of the project

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0269.6	Add a new 500 kV breaker at Whitpain between #3 transformer and 5029 line		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
b0269.7	Replace North Wales 230 kV breaker #105		PECO (100%)
b0280.1	Install 161 MVAR capacitor at Warrington 230 kV substation		PECO 100%
b0280.2	Install 161 MVAR capacitor at Bradford 230 kV substation		PECO 100%
b0280.3	Install 28.8 MVAR capacitor at Warrington 34 kV substation		PECO 100%
b0280.4	Install 18 MVAR capacitor at Waverly 13.8 kV substation		PECO 100%

* Neptune Regional Transmission System, LLC

†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project

††Cost allocations associated with below 500 kV elements of the project

PECO Energy Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0287	Install 600 MVAR Dynamic Reactive Device in Whitpain 500 kV vicinity		AEC (*1.66%*) / AEP (*14.16%*) / APS (*5.73%*) / ATSI (*7.88%*) / BGE (*4.22%*) / ComEd (*13.31%*) / Dayton (*2.11%*) / DEOK (*3.29%*) / DL (*1.75%*) / DPL (*2.50%*) / Dominion (*12.86%*) / EKPC (*1.87%*) / JCPL (*3.74%*) / ME (*1.90%*) / NEPTUNE* (*0.44%*) / PECO (*5.34%*) / PENELEC (*1.89%*) / PEPCO (*3.99%*) / PPL (*4.84%*) / PSEG (*6.26%*) / RE (*0.26%*)
b0351	Reconductor Tunnel – Grays Ferry 230 kV		PECO (100%)
b0352	Reconductor Tunnel – Parrish 230 kV		PECO (100%)
b0353.1	Install 2% reactors on both lines from Eddystone – Llanerch 138 kV		PECO (100%)
b0353.2	Install identical second 230/138 kV transformer in parallel with existing 230/138 kV transformer at Plymouth Meeting		PECO 100%
b0353.3	Replace Whitpain 230 kV breaker 135		PECO (100%)
b0353.4	Replace Whitpain 230 kV breaker 145		PECO (100%)
b0354	Eddystone – Island Road Upgrade line terminal equipment		PECO 100%

* Neptune Regional Transmission System, LLC
††Cost allocations associated with below 500 kV elements of the project

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0355	Reconductor Master – North Philadelphia 230 kV line		PECO 100%
b0357	Reconductor Buckingham – Pleasant Valley 230 kV		JCPL (37.89%) / Neptune* (4.55%) / PSEG (55.19%) / RE (2.37%)
b0359	Reconductor North Philadelphia – Waneeta 230 kV circuit		PECO 100%
b0402.1	Replace Whitpain 230 kV breaker #245		PECO (100%)
b0402.2	Replace Whitpain 230 kV breaker #255		PECO (100%)
b0438	Spare Whitpain 500/230 kV transformer		PECO (100%)
b0443	Spare Peach Bottom 500/230 kV transformer		PECO (100%)
b0505	Reconductor the North Wales – Whitpain 230 kV circuit		AEC (8.58%) / DPL (7.76%) / PECO (83.66%)
b0506	Reconductor the North Wales – Hartman 230 kV circuit		AEC (8.58%) / DPL (7.76%) / PECO (83.66%)
b0507	Reconductor the Jarrett – Whitpain 230 kV circuit		AEC (8.58%) / DPL (7.76%) PECO (83.66%)
b0508.1	Replace station cable at Hartman on the Warrington - Hartman 230 kV circuit		PECO (100%)
b0509	Reconductor the Jarrett – Heaton 230 kV circuit		PECO (100%)

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0727	Rebuild Bryn Mawr – Plymouth Meeting 138 kV line		AEC (1.25%) / DPL (3.11%) / PECO (95.64%)
b0789	Reconductor the line to provide a normal rating of 677 MVA and an emergency rating of 827 MVA		AEC (0.73%) / JCPL (17.52%) / NEPTUNE* (1.72%) / PECO (44.88%) / PSEG (33.83%) / RE (1.32%)
b0790	Reconductor the Bradford – Planebrook 230 kV Ckt. 220-31 to provide a normal rating of 677 MVA and emergency rating of 827 MVA		JCPL (17.46%) / NEPTUNE* (1.71%) / PECO (45.51%) / PSEG (34.00%) / RE (1.32%)
b0829.1	Replace Whitpain 230 kV breaker '155'		PECO (100%)
b1073	Install 2 new 230 kV breakers at Planebrook (on the 220-02 line terminal and on the 230 kV side of the #9 transformer)		PECO (100%)
b0829.2	Replace Whitpain 230 kV breaker '525'		PECO (100%)
b0829.3	Replace Whitpain 230 kV breaker '175'		PECO (100%)
b0829.4	Replace Plymouth Meeting 230 kV breaker '225'		PECO (100%)
b0829.5	Replace Plymouth Meeting 230 kV breaker '335'		PECO (100%)
b0841	Move the connection points for the 2nd Plymouth Meeting 230/138 kV XFMR		PECO (100%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0842	Install a 2nd 230/138 kV XFMR and 35 MVAR CAP at Heaton 138 kV bus		PECO (100%)
b0842.1	Replace Heaton 138 kV breaker '150'		PECO (100%)
b0843	Install a 75 MVAR CAP at Llanerch 138 kV bus		PECO (100%)
b0844	Move the connection point for the Llanerch 138/69 kV XFMR		PECO (100%)
b0887	Replace Richmond-Tacony 69 kV line		PECO (100%)
b0920	Replace station cable at Whitpain and Jarrett substations on the Jarrett - Whitpain 230 kV circuit		PECO (100%)
b1014.1	Replace Circuit breaker, Station Cable, CTs and Wave Trap at Eddistone 230 kV		PECO (100%)
b1014.2	Replace Circuit breaker, Station Cable, CTs Disconnect Switch and Wave Trap at Island Rd. 230 kV		PECO (100%)
b1015	Replace Breakers #115 and #125 at Printz 230 kV substation		PECO (100%)
b1156.1	Upgrade at Richmond 230 kV breaker '525'		PECO (100%)
b1156.2	Upgrade at Richmond 230 kV breaker '415'		PECO (100%)
b1156.3	Upgrade at Richmond 230 kV breaker '475'		PECO (100%)
b1156.4	Upgrade at Richmond 230 kV breaker '575'		PECO (100%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1156.5	Upgrade at Richmond 230 kV breaker '185'		PECO (100%)
b1156.6	Upgrade at Richmond 230 kV breaker '285'		PECO (100%)
b1156.7	Upgrade at Richmond 230 kV breaker '85'		PECO (100%)
b1156.8	Upgrade at Waneeta 230 kV breaker '425'		PECO (100%)
b1156.9	Upgrade at Emilie 230 kV breaker '815'		PECO (100%)
b1156.10	Upgrade at Plymouth Meeting 230 kV breaker '265'		PECO (100%)
b1156.11	Upgrade at Croydon 230 kV breaker '115'		PECO (100%)
b1156.12	Replace Emilie 138 kV breaker '190'		PECO (100%)
b1178	Add a second 230/138 kV transformer at Chichester. Add an inductor in series with the parallel transformers		JCPL (4.17%) / Neptune (0.44%) / PECO (82.73%) / PSEG (12.18%) / RE (0.48%)
b1179	Replace terminal equipment at Eddystone and Saville and replace underground section of the line		PECO (100%)
b1180.1	Replace terminal equipment at Chichester		PECO (100%)
b1180.2	Replace terminal equipment at Chichester		PECO (100%)
b1181	Install 230/138 kV transformer at Eddystone		PECO (100%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1182	Reconductor Chichester – Saville 138 kV line and upgrade terminal equipment		JCPL (5.12%) / Neptune (0.54%) / PECO (79.46%) / PSEG (14.31%) / RE (0.57%)
b1183	Replace 230/69 kV transformer #6 at Cromby. Add two 50 MVAR 230 kV banks at Cromby		PECO (100%)
b1184	Add 138 kV breakers at Cromby, Perkiomen, and North Wales; add a 35 MVAR capacitor at Perkiomen 138 kV		PECO (100%)
b1185	Upgrade Eddystone 230 kV breaker #365		PECO (100%)
b1186	Upgrade Eddystone 230 kV breaker #785		PECO (100%)
b1197	Reconductor the PECO portion of the Burlington – Croydon circuit		PECO (100%)
b1198	Replace terminal equipments including station cable, disconnects and relay at Conowingo 230 kV station		PECO (100%)
b1338	Replace Printz 230 kV breaker ‘225’		PECO (100%)
b1339	Replace Printz 230 kV breaker ‘315’		PECO (100%)
b1340	Replace Printz 230 kV breaker ‘215’		PECO (100%)
b1398.6	Reconductor the Camden – Richmond 230 kV circuit (PECO portion) and upgrade terminal equipments at Camden substations		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)

PECO Energy Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1398.8	Reconductor Richmond – Waneeta 230 kV and replace terminal equipments at Richmond and Waneeta substations		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)
b1398.12	Replace Graysferry 230 kV breaker '115'		PECO (100%)
b1398.13	Upgrade Peach Bottom 500 kV breaker '225'		AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)†
b1398.14	Replace Whitpain 230 kV breaker '105'		PECO (100%)
b1590.1	Upgrade the PECO portion of the Camden – Richmond 230 kV to a six wire conductor and replace terminal equipment at Richmond.		BGE (3.06%) / ME (0.83%) / PECO (91.70%) / PEPCO (1.94%) / PPL (2.47%)
b1591	Reconductor the underground portion of the Richmond – Waneeta 230 kV and replace terminal equipment		BGE (4.54%) / DL (0.27%) / ME (1.04%) / PECO (88.11%) / PEPCO (2.79%) / PPL (3.25%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1717	Install a second Waneeta 230/138 kV transformer on a separate bus section		PECO (100%)
b1718	Reconductor the Crescentville - Foxchase 138 kV circuit		PECO (100%)
b1719	Reconductor the Foxchase - Bluegrass 138 kV circuit		PECO (100%)
b1720	Increase the effective rating of the Eddystone 230/138 kV transformer by replacing a circuit breaker at Eddystone		PECO (100%)
b1721	Increase the rating of the Waneeta - Tuna 138 kV circuit by replacing two 138 kV CTs at Waneeta		PECO (100%)
b1722	Increase the normal rating of the Cedarbrook - Whitemarsh 69 kV circuit by changing the CT ratio and replacing station cable at Whitemarsh 69 kV		PECO (100%)
b1768	Install 39 MVAR capacitor at Cromby 138 kV bus		PECO (100%)
b1900	Add a 3rd 230 kV transmission line between Chichester and Linwood substations and remove the Linwood SPS		PECO (70.24%) / JCPL (6.07%) / ATSI (1.24%) / PSEG (21.01%) / RE (0.84%) / NEPTUNE* (0.60%)
b2140	Install a 3rd Emilie 230/138 kV transformer		PECO (100%)
b2145	Replace two sections of conductor inside Richmond substation		PECO (100%)

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

(8) PECO Energy Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2130	Replace Waneeta 138 kV breaker '15' with 63 kA rated breaker		PECO (100%)
b2131	Replace Waneeta 138 kV breaker '35' with 63 kA rated breaker		PECO (100%)
b2132	Replace Waneeta 138 kV breaker '875' with 63 kA rated breaker		PECO (100%)
b2133	Replace Waneeta 138 kV breaker '895' with 63 kA rated breaker		PECO (100%)
b2134	Plymouth Meeting 230 kV breaker '115' with 63 kA rated breaker		PECO (100%)
b2222	Install a second Eddystone 230/138 kV transformer		PECO (100%)
b2222.1	Replace the Eddystone 138 kV #205 breaker with 63kA breaker		PECO (100%)
b2222.2	Increase Rating of Eddystone #415 138kV Breaker		PECO (100%)
b2236	50 MVAR reactor at Buckingham 230 kV		PECO (100%)
b2527	Replace Whitpain 230 kV breaker ‘155’ with 80kA breaker		PECO (100%)
b2528	Replace Whitpain 230 kV breaker ‘525’ with 80kA breaker		PECO (100%)
b2529	Replace Whitpain 230 kV breaker ‘175’ with 80 kA breaker		PECO (100%)
b2549	Replace terminal equipment inside Chichester substation on the 220-36 (Chichester – Eddystone) 230 kV line		PECO (100%)

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2550	Replace terminal equipment inside Nottingham substation on the 220-05 (Nottingham – Daleville- Bradford) 230 kV line		PECO (100%)
b2551	Replace terminal equipment inside Llanerch substation on the 130-45 (Eddystone to Llanerch) 138 kV line		PECO (100%)
b2572	Replace the Peach Bottom 500 kV '#225' breaker with a 63kA breaker		PECO (100%)
b2694	Increase ratings of Peach Bottom 500/230 kV transformer to 1479 MVA normal/1839 MVA emergency		AEC (3.97%)/ AEP (5.77%)/ APS (4.27%)/ ATSI (6.15%)/ BGE (1.63%)/ ComEd (0.72%)/ Dayton (1.06%)/ DEOK (1.97%)/ DL (2.25%)/ Dominion (0.35%)/ DPL (14.29%)/ ECP (0.69%)/ EKPC (0.39%)/ HTP (0.96%)/ JCPL (6.84%) MetEd (3.28%)/ Neptune (2.14%)/ PECO (16.42%)/ PENELEC (3.94%)/ PPL (8.32%)/ PSEG (14.13%)/ RECO (0.44%)
b2752.2	Tie in new Furnace Run substation to Peach Bottom – TMI 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%)
b2752.3	Upgrade terminal equipment and required relay communication at Peach Bottom 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%)

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2766.2	Upgrade substation equipment at Peach Bottom 500 kV to increase facility rating to 2826 MVA normal and 3525 MVA emergency		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (0.05%) / APS (11.16%) / BGE (22.34%) / Dayton (2.18%) / DEOK (4.19%) / DPL (0.20%) / ECP** (1.03%) / EKPC (1.94%) / JCPL (10.82%) / NEPTUNE* (1.14%) / HTP*** (1.10%) / POSEIDON**** (0.63%) / PENELEC (0.06%) / PEPCO (18.97%) / PSEG (23.26%) / RECO (0.93%)

*Neptune Regional Transmission System, LLC
** East Coast Power, LLC
***Hudson Transmission Partners, LLC
****Poseidon Transmission 1, LLC

PECO Energy Company (cont.)

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

b2774	Reconductor the Emilie - Falls 138 kV line, and replace station cable and relay		PECO (100%)
b2775	Reconductor the Falls - U.S. Steel 138 kV line		PECO (100%)
b2850	Replace the Waneeta 230 kV "285" with 63kA breaker		PECO (100%)
b2852	Replace the Chichester 230 kV "195" with 63kA breaker		PECO (100%)
b2854	Replace the North Philadelphia 230 kV "CS 775" with 63kA breaker		PECO (100%)
b2855	Replace the North Philadelphia 230 kV "CS 885" with 63kA breaker		PECO (100%)
b2856	Replace the Parrish 230 kV "CS 715" with 63kA breaker		PECO (100%)
b2857	Replace the Parrish 230 kV "CS 825" with 63kA breaker		PECO (100%)
b2858	Replace the Parrish 230 kV "CS 935" with 63kA breaker		PECO (100%)
b2859	Replace the Plymouth Meeting 230 kV "215" with 63kA breaker		PECO (100%)
b2860	Replace the Plymouth Meeting 230 kV "235" with 63kA breaker		PECO (100%)
b2861	Replace the Plymouth Meeting 230 kV "325" with 63kA breaker		PECO (100%)
b2862	Replace the Grays Ferry 230 kV "705" with 63kA breaker		PECO (100%)

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2863	Replace the Grays Ferry 230 kV "985" with 63kA breaker		PECO (100%)
b2864	Replace the Grays Ferry 230 kV "775" with 63kA breaker		PECO (100%)

Attachment 8 HTP FERC Order

Attachment 8

161 FERC ¶ 61,262
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Neil Chatterjee,
Robert F. Powelson, and Richard Glick.

PJM Interconnection, L.L.C. Docket No. EL17-84-000

ORDER REQUIRING PJM TO PERMIT CONVERSION OF FIRM TO NON-FIRM TRANSMISSION WITHDRAWAL RIGHTS UNDER INTERCONNECTION SERVICE AGREEMENT

(Issued December 15, 2017)

1. On September 8, 2017, the Commission instituted a proceeding pursuant to section 206 of the Federal Power Act (FPA) directing PJM Interconnection, L.L.C. (PJM) and Public Service Electric and Gas Company (PSEG or Interconnected Transmission Owner) to show cause: (1) why the existing Interconnection Service Agreement (Existing ISA) between Hudson Transmission Partners, LLC (HTP), PSEG, and PJM is not unjust and unreasonable and unduly discriminatory to the extent it fails to allow HTP to convert Firm Transmission Withdrawal Rights (TWRs) to Non-Firm TWRs; and (2) why PSEG's failure to consent to an amendment to the Existing ISA reflecting the same is not unjust, unreasonable, and unduly discriminatory.[1] As discussed below, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit HTP to convert its Firm TWRs to Non-Firm TWR.

I. **Background**

2. PJM's Open Access Transmission tariff (tariff or OATT) provides merchant transmission facilities with the right to elect TWRs in lieu of other transmission rights[2]

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[1] *PJM Interconnection, L.L.C.*, 160 FERC ¶ 61,056 (2017) (Show Cause Order).

[2] Interconnection customers can elect TWRs in lieu of Incremental Deliverability Rights, Incremental Auction Revenue Rights, Incremental Capacity Transfer Rights, and Incremental Available Transfer Capability Revenue Rights. *See* PJM OATT § 232, Transmission Injection Rights and Transmission Withdrawal Rights.

and to request either Firm or Non-Firm TWRs. Firm TWRs allow the merchant transmission facility to schedule energy and capacity withdrawals from the PJM system.[3] In contrast, Non-Firm TWRs only allow the merchant transmission facility to schedule energy and, as such, are similar to Non-Firm Point-to-Point Transmission Service in that Non-Firm TWRs allow the merchant transmission facility to schedule transmission service on an as-available basis and are subject to curtailment.[4]

3. Once a merchant transmission facility has elected to obtain TWRs rather than another type of transmission right, PJM determines the necessary upgrades to support the Firm or Non-Firm TWRs requested through its interconnection process.[5] Upon receiving an interconnection request, PJM undertakes feasibility and system impact studies, and based on these costs, the merchant transmission facility decides the level of Firm or Non-Firm TWRs it wishes to obtain. The interconnecting merchant transmission facility is assigned the costs of the Merchant Network Upgrades that would not have been incurred "but for" the interconnection request.[6] The merchant transmission facility, PJM, and the transmission owner to which the facility will be interconnected enter into a three-party ISA establishing the costs and conditions of the interconnection. In addition, a merchant

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[3] Firm TWRs have rights similar to those under Firm Point-to-Point Transmission Service. Firm TWRs are rights to schedule energy and capacity withdrawals between a Point of Interconnection of merchant transmission facility with the transmission system that can only be awarded to a merchant transmission facility, whereas Firm Point-to-Point Transmission Service is reserved or scheduled energy between specified Points of Receipt and Points of Delivery for transmission customers generally. *See* PJM OATT § I, OATT Definitions 1.13A, E-F, 5.0.1 and Definitions L-M-N, 14.0.0. *See also* PJM OATT § II, Point-to-Point Transmission Service.

[4] *See* PJM OATT § I, OATT Definitions L-M-N, 14.0.0, Non-Firm Transmission Withdrawal Rights.

[5] PJM OATT § 232.3, Determination of Transmission Injection Rights and Transmission Withdrawal Rights to be Provided to Interconnection Customer.

[6] *PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,277, at P 4 (2003). Merchant Network Upgrades are additions or upgrades to, or replacement of, existing transmission system facilities by or on behalf of a merchant transmission facility developer. *See* PJM OATT, § I, OATT Definitions - L - M - N, 11.0.0. In exchange for their Merchant Network Upgrades, merchant transmission facilities receive Firm TWRs and Financial Transmission Rights. *See* PJM Filing, ER03-405-000 at 12 (identifying transmission-related rights to which merchant transmission facility developers may be entitled), PJM Interconnection, L.L.C./Intra-PJM Tariffs, OATT 206.5 Estimates of Certain Upgrade-Related Rights.

transmission facility is responsible, on an annual basis, for the costs of any post-interconnection network upgrades to the transmission system necessary to support the merchant transmission facility's Firm TWRs.[7]

Filing in Docket No. ER17-2073-000

4. The Existing ISA sets out the rights and responsibilities of PJM, HTP, and PSEG with respect to the interconnection to the PJM system of the Hudson Line,[8] a 660 MW high voltage direct current (HVDC) fully controllable merchant transmission facility that connects PJM in Northern New Jersey and the New York Independent System Operator, Inc. (NYISO) in New York City via a 345 kV undersea cable.[9] On July 10, 2017, at the request of HTP, PJM filed, under section 205 of the FPA, an unexecuted amended ISA (Amended ISA) among PJM, HTP, and PSEG, to be effective June 2, 2017.[10] PJM filed the Amended ISA unexecuted as PSEG, a party to the agreement, did not consent. Under the Amended ISA, HTP sought to convert its 320 megawatts (MW) of Firm TWRs to Non-Firm TWRs, resulting in 673 MW of Non-Firm TWRs and 0 MW of Firm TWRs. PJM stated that the proposed amendment to the Existing ISA comported with the 673 MW Nominal Rated Capability of the facility specified in the Existing ISA and that

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[7] *See* PJM OATT § Schedule 12 (b), and PJM OATT § 232.2, Right of Interconnection Customer to Transmission Injection Rights and Transmission Withdrawal Rights. *See also*, *PJM Interconnection, L.L.C.*, Opinion No. 503, 129 FERC ¶ 61,161 (2009) (finding that merchant transmission facilities should be responsible for the costs of maintaining network reliability, including costs for RTEP responsibility assignments, based on their Firm TWRs).

[8] HTP states that the Hudson Line, over which PJM has operational control, went into service in June of 2013. HTP Response, Docket No. EL14-84-000, at 5.

[9] HTP states that, pursuant to a long-term offtake contract, it transferred all of its Firm TWRs on the Hudson Line to the New York Power Authority (NYPA) for the purpose of exporting energy and capacity from PJM to NYISO. HTP states that NYPA pays for the rights that it receives under the long-term offtake contract, including costs of network upgrades required for the interconnection of the Hudson Line to PJM and for PJM RTEP transmission enhancement costs allocated to HTP under the existing Schedule 12 of the PJM OATT. Show Cause Order, 160 FERC ¶ 61,056 at P5; HTP Response, Docket No. EL14-84-000, at 5-6.

[10] PJM made this filing in Docket No. ER17-2073-000.

HTP's request would not adversely impact the operation or reliability of the PJM system.[11]

5. In the September 8, 2017 order, the Commission rejected the Amended ISA, finding that neither the Existing ISA nor PJM's tariff permitted PJM to file, under section 205, an unexecuted amended ISA with modifications requested by an interconnection customer.[12] While the Commission rejected PJM's filing, the Commission also found that, based on the evidence in the proceeding, the Existing ISA may be unjust and unreasonable and unduly discriminatory to the extent that it fails to permit HTP to convert Firm TWRs to Non-Firm and that PSEG's withholding of consent to the Amended ISA may also be unjust and unreasonable. Accordingly, the Commission instituted a proceeding, in Docket No. EL17-84-000, pursuant to section 206 of the FPA, requiring PSEG and PJM to show cause why the Existing ISA and PSEG's failure to consent to the Amended ISA is not unjust and unreasonable and unduly discriminatory.

6. In instituting the section 206 proceeding, the Commission stated that not permitting HTP to reduce the quality of its service from Firm TWRs to Non-Firm TWRs appeared to be unjust and unreasonable in these factual circumstances. The Commissioned reasoned that (1) HTP had fully paid for the network upgrades necessary for its Firm TWRs and therefore the reduction would not affect payments for previously constructed facilities;[13] (2) the conversion would not exceed the nominal rated capability of the Hudson Line and therefore system withdrawals would not increase; (3) HTP operates a DC line that is fully controllable by PJM, so PJM can shut off flows, consistent with applicable rules and procedures, in the event that a reliability or other operational

[11] Show Cause Order, 160 FERC ¶ 61,056 at P 5.

[12] The Commission found that, under PJM's tariff and the Existing ISA, without the consent of all parties to the Amended ISA, HTP was required to file under section 206 of the FPA to amend the Existing ISA. Show Cause Order, 160 FERC ¶ 61,056 at PP 34-40.

[13] *See* Opinion No. 503, 129 FERC ¶ 61,161 at P 80 & n.84 ("PJM would not need to incur the upgrades since it has *no obligation to plan for Non-Firm Transmission Withdrawal Rights in the RTEP process*") (emphasis added) and P 110 ("As the system changes for a variety of reasons (e.g., retirements and load growth), it may be necessary to construct additional facilities in order for PJM to be able to provide the level of *Firm Transmission Withdrawal Rights* to which the customers subscribed. In those circumstances, we find it just and reasonable and not unduly discriminatory or preferential for PJM to charge the Merchant Transmission Facilities for the costs of assuring their service.") (emphasis added).

problem arises; and (4) HTP's relinquishing of Firm TWRs would not adversely impact the operation or reliability of the PJM system.[14]

7. In response to a PSEG argument, the Commission also stated that requiring HTP to terminate the Existing ISA and disconnect an already constructed transmission line, rather than permitting an amendment of the Existing ISA to convert Firm TWRs to Non-Firm TWRs, appeared to be unjust and unreasonable. The Commission noted that Non-Firm TWRs impose less of a burden on the system than HTP's Firm TWRs and that PJM, as the system operator, finds that such a conversion will not have adverse reliability or operational impacts.[15]

8. The Commission also found that the protestors' arguments related to cost allocation were beyond the scope of the proceeding because such arguments challenged the justness and reasonableness of PJM's RTEP cost allocation method, not whether HTP should be able to convert its Firm TWRs to Non-Firm.[16]

9. On September 8, 2017, Linden VFT, L.L.C. (Linden) filed a request for rehearing of the Show Cause Order, which is still pending before the Commission.

II. Notice of Filing and Responsive Pleadings

10. Notice of the Show Cause Order was published in the *Federal Register*, 82 Fed. Reg. 43,535 (Sept. 18, 2017), with interventions due on or before September 29, 2017.

11. Timely motions to intervene were filed by Duke Energy Corporation; PPL Electric Utilities Corporation; Exelon Corporation; FirstEnergy Service Company (FirstEnergy), ITC Lake Erie Connector, LLC; American Electric Power Service Corporation; Monitoring Analytics, LLC, acting in its capacity as Independent Market Monitor for PJM (Market Monitor); NYPA; HTP; New Jersey Board of Public Utilities (NJBPU); and Consolidated Edison Energy, Inc. Out-of-time motions to intervene were filed by Consolidated Edison Company of New York (Con Edison); Long Island Power Authority and its operating subsidiary, Long Island Lighting Company d/b/a LIPA; City of New York, New York (New York City); and Linden VFT, L.L.C. (Linden).

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[14] Show Cause Order, 160 FERC ¶ 61,056 at P 43.

[15] *Id*. P 44.

[16] *Id.* P 45.

12. On October 25, 2017, and October 30, 2017, respectively, NYPA and HTP each filed answers to PSEG's response to the Show Cause Order. NJBPU filed comments on October 10, 2017 and on October 25, 2017, Linden filed an answer to PSEG's response to the Show Cause Order and NJBPU's comments. The Market Monitor filed comments on November 1, 2017. On November 3, 2017, Linden filed an answer to the Market Monitor's November 1st comments. On November 9, 2017, HTP filed an answer to the Market Monitor's November 1st comments. On November 10, 2017, the Market Monitor filed an answer to Linden's November 3rd and HTP's November 9th answers and a motion to lodge information in the related but non-consolidated complaint filed by Linden against PJM in order to provide a more complete record in that proceeding. On November 13, 2017, Linden filed an answer to the Market Monitor's November 10th comments and motion to lodge. On November 14, 2017, NYPA filed an answer to the Market Monitor's November 1st and 13th comments. On November 17, 2017, FirstEnergy, on behalf of the PJM Transmission Owners, filed comments in response to Linden's November 3rd and November 13th answers.

III. Show Cause Order Responses, Comments, and Answers

13. In its response, PJM agrees that, given the unique facts of this case, it is reasonable for the Commission to consider whether the Existing ISA is unjust and unreasonable and unduly discriminatory if HTP is not permitted to reduce the quality of its service from Firm to Non-Firm TWRs. As noted by the Commission, PJM states that those relevant facts include: (1) HTP has fully paid for the network upgrades required to receive Firm TWRs (therefore the reduction of service from Firm to Non-Firm TWRs will not affect HTP's responsibility to fund previously constructed facilities); (2) the conversion will not exceed the nominal rated capability of the Hudson Line (because system withdrawals will not increase); (3) HTP's line is fully controllable by PJM (so PJM can shut off flows in the event that a reliability or operational problem arises), and (4) allowing HTP to convert its Firm TWRs to Non-firm TWRs will not adversely impact the operation or reliability of the PJM transmission system. Should the Commission allow HTP to amend its ISA to convert its Firm TWRs to Non-Firm TWRs, PJM contends that the termination of the Firm TWRs should not relieve HTP of its cost responsibility obligations under Schedule 12 of the PJM tariff that were incurred prior to termination of its Firm TWRs and that any future cost responsibility obligations should terminate in accordance with existing tariff processes.

14. In its response, PSEG argues cost allocation is not beyond the scope of this proceeding, and the amendment to the Existing ISA will result in preferential rates for New York customers as HTP will avoid a share of cost responsibility that it caused. PSEG further argues that it reasonably relied upon the long-term duration of the Existing ISA, and permitting an unilateral amendment of ISAs will undermine the interconnection

process. PSEG adds that the provisions of the Existing ISA are protected by the *Mobile-Sierra* doctrine.[17] Finally, PSEG argues HTP's amendment to its Existing ISA raises issues of material fact that require that this matter be set for hearing and settlement procedures. NJBPU also filed comments arguing cost allocation is not beyond the scope of this proceeding.

15. In their answers, HTP, NYPA, and Linden argue that PSEG fails to provide a reasonable basis for PSEG's refusal to consent to HTP's request to reduce the quality of its service under the Existing ISA by converting its Firm TWRs to Non-Firm TWRs and therefore, PSEG's refusal to consent to amending the Existing ISA is unjust, unreasonable, and unduly discriminatory and preferential. They also argue that, regardless of PSEG's unreasonable refusal to consent, the Existing ISA is unjust and unreasonable and unduly discriminatory to the extent that it fails to permit HTP to reduce the quality of its service under the Existing ISA by relinquishing its Firm TWRs and retaining only Non-Firm TWRs. HTP also requests that the Commission act on the Show Cause Order and grant the relief requested by no later than December 15, 2017.

16. As further detailed below, the PJM Market Monitor and PJM Transmission Owners filed comments concerning the allocation of costs for RTEP projects to Firm Point-to-Point transmission customers as it may relate to a merchant transmission facility's request for Firm Point-to-Point transmission service.

A. <u>Mobile Sierra</u>

17. PSEG contends that the provisions of the Existing ISA are protected by the *Mobile-Sierra* doctrine. PSEG states that the Existing ISA was filed and accepted by the Commission and as such it has the force of a filed rate.[18] PSEG argues that the *Mobile-Sierra* doctrine requires that the Commission presume that the contract rates and terms contained in the Existing ISA are just and reasonable, unless otherwise shown to be contrary to the public interest.[19] PSEG states that the presumption may be overcome only if the Commission concludes that the contract seriously harms the public interest,[20] which

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[17] *F.P.C. v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956); *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 344 (1956) (Mobile-Sierra).

[18] PSEG Response, Docket No. EL17-84-000 at 7 (citing *Town of Norwood v. F.E.R.C.*, 217 F.3d 24, 28 (1st Cir 2000), *cert. denied*, 532 U.S 993 (2001)).

[19] *Id*. (citing *NRG Power Mktg., LLC v. Me. Pub. Utils.Comm'n*, 558 U.S. 165, 167 (2010)).

[20] *Id.* (citing *Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1 of Snohomish County*, 554 U.S. 527, 128 S.Ct. 2733, 2736 171 L.Ed.2d 607 (2008)).

generally requires "a finding that the existing rate or term 'might impair the financial ability of [a] public utility to continue its service,' or that the rate would 'cast upon other consumers an excessive burden, or be unduly discriminatory,' [or that there are] other 'circumstances of unequivocal public necessity.'"[21] PSEG states that is not the case here and the Existing ISA must not be disturbed.

18. HTP and Linden argue that the limited revisions in the Amended ISA are not protected by the *Mobile-Sierra* doctrine. Linden states that in order to determine whether the *Mobile-Sierra* presumption applies to a contract, the Commission considers whether a contract "embodies either: (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations."[22] Linden states that contracts that have the characteristics of the first category may be eligible to qualify for the *Mobile-Sierra* presumption, but contracts that have the characteristics of the latter "constitute tariff rates, terms, or conditions to which the *Mobile-Sierra* presumption does not apply."[23] Linden states that the Commission has further explained that terms of an agreement that are "incorporated into the service agreements of all present and future customers…are properly classified as tariff rates and the *Mobile-Sierra* presumption would not apply."[24] Linden argues that the Existing ISA is a form agreement, the *pro forma* for which is attached to the PJM tariff as Attachment O. Thus, Linden concludes, it constitutes a tariff rate that is not eligible for the *Mobile-Sierra* presumption. Linden states that, as the relevant language is in the form agreement, the parties were not in a position to negotiate the terms and conditions of this agreement "freely at arm's length." HTP also points out that PSEG did not seek

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[21] *Id.* (citing *Wis. Pub. Power*, 493 F.3d at 271 (quoting Fed. Power Comm'n v. Sierra Pac. Power Co., 350 U.S. 348, 355, 76 S.Ct. 368, 100 L.Ed. 388 (1956); Permian Basin Area Rate Cases, 390 U.S. 747, 822, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968)).

[22] Linden Answer, Docket No. EL17-84-000, at 13 (citing *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 183 (2013) (PJM)).

[23] *Id.* (citing *PJM*, 142 FERC ¶ 61,214 at P 183 (citing *New England Power Generators Ass'n, Inc. v. FERC*, 707 F.3d 364 (D.C. Cir. 2013)).

[24] *Id.* (citing *PJM*, 142 FERC ¶ 61,214 at P 184 (citing *Carolina Gas Transmission Corp.*, 136 FERC ¶ 61,014 at P 17 (2011) (Carolina Gas)).

rehearing of the Commission's conclusion in the Show Cause Order that the changes in this proceeding are not contract rates and are instead "non-rate" terms of service.[25]

19. Linden and NYPA argue that, even if the *Mobile-Sierra* presumption were to apply, the Commission may overcome the Mobile-Sierra presumption by determining that the Existing ISA and PSEG's refusal to consent to the Amended ISA is not consistent with the public interest. Linden states that U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has held that "a *Mobile-Sierra* contract will not automatically shield any and all discriminatory treatment from attack under Section 205(b) of the Federal Power Act. Rather, that section remains an independent force which must be accommodated."[26]

20. NYPA contends that the Commission has previously determined that any presumption of *Mobile-Sierra* protection created by inclusion of a *Mobile-Sierra* clause may be overcome by a reservation of rights provision and in such instances, the just and reasonable standard of review applies.[27] NYPA states that section 22.3 of the Existing ISA specifically reserves to all parties their rights "with respect to changes in applicable rates or charges under Section 205 of the Federal Power Act . . . or any of the rights of any Interconnection Party under Section 206 of the Federal Power Act." NYPA states that such language unambiguously preserves all parties' section 206 rights under the ordinary just and reasonable standard.

B. <u>Cost Allocation</u>

21. PSEG and NJBPU disagree with the Commission determination that cost allocation is beyond the scope of this proceeding. PSEG argues that allowing HTP to unilaterally change terms by converting its Firm TWRs to Non-Firm, so it can escape its cost responsibilities and continue to benefit from needed infrastructure investment while

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[25] HTP Answer, Docket No. EL17-84-000, at 18 (citing Show Cause Order, 160 FERC ¶ 61,056 at P 39).

[26] Linden Answer, Docket No. EL17-84-000, at 14 (citing *Town of Norwood*, 587 F.2d at 1311).

[27] NYPA Answer, Docket No. EL17-84-000, at 14 (citing *Ontelaunee Power Operating Co., LLC v. Metropolitan Edison Co.*, 119 FERC ¶ 61,181, at PP 21, 24- 25, n.19 (2007) (<u>Ontelaunee Power</u>) (citing *Kiowa Power Partners, LLC v. Pub. Serv. Co. of Okla.*, 110 FERC ¶ 61,118, at P 10 (2005)); *Duke Energy Hinds, LLC*, 102 FERC ¶ 61,068, at P 21 (2003); *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,168, at PP 8, 38-39 (2006)).

passing a portion of its legitimate transmission cost obligation on to New Jersey ratepayers would be unjust and unreasonable.

22. PSEG also argues that allowing amendment of the ISA will result in preferential rates for New York customers to the detriment of New Jersey ratepayers. PSEG states that both the New York Independent System Operator, Inc. (NYISO) and New York Public Service Commission (NYPSC) concede that there are benefits to New York ,such as operational, reliability, and resource adequacy support for the New York Control Area (NYCA). PSEG states that New York customers will continue to receive these benefits even after the conversion to Non-Firm TWRs without any responsibility for the continued costs which will then fall to New Jersey ratepayers. Further, PSEG states that HTP's withdrawal requirement has, in some instances, driven the need for RTEP projects in the Northern PSEG zone. Similarly, PSEG states that, but for HTP's Firm TWRs, some of these projects may not have been built or at the least may have been delayed for many years, or the system may have been planned in a different way.[28] PSEG contends that, if HTP is permitted to escape from the market and financial risks associated with its project and does not continue to bear its appropriate share of cost responsibility for PJM transmission facilities, then the cost allocation to customers in PJM will need to be increased to cover the costs, while HTP and the load that they are serving in New York unjustly and unreasonably get a "free ride."

23. PSEG also argues that opening the door to unilateral amendment of ISAs will undermine the entire RTO interconnection process. PSEG states that it reasonably relied upon the long-term duration of the Existing ISA. PSEG states that allowing HTP to circumvent the PJM documented interconnection procedures is prejudicial to other transmission customers seeking to interconnect, disruptive of the orderly nature of the PJM queue process and has absolutely no basis in the PJM Tariff. PSEG explains that the PJM transmission system is planned and designed to accommodate a planned MW quantity, both at the time of a facility's interconnection, and in subsequent studies to maintain the reliability of the transmission system.

24. With respect to PSEG's RTEP cost allocation arguments, HTP, NYPA, and Linden argue that PSEG's arguments do not provide a reasonable basis for PSEG's refusal to consent to the Amended ISA. Those arguments, they contend, reflect a challenge to the justness and reasonableness of PJM's cost allocation, which must be raised in a separate section 206 complaint. HTP states that Schedule 12 is not the subject of this proceeding and the existing cost allocation methodology in Schedule 12 is not modified or changed in any way by the Amended ISA. Similarly, HTP states that the Amended ISA does not propose any changes to PJM's existing transmission expansion

[28] PSEG Response, Docket No. EL17-84-000, at 13 (citing Khadr Affidavit at P 23).

planning methodology in the PJM Operating Agreement. HTP states that it will not continue to benefit from PJM transmission planning for new RTEP expansion projects because PJM will no longer plan for HTP in its RTEP transmission expansion planning.[29]

25. Linden also points out that PSEG made the same arguments in *New York Indep. Sys. Operator, Inc.*, 161 FERC ¶ 61,033 (2017) with respect to Con Edison and the Commission rejected PSEG's arguments. Linden states that PSEG's fear of cost reallocations to the New Jersey ratepayers resulting from the operation of the Schedule 12 reallocation process cannot be a just and reasonable basis for PSEG to refuse to consent to HTP reducing the service level of its Firm TWRs.

26. HTP also disputes PSEG's argument that permitting HTP to reduce the quality of its service in the Amended ISA would result in preferential rates for New York customers. HTP states that it has assumed the full market and financial risks for its project and has paid approximately $650 million in capital costs to construct the Hudson Line. HTP also states that it and NYPA have paid approximately $320 million for network upgrades to the PJM system for the interconnection of the Hudson Line to the PJM system. HTP states that, as a merchant transmission facility, HTP is not allowed to recover the costs for these transmission facilities through the PJM transmission rates. HTP states that, in addition, all HTP customers using the Hudson Line, including NYPA, are required by PJM to use Point-to-Point transmission service and pay PJM for it. HTP states that this includes ancillary services associated with Point-to-Point transmission service, including Scheduling service, Reactive Support and Voltage Control service, and Black Start service. For these reasons, HTP asserts that it and NYPA have paid, and will continue to pay, for the Hudson Line and use of the Hudson Line and the benefits that it provides. However, HTP notes that following a reduction in service level, it will no longer enjoy the right to schedule capacity withdrawals across the Hudson Line using Firm TWRs and PJM will no longer include HTP's Firm TWRs in its transmission expansion planning under the PJM Operating Agreement.

27. HTP and NYPA also argue that reducing the quality of its service in the Amended ISA will not open the door to unilateral amendment of ISAs or undermine the entire RTO interconnection process. HTP argues that this proceeding concerns a narrow, single issue that only applies to three merchant transmission facilities in PJM, two of which are parties to the proceeding. NYPA states that the anticompetitive behavior of

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[29] HTP Answer, Docket No. EL17-84-000, at 14 (citing PJM Operating Agreement, Schedule 6, Sect. 1.1. PJM Manual 14B: PJM Regional Transmission Expansion Planning Process, Att. C.7.3 (Rev. 39, Sept. 28, 2017) (Firm TWRs are included in the RTEP planning model); Opinion No. 503, 129 FERC ¶ 61,161 at P 80, n.84 ("PJM … has no obligation to plan for Non-Firm Transmission Withdrawal Rights in the RTEP process. Citing Tr. 278:5 – 280:15 (PJM Witness Herling)).

interconnecting transmission owners that refuse to consent to changes in interconnection service elections is what threatens to undermine the RTO interconnection process. Contrary to PSEG, HTP also asserts that, under the PJM Operating Agreement and PJM Manual 14-B, PJM performs its RTEP transmission expansion planning only for load and for Firm TWRs that are held by merchant transmission facilities. HTP states that under the terms of the PJM Operating Agreement and PJM Manual 14B, PJM will no longer perform its RTEP transmission expansion planning taking into account Firm TWRs held by HTP, and will no longer plan the PJM system to accommodate any such Firm TWRs.

28. HTP, NYPA, and Linden also dispute PSEG's claim that it relied on HTP's Firm TWRs being included in PJM's transmission planning and cost allocation for a "long-term duration." They contend that there is no reasonable basis for such reliance in light of the Existing ISA, the PJM tariff and the Commission's prior decisions. They argue that PSEG's claim is undercut by PSEG's acknowledgement that HTP is permitted to terminate the Existing ISA without the consent of PSEG, which would terminate all of HTP's interconnection rights, including the Firm TWRs. Linden states that, under Schedule 12 of the PJM tariff, cost allocation for regional transmission upgrades is based solely on firm use of an upgrade and shifts over time as different upgrade users change their firm service. Linden also claims that having a methodology that purports to update PJM-determined "beneficiaries" of RTEP projects each year was touted by the PJM Transmission Owners, including PSEG, as a primary benefit of the Solution-based DFAX methodology (as compared to its predecessor, Violation-based DFAX) because it theoretically allocates costs of projects to the use of those projects over time throughout their life, rather than only at the time of the upgrade.[30] Linden also asserts that there is nothing in the PJM tariff that requires or even suggests that merchant transmission facilities would or could be allocated costs for the life of an upgrade under Solution-based DFAX based on the number of Firm TWRs they hold when the RTEP project is first proposed.

29. NJBPU contends that the issue of cost allocation is not beyond the scope of this proceeding, as cost allocation is primarily what HTP and Linden seek to avoid. NJBPU states that the Amended ISA cannot be viewed in a vacuum. NJBPU states that HTP has conceded that the Amended ISA is an attempt to gain relief from RTEP costs in this matter, when such relief has not been granted in other proceedings. NJBPU states that indulging this collateral attack sets a dangerous precedent likely to inundate the

[30] Linden Answer, Docket No. EL17-84-000, at 12 (citing PJM Transmission Owners Filing, Transmittal Letter at 11, Docket No. ER13-90-000 (filed Oct. 11, 2012) ("because Solution-Based DFAX is based on the analysis of flows on the new facility, the analysis can be updated annually to capture changes in the distribution of the benefits of the new transmission facility")).

Commission with unwanted litigation from parties seeking a favorable decision by any means necessary. In addition, NJBPU argues that, if HTP is successful in avoiding its share of cost responsibility for PJM transmission facilities, then the cost allocation to customers in PJM will be increased to cover the costs as load in New York continues to receive the same benefits. NJBPU argues that it is unjust and unreasonable for load in New York to receive such benefit for nothing—and that is precisely what is sought.

30. In its answer, the Market Monitor addresses an alleged discrepancy in the allocation of costs for merchant transmission providers which hold firm point to point transmission contracts and those that hold Firm TWRs. The Market Monitor contends that Linden seeks to substitute Firm Point-to-Point Transmission service coupled with Non-Firm TWRs to maintain the ability to export capacity to the NYISO from PJM with the same level of transmission service they have with Firm TWRs. The Market Monitor asserts that this creates a discrepancy in cost allocation between section 232.2 and Schedule 12 of the tariff in that Schedule 12 omits any reference to merchant transmission facilities that hold both firm transmission service to the PJM border and Non-Firm TWRs. The Market Monitor concludes that it would not be just and reasonable to merchant transmission providers to retain the same capacity export though firm point-to-point transmission service and avoid RTEP cost allocation.

31. The PJM Transmission Owners also filed an answer clarifying that Schedule 12 defines customers with Firm Point-to-Point Transmission Service as customers responsible for the costs of RTEP projects.[31] The PJM Transmission Owners also state that Schedule 7 specifies that Firm Point-to-Point transmission customers should not be charged for the same RTEP costs under their applicable Point-to-Point service rate, and that Firm Point-to-Point customers can thus be assessed RTEP costs.[32]

C. <u>Reliability</u>

32. PSEG requests that the matter be set for hearing and settlement procedures, if not summarily dismissed. PSEG asserts that the issue of the operational and reliability impacts, as well as changes in locational marginal price (LMP) changes due to HTP converting its Firm TWRs to Non-Firm TWRs raises a multitude of disputed material facts that require that this matter be set for hearing and settlement procedures.

33. HTP, NYPA, and Linden oppose PSEG's request for a hearing. HTP argues that none of the claims made in the affidavit of PSEG's expert, Mr. Khadr, identified a

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[31] PJM Transmission Owners Response, Docket No. EL17-84-000, at 4 (citing PJM OATT, Schedule 12 § (b)(viii)).

[32] *Id*. at 5 (citing PJM OATT, Schedule 7 § 7).

genuine issue of material fact that requires a hearing. Linden states that the NYISO Reliability Needs Assessment (RNA) upon which Mr. Khadr relies to support the claim that there is a genuine reliability issue represents a resource adequacy study used in conjunction with ensuring that a Loss of Load Expectation does not exceed one event in 10 years; it is not a transmission planning study and does not address whether a transmission system component requires upgrades.[33] Further, Linden states that NYISO's RNA is (and has been) based on the entire 660 MW capability of the HTP facility since HTP went into service, rather than HTP's 320 MW of Firm TWRs.[34] HTP, NYPA, and Linden also point out that PJM and NYISO are parties to this proceeding and neither has identified any reliability concerns with HTP reducing the quality of its serviced in the Amended ISA and converting its Firm TWRs to Non-Firm TWRs. Rather, Linden notes that PJM determined that HTP's conversion of Firm TWRs would not have adverse reliability or operational impacts.

34. HTP also disputes Mr. Khadr's assertions that after the reduction in the quality of HTP's service, the Hudson Line will remain used and useful to HTP and NYISO, and "all costs associated with HTP's existence will exclusively be borne by New Jersey ratepayers."[35] HTP states that it (and NYPA) is responsible for (1) approximately $650 million in capital costs for constructing the Hudson Line; (2) all of the costs to operate and maintain the Hudson Line and, because HTP is a merchant transmission facility; and (3) approximately $320 million to PJM for network upgrades in the Existing ISA. HTP also points out that all of HTP's customers using the Hudson Line, including NYPA, are required by the PJM tariff to use and pay for PJM Point-to-Point transmission service and PJM ancillary service charges, including PJM scheduling charges, PJM reactive support and voltage control charges, and PJM black start service charges.

35. HTP also argues that PSEG's and Mr. Khadr's assertion that HTP's Firm TWRs might have contributed to, or in some cases driven, the need for RTEP projects, and such projects may not have been built or may have been delayed, is speculation and even it were true, that is how PJM's transmission expansion planning process works.

36. HTP argues that, in order for PSEG's refusal to consent to the Amended ISA to be reasonable, it would have to be within the objective criteria established in section 205 of the PJM tariff for the study and evaluation of facility interconnections' impact on operation and reliability of the PJM system. HTP states that any refusal of the

[33] Linden Answer, Docket No. EL17-84-000, at 5-6.

[34] *Id.* at 5-6.

[35] HTP Answer, Docket No. EL17-84-000, at 29 (citing Khadr Affidavit at P 6).

interconnected transmission owner (i.e., PSEG) to refuse an interconnection request for reasons other than those objective criteria, as it has done here, is unjust, unreasonable, and unduly discriminatory, a violation of the PJM tariff, and a violation of open access transmission service under Order No. 888.[36] NYPA agrees the basis of PSEG's interference contradicts the role of transmission owners in party interconnection agreements, and emphasizes that the Commission, in Order No. 2003, clarified: "It is our intent that, while the Transmission Owner is a necessary part of interconnecting to a facility under the operational control of an RTO or ISO, its role in negotiating the agreement will be a limited one."[37]

37. HTP also contends that requiring HTP to terminate its ISA completely and, disconnect the Hudson Line from the PJM system, and reenter and restart the PJM interconnection process in order to permit HTP to reduce the quality of its service in the ISA, would be extraordinarily prejudicial to HTP. HTP contends that reentering the PJM interconnection queue process would require one to three years to complete, during which time the Hudson Line would be forcibly disconnected from the PJM system. Therefore, HTP asserts it would face the prospect of paying for interconnection upgrades twice for the same service under the PJM tariff.

38. HTP also argues that the Existing ISA should permit HTP to reduce the quality of its service under the Existing ISA by relinquishing its Firm TWRs and retaining only Non-Firm TWRs, and direct PJM to make the necessary changes to permit HTP to so reduce the quality of its service under the Existing ISA. HTP states that permitting HTP to reduce the quality of its service by relinquishing its Firm TWRs and retaining only Non-Firm TWRs is consistent with other provisions of the PJM tariff and the Existing

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[36] *Id*. at 32-34.

[37] NYPA Answer, Docket No. EL17-84-000, at 17 (citing *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, FERC Stats. & Regs., Regs. Preambles 2001-2005 ¶ 31,160, at PP 785-86 (2004) (emphasis added), *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs., Regs. Preambles 2001-2005 ¶ 31,171, *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs., Regs. Preambles 2001-2005 ¶ 31,190 (2005), *aff'd sub nom*. *Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008)).

ISA regarding interconnection rights.[38] For example, HTP states that section 232.7 of the PJM tariff allows PJM to unilaterally reduce the amount of HTP's TWRs without terminating the Existing ISA, and without the consent of PSEG or HTP. HTP states that, under section 232.7 of the PJM tariff, "Loss of … Transmission Withdrawal Rights," PJM has the unilateral right to make a partial reduction in the amount of TWRs in the Existing ISA, without the consent of PSEG (or HTP) and without termination of the ISA, in the event that the Hudson Line fails to operate or be capable of operating at the capacity level associated with the TWRs for any consecutive three-year period. HTP states that it is unduly discriminatory for the PJM Tariff to permit PJM to unilaterally reduce the quality of HTP's service under the Existing ISA without terminating the ISA and without the consent of PSEG, but not to permit HTP to reduce the quality if its service under the Existing ISA without terminating the ISA and without the consent of PSEG.

IV. Discussion

A. Procedural Matters

39. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[39] the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedures,[40] the Commission will grant the late-filed motions to intervene given their interest in the proceeding, the early stages of the proceeding, and the absence of undue prejudice or delay.

[38] HTP Answer, Docket No. EL17-84-000, at 36-41. HTP also cites section 230.3.3 of the PJM OATT (permitting an existing generator to replace its generating facility, using "a portion or all" of its existing capacity interconnection rights, without the consent of its Interconnected Transmission Owner and without terminating its interconnection agreement), section 16.1.2 of the Existing ISA (permitting HTP, at any time, to "unilaterally terminate the Interconnection Service Agreement" without the consent of PJM or PSEG, upon sixty days prior written notice), and section 3.1 of the Existing ISA (providing that HTP "may undertake modifications to its facilities" without the consent of PSEG, provided that the modifications do not have a permanent adverse impact on the Interconnection Transmission Owner's (i.e., PSEG's) facilities).

[39] 18 C.F.R. § 385.214 (2017).

[40] 18 C.F.R. § 385.214(d) (2017).

40. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure prohibits an answer to a protest or to an answer unless otherwise ordered by the decisional authority.[41] We will accept the answers filed in this docket because they provide information that assisted us in our decision-making process.

B. <u>Substantive Matters</u>

41. As discussed below, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit HTP to convert its Firm TWRs to Non-Firm TWRs.[42] Accordingly, PJM shall make a compliance filing within 7 days of the date of this order amending the section 2.2 of Specifications for the Existing ISA to reflect the conversion of 320 MW Firm TWRs to a total of 0 MW of Firm TWRs and 673 MW Non-Firm TWRs, effective the date of this order.

42. We see no reasonable basis for barring HTP from converting from higher quality Firm TWRs to lower quality Non-Firm TWRs by amending the Existing ISA. ISAs establish the requirements and upgrades necessary for interconnection. Once a merchant transmission facility has elected to obtain Firm TWRs, PJM determines the necessary upgrades to support the Firm TWRs requested through its interconnection process. HTP already has satisfied the interconnection requirements, and we find that requiring it to maintain such Firm TWRs for the life of the merchant transmission facility is unjust and unreasonable in the absence of any operational or reliability basis for doing so.

43. Under the Existing ISA and PJM's tariff, PJM must guarantee that its transmission system is robust enough to permit HTP to use its Firm TWRs to export 320 MWs of power from its source in PJM across the river to New York at all times. Converting those Firm TWRs to Non-Firm TWRs imposes no additional obligation on PJM and, in fact, is less burdensome in that PJM will no longer have to guarantee that its transmission system can support such use. In terms of reliability, PJM states that "the conversion will not exceed the nominal rated capability of the HTP line (because system withdrawals will not

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[41] 18 C.F.R. § 385.213(a)(2) (2017).

[42] In the Show Cause Order, the Commission required PSEG and PJM to show cause (1) why the Existing ISA is not unjust and unreasonable and unduly discriminatory to the extent it fails to allow HTP to convert Firm TWRs to Non-Firm TWRs and (2) why PSEG's failure to consent to an amendment to the Existing ISA reflecting the same is not unjust, unreasonable, and unduly discriminatory. Because we have found that the Existing ISA is unjust and reasonable insofar as it does not permit HTP to convert its Firm TWRs to Non-Firm TWRs, we need not address whether PSEG acted unreasonably in withholding consent to an amendment to the Existing ISA reflecting the same.

increase,"[43] and no additional facilities would be necessary to support HTP's conversion from Firm TWRs to Non-Firm TWRs. In any case, HTP's line is fully controllable by PJM so that PJM can shut off flows if those flows jeopardize reliability or cause operational problems in New Jersey or elsewhere on the PJM system. PJM recognizes in its response to the Show Cause Order that for these reasons, the conversion to Non-Firm TWRs will not affect the operation or reliability of the PJM system, [44] and PSEG has offered no evidence to the contrary.

44. PSEG argues that, under section 16.1.2 and 16.2.1 of Appendix 2 of the Existing ISA,[45] HTP could effectuate such a reduction in Firm TWRs by exercising its unilateral right to terminate the Existing ISA and disconnecting its line. HTP could then reapply for Non-Firm TWRs. However, interpreting the Existing ISA, as PSEG did in its protest in Docket No. ER17-2073-000, to require that HTP terminate the Existing ISA and disconnect an already operational merchant transmission facility, rather than amending the Existing ISA to convert Firm TWRs to Non-Firm TWRs, would be unjust and unreasonable. As PJM states, "HTP has fully paid for the network upgrades required to receive Firm TWRs (therefore the reduction of service from Firm to Non-Firm TWRs

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[43] PJM Response, Docket No. EL17-84-000, at 3. *See also* PJM Transmittal, Docket No. ER17-2073-000, at 3-4 (PJM stated that the conversion "corresponds to the nominal rated capability of the facility of 673 MW").

[44] PJM Response, Docket No. EL17-84-000, at 3.

[45] Section 16.1.2 of Appendix 2 of the Existing ISA provides as follows:

> Interconnection Customer may unilaterally terminate the Interconnection Service Agreement pursuant to Applicable Laws and Regulations upon providing Transmission Provider and the Interconnected Transmission Owner sixty (60) days prior written notice thereof, provided that Interconnection Customer is not then in Default under the Interconnection Service Agreement.

Section 16.2.1 of Appendix 2 of the Existing ISA provides as follows:

> Disconnection: Upon termination of the Interconnection Service Agreement in accordance with this Section 16, Transmission Provider and/or the Interconnected Transmission Owner shall, in coordination with Interconnection Customer, physically disconnect the Customer Facility from the Transmission System, except to the extent otherwise allowed by this Appendix 2.

will not affect HTP's responsibility to fund previously constructed facilities)."[46] We also do not find, as PSEG alleges, that allowing HTP to convert its Firm TWRs to Non-Firm TWRs will undermine the interconnection process as HTP has already fulfilled its interconnection requirements. As discussed above, Non-Firm TWRs impose less of a burden on the transmission system than do Firm TWRs, and HTP's conversion of Firm TWRs to Non-Firm TWRs does not, as PJM points out, require any additional system upgrades as the Non-Firm TWRs do not increase system withdrawals.[47] Moreover, PJM, as the system operator, finds that such a conversion will not have adverse reliability or operational impacts, and HTP's amendment to the Existing ISA will not affect payments for previously constructed facilities.[48] Thus, we find that it is unjust and unreasonable not to allow HTP to amend the Existing ISA to convert its Firm TWRs to Non-Firm TWRs.[49]

45. PSEG makes three arguments against finding the Existing ISA unjust and unreasonable: that the Existing ISA is a bilateral contract governed by the public interest *Mobile-Sierra* standard; the issue of operational and reliability impacts raises a multitude of disputed material facts regarding the effect on the NYISO system warranting a hearing; and cost allocation is not beyond the scope of the proceeding. We address each of these arguments in turn.

1. Mobile-Sierra

46. As a threshold matter, we find that the Existing ISA is not eligible for the *Mobile-Sierra* "public interest" presumption. Aside from the fact that the Existing ISA was filed and accepted by the Commission, PSEG provides no other support for its contention that the Existing ISA is protected by the *Mobile-Sierra* doctrine.[50] As the Commission has explained, the *Mobile-Sierra* "public interest" presumption applies to an agreement only if the agreement has certain characteristics that justify the presumption. In ruling on

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[46] PJM Response, Docket No. EL17-84-000, at 3.

[47] *Id*. *See also* PJM Transmittal, Docket No. ER17-2073-000, at 3-4 (PJM stated that the conversion "corresponds to the nominal rated capability of the facility of 673 MW").

[48] Show Cause Order, 160 FERC ¶ 61,056 at P 43.

[49] *See, e.g., New York Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116 at (2015) (requiring that ISO be the entity that makes the determination whether a specific generator is needed to ensure reliable transmission service).

[50] PSEG Response, Docket No. EL17-84-000, at 7.

whether the characteristics necessary to justify a *Mobile-Sierra* presumption are present, the Commission must determine whether the agreement at issue embodies either: (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations. Unlike the latter, the former constitute contract rates, terms, or conditions that necessarily qualify for a *Mobile-Sierra* presumption.

47. We find that the terms and conditions of the Existing ISA at issue here are generally applicable and, therefore, are not protected by the *Mobile-Sierra* presumption. The granting of Firm and Non-Firm TWRs to a Transmission Interconnection Customer is governed by generally applicable provisions of the PJM tariff, namely section 232 of the PJM tariff.[51] Once determined by PJM following a System Impact Study, such rights become available to the Transmission Interconnection Customer (e.g., HTP) pursuant to execution of an ISA based on the *pro forma* ISA attached to the PJM tariff as Attachment O. The terms and conditions in the Existing ISA, including the terms related to Amendments, Termination, and Disconnection, were identical in relevant part to the terms and conditions set forth in the *pro forma* ISA in PJM's tariff.[52] The Commission has found that such generally applicable rates, terms and conditions are not the type of contract rates that qualify for the *Mobile-Sierra* presumption.[53]

48. Another, independent reason why the *Mobile-Sierra* presumption does not apply in these circumstances is that the Existing ISA contains the same standard *Memphis*

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[51] *See* PJM Tariff, Section 232.3 (Determination of Transmission Injection Rights and Transmission Withdrawal Rights to be Provided to Customer) ("The Office of Interconnection [PJM] shall determine the … Transmission Withdrawal Rights … to be provided to eligible Transmission Interconnection Customer(s)").

[52] Schedule F of the Existing ISA contains non-standard terms and conditions that set forth the terms and cost for HTP to acquire additional Firm TWRs above the 320 MW currently set forth in the Existing ISA.

[53] *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,059 (2013), *on reh'g*, 149 FERC ¶ 61,048, at PP 100-104 (2014), *denying petition for review*, *Okla. Gas & Elec. Co. v. FERC*, 827 F.3d 75, 76 (D.C. Cir. 2016); *PJM*, 142 FERC ¶ 61,214 at P 184 (citing *Carolina Gas*, 136 FERC ¶ 61,014 at P 17 (holding that the terms of an agreement that are "incorporated into the service agreements of all present and future customers…are properly classified as tariff rates and the *Mobile-Sierra* presumption would not apply.").

clause[54] as in the *pro forma* ISA. That provision preserves for PJM and PSEG their section 205 filing rights and preserves the rights of any Interconnection Party to bring complaints under section 206. Specifically, section 22.3 of the Existing ISA states in pertinent part:

> This Interconnection Service Agreement may be amended or supplemented only by a written instrument duly executed by all Interconnection Parties. An amendment to the Interconnection Service Agreement shall become effective and a part of this Interconnection Service Agreement upon satisfaction of all Applicable Laws and Regulations. Notwithstanding the foregoing, nothing contained in this Interconnection Service Agreement shall be construed as affecting in any way any of the rights of any Interconnection Party with respect to changes in applicable rates or charges under Section 205 of the Federal Power Act and/or FERC's rules and regulations thereunder, or any of the rights of any Interconnection Party under Section 206 of the Federal Power Act and/or FERC's rules and regulations thereunder.

While section 22.3 states that the Existing ISA may be amended "only by a written instrument duly executed by all Interconnection Parties…", the second sentence of the provision protects the parties' unilateral filing rights. Consistent with court precedent, the Commission has found that such provisions apply the ordinary just and reasonable standard: "where provisions in an Interconnection Agreement allow either party to unilaterally request changes under FPA sections 205 or 206, the Commission has the authority to require changes to the contracts under the just and reasonable standard."[55]

2. Cost Allocation

49. PSEG and NJBPU argue that HTP should not be permitted to relinquish its Firm TWRs, because, under Schedule 12 of PJM's tariff, HTP would no longer be allocated costs for RTEP projects that PSEG alleges were caused by HTP's Firm TWRs and benefit HTP. However, as explained below, it is the cost allocation provisions in

[54] *United Gas Co. v. Memphis Gas Div*., 358 U.S. 103 (1958) (contracts can preserve the rights of parties to revise rates under ordinary just and reasonable standard).

[55] *Ontelaunee Power*, 119 FERC ¶ 61,181 at P 24 (citing *Duke Energy Hinds*, 102 FERC ¶ 61,068 at P 21). *See also Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 954 (D.C. Cir. 1983) ("specific acknowledgment of the possibility of future rate change is virtually meaningless unless it envisions a just-and-reasonable standard").

Schedule 12 that provide that a Merchant Transmission Owner that does not own Firm TWRs does not receive cost responsibility assignments for RTEP projects.[56] Neither PSEG nor NJBPU have argued that those provisions are unjust and unreasonable. Accordingly, we find that their cost allocation argument does not provide a basis for precluding HTP from terminating its Firm TWRs under the Existing ISA.

50. Under Schedule 12 of the PJM tariff, a merchant transmission facility's cost responsibility assignments for RTEP projects are calculated based that facility's Firm TWRs.[57] As the Commission has explained, the reason that the costs of RTEP projects are allocated to merchant transmission facilities with Firm TWRs is that PJM is required to provide firm service to those facilities and therefore those facilities are responsible for contributing to facilities necessary to support that firm service:

> PJM is required to provide reliable service up to the Firm Transmission Withdrawal Rights held by these customers. In order to provide such rights, PJM must require the construction of RTEP upgrades. The Merchant Transmission Facilities can avoid these costs if instead of opting for Firm Transmission Withdrawal Rights, they opt only for Non-Firm Transmission Withdrawal Rights under the tariff.[58]

As of the effective date of HTP's conversion of its Firm TWRs to Non-Firm TWRs, PJM is no longer required to provide firm service and can curtail non-firm service whenever necessary to preserve reliability.[59] Under Schedule 12, therefore, RTEP upgrade costs would no longer be allocable to HTP. The cost responsibility assignments for RTEP projects are updated annually based on a range of inputs and values to determine beneficiaries of RTEP projects.[60] Thus, under Schedule 12, cost responsibility

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[56] Although PJM implements the cost allocation provisions of Schedule 12 of the Tariff, the cost allocation method is determined by the PJM Transmission Owners, and it is the PJM Transmission Owners, not PJM, that have the section 205 filing rights for the PJM cost allocation method. *See Atlantic City Electric Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).

[57] *See* PJM OATT, Schedule 12 § (b)(i) (3.0.0).

[58] Opinion No. 503, 129 FERC ¶ 61,161 at P 80.

[59] *See* PJM OATT, Schedule 12 § (b)(i) (3.0.0). *See* PJM OATT § I, OATT Definitions L-M-N, 14.0.0, Non-Firm Transmission Withdrawal Rights. *See also* PJM OATT § II, Point-to-Point Transmission Service.

[60] *See* PJM OATT, Schedule 12 § (b)(iii)(H).

assignments for RTEP projects will shift over time as usage by transmission customers of a RTEP project changes over its lifespan.[61] For example, HTP's cost responsibility assignment increased as a direct result of the termination of Con Edison's transmission service agreements.[62] Contrary to PSEG's assertion, the PJM tariff does not require a merchant transmission facility, like HTP, to be allocated costs for an RTEP project over the life of that project based on the MWs of Firm TWRs the merchant transmission facility held at the time that the RTEP project was approved by PJM.[63] As noted, neither PSEG nor NJBPU has contended that these provisions are unjust and unreasonable.

51. Moreover, we also find unpersuasive PSEG's argument that it reasonably relied upon the long-term duration of the Existing ISA, and HTP maintaining its Firm TWRs, as providing for long-term cost responsibility assignments for RTEP projects to HTP. As PSEG itself acknowledged, HTP has the right unilaterally to terminate the Existing ISA, including its Firm TWRs, at any time.[64] As we explained earlier, requiring HTP to terminate its rights in order to convert its Firm TWRs to Non-Firm TWRs is unjust and unreasonable as making such changes will not result in reliability or operational difficulties for the PJM system.

52. Similarly, the PJM Market Monitor raises concerns with Schedule 12 and requests changes thereto in order to address an alleged discrepancy in the cost responsibility assignments for RTEP projects for merchant transmission providers that hold firm point-to-point transmission service and those that hold Firm TWRs. Those general concerns with Schedule 12 do not address whether HTP should be permitted to convert its Firm TWRs to Non-Firm TWRs. The PJM Transmission Owners also raise concerns regarding the cost responsibility assignments for RTEP projects to firm point-to-point transmission customers. We reject, as beyond the scope of this proceeding, these comments. The cost responsibility assignments for RTEP projects for firm point-to-point

[61] Schedule 12 updates cost allocations annually based on changes to the system's topology, load changes, and other events such as termination of service. *See* PJM OATT, Schedule 12 § (b).

[62] Show Cause Order, 160 FERC ¶ 61,056 at n.24.

[63] *See* PJM OATT, Schedule 12 § (b)(iii).

[64] Show Cause Order, 160 FERC ¶ 61,056 at P 6.

transmission customers under Schedule 12 are unrelated to the issue of whether HTP should be permitted to convert its Firm TWRs to Non-Firm TWRs.

3. **Reliability**

53. PSEG argues that allowing HTP to convert its Firm TWRs to Non-Firm TWRs will adversely affect the operation or reliability of the PJM transmission system, and raises a multitude of disputed material facts that require that the Commission set this matter for hearing and settlement procedures. In support of its contention, PSEG relies on the affidavit of Mr. Khadr, who asserts that there might be "critical reliability consequences" in NYISO as a result of HTP reducing the quality of its service under the Existing ISA and converting its Firm TWRs to Non-Firm TWR. Mr. Khadr bases his claim on NYISO's 2016 RNA. Mr. Khadr contends that because the 2016 RNA models 660 MW of flows from the HTP facility, 320 MW of which is firm, the 2016 RNA "shows great dependency on the PJM system and the PSE&G system in particular."[65] Mr. Khadr contends that if HTP is permitted to convert its Firm TWRs entirely to Non-Firm, "NYISO [will be] depending on an additional 320 MW across the Hudson Line that PJM will, properly, not be including in its planning assumption across the PJM/NYISO interface."[66]

54. PSEG, however, does not provide any evidence that the relinquishment of Firm TWRs would cause any reliability or operational problems for PJM, the region in which the service in dispute would actually be provided. With HTP's conversion of its Firm TWRs to Non-Firm TWRs, PJM, with its operational control over the Hudson Line, may curtail firm exports on the facility when necessary to support PJM's reliability or operational needs.[67] As to any potential effects on LMPs in PJM, such effects can result from any type of non-firm transmission service and are not a reason to require HTP to retain Firm TWRs.

55. Moreover, the studies cited by Mr. Khadr do not support that HTP's maintenance of its Firm TWRs is critical to NYISO's reliability. In his affidavit, Mr. Khadr references only a diagram of topology zones included in the RNA, which includes a reference to the capability of flowing 660 MW of flows from the Hudson Line into NYISO alongside other flows from PJM into NYISO. Contrary to Mr. Khadr's claims, however, the diagram makes no reference to the 320 MWs of Firm TWRs, nor does it assert that those MWs are critical to NYISO's reliability. Thus, the presence of Firm TWRs in PJM has

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[65] Khadr Affidavit at P 7.

[66] *Id*. P 8.

[67] PJM Response, Docket No. EL17-84-000, at 3.

not led to capacity that NYISO relies upon in serving its resource adequacy needs. NYISO has also asserted that reliability would be negatively impacted only if the Hudson Line is taken out of service. Since these issues can be resolved based on the written record, we find no material issues of disputed fact and see no need for a trial-type hearing.[68]

The Commission orders:

(A) As discussed in the body of this order, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit HTP to convert its Firm TWRs to Non-Firm TWR.

(B) PJM shall make a compliance filing within 7 days of the date of this order amending section 2.2 of Specifications for the Existing ISA to reflect the conversion of 320 MW Firm TWRs to a total of 0 MWs Firm TWRs and 673 MW Non-Firm TWRs, effective the date of this order.

By the Commission. Chairman McIntyre is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[68] *See, e.g.*, *Pennsylvania Pub. Util. Comm'n v. FERC*, 881 F.2d 1123, 1126 (D.C. Cir. 1989); *Union Pacific Fuels, Inc. v. FERC*, 129 F.3d 157, 164 (D.C. Cir. 1997). ("FERC may resolve factual issues on a written record unless motive, intent, or credibility are at issue or there is a dispute over a past event"). "Mere allegations of disputed fact are insufficient to mandate a hearing; a petitioner must make an adequate proffer of evidence to support them." *Woolen Mill Ass'n v. FERC*, 917 F.2d 589, 592 (D.C. Cir. 1990) (citing *Pennsylvania Pub. Utility Comm'n v. FERC*, 881 F.2d 1123, 1126 (D.C.Cir.1989) and *Cerro Wire & Cable Co. v. FERC*, 677 F.2d 124, 124 (D.C.Cir.1982)).

Document Content(s)

Attachment 9 Linden VFT FERC Order

Attachment 9

161 FERC ¶ 61,264
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Neil Chatterjee,
Robert F. Powelson, and Richard Glick.

Linden VFT, LLC
v.
Public Service Electric and Gas Company
and PJM Interconnection, L.L.C.

Docket No. EL17-90-000

ORDER GRANTING COMPLAINT, IN PART

(Issued December 15, 2017)

1. On September 18, 2017, Linden VFT, LLC (Linden),[1] pursuant to section 206 of the Federal Power Act (FPA),[2] filed a complaint (Complaint) contending that Public Service Electric and Gas Company (PSEG) is unreasonably withholding its consent to an amendment to the existing Linden interconnection service agreement (Existing ISA) between Linden, PJM Interconnection, L.L.C. (PJM), and PSEG to allow Linden to convert Firm Transmission Withdrawal Rights (Firm TWRs) to Non-Firm Transmission Withdrawal Rights (Non-Firm TWRs).[3] Additionally, or alternatively, Linden contends that the PJM Open Access Transmission Tariff (tariff or OATT) is unjust and unreasonable to the extent that it does not permit a merchant transmission facility

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[1] Linden owns and operates a controllable alternating-current Merchant Transmission Facility that connects PJM Interconnection, L.L.C. (PJM) with New York Independent System Operator (NYISO).

[2] 16 U.S.C. §§ 824e (2012).

[3] *See* Service Agreement No. 3579, *PJM Interconnection, L.L.C.*, 144 FERC ¶ 61,070 (2013).

Owner to reduce all of its Firm TWRs to Non-Firm TWRs without an amendment to its ISA or the consent of the transmission owner that is party to that agreement.[4]

2. As discussed below, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit Linden to convert its Firm TWRs to Non-Firm TWR.

I. Background

3. PJM's Open Access Transmission tariff (tariff or OATT) provides merchant transmission facilities with the right to elect TWRs in lieu of other transmission rights and to request either Firm or Non-Firm TWRs.[5] Firm TWRs allow the merchant transmission facility to schedule energy and capacity withdrawals from the PJM system.[6] In contrast, Non-Firm TWRs only allow the merchant transmission facility to schedule energy and, as such, are similar to Non-Firm Point-to-Point Transmission Service in that Non-Firm TWRs allow the merchant transmission facility to schedule transmission service on an as-available basis and are subject to curtailment.[7]

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[4] Firm Transmission Withdrawal Rights are defined as the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Non-Firm Transmission Withdrawal Rights are defined as the rights to schedule energy withdrawals from a specified point on the Transmission System. *See* PJM OATT § I, OATT Definitions 1.13A,E-F, 5.0.1 and L-M-N, 14.0.0.

[5] Interconnection customers can elect TWRs in lieu of Incremental Deliverability Rights, Incremental Auction Revenue Rights, Incremental Capacity Transfer Rights, and Incremental Available Transfer Capability Revenue Rights. *See* PJM OATT § 232, Transmission Injection Rights and Transmission Withdrawal Rights.

[6] Firm TWRs have rights similar to those under Firm Point-to-Point Transmission Service. Firm TWRs are rights to schedule energy and capacity withdrawals between a point of interconnection of a merchant transmission facility with the transmission system that can only be awarded to a merchant transmission facility, whereas Firm Point-to-point Transmission Service is reserved or scheduled energy between specified Points of Receipt and Points of Delivery for transmission customers generally. *See* PJM OATT § I, OATT Definitions 1.13A, E-F, 5.0.1 and Definitions L-M-N, 14.0.0. *See also* PJM OATT § II, Point-to-Point Transmission Service.

[7] *See* PJM OATT § I, OATT Definitions L-M-N, 14.0.0, Non-Firm Transmission Withdrawal Rights.

4. Once a merchant transmission facility has elected to obtain TWRs rather than another type of transmission rights, PJM determines the necessary upgrades to support the Firm or Non-Firm TWRs requested through its interconnection process.[8] Upon receiving an interconnection request, PJM undertakes feasibility and system impact studies, and based on these costs, the merchant transmission facility decides the level of Firm TWRs it wishes to obtain. The interconnecting merchant transmission facility is assigned the costs of the Merchant Network Upgrades that would not have been incurred "but for" the interconnection request.[9] The merchant transmission facility, PJM, and the transmission owner to which the facility will be interconnected enter into a three-party ISA establishing the costs and conditions of the interconnection. In addition, a merchant transmission facility is responsible for the costs of any post-interconnection network upgrades that are included in the Regional Transmission Expansion Plan (RTEP) necessary to support the merchant transmission facility's Firm TWRs.[10]

5. The Existing ISA sets out the rights and responsibilities of PJM, Linden, and PSEG with respect to the interconnection to the PJM system of Linden's facility, a 315 megawatt (MW) merchant transmission project consisting of three 105 MW variable frequency transformers connected between the PSEG system and the Consolidated Edison Company of New York, Inc. system. On August 9, 2017, PJM, at the request of Linden, filed, under section 205 of the FPA,[11] an unexecuted, amended ISA between PJM, Linden, and PSEG. Linden sought to amend its Existing ISA to convert its

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[8] PJM OATT § 232.3, Determination of Transmission Injection Rights and Transmission Withdrawal Rights to be Provided to Interconnection Customer.

[9] *PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,277, at P 4 (2003). Merchant Network Upgrades are additions or upgrades to, or replacement of, existing transmission system facilities by or on behalf of a merchant transmission facility developer. *See* PJM OATT§ I, OATT Definitions - L - M - N, 11.0.0. In exchange for their Merchant Network Upgrades, merchant transmission facilities receive Firm TWRs and Financial Transmission Rights. *See* PJM Filing, ER03-405-000 at 12 (identifying transmission-related rights to which merchant transmission facility developers may be entitled), PJM OATT, 206.5 Estimates of Certain Upgrade-Related Rights.

[10] *See* PJM OATT § Schedule 12 (b), and PJM OATT § 232.2, Right of Interconnection Customer to Transmission Injection Rights and Transmission Withdrawal Rights. *See also*, *PJM Interconnection, L.L.C.*, Opinion No. 503, 129 FERC ¶ 61,161 (2009) (finding that merchant transmission facilities should be responsible for the costs of maintaining network reliability, including RTEP costs, based on their Firm TWRs).

[11] 16 U.S.C. § 824d (2012).

330 MW of Firm TWRs to Non-Firm TWRs.[12] On October 5, 2017, the Commission rejected PJM's filing, finding that neither the Existing ISA nor PJM's tariff permitted PJM to file, under section 205, an unexecuted amended ISA with modifications requested by an interconnection customer, noting that subsequent to the filing of amendments to the Linden ISA, Linden filed its Complaint.[13] The Commission stated that it would address concerns related to Linden's request to convert its Firm TWRs to Non-Firm TWRs in proceedings related to the Complaint.

II. Linden Complaint

6. In its Complaint, Linden argues that PSEG is unreasonably withholding its consent to the amendment of the Existing ISA, which constitutes an abuse of power and violates principles of open access.[14] In support of its request that the Commission direct PSEG to consent to the amendment to the Existing ISA, Linden argues that PSEG has not identified a legitimate objection to Linden's request to amend the Existing ISA.[15] Linden also states that it has fully paid for the network upgrades necessary to support its Firm TWRs. Linden argues that there are no reliability concerns or operational issues raised as a result of its request to reduce the level of service from Firm TWRs to Non-Firm TWRs, and, because PJM is not obligated to plan to support Non-Firm TWRs, PJM will not need to plan any additional upgrades as of result of it request. Linden adds that its transmission facility will remain fully controllable by PJM, and in the event of a reliability or other operational issue, flow can be shut off consistent with applicable rules and procedures.[16]

7. Linden analogizes TWRs with Point-to-Point Transmission Service in which transmission service customers are free to select between firm and non-firm service without incurring additional non-firm transmission service charges or executing a new service agreement.[17] Linden specifically identifies that those entities owning and operating generation facilities are free to convert Firm Point-to-Point

[12] PJM made this filing under Docket No. ER17-2267-000.

[13] *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,021 (2017).

[14] Complaint at 9-10.

[15] *Id.* at 11.

[16] *Id.* at 11-12.

[17] *Id.* at 12.

Transmission Service to non-firm transmission service without amending their interconnection agreements.[18]

8. Linden further contends that PSEG could not have reasonably relied on an allocation of costs to Linden for post-interconnection network upgrades.[19] Linden argues that, under the PJM tariff, cost responsibility assignments for RTEP projects are based on Firm TWRs, and are updated annually. Linden argues that there is nothing in the tariff that requires or even suggests that costs could be allocated for the life of an upgrade based on the Firm TWRs held by merchant transmission facilities when the project is included in the RTEP.[20] Linden notes that PSEG admits that Linden could unilaterally terminate the Existing ISA.[21] Linden contends that the Commission should not allow PSEG to withhold consent to the amendment to the Existing ISA for financial reasons. Linden further argues that concerns related to cost responsibility assignments are irrelevant to its request to reduce the level of service of its TWRs.

9. In addition, or alternatively, Linden requests that the Commission direct PJM to revise its tariff to permit merchant transmission facilities to unilaterally reduce the service level of their TWRs without requiring an amendment to the Existing ISA.[22] Linden maintains that the tariff establishes procedures in which a merchant transmission facility may request TWRs and elect the associated level of service; specifically, firm, non-firm, or some combination of the two. Linden contends that although the Commission may already interpret the tariff to provide merchant transmission facilities with the unilateral right to reduce their Firm TWRs to Non-Firm TWRs without requiring an amendment to an Existing ISA, this is not explicitly provided for in the tariff.[23]

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[18] *Id.* at 13.

[19] *Id.* at 14.

[20] *Id.* at 15.

[21] *Id.* at 16.

[22] *Id.* at 17. Linden requests that if an amendment is necessary, the tariff should be amended to specify that the merchant transmission facility has the right to file an unexecuted ISA. *Id.* at 21.

[23] *Id.* at 19.

III. Notice of Filing and Responsive Pleadings

10. Notice of the Complaint was published in the *Federal Register*, 82 Fed. Reg. 44,766 (2017), with interventions and protests due on or before October 10, 2017.

11. Notice of intervention was filed by New Jersey Board of Public Utilities (New Jersey Board). Timely motions to intervene were filed by FirstEnergy Service Company; Exelon Corporation; Monitoring Analytics;[24] Public Citizen, Inc.; Hudson Transmission Partners, LLC (HTP);[25] Consolidated Edison Company of New York, Inc.; Long Island Power Authority; PPL Electric Utilities Corporation; Brookfield Energy Marketing LP; American Electric Power Service Corporation; New York Power Authority; ITC Lake Erie Connector, LLC; and City of New York.

12. PJM filed an answer to the Complaint. PJM states that it will comply with any findings and directives that the Commission reasonably requires. PJM requests that should the Commission allow Linden to amend its Existing ISA to convert its Firm TWRs to Non-Firm TWRs, the Commission should grant the requested effective date with the understanding that such effective date shall not relieve Linden of its RTEP cost responsibility obligations under Schedule 12 of the tariff.[26]

13. PSEG filed a motion to dismiss, or in the alternative, an answer requesting that the Commission deny the Complaint. PSEG states that through the Complaint, Linden seeks to reduce Firm TWRs in an attempt to avoid cost responsibility assignments for RTEP projects, assignments that are the subject of other complaints and related proceedings that are currently pending before the Commission. PSEG argues that the Complaint is nothing more than a collateral attack on PJM's cost allocation method and an end run of those other proceedings. PSEG states that Linden's real grievance is the cost allocation method, and because the Complaint provides no new evidence, those other proceedings are the proper vehicle to address its concerns. Accordingly, PSEG requests that the Commission dismiss the Complaint.

14. In the alternative, PSEG requests that the Commission deny the Complaint. PSEG contends that Linden should not be allowed to amend its Existing ISA so that it can escape its cost responsibility assignments for RTEP projects. PSEG argues that it reasonably relied on Linden maintaining its Firm TWRs, and there is an expectation that

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[24] As the Independent Market Monitor for PJM (Market Monitor).

[25] In a separate proceeding, Linden sought to convert its Firm TWRs to Non-Firm TWRs. *See PJM Interconnection, L.L.C.*, 160 FERC ¶ 61,021 (2017).

[26] *See* PJM OATT, Schedule 12, §§ (b) (i), (iii).

the Linden facility will remain in service and will continue to be beneficial to New York. PSEG contends that if Linden is permitted to convert its Firm TWRs to Non-Firm TWRs, Linden and New York will continue to benefit from interconnection with the PJM transmission system at the expense of New Jersey ratepayers. PSEG states that the PJM transmission system is planned and designed to accommodate a planned megawatt quantity, both at the time of interconnection and in subsequent studies to maintain reliability. PSEG argues that the fact that a merchant transmission facility may not be using all of the Firm TWRs allotted to it under its existing ISA is irrelevant to the transmission planning process.

15. PSEG further argues that to allow for the unilateral amendment of existing ISAs because one party to the agreement is no longer satisfied accords unfair and undue preferential treatment, as well as compromises and introduces significant additional uncertainties into the interconnection queue process, potentially further inhibiting infrastructure development. PSEG adds that the *Mobile-Sierra* doctrine requires that the Commission presume that the contract rates and terms contained in the Existing ISA are just and reasonable unless otherwise shown to be contrary to the public interest, and that showing has not been made in this proceeding.[27]

16. New Jersey Board filed comments supporting PSEG's motion to dismiss, and argues that Linden's efforts to eliminate its cost allocation are intended to yield a preferential rate for customers in New York at the unjust and unreasonable expense of New Jersey ratepayers.

17. Linden filed an answer to PSEG reiterating that PJM has no obligation to plan its system for Non-Firm TWRs. Noting that PSEG's motion focuses largely on cost allocation issues, Linden answers that PSEG's challenge as it relates to the operation of the cost allocation provisions of the tariff represents a collateral attack on the Commission's order accepting provisions providing for a process that reallocates cost responsibilities assignments on an annual basis. Linden argues that the Commission should not in this proceeding address cost allocation issues already pending in other proceedings. Linden states that, where PJM's tariff permits cost responsibility assignments to shift over time as different users benefit from an upgrade, there is no reasonable basis for PSEG to rely on Linden maintaining its Firm TWRs over the long term. Further, Linden notes that PSEG acknowledges that Linden has the unilateral right to terminate its Existing ISA.

18. Addressing PSEG's *Mobile-Sierra* arguments, Linden answers that contracts that

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[27] PSEG Answer at 6. *See United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956) (*Mobile-Sierra*).

apply generally applicable rates, terms, or conditions, such as the relevant language of Linden's Existing ISA, do not qualify for protections provided by the *Mobile-Sierra* doctrine. Linden states that, as the relevant language is in the form agreement, the parties were not in a position to negotiate the terms and conditions of this agreement "freely at arm's length." Linden states that, as the relevant language is in the form agreement, the parties were not in a position to negotiate the terms and conditions of this agreement "freely at arm's length." Furthermore, Linden argues that, where the existing rate or term might impair the financial ability of a public utility to continue its service, PSEG's actions are sufficient to meet the public interest standard and overcome the *Mobile-Sierra* presumptions.

19. The Market Monitor, noting that Linden has taken steps to obtain Firm Point-to-Point Transmission service coupled with Non-Firm TWRs, filed comments that address the responsibility for an allocation of transmission upgrade costs to transmission customers that have a point of delivery at the border where the transmission system interconnects with merchant transmission facilities. The Market Monitor contends that Linden seeks to substitute Firm Point-to-Point Transmission service coupled with Non-Firm TWRs to maintain the ability to export capacity to the NYISO from PJM with the same level of transmission service they have with Firm TWRs. The Market Monitor asserts that this creates a discrepancy in cost allocation between section 232.2 and Schedule 12 of the tariff in that Schedule 12 omits any reference to merchant transmission facilities that hold both firm transmission service to the PJM border and Non-Firm TWRs. The Market Monitor concludes that it would not be just and reasonable to require merchant transmission providers to retain the same capacity exports though firm point-to-point transmission service and avoid RTEP cost allocation.

20. The PJM Transmission Owners also filed an answer in response to Linden, to clarify that Schedule 12 defines customers with Firm Point-to-Point Transmission Service as customers responsible for the costs of RTEP projects. The PJM Transmission Owners also state that Schedule 7 specifies that Firm Point-to-Point transmission customers should not be charged for the same RTEP costs under their applicable Point-to-Point service rate, and that Firm Point-to-Point customers can thus be assessed RTEP costs.[28]

IV. <u>Discussion</u>

A. <u>Procedural Matters</u>

21. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[29] the notice of intervention and timely, unopposed motions to intervene serve to make

[29] 18 C.F.R. § 385.214 (2017).

the entities that filed them parties to this proceeding.

22. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure,[30] prohibits an answer to a protest and or answer unless otherwise ordered by the decisional authority. We will accept the answers and responsive pleadings because they have provided information that assisted us in our decision-making process.

B. Complaint

23. We grant the Complaint, in part. As discussed below, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit Linden to convert its Firm TWRs to Non-Firm TWRs.[31] Accordingly, upon written notice from Linden, PJM shall make a compliance filing amending section 2.2 of Specifications for the Existing ISA to reflect the conversion of 330 MW Firm TWRs for a total of 0 MW Firm TWRs and 330 MW Non-Firm TWRs, to be effective on the date requested by Linden in its written notice, but no earlier than the date of that notice.[32] Because we find that Linden may convert its Firm TWRs to Non-Firm TWRs, we further find that revisions to the *pro forma* tariff are unnecessary. We reject the arguments that the Commission should dismiss the Complaint.

24. We see no reasonable basis for barring Linden from converting from higher quality Firm TWRs to lower quality Non-Firm TWRs by amending the Existing ISA. ISAs establish the requirements and upgrades necessary for interconnection. Once a merchant transmission facility has elected to obtain Firm TWRs, PJM determines the necessary upgrades to support the Firm TWRs requested through its interconnection process. Linden already has satisfied these interconnection requirements, and we find

[30] 18 C.F.R. § 385.213(a)(2) (2017).

[31] In the Complaint, Linden argues (1) the PJM tariff is unjust and unreasonable and unduly discriminatory to the extent it fails to allow Linden to convert Firm TWRs to Non-Firm TWRs and (2) PSEG's failure to consent to an amendment to the Existing ISA reflecting the same is unjust, unreasonable, and unduly discriminatory. Because we have found that the Existing ISA is unjust and reasonable insofar as it does not permit Linden to convert its Firm TWRs to Non-Firm TWRs, we need not address whether PSEG acted unreasonably in withholding consent to an amendment to the Existing ISA reflecting the same.

[32] Linden does not request a specific effective date for its amendment to the Existing ISA. Rather, Linden requests that the Commission act on its Complaint by December 15, 2017 in order for Linden to provide notice to PJM and PSEG of its amendment to the Existing ISA no later than December 31, 2017. Complaint at 2, 25-26.

that requiring it to maintain such Firm TWRs for the life of the merchant transmission facility is unjust and unreasonable in the absence of any operational or reliability basis for doing so.

25. Under the Existing ISA and PJM's tariff, PJM must guarantee that its transmission system is robust enough to permit Linden to use its Firm TWRs to export 330 MWs of power from its source in PJM across the river to New York at all times. Converting those Firm TWRs to Non-Firm TWRs imposes no additional obligation on PJM and, in fact, is less burdensome in that PJM will no longer have to guarantee that its transmission system can support such use. In terms of reliability, Linden supports that the conversion "will not exceed the nominal rated capability of Linden VFT's facility"[33], and no additional facilities would be necessary to support Linden's conversion from Firm TWRs to Non-Firm TWRs. In any case, the Linden facility is fully controllable by PJM so that PJM can shut off flows if those flows jeopardize reliability or cause operational problems in New Jersey or elsewhere on the PJM system.[34] PSEG has offered no evidence to the contrary.

26. PSEG argues that, under section 16.1.2 and 16.2.1 of Appendix 2 of the ISA, Linden could effectuate such a reduction in Firm TWRs by exercising its unilateral right to terminate the Existing ISA and disconnecting its line. Linden could then reapply for Non-Firm TWRs. However, interpreting the Existing ISA, as PSEG did in its protest in Docket No. ER17-2267-000, to require that Linden terminate the Existing ISA and disconnect an already operational merchant transmission facility, rather than amending the Existing ISA, to convert Firm TWRs to Non-Firm TWRs, would be unjust and unreasonable. Linden supports that it has "fully paid for the network upgrades necessary for its Firm [TWRs] and therefore the reduction will not affect payments for previously constructed facilities."[35] We also do not find, as PSEG alleges, that allowing Linden to convert its Firm TWRs to Non-Firm TWRs will undermine the interconnection process as Linden has already fulfilled its interconnection requirements. As discussed above, Non-Firm TWRs impose less of a burden on the transmission system than do Firm TWRs, and Linden's conversion of Firm TWRs to Non-Firm TWRs does not require any additional system upgrades as the Non-Firm TWRs do not increase system withdrawals.[36] Moreover, PJM, as the system operator, does not represent that such a conversion will have adverse reliability or operational impacts, and Linden's amendment to the Existing

[33] Complaint at 11.

[34] Complaint at 11.

[35] Complaint at 11.

[36] Linden explains that it does not seek to expand the withdrawal capacity of its facilities, Complaint at 27.

ISA will not affect payments for previously constructed facilities.[37] Thus, we find that it is unjust and unreasonable not to allow Linden to amend the Existing ISA to convert its Firm TWRs to Non-Firm TWRs.

1. Mobile-Sierra

27. As a threshold matter, we find that the Existing ISA is not eligible for the *Mobile-Sierra* "public interest" presumption. Aside from the fact that the Existing ISA was filed and accepted by the Commission, PSEG provides no other support for its contention that the Existing ISA is protected by the *Mobile-Sierra* doctrine.[38] As the Commission has explained, the *Mobile-Sierra* "public interest" presumption applies to an agreement only if the agreement has certain characteristics that justify the presumption. In ruling on whether the characteristics necessary to justify a *Mobile-Sierra* presumption are present, the Commission must determine whether the agreement at issue embodies either: (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations. Unlike the latter, the former constitute contract rates, terms, or conditions that necessarily qualify for a *Mobile-Sierra* presumption.

28. We find that the terms and conditions of the Existing ISA at issue here are generally applicable and, therefore, are not protected by the *Mobile-Sierra* presumption. The granting of Firm and Non-Firm TWRs to a Transmission Interconnection Customer is governed by generally applicable provisions of the PJM Tariff, namely section 232 of the PJM Tariff.[39] Once determined by PJM following a System Impact Study, such rights become available to the Transmission Interconnection Customer (e.g., Linden) pursuant to execution of an ISA based on the *pro forma* ISA attached to the PJM Tariff as Attachment O. The terms and conditions in the Existing ISA, including the terms related to Amendments, Termination, and Disconnection, were identical in relevant part to the

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[37] *See PJM Interconnection, L.L.C.,* 160 FERC ¶ 61,056, at P 43 (2017).

[38] PSEG Answer at 6.

[39] *See* PJM Tariff, Section 232.3 (Determination of Transmission Injection Rights and Transmission Withdrawal Rights to be Provided to Customer) ("The Office of Interconnection [PJM] shall determine the … Transmission Withdrawal Rights … to be provided to eligible Transmission Interconnection Customer(s)").

terms and conditions set forth in the *pro forma* ISA in PJM's Tariff.[40] The Commission has found that such generally applicable rates, terms and conditions are not the type of contract rates that qualify for the *Mobile-Sierra* presumption.[41]

29. Another, independent reason why the *Mobile-Sierra* presumption does not apply in these circumstances is that the Existing ISA contains the same standard *Memphis* clause[42] as in the *pro forma* ISA. That provision preserves for PJM and PSEG their section 205 filing rights and preserves the rights of any Interconnection Party to bring complaints under section 206. Specifically, section 22.3 of the Existing ISA states in pertinent part:

> This Interconnection Service Agreement may be amended or supplemented only by a written instrument duly executed by all Interconnection Parties. An amendment to the Interconnection Service Agreement shall become effective and a part of this Interconnection Service Agreement upon satisfaction of all Applicable Laws and Regulations. Notwithstanding the foregoing, nothing contained in this Interconnection Service Agreement shall be construed as affecting in any way any of the rights of any Interconnection Party with respect to changes in applicable rates or charges under Section 205 of the Federal Power Act and/or FERC's rules and regulations thereunder, or any of the rights of any

[40] Section 2.1 of the Specifications and Schedule F of the Existing ISA contain non-standard terms and conditions. Schedule F of the Existing ISA sets forth the status of the construction and transfer of ownership of certain switchyard facilities and reserves certain rights with respect to the transfer of ownership of the switchyard facilities. The non-standard terms and conditions in Section 2.1 of the Specifications separate~~s~~ transmission injection rights by energy and capacity and makes capacity transmission injection rights contingent on completion of a certain RTEP upgrade.

[41] *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,059 (2013), *on reh'g*, 149 FERC ¶ 61,048, at PP 100-104 (2014), *denying petition for review*, *Okla. Gas & Elec. Co. v. FERC*, 827 F.3d 75, 76 (D.C. Cir. 2016); *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 184 (2013) (citing *Carolina Gas Transmission Corp.*, 136 FERC ¶ 61,014, at P 17 (2011) (holding that the terms of an agreement that are "incorporated into the service agreements of all present and future customers…are properly classified as tariff rates and the *Mobile-Sierra* presumption would not apply.").

[42] *United Gas Co. v. Memphis Gas Div*., 358 U.S. 103 (1958) (contracts can preserve the rights of parties to revise rates under ordinary just and reasonable standard).

> Interconnection Party under Section 206 of the Federal Power Act and/or FERC's rules and regulations thereunder.

30. While section 22.3 states that the Existing ISA may be amended "only by a written instrument duly executed by all Interconnection Parties…", the second sentence of the provision protects the parties' unilateral filing rights. Consistent with court precedent, the Commission has found that such provisions apply the ordinary just and reasonable standard: "where provisions in an Interconnection Agreement allow either party to unilaterally request changes under FPA sections 205 or 206, the Commission has the authority to require changes to the contracts under the just and reasonable standard."[43]

2. Cost Allocation

31. PSEG and New Jersey Board also argue that Linden should not be permitted to relinquish its Firm TWRs, because, under Schedule 12 of PJM's tariff, Linden would no longer be allocated costs for RTEP projects that PSEG alleges were caused by Linden's Firm TWRs and benefit Linden. However, as explained below, it is the cost allocation provisions in Schedule 12 that provide that a Merchant Transmission Owner that does not own Firm TWRs does not receive cost responsibility assignments for RTEP projects.[44] Neither PSEG nor New Jersey Board have argued that those provisions are unjust and unreasonable. Accordingly, we find that their cost allocation argument does not provide a basis for precluding Linden from terminating its Firm TWRs under the Existing ISA.

32. Under Schedule 12 of the PJM tariff, a merchant transmission facility's cost responsibility assignments for RTEP projects are calculated based on that facility's Firm TWRs.[45] As the Commission has explained, the reason that the costs of RTEP projects are allocated to merchant transmission facilities with Firm TWRs is that PJM is required

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[43] *Ontelaunee Power Operating Co., LLC*, 119 FERC ¶ 61,181, at P 24 (2007) (citing *Duke Energy Hinds LLC*, 102 FERC ¶ 61,068, at P 21 (2003)). *See also Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 954 (D.C. Cir. 1983) ("specific acknowledgment of the possibility of future rate change is virtually meaningless unless it envisions a just-and-reasonable standard").

[44] Although PJM implements the cost allocation provisions of Schedule 12 of the Tariff, the cost allocation method is determined by the PJM Transmission Owners, and it is the PJM Transmission Owners, not PJM, that have the section 205 filing rights for the PJM cost allocation method. *See Atlantic City Electric Co. v. FERC,* 295 F.3d 1 (D.C. Cir. 2002).

[45] *See* PJM OATT, Schedule 12, §§ (b)(i) (3.0.0).

to provide reliable service to those facilities and therefore those merchant transmission providers are responsible for contributing to facilities necessary to support that firm service:

> PJM is required to provide reliable service up to the Firm Transmission Withdrawal Rights held by these customers. In order to provide such rights, PJM must require the construction of RTEP upgrades. The Merchant Transmission Facilities can avoid these costs if instead of opting for Firm Transmission Withdrawal Rights, they opt only for Non-Firm Transmission Withdrawal Rights under the tariff.[46]

As of the effective date of Linden's conversion of its Firm TWRs to Non-Firm TWRs, PJM is no longer required to provide firm service and can curtail non-firm service whenever necessary to preserve reliability.[47] Under Schedule 12, therefore, RTEP project costs would no longer be allocable to Linden as of the effective date of Linden's conversion from Firm TWRs to Non-Firm TWRs. The cost responsibility assignments for RTEP projects are updated annually based on a range of inputs and values to determine beneficiaries of RTEP projects.[48] Thus, under Schedule 12, cost responsibility assignments for RTEP projects shift over time as usage by transmission customers of a RTEP project changes over its lifespan.[49] For example, Linden's cost responsibility assignment increased as a direct result of the termination of Con Edison's transmission service agreements.[50] Contrary to PSEG's assertion, the PJM tariff does not require a merchant transmission facility, like Linden, to be allocated costs for an RTEP project over the life of that project based on the MWs of Firm TWRs they held at the time that the RTEP project was approved by PJM.[51] As noted, neither PSEG nor New Jersey

[46] *PJM Interconnection, L.L.C.* Opinion No. 503, 129 FERC ¶ 61,161, at P 80 (2009).

[47] *See* PJM OATT, Schedule 12 § (b)(i) (3.0.0). *See* PJM OATT § I, OATT Definitions L-M-N, 14.0.0, Non-Firm Transmission Withdrawal Rights. *See also* PJM OATT § II, Point-to-Point Transmission Service.

[48] *See* PJM OATT, Schedule 12 § (b)(iii)(H).

[49] Schedule 12 updates cost allocations annually based on changes to the system's topology, load changes, and other events such as termination of service. *See* PJM OATT, Schedule 12 § (b).

[50] Complaint at 7-8, s*ee also* Mellana Affidavit at P 8.

[51] *See* PJM OATT, Schedule 12 § (b)(iii).

Board has contended that these provisions are unjust and unreasonable.

33. PSEG argues that the Complaint is a collateral attack on the PJM cost allocation method. We disagree. As discussed above, we find the Complaint appropriately raises concerns relating to Linden's request to convert Firm TWRs to Non-Firm TWRs. While PSEG identifies the potential for Linden's cost responsibility assignments for RTEP projects to change as a result of its request to convert its Firm TWRs to Non-Firm TWRs, this potential simply reflects the operation of the cost allocation method in the tariff, not a collateral attack of it.

34. Moreover, we are not persuaded by PSEG's arguments that the Commission should dismiss the Complaint because PSEG reasonably relied upon the long-term duration of the Existing ISA, and Linden maintaining its Firm TWRs, as providing for long-term cost responsibility assignments for RTEP projects to Linden. As PSEG itself acknowledged, Linden has the right unilaterally to terminate the Existing ISA, including its Firm TWRs, at any time.[52] As we explained earlier, requiring Linden to terminate its rights in order to convert its Firm TWRs to Non-Firm TWRs is unjust and unreasonable as making such changes will not result in reliability or operational difficulties for the PJM system.

35. Similarly, the Market Monitor raises concerns with Schedule 12 and requests changes thereto in order to address an alleged discrepancy in the cost responsibility assignments for RTEP projects for merchant transmission providers that hold firm point-to-point transmission service and those that hold Firm TWRs. Those general concerns with Schedule 12 do not address whether Linden should be permitted to convert its Firm TWRs to Non-Firm TWRs. The PJM Transmission Owners also raise concerns regarding the cost responsibility assignments for RTEP projects to firm point-to-point transmission customers. We reject, as beyond the scope of this proceeding, these comments. The cost responsibility assignments for RTEP projects for firm point-to-point transmission customers under Schedule 12 are unrelated to the issue of whether Linden should be permitted to convert its Firm TWRs to Non-Firm TWRs.

<u>The Commission orders</u>:

(A) We grant the Complaint in part, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit Linden to convert its Firm TWRs to Non-Firm TWRs, as discussed in the body of this order.

(B) Upon written notice from Linden, PJM shall make a compliance filing amending the section 2.2 of Specifications for the Existing ISA to reflect the conversion

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[52] Complaint at 16.

of 330 MW Firm TWRs for a total 0 MWs of Firm TWRs and 330 MW Non-Firm TWRs, to be effective on the date requested by Linden in its written notice, but no earlier than the date of that notice, as discussed in the body of this order.

By the Commission. Chairman McIntyre is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

Attachment 10 (PSE&G FERC Formula Rate filing)

Hesser G. McBride, Jr.
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PSEG
Services Corporation

January 9, 2018

VIA EFILING

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

Re: Public Service Electric and Gas Company
Docket No. ER09-1257-000
Informational Filing of 2018 Formula Rate Annual Update (Revision)

Dear Secretary Bose:

On behalf of Public Service Electric and Gas Company ("PSE&G"), attached please find a revised informational filing of PSE&G's 2018 Transmission Formula Rate Annual Update. On October 16, 2017, PSE&G filed with the Federal Energy Regulatory Commission in the above-captioned docket a 2018 Formula Rate Annual Update ("Annual Update"). The Annual Update filing was revised by an errata filing made by PSE&G on October 27, 2017.

This revised informational filing is being made to implement the recent reduction in the federal corporate income tax rate pursuant to the Tax Cuts and Jobs Act of 2017 ("TCJA"), *Public Law No. 115-97*. More specifically, in this informational filing PSE&G has updated the Federal Income Tax Rate value posted in Excel Row 206 of Appendix A to the Annual Update from 35% to 21%.

Also, enclosed please find an updated version of Exhibit 1 of the Annual Update, which includes a revised version of PSEG's 2018 Formula Rate Annual Update. Any other aspects of the TCJA that impact the 2018 annual revenue requirement will be incorporated in the true-up filing of the 2018 rate.

The October 27, 2017 Annual Update filing remains unchanged in all other respects. This revised informational filing reduces the 2018 annual revenue requirement forecasted in the Annual Update by $148,235,120.

The revised formula rate template in Exhibit 1 is also being provided to PJM Interconnection, L.L.C. for posting on its website. Consistent with the Commission

Staff's Guidance on Formula Rate Updates, PSE&G is submitting the updated formula rate template in Microsoft Excel format.

Thank you for your attention to this matter and please advise the undersigned of any questions.

Respectfully submitted,

Hesser G. McBride, Jr.

Hesser G. McBride, Jr.

Attachments

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2018
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense	(Note O)	Attachment 5	31,626,000
2	Total Wages Expense	(Note O)	Attachment 5	207,395,000
3	Less A&G Wages Expense	(Note O)	Attachment 5	9,733,000
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	197,662,000
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**16.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	20,900,387,637
7	Common Plant in Service - Electric		(Line 22)	180,548,962
8	Total Plant in Service		(Line 6 + 7)	21,080,936,599
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	Attachment 5	3,736,217,375
10	Accumulated Intangible Amortization - Electric	(Note B)	Attachment 5	6,181,302
11	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	Attachment 5	29,686,389
12	Accumulated Common Amortization - Electric	(Note B)	Attachment 5	49,202,101
13	Total Accumulated Depreciation		(Line 9 + Line 10 + Line 11 + Line 12)	3,821,287,167
14	Net Plant		(Line 8 - Line 13)	17,259,649,432
15	Transmission Gross Plant		(Line 31)	11,254,947,402
16	**Gross Plant Allocator**		(Line 15 / Line 8)	**53.3892%**
17	Transmission Net Plant		(Line 43)	10,235,109,330
18	**Net Plant Allocator**		(Line 17 / Line 14)	**59.3008%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	Attachment 5	11,162,840,225
20	General	(Note B)	Attachment 5	332,299,612
21	Intangible - Electric	(Note B)	Attachment 5	15,038,477
22	Common Plant - Electric	(Note B)	Attachment 5	180,548,962
23	Total General, Intangible & Common Plant		(Line 20 + Line 21 + Line 22)	527,887,051
24	Less: General Plant Account 397 -- Communications	(Note B)	Attachment 5	36,924,263
25	Less: Common Plant Account 397 -- Communications	(Note B)	Attachment 5	35,209,921
26	General and Intangible Excluding Acct. 397		(Line 23 - Line 24 - Line 25)	455,752,867
27	Wage & Salary Allocator		(Line 5)	16.0000%
28	General and Intangible Plant Allocated to Transmission		(Line 26 * Line 27)	72,920,643
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Attachment 5	19,186,533
30	Total General and Intangible Functionalized to Transmission		(Line 28 + Line 29)	92,107,177
31	**Total Plant In Rate Base**		(Line 19 + Line 30)	**11,254,947,402**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Note B & J)	Attachment 5	968,854,890
33	Accumulated General Depreciation	(Note B & J)	Attachment 5	139,970,808
34	Accumulated Common Plant Depreciation - Electric	(Note B & J)	Attachment 5	78,888,490
35	Less: Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Attachment 5	30,305,351
36	Balance of Accumulated General Depreciation		(Line 33 + Line 34 - Line 35)	188,553,948
37	Accumulated Intangible Amortization - Electric	(Note B)	(Line 10)	6,181,302
38	Accumulated General and Intangible Depreciation Ex. Acct. 397		(Line 36 + 37)	194,735,249
39	Wage & Salary Allocator		(Line 5)	16.0000%
40	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 38 * Line 39)	31,157,719
41	Accumulated General Depreciation Associated with Acct. 397 Directly Assigned to Transmis	(Note B & J)	Attachment 5	19,825,463
42	**Total Accumulated Depreciation**		(Lines 32 + 40 + 41)	**1,019,838,072**
43	**Total Net Property, Plant & Equipment**		(Line 31 - Line 42)	**10,235,109,330**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2018
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
44	**ADIT net of FASB 106 and 109**	(Note Q)	Attachment 1	-2,502,792,692
	CWIP for Incentive Transmission Projects			
45	CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	102,222,422
	Abandoned Transmission Projects			
45a	Unamortized Abandoned Transmission Projects	(Note R)	Attachment 5	0
46	**Plant Held for Future Use**	(Note C & Q)	Attachment 5	18,085,194
	Prepayments			
47	Prepayments	(Note A & Q)	Attachment 5	0
	Materials and Supplies			
48	Undistributed Stores Expense	(Note Q)	Attachment 5	0
49	Wage & Salary Allocator		(Line 5)	16.0000%
50	Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51	Transmission Materials & Supplies	(Note N & Q))	Attachment 5	48,632,000
52	Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	48,632,000
	Cash Working Capital			
53	Operation & Maintenance Expense		(Line 80)	133,933,189
54	1/8th Rule		1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	16,741,649
	Network Credits			
56	Outstanding Network Credits	(Note N & Q))	Attachment 5	0
57	**Total Adjustment to Rate Base**		**(Lines 44 + 45 + 45a + 46 + 47 + 52 + 55 - 56)**	**(2,317,111,428)**
58	**Rate Base**		(Line 43 + Line 57)	**7,917,997,903**
	Operations & Maintenance Expense			
	Transmission O&M			
59	Transmission O&M	(Note O)	Attachment 5	107,887,010
60	Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61	**Transmission O&M**		(Lines 59 + 60)	**107,887,010**
	Allocated Administrative & General Expenses			
62	Total A&G	(Note O)	Attachment 5	172,512,000
63	Plus: Actual PBOP expense	(Note J)	Attachment 5	26,864,000
64	Less: Actual PBOP expense	(Note O)	Attachment 5	37,487,000
65	Less Property Insurance Account 924	(Note O)	Attachment 5	3,032,000
66	Less Regulatory Commission Exp Account 928	(Note E & O)	Attachment 5	10,400,000
67	Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	2,125,000
68	Less EPRI Dues	(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	146,332,000
70	Wage & Salary Allocator		(Line 5)	16.0000%
71	**Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**23,413,179**
	Directly Assigned A&G			
72	Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	835,000
73	General Advertising Exp Account 930.1	(Note K & O)	Attachment 5	0
74	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 72 + Line 73)	835,000
75	Property Insurance Account 924		(Line 65)	3,032,000
76	General Advertising Exp Account 930.1	(Note F & O)	Attachment 5	0
77	Total Accounts 928 and 930.1 - General		(Line 75 + Line 76)	3,032,000
78	Net Plant Allocator		(Line 18)	59.3008%
79	**A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**1,798,000**
80	**Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**133,933,189**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2018
	Depreciation & Amortization Expense			
	Depreciation Expense			
81	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note J & O)	Attachment 5	266,279,924
81a	Amortization of Abandoned Plant Projects	(Note R)	Attachment 5	0
82	General Depreciation Expense Including Amortization of Limited Term Plant	(Note J & O)	Attachment 5	27,729,088
83	Less: Amount of General Depreciation Expense Associated with Acct. 397	(Note J & O)	Attachment 5	7,252,148
84	Balance of General Depreciation Expense		(Line 82 - Line 83)	20,476,940
85	Intangible Amortization	(Note A & O)	Attachment 5	11,136,699
86	Total		(Line 84 + Line 85)	31,613,639
87	Wage & Salary Allocator		(Line 5)	16.00%
88	General Depreciation & Intangible Amortization Allocated to Transmission		(Line 86 * Line 87)	5,058,195
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission	(Note J & O)	Attachment 5	1,908,451
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**		(Line 88 + Line 89)	**6,966,646**
91	**Total Transmission Depreciation & Amortization**		**(Lines 81 + 81a + 90)**	**273,246,570**
	Taxes Other than Income Taxes			
92	Taxes Other than Income Taxes	(Note O)	Attachment 2	10,432,800
93	**Total Taxes Other than Income Taxes**		(Line 92)	**10,432,800**
	Return \ Capitalization Calculations			
94	**Long Term Interest**		p117.62.c through 67.c	299,596,596
95	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
96	Proprietary Capital	(Note P)	Attachment 5	8,201,697,087
97	Less Accumulated Other Comprehensive Income Account 219	(Note P)	Attachment 5	1,021,739
98	Less Preferred Stock		(Line 106)	0
99	Less Account 216.1	(Note P)	Attachment 5	3,331,169
100	**Common Stock**		(Line 96 - 97 - 98 - 99)	8,197,344,179
	Capitalization			
101	Long Term Debt	(Note P)	Attachment 5	7,362,278,245
102	Less Loss on Reacquired Debt	(Note P)	Attachment 5	63,934,374
103	Plus Gain on Reacquired Debt	(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss	(Note P)	Attachment 5	16,982,115
105	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	7,281,361,756
106	Preferred Stock	(Note P)	Attachment 5	0
107	Common Stock		(Line 100)	8,197,344,179
108	**Total Capitalization**		(Sum Lines 105 to 107)	15,478,705,935
109	Debt % — Total Long Term Debt		(Line 105 / Line 108)	47.04%
110	Preferred % — Preferred Stock		(Line 106 / Line 108)	0.00%
111	Common % — Common Stock		(Line 107 / Line 108)	52.96%
112	Debt Cost — Total Long Term Debt		(Line 94 / Line 105)	0.0411
113	Preferred Cost — Preferred Stock		(Line 95 / Line 106)	0.0000
114	Common Cost — Common Stock	(Note J)	Fixed	0.1168
115	Weighted Cost of Debt — Total Long Term Debt (WCLTD)		(Line 109 * Line 112)	0.0194
116	Weighted Cost of Preferred — Preferred Stock		(Line 110 * Line 113)	0.0000
117	Weighted Cost of Common — Common Stock		(Line 111 * Line 114)	0.0619
118	**Rate of Return on Rate Base (ROR)**		(Sum Lines 115 to 117)	**0.0812**
119	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**643,031,192**

Public Service Electric and Gas Company

ATTACHMENT H-10A

			Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2018
Formula Rate -- Appendix A					
Shaded cells are input cells					
Composite Income Taxes					
	Income Tax Rates				
120	FIT=Federal Income Tax Rate		(Note I)		21.00%
121	SIT=State Income Tax Rate or Composite				9.00%
122	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
123	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			28.11%
124	T / (1-T)				39.10%
	ITC Adjustment				
125	Amortized Investment Tax Credit	enter negative	(Note O)	Attachment 5	-561,000
126	1/(1-T)			1 / (1 - Line 123)	139.10%
127	Net Plant Allocation Factor			(Line 18)	59.30%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-462,759**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**191,508,964**
130	**Total Income Taxes**			**(Line 128 + Line 129)**	**191,046,205**
Revenue Requirement					
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	10,235,109,330
132	Total Adjustment to Rate Base			(Line 57)	-2,317,111,428
133	**Rate Base**			(Line 58)	**7,917,997,903**
134	Total Transmission O&M			(Line 80)	133,933,189
135	Total Transmission Depreciation & Amortization			(Line 91)	273,246,570
136	Taxes Other than Income			(Line 93)	10,432,800
137	Investment Return			(Line 119)	643,031,192
138	Income Taxes			(Line 130)	191,046,205
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**1,251,689,957**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	11,162,840,225
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	11,162,840,225
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	1,251,689,957
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**1,251,689,957**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	21,251,492
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**1,230,438,464**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**1,251,689,957**
150	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**10,296,207,758**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**12.1568%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**9.5706%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 15(	**1.4698%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
154	Gross Revenue Requirement Less Return and Taxes			(Line 144 - Line 137 - Line 138)	**417,612,559**
155	Increased Return and Taxes			Attachment 4	**892,406,517**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**1,310,019,076**
157	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**10,296,207,758**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**12.7233%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**10.1371%**
160	**Net Revenue Requirement**			(Line 148)	**1,230,438,464**
161	True-up amount			Attachment 6	**12,591,534**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission :			Attachment 7	**5,789,354**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**1,248,819,352**
	Network Zonal Service Rate				
165	1 CP Peak		(Note L)	Attachment 5	**9,566.9**
166	Rate ($/MW-Year)			(Line 164 / 165)	**130,535.22**
167	**Network Service Rate ($/MW/Year)**			**(Line 166)**	**130,535.22**

Public Service Electric and Gas Company ATTACHMENT H-10A Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2018

Shaded cells are input cells

Notes

A Electric portion only

B Calculated using 13-month average balances

C Includes Transmission portion only. At each annual informational filing, Company will identify for each parcel of land an intended use within a 15 year period

D Includes all EPRI Annual Membership Dues

E Includes all Regulatory Commission Expenses

F Includes Safety related advertising included in Account 930.1

G Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h

H CWIP can only be included if authorized by the Commission

I 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

J ROE will be supported in the original filing and no change in ROE will be made absent a filing at FERC
PBOP expense shall be based upon the Company's Actual Annual PBOP Expense until changed by a filing at FERC
The actual Annual PBOP Expense to be included in the Formula Rate Annual Update that is required to be filed on or before October 15 of each year shall be based upon the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees for PBOP and as included by the Company in its most recent True-up Adjustment filing.
PSEG will provide, in connection with each annual True-Up Adjustment filing a confidential copy of relevant pages from annual actuarial valuation report supporting the derivation of the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees
Depreciation rates shown in Attachment 8 are fixed until changed as the result of a filing at FERC
If book depreciation rates are different than the Attachment 8 rates, PSE&G will provide workpapers at the annual update to reconcile formula depreciation expense and depreciation accruals to FERC Form 1 amounts

K Education and outreach expenses relating to transmission, for example siting or billing

L As provided for in Section 34.1 of the PJM OATT; the PJM established billing determinants will not be revised or updated in the annual rate reconciliations

M Amount of transmission plant excluded from rates per Attachment 5

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A
Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole on Line "&A248&"."

O Expenses reflect full year plan

P The projected capital structure shall reflect the capital structure from the FERC Form 1 data. For all other formula rate calculations, the projected capital structure and actual capital structure shall reflect the capital structure from the most recent FERC Form 1 data available.
Calculated using the average of the prior year and current year balances

Q Calculated using beginning and year end projected balances

END R Unamortized Abandoned Plant and Amortization of Abandoned Plant may only be included pursuant to a Commission Order authorizing such inclusion

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2018

	Only Transmission Related	Plant Related	Labor Related	Total ADIT	
ADIT- 282	(2,597,832,425)	0	(36,267,968)		From Acct. 282 total, below
ADIT-283	0	(14,192,780)	0		From Acct. 283 total, below
ADIT-190	0	0	12,168,870		From Acct. 190 total, below
Subtotal	(2,597,832,425)	(14,192,780)	(24,099,098)		
Wages & Salary Allocator			16.0000%		
Net Plant Allocator		59.3008%			
End of Year ADIT	(2,597,832,425)	(8,416,431)	(3,855,865)	**(2,610,104,721)**	
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(2,383,691,531)	(8,797,786)	(2,991,346)	**(2,395,480,663)**	
Average Beginning and End of Year ADIT	(2,490,761,978)	(8,607,109)	(3,423,606)	**(2,502,792,692)**	Appendix A, Line 44

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 108
(14,192,780) < From Acct 283, below

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

A	B	C	D	E	F	G
ADIT-190	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
ADIT - Contribution In Aid of Construction	33,971,473	33,971,473	-	-	-	Represents the estimated IRC 118 amount (CIAC)
Vacation Pay	631,750	-	-	-	631,750	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	180,153,245	-	-	-	180,153,245	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	3,105,261	-	-	-	3,105,261	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	395,586	-	-	-	395,586	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	-	-	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	189,384	189,384	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	5,554,630	-	-	5,554,630	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	(1,631,739)	(9,668,012)	-	-	8,036,273	-
Subtotal - p234	**222,369,590**	**24,492,845**		**5,554,630**	**192,322,115**	
Less FASB 109 Above if not separately removed	5,554,630			5,554,630		
Less FASB 106 Above if not separately removed	180,153,245				180,153,245	
Total	**36,661,715**	**24,492,845**		**0**	**12,168,870**	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2018

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	***Total***	***Gas, Prod Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Depreciation - Liberalized Depreciation (Federal)	(4,004,267,788)	(1,595,753,854)	(2,375,774,816)	-	(32,739,118)	For federal - Column D represents the direct assignment of prorated ADIT associated with Transmission assets,, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Depreciation - Liberalized Depreciation (State)	(412,147,501)	(186,561,043)	(222,057,608)	-	(3,528,850)	For state - Column D represents the direct assignment of prorated ADIT associated with Transmission assets,, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Accounting for Income Taxes	(317,127,352)	(267,274,356)	(49,588,141)	-	(264,855)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,733,542,641)**	**(2,049,589,252)**	**(2,647,420,566)**	**0**	**(36,532,823)**	
Less FASB 109 Above if not separately removed	(49,852,996)		(49,588,141)	0	(264,855)	
Less FASB 106 Above if not separately removed						
Total	**(4,683,689,644)**	**(2,049,589,252)**	**(2,597,832,425)**	**0**	**(36,267,968)**	

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2018

A	B	C	D	E	F	G
ADIT-283	***Total***	**Gas, Prod or Other Related**	**Only Transmission Related**	**Plant**	**Labor**	
Environmental Cleanup Costs	(61,165,265)	(61,165,265)	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	11,114,837	11,114,837	-	-	-	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(105,453,531)	(105,453,531)	-	-	-	Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(14,192,780)	-	-	(14,192,780)	-	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(158,168,868)	(158,168,868)	-	-	-	Associated with Pension Liability not in rates
Sales Tax Reserve	-	-	-	-	-	Sales tax audit reserve
Miscellaneous	37,177,610	37,177,610	-	-	-	Miscellaneous Tax Adjustments
Deferred Gain	(46,845,469)	(46,845,469)	-	-	-	Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(232,692,205)	-	-	(232,692,205)	-	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(570,225,671)**	**(323,340,687)**		**(246,884,985)**		
Less FASB 109 Above if not separately removed	(232,692,205)			(232,692,205)		
Less FASB 106 Above if not separately removed						
Total	**(337,533,467)**	**(323,340,687)**		**(14,192,780)**		

Instructions for Account 283:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2017

	Only Transmission Related	Plant Related	Labor Related	Total ADIT	
ADIT- 282	(2,383,691,531)	0	(30,864,733)		From Acct. 282 total, below
ADIT-283	0	(14,835,865)	0		From Acct. 283 total, below
ADIT-190	0	0	12,168,870		From Acct. 190 total, below
Subtotal	(2,383,691,531)	(14,835,865)	(18,695,863)		
Wages & Salary Allocator			16.0000%		
Net Plant Allocator		59.3008%			
End of Year ADIT	(2,383,691,531)	(8,797,786)	(2,991,346)	**(2,395,480,663)**	

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 108
(14,835,865) < From Acct 283, below

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

A	B	C	D	E	F	G
ADIT-190	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
ADIT - Contribution In Aid of Construction	37,748,575	37,748,575	-	-	-	Represents the estimated IRC 118 amount (CIAC)
Vacation Pay	631,750	-	-	-	631,750	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	179,879,275	-	-	-	179,879,275	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	3,105,261	-	-	-	3,105,261	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	395,586	-	-	-	395,586	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	-	-	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	189,384	189,384	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	5,554,630	-	-	5,554,630	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	(1,631,739)	(9,668,012)	-	-	8,036,273	0
Subtotal - p234	**225,872,721**	**28,269,947**		**5,554,630**	**192,048,144**	
Less FASB 109 Above if not separately removed	5,554,630			5,554,630		
Less FASB 106 Above if not separately removed	179,879,275				179,879,275	
Total	**40,438,817**	**28,269,947**		**0**	**12,168,870**	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2017

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Depreciation - Liberalized Depreciation (Federal)	(3,710,135,516)	(1,484,577,833)	(2,198,221,800)	-	(27,335,883)	For Federal - Column D represents the direct assignment of ADIT, unprorated, associated with Transmission assets, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Depreciation - Liberalized Depreciation (State)	(360,901,871)	(171,903,290)	(185,469,731)	-	(3,528,850)	For State - Column D represents the direct assignment of ADIT, unprorated, associated with Transmission assets, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Accounting for Income Taxes	(49,852,996)	-	(49,588,141)	-	(264,855)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,120,890,383)**	**(1,656,481,123)**	**(2,433,279,672)**	**0**	**(31,129,588)**	
Less FASB 109 Above if not separately removed	(49,852,996)		(49,588,141)	0	(264,855)	
Less FASB 106 Above if not separately removed						
Total	**(4,071,037,387)**	**(1,656,481,123)**	**(2,383,691,531)**	**0**	**(30,864,733)**	

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2017

A	B	C	D	E	F	G
ADIT-283	*Total*	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	
Environmental Cleanup Costs	(61,165,265)	(61,165,265)	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	11,699,896	11,699,896	-	-	-	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(104,257,965)	(104,257,965)	-	-	-	Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(14,835,865)	-	-	(14,835,865)	-	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(158,168,868)	(158,168,868)	-	-	-	Associated with Pension Liability not in rates
Sales Tax Reserve	-	-	-	-	-	Sales tax audit reserve
Miscellaneous	32,730,151	32,730,151	-	-	-	Miscellaneous Tax Adjustments
Deferred Gain	(46,845,469)	(46,845,469)	-	-	-	Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(232,692,205)	-	-	(232,692,205)	-	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(573,535,590)**	**(326,007,521)**		**(247,528,070)**		
Less FASB 109 Above if not separately removed	(232,692,205)			(232,692,205)		
Less FASB 106 Above if not separately removed						
Total	**(340,843,386)**	**(326,007,521)**		**(14,835,865)**		

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 2 - Taxes Other Than Income Worksheet - December 31, 2018

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*	
	Plant Related				
1	Real Estate	21,308,000			Attachment #5
2	***Total Plant Related***	21,308,000	N/A	7,881,000	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	14,264,750			
4	Federal Unemployment Tax	322,070			
5	New Jersey Unemployment Tax	687,790			
6	New Jersey Workforce Development	674,100			
7					
8	***Total Labor Related***	15,948,710	16.0000%	2,551,800	
	Other Included		***Net Plant Allocator***		
9					
10					
11					
12					
13	***Total Other Included***	0	59.3008%	0	
14	***Total Included (Lines 8 + 14 + 19)***	37,256,710		10,432,800	
	Currently Excluded				
15	Corporate Business Tax	0			
16	TEFA	0			
17	Use & Sales Tax	0			
18	Local Franchise Tax	0			
19	PA Corporate Income Tax	0			
20	Municipal Utility	0			
21	Public Utility Fund	0			
22	**Subtotal, Excluded**	0			
23	**Total, Included and Excluded (Line 20 + Line 28)**	37,256,710			
24	**Total Other Taxes from p114.14.g - Actual**	37,256,710			
25	Difference (Line 29 - Line 30)	-			

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Net Plant Allocator. If the taxes are 100% recovered at retail they shall not be included. Real Estate taxes are directly assigned to Transmission.

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they shall not be included.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Net Plant Allocator; provided, however, that overheads shall be treated as in footnote B above.

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 3 - Revenue Credit Workpaper - December 31, 2018

	Accounts 450 & 451		
1	Late Payment Penalties Allocated to Transmission		0
	Account 454 - Rent from Electric Property		
2	Rent from Electric Property - Transmission Related (Note 2)		600,000
	Account 456 - Other Electric Revenues		
3	Transmission for Others		0
4	Schedule 1A		4,665,000
5	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner)		
6	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		6,650,000
7	Professional Services (Note 2)		45,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		7,962,979
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,845,371
10	Gross Revenue Credits	(Sum Lines 1-9)	24,768,349
11	Less line 18	- line 18	(3,516,857)
12	Total Revenue Credits	line 10 + line 11	21,251,492
13	Revenues associated with lines 2, 7, and 9 (Note 2)		5,490,371
14	Income Taxes associated with revenues in line 13		1,543,343
15	One half margin (line 13 - line 14)/2		1,973,514
16	All expenses (other than income taxes) associated with revenues in line 13 that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.		-
17	Line 15 plus line 16		1,973,514
18	Line 13 less line 17		3,516,857

Note 1 If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 2 Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). PSE&G will retain 50% of net revenues consistent with *Pacific Gas and Electric Company* , 90 FERC ¶ 61,314. Note: in order to use lines 13-18, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE			
A	100 Basis Point increase in ROE and Income Taxes		Line 27 + Line 42 from below	892,406,517
B	100 Basis Point increase in ROE			1.00%
Return Calculation				
			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	7,917,997,903
2	**Long Term Interest**		p117.62.c through 67.c	299,596,596
3	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
4	Proprietary Capital		Attachment 5	8,201,697,087
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	1,021,739
6	Less Preferred Stock		(Line 106)	0
7	Less Account 216.1		Attachment 5	3,331,169
8	Common Stock		(Line 96 - 97 - 98 - 99)	8,197,344,179
	Capitalization			
9	Long Term Debt		Attachment 5	7,362,278,245
10	Less Loss on Reacquired Debt		Attachment 5	63,934,374
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	16,982,115
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	7,281,361,756
14	Preferred Stock		Attachment 5	0
15	Common Stock		(Line 100)	8,197,344,179
16	Total Capitalization		(Sum Lines 105 to 107)	15,478,705,935
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	47.0%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	0.0%
19	Common %	Common Stock	(Line 107 / Line 108)	53.0%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0411
21	Preferred Cost	Preferred Stock	(Line 95 / Line 106)	0.0000
22	Common Cost	Common Stock	(Line 114 + 100 basis points)	0.1268
23	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 109 * Line 112)	0.0194
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0000
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0672
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0865**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**684,963,996**
Composite Income Taxes				
	Income Tax Rates			
28	FIT=Federal Income Tax Rate			21.00%
29	SIT=State Income Tax Rate or Composite			9.00%
30	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
31	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.11%
35	CIT = T / (1-T)			39.10%
36	1 / (1-T)			139.10%
	ITC Adjustment			
37	Amortized Investment Tax Credit	enter negative	Attachment 5	-561,000
38	1/(1-T)		1 / (1 - Line 123)	139%
39	Net Plant Allocation Factor		(Line 18)	59.3008%
40	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-462,759**
41	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		207,905,280
42	**Total Income Taxes**			**207,442,521**

Electric / Non-electric Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Jan	Feb	Mar	Apr	May	Jun
	Plant Allocation Factors									
6	Electric Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.104g	19,742,890,957	19,825,595,886	20,104,813,744	20,326,447,804	20,629,167,815	20,938,813,587	21,251,316,482
7	Common Plant in Service - Electric	(Note B)	p356	166,892,472	174,040,289	175,018,338	175,371,682	177,520,426	178,196,663	183,353,886
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	p219.29c	3,575,858,512	3,602,342,995	3,624,829,494	3,648,313,023	3,672,223,218	3,698,796,132	3,725,777,927
10	Accumulated Intangible Amortization	(Note B)	p200.21c	5,106,935	5,257,546	5,408,158	5,558,770	5,709,382	5,859,994	6,089,439
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	26,784,199	27,457,199	28,135,932	28,228,175	28,909,914	29,458,853	30,106,466
12	Accumulated Common Amortization - Electric	(Note B)	p356	44,901,775	45,593,505	46,288,901	46,986,589	47,707,734	48,432,088	49,160,796
	Plant In Service									
19	Transmission Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.58.g	10,365,352,227	10,418,460,440	10,654,754,333	10,803,752,626	11,047,483,689	11,197,875,412	11,396,279,745
20	General (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.99.g	283,648,204	282,074,003	282,991,051	296,126,545	317,361,077	334,115,384	359,257,530
21	Intangible - Electric	(Note B)	p205.5.g	11,449,861	11,449,861	11,449,861	11,449,861	11,449,861	11,449,861	18,069,861
22	Common Plant in Service - Electric	(Note B)	p356	166,892,472	174,040,289	175,018,338	175,371,682	177,520,426	178,196,663	183,353,886
24	General Plant Account 397 -- Communications	(Note B)	p207.94g	32,169,518	31,810,056	31,876,056	31,943,056	31,436,763	31,502,763	42,721,534
25	Common Plant Account 397 -- Communications	(Note B)	p356	35,317,165	35,317,165	35,317,165	35,317,165	35,317,165	35,317,165	35,317,165
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Company Records	20,410,777	20,410,777	20,410,777	20,410,777	20,410,777	20,410,777	20,409,814
	Accumulated Depreciation									
32	Transmission Accumulated Depreciation	(Note B & J)	p219.25.c	892,839,935	905,106,797	917,307,248	928,910,694	938,625,603	949,517,295	961,072,796
33	Accumulated General Depreciation	(Note B & J)	p219.28.b	143,531,156	142,881,390	139,215,665	137,245,265	137,612,587	138,829,382	139,517,055
34	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	p356	71,685,975	73,050,704	74,424,833	75,214,764	76,617,648	77,890,941	79,267,262
35	Accumulated General Depreciation Associated with Acct. 397	(Note B & J)	Company Records	28,475,982	28,693,363	29,337,757	29,982,709	30,050,149	30,691,431	31,416,975
41	Acc. Deprec. Acct. 397 Directly Assigned to Transmission	(Note B & J)	Company Records	20,064,602	20,234,691	20,404,781	20,574,871	20,744,961	20,915,051	21,084,169

Line #s	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-electric Portion
6	21,275,826,367	21,310,782,349	21,361,638,363	21,392,735,723	21,488,874,616	22,056,135,585	20,900,387,637	
7	183,803,836	184,182,556	184,503,100	184,138,849	184,739,613	195,374,795	180,548,962	
9	3,754,325,988	3,787,335,889	3,820,361,059	3,852,958,335	3,887,247,801	3,920,455,502	3,736,217,375	
10	6,319,170	6,549,187	6,779,346	7,009,506	7,239,665	7,469,825	6,181,302	
11	30,706,076	31,152,681	31,616,888	31,348,042	32,065,970	29,952,655	29,686,389	
12	49,893,170	50,630,128	51,371,669	52,117,564	52,867,814	53,675,584	49,202,101	
19	11,402,371,078	11,409,839,411	11,442,672,744	11,453,360,077	11,528,537,410	11,996,183,743	11,162,840,225	
20	357,382,915	358,669,946	359,343,461	360,848,977	363,831,120	364,244,743	332,299,612	
21	18,093,861	18,117,861	18,129,861	18,129,861	18,129,861	18,129,861	15,038,477	
22	183,803,836	184,182,556	184,503,100	184,138,849	184,739,613	195,374,795	180,548,962	
24	40,247,165	40,412,165	40,515,165	40,582,125	42,738,947	42,060,110	36,924,263	
25	35,265,190	35,265,190	35,000,156	35,000,156	34,992,175	34,985,952	35,209,921	
29	17,787,788	17,787,788	17,787,788	17,787,747	17,777,570	17,621,777	19,186,533	
32	976,553,613	993,348,882	1,009,381,169	1,024,313,830	1,040,675,847	1,057,459,855	968,854,890	
33	137,607,804	138,477,823	139,342,936	140,970,309	142,263,293	142,125,843	139,970,808	
34	80,599,246	81,782,809	82,988,557	83,465,606	84,933,784	83,628,239	78,888,490	
35	29,436,351	30,151,445	30,600,156	31,314,418	32,028,469	31,790,354	30,305,351	
41	18,610,375	18,758,606	18,906,838	19,055,029	19,192,998	19,184,053	19,825,463	

Wages & Salary

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
2	Total Wage Expense	(Note A)	p354.28b	207,395,000
3	Total A&G Wages Expense	(Note A)	p354.27b	9,733,000
1	Transmission Wages		p354.21b	31,626,000

Transmission / Non-transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Plant Held for Future Use (Including Land)	(Note C & Q)	p214.47.d	20,440,107	27,940,107	24,190,107
46	Transmission Only			17,076,194	19,094,194	18,085,194

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year	Electric Beginning Year Balance	Electric End of Year Balance	Average Balance	Wage & Salary Allocator	To Line 47
	Prepayments								
47	Prepayments	(Note A & Q)	p111.57c	0	0	0	0	16.000%	-

Materials and Supplies

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Materials and Supplies					
48	Undistributed Stores Exp	(Note Q)	p227.16.b,c	0	0	0
51	Transmission Materials & Supplies	(Note N & Q))	p227.8.b,c	48,632,000	48,632,000	48,632,000

Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Network Credits					
56	**Outstanding Network Credits**	(Note N & Q))	From PJM	0	0	0

O&M Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
59	Transmission O&M	(Note O)	p.321.112.b	107,887,010
60	Transmission Lease Payments		p321.96.b	-

Property Insurance Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
65	Property Insurance Account 924	(Note O)	p323.185b	3,032,000

Adjustments to A & G Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
62	Total A&G Expenses (Benefit Costs determined in accordance with ASU 2017-17)		p323.197b	172,512,000
				-
63	Actual PBOP expense	(Note J)	Company Records	26,864,000
64	Actual PBOP expense	(Note O)	Company Records	37,487,000

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related
	Allocated General & Common Expenses				
66	Regulatory Commission Exp Account 928	(Note E & O)	p323.189b	10,400,000	-
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	835,000	835,000

General & Common Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	EPRI Dues
68	Less EPRI Dues	(Note D & O)	p352-353	-	-

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Safety Related	Non-safety Related
	Directly Assigned A&G					
73	General Advertising Exp Account 930.1	(Note K & O)	p323.191b	2,125,000	-	2,125,000

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Education & Outreach	Other
	Directly Assigned A&G					
76	General Advertising Exp Account 930.1	(Note K & O)	p323.191b	2,125,000	-	2,125,000

Depreciation Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Depreciation Expense			
81	Depreciation-Transmission	(Note J & O)	p336.7.f	266,279,924
82	Depreciation-General & Common	(Note J & O)	p336.10&11.f	27,729,088
83	Depreciation-General Expense Associated with Acct. 397	(Note J & O)	Company Records	7,252,148
85	Depreciation-Intangible	(Note A & O)	p336.1.f	11,136,699
89	Transmission Depreciation Expense for Acct. 397	(Note J & O)	Company Records	1,908,451

Direct Assignment of Transmission Real Estate Taxes

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related	Non-Transmission
92	Real Estate Taxes - Directly Assigned to Transmission		p263.33i	21,308,000	7,881,000	13,427,000

PSE&G's real estate taxes detail is in an access database which contains a list of the towns PSE&G pays taxes to, which are billed on a quarterly basis for various parcels of property by major classification.
Every parcel is associated with a Lot & Block number. These Lot & Blocks are identified to a particular type of property and are labeled. This is the breakout of transmission real estate taxes from total electric.

Return \ Capitalization

Line #s	Descriptions	Notes	Page #'s & Instructions	2015 End of Year	2016 End of Year	Average
96	Proprietary Capital	(Note P)	p112.16.c,d	7,629,005,378	8,774,388,796	8,201,697,087
97	Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	1,227,004	816,474	1,021,739
99	Account 216.1	(Note P)	p119.53.c&d	3,474,616	3,187,722	3,331,169
101	Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	6,861,859,145	7,862,697,345	7,362,278,245
102	Loss on Reacquired Debt	(Note P)	p111.81.c,d	66,774,576	61,094,172	63,934,374
103	Gain on Reacquired Debt	(Note P)	p113.61.c,d	-	-	0
104	ADIT associated with Gain or Loss on Reacquired Debt	(Note P)	p277.3.k (footnote)	16,982,115	16,982,115	16,982,115
106	Preferred Stock	(Note P)	p112.3.c,d	-	-	0

MultiState Workpaper

Line #s	Descriptions	Notes	Page #'s & Instructions	State 1	State 2	State 3
	Income Tax Rates					
				NJ		
121	SIT=State Income Tax Rate or Composite	(Note I)		9.00%		

Amortized Investment Tax Credit

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
125	Amortized Investment Tax Credit	(Note O)	p266.8.f	561,000

Excluded Transmission Facilities

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average
141	Excluded Transmission Facilities	(Note B & M)		-	-	-	-	-	-	-	-	-	-	-	-	-	0

Interest on Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
147	Interest on Network Credits	(Note N & O)		-

Facility Credits under Section 30.9 of the PJM OATT

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Revenue Requirement			
163	Facility Credits under Section 30.9 of the PJM OATT			-

PJM Load Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	1 CP Peak
	Network Zonal Service Rate			
165	1 CP Peak	(Note L)	PJM Data	9,566.9

Abandoned Transmission Projects

Line #s		Descriptions		BRH Project	Project X	Project Y
	a	Beginning Balance of Unamortized Transmission Projects	Per FERC Order	$ -	$ -	$ -
Attachment 7	b	Years remaining in Amortization Period	Per FERC Order	$ -	$ -	$ -
81	c	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(line a / line b)	$ -	$ -	$ -
	d	Ending Balance of Unamortized Transmission Projects	(line a - line c)	$ -	$ -	$ -
	e	Average Balance of Unamortized Abandoned Transmission Projects	(line a + d)/2	$ -	$ -	$ -
	g	Non Incentive Return and Income Taxes	(Appendix A line 137+ line 138)	$ -	$ -	$ -
	h	Rate Base	(Appendix A line 58)	$ -	$ -	$ -
Attachment 7	i	Non Incentive Return and Income Taxes	(line g / line h)	-	-	-
		Docket No. ER12-2274-000 authorizing $3,500,000 amortization over one-year recovery of BRH Abandoned Transmission Project		ER12-2274		

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service - December 31, 2018

The True-Up Adjustment component of the Formula Rate for each Rate Year beginning with 2010 shall be determined as follows:

(i) Beginning with 2009, no later than June 15 of each year PSE&G shall recalculate an adjusted Annual Transmission Revenue Requirement for the previous calendar year based on its actual costs as reflected in its Form No. 1 and its books and records for that calendar year, consistent with FERC accounting policies. [2]

(ii) PSE&G shall determine the difference between the recalculated Annual Transmission Revenue Requirement as determined in paragraph (i) above, and ATRR based on projected costs for the previous calendar year (True-Up Adjustment Before Interest).

(iii) The True-Up Adjustment shall be determined as follows:

True-Up Adjustment equals the True-Up Adjustment Before Interest multiplied by (1+i)^24 months

Where: i = Sum of (the monthly rates for the 10 months ending October 31 of the current year and the monthly rates for the 12 months ending December 31 of the preceding year) divided by 21 months.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
July	2008	TO populates the formula with Year 2008 estimated data
October	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
October	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
October	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
October	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
October	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	2011	TO populates the formula with Year 2010 actual data and calculates the 2010 True-Up Adjustment Before Interest
October	2011	TO calculates the Interest to include in the 2010 True-Up Adjustment
October	2011	TO populates the formula with Year 2012 estimated data and 2010 True-Up Adjustment
June	2012	TO populates the formula with Year 2011 actual data and calculates the 2011 True-Up Adjustment Before Interest
October	2012	TO calculates the Interest to include in the 2011 True-Up Adjustment
October	2012	TO populates the formula with Year 2013 estimated data and 2011 True-Up Adjustment
June	2013	TO populates the formula with Year 2012 actual data and calculates the 2012 True-Up Adjustment Before Interest
October	2013	TO calculates the Interest to include in the 2012 True-Up Adjustment
October	2013	TO populates the formula with Year 2014 estimated data and 2012 True-Up Adjustment
June	2014	TO populates the formula with Year 2013 actual data and calculates the 2013 True-Up Adjustment Before Interest
October	2014	TO calculates the Interest to include in the 2013 True-Up Adjustment
October	2014	TO populates the formula with Year 2015 estimated data and 2013 True-Up Adjustment
June	2015	TO populates the formula with Year 2014 actual data and calculates the 2014 True-Up Adjustment Before Interest
October	2015	TO calculates the Interest to include in the 2014 True-Up Adjustment
October	2015	TO populates the formula with Year 2016 estimated data and 2014 True-Up Adjustment
June	2016	TO populates the formula with Year 2015 actual data and calculates the 2015 True-Up Adjustment Before Interest
October	2016	TO calculates the Interest to include in the 2015 True-Up Adjustment
October	2016	TO populates the formula with Year 2017 estimated data and 2015 True-Up Adjustment
June	2017	TO populates the formula with Year 2016 actual data and calculates the 2016 True-Up Adjustment Before Interest
October	2017	TO calculates the Interest to include in the 2016 True-Up Adjustment
October	2017	TO populates the formula with Year 2018 estimated data and 2016 True-Up Adjustment

Formula Rate was not in effect for 2006 or 2007.

[2] To the extent possible each input to the Formula Rate used to calculate the actual Annual Transmission Revenue Requirement included in the True-Up Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form 1 by the application of clearly identified and supported information. If the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

Calendar Year — Complete for Each Calendar Year beginning in 2009

A	ATRR based on actual costs included for the previous calendar year but excludes the true-up adjustment.	1,075,953,704	
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	1,064,228,952	
C	Difference (A-B)	11,724,752	<Note: for the first rate year, divide this reconciliation amount by 12 and multiply by the number of months and fractional months the rate was in effect.
D	Future Value Factor (1+i)^24	1.07393	
E	True-up Adjustment (C*D)	12,591,534	

Where:
i = average interest rate as calculated below

Interest on Amount of Refunds or Surcharges

Month	Yr	Month
January	Year 1	0.2800%
February	Year 1	0.2600%
March	Year 1	0.2800%
April	Year 1	0.2800%
May	Year 1	0.2900%
June	Year 1	0.2800%
July	Year 1	0.3000%
August	Year 1	0.3000%
September	Year 1	0.2900%
October	Year 1	0.3000%
November	Year 1	0.2900%
December	Year 1	0.3000%
January	Year 2	0.3000%
February	Year 2	0.2700%
March	Year 2	0.3000%
April	Year 2	0.3000%
May	Year 2	0.3200%
June	Year 2	0.3000%
July	Year 2	0.3400%
August	Year 2	0.3400%
September	Year 2	0.3300%
Average Interest Rate		0.2976%

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

	Estimated Additions - 2018												
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Other Projects PIS (monthly additions)	Ridge Road 69kV Breaker Station (B1255) (monthly additions)	Reconfigure Kearny- Loop in P2216 Ckt (B1589) (monthly additions)	Reconfigure Brunswick Sw- New 69kVCkt-T (B2146) (monthly additions)	350 MVAR Reactor Hopatcong 500kV (B2702) (monthly additions)	Mickleton-Gloucester-Camden(B1398-B1398.7) (monthly additions)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (monthly additions)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (monthly additions)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (monthly additions)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (monthly additions)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (monthly additions)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (monthly additions)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (monthly additions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
Dec-17	9,222,677,668	33,382,127	1,530,376	74,949,196	-	438,784,743	174,641,754	43,133,750	24,754,173	15,218,118	-	-	15,218,118
Jan	22,521,913	191,572	-	-	-	5,000	16,938	1,137	1,137	200,524	-	-	200,524
Feb	39,984,029	190,217	-	-	-	5,000	72,474	13,156,649	13,156,649	141,962,430	13,155,532	-	43,884
Mar	48,273,703	594,143	-	-	-	5,000	60,637	430,421	430,421	799,071	386,938	26,103,784	22,171
Apr	55,032,865	223,817	-	-	-	5,000	17,253	8,786,110	581,716	843,679	105,436,138	36,175,259	33,149,302
May	123,826,918	129,299	19,584,758	1,947,000	-	80,000	18,211	687,981	420,170	701,225	711,485	298,021	316,633
Jun	150,159,437	18,565	106,000	9,641,161	21,224,080	100,000	19,771	562,066	8,535,382	614,707	729,092	390,579	378,065
Jul	4,051,043	-	35,000	-	18,000	100,000	23,267	260,922	387,476	345,990	93,225	51,796	22,392
Aug	3,662,511	-	88,000	-	18,000	100,000	18,258	259,612	363,825	367,208	125,010	24,657	681
Sep	30,948,506	-	37,000	-	15,000	100,000	23,797	252,489	308,420	321,919	73,336	20,202	888
Oct	8,829,690	-	36,000	-	9,000	100,000	25,867	254,326	302,616	310,929	75,766	20,349	-
Nov	14,165,647	-	35,000	59,287,359	9,000	-	16,108	257,297	306,151	310,860	66,590	14,480	-
Dec	465,669,098	-	35,000	426,000	8,000	-	15,017	277,237	66,677	332,611	69,412	13,262	-
Total	**10,189,803,028**	**34,729,740**	**21,487,134**	**146,250,715**	**21,301,080**	**439,384,743**	**174,969,351**	**68,319,997**	**49,614,813**	**162,329,270**	**120,922,525**	**63,112,389**	**49,352,658**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Transmission Enhancement Charges (Before True-Up) - 2018

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
511,849,690	**1,901,999**	**772,843**	**8,279,691**	**2,099,946**	**2,665,229**	**2,568,254**	**1,570,839**	**686,810**	**2,101,858**	**2,697**	**946,750**	**2,154,499**

Actual Transmission Enhancement Charges - 2016

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
549,724,505	**2,293,690**	**930,448**	**9,968,442**	**2,528,394**	**3,208,097**	**3,110,954**	**1,890,650**	**826,705**	**2,529,913**	**3,247**	**1,139,246**	**2,592,387**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Reconciliation by Project (without interest)

	Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
	28,517,873	**(22,848)**	**(8,620)**	**(106,012)**	**(23,351)**	**(29,948)**	**(30,044)**	**(17,700)**	**(7,717)**	**(31,969)**	**(30)**	**(10,755)**	**(24,532)**
Interest		1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
30,626,128	**(24,537)**	**(9,257)**	**(113,849)**	**(25,077)**	**(32,162)**	**(32,265)**	**(19,009)**	**(8,287)**	**(34,332)**	**(32)**	**(11,550)**	**(26,346)**

Estimated Transmission Enhancement Charges (After True-Up) -2018

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
542,475,818	**1,877,462**	**763,586**	**8,165,842**	**2,074,869**	**2,633,067**	**2,535,989**	**1,551,830**	**678,523**	**2,067,526**	**2,664**	**935,200**	**2,128,153**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Additions - 2018													
(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (monthly additions)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (monthly additions	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (monthly additions)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (monthly additions)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (monthly additions)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (monthly additions)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (monthly additions)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (monthly additions)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (monthly additions)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (monthly additions)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (monthly additions)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (monthly additions)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(CWIP)
15,218,118	30,700,815	30,700,815	44,419,189	44,419,189	29,425,776	24,754,173	26,818,736	26,818,736	15,218,118	15,218,118	17,350,419	-	704,837
200,524	14,291,067	14,291,067	321,453	321,453	23,885	1,137	-	-	200,524	200,524	117,832	-	-
43,884	264,809	264,809	255,631	255,631	29,038	1,117	-	-	43,884	43,884	208,810	13,155,532	(50,196)
71,111,339	32,666	32,666	46,245	46,245	147,489	43,483	1,100	1,100	22,171	22,171	(1,607)	386,938	-
239,947	141,110	141,110	84,275	84,275	354,519	1,159	-	-	31,610	31,610	1,789,753	580,558	-
251,153	139,928	139,928	69,727	69,727	344,120	1,223	-	-	45,975	45,975	143,322	418,947	-
221,639	17,158	17,158	13,175	13,175	5,112,642	1,328	-	-	9,958	9,958	166,226	343,014	(654,641)
237,835	4,654	4,654	4,654	4,654	212,487	1,562	-	-	868	868	179,989	49,997	-
201,868	3,652	3,652	3,652	3,652	1,993,527	1,226	-	-	681	681	122,848	105,132	-
308,736	4,760	4,760	4,760	4,760	189,367	1,598	-	-	888	888	160,123	51,137	-
310,087	3,900	3,900	3,900	3,900	190,744	1,610	-	-	-	-	153,239	51,509	-
307,603	3,946	3,946	3,946	3,946	184,830	1,628	-	-	-	-	146,887	52,111	-
329,102	3,438	3,438	3,438	3,438	192,764	1,755	-	-	-	-	140,496	56,149	-
88,981,836	**45,611,902**	**45,611,902**	**45,234,044**	**45,234,044**	**38,401,188**	**24,812,999**	**26,819,837**	**26,819,837**	**15,574,675**	**15,574,675**	**20,678,337**	**15,251,024**	**0**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Transmission Enhancement Charges (Before True-Up) - 2018

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
2,237,137	**8,216,634**	**1,537,343**	**1,987,742**	**685,500**	**4,966,854**	**1,730,197**	**2,373,909**	**6,919,796**	**8,103,744**	**1,267,230**	**642,820**	**4,713,850**	**84,864,454**

Actual Transmission Enhancement Charges - 2016

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
2,691,625	**9,901,291**	**1,849,551**	**2,391,449**	**824,687**	**5,978,667**	**2,083,057**	**2,856,436**	**9,096,222**	**9,746,523**	**1,524,089**	**776,124**	**5,688,534**	**102,755,603**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Reconciliation by Project (without interest)

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
(25,540)	(517,088)	(17,589)	(22,732)	(7,964)	(59,384)	(80,284)	(69,701)	(147,778)	(85,367)	6,830	(7,274)	(53,963)	(1,059,483)

1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
(27,428)	(555,315)	(18,890)	(24,412)	(8,553)	(63,774)	(86,219)	(74,854)	(158,703)	(91,678)	7,335	(7,811)	(57,952)	(1,137,808)

Estimated Transmission Enhancement Charges (After True-Up) -2018

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
2,209,709	7,661,319	1,518,454	1,963,330	676,947	4,903,080	1,643,978	2,299,056	6,761,094	8,012,066	1,274,565	635,009	4,655,898	83,726,646

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Additions - 2018

(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)	(AR)	(AS)	(AT)		(AU)
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (monthly additions)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (monthly additions)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (monthly additions)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (monthly additions)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (monthly additions)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (monthly additions)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (monthly additions)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (monthly additions	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (monthly additions)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (monthly additions)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (monthly additions)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (monthly additions)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (monthly additions)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (monthly additions)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (monthly additions)				Ridge Road 69kV Breaker Station (B1255)
(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)				(in service)
15,873,514	14,614,183	133,132,128	103,234,243	53,061,761	27,376,832	59,546,744	1,074,767	1,034,193	1,703,883	13,549	763,249	763,249	16,545	16,545	25,613,549	12,374,116		**Dec-17**	9,222,677,668	33,382,127
652,831	(1,557,054)	1,815,939	1,055,192	509,173	686,858	657,991	(1,074,767)	(1,034,193)	330,990	-	-	-	-	-	(22,742,030)	85,192		**Jan**	22,521,913	33,573,699
(11,470,385)	(10,596,791)	(134,948,067)	(10,669,451)	1,210,747	1,145,475	319,400	-	-	131,819	1,113	(58,480)	(58,480)	(1,199)	(1,199)	264,924	(12,459,152)		**Feb**	39,984,029	33,763,916
1,295,284	1,599,104	-	288,524	(22,682,892)	312,521	(60,524,135)	-	-	754,485	-	-	-	-	-	(1,558,855)	-		**Mar**	48,273,703	34,358,059
(6,351,243)	624,357	-	(93,908,509)	(32,098,788)	(29,521,685)	-	-	-	804,726	-	-	-	-	-	(1,577,588)	-		**Apr**	55,032,865	34,581,876
-	307,672	-	-	-	-	-	-	-	710,942	-	-	-	-	-	-	-		**May**	123,826,918	34,711,175
-	(4,991,470)	-	-	-	-	-	-	-	(4,436,845)	(14,662)	(704,769)	(704,769)	(15,346)	(15,346)	-	(156)		**Jun**	150,159,437	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Jul**	4,051,043	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Aug**	3,662,511	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Sep**	30,948,506	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Oct**	8,829,690	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Nov**	14,165,647	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Dec**	465,669,098	34,729,740
(0)	**(0)**	**(0)**	**0**	**0**	**(0)**	**(0)**	**0**	**(0)**	**(0)**	**0**	**0**	**0**	**(0)**	**(0)**	**0**	**(0)**		**Total**	**10,189,803,028**	**447,479,030**
																		13 Month Average CWIP to Appendix A, line 45	**783,831,002**	**34,421,464** **12.88**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Transmission Enhancement Charges (Before True-Up) - 2018

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
39,257,924	**49,741,703**	**40,364,207**	**71,935,992**	**-**	**20,262,866**	**7,311,454**	**4,948,493**	**16,480,496**	**10,206,715**	**5,445,790**	**4,618,938**	**8,471,130**	**5,266,819**	**5,266,819**	**5,340,569**	**5,340,569**	**3,949,660**	**2,932,429**	**3,107,951**	**3,107,951**

Actual Transmission Enhancement Charges - 2016

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
47,233,422	**60,066,502**	**48,529,997**	**74,236,857**	**49,268,709**	**14,148,115**	**1,874,846**	**1,874,846**	**47,577**	**-**	**-**	**47,577**	**47,577**	**71,227**	**71,227**	**71,227**	**71,227**	**2,252,189**	**1,874,846**	**2,363,328**	**2,363,328**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Reconciliation by Project (without interest)

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
(241,416)	**1,274,783**	**(244,661)**	**(29,570,588)**	**49,268,709**	**2,507,949**	**394,617**	**394,617**	**47,577**	**-**	**-**	**47,577**	**47,577**	**71,227**	**71,227**	**71,227**	**71,227**	**204,949**	**394,615**	**464,535**	**464,535**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
(259,263)	**1,369,024**	**(262,749)**	**(31,756,668)**	**52,911,022**	**2,693,356**	**423,790**	**423,790**	**51,095**	**-**	**-**	**51,095**	**51,095**	**76,493**	**76,493**	**76,493**	**76,493**	**220,101**	**423,788**	**498,877**	**498,877**

Estimated Transmission Enhancement Charges (After True -Up) - 2018

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
38,998,661	**51,110,727**	**40,101,459**	**40,179,324**	**52,911,022**	**22,956,222**	**7,735,244**	**5,372,283**	**16,531,590**	**10,206,715**	**5,445,790**	**4,670,033**	**8,522,224**	**5,343,312**	**5,343,312**	**5,417,062**	**5,417,062**	**4,169,761**	**3,356,217**	**3,606,828**	**3,606,828**

Public Service Electric and Gas Company
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Estimated Additions - 2018

(AV)	(AW)	(AX)	(AY)	(AZ)	(BA)	(BB)	(BC)	(BD)	(BE)	(BF)	(BG)	(BH)	(BI)
Reconfigure Kearny- Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Mickleton-Gloucester-Camden(B1398-B1398.7)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
1,530,376	74,949,196	-	438,784,743	174,641,754	43,133,750	24,754,173	15,218,118	-	-	15,218,118	15,218,118	30,700,815	30,700,815
1,530,376	74,949,196	-	438,789,743	174,658,692	43,134,887	24,755,311	15,418,642	-	-	15,418,642	15,418,642	44,991,882	44,991,882
1,530,376	74,949,196	-	438,794,743	174,731,166	56,291,536	37,911,960	157,381,072	13,155,532	-	15,462,526	15,462,526	45,256,691	45,256,691
1,530,376	74,949,196	-	438,799,743	174,791,803	56,721,957	38,342,381	158,180,143	13,542,470	26,103,784	15,484,696	86,573,865	45,289,358	45,289,358
1,530,376	74,949,196	-	438,804,743	174,809,056	65,508,067	38,924,097	159,023,821	118,978,608	62,279,043	48,633,998	86,813,812	45,430,467	45,430,467
21,115,134	76,896,196	-	438,884,743	174,827,266	66,196,048	39,344,267	159,725,046	119,690,093	62,577,064	48,950,631	87,064,965	45,570,395	45,570,395
21,221,134	86,537,356	21,224,080	438,984,743	174,847,038	66,758,114	47,879,648	160,339,753	120,419,185	62,967,643	49,328,697	87,286,605	45,587,553	45,587,553
21,256,134	86,537,356	21,242,080	439,084,743	174,870,305	67,019,036	48,267,125	160,685,743	120,512,411	63,019,439	49,351,089	87,524,440	45,592,207	45,592,207
21,344,134	86,537,356	21,260,080	439,184,743	174,888,562	67,278,648	48,630,949	161,052,951	120,637,420	63,044,096	49,351,770	87,726,308	45,595,858	45,595,858
21,381,134	86,537,356	21,275,080	439,284,743	174,912,360	67,531,137	48,939,370	161,374,870	120,710,757	63,064,298	49,352,658	88,035,044	45,600,618	45,600,618
21,417,134	86,537,356	21,284,080	439,384,743	174,938,226	67,785,463	49,241,985	161,685,799	120,786,523	63,084,647	49,352,658	88,345,131	45,604,518	45,604,518
21,452,134	145,824,715	21,293,080	439,384,743	174,954,334	68,042,760	49,548,136	161,996,659	120,853,113	63,099,127	49,352,658	88,652,734	45,608,464	45,608,464
21,487,134	146,250,715	21,301,080	439,384,743	174,969,351	68,319,997	49,614,813	162,329,270	120,922,525	63,112,389	49,352,658	88,981,836	45,611,902	45,611,902
178,325,947	**1,176,404,387**	**148,879,560**	**5,707,551,661**	**2,272,839,913**	**803,721,399**	**546,154,215**	**1,794,411,887**	**1,110,208,636**	**592,351,530**	**504,610,798**	**923,104,026**	**576,440,730**	**576,440,730**
13,717,381	**90,492,645**	**11,452,274**	**439,042,435**	**174,833,839**	**61,824,723**	**42,011,863**	**138,031,684**	**85,400,664**	**45,565,502**	**38,816,215**	**71,008,002**	**44,341,595**	**44,341,595**
8.30	**8.04**	**6.99**	**12.99**	**12.99**	**11.76**	**11.01**	**11.05**	**9.18**	**9.39**	**10.22**	**10.37**	**12.64**	**12.64**

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Estimated Transmission Enhancement Charges (Before True-Up) - 2018														
New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
1,835,238	**1,835,212**	**2,226,613**	**1,479,264**	**1,368,849**	**2,193,902**	**4,116,007**	**3,664,036**	**129,905**	**1,639,441**	**10,815,286**	**1,368,726**	**-**	**-**

							Actual Transmission Enhancement Charges - 2016						
New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
25,899	**27,513**	**141,823**	**-**	**1,646,241**	**2,637,556**	**556,391**	**4,451,390**	**153,181**	**-**	**-**	**-**	**-**	**-**

Public Service Electric and Gas Company
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Reconciliation by Project (without interest)

New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
25,899	**27,513**	**141,823**	**-**	**(7,964)**	**112,364**	**(2,251,480)**	**325,597**	**153,181**	**-**	**-**	**-**	**-**	**-**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
27,813	**29,547**	**152,308**	**-**	**(8,552)**	**120,671**	**(2,417,927)**	**349,668**	**164,506**	**-**	**-**	**-**	**-**	**-**

Estimated Transmission Enhancement Charges (After True -Up)- 2018

New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
1,863,051	**1,864,759**	**2,378,921**	**1,479,264**	**1,360,297**	**2,314,572**	**1,698,080**	**4,013,704**	**294,411**	**1,639,441**	**10,815,286**	**1,368,726**	**-**	**-**

Public Service Electric and Gas Company
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Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Additions - 2018

(BJ)	(BK)	(BL)	(BM)	(BN)	(BO)	(BP)	(BQ)	(BR)	(BS)	(BT)	(BU)	(BV)	(BW)
Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(CWIP)	(CWIP)	(CWIP)	(CWIP)
44,419,189	44,419,189	29,425,776	24,754,173	26,818,736	26,818,736	15,218,118	15,218,118	17,350,419	-	704,837	15,873,514	14,614,183	133,132,128
44,740,642	44,740,642	29,449,661	24,755,311	26,818,736	26,818,736	15,418,642	15,418,642	17,468,251	-	704,837	16,526,345	13,057,129	134,948,067
44,996,273	44,996,273	29,478,699	24,756,428	26,818,736	26,818,736	15,462,526	15,462,526	17,677,062	13,155,532	654,641	5,055,960	2,460,338	(0)
45,042,518	45,042,518	29,626,188	24,799,911	26,819,837	26,819,837	15,484,696	15,484,696	17,675,454	13,542,470	654,641	6,351,244	4,059,442	(0)
45,126,793	45,126,793	29,980,708	24,801,069	26,819,837	26,819,837	15,516,306	15,516,306	19,465,207	14,123,028	654,641	(0)	4,683,799	(0)
45,196,520	45,196,520	30,324,827	24,802,292	26,819,837	26,819,837	15,562,281	15,562,281	19,608,529	14,541,974	654,641	(0)	4,991,471	(0)
45,209,694	45,209,694	35,437,469	24,803,620	26,819,837	26,819,837	15,572,239	15,572,239	19,774,755	14,884,989	0	(0)	(0)	(0)
45,214,348	45,214,348	35,649,956	24,805,182	26,819,837	26,819,837	15,573,107	15,573,107	19,954,744	14,934,986	0	(0)	(0)	(0)
45,218,000	45,218,000	37,643,482	24,806,408	26,819,837	26,819,837	15,573,788	15,573,788	20,077,592	15,040,118	0	(0)	(0)	(0)
45,222,759	45,222,759	37,832,849	24,808,006	26,819,837	26,819,837	15,574,675	15,574,675	20,237,715	15,091,255	0	(0)	(0)	(0)
45,226,660	45,226,660	38,023,594	24,809,616	26,819,837	26,819,837	15,574,675	15,574,675	20,390,954	15,142,764	0	(0)	(0)	(0)
45,230,605	45,230,605	38,208,424	24,811,244	26,819,837	26,819,837	15,574,675	15,574,675	20,537,842	15,194,875	0	(0)	(0)	(0)
45,234,044	45,234,044	38,401,188	24,812,999	26,819,837	26,819,837	15,574,675	15,574,675	20,678,337	15,251,024	0	(0)	(0)	(0)
586,078,044	**586,078,044**	**439,482,822**	**322,326,260**	**348,654,574**	**348,654,574**	**201,680,405**	**201,680,405**	**250,896,862**	**160,903,014**	**4,028,239**	**43,807,061**	**43,866,358**	**268,080,194**
45,082,926	**45,082,926**	**33,806,371**	**24,794,328**	**26,819,583**	**26,819,583**	**15,513,877**	**15,513,877**	**19,299,759**	**12,377,155**				
12.96	**12.96**	**11.44**	**12.99**	**13.00**	**13.00**	**12.95**	**12.95**	**12.13**	**10.55**	**13.00**	**13.00**	**13.00**	**13.00**
										309,865	**3,369,774**	**3,374,335**	**20,621,553**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Transmission Enhancement Charges (Before True-Up) - 2018													
North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	**-**	**-**	**-**	**-**	**-**	**-**	**31,344**	**322,857**	**419,841**	**1,976,705**	**2,908,909**	**1,425,414**	**841,713**

							Actual Transmission Enhancement Charges - 2016						
North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	**-**	**-**	**-**	**-**	**11,982,038**	**4,104,014**	**5,126,158**	**857,240**	**921,870**	**3,473,891**	**1,695,242**	**1,011,439**	**749,927**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Reconciliation by Project (without interest)

North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	**-**	**-**	**-**	**-**	**3,522,083**	**3,748,178**	**(700,564)**	**(569,315)**	**(143,008)**	**586,708**	**59,227**	**(538,073)**	**(257,986)**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	**-**	**-**	**-**	**-**	**3,782,462**	**4,025,272**	**(752,355)**	**(611,403)**	**(153,580)**	**630,082**	**63,605**	**(577,852)**	**(277,058)**

Estimated Transmission Enhancement Charges (After True-Up) - 2018

North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	**-**	**-**	**-**	**-**	**3,782,462**	**4,025,272**	**(721,012)**	**(288,547)**	**266,261**	**2,606,787**	**2,972,515**	**847,562**	**564,655**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

(BX)	(BY)	(BZ)	(CA)	(CB)	(CC)	(CD)	(CE)	(CF)	(CG)	(CH)	(CI)	(CJ)	(CK)
Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (monthly additions)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (monthly additions)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (monthly additions)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (monthly additions)
(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)
103,234,243	53,061,761	27,376,832	59,546,744	1,074,767	1,034,193	1,703,883	13,549	763,249	763,249	16,545	16,545	25,613,549	12,374,116
104,289,435	53,570,934	28,063,690	60,204,735	0	(0)	2,034,872	13,549	763,249	763,249	16,545	16,545	2,871,520	12,459,308
93,619,985	54,781,681	29,209,165	60,524,134	0	(0)	2,166,691	14,662	704,769	704,769	15,346	15,346	3,136,443	156
93,908,509	32,098,788	29,521,686	(0)	0	(0)	2,921,177	14,662	704,769	704,769	15,346	15,346	1,577,588	156
0	0	(0)	(0)	0	(0)	3,725,903	14,662	704,769	704,769	15,346	15,346	0	156
0	0	(0)	(0)	0	(0)	4,436,845	14,662	704,769	704,769	15,346	15,346	0	156
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
395,052,176	**193,513,166**	**114,171,370**	**180,275,609**	**1,074,771**	**1,034,189**	**16,989,371**	**85,746**	**4,345,571**	**4,345,571**	**94,474**	**94,474**	**33,199,102**	**24,834,045**
13.00	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**
30,388,629	**14,885,628**	**8,782,413**	**13,867,355**	**82,675**	**79,553**	**1,306,875**	**6,596**	**334,275**	**334,275**	**7,267**	**7,267**	**2,553,777**	**1,910,311**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Transmission Enhancement Charges (Before True-Up) - 2018												
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
1,328,392	**8,046**	**7,738**	**-**	**-**	**136,075**	**702**	**33,744**	**33,744**	**735**	**735**	**160,162**	**183,255**

							Actual Transmission Enhancement Charges - 2016					
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
2,311,095	**1,295,020**	**1,295,020**	**1,342,797**	**1,342,797**	**868,195**	**704,952**	**908,856**	**915,296**	**597,380**	**597,124**	**2,125,894**	**157,609**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Reconciliation by Project (without interest)

Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
517,581	**175,506**	**175,506**	**66,363**	**66,363**	**(213,626)**	**(158,798)**	**(417,851)**	**(408,383)**	**(41,915)**	**(42,254)**	**1,274,130**	**11,628**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
555,844	**188,481**	**188,481**	**71,269**	**71,269**	**(229,419)**	**(170,537)**	**(448,742)**	**(438,574)**	**(45,014)**	**(45,378)**	**1,368,323**	**12,488**

Estimated Transmission Enhancement Charges (After True -Up) - 2018

Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
1,884,236	**196,527**	**196,218**	**71,269**	**71,269**	**(93,344)**	**(169,836)**	**(414,998)**	**(404,830)**	**(44,279)**	**(44,643)**	**1,528,485**	**195,743**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 **For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the**
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)
10		Details		**Branchburg (B0130)**	**Kittatinny (B0134)**	**Essex Aldene (B0145)**	**New Freedom Trans.(B0411)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		20,645,602	8,069,022	86,467,721	22,188,863
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		491,562	192,120	2,058,755	528,306
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2006	2007	2007	2007

		Invest Yr												
21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006	20,680,597	492,395	4,652,471									
23	W Increased ROE	2006	20,680,597	492,395	4,652,471									
24	W 11.68 % ROE	2007	20,188,202	492,395	4,553,422	8,069,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757
25	W Increased ROE	2007	20,188,202	492,395	4,553,422	8,069,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757
26	W 11.68 % ROE	2008	19,695,807	492,395	4,454,372	7,988,972	192,120	1,799,169	85,706,843	2,061,086	19,301,739	21,704,582	528,306	4,894,366
27	W Increased ROE	2008	19,695,807	492,395	4,454,372	7,988,972	192,120	1,799,169	85,706,843	2,061,086	19,301,739	21,704,582	528,306	4,894,366
28	W 11.68 % ROE	2009	19,203,412	492,395	4,523,234	7,796,853	192,120	1,828,696	83,645,756	2,061,086	19,618,517	21,176,276	528,306	4,973,254
29	W Increased ROE	2009	19,203,412	492,395	4,523,234	7,796,853	192,120	1,828,696	83,645,756	2,061,086	19,618,517	21,176,276	528,306	4,973,254
30	W 11.68 % ROE	2010	18,711,016	492,395	4,095,968	7,604,733	192,120	1,656,722	81,584,670	2,061,086	17,773,557	20,647,970	528,306	4,504,919
31	W Increased ROE	2010	18,711,016	492,395	4,095,968	7,604,733	192,120	1,656,722	81,584,670	2,061,086	17,773,557	20,647,970	528,306	4,504,919
32	W 11.68 % ROE	2011	18,218,621	492,395	3,746,858	7,412,613	192,120	1,516,263	79,523,584	2,061,086	16,266,692	20,119,663	528,306	4,122,360
33	W Increased ROE	2011	18,218,621	492,395	3,746,858	7,412,613	192,120	1,516,263	79,523,584	2,061,086	16,266,692	20,119,663	528,306	4,122,360
34	W 11.68 % ROE	2012	17,726,226	492,395	3,154,416	7,220,494	192,120	1,276,451	77,462,497	2,061,086	13,693,952	19,591,357	528,306	3,470,422
35	W Increased ROE	2012	17,726,226	492,395	3,154,416	7,220,494	192,120	1,276,451	77,462,497	2,061,086	13,693,952	19,591,357	528,306	3,470,422
36	W 11.68 % ROE	2013	17,233,831	492,395	2,886,756	7,028,374	192,120	1,168,598	75,401,411	2,061,086	12,536,886	19,063,051	528,306	3,176,807
37	W Increased ROE	2013	17,233,831	492,395	2,886,756	7,028,374	192,120	1,168,598	75,401,411	2,061,086	12,536,886	19,063,051	528,306	3,176,807
38	W 11.68 % ROE	2014	16,741,436	492,395	2,555,172	6,836,255	192,120	1,034,441	73,340,324	2,061,086	11,097,629	18,534,745	528,306	2,812,043
39	W Increased ROE	2014	16,741,436	492,395	2,555,172	6,836,255	192,120	1,034,441	73,340,324	2,061,086	11,097,629	18,534,745	528,306	2,812,043
40	W 11.68 % ROE	2015	16,249,041	492,395	2,397,208	6,644,135	192,120	970,986	71,279,238	2,061,086	10,416,881	18,006,439	528,306	2,639,133
41	W Increased ROE	2015	16,249,041	492,395	2,397,208	6,644,135	192,120	970,986	71,279,238	2,061,086	10,416,881	18,006,439	528,306	2,639,133
42	W 11.68 % ROE	2016	15,743,650	492,086	2,293,690	6,452,016	192,120	930,448	69,120,244	2,058,755	9,968,442	17,478,132	528,306	2,528,394
43	W Increased ROE	2016	15,743,650	492,086	2,293,690	6,452,016	192,120	930,448	69,120,244	2,058,755	9,968,442	17,478,132	528,306	2,528,394
44	W 11.68 % ROE	2017	15,264,250	492,395	2,176,785	6,259,896	192,120	882,891	67,157,065	2,061,086	9,471,779	16,949,826	528,306	2,398,697
45	W Increased ROE	2017	15,264,250	492,395	2,176,785	6,259,896	192,120	882,891	67,157,065	2,061,086	9,471,779	16,949,826	528,306	2,398,697
46	W 11.68 % ROE	2018	14,737,169	491,562	1,901,999	6,067,776	192,120	772,843	65,000,402	2,058,755	8,279,691	16,421,520	528,306	2,099,946
47	W Increased ROE	2018	14,737,169	491,562	1,901,999	6,067,776	192,120	772,843	65,000,402	2,058,755	8,279,691	16,421,520	528,306	2,099,946

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

			Formula Line		
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
3		A	152	Net Plant Carrying Charge without Depreciation	9.57%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5		C		Line B less Line A	0.57%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

		Details		New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		27,005,248	25,654,455	15,731,554	6,961,495
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		642,982	610,820	374,561	165,750
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2008	2009	2009	2008

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008	24,921,237	88,646	837,584							6,961,495	25,372	239,734
27	W Increased ROE	2008	24,921,237	88,646	837,584							6,961,495	25,372	239,734
28	W 11.68 % ROE	2009	26,916,602	642,982	6,292,837	19,700,217	288,478	2,831,673	15,773,880	234,561	2,302,423	6,936,122	165,750	1,621,657
29	W Increased ROE	2009	26,916,602	642,982	6,292,837	19,700,217	288,478	2,831,673	15,773,880	234,561	2,302,423	6,936,122	165,750	1,621,657
30	W 11.68 % ROE	2010	26,273,620	642,982	5,703,044	25,488,527	613,738	5,522,598	15,539,319	375,568	3,368,301	6,770,372	165,750	1,469,662
31	W Increased ROE	2010	26,273,620	642,982	5,703,044	25,488,527	613,738	5,522,598	15,539,319	375,568	3,368,301	6,770,372	165,750	1,469,662
32	W 11.68 % ROE	2011	25,630,832	642,987	5,221,521	24,896,838	614,263	5,061,682	15,121,425	374,561	3,075,759	6,604,623	165,750	1,345,559
33	W Increased ROE	2011	25,630,832	642,987	5,221,521	24,896,838	614,263	5,061,682	15,121,425	374,561	3,075,759	6,604,623	165,750	1,345,559
34	W 11.68 % ROE	2012	24,987,652	642,982	4,395,482	24,282,576	614,263	4,260,879	14,746,864	374,561	2,589,159	6,438,873	165,750	1,132,702
35	W Increased ROE	2012	24,987,652	642,982	4,395,482	24,282,576	614,263	4,260,879	14,746,864	374,561	2,589,159	6,438,873	165,750	1,132,702
36	W 11.68 % ROE	2013	24,344,669	642,982	4,025,278	23,668,312	614,263	3,902,590	14,372,303	374,561	2,371,359	6,273,123	165,750	1,037,298
37	W Increased ROE	2013	24,344,669	642,982	4,025,278	23,668,312	614,263	3,902,590	14,372,303	374,561	2,371,359	6,273,123	165,750	1,037,298
38	W 11.68 % ROE	2014	23,701,687	642,982	3,563,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
39	W Increased ROE	2014	23,701,687	642,982	3,563,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
40	W 11.68 % ROE	2015	23,058,705	642,982	3,346,067	22,439,786	614,263	3,244,794	13,623,182	374,561	1,971,555	5,941,623	165,750	862,264
41	W Increased ROE	2015	23,058,705	642,982	3,346,067	22,439,786	614,263	3,244,794	13,623,182	374,561	1,971,555	5,941,623	165,750	862,264
42	W 11.68 % ROE	2016	22,415,723	642,982	3,208,097	21,819,123	614,111	3,110,954	13,248,621	374,561	1,890,650	5,775,874	165,750	826,705
43	W Increased ROE	2016	22,415,723	642,982	3,208,097	21,819,123	614,111	3,110,954	13,248,621	374,561	1,890,650	5,775,874	165,750	826,705
44	W 11.68 % ROE	2017	21,772,741	642,982	3,045,575	21,211,259	614,263	2,954,897	12,874,060	374,561	1,795,196	5,610,124	165,750	784,820
45	W Increased ROE	2017	21,772,741	642,982	3,045,575	21,211,259	614,263	2,954,897	12,874,060	374,561	1,795,196	5,610,124	165,750	784,820
46	W 11.68 % ROE	2018	21,129,759	642,982	2,665,229	20,452,549	610,820	2,568,254	12,499,499	374,561	1,570,839	5,444,374	165,750	686,810
47	W Increased ROE	2018	21,129,759	642,982	2,665,229	20,452,549	610,820	2,568,254	12,499,499	374,561	1,570,839	5,444,374	165,750	686,810

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Roseland Transformers (B0274)			Wave Trap Branchburg (B0172.2)			Reconductor Hudson - South Waterfront (B0813)			Reconductor South Mahwah J-3410 Circuit (B1017)		
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%			9.57%			9.57%			9.57%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%			9.57%			9.57%			9.57%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,014,433			27,988			9,158,918			20,626,991		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		500,344			666			218,069			491,119		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2009			2008			2010			2011		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008				36,369	577	5,114						
27		W Increased ROE	2008				36,369	577	5,114						
28		W 11.68 % ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379						
29		W Increased ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379						
30		W 11.68 % ROE	2010	20,797,967	501,579	4,507,079	27,122	666	5,890	8,806,222	18,700	169,959			
31		W Increased ROE	2010	20,797,967	501,579	4,507,079	27,122	666	5,890	8,806,222	18,700	169,959			
32		W 11.68 % ROE	2011	20,302,520	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,623,951	300,198	2,435,793
33		W Increased ROE	2011	20,302,520	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,623,951	300,198	2,435,793
34		W 11.68 % ROE	2012	19,802,055	501,755	3,475,512	25,212	666	4,453	8,922,149	218,069	1,557,946	20,326,793	491,119	3,543,678
35		W Increased ROE	2012	19,802,055	501,755	3,475,512	25,212	666	4,453	8,922,149	218,069	1,557,946	20,326,793	491,119	3,543,678
36		W 11.68 % ROE	2013	19,300,300	501,755	3,183,218	24,546	666	4,077	8,704,079	218,069	1,427,360	19,835,674	491,119	3,246,963
37		W Increased ROE	2013	19,300,300	501,755	3,183,218	24,546	666	4,077	8,704,079	218,069	1,427,360	19,835,674	491,119	3,246,963
38		W 11.68 % ROE	2014	18,798,545	501,755	2,817,996	23,880	666	3,609	8,486,010	218,069	1,263,663	19,344,555	491,119	2,874,636
39		W Increased ROE	2014	18,798,545	501,755	2,817,996	23,880	666	3,609	8,486,010	218,069	1,263,663	19,344,555	491,119	2,874,636
40		W 11.68 % ROE	2015	18,296,790	501,755	2,646,618	23,213	666	3,388	8,267,940	218,069	1,187,289	18,853,437	491,119	2,701,236
41		W Increased ROE	2015	18,296,790	501,755	2,646,618	23,213	666	3,388	8,267,940	218,069	1,187,289	18,853,437	491,119	2,701,236
42		W 11.68 % ROE	2016	17,735,762	500,344	2,529,913	22,547	666	3,247	8,049,871	218,069	1,139,246	18,362,318	491,119	2,592,387
43		W Increased ROE	2016	17,735,762	500,344	2,529,913	22,547	666	3,247	8,049,871	218,069	1,139,246	18,362,318	491,119	2,592,387
44		W 11.68 % ROE	2017	17,293,281	501,755	2,410,045	21,880	666	3,081	7,831,801	218,069	1,082,298	17,871,199	491,119	2,463,182
45		W Increased ROE	2017	17,293,281	501,755	2,410,045	21,880	666	3,081	7,831,801	218,069	1,082,298	17,871,199	491,119	2,463,182
46		W 11.68 % ROE	2018	16,733,664	500,344	2,101,858	21,214	666	2,697	7,613,732	218,069	946,750	17,380,080	491,119	2,154,499
47		W Increased ROE	2018	16,733,664	500,344	2,101,858	21,214	666	2,697	7,613,732	218,069	946,750	17,380,080	491,119	2,154,499

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
		Formula Line			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%	
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%	
5	C		Line B less Line A	0.57%	
6	**FCR if a CIAC**				
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%	

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Reconductor South Mahwah K-3411 Circuit (B1018)			Branchburg 400 MVAR Capacitor (B0290)			Saddle Brook - Athenia Upgrade Cable (B0472)			Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)		
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%			9.57%			9.57%			9.57%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%			9.57%			9.57%			9.57%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,170,273			77,352,830			14,404,842			18,664,931		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		504,054			1,841,734			342,972			444,403		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2011			2012			2012			2012		
21			Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011	20,511,158	37,566	284,735									
33		W Increased ROE	2011	20,511,158	37,566	284,735									
34		W 11.68 % ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
35		W Increased ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
36		W 11.68 % ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
37		W Increased ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
38		W 11.68 % ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
39		W Increased ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
40		W 11.68 % ROE	2015	19,620,544	504,054	2,804,096	75,364,829	1,915,127	10,749,859	13,508,484	342,972	1,926,521	17,459,022	444,403	2,491,058
41		W Increased ROE	2015	19,620,544	504,054	2,804,096	75,364,829	1,915,127	10,749,859	13,508,484	342,972	1,926,521	17,459,022	444,403	2,491,058
42		W 11.68 % ROE	2016	19,116,490	504,054	2,691,625	70,419,117	1,842,970	9,901,291	13,165,512	342,972	1,849,551	17,014,619	444,403	2,391,449
43		W Increased ROE	2016	19,116,490	504,054	2,691,625	70,419,117	1,842,970	9,901,291	13,165,512	342,972	1,849,551	17,014,619	444,403	2,391,449
44		W 11.68 % ROE	2017	18,612,436	504,054	2,557,912	71,534,576	1,915,127	9,808,871	12,822,540	342,972	1,757,923	16,570,216	444,403	2,272,904
45		W Increased ROE	2017	18,612,436	504,054	2,557,912	71,534,576	1,915,127	9,808,871	12,822,540	342,972	1,757,923	16,570,216	444,403	2,272,904
46		W 11.68 % ROE	2018	18,108,382	504,054	2,237,137	66,609,121	1,841,734	8,216,634	12,479,567	342,972	1,537,343	16,125,813	444,403	1,987,742
47		W Increased ROE	2018	18,108,382	504,054	2,237,137	66,609,121	1,841,734	8,216,634	12,479,567	342,972	1,537,343	16,125,813	444,403	1,987,742

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if if not a CIAC**

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		6,390,403	46,035,637	15,865,267	21,736,918
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		152,152	1,096,087	377,744	517,546
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2012	2012	2011	2013

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011							2,640,253	9,537	73,000			
33	W Increased ROE	2011							2,640,253	9,537	73,000			
34	W 11.68 % ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
35	W Increased ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
36	W 11.68 % ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
37	W Increased ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
38	W 11.68 % ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
39	W Increased ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
40	W 11.68 % ROE	2015	6,029,218	152,152	858,935	43,772,546	1,096,982	6,228,271	15,276,916	378,019	2,168,874	21,267,327	524,777	3,017,865
41	W Increased ROE	2015	6,029,218	152,152	858,935	43,772,546	1,096,982	6,228,271	15,276,916	378,019	2,168,874	21,267,327	524,777	3,017,865
42	W 11.68 % ROE	2016	5,877,066	152,152	824,687	42,662,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
43	W Increased ROE	2016	5,877,066	152,152	824,687	42,662,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
44	W 11.68 % ROE	2017	5,724,913	152,152	783,889	41,578,581	1,096,982	5,685,123	14,510,533	378,022	1,979,240	20,217,772	524,777	2,755,781
45	W Increased ROE	2017	5,724,913	152,152	783,889	41,578,581	1,096,982	5,685,123	14,510,533	378,022	1,979,240	20,217,772	524,777	2,755,781
46	W 11.68 % ROE	2018	5,572,761	152,152	685,500	40,444,309	1,096,087	4,966,854	14,131,308	377,744	1,730,197	19,396,499	517,546	2,373,909
47	W Increased ROE	2018	5,572,761	152,152	685,500	40,444,309	1,096,087	4,966,854	14,131,308	377,744	1,730,197	19,396,499	517,546	2,373,909

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

Line		Formula Line	Description	
1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	125
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	10.28%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		62,937,256	72,380,453	11,276,183	5,857,687
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,498,506	1,723,344	268,481	139,469
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2013	2014	2014	2010

Line		Invest Yr	B1155 Ending	B1155 Depreciation or Amortization	B1155 Revenue	B1399 Ending	B1399 Depreciation or Amortization	B1399 Revenue	B1590 Ending	B1590 Depreciation or Amortization	B1590 Revenue	b0489.5-B0489.15 Ending	b0489.5-B0489.15 Depreciation or Amortization	b0489.5-B0489.15 Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010										2,662,585	7,802	70,915
31	W Increased ROE	2010										2,662,585	7,802	70,915
32	W 11.68 % ROE	2011										5,849,885	116,061	966,188
33	W Increased ROE	2011										5,849,885	116,061	1,014,845
34	W 11.68 % ROE	2012										5,733,823	139,469	1,000,541
35	W Increased ROE	2012										5,733,823	139,469	1,051,531
36	W 11.68 % ROE	2013	20,876,286	101,812	695,908							5,594,354	139,469	916,713
37	W Increased ROE	2013	20,876,286	101,812	695,908							5,594,354	139,469	967,047
38	W 11.68 % ROE	2014	60,374,269	1,439,907	8,878,852	68,405,611	556,909	3,438,903	7,389,782	37,992	234,599	5,454,886	139,469	811,586
39	W Increased ROE	2014	60,374,269	1,439,907	8,878,852	68,405,611	556,909	3,438,903	7,389,782	37,992	234,599	5,454,886	139,469	859,361
40	W 11.68 % ROE	2015	61,346,085	1,497,329	8,688,697	71,213,315	1,708,815	10,056,881	11,126,578	265,823	1,570,150	5,315,417	139,469	762,575
41	W Increased ROE	2015	61,346,085	1,497,329	8,688,697	71,213,315	1,708,815	10,056,881	11,126,578	265,823	1,570,150	5,315,417	139,469	808,174
42	W 11.68 % ROE	2016	65,275,261	1,626,531	9,096,222	70,112,484	1,723,291	9,746,523	10,972,368	268,481	1,524,089	5,175,948	139,469	731,772
43	W Increased ROE	2016	65,275,261	1,626,531	9,096,222	70,112,484	1,723,291	9,746,523	10,972,368	268,481	1,524,089	5,175,948	139,469	776,124
44	W 11.68 % ROE	2017	63,648,517	1,626,495	8,650,024	68,474,262	1,724,855	9,280,898	10,705,213	268,300	1,449,606	5,036,479	139,469	695,238
45	W Increased ROE	2017	63,648,517	1,626,495	8,650,024	68,474,262	1,724,855	9,280,898	10,705,213	268,300	1,449,606	5,036,479	139,469	737,976
46	W 11.68 % ROE	2018	56,645,182	1,498,506	6,919,796	66,666,584	1,723,344	8,103,744	10,435,588	268,481	1,267,230	4,897,011	139,469	608,143
47	W Increased ROE	2018	56,645,182	1,498,506	6,919,796	66,666,584	1,723,344	8,103,744	10,435,588	268,481	1,267,230	4,897,011	139,469	642,820

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

Line		Formula Line		
1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)	Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		125	125	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.28%	10.28%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		40,538,248	720,620,844	356,333,540	439,384,743
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		965,196	17,157,639	8,484,132	10,461,542
19	Months in service for depreciation expense from			13.00	13.00	13.00	12.99
20	Year placed in Service (0 if CWIP)			2011	2012	2011	2013

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011	7,844,331	111,778	905,525				19,902,939	147,204	1,150,144			
33	W Increased ROE	2011	7,844,331	111,778	952,449				19,902,939	147,204	1,150,144			
34	W 11.68 % ROE	2012	7,628,074	184,491	1,331,330	4,694,511	8,598	62,828	19,848,511	475,501	3,452,558			
35	W Increased ROE	2012	7,628,074	184,491	1,399,243	4,694,511	8,598	66,040	19,848,511	475,501	3,452,558			
36	W 11.68 % ROE	2013	6,391,895	159,242	1,047,292	25,426,870	605,606	4,138,257	118,115,741	2,827,106	19,237,368	777,714	1,424	9,736
37	W Increased ROE	2013	6,391,895	159,242	1,104,801	25,426,870	605,606	4,367,027	118,115,741	2,827,106	19,237,368	777,714	1,424	9,736
38	W 11.68 % ROE	2014	40,082,737	717,210	4,387,056	666,963,000	10,160,548	62,692,814	333,325,376	6,107,990	37,392,933	83,696,796	854,944	5,279,191
39	W Increased ROE	2014	40,082,737	717,210	4,647,913	666,963,000	10,160,548	66,426,879	333,325,376	6,107,990	37,392,933	83,696,796	854,944	5,279,191
40	W 11.68 % ROE	2015	39,365,526	965,196	5,579,868	711,440,230	16,714,518	97,780,708	346,271,067	8,256,393	47,814,854	436,685,203	6,739,741	39,857,912
41	W Increased ROE	2015	39,365,526	965,196	5,917,569	711,440,230	16,714,518	103,713,135	346,271,067	8,256,393	47,814,854	436,685,203	6,739,741	39,857,912
42	W 11.68 % ROE	2016	38,400,330	965,196	5,359,489	694,520,844	17,213,677	96,796,429	338,712,254	8,485,957	47,233,422	430,951,154	10,495,692	60,066,502
43	W Increased ROE	2016	38,400,330	965,196	5,688,534	694,520,844	17,213,677	102,755,603	338,712,254	8,485,957	47,233,422	430,951,154	10,495,692	60,066,502
44	W 11.68 % ROE	2017	37,435,134	965,196	5,096,113	678,154,289	17,211,186	92,044,606	330,265,484	8,488,706	44,933,061	421,661,646	10,462,931	56,992,730
45	W Increased ROE	2017	37,435,134	965,196	5,413,780	678,154,289	17,211,186	97,799,286	330,265,484	8,488,706	44,933,061	421,661,646	10,462,931	56,992,730
46	W 11.68 % ROE	2018	36,469,937	965,196	4,455,592	658,706,710	17,157,639	80,199,899	321,544,683	8,484,132	39,257,924	410,830,010	10,453,391	49,741,703
47	W Increased ROE	2018	36,469,937	965,196	4,713,850	658,706,710	17,157,639	84,864,454	321,544,683	8,484,132	39,257,924	410,830,010	10,453,391	49,741,703

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

Line					
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.57%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5		C		Line B less Line A	0.57%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**North Central Reliability (West Orange Conversion (B1154)**	**Northeast Grid Reliability Project (B1304.1-B1304.4)**	**Northeast Grid Reliability Project (B1304.5-B1304.21)**	**Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)**
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	25	25	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.71%	9.71%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		370,006,995	625,390,228	-	174,969,351
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,809,690	14,890,244	-	4,165,937
19	Months in service for depreciation expense from			13.00	13.00		12.99
20	Year placed in Service (0 if CWIP)			2012	2013	2016	2016

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21														
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012	16,441,748	30,113	220,046									
35	W Increased ROE	2012	16,441,748	30,113	220,046									
36	W 11.68 % ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	592,253						
37	W Increased ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	598,801						
38	W 11.68 % ROE	2014	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,708,781						
39	W Increased ROE	2014	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,884,013						
40	W 11.68 % ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,296,391				-	-	-
41	W Increased ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,859,053				-	-	-
42	W 11.68 % ROE	2016	347,072,992	8,805,472	48,529,997	615,905,487	12,804,341	73,330,415	352,027,464	8,381,606	48,665,417	178,685,539	2,436,719	14,148,115
43	W Increased ROE	2016	347,072,992	8,805,472	48,529,997	615,905,487	12,804,341	74,236,857	352,027,464	8,381,606	49,268,709	178,685,539	2,436,719	14,148,115
44	W 11.68 % ROE	2017	338,731,158	8,813,920	46,192,451	597,948,245	14,904,549	80,887,339	351,791,077	8,375,978	47,195,653	173,780,513	4,177,297	23,318,838
45	W Increased ROE	2017	338,731,158	8,813,920	46,192,451	597,948,245	14,904,549	81,902,152	351,791,077	8,375,978	47,792,699	173,780,513	4,177,297	23,318,838
46	W 11.68 % ROE	2018	329,702,206	8,809,690	40,364,207	587,359,389	14,890,244	71,104,128	-	-	-	168,355,336	4,162,710	20,262,866
47	W Increased ROE	2018	329,702,206	8,809,690	40,364,207	587,359,389	14,890,244	71,935,992	-	-	-	168,355,336	4,162,710	20,262,866

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.57%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5		C		Line B less Line A	0.57%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)**	**Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)**	**Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)**	**Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		68,319,997	49,614,813	162,329,270	120,922,525
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,626,667	1,181,305	3,864,983	2,879,108
19	Months in service for depreciation expense from			11.76	11.01	11.05	9.18
20	Year placed in Service (0 if CWIP)			2016	2016	2015	2018

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015							225,037	412	2,441			
41	W Increased ROE	2015							225,037	412	2,441			
42	W 11.68 % ROE	2016	23,849,835	322,903	1,874,846	23,849,835	322,903	1,874,846	349,923	8,202	47,577			
43	W Increased ROE	2016	23,849,835	322,903	1,874,846	23,849,835	322,903	1,874,846	349,923	8,202	47,577			
44	W 11.68 % ROE	2017	24,121,486	572,715	3,199,550	24,121,486	572,715	3,199,550	15,071,025	193,511	1,090,341			
45	W Increased ROE	2017	24,121,486	572,715	3,199,550	24,121,486	572,715	3,199,550	15,071,025	193,511	1,090,341			
46	W 11.68 % ROE	2018	67,424,378	1,472,017	7,311,454	48,719,195	1,000,282	4,948,493	162,127,145	3,286,469	16,480,496	120,922,525	2,033,349	10,206,715
47	W Increased ROE	2018	67,424,378	1,472,017	7,311,454	48,719,195	1,000,282	4,948,493	162,127,145	3,286,469	16,480,496	120,922,525	2,033,349	10,206,715

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

Line		Formula Line		
1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		63,112,389	49,352,658	88,981,836	45,611,902
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,502,676	1,175,063	2,118,615	1,085,998
19	Months in service for depreciation expense from			9.39	10.22	10.37	12.64
20	Year placed in Service (0 if CWIP)			2018	2015	2015	2015

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21														
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015				225,037	412	2,441	225,037	412	2,441	225,037	412	2,441
41	W Increased ROE	2015				225,037	412	2,441	225,037	412	2,441	225,037	412	2,441
42	W 11.68 % ROE	2016				349,923	8,202	47,577	349,923	8,202	47,577	723,468	12,273	71,227
43	W Increased ROE	2016				349,923	8,202	47,577	349,923	8,202	47,577	723,468	12,273	71,227
44	W 11.68 % ROE	2017				48,229,026	259,831	1,464,046	15,071,025	193,511	1,090,341	24,740,340	338,724	1,908,566
45	W Increased ROE	2017				48,229,026	259,831	1,464,046	15,071,025	193,511	1,090,341	24,740,340	338,724	1,908,566
46	W 11.68 % ROE	2018	63,112,389	1,084,893	5,445,790	49,084,212	924,196	4,618,938	88,779,710	1,690,667	8,471,130	45,260,492	1,055,752	5,266,819
47	W Increased ROE	2018	63,112,389	1,084,893	5,445,790	49,084,212	924,196	4,618,938	88,779,710	1,690,667	8,471,130	45,260,492	1,055,752	5,266,819

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

Line		Formula Line		
1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)**	**Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)**	**Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)**	**Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)**
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		45,611,902	45,234,044	45,234,044	38,401,188
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,085,998	1,077,001	1,077,001	914,314
19	Months in service for depreciation expense from			12.64	12.96	12.96	11.44
20	Year placed in Service (0 if CWIP)			2015	2015	2015	2016

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21														
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441			
41	W Increased ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441			
42	W 11.68 % ROE	2016	723,468	12,273	71,227	723,468	12,273	71,227	723,468	12,273	71,227	28,441,681	387,893	2,252,189
43	W Increased ROE	2016	723,468	12,273	71,227	723,468	12,273	71,227	723,468	12,273	71,227	28,441,681	387,893	2,252,189
44	W 11.68 % ROE	2017	24,740,340	338,724	1,908,566	36,209,684	485,767	2,737,100	36,209,684	485,767	2,737,100	28,907,314	688,967	3,843,966
45	W Increased ROE	2017	24,740,340	338,724	1,908,566	36,209,684	485,767	2,737,100	36,209,684	485,767	2,737,100	28,907,314	688,967	3,843,966
46	W 11.68 % ROE	2018	45,260,492	1,055,752	5,266,819	44,735,591	1,073,403	5,340,569	44,735,591	1,073,403	5,340,569	37,324,329	804,914	3,949,660
47	W Increased ROE	2018	45,260,492	1,055,752	5,266,819	44,735,591	1,073,403	5,340,569	44,735,591	1,073,403	5,340,569	37,324,329	804,914	3,949,660

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.57%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5		C		Line B less Line A	0.57%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.

Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)**	**New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)**	**New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)**	**New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		24,812,999	26,819,837	26,819,837	15,574,675
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		590,786	638,568	638,568	370,826
19	Months in service for depreciation expense from			12.99	13.00	13.00	12.95
20	Year placed in Service (0 if CWIP)			2016	2016	2016	2015

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015										225,037	412	2,441
41	W Increased ROE	2015										225,037	412	2,441
42	W 11.68 % ROE	2016	23,849,835	322,903	1,874,846	27,523,727	407,034	2,363,328	27,523,727	407,034	2,363,328	349,923	4,465	25,899
43	W Increased ROE	2016	23,849,835	322,903	1,874,846	27,523,727	407,034	2,363,328	27,523,727	407,034	2,363,328	349,923	4,465	25,899
44	W 11.68 % ROE	2017				25,328,064	610,761	3,405,679	25,328,064	610,761	3,405,679	15,071,025	193,511	1,090,341
45	W Increased ROE	2017				25,328,064	610,761	3,405,679	25,328,064	610,761	3,405,679	15,071,025	193,511	1,090,341
46	W 11.68 % ROE	2018	24,490,096	590,341	2,932,429	25,802,041	638,561	3,107,951	25,802,041	638,561	3,107,951	15,376,287	369,378	1,835,238
47	W Increased ROE	2018	24,490,096	590,341	2,932,429	25,802,041	638,561	3,107,951	25,802,041	638,561	3,107,951	15,376,287	369,378	1,835,238

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
		Formula Line			
3	A	152	Net Plant Carrying Charge without Depreciation		9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		10.14%
5	C		Line B less Line A		0.57%
6	**FCR if a CIAC**				
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		15,574,675	20,678,337	15,251,024	12,087,537
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		370,826	492,341	363,120	287,798
19	Months in service for depreciation expense from			12.95	12.13	10.55	13.00
20	Year placed in Service (0 if CWIP)			2015	2017	2018	2015

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015	225,037	412	2,441							11,980,348	216,491	1,282,387
41	W Increased ROE	2015	225,037	412	2,441							11,980,348	216,491	1,282,387
42	W 11.68 % ROE	2016	349,923	4,743	27,513	2,241,267	24,426	141,823				11,871,005	287,798	1,646,241
43	W Increased ROE	2016	349,923	4,743	27,513	2,241,267	24,426	141,823				11,871,005	287,798	1,646,241
44	W 11.68 % ROE	2017	15,071,025	193,511	1,090,341	58,015,888	871,281	4,909,357				11,583,195	287,722	1,565,912
45	W Increased ROE	2017	15,071,025	193,511	1,090,341	58,015,888	871,281	4,909,357				11,583,195	287,722	1,565,912
46	W 11.68 % ROE	2018	15,376,009	369,378	1,835,212	19,782,631	459,518	2,226,613	15,251,024	294,694	1,479,264	11,295,526	287,798	1,368,849
47	W Increased ROE	2018	15,376,009	369,378	1,835,212	19,782,631	459,518	2,226,613	15,251,024	294,694	1,479,264	11,295,526	287,798	1,368,849

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

		Formula Line		
1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

		Details		Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		19,272,633	34,729,740	32,027,160	-
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		458,872	826,899	762,551	-
19	Months in service for depreciation expense from			13.00	13.00	13.00	-
20	Year placed in Service (0 if CWIP)			2015	2016	2015	2015

			Mickleton-Gloucester 230kV Circuit (B2139)			Ridge Road 69kV Breaker Station (B1255)			Cox's Corner-Lumberton 230kV Circuit (B1787)			Sewaren Switch 230kV Conversion (B2276)		
21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015	18,260,361	232,128	1,375,013	-	-	-	17,370,246	185,057	1,096,185	13,591,177	156,762	928,580
41	W Increased ROE	2015	18,260,361	232,128	1,375,013	-	-	-	17,370,246	185,057	1,096,185	13,591,177	156,762	928,580
42	W 11.68 % ROE	2016	19,039,119	458,839	2,637,556	4,024,723	95,827	556,391	32,167,824	770,307	4,451,390	118,288,759	2,820,131	16,356,354
43	W Increased ROE	2016	19,039,119	458,839	2,637,556	4,024,723	95,827	556,391	32,167,824	770,307	4,451,390	118,288,759	2,820,131	16,356,354
44	W 11.68 % ROE	2017	18,357,357	452,946	2,478,656	35,212,643	267,164	1,488,600	30,829,183	755,191	4,157,150	116,563,457	2,815,636	15,669,479
45	W Increased ROE	2017	18,357,357	452,946	2,478,656	35,212,643	267,164	1,488,600	30,829,183	755,191	4,157,150	116,563,457	2,815,636	15,669,479
46	W 11.68 % ROE	2018	18,128,720	458,872	2,193,902	34,366,749	826,899	4,116,007	30,316,606	762,551	3,664,036	-	-	-
47	W Increased ROE	2018	18,128,720	458,872	2,193,902	34,366,749	826,899	4,116,007	30,316,606	762,551	3,664,036	-	-	-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

Line		Formula Line		
1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

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Line		Details		**Install Conemaugh 250MVAR Cap Bank (B0376)**	**Reconfigure Kearny- Loop in P2216 Ckt (B1589)**	**Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)**	**350 MVAR Reactor Hopatcong 500kV (B2702)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		1,108,058	21,487,134	146,250,715	21,301,080
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		26,382	511,598	3,482,160	507,169
19	Months in service for depreciation expense from			13.00	8.30	8.04	6.99
20	Year placed in Service (0 if CWIP)			2016	2018	2017	2018

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015												
41	W Increased ROE	2015												
42	W 11.68 % ROE	2016	1,108,058	26,382	153,181									
43	W Increased ROE	2016	1,108,058	26,382	153,181									
44	W 11.68 % ROE	2017												
45	W Increased ROE	2017												
46	W 11.68 % ROE	2018	1,081,675	26,382	129,905	21,487,134	326,604	1,639,441	146,250,715	2,154,587	10,815,286	21,301,080	272,673	1,368,726
47	W Increased ROE	2018	1,081,675	26,382	129,905	21,487,134	326,604	1,639,441	146,250,715	2,154,587	10,815,286	21,301,080	272,673	1,368,726

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

Line		Formula Line		
1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if not a CIAC**			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Susquehanna Roseland < 500KV (B0489.4) (CWIP)**	**Susquehanna Roseland >= 500kV (B0489) (CWIP)**	**North Central Reliability (West Orange Conversion) (B1154) (CWIP)**	**Mickleton-Gloucester-Camden(B1398-B1398.7) (CWIP)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		125	125	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.28%	10.28%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-	-	-	-
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-	-	-	-
19	Months in service for depreciation expense from						
20	Year placed in Service (0 if CWIP)						

Line			Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008				8,927,082		819,421						
27		W Increased ROE	2008				8,927,082		858,682						
28		W 11.68 % ROE	2009	8,601,534		794,647	33,993,795		3,927,226						
29		W Increased ROE	2009	8,601,534		833,737	33,993,795		4,120,411						
30		W 11.68 % ROE	2010	10,121,290		1,719,499	83,961,998		10,780,919						
31		W Increased ROE	2010	10,121,290		1,811,185	83,961,998		11,355,769						
32		W 11.68 % ROE	2011	30,831,150		3,376,923	133,618,838		19,674,374	19,588,655		1,299,846	1,648,851		56,106
33		W Increased ROE	2011	30,831,150		3,565,874	133,618,838		20,775,227	19,588,655		1,299,846	1,648,851		56,106
34		W 11.68 % ROE	2012	38,077,851		5,359,127	264,235,891		27,190,938	139,052,337		10,137,161	22,706,717		1,587,335
35		W Increased ROE	2012	38,077,851		5,676,479	264,235,891		28,801,108	139,052,337		10,137,161	22,706,717		1,587,335
36		W 11.68 % ROE	2013	40,538,248		5,381,625	567,928,477		56,420,758	79,292,223		21,408,869	117,558,986		7,924,475
37		W Increased ROE	2013	40,538,248		5,730,133	567,928,477		60,074,507	79,292,223		21,408,869	117,558,986		7,924,475
38		W 11.68 % ROE	2014	12,476,737		1,537,307	34,481,067		28,945,163	31,617,517		3,895,715	160,260,925		16,099,944
39		W Increased ROE	2014	12,476,737		1,646,580	34,481,067		31,002,624	31,617,517		3,895,715	160,260,925		16,099,944
40		W 11.68 % ROE	2015	-		-	15,544,417		1,822,213	-		-	81,558,947		9,560,846
41		W Increased ROE	2015	-		-	15,544,417		1,955,563	-		-	81,558,947		9,560,846
42		W 11.68 % ROE	2016	-		-	-		-	-		-	-		-
43		W Increased ROE	2016	-		-	-		-	-		-	-		-
44		W 11.68 % ROE	2017	-		-	-		-	-		-	-		-
45		W Increased ROE	2017	-		-	-		-	-		-	-		-
46		W 11.68 % ROE	2018	-		-	-		-	-		-	-		-
47		W Increased ROE	2018	-		-	-		-	-		-	-		-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
		Formula Line			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%	
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%	
5	C		Line B less Line A	0.57%	
6	**FCR if a CIAC**				
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%	

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9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	25
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.71%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-	-	-	-
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-	-	-	-
19	Months in service for depreciation expense from						
20	Year placed in Service (0 if CWIP)						

Line		Invest Yr	Mickleton Ending	Mickleton Depreciation or Amortization	Mickleton Revenue	Burlington (B1156) Ending	Burlington (B1156) Depreciation or Amortization	Burlington (B1156) Revenue	Burlington (B1156.13-B1156.20) Ending	Burlington (B1156.13-B1156.20) Depreciation or Amortization	Burlington (B1156.13-B1156.20) Revenue	Northeast Grid Ending	Northeast Grid Depreciation or Amortization	Northeast Grid Revenue
21														
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011				22,089,378		1,874,440						
33	W Increased ROE	2011				22,089,378		1,874,440						
34	W 11.68 % ROE	2012	532,375		24,600	128,653,138		10,501,318	9,231,712		791,084	81,587,177		6,341,372
35	W Increased ROE	2012	532,375		24,600	128,653,138		10,501,318	9,231,712		791,084	81,587,177		6,416,475
36	W 11.68 % ROE	2013	532,375		73,965	155,344,760		22,819,788	8,854,018		1,275,855	184,611,449		18,512,179
37	W Increased ROE	2013	532,375		73,965	155,344,760		22,819,788	8,854,018		1,275,855	184,611,449		18,751,945
38	W 11.68 % ROE	2014	532,375		65,596	56,976,438		7,020,285	3,745,932		461,551	211,553,988		28,743,491
39	W Increased ROE	2014	532,375		65,596	56,976,438		7,020,285	3,745,932		461,551	211,553,988		29,152,116
40	W 11.68 % ROE	2015	204,760		24,003	-		-	-		-	232,789,181		31,313,982
41	W Increased ROE	2015	204,760		24,003	-		-	-		-	232,789,181		31,772,294
42	W 11.68 % ROE	2016	-		-	-		-	-		-	103,162,268		11,805,242
43	W Increased ROE	2016	-		-	-		-	-		-	103,162,268		11,982,038
44	W 11.68 % ROE	2017	-		-	-		-	-		-	-		-
45	W Increased ROE	2017	-		-	-		-	-		-	-		-
46	W 11.68 % ROE	2018	-		-	-		-	-		-	-		-
47	W Increased ROE	2018	-		-	-		-	-		-	-		-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

Line		Formula Line		
1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)**	**Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)**	**Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)**	**Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)**
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		25	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.71%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-	327,500	3,373,416	4,386,778
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-	7,798	80,319	104,447
19	Months in service for depreciation expense from				13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)						

Line			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
21															
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012	5,537,185		457,198									
35		W Increased ROE	2012	5,537,185		462,613									
36		W 11.68 % ROE	2013	18,052,410		1,627,531									
37		W Increased ROE	2013	18,052,410		1,648,610									
38		W 11.68 % ROE	2014	33,293,621		3,699,551	9,496,612		391,383	1,589,541		61,526	1,531,032		58,653
39		W Increased ROE	2014	33,293,621		3,752,145	9,496,612		391,383	1,589,541		61,526	1,531,032		58,653
40		W 11.68 % ROE	2015	31,157,349		2,302,742	79,833,944		3,818,309	14,281,935		836,684	14,081,213		819,896
41		W Increased ROE	2015	31,157,349		2,336,445	79,833,944		3,818,309	14,281,935		836,684	14,081,213		819,896
42		W 11.68 % ROE	2016	35,334,506		4,043,459	518,235		5,126,158	11,570,665		857,240	2,658,598		921,870
43		W Increased ROE	2016	35,334,506		4,104,014	518,235		5,126,158	11,570,665		857,240	2,658,598		921,870
44		W 11.68 % ROE	2017	-		-	2,271,018		519,803	23,927,668		2,300,724	13,263,928		1,087,121
45		W Increased ROE	2017	-		-	2,271,018		519,803	23,927,668		2,300,724	13,263,928		1,087,121
46		W 11.68 % ROE	2018	-		-	327,500		31,344	3,373,416		322,857	4,386,778		419,841
47		W Increased ROE	2018	-		-	327,500		31,344	3,373,416		322,857	4,386,778		419,841

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.57%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5		C		Line B less Line A	0.57%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

				Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	**Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)**	**Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)**	**Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)**
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		20,653,909	30,394,186	14,893,653	8,794,765
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		491,760	723,671	354,611	209,399
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)						

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	2,114,342		74,197	1,476,460		58,912	838,906		41,991	433,918		21,259
39	W Increased ROE	2014	2,114,342		74,197	1,476,460		58,912	838,906		41,991	433,918		21,259
40	W 11.68 % ROE	2015	7,520,100		530,656	1,567,639		105,699	3,286,307		178,025	3,386,828		209,207
41	W Increased ROE	2015	7,520,100		530,656	1,567,639		105,699	3,286,307		178,025	3,386,828		209,207
42	W 11.68 % ROE	2016	65,119,433		3,473,891	36,960,137		1,695,242	24,980,240		1,011,439	14,073,743		749,927
43	W Increased ROE	2016	65,119,433		3,473,891	36,960,137		1,695,242	24,980,240		1,011,439	14,073,743		749,927
44	W 11.68 % ROE	2017	103,139,173		8,457,930	100,004,406		7,165,306	50,261,443		4,476,177	4,257,610		1,981,744
45	W Increased ROE	2017	103,139,173		8,457,930	100,004,406		7,165,306	50,261,443		4,476,177	4,257,610		1,981,744
46	W 11.68 % ROE	2018	20,653,909		1,976,705	30,394,186		2,908,909	14,893,653		1,425,414	8,794,765		841,713
47	W Increased ROE	2018	20,653,909		1,976,705	30,394,186		2,908,909	14,893,653		1,425,414	8,794,765		841,713

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if if not a CIAC**

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

Line		Formula Line		
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		13,879,908	84,069	80,847	(0)
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		330,474	2,002	1,925	(0)
19	Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00	13.00	13.00	
20							

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	1,370,003		56,093	597,317		24,145	597,317		24,145	569,297		24,114
39	W Increased ROE	2014	1,370,003		56,093	597,317		24,145	597,317		24,145	569,297		24,114
40	W 11.68 % ROE	2015	7,110,556		414,795	4,018,145		249,912	4,018,145		249,912	3,852,871		236,839
41	W Increased ROE	2015	7,110,556		414,795	4,018,145		249,912	4,018,145		249,912	3,852,871		236,839
42	W 11.68 % ROE	2016	45,554,419		2,311,095	21,015,450		1,295,020	21,015,450		1,295,020	22,912,843		1,342,797
43	W Increased ROE	2016	45,554,419		2,311,095	21,015,450		1,295,020	21,015,450		1,295,020	22,912,843		1,342,797
44	W 11.68 % ROE	2017	55,639,039		5,480,161	53,134		937,564	53,134		937,564	11,129,698		1,228,147
45	W Increased ROE	2017	55,639,039		5,480,161	53,134		937,564	53,134		937,564	11,129,698		1,228,147
46	W 11.68 % ROE	2018	13,879,908		1,328,392	84,069		8,046	80,847		7,738	(0)		-
47	W Increased ROE	2018	13,879,908		1,328,392	84,069		8,046	80,847		7,738	(0)		-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)**	**Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)**	**Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)**	**New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)**
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		(0)	1,421,804	7,334	352,578
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		(0)	33,852	175	8,395
19	Months in service for depreciation expense from				13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)						

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	569,297		24,114	1,581,597		63,898	1,286,903		48,434	4,799,334		220,160
39	W Increased ROE	2014	569,297		24,114	1,581,597		63,898	1,286,903		48,434	4,799,334		220,160
40	W 11.68 % ROE	2015	3,852,871		236,839	14,750,089		849,382	13,603,685		780,003	20,855,739		1,506,352
41	W Increased ROE	2015	3,852,871		236,839	14,750,089		849,382	13,603,685		780,003	20,855,739		1,506,352
42	W 11.68 % ROE	2016	22,912,843		1,342,797	946,989		868,195	34,036		704,952	210,981		908,856
43	W Increased ROE	2016	22,912,843		1,342,797	946,989		868,195	34,036		704,952	210,981		908,856
44	W 11.68 % ROE	2017	11,129,698		1,228,147	2,422,164		197,896	777,902		85,840	1,212,870		130,718
45	W Increased ROE	2017	11,129,698		1,228,147	2,422,164		197,896	777,902		85,840	1,212,870		130,718
46	W 11.68 % ROE	2018	(0)		-	1,421,804		136,075	7,334		702	352,578		33,744
47	W Increased ROE	2018	(0)		-	1,421,804		136,075	7,334		702	352,578		33,744

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

		Details		**New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)**	**New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)**	**New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)**	**New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)**
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		352,578	7,678	7,678	1,673,479
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,395	183	183	39,845
19	Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00	13.00	13.00	13.00
20							

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	5,002,105		223,171	123,509		4,946	124,051		4,952	337,481		13,854
39	W Increased ROE	2014	5,002,105		223,171	123,509		4,946	124,051		4,952	337,481		13,854
40	W 11.68 % ROE	2015	21,058,511		1,530,122	2,601,853		148,281	2,602,395		148,345	2,972,226		101,157
41	W Increased ROE	2015	21,058,511		1,530,122	2,601,853		148,281	2,602,395		148,345	2,972,226		101,157
42	W 11.68 % ROE	2016	96,330		915,296	9,752,687		597,380	9,750,168		597,124	35,618,949		2,125,894
43	W Increased ROE	2016	96,330		915,296	9,752,687		597,380	9,750,168		597,124	35,618,949		2,125,894
44	W 11.68 % ROE	2017	1,241,892		133,921	4,472,474		493,532	4,472,773		493,565	15,327,955		1,691,419
45	W Increased ROE	2017	1,241,892		133,921	4,472,474		493,532	4,472,773		493,565	15,327,955		1,691,419
46	W 11.68 % ROE	2018	352,578		33,744	7,678		735	7,678		735	1,673,479		160,162
47	W Increased ROE	2018	352,578		33,744	7,678		735	7,678		735	1,673,479		160,162

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes
12	Useful life of the project	Life		42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		1,914,773
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		45,590
19	Months in service for depreciation expense from			13.00
20	Year placed in Service (0 if CWIP)			

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Total	Incentive Charged	Revenue Credit	
22	W 11.68 % ROE	2006				$ 4,652,471		$ 4,652,471	
23	W Increased ROE	2006				$ 4,652,471	$ 4,652,471		$ -
24	W 11.68 % ROE	2007				$ 29,476,571		$ 29,476,571	
25	W Increased ROE	2007				$ 29,476,571	$ 29,476,571		$ -
26	W 11.68 % ROE	2008				$ 32,346,385		$ 32,346,385	
27	W Increased ROE	2008				$ 32,385,646	$ 32,385,646		$ 39,261
28	W 11.68 % ROE	2009				$ 51,356,608		$ 51,356,608	
29	W Increased ROE	2009				$ 51,588,883	$ 51,588,883		$ 232,275
30	W 11.68 % ROE	2010				$ 61,349,032		$ 61,349,032	
31	W Increased ROE	2010				$ 62,015,568	$ 62,015,568		$ 666,536
32	W 11.68 % ROE	2011				$ 78,438,322		$ 78,438,322	$ -
33	W Increased ROE	2011				$ 79,823,709	$ 79,823,709		$ 1,385,386
34	W 11.68 % ROE	2012				$ 129,728,618		$ 129,728,618	
35	W Increased ROE	2012				$ 131,858,773	$ 131,858,773		$ 2,130,155
36	W 11.68 % ROE	2013				$ 279,708,533		$ 279,708,533	
37	W Increased ROE	2013				$ 284,314,797	$ 284,314,797		$ 4,606,265
38	W 11.68 % ROE	2014	133,460		5,677	$ 342,977,142		$ 342,977,142	
39	W Increased ROE	2014	133,460		5,677	$ 349,823,024	$ 349,823,024		$ 6,845,883
40	W 11.68 % ROE	2015	258,129		20,804	$ 434,110,713		$ 434,110,713	
41	W Increased ROE	2015	258,129		20,804	$ 441,614,467	$ 441,614,467		$ 7,503,754
42	W 11.68 % ROE	2016	2,173,541		157,609	$ 558,001,204		$ 558,001,204	
43	W Increased ROE	2016	2,173,541		157,609	$ 566,080,859	$ 566,080,859		$ 8,079,655
44	W 11.68 % ROE	2017	14,065,098		934,008	$ 576,209,051		576,209,051	
45	W Increased ROE	2017	14,065,098		934,008	$ 583,935,997	$ 583,935,997		$ 7,726,945
46	W 11.68 % ROE	2018	1,914,773		183,255	$ 506,060,336		$ 506,060,336	
47	W Increased ROE	2018	1,914,773		183,255	$ 511,849,690	$ 511,849,690		$ 5,789,354

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 8 - Depreciation Rates

Plant Type	PSE&G
Transmission	2.40
Distribution	
High Voltage Distribution	2.49
Meters	2.49
Line Transformers	2.49
All Other Distribution	2.49
General & Common	
Structures and Improvements	1.40
Office Furniture	5.00
Office Equipment	25.00
Computer Equipment	14.29
Personal Computers	33.33
Store Equipment	14.29
Tools, Shop, Garage and Other Tangible Equipment	14.29
Laboratory Equipment	20.00
Communications Equipment	10.00
Miscellaneous Equipment	14.29

Public Service Electric and Gas Company
Projected Costs of Plant in Forecasted Rate Base and In-Service Dates
12 Months Ended December 31, 2018

Required Transmission Enhancements

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2018) *	Anticipated/Actual In-Service Date *
b0130	Replace all derated Branchburg 500/230 kv transformers	$ 20,645,602	Jan-06
b0134	Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	$ 8,069,022	Aug-07
b0145	Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	$ 86,467,721	Aug-07
b0411	Install 4th 500/230 kV transformer at New Freedom	$ 22,188,863	May-09
b0498	Loop the 5021 circuit into New Freedom 500 kV substation	$ 27,005,248	May-09
b0161	Install 230-138kV transformer at Metuchen substation	$ 25,654,455	Nov-08
b0169	Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	$ 15,731,554	May-08
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	$ 6,961,495	May-09
b0274	Replace both 230/138 kV transformers at Roseland	$ 21,014,433	Apr-12
b0172.2	Replace wave trap at Branchburg 500kV substation	$ 27,988	Feb-07
b0813	Reconductor Hudson - South Waterfront 230kV circuit	$ 9,158,918	May-12
b1017	Reconductor South Mahwah 345 kV J-3410 Circuit	$ 20,626,991	Dec-12
b1018	Reconductor South Mahwah 345 kV K-3411 Circuit	$ 21,170,273	May-11
b0290	Branchburg 400 MVAR Capacitor	$ 77,352,830	Nov-10
b0472	Saddle Brook - Athenia Upgrade Cable	$ 14,404,842	Nov-08
b0664-b0665	Branchburg-Somerville-Flagtown Reconductor	$ 18,664,931	Apr-12
b0668	Somerville -Bridgewater Reconductor	$ 6,390,403	Apr-12
b0814	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	$ 46,035,637	Dec-10
b1410-b1415	Replace Salem 500 kV breakers	$ 15,865,267	Oct-12
b1228	230kV Lawrence Switching Station Upgrade	$ 21,736,918	May-11
b1155	Branchburg-Middlesex Swich Rack	$ 62,937,256	Dec-11
b1399	Aldene-Springfield Rd. Conversion	$ 72,380,453	Dec-12
b1590	Upgrade Camden-Richmond 230kV Circuit (B1590)	$ 11,276,183	Apr-13
b1588	Uprate EaglePoint-Gloucester 230kV Circuit	$ 12,087,537	May-11
b2139	Build Mickleton-Gloucester Corridor Ultimate Design	$ 19,272,633	Dec-13
b1255	Ridge Road 69kV Breaker Station	$ 34,729,740	Jun-16
b1787	New Cox's Corner-Lumberton 230kV Circuit	$ 32,027,160	Nov-13
b0376	Install Conemaugh 250MVAR Cap Bank (B0376)	$ 1,108,058	Mar-16
b1589	Reconfigure Kearny- Loop in P2216 Ckt (B1589)	$ 21,487,134	May-18
b2146	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	$ 146,250,715	Oct-17
b2702	350 MVAR Reactor Hopatcong 500kV (B2702)	$ 21,301,080	Jun-18
b0489.5-b0489.15	Susquehanna Roseland Breakers(In-Service)	$ 5,857,687	Jun-14
b0489.4	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project) (In-Service)	$ 40,538,248	Nov-11
b0489	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project) (In-Service)	$ 720,620,844	Mar-15
b1156	Burlington - Camden 230kV Conversion (In-Service)	$ 356,333,540	Oct-14
b1398 - b1398.7	Mickleton-Gloucester-Camden(In-Service)	$ 439,384,743	Jun-15
b1154	North Central Reliability (West Orange Conversion) (In-Service)	$ 370,006,995	Jun-15
b1304.1-b1304.4	Northeast Grid Reliability Project (In-Service)	$ 625,390,228	Jun-15
b2436.10	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	$ 174,969,351	Jan-16
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	$ 68,319,997	May-16
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	$ 49,614,813	May-16
b2436.33	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades	$ 162,329,270	Dec-15
b2436.34	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	$ 120,922,525	Feb-18
b2436.50	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	$ 63,112,389	Mar-18
b2436.60	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	$ 49,352,658	Dec-15
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	$ 26,819,837	May-16
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	$ 26,819,837	May-16
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	$ 15,574,675	Dec-15
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	$ 15,574,675	Dec-15
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	$ 20,678,337	Jul-16
	Total	**$ 4,581,326,904**	

*** May vary from original PJM Data due to updated information.***

Public Service Electric and Gas Company

Accumulated Deferred Income Taxes Using The Proration Methodology - Tax Basis

Amounts reflected in Annual Update Filing

2017 EOY Amount	(2,383,691,531)	A
2018 EOY Amount	(2,597,832,425)	B

Account 282, Transmission Plant-related Liberalized Depreciation, for 2018

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line	Year	Month	Projected Monthly (Increase) In ADIT - Depreciable Tax Basis	Days Outstanding During the Year	Proration Percentage	Monthly Prorated Amount	Cumulative "prorated" ADIT	Beginning & Ending ADIT Balance
1	2017	Dec						(2,383,691,531) A
2	2018	Jan	(23,167,070)	335	91.78%	(21,262,928)	(2,404,954,459)	
3	2018	Feb	(23,640,412)	307	84.11%	(19,883,853)	(2,424,838,312)	
4	2018	Mar	(24,080,123)	276	75.62%	(18,208,531)	(2,443,046,843)	
5	2018	Apr	(25,252,039)	246	67.40%	(17,019,182)	(2,460,066,025)	
6	2018	May	(24,392,170)	215	58.90%	(14,367,991)	(2,474,434,016)	
7	2018	Jun	(24,900,952)	185	50.68%	(12,621,031)	(2,487,055,047)	
8	2018	Jul	(23,470,852)	154	42.19%	(9,902,771)	(2,496,957,818)	
9	2018	Aug	(23,044,552)	123	33.70%	(7,765,698)	(2,504,723,516)	
10	2018	Sep	(23,177,202)	93	25.48%	(5,905,424)	(2,510,628,940)	
11	2018	Oct	(23,569,552)	62	16.99%	(4,003,595)	(2,514,632,535)	
12	2018	Nov	(23,121,902)	32	8.77%	(2,027,126)	(2,516,659,661)	
13	2018	Dec	(23,576,902)	1	0.27%	(64,594)	(2,516,724,255)	
		Total	(285,393,730)			(133,032,724)		

14	Projected 2018 Liberalized Depreciation based on ADIT Proration Methodology:	(133,032,724)
15	Plus: Projected 2018 ADIT associated with Liberalized Deprecation not subject to Proration Methodology:	(81,108,169)
16	Projected 2018 EOY Federal and State Liberalized Depreciation ADIT included in the FERC Formula Filing:	(2,597,832,425) B

Explanations:

Col. 8, Line 1	Represents the estimated beginning plant-related Liberalized Depreciation ADIT balance as of 1/1/2018.
Lines 2 - 13	Represents the Forecasted Rate period (e.g. 2018).
Col. 3	Represents the monthly (increase) additions to the ADIT balance associated with depreciatable tax basis before proration.
Col. 4	Number of days remaining in the year as of and including the last day of the month.
Col. 5	Col. 4 divided by the number of days in the year, 365.
Col. 6	Col. 3 multiplied by Col. 5.
Col. 7	Col. 6 of previous month plus Col. 7; represents the cumulative balance.
Col. 8, Line 14	Total projected plant-related Liberalized Depreciation ADIT related to depreciable tax basis.
Col. 8, Line 15	Projected plant-related Liberalized Depreciation ADIT that is not subjected to the proration rules.
Col. 8, Line 16	Projected Total EOY balance of plant-related Liberalized Depreciation ADIT that is included in the formula rate.

Public Service Electric and Gas Company

Accumulated Deferred Income Taxes Using The Proration Methodology - Tax Basis

Amounts reflected in Annual Update Filing

2017 EOY Amount	(30,864,733)	A
2018 EOY Amount	(36,267,968)	B

Account 282, Common Plant-related Liberalized Depreciation, for 2018

Line	(1) Year	(2) Month	(3) Projected Monthly (Increase) In ADIT - Depreciable Tax Basis	(4) Days Outstanding During the Year	(5) Proration Percentage	(6) Monthly Prorated Amount	(7) Cumulative "prorated" ADIT	(8) Beginning & Ending ADIT Balance
1	2017	Dec						(30,864,733) A
2	2018	Jan	(337,186)	335	91.78%	(309,472)	(31,174,205)	
3	2018	Feb	(337,186)	307	84.11%	(283,606)	(31,457,811)	
4	2018	Mar	(337,186)	276	75.62%	(254,968)	(31,712,779)	
5	2018	Apr	(337,186)	246	67.40%	(227,254)	(31,940,033)	
6	2018	May	(337,186)	215	58.90%	(198,616)	(32,138,649)	
7	2018	Jun	(337,186)	185	50.68%	(170,903)	(32,309,552)	
8	2018	Jul	(337,186)	154	42.19%	(142,265)	(32,451,817)	
9	2018	Aug	(337,186)	123	33.70%	(113,627)	(32,565,444)	
10	2018	Sep	(337,186)	93	25.48%	(85,913)	(32,651,357)	
11	2018	Oct	(337,186)	62	16.99%	(57,275)	(32,708,632)	
12	2018	Nov	(337,186)	32	8.77%	(29,562)	(32,738,194)	
13	2018	Dec	(337,186)	1	0.27%	(924)	(32,739,118)	
		Total	(4,046,234)			(1,874,385)		

Line	Description	Amount
14	Projected 2018 Liberalized Depreciation based on ADIT Proration Methodology:	(1,874,385)
15	Plus: Projected 2018 ADIT associated with Liberalized Deprecation not subject to Proration Methodology:	(3,528,850)
16	Projected 2018 EOY Federal and State Liberalized Depreciation ADIT included in the FERC Formula Filing:	(36,267,968) B

Explanations:

Col. 8, Line 1	Represents the estimated beginning plant-related Liberalized Depreciation ADIT balance as of 1/1/2018.
Lines 2 - 13	Represents the Forecasted Rate period (e.g. 2018).
Col. 3	Represents the monthly (increase) additions to the ADIT balance associated with depreciatable tax basis before proration.
Col. 4	Number of days remaining in the year as of and including the last day of the month.
Col. 5	Col. 4 divided by the number of days in the year, 365.
Col. 6	Col. 3 multiplied by Col. 5.
Col. 7	Col. 6 of previous month plus Col. 7; represents the cumulative balance.
Col. 8, Line 14	Total projected plant-related Liberalized Depreciation ADIT related to depreciable tax basis.
Col. 8, Line 15	Projected plant-related Liberalized Depreciation ADIT that is not subjected to the proration rules.
Col. 8, Line 16	Projected Total EOY balance of plant-related Liberalized Depreciation ADIT that is included in the formula rate.